Energy

Annual Report
2017-2018

Alberta Government

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Acronyms and Notations

AER	Alberta Energy Regulator
AESO	Alberta Electric System Operator
AMI	Alberta Mineral Information
APMC	Alberta Petroleum Marketing Commission
ARP	Alberta Natural Gas Reference Price
AUC	Alberta Utilities Commission
bbl	Barrel
bbl/d	Barrels per day
Bcf/d	Billion cubic feet per day
CARS2	Corporate Accounting and Reporting System
CCS	Carbon Capture and Storage
Cdn$	Canadian Dollar
Cf	Cubic foot
COO	Crude Oil Operations
EDAC	Economic Development Advisory Committee
EFT	Electronic File Transfer
EORP	Enhanced Oil Recovery Program
ER&T	Emerging Resources and Technologies Initiative
ETS	Electronic Transfer System
FIS	Field Surveillance Inspection System
GJ	Gigajoule
ha	Hectare
IDA	Integrated decision approach
IEEP	Incremental Ethane Extraction Program
IMAGIS	Integrated Management Alberta Government Information System
IRMS	Integrated Resource Management System
ISO	International Standards Organization
LAMAS	Land Automated Mineral Agreement System
MGA	Review Municipal Government Act Review
MIM	Metallic and Industrial Minerals
MINRS	Metallic and Industrial Minerals Royalty Revenues
MMV	Plan Measurement, Monitoring and Verification Plan
MRIS	Mineral Revenues Information System
MSA	Market Surveillance Administrator
MW	Megawatt
NEB	National Energy Board
NGTL	TransCanada's NOVA Gas Transmission Ltd.
NWRP	North West Redwater Partnership
OASIS	Oil Sands Administrative and Strategic Information System
OPEC	Organization of the Petroleum Exporting Countries
OWA	Orphan Well Association
PBR	Performance-based regulation
PDP	Petrochemicals Diversification Program
PPA	Power Purchase Agreement
PSAC	Petroleum Services Association of Canada
RAM	Royalty and Marketing System
RECSI	Regional Electricity Cooperation and Strategic Infrastructure Initiative
REP	Renewable Electricity Program
RRO	Regulated Rate Option
SAGD	Steam assisted gravity drainage
SCO	Synthetic Crude Oil
Tcf	Trillion cubic feet
US$	United States Dollar
VoU	Voices of Understanding
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 *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 audited consolidated financial statements 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 Department of Energy, the Alberta Energy Regulator, the Alberta Utilities Commission, the Alberta Petroleum Marketing Commission, the Post-closure Stewardship Fund, and the Balancing Pool;**
- **other financial information as required by the *Financial Administration Act* and *Fiscal Planning and Transparency Act*, either as separate reports or as a part of the financial statements, 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, 2018, 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 6, 2018 with material economic or fiscal implications of which I am aware have been considered in the preparation of this report.

Original signed by Honourable Margaret McCuaig-Boyd
Minister of Energy

Message from the Minister

Global changes in how energy is being produced and consumed provide opportunities for Alberta to be both an energy innovator and climate leader. Our province's transition to a low-emission future will not happen overnight, but we are preparing our energy sector and our economy for this new reality. Whether this derives from our traditional strengths within the oil sands and oil and gas, or new developments in shale resources, petrochemical diversification and renewable electricity generation, our government continues to ensure that Alberta simultaneously combats climate change and supports energy development.

Throughout 2017-18, our government continued to promote and invest in Alberta's renewable and non-renewable energy resources. For generations, they have been part of our economic foundation, contributing jobs, growing businesses and generating revenues to deliver public services such as schools, roads and hospitals. They will continue to play an essential part of our lives as the building blocks that maintain our high standard of living.

We were successful in securing federal approval for the Trans Mountain Pipeline Expansion project thanks in large part to Alberta's Climate Leadership Plan. The pipeline application itself was subject to a rigorous and thorough review before the federal government granted approval. We spoke in support of this project numerous times and sought intervenor status in court actions when possible. We have played by the rules and continue to defend our workers, our economy and our progress on climate action as it relates to Trans Mountain.

On May 29th, the Government of Canada announced that it was purchasing the Trans Mountain pipeline. Alberta supported this purchase because it ensured that construction would resume immediately and because it provided certainty that the pipeline would be completed. We are now closer than ever before to getting this pipeline built and getting a better price for our natural resources.

We also continued to monitor developments on other major pipelines. We were pleased to see construction begin on Enbridge's Line 3 replacement pipeline in 2017, as well as progress on the Keystone XL project. The fact is our economy is losing millions of dollars without this market access. We will continue to stand up for Alberta and the numerous benefits derived from our oil and gas industry.

Over the last year, we have built vital partnerships to lay the groundwork for future success led by Premier Notley promoting Alberta during her 10-day mission to Asia. I also ensured Alberta's oil and gas sector was the focus of my follow-up mission that included Japan, China and South Korea. A highlight of my U.S. missions last year was CERAWeek, a major U.S. energy conference in Houston, where I encouraged investment in Alberta's unconventional oil and gas industry. This included a focus on the vast oil and gas reserves of the Duvernay and Montney shale formations that continue to generate great interest amongst investors.

Closer to home, our strategic investment incentives through the first round of the Petrochemicals Diversification Program were rewarded in 2017. Inter Pipeline confirmed it was proceeding with two new facilities in the Industrial Heartland that will turn 22,000 barrels of propane per day into propylene. The other successful proponent under this program, Canada Kuwait Petrochemical

Corporation, has begun front-end engineering for its proposed integrated propane dehydrogenation and polypropylene facilities. These two projects represent more than $6 billion in new private investment, creating up to 4,200 jobs during construction and more than 240 full-time jobs once the facilities are operational. Building on this success, as well as recommendations from the Energy Diversification Advisory Committee, we introduced the *Energy Diversification Act* to seize upon further opportunities to diversify our economy through petrochemical development.

In 2017, we also took steps to address historic oil and gas liabilities by leveraging $30 million in federal dollars to lend the Orphan Well Association $235 million to speed up the reclamation of abandoned oil and gas well sites. This will create up to 1,650 new jobs over the next three years while maintaining the polluter-pays principle. These measures complement our ongoing review of oil and gas liabilities on the landscape. It also aligns with changes to Alberta Energy Regulator (AER) Directive 067 to empower the AER to provider greater scrutiny to new licence applications, and assess the risks that a new licensee may pose with respect to meeting their clean-up obligations.

On the electricity front, in December 2017 I announced that the first round of our Renewable Electricity Program was successful beyond expectations and generated the lowest renewable electricity pricing ever in Canada. The three companies chosen under this program will invest about $1 billion in green power generation in Alberta totalling approximately 600 megawatts. Building on this success, we launched rounds two and three of the program in March 2018. The second round will provide 300 megawatts of renewable power and includes an Indigenous equity component which will help create jobs and economic benefits in Indigenous communities. Round Three follows the format of Round One and will add approximately 400 megawatts of renewable electricity. In total, the Renewable Electricity Program is expected to attract about $10 billion in new private investment by 2030.

We also passed *An Act to Cap Regulated Electricity Rates* to ensure Alberta families, farms and small businesses on the Regulated Rate Option do not pay more than 6.8 cents per kilowatt hour over a four-year period, ending May 31, 2021. This rate cap protects Albertans by providing them with more stable electricity prices as the province transitions to a cleaner electricity grid and a more stable electricity market.

These are just a few of the highlights of the Ministry of Energy's successes over the past year, which shows that Alberta can be a sustainable, progressive energy producer, balancing energy development with climate leadership. I look forward to continued progress and success in supporting Alberta's energy industry and serving Albertans in 2018-19.

Original signed by Honourable Margaret McCuaig-Boyd
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

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 consolidated financial statements 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 consolidated financial statements and performance results. The consolidated financial statements and the performance results, of necessity, include amounts that are based on estimates and judgments. The consolidated financial statements are prepared in accordance with 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 2017.

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 and 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 Coleen Volk
Deputy Minister
Department of Energy

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

Original signed by Jim Ellis
President and CEO
Alberta Energy Regulator

Original signed by Mark Kolesar
Acting Chair
Alberta Utilities Commission

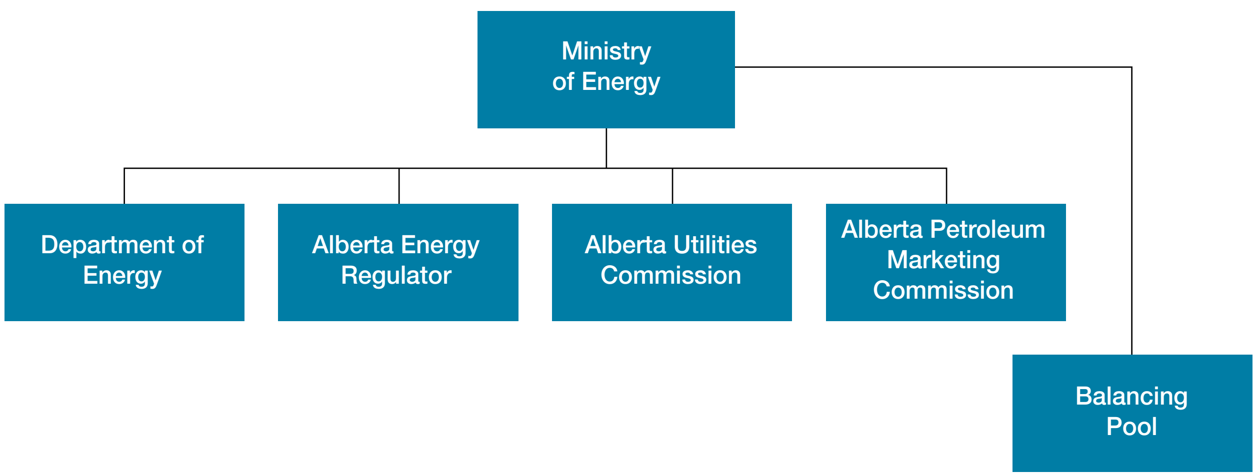
Date: June 6, 2018

Results Analysis

Ministry Overview

The Ministry of Energy manages Alberta's energy resources to ensure they are developed in responsible ways that benefit and bring value to Albertans. The ministry strives to ensure sustained prosperity in the interests of Albertans through the stewardship of energy and mineral resources. Sustained prosperity includes having 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 Post-closure Stewardship Fund and the Balancing Pool. Each entity plays an important role in overseeing the orderly development of Alberta's energy resources.



The outcomes in Energy's 2017-20 Business Plan are:

- Albertans benefit economically from responsible energy and mineral development and access to global markets.
- Effective stewardship and regulation of Alberta's energy and mineral resources.
- Albertans benefit from a stable, reliable electricity system that protects consumers, attracts investment, and has improved environmental performance.

Department of Energy

- Acts as the steward of Alberta's energy resources on behalf of all Albertans
- Develops policy to manage development of Alberta's non-renewable resources, such as conventional and unconventional oil and gas, oil sands, coal and petrochemicals
- Ensures the integration of natural resource policies and serves as an interface between policy development and policy assurance
- Grants industry the ability to explore and develop Alberta's energy and mineral resources
- Collects revenues from the development of Alberta's energy and mineral resources on behalf of Albertans
- Establishes, administers and monitors the effectiveness of Alberta's royalty systems for Crown minerals
- Establishes the framework for responsible industry-led investment in electricity infrastructure and markets for the reliable delivery of electricity to consumers
- Administers the carbon capture and storage Post-closure Stewardship Fund
- Leads Alberta's market access efforts with internal, external and international stakeholders

Alberta Energy Regulator

- Independently makes decisions regarding resource 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
- Provides for the safe, efficient, orderly, and environmentally responsible development of energy resources
- Provides geoscience information, evaluation and advice about the geology of Alberta that is used to support the exploration, resource appraisal, sustainable development, regulation, and conservation of Alberta's resources through the Alberta Geological Survey

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
- Develops commodity prices used in royalty calculations
- Assists with the development of new energy markets and transportation infrastructure
- Manages the implementation of Alberta's Bitumen Royalty-in-Kind policy
- 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

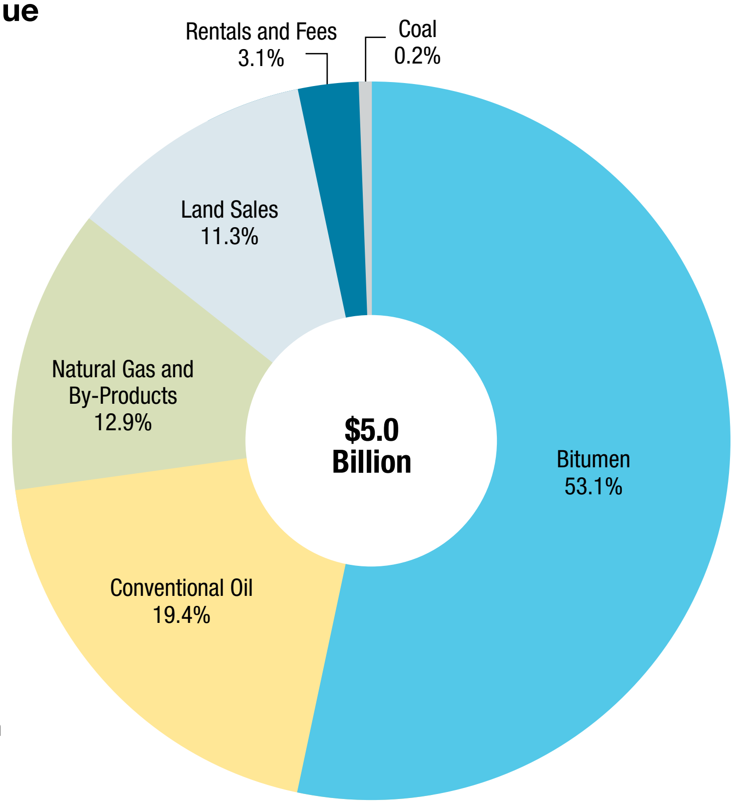
Non-Renewable Resource Revenue

Energy development in Alberta is a key provider of jobs, business opportunities, taxes and royalty revenues that fund important government programs for Albertans. Energy development also drives activity in a number of other industries, including construction and manufacturing, which benefit 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 hydrocarbons that are produced and sold from the province's resources. Albertans, as owners, collect value from our resources through royalties.

Developing Alberta's resources requires a partnership between the province and energy companies. The price received and the costs involved in producing and selling those resources affect the amount of value available for royalties. The following table is a comparison of budgeted and actual revenues generated for fiscal year 2017-18. Non-renewable resource revenues totalled $5.0 billion compared with a budgeted amount of $3.8 billion.



2017-18 Non-Renewable Resource Revenue
Source: Government of Alberta

Revenue ($ Millions)	2017-18 Budget	2017-18 Actual
Bitumen	2,546	2,643
Conventional Oil	476	965
Natural Gas and By-Products	455	645
Land Sales	148	564
Rentals and Fees	117	153
Coal	12	12
Non-Renewable Resource Revenue	**3,754**	**4,980**

Source: Government of Alberta

Note: Numbers do not add up precisely due to rounding.

Bitumen royalties remained the largest contribution to provincial resource royalty revenue. In 2017-18, bitumen revenue totalled $2.6 billion, or 53 per cent of the non-renewable resource revenue. Actual bitumen royalties were about 4 per cent, or $97 million higher than budgeted.

Conventional crude oil royalties contributed $965 million, representing about a fifth of total non-renewable resource revenue in 2017-18. Conventional crude oil royalties were $489 million, or more than twice as much as the budgeted amount due to a slightly narrower differential than budgeted and higher condensate production with improved prices for West Texas Intermediate (WTI) towards the end of the fiscal year.

Natural gas and by-products royalties brought in $645 million and were $190 million, or 42 per cent above the budgeted amount. Prices for natural gas by-products such as propane, butane and pentanes plus follow oil prices. The improved oil prices spurred increased production as companies are trying to maximize natural gas liquids extraction. The Gas Cost Allowance, which is deductible against royalties, was roughly $300 million lower than budgeted, contributing to increases in net royalties. This is as a result of lower costs in response to industry initiatives to improve profitability.

In 2017-18, **bonuses and sales of Crown leases** totalled $564 million, which was $416 million higher than the budgeted amount, or almost four times as much as originally budgeted. The majority of the sales were from petroleum and natural gas, and oil sands leases. The averaged bid price was almost 100 per cent higher than that of 2016-17, and the number of hectares sold was nearly 50 per cent higher. The strong sales are a result of improved interest.

Revenue from **rentals and fees** was $153 million in 2017-18, exceeding the budgeted revenue by $36 million, or 30 per cent. Rentals and fees revenue are tied to sales in the current and the previous four years. The higher than budgeted revenue was mainly due to higher number of hectares and retention rates for leases and licences by industry.

In 2017-18, revenue from coal royalty was on budget at $12 million.

A detailed discussion of the impact of oil and gas prices and production on royalties follows.

Non-Renewable Resource Revenue Forecasting

The department is responsible for forecasting non-renewable resource revenues for the Government of Alberta.

The Government of Alberta's non-renewable revenue forecasts are based on economic conditions at the time of the forecast, anticipated economic growth, non-renewable resource demand trends and expected supply levels. Commonly, the most influential factor affecting non-renewable resource revenue is commodity prices. Other factors such as capital and operating costs, the Canadian-U.S. dollar exchange rate and production also affect royalty revenues. Unanticipated changes in these factors can result in significant differences between the budget forecast and the actual results.

Factors Affecting Royalty Revenue and Forecasting

- Commodity prices
- Capital and operating costs
- Canadian-U.S. dollar exchange rate
- Inflation
- Production rates

Unanticipated changes in these factors can result in significant differences between the budget forecast and the actual results.

The Department of Energy models the complex system to calculate royalties and forecast non-renewable resource revenue. To develop price forecasts, the department uses forecasts by 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 department incorporates the futures market 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.

Non-Renewable Resource Revenue ($ Millions)						
	Actual			Forecast		
	2015-16	2016-17*	2017-18	2018-19	2019-20	2020-21
Total	$2,789	$3,105	$4,980	$3,829	$4,183	$5,001

Source: Government of Alberta
*Reclassified.

Going forward, non-renewable resource revenue is forecast at approximately $3.8 billion in 2018-19, which is $1.2 billion or 23 per cent lower than the actual for 2017-18. The decrease in projected revenue is primarily from lower bitumen royalties, due to a widening of the light-heavy oil price differential, a higher exchange rate forecast, and a more normalized land lease sales relative to the unexpected boost in 2017-18.

The non-renewable resource revenue in 2018-19 is projected to account for eight per cent of total government revenue, and is expected to grow to nine per cent by 2020-21 when resource revenues are forecast to increase to $5.0 billion. During the forecast period from 2018-19 to 2020-21, resource revenue is estimated to increase by an average of 14 per cent per year driven by accelerating bitumen royalties from mildly improving oil prices, rising production and lower costs, in spite of an expected continued wide differential.

Commodity Prices And Trends

Commodity Prices	2017-18 Budget	2017-18 Actual	2018-19 Forecast
WTI (US$/bbl)	55.00	53.69	59.00
Exchange rate	US$0.76	US$0.78	US$0.80
Light-heavy differential (US$/bbl)	16.00	14.40	22.40
WCS (US$/bbl)	39.00	39.29	36.60
ARP for natural gas (Cdn$/GJ)	2.90	1.82	2.00

Source: Government of Alberta

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

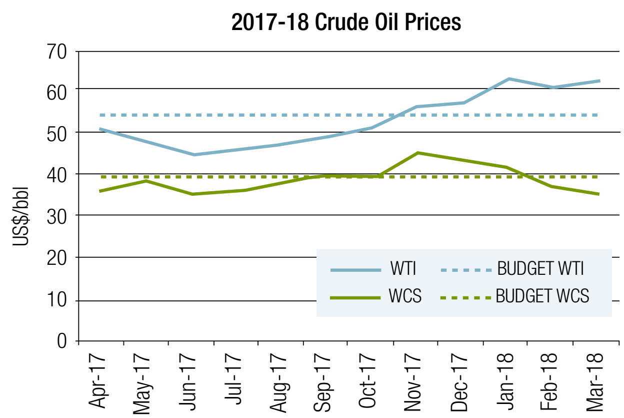
Oil Prices

Oil prices differ depending on crude quality and access to markets. The difference in price is affected by differences in crude quality between light sweet and heavy sour oils, location, market demand for heavy crude, and by access to markets for these products. Alberta exports both light and heavy crude oil. However, the majority of Alberta's oil production growth and oil exports is from heavy crude, whose price per barrel (bbl) is discounted from light sweet prices.

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.

Budget 2017 was based on an estimate of US$55.00 per barrel price for WTI crude oil and an exchange rate of 76 U.S. cents to a Canadian dollar. Crude oil prices have generally been trending up since February 2016, when they hit their lowest monthly level in years.

In late 2016, the Organization of the Petroleum Exporting Countries (OPEC) members and several non-OPEC producers agreed to reduce output by 1.8 million barrels per day (bbl/d), commencing in 2017. On average, WTI prices increased during the first three months of 2017 relative to the previous quarter, supported by the OPEC and non-OPEC agreement on production restraint and solid global demand growth. The higher prices also contributed to increased activity from U.S. producers and created some concerns about the pace of global market re-balancing as crude inventories remained high. This put some downward pressure on prices during the second and third quarters of 2017. During the last quarter of 2017, OPEC and non-OPEC production agreement cuts were extended, and are expected to remain in place until the end of 2018. This, together with continued demand growth, OPEC compliance, supply disruptions from pipeline outages and geopolitical events, as well as reduced global inventories, contributed to an increase in WTI prices during the last quarter of 2017 to US$55.39, or the highest quarterly level since the second quarter of 2015. Most analysts are forecasting that prices will be supported by the OPEC and non-OPEC supply compliance, but restrained by expanding U.S. shale production prompted by the higher prices.

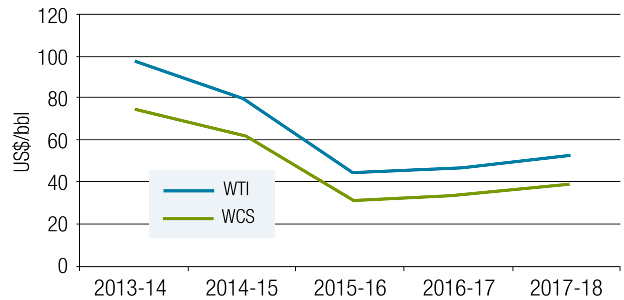


Sources: U.S. Energy Information Administration; Alberta Ministry of Energy

The WCS price in U.S. dollars for the 2017-18 fiscal year was slightly higher than budgeted mainly due to the decision from OPEC to cut crude oil production that was more focused on heavier crude types which increased global and North American heavy oil prices. This is despite the decline in heavy oil prices that took place towards the end of 2017 due to production exceeding available pipeline capacity together with some recent pipeline disruptions and delayed response from crude by rail.

The difference between the WTI and WCS prices is the **light-heavy differential**. When oil pipelines leaving Canada reach full capacity, Canadian oil prices are discounted to reflect a higher rail transportation cost and receive a bigger price discount compared to WTI. This reduces the royalty revenue received by Albertans.

Crude Oil Prices (Five-Year Trend)



Source: Ministry of Energy

The budgeted light-heavy differential was US$16/bbl for 2017-18, resulting in a WCS price of US$39/bbl. The actual light-heavy differential was US$14.40/bbl, which was US$1.60/bbl less than the initial forecast. The actual WCS price averaged US$39.29/bbl in 2017-18, slightly higher than budget as the narrower differential more than offset the lower WTI price.

The WTI price averaged almost US$93/bbl in the four fiscal years 2010-11 to 2013-14, but then declined by approximately 70 per cent, from about US$105/bbl in June 2014 to around US$30/bbl in February 2016. The decline in WTI price was due to a combination of a number of factors, from global supply growth exceeding demand growth, with supply boosted by significant increases including from North American production, continuing increases in global inventories, and demand muted by a slowdown in developing economies. WTI prices increased from US$45.00/bbl in 2015-16 to US$47.94/bbl in 2016-17 after OPEC members and several non-OPEC producers agreed to reduce output by 1.8 million bbl/d, commencing in 2017. The deal has been extended to the end of 2018 providing further support to WTI prices which increased to US$53.69/bbl in 2017-18. It is expected that prices will be supported by the OPEC/non-OPEC deal but restrained by U.S. shale production growth. Overall, prices at the end of 2017 and start of 2018 increased due to decreasing U.S. and OECD inventories, OPEC/non-OPEC supply restraints and increased global demand.

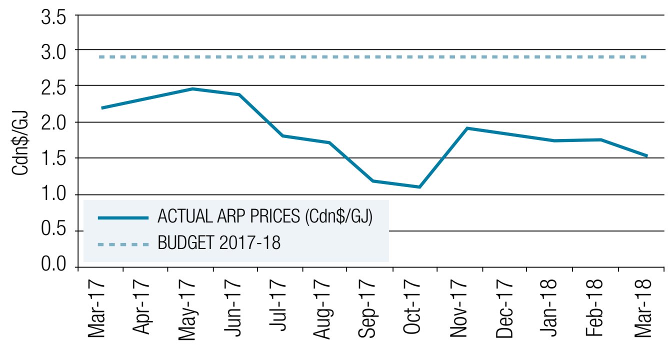
The WCS price saw a considerable decline from almost US$73/bbl during the 2010-11 to 2013-14 fiscal years to US$31.60/bbl in 2015-16. The WCS price has recovered since then averaging US$34.01/bbl in 2016-17 and US$39.29/bbl in 2017-18.

A combination of factors, such as persistent global oversupply, continuing build-ups in global inventories and concerns over demand growth, put significant downward pressure on prices but once global prices start to recover, WCS generally improves as well. WCS price received an additional uplift in 2017 as the decision of OPEC and non-OPEC producers to reduce crude oil production was more focused on heavier crude types. Nonetheless, as crude oil production from Alberta is exceeding available pipeline capacity, WCS prices are expected to remain low despite a projected increase in global crude oil prices.

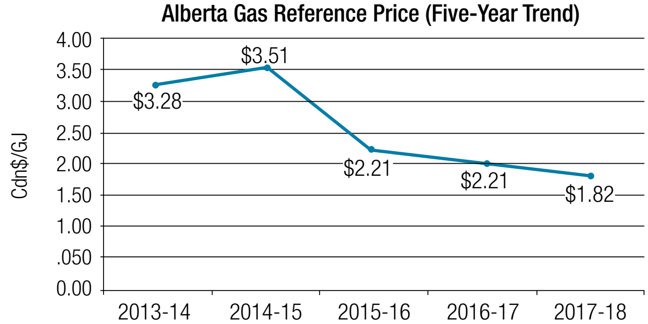
Natural Gas Prices

The **Alberta Natural Gas Reference Price (ARP)** for natural gas is used in natural gas royalty formulas and the royalty rate that will be applied to natural gas.

Overall, the general rule of supply and demand determines natural gas prices in North America. Storage levels and weather patterns affect prices as it impacts 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.



Source: Government of Alberta



Source: Government of Alberta

Despite other North American benchmark natural gas prices firming year-over-year throughout 2017, AECO prices were particularly weak and volatile due to robust U.S. and Canadian production, as well as infrastructure issues in Western Canada. A series of infrastructure outages and maintenance in the TransCanada's NOVA Gas Transmission Ltd. (NGTL) system have backed up supply in the natural gas market, contributing to a worsening of the already oversupplied market. Moreover, TransCanada has started enforcing curtailment rules on the NGTL system since July 2017. The combined impact led AECO prices to be heavily discounted and volatile to other North American benchmark prices in the summer and fall of 2017.

After the significant expansion of shale production in the United States commenced around the 2009-10 fiscal year, Henry Hub natural gas price, which is the North American benchmark, has generally been on a declining trend, due to expectations of a strong North American growth in shale gas production. The production growth in the U.S. Appalachian region has been one of the key contributors to the growth in the North American natural gas supply, displacing Western Canadian Sedimentary Basin supply in its traditional markets. The main exception to the overall downward gas price trend took place in 2014, due to the very cold weather, which provided an uplift for natural gas prices due to a sudden surge in gas demand for heating.

The overall growth in North American gas production has also contributed to a downward push in Canadian gas prices. Domestically, the ARP also followed a downward trend over the 2013-14 to

2017-18 period, with the exception of the 2014-15 fiscal year during which heating demand resulted in significant drains of gas inventory storage. As a result, ARP was pushed up, and this led to an overall increase in the 2014-15 ARP price relative to the previous fiscal year.

In the 2014-15 fiscal year, ARP was at Cdn$3.51/Gigajoule (GJ). It declined every fiscal year thereafter and settled below Cdn$2.00/GJ in 2017-18. In addition to higher overall gas supply in North America, the overall ARP decline was also partially driven by the Canadian gas market developments, such as a strong production in B.C. and Alberta, and in particular, the liquids drilling in Alberta's Montney play. Associated infrastructure and maintenance issues also contributed to the downward ARP trend.

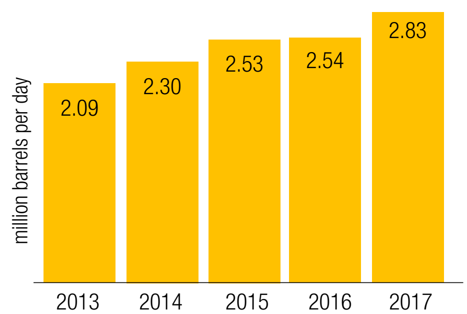
Royalties in Budget 2017 were based on a gas price forecast of Cdn$2.90/GJ for ARP. ARP averaged Cdn$1.82/GJ in the fiscal year 2017-18. The actual gas price was below budgeted levels at the end of the fiscal year due to a combination of pipeline maintenance issues, regional surplus from limited outlets to supply, continued U.S. natural gas production growth, robust Canadian production and TransCanada's curtailment enforcement on its pipeline systems in Western Canada.

Production

Crude Bitumen Production

Crude bitumen production increased by about 12 per cent from 2.54 million bbl/d in 2016 to 2.83 million bbl/d in 2017, and therefore continued an escalating trend that has been underway since 2008. Most of the production increase was due to the completion and ramp-up of oil sands projects that were sanctioned before the crude oil price decline. Additionally, bitumen production recovered from the outages suffered in 2016 due to the Fort McMurray wildfire. The share of crude bitumen production as a percentage of global consumption increased in 2017, to 2.9 per cent from 2.6 per cent in 2016.

Alberta Crude Bitumen Production



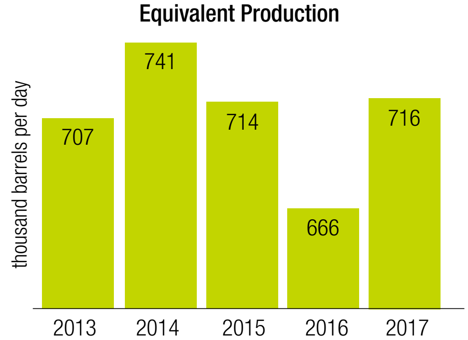
Source: Alberta Energy Regulator

Conventional Crude Oil and Equivalent Production

Production of crude oil and equivalent (condensate and pentanes plus) increased from about 665,800 bbl/d in 2016 to about 715,900 bbl/d in 2017, approximately an eight per cent increase.

Conventional production slightly increased by 0.4 per cent from 2016 to 2017, from about 444,200 bbl/d to about 446,100 bbl/d. The increase in condensate and pentanes plus production continued in 2017; the production went up by

Alberta Conventional Crude and Equivalent Production



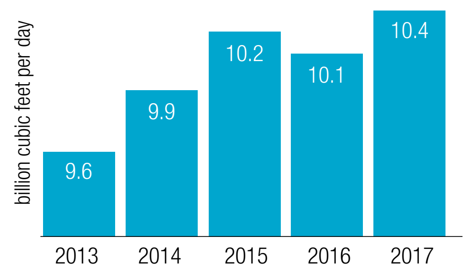
Source: Alberta Energy Regulator

22 per cent from 221,600 bbl/d in 2016 to 269,700 bbl/d in 2017. According to the Alberta Energy Regulator (AER), production of pentanes plus is expected to increase during the forecast period leading up to 2027, as a result of natural gas producers continuing to target condensate.

Natural Gas Production

From 2016 to 2017, marketable natural gas production increased from 10.1 billion cubic feet per day (Bcf/d) in 2016 to 10.4 Bcf/d in 2017, a two per cent increase. According to the AER, the overall increase was driven by the production increases in Petroleum Services Association of Canada (PSAC) area 2, the largest gas producing area in the province; out of the other six areas in the province, only one other area experienced a production increase. PSAC 2 production increases were largely associated with new wells placed on production using horizontal multistage fracturing, which demonstrates the productivity of these wells.

Alberta Marketable Gas Production



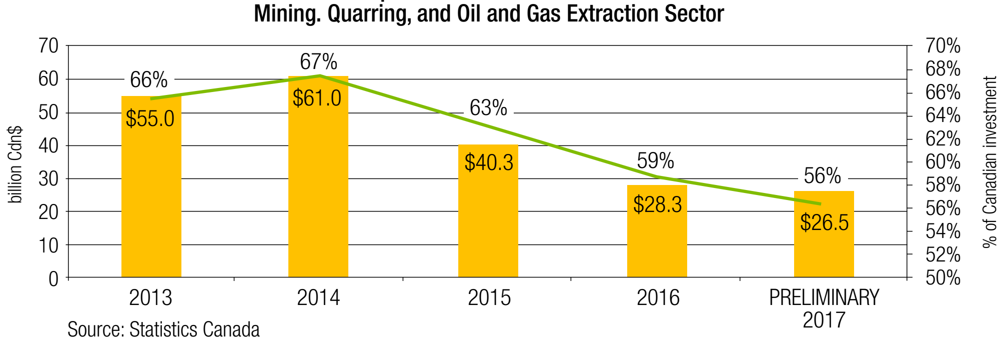
Source: Alberta Energy Regulator

Investment

Industry investment has been vital to the economic performance of the province. 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. This has been more of a challenge following the significant decline in oil prices that took place in late 2014. After hitting an all-time high in 2014, capital investment in this sector has been on a declining trend.

However, industry activity in the province actually increased in 2017 as oil prices significantly increased from the prior year.

Capital Investment in Alberta
Mining. Quarring, and Oil and Gas Extraction Sector



Source: Statistics Canada

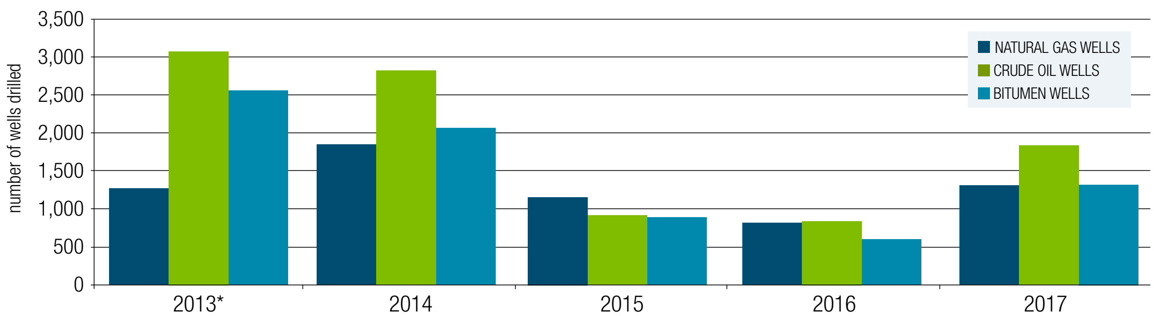
Although investment in Alberta was down substantially from the 2014 level, Alberta still attracted a significant majority of total Canadian investment in the mining, quarrying, and oil and gas extraction industry, and had more investment in this industry than all of the rest of Canada combined. In 2017, Alberta's investment in energy industry accounted for an estimated 56 per cent of the Canadian investment in this industry.

Drilling

The chart below presents drilling activity in Alberta over the 2013-17 period. Wells drilled include both development and exploratory wells. As seen in the chart, the total number of wells drilled in Alberta significantly declined from 2014 to 2016. In 2016, natural gas wells, crude oil wells, and bitumen wells reached their lowest level during the examined period, at 811, 836 and 610, respectively. However, drilling activity significantly re-bounded from 2016 to 2017. Over the 2016-17 period, total successful natural gas wells drilled increased by 60 per cent, from 811 in 2016 to 1,295 in 2017.

Likewise, over the 2016-17 period, total successful crude oil wells drilled increased by 119 per cent, from 836 in 2016 to 1,831 in 2017. Bitumen wells drilled followed a similar trend, increasing by 115 per cent from 610 in 2016 to 1,309 in 2017.

Drilling Activity in Alberta

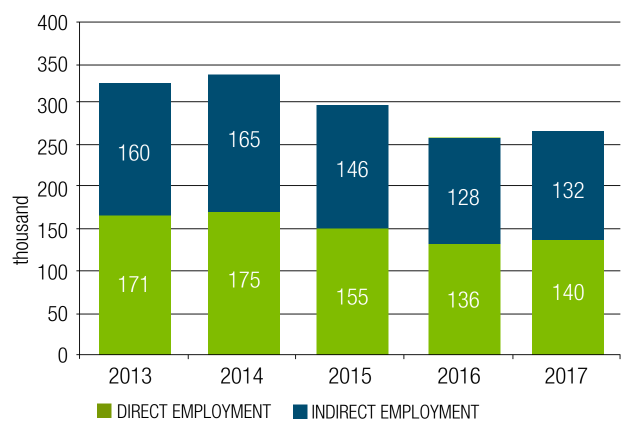


Source: Alberta Energy Regulator
*Amended data

Employment

Upstream energy sector employment has been important to the economic performance of Alberta. Oil prices significantly declined in late 2014, and remained relatively low throughout 2015 and 2016, which had a major impact on employment in Alberta's upstream energy sector. Direct employment, after climbing to about 175,000 people in 2014, declined by 11 per cent from 2014 to 2015, and then declined further by 13 per cent from 2015 to 2016. However, in 2017, the employment in the sector increased by three per cent, the first year-over-year increase in three years.

Employment in Mining, Quarrying, and Oil and Gas Extraction



Source: Statistics Canada

When indirect employment in the mining, quarrying, and oil and gas extraction is taken into account, Alberta's total employment in the sector increased from about 264,000 people in 2016 to approximately 272,000 people; total direct and indirect employment in the sector in 2017 corresponded to about 12 per cent of total employment in Alberta in 2017. In the case of employment in mining, quarrying, oil and gas extraction, an example of the direct employment impact is an oil rig worker; indirect impact would include an employee who works at the power station which supplies the oil rig with electricity.

Royalty Programs

The Government of Alberta owns 81 per cent of oil and gas resources in Alberta and collects royalties from companies when an oil or gas well or oil sands 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 revenue and numerous other benefits to the provincial economy. This work supports outcome one from Energy's 2017-20 Business Plan: Albertans benefit from 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.

This report presents a number of different royalty revenues and adjustments for crude oil, natural gas and by-products. While related, each royalty revenue adjustment needs to be interpreted in its own unique context. These numbers are generated using different data sources and methodologies, and are for different purposes, and, as such, are not directly comparable.

It is important to keep in mind that:

- The actual royalty revenues are revenues the Crown collects on production from all wells in the province and are reported in the financial statements on a fiscal-year basis.
- Royalty adjustment refers to the amount by which royalty was reduced from what would have been assessed under the generic royalty formulas due to a particular royalty program. The royalty adjustments are for wells that qualified under the royalty programs and are reported in the financial statements on a fiscal-year basis.
- The total royalty revenue of each royalty program is sourced from various royalty reporting systems for crude oil, natural gas and oil sands. These systems are reported on a calendar-year basis and reflect the amendments filed by industry each year. Amendments can be filed for up to three years from the production month. 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.

Most of the royalty programs provide royalty adjustments early in the life cycle of the well or project while revenues from wells participating in the program occur during the entire production life of a well. Therefore, comparing the royalty adjustments against the royalty revenue is only relevant when done over the life of each well or project and should take into account, as far as possible, the value of investments that would not have been made without the program.

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 2017-18, the department established two new 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 and replaces the existing Enhanced Oil Recovery Program.

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.

Alberta is encouraging the use of enhanced recovery methods for petroleum and natural gas through the Enhanced Hydrocarbon Recovery Program. This program aims to conserve the province's resources by targeting recovery methods that use fluid injection such as hydrocarbons, carbon dioxide, nitrogen or chemicals.

During 2017-18, the Enhanced Hydrocarbon Recovery Program received interest from eight companies (some companies had multiple applications). In total, the department received 11 applications for the Enhanced Hydrocarbon Recovery Program. All applications were under review during 2017-18, therefore, no royalty adjustments resulted in the fiscal year.

Emerging Resources Program

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

- Provide appropriate royalty treatment for strategic emerging oil and gas resources that are high cost and high risk;
- Promote innovation and industry experience to accelerate the development of these resources; and,

- Generate incremental royalty revenue for Albertans over the long-term.

During 2017-18, the Emerging Resources Program received interest from 16 companies (including partnerships). In total, the department received 11 applications for the Emerging Resources Program. One application was approved and the other applications were still under review in 2017-18. No royalty adjustments resulted during the 2017-18 fiscal year.

Alberta Royalty Framework's Royalty Programs

The department has a number of royalty programs under the Alberta Royalty Framework that are no longer accepting new entrants as of January 1, 2017 and will be phased out once their regulation expires. They will be replaced by the Enhanced Hydrocarbon Recovery Program and the Emerging Resources program. The programs to be phased out include the Natural Gas Deep Drilling Program and the Enhanced Oil Recovery Program. The ministry will continue to monitor and report on the progress of these programs until they have officially expired.

In the 2017-18 fiscal year, 11 royalty programs provided more than $1.5 billion in royalty adjustments to oil and gas producers.

Royalty Programs	Royalty Adjustments 2017-18 ($ Millions)
Natural Gas Deep Drilling Program	$1,071.6
Shale Gas	$199.9
Horizontal Oil	$87.0
Incremental Ethane Extraction Program	$63.4
Enhanced Oil Recovery Program	$21.5
Horizontal Gas	$10.3
Proprietary Waiver	$2.3
Innovative Energy Technologies Program	$0.3
Otherwise Flared Solution Gas	$0.2
Deep Oil Exploratory Well	$0.1
Coalbed Methane	$0.0
Total Royalty Adjustments	**$1,455.7**

Natural Gas Deep Drilling Program

The Natural Gas Deep Drilling Program (NGDDP) was intended to encourage new exploration and developing production by providing a royalty adjustment to wells with a vertical depth greater than 2,000 metres. Deeper natural gas wells under the program are contributing significantly and at an increasing level to Alberta's total gas and liquids production. No new wells were accepted into the program in 2017.

The royalty adjustment is based on the well's measured depth and is provided for a period of up to five years following the well's 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. In fiscal year 2017-18, the program provided the largest amount of royalty adjustments to oil and gas companies – approximately $1.1 billion. This aligns with the increase in the total gas production from eligible gas wells for the 2016 calendar year. The total residue gas increased by 10 per cent and total liquids increased by 32 per cent from 2015. Residue gas is the gas mixture left after separation and processing of natural gas liquids that are ready for delivery to the pipeline.

The number of new gas wells eligible under the program declined from 848 in 2015 to 594 in 2016 based on calendar year results. The decline is attributed to the global economic downturn and decreased pricing in 2015 and 2016 which resulted in fewer wells overall and therefore fewer metres drilled. Despite the decline in the number of eligible wells in 2016, new eligible wells as a proportion of total new gas wells drilled in the province has been increasing, with 45 per cent of total new gas wells being eligible under the program in 2016. This could be attributed to a number of factors that include the shift in industry's development focus to target deeper, liquids-rich formations (such as shale) and drilling horizontal, multi-fractured wells. Natural gas liquids improve a well's economics due to higher product value and are driving the drilling of most natural gas wells in the province.

Natural Gas Deep Drilling Program					
Production Years (Calendar Year)	**2012**	**2013**	**2014**	**2015**	**2016**
Number of new eligible gas wells as a proportion of total new gas wells in the province.	17%	22%	30%	38%	45%

In the 2016 calendar year, gas wells in the program contributed about $261 million in total royalty revenues after the royalty adjustment (revenue before further deductions such as the Gas Cost Allowance). Total royalty has decreased by $19 million from 2015, despite a total increase in gas and liquids production from eligible wells over the same period. This can most likely be attributed to the drop in commodity prices which led to fewer wells being drilled. In addition, royalty rates for natural gas and field condensate are both price and production sensitive. This means that in a low price environment, the royalty rates determined by the generic royalty formulas are also low, resulting in less total royalty being collected. No new wells were accepted into the program in 2017.

