Energy

Annual Report
2014-2015

Government

Energy

Annual Report 2014-2015

Preface

The Public Accounts of Alberta are prepared in accordance with the *Financial Administration Act* and the *Fiscal Management Act*. The Public Accounts consist of the annual report of the Government of Alberta and the annual reports of each of the 19 ministries.

The annual report of the Government of Alberta contains 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 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 and the Post-closure Stewardship Fund;**
- **other financial information as required by the *Financial Administration Act* and *Fiscal Management 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 Message

Energy is responsible for ensuring sustained prosperity in the best interests of Albertans through the stewardship of energy and mineral resource systems, responsible development and wise use of energy. This includes a focus on the social, economic and environmental impacts of Alberta's resource development. The following report highlights results achieved by the Ministry of Energy in the 2014-15 fiscal year.

Government recognizes the important role that Alberta's energy industries have in our economy, and the challenges they currently face. Our approach to energy policy will be measured and take into account all points of view.

I look forward to working with my colleagues, department staff and other stakeholders to ensure that the priorities of Albertans are first and foremost. As a government, one of our priorities will be to review the province's royalty system, working with partners in a transparent process to bring out the best outcome for Albertans. We are committed to working together to solve challenges and to seek new opportunities as we continue to build this great province.

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

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 agrees with underlying data and the sources used to prepare it.
- Understandability and Comparability – current results are presented clearly in accordance with the stated methodology and are comparable with previous years.
- Completeness - performance measures and targets match those included in the Ministry's Budget 2014.

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, the Minister of Finance and the Minister of Energy information needed to fulfill their responsibilities; and
- facilitate preparation of ministry business plans and annual reports required under the *Fiscal Management Act.*

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

Original signed by Grant D. Sprague, Q.C.
Deputy Minister
Department of Energy

Original signed by Jim Ellis
President and CEO
Alberta Energy Regulator

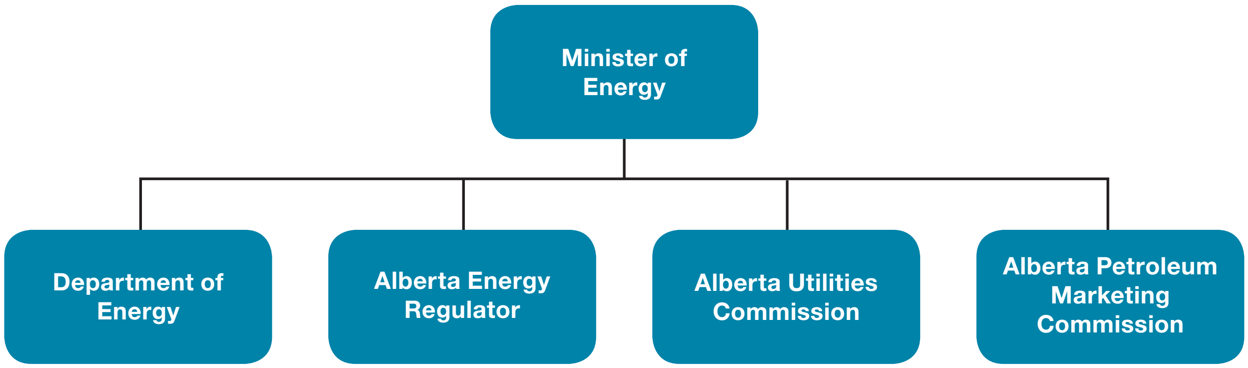
Original signed by Willie Grieve
Chairman,
Alberta Utilities Commission

Original signed by Richard Masson
Chief Executive Officer
Alberta Petroleum Marketing Commission

Date: June 3, 2015

Ministry Overview

The ministry consists of the Department of Energy (DOE), the Alberta Energy Regulator (AER), the Alberta Utilities Commission (AUC), the Alberta Petroleum Marketing Commission (APMC) and the Post-closure Stewardship Fund.



DOE

- Acts as the steward of Alberta's energy system on behalf of all Albertans
- Develops policy and manages development of Alberta's non-renewable resources (including natural gas, conventional oil, oil sands, coal and petrochemicals) and renewable energy
- Ensures the integration of natural resource policies and serves as an interface between policy development and policy assurance
- Grants industry the right to explore and develop Alberta's energy and mineral resources
- Establishes, administers and monitors the effectiveness of Alberta's royalty systems regarding Crown minerals
- Collects revenues from the development of Alberta's energy and mineral resources on behalf of Albertans
- Establishes the framework for responsible industry-led investment in electricity infrastructure and markets for the reliable delivery of electricity to all consumers
- Administers the Post-closure Stewardship Fund

AER

- Provides for the safe, efficient, orderly and environmentally responsible development of the province's energy resources. This includes allocating and conserving water, managing public lands, and protecting the environment, while securing economic benefits for all Albertans
- Provides full life-cycle regulatory oversight of energy resource development in Alberta from application to reclamation
- Ensures the effective and efficient assurance of policy outcomes - set by the Government of Alberta - through energy regulation

AUC	▪ 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 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 AUC ▪ Ensures the delivery of Alberta's utility services takes place in a manner that is fair, responsible and in the public interest

APMC	▪ 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 (BRIK) policy

Energy Highlights

Resource		2013-14	2014-15
Bitumen	Revenue	$5.22 billion	$5.05 billion
	Percentage of non-renewable resource revenue	55%	56%
	Bitumen wells drilled (Development)	1,813 (2013)	2,033 (2014)
	Total bitumen production in barrels per day (bbl/d)	2.09 million bbl/d (2013)	2.30 million bbl/d (2014)
	Marketable bitumen and Synthetic Crude Oil (SCO) production	1.94 million bbl/d (2013)	2.16 million bbl/d (2014)
Conventional Crude Oil	Revenue	$2.48 billion	$2.24 billion
	Percentage of non-renewable resource revenue	26%	25%
	Crude oil wells drilled (Development)	2,301 (2013)	2,528 (2014)
	Average price for West Texas Intermediate per barrel	US$99.05	US$80.48
	Crude oil production	0.58 million bbl/d (2013)	0.59 million bbl/d (2014)
	Pentanes and condensate production	0.13 million bbl/d (2013)	0.15 million bbl/d (2014)
Total Crude and Equivalent	Revenue	$7.70 billion	$7.29 billion
	Production (conventional, marketable bitumen and SCO, pentanes and condensates)	2.65 million bbl/d (2013)	2.90 million bbl/d (2014)
	Total crude oil deliveries	2.75 million bbl/d (2013)	3.01 million bbl/d (2014)
	* To the United States	73%	74%
	* Within Alberta	15%	15%
	* To rest of Canada	12%	11%
	* Offshore	0.2%	0.1%
Natural Gas and By-Product	Revenue	$1.10 billion	$0.99 billion
	Percentage of non-renewable resource revenue	12%	11%
	Number of conventional natural gas wells drilled (Development)	917 (2013)	1,529 (2014)
	Average Alberta Gas Reference Price per Gigajoule (GJ)	$3.28/GJ	$3.51/GJ
	Total marketable natural gas production including Coalbed Methane (CBM) in trillion cubic feet (Tcf)	3.5 Tcf (2013)	3.6 Tcf (2014)
	CBM production	0.27 Tcf (2013)	0.24 Tcf (2014)
	Total natural gas deliveries	4.2 Tcf (2013)	4.4 Tcf (2014)
	* To the United States	36%	34%
	* Within Alberta	36%	35%
	* To rest of Canada	28%	31%

Resource		2013-14	2014-15
Bonuses and sales of Crown Leases	Revenue from bonuses and sales of Crown leases	$0.59 billion	$0.48 billion
	Revenue from rentals and fees	$0.17 billion	$0.17 billion
	Average price per hectare (ha) paid for petroleum and natural gas mineral rights	$327.52	$357.04
	Petroleum and natural gas hectares sold	1,792,294 ha	1,277,405 ha
	Average price per hectare paid for oil sands mineral rights	$248.44	$521.64
	Oil sands hectares sold	111,690 ha	46,510 ha
Freehold Mineral Tax	Revenue	$146 million	$172 million
Wells and Licences	Well Licences issued	9,894 (2013)	9,345 (2014)
	Industry drilling	5,367 (2013)	4,562 (2014)
Coal	Revenue	$16 million	$16 million
	Established coal reserves (estimate)	33.3 billion tonnes (2013)	33.2 billion tonnes (2014)
	Raw coal production	34.5 million tonnes (2013)	33.8 million tonnes (2014)
	Total marketable coal deliveries	28.3 million tonnes (2013)	31.0 million tonnes (2014)
	Percentage of total coal deliveries exported out of province	23% (2013)	20% (2014)
Electricity	Total generation capacity in Megawatts (MW)	14,598 MW (2013)	15,314 MW (2014)
	Total generation capacity from renewable sources	2,430 MW (2013)	2,797 MW (2014)
	Total generation capacity from coal	6,258 MW (2013)	6,258 MW (2014)
Metallic and Industrial Minerals	Revenue	$633,980	$599,575
	Hectares of mineral permits issued to exploration companies	2.3 million ha	1.7 million hectares

Note on sources and data usage:

Energy relied on data gathered by the Department, as well as the Government of Alberta, Alberta Energy Regulator, Alberta Utilities Commission, U.S. Energy Information Administration and Statistics Canada to complete the Energy Highlights table. The Department applied specific conversions and calculations to select data gathered from external sources, and therefore, results published above may differ from results reported by the sources.