The Emerging Resources and Technologies Initiative

Introduced in 2010, the purpose of the Emerging Resources and Technologies Initiative (ER&T) was 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 were accepted into the program in 2017.

The number of wells entering the program fell dramatically in 2015 and 2016. There were 437 new oil wells and 744 new gas wells under the program in 2016. This represented a 22 per cent decrease from the 1,739 oil and gas wells that qualified in 2015. This is attributed to the global economic downturn and depressed commodity prices in 2015 and 2016.

Production under the program is measured for wells in each of the four situations. Increased production was observed from wells in horizontal oil, shale gas and horizontal gas but not for coalbed methane.

Horizontal Oil and Horizontal Gas

Overall production from horizontal oil and gas wells decreased in 2016 compared to 2015. Gas production decreased to 7.6 million cubic metres from 10.1 million cubic metres in 2015. Gas liquids production saw a slight increase to 3.5 million cubic metres from 3.4 million cubic metres in 2015.

Horizontal oil wells showed decreases of 40 per cent and 55 per cent in 2016 oil production and solution gas production, respectively from 2015 to 2016. Oil production decreased to 4.5 million cubic metres from 7.4 million cubic metres in 2015. Solution gas production decreased to 0.9 million cubic metres from 1.9 million cubic metres in 2015. This decline was driven by the global collapse in oil prices. Solution gas is the gas that is separated from crude oil or crude bitumen after recovery from a well event.

In 2017-18, horizontal oil provided $87.0 million and horizontal gas allowed for $10.3 million in royalty adjustments.

Shale Gas

Production rates from shale wells appear to be increasing which could be attributed to better well drilling and completion techniques. In the 2016 calendar year, shale gas production increased by 0.6 million cubic metres from 2015 levels of 1.7 million cubic metres. This includes volumes from residue gas, liquids, oil, and solution gas production. The low upfront royalty rate provided under the program was intended to improve well economics and contribute to the growth in activity in emerging shale formations.

The total royalty adjustment by shale gas in the 2017-18 fiscal year was $199.9 million.

Coalbed Methane

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.

In the 2017-18 fiscal year, coalbed methane provided $7,000 in royalty adjustments.

The total royalty revenue for ER&T in 2016 was $125.7 million compared to the 2015 total royalty revenue of $164 million. This is a result of depressed oil and gas prices in 2016 which led to fewer wells being drilled and qualifying for the program. In addition, royalty rates for oil and gas are both price and production sensitive. In a low price environment, the royalty rates determined by the generic royalty formulas are also low, resulting in less total royalty being collected.

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 bbl/d of ethane for petrochemical companies to use as feedstock.

The program allows for a 60-month royalty credit eligibility period. When a project reaches its 60-month maximum, it is no longer considered in-service for the purposes of the program. To date, 13 of the 16 approved projects have been in-service.

In the 2016-17 fiscal year, 10 of the 16 approved projects were in-service for the program and approximately $22.4 million in royalty credits were issued to the project proponents. These 10 projects are capable of providing up to 73,073 bbl/d of additional ethane or about 58 per cent of the total approved incremental ethane capacity approved by the Department of Energy. Of the remaining six projects, three have completed their 60-month royalty credit eligibility and three are not in service.

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. Over the next three years, the Department of Energy 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 will end on December 31, 2021. No new projects were accepted into the program as of January 1, 2017.

In 2017-18, up to $63.4 million is eligible as royalty credits under this program.

Enhanced Oil Recovery Program

The Enhanced Oil Recovery Program (EORP) was implemented in 2014 and is intended to encourage incremental crude oil production through enhanced oil recovery methods. 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 schemes were accepted into the program in 2017.

Two new applications were received in 2016 under this program, but no new schemes were approved into the program. The low number of applications received is likely a result of the decrease in overall new enhanced oil recovery development in the province due to the economic downturn and depressed oil prices and capital market.

Total Crown production from enhanced oil recovery in 2016 was 0.7 million cubic metres, which is a decrease of 0.2 million cubic metres or 24 per cent from the previous year. This resulted in a total royalty revenue decrease of $11 million in 2016 from the $34.6 million reported in 2015. The decrease in total Crown production and total royalty revenue in EORP could be the result of the low oil prices and depressed market. Of this total royalty revenue, about $21 million was considered incremental royalty to the Crown that otherwise would not have been generated without the program. This is a $10 million decrease from the $31 million incremental royalty revenue reported in 2015.

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 support, the enhanced oil recovery schemes may not even reach the stage of base oil production. In that regard, any royalty generated from those enhanced oil recovery schemes could be considered ‘incremental’ to the Crown.

In 2017-18, the EORP provided $21.5 million in royalty adjustments.

Government Business Enterprises Revenues

The Balancing Pool's Net Liabilities were reduced from $2.0 billion as of March 31, 2017 to $1.2 billion as of March 31, 2018. The reduction is the result of updated Provision for Onerous Contracts forecast associated with the return of the Power Purchase Arrangements (PPAs). This provision is based on:

- electricity price forecast to 2020; and
- the final settlements on the returned PPAs.

The provision amount will change annually as new information is available. These changes during 2017-18 have resulted in the inclusion of $763 million in net income from the Balancing Pool.

Ministry Expenditure Highlights

Energy's 2017-18 operating expenditure surplus of $186 million arose from the following:

- The capital grant transferred for the Alberta Carbon Trunk Line was $164 million lower than budgeted as the construction milestones were not met due to various delays. In the second year of full operations, the Quest project captured another 1.2 million tonnes of carbon dioxide.
- During the year, the AER collected $15 million less in orphan well levies than the previous year. This deferral was required to consolidate the issuance of two orphan levies per year, each in the amount of $15 million, into a single levy. Therefore, the amount transferred to the Orphan Well Association was $15 million lower than budgeted.
- The Cost of Selling Oil is a non-discretionary expense associated with the volume of crude oil received as royalties. The 2017-18 expense was $10 million higher than the previous fiscal but $10 million lower than budget as actual production slowly increased during the year with improved commodity prices.

OUTCOME 1

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

What this means:

The ministry develops and manages policies and programs related to the province's royalty system. It accurately calculates and fully collects revenues from energy and mineral royalties, land sales, bonuses and rent. The ministry explores ways to encourage value-added processing within the province through the diversification of the energy resource value chains. The ministry continues to seek opportunities to increase access to global markets to strengthen both provincial and national economies.

Key strategies to achieve this outcome included:

1.1 Develop policies and initiatives that support the diversification of energy resource value chains and value-added processing in the province.

1.2 Enhance transparency of Alberta's royalty system.

1.3 Foster and strengthen energy-related relationships nationally and globally to emphasize Alberta's commitment to reducing carbon emissions, and to improve market access and receptivity for Alberta's energy resources and products.

Key Achievements:

1.1 SUPPORTING ENERGY DIVERSIFICATION

Energy Diversification Advisory Committee Report

Over the last decade, the energy landscape in Alberta and around the world has changed significantly. Diversification of Alberta's energy sector is a critical mitigation strategy to anticipate and adapt to global, system-wide energy changes currently underway. Expanding Alberta's downstream value-add sector and increasing export opportunities are essential to preserving Alberta's oil and gas sectors and growing domestic and international markets.

The Government of Alberta formed the Energy Diversification Advisory Committee (EDAC) in October 2016 to explore opportunities to diversify Alberta's energy sector, create jobs, and stimulate investment by adding value to the province's energy resources.

EDAC built on the work of the Royalty Review Advisory Panel, and incorporated many best practices developed for that process. EDAC's work included significant engagement with industry participants, which was well received, and offered a positive example of how similar engagements can be structured for future projects.

On February 26, 2018, EDAC submitted its final report which contained 36 recommendations. Government accepted the committee's advice and began moving forward immediately on a number of recommendations. Implementation of energy diversification initiatives in relation to EDAC's advice will continue into 2018-19.

The Ministry of Energy provided extensive analytical support for the development of the EDAC report. This included activities such as:

- Running and modification of cash flow models;
- Market analysis;
- Production estimates;
- Identification of information requirements; and
- Development of indicators related to energy diversification and value adding activity in the province.

In supporting EDAC in the development of its report, the ministry expanded its in-house knowledge of the downstream sector. An additional benefit was the expansion of the network of analytic expertise across government as a result of cross-ministry collaboration.

The cost of EDAC activities in 2017-18 was approximately $320,000.

Bill 1, Energy Diversification Act

On March 8, 2018, the Government of Alberta tabled Bill 1, *The Energy Diversification Act*, which would bring together initiatives that build upon Alberta's energy strengths to create thousands of jobs, attract billions of dollars in private investment and secure Alberta's energy future through diversification and innovation.

Included in this act is a commitment of up to $2 billion to leverage private investment, including:

- $500 million in royalty credits for a second round of the Petrochemicals Diversification Program (PDP) spread out over four years
- $500 million in loan guarantees and grants to establish a Petrochemical Feedstock Infrastructure Program spread out over three years
- $1 billion in loan guarantees and grants to initiate a Partial Upgrading Program spread out over eight years

It is anticipated that these initiatives will attract $10 billion in private investment, create 8,000 construction jobs and hundreds more operational jobs. More importantly, it will spur the continued development of new energy resource value chains and in turn, enable future growth of the downstream energy sector.

Petrochemicals Diversification Program (PDP)

The PDP was launched in 2016 as part of Alberta's efforts to diversify the energy industry and economy, create jobs, and attract investment. It leverages Alberta's large supply of natural gas and natural gas liquids, and aims to tap the growing global demand for higher value products. Higher value products are raw resource products that go through more value-added processing. The program was created to encourage companies to invest in the development of new petrochemical facilities in the province by offering royalty credits.

Projects do not receive royalty credits until the petrochemical facilities are in operation. Once operating, they become eligible to earn royalty credits by processing propane into higher value products. While petrochemical facilities do not directly benefit from royalty credits as they do not pay royalties, the credits earned can be traded with an oil or natural gas producer. The producer can then use these credits to reduce its royalty payments to offset the cost of extracting natural gas and oil.

PDP 1 was launched in February 2016 and targeted methane and propane upgrading. A competitive application process was completed, with two projects being approved to receive up to a combined total of $500 million in royalty credits for propane-based projects: Inter Pipeline's integrated petrochemicals complex and Canada Kuwait Petrochemical Corporation (formerly Pembina/PIC)'s integrated propane dehydrogenation and polypropylene facilities.

Approved Projects

- In December 2017, Inter Pipeline, based in Calgary, announced that it has approved the construction of the company's proposed $3.6 billion Heartland Petrochemical Complex, which includes a propane dehydration plant approved to receive $200 million in royalty credits.
- Canada Kuwait Petrochemical Corporation is expected to make a final investment decision in the coming months on its $4 billion propane dehydrogenation and polypropylene complex. The company is approved to receive up to $300 million in royalty credits.

Building on Alberta's large supply of natural gas and natural gas liquids, PDP 2 was announced in March 2018. It encourages companies to build manufacturing facilities that turn petrochemicals into more valuable products, such as plastics, fabrics and electronics.

The program was expanded to include proposals for ethane, in addition to propane and methane. Ethane is used to create components needed for plastics, detergents, lubricants and other household products.

Petrochemical manufacturing is the largest manufacturing sector in Alberta, directly employing more than 7,500 people and exporting $8.2 billion worth of goods each year.

The Government of Alberta is committing another $500 million in royalty credits under PDP 2 to attract new plants to Alberta.

Petrochemical Feedstock Infrastructure Program

The new Petrochemical Feedstock Infrastructure Program will help industry build facilities to capture natural gas liquids required for petrochemical manufacturing, such as ethane, methane and butane.

Increasing Alberta's supply of raw components reduces the need to import from the United States or elsewhere. It also meets a necessary condition for industry to construct and operate world-class petrochemical processing facilities in our province.

This initiative will:

- supply a growing petrochemical industry
- add value to Alberta's energy resources
- lower the carbon intensity of a barrel of oil

The Petrochemical Feedstock Infrastructure Program is intended to complement PDP 2.

Partial Upgrading Program

The Partial Upgrading Program will encourage companies to build two to five bitumen upgrading facilities in Alberta that increase the value of the province's resources before it is exported. Partial upgrading reduces the thickness of oil sands bitumen which means it does not need to be mixed with diluent. Without the added diluent, a greater volume of bitumen can be shipped through pipelines.

Upgrading will enhance the competitiveness of the oil sands industry by:

- Improving the quality of Alberta's bitumen
- Reducing industry costs and discounts on bitumen
- Increasing pipeline capacity and potential markets
- Enabling more refineries to process bitumen products

Sturgeon Refinery

The Alberta Petroleum Marketing Commission (APMC) team is preparing for the start-up of the refinery. All financial processes and controls are in place to handle the financial transactions beginning with the toll commencement date of June 1, 2018, and upon the start of commercial operations forecast to take place by the end of 2018.

The APMC's role in the North West Redwater Partnership (NWRP) includes feedstock provider, toll payer, and subordinated debt lender. APMC is responsible for supplying 75 per cent of the refinery bitumen feedstock, retaining 75 per cent of the refined products and paying 75 per cent of the cost of service toll for processing. The commission has borrowed a total of $432 million from Treasury Board and Finance to lend to the Sturgeon Refinery. The timelines for the commission repaying the debt to Treasury Board and Finance corresponds to the NWRP repayment of the term loan to the commission.

While loans to NWRP are outstanding, APMC obtained a voting interest (25 per cent) of the NWRP Executive Leadership Committee, which is in proportion with its contribution to equity. This has provided APMC with some involvement in the refinery's business, but does not extend to control over the construction or engineering. In addition, APMC remained fully engaged through participation in the Operations Committee, Operations Executive Leadership Committee, Health, Safety and Environment Committee and the Finance Committee. APMC also participated in regular commercial steering committee meetings to discuss and assess potential feedstock and offtake marketing arrangements. APMC continued to participate in the new steering committee to align financial and operational processes for the application of the cost of service toll outlined in the processing agreements.

The most fundamental risk to APMC relating to the Sturgeon Refinery is that the difference in price between final products (diesel and diluent) and the feedstock (diluted bitumen) will not be enough to cover the cost of upgrading and refining the feedstock due to market conditions. If there is a narrow differential between bitumen and light oil and products, then the refinery contract could result in losses. If there is a wide differential, then it can result in positive cash flow. While this risk cannot be directly managed, part of the value of the arrangement is that it provides hedging on a small part of Alberta's bitumen. If the differences between bitumen and light oil are wide, royalties will be lower but the refinery contract will be more profitable. If the differences are narrow, the refinery contract will be less profitable but royalties will be higher. This is a recognized cost and benefit of such a physical hedge. The department expects phase 1 of the project to provide positive returns for Albertans. Returns will be affected by commodity prices for refined products and feedstock, the potential for a narrow differential between bitumen and light oil and products, final capital cost and timing of full operations.

Energy Sector Strategy

The Energy Sector Strategy under the Government of Alberta's Sector Strategies Initiative (led by the Ministry of Economic Development and Trade) will help inform and provide guidance to the Government of Alberta when developing programs and policies to support economic development initiatives. The strategy provides a framework to guide government short-term and long-term decision-making as it relates to economic development and diversification opportunities in Alberta's energy sector.

The development of the Energy Sector Strategy started in December 2017. The Ministry of Energy provided the completed sector strategy to the Ministry of Economic Development and Trade to incorporate into the full range of sector strategies being developed across government.

1.2 ENHANCING TRANSPARENCY OF ALBERTA'S ROYALTY SYSTEM

In 2017-18, the Ministry of Energy provided enhanced transparency of Alberta's royalty system thereby fulfilling a key recommendation of the Royalty Review Advisory Panel report called *Alberta at a Crossroads*. On November 30, 2017, the royalty website was launched: https://www.alberta.ca/albertas-royalty-framework.aspx. With this website comes increased transparency for the public and greater awareness and confidence in the ministry's achievements towards its mandate to collect the Crown's share of energy resources on behalf of Albertans.

The website was developed with an intent to better inform and educate Albertans on the royalty system and how it works. Royalties are an important way that Albertans collect value from the development of the province's energy resources. The website provides information on performance indicators for the province's royalty system.

Published data includes oil sands royalty information such as costs and revenue for each oil sands project in Alberta for the 2016 reporting year. Publication of oil sands royalty information by project will be refreshed annually. In providing this information, changes were made to the *Mines and Minerals Administration Regulation*. To address industry concerns that publication of specific cost and revenue information may cause commercial harm in certain situations, the ability to apply for an exemption to the publication of those particular data fields was offered by the government to companies meeting exemption criteria. A total of four oil sands projects had data fields exempted.

To minimize potential confusion between timing of the release of project data and release of corporate financial data that occurs in the spring of each year, the ministry will publish annual oil sands project data in June, after industry releases its corporate financial information. Revisions and finalization processes to enable government to establish these reporting requirements took much longer than expected. This resulted in the first publication of data occurring later than the original target. Based on the timing and efforts involved in this project, longer lead times will be considered for the internal revisions and finalization for similar initiatives.

The four guiding principles of the royalty system are directly linked to transparency and are published in the Royalty Review Advisory Panel report:

Alberta at a Crossroads

1. Optimize returns to Albertans
2. Attract investment and promote job creation
3. Support downstream value-added industries
4. Encourage environmental responsibility in the oil and gas sector

The website helps Albertans examine how the energy industry impacts the province and the direct benefits generated for Albertans. These are measured through performance indicator reporting. Performance indicators are a way to view the whole spectrum of activity that takes place in the energy industry, both in the upstream and downstream sectors.

The performance indicators related to the guiding principles are listed below and are also published on the royalty website.

Optimize Returns to Albertans
- Total royalty revenue collected
- Alberta oil and gas production
- Oil and gas contributions to Alberta's economy
- The revenue from each barrel of oil and gas, in general, for different types of wells and projects

Attract Investment and Promote Job Creation
- Employment in Alberta, as a result of mining, quarrying, and oil and gas extraction
- Upstream mining, quarrying, and oil and gas extraction sector and investment in Alberta as a percentage of Canada's energy investment

Support Downstream Value-Added Industries
- Value of basic and industrial chemical, plastic and rubber exports
- Employment in the downstream sector
- Capital investment in downstream processing

Encourage Environmental Responsibility in the Oil and Gas Sector
- Greenhouse gas emissions
- The amount of water used for oil and gas extraction
- Tailings ponds
- Pipeline safety

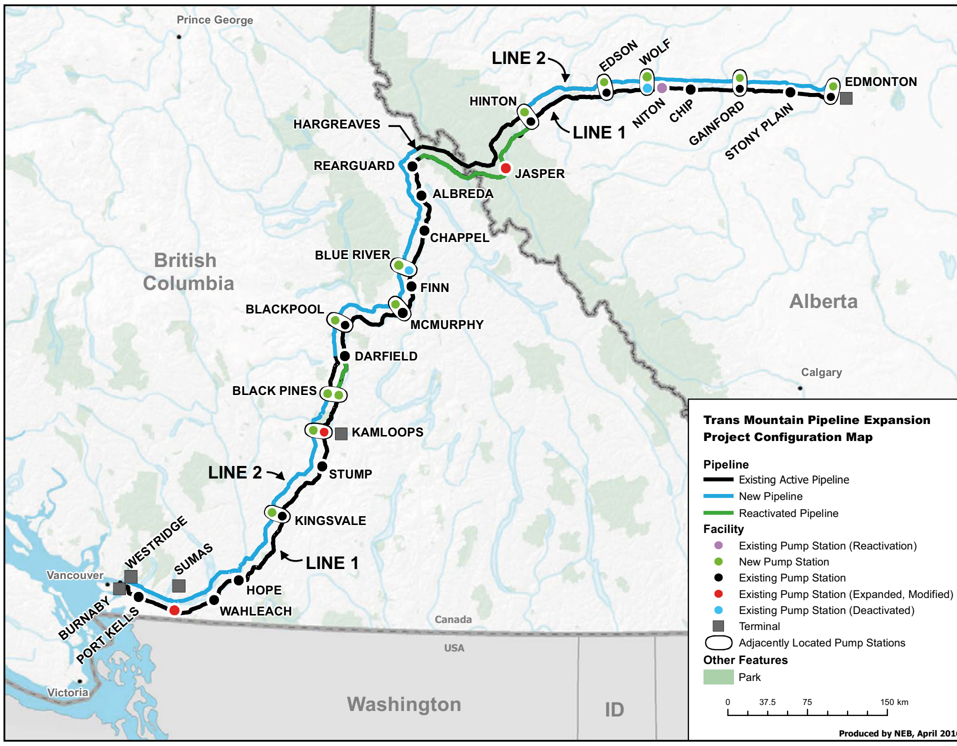
The primary challenge in this work is the lack of data granularity. It is an ongoing limitation, and a determining factor on what data can be reported. The challenges were addressed by researching and clearly identifying data availability and limitations, which enabled the development of performance indicators that met the requirements without creating significant information gaps.

The cost of enhancing transparency of the royalty system in 2017-18 was $1.35 million.

1.3 IMPROVING MARKET ACCESS

Oil export capacity is constrained without new pipeline infrastructure. Adding to this problem, Alberta's sole international export customer is also a competitor. Alberta's limitation to sell and move oil to just a single, saturated market – the U.S. - has resulted in significantly discounted prices for its energy products. Access to high-demand markets in Asia, India and Europe offers opportunities for better returns and diversification of the province's customer base. The Government of Alberta's objective is to ensure energy infrastructure is constructed in an environmentally responsible and safe manner to provide reliable market access for Alberta's energy exports.

Kinder Morgan Trans Mountain Expansion Project



Capital cost: $7.4 billion

Capacity: Increase from 300,000 bbl/d to 890,000 bbl/d

Route: 1,150 km from Strathcona County, Alberta to Burnaby, B.C.

Markets: U.S. West Coast and Asia

In-service date: December 2020

The project will twin the existing Trans Mountain Pipeline, which was established in 1953 and runs from Strathcona County, Alberta to Burnaby, B.C.

Source: National Energy Board

Trans Mountain Expansion Project Configuration Map (2016, April), http://www.neb-one.gc.ca/pplctnflng/mjrpp/trnsmntnxpnsn/mg/mp-eng.pdf, National Energy Board. Reproduced with the permission of Public works and Government Services, [2018].

Economic Benefits

According to the Conference Board of Canada, the combined government revenue impact for construction and the first 20 years of operation, including taxes that can be used for public services, is $46.7 billion.

- Alberta receives $19.4 billion
- B.C. receives $5.7 billion
- The rest of Canada shares $21.6 billion

The Conference Board of Canada estimates that the project will generate more than 800,000 direct, indirect and induced person-years of employment during development, operations and as a result of higher netbacks.

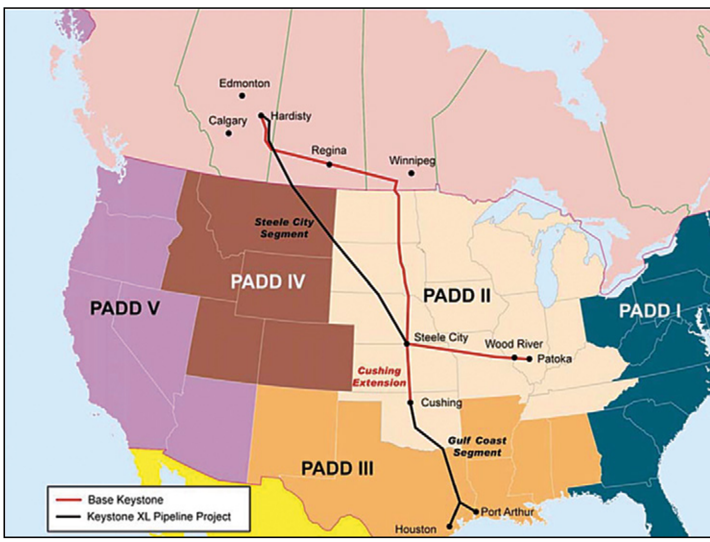
In October 2017, Alberta acted as intervenor in the Federal Court of Appeal judicial review of the Kinder Morgan Trans Mountain Expansion Project, taking the position that the project is in the national interest and will bring economic benefit to all Canadians. Alberta also participated as an intervenor before the National Energy Board (NEB) in a challenge of the applicability of City of Burnaby bylaws to the Trans Mountain Expansion Project.

In 2017-18, Premier Notley completed a cross-country speaking tour to reiterate Alberta's support for pipelines to all Canadians. During speeches at the Empire Club of Canada in Toronto, the Economic Club of Canada in Ottawa, the Greater Vancouver Board of Trade and the Edmonton and Calgary Chambers of Commerce, the premier shared Alberta's perspective on the importance of the Kinder Morgan Trans Mountain Expansion Project and its importance to Alberta's and Canada's economy. To defend Alberta's interests and the national need for tidewater oil market access, Premier Notley created the Market Access Task Force to offer advice for encouraging and promoting market access for Alberta's oil and gas through pipelines to tidewater.

In March 2018, the Government of Alberta indicated in its Speech from the Throne that it would be introducing legislation to provide Alberta with additional tools to defend Alberta's right to get the possible price for our oil and gas resources.

In May 2018, the Government of Canada announced that it was purchasing the Trans Mountain pipeline. Alberta supported this purchase because it ensured that construction would resume immediately and because it provided certainty that the pipeline would be completed.

TransCanada Keystone XL



Capital cost: $8 billion

Capacity: 830,000 bbl/d

Route: 1,897 km from Hardisty, Alberta to Steele City, Nebraska

Markets: U.S. Gulf Coast

In-service date: 2021

The proposed Keystone XL pipeline would be the fourth phase of an existing pipeline and run from Hardisty, Alberta to Steele City, Nebraska. The pipeline then joins an existing line, which carries crude to refineries in Cushing, Oklahoma and the U.S. Gulf Coast.

Source: National Energy Board

TransCanada Keystone XL Pipeline Map (2018, May, Last Modified), http://www.neb-one.gc.ca/pplctnflng/mjrpp/kstnxl2/index-eng.html, National Energy Board. Reproduced with the permission of Public works and Government Services, [2018].

Economic Benefits

Based on TransCanada's initial estimates:

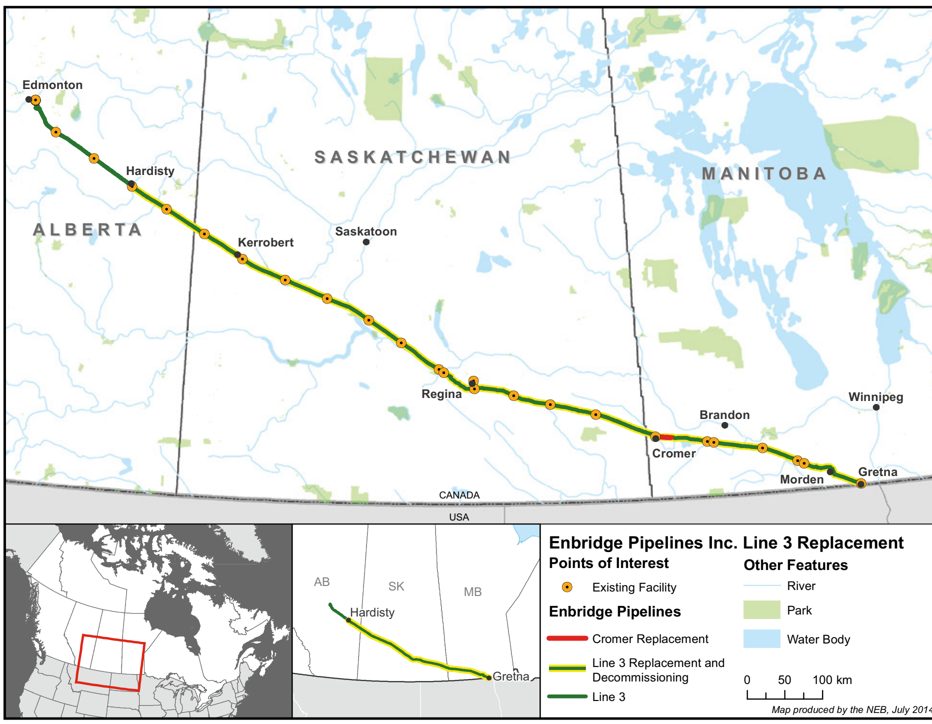
- The $1.2 billion Canadian leg of the project is projected to create 2,200 construction jobs
- The project is expected to result in an additional $3.7 million in property taxes annually in Alberta and $1.3 million annually in Saskatchewan
- More than 42,000 direct and indirect jobs are expected to be created in the U.S.

In anticipation of Keystone XL construction, TransCanada is investing in additional proposed infrastructure projects such as terminals in Alberta worth over $5.4 billion.

The U.S. Gulf Coast has a four million bbl/d heavy oil processing capacity. This market represents a long-term source of heavy crude demand. Even with increasing light oil production from U.S. shale, refineries will continue to need heavy oil to meet their refining capacity.

The province sent a letter providing high-level energy and trade information to the Nebraska Public Service Commission to support their consideration of the TransCanada Keystone XL pipeline. Through APMC, the province also signed an agreement committing to ship 50,000 bbl/d on the Keystone XL pipeline for 20 years in support of the project.

Enbridge Line 3 Replacement Project



Capital cost: $8.2 billion (largest in Enbridge's history)

Capacity: 760,000 bbl/d

Route: 1,660 km from Hardisty, Alberta to Superior, Wisconsin

Markets: U.S. Midwest

In-service date: Second Half of 2019

The Line 3 Replacement Project involves the replacement of a nearly 60-year-old pipeline that, due to integrity concerns, is operating at 390,000 bbl/d. The replacement of Line 3 will restore the pipeline to its original capacity of 760,000 bbl/d. Line 3 forms part of Enbridge's Mainline System which runs from Hardisty, Alberta to Superior, Wisconsin. It is a mixed-service line capable of carrying a variety of crude oils.

Source: National Energy Board

Enbridge Pipelines Inc. Line 3 Replacement. Route Map. (2014, July). Enbridge Pipelines Inc. - Line 3 Replacement Program. Project Information. (2018, May – Last updated), https://www.neb-one.gc.ca/pplctnflng/mjrpp/ln3rplcmnt/prjctnf-eng.html, National Energy Board. Reproduced with the permission of Public Works and Government Services, [2018].

Economic Benefits

- According to Enbridge, construction of the project will create 24,493 temporary full-time equivalent positions in Canada.
  - 9,223 direct and indirect jobs in Alberta
  - 7,833 direct and indirect jobs in Saskatchewan
  - 3,274 direct and indirect jobs in Manitoba
- $50 million in benefits to Indigenous communities in Canada
- The project will contribute more than $2.9 billion in GDP in Canada:
  - Alberta $1.4 billion
  - Saskatchewan $1.1 billion
  - Manitoba $392 million
  - British Columbia $26.7 million

To support the Enbridge Line 3 Replacement Project, Premier Notley sent a letter to the Minnesota Department of Commerce regarding the draft environmental impact statement for the Enbridge Line 3 Replacement Project. On August 10, 2017 the premier participated in the groundbreaking for construction of the Line 3 Replacement Project in Hardisty, Alberta.

TransCanada Energy East

In May 2017, Minister McCuaig-Boyd sent a letter and technical submission to Minister Carr, the federal Minister of Natural Resources on the draft TransCanada Energy East - List of Issues for the NEB's Technical Hearing for the project, citing concerns about assessment of upstream and downstream greenhouse gas emissions and jurisdictional concerns. These concerns were later reiterated in a letter sent in October 2017 as part of the province's comments to NEB on the final list of Energy East - List of Issues.

Despite efforts to move the project forward, in early October 2017, TransCanada announced that it has cancelled plans for the project, citing changing circumstances. The Energy East pipeline project had the potential to open up access to refineries in eastern Canada and offshore markets, resulting in economic benefits for all Canadians.

National Energy Board (NEB) Modernization

In 2015, the federal government announced its intent to review and update environmental and regulatory processes in Canada. This included modernizing the NEB and changing the way that environmental assessments are carried out in Canada. Large infrastructure projects such as pipelines, oil sands mines, refineries, and railways require federal assessment and approval. Such changes are of significant consequence to Alberta and its stakeholders.

In the May 2017 letter on Energy East – List of Issues to the federal Minister of Natural Resources, Minister McCuaig-Boyd also addressed concerns about inconsistency with the federal government's interim measures for pipelines reviews and NEB modernization. Minister McCuaig-Boyd sent a letter and technical submission to the federal government regarding concerns with the NEB expert panel report. Along with Shannon Phillips, Minister of Environment and Parks, Minister McCuaig-Boyd sent a joint letter and technical submission to the federal government commenting on concerns with the federal discussion paper on regulatory and environmental reviews.

Federal Proposed Oil Tanker Moratorium

In May 2017, the federal government introduced Bill C-48, the proposed *Oil Tanker Moratorium Act*. The proposed legislation seeks to formalize a crude oil tanker moratorium on B.C.'s North Coast. The proposed legislation would prevent crude oil from being shipped out of the Port of Prince Rupert, a deepwater port that can accept very large crude carriers with the shortest route to Asia of any Canadian port, offering a full-day's sailing advantage over other Pacific ports which helps reduce transportation costs. The Government of Alberta also made a technical submission to the federal government regarding Bill C-48, the proposed *Oil Tanker Moratorium Act* that showed inaccuracies in the testing method for the classification of condensates.

Inaccurately classifying condensates as a persistent oil would restrict export opportunities for condensates under the *Oil Tanker Moratorium Act* and jeopardize Alberta's efforts to diversify the economy.

Strengthening Energy-Related Relationships

During 2017-18, the Government of Alberta was engaged in a number of activities to build and strengthen energy-related relationships.

Premier Notley raised the profile of Alberta's energy and environmental sectors in China and Japan during her mission in 2017. Agreements with both countries were signed as a result which strengthened the province's trade ties in the region. The agreement with the China National Development and Reform Commission – Energy Research Institute has a focus on research and industry cooperation in the areas of energy and environment between Alberta and China. The agreement with the Japan Oil, Gas and Metals National Corporation enhances the enterprise's existing investment in the oil sands and will lead to deepened technology cooperation between Japan and Alberta.

In April 2017, Minister McCuaig-Boyd delivered a panel presentation and promoted investment opportunities within Alberta's electricity system at the Bloomberg New Energy Finance Future of Energy Summit in New York City, which showcased the investment opportunities created through Alberta's electricity policies. While in New York City, the minister also met with executives, investment groups, capacity market operators and utility scale developers.

In June 2017, Minister McCuaig-Boyd delivered a panel presentation at the Energy Council meeting in North Dakota. In addition, the minister also advanced Alberta's energy priorities through several political engagements with U.S. counterparts. With a new U.S. administration and state-level concerns becoming ever more important to pipeline review processes, the value of this type of engagement has increased in recent years.

In September 2017, Minister McCuaig-Boyd led an official delegation to Japan, China and Korea to position the export capacity of the province as viable and strong. The delegation highlighted the potential for shale oil and gas and emissions-reduction cooperation. Overall, the delegation promoted Alberta as a competitive province for foreign investments. Alberta has significant trade relationships with Japan, China, and Korea, with Alberta exporting an annual average of $1.8, $3.26, and $0.3 billion respectively in merchandise to these countries between 2012 and 2016. China has been the world's largest energy consumer since 2011. China is also the world's leading investor in alternative energy projects. Continuing to foster these energy-related relationships offers the potential for innovation in energy and increased trade and economic activity between Alberta and the Asia-Pacific region.

In December 2017, Minister McCuaig-Boyd hosted the U.S.-based Energy Council 2017 Global Energy and Environmental Issues Conference as the vice chair in Banff, Alberta. The minister emphasized the importance of energy trade with the U.S. She also highlighted Alberta's energy sector as a resilient, secure and desirable place to do business where there is leadership on climate change. Over 60 U.S. elected officials attended the conference.

Overall, in 2017-18, continuous changes to the Government of Canada's regulatory requirements, processes and hearings posed significant challenges to several market access related activities of interest for Alberta, including the Trans Mountain Expansion Project, resulting in impact on Alberta's competitiveness and investor confidence. Despite regulatory approvals, ongoing regulatory and legal processes, and challenges from project opponents continued to impact completion of projects which are in the best interest of all Canadians. Ongoing regulatory and legal challenges in the U.S. have also further delayed approvals of Keystone XL and the Line 3 Replacement Project.

During 2017-18, the Government of Alberta took all available steps, including active engagement and outreach with the Government of Canada at various intergovernmental tables, from participating in regulatory hearings and legal proceedings to providing technical input and engaging with decision-makers on both sides of the border to help move projects forward and advocate for Alberta's environmentally responsible energy sector. Alberta's continued push for pipeline infrastructure and market access is important and must be sustained beyond regulatory approvals and legal challenges until new pipelines are built and in operation.

Cost of market access activities in the Department of Energy in 2017-18 was approximately $4.22 million.

Alberta CoLab Systemic Design and Strategic Foresight:

In 2017, the Alberta CoLab was involved in over 23 Ministry of Energy initiatives with primary focus on advancing work in the areas of longer-term energy transition. Projects ranged from leading and designing stakeholder engagement for EDAC to improving the efficiency and effectiveness of the department's recruitment and classification system. Since its launch in 2014, the CoLab has provided interactive training on systemic design and strategic foresight to over 1,300 public servants and currently serves in an advising and mentorship role for other Canadian innovation labs.

The future of Alberta's energy system continues to be strongly linked with changes happening on a national and international scale. This future will be influenced by a number of factors outside the control of policy makers and the various stakeholders who shape the energy space. For example, recent developments around crude oil market access may impact Alberta and Canada's long-term competitiveness. It is important to look forward and identify how the province can enhance its current performance while preparing for what may lie ahead.

Energy transition is influenced by both technology and social innovation. As such, Alberta's CoLab's structure and portfolio has been modified to incorporate these perspectives as part of work going forward. A new focus of the CoLab's work is in the technology innovation space whereby the team also provides technical advisory services and strategic thinking in regards to clean technology development and innovation funding in the energy space.

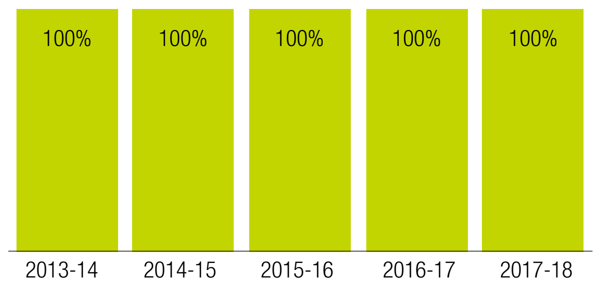
Performance Measures

Performance Measure 1.a: Revenue from oil, oil sands, gas and land sales bonuses are fully collected

Target

100 per cent of amounts owed are collected.

Results



Note: Excludes disputed amounts

Discussion of Results

One of the Department of Energy's mandates is to collect the Crown's share of energy resources on behalf of Albertans. This performance measure supports this mandate by gauging the ability of the Department of Energy to collect the amounts owed through the development of Alberta's resources.

The department requires all royalty to be calculated and paid in cash or delivered in kind by a prescribed due date. Systems and processes are in place to collect royalties and to identify and follow up expeditiously on overdue accounts. Processes are also in place to collect overdue accounts and related interest and penalties.

The results reported in this measure are based on financial obligations in which there are no disputes between the Government of Alberta and entities owing funds to the Government of Alberta. In the latter case, disputed amounts are excluded from the results until all outstanding matters are resolved. Upon resolution, historical results are reviewed and, if necessary, retroactively adjusted.

During the year, all amounts have been or are in the process of being collected, and no write-offs have been made. In 2017-18 the revenue collection measure result was 100 per cent, the same as in the previous four fiscal years.

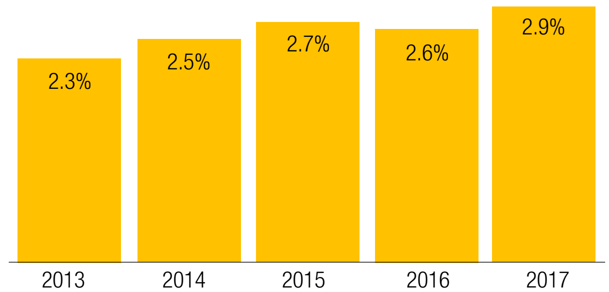
Performance Measure 1.b: Alberta's oil sands supply share of global consumption

Target

2.9 per cent of global oil consumption is supplied by Alberta's oil sands.

Results

Alberta's oil sands supply share of global oil consumption



Discussion of Results

Alberta's oil sands supply share of global oil consumption performance measure was introduced for the first time in the 2012-15 Energy Business Plan. Therefore, this is the sixth annual report to present the results of this measure.

Development of Alberta's oil sands, and the oil sands' role in the global energy mix, is a highly complex system over which policy must both balance multiple priorities and adapt 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 oil sands industry in Alberta has been significantly affected by the decline in the oil prices that got underway in late 2014. Oil prices significantly declined in late 2014, and remained relatively low throughout 2015 and 2016. In September 2014, WTI price was US$93.03/bbl while in December 2014 it was US$59.29/bbl. The average annual WTI price declined from US$93.00/bbl in 2014 to US$48.79 in 2015. In 2016, the average annual WTI price further declined to US$43.32/bbl, although it moderately recovered in 2017 to US$50.95.

Overall, total crude bitumen production increased by about 12 per cent from 2016 to 2017, from about 2.5 million bbl/d to 2.8 million bbl/d. Both mined and in-situ production experienced year-over-year increases – by about 11 per cent and 12 per cent respectively. According to the AER, total mineable raw production went up primarily due to recovery from Fort McMurray wildfires and project phases moving towards operation. Overall, total mined bitumen production went up from 1.15 million bbl/d in 2016 to about 1.28 million bbl/d in 2017.

Also, growth in production for in-situ projects was higher in 2017, mainly due to greater production of steam-assisted gravity drainage, also known as SAGD schemes. AER indicates that production increases for these and other in-situ recovery schemes more than offset the reduced production of primary and experimental schemes in 2017 relative to the previous year. Total in-situ bitumen production increased from 1.39 million bbl/d in 2016 to 1.56 million bbl/d in 2017.

The rate of Alberta's crude bitumen production increase from 2016 to 2017 was significantly larger that the rate of global year-over-year consumption increase, which went up by 1.7 per cent during this time period, from 96.2 million bbl/d to 97.8 million bbl/d. As a result, Alberta's oil sands supply share of global oil consumption experienced an increase, from 2.6 per cent in 2016 to 2.9 per cent in 2017. The 2017 actual result, at 2.9 per cent, was on target.

OUTCOME 2

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

What this means:

The ministry engages with all stakeholders on issues involving responsible resource development of Alberta's energy and mineral resources. A strategic and integrated system approach to responsible resource development in the province strengthens the overall environmental, economic and social outcomes for the benefit of Albertans and demonstrates the province's commitment to addressing climate change. Through the AER, the ministry regulates Alberta's energy industry to ensure the efficient, safe, orderly and environmentally responsible development and sustainable management of energy resources. Through the Alberta Utilities Commission (AUC), the ministry further supports the interests of Albertans by ensuring that the delivery and regulation of Alberta's utility service is fair and responsible.

Key strategies to achieve this outcome included:

2.1 Collaborate with other ministries to establish a balanced and sustainable approach to resource management to manage the combined or cumulative effects of resource development, including regional planning, and address increasing industry liability related to inactive, aging and orphaned wells and facilities, and reclamation timelines.

2.2 Enhance regulation and oversight to ensure the safe, efficient, effective, credible and environmentally responsible development of Alberta's energy resources.

2.3 Enhance regulation and oversight of Alberta's utilities to ensure social, economic and environmental interests of Alberta are protected by effective utility regulation.

2.4 In conjunction with the Alberta Climate Change Office, work toward the development of regulatory standards to implement Alberta's Climate Leadership Plan to reduce methane levels for the oil and gas sector by 2025.

2.5 Support development and implementation of policy and regulations from Alberta's Climate Leadership Plan to reduce oil sands emissions.

Key Achievements:

2.1 IMPROVING LIABILITY MANAGEMENT AND MANAGING CUMULATIVE EFFECTS

Liability Management Review

To support the effective stewardship and regulation of energy and mineral resources, the Government of Alberta continued the review of Alberta's liability management system for upstream oil and gas along with the Ministry of Environment and Parks and AER. As part of this review, engagement sessions were held with stakeholders and Indigenous communities in the summer of 2017 to identify and discuss which parts of the liability management system are working well and which parts or programs could be improved. The input received through these engagement sessions has informed the ongoing work and policy development for the review.

In addition, ongoing improvements were identified and implemented by the AER, including changes to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*. These changes ensure there are consequences for operators who try to circumvent their clean-up responsibilities.

In alignment with the intended outcomes of the liability management review, the Government of Alberta used a $30 million grant from the Government of Canada to cover the costs of providing a $235 million loan to the Orphan Well Association (OWA). The loan will help the OWA address the growing inventory of orphaned sites, while creating jobs in the oilfield and environmental service sectors and maintaining the polluter pays principle. The OWA will report quarterly on performance measures that will assist government in tracking how many sites are cleaned up and how many jobs are created as a result of the loan program.

Repayment of the loan will be funded through the existing orphan fund levy paid by industry and managed on the OWA's behalf by the AER.

To learn more about OWA's work on managing the province's orphan wells and to read the association's annual report, visit: www.orphanwell.ca.

Caribou Range Planning

Alberta's Caribou Action Plan was approved in July 2017 and provided a basis to understand potential operational and policy changes to the resource development system. The Ministry of Energy supported the Ministry of Environment and Parks on the release of the draft Provincial Woodland Caribou Range Plan in December 2017, and has established provisions to reduce impact on critical habitat through restrictions for untenured land and extensions for existing tenure in caribou ranges. The ministry also assisted with Phase 2 Engagement on the Caribou Action Plan in spring 2018.

On March 19, 2018, the Ministry of Environment and Parks announced that Alberta is suspending portions of the draft plan pending further research and engagement with the federal government.

Moose Lake Access Management Plan

To support the effective stewardship of Alberta's energy resources in support of the Lower Athabasca Regional Plan and to uphold the principles of the United Nations Declaration on the Rights of Indigenous Peoples, the Ministry of Energy contributed to the development of the Moose Lake Access Management Plan.

The Ministry of Energy supported the Ministry of Environment and Parks in developing the draft Moose Lake Access Management Plan in January 2018 in collaboration with the Ministry of Indigenous Relations. These efforts included collaboration with the Fort McKay First Nation, with the draft plan aligning with government's support for 43 of the 45 co-lead recommendations submitted under the Renewed Collaboration Agreement process. As part of the plan, the ministries developed a mechanism for managing cumulative impacts in the region. The draft plan was released in February 2018 and public comment was accepted until March 2018.

The Ministry of Energy will continue to proactively collaborate and build cross-ministry relationships and engage stakeholders on range planning as it provides the best means to understand issues and develop balanced plans.

Municipal Government Act (MGA) Review

In 2017-18, the Ministry of Energy provided support to the Ministry of Municipal Affairs in the MGA Review by coordinating policy analysis related to municipal legislation and policies that impact energy development. The ministry provided input on electricity-related matters, which was critical given the many changes occurring in Alberta's electricity legislation and policies. The ministry also provided analysis on the roles and responsibilities that municipalities have in Alberta's electricity system. The intended outcome was to foster mutual understanding of energy and municipal issues where they intersect, and to support the development of municipal legislation and policies that are reflective of the needs of both energy and municipal stakeholders.

The Ministry of Energy participated in the MGA Review from its inception in 2012 to its conclusion in fall 2017. The ministry participated in all engagement opportunities to ensure draft proposals were reviewed and that adequate input was provided to the Ministry of Municipal Affairs. The ministry continues to participate in implementation activities, such as the Big City Charters Collaboration Tables.

2.2 ENHANCING REGULATION AND OVERSIGHT OF RESOURCE DEVELOPMENT

In 2017-18, AER focused on a variety of activities to facilitate stewardship of Alberta's energy and mineral resources, including:

- Effective management of public safety, environmental risks and impacts.
- Effective management of resource conservation and minimized financial liability on Albertans.
- Maintaining an efficient regulatory system that uses a new integrated approach to decisions for energy development.
- Engaging stakeholders to improve confidence about how energy is developed in Alberta, with a focus on strengthening Indigenous relationships.
- Implementing enterprise learning, with a focus on developing competencies and skills in the organization.

Integrated Decision Approach

One of the significant initiatives that the AER worked on in 2017-18 was the implementation of an integrated decision approach (IDA) for energy development, using a new technology known as OneStop. IDA is based on the concept of one application, one review, one decision and is applicable across the life cycle of energy development. This supports efforts to enhance regulation and oversight of energy resource development and increases the effectiveness of the regulator's decisions by focusing on what matters most to Albertans. It also makes the regulator's administrative processes more efficient and offers more transparency, allowing Albertans to see the whole picture of a proposed energy project. Full implementation of the IDA is underway.

OneStop is a technology system designed to streamline the application process for industry, while at the same time supporting better-informed decision making at the AER. It is a hybrid between custom development and off-the-shelf solutions. OneStop enables integration by bringing relevant data into one space to support cohesive decision-making. It encompasses a range of resource development activities, from exploration to reclamation, and is scalable, from small to large projects. Currently, operators can use the OneStop system to submit applications for new pipeline construction, pipeline amendments, reclamation certificates and water approvals.

As a result of implementing OneStop, decision timelines have been reduced by 99 per cent for applications meeting all minimum requirements, and 67 per cent for applications requiring additional review. Industry has provided AER with calculated cost savings for regulatory projects. In 2017, pipeline licensing was transitioned into OneStop technology. The savings for the first six months using the new system are estimated to be between $0.9 million to $2.6 million for new pipeline applications.

AER has also made additional efforts to improve regulatory efficiency in Alberta's resource development activities. The regulator undertook initiatives to reduce regulatory burden on businesses and industry without impact on safety or the environment. This has resulted in $143 million in industry-verified savings in the 2017-18 fiscal year due to more efficient regulatory processes.

Industry savings for regulatory efficiency is provided by industry upon request. Cost savings are calculated relative to the project deliverables. For example, savings on well application processes would be calculated on an average of time saved per well within a given formation for a specific project. The Canadian Association of Petroleum Producers also provides its own assessment on cost savings using an industry standard methodology mostly reliant on net present value.

Regulatory Excellence

The AER's Regulatory Excellence Model continues to be foundational to the organization's planning and operational delivery, bringing together strategy and function to engage stakeholders and provide effective regulatory development and delivery. AER also made progress on the following resource development issues in fiscal 2017-18:

- Released the *Water Use Performance Report* in May 2017, which provides information to the public on how water is allocated and used to recover oil, gas, and oil sands resources.
- Continued to develop the decision-making process for tailings management plan applications, which establishes performance requirements. An update to Directive 085 (Bulletin 2017-17) was issued in fiscal 2017-18 as part of these efforts.
- Addressed high-risk wells as part of efforts to mitigate public or environmental risks. High-risk well compliance is 94 per cent, and this inventory is reviewed monthly.
- The Inactive Well Compliance Program (IWCP) was introduced in 2015 to address the backlog inventory of low and medium risk inactive wells non-compliant with Directive 013, and bring these wells into compliance within five years. Currently 70 per cent of all IWCP wells are compliant. There are still two years remaining in the program.
- Continued to provide regulatory support to the Government of Alberta as it led multi-stakeholder engagement through the Methane Reduction Oversight Committee as part of the Climate Leadership Plan.

Ensuring Regulatory Compliance

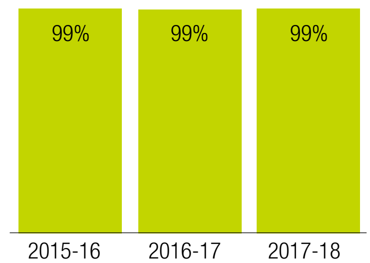
The AER initially established this indicator based on data compiled during the transition to a new Compliance Assurance Framework which better reflects its new authorities and mandate. This indicator reports the expected percentage of inspections conducted that are in compliance with regulatory requirements.

In the 2017-18 fiscal year the AER conducted 10,409 initial inspections. The inspections resulted in the issuance of 76 enforcement actions comprised of 35 suspensions, 13 warning letters, four administrative penalties, one administrative sanction, 20 orders, zero Court of Queen's Bench Interim Orders, and three prosecutions. The 2017-18 results are within the expected range of compliance and demonstrate progress toward the desired outcome of ensuring industry compliance with regulatory requirements.

2017-18 Regulatory Compliance

	Number of inspections resulting in a finding of compliance	Total number of inspections	Percentage of inspections resulting in a finding of compliance
April 1, 2017 – March 31, 2018	10,333	10,409	99%

Regulatory compliance (AER): Percentage of inspections that are in compliance with regulatory requirements.



Factors like changing market conditions, changing political climates, insolvency, incidents, and other PESTLE (political, economic, social, technological, legal, and environmental) factors make it difficult to attain 100 per cent compliance.

Inspections are selected based on an enterprise management approach to defining and applying risk as well as the predetermined level of risk that the activity may pose to health and safety, the environment, resource conservation, and stakeholder confidence in the regulatory process, including public and political influences.

The AER places higher priority on reactive work, such as incidents or complaints. The amount of reactive inspection work can significantly impact the reported result for this measure because the nature of the work is unplanned and has a high chance of resulting in enforcement action and because, less time will be spent conducting proactive compliance activities.

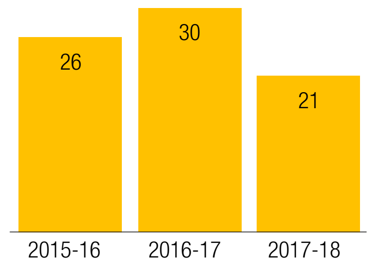
AER's strict requirements and inspection and audit programs ensure that the verification of compliance is done in a way that protects the environment and public safety. By sharing AER investigation reports externally companies have the opportunity to learn the root cause of situations and improve their practices. Continuing to meeting with companies that historically have had poor performance and publicly sharing the Pipeline Industry Performance Report and Water Use Industry Performance report allows companies to understand how they measure up. Additionally the AER works with companies years in advance to help manage energy development to make sure they are prepared to meet their obligations at the end of a project's life. Internally, we continue to prioritize staff training to align with our high priority inspection and audit areas and continue to enhance our industry education program.

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

Pipeline Safety

The AER is focused on ensuring the safe transportation of hazardous products by regulating development in a way that reduces risk and ensures Albertans reap the economic rewards of the energy resources. A reportable pipeline incident under the AER's jurisdiction is any pipeline release, break or contact damage (regardless if there is a release) (Section 35 of the *Pipeline Act*). The number of high-consequence pipeline incidents – those that could have significant impacts to public safety, wildlife, or the environment, or involves the release of a substance that affects a large area or water body. All pipeline incidents are preventable and the AER's long term goal is zero incidents.

Number of high-consequence pipeline incidents



In looking specifically at high-consequence pipeline incidents, there was a 30 per cent decrease in incidents in the 2017-18 fiscal year compared to the 2016-17 fiscal year.

Over the past 10 years, even as the total length of pipelines grew by 11 per cent, the number of pipeline incidents dropped by 48 per cent. This resulted in a pipeline failure rate of 0.98 incidents per 1000 kilometres of pipeline in 2017 compared with a failure rate of 2.08 in 2008. This reduction is largely due to improvements to requirements and inspection programs, and a greater focus on industry education and pipeline safety within the energy industry.

Strengthening Relationships with Indigenous Communities

The Government of Alberta is committed to strengthening relationships with Indigenous communities. In 2017-18, AER focused on further developing its relationship with Indigenous communities and to ensure that their views inform resource development in the province. The regulator co-drafted *Voices of Understanding (VoU): Looking through the Window* with Dr. Reg Crow Shoe, a Blackfoot elder. The book was released September 21, 2017 and speaks to acknowledging parallel processes, the opportunity to fundamentally shift the way the regulator interacts with Indigenous communities, and the different decision-making models and ethical spaces for Indigenous communities and the regulator to work together. The *VoU* was created within AER's Stakeholder Engagement Framework and was developed as a guiding document. These collaborative efforts enhance engagement with communities and ensure that resource development in the province benefits all Albertans.

The energy development landscape in Alberta continues to change rapidly, driven by economic circumstances, technological shift, and changing expectations. Maintaining the relevant organizational competencies and skills in relation to these changes is a continuous challenge. To ensure that it can remain adaptive to these changes and can provide the most informed regulatory oversight of the province's resource development activities, AER introduced enterprise learning to the organization. Enterprise learning will focus on developing the competencies and skills needed to remain receptive and adaptive to the changes in the areas that impact AER's activities.

Read more about AER's activities in its 2017-18 annual report at www.aer.ca.

The cost of the AER's activities in 2017-18 was approximately $269 million, and was funded by industry levies.

2.3 ENHANCING UTILITIES REGULATION

Review of Alberta's Distribution System-Connected Generation

To make it easier for Albertans to generate their own electricity through sources such as wind and solar, the Government of Alberta directed the AUC to carry out a thorough review of distribution-connected generation in Alberta. In late 2017, AUC provided a report to the Minister of Energy on its inquiry and review of distribution system-connected generation which is among the sources that will contribute to Alberta meeting its 30 per cent renewable electricity generation target by 2030. The review involved a wide spectrum of stakeholders including the Alberta Electric System Operator (AESO), transmission facility owners, distribution wire owners, Rural Electrification Associations, retailers, municipalities, micro-generators, First Nations and members of the public. While there were no specific recommendations in the final report, it offered observations intended to help inform government policy development which will shape the commission's work on distribution-connected generation.

Performance-Based Regulation

In February 2018, AUC released its performance-based regulation (PBR) - a regulatory tool to encourage distribution utility companies to be more efficient so that ratepayers can benefit through lower rates over time when compared to a traditional cost-of-service model. PBR also safeguards system reliability and service quality. The rebasing decision sets the going-in rates for the next-generation PBR plans spanning 2018 to 2022. The first round of PBR was introduced in 2013, and this rebasing decision sets a new base for the revised PBR formula to be applied to each of the utilities for the new 2018 to 2022 PBR plans. It also modifies the treatment of supplemental capital expenditures into two classes. This is expected to better recognize the unique circumstances of individual utilities and to provide the distribution utilities stronger incentives to manage their capital spending.

Updated eFiling System

In fiscal 2017-18, AUC updated its eFiling System to add new tracking to assist applicants, intervenors and commission staff members with an effective, efficient and transparent way to track directions and conditions from its decisions. This new tracking functionality displays clear deadlines for compliance with decision directions and will track the status of compliance with:

- Construction reports;
- Environmental studies;
- Noise impact assessments;
- Reclamation notices;
- Safety requirements and reporting; and
- Administrative reports.

Historically, tracking was labour intensive and did not provide a standardized method to communicate expectations to applicants or report on the status and results. With the updated system, AUC can track information and communicate more efficiently with applicants.

Compliance and Rules Reviews

In 2016-17, AUC implemented an approach to assess the compliance of AUC regulated transmission facilities where the application requirements were streamlined or eliminated. This initial review focused on capital maintenance projects and minor alterations to transmission facilities. The compliance review confirmed that facility owners were in compliance with regulatory requirements. This past year, the commission conducted a similar compliance review and once again, the review indicated that facility owners were in compliance. It also validated the effectiveness of the streamlined process and facility owners' approach to the exemptions. Furthermore, these streamlined processes enabled savings by way of reducing the number and workload associated with low-risk applications, resulting in more efficient management of funds.

In 2017-18, AUC conducted a review of its rules. Commission rules are documents setting out new or amended requirements or processes to be implemented and followed by entities under the jurisdiction of the commission. From time-to-time rules are changed and updated, and parties are invited to become involved in a consultation to revise these rules and to address emerging issues.

This past fiscal year, AUC revised both natural gas and electricity settlement systems rules. The changes to AUC rules 021 and 028 reflect consultation undertaken by the commission with representatives of wire service providers, natural gas distributors, load settlement agents, meter data managers, retailers and billing agents, as well as with the Utilities Consumer Advocate and AESO. Working with stakeholders, the commission identified improvements and changes to the rules to keep them relevant and reflective of the requirements of the retail natural gas and electricity markets.

Read more about AUC's 2017-18 activities at www.auc.ab.ca.

Cost of AUC activities in 2017-18 was $33.2 million and was fully funded by industry.

2.4 REDUCING METHANE IN THE OIL AND GAS SECTOR

The release of methane gas has a significant impact on climate change. It is both naturally-occurring and generated by human activity, but human activity accounts for a vast majority of methane emissions on the planet. Methane's impact is about 25 times greater than carbon dioxide over a 100-year period. Alberta's oil and gas industry is the largest emitter of methane gas in the province. In 2014, methane emissions from the oil and gas sector were equal to about 31.4 megatonnes of carbon dioxide. This made up about 70 per cent of Alberta's overall methane emissions, and contributed to 25 per cent of all gas emissions from the upstream oil and gas sector. Targeting these methane emissions can help the province make significant progress on its emissions reduction targets.

Throughout this past fiscal year, the Ministry of Energy has been supporting the Alberta Climate Change Office, AER, other partner ministries and stakeholders, including industry, on developing regulatory standards to implement commitments under the Climate Leadership Plan. In particular, the Climate Leadership Plan has set a 45 per cent reduction target for methane emissions from the oil and gas sector by 2025 from 2014 levels.

The federal government is also targeting overall greenhouse gas emissions which includes methane and Alberta worked actively to ensure alignment between federal and provincial emissions reduction initiatives.

Alberta's goal is to ensure that the methane reduction target is achieved with minimal impacts on jobs and the economy. In 2017-18, as part of that work, the Government of Alberta continued to engage the Methane Reduction Oversight Committee on the regulatory approach to achieving the reduction as part of its work on overall greenhouse gas emissions reduction. The Methane Reduction Oversight Committee consists of members from government, industry, environmental non-governmental organizations and technology groups. Efforts involved the utilization of a multi-stakeholder process to provide expertise and input into the development of regulatory standards to reduce methane emissions from the oil and gas sector. There is ongoing intergovernmental engagement between Environment and Climate Change Canada and the western provinces to coordinate methane action federally, and between oil and gas producing provinces and territories.

2.5 REDUCING OIL SANDS EMISSIONS

Carbon Competitiveness Incentive Regulation

On December 18, 2017, the Government of Alberta established the *Carbon Competitiveness Incentive Regulation*, replacing the *Specified Gas Emitters Regulation*. These efforts support the development and implementation of policy and regulations from Alberta's Climate Leadership Plan to reduce oil sands emissions.

Helping to Shape the Federal Clean Fuels Standard

The Government of Alberta has been providing input to Environment and Climate Change Canada to inform the development of emissions reduction regulations that are anticipated to be in place in mid-2019. The intended result of these national regulations is to reduce emissions from transportation fuels derived from oil and oil sands projects in Canada.

A key challenge is to ensure that Alberta's interests are reflected in these national climate change efforts. Factors such as impact on Alberta businesses, particularly with the layering of climate policies and regulations, are of central importance. The Government of Alberta will continue to work to shape a federal emissions regulation that will protect the environment and meet the emissions reduction goal at the lowest possible cost to industry.

ADDITIONAL ACHIEVEMENTS

Carbon Capture and Storage (CCS)

The Government of Alberta has committed $1.24 billion dollars over 15 years to two CCS projects that together will capture approximately 2.76 million tonnes of carbon dioxide and equivalents each year. This is roughly equivalent to the annual emissions of 600,000 cars. The first project is the Quest initiative which captures more than one million tonnes of carbon dioxide per year from the Shell Scotford Upgrader and permanently stores it underground in a deep saline aquifer. The second project, the Alberta Carbon Trunk Line, will have the potential to capture 1.68 million tonnes of carbon dioxide from the Agrium Canada Partnership fertilizer plant and the North West Upgrader near Fort Saskatchewan once operational. The carbon dioxide will be transported through a 240 kilometre pipeline and used in enhanced oil recovery operations in central Alberta.

Throughout the year, the ministry continued to monitor, administer and ensure compliance under the CCS funding agreements for the Alberta Carbon Trunk Line and Quest projects.

The Quest project has successfully injected over two million tonnes of carbon dioxide since mid-2015 and has received payments for the carbon dioxide sequestered during its two years of operation. As part of the injection payment process, a third party is required to certify the tonnes of carbon dioxide sequestered. This process provides confidence in the tonnes of carbon dioxide accounted for in the Post-closure Stewardship Fund.

A Measurement, Monitoring, and Verification Plan (MMV) plan was submitted by the Quest project in 2017 and was reviewed and approved by the ministry. The ministry also worked with Enhance Energy Inc., Alberta Carbon Trunk Line project to finalize their MMV submission to the AER as part of their regulatory approval.

In 2017, the Post-closure Stewardship Fund collected its second injection levy from the Quest project. The levy helps provide for the maintenance of CCS sites by the Government of Alberta, after CCS operations cease and government assumes liability for any stored carbon dioxide.

The department has been working with Shell on transferring its interest in the CCS funding agreement to Canadian Natural Upgrading Limited, which bought the Shell Upgrader and Quest project.

In 2017-18, the Department of Energy and AER supported the development of international standards for CCS activities through the International Organization for Standardization (ISO). This support has included participating on technical committees and the Canadian Mirror Committee for ISO Technical Committee 265, carbon dioxide capture, transportation, and geological storage.

Participation in standards development provides an opportunity to share Alberta's CCS regulatory experience internationally. It also provides valuable insight from other jurisdictions as work to enhance the regulatory framework for CCS activities continues.

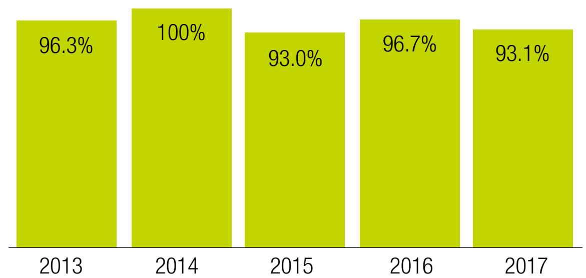
Performance Measures

Performance Measure 2.a: Timeliness of the need and facility applications (AUC)

Target

Percentage of needs and facility application (AUC):100 per cent of needs and facility applications determined within 180 days of the application being deemed complete.

Results



Source: Alberta Utilities Commission

Notes: The 2009 actual was revised from 97.8 per cent to 92 per cent to capture only needs and facility applications. The previously recorded results included applications for power plants and other minor facility applications which do not have the 180 day legislative deadline.

Discussion of Results

In accordance with standards established in Alberta law, when the AUC considers an application for expansion or enhancement of the capability of the transmission system, it must make a decision in a timely manner, and if possible, within 180 days after receipt of a complete application. This includes applications for approval, permit or licence relating to a needs identification document, transmission line or part of a transmission line.

For 2017, the AUC met this standard 93.1 per cent of the time as 27 of 29 decisions were issued within the 180-day timeline. The decisions that missed the 180-day deadline were delayed by procedural matters related to the deferral of a hearing (requested by participants), and prolonged record development phases for the two proceedings. Both decisions were issued within the 90-day extension period permissible through legislation.

OUTCOME 3

Albertans benefit from a stable, reliable electricity system that protects consumers, attracts investment, and has improved environmental performance.

What this means:

An electricity system that has reasonable prices, eliminates emissions from coal-fired electricity, and creates a positive investment climate is vital to the social and economic foundation of Alberta. A modern electricity system is needed in Alberta to support the transition to a cleaner energy future and meet the needs of a growing province. The Ministry of Energy collaborates with other ministries, agencies, stakeholders, and Indigenous communities to develop and deliver effective electricity system policies and programs.

Key strategies to achieve this outcome included:

3.1 Collaborate with other ministries to implement recommendations and manage regulatory requirements from Alberta's Climate Leadership Plan to transition Alberta's electricity system to a lower carbon system, including:

- Implement a plan to phase out emissions from coal fired electricity generation by 2030; and
- Deliver on Alberta's commitment to 30 per cent electricity production from renewables by 2030.

3.2 Develop and implement policy to smart regulate Alberta's electricity retail system that will protect consumers, including a Regulated Rate Option that will be capped from June 1, 2017 to May 31, 2021 at no more than 6.8 cents per kilowatt hour to protect families, farms and small business from price spikes.

3.3 Create a reliable electricity system that is affordable for Albertans and attractive to investors by implementing an electricity capacity market.

3.4 Collaborate with other governments to further explore electricity interties.

Key Achievements:

3.1 IMPLEMENTING THE CLIMATE LEADERSHIP PLAN

In 2016, the Government of Alberta outlined the Climate Leadership Plan, a made-in-Alberta strategy aimed at diversifying the economy, creating jobs and reducing greenhouse gas emissions that cause climate change.

The province's electricity sector is a key component of Alberta's Climate Leadership Plan. In 2015, about 16 per cent of the province's greenhouse gas emissions came from the electricity sector; the majority of it coming from coal-fired electricity generation. Alberta is ending pollution from coal-generated electricity by 2030, and developing more renewable electricity to transition to a lower carbon energy system. This includes allowing coal units to convert to natural gas where economically viable, and creating opportunities for private investment in generation technologies through initiatives like the Renewable Electricity Program (REP).

Coal Transition

Phasing out emissions from coal-generated electricity by 2030 is a key commitment under the Climate Leadership Plan and is a major and necessary step to reducing greenhouse gas emissions.

In late 2016, government announced off-coal agreements with ATCO, Capital Power, and TransAlta to end coal-fired emissions by 2030 and the provision of transition payments for the six coal-fired units expected to operate beyond 2030. As of September 2017, a third party audit of the companies' reported net book values was complete and the first of 14 annual transition payments were issued. The transition payments were paid from revenues generated by Alberta's price on industrial carbon emissions, and not from consumer electricity bills.

The Ministry of Energy remains engaged with its federal counterparts and generators in Alberta to ensure a smooth transition towards a lower carbon economy. Working together, the province and federal government are enhancing Alberta's international reputation as a responsible developer in the transition towards a lower carbon future – which is a competitive advantage in the global market.

The Ministry of Energy continues to support impacted coal community work led by the Ministry of Economic Development and Trade and the federal government. In 2017, the Coal Community Transition Fund and Coal Workforce Transition Program were released to support projects in coal communities and affected coal workers across the province.

Coal transition initiatives are crucial to Alberta's economy and enable the province to mitigate challenges and realize opportunities. These include the retirement of coal generation, the addition of renewables on an unprecedented scale, and the need to maintain investor confidence.

Renewable Electricity Program (REP)

On November 3, 2016, the Government of Alberta announced the implementation of the REP to support Alberta in meeting its target of 30 per cent of the electricity generated in the province coming from renewable sources by 2030. This target was committed to under the Climate Leadership Plan and put into force by the *Renewable Electricity Act*. REP will help to displace high emitting generation sources in Alberta's electricity system by increasing the production of electricity from renewable sources such as wind, solar, geothermal, sustainable biomass, and hydro.

The program is expected to add 5,000 megawatts of new renewable electricity capacity by 2030 using competitive processes administered by AESO. The Department of Energy is working closely with AESO to provide policy guidance, secure government approvals, and ensure alignment with other climate and electricity initiatives.

The Ministry of Energy will incent investment in Alberta's electricity system will be enabled through a series of open and transparent competitive processes to identify the most cost effective projects, while ensuring projects come online in a way that does not impact grid reliability. Successful projects will be privately funded and supported by reinvesting a portion of carbon revenues from large industrial emitters.

The first auction was started on March 31, 2017 and applied an indexed renewable energy credit mechanism to deliver the lowest program costs, create certainty for investors, and maximize competition. The provision of a set price for the power produced was designed to provide revenue certainty for project developers.

In December 2017, AESO announced three successful bids under Round One of the REP, totaling 600 megawatts of renewable electricity and setting a record for the lowest renewable electricity pricing in Canada.

- The weighted average bid price of the competitive bids came in at 3.7 cents per kilowatt hour, which is the lowest price for a utility scale project in Canada and among the lowest ever in North America.
- Projects will be built and operational by the end of 2019.
- The projects awarded contracts in the first round will result in about $1 billion of private-sector investment in green power generation in Alberta.
- The successful bidders will add approximately 600 megawatts of renewable power, or enough to power up to 255,000 homes from wind projects throughout the province. This amount represents 200 megawatts more than what was originally forecast.
- The exceptionally competitive response from investors means that even with the larger volume of megawatts procured, the cost of REP Round One will be lower than originally budgeted.

Successful Bidders and Projects

- Capital Power, an Alberta-based company will build the 201-megawatt wind project 60 kilometres southwest of Medicine Hat.
- EDP Renewables Canada Ltd. will build a 248-megawatt wind farm at their Sharp Hills project east of Hanna, roughly 50 kilometres north of Oyen.
- Enel Green Power North America, Inc. will build two projects – a 115-megawatt Riverview Wind Farm and a 31-megawatt Phase 2 of Castle Rock Ridge Wind Power Plant just outside of Pincher Creek.

In March 2018, the Government of Alberta announced plans for REP rounds two and three which will run in parallel and will build upon the key features that were essential to the success of Round One. Round Two has a procurement target of 300 megawatts and includes a minimum of 25 per cent Indigenous equity ownership requirement. Round Three has a procurement target of 400 megawatts and will follow the same format as Round One.

Eligible projects are:

- Limited to new or expanded renewable electricity generation projects located in Alberta;
- Able to connect to the existing distribution or transmission systems;
- Greater than five megawatts; and
- Utilize fuels that meet Alberta's definition of renewable energy resources as defined in the *Renewable Electricity Act*.

There were some lessons learned from Round One that are valuable to consider and integrate into future rounds. First, it was noted that procuring the total goal of 5000 megawatts in small, staged quantities and keeping the eligibility criteria simple resulted in strong competition which drove prices down. AESO administers the program, maintains the integrity of the competition and enabled the round to be successful. AESO is overseen by a fairness advisor and has the resources and ability to design and deliver REP auctions. It is also important to require all successful REP proponents to adhere to the same regulatory approvals to maintain consistency and ensure environmental impacts are addressed.

Through the first round of the program, the province has already secured 12 per cent of the 5000 megawatts planned for under the REP.

Coal-to-Gas Conversion

Coal-to-gas converted units will play a key role in the transition away from coal-fired generation to lower carbon sources of energy. Compared with new natural gas combined cycle plants, coal-to-gas conversions have the potential to reduce the capital costs of natural gas generation to replace coal-fired electricity by about 90 per cent. Coal-to-gas conversions will save overall capital while providing an approximate 50 per cent reduction in carbon dioxide emissions with even greater reductions in sulfur oxides, lead, and other pollutants from the existing coal fleet.

The Ministry of Energy is actively working to remove barriers and establish policy and regulatory clarity to enable companies to make informed decisions on converting coal-fired generating units to natural gas. The Ministry of Energy is working closely with its provincial and federal counterparts, industry, and stakeholders to ensure that transition from coal-to-gas are successfully implemented in Alberta.

Provincial Air Quality Standards

In 2017-18, the Ministry of Energy partnered with the Ministry of Environment and Parks in the development of a recommended provincial nitrogen oxides air quality standard for converted units through the multi-stakeholder Clean Air Strategic Alliance process.

On February 20, 2018, government advised the Clean Air Strategic Alliance working group (including industry, the Samson Cree First Nation, environmental non-government organizations, and local communities) that its consensus air quality recommendation was accepted and would be implemented for coal-to-gas converted generation units. This is the first consensus recommendation on an electricity issue from the Clean Air Strategic Alliance since the original 2003 Electricity Emissions Management Framework.

Federal Emissions Standards

In 2017-18, the Ministry of Energy worked with federal government counterparts (Environment and Climate Change Canada) in developing greenhouse gas regulations for coal-to-gas unit conversions. In particular, the ministry conveyed Alberta's interests and concerns related to the proposed federal emissions regulations to ensure the options considered would support industry while protecting the environment.

On February 16, 2018, Environment and Climate Change Canada released the proposed federal Regulations Limiting Carbon Dioxide Emissions from Natural Gas-Fired Generation of Electricity and amendments to the federal Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations. This includes greenhouse gas performance standards for coal-to-gas converted units.

The federal government incorporated much of Alberta's feedback in the proposed regulations. The new emissions standards provide Alberta generators with conversion options which will reduce emissions while maintaining jobs and creating investment in Alberta.

The Ministry of Energy continues to work with the Ministry of Environment and Parks, and Environment and Climate Change Canada to ensure the next steps are implemented accordingly.

Geothermal Energy

Geothermal energy comes from the heat beneath the earth's surface and can be harnessed for electricity generation. It is a renewable source because the heat beneath the surface is in constant production. Alberta has the opportunity to explore geothermal energy to be harnessed from abandoned oil and gas wells and reduce energy costs. Enabling renewable energy such as deep geothermal is an important part of the Government of Alberta's efforts to diversify its economy and meet climate objectives.

The Ministry of Energy is currently working in collaboration with cross-ministry and provincial agency partners to develop an interim regulatory roadmap in the absence of a deep geothermal regulatory framework. The Department of Energy is leading the initiative, supported by the Ministry of Economic Development and Trade, the Ministry of Environment and Parks, AER, Alberta Climate Change Office, and the Ministry of Indigenous Relations.

Unlike shallow geothermal development, Alberta does not have policies and regulation for deep geothermal resource development. Until this work is complete, deep geothermal pilot projects in Alberta are being assessed on a case by case basis as policy is developed. Stakeholder engagement has been important to better understand the nature of the deep geothermal resource in Alberta.

Dispatchable Renewables

The Ministry of Energy has made significant strides as we prepare to transition from coal and support more renewable electricity in the province. The province continues to work with industry and communities to explore options for the future of electricity in Alberta beyond coal.

Energy expert Terry Boston recommended that government encourage hydroelectric development in the province to enable intermittent resources such as wind and solar. In November 2017, the Government of Alberta directed AESO to assess how dispatchable renewables (including hydroelectric development, geothermal and biomass) and electricity storage could benefit the province's electricity system as it transitions towards 30 per cent renewable generation by 2030. Dispatchable generation means that electricity can be dispatched when there is a need for it, and adjusted or turned off when not required, such as hydroelectric generation.

AESO will provide its technical report to government by June 2018. AESO will carefully coordinate this assessment with ongoing capacity market design work and any future REP competitions.

3.2 PROTECTING CONSUMERS FROM ELECTRICITY PRICE SPIKES

In the current energy only electricity market, Alberta power consumers are vulnerable to sudden price spikes. Prices have increased by as much as 65 per cent (4.66 cents per kilowatt hour) in a single month (April 2011) or fallen by as much as 42 per cent (or 4.14 cents per kilowatt hour) in a single month (June 2014). Although the province in recent years has experienced historically low electricity prices, these trends are not expected to remain stable as Alberta's wholesale electricity prices return to more historic levels.

On November 22, 2016, the Government of Alberta announced the introduction of the Regulated Rate Option (RRO) price cap effective June 1, 2017, to ensure stable electricity prices as Alberta transitions to a reliable, low emission electricity system. The cap was made available to all consumers on the RRO, including residential, farm, irrigation, and small commercial consumers using less than 250,000 kilowatt hour of electricity per year.

Under the RRO, consumers pay the lower of the regulated rate or the government's rate from June 2017 through end of May 2021. An *Act to Cap Regulated Electricity Rates* came into effect in spring 2017. Subsequently, regulations have been enacted to achieve full implementation of the rate cap. Providers cannot bill customers more than 6.8 cents per kilowatt hour for the electricity component of their bill and should the cost be higher, the government will pay the provider the difference from carbon levy funds. Reinvesting the carbon fund levy into Alberta's electricity system enables the province to move to a more stable, greener electricity system. The rate cap provides price protection for Albertans until 2021 when the province will move to a capacity market system that provides more stability.

On January 1, 2018, the province also established a rate cap regulation for Medicine Hat. The RRO is the default electricity contract for the vast majority of Albertans, but does not apply to Medicine Hat consumers because the city operates its own power utilities. To ensure Medicine Hat residents receive the same protections as other Albertans, the government worked with the municipality to develop a regulation that keeps electricity prices stable and affordable.

The government requested that the Market Surveillance Administrator (MSA) consider options for enhancing the RRO. The department continues to consider what, if any, changes are required to the RRO, including consideration of the MSA report. As part of the implementation and administration of the RRO cap policy, the Department of Energy is working closely with agencies and partner ministries to ensure appropriate information, sharing, learning and communications. This will ensure the department has a good appreciation of the market factors that could impact the regulated rates.

3.3 TRANSITIONING TO A CAPACITY MARKET SYSTEM

On November 23, 2016, the government announced that Alberta would transition to a capacity market, based on recommendations from current and potential energy investors, external experts, consumer groups, and AESO. A capacity market will protect consumers from price volatility and ensure a reliable supply of electricity at stable, affordable prices.

Alberta currently has an "energy-only" electricity market. This market system relies on market volatility as the signal for new investment. In an "energy-only" system, investors look out for when electricity prices spike, and will rely on a few high-priced hours to recover their invested capital. Relying on this volatility and tighter supply of power as the drivers for investment is not expected to be a stable and reliable system in the future. This is particularly important as over the next 14 years, it is estimated that Alberta will need up to $25 billion of new investment in electricity generation to support the transition towards cleaner sources of energy and to meet the electricity needs of a growing province. Analysis indicates that an "energy-only" market system will not bring about the investments needed for new electricity generation capacity in Alberta.

Investors also appreciate the stability, predictability and familiarity of capacity markets. They are paid for the electricity they sell, but also for maintaining the ability to generate more if needed, managed through a competitive contracting process to ensure the best possible price for Albertans.

Implementing a capacity market in Alberta will help attract investment to facilitate the transition away from coal-fired generation and ensure Albertans have reliable, affordable electricity in the future.

Capacity markets are used throughout the world, including in the United States and United Kingdom. They currently serve over 137 million electricity consumers in more than 30 U.S. states.

The transition to a capacity market is critical to the success of a number of government electricity initiatives and to maintaining long-term electricity reliability. The capacity market framework will be in place by 2021.

Benefits of a capacity market include:

- Lower consumer costs compared to alternative options;
- Reduced price volatility and market uncertainty;
- Stable, reliable electricity supply;
- Investor confidence and timely development of new generation; and
- A smooth transition to greener electricity.

The Department of Energy is leading the policy development of the capacity market, and AESO is leading the technical design aspect of the capacity market. Throughout fall 2017, the ministry engaged numerous stakeholders to support and inform policy and legislation development of a capacity market. Stakeholders included incumbent generation, transmission, distribution, and retail companies, Rural Electrification Associations, industry associations, industrial load, potential investors, electricity-related non-governmental organizations, electricity agencies, and electricity consumer representatives. The department and AESO have been working closely together to ensure that the policy development and technical market designs align well.

The ministry addressed two key challenges this past fiscal in its work on capacity market. The first was to ensure that the ministry sought out timely stakeholder input to inform the development of the policy and technical design. Design complexity was also a factor. A significant number of interdependent changes and decisions need to be made as part of the transition to a capacity market. A delay in one change or decision could have a negative cascading impact on implementation timelines. Design and implementation will take two to three years due to:

- complexity required to design a capacity market;
- need for supporting legislation;
- requirement for a revised regulatory environment; and
- need for robust regulatory approvals

The design and implementation of a capacity market is an intense and technical endeavor, particularly to meet implementation by 2021. Close collaboration between the Department of Energy, and Alberta's electricity agencies and sector stakeholders has proven essential to this work. Coordination of engagements led by the department and AESO was important to ensure stakeholders were able to participate in both processes.

3.4 EXPLORING ELECTRICITY INTERTIES

Transmission interties enable the import and export of electricity into and out of Alberta. Interties enable the province to maintain supply stability and resiliency in its electricity system and offer economic benefits to Alberta's electricity generators through electricity export. The Government of Alberta supports transmission interties with other jurisdictions that benefit the province.

Regional Electricity Cooperation and Strategic Infrastructure Initiative (RECSI)

RECSI is a Government of Canada initiative involving the governments and electric system operators from Alberta, British Columbia, Saskatchewan, Manitoba, and the Northwest Territories.

Through the RECSI study the federal government and provinces are exploring promising electricity infrastructure projects in the western provinces with the potential to assist Alberta and Saskatchewan in transitioning to low-carbon electricity generation.

AESO may use existing and/or new interties to manage the system as more intermittent renewable energy is added to the province's electricity system. AESO is also actively considering how interties are treated in the capacity market as it may impact the degree to which electricity is imported and exported moving forward. It should be noted that renewable electricity imported into the province through interties will not count towards the 30 per cent renewable electricity by 2030 target.

Generally, greater intertie connectivity between Alberta and its neighbours provides greater options on how to flow power in and out of Alberta, which can support grid resiliency. The ministry will consider leveraging the RESCI study results to:

- Pursue opportunities for federal funding for intertie development.
- Understand how intertie volumes in the capacity market will be treated, and consider the development of an intertie policy.

Controlling transmission costs in Alberta continues to be a key focus area for the Ministry of Energy as it aligns with the Government of Alberta's consumer protection goals. Consumers in Alberta bear the cost of transmission, and divide the costs of interties between jurisdictions. Infrastructure costs, both transmission and distribution are currently the largest portion of a residential consumer's bill. Building more transmission could add to consumer cost in the absence of other funding sources such as federal infrastructure funding.

OUTCOME 3

Performance Measures

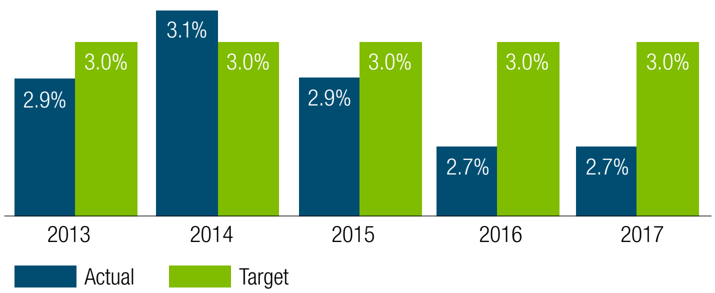
Performance Measure 3.a: Transmission Losses

Target

To maintain a minimum level in transmission line losses. The target for 2017 was 3.0% ± 0.3%.

Results

Actual and Target Transmission Line Losses (%)



Discussion of Results

Electricity is a facilitator of economic development in Alberta. A reliable and resilient electricity transmission system is required to ensure electricity can be delivered where and when it is needed. By ensuring development of a robust transmission system, renewable and thermal generators will know that they will be able to efficiently move their product to market, and to the consumers that depend on it daily. The transmission system has been, and continues to be, built to accommodate greater amounts of renewable energy to support Alberta's transition to a low carbon grid. Existing and near-term infrastructure projects are expected to support greater amounts of renewable generation in the south and central-east regions. Generally, there is renewable energy potential throughout the province. Optimal use of power from these sources depends on our ability to bring it to where it is needed.

Transmission losses are an indicator of efficiency of the transmission system. A transmission system with adequate capacity will have lower losses than a system that requires upgrading. The hourly volumes of line losses vary based on load and export levels, the distance between generation and load, and changes in the transmission topology. Transmission and generation outage schedules, unplanned transmission and generation outages, and market dispatches also affect the volume of losses. The value of line losses is calculated on the hourly pool price.

The transmission loss of 2.7 per cent for 2017 meets the target of 3.0 ±0.3 per cent. The benefits of maintaining low transmission line losses for Albertans are lower system costs, reduced wasted energy, and the environmental benefits associated with the need for less electricity generation.

Until recently, the line loss target was a qualitative target that was drawn from the transmission policy development process in 2003. At the time, a target of three per cent was deemed reasonable.

However, starting in 2018, the methodology for calculating line loss targets was changed to reflect the five-year rolling average of prior line losses. As well, the five-year rolling averages used data from the annual totals of the monthly loss factor customer volumes and monthly loss volumes. These line losses are calculated in the AESO's Rider E Calibration Factor report for each quarter, which results in slightly higher actual line losses because both volumes use data up to the meter. In previous years, the generation volume included generation behind the meter, resulting in a lower calculated line loss value.

Performance Measure 3.b: Power Generation

Target

Maintain a minimum seven per cent margin over peak demand.

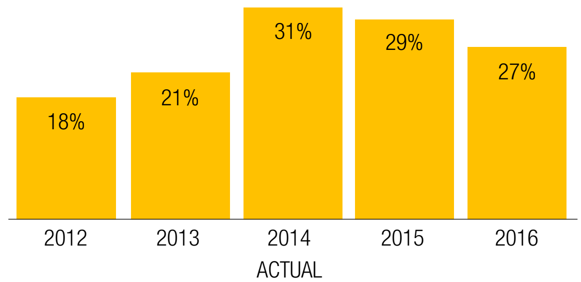
Discussion of Results

Alberta's economic prosperity and high standard of living relies on access to reliable and plentiful electricity. Maintaining a reliable and resilient electricity system as measured by the health of the power margin is a key objective of every electric system around the world.