RESULTS ANALYSIS

AUDITOR GENERAL *Alberta*

Review Engagement Report

To the Members of the Legislative Assembly

I reviewed three of eight performance measures in the Ministry of Energy's Annual Report 2014–2015. The reviewed performance measures are the responsibility of the ministry and are prepared based on the following criteria:

- *Reliability*—The information used in applying performance measure methodologies agrees with 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*—The goals, performance measures and related targets match those included in the ministry's budget 2014.

My review was made in accordance with Canadian generally accepted standards for review engagements and, accordingly, consisted primarily of enquiry, analytical procedures and discussion related to information supplied to me by the ministry.

A review does not constitute an audit and, consequently, I do not express an audit opinion on the performance measures. Further, my review was not designed to assess the relevance and sufficiency of the reviewed performance measures in demonstrating ministry progress towards the related goals.

Based on my review, nothing has come to my attention that causes me to believe that the performance measures identified as reviewed by the Office of the Auditor General in the ministry's annual report 2014–2015 are not, in all material respects, presented in accordance with the criteria of reliability, understandability, comparability and completeness as described above.

Original signed by Merwan N. Saher, FCA
Auditor General

May 12, 2015
Edmonton, Alberta

Performance measures reviewed by the Office of the Auditor General are marked with an asterisk (*) on the Performance Measures Summary Table.

Performance Measures Summary Table

	Goals/Performance Measures	Prior Year's Results				Target	Current Actual
1.	**Albertans are assured of the benefits from energy and mineral resource development**						
Performance Measures							
1.a*	Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions[1]	Alberta within first quartile (2009) 35.99%[r] (Natural Gas) 43.02% (Conventional Oil)	Alberta within first quartile (2010) 34.65%[r] (Natural Gas) 41.34% (Conventional Oil)	Alberta within first quartile (2011) 32.77%[r] (Natural Gas) 38.97% (Conventional Oil)	Alberta within first quartile (2012) 28.19% (Natural Gas) 36.60% (Conventional Oil)	Alberta will have a combined tax and royalty rate that is in the top quartile of investment opportunities compared to similar jurisdictions	Alberta within first quartile (2013) 29.23%[2] (Natural Gas) 36.42% (Conventional Oil)
1.b	Revenues from oil, oil sands, gas and land sale bonuses are fully collected: Percentage of amounts collected compared to amounts owed[3]	100% (2009)	100% (2010)	100% (2011)	100% (2012)	100%	100% (2013)
1.c	Alberta's oil sands supply share of global oil consumption	1.8% (2010)	1.9%[4] (2011)	2.1% (2012)	2.3% (2013)	2.3%	2.5% (2014)
Performance Indicators							
1.a	Alberta's total crude bitumen production (thousands of barrels per day)	1,613.4 (2010)	1,744.6 (2011)	1,921.7 (2012)	2,085.4 (2013)	N/A	2,304.2 (2014)
1.b	Conventional crude oil and equivalent annual production (thousands of barrels per day)	581.9 (2010)	609.4 (2011)	672.0 (2012)	709.0 (2013)	N/A	742.8 (2014)
1.c	Total marketable natural gas and annual production (billion cubic feet per day)[5]	10.85 (2010)	10.38 (2011)	9.80 (2012)	9.69 (2013)	N/A	9.91 (2014)
1.d	Upstream oil and gas industry investment in Alberta ($ billions)[6] • Total conventional and non-conventional oil and gas extraction investment	21.6 (2009)	35.6 (2010)	44.6 (2011)	51.9 (2012)	N/A	53.47[7] (2013)

Goals / Performance Measures		Prior Year's Results				Target	Current Actual
2.	**Effective stewardship of Alberta's energy resources and regulatory systems is achieved through leadership and engagement with citizens, communities, industry and governments**						
Performance Measures							
2.a	Albertans' assessment of their energy knowledge (biennial)	n/a (2010)	63% (2011)	n/a (2012)	64% (2013)	To maintain or increase the previous year's results.	n/a (2014)
2.b*	Regulatory Noncompliance (AER/ERCB): Percentage of field inspections finding high risk regulatory noncompliance	1.7% (2010)	3.2% (2011)	3.6% (2012)	3.4% (2013)	Less than or equal to 3.0%	4.4% (2014)
3.	**Development of energy related infrastructure and cleaner energy technologies is actively led and supported**						
Performance Measures							
3.a	Transmission Losses (%)	3.8% (2010)	3.4% (2011)	2.9% (2012)	2.9% (2013)	3.0%	3.1% (2014)
3.b*	Power generation: Margin between Firm Generating Capacity and Peak Demand (MW)[8]	17% (2010)	12% (2011)	18% (2012)	18% (2013)	Maintain a minimum 7% margin over peak demand	21% (2014)
3.c	Timeliness of the Needs and Facility Applications (AUC): Percentage of needs and facility applications determined within 180 days of the application being deemed complete	100% (2010)	98.7% (2011)	93.1% (2012)	96.3% (2013)	100%	100% (2014)
Performance Indicators							
3.a	Alternative and renewable generation capacity in Alberta (megawatts)[9]	5,678 (2010)	5,805 (2011)	6,478 (2012)	6,590 (2013)	N/A	6,956 (2014)

Notes:

r For the years 2009-11, the combined tax and royalty rates for Alberta natural gas are updated retroactively to reflect the revision in calculating Alberta's effective natural gas royalty rates. With the change, Alberta still remained within the first quartile of investment opportunities compared to similar jurisdictions.

1 The comparator jurisdictions include: British Columbia, Saskatchewan, California, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming.

2 First quartile threshold: natural gas, up to 49.72 per cent; conventional oil, up to 51.00 per cent.

3 Excludes disputed amounts.

4 The 2011 result has been revised from 2.0 per cent reported in the 2013-14 Annual Report to 1.9 per cent, due to the retroactive revision of the total global consumption number reported for that year.

5 The Alberta Energy Regulator has modified the methodology and format of ST-3 Gas Report effective January 2013 production month.

6 The upstream oil and gas sector consists of conventional oil and gas industry, and the oil sands industry.

7 Preliminary actuals for 2013.

8 Through industry investment, Alberta's net supply margin of electricity will be sufficient to ensure reliable power supply.

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.

9 Alternative and renewable generation capacity in Alberta includes wind, hydroelectricity, biomass, and natural gas cogeneration technologies.

* Indicates Performance Measures that have been reviewed by the Office of the Auditor General.

The performance measures indicated with an asterisk were selected for review by ministry management based on the following criteria established by government:

- Enduring measures that best represent the goal;
- Measures for which new data is available; and
- Measures that have well established methodology.

For more detailed information, see the "Performance Measure Methodologies" section in Appendix A on pages 36-39.

The table contains eight performance measures and five performance indicators. Performance indicators show progress toward achievement of long term outcomes that a ministry does not have direct influence over and, as such, no targets are required.

Non-Renewable Resource Revenue

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 Canada-US exchange rate and production also affect royalty revenues. Unanticipated changes in these factors could result in significant differences between the budget forecast and the actual results.

Understanding Commodity Prices

Prices differ depending on crude quality and access to markets. Today, Brent crude from the North Sea is considered the global price benchmark for light sweet oil given its ability to reach global markets.

The West Texas Intermediate (WTI) is the North American price benchmark for light sweet oil. WTI, denominated in American dollars, trades at a discount to Brent crude. Increasing North American crude supply and the U.S. ban on crude exports have made the gap between Brent and WTI wider in the last few years.

Western Canadian Select (WCS) is a North American price benchmark for heavy crude oil.

The light-heavy differential is the difference between the WTI and WCS prices. The differential is affected by differences in crude quality between light sweet and heavy sour oils, market demand for heavy crude, and by access to markets for these products. When oil pipelines are at full capacity, Canadian conventional oil prices are discounted and receive a bigger discount compared to WTI, which reduces the royalty revenue received by Albertans.

The Alberta reference price for natural gas is used in natural gas royalty formulas and determines the royalty rate that will be applied to natural gas. Storage levels and weather patterns affect this price 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.

Changes in Commodity Prices during 2014-15

The drop in crude oil prices was the most significant factor impacting non-renewable resource revenue as it affected both royalty rates and the value of sale.

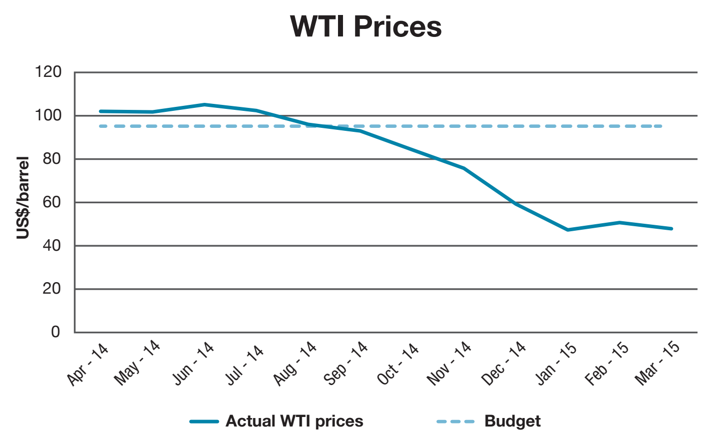
Selected indicators for budgeting purposes

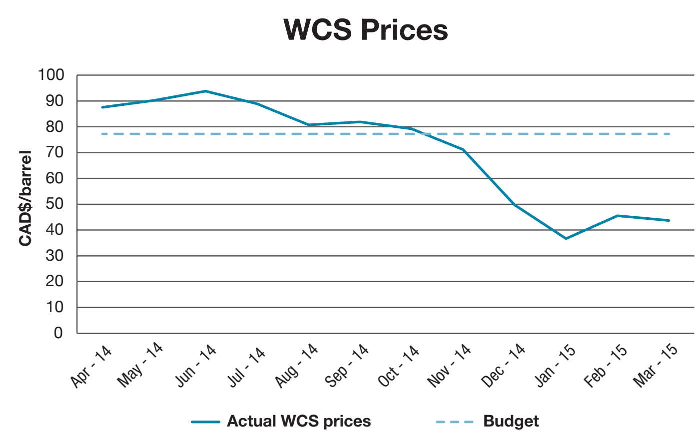
	2014-15 Budget	2014-15 Actual
WTI (US$/bbl)	95.22	80.48
Exchange rate	US$0.91	US$0.88
Light heavy differential (US$/bbl)	25.00	17.30
WCS (CAD$/bbl)	77.18	70.78
Alberta reference price for natural gas (CAD$/GJ)	3.29	3.51

Budget 2014 was based on a US$95.22 per barrel price for WTI crude oil and a 91 cent Canada-U.S. exchange rate. The actual 2014-15 WTI price was US$80.48 per barrel based on an average of the monthly prices and an 88 cent exchange rate. Actual prices for WTI averaged over US$100 per barrel during the first half of the 2014-15 fiscal year. Higher than forecasted prices were mainly due to geopolitical risk in the Middle East and elsewhere. During the second half of the fiscal year, the global oversupply of crude combined with the Organization of Petroleum Exporting Countries (OPEC)'s decision not to cut production resulted in WTI prices averaging just over US$60 per barrel.

The forecasted light-heavy differential was US$25 per barrel, giving a WCS price of CAD$77.18 per barrel. The actual light-heavy differential was US$17.30 per barrel and the WCS price averaged CAD$70.78 per barrel. The improved light-heavy differential was due to increased rail and pipeline crude takeaway capacity from Western Canada to both the rest of Canada and the United States. The following pipelines improved market access to U.S. heavy crude refining centres in the Midwest and Gulf Coast regions: the TransCanada Gulf Coast, the Enbridge Flanagan South and the twinning of Seaway.

The WCS price was lower than budgeted due to the collapse in global energy prices after September 2014. Prices for WCS averaged over CAD$87 per barrel during the first half of the 2014-15 fiscal year. Higher than forecasted WTI prices, mainly due to geopolitical risk affecting global crude oil, a smaller light-heavy differential, and weaker Canadian dollar were the primary reasons for the higher WCS price. During the second half of the fiscal year, the global oversupply of crude combined with OPEC's decision not to cut production resulted in a much lower WTI price, which drove down the WCS price. Alberta producers and government revenue were sheltered in part by a smaller light-heavy differential due to increasing pipeline and takeaway capacity from Western Canada, and a weaker exchange rate, leading WCS prices to average just over CAD$54 per barrel.





Royalties in *Budget 2014* were based on a gas price forecast of CAD$3.29 per gigajoule for the Alberta natural gas reference price. The Alberta natural gas reference price averaged CAD$3.51 per gigajoule in 2014-15. While gas prices were well above budgeted levels at the beginning of the year due to a colder than expected winter, a mild summer, increased U.S. and Canadian production levels meant that storage levels were more than adequate for the 2014-15 heating season and prices dropped significantly over the fiscal year.

Other key factors that affect Royalty Revenues

Exchange rates: A lower Canadian dollar increases royalty revenue as WTI prices are set in U.S. dollars and increase when converted into Canadian dollars. Royalty revenue decreases when the exchange rate increases.

Cost increases and inflation: Oil sands royalties are based on project revenue minus cost. Inflation and increases in capital and operating costs lead to lower bitumen royalty revenues.

Production forecasts: Production forecasts are impacted by crude oil prices. Higher prices lead to higher forecasted production while lower prices have the opposite effect. Production disruption in any one of the major projects can have a significant impact on royalties.

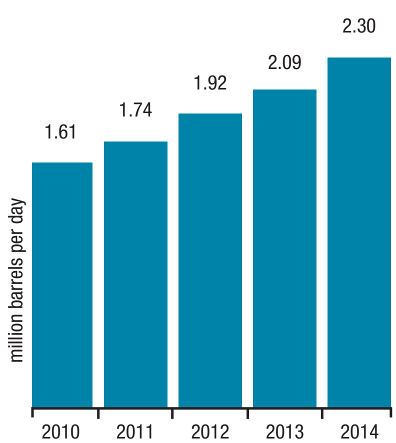
Production Trends

Crude bitumen production increased from 2.09 million bbl/d in 2013 to 2.30 million bbl/d in 2014, an escalating trend since 2008. The share of crude bitumen production as a percentage of global consumption has also increased in 2014, to 2.5 per cent from 2.3 per cent in 2013.

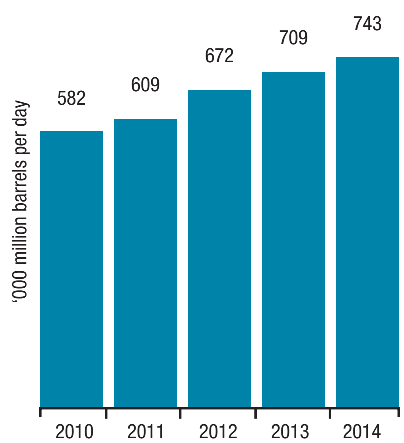
The production of conventional crude oil and equivalent increased from about 709 thousand bbl/d in 2013 to 743 thousand bbl/d in 2014.

Marketable natural gas production increased from 9.7 billion cubic feet per day (Bcf/d) in 2013 to 9.9 Bcf/d in 2014.

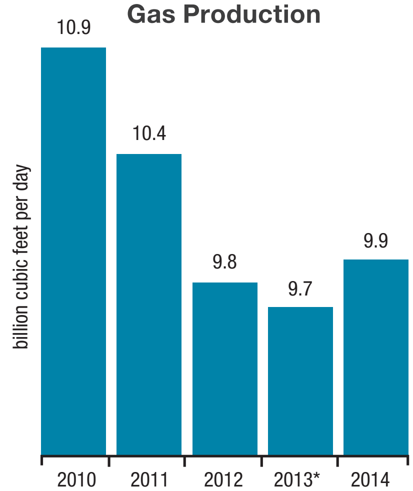
Alberta Crude Bitumen Production



Alberta Conventional Crude and Equivalent Production



Alberta Marketable Gas Production



*The Alberta Energy Regulator has modified the methodology and format of ST-3 Gas Report effective January 2013 production month

Non-Renewable Resource Revenues

The following table is a comparison of the actual revenue collected and the budgeted revenues.