For this measure, the desired outcome is to maintain a minimum seven per cent margin over the annual peak demand. The seven per cent margin is a specific identifiable reliability requirement set by the Western Electricity Coordinating Council, the regional entity responsible for coordinating electric system reliability in several jurisdictions in Canada, United States and Mexico.

Results

Power Generation: Margin between Firm Generating Capacity[1] and Peak Demand



Sources: Alberta Utilities Commission (AUC), Alberta Electric System Operator (AESO) and Alberta Department of Energy.

[1] Firm Generating Capacity excludes:
- wind power, which is not dispatchable on a consistent basis;
- small hydro, which has minimal storage capability for operation during winter, when peak demand occurs;
- 25 per cent of large hydro, to reflect limitations on its output during winter, when peak demand occurs; and
- tie line capacity, which is not dispatchable on a consistent basis.

In 2017, this target was surpassed, with a 27 per cent margin. Firm electricity generating capacity was calculated at 14,905 MW for 2017. This was a 169 MW (or 1.1 per cent) increase over the 2016 level. The peak demand in the winter period of the climatic year (October 1, 2017 to March 31, 2018) was 11,697 MW. This was 239 MW (or 2.1 per cent) higher than the peak of 11,458 MW set in the winter climatic year (October 1, 2016 to March 31, 2017).

Under Alberta's current energy-only system, Alberta defers to market forces and private investors to build generation and determine the amount of the excess generating capacity to meet the highest system demand when it occurs. Challenges with this system have surfaced in recent years. Alberta will need up to an estimated $25 billion of new investment in electricity generation by 2030 to support the transition toward cleaner sources of energy and meet the electricity needs of a growing province. Concerns were raised by the Alberta Electric System Operator that the current energy-only system may not ensure the investment in new generation that Alberta will need in the future. This was supported by third-party analysis that reported a global trend toward reluctance among developers around investing in energy-only markets.

In November 2016, government announced Alberta would transition from an energy-only system to a capacity market framework. It was determined that a capacity market framework would better enable Alberta to attract future investment in electricity generation to meet both projected growth in electricity use and replacement of retiring supply. As such, there is work currently underway to transition Alberta's electricity market to a capacity market framework. The most salient feature of a capacity market is for government to mandate and administratively provide for sufficient private investment in electricity generation capability for the province instead of relying only on the energy-only market to serve that function. Based on the current timelines, a capacity market is due to be in place in Alberta in 2021. For this reason, this performance measure is no longer necessary. Under a capacity market the amount of new generation builds will be administratively determined and a government agency is mandated to ensure the sufficient generation is built in a timely fashion.

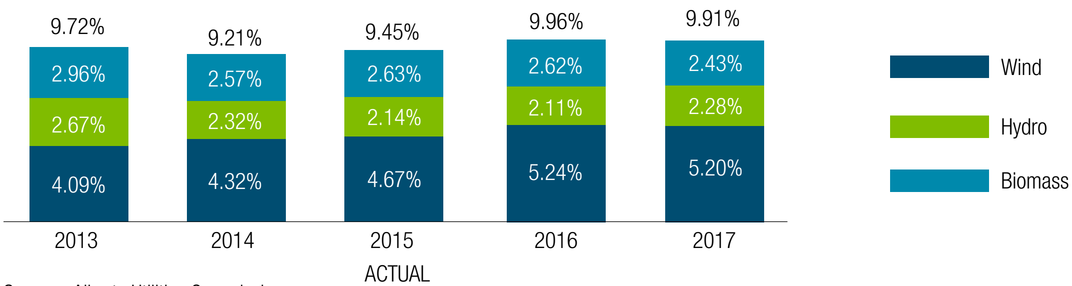
Performance Measure 3.c: Percentage of electricity produced in Alberta from renewable sources (megawatts)

Target

30% of electricity generation from renewables by 2030.

Results

Renewable Electricity Share of Total Generation*



Sources: Alberta Utilities Commission
*Totals may not add up due to rounding

Discussion of Results

Moving away from coal-fired electricity towards renewable energy sources is a key pillar of the Climate Leadership Plan. Increasing renewable electricity generation will help Alberta reduce its greenhouse gas emissions.

Under the *Renewable Electricity Act*, Alberta has established a target that at least 30 per cent of the electric energy produced in Alberta will come from renewable energy resources by 2030. The renewable electricity generated will be measured on an annual basis.

The percentage change between 2016 and 2017 indicates a small decrease in the renewable electricity share of total generation; however, there was an increase in both renewables and non-renewable generation and a cumulative increase in electricity generation. While renewable electricity generation had a slight increase (approx. 25GWh), total electricity generation had a substantial increase (approximately 690 GWh). This was responsible for the decrease in the percentage of electricity generation from renewables from 9.96 per cent in 2016 to 9.91 per cent in 2017. According to AESO forecasts, it is expected that the percentage of renewable electricity generated will significantly increase in 2019-20, when REP rounds come on line.

Renewable electricity generation in Alberta since the mid-1990s has grown mostly based on market signals rather than through government incentives and support programs. Moving forward, renewable generation is expected to grow based predominately through the Renewable Electricity Program as well as other government incentive programs for community and small scale generation. The REP was established to encourage the development of 5,000 MW of renewable electricity generation capacity connected to the Alberta grid between now and 2030. The AESO is responsible for implementing and administering the program through a series of competitions that will incent the development of renewable electricity generation through the purchase of renewable attributes.

This measure will help track and report on the progress towards ensuring at least 30 per cent of the electric energy produced in Alberta comes from renewable energy sources by 2030.

Discussion of Risks

The Ministry of Energy used the internationally recognized ISO 31000 Standard for Risk Management to provide principles, framework and a process for managing organizational risks. The Department of Energy applied this standard to assist staff in identifying and mitigating challenges that would adversely affect achievement of department outcomes and key strategies as described in Energy's 2017-20 Business Plan.

The flow of capital investment into Alberta for the development of energy and mineral resources was identified as a key area of risk, which could impact upon Albertans ability to benefit economically from responsible energy and mineral development. The PDP, the introduction of the *Energy Diversification Act*, the continued fight for pipelines and market access, and the AER's implementation of the Integrated Decision Approach (one application-one review-one decision) are examples of measures the ministry has taken to mitigate this risk.

The electricity system was identified as a key area of risk, as Alberta moves towards a stable, reliable electricity system that protects consumers, attracts investment, and has improved environmental performance. The REP, the transition to a capacity market system, the implementation of the *Act to Cap Regulated Electricity Rates*, providing consumers with a RRO cap, and RESCI are examples of efforts the Ministry of Energy has taken to reduce risk and achieve department outcomes.

The Ministry of Energy also recognised that decisions on energy resource development require careful consideration of economic, environmental and social outcomes, and that consultation and engagement are key to mitigating risks. The ministry has enhanced capacity in these areas by establishing an Engaging Communities Practice Group. The ministry continues to collaborate with other ministries through IRMS and conducts engagement sessions with Indigenous communities, industry participants and other stakeholders.

Appendix A: Energy Highlights

Resource		2016-17	2017-18
Bitumen	Revenue	$1.48 billion	$2.64 billion
	Percentage of non-renewable resource revenue	48%	53%
	Bitumen wells drilled[1]	610 (2016)	1,309 (2017)
	Total bitumen production in bbl/d	2.54 million bbl/d (2016)	2.83 million bbl/d (2017)
	Marketable bitumen and Synthetic Crude Oil (SCO) production	2.41 million bbl/d (2016)	2.68 million bbl/d (2017)
Conventional Crude Oil	Revenue	$0.72 billion	$0.96 billion
	Percentage of non-renewable resource revenue	23%	19%
	Average price for West Texas Intermediate (WTI)	US$47.94/bbl	US$53.69/bbl
	Conventional crude oil production	0.44 million bbl/d (2016)	0.45 million bbl/d (2017)
	Pentanes and condensate production	0.22 million bbl/d (2016)	0.27 million bbl/d (2017)
	Crude oil wells drilled[1]	836 (2016)	1,831 (2017)
Total Crude and Equivalent	Revenue[2]	$2.21 billion	$3.61 billion
	Production (conventional, marketable bitumen and SCO, pentanes plus and condensates)	3.08 million bbl/d (2016)	3.40 million bbl/d (2017)
	Removals from Alberta[3]	2.96 million bbl/d (2016)	3.25 million bbl/d (2017)
	* % of total crude oil and equivalent disposition	86% (2016)	85% (2017)
Natural Gas and By-Products	Revenue	$0.52 billion	$0.64 billion
	Percentage of non-renewable resource revenue	17%	13%
	Average Alberta Gas Reference Price (ARP)	$2.01/GJ	$1.82/GJ
	Number of conventional natural gas wells drilled[1]	811 (2016)	1,295 (2017)
	Total marketable natural gas production including Coalbed Methane (CBM)	3.7 Tcf (2016)	3.8 Tcf (2017)
	Coalbed Methane production[4]	0.23 Tcf (2016)	0.22 Tcf (2017)
	Total natural gas deliveries[5]	4.23 Tcf (2016)	4.38 Tcf (2017)
	* To the United States	35%	37%
	* Within Alberta	38%	40%
	* To rest of Canada	27%	23%

Notes:
1 Data on wells drilled include both development and exploratory wells.
2 Royalty revenue result for 2016-17 has been retroactively adjusted due to reclassification that took place since the publication of the previous Annual Report.
3 Alberta Energy Regulator no longer reports the split between oil volumes that are sent to the United States and to the rest of Canada. All volumes, removed from Alberta, are reported as a single category. 2016 total crude oil deliverables and disposition percentage results have been retroactively revised, due to the change in methodology.
4 Coalbed methane value for 2017 is an estimate.
5 2016 total natural gas deliveries and gas disposition percentages are retroactively revised, on the basis of an updated source.

Resource		2016-17	2017-18
Bonuses and Sales of Crown Leases	Revenue from bonuses and sales of Crown leases	$0.20 billion	$0.56 billion
	Revenue from rentals and fees	$0.15 billion	$0.15 billion
	Average price per hectare (ha) paid at petroleum and natural gas rights sales[6]	$194.16	$415.45
	Petroleum and natural gas hectares sold at auction[6]	977,223 ha	1,229,511 ha
	Average price per hectare paid for oil sands mineral rights[6]	$239.35	$234.09
	Oil sands hectares sold at auction[6]	55,458 ha	222,792 ha
Freehold Mineral Tax	Revenue	$57 million	$67 million
Wells and Licences	Well licences issued	3,608 (2016)[7]	5,800 (2017)
	Industry drilling	3,025 (2016)[8]	5,308 (2017)
Coal	Revenue	$26 million	$12 million
	Established coal reserves (estimate)	33.2 billion tonnes	33.2 billion tonnes
	Raw coal production	29.6 million tonnes (2016)	26.8 million tonnes (2017)
	Total marketable coal deliveries	26,1 million tonnes (2016)	24.2 million tonnes (2017)
	Percentage of total coal deliveries exported out of province	14.5% (2016)	13.3% (2017)
Electricity	Total generation capacity in Megawatts (MW)	16,525 MW (2016)	16,702 MW (2017)
	Total generation capacity from renewable sources	2,831 MW (2016)	2,828 MW (2017)
	Total generation capacity from coal	6,273 MW (2016)	6,273 MW (2017)
Metallic and Industrial Minerals	Metallic and Industrial minerals Royalty Revenues (MINRS)	$511,693	$540,773
	Hectares of mineral permits issued to exploration companies (LAMAS,MIM Permits and New Application Issued)	1.5 million ha	2.0 million ha

Notes:

6 Excluded from these figures are direct sales which comprise of fractional land, complementing rights or single substance leases. These sales are initiated by the purchaser and are therefore not predictable in nature.

7 Total well licences data for 2016 has been retroactively revised.

8 Total industry drilling data for 2016 has been retroactively revised. 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.

Appendix B: Performance Measures & Indicators Methodology

Performance Measure 1.a: Revenues from oil, oil sands, gas and land sales bonuses are fully collected

Oil:

Oil royalty volumes owed to the Crown are calculated in the Royalty and Marketing (RAM) system. The volumes owed to the Crown are taken in kind, rather than invoiced. The volumes owed are imported from RAM into the Crude Oil Operations (COO) system. Reconciliations between the volumes calculated by RAM and the volumes actually delivered by industry are performed by the department, who also follows up and resolves any discrepancies. The department collects the revenue for the Crown's volumes marketed either directly, or by the Crown's agents, then calculates the net value of all royalty sales, and remits the proceeds to Treasury Board and Finance.

Oil Sands:

Oil Sands Administrative and Strategic Information System (OASIS) calculates the monthly amounts to be collected based on the Good Faith Estimates, the Monthly Royalty Calculations and the Non-Project Royalty reports and annual adjustments based on the End of Period Statements. All royalty reporting must be submitted electronically to the Department of Energy, using the webbased Electronic Transfer System (ETS). OASIS then sends the charge information to the Corporate Accounting and Reporting System (CARS2). During these processes, there are limited manual interfaces. An information report is available from OASIS to identify the reconciliation of OASIS to CARS2 charge transfers.

Land Sale Bonuses:

The majority of oil sands and petroleum and natural gas agreements are acquired through a public tender process. Each year the department holds an average of 24 public sales, referred to as "Public Offerings." The word "sale" is used by tradition, although it is a misnomer, since the Crown always retains title to its minerals. The rights are leased, not sold. The process is an auction, in which companies or individuals submit bids on a parcel of oil sands or petroleum and natural gas rights.

The highest bidder for each parcel is generally awarded an agreement. Individuals or companies submit a posting request electronically to the department through webbased ETS. The Public Offering, available on the department's website, is published eight weeks in advance of the sale date. Bidders can electronically submit bids for sale parcels through ETS until noon on the sale day. After this deadline, a user cannot submit or withdraw a bid.

The total bid for each parcel must include a $625 agreement issuance fee, the first year's annual rental of $3.50 per hectare, and the bonus amount, as determined by the bidder. For oil sands rights, the standard minimum bonus bid is $2.50 per hectare for leases and $1.25 per hectare for permits. For petroleum and natural gas rights, the standard minimum bonus bid is $2.50 per hectare for leases and $1.25 per hectare for licences. The Electronic Funds Transfer is the form of payment accepted for winning bids. The results of the sale are published on the department's website by 3:30 p.m. on the sale day. The sale results include the parcel number, the name of the successful bidder and the bonus amount paid for each parcel.

After the sale, winning bids are uploaded from ETS to the Land Automated Mineral Agreement System (LAMAS). The following day, winning bids are uploaded from LAMAS to the Alberta Mineral Information (AMI) system. Payments are typically pulled electronically through LAMAS via EFT (Royal Bank on behalf of the department) on the day of the sale or the following day. Payments are then transferred to CARS2 as Revenues and Receivable. Payment is reflected in CARS2 as Cash in Transit and Receivables, which are then entered into IMAGIS.

Gas:
The Mineral Revenues Information System (MRIS) receives the data to perform monthly royalty calculations and generates a Gas Royalty Invoice on a monthly basis. MRIS passes a file to CARS2 and a Statement of Account is generated on or before the fifteenth of each month in MRIS and then issued to industry. Payments are due on the last day of the month. Aged Analysis reports are generated monthly on the CARS2 system. Collection action occurs on accounts that are past due.

Performance Measure 1.b: Alberta's oil sands supply share of global oil consumption

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

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 AER's reports. Global oil consumption data is based on the Oil Market Report, published by the International Energy Agency.

Performance Indicator 1.a: Alberta's total crude bitumen production (thousands of bbl/d)

The indicator reports total bitumen production in Alberta, which is the sum of total mined bitumen production and total in-situ bitumen production. Bitumen production data is calculated from the AER's reports. For this indicator, data is compiled and presented on a calendar year basis.

Performance Indicator 1.b: Alberta's conventional crude oil and equivalent annual production (thousands of bbl/d)

For this indicator, Ministry of Energy reports conventional crude oil and equivalent production volumes that consist of volumes of conventional light, medium, heavy and ultra heavy oil, as well as volumes of pentanes and condensate. The production data is calculated from AER's reports by adding all components that make up conventional crude oil, and condensate and pentanes plus. This indicator excludes oil sands derived oil volumes. For this indicator, data is compiled and presented on a calendar year basis.

Performance Indicator 1.c: Alberta's total marketable natural gas annual production (billion cubic feet per day)

For this indicator, Ministry of Energy reports total marketable natural gas production volumes. The volume of total marketable natural gas includes conventional marketable gas, coal bed methane and shale gas production; however, the volume cannot be broken down by different streams of gas, and is reported as a single volume. Marketable natural gas production data is calculated from the AER's reports. For this indicator, data is compiled and presented on a calendar year basis.

Performance Indicator 1.d: Upstream: Mining, Quarrying, and Oil and Gas industry investment in Alberta (Formerly: Upstream Oil and Gas Industry Investment in Alberta).

The present, 2017-18 Annual Report is the first Annual Report that reports the revised version of the indicator. Previously, the indicator focused only on oil and gas extraction, which consists of both conventional oil and gas, and oil sands extraction. The revised indicator has been expanded to include the entire upstream energy extraction sector; in addition to oil and gas extraction, the expanded indicator now also covers mining and quarrying, and support activities for mining, and oil and gas extraction.

The updated indicator has been reported by Ministry of Energy in the 2018-21 Business Plan; the present Annual Report has switched to directly reporting the indicator based on the new methodology, as opposed to continuing methodology aligned with the 2017-20 Business Plan, to ensure full consistency of the indicator with investment data presently reported by Ministry of Energy.

The data for the Indicator is taken from Statistics Canada. Data is reported on a calendar year basis. In addition to actual results, the revised indicator now also reports the most current preliminary actual result, to enhance the timeliness of data presentation. This represents another change from the previous version of the indicator, which only reported the actual results.

Performance Indicator 1.e: Total percentage of crude oil leaving Alberta

For this indicator, Ministry of Energy reports a share of total volumes of crude oil leaving Alberta as a percentage of total disposition. All data is calculated from the AER's reports. Due to the revision of the source report by the AER, the results included in the 2016-17 Annual Report have been retroactively revised. Also, due to the change in reporting, the option of further breaking down oil volumes by volumes that are sent to the United States and to the rest of Canada, as was done in the 2016-17 Annual Report, is no longer available. Presently, all volumes that leave Alberta are reported by the AER as a single stream, identified as "removals from Alberta". For the indicator, the results are compiled and reported on a calendar year basis.

Performance Indicator 1.f: Total percentage of natural gas leaving Alberta

For this indicator, Ministry of Energy reports the share of total volumes of natural gas leaving Alberta as a percentage of total disposition. All data is calculated from the AER's reports. Due to the revision of the source report by the AER, the results included in the 2016-17 Annual Report have been retroactively revised. Unlike in the case of "Total percentage of crude oil leaving Alberta" indicator, AER reports greater detail for disposition destinations; therefore, the present Annual Report provides further breakdown by shares of disposition going to the United States and the rest of Canada. For the indicator, the results are compiled and reported on a calendar year basis.

Performance Measure 2.a: Timeliness of the needs and facility applications

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 AUC deems the application complete. The status of applications is tracked daily.

Performance Indicator 2.a: Regulatory compliance

The AER established a target of 97 per cent for this measure in 2014 based on data compiled during the transition to the new compliance assurance framework, which better reflects its new authorities and mandate. The target is the expected percentage of inspections conducted that are in compliance with regulatory requirements.

AER staff inspects operations of the upstream oil and gas and coal mining industries with respect to the drilling, production, and disposal of hydrocarbons and associated wastes. All inspection results are recorded into the Field Surveillance Inspection System (FIS) and result in an outcome of either compliant or noncompliant. If the inspection is noncompliant the triage tool is used to assess the significance of the noncompliance and determine the need for an investigation. If an investigation is warranted, information and evidence is collected relevant to the noncompliance. The investigation will determine if an enforcement action is required. The data is based on inspections performed in 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, and is counted based on the year the inspection was initiated.

Performance Indicator 2.b: Pipeline incidents

The AER is focused on ensuring the safe transportation of hazardous products by regulating development in a way that reduces risk and ensures Albertans reap the economic rewards of the energy resources. A reportable pipeline incident under the AER's jurisdiction is any pipeline release, break or contact damage (regardless if there is a release) (Section 35 of the *Pipeline Act*). Incident information is entered into the AER's FIS database by AER inspectors. The incident information is used to assign a consequence rating by the AER to indicate the potential severity of an incident. The rating is based on information of the incident regarding a set of indicators that reflect the impacts on the environment, wildlife, and public. 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.

The Pipeline Technical Specialist and Industry Operations pipeline subject matter experts regularly complete data integrity reviews on pipeline incident records, which include the consequence rating assigned, and the inspection data. Records are reviewed for accuracy and consistency with established data integrity procedures.

Performance Measure 3.a: Transmission losses

Every year, the AESO publishes two data points required for transmission line loss calculations: Alberta's annual internal load (in gigawatt hours) and line losses (in gigawatt hours). The calculation for this performance measure is:

$$\text{Transmission Losses (\%)} = \frac{\text{Line Losses}}{\text{Alberta's annual internal load volumes}} \times 100\%$$

Source Documentation: AESO publishes Alberta's annual internal load each year in its Annual Market Statistics report. AESO publishes line losses each year in its annual report. AESO calculates line losses as follows:

$$\text{Line Losses} = (\text{Total Generation} + \text{Imports}) - (\text{Total Consumption} + \text{Exports})$$

Performance Measure 3.b: Power generation

The intent of the measure is to demonstrate that there is sufficient margin between firm electricity generating capacity and peak demand. The margin for the measure is reported as the percentage megawatt difference between firm generating capacity and peak demand. For this performance measure, all wind and a portion of the hydro capacity, which are not dispatchable on a consistent basis, are excluded from the total installed generating capacity. Peak demand is defined as the highest hourly recorded system demand (in megawatt-hours) in the climatic year (October 1, 2017 to March 31, 2018) as recorded by the AESO.

Performance Measure 3.c: Renewable generation

In Alberta, a renewable energy resource means an energy resource that occurs naturally and that can be replenished or renewed within a human lifespan, including, but not limited to moving water, wind, heat from the earth, sunlight, and sustainable biomass.

Electricity generation data from both renewable and non-renewable sources is collected and reported annually by the AUC. The source of information is regulatory filings under the *Hydro and Electric Energy Act* by operators of power generating facilities.

The result of the measure, for any given year, is calculated as follows:

$$\frac{\text{Electricity generated in Alberta from all renewable sources (megawatt hours)}}{\text{Total electricity generated in Alberta (megawatt hours)}} \times 100\%$$

The data is collected and reported annually by the AUC.

Financial Information

MINISTRY OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2018

Independent Auditor's Report

Auditor General OF ALBERTA

To the Members of the Legislative Assembly

Report on the Consolidated Financial Statements

I have audited the accompanying consolidated financial statements of the Ministry of Energy, which comprise the consolidated statement of financial position as at March 31, 2018, and the consolidated statements of operations, change in net debt and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these 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 consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these consolidated financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Ministry of Energy as at March 31, 2018, 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.

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

June 6, 2018
Edmonton, Alberta

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF OPERATIONS

Year ended March 31, 2018

(in thousands)

	2018		2017
	Budget	Actual	Restated - Note 3 (Note 23)
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 3,754,000	$ 4,980,149	$ 3,104,550
Freehold Mineral Rights Tax	90,000	67,360	57,059
Industry Levies and Licenses	309,776	291,681	300,114
Other Revenue	5,539	14,155	10,265
Net Income/(Loss) from Government Business Enterprises	69,000	802,467	(1,921,895)
	4,228,315	6,155,812	1,550,093
Expenses - Directly Incurred (Schedule 2)			
Ministry Support Services	5,696	6,712	6,189
Resource Development and Management	90,867	95,023	92,993
Cost of Selling Oil	85,000	74,623	65,140
Climate Leadership Plan	34,884	33,598	1,118,786
Carbon Capture and Storage	214,984	50,898	30,659
Energy Regulation	251,256	253,253	245,959
Utilities Regulation	36,129	33,123	31,123
Orphan Well Abandonment (Note 4)	30,500	15,796	31,028
Post-Closure Expense	230	-	-
	749,546	563,026	1,621,877
Annual Surplus/ (Deficit)	$ 3,478,769	$ 5,592,786	$ (71,784)

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at March 31, 2018

(in thousands)

	2018 Actual	2017 Restated - Note 3 (Note 23)
Financial Assets		
Cash and Cash Equivalents (Note 5)	$ 269,913	$ 274,136
Accounts Receivable (Notes 6)	540,300	284,830
Inventory for Resale (Note 8)	1,319	914
Pension Assets/(Obligations) (Note 9)	1,028	918
Equity in Government Business Enterprises		
Alberta Petroleum Marketing Commission (Schedule 3)	104,999	65,073
The Balancing Pool (Schedule 4)	(1,189,462)	(1,952,003)
	(271,903)	(1,326,132)
Liabilities		
Accounts Payable and Accrued Liabilities	115,431	98,082
Gas Royalty Deposits (Note 10)	112,312	112,066
Unearned Revenue	64,165	67,110
Tenant Incentives (Note 11)	22,037	20,947
Coal Phase-Out Agreements (Note 13)	1,049,673	1,114,613
Capital Lease Obligations	88	-
	1,363,706	1,412,818
Net Debt	(1,635,609)	(2,738,950)
Non-Financial Assets		
Tangible Capital Assets (Note 14)	95,357	91,381
Prepaid Expenses	13,127	12,258
Net Liabilities	(1,527,125)	(2,635,311)
Net Liabilities at Beginning of Year	(2,635,311)	(310,471)
Annual Surplus/(Deficit)	5,592,786	(71,784)
Net Financing Provided For General Revenues	(4,484,600)	(2,253,056)
Net Liabilities at End of Year	$ (1,527,125)	$ (2,635,311)

Contractual rights (Note 7)

Contingent Liabilities, Contractual Obligations and Program Commitments (Notes 15, 16 and 18)

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF CHANGE IN NET DEBT

As at March 31, 2018

(in thousands)

	2018 Actual	2017 Restated - Note 3 (Note 23)
Annual Surplus/(Deficit)	$ 5,592,786	$ (71,784)
Acquisition of Tangible Capital Assets (Note 14)	(24,796)	(17,935)
Amortization of Tangible Capital Assets (Note 14)	20,790	21,530
Loss on Disposal of Tangible Capital Assets (Note 14)	604	78
Proceeds on Disposal of Tangible Capital Assets (Note 14)	6	-
Transfer (in) of Tangible Capital Assets (Note 14)	(613)	-
Manual adjustment to Opening Tangible Capital Assets (Note 14)	33	-
(Increase)/Decrease in Prepaid Expenses	(869)	75
Net Financing Provided For General Revenue	(4,484,600)	(2,253,056)
Decrease/(Increase) in Net Debt	1,103,341	(2,321,092)
Net Debt at Beginning of Year	(2,738,950)	(417,858)
Net Debt at End of Year	$ (1,635,609)	$ (2,738,950)

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended March 31, 2018

(in thousands)

	2018 Actual	2017 Restated - Note 3
		(Note 23)
Operating Transactions		
Annual Surplus/(Deficit)	$ 5,592,786	(71,784)
Net (Income)/Loss from Government Business Enterprises	(802,467)	1,921,895
Non-cash Items included in Annual Surplus/(Deficit)		
Amortization of Tangible Capital Assets (Note 14)	20,790	21,530
Transfer of Tangible Capital Assets (Note 14)	(613)	-
Manual adjustment to Opening Tangible Capital Assets (Note 14)	33	-
Change in Pension obligations	(110)	(2,375)
Loss on Disposal of Tangible Capital Assets (Note 14)	604	78
	4,811,023	1,869,344
Increase in Accounts Receivable	(255,470)	(132,879)
Increase in Inventory for Resale	(405)	(637)
(Increase)/Decrease in Prepaid Expenses	(869)	75
Increase/(Decrease) in Accounts Payable and Accrued Liabilities	17,349	(285,740)
Decrease in Unearned Revenue	(2,945)	(1,987)
(Decrease)/Increase in Coal Phase-Out Agreements	(64,940)	1,114,613
Increase/(Decrease) in Tenant Incentives	1,090	(1,376)
Increase in Capital Lease Obligations	88	-
Cash Provided by Operating Transactions	4,504,921	2,561,413
Capital Transactions		
Acquisition of Tangible Capital Assets (Note 14)	(24,796)	(17,935)
Proceeds on Disposal of Tangible Capital Assets (Note 14)	6	-
Cash Applied to Capital Transactions	(24,790)	(17,935)
Financing Transactions		
Net Financing Provided for General Revenues	(4,484,600)	(2,253,056)
Increase/(Decrease) in Gas Royalty Deposits	246	(100,886)
Cash Applied to Financing Transactions	(4,484,354)	(2,353,942)
(Decrease)/Increase in Cash and Cash Equivalents	(4,223)	189,536
Cash and Cash Equivalents at Beginning of Year	274,136	84,600
Cash and Cash Equivalents at End of Year	$ 269,913	$ 274,136

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

MINISTRY OF ENERGY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
March 31, 2018
(in thousands)

NOTE 1 AUTHORITY & PURPOSE

The Minister of Energy has been designated as responsible for various Acts by the *Government Organization Act* and its regulations. To fulfill these responsibilities, the Minister administers the organizations listed below. The authority under which each organization operates is also listed. Together, these organizations form the Ministry of Energy.

Organization	Authority
Department of Energy (The Department)	*Government Organization Act*
Alberta Energy Regulator (The AER)	*Responsible Energy Development Act*
Alberta Utilities Commission (The AUC)	*Alberta Utilities Commission Act*
Alberta Petroleum Marketing Commission (The Commission)	*Petroleum Marketing Act (as amended on January 10, 2014) and the Natural Gas Marketing Act*
Post-Closure Stewardship Fund	*Mines and Minerals Act*
The Balancing Pool (The BP)	*The Electric Utilities Act (2003)*

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

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

(a) Basis of Consolidation

The Department of Energy, the AER, the AUC, and the Post-Closure Stewardship Fund, which all report under Canadian public sector accounting standards, are consolidated on a line by line basis.

The accounts of government sector entities, except those designated as government business enterprises, are consolidated using the line-by-line method. Under this method, accounting policies of the consolidated entities are adjusted to conform to government accounting policies and the results of each line item in their financial statements (revenue, expense, assets, and liabilities) are included in government's results. Intra-ministry transactions (revenue, expenses, capital, investing and financing transactions, and related asset and liability accounts) have been eliminated.

The Commission and The BP are government business enterprises and are accounted for on a modified equity basis, with the equity being computed in accordance with International Financial Reporting Standards (IFRS). Under the modified equity method, the accounting policies of the Commission and the BP are not adjusted to conform to those of the Ministry of Energy. Inter-entity revenue and expense transactions and related asset and liability balances are not eliminated.

(b) Basis of Financial Reporting

Revenues

All revenues are reported on the accrual basis of accounting. Cash received for which goods or services have not been provided by year end is recognized as unearned revenue.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) Basis of Financial Reporting (cont'd)

Revenues (cont'd)

The provincial royalty system is predicated on self-reporting where the petroleum and natural gas industry is expected to understand the relevant energy legislation (statutes and regulations) and comply with them. This has an impact on the completeness of revenue when the petroleum and natural gas industry do not fully meet the legislative requirements and, for example, report inaccurate or incomplete production data. The ministry has implemented systems and controls to detect and correct situations where the petroleum and natural gas industry has not complied with the various Acts and Regulations the ministry administers. These systems and controls, based on areas of highest risk, include performing audits of the petroleum and natural gas industry records where determined necessary by the ministry. The ministry does not estimate the effect of misreported revenue. Any impacts on revenue of refiling by industry are recognized in the year of refiling.

Crude oil and natural gas royalties are determined based on monthly production. Revenue is recognized when the resource is produced by the mineral rights holders.

Bitumen royalty is determined based on revenues from production sold by projects less the costs of that production and the costs of selling the Crown's royalty share. Royalty revenue is recognized when the resource is produced by the mineral rights holders.

Freehold mineral rights taxes are determined at the end of a calendar year based on production and costs of production incurred in the calendar year. Revenue is recognized on a prorated basis, by month, of the estimated calendar year taxes that will be due to the Crown.

Revenue from bonuses and sales of Crown leases is recognized when the Crown leases are sold. Rentals and fees revenue is recognized over the term of the leases.

Industry levies and assessments are recognized as revenue in the year receivable.

Revenue for the Post Closure Stewardship Fund are based on reported injection of volumes of carbon dioxide 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.

Transfers of tangible capital assets from other government departments or entities are recognized as revenue.

Expenses

<u>Directly Incurred</u>

Directly incurred expenses are those costs the ministry has primary responsibility and accountability for, as reflected in the government's budget documents.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) **Basis of Financial Reporting (cont'd)**

Directly Incurred (cont'd)

In addition to program operating expenses such as salaries, supplies, etc., directly incurred expenses also include:

- amortization of tangible capital assets,
- pension costs which comprise the cost of employer contributions for current service of employees during the year. The AER and the AUC have their own defined benefit pension plans. The AER's and the AUC's pension expense 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 retirement age of employees. Net accumulated actuarial gain or loss is deferred and amortized over the average remaining service period of the active employees, which is 7 years. For the purpose of calculating the expected return, plan assets are valued at fair value. Past service costs arising from plan amendments are accounted for in the period of the plan amendment.
- valuation adjustments which include changes in the valuation allowances used to reflect financial assets at their net recoverable or other appropriate value. Valuation adjustments also represent the change in management's estimate of future payments arising from obligations relating to vacation pay, guarantees and indemnities.

Grants are recognized as expenses when authorized, eligibility criteria, if any, are met by the recipients and a reasonable estimate of the amounts can be made.

Incurred by Others

Services contributed by other entities in support of the ministry's operations are not recognized and are disclosed in Schedule 5 and allocated to programs in Schedule 6.

Valuation of Financial Assets and Liabilities

Fair value is the amount of consideration agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

The fair values of Cash and Cash Equivalents, Accounts Receivable, Loans and Advances, and Accounts Payable and Accrued Liabilities are estimated to approximate their carrying values because of the short term nature of these instruments.

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 of the ministry are limited to financial claims, such as advances to and receivables from other organizations, employees and other individuals, as well as inventories held for resale.

Assets acquired by right are not included.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) Basis of Financial Reporting (cont'd)

Financial Assets (cont'd)

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

Inventory for Resale
Inventory consists of conventional and synthetic oil in feeder and trunk pipelines. Inventories are stated at lower of cost or net realizable value.

Liabilities

Liabilities are recognized to the extent that they represent present obligations as a result of events and transactions occurring prior to the end of fiscal year. The settlement of liabilities will result in sacrifice of economic benefits in the future.

Liabilities include all financial claims payable by the ministry at fiscal year end.

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 government services;
b) may be consumed in the normal course of operations; and
c) are not for sale in the normal course of operations.

Non-financial assets of the ministry are limited to tangible capital assets and prepaid expenses.

Tangible Capital Assets
Tangible capital assets of the ministry are recognized at historical cost and amortized on a straight-line basis over the estimated useful lives of the assets. The threshold for capitalizing new systems development is $250,000 and the threshold for major systems enhancements is $100,000. The threshold for all other tangible capital assets is $5,000.

Amortization is only charged if the tangible capital asset is put into service.

When tangible capital assets are gifted or sold for a nominal sum, the net book values of these assets less any nominal proceeds are recognized as grants in kind.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(b) Basis of Financial Reporting (cont'd)

Measurement Uncertainty

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount. Natural gas and by-products revenue recognized as $644,502 (2017 - $519,746), bitumen royalty recognized as $2,642,513 (2017 - $1,483,459), and crude oil royalty revenue recognized as $964,956 (2017 - $723,717) in these consolidated financial statements are subject to measurement uncertainty.

Natural gas and by-products revenue is calculated based on allowable costs incurred by the royalty payers and production volumes that are reported to the ministry by royalty payers. Industry may modify their royalty and gas cost allowance for non-statute barred years. These amounts could vary significantly from that which was initially reported. The ministry estimates what the costs, volumes and royalty rates for the fiscal year should be based on statistical analysis of industry data. Based on historical data, changes to natural gas and by-products revenues was approximately $81,386 (2017 - $94,492).

For projects from which bitumen royalty is paid and the project has reached payout, the royalty rate used to determine the royalties is based on the average price of West Texas Intermediate crude oil in Canadian dollars for the calendar year. Royalty rates will start at 25% of net profits when oil is priced at fifty five dollars per barrel or less, and increase to a maximum of 40% of net profits when oil is priced at one hundred and twenty dollars or more. Payout is defined at the first date at which the cumulative revenue of a project first equals the cumulative cost of the project.

Crude Oil royalty is calculated based on industry submissions related to specific producing wells' production, density, and the par price (average price for grades of oil in the province for the month). Since costs relating to production, density, and enhanced oil recovery submitted by industry are subject to audit and industry has the ability to file amendments prior to the production year being statute barred (4 years), crude oil royalty could vary significantly from initial submissions. Based on historical data, changes to crude oil royalty revenues was approximately $3,113.

The Ministry, through its agent Alberta Petroleum Marketing Commission (APMC), is party to the North West Redwater Partnership. The Ministry has used judgement to estimate the net present value of the processing agreement with the North West Redwater Partnership, as well as to estimate the monthly toll commitments as disclosed in Schedule 3.

The BP's provisions for onerous contracts have been recorded at the lower of the present value of continuing the PPAs and the expected costs of terminating them as disclosed in Schedule 4.

(c) Change in Accounting Policy

The ministry has prospectively adopted the following standards from April 1, 2017: PS2200 Related Party Disclosures, PS 3420 Inter-Entity Transactions, PS 3210 Assets and PS 3380 Contractual Rights which are reflected in Note 2, Note 7, Note 17, and Schedule 5.

(in thousands)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(d) Future Accounting Changes

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

- **PS3430 Restructuring Transactions (effective April 1, 2018)**
  This standard provides guidance on how to account for and report restructuring transactions by both transferors and recipients of assets and/or liabilities, together with related party programs or operating responsibilities.

- **PS 3280 Asset Retirement Obligations (effective April 1, 2021)**
  Effective April 1, 2021, this standard provides guidance on how to account for and report a liability for retirement of a tangible capital asset.

- **PS 3450 Financial Instruments (effective April 1, 2021)**
  Adoption of this standard requires corresponding adoption of PS 2601 Foreign Currency Translation, PS 1201 Financial Statement Presentation, and PS 3041 Portfolio Investments in the same fiscal period. These standards provide guidance on: recognition, measurement and disclosure of financial instruments; standards on how to account for and report transactions that are denominated in a foreign currency; general reporting principles and standards for the disclosure of information in financial statements; and how to account for and report portfolio investments.

NOTE 3 GOVERNMENT REORGANIZATIONS

Effective September 1, 2017, the Government of Alberta consolidated communications and marketing functions across all ministries into one corporate service division called Communications and Public Engagement within the Department of Treasury Board and Finance. Comparatives for 2017 have been restated as if the current organizational structure had always been the same. The opening liabilities and net debt as at April 1, 2016 are restated as follows:

Net liabilities on April 1, 2016 are made up as follows:

Net Liabilities as previously reported	$	(309,010)
Transfer to Ministry of Treasury Board and Finance		(1,461)
Net Liabilities at April 1, 2016	$	(310,471)

Net Debt on April 1, 2016 is made up as follows:

Net Debt as previously reported	$	(416,397)
Transfer to Ministry of Treasury Board and Finance		(1,461)
Net Debt at April 1, 2016	$	(417,858)

(in thousands)

NOTE 4 ORPHAN WELL ABANDONMENT

The AER has delegated the authority to manage the abandonment and reclamation of wells, facilities and pipelines that are licensed to defunct licensees to the Alberta Oil and Gas Orphan Abandonment and Reclamation Association (Orphan Well Association). The AER grants all of its orphan well abandonment revenues (levy and application fees) to the Orphan Well Association. During the year ended March 31, 2018, the AER collected $15,106 (2017 - $30,448) in levies and $690 (2017 - $580) in application fees.

NOTE 5 CASH AND CASH EQUIVALENTS

Cash consists of deposits in the Canadian financial institutions which are managed by the Province of Alberta with the objective of providing competitive interest income to depositors 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. Included in cash and cash equivalents is $535 (2017 - $272) restricted for use on behalf of the Post Closure Stewardship Fund.

NOTE 6 ACCOUNTS RECEIVABLE

Accounts receivable royalties are secured by a claim against the mineral leases and are interest bearing in accordance with the applicable legislation.

NOTE 7 CONTRACTUAL RIGHTS

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

	2018	2017
Contractual Rights from Contracts	$ 4,775	$ 40

Estimated amounts that will be received or receivable for each of the next five years and thereafter are as follows:

	Contracts
2018-19	$ 4,228
2019-20	188
2020-21	159
2021-22	100
2022-23	100
Thereafter	-
	$ 4,775

NOTE 8 INVENTORY FOR RESALE

Inventory reported consists of crude oil inventory held for selling by APMC. Inventory is calculated based on inventory volumes held in various revenue pools multiplied by average pricing.

(in thousands)

NOTE 9 PENSION ASSETS/OBLIGATIONS

The ministry participates in multi-employer pension plans, Management Employees Pension Plan (MEPP) and Public Service Plan (PSPP) and Supplementary Retirement Plan for Public Service Managers (SRP). The expense for these pension plans is equivalent to the annual contributions of $28,094 for the year ended March 31, 2018 (2017 - $28,942).The ministry is not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2017, the MEPP reported a surplus of $866,006 (2016 - surplus $402,033), the PSPP reported a surplus of $1,275,843 (2016 surplus - $302,975) and the SRP reported a deficiency of $54,984 (2016 - deficiency $50,020).

The ministry also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2018 the Bargaining Unit Plan reported an actuarial surplus of $111,983 (2017 - surplus $101,515) and the Management, Opted Out and Excluded Plan an actuarial surplus of $29,805 (2017 - surplus $31,439). The expense for these two plans is limited to the employer's annual contributions for the year.

In addition, the AER and the AUC maintain their 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, 2016. The accrued benefit obligation as at March 31, 2018 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, 2019.

Pension plan assets are valued at market values. Significant weighted average actuarial and economic assumptions used to value accrued benefit obligations and pension benefit costs are as follows:

	AER		AUC	
	2018	2017	2018	2017
Weighted average actual return	4.8%	8.5%	2.4%	7.9%
Accrued benefits obligations				
Discount rate	5.0%	4.6%	4.7%	4.4%
Rate of compensation increase	0% until Sep 30, 2019, 3.5% thereafter	0% until Mar 31, 2018, 3.5% thereafter	3.5%	3.5%
Long – term inflation rate	2.0%	2.0%	2.0%	2.0%
Pension benefit costs for the year				
Discount rate	4.6%	4.7%	4.4%	4.5%
Expected rate of return on plan assets	4.6%	4.7%	4.4%	4.5%
Rate of compensation increase	0% until Mar 31, 2018, 3.5% thereafter	0% until Mar 31, 2017, 3.5% thereafter	3.5%	3.5%

(in thousands)

NOTE 9 PENSION ASSETS/(OBLIGATIONS) (cont'd)

	AER		AUC	
	2018	2017	2018	2017
Funded status and amounts				
Market value of plan assets	$ 61,932	$ 56,633	$ 11,133	$ 11,286
Accrued benefit obligation	58,919	58,200	10,275	10,925
Plan surplus/(deficit)	3,013	(1,567)	858	361
Unamortized actuarial (gain)/loss	(2,275)	2,077	(568)	47
Pension obligations	$ 738	$ 510	$ 290	$ 408
Pension benefit costs				
Current period benefit costs	$ 4,267	$ 4,302	$ 614	$ 608
Interest cost	2,824	2,690	504	477
Expected return on plan assets	(2,711)	(2,358)	(509)	(396)
Amortization of actuarial losses	560	861	88	186
	$ 4,940	$ 5,495	$ 697	$ 875
Additional information				
Employer contribution	$ 5,169	$ 6,697	$ 579	$ 2,048
Employees' contribution	875	840	105	109
Benefit paid	3,544	3,001	1,107	166
Asset Allocation				
Equity securities	44.3%	48.8%	45.8%	49.7%
Debt securities	23.3%	36.0%	18.1%	27.0%
Alternatives	18.7%	0.0%	0.0%	0.0%
Other	13.7%	15.2%	36.1%	23.3%
	100.0%	100.0%	100.0%	100.0%

NOTE 10 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.

NOTE 11 TENANT INCENTIVES

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

(in thousands)

NOTE 11 TENANT INCENTIVES (cont'd)

	2018			2017
	Leasehold Improvement Costs	**Reduced Rent Benefits and Rent-Free Periods**	**Total**	**Total**
Beginning of Year	$ 16,647	$ 4,001	$ 20,648	$ 22,264
Additions During Year	-	-	-	-
Amortization	(1,252)	(364)	(1,616)	(1,616)
End of Year	$ 15,395	$ 3,637	$ 19,032	$ 20,648

The AUC has received lease incentives through its office lease agreements. During 2018, the AUC received $2,790 in lease incentives in the form of cash and free rent (2017 - $324). Also, the AUC has a contractual right to receive an additional lease incentive of $4,020 in the form of cash and free rent in the next fiscal year.

	2018			2017
	Leasehold Improvement Costs	**Reduced Rent Benefits and Rent-Free Periods**	**Total**	**Total**
Beginning of Year	$ 47	$ 252	$ 299	$ 59
Additions During Year	-	2,790	2,790	324
Amortization	(84)		(84)	(84)
End of Year	$ (37)	$ 3,042	$ 3,005	$ 299

NOTE 12 LIABILITY FOR CONTAMINATED SITES

As at March 31, 2018, the AER is not responsible, nor has it accepted responsibility, for performing remediation work at contaminated sites. As at March 31, 2018, the AER's liability for contaminated sites was $nil (2017 - $nil).

NOTE 13 COAL PHASE-OUT AGREEMENTS

The phase out of coal-fired generators is in alignment with the Province's Climate Leadership Plan (CLP). 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.

(in thousands)

NOTE 13 COAL PHASE-OUT AGREEMENTS (cont'd)

The Ministry of Energy reached agreements with the three parties and will make payments totalling $96,970 annually to the three generators. The first payment was made July 31, 2017 and payments will continue for the next 13 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 owner 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 electricity business.

In addition to the amounts reported below, $3,806 of the July 2017 annual payment is currently under dispute and will be included in Accounts payable and Other Accrued Liabilities until a settlement is reached.

The present value of the remaining 13 payments, discounted at 3% (representing the government's average 10-year bond rate at time of negotiations), is $1,049,673. The amount of the draw down over the next five years and thereafter are as follows:

	Annual Payment	Principal	Interest
2018-19	96,970	67,063	29,907
2019-20	96,970	69,098	27,872
2020-21	96,970	71,196	25,774
2021-22	96,970	73,357	23,613
2022-23	96,970	75,583	21,387
Thereafter	775,763	693,376	82,387
	$ 1,260,613	$ 1,049,673	$ 210,940

NOTE 14 TANGIBLE CAPITAL ASSETS

	Land	Leasehold Improvements	Equipment (1)	Computer Hardware/ Software	Total
Estimated Useful Life	indefinite	lease term	3-40 years	3-10 years	
Historical Cost (2)					
Beginning of Year (reported)	$ 282	$ 43,071	$ 23,027	$ 242,820	$ 309,200
Manual adjustment to assets (3)	-	-	-	(45)	(45)
Additions	-	6,176	2,705	15,915	24,796
Transfer of Capital Assets (4)	-	-	-	613	613
Disposals, Including Write-downs	-	(2)	(2,576)	(6,734)	(9,312)
	$ 282	$ 49,245	$ 23,156	$ 252,569	$ 325,252

(in thousands)

NOTE 14 TANGIBLE CAPITAL ASSETS (cont'd)

	Land	Leasehold Improvements	Equipment [1]	Computer Hardware/ Software	Total
Accumulated Amortization					
Beginning of Year	$ -	$ 15,415	$ 14,693	$ 187,711	$ 217,819
Manual adjustment to assets [3]	-	-	-	(12)	(12)
Amortization Expense	-	2,871	1,640	16,279	20,790
Disposals, Including Write-downs	-	(2)	(2,067)	(6,633)	(8,702)
	$ -	$ 18,284	$ 14,266	$ 197,345	$ 229,895
Net Book Value at March 31, 2018	$ 282	$ 30,961	$ 8,890	$ 55,224	$ 95,357
Net Book Value at March 31, 2017	$ 282	$ 27,656	$ 8,334	$ 55,109	$ 91,381

[1] Equipment includes office equipment and furniture and other equipment.

[2] Historical cost includes work-in-progress at March 31, 2018 totaling $7,100 (2017 - $8,051) comprised of $7,096 (2017 - $8,009) of computer hardware and software and leasehold improvements $4 (2017 - $42).

[3] Asset Management system duplicated asset additions, manual adjustments were made to correct opening balance.

NOTE 15 CONTINGENT LIABILITIES

The ministry is involved in legal matters where damages are being sought. These matters may give rise to contingent liabilities. Accruals will be made in specific instances where it is likely that losses will be incurred based on a reasonable estimate.

The ministry has been named in ten claims (2017 - eleven), the outcome of which are not determinable. Of these claims six have specified amounts totalling $23,559,691 (2017 - seven claims totalling $23,557,180). The remaining four claims (2017 - four) have no specified amounts. Included in total claims are seven (2017 - six) claims in which the ministry has been jointly named with other ministries.

The resolution of the indeterminable claim may result in a liability, if any, that may be significantly lower than the claimed amount.

(in thousands)

NOTE 16 CONTRACTUAL OBLIGATIONS

As at March 31, 2018, the ministry had contractual obligations totaling $911,647 (2017 - $967,361).

Contractual obligations are obligations of the ministry to others that will become liabilities in the future when the terms of those contracts or agreements are met. These amounts include obligations under long-term contracts with contract payment requirements for each of the next five years and thereafter are as follows:

	Grant Agreements	Service Contracts	Long-Term Leases	Total
2018-19	$ 272,215	$ 9,461	$ 35,824	$ 317,500
2019-20	71,330	3,067	22,284	96,681
2020-21	58,370	2,939	17,602	78,911
2021-22	58,350	2,924	14,233	75,507
2022-23	58,350	-	13,929	72,279
Thereafter	180,634	-	90,135	270,769
	$ 699,249	$ 18,391	$ 194,007	$ 911,647

NOTE 17 ADMINISTRATION OF PROGRAMS/PROJECTS ON BEHALF OF OTHER GOVERNMENT DEPARTMENTS

The ministry administers two projects on behalf of other departments under different memorandums of understanding (MOU), the details of those programs that are under administration and the expenses incurred by the ministry are as follows:

Departments/ Entities	Date MOU Entered Into	Description of Services Provided	2018	2017
Department of Agriculture & Forestry	July 2017	Shared Service Agreement for Corporate Accounting and Reporting System (CARS)	$ 15	$ 15
Department of Environment & Parks	October 2017	Shared Service Agreement for Corporate Accounting and Reporting System	647	562
Department of Environment & Parks	April 2015	Shared Service Agreement for Electronic Transfer System (ETS)	20	20
			$ 682	$ 597

NOTE 18 PROGRAM COMMITMENTS

Renewable Energy Program

The Renewable Electricity Program (REP) targets the development of renewable electricity generation capacity as part of its target of 30 percent renewable electricity by 2030. The government has contracted with the Alberta Electric System Operator (AESO) to implement and administer the program.

Under this program, the government participates in the market risks of electricity prices by ensuring REP generators are kept whole by making sure the difference between the pool price and the accepted strike price is netted out, as follows:

a) When the market prices are high, the government will receive payments from the REP generator for pool prices that are in excess of the accepted strike price; and
b) When the market prices are low, the government will pay the REP generator the difference between the pool prices and the accepted strike price.

On December 13, 2017 , REP Round 1 was concluded successfully and will deliver nearly 600 MW of wind generation at a weighted average bid price of $37/MWh.

Petrochemicals Diversification Program (PDP)

The Petrochemicals Diversification Program was designed to encourage companies to invest in the development of Alberta petrochemical facilities by providing up to $500 million in incentives through royalty credits.

Under the Program, the two projects may receive up to $500 million in royalty credits provided the following:

a) Projects must achieve a Final Investment Decision to proceed within 18 months.
b) Commercialization of the projects in 2021.
c) The amount of royalty credit is calculated based on the actual consumption of propane to produce polypropylene.

During the year, the following two projects have been approved under this program:

Calgary-based Inter Pipeline was approved to receive up to $200 million under the program. The company made a final investment decision in December, 2017 that will see two new facilities built in the Industrial Heartland, near Fort Saskatchewan, that will process propane into value-added plastics products.

Canada Kuwait Petrochemical Corporation (formerly Pembina/PIC)'s integrated propane dehydrogenation polypropylene facilities were approved to receive up to $300 million in royalty credits under the program. The company has begun front-end engineering design work for its project and is expected to make a final investment decision in early 2019.

NOTE 19 TRUST FUNDS UNDER ADMINSTRATION

The Department of Energy administers the Oil and Gas Conservation Trust consisting of public money over which the Legislature has no power of appropriation. Because the Province has no equity in the fund and administers the fund for the purpose of various trusts, the fund is not included in the ministries' financial statements. As at March 31, 2018, the funds in the Oil and Gas Conservation Trust are $5,000 (2017 - $4,674).

The AER collects financial security under a number of different programs to protect the public from paying costs associated with abandonment and reclamation of upstream wells, facilities, pipelines, mines, mine sites and oilfield waste management facilities. The security deposits are held on behalf of licensees. The AER administers the programs in accordance with specified acts and regulations and does not have any financial risk associated with security collected. At March 31, 2018, the AER held $135,330 (2017 - $162,301) in cash and an additional $1,546,396 (2017 - $1,583,637) in letters of credit. Security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria.

NOTE 20 ROYALTY REDUCTION PROGRAMS

The ministry provides eleven oil and gas royalty reduction programs. The intent of these programs is to encourage industry to produce from wells which otherwise would not be economically productive. For the year ended March 31, 2018, the royalties received under these programs were reduced by $1,455,860 (2017 - $1,180,112).

NOTE 21 BITUMEN CONSERVATION

In 2004-05 the Alberta Energy and Utilities (EUB) Board (now known as the AER) released its Bitumen Conservation Requirements decisions regarding the status of natural gas wells in the Wabiskaw-McMurray region of the Athabasca Oil Sands area. The decisions recommended the shut-in of Wabiskaw-McMurray natural gas totaling about 53.6 billions of cubic feet annually to protect about 25.5 billion barrels of potentially recoverable bitumen. The Natural Gas Royalty Regulations, 2002 was amended to provide a royalty mechanism that would allow the Minister of Energy to calculate a royalty adjustment each month for gas producers affected by the EUB decisions. The Natural Gas Royalty Regulations, 2002 was also amended to provide for the royalty adjustment to be recovered through additional royalty on the shut-in wells when they return to production through amendments to the provisions that deal with the calculation of the royalty share of gas. The amendments provide for an increase over and above the usual royalty rate, and extend to new wells that produce from the shut-in zone. The effect of these adjustments was to reduce natural gas and by-products revenue by $7,492 (2017 - $9,897).

NOTE 22 SUBSEQUENT EVENTS

On November 22, 2016, the government announced a four-year price cap to protect families, farms, and small businesses from volatility in electricity prices as the province makes necessary reforms to the electricity system. The program runs from June 2017 to May 2021. During this period, consumers on the Regulated Rate Option (RRO) will pay the lower of the market rate or the government's ceiling rate of 6.8 cents per kilowatt hour.

Subsequent to March 31, 2018, the market price of electricity exceeded the government's ceiling rate of 6.8 cents per kilowatt hour, which resulted in a cost to the ministry of $8,438 under the Regulated Rate Option Program.

NOTE 22 SUBSEQUENT EVENTS (cont'd)

Effective April 1, 2018, the government consolidated human resource functions under the Public Service Commission within the Ministry of Treasury Board and Finance.

Effective April 1, 2018, the government consolidated the Freedom of Information and Protection of Privacy (FOIP) delivery services under the Ministry of Service Alberta.

Effective April 1, 2018, the government consolidated information management and technology services under the Ministry of Service Alberta.

NOTE 23 COMPARATIVE FIGURES

Certain 2017 figures have been reclassified to conform to 2018 presentation.

NOTE 24 APPROVAL OF FINANCIAL STATEMENTS

The Deputy Minister and Senior Financial Officer approved these consolidated financial statements.

MINISTRY OF ENERGY **Schedule 1**

CONSOLIDATED SCHEDULE TO FINANCIAL STATEMENTS

REVENUES

Year ended March 31, 2018

(in thousands)

	2018		2017
	Budget	**Actual**	**Actual**
			(Note 23)
Non-Renewable Resource Revenue (Note 20)			
Bitumen Royalty	$ 2,546,000	$ 2,642,513	$ 1,483,459
Crude Oil Royalty	476,000	964,956	723,717
Natural Gas and By-Products Royalty (Note 21)	455,000	644,502	519,746
Bonuses and Sales of Crown Leases	148,000	563,904	203,276
Rentals and Fees	117,000	152,642	148,170
Coal Royalty	12,000	11,632	26,182
	3,754,000	4,980,149	3,104,550
Freehold Mineral Rights Tax	90,000	67,360	57,059
Industry Levies and Licenses	309,776	291,681	300,114
Other Revenue	5,539	14,155	10,265
	4,159,315	5,353,345	3,471,988
Net Income/(Loss) from Government Business Enterprises	69,000	802,467	(1,921,895)
Total Revenue	$ 4,228,315	$ 6,155,812	$ 1,550,093

MINISTRY OF ENERGY **Schedule 2**

CONSOLIDATED SCHEDULE TO FINANCIAL STATEMENTS

EXPENSES - DIRECTLY INCURRED

Year ended March 31, 2018

(in thousands)

	2018 Budget	2018 Actual	2017 Restated - Note 3 (Note 23)
Grants	$ 213,725	$ 50,613	$ 1,144,994
Salaries, Wages and Employee Benefits	284,155	276,961	271,463
Supplies and Services	166,680	158,741	147,224
Orphan Well Abandonment	30,500	15,796	31,028
Amortization of Tangible Capital Assets (Note 14)	22,500	20,790	21,530
Other (1)	31,986	40,203	6,157
Loss on disposal of Tangible Capital Asset	-	604	78
Total Expenses before Recoveries	749,546	563,708	1,622,474
Less Recovery from Support Service Arrangements with Related Parties (2) (Note 17)	-	(682)	(597)
	$ 749,546	$ 563,026	$ 1,621,877

(1) Included in Other expense is $31,883 related to the Coal Phase out agreements.

(2) The ministry provides financial services to the Departments of Environment & Parks and Agriculture & Forestry. Costs incurred by the ministry for these services are recovered from the respective departments/entities and are detailed in Note 17.

MINISTRY OF ENERGY **Schedule 3**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

EQUITY IN GOVERNMENT BUSINESS ENTERPRISE - APMC

Year ended March 31, 2018

(in thousands)

	2018	2017
Accumulated surplus		
Opening accumulated surplus	$ 65,073	$ 34,965
Revenues		
Marketing of Oil	6,508	4,531
Financing Transactions	41,678	32,702
Total revenue	48,186	37,233
Total expense	8,260	7,125
Net income for the year	39,926	30,108
Accumulated surplus at end of year	$ 104,999	$ 65,073
Represented by		
Assets		
Cash and short-term investments	$ 7,458	$ 5,392
Term Loan	543,111	393,583
Other assets	101,997	89,332
Total assets	652,566	488,307
Liabilities		
Accounts payable	11,272	8,977
Due to Government of Alberta	441,673	330,249
Due to the Department of Energy	94,622	84,008
Total liabilities	547,567	423,234
	$ 104,999	$ 65,073

COMMITMENTS *(in thousands)*

(a) North West Redwater Partnership

On November 8, 2012 NWRP, announced the sanctioning of the construction of Phase 1 of the Sturgeon Refinery which it will build, own and operate. The Commission has entered into agreements whereby NWRP will process and market Crown royalty bitumen, or equivalent volumes, collected pursuant to the Bitumen Royalty in Kind initiative in order to capture additional value within Alberta. NWRP will market the refined products (primarily ultra low sulphur diesel and low sulphur vacuum gas oil) on behalf of the Commission. There is risk to the Commission under these agreements pertaining to the price differential between bitumen supplied as feedstock and marketed refined products, relative to the costs of the processing toll.

(in thousands)

(a) North West Redwater Partnership (cont'd)

Under the processing agreement, 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) for 30 years. The toll includes flow through costs as well as costs related to facility construction, estimated to be $9.7 billion (2017 - $9.4 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 term of the commitment begins upon June 1, 2018. No amounts have been paid under this agreement to date.

The nominal tolls under the processing agreement, assuming a $9.7 billion (2017 - $9.4 billion) Facility Capital Cost, market interest rates and 2% operating cost inflation rate, are estimated above. The total estimated tolls have been increased by $0.07 billion (2017 - $1.2 billion increase) relative to March 2017, due primarily to higher debt tolls related to higher Facility Capital Cost offset by lower energy operating costs and interest rates. As at March 31, 2018, NWRP has issued $6.35 billion (2017 - $6.35 billion) in bonds at lower than anticipated rates.

No value has been ascribed to the anticipated refining profits available to APMC over the term of the agreement.

(b) North West Redwater Partnership Monthly Toll Commitment

The Commission has used judgment to estimate the toll 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.

NWRP targets the refinery to come on stream to process bitumen feedstock with a commercial operations anticipated to commence December 2018. The future toll commitments are estimated to be:

2018-19	$ 331,000
2019-20	658,000
2020-21	802,000
2021-22	976,000
2022-23	966,000
Thereafter	22,293,000

(c) Term Loan Provided to North West Redwater Partnership

As part of the Subordinated Debt Agreement with the Partnership, the Commission provided a $432 million loan (2017 - $324 million). These amounts plus the accrued interest will be repaid on a straight line basis over ten years by the Partnership beginning one year after commercial start-up of the Sturgeon Refinery. Upon initiation of commercial operations the total amount of the term loan will be adjusted to reflect an agreed equity to debt ratio.

While loans to the Partnership are outstanding, the Commission is entitled to a 25 percent voting interest on an Executive Leadership Committee, which is charged with overseeing and making decisions on the construction and start-up of the Sturgeon Refinery. Because of the 25 percent voting interest, the Commission has significant influence over the Partnership. However, the Commission has no equity ownership interest in the Partnership and does not account for the Sturgeon Refinery or its operations in its financial statements.

(c) Term Loan Provided to North West Redwater Partnership (cont'd)

Under the agreements related to the Facility Capital Costs for the Sturgeon Refinery, the financing structure is required to be 80% senior debt and 20% equity/subordinated debt. The Commission is committed to provide 50% of the subordinated debt required to meet this test. A final reconciliation of the amount of subordinated debt required will be done six months after Commercial Operation Date. The calculation of the 80/20 ratio allows for the deduction of cumulative debt service costs (accrued interest) at this time, while prior to this time the calculation does not allow for the deduction of accumulated debt service costs, which could result in a temporary need for additional subordinated debt lending by The Commission.

The Commission is forecasting to provide NWRP an additional $13 million in 2018 (2017 - $95 million) of subordinated debt. In 2018 The Commission anticipates NWRP will repay $94 million (2017 - $60 million) to APMC as part of the final subordinated debt true-up six months after Commercial Operations Date.

(d) North West Redwater Partnership 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 catalyst volumes or energy consumption; pricing related variables such as 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 on information from various sources including forecasts of global consultancies, reserve evaluation consultants, forward markets and the Government of Alberta.

Based on the analysis, APMC determined the agreement has a positive net present value and no provision is required.

(e) Energy East Pipeline Project

The Commission received a Notice of Termination from Energy East Pipeline Limited Partnership, effective December 6, 2017. As per the terms of the Transportation Services Agreement with termination by the Carrier, APMC has no financial commitments or liabilities.

(f) Keystone XL Pipeline Project

The Commission has entered into agreements for 50,000 barrels per day of pipeline transportation service capacity from Hardisty, Alberta to Port Arthur, Houston, Texas. The term of the contracts is 20 years and the in service date is estimated to be mid 2021. The Keystone XL project has regulatory approval, however the carrier has not announced Final Investment Decision (FID). Once FID occurs, APMC is committed by the take-or-pay provisions of the contracts to pay approximately $130 million in tolls annually. Additional tolls will be incurred depending on the volumes APMC transports through the pipeline.

(g) Subsequent events

<u>Short term debt</u>
On April 4, 2018 APMC replaced its short term debt of $115.248 million originally issued April 5, 2017 with new short term debt of $116.127 million at 1.805% interest due April 4, 2019.

On May 30, 2018 APMC replaced its short term debt of $21 million originally issued May 31, 2017 with new short term debt of $21.203 million at 1.873% interest due May 30, 2019.

MINISTRY OF ENERGY **Schedule 4**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

EQUITY IN GOVERNMENT BUSINESS ENTERPRISE - THE BALANCING POOL

Year ended March 31, 2018

(in thousands)

	2018	2017
		(3 Months)
Accumulated equity		
Opening accumulated equity (January 1, 2017)	$ (1,952,003)	$ (1,966,788)
Total revenues	913,328	177,703
Total expense	249,003	179,803
Receipt of Consumer Allocation	98,216	16,885
Net income for the year	762,541	14,785
Accumulated equity at end of year	$ (1,189,462)	$ (1,952,003)
Represented by		
Assets		
Cash and cash equivalents	$ 12,258	$ 27,699
Term Loan	3,917	7,838
Other assets	314,558	284,684
Total assets	330,733	320,221
Liabilities		
Accounts payable [1]	375,432	292,483
Reclamation and abandonment provision	15,696	29,817
Loans and borrowing [2]	802,703	231,853
Power Purchase Arrangement liabilities	326,364	1,718,071
Total liabilities	1,520,195	2,272,224
	$ (1,189,462)	$ (1,952,003)

(1) Included in Accounts payable is $61.7 million (2017- $126 Million) of payments in lieu of taxes that are payable to the Province.

(2) Loans and borrowing is made up of short-term discount notes issued to the Province with maturity dates ranging from 31 to 90 days with annual interest charges ranging from 1.64% to 1.69% (2017 - 0.9% to 1.0%).

(a) Deemed Control

The Province created the Balancing Pool (BP) in 1998 to manage certain assets, liabilities, revenues and expenses arising from the transition to competition in Alberta's electric industry. The BP was established as a separate statutory corporation on June 1, 2003.

The BP is required to respond to certain extraordinary events during the operating period of all of the Power Purchase Arrangements (PPAs) such as force majeure, unit destruction, Buyer or Owner default or termination of a PPA. When a Buyer terminates a PPA, the BP will assume all remaining rights and obligations pursuant to the PPA assuming the PPA continues. The *Electric Utilities Act* requires the BP to manage generation assets in a commercial manner.

A series of legislative and regulatory changes and initiatives culminated in the Ministry to be deemed in control of the BP for financial reporting purposes with an effective date of January 1, 2017. The comparatives presented in these financial statements reflect operations for the three-month period ended March 31, 2017 and the cost of assuming the net liabilities of the BP as at January 1, 2017.

(b) Measurement Uncertainty

These financial statements are primarily based on the financial statements of the BP for the year ended December 31, 2017 and unaudited interim financial statements for the period January 1 to March 31, 2018. The preparation of these financial statements requires the use of estimates and assumptions. These estimates and assumptions have been made using careful judgement. Actual results are likely to differ from the results derived using these estimates. As a consequence, there is a significant risk of a material adjustment to the carrying amounts of assets and liabilities within the next financial year.

(c) Contingent Liabilities and Commitments

<u>Terminated Power Purchase Arrangements</u>
Termination notice has not been provided to the Owners of Genesee, Keephills and Sheerness PPA's as at March 31, 2018. The actual costs may be different than those reflected in the Power Purchase Arrangement liabilities.

<u>Retroactive Line Loss Adjustment</u>
In December 2017, the Alberta Utilities Commission reached its decision on Proceeding 790. As a result, the Balancing Pool will incur additional charges as a result of the retroactive adjustments to line loss factors in relation to the various PPAs. An estimated provision in the amount of $42.5 million (2016 – $114.0 million) has been recorded in trade payable and other accrued liabilities for the retroactive line loss adjustment as a result of the AUC's December 2017 decision. The estimate has been prepared using the Module B method based on Incremental Loss Factors with generation scaling.

(c) Contingent Liabilities and Commitments (cont'd)

Various matters before the AUC regarding the retroactive line loss adjustments are under review and appeal including the retroactive nature of the adjustments and prospective line loss factors used to calculate the adjustment. The AUC's decision regarding its authority and jurisdiction has also been challenged. The quantum of any retroactive adjustment will be dependent upon the methodology finally adopted and approved by the AUC. Given the uncertainty of the final methodology, the Balancing Pool estimates may be higher or lower than the current estimate reflected in these financial statements.

<u>Payments (Refunds) in Lieu of Tax</u>

Approximately $62 million of payments in lieu of taxes payable remain under dispute with a municipal entity. A provision of $30.3 million has been recorded in relation to the disputed matters and reflected as Other income (expense) from operating activities in 2016. This provision has been accrued in trade payables and other accrued liabilities.

<u>MSA Investigation</u>

On April 13, 2017, the Balancing Pool received a notice of investigation and request for information from the Market Surveillance Administrator ("MSA"). The Balancing Pool has provided the MSA with the requested information and the investigation is currently on-going.

MINISTRY OF ENERGY **Schedule 5**
CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS
RELATED PARTY TRANSACTIONS
Year ended March 31, 2018
(in thousands)

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 in the ministry and their close family members.

The ministry and its employees paid or collected certain taxes and fees set by regulation for premiums, licenses and other charges. These amounts were incurred in the normal course of business, reflect charges applicable to all users, and have been excluded from this Schedule.

The ministry had the following transactions with related parties reported on the Statement of Operations and the Statement of Financial Position at the amount of consideration agreed upon between the related parties:

	2018	2017
Accounts Receivable	$ 918	$ 8
Accounts Payable and Accrued Liabilities	$ 167	$ 757
Revenue		
Transfer of Tangible Capital Assets	$ 613	$ -
Other services	1,123	264
	$ 1,736	$ 264
Expenses - Directly Incurred		
Grants	-	-
Other services	$ 7,296	6,447
	$ 7,296	$ 6,447
Contractual Rights	$ 255	$ 40
Contractual Obligations	$ 5,867	$ -

The above transactions do not include support service arrangement transactions disclosed in Schedule

The ministry also had the following transactions with related parties for which no consideration was exchanged. The amounts for these related party transactions are estimated based on the costs incurred by the service provider to provide the service. These amounts are not reported in the consolidated financial statements and are disclosed in Schedule 6.

	2018	2017 Restated - Note 3
Expenses - Incurred by Others		
Accommodation	$ 6,755	$ 6,610
Legal	4,607	4,576
Business Services	2,351	2,583
	$ 13,712	$ 13,769

MINISTRY OF ENERGY **Schedule 6**

CONSOLIDATED SCHEDULE TO FINANCIAL STATEMENTS

ALLOCATED COSTS

Year ended March 31, 2018

(in thousands)

		2018 Expenses - Incurred by Others				2017 (Note 23)
Program	**Expenses** [1]	**Accommodation Costs** [2]	**Legal Services** [3]	**Business Services** [4]	**Total Expenses**	**Total Expenses Restated - Note 3**
Ministry Support Services	$ 6,712	$ 541	$ 348	$ -	$ 7,601	$ 8,058
Resource Development and Management	95,023	6,002	4,259	2,351	107,634	104,739
Cost of Selling Oil	74,623	-	-	-	74,623	65,140
Energy Regulation	253,253	-	-	-	253,253	245,959
Utilities Regulation	33,123	-	-	-	33,123	31,123
Climate Leadership Plan	33,598	131	-	-	33,729	1,118,849
Carbon Capture and Storage	50,898	81	-	-	50,979	30,750
Orphan Well Abandonment	15,796	-	-	-	15,796	31,028
	$ 563,026	$ 6,755	$ 4,607	$ 2,351	$ 576,738	$ 1,635,646

(1) Expenses - Directly Incurred as per Consolidated Statement of Operations.

(2) Costs shown for Accommodation are allocated by budgeted Full-Time Equivalent Employment.

(3) Costs shown for Legal Services are allocated by estimated costs incurred by each program.

(4) Costs shown for Business Service include charges for information technology support, vehicles, internal audit services and other services are allocated by costs in certain programs.

DEPARTMENT OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2018

Independent Auditor's Report

Auditor General OF ALBERTA

To the Minister of Energy

Report on the Financial Statements

I have audited the accompanying financial statements of the Department of Energy, which comprise the statement of financial position as at March 31, 2018 and the statements of operations, change in net debt and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Department of Energy as at March 31, 2018, 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.

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

June 6, 2018
Edmonton, Alberta

DEPARTMENT OF ENERGY

STATEMENT OF OPERATIONS

Year ended March 31, 2018

(in thousands)

	2018		2017
	Budget	**Actual**	**Restated - Note 3** (Note 21)
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 3,754,000	$ 4,980,149	$ 3,104,550
Freehold Mineral Rights Tax	90,000	67,360	57,059
Other Revenue	500	4,168	3,803
	3,844,500	5,051,677	3,165,412
Expenses - Directly Incurred (Schedule 2)			
Ministry Support Services	5,696	6,712	6,189
Resource Development and Management	90,867	95,023	93,059
Cost of Selling Oil	85,000	74,623	65,140
Climate Leadership Plan	34,884	33,598	1,119,232
Carbon Capture and Storage	214,984	50,898	30,659
	431,431	260,854	1,314,279
Annual Surplus	$ 3,413,069	$ 4,790,823	$ 1,851,133

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

DEPARTMENT OF ENERGY

STATEMENT OF FINANCIAL POSITION

As at March 31, 2018

(in thousands)

	2018 Actual	2017 Restated - Note 3 (Note 21)
Financial Assets		
Cash and Cash Equivalents (Note 4)	$ 243,088	$ 229,411
Accounts Receivable (Note 5)	533,707	277,663
Inventory for Resale (Note 7)	1,319	914
	778,114	507,988
Liabilities		
Accounts Payable and Accrued Liabilities (Note 8)	91,518	64,999
Gas Royalty Deposits (Note 9)	112,312	112,066
Unearned Revenue	64,165	65,113
Coal Phase-Out Agreements (Note 10)	1,049,673	1,114,613
	1,317,668	1,356,791
Net Debt	(539,554)	(848,803)
Non-Financial Assets		
Tangible Capital Assets (Note 11)	20,174	23,200
Net Liabilities	(519,380)	(825,603)
Net Liabilities at Beginning of Year	(825,603)	(423,680)
Annual Surplus	4,790,823	1,851,133
Net Financing Provided For General Revenues	(4,484,600)	(2,253,056)
Net Liabilities at End of Year	$ (519,380)	$ (825,603)

Contractual rights (Note 6)

Contingent Liabilities, Contractual Obligations and Program Commitments (Notes 12, 13 and 15)

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

DEPARTMENT OF ENERGY

STATEMENT OF CHANGE IN NET DEBT

As at March 31, 2018

(in thousands)

	2018 Actual	2017 Restated - Note 3
		(Note 21)
Annual Surplus	$ 4,790,823	$ 1,851,133
Acquisition of Tangible Capital Assets (Note 11)	(1,864)	(4,902)
Amortization of Tangible Capital Assets (Note 11)	5,470	5,977
Transfer in out of Tangible Capital Assets (Note 11)	(613)	-
Manual adjustment to Opening Tangible Capital Assets (Note 11)	33	-
Net Financing Provided For General Revenue	(4,484,600)	(2,253,056)
Decrease/(Increase) in Net Debt	309,249	(400,848)
Net Debt at Beginning of Year	(848,803)	(447,955)
Net Debt at End of Year	$ (539,554)	$ (848,803)

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

DEPARTMENT OF ENERGY

STATEMENT OF CASH FLOWS

Year ended March 31, 2018

(in thousands)

	2018 Actual	2017 Restated - Note 3 (Note 21)
Operating Transactions		
Annual Surplus	$ 4,790,823	$ 1,851,133
Non-cash Items included in Annual Surplus		
Amortization of Tangible Capital Assets (Note 11)	5,470	5,977
Transfer of Tangible Capital Assets (Note 11)	(613)	-
Manual adjustment to Opening Tangible Capital Assets (Note 11)	33	-
	4,795,713	1,857,110
Increase in Accounts Receivable	(256,044)	(144,232)
Increase in Inventory	(405)	(637)
Increase/(Decrease) in Accounts Payable and Accrued Liabilities	26,519	(284,095)
Decrease in Unearned Revenue	(948)	(2,380)
Decrease in Coal Phase-Out Agreements (Note 10)	(64,940)	1,114,613
Cash Provided by Operating Transactions	4,499,895	2,540,379
Capital Transactions		
Acquisition of Tangible Capital Assets (Note 11)	(1,864)	(4,902)
Cash Applied to Capital Transactions	(1,864)	(4,902)
Financing Transactions		
Net Financing Provided for General Revenues	(4,484,600)	(2,253,056)
Increase/(Decrease) in Gas Royalty Deposits (Note 9)	246	(100,886)
Cash Applied to Financing Transactions	(4,484,354)	(2,353,942)
Increase in Cash and Cash Equivalents	13,677	181,535
Cash and Cash Equivalents at Beginning of Year	229,411	47,876
Cash and Cash Equivalents at End of Year	$ 243,088	$ 229,411

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

DEPARTMENT OF ENERGY
NOTES TO FINANCIAL STATEMENTS
March 31, 2018
(in thousands)

NOTE 1 AUTHORITY & PURPOSE

The Department of Energy operates under the authority of the *Government Organization Act* , Chapter G-10, Revised Statutes of Alberta 2000.

The Department of Energy is responsible for ensuring the development of Alberta's resources through the stewardship of energy and mineral resource systems. These resources include both non-renewable and renewable resources.

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. Cash received for which goods or services have not been provided by year end is recognized as unearned revenue.

The provincial royalty system is predicated on self-reporting where the petroleum and natural gas industry is expected to understand the relevant energy legislation (statutes and regulations) and comply with them. This has an impact on the completeness of revenue when the petroleum and natural gas industry do not fully meet the legislative requirements and, for example, report inaccurate or incomplete production data. The department has implemented systems and controls to detect and correct situations where the petroleum and natural gas industry has not complied with the various Acts and Regulations the department administers. These systems and controls, based on areas of highest risk, include performing audits of the petroleum and natural gas industry records where determined necessary by the department. The department does not estimate the effect of misreported revenue. Any impacts on revenue of refiling by industry are recognized in the year of refiling.

Crude oil and natural gas royalties are determined based on monthly production. Revenue is recognized when the resource is produced by the mineral rights holders.

Bitumen royalty is determined based on revenues from production sold by projects less the costs of that production and the costs of selling the Crown's royalty share. Royalty revenue is recognized when the resource is produced by the mineral rights holders.

Freehold mineral rights taxes are determined at the end of a calendar year based on production and costs of production incurred in the calendar year. Revenue is recognized on a prorated basis, by month, of the estimated calendar year taxes that will be due to the Crown.

Revenue from bonuses and sales of Crown leases is recognized when the Crown leases are sold. Rentals and fees revenue is recognized over the term of the leases.

Transfers of tangible capital assets from other government departments or entities are recognized as revenue.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(a) **Basis of Financial Reporting (cont'd)**

Expenses

Directly Incurred

Directly incurred expenses are those costs the department has primary responsibility and accountability for, as reflected in the government's budget documents.

In addition to program operating expenses such as salaries, supplies, etc., directly incurred expenses also include:

- amortization of tangible capital assets,
- pension costs which comprise the cost of employer contributions for current service of employees during the year, and
- valuation adjustments which include changes in the valuation allowances used to reflect financial assets at their net recoverable or other appropriate value. Valuation adjustments also represent the change in management's estimate of future payments arising from obligations relating to vacation pay, guarantees and indemnities.

Grants are recognized as expenses when authorized, eligibility criteria, if any, are met by the recipients and a reasonable estimate of the amounts can be made.

Incurred by Others

Services contributed by other entities in support of the department's operations are not recognized and are disclosed in Schedule 5 and allocated to programs in Schedule 6.

Valuation of Financial Assets and Liabilities

Fair value is the amount of consideration agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

The fair values of Cash and Cash Equivalents, Accounts Receivable, Loans and Advances, and Accounts Payable and Accrued Liabilities are estimated to approximate their carrying values because of the short term nature of these instruments.

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 of the department are limited to financial claims, such as cash and cash equivalents, advances to and receivables from other organizations, employees and other individuals, as well as inventories held for resale.

Assets acquired by right are not included.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(a) **Basis of Financial Reporting (cont'd)**

Financial Assets (cont'd)

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

Inventory for Resale
Inventory consists of conventional and synthetic oil in feeder and trunk pipelines. Inventories are stated at lower of cost or net realizable value.

Liabilities

Liabilities are present obligations of the department to external organizations and individuals arising from past transactions or events, 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 government services;
b) may be consumed in the normal course of operations; and
c) are not for sale in the normal course of operations.

Non-financial assets of the department are limited to tangible capital assets.

Tangible Capital Assets
Tangible capital assets of the department are recognized at historical cost and amortized on a straight-line basis over the estimated useful lives of the assets. The threshold for capitalizing new systems development is $250,000 and the threshold for major systems enhancements is $100,000. The threshold for all other tangible capital assets is $5,000.

Amortization is only charged if the tangible capital asset is put into service.

General Revenue Fund

All departments of the Government of Alberta operate within the General Revenue Fund (the Fund). The Fund is administered by the President of Treasury Board and Minister of Finance. All cash receipts of departments are deposited into the Fund and all cash disbursements made by departments are paid from the Fund. Net Financing provided from (for) General Revenues is the difference between all cash receipts and all cash disbursements made.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(a) **Basis of Financial Reporting (cont'd)**

Measurement Uncertainty

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount. Natural gas and by-products revenue recognized as $644,502 (2017 - $519,746), bitumen royalty recognized as $2,642,513 (2017 - $1,483,459), and crude oil royalty revenue recognized as $964,956 (2017 - $723,717) in these financial statements are subject to measurement uncertainty.

Natural gas and by-products revenue is calculated based on allowable costs incurred by the royalty payers and production volumes that are reported to the department by royalty payers. Industry may modify their royalty and gas cost allowance for non-statute barred years. These amounts could vary significantly from that which was initially reported. The department estimates what the costs, volumes and royalty rates for the fiscal year should be based on statistical analysis of industry data. Based on historical data, changes to natural gas and by-products revenues was approximately $81,386 (2017 - $94,492).

For projects from which bitumen royalty is paid and the project has reached payout, the royalty rate used to determine the royalties is based on the average price of West Texas Intermediate crude oil in Canadian dollars for the calendar year. Royalty rates will start at 25% of net profits when oil is priced at fifty five dollars per barrel or less, and increase to a maximum of 40% of net profits when oil is priced at one hundred and twenty dollars or more. Payout is defined at the first date at which the cumulative revenue of a project first equals the cumulative cost of the project.

Crude Oil royalty is calculated based on industry submissions related to specific producing wells' production, density, and the par price (average price for grades of oil in the province for the month). Since costs relating to production, density, and enhanced oil recovery submitted by industry are subject to audit and industry has the ability to file amendments prior to the production year being statute barred (4 years), crude oil royalty could vary significantly from initial submissions. Based on historical data, changes to crude oil royalty revenues was approximately $3,113.

(b) **Change in Accounting Policy**

The department has prospectively adopted the following standards from April 1, 2017: PS2200 Related Party Disclosures, PS 3420 Inter-Entity Transactions, PS 3210 Assets and PS 3380 Contractual Rights which are reflected in Note 2, Note 6, Note 14 and Schedule 5.

(in thousands)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES (cont'd)

(c) Future Accounting Changes

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

- **PS3430 Restructuring Transactions (effective April 1, 2018)**
  This standard provides guidance on how to account for and report restructuring transactions by both transferors and recipients of assets and/or liabilities, together with related party programs or operating responsibilities.

- **PS 3280 Asset Retirement Obligations (effective April 1, 2021)**
  Effective April 1, 2021, this standard provides guidance on how to account for and report a liability for retirement of a tangible capital asset.

- **PS 3450 Financial Instruments (effective April 1, 2021)**
  Adoption of this standard requires corresponding adoption of PS 2601 Foreign Currency Translation, PS 1201 Financial Statement Presentation, and PS 3041 Portfolio Investments in the same fiscal period. These standards provide guidance on: recognition, measurement and disclosure of financial instruments; standards on how to account for and report transactions that are denominated in a foreign currency; general reporting principles and standards for the disclosure of information in financial statements; and how to account for and report portfolio investments.

  Management is currently assessing the impact of these standards on the financial statements.

NOTE 3 GOVERNMENT REORGANIZATIONS

Effective September 1, 2017, the Government of Alberta consolidated communications and marketing functions across all ministries into one corporate service division called Communications and Public Engagement within the Department of Treasury Board and Finance. Comparatives for 2017 have been restated as if the current organizational structure had always been the same. The opening liabilities and net debt as at April 1, 2016 are restated as follows:

Net liabilities on April 1, 2016 are made up as follows:

Net Liabilities as previously reported	$	(422,219)
Transfer to Ministry of Treasury Board and Finance		(1,461)
Net Liabilities at April 1, 2016	$	(423,680)

Net Debt on April 1, 2016 is made up as follows:

Net Debt as previously reported	$	(446,494)
Transfer to Ministry of Treasury Board and Finance		(1,461)
Net Debt at April 1, 2016	$	(447,955)

(in thousands)

NOTE 4 CASH AND CASH EQUIVALENTS

Cash consists of deposits in Canadian financial institutions which are managed by the Province of Alberta with the objective of providing competitive interest income to depositors while maintaining appropriate security and liquidity 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.

NOTE 5 ACCOUNTS RECEIVABLE

Accounts receivable royalties are secured by a claim against the mineral leases and are interest bearing in accordance with the applicable legislation.

	2018			2017
	Gross Amount	Allowance for Doubtful Accounts	Net Realizable Value	Net Realizable Value
Non-Renewable Royalty Receivables	$ 547,551	$ 13,844	$ 533,707	$ 277,663
Bioenergy Grant Recoveries	6,621	6,621	-	-
	$ 554,172	$ 20,465	$ 533,707	$ 277,663

NOTE 6 CONTRACTUAL RIGHTS

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

	2018	2017
Contractual Rights from Contracts	$ 2,873	$ 2,393

Estimated amounts that will be received or receivable for each of the next five years and thereafter are as follows:

	Contracts
2018-19	$ 2,473
2019-20	100
2020-21	100
2021-22	100
2022-23	100
Thereafter	-
	$ 2,873

NOTE 7 INVENTORY FOR RESALE

Inventory reported consists of crude oil inventory held for marketing by APMC. Inventory is calculated based on inventory volumes held in various revenue pools multiplied by average pricing.

(in thousands)

NOTE 8 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2018	2017
Trade	$ 2,472	$ 3,719
Gas Royalty Refunds Payable	66,034	$ 32,732
Other Accrued Liabilities	23,012	28,548
	$ 91,518	$ 64,999

NOTE 9 GAS ROYALTY DEPOSITS

The department 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 department does not pay interest on the deposits.

NOTE 10 COAL PHASE-OUT AGREEMENTS

The phase out of coal-fired generators is in alignment with the Province's Climate Leadership Plan (CLP). 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 reached agreements with the three parties and will make payments totalling $96,970 annually to the three generators. The first payment was made July 31, 2017 and payments will continue for the next 13 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 owner 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 electricity business.

In addition to the amounts reported below, $3,806 of the July 2017 annual payment is currently under dispute and will be included in Accounts payable and Other Accrued Liabilities until a settlement is reached.

The present value of the remaining 13 payments, discounted at 3% (representing the government's average 10-year bond rate at time of negotiations), is $1,049,673. The amount of the draw down over the next five years and thereafter are as follows:

	Annual Payment	Principal	Interest
2018-19	96,970	67,063	29,907
2019-20	96,970	69,098	27,872
2020-21	96,970	71,196	25,774
2021-22	96,970	73,357	23,613
2022-23	96,970	75,583	21,387
Thereafter	775,763	693,376	82,387
	$ 1,260,613	$ 1,049,673	$ 210,940

(in thousands)

NOTE 11 TANGIBLE CAPITAL ASSETS

	Equipment [1]	Computer Hardware and Software	Total
Estimated Useful Life	3-40 years	3-10 years	
Historical Cost [2]			
Beginning of Year (reported)	$ 6,007	$ 109,088	$ 115,095
Manual adjustment to assets [3]	-	(45)	(45)
Additions	63	1,801	1,864
Transfer of Capital Assets [4]	-	613	613
	$ 6,070	$ 111,457	$ 117,527
Accumulated Amortization			
Beginning of Year	$ 5,021	$ 86,874	$ 91,895
Manual adjustment to assets [3]		(12)	(12)
Amortization Expense	384	5,086	5,470
	$ 5,405	$ 91,948	$ 97,353
Net Book Value at March 31, 2018	$ 665	$ 19,509	$ 20,174
Net Book Value at March 31, 2017	$ 986	$ 22,215	$ 23,200

(1) Equipment includes office equipment and furniture and other equipment.