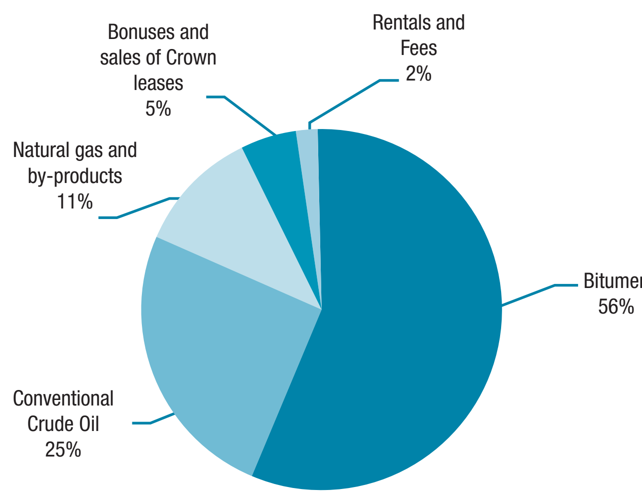
Revenue ($ Millions)	2014-15 Budget	2014-15 Actual
Bitumen	5,579	5,049
Crude oil	2,019	2,245
Natural Gas and By-products	823	989
Bonuses and sales of Crown leases	623	476
Rentals and fees	153	172
Coal	12	16
Non-Renewable Resource Revenue	9,209	8,948

For the sixth fiscal year in a row, **bitumen** royalty made the largest contribution to provincial resource royalty revenue. In 2014-15, bitumen revenue accounted for $5.0 billion, or about 56 per cent of the non-renewable resource revenue of $8.9 billion. Bitumen royalties were lower than budgeted due to lower crude oil prices, and higher operating and capital costs. The lower light-heavy differential and the lower exchange rate partially offset some of the negative impact of lower prices and higher costs.

Conventional crude oil royalties contributed $2.2 billion, about 25 per cent, to provincial revenue in 2014-15. Conventional crude oil royalties were higher than budgeted due to the improved light-heavy differential. This increased the medium, heavy, and ultra-heavy oil prices setting higher conventional royalty rates than anticipated. In addition, a weaker Canadian dollar and the lower than budgeted costs of oil royalty reduction programs meant that conventional oil royalties were higher than budgeted.

The third largest source of resource revenue was **natural gas and by-products** royalties, which brought in $989 million. Royalties for natural gas and by-products were above budget due to higher than forecasted prices and production. Higher costs for processing the Crown's share of the royalty gas and by-products offset some of the impact of higher prices and production levels.

In 2014-15, $476 million was collected from **bonuses and sales of Crown leases**. The forecast for the petroleum and natural gas price per hectare uses a statistical model using the forecasted oil and gas price and production, and industry cash flow. A statistical time series model is used to forecast the number of hectares that will be sold. The petroleum and natural gas bonus payments were $456 million, compared to a *Budget 2014* forecast of $611 million. The average price per hectare was $357.04 compared to a *Budget 2014* forecast of $423.85/hectare, and 165,144 fewer hectares than budgeted were sold. Oil sands sales totaled $24 million compared to a *Budget 2014* forecast of $11.7 million. The average price per hectare was $521.64 compared to the *Budget 2014* forecast of $135.58.



Total non-renewable resource revenue 2014-15: $8.9 billion

Note: Totals do not add up exactly due to rounding.

Revenue from **rentals and fees** was $172 million in 2014-15. Rentals and fees revenue was higher than budgeted as more hectares were retained by industry than budgeted and fees for mineral activities were higher than budgeted.

In 2014-15, revenue from **coal** royalty was $16 million. Coal royalty was higher than budgeted due to subbituminous coal production being greater than budgeted.

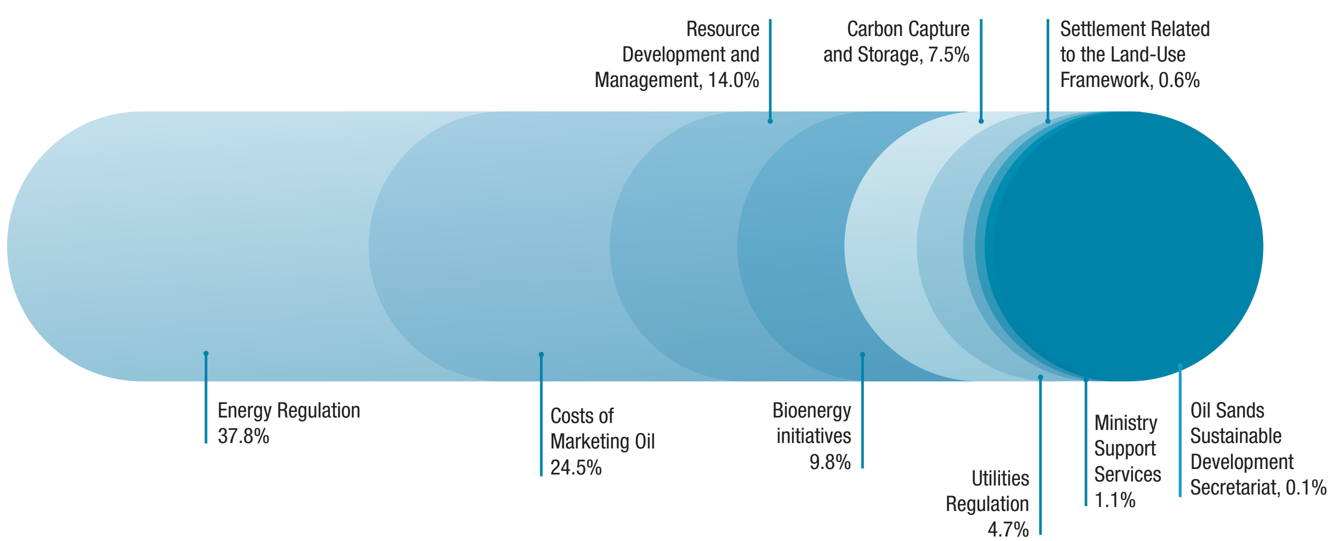
Ministry Expenditure Highlights

Energy's operational expense in 2014-15 was $720 million, a decrease of $79 million from 2013-14, and a decrease of $124 million from *Budget 2014*.

- As the Alberta Energy Regulator finalized its transition to become the single regulator of energy resource activities in Alberta, the 2014-15 expenditures were $27 million over *Budget 2014*. The over expenditures by AER is offset by increased revenues generated from levies on industry.
- The decrease in Costs of Marketing Oil of $33 million from *Budget 2014* was due to a reduction in the total cost of purchases and transportation of the oil from the well head to Edmonton.
- Resource Development and Management expenses were $13 million above *Budget 2014* primarily due to increases in activities to support Market Access, employee costs, amortization and a one time Service Alberta fee for migration to the Government of Alberta domain.
- $70 million was provided under the Bioenergy Producer Credit program in 2014-15 to encourage a variety of bioenergy products, such as renewable fuels, liquid biofuels, electricity, heat and biomass pellets and gas productions. The program was $36 million less than *Budget 2014* as maximum potential production levels have not yet been reached. The existing agreements under this program will be completed in 2015-16.
- The Carbon Capture and Storage program was $93 million less than *Budget 2014* as construction of one of the two approved projects was not achieved during the year as expected. Total support for carbon capture and storage so far is $303 million.

Ministry of Energy Expenses by Program 2014 - 2015

$720 million in total expenses



GOAL ONE – Albertans are assured of the benefits from energy and mineral resource development

For the benefit of Albertans, the ministry accurately calculates and fully collects revenues from energy royalties and sales bonuses. The ministry also 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. The ministry continues to seek opportunities to increase access to global markets to strengthen both provincial and national economies.

Performance Measures

Performance Measure 1.a: Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions

Target

In the 2014-17 Business Plan, the target was for Alberta to have a combined royalty and tax rate that is in the top quartile of investment opportunities compared to similar jurisdictions.

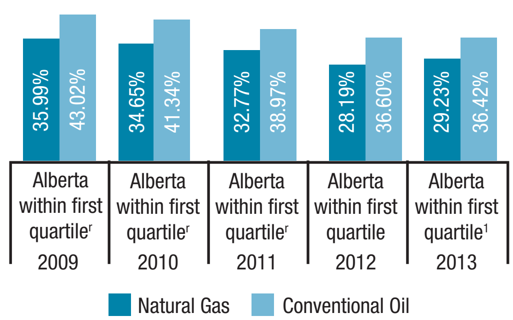
Discussion of Results

This measure was previously chosen as a proxy for total government share. The combined tax and royalty rate was considered to be a) measurable, b) commonly understood, c) proactive and timely, d) comparable with other jurisdictions and, e) consistent with other measures of competiveness.

This enabled the Government of Alberta to monitor and evaluate whether or not Alberta has a competitive royalty regime to attract industry investment, and to determine if the appropriate shares of royalty revenue are being collected from the development of these resources on behalf of Albertans.