(2) Historical cost includes work-in-progress at March 31, 2018 totaling $450 (2017 - $3,392) for computer software.

(3) Asset Management system duplicated asset additions, manual adjustments were made to correct opening balance.

(4) Transfers of capital assets from Department of Service Alberta under the One IMT Project.

NOTE 12 CONTINGENT LIABILITIES

The department is involved in legal matters where damages are being sought. These matters may give rise to contingent liabilities. Accruals will be been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate.

The department has been named in ten claims (2017 - eleven), the outcome of which are not determinable. Of these claims six have specified amounts totalling $23,559,691 (2017 - seven claims totalling $23,557,180). The remaining four claims (2017 - four) have no specified amounts. Included in total claims are seven (2017 - six) claims in which the department has been jointly named with other departments.

The resolution of the indeterminable claim may result in a liability, if any, that may be significantly lower than the claimed amount.

(in thousands)

NOTE 13 CONTRACTUAL OBLIGATIONS

As at March 31, 2018, the department had contractual obligations totaling $717,640 (2017 - $773,545).

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

These amounts include obligations under long-term contracts with contract payment requirements for each of the next five years and thereafter are as follows:

	Grant Agreements	Service Contracts	Total
2018-19	$ 272,215	$ 9,461	$ 281,676
2019-20	71,330	3,067	74,397
2020-21	58,370	2,939	61,309
2021-22	58,350	2,924	61,274
2022-23	58,350	-	58,350
Thereafter	180,634	-	180,634
	$ 699,249	$ 18,391	$ 717,640

NOTE 14 ADMINISTRATION OF PROGRAMS/PROJECTS ON BEHALF OF OTHER GOVERNMENT DEPARTMENTS

The department administers two projects on behalf of other departments under different memorandums of of understanding (MOU). The details of those programs that are under administration and the expenses incurred by the department are as follows:

Departments/ Entities	Date MOU Entered Into	Description of Services Provided	2018	2017
Department of Agriculture & Forestry	July 2017	Shared Service Agreement for Corporate Accounting and Reporting System (CARS)	$ 15	$ 15
Department of Environment & Parks	October 2017	Shared Service Agreement for Corporate Accounting and Reporting System (CARS)	647	562
Department of Environment & Parks	April 2015	Shared Service Agreement for Electronic Transfer System (ETS)	20	20
Alberta Energy Regulator	April 2013	Operations and Maintenance Cost Sharing for Petrinex	2,353	2,178
			$ 3,035	$ 2,775

Included in Account Receivable and Schedule 5 is $588 (2017 - $479) relating to the administration of programs on behalf of other departments.

NOTE 15 PROGRAM COMMITMENTS

Renewable Energy Program

The Renewable Electricity Program (REP) targets the development of renewable electricity generation capacity as part of its target of 30 percent renewable electricity by 2030. The government has contracted with the Alberta Electric System Operator (AESO) to implement and administer the program.

Under this program, the government participates in the market risks of electricity prices by ensuring REP generators are kept whole by making sure the difference between the pool price and the accepted strike price is netted out, as follows:

a) When the market prices are high, the government will receive payments from the REP generator for pool prices that are in excess of the accepted strike price; and
b) When the market prices are low, the government will pay the REP generator the difference between the pool prices and the accepted strike price.

On December 13, 2017 REP Round 1 was concluded successfully and will deliver nearly 600 MW of wind generation at a weighted average bid price of $37/MWh.

Petrochemicals Diversification Program (PDP)

The Petrochemicals Diversification Program was designed to encourage companies to invest in the development of Alberta petrochemical facilities by providing up to $500 million in incentives through royalty credits.

Under the Program, the two projects may receive up to $500 million in royalty credits provided the following:

a) Projects must achieve a Final Investment Decision to proceed within 18 months.
b) Commercialization of the projects in 2021.
c) The amount of royalty credit is calculated based on the actual consumption of propane to produce polypropylene.

During the year, the following two projects have been approved under this program:

Calgary-based Inter Pipeline was approved to receive up to $200 million under the program. The company made a final investment decision in December, 2017 that will see two new facilities built in the Industrial Heartland, near Fort Saskatchewan, that will process propane into value-added plastics products.

Canada Kuwait Petrochemical Corporation (formerly Pembina/PIC)'s integrated propane dehydrogenation polypropylene facilities were approved to receive up to $300 million in royalty credits under the program. The company has begun front-end engineering design work for its project and is expected to make a final investment decision in early 2019.

NOTE 16 TRUST FUNDS UNDER ADMINSTRATION

The department administers the Oil and Gas Conservation Trust consisting of public money over which the Legislature has no power of appropriation. Because the Province has no equity in the fund and administers the fund for the purpose of various trusts, the fund is not included in the department's financial statements.

As at March 31, 2018, the funds in the Oil and Gas Conservation Trust are $5,000 (2017 - $4,674).

NOTE 17 PENSION ASSETS/OBLIGATIONS

The department participates in multi-employer pension plans, Management Employees Pension Plan (MEPP) and Public Service Plan (PSPP) and Supplementary Retirement Plan for Public Service Managers (SRP). The expense for these pension plans is equivalent to the annual contributions of $8,627 for the year ended March 31, 2018 (2017 - $9,395).The department is not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2017, the MEPP reported a surplus of $866,006 (2016 - surplus $402,033), the PSPP reported a surplus of $1,275,843 (2016 surplus - $302,975) and the SRP reported a deficiency of $54,984 (2016 - deficiency $50,020).

The department also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2018, the Bargaining Unit Plan reported an actuarial surplus of $111,983 (2017 - surplus $101,515) and the Management, Opted Out and Excluded Plan an actuarial surplus of $29,805 (2017 - surplus $31,439). The expense for these two plans is limited to the employer's annual contributions for the year.

NOTE 18 ROYALTY REDUCTION PROGRAMS

The department provides eleven oil and gas royalty reduction programs. The intent of these programs is to encourage industry to produce from wells which otherwise would not be economically productive. For the year ended March 31, 2018, the royalties received under these programs were reduced by $1,455,860 (2017 - $1,180,112).

NOTE 19 BITUMEN CONSERVATION

In 2004-05 the Alberta Energy and Utilities (EUB) Board (now known as the AER) released its Bitumen Conservation Requirements decisions regarding the status of natural gas wells in the Wabiskaw-McMurray region of the Athabasca Oil Sands area. The decisions recommended the shut-in of Wabiskaw-McMurray natural gas totaling about 53.6 billions of cubic feet annually to protect about 25.5 billion barrels of potentially recoverable bitumen. The Natural Gas Royalty Regulations, 2002 was amended to provide a royalty mechanism that would allow the Minister of Energy to calculate a royalty adjustment each month for gas producers affected by the EUB decisions. The Natural Gas Royalty Regulations, 2002 was also amended to provide for the royalty adjustment to be recovered through additional royalty on the shut-in wells when they return to production through amendments to the provisions that deal with the calculation of the royalty share of gas. The amendments provide for an increase over and above the usual royalty rate, and extend to new wells that produce from the shut-in zone. The effect of these adjustments was to reduce natural gas and by-products revenue by $7,492 (2017 - $9,897).

NOTE 20 SUBSEQUENT EVENTS

On November 22, 2016, the government announced a four-year price cap to protect families, farms, and small businesses from volatility in electricity prices as the province makes necessary reforms to the electricity system. The program runs from June 2017 to May 2021. During this period, consumers on the Regulated Rate Option (RRO) will pay the lower of the market rate or the government's ceiling rate of 6.8 cents per kilowatt hour.

Subsequent to March 31, 2018, the market price of electricity exceeded the government's ceiling rate of 6.8 cents per kilowatt hour, which resulted in a cost to the department of $8,438 under the Regulated Rate Option Program

Effective April 1, 2018, the government consolidated human resource functions under the Public Service Commission within the Department of Treasury Board and Finance.

Effective April 1, 2018, the government consolidated the Freedom of Information and Protection of Privacy (FOIP) delivery services under the Department of Service Alberta.

Effective April 1, 2018, the government consolidated information management and technology services under the Department of Service Alberta.

NOTE 21 COMPARATIVE FIGURES

Certain 2017 figures have been reclassified to conform to 2018 presentation.

NOTE 22 APPROVAL OF FINANCIAL STATEMENTS

The Deputy Minister and Senior Financial Officer approved these financial statements.

DEPARTMENT OF ENERGY **Schedule 1**

SCHEDULE TO FINANCIAL STATEMENTS

REVENUES

Year ended March 31, 2018

(in thousands)

	2018 Budget	2018 Actual	2017 Actual (Note 21)
Non-Renewable Resource Revenue (Note 18)			
Bitumen Royalty	$ 2,546,000	$ 2,642,513	$ 1,483,459
Crude Oil Royalty	476,000	964,956	723,717
Natural Gas and By-Products Royalty (Note 19)	455,000	644,502	519,746
Bonuses and Sales of Crown Leases	148,000	563,904	203,276
Rentals and Fees	117,000	152,642	148,170
Coal Royalty	12,000	11,632	26,182
	3,754,000	4,980,149	3,104,550
Freehold Mineral Rights Tax	90,000	67,360	57,059
Other Revenue	500	4,168	3,803
Total Revenue	$ 3,844,500	$ 5,051,677	$ 3,165,412

DEPARTMENT OF ENERGY **Schedule 2**

SCHEDULE TO FINANCIAL STATEMENTS

EXPENSES - DIRECTLY INCURRED

Year ended March 31, 2018

(in thousands)

	2018		2017
	Budget	**Actual**	**Restated - Note 3** (Note 21)
Grants	$ 213,725	$ 50,613	$ 1,148,365
Salaries, Wages and Employee Benefits	77,624	76,180	73,138
Supplies and Services	99,126	91,423	83,419
Amortization of Tangible Capital Assets (Note 11)	8,970	5,470	5,977
Other (1)	31,986	40,203	6,155
Total Expenses before Recoveries	431,431	263,889	1,317,054
Less Recovery from Support Service Arrangements with Related Parties (2) (Note 14)	-	(3,035)	(2,775)
	$ 431,431	$ 260,854	$ 1,314,279

(1) Included in Other expense is $31,883 related to the Coal Phase out agreements.

(2) The department provides financial services to the Departments of Environment & Parks, Agriculture & Forestry and Alberta Energy Regulator. Costs incurred by the department for these services are recovered from the respective departments/entities and are detailed in Note 14.

DEPARTMENT OF ENERGY **Schedule 3**

SCHEDULE TO FINANCIAL STATEMENTS

LAPSE/ENCUMBRANCE

Year ended March 31, 2018

(in thousands)

	Voted Estimate [1]	Adjustments [2]	Adjusted Voted Estimate	Voted Actuals [3]	Unexpended (Over Expended)
Program - Operational					
Program - Ministry Support Services					
1.1 Minister's Office	$ 705	$ -	$ 705	$ 727	$ (22)
1.2 Deputy Minister's Office	485	-	485	487	(2)
1.3 Communications	1,444	(1,444)	-	348	(348)
1.4 Corporate Services	4,506	-	4,506	5,150	(644)
	7,140	(1,444)	5,696	6,712	(1,016)
Program - Resource Development and Management					
2.1 Revenue Collection	41,381	-	41,381	40,422	959
2.2 Resource Development	39,476	-	39,476	38,790	686
2.3 Royalty Review Implementation	1,000	-	1,000	686	314
	81,857	-	81,857	79,898	1,959
Program - Biofuel Initiatives					
3 Biofuel Initiatives	-	-	-	-	-
	-	-	-	-	-
Program - Cost of Selling Oil					
4 Cost of Selling Oil	85,000	-	85,000	74,623	10,377
	85,000	-	85,000	74,623	10,377
Program - Climate Leadership Plan					
5.1 Coal Phase-Out Agreements	31,946	-	31,946	31,883	63
5.2 Climate Leadership Initiatives	2,938	-	2,938	1,715	1,223
	34,884	-	34,884	33,598	1,286
Total	$ 208,881	$ (1,444)	$ 207,437	$ 194,831	$ 12,606
Lapse/(Encumbrance)					$ 12,606
Program - Capital					
2.1 Revenue Collection	4,749	-	4,749	875	3,874
2.2 Resource Development	650	-	650	989	(339)
	$ 5,399		$ 5,399	$ 1,864	$ 3,535
Lapse/(Encumbrance)					$ 3,535
Financial Transactions					
5.1 Coal Phase-Out Agreements	$ 65,025	$ -	65,025	65,087	$ (62)
	$ 65,025	$ -	$ 65,025	$ 65,087	$ (62)
Lapse/(Encumbrance)					$ (62)

(1) As per "Operational Vote by Program", "Voted Capital Vote by Program" and "Financial Transaction Vote by Program" page of 2017-18 Government Estimates.

(2) Adjustments include transfers between votes approved by Order in Council #275/2017.

(3) Actuals exclude non-voted amounts such as statutory programs, amortization and valuation adjustments.

DEPARTMENT OF ENERGY **Schedule 4**

SCHEDULE FOR FINANCIAL STATEMENTS

SALARY AND BENEFITS DISCLOSURE

Year ended March 31, 2018

(in thousands)

	2018				2017
	Base Salary [(1)]	Other Cash Benefits [(2)]	Other Non-cash Benefits [(3)]	Total	Total
Deputy Minister [(4)]	$ 300	-	$ 70	$ 370	$ 484
Executives					
Assistant Deputy Minister - Strategic Policy Division	193	-	43	236	242
Assistant Deputy Minister - Resource Revenue & Operations [(5) (6)]	198	-	48	246	253
Assistant Deputy Minister - Ministry Support Services	193	-	43	236	242
Assistant Deputy Minister - Resource Development Policy	183	-	44	227	241
Assistant Deputy Minister - Electricity & Sustainable Energy	187	-	48	235	235
Assistant Deputy Minister - Oil Sands [(7)]	-	-	-	-	149
Assistant Deputy Minister - Integration & Innovation [(8)]	-	-	-	-	143
Other Executives					
Special Advisor - Office of the Deputy Minister [(9)]	52	-	11	63	-
Special Advisor - Tenure and Operational Initiatives [(10)]	37	24	8	69	97
Director - Communications [(11)]	123	-	28	151	164

(1) Base salary includes regular salary and earning such as acting pay.

(2) Other cash benefits include vacation payouts and lump sum payments.

(3) Other non-cash benefits include government's share of all employee benefits and contributions or payments made on behalf of employees including pension, supplementary retirement plans, health care, dental coverage, group life insurance, short and long term disability plans, health spending account expense, and professional memberships and tuition fees.

(4) Automobile provided, no dollar amount included in other non-cash benefits.

(5) Effective November 1, 2016, the Deputy Minister announced a revised executive team structure. The division portfolio name was changed to "Resource Revenue & Operations" from "Resource Revenue & Operations/Strategic Initiatives" at this time.

(6) This position was occupied by two individuals throughout the year. The first individual was in the position from April 1, 2017 to July 5, 2017. The second individual was in the position from July 6, 2017 to December 19, 2017. The first individual returned to the position from December 20, 2017 to March 31, 2018.

(7) Effective November 1, 2016, the Deputy Minister announced a revised executive team structure. This position no longer exists.

(8) This position was created effective April 10, 2016. Effective November 1, 2016, the Deputy Minister announced a revised executive team structure. This position no longer exists.

(9) This position was created effective April 1, 2017. Effective July 6, 2017, the Deputy Minister announced a revised executive team. This position no longer exists.

(10) This position was created effective November 1, 2016 when the Deputy Minister announced a revised executive team structure; as of May 31, 2017 this position no longer exists.

(11) The base salary and other non-cash benefits related to this position from the period of April 1, 2017 to March 31, 2018, was paid by the Ministry of Treasury Board & Finance. This position was occupied by three individuals throughout the fiscal year. The first individual from April 1, 2017 to September 8, 2017. The second individual from September 9, 2017 to January 21, 2018. The third individual from January 22, 2018 to March 31, 2018.

DEPARTMENT OF ENERGY **Schedule 5**

SCHEDULE TO FINANCIAL STATEMENTS

RELATED PARTY TRANSACTIONS

Year ended March 31, 2018
(in thousands)

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 in the Department and their close family members.

The department and its employees paid or collected certain taxes and fees set by regulation for premiums, licenses and other charges. These amounts were incurred in the normal course of business, reflect charges applicable to all users, and have been excluded from this Schedule.

The department had the following transactions with related parties reported on the Statement of Operations and the Statement of Financial Position at the amount of consideration agreed upon between the related parties:

	Entities in the Ministry		Other Entities	
	2018	2017	2018	2017
Accounts Receivable	$ 95,211	$ 84,487	$ -	$ -
Accounts Payable	$ -	$ 1,123	$ 2	$ 2
Revenue				
Transfer of Tangible Capital Assets	$ -	$ -	$ 613	$ -
Other services	-	-	-	8
	$ -	$ -	$ 613	$ 8
Expenses - Directly Incurred				
Grants	-	3,371	-	-
Other services	-	-	$ 2,865	2,810
	$ -	$ 3,371	$ 2,865	$ 2,810
Contractual Rights	$ 2,353	$ 2,353	$ 20	$ 40

The above transactions do not include support service arrangement transactions disclosed in Schedule 2.

The department also had the following transactions with related parties for which no consideration was exchanged. The amounts for these related party transactions are estimated based on the costs incurred by the service provider to provide the service. These amounts are not reported in the financial statements and are disclosed in Schedule 6.

	Entities in the Ministry		Other Entities	
	2018	2017	2018	2017 Restated - Note 3
Expenses - Incurred by Others				
Accommodation	$ -	$ -	$ 6,755	$ 6,610
Legal	-	-	4,607	4,576
Business Services	-	-	2,351	2,583
	$ -	$ -	$ 13,712	$ 13,769

DEPARTMENT OF ENERGY **Schedule 6**

SCHEDULE TO FINANCIAL STATEMENTS

ALLOCATED COSTS

Year ended March 31, 2018

(in thousands)

		2018				2017
		Expenses - Incurred by Others				(Note 21)
Program	**Expenses [1]**	**Accommodation Costs [2]**	**Legal Services [3]**	**Business Services [4]**	**Total Expenses**	**Total Expenses Restated - Note 3**
Ministry Support Services	$ 6,712	$ 541	$ 348	$ -	$ 7,601	$ 8,057
Resource Development and Management	95,023	6,002	4,259	2,351	107,634	104,806
Cost of Selling Oil	74,623	-	-	-	74,623	65,140
Climate Leadership Plan	33,598	131	-	-	33,729	1,119,295
Carbon Capture and Storage	50,898	81	-	-	50,979	30,750
	$ 260,854	$ 6,755	$ 4,607	$ 2,351	$ 274,566	$ 1,328,048

(1) Expenses - Directly Incurred as per Statement of Operations.

(2) Accommodation Costs are allocated by budgeted Full-Time Equivalent Employment.

(3) Legal Services Costs are allocated by estimated costs incurred by each program.

(4) Business Service Costs, including charges for IT support, vehicles, internal audit services and other services are allocated by costs in certain programs.

ALBERTA ENERGY REGULATOR

FINANCIAL STATEMENTS
For the year ended March 31, 2018

Independent Auditor's Report

Auditor General OF ALBERTA

To the Board of Directors of the Alberta Energy Regulator

Report on the Financial Statements

I have audited the accompanying financial statements of the Alberta Energy Regulator, which comprise the statement of financial position as at March 31, 2018, and the statements of operations, change in net debt, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Energy Regulator as at March 31, 2018, and the results of its operations, its remeasurement gains and losses, its changes in net debt, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards..

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

May 10, 2018
Edmonton, Alberta

ALBERTA ENERGY REGULATOR
STATEMENT OF OPERATIONS
Year Ended March 31, 2018
(in thousands)

	2018		2017
	Budget (Note 3, Schedule 3)	Actual	Actual
Revenues			
Industry levies and assessments	$ 274,847	$ 260,021	$ 269,222
Information, services and fees	3,542	7,901	5,132
Government transfer - provincial grant	-	-	3,338
Investment income	867	1,747	1,062
	279,256	269,669	278,754
Expenses (Schedule 1)			
Energy regulation	244,619	249,752	245,959
Orphan well abandonment (Note 4)	30,500	15,796	31,028
Climate leadership plan	6,637	3,501	2,925
	281,756	269,049	279,912
Annual operating surplus (deficit)	(2,500)	620	(1,158)
Accumulated surplus at beginning of year	60,953	60,953	62,111
Accumulated surplus at end of year	$ 58,453	$ 61,573	$ 60,953

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

ALBERTA ENERGY REGULATOR

STATEMENT OF FINANCIAL POSITION

As at March 31, 2018

(in thousands)

	2018	2017
Financial assets		
Cash and cash equivalents (Note 5)	$ 15,644	$ 32,975
Accounts receivable (Note 6)	7,548	7,982
Pension assets (Note 12)	738	510
	23,930	41,467
Liabilities		
Accounts payable and accrued liabilities (Note 7)	17,023	19,299
Payable to Orphan Well Association	806	14,115
Deferred lease incentives (Note 10)	19,032	20,648
	36,861	54,062
Net debt	(12,931)	(12,595)
Non-financial assets		
Tangible capital assets (Note 13)	62,718	62,426
Prepaid expenses and other assets	11,786	11,122
	74,504	73,548
Net assets		
Accumulated surplus (Note 14)	$ 61,573	$ 60,953

Contingent liabilities and contractual obligations (Note 15 and Note 16)

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

ALBERTA ENERGY REGULATOR
STATEMENT OF CHANGE IN NET DEBT
Year Ended March 31, 2018
(in thousands)

	2018		2017
	Budget (Note 3)	Actual	Actual
Annual operating surplus (deficit)	$ (2,500)	$ 620	$ (1,158)
Acquisition of tangible capital assets (Note 13)	(9,000)	(14,268)	(12,109)
Amortization of tangible capital assets (Note 13)	11,500	13,848	14,037
Loss on disposal and write-down of tangible capital assets		128	76
Increase in prepaid expenses and other assets		(664)	(145)
(Increase) decrease in net debt	-	(336)	701
Net debt at beginning of year	(12,595)	(12,595)	(13,296)
Net debt at end of year	$ (12,595)	$ (12,931)	$ (12,595)

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

ALBERTA ENERGY REGULATOR
STATEMENT OF CASH FLOWS
Year Ended March 31, 2018
(in thousands)

	2018	2017
Operating transactions		
Annual operating surplus (deficit)	$ 620	$ (1,158)
Non-cash items		
Amortization of tangible capital assets (Note 13)	13,848	14,037
Loss on disposal and write-down of tangible capital assets	128	76
Change in pension obligations	(228)	(1,202)
Amortization of deferred lease incentives (Note 10)	(1,616)	(1,616)
	12,752	10,137
Decrease in accounts receivable	434	10,167
(Increase) in prepaid expenses and other assets	(664)	(145)
(Decrease) increase in accounts payable and accrued liabilities	(2,276)	1,052
(Decrease) in grant payable to Orphan Well Association	(13,309)	(978)
Cash (applied to) provided by operating transactions	(3,063)	20,233
Capital transactions		
Acquisition of tangible capital assets (Note 13)	(14,268)	(12,109)
Cash applied to capital transactions	(14,268)	(12,109)
Financing transactions		
Proceeds from line of credit	-	16,138
Debt repayment	-	(16,138)
Cash applied to financing transactions	-	-
(Decrease) increase in cash and cash equivalents	(17,331)	8,124
Cash and cash equivalents at beginning of year	32,975	24,851
Cash and cash equivalents at end of year	$ 15,644	$ 32,975

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

Note 1 Authority and purpose

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.

Note 2 Summary of significant accounting policies and reporting practices

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

(a) 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.

Government transfers

Transfers from the Government of Alberta, without stipulations for the use of the transfer, are recognized as revenue when the transfer is authorized and the AER is eligible to receive the funds.

(b) Expenses

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

(c) 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 cost for the year are calculated using the expected rate of return on plan assets as its discount rate. The expected return on plan assets is determined using market values of plan assets.

Actuarial gains and losses are amortized over the average remaining service period of the active employees, which is 10.9 (2017 - 10.5) years.

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

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

(c) Employee future benefits (continued)

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 is comprised of 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.

(d) 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
Accounts payable and accrued liabilities	Cost
Payable to the Orphan Well Association	Cost
Deferred lease incentive	Amortized cost

The AER has not designated any financial assets or liabilities in the fair value category, has no 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.

(e) 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 AER's financial claims on external organizations and individuals at the year end.

Cash and cash equivalents

Cash is comprised of cash on hand and demand deposits.

Accounts receivable

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

(f) Liabilities

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

Liabilities include all financial claims payable by the AER at fiscal year end.

Deferred lease incentives

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

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

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. The liability is recognized net of any expected recoveries. A liability for remediation of contaminated sites normally results from an operation that is no longer in productive use and is recognized when all of the following criteria are met:

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

(g) 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 are limited to tangible capital assets and prepaid expenses and other assets.

Tangible capital assets

Tangible 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 and are amortized over their estimated useful lives using the following methods:

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 includes 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 Statement of Operations.

Prepaid expense

Prepaid expense is recognized at cost and amortized based on the terms of the agreements.

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

(h) Measurement uncertainty

Measurement uncertainty exists when there is a variance between the recognized or disclosed amount and another reasonably possible amount. 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.

(i) Change in accounting policy

The AER has prospectively adopted the following standards from April 1, 2017: PS 2200 Related Party Disclosure, PS 3420 Inter-Entity Transactions, PS 3210 Assets, PS 3320 Contingent Assets and PS 3380 Contractual Rights.

The adoption of these new standards did not have a material impact on the financial statements.

(j) Future accounting changes

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

PS 3430 Restructuring Transactions (effective April 1, 2018)
This standard provides guidance on how to account for and report restructuring transactions by both transferors and recipients of assets and/or liabilities, together with related program or operating responsibilities.

PS 3280 Asset Retirement Obligations (effective April 1, 2021)
This standard provides guidance on how to account for and report a liability for retirement of a tangible capital asset.

Management is currently assessing the impact of these standards on the financial statements.

Note 3 Budget

The budget is based on the AER Business Plan for the year ended March 31, 2018. The budget and budget adjustments have been approved by the Government of Alberta.

Note 4 Orphan well abandonment

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 Alberta Oil and Gas Orphan Abandonment and Reclamation Association (Orphan Well Association). The AER transfers all of its orphan well revenues (levy and application fees) to the Orphan Well Association. During the year ended March 31, 2018, the AER collected $15,106 (2017 - $30,448) in levies and $690 (2017 - $580) in application fees.

Note 5 Cash and cash equivalents

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, 2018, the AER earned interest at the rate of 1.4% (2017 - 1.0%).

(in thousands)

Note 6 Accounts receivable

	2018			2017
	Gross amount	Allowance for doubtful accounts	Net realizable value	Net realizable value
Accounts receivable	$ 10,701	$ (3,153)	$ 7,548	$ 7,982

Note 7 Accounts payable and accrued liabilities

	2018	2017
Accounts payable	$ 4,992	$ 6,194
Accrued liabilities	10,191	11,108
Unearned revenue	1,840	1,997
	$ 17,023	$ 19,299

Note 8 Financial instruments

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

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 financial liabilities. The AER does not consider this to be a significant risk as the AER collects funding at the beginning of the year to meet all obligations that arise during the year. In addition, the available credit facility provides financial flexibility to allow the AER to meet its obligations if funding cannot be collected on a timely basis.

(b) Credit risk

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

Note 9 Revolving line of credit

During 2018, the AER had an unsecured $50,000 revolving line of credit. Amounts borrowed can only be applied to general corporate purposes and exclude the funding of operating deficits and/or capital expenditures. Bank advances on the line of credit are payable on demand and bear interest at prime less 0.5%. As at March 31, 2018, the outstanding balance for the revolving line of credit was $nil (2017 -$nil).

For the year ended March 31, 2018, interest expense on the revolving line of credit was $nil (2017 - $13).

(in thousands)

Note 10 Deferred lease incentives

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

	2018			2017
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 16,647	$ 4,001	$ 20,648	$ 22,264
Additions during the year	-	-	-	-
Amortization	(1,252)	(364)	(1,616)	(1,616)
Balance at end of year	$ 15,395	$ 3,637	$ 19,032	$ 20,648

Note 11 Liability for contaminated sites

As at March 31, 2018, the AER is not responsible, nor has it accepted responsibility, for performing remediation work at contaminated sites. As at March 31, 2018, the AER's liability for contaminated sites was $nil (2017 - $nil).

Note 12 Employee future benefits

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, 2018, the expense for these pension plans is equal to the contribution of $17,540 (2017 - $17,766). 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, 2016. The accrued benefit obligation as at March 31, 2018 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, 2019.

Pension plan assets are valued at market values. During the year ended March 31, 2018 the weighted average actual return on plan assets was 4.8% (8.5% in 2017).

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

Accrued benefit obligations	2018	2017
Discount rate	5.0%	4.6%
Rate of compensation increase	0% until Sep 30, 2019, 3.5% thereafter	0% until Mar 31, 2018, 3.5% thereafter
Long-term inflation rate	2.0%	2.0%

(in thousands)

Note 12 Employee future benefits (continued)

Pension benefit costs for the year	2018	2017
Discount rate	4.6%	4.7%
Expected rate of return on plan assets	4.6%	4.7%
Rate of compensation increase	0% until Mar 31, 2018, 3.5% thereafter	0% until Mar 31, 2017, 3.5% thereafter

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

	2018	2017
Market value of plan assets	$ 61,932	$ 56,633
Accrued benefit obligations	58,919	58,200
Plan surplus (deficit)	3,013	(1,567)
Unamortized actuarial (gains)/losses	(2,275)	2,077
Pension assets	$ 738	$ 510

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

	2018	2017
Current period benefit cost	$ 4,267	$ 4,302
Interest cost	2,824	2,690
Expected return on plan assets	(2,711)	(2,358)
Amortization of actuarial losses	560	861
	$ 4,940	$ 5,495

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

	2018	2017
AER contribution	$ 5,169	$ 6,697
Employees' contribution	875	840
Benefits paid	3,544	3,001

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

	2018	2017
Equity securities	44.3%	48.8%
Debt securities	23.3%	36.0%
Alternatives	18.7%	0.0%
Other	13.7%	15.2%
	100.0%	100.0%

(in thousands)

Note 13 Tangible capital assets

	2018					2017
	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						
Beginning of year	$ 282	$ 39,642	$ 14,810	$ 124,146	$ 178,880	$ 181,106
Additions	-	195	639	13,434	14,268	12,109
Disposals, including write-downs	-	(2)	(1,219)	(5,093)	(6,314)	(14,335)
	282	39,835	14,230	132,487	186,834	178,880
Accumulated amortization						
Beginning of year	$ -	$ 12,413	$ 8,536	$ 95,505	$ 116,454	$ 116,676
Amortization expense	-	2,509	1,131	10,208	13,848	14,037
Effect of disposals, including write-downs	-	(2)	(1,177)	(5,007)	(6,186)	(14,259)
	-	14,920	8,490	100,706	124,116	116,454
Net book value at March 31, 2018	$ 282	$ 24,915	$ 5,740	$ 31,781	$ 62,718	
Net book value at March 31, 2017	$ 282	$ 27,229	$ 6,274	$ 28,641		$ 62,426

Historical cost includes work-in-progress at March 31, 2018 totaling $6,650 (March 31, 2017 - $4,659) comprised of: computer hardware and software $6,646 (March 31, 2017 - $4,617) and leasehold improvements $4 (March 31, 2017 - $42).

Note 14 Accumulated surplus

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

	2018			2017
	Investments in tangible capital assets [(a)]	Unrestricted net assets	Accumulated surplus	Accumulated surplus
Balance at beginning of year	$ 45,779	$ 15,174	$ 60,953	$ 62,111
Annual operating surplus (deficit)	-	620	620	(1,158)
Net investment in capital assets	1,544	(1,544)	-	-
Balance at end of year	$ 47,323	$ 14,250	$ 61,573	$ 60,953

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

(in thousands)

Note 15 Contingent liabilities

The AER, in the conduct of its normal activities, is a defendant in a number of legal proceedings. While the ultimate outcome and liability of these proceedings cannot be reasonably determined at this time, the AER believes that any settlement will not have a material adverse effect on the financial position or the results of operations of the AER. Based on legal advice, management has concluded that none of the claims meet the criteria for recognizing an accrued liability under PSAS.

Note 16 Contractual obligations

As at March 31, 2018, the AER had contractual obligations totalling $183,751 (2017 - $189,462).

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.

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

	2018
2019	$ 34,133
2020	21,311
2021	16,629
2022	13,454
2023	13,151
Thereafter	85,073
	$ 183,751

Note 17 Assets under administration

The AER administers security deposit programs 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 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, 2018, assets under administration included security deposits held under the following programs:

	2018 Cash	2017 Cash	2018 Letters of Credit	2017 Letters of Credit
Licensee Liability Rating program	$ 86,574	$ 114,146	$ 189,910	$ 232,255
Mine Financial Security program	41,567	40,993	1,351,072	1,345,974
Other programs	7,189	7,162	5,414	5,408
	$ 135,330	$ 162,301	$ 1,546,396	$ 1,583,637

(in thousands)

Note 18 Related party transactions

Related parties are those entities consolidated or accounted for on the modified equity basis in the Government of Alberta's financial statements. Related parties also include key management personnel and close family members of those individuals. In 2018, there were no outstanding amounts or transactions other than compensation, between the AER and its key management personnel. Key management personnel compensation is disclosed in Schedule 2.

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

	Entities in the Ministry of Energy		Other entities	
	2018	**2017**	**2018**	**2017**
Revenues				
Government transfer - provincial grant	$ -	$ 3,338	$ -	$ -
Information, services and fees	67	66	1,365	417
	$ 67	$ 3,404	$ 1,365	$ 417

	Entities in the Ministry of Energy		Other entities	
	2018	**2017**	**2018**	**2017**
Expenses				
Computer services	$ 2,373	$ 2,199	$ 2,511	$ 1,651
Buildings	-	-	602	617
Administrative	-	-	1,458	1,290
Consulting services	-	-	915	1,371
	$ 2,373	$ 2,199	$ 5,486	$ 4,929
Receivable from	$ 17	$ 3,505	$ 922	$ 12
Payable to	$ 588	$ 509	$ 1,501	$ 692
Unearned revenue	$ -	$ -	$ 131	$ 583
Contractual obligations [(a)]	$ 4,515	$ 4,377	$ 3,705	$ 4,279

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

Note 19 Comparative figures

Certain 2017 figures have been reclassified to conform to the 2018 presentation.

Note 20 Approval of financial statements

These financial statements were approved by the AER Board of Directors on May 10, 2018.

ALBERTA ENERGY REGULATOR **Schedule 1**

SCHEDULE TO THE FINANCIAL STATEMENTS

Expenses - Detailed by Object

Year Ended March 31, 2018

(in thousands)

	2018	2017
Salaries, wages and employee benefits	$ 178,362	$ 176,443
Buildings	18,479	16,936
Computer services	18,094	16,742
Orphan well abandonment	15,796	31,028
Consulting services	14,463	14,302
Amortization of tangible capital assets	13,848	14,037
Administrative	4,582	5,320
Travel and transportation	4,471	4,115
Equipment rent and maintenance	815	884
Loss on disposal and write-down of tangible capital assets	128	76
Abandonment and enforcement	11	29
	$ 269,049	$ 279,912

ALBERTA ENERGY REGULATOR **Schedule 2**
SCHEDULE TO THE FINANCIAL STATEMENTS
Salary and Benefits Disclosure
Year Ended March 31, 2018
(in thousands)

	2018				2017
Position	**Base salary [a]**	**Other cash benefits [b]**	**Other non-cash benefits [c]**	**Total [d]**	**Total [e]**
Board of Directors					
Chairman	$ 216	$ -	$ 4	$ 220	$ 233
Board Director [f]	92	-	3	95	110
Board Director [g]	91	-	4	95	50
Board Director [g]	86	-	3	89	48
Board Director [h]	45	-	3	48	-
Board Director [i]	44	-	2	46	48
Board Director [h]	40	-	4	44	-
Board Director [j]	42	-	1	43	24
Board Director [k]	-	-	-	-	54
Board Director [l]	-	-	-	-	26
Board Director [l]	-	-	-	-	25
Executives					
President and Chief Executive Officer [m]	525	68	135	728	695
Chief Hearing Commissioner	209	18	57	284	291
Executive Vice-President, Corporate Services	273	87	74	434	438
Executive Vice-President and General Counsel [q]	273	77	105	455	466
Former Executive Vice-President, Operations [n,q]	55	15	18	88	527
Executive Vice-President, Operations [o,q]	247	62	57	366	-
Executive Vice-President, Stakeholder & Government Engagement	273	93	78	444	446
Former Executive Vice-President, Strategy & Regulatory [p,q]	70	15	10	95	404
Executive Vice-President, Strategy & Regulatory [o,q]	247	61	88	396	-

(a) Includes retainers and per diems for Board Directors. Members of the Board of Directors do not participate in the AER's pension plans. Includes pensionable base pay for Executives.
(b) Payments in lieu of vacation and health benefits, vehicle allowances, and short term incentive payments for Executive Vice-Presidents.
(c) 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 or payments made for professional memberships, tuition fees and fair market value of parking.
(d) Salaries and benefits for the Board of Directors are presented in descending order.
(e) The 2017 figures have been restated by a total of $31 to include the fair market value of parking provided to Executives to conform to the 2018 presentation.
(f) The incumbent left the position effective February 19, 2018.
(g) The incumbent held the position effective October 1, 2016.
(h) The incumbent held the position effective October 18, 2017.
(i) The incumbent held the position from October 1, 2016 to September 30, 2017.
(j) The incumbent left the position effective June 16, 2016 and was rehired effective October 18, 2017.
(k) The incumbent left the position effective September 30, 2016.
(l) The incumbent left the position effective June 16, 2016.
(m) Automobile provided, no dollar amount included in other non-cash benefits.
(n) The incumbent left the position effective June 2, 2017.
(o) The incumbent held the position effective May 8, 2017.
(p) The incumbent left the position effective July 4, 2017.

(in thousands)

(q) 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 the 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. The costs detailed below are only for those employees included in Schedule 2 who participate in the SEPP and SRP maintained by the AER to compensate senior staff who do not participate in the government management pension plans.

	2018			2017
Position	**Current service cost**	**Prior service and other costs**	**Total**	**Total [r]**
Executive Vice-President and General Counsel	$ 41	$ 2	$ 43	$ 53
Former Executive Vice-President, Operations [s]	9	1	10	61
Executive Vice-President, Operations [t]	12	1	13	12
Former Executive Vice-President, Strategy & Regulatory [u]	-	9	9	24
Executive Vice-President, Strategy & Regulatory [t]	26	2	28	34

Position	**Accrued obligation April 1, 2017**	**Changes in accrued obligation**	**Accrued obligation March 31, 2018**	**2017 [r]**
Executive Vice-President and General Counsel	$ 525	$ 47	$ 572	$ 525
Former Executive Vice-President, Operations [s]	270	(270)	-	270
Executive Vice-President, Operations [t]	30	12	42	30
Former Executive Vice-President, Strategy & Regulatory [u]	1,180	124	1,304	1,180
Executive Vice-President, Strategy & Regulatory [t]	375	43	418	375

(r) The 2017 figures have been restated to include balances related to the incumbents who were appointed to their positions in 2018 as they were members of the pension plans prior to their appointment date.

(s) Includes service to June 2, 2017.

(t) Includes amounts for the year ended March 31, 2018 as the incumbents were members of the pension plans prior to their appointment date.

(u) Includes service to July 4, 2017.

ALBERTA ENERGY REGULATOR **Schedule 3**

SCHEDULE TO THE FINANCIAL STATEMENTS

Actual Results Compared with Budget

Year Ended March 31, 2018

(in thousands)

	Budget (Note 3)	Adjustments [(a)]	Adjusted budget	Actual
Revenues				
Industry levies and assessments	$ 274,847	$ (15,000)	$ 259,847	$ 260,021
Information, services and fees	3,542	-	3,542	7,901
Investment income	867	-	867	1,747
	279,256	(15,000)	264,256	269,669
Expenses				
Energy regulation	244,619	-	244,619	249,752
Orphan well abandonment	30,500	(15,000)	15,500	15,796
Climate leadership plan	6,637	-	6,637	3,501
	281,756	(15,000)	266,756	269,049
	(2,500)	-	(2,500)	620
Capital				
Capital investment	9,000	-	9,000	14,268
Less: Amortization	(11,500)	-	(11,500)	(13,848)
Loss on disposal and write-down of tangible capital assets				(128)
Net capital investment	(2,500)	-	(2,500)	292
Surplus	$ -	$ -	$ -	$ 328

(a) The Adjustments reflect the reduction in orphan well levy required to consolidate issuance of two orphan levies into one and to start collecting a single levy at the beginning of the fiscal year.

ALBERTA UTILITIES COMMISSION

FINANCIAL STATEMENTS
For the year ended March 31, 2018

Independent Auditor's Report

Auditor General OF ALBERTA

To the Members of the Alberta Utilities Commission

Report on the Financial Statements

I have audited the accompanying financial statements of the Alberta Utilities Commission, which comprise the statement of financial position as at March 31, 2018, and the statements of operations, change in net financial assets and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Utilities Commission as at March 31, 2018, and the results of its operations, its remeasurement gains and losses, its changes in net financial assets, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

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

May 15, 2018
Edmonton, Alberta

ALBERTA UTILITIES COMMISSION
STATEMENT OF OPERATIONS
Year Ended March 31, 2018

	2018		2017
	Budget (Schedule 3)	Actual	Actual
	(in thousands)		
Revenues			
Administration fees	$ 34,929	$ 31,412	$ 30,628
Investment income	300	227	178
Professional services	100	175	189
	35,329	31,814	30,995
Expenses			
Utility regulation (Schedule 1)	36,129	33,190	31,123
Annual operating deficit	(800)	(1,376)	(128)
Accumulated surplus, beginning of year	15,854	15,854	15,982
Accumulated surplus, end of year	**$ 15,054**	**$ 14,478**	**$ 15,854**

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF FINANCIAL POSITION
As at March 31, 2018

	2018	2017
	(in thousands)	
Financial Assets		
Cash and cash equivalents (Note 4)	$ 10,645	$ 11,478
Accounts receivable	144	255
Accrued pension asset (Note 6)	290	408
	11,079	12,141
Liabilities		
Accounts payable and accrued liabilities	7,311	2,876
Deferred lease incentive (Note 7)	3,005	299
Capital lease obligation	88	-
	10,404	3,175
Net Financial Assets	675	8,966
Non-Financial Assets		
Capital assets (Note 8)	12,462	5,752
Prepaid expenses	1,341	1,136
	13,803	6,888
Net Assets		
Accumulated surplus (Note 9)	$ 14,478	$ 15,854

Contractual obligations (Note 10)

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF CHANGE IN NET FINANCIAL ASSETS
Year Ended March 31, 2018

	2018		2017
	Budget (Schedule 3)	Actual	Actual
	----------------------------------(in thousands)----------------------------------		
Annual operating deficit	$ (800)	$ (1,376)	$ (128)
Acquisition of capital assets	(11,500)	(8,664)	(921)
Amortization of capital assets	1,800	1,472	1,516
Loss on disposal of capital assets		476	2
Proceeds on disposal of capital assets		6	-
(Decrease) increase in prepaid expenses		(205)	219
(Decrease) increase in net financial assets in the year	(10,500)	(8,291)	688
Net financial assets, beginning of year	8,966	8,966	8,278
(Net Debt) net financial assets, end of year	**$ (1,534)**	**$ 675**	**$ 8,966**

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF CASH FLOWS
Year Ended March 31, 2018

	2018	2017
	(in thousands)	
Operating transactions		
Annual operating deficit	$ (1,376)	$ (128)
Non-cash items		
Amortization of capital assets	1,472	1,516
Pension expense	697	875
Loss on disposal of capital assets	476	2
Decrease in accounts receivable	111	45
(Increase) decrease in prepaid expenses	(205)	219
Increase (decrease) in accounts payable and accrued liabilities	4,435	(195)
Cash provided by operating transactions	5,610	2,334
Capital transactions		
Acquisition of capital assets	(8,664)	(921)
Proceeds on disposal of capital assets	6	-
Cash applied to capital transactions	(8,658)	(921)
Financing transactions		
Pension obligations funded	(579)	(2,048)
Net lease incentives	2,706	240
Lease obligation capitalized	88	-
Cash provided by (applied to) financing transactions	2,215	(1,808)
Decrease in cash and cash equivalents	(833)	(395)
Cash and cash equivalents, beginning of year	11,478	11,873
Cash and cash equivalents, end of year	**$ 10,645**	**$ 11,478**

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

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.

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.

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 11 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 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.

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 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 represent 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 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 recorded when there is an appropriate basis of measurement and management can reasonably estimate the amount. 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.

(in thousands of dollars)

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

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 government 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 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 expense
Prepaid expense 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 incorporate multiple assumptions. Actual results for amortization and accrued pension asset may differ from reported values.

Change in accounting policy

The AUC has prospectively adopted the following standards from April 1, 2017: PS 2200 Related Party Disclosures, PS 3420 Inter-Entity Transactions, PS 3210 Assets, PS 3320 Contingent Assets and PS 3380 Contractual Rights.

Disclosures for contractual rights and related party transactions are provided under Note 7 and Note 11. Adoption of PS 3420 Inter-Entity Transactions, PS 3210 Assets and PS 3320 Contingent Assets have not impacted the AUC's financial statements.

Note 3 Future accounting changes

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

PS 3430 Restructuring Transactions (effective April 1, 2018)

This standard provides guidance on how to account for and report restructuring transactions by both transferors and recipients of assets and/or liabilities, together with related program or operating responsibilities. Management has completed a review of this standard and does not anticipate any impact on the AUC's financial statements.

PS 3280 Asset Retirement Obligations (effective April 1, 2021)

Effective April 1, 2021, this standard provides guidance on how to account for and report a liability for retirement of a tangible capital asset. Management is currently assessing the impact of this standards on the financial statements.

Note 4 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, 2018, securities held by the Fund have a time-weighted return of 1.1 per cent per annum (2017: 0.9 per cent).

Note 5 Financial instruments

The AUC has the following financial instruments: accounts receivable, accounts payable and 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, 2018, the balance of accounts receivables does not contain amounts that were past due or uncollectible.

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 $1,927 for the year ended March 31, 2018 (2017: $1,781). 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, 2016. The accrued benefit obligation as at March 31, 2018 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, 2019.

Pension plan assets are valued at market values. During the year ended March 31, 2018 the weighted average actual return on plan assets was 2.44 per cent (2017: 7.89 per cent).

(in thousands of dollars)

Note 6 Pension (continued)

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

	March 31, 2018	March 31, 2017
Accrued benefit obligations		
Discount rate	4.70%	4.40%
Rate of compensation increase	3.50%	3.50%
Long-term inflation rate	2.00%	2.00%

	2018	2017
Pension Benefit costs for the year		
Discount rate	4.40%	4.48%
Expected rate of return on plan assets	4.40%	4.48%
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, 2018	March 31, 2017
Market value of plan assets	$ 11,133	$ 11,286
Accrued benefit obligations	10,275	10,925
Plan surplus	858	361
Unamortized actuarial (gain) loss	(568)	47
Accrued pension asset	$ 290	$ 408

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

	2018	2017
Current period benefit costs	$ 614	$ 608
Interest cost	504	477
Expected return on plan assets	(509)	(396)
Amortization of actuarial losses	88	186
	$ 697	$ 875

The average remaining service period of active employees is 6.6 years (2017: 6.9 years).

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

	2018	2017
AUC contribution	$ 579	$ 2,048
Employees' contribution	105	109
Benefits paid	1,107	166

(in thousands of dollars)

Note 6 Pension (continued)

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

	March 31, 2018	March 31, 2017
Equity securities	45.80%	49.70%
Debt securities	18.10%	27.00%
Other	36.10%	23.30%
	100.00%	100.00%

Note 7 Deferred lease incentive

The AUC has received lease incentives through its office lease agreements. During 2018, the AUC received $2,790 in lease incentives in the form of cash and free rent (2017: $324). Also, the AUC has a contractual right to receive an additional lease incentive of $4,020 in the form of cash and free rent in the next fiscal year.

	2018	2017
Opening balance	$ 299	$ 59
Cash incentive received	2,755	-
Rent free period received	35	324
Lease incentive amortized	(84)	(84)
Closing balance	$ 3,005	$ 299

Note 8 Capital assets

	March 31, 2018				March 31, 2017
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	$ 2,209	$ 9,586	$ 3,428	$ 15,223	$ 14,658
Additions	2,003	680	5,981	8,664	921
Disposals	(1,357)	(1,641)	-	(2,998)	(356)
	$ 2,855	$ 8,625	$ 9,409	$ 20,889	$ 15,223
Accumulated amortization					
Beginning of year	$ 1,135	$ 5,334	$ 3,002	$ 9,471	$ 8,309
Amortization expense	125	985	362	1,472	1,516
Effect of disposals	(890)	(1,626)	-	(2,516)	(354)
	$ 370	$ 4,693	$ 3,364	$ 8,427	$ 9,471
Net book value at March 31, 2018	**$ 2,485**	**$ 3,932**	**$ 6,045**	**$ 12,462**	**$ 5,752**
Net book value at March 31, 2017	**$ 1,074**	**$ 4,252**	**$ 426**	**$ 5,752**	

(in thousands of dollars)

Note 9 Accumulated surplus

Accumulated surplus is comprised of the following:

	2018			2017
	Investments in capital assets	Unrestricted surplus	Total	Total
Opening balance	$ 5,752	$ 10,102	$ 15,854	$ 15,982
Annual operating deficit	-	(1,376)	(1,376)	(128)
Net investment in capital assets	6,710	(6,710)	-	-
Closing balance	$ 12,462	$ 2,016	$ 14,478	$ 15,854

Note 10 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:

Obligations under operating leases, service contracts and maintenance agreements	
	Total
2019	$ 1,691
2020	973
2021	973
2022	779
2023	778
Thereafter	5,062
	$ 10,256

Note 11 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, 2018 the AUC received and paid $144 (2017: $148) 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 12 Approval of financial statements

These financial statements were approved by the AUC's Commission Members.

ALBERTA UTILITIES COMMISSION

Schedule 1

EXPENSES - DETAILED BY OBJECT

Year Ended March 31, 2018

	2018		2017
	Budget	**Actual**	**Actual**
	(in thousands)		
Salaries, wages and employee benefits	$ 25,625	$ 22,847	$ 21,855
Supplies and services	8,704	8,395	7,750
Amortization of capital assets	1,800	1,472	1,516
Loss on disposal of capital assets	-	476	2
	$ 36,129	$ 33,190	$ 31,123

ALBERTA UTILITIES COMMISSION
SALARY AND BENEFITS DISCLOSURE
Year Ended March 31, 2018

Schedule 2

	2018				2017
	Base Salary (1)	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
	-(in thousands)-				
Chair of the Commission	$ 346	$ 67	$ 89	$ 502	$ 505
Vice-Chair	218	49	22	289	299
Commission Member	195	68	17	280	248
Commission Member	195	22	59	276	285
Commission Member (4)	188	55	16	259	257
Commission Member (5)	195	10	56	261	115
Commission Member	195	8	54	257	259
Commission Member (6)	195	2	58	255	18
Commission Member (6)	195	2	57	254	25

(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) Position became vacant as of March 19, 2018.

(5) Position was vacant for seven months in 2017.

(6) Position was vacant for eleven months in 2017.

ALBERTA UTILITIES COMMISSION
AUTHORIZED BUDGET
Year Ended March 31, 2018

Schedule 3

	Budget (Estimate)	Authorized Changes	Authorized Budget	Actual
	(in thousands)			
Revenues				
Administration fees	$ 34,929	$ -	$ 34,929	$ 31,412
Investment income	300	-	300	227
Professional services	100	-	100	175
	35,329	-	35,329	31,814
Expenses				
Utility regulation	36,129	-	36,129	33,190
Net Capital Investment				
Capital investment	1,000	10,500	11,500	8,664
Less:				
Amortization	(1,800)	-	(1,800)	(1,472)
Loss on disposal of capital assets	-	-	-	(476)
Proceed on disposal of capital assets	-	-	-	(6)
	(800)	10,500	9,700	6,710
	$ -	$ (10,500)	$ (10,500)	$ (8,086)

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2018. The Budget and Authorized Changes have been approved by the government of Alberta.

ALBERTA PETROLEUM MARKETING COMMISSION

FINANCIAL STATEMENTS
For the year ended December 31, 2017

Auditor General OF ALBERTA

Independent Auditor's Report

To the Board of Directors of the Alberta Petroleum Marketing Commission

Report on the Financial Statements

I have audited the accompanying financial statements of the Alberta Petroleum Marketing Commission, which comprise the statement of financial position as at December 31, 2017, and the statements of income and comprehensive income, changes in assets and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

Auditor's Responsibility

My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion

In my opinion, the financial statements present fairly, in all material respects, the financial position of the Alberta Petroleum Marketing Commission as at December 31, 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

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

June 6, 2018
Edmonton, Alberta

Alberta Petroleum Marketing Commission

Statement of Financial Position
As at December 31
(thousands of Canadian dollars)

	2017	2016
Assets		
Cash and short term investments (Note 6)	$ 7,173	$ 4,176
Accounts receivable	91,284	78,082
Intangible assets under development (Notes 7 and 14)	8,125	6,030
Term loan (Note 8)	391,963	324,363
Accrued interest on term loan	98,746	60,896
Total assets	$ 597,291	$ 473,547
Liabilities		
Accounts payable (Note 9)	$ 21,862	$ 18,579
Due to the Department of Energy (Note 10)	81,118	67,809
Short term debt (Note 11)	391,963	324,363
Accrued interest on short term debt	8,017	5,295
Total liabilities	$ 502,960	$ 416,046
Net assets	$ 94,331	$ 57,501
Total liabilities and net assets	$ 597,291	$ 473,547

Commitments (Note 13)

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

Alberta Petroleum Marketing Commission

Statement of Income and Comprehensive Income
For the year ended December 31
(thousands of Canadian dollars)

	2017	2016
Conventional crude oil marketing operations		
Marketing fee revenue (Note 14)	$ 6,304	$ 4,313
Finance income	45	28
	6,349	4,341
Expenses		
Wages and benefits (Note 14)	3,816	3,765
Consulting	560	319
Software and maintenance (Note 14)	88	735
Directors' fees	66	34
Dues and subscriptions	65	95
Travel	11	49
Telephone	9	17
Conferences	8	15
Other	10	14
	4,633	5,043
Net (loss) income from conventional crude oil marketing operations	1,716	(702)
Sturgeon Refinery		
Finance income	37,850	32,003
Finance costs	(2,722)	(2,345)
Trust costs	(14)	(3)
Net income attributable to Sturgeon Refinery	35,114	29,655
Net income and comprehensive income	$ 36,830	$ 28,953

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

Alberta Petroleum Marketing Commission

Statement of Changes in Net Assets
For the year ended December 31
(thousands of Canadian dollars)

	2017	2016
Net assets, beginning of year	$ 57,501	$ 28,548
Net income and comprehensive income	36,830	28,953
Net assets, end of year	$ 94,331	$ 57,501

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

Alberta Petroleum Marketing Commission

Statement of Cash Flows
For the year ended December 31
(thousands of Canadian dollars)

	2017	2016
Operating activities		
Net income and comprehensive income	$ 36,830	$ 28,953
Non-cash items included in net income		
Accrued interest on term loan	(37,850)	(32,003)
Accrued interest on short term debt	2,722	2,345
Changes in non-cash working capital		
(Increase) in accounts receivable	(13,202)	(6,714)
Decrease in prepaid expenses	-	13
Increase/(decrease) in accounts payable	3,283	(4,483)
Increase in due to Department of Energy	13,309	13,338
Net cash from operating activities	5,092	1,449
Investing activities		
Term loan	(67,600)	(99,363)
Intangible assets under development	(2,095)	(2,396)
Net cash used in investing activities	(69,695)	(101,759)
Financing activities		
Proceeds from issuance of short term debt	67,600	99,363
Net cash from financing activities	67,600	99,363
Increase/(decrease) in cash and short term investments	2,997	(947)
Cash and short term investments, beginning of year	4,176	5,123
Cash and short term investments, end of year	$ 7,173	$ 4,176

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

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 the Province of Alberta (the "Province"), as represented by the Department of Energy (the "Department"), 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 Department and transferring the proceeds received from the sale of the crude oil back to the Department. These financial statements disclose the transactions the Commission incurs while acting as agent on behalf of the Department.

The *Petroleum Marketing Act* was amended on January 10, 2014. The amendments provided the Minister with new power to give directions to the APMC; modernized and improved the basic corporate rules under which the 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 the 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" or "Sturgeon Refinery") and the commitment to capacity on the Keystone XL Pipeline 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, the Commission is not subject to 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 financial statements were authorized for issue by the Board of Directors on June 6, 2018.

Note 2 Basis of preparation

(a) Basis of presentation

These financial statements have been prepared in compliance with International Financial Reporting Standards (IFRS) as published by the International Accounting Standards Board (IASB).

(b) Basis of measurement

The financial statements have been prepared under the historical cost convention, except as disclosed in the significant accounting policies in Note 3.

(c) Financial and presentation currency

These financial statements are presented in Canadian dollars, which is the Commission's functional currency.

Note 3 Significant accounting policies

The precise determination of many assets and liabilities is dependent upon future events. Accordingly, the preparation of financial statements for a reporting period necessarily involves the use of estimates and approximations which have been made using careful judgment. Actual results could differ from those estimates. These financial statements have, in the Commission's opinion, been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

(a) Revenue recognition

The Commission acts as an agent on behalf of the Department to accept delivery of and market the Province's royalty share of crude oil (the "conventional crude oil marketing activities"). As part of these activities, the Commission has entered into an agreement with Shell Trading Canada (Shell) for them to manage the transportation logistics and purchase approximately 90% of the royalty share of crude oil at index-based pricing. The Commission markets the remaining 10% of the royalty share. Amounts collected on behalf of the Department for conventional crude oil marketing activities are not revenue as the Commission never holds title to the barrels. Instead, the Commission earns revenue through marketing fees collected from the Department based on net volumes sold.

Revenue is recognized from marketing fees when earned, which corresponds to the service period in which the conventional crude oil marketing activities take place.

As part of the marketing activities, inventory of $1,588 is being held in a fiduciary capacity on behalf of the Department at December 31, 2017 ($819 as at December 31, 2016). 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, inventory is not recognized.

(b) Foreign currency

Transactions in foreign currencies are translated to the appropriate functional currency at foreign exchange rates that approximate those on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the appropriate functional currency at foreign exchange rates at the financial position date. Foreign exchange differences arising on translation are recognized in income. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction.

(c) Financial instruments

Financial assets and liabilities are recognized when the Commission becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Commission has transferred substantially all of the risks and rewards of ownership. Financial liabilities are derecognized when the obligation specified in the contract is discharged, cancelled or expires or the cash flows are modified in a way that is in substance an extinguishment.

All financial instruments are initially recognized at fair value on the statement of financial position. Measurement of financial instruments subsequent to the initial recognition is based on how each financial instrument was initially classified. APMC's financial instruments are classified into the following two categories: financial assets at amortized cost; or financial liabilities at amortized cost. The Commission's financial assets include: cash and short term investments, accounts receivable and term loan. The Commission's financial liabilities consist of: accounts payable, due to Department of Energy and short term debt. The financial assets and liabilities are measured subsequent to initial recognition at amortized costs using the effective interest method and impairment losses are recorded in the statement of income and comprehensive income when they occur. Transaction costs adjust the carrying amount initially recognized for a financial asset or liability.

Financial assets and liabilities are offset and the net amount reported in the statement of financial position when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis or realize the asset and settle the liability simultaneously.

(d) Impairment of loans and receivables

Loans and receivables are assessed at each reporting date to determine whether there is any objective evidence of impairment. A loan or receivable is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in income in the period incurred. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the statement of income and comprehensive income. The reversal amount would not be more than the asset's carrying amount.

(e) Finance income

Finance income generated from conventional crude oil marketing operations comprises interest income earned on short term investments. Finance income related to the Sturgeon Refinery is earned on a term loan at prime plus six percent compounded monthly.

(f) 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 statement of income and comprehensive income and offsetting liability on the statement of financial position.

(g) Intangible assets under development

The Commission is in the process of replacing its legacy operating and accounting software. Costs related to software developed or purchased for internal use are capitalized if it is probable those future economic benefits will flow to APMC and that the cost can be measured reliably. Eligible costs include: billings from the Department's Information Management Technical Services (IMTS) group for development; directly attributable costs; consulting and wages and benefits of people working on the project.

Once the project is complete the total cost will be amortized on a straight line basis over the estimated useful life of the software.

(h) Impairment of intangible assets under development

The carrying amounts of non-financial assets, which include the intangible assets under development, 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 statement of income and comprehensive income.

If the circumstances leading to the impairment are no longer present, an impairment loss may be reversed. The extent of the impairment loss that can be reversed is determined by the carrying cost net of amortization that would have existed if the impairment had not occurred. 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 statement of income and comprehensive income.

Note 4 New standards and accounting pronouncements not yet effective

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2018 and have not been applied in preparing the financial statements for the year ended December 31, 2017. The standards applicable to the Commission are as follows and will be adopted on their respective effective dates.

(a) Revenue recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue from Contracts with Customers"* ("IFRS 15") replacing International Accounting Standard 11, "*Construction Contracts*" ("IAS 11"), IAS 18, "*Revenue*" ("IAS 18"), and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Commission will adopt the standard when it becomes effective and does not anticipate that this standard will result in significant accounting changes to current operations. APMC is currently assessing the impact of IFRS 15 on its accounting for the Sturgeon Refinery when it achieves the Commercial Operations Date (COD) later in 2018.

(b) Financial instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39"). IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in Other Comprehensive Income rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. The APMC does not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Commission will adopt the standard when it becomes effective. The Commission does not anticipate the classification and measurement of its financial instruments to change. An impairment provision will be calculated for its financial assets as at December 31, 2017 and this amount will be reflected in the 2018 opening net assets.

Note 5 Critical accounting estimates and judgments

(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 the accounting policy choice. 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 North West Redwater Partnership and Keystone XL Pipeline 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 financial statements.

(b) Revenue recognition

The Commission has exercised judgment in determining whether it is acting as a principal or an agent with respect to conventional crude oil marketing activities. The Commission would be acting as a principal if it has exposure to the significant risks and rewards associated with rendering the marketing services. The Commission accepts delivery of and markets the Province'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. However, the Commission is not exposed to significant inventory, credit, or price risk, and therefore does not have the exposure to the significant risks and rewards of ownership, which is indicative of an agency relationship. Therefore the gross inflows and economic benefits of conventional crude oil marketing activities are considered collected on behalf of the Department and are not recognized as revenue. Had the Commission been considered to be a principal, the statement of income and comprehensive income would have included the following additional amounts: $814,913 revenues, $75,037 expenses and $739,876 royalties to be transferred to the Department (2016: $561,301 revenues, $63,614 expenses and $497,687 royalties to be transferred to the Department).

(c) NWRP – Significant influence

In 2017 APMC lent an additional $67.6 million to NWRP (total as at December 31, 2017 $391.963 million) in the form of term loans. NWRP is a general partnership formed by CNR (Redwater) Limited (formerly Canadian Natural Upgrading Limited), a wholly-owned subsidiary of Canadian Natural Resources Limited 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.

NWRP has entered into various agreements to construct and operate a refinery 45 kilometres north-east of Edmonton to have the capacity to process approximately 50,000 barrels per day (bbl/d) of bitumen at an updated facility capital cost (FCC) budget of $9.7 billion ($9.0 billion as at December 31, 2016). A higher than expected USD/CAD exchange rate, scope changes, and productivity challenges during construction have resulted in upward budgetary pressures. APMC will provide 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 two 30 year fee-for-service tolling agreements. NWRP targets the refinery to come on stream to process bitumen feedstock with COD in the 4th quarter of 2018.

This term loan earns interest at a rate of prime plus six percent, compounded monthly, and will be repaid over 10 years starting one year after commercial start-up. While the loan to NWRP is 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.

(in thousands of Canadian dollars unless otherwise stated)

The Commission has exercised judgment in determining APMC has significant influence over NWRP. However the Commission has no equity ownership interest in NWRP. APMC will not equity account for NWRP within the accounts of the Commission's financial statements, however will provide summarized NWRP financial information in these notes. See Note 8 for further details.

(d) NWRP - Monthly toll commitment

The Commission has used judgment to estimate the toll commitments included in Note 13 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.

(e) NWRP - 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 catalyst volumes or energy consumption; pricing related variables such as 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 on information from various sources including forecasts of global consultancies, reserve evaluation consultants, forward markets and the Government of Alberta.

Based on the analysis as at the authorization date of these financial statements, APMC determined the agreement has a positive net present value and no provision is required.

(f) Keystone XL Pipeline Project – Monthly toll commitment

The Commission has used judgment to estimate the toll commitments included in Note 13 Commitments. This estimate is based on the terms and conditions agreed to within the Transportation Service Agreements (TSA's), including the contract term, capacity commitment and a per barrel toll estimate.

Note 6 Cash and short term investments

	December 31, 2017	December 31, 2016
Cash and short term investments	$ 5,248	$ 4,176
Cash, Initial Proceeds Trust Account	1,925	-
	$ 7,173	$ 4,176

(in thousands of Canadian dollars unless otherwise stated)

Cash and short term investments consist of deposits in the Consolidated Cash Investment Trust Fund (the "Fund") which is managed by the Province of Alberta to provide competitive interest income 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 December 31, 2017, securities held by the Fund have a rate of return of 0.94% per annum (0.85% per annum – 2016). Due to the short term nature of Fund investments the carrying value approximates fair value.

The Initial Proceeds Trust Account are monies held by Computershare (a trustee on behalf of the Sturgeon Refinery Tollpayers – APMC and CNRL).

Note 7 Intangible assets under development

	December 31, 2017	December 31, 2016
Balance, beginning of year	$ 6,030	$ 3,634
Additions	2,095	2,396
Balance, end of year	$ 8,125	$ 6,030

Note 8 Term loan

	December 31, 2017	December 31, 2016
Balance, beginning of year	$ 324,363	$ 225,000
Additions	67,600	99,363
Balance, end of year	$ 391,963	$ 324,363

During the year the Commission lent an additional $67.600 million to NWRP as a term loan representing monthly drawdowns per the subordinated debt agreement. This term loan earns interest at a rate of prime plus six percent, compounded monthly, and will be repaid over 10 years starting one year after commercial start-up.

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.

Because of the 25 percent voting interest APMC has significant influence over NWRP. However the Commission has no equity ownership interest in NWRP. APMC will not equity account for the Sturgeon Refinery within the accounts of its financial statements.

Summarized audited financial information with respect to NWRP is presented below as of December 31, 2017. This information has been prepared in accordance with IFRS as issued by the IASB.

(in thousands of Canadian dollars unless otherwise stated)

	NWRP (100% Interest)	
	2017	2016
Current assets	$ 290,622	$ 97,227
Non-current assets	$ 10,540,474	$ 8,272,132
Current liabilities	$ 2,476,234	$ 586,408
Non-current liabilities	$ 10,245,578	$ 7,259,891
Partners' equity	$ 585,518	$ 523,060
Revenue	$ -	$ -
Net income and comprehensive income attributable to Partners	$ 62,458	$ 13,956

Non-current assets primarily consist of property plant and equipment, which includes: engineering; procurement activities; site construction costs; module fabrication; capitalized interest, and other costs directly attributable to the project. Non-current liabilities primarily include senior secured long term notes, credit facilities (with both Canadian and U.S. dollar denominated debt) and subordinated debt.

The net income and comprehensive income attributable to Partners primarily contains foreign exchange gains offset by general and administrative costs.

Note 9 Accounts payable

	December 31, 2017	December 31, 2016
Trade payables	$ 12,122	$ 10,391
GST	9,740	8,188
	$ 21,862	$ 18,579

Note 10 Due to the Department of Energy

	December 31, 2017	December 31, 2016
Due to Department, beginning of year	$ 67,809	$ 54,471
Amount to be transferred	739,876	497,687
Amount remitted	(726,567)	(484,349)
Due to Department, end of year	$ 81,118	$ 67,809

(in thousands of Canadian dollars unless otherwise stated)

Note 11 Short term debt

	December 31, 2017	December 31, 2016
Balance, beginning of year	$ 324,363	$ 225,000
Additions	67,600	99,363
Balance, end of year	$ 391,963	$ 324,363

Details related to additions are as follows:

Date Issued	Amount	Interest Rate	Due Date
Jan 04, 2016	$ 99,363	0.715%	Jan 03, 2017
May 31, 2017	$ 21,000	0.770%	May 30, 2018
Jun 30, 2017	1,500	1.041%	Jun 29 2018
Jul 31, 2017	8,000	1.286%	Jul 30, 2018
Aug 31, 2017	6,750	1.350%	Aug 31, 2018
Sep 29, 2017	6,100	1.571%	Sep 28, 2018
Oct 31, 2017	7,850	1.520%	Oct 30, 2018
Nov 30, 2017	16,400	1.440%	Nov 29, 2018
	$ 67,600		

APMC's intention is to borrow additional short term funds (with a one year term) from Treasury Board and Finance when these amounts come due and repay the aggregated amounts (both principal and interest) over 10 years starting the year after the Sturgeon Refinery COD. The timing of APMC repaying of this debt is expected to correspond to NWRP's repayment of the term loan to the Commission (see Note 8).

Note 12 Financial instruments

The Commission's financial instruments consist of cash and short term investments, accounts receivable, term loan, accounts payable, short term debt and amounts due to the Department. The Commission has classified cash and short term investments, accounts receivable and term loan as loans and receivables, and accounts payable, due to the Department and short term debt as financial liabilities at amortized cost. The Commission's financial instruments are initially recorded at amortized cost using the effective interest method. The fair values of the financial instruments approximate their carrying values due to the short term maturities of those instruments.

The Commission is exposed to a variety of financial risks: market risk (interest rate risk), credit risk, and liquidity risk. The nature of the risks faced by the Commission and its policies for managing such risks remains unchanged from December 31, 2016.

(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 balance (Note 6). For 2016 and 2017, 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 2017 finance income by $4.8 million (2016 $3.8 million). A 100 basis point decline in prime would have reduced 2017 finance income by $4.7 million (2016 $3.8 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 short term investments and accounts receivable. The maximum amount of credit risk exposure is limited to the carrying value of the balances disclosed in these financial statements.

The Commission manages its exposure to credit risk on cash and short term investments by placing these financial instruments with the Consolidated Cash Investment Trust Fund (Note 6).

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 an allowance for credit losses is provided in the period in which losses become known. There were no balances past their contractual due date as at December 31, 2017 and December 31, 2016. Any credit losses on accounts receivable would be charged on to the Department.

APMC has issued term loans totaling $391.963 million to NWRP. NWRP is an investment grade counterparty. Bonds issued by NWRP received a BBB+ credit rating 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.

(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, and the ability for the Commission to obtain financing through external banking credit facilities or obtaining borrowing from Treasury Board and Finance.

The term loan is structured so that APMC will receive repayments starting one year after commercial start-up 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 APMC intends to borrow additional funds from Treasury Board and Finance and then to match the repayment terms detailed for the term loan above.

(d) 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 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.

(in thousands of Canadian dollars unless otherwise stated)

	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	$ 162,770	$ 71,486	$ 91,284
Accounts payable (Note 9)	(93,206)	(71,344)	(21,862)
Net position, December 31, 2017	$ 69,564	$ 142	$ 69,422
Accounts receivable	$ 140,768	$ 62,686	$ 78,082
Accounts payable (Note 9)	(82,440)	(63,861)	(18,579)
Net position, December 31, 2016	$ 58,328	$ (1,175)	$ 59,503

(e) Capital management

The capital structure includes the Commission's net assets. 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 Department of Energy through responsible selling 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.

Note 13 Commitments

	2018	2019	2020	2021	2022	Beyond 2022	Total
NWRP Tolls	$ 173,000	$ 631,000	$ 741,000	$ 982,000	$ 958,000	$ 22,541,000	$ 26,026,000

(a) NWRP Tolls

On November 8, 2012 NWRP, announced the sanctioning of the construction of Phase 1 of the Sturgeon Refinery which it will build, own and operate. The Commission has entered into agreements whereby NWRP will process 37,500 bbls/day of bitumen (55,000 bbls/day of diluted bitumen) into refined products. NWRP will market the refined products (primarily ultra low sulphur diesel and low sulphur vacuum gas oil) on behalf of the Commission. There is risk to the Commission under these agreements pertaining to the price differential between bitumen supplied as feedstock and marketed refined products, relative to the costs of the processing toll.

Under the processing agreement, 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) for 30 years. The toll includes flow through costs as well as costs related to facility construction, estimated to be $9.7 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 term of the commitment begins at Toll Commencement Date (June 1, 2018). No amounts have been paid under this agreement to date.

The nominal tolls under the processing agreement assuming: a $9.7 billion FCC; market interest rates; and 2% operating cost inflation rate, are estimated above. The total estimated tolls have increased $71 million relative to 2016, due primarily to increased capital costs offset by lower energy operating costs and interest rates. As of the authorization date of these financial statements NWRP has issued $6.35 billion in bonds at lower than anticipated rates.

No value has been ascribed to the anticipated refining profits available to APMC over the term of the agreement. In addition no value has been credited for finance income net of finance costs on term loans outstanding to NWRP.

(b) Energy East Pipeline Project

The Commission received a Notice of Termination from Energy East Pipeline Limited Partnership, effective December 6, 2017. As per the terms of the Transportation Services Agreement with termination by the Carrier, APMC has no financial commitments or liabilities.

(c) NWRP Term loan

Under the agreements related to FCC for the Sturgeon Refinery, the financing structure is required to be 80% senior debt and 20% equity/subordinated debt. As part of the Subordinated Debt Facilities – Base and Additional agreements, executed April 7, 2014 APMC is committed to provide 50% of the subordinated debt required to meet this test. This commitment relates to incremental FCC from April 7, 2014 until six months after COD, when FCC is finalized.

Up to 6 months after COD the calculation of the 80/20 ratio does not allow for the deduction of cumulative debt service costs (accrued interest) which could result in a temporary need for additional subordinated debt lending by APMC. A final reconciliation of the amount of subordinated debt required will be done six months after COD at which time the calculation does allow for the deduction of accumulated debt service costs which would result in monies being returned to APMC.

Management is forecasting APMC to provide NWRP an additional $66 million in 2018 ($40.25 million has been provided up to the authorization date) of subordinated debt. In 2019 the Commission anticipates NWRP will repay $100 million to APMC as part of the final subordinated debt true-up six months after COD.

(d) Keystone XL Pipeline Project.

The Commission has entered into agreements for 50,000 barrels per day of firm pipeline transportation service capacity from Hardisty, Alberta to Port Arthur/Houston, Texas. The term of the contracts is 20 years and an in service date is estimated to be mid-2021. The Keystone XL Pipeline Project has regulatory approval, however the Carrier has not announced their Final Investment Decision (FID). Once FID occurs, APMC is committed by the take-or-pay provisions of the contracts to pay approximately $130 million in tolls annually. Additional tolls will be incurred depending on the volumes APMC transports through the pipeline.

Note 14 Related party transactions

The Department pays the Commission a fee to market crude oil on its behalf under conventional crude oil marketing activities, reported as marketing fees within the statement of income and comprehensive income. The amounts owing to the Department have been disclosed in Note 10.

The Commission enters into transactions with the Department of Energy, a related party, in the normal course of business. The Department incurs costs for salaries on behalf of the Commission, as recognized under wages and benefits (2017 $2,231, 2016 $2,054) and software and maintenance (2017 $72, 2016 $73) within the statement of income and comprehensive income. In addition some of the Department salaries have been capitalized within Intangible assets under development (2017 $173, 2016 $182).

The Commission has outstanding short term debt with Treasury Board and Finance. For more details see Note 11.

The Board members of the Commission, executive management and their close family members are deemed to be related parties of the Commission. Transactions with close family members are immaterial; compensation for Board members and executive management is disclosed in Note 15.

(in thousands of Canadian dollars unless otherwise stated)

Note 15 Salaries and benefit disclosure

Key management personnel include the Commission's Chief Executive Officer, Executive Director Business Development, Director of Finance and Board Members. The amounts in the financial statements relating to board members and key management compensation in 2017 and 2016 are as follows:

	2017				2016
	Base Salary	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
Board Members (1)	$ -	$ 66	$ -	$ 66	$ 34
Chief Executive Officer - Prior	328	16	5	349	636
Chief Executive Officer - Interim	104	1	21	126	-
Chief Executive Officer - Current	9	2	1	12	-
Senior Management					
Executive Director, Business Development	420	25	7	452	454
Director of Finance	234	25	9	268	268

(1) The Chair of the Board (Deputy Minister, Department of Energy) and one director (Assistant Deputy Minister, Department of Energy) are unpaid. Two outside Board Members were added in the 3rd quarter of 2017, bringing the total number of outside Board Members to three. The outside Board Members receive an annual retainer and meeting fees.

(2) As per their employment contracts the three key management personnel receive cash payments in lieu of benefits.

(3) Included in Other Non-cash benefits are employer contributions to Canada Pension Plan, Employment Insurance, reimbursement of parking and fitness facility membership costs. The Interim Chief Executive Officer received life insurance, extended medical, dental, pension and retirement compensation allowance benefits.

The Prior Chief Executive Officer (CEO) resigned effective July 5, 2017. The Interim CEO was in place from July 6 to December 19, 2017. The Current CEO was hired effective December 20, 2017.

Note 16 Subsequent events

Short term debt

On January 2, 2018 the Commission borrowed $19.5 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.700% due January 2, 2019.

On January 2, 2018 APMC replaced its short term debt of $100.074 million originally issued January 2, 2018 with new short term debt of $100.812 million at 1.700% interest due January 2, 2019.

On January 31, 2018 the Commission borrowed $12.5 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.750% due January 30, 2019.

On February 28, 2018 APMC borrowed $4.7 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.750% due February 27, 2019.

On March 29, 2018 the Commission borrowed $3.56 million of short term debt from Treasury Board and Finance at an effective interest rate of 1.780% due March 29, 2019.

On April 4, 2018 APMC replaced its short term debt of $115.248 million originally issued April 5, 2017 with new short term debt of $116.127 million at 1.805% interest due April 4, 2019.

On May 30, 2018 APMC replaced its short term debt of $21 million originally issued May 31, 2017 with new short term debt of $21.203 million at 1.873% interest due May 30, 2019.

Term Loan to NWRP

Up to the authorization date the Commission has lent an additional $40.25 million term loan to NWRP on the same terms and conditions as the term loans issued previously (see Note 8). These monies are being forwarded in response to monthly Drawdown Notices issued by NWRP, pursuant to the terms and conditions of the subordinated debt agreement.

POST-CLOSURE STEWARDSHIP FUND

FINANCIAL STATEMENTS
For the year ended March 31, 2018

Independent Auditor's Report

Auditor General
OF ALBERTA

To the Minister of Energy

Report on the Financial Statements
I have audited the accompanying financial statements of the Post-Closure Stewardship Fund, which comprise the statement of financial position as at March 31, 2018 and the statements of operations, change in net financial assets and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these 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 financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility
My responsibility is to express an opinion on these financial statements based on my audit. I conducted my audit in accordance with Canadian generally accepted auditing standards. Those standards require that I comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

I believe that the audit evidence I have obtained is sufficient and appropriate to provide a basis for my audit opinion.

Opinion
In my opinion, the financial statements present fairly, in all material respects, the financial position of the Post Closure Stewardship Fund as at March 31, 2018, 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.

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

June 6, 2018
Edmonton, Alberta

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF OPERATIONS

Year ended March 31, 2018

(in thousands)

	2018		2017
	Budget	**Actual**	**Actual**
Revenue			
Injection Levy (Note 3)	$ 230	$ 248	$ 264
Investment Income (Note 4)	-	4	-
Net Operating Results	230	252	264

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF FINANCIAL POSITION

As at March 31, 2018

(in thousands)

	2018	2017
Assets		
Cash (Note 4)	$ 536	$ 272
Accounts Receivable	128	140
Net Assets	**$ 664**	**$ 412**
Net Assets at Beginning of Year	$ 412	$ 148
Annual Operating Results	252	264
Net Assets at End of Year	**$ 664**	**$ 412**

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF CHANGE IN NET FINANCIAL ASSETS

Year ended March 31, 2018

(in thousands)

	2018		2017
	Budget	Actual	Actual
Annual Operating Results	$ 230	$ 252	$ 264
Increase in Net Assets	$ 230	$ 252	$ 264
Net Assets at Beginning of Year	-	412	148
Net Assets at End of Year	**$ 230**	**$ 664**	**$ 412**

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF CASH FLOWS

Year ended March 31, 2018

(in thousands)

	2018		2017	
Operating Transactions				
Net Operating Results	$	252	$	264
Decrease in Accounts Receivable		12		8
Increase in Cash and Cash Equivalents	**$**	**264**	**$**	**272**
Cash and Cash Equivalents at Beginning of Year		272		-
Cash and Cash Equivalents at End of Year	**$**	**536**	**$**	**272**

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND
NOTES TO FINANCIAL STATEMENTS
March 31, 2018
(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 funds have been internally restricted under Section 122 of the MMA and is not available for government's general use. Any income earned on the Fund is likewise restricted in its use.

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.

Valuation of 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, 2018, 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 11% 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 General Revenue Fund on behalf of the Post Closure Stewardship Fund. The fund earns interest at Prime less 2.25%.

NOTE 5 APPROVAL OF FINANCIAL STATEMENTS

The Deputy Minister and the Senior Financial Officer approve these financial statements.

balancingpool

2017 Annual Report

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BALANCING POOL

FINANCIAL STATEMENTS
For the year ended December 31, 2017

April 10, 2018

Independent Auditor's Report

To the Directors of the Balancing Pool

We have audited the accompanying financial statements of the Balancing Pool, which comprise the statements of financial position as at December 31, 2017 and December 31, 2016 and the statements of income (loss) and comprehensive income (loss) and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

Auditor's responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of the Balancing Pool as at December 31, 2017 and December 31, 2016 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

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Statements of Financial Position

(in thousands of Canadian dollars)	2017	2016
Assets		
Current assets		
Cash and cash equivalents	50,772	16,078
Trade and other receivables (Note 5)	130,124	77,157
Current portion of long-term receivables (Note 6)	1,980	-
Current portion of hydro power purchase arrangement (Note 8 b i)	57,566	-
Current portion of intangible assets (Note 7)	153,120	-
	393,562	93,235
Long-term receivables (Note 6)	3,902	7,824
Investments (Note 9)	12,370	15,684
Property, plant and equipment (Note 10)	27	57
Hydro power purchase arrangement (Note 8 b i)	120,250	48,484
Intangible assets (Note 7)	-	149,289
Total Assets	530,111	314,573
Liabilities		
Current liabilities		
Trade payable and other accrued liabilities (Note 11)	561,713	486,164
Related party loan (Note 17)	566,315	-
Current portion of hydro power purchase arrangement (Note 8 b i)	-	10,053
Current portion of small power producer contracts (Note 8 b ii)	3,424	5,902
Current portion of reclamation and abandonment provision (Note 12)	7,767	3,671
Current portion of other long-term obligations (Note 13)	529,073	1,332,031
	1,668,292	1,837,821
Small power producer contracts (Note 8 b ii)	298	5,437
Reclamation and abandonment provision (Note 12)	13,871	26,361
Other long-term obligations (Note 13)	128,648	411,742
Total Liabilities	1,811,109	2,281,361
Net liabilities attributable to the Balancing Pool deferral account (Note 1, 14)	(1,280,998)	(1,966,788)
Contingencies and commitments (Note 15)		
Subsequent event (Note 18)		

On behalf of the Balancing Pool:

Original signed by Robert Bhatia, Chair

Original signed by Greg Pollard, Audit and Finance Committee Chair

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

Statements of Income (Loss) and Comprehensive Income (Loss)

(in thousands of Canadian dollars)	2017	2016
Revenue from contracts with customers		
Sale of electricity (Note 3)	661,586	463,923
Consumer Collection (Note 3, 14)	66,003	-
Sale of generating capacity and termination revenue (Note 3, 15)	716	28,743
	728,305	492,666
Other income (expense) from operating activities		
Changes in fair value of hydro power purchase arrangement (Note 8 b i)	159,718	(222,670)
Payments (refunds) in lieu of tax	3,069	(133,349)
Investment income – interest and dividends	313	4,836
Changes in fair value of investments (Note 9)	32	(6,572)
	163,132	(357,755)
Expenses		
Cost of sales (Note 16)	621,571	753,705
Mandated costs (Note 17)	6,227	6,155
General and administrative	4,139	3,814
Force majeure costs	5,306	2,110
Investment management costs	31	534
Changes in fair value of small power producer contracts (Note 8 b ii)	(3,404)	6,048
Reclamation and abandonment provision (Note 12)	(7,109)	(75)
Power purchase arrangement provision (Note 13)	(424,544)	1,648,395
Property, plant and equipment impairment loss (Note 10)	-	264,678
	202,217	2,685,364
Income (loss) from operating activities	689,220	(2,550,453)
Other income (expense)		
Finance expense (Note 12, 17)	(3,558)	(804)
Other income	128	121
	(3,430)	(683)
Change in net liabilities attributable to the Balancing Pool deferral account (Note 14)	685,790	(2,551,136)

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

Statements of Cash Flows

(in thousands of Canadian dollars)	2017	2016
Cash flow provided by (used in)		
Operating activities		
Change in net liabilities attributable to the Balancing Pool deferral account	685,790	(2,551,136)
Items not affecting cash		
Amortization, depreciation and impairment (Note 10)	30	330,888
Reclamation and abandonment provision (Note 12)	(7,109)	(75)
Power purchase arrangement provision (Note 13)	(1,086,052)	1,647,073
Line loss provision (reversal) (Note 13, 16)	(114,042)	-
Fair value changes on small power producer contracts (Note 8 b ii)	(3,404)	6,048
Fair value changes on hydro power purchase arrangement (Note 8 b i)	(159,718)	222,670
Fair value changes on financial investments (Note 9)	(1)	121,707
Finance expense (Note 12, 17)	3,558	804
Reclamation and abandonment expenditures (Note 12)	(1,480)	(486)
Net change in other assets:		
Intangible assets (Note 7)	(2,000)	(139,837)
Long-term receivable (Note 6)	1,942	(7,824)
Power purchase arrangement lease obligation	-	(250,987)
Net change in non-cash working capital:		
Trade and other receivables	(52,967)	(61,064)
Trade payable and other accrued liabilities	189,591	411,584
Net cash used in operating activities	(545,862)	(270,635)
Investing activities		
Interest, dividends and other gains	(186)	(119,884)
Sale of investments (Note 9)	3,501	687,212
Purchase of intangible assets (Note 7)	(1,831)	(9,452)
Net cash provided by investing activities	1,484	557,876
Financing activities		
Hydro power purchase arrangement net receipts (payments) (Note 8 b i)	20,333	(18,468)
Payment of power purchase arrangement lease obligation	-	(61,524)
Proceeds from issue of related party loan (Note 17)	562,952	-
Small power producer contracts net payments (Note 8 b ii)	(4,213)	(6,077)
Payment of the consumer allocation (Note 14)	-	(190,167)
Net cash (used in) provided by financing activities	579,072	(276,236)
Change in cash and cash equivalents	34,694	11,005
Cash and cash equivalents, beginning of year	16,078	5,073
Cash and cash equivalents, end of year	50,772	16,078

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

Notes to Financial Statements

1. Reporting Entity and Nature of Operations

Formation and Duties of the Balancing Pool

The Balancing Pool was created by the Government of Alberta to help manage certain assets, liabilities, revenues and expenses arising from the transition to competition in 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). The requirement to establish the Balancing Pool was set out in the *Balancing Pool Regulation*.

With the proclamation of the *Electric Utilities Act* (2003) (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 Balancing Pool.

Under the EUA the Corporation is required to operate with no profit or loss (Note 14) and no share capital for the Corporation has been issued. The Balancing Pool 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.

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, unit destruction, Buyer or Owner default or termination of a PPA. In situations resulting in termination of a PPA by a Buyer, the Balancing Pool will assume all remaining rights and obligations pursuant to the PPA assuming the PPA continues. The Balancing Pool acted as Buyer of the PPAs that were not sold at the public auction held by the Government of Alberta in August 2000, assuming all rights and obligations of a Buyer of these PPAs. Under the EUA the Balancing Pool is 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.