Figure 1.a

Combined tax and royalty rates for Alberta natural gas and conventional oil production compared to similar jurisdictions.



Source: Department of Energy

Notes

r For the years 2009-2011, the combined tax and royalty rates for Alberta natural gas were updated retroactively to reflect the revision in calculating Alberta's effective natural gas royalty rates. With the change, Alberta still remained within the first quartile of investment opportunities compared to similar jurisdictions.

1 First quartile threshold: natural gas, up to 49.72 per cent; conventional oil, up to 51.00 per cent.

Comparator jurisdictions for Alberta include British Columbia, Saskatchewan, and the following U.S. states: California, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah and Wyoming. The combined tax and royalty rates for each jurisdiction are ranked with the lowest three which comprise the first quartile.

During 2010, the Alberta government unveiled a number of initiatives to address the long-term competiveness of Alberta's natural gas and conventional oil sectors. Conventional oil and natural gas royalty rates were modified to encourage innovation and promote the use of new technologies. As a result of the recommendations in 2011 from the Regulatory Enhancement Task Force intended to improve and streamline the regulatory system, the *Responsible Energy Development Act* was passed in December 2012. This created a single regulator for upstream oil, gas, oil sands and coal projects in the province. These changes were deemed necessary to address the new reality of increased supply competition from unconventional resources (e.g., shale gas and tight oil) located near Alberta's traditional export markets in eastern Canada and the United States.

Since 2009, when the department started tracking the results, Alberta has consistently remained within the first quartile. In 2013, Alberta retained its place within the first quartile of similar jurisdictions based on the combined tax and royalty rates for natural gas and conventional oil. Along with Alberta, British Columbia and Saskatchewan were among the top three jurisdictions that remained in the top quartile in both 2012 and 2013.

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

Target

100 per cent of amounts owed are collected.

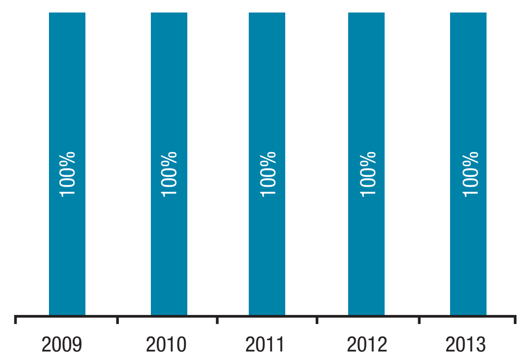
Discussion of Results

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 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.

Figure 1.b

Revenues from oil, oil sands, gas, and land sale bonuses are fully collected. Percentage of amounts collected compared to amounts owed.



Sources: Alberta Petroleum Marketing Commission, Department of Energy.
Note: excludes disputed amounts.

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 2013 and for this annual report, the revenue collection measure result was 100 per cent, the same as the previous four annual reports.

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

Target

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

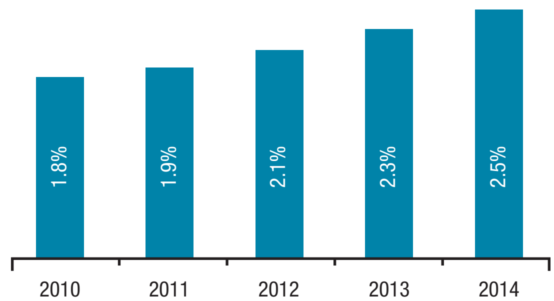
Discussion of Results

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 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.

Figure 1.c

Alberta's oil sands supply share of global oil consumption.



Source: Alberta Energy Regulator ST-39 and ST-53 Reports; International Energy Agency; Oil Market Report.

Notes:

1 2011 result has been revised from 2.0 per cent reported in the 2013-14 Annual Report to 1.9 per cent due to the retroactive revision of the total global consumption number reported for that year.

Alberta's oil sands supply share of global oil consumption was 2.5 per cent in 2014, exceeding the targeted 2.3 per cent. The increase in Alberta's share from 2013 to 2014 was driven by the solid increase in total oil sands production in Alberta, as well as a smaller annual increase in global consumption than was recorded for previous years.

Over the past several years, oil sands production consistently increased. From 2010 to 2011, oil sands production increased by eight per cent, from about 1.61 million barrels per day (bbl/d) in 2010 to about 1.74 million bbl/d in 2011. From 2011 to 2012, oil sands production increased by 10 per cent, from about 1.74 million bbl/d in 2011 to about 1.92 million bbl/d in 2012. Alberta oil sands production further increased to about 2.09 million bbl/d in 2013, a nine per cent increase compared to 2012.

In 2014, oil sands production reached an all-time record, at 2.30 million bbl/d, a 10 per cent increase from the 2013 level. However, global consumption in 2014 increased by about 0.8 per cent from its 2013 level. By comparison, global consumption increased by 1.1 per cent from 2010 to 2011, 1.2 per cent from 2011 to 2012, and 1.3 per cent from 2012 to 2013. The combination of higher Alberta production growth and lower global consumption growth pushed Alberta's share up.

Key Achievements

Business Plan Priority Initiative 1.1: Develop opportunities to expand Alberta's access to key global markets to better serve Alberta's long-term interests with respect to energy commodities.

- Energy is at various stages of involvement in advocacy processes before the **National Energy Board** in the Trans Mountain Expansion and the Energy East Pipeline projects. Energy's participation in the hearing processes is providing Alberta with key insights and information and ensuring the National Energy Board has a clear record and fully understands the important economic benefits of the projects.

  In addition to Energy, the Alberta Petroleum Marketing Commission, an Energy East shipper, also applied to participate in TransCanada's Energy East National Energy Board hearing.

  The National Energy Board approved Alberta's application to participate in the Trans Mountain Pipeline Expansion hearing. Energy is monitoring and assessing the evidentiary record to ensure the National Energy Board has a comprehensive record before preparing a recommendation report to federal cabinet.
- Energy advanced research and knowledge of **pipeline performance and safety** through its work with research and academic institutions across the province. The department also worked with Natural Resources Canada in the development of measures to strengthen pipeline spill prevention, preparedness and response and liability regimes under the federal *Pipeline Safety Act*.
- Energy met with key stakeholders to advance **oil market diversification** across Canada, including port authorities, pipeline and rail companies, industry associations, the business community, Aboriginal peoples and academia.
- Alberta's **international energy advocacy** efforts aim to further build Alberta's reputation as a reliable and environmentally responsible energy supplier in support of increasing market access in key global markets. In 2014-15, the department focused on attracting industry investment and forming partnerships that lead to job creation, business opportunities, tax revenue, and other benefits for the provincial economy.
- Energy provided ongoing technical input and advice to help inform the **European Union Fuel Quality Directive** Implementing Measure. Alberta's technical input has continued to inform aspects of the developing directive, and resulted in a finalized Fuel Quality Directive Implementing Measure that is fair, science-based, and will continue to allow for commercial access of oil sands crude oil to the European Union.

Business Plan Priority Initiative 1.2: Expand and deepen energy-related collaboration in key Asian markets to secure market access opportunities for Alberta companies and resources.

- Asia is an important market for Alberta's energy resources and creating productive, long-term relationships with **key Asian partners** is a high priority. During 2014-15, Energy took steps in expanding and deepening relationships with China, Japan and Korea with the aim of promoting energy collaboration and market access.

Business Plan Priority Initiative 1.3: Develop policies and programs to encourage energy processing and petrochemical development in Alberta.

- Construction of the **North West Redwater Partnership's Sturgeon Refinery** is approximately one third complete as of December 2014. The project is on target to achieve the budget of $8.5 billion. APMC uses a cash flow model to determine if the unavoidable costs of meeting the obligations under the North West Redwater Partnership's Processing Agreement exceed the economic benefits expected to be received. Based on the analysis, APMC determined the agreement has a positive net present value and no provision is required. The APMC will supply 37,500 barrels of oil per day of bitumen, plus diluent, for 30 years, which is roughly 75 per cent of the refinery's capacity. The refinery will primarily produce high value ultra-low sulphur diesel fuel and diluent beginning in mid-2017. The refinery will feed carbon dioxide from its processes into the Alberta Carbon Trunk Line, a commercial-scale carbon capture and storage project currently under construction and supported by Alberta's carbon capture and storage funding program.
- The **Incremental Ethane Extraction Program** (IEEP) is a $350 million program that encourages increased petrochemical production in Alberta by providing incentives through royalty credits to offset the high capital costs of recovering incremental barrels of ethane feedstock. The IEEP funds are now fully designated. Approximately $1.8 billion in projected new capital investment and the production of approximately 92,000 barrels per day of ethane by industry is associated with IEEP. Eleven Annual Eligibility Applications were received for the 2014 calendar year ethane production. IEEP incents ethane extraction from natural gas and refinery and oil sands upgrader off-gases.
- In 2014-15, the department worked with the Alberta Geological Survey to develop a **web-based mineral inventory database** to address provincial mineral geoscience needs. This database will support mineral exploration and investment in Alberta, informed decision-making by government, as well as economic diversification.

Additional Achievements

- Alberta competes for investment with other resource-rich jurisdictions to ensure continuous development of its energy industry. In 2013, preliminary actual results indicate that at an estimated total of $53.4 billion **capital expenditure in Alberta's upstream oil and gas industry** was the highest ever in the province's history, which is a positive reflection on Alberta's ability to attract investment.
- Administrative changes for a streamlined **Enhanced Oil Recovery** (EOR) Program were implemented in 2014 through passage of the new EOR Royalty Regulation. The streamlined program replaced the former EOR Royalty Relief Program.

GOAL TWO – Effective stewardship of Alberta's energy resources and regulatory systems is achieved through leadership and engagement with citizens, communities, industry, and governments

The ministry regulates Alberta's energy industry to ensure the efficient, safe, orderly and environmentally responsible development and sustainable management of energy and mineral resources. An integrated, big-picture approach to responsible resource development in the province enables strategic and integrated policies and plans that consider the overall environmental, economic and social outcomes of sustainable energy and mineral development for the benefit of Albertans. The ministry further supports the interests of Albertans by ensuring that the delivery and regulation of Alberta's utility services are fair and responsible.

Performance Measures

Performance Measure 2.a: Albertans' assessment of their energy knowledge

Target

To maintain or increase the previous year's results.

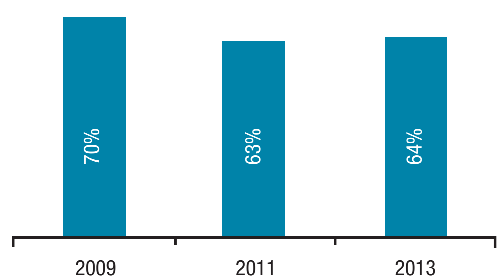
Discussion of Results

The Government of Alberta's long-term vision for sustainable energy development in the province identifies the need for Albertans to increase their knowledge and awareness about Alberta's energy resources and how these resources contribute to Alberta's economy and prosperity.

This performance measure, based on a biennial survey, tracks Albertans' assessments of their energy knowledge. The most recent biennial survey, conducted in the summer of 2013, will therefore be used for the 2014-15 reporting year.

Figure 2.a

Albertans' assessment of their energy knowledge (biennial survey).



Source: 2013 Omni Alberta Survey

Of the participants surveyed, 64 per cent believe that they are knowledgeable about the energy industry in Alberta, an improvement of one per cent from the biennial survey conducted in 2011. It is also consistent with the target of maintaining or increasing the previous year's results.

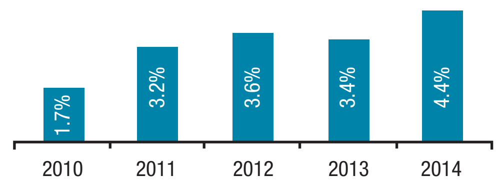
Performance Measure 2.b: Regulatory noncompliance

Target

Less than or equal to three per cent of final inspections finding high risk regulatory noncompliance.

Figure 2.b

Percentage of field inspections finding high risk regulatory noncompliance.



Source: Field Surveillance Inspection System database and AER Waste Management Inspection Spreadsheet, March 2015.

Discussion of Results

A high-risk noncompliance occurs when a licence has failed to address regulations or requirements. The resulting contravention of regulations or requirements has the potential of causing a significant impact on the public, the environment, and/or resource conservation. This performance measure reflects industry's compliance with regulatory requirements.

In the 2014 calendar year, the AER conducted 13,815 initial inspections, investigations and odour investigations. As a result of these inspections, 610 high-risk noncompliances were discovered, 233 of which were related to pipelines.

Year	Number of high-risk regulatory noncompliance inspections	Total number of inspections	Percentage of field inspections finding high-risk regulatory noncompliance
2014	**610**	**13,815**	**4.4%**
2013	420	12,367	3.4%
2012	447	12,481	3.6%
2011	438	13,832	3.2%
2010	239	14,345	1.7%

The 2014 result is 1.4 per cent above the 2014–17 business plan's target of three per cent. The target is based on historical data and represents the expected percentage of field inspections finding high-risk regulatory noncompliance. The target was established prior to 2011 when the organization adopted the use of an integrated risk-management framework. The AER has integrated this risk-management tool into the AER's field inspections over the past two years. Inspectors focus on higher-risk, higher-value inspections as determined by the field operations technical specialist in each inspection discipline and by the field centre. The selection of operations for inspection is based on internally defined risk criteria as well as external factors such as incidents and complaints. In 2014, the following four factors contributed to an increase in the percentage of high-risk regulatory noncompliance:

- a greater number of inspections due to increased capacity, resulting from additional Environment and Sustainable Resource Development (ESRD) staff joining the AER as a result of the Regulatory Enhancement Project;
- an increase in focused inspections in the Peace River area in response to recommendations from the Peace River proceeding;
- a focus on operators with known issues and a history of noncompliance; and
- a greater number of pipeline inspections, a discipline with the greatest amount of overall noncompliance amongst all inspection disciplines.

The AER works with industry to prevent regulatory noncompliance. To ensure greater understanding of the regulatory requirements, the AER continues to educate industry through targeted presentations and operator awareness sessions.

Key Achievements

Business Plan Priority Initiative 2.1: Collaborate with Environment and Sustainable Resource Development and other ministries to continue the implementation of recommendations under the Regulatory Enhancement Project, including all phases of the AER's transition.

- The **Policy Management Office** was established to continue to deliver on Regulatory Enhancement Project recommendations, and provide leadership in facilitating and enabling integration between policy development of the Government of Alberta and policy assurance of the AER. The Policy Management Office collaborated with ESRD, Aboriginal Relations, Health, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, and the AER to ensure supports are in place to maintain the province's strong commitment to the environment and public safety and to work toward building the province's reputation as a responsible energy producer.
- On October 1, 2014 the **AER's jurisdiction expanded** to include environmental assessments for all energy-related projects. The environmental assessment process requires companies to examine the effects that a proposed project may have on the environment.
- The **Common Risk Management Framework** was completed in November 2014 and the Framework Management Committee was completed in March 2015 to support its implementation. The common risk management framework establishes principles for partner organizations in determining their engagement approach and policy issues.
- The **Policy Systems Review Project** Final Report, a qualitative research project that provides a comprehensive overview of the natural resource and environmental policy system in 2014, was completed in February 2015 and report findings were shared with participating organizations.
- In 2014-15, Energy further supported cross-ministry policy integration and collaboration by populating the online **Alberta Responsible Energy Policy System** with 251 relevant departmental documents. Increased integration, collaboration and information sharing across government benefits all Albertans by ensuring that natural resource development is managed in a comprehensive way.

Business Plan Priority Initiative 2.2: Coordinate the development of a Canadian Energy Strategy with other provinces and territories as a co-lead with Manitoba and Newfoundland and Labrador.

- The **Canadian Energy Strategy** provided Alberta with the opportunity to build positive relationships with its provincial and territorial partners and advance areas of common interest for the benefit of all Canadians.
- A draft Canadian Energy Strategy was prepared for the annual summer Council of the Federation meeting in Prince Edward Island in August 2014. At the meeting, it was agreed that officials would review the draft strategy in light of amendments proposed by Ontario and Quebec.

Business Plan Priority Initiative 2.3: Enhance awareness and understanding of existing and emerging trends and opportunities related to energy and mineral development provincially, nationally and internationally.

- Energy continues to **advance energy literacy** within the province by working with key industry, governmental, and non-governmental stakeholders through informal engagement and strategic investments. Energy literacy can promote informed dialogue with key stakeholders, which in turn supports Alberta's policy objectives of market access, regulatory review, and social licence.

- Energy's two-year grant of $250,000 to a literacy specialist resulted in energy literacy programing in 870 classrooms, professional development opportunities for approximately 100 teachers, and helped develop and distribute more than 1,350 learning resources to teachers and classrooms across the province. Another two-year grant of $135,000 supported communities in participating in resource management decisions affecting them by building stakeholder relationships and sharing energy sector information.
- Energy was an observer on the Alberta Council for Environmental Education's education task force, which developed recommendations for changes to the Alberta Kindergarten to Grade 12 curriculums that would increase energy and environmental literacy.

Business Plan Priority Initiative 2.4: Using a risk-based approach, continue to streamline regulatory processes and eliminate the need for utility sector applicants to file low-risk applications.