In late 2016, following the PPA terminations, the Government of Alberta enacted changes to the EUA which allow the Treasury Board to make loans to the Balancing Pool at the recommendation of the Minister of Energy and to guarantee the Balancing Pool's obligations. The Government of Alberta also enacted changes in 2016 to the *Balancing Pool Regulation* which stipulated the consumer collection for 2017 be set at $65.0 million for the year, estimated at $1.10/megawatt hour ("MWh"). For 2018, the Board of Directors approved a consumer collection of $3.10/MWh estimated at an annual amount of $190.0 million. Any cash shortfall that the consumer collection is unable to satisfy will be financed by funds obtained through the loan agreement with the Government of Alberta and subsequently recovered from electricity consumers over the period of January 1, 2017 to December 31, 2030 (Note 17).

Revenue from Contracts with Customers

i) Sale of electricity and generating capacity

The Balancing Pool earns or earned revenue from the sale of electricity sourced from the PPAs it holds or held, namely, Genesee, Battle River 5, Sheerness, Keephills, Sundance A, Sundance B and Sundance C.

The Balancing Pool has also earned revenue from the sale of generating capacity in the form of strip contracts which transfer the associated offer rights and energy output of the Genesee PPA to third party buyers. The contracts commenced on November 1, 2014. See Note 15 for events related to the strip contract terminations in 2016.

Electricity that is not otherwise contracted is sold into the spot market. Ancillary services from the PPAs are sold to the Alberta Electric System Operator ("AESO") through a competitive exchange.

ii) Consumer collection

Effective January 1, 2017, the Corporation early adopted IFRS 15, *Revenue from contracts from customers*, on a modified retrospective basis. 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. In 2016, the payment of the consumer allocation was accounted for as a reduction to the Balancing Pool Deferral Account. 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 holds the hydro PPA. As such, the Balancing Pool has retained the right to the market value of the associated electricity and is responsible for the PPA obligations from certain hydro plants in the province of Alberta. The cash flow associated with the hydro PPA is 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 is 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, dividends and capital gains and losses.

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 that *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 Administration.

Expenses

i) Cost of sales

Under the terms of the various PPAs, the Balancing Pool is obligated to pay certain fixed and variable costs to the Owners of the various generation assets.

ii) Small power producer ("SPP") contracts

Under the provisions of the *Small Power Research and Development Act*, public utilities were required to enter into production contracts with small power producers who own and operate eligible power production facilities.

Under the provisions of the *Independent Power and Small Power Regulation*, the Balancing Pool must pay to the public utility any deficit or receive any surplus realized by the public utility from the production contracts. The net present value of these estimated payments is recorded as a liability and any revaluation adjustment is included in net results of income.

iii) 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, 2017 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, 2016.

These financial statements were authorized and approved for issue by the Board of the Balancing Pool on April 10, 2018.

Certain comparative amounts have been reclassified to conform to the current presentation.

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 and investments, which are measured at fair value.

Revenue from Contracts with Customers

The Balancing Pool adopted IFRS 15, *Revenue from contracts with customers*, effective for its annual reporting period commencing January 1, 2017. The Balancing Pool elected to apply the standard on a modified retrospective basis, which resulted in changes in accounting policies and adjustments to the amounts recognized in the financial statements explained below. In accordance with the transition provisions in IFRS 15, comparatives for the 2016 financial year have not been restated, and completed contracts prior to January 1, 2017, the date of adoption of IFRS 15, were not required to be reassessed. No revenue contracts that required cumulative adjustments on transition were identified as at January 1, 2017.

(a) Sale of electricity and generating capacity

Revenues from the sale of electricity, generating capacity 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, generating capacity 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, generating capacity and ancillary services.

(b) Consumer collection (allocation)

In previous reporting periods, receipts (or payments) with respect to the consumer allocation were accounted for as a change in the Balancing Pool's deferral account, rather than revenue in the Balancing Pool's statement of income (loss) and comprehensive income (loss). Upon adoption of IFRS 15, consumer collection revenue is recognized in the statement of income (loss) and comprehensive income (loss) on an accrual basis in the period in which amounts are charged (refunded) to electricity customers based on an annualized tariff amount, which is the point in time when control of the goods and services passes to the customer. Consumer collection revenue is measured at the fair value of the consideration received or receivable. The Corporation has elected to recognize revenue based on amounts invoiced.

The timing of revenue recognition does not result in any contract assets or liabilities and there are no unfulfilled performance obligations at any point in time. The Balancing Pool has applied judgment in the application of its accounting policy that the consumer collection (allocation) represents a contract with a customer in the scope of IFRS 15 (see Note 1).

Other Income (Expense) Recognition

(a) Hydro power purchase arrangement

The hydro PPA 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) Small power producer contracts

Small power producer contracts are recorded at the present value of the estimated future net payments to be received (or paid) under these contracts. The change in value of this liability 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 from operating activities.

(c) Investment income and changes in fair value of investments

Investment income resulting from interest and dividends is recorded on an accrual basis when there is reasonable assurance as to its measurement and collectability. Investment income also includes realized and unrealized gains and losses on investments sold and realized foreign currency exchange rate gains and losses on sale of foreign investments excluding fund management fees.

(d) 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 are recorded in the current year.

Income Taxes

No provision has been made for current or deferred income tax as the Balancing Pool is exempt from Federal and Provincial tax.

Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash on deposit at the bank.

Trade and Other Receivables and Prepaid Expenses

Trade and other receivables are classified as loans and receivables and are measured at amortized cost less any impairment.

Intangible Assets (Emission Credits)

Emission credits, which have been purchased or acquired through PPA negotiated settlements and held for compliance purposes, are recorded by the Balancing Pool as indefinite life intangible assets. 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 will be used to satisfy future environmental compliance obligations of the PPAs associated with the *Specified Gas Emitters Regulation* and the *Carbon Competitiveness Incentive Regulation*. 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 are accounted as long-term receivables with fixed payments receivable on each of December 31, 2018, 2019 and 2020. 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 and Small Power Producer Contracts

The hydro PPA and small power producer contracts are derivative financial instruments classified as held for trading. They are recorded as of the period end date at their fair value. Fair value is measured as the present value of the estimated future net payments to be received (or paid) under the contracts 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 forecasting future prices using a merit order dispatch model.

Electricity Price Risk Management and Financial Instruments – Risk Management Asset and Liabilities

The Balancing Pool may utilize swap contracts to manage its exposure to electricity price fluctuations which require payments to (or receipts from) counterparties based on the differential between fixed and floating prices for electricity and other contractual arrangements. The estimated fair value of all derivative instruments is based on reported values in the electricity forward market.

Derivative financial instruments are classified as held for trading and are recorded at fair value. All changes in fair value are included in results of income.

Investments

The Corporation has designated its fixed income and equity securities upon initial recognition at fair value through profit and loss in accordance with IAS 39, *Financial instruments: recognition and measurement*. They are recorded at estimated fair value, as of the period end date, measured based on the bid price in active markets. Unrealized gains or losses resulting from changes in fair value are recorded in income.

Property, Plant and Equipment ("PP&E")

PP&E are stated at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditure directly attributable to the acquisition of the asset. When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. Gains and losses on disposal of an item of property, plant, and equipment are determined by comparing the proceeds from disposal with the carrying amount of PP&E, and are recognized within other income in profit and loss. PP&E, which comprises office equipment, is depreciated on a straight-line basis over a three- to five-year useful life.

Impairment – Non-Financial Assets

For the purpose of impairment testing, non-financial assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets – a cash generating unit ("CGU").

The carrying amounts of non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment, such as decreased forward electricity prices. If any such indication exists, then the amount recoverable from the asset is estimated. The recoverable amount is the greater of the value in use or fair value less costs to dispose.

Value in use is based on the estimated net future cash flows discounted to their present value. The discounted cash flow is determined using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. The recoverable amount is generally computed by reference to the present value of the future cash flows. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the Statement of Income (Loss) and Comprehensive Income (Loss).

Impairment losses recognized in prior years are reassessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and amortization, if no impairment loss had been permitted to be recognized.

Impairment – Financial Assets

Financial assets have been assessed for indicators of impairment at the end of each reporting period. Receivables are carried at amortized cost. The amount of any impairment loss is recognized as the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the asset's original effective interest rate. Any impairment loss is recognized in the Statement of Income (Loss) and Comprehensive Income (Loss). Should the amount of the estimated impairment loss increase or decrease following a subsequent event, the previously recognized impairment loss is adjusted through the Statement of Income (Loss) and Comprehensive Income (Loss).

Reclamation and Abandonment Obligations

Reclamation and abandonment obligations include legal obligations requiring the Balancing Pool to fund the decommissioning of tangible long-lived assets such as generation and production facilities. A provision is made for the estimated cost of site restoration.

Reclamation and abandonment obligations are measured as the present value of management's best estimate of expenditures required to settle the present obligation at the period end date. Subsequent to the initial measurement, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as a finance expense. Increases/decreases due to changes in the estimated future cash flows are expensed. Actual costs incurred upon settlement of the reclamation and abandonment obligations are charged against the provision to the extent the provision was established.

The Balancing Pool's estimates of reclamation and abandonment obligations are based on reclamation standards that meet current regulatory requirements. The estimate of the total liability of future site restoration costs may be subject to change based on amendments to laws and regulations. Accordingly, the amount of the liability will be subject to re-measurement at each period end date.

The Balancing Pool has recorded an estimate of the cost to remediate certain Isolated Generating Unit sites in Alberta. Actual expenditures incurred to remediate these sites will reduce this liability and any increase in this liability will be charged to expense when estimated costs are known to exceed the remaining liability balance.

An amount has also been provided for the decommissioning of the H.R. Milner generating station which is being accreted annually; revisions to this estimate will be charged or credited to net results of income (loss).

Pursuant to Section 7 of the *Power Purchase Arrangements Regulation*, the Owner of a generating unit who applies to the Alberta Utilities Commission ("AUC") to decommission a unit within one year of the termination of the PPA is entitled to receive from the Balancing Pool the amount by which the decommissioning costs exceed the amount the Owner collected from consumers before January 1, 2001 and subsequently through a PPA, provided that the unit has ceased generating electricity and subject to AUC approval. This provision does not apply to generation units that are decommissioned after December 31, 2018.

The reclamation and abandonment provision includes an estimate of the expected future costs associated with PPA decommissioning costs. Any underfunded decommissioning liabilities are passed to the Balancing Pool in circumstances where a plant Owner elects to discontinue operations and decommission the respective plant following a PPA termination or PPA expiry.

The discount rate used to value these liabilities is based upon the risk-free rate and adjusted for other risks associated with these liabilities.

Provisions for Onerous Contracts (Other Long-Term Obligations)

A provision for an onerous contract is recognized when the unavoidable cost of meeting the obligations under the contract exceed the economic benefits expected to be derived from the contract. The provision is measured at the lower of the expected cost of terminating the contract and the expected cost of continuing performance under the contract. The Balancing Pool has recognized onerous contract provisions for the following PPAs: Battle River 5, Sheerness, Sundance A, Sundance B, Sundance C, Keephills and Genesee. The provisions for onerous contracts have been classified as part of other long-term obligations on the Statements of Financial Position.

The discount rate used to measure these liabilities is based upon the risk-free rate. Where the Balancing Pool expects some or all of the provision will be reimbursed by a third party, the expense relating to any provision is presented in the Statement of Income (Loss) and Comprehensive Income (Loss) net of the reimbursement. The expected reimbursement receivable is recognized as an asset if it is virtually certain that the reimbursement will be received and the amount receivable can be measured reliably.

Other Provisions (Trade Payables and Accrued Liabilities)

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 and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as interest expense.

Genesee Power Purchase Arrangement and Related Finance Lease Obligation

The Genesee PPA transfers to the Balancing Pool substantially all the benefits and some of the risks of ownership and therefore the arrangement is classified as a finance lease, 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.

Each lease payment is allocated between the liability and expenses.

The capitalized asset is included in PP&E at an amount not exceeding the estimated net future cash flows arising from operations over the remaining life of the PPA. The value of the Genesee PPA is stated at cost, less accumulated depreciation and amortization.

The Genesee finance lease obligation is now recognized and reported as part of other long-term obligations (provision for onerous contracts). See Notes 10 and 13 for events related to impairment and recognition of an onerous contract for the Genesee PPA.

Accounting Standards Issued But Not Yet Adopted

The IASB issued the following standards, which are issued but have not yet been adopted by the Balancing Pool.

IFRS 9 – *Financial instruments* – is the first standard issued as part of a wider project to replace IAS 39 – *Financial instruments – recognition and measurement*. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets and a new hedge accounting model. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Balancing Pool has completed the assessment of the impact that the new standard will have on its financial statements and has not identified any significant changes other than additional disclosure.

IFRS 16 – *Leases* - In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. IFRS 16 provides a single lessee accounting model, requiring lessees to recognize assets and liabilities for all leases unless the lease term is 12 months or less or the underlying asset has a low value. The approach to lessor accounting will remain unchanged from its predecessor, IAS 17. IFRS 16 is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted. The Balancing Pool is currently evaluating the impact that the amended standard will have on its financial statements.

4. Significant Accounting Judgments, Estimates and Assumptions

The timely preparation of the financial statements requires that management make estimates and assumptions and use judgment regarding the reported value of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements and the amounts of revenues and expenses reported for the year. Such estimates reflect management's best estimate of future events as of the date of the financial statements. These financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies summarized below. Accordingly, actual results will differ from estimated amounts as future confirming events occur.

Critical Judgments in Applying Accounting Policies

Management has made critical judgments in applying accounting policies, including when:

- concluding that the consumer collection (allocation) is accounted for as revenue (refund of revenue) from a contract with a customer (Note 1, 14);
- forecasting future power prices and capacity factors;
- estimating the probability that specific PPA Owners will elect to decommission the PPA-related generating units within one year of termination of the PPA;
- assessing the impact of events related to the termination of certain PPAs and the related commitments (Note 15) and provisions (Note 13) arising therefrom; and
- estimating the amount of the liability related to the AUC Proceeding 790 ("retroactive line loss adjustment") (Note 15).

These critical judgements have been made in the process of applying accounting policies and have a significant effect on the amounts recognized in the financial statements.

Key Sources of Estimation Uncertainty

Since the determination of certain assets, liabilities, revenues and expenses are 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)
- Other long-term obligations (Note 13)
- Small power producer contracts (Note 8 b ii)
- Accrued Liabilities, retroactive line loss adjustment (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.

5. Trade and Other Receivables

(in thousands of dollars)	December 31, 2017	December 31, 2016
Trade receivables	125,366	75,137
Other receivables	4,758	2,020
	130,124	77,157

6. Long-term receivables

(in thousands of dollars)	December 31, 2017	December 31, 2016
Opening balance, long-term receivable	7,824	-
Accretion	58	-
Cash settlement receivable from PPA settlements (Note 15)	-	5,824
Emission credits receivable from PPA settlements (Note 15)	-	2,000
Emission credits received from PPA settlements (Note 15)	(2,000)	-
Closing balance, long-term receivable	5,882	7,824
Less: Current portion	(1,980)	-
	3,902	7,824

The $2.0 million of emission credits receivable from PPA settlements were received in December 2017.

7. Intangible Assets

(in thousands of dollars)	December 31, 2017	December 31, 2016
Opening balance, emission credits	149,289	-
Additions from purchases	1,831	9,452
Additions from PPA settlements received (Note 15)	2,000	139,837
Closing balance, emission credits	153,120	149,289
Less: Current portion	(153,120)	-
	-	149,289

At December 31, 2017, the Balancing Pool had $153.1 million (2016 – $149.3 million) in emission credits, which can be used to offset compliance obligations associated with the PPAs. In 2017, the Balancing Pool received $2.0 million (2016 – $139.8 million) in emissions credits as part of the negotiated settlements reached for certain terminated PPAs and purchased $1.8 million (2016 – $9.5 million) in emission credits.

No impairments of emission credits were recognized during the year ended December 31, 2017 (2016 – $nil).

8. Accounting for Financial Instruments

8. a) Risk Management Overview

The Balancing Pool's activities expose the Balancing Pool to a variety of financial risks: market risk (including fluctuating market prices, plant availability, risks associated with PPA payments and receipts and currency and interest rate risk), 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, the Audit and Finance Committee and the Board.

Market Risk – Power

i) Fluctuating Market Prices: Changes in the market price for electricity and ancillary services affect the amount of revenues that the Balancing Pool receives from the PPAs, including the hydro PPA. Changes in the market price for electricity also affect the amounts paid or received by the Balancing Pool under the small power producer contracts. 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 can impact 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 generates at levels below target availability. If the plant generates above the target availability, the Balancing Pool is required to make payments to the 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. A 1% increase to the long-term government bond rate would increase the annual capacity payments by an estimated $12.8 million for the terminated PPAs. Likewise a 1% decrease to the long-term government bond rate would decrease the annual capacity payments by an estimated $12.8 million.

Market Risk

i) Currency and Interest Rate Risk: The Balancing Pool is exposed to currency risk and interest rate risk. There is the possibility that the value of investments will change due to fluctuations in market interest rates.

ii) Price Risk: The investment portfolio is exposed to fixed income securities price risk. This arises from investments held in the investment portfolio for which prices in the future are uncertain. Where non-monetary financial instruments are denominated in currencies other than the Canadian dollar, the price initially expressed in foreign currency and then converted into Canadian dollars will also fluctuate because of changes in foreign exchange rates. Item (i) "Currency and Interest Rate Risk" above sets out how this component of price risk is measured.

iii) Counterparty Credit Risk: The Balancing Pool is exposed to counterparty credit risk. In the event of a default on payments from counterparties to the hydro PPA, small power producer contracts, forward sale contracts or mark-to-market on forward sale contracts, a financial loss may be 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 is regularly monitored by management and the Audit and Finance Committee. The Balancing Pool has minimal credit risk related to its receivables as they consist 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.

iv) 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 non-derivative and net-settled financial and other liabilities into relevant maturity groupings based on the remaining period from the period end date to the contract maturity date.

(in thousands of dollars)	1 year	2 – 5 years	Total
	December 31, 2017		
Trade payables	199,647	-	199,647
Other accrued liabilities	362,066	-	362,066
Small power producer contracts	3,424	298	3,722
Related party loan	566,315	-	566,315
Reclamation and abandonment	7,767	13,871	21,638
Other long-term obligations	529,073	128,648	657,721
Total	1,668,292	142,817	1,811,109
(in thousands of dollars)	December 31, 2016		
Trade payables	120,918	-	120,918
Other accrued liabilities	214,880	150,366	365,246
Current portion of hydro PPA	10,053	-	10,053
Small power producer contracts	5,902	5,437	11,339
Reclamation and abandonment	3,671	26,361	30,032
Other long-term obligations	1,332,031	411,742	1,743,773
Total	1,687,455	593,906	2,281,361

8. b) Analysis of Financial Instruments

i) Hydro power purchase arrangement

The Balancing Pool is 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 is 1,620 gigawatt hours ("GWh") per annum from 2018 to 2020. Hydro PPA receipts are settled on a monthly basis.

The remaining term of the hydro PPA is three years to December 31, 2020. At December 31, 2017, the net present value of the hydro PPA was estimated at $177.8 million (2016 – $38.4 million). Key assumptions in this valuation are a discount rate of 11.1% (2016 – 10.2%) and an estimated forecast average electricity market price of $51.95/MWh for the period between 2018 through to 2020 (2016 – $32.35/MWh for 2017 to 2020).

Hydro Power Purchase Arrangement *(in thousands of dollars)*	2017	2016
Hydro power purchase arrangement, opening balance	38,431	242,633
Accretion and current year change	34,306	(20,109)
Net cash (receipts) payments	(20,333)	18,468
Revaluation of hydro power purchase arrangement asset	125,412	(202,561)
Hydro power purchase arrangement, closing balance	177,816	38,431
Less: Current portion (receivable) payable	(57,566)	10,053
	120,250	48,484

The estimated value of this asset varies based on the assumptions used and there is a high degree of measurement uncertainty. The following table summarizes the impact on the hydro PPA value when the estimated forecast average market price is increased or decreased by 10% and the discount rate is increased or decreased by 1%, all other inputs being constant.

	Impact of change to price volatility		Impact of change to discount rate	
(in thousands of dollars)	**Increase price by 10%**	**Decrease price by 10%**	**Increase discount rate by 1%**	**Decrease discount rate by 1%**
Change in fair value as at December 31, 2017	34,663	(34,663)	(3,214)	3,312
Change in fair value as at December 31, 2016	9,219	(9,219)	(1,319)	1,376

ii) Small power producer contract

At December 31, 2017, one small power producer contract with a total allocated capacity of 10 MW remains active (2016 – one contract with capacity of 10 MW). The contract price is $79.70/MWh and the contract completion date is February 15, 2019. Under this contract, the price that the small power producer receives from the counterparty utility company is fixed. If the market price is below the contract price, the Balancing Pool must pay the difference to the utility company. If the market price exceeds the contract price, the utility company must pay the difference to the Balancing Pool.

At December 31, 2017, the net present value of cash flows from the Balancing Pool for this contract was estimated to be a $3.7 million liability (2016 – $11.3 million liability). The estimated value of this liability varies based on the assumptions used and there is a high degree of measurement uncertainty. The key assumption used in this valuation is an estimated forecast average electricity market price of $50.58/MWh for 2018 through to 2019 (2016 – $29.02 / MWh for 2017 to 2019).

Small Power Producer Contract *(in thousands of dollars)*	**2017**	**2016**
Small power producer contract, opening balance	(11,339)	(11,368)
Accretion and current year change	1,616	(1,391)
Net cash payments	4,213	6,077
Revaluation of small power producer contract	1,788	(4,657)
Small power producer contracts, closing balance	(3,722)	(11,339)
Less: Current portion	3,424	5,902
	(298)	(5,437)

The value of the contract varies depending on the assumptions used in the valuation. The following table summarizes the impact on the small power producer contract value when the estimated forecast average market price is increased or decreased by 10%, all other inputs being constant.

	Impact of change to price volatility	
(in thousands of dollars)	**Increase price by 10%**	**Decrease price by 10%**
Change in fair value as at December 31, 2017	537	(537)
Change in fair value as at December 31, 2016	601	(602)

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, 2017			
Assets				
Cash and cash equivalents	50,772	-	-	50,772
Investments – fixed income securities	-	12,370	-	12,370
Hydro power purchase arrangement	-	-	177,816	177,816
	50,772	12,370	177,816	240,958
Liabilities				
Small power producer contracts	-	-	3,722	3,722
	-	-	3,722	3,722
	50,772	12,370	174,094	237,236
	December 31, 2016			
Assets				
Cash and cash equivalents	16,078	-	-	16,078
Investments – fixed income securities	-	15,684	-	15,684
Hydro power purchase arrangement	-	-	48,484	48,484
	16,078	15,684	48,484	80,246
Liabilities				
Hydro power purchase arrangement	-	-	10,053	10,053
Small power producer contracts	-	-	11,339	11,339
	-	-	21,392	21,392
	16,078	15,684	27,092	58,854

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 pooled equity and 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. The changes in value, key assumptions and sensitivities in Level 3 instruments for the years ended December 31, 2017 and 2016 are disclosed in note 8 b i) and in note 8 b ii).

9. Investments

	December 31, 2017		December 31, 2016	
(in thousands of dollars)	**Market Value**	**Cost**	**Market Value**	**Cost**
Fixed income securities	12,369	12,369	15,670	15,670
Global equities	1	1	14	15
Total investments	12,370	12,370	15,684	15,685

(in thousands of dollars)	**2017**	**2016**
Investments, beginning of year	15,684	704,719
Interest and dividends	155	4,749
Realized capital gains	31	115,135
Sale of investments	(3,501)	(687,212)
Unrealized capital gain (loss)	1	(121,707)
Investments, end of year	12,370	15,684

The following table provides disclosure on the movements in the fair value of the investments.

Unrealized Market Gain (Loss) *(in thousands of dollars)*	Fixed Income Securities	Canadian Equities	Global Equities	Totals
Unrealized market gain, December 31, 2016	2,345	26,669	92,692	121,706
Changes in value attributable to:				
Change during the year	(987)	12,143	(17,728)	(6,572)
Realized gain on sales of investments	(1,358)	(38,812)	(74,965)	(115,135)
Net change during the year	(2,345)	(26,669)	(92,693)	(121,707)
Unrealized market gain (loss), December 31, 2017	-	-	(1)	(1)
Changes in value attributable to:				
Change during the year	10	-	22	32
Realized gain on sales of investments	(10)	-	(21)	(31)
Net change during the year	-	-	1	1
Unrealized market gain (loss), December 31, 2017	-	-	-	-

10. Property, Plant and Equipment

(in thousands of dollars)	Genesee PPA	Office Equipment	Total
Costs			
Balance as at December 31, 2015, 2016, 2017	1,505,670	575	1,506,245
Accumulated Amortization, Depreciation and Impairment			
Balance as at December 31, 2015	1,174,822	478	1,175,300
Amortization and depreciation	66,170	40	66,210
Impairment loss	264,678	-	264,678
Balance as at December 31, 2016	1,505,670	518	1,506,188
Amortization and depreciation	-	30	30
Balance as at December 31, 2017	1,505,670	548	1,506,218
Net Book Value			
As at December 31, 2016	-	57	57
As at December 31, 2017	-	27	27

During 2016, an impairment loss of $264.7 million had been recorded with respect to the Genesee PPA as a result of the decline in forward market electricity prices and increased environmental compliance costs. The key assumption used to determine the recoverable amount was the estimated forecast average electricity market price of $22.57/MWh for 2017, $32.43/MWh for 2018, $32.07/MWh for 2019 and $42.32/MWh for 2020.

During 2017, as a result of increases in the forward market electricity prices, the Balancing Pool assessed whether there were indications of impairment reversal. No reversal of impairment was recognized during the year ended December 31, 2017.

11. Trade Payable and Other Accrued Liabilities

(in thousands of dollars)	December 31, 2017	December 31, 2016
Trade payables	199,647	120,918
Accrued liabilities – Greenhouse gas obligation	215,124	99,629
Accrued liabilities – PILOT refunds	82,854	132,983
Accrued liabilities – Retroactive line loss adjustment	42,470	114,042
Accrued liabilities – Other	21,618	18,592
	561,713	486,164

12. Reclamation and Abandonment Provision

(in thousands of dollars)	H.R. Milner Generating Station	Isolated Generation Sites	Cost to Decommission PPAs	Total
At January 1, 2016	13,128	5,463	11,198	29,789
Net increase (decrease) in liability	1,133	1,832	(3,040)	(75)
Liabilities paid in period	-	(486)	-	(486)
Accretion expense	355	147	302	804
At December 31, 2016	14,616	6,956	8,460	30,032
Less: Current portion	-	(3,671)	-	(3,671)
	14,616	3,285	8,460	26,361
At January 1, 2017	14,616	6,956	8,460	30,032
Net increase (decrease) in liability	(443)	154	(6,820)	(7,109)
Liabilities paid in period	(1,053)	(427)	-	(1,480)
Accretion expense	95	45	55	195
At December 31, 2017	13,215	6,728	1,695	21,638
Less: Current portion	(2,050)	(5,717)	-	(7,767)
	11,165	1,011	1,695	13,871

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, which was executed in 2001, the Balancing Pool assumed 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. It is estimated that these costs will be incurred in 2020. These costs have been discounted at 1.5% (2016 – 0.6%) yielding the present value of the related liability. At December 31, 2017, the provision was decreased by $0.4 million (2016 – $1.1 million increase) to reflect a change in the discount rate and estimated payment date.

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 $1.1 million (2016 – $0.5 million) were incurred in 2017. 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 1.5% (2016 – 0.6%). 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 2019. At December 31, 2017, an increase of $0.2 million (2016 – $1.8 million increase) was recorded to reflect a change in estimation to complete the project.

12 c) Decommissioning Costs of PPAs

Pursuant to Section 7 of the *Power Purchase Arrangements Regulation*, the Owner of a generating unit who applies to the AUC to decommission a unit within one year of the termination of the PPA is entitled to receive funding from the Balancing Pool. The amount of funding provided by the Balancing Pool is the amount by which the decommissioning costs (net of salvage) exceed the decommissioning amounts the Owner collected from related consumers before January 1, 2001 and subsequently through the related PPA. Subject to AUC approval, Owners are eligible to collect this shortfall provided that the unit has ceased generating electricity. This provision does not apply to units that cease operations after December 31, 2018.

In December 31, 2017, the Balancing Pool recorded a $6.8 million decrease (2016 – $3.0 million decrease) to the provision for decommissioning the PPAs. The provision is based upon management's best estimate of decommissioning costs, assessment of the impact of Provincial and Federal environmental legislation on the ongoing viability of the various units and the probability an Owner of a generating unit will elect to retire the unit within the timeframe and to then make an application to the AUC to proceed with decommissioning. Estimated decommissioning costs were discounted at 1.5% (2016 – 0.6%).

13. Other Long-Term Obligations

(in thousands of dollars)	Genesee	Battle River 5	Sundance A	Sundance B	Sundance C	Keephills	Sheerness	Total
At January 1, 2016	-	96,700	-	-	-	-	-	96,700
Net increase in liability	542,453	136,712	100,502	211,919	217,104	298,448	578,905	2,086,043
Losses	-	(81,491)	(53,687)	(77,669)	(68,492)	(42,443)	(115,188)	(438,970)
At December 31, 2016	542,453	151,921	46,815	134,250	148,612	256,005	463,717	1,743,773
Less: Current portion	(130,711)	(151,921)	(46,815)	(134,250)	(148,612)	(256,005)	(463,717)	(1,332,031)
	411,742	-	-	-	-	-	-	411,742
At January 1, 2017	542,453	151,921	46,815	134,250	148,612	256,005	463,717	1,743,773
Net increase (decrease) in liability	(265,424)	32,024	33,208	61,388	46,144	(114,800)	(217,027)	(424,487)
Losses	(129,082)	(69,947)	(80,023)	(99,677)	(86,098)	(71,621)	(125,117)	(661,565)
At December 31, 2017	147,947	113,998	-	95,961	108,658	69,584	121,573	657,721
Less: Current portion	(83,050)	(113,998)	-	(95,961)	(108,658)	(50,473)	(76,933)	(529,073)
	64,897	-	-	-	-	19,111	44,640	128,648

Pursuant to Section 96 of the EUA, following Buyer-initiated terminations in 2016, the Battle River 5 PPA, Sundance A, Sundance B, Sundance C, Sheerness and Keephills PPAs were transferred to the Balancing Pool. While the Balancing Pool holds the PPAs, it will assume responsibility for ongoing capacity payments and other PPA-related costs and is responsible for selling the output into the wholesale power market.

Based on the estimated forecast average electricity market price of $46.22/MWh for 2018, $54.97/MWh for 2019 and $54.67/MWh for 2020 (2016 – $22.57/MWh for 2017, $32.43/MWh for 2018, $32.07/MWh for 2019 and $42.32/MWh for 2020), the unavoidable costs of meeting the obligations under the PPAs are expected to exceed the economic benefits derived from the PPAs. As a result, onerous contract provisions have been recognized and measured at the lower of the present value of continuing the PPAs and the expected costs of terminating them. Cost of termination includes the estimated net costs of holding the PPAs over the minimum six-month notice period preceding such termination plus a termination payment. For purposes of measuring the onerous contract provision under IFRS, the minimum six-month notice period is estimated to commence on January 1, 2018 for the Genesee, Keephills and Sheerness PPAs. The Balancing Pool has issued PPA termination notices for Sundance B and C; the six-month notice period commenced on September 15, 2017. The Battle River 5 PPA minimum six-month notice period is estimated to commence on March 1, 2018. The termination payment represents the net book value of the units which is estimated at $1.3 billion (2016 – $1.4 billion). The estimated future costs for the PPAs were discounted at 1.5% (2016 – 0.6%), except for Genesee, Keephills and Sheerness's future costs which where discounted at 1.7% (2016 – 1.0%).

Future cash flow requirements may include operating losses where the price in Alberta's hourly wholesale electricity market is less than the operating costs over the period of 2017 through to 2020. It is expected operating costs would include amounts associated with the *Specified Gas Emitters Regulation* and the *Carbon Competitiveness Incentive Regulation* for all of the PPAs for the period of 2017 through to 2020. Revenue is also dependent on generating capacity factors of the different PPAs, which can vary for each PPA.

As disclosed in Note 10, the Genesee PPA finance lease asset was fully impaired as at December 31, 2016 due to the decline in forward market electricity prices and increased environmental compliance costs. Furthermore, in 2016 the existing Genesee PPA lease obligation was reclassified to other long-term obligations as an onerous contract and an additional onerous contract provision has been calculated by taking the unavoidable costs that will be incurred under the contract, excluding those that were previously included within the Genesee PPA Lease Obligation, less any estimated revenue.

See Note 15, Contingencies and Commitments, for additional information with respect to the termination of PPAs and subsequent negotiation of settlement agreements.

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 extends the life of the Balancing Pool to December 31, 2030.

A reconciliation of the opening and closing Balancing Pool deferral account is provided below.

Balancing Pool Deferral Account *(in thousands of dollars)*	**2017**	**2016**
Deferral account, beginning of year	(1,966,788)	774,515
Change in net liabilities attributable to the Balancing Pool deferral account	685,790	(2,551,136)
Payment of consumer allocation	-	(190,167)
Deferral account, end of year	(1,280,998)	(1,966,788)

In December 2016, the Board of Directors approved a 2017 consumer collection of $1.10/MWh for an estimated total collection from electricity consumers of $66.0 million in accordance with the *Balancing Pool Regulation*. In December 2017, the Board of Directors approved a 2018 consumer collection of $3.10/MWh for an estimated total collection from electricity consumers of $190.0 million in accordance with the *Balancing Pool Regulation*.

As a result of the Balancing Pool's adoption of IFRS 15, *Revenue from contracts with customers*, on January 1, 2017, the 2017 consumer collection of $66.0 million is recorded in revenue. The 2016 amount is recognized directly within the Balancing Pool's deferral account.

15. Contingencies and Commitments

Terminated Power Purchase Arrangements

Pursuant to Section 96 of the EUA, except for an Owner's termination for destruction, where a PPA is terminated the PPA is deemed to have been sold to the Balancing Pool. Buyer-initiated termination could be triggered by a change in law which renders the PPA unprofitable or more unprofitable for the Buyer, an event of force majeure lasting greater than six months or Owner default in performing its obligations. Termination under these provisions would result in the transfer of the PPA to the Balancing Pool. The Balancing Pool would then assume responsibility for ongoing capacity payments and other PPA-related costs and would be responsible for selling the output into the wholesale power market.

During the latter part of 2015 and first quarter of 2016, the Balancing Pool received notices of termination for six PPAs. The Balancing Pool immediately assumed responsibility for all financial obligations associated with the terminated PPAs.

On July 25, 2016, the Attorney General of Alberta filed an application with the Alberta Court of Queen's Bench seeking declarations relating to the validity of certain provisions of the Battle River 5 PPA, Sundance A PPA, Sundance B PPA, Sundance C PPA, Sheerness PPA and Keephills PPA. The Attorney General also sought judicial review of the Balancing Pool's decision to accept termination by ENMAX PPA Management Inc. of the Battle River 5 PPA. The Balancing Pool, the AUC, ENMAX PPA Management Inc. ("ENMAX") and other parties with interests in PPAs were named as respondents.

On November 24, 2016, the Government of Alberta reached settlement agreements with the Buyers of the Sundance A PPA, Sundance B PPA, Sundance C PPA, and Sheerness PPA. As a result of these settlement agreements, as at December 31, 2016 the Balancing Pool had received reimbursement of $39.0 million in cash in relation to the onerous contract provisions disclosed in Note 13 and had recognized intangible assets (emission credits) of $139.8 million (Note 7) and long-term receivables (cash receivable and emission credits receivable) of $7.8 million (Note 6) in relation to reimbursements relating to the onerous contract provisions. The reimbursements have been recorded as an offset against the expenses related to the provision for other long-term obligations in the Statements of Income (Loss) and Comprehensive Income (Loss).

In addition, the Balancing Pool has agreed to assume all obligations, including past obligations, as the Buyer under the Sundance A PPA, Sundance B PPA and Sheerness PPA. The Balancing Pool has also recorded a provision in accrued liabilities in relation to the retroactive line loss adjustment. The Balancing Pool is currently not aware of any other liabilities outstanding in relation to the various PPAs.

For those PPAs which have been or which may ultimately be returned to the Balancing Pool, the Balancing Pool has the option to hold the PPAs, resell the PPAs or to terminate the PPAs by paying the Owner a termination payment equal to the net book value.

On February 24, 2017, ENMAX filed a legal proceeding against the Balancing Pool with respect to the disputed effective date of the Battle River 5 PPA termination. On November 16, 2017 the Court of Queen's Bench released its decision that the effective date of the Battle River 5 PPA termination is January 1, 2016 as argued by ENMAX. There is no further financial impact to the Balancing Pool as a result of this ruling by the Court of Queen's Bench as the Balancing Pool has been responsible for the Battle River 5 PPA costs as of January 1, 2016.

On July 14, 2017, ENMAX filed and served a Statement of Claim, asking the Court for injunctive relief requiring the Balancing Pool to make a decision respecting the termination of the Keephills PPA and to assume offer and dispatch control with respect to the Keephills PPA. On November 22, 2017 the Court of Queen's Bench rendered its decision and granted ENMAX one of two injunctions. The Court of Queen's Bench adjudicated that the Balancing Pool must complete its assessment and verification of the Keephills PPA termination event. The Court of Queen's Bench dismissed the application by ENMAX for an interim injunction compelling the Balancing Pool to assume offer and dispatch control of the Keephills PPA.

On December 6, 2017 the Balancing Pool completed the assessment and verification of the Keephills PPA termination and accepted the termination.

Genesee PPA Energy Strip Contracts

In 2014, the Balancing Pool sold two 100-MW strip contracts for generating capacity from the Genesee PPA (representing 26% of the total Genesee PPA capacity). The two contracts commenced on November 1, 2014 and were contracted to expire on October 31, 2017. Terms of the contracts required the purchaser to pay a fixed monthly fee established by a competitive bid process and amounts intended to cover certain PPA costs payable by the Balancing Pool.

A negotiated settlement was reached in March 2016 with one of the strip buyers resulting in the termination of the strip contract. A negotiated settlement was also reached in December 2016 with the other strip buyer resulting in the termination of the other strip contract as part of the settlements of the disputed PPA terminations discussed above.

Revenue from the sale of the energy strip contracts, including termination revenue of $0.7 million (2016 – $14.3 million), has been recorded in sale of generating capacity and termination revenue on the Statements of Income (Loss) and Comprehensive Income (Loss).

Payments (Refunds) In Lieu of Tax

Alberta Tax and Revenue Administration has issued notices of re-assessment for several tax years (dating back to 2001) to a municipal entity that has been subject to PILOT. The municipal entity has disagreed with many aspects of the notices of re-assessment and has filed notices of objection for those tax years. The municipal entity proceeded with litigation to resolve the various tax matters. A number of these matters were resolved in 2016 through negotiated settlement and through the courts, resulting in a refund of $96.0 million to the municipal entity. The refund of $96.0 million was reflected as Other income (expense) from operating activities in 2016. This refund was accrued in trade payable and other accrued liabilities.

In 2017, the Balancing Pool issued PILOT refunds of $50.1 million to the municipal entity which were accrued in 2016.

Approximately $61.7 million remains under dispute with the municipal entity for the tax years of 2001 through to 2015. A provision of $30.3 million has been recorded in relation to the disputed matters and reflected as Other income (expense) from operating activities in 2016. This provision has been accrued in trade payables and other accrued liabilities.

Retroactive Line Loss Adjustment (AUC Proceeding 790)

The retroactive line loss adjustment referred to as the AUC Proceeding 790, currently underway before the AUC, is intended to address complaints regarding the *ISO Transmission Loss Factor Rule and Loss Factor Methodology*. Line loss factors form part of transmission charges that are paid by generators in Alberta. The Balancing Pool is exposed to a retroactive line loss adjustment for certain PPAs.

In January 2015, the AUC determined that it has the jurisdiction and authority to retroactively adjust the line loss factors and the methodology dating back to 2006.

The AUC has been presented with three different methodologies for calculating retroactive line loss adjustments, the first being the AESO methodology based on Incremental Loss Factor with load scaling. The second is the AUC methodology ("Module B") based on Incremental Loss Factor with generation scaling. The third method is a methodology developed by Maxim Power Corporation. A description of the various methodologies can be found in the AESO's exhibits presented in 790-140.3 of the AUC Proceeding 790.

In December 2017, the AUC reached its decision, whereby the AUC ruled that the Module B methodology will be used to calculate retroactive line loss adjustments. The AUC also ruled that the original system transmission service contract holder will be responsible for the retroactive line loss adjustments.

The Balancing Pool will incur additional charges as a result of the retroactive adjustments to line loss factors in relation to the various PPAs. An estimated provision in the amount of $42.5 million (2016 – $114.0 million) has been recorded in trade payable and other accrued liabilities for the retroactive line loss adjustment as a result of the AUC's December 2017 decision. The estimate has been prepared using the Module B method based on Incremental Loss Factors with generation scaling.

Various matters before the AUC regarding the retroactive line loss adjustments are under review and appeal including the retroactive nature of the adjustments and prospective line loss factors used to calculate the adjustment. The AUC's decision regarding its authority and jurisdiction has also been challenged. The quantum of any retroactive adjustment will be dependent upon the methodology finally adopted and approved by the AUC. Given the uncertainty of the final methodology, the Balancing Pool estimates may be higher or lower than the current estimate reflected in these financial statements.

Market Surveillance Administrator Investigation

On April 13, 2017, the Balancing Pool received a notice of investigation and request for information from the Market Surveillance Administrator ("MSA"). The Balancing Pool has provided the MSA with the requested information and the investigation is currently on-going.

16. Cost of Sales

(in thousands of dollars)	December 31, 2017	December 31, 2016
Cost of power purchase arrangements and power marketing charges	1,283,106	1,126,465
Losses on PPAs recorded against other long-term obligations	(661,565)	(438,970)
Amortization and depreciation on assets	30	66,210
	621,571	753,705

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)*	2017	2017
Salaries and other short-term employee benefits	643	561
Total	643	561

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. Effective January 1, 2017, 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.

(in thousands of dollars)	Interest Rate	December 31, 2017
Short-term discount note due on Jan. 15, 2018	1.32%	382,792
Short-term discount note due on Feb. 26, 2018	1.40%	35,422
Short-term discount note due on Feb. 26, 2018	1.44%	25,443
Short-term discount note due on Mar. 12, 2018	1.43%	122,658
		566,315

At December 31, 2017, the Balancing Pool had $566.3 million in short-term discount notes issued to the Government of Alberta, including accrued interest of $0.4 million.

As 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 100% of the annual costs for the Transmission Facilities Cost Monitoring Committee ("TFCMC") and the Retail Market Review Committee ("RMRC").

In 2017, the Balancing Pool expensed $5.0 million (2016 – $5.4 million) for the UCA and $1.2 million (2016 - $0.7 million) for the TFCMC and RMRC in aggregate.

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 2017, the Balancing Pool collected $66.0 million from electricity consumers through the AESO's transmission tariff (2016 – $190.2 million distributed).

18. Subsequent Event

On March 8, 2018, the Government of Alberta reached a settlement agreement with the Buyer of the Battle River 5 PPA and Keephills PPA bringing a conclusion to the Attorney General of Alberta's application with the Alberta Court of Queen's Bench.

On March 21, 2018, the Balancing Pool provided notice to Alberta Power (2000) Ltd. (ATCO) that the Battle River 5 PPA will be terminated. The termination of the PPA will be effective no later than September 30, 2018, though ATCO and the Balancing Pool may agree to a shorter notice period.

Statutory Reports

Public Interest Disclosure (Whistleblower Protection) 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 on request.

There were no disclosures of wrongdoing filed with my office for your department between April 1, 2017 and March 31, 2018.

Other Information

For additional copies, please contact:

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Tel: 780-427-8050
To call toll free within Alberta, dial 310-0000 first.

The Ministry of Energy Annual Report 2017-18 is available on the open government portal:
https://open.alberta.ca/publications/1703-4582

Current information about the organizations that were part of the Ministry of Energy in 2017-18 is available at the following websites

For the Department of Energy:
www.energy.alberta.ca

For the Alberta Energy Regulator:
www.aer.ca

For the Alberta Utilities Commission:
www.auc.ab.ca

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