- In 2014-15, the AUC made changes to **AUC Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments**, implementing legislative amendments that came into force on September 22, 2014 to improve regulatory efficiency of the transmission connection process.
- The AUC **eliminated the application requirements for power plants with a generating capacity of less than 10 megawatts** that are generating electric energy solely for the use of the owner, if the owner of the power plant satisfies certain public interest requirements. This change eliminates the requirement to file an application for most remote, temporary and emergency power plants to improve regulatory efficiency in Alberta.
- The AUC introduced a rule to **streamline the municipal franchise application process** following a number of stakeholder consultations with electric and gas distribution utilities, and the Alberta Urban Municipalities Association. The streamlining of franchise applications will result in a shorter review process and quicker approvals, in most cases approvals being granted in 10 days or less.

Additional Achievements

- Energy is leading a cross-ministry process to develop an **energy strategy** to provide long-term strategic direction for the province. In November 2014, the Integrated Resource Management System Deputy Ministers' Committee formally endorsed the approach which will build a strategic perspective on the energy system over a longer-term horizon.
- In 2014, the Government of Alberta, led by Energy, invited Albertans and stakeholders to provide input on **energy development in or near urban areas** through roundtable discussions and an online survey. This forum allowed Albertans to offer their suggestions on how provincial policies and regulations can better balance urban growth and opportunities for future energy development.
- The **Lower Athabasca Regional Plan**, the first of seven regional plans across the province, provides strategic direction to balance long-term opportunities for oil sands development with environmental and social considerations. In 2014-15, Energy cancelled 29 agreements and paid out $5.4 million in compensation to support implementation of new conservation areas.
- The **South Saskatchewan Regional Plan** (SSRP) came into effect September 1, 2014, following consultation and engagement with Albertans. The SSRP provides strategic direction to facilitate the establishment of new conservation areas for the protection of headwaters and water security, protect species-at-risk, and manage recreation. This direction balances environmental and social values with development and will increase certainty for industry to access subsurface resources.
- Energy provided advice and technical analysis for the development of the Terms of Reference and Profile of the Region for the **North Saskatchewan Regional Plan** which were released to the public in May 2014. The department provided technical analysis of energy and mineral resources in the region to support the discussions and deliberations of the Regional Advisory Council.

- The department provided technical analysis of energy and mineral resources in support of background preparation work for the **Upper and Lower Peace Regional Plans**.
- In addition, Energy continued its cross-ministry collaboration with ESRD on the development of the range plans for the **Little Smoky and A La Peche caribou ranges**. This work includes ongoing engagement with stakeholders, including the energy industry, forestry sector, municipalities, aboriginal communities, and environmental organizations, on potential management options that will meet federal and provincial requirements.
- In the **Athabasca Oil Sands Area**, work continued to cancel all oil sands subsurface dispositions within the Urban Development Sub-Region. As of March 2015, 20 of the 40 oil sands leases within the Urban Development Sub-Region boundary have been cancelled and leaseholders compensated for costs incurred.

  In the **Cold Lake Oil Sands Area**, multi-stakeholder teams were set up to identify strategies to support implementation of the Comprehensive Regional Infrastructure Sustainability Plans, in particular identifying integrated approaches to address regional needs for roads, aviation and housing.

  In the **Peace River Oil Sands Area**, work was completed and further analysis is being undertaken to create additional long-term bitumen production forecasts for the region. Population and infrastructure planning will be based on this work.
- In regards to air emissions, the AER amended ***Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*** to address off-lease non hydrogen sulfide odours/releases and to require gas conservation. These changes give the AER additional enforcement authority to address these issues. As of January 15, 2015, the AER requires operators in the Three Creeks and Reno areas near Peace River to effectively eliminate venting except in emergency situations.
- To further ensure **pipeline safety**, the AER ordered an audit of Plains Midstream Canada in July 2013, based upon significant noncompliance with AER requirements. The AER completed the audit, posted its findings online, and lifted the Section 22 order in August 2014. The audit concludes that Plains made significant advances to ensure it can meet regulatory requirements and the company is capable of operating in compliance with pipeline regulatory requirements in Alberta.
- To enhance standards related to oil and gas well construction activities, additional regulatory requirements were also introduced following the AER's investigation of a series of **seismic events** in an area approximately 33 km west of Fox Creek. In February 2015, the AER released new seismic and monitoring requirements for hydraulic fracturing operators in the Fox Creek area.
- Over the past year, the AER reduced costs by $270 million annually by revising outdated rules and unnecessary processes that address low-risk activities through the **Near-Term Action program and continuous improvement initiative**.
- The AUC concluded an **integrity management and emergency response review of gas utility pipelines** in Alberta under the AUC's jurisdiction in 2013-14. At that time, the AUC also identified opportunities for improvements and, in 2014-15, worked with the gas utility pipeline operators to implement the recommendations set out in the initial review.
- The AUC continued to **improve the notification process** in AUC Bulletin 2014-10 by implementing an earlier issuance of public notice related to electric and natural gas facility applications. The early issuance of notices will maintain, and potentially improve, current process timelines, enable the Commission and applicants to identify interventions earlier in the process and allow for increased flexibility within the proceeding schedule.

GOAL THREE – Development of energy related infrastructure and cleaner energy technologies is actively led and supported

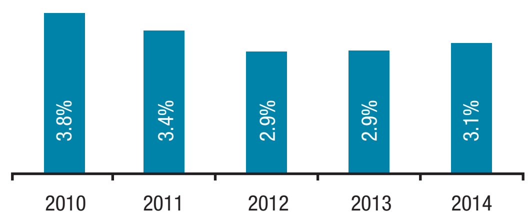
Reliable, efficient and resilient energy systems are vital to the social and economic foundation of Alberta. To meet the increasing demand for electricity and to access new markets, energy-related infrastructure is needed. In the interest of Albertans, the ministry develops effective innovation policies and programs and works with other ministries and stakeholders to support energy infrastructure development, innovative technologies and energy and mineral resource processing improvements.

Performance Measures

Performance Measure 3.a: Transmission losses

Target
To maintain a minimum level in transmission losses. The target for 2014-15 was 3.0 plus or minus 0.3 per cent.

Figure 3.a
Transmission losses.



Source: Alberta Electric System Operator

Discussion of Results
Electricity is a facilitator of economic development in Alberta. A strong, reliable and efficient electricity transmission system is required to ensure electricity can be delivered where and when it is needed. By ensuring development of a hardy transmission system, generation developers will know that they will be able to efficiently move their product to market. In turn, they will have confidence to develop new generation ensuring an adequate, reliable supply of electricity to Albertans.

Alberta has significant potential renewable or low-emission electricity generation. There are hydroelectric resources in the north, wind and solar in the south, and biomass in the northwest. 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 line loss of 3.1 per cent for 2014 meets the target of 3.0 plus or minus 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.

Performance Measure 3.b: Power generation

Target

Maintain a minimum seven per cent margin over peak demand.

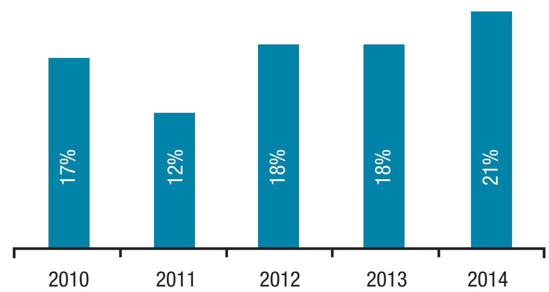
Discussion of Results

Alberta's economic prosperity and high standard of living relies on access to reliable and plentiful electricity. The Government of Alberta has created a framework that facilitates a competitive wholesale power market. This framework has resulted, over the long term, in electricity supply keeping pace with Alberta's growing demand for power.

For this measure, 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 the Western Interconnection that extends from Canada to Mexico.

Figure 3.b

Margin (megawatts) between firm generating capacity[1] and peak demand.



Sources: Alberta Utilities Commission, Alberta Electric System Operator and Department of Energy.

Notes: Through industry investment, Alberta's net supply margin of electricity will be sufficient to ensure reliable power supply.

[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.

Firm electricity generating capacity was calculated at 13,551 megawatts (MW) for 2014. This was a 371 MW (or 2.8 per cent) increase over the 2013 level. The peak demand in the winter period of the climatic year (October 1, 2014 to March 31, 2015) reached the all-time high of 11,229 MW. This was 90 MW (or 0.8 per cent) higher than the peak of 11,139 MW set in the previous winter climatic year (October 1, 2013 to March 31, 2014).

In 2014, the margin between the firm electricity generating capacity and peak demand was 21 per cent. This result is an indication that Albertans' electricity needs are being met through a resilient electricity system.

Performance Measure 3.c: Timeliness of the needs and facility applications

Target

100 per cent of needs and facility applications determined within 180 days of the application being deemed complete.

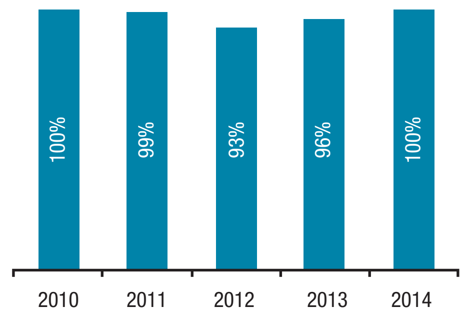
Discussion of Results

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

For 2014, the AUC met this standard 100 per cent of the time as 56 of 56 decisions were issued within the 180-day timeline.

Figure 3.c

Percentage of needs and facility applications determined within 180 days of the application being deemed complete.



Source: Alberta Utilities Commission

Key Achievements

Business Plan Priority Initiative 3.1: Encourage greater microgeneration development in Alberta.

- Alberta's **Micro-generation Regulation** continues to enable Albertans to generate their own alternative and renewable electricity to meet their own electricity needs. In 2014-15, 266 new micro-generation sites were connected, adding nearly two megawatts (MW) of alternative and renewable generation capacity to Alberta's grid. As of March 2015, there are 1,183 micro-generation sites in Alberta with a total installed capacity of over 6.7 MW.

Business Plan Priority Initiative 3.2: Implement policy improvements arising from the Retail Market Review Committee to enhance Alberta's competitive retail market and to continue to meet Alberta's electricity and natural gas needs.

- In December 2014, the **MLA Retail Market Review Committee** (RMRC) Implementation Team report was released and three of the recommendations were immediately accepted which amend the Billing Regulation and the Regulated Rate Option Regulation; merge the retail electricity and natural gas codes of conduct into one Code of Conduct Regulation, and change the name of the Regulated Rate Option.
- In 2014-15, amendments were made to clarify the Local Access Fee and merge the codes of conduct.

Business Plan Priority Initiative 3.3: Develop Electricity Strategy 2020 to ensure a resilient electricity system and competitive market.

- In 2014-15, the department continued to frame a longer term **electricity strategy** for Alberta. Building on previous consultations with stakeholders, Energy identified the strategic outcomes for a resilient electricity system, guiding principles for engagement, and initial aspects of system performance.

Additional Achievements

- In 2014-15, the department continued to monitor, administer and ensure compliance under the two **carbon capture and storage** funding agreements while fulfilling obligations under the *Carbon Capture and Storage Funding Act*. As of March 31, 2015, a total of $302.5 million has been paid to the projects for achievement of construction milestones.
- The **Innovative Energy Technologies Program** is a $200 million commitment by the Government of Alberta which supports innovation, research and technology development. The program provides royalty adjustments to support first-of-a-kind applied research pilot projects that use innovative technologies to further the production of oil, oil sands (mining and in-situ) and natural gas. In 2014-15 there were six active projects, two of which were completed during the year.
- The **Bioenergy Producer Credit Program** is a five-year program that was initiated in April 2011 to support the production of energy products from biomass such as agricultural products and waste. In 2014-15 a total of $59.2 million was paid to 26 grant recipients under the Bioenergy Producer Credit Program. This reflects payments made in support of production for the first three quarters of 2014-15 as the payments for the fourth quarter have not yet been determined.
- **Alternative and renewable generating capacity** has grown steadily over the past five years with a 22 per cent increase from 2010 to 2014. This was largely driven by growth in both wind power and gas cogeneration. In 2014, 44 per cent of the province's electricity generating capacity came from alternative and renewable energy sources.
- In 2014-15, the AUC oversaw the **Cost Oversight Management** (COM) function on a pilot basis to assess its effectiveness. The COM function is a new regulatory approach to electricity transmission cost review and seeks to provide proactive, third-party expert review and comment on transmission project costs at earlier, specific stages of a transmission project from planning through to construction completion. The current regulatory process is largely an after-the-fact review of costs after the project has been constructed.

Appendix A: Performance Measure Methodologies

Performance Measure 1.a: Combined tax and royalty rates for Alberta natural gas and conventional oil production, compared to similar jurisdictions

Combined tax and royalty rate includes the following:

- Royalties;
- Corporate income taxes (federal & state/provincial);
- Severance taxes; and
- Ad valorem taxes

Comparator jurisdictions for Alberta include British Columbia, Saskatchewan, and the following U.S. states: California, Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming. The Department of Energy regularly monitors resource development activity throughout North America and updates the list of comparator jurisdictions as required to reflect the top competing jurisdictions against Alberta.

This measure was considered an "early warning" signal to indicate whether the royalty system requires amendment. If the comparison of combined tax and royalty rate is indicating possible fiscal system change, closer attention to the other indicators such as government share, investor rate of return, and net present value would be required. This is more appropriately addressed through special studies that are future focused and account for the many factors that influence investment decisions.

The combined tax and royalty rates from all 13 comparator jurisdictions are manually calculated from data obtained from reliable third-party external sources, except for the Alberta effective royalty rate which is provided from within the ministry. The calculation of Alberta's effective natural gas royalty rates was modified to better represent the combined effective royalty rates for natural gas and natural gas liquids net of any royalty adjustments and eligible cost deductions.

The combined tax and royalty rates for each jurisdiction are then ranked with the lowest three comprising the first quartile.

Performance Measure 1.b: 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 Operation (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, calculates the net value of all royalty sales, and remits the proceeds to Treasury.

Oil Sands Royalty:
Oil Sands Administrative and Strategic Information System (OASIS) calculates the monthly amounts to be collected based on the Good Faith Estimates (GFE), the Monthly Royalty Calculations (MRC) and the Non-Project Royalty (NPR) reports and annual adjustments based on the End of Period Statements (EOPS). All royalty reporting must be submitted electronically to the department, using the web-based Electronic Transfer System (ETS). OASIS then sends the charge information to the Corporate Accounting Revenue 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 awarded an agreement, with the possible exception of parcels sold in Métis Settlements.

Individuals or companies submit a posting request electronically to the department through the web-based 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 (EFT) is the form of payment accepted for winning bids. The results of the sale are published on the department's website by 3:30 pm 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 sale or 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 the Integrated Management Information System.

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 the 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.

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

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

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

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

Performance Measure 2.a: Albertans' assessment of their energy knowledge

The intent of this performance measure is to survey Albertans' awareness of their energy knowledge using their self-assessed knowledge of the energy industry as a proxy. To ensure validity, the same question has been asked every two years since the 2009 benchmark was established.

In the 2013-16 Business Plan, the target for this performance measure was revised to reflect a trend rather than a median target. In other words, a trend indicating that Albertans' energy awareness is maintained or has increased from the previous year's results provides more insight than a numerical target; in this case, of 63 per cent.

Performance Measure 2.b: Regulatory noncompliance

The AER established a three per cent target for this measure based on historical data. The target is the expected percentage of field inspections finding high-risk regulatory noncompliance.

The AER uses a risk-based inspection strategy that focuses on higher-risk, higher-value inspections. The AER selects a sample for inspections based on both internally defined risk criteria and external factors such as incidents or complaints.

AER field operations staff inspect the operations of the upstream oil and gas industry. Inspections result in a rating of satisfactory, low-risk noncompliant, or high-risk noncompliant. These ratings are entered into the Field Surveillance Inspection System database. Inspections of waste management facilities are an exception, as they do not have licence numbers. The data is based on inspections performed in all inspection disciplines and is counted based on the date of the initial inspection.

Incidents and complaints change the focus of the inspection strategy from year to year, in that the AER may expand its inspections to determine whether the problem is occurring at other sites.

Performance Measure 3.a: Transmission losses

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

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

Source Documentation: The AESO publishes Alberta's annual internal load each year in its Annual Market Statistics report. The AESO publishes line losses each year in its Annual Report. The 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 MW 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, 2014 through to March 31, 2015) as recorded by the Alberta Electric System Operator.

Notes: Through industry investment, Alberta's net supply margin of electricity will be sufficient to ensure reliable power supply.

Performance Measure 3.c: 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.

MINISTRY OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2015

AUDITOR GENERAL *Alberta*

Independent Auditor's Report

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, 2015, and the consolidated statements of operations 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, 2015, and the results of its operations and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

June 3, 2015
Edmonton, Alberta

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF OPERATIONS

Year ended March 31, 2015

(in thousands)

	2015		2014
	Constructed Budget (Schedule 3)	Actual	Actual
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 9,209,000	$ 8,947,873	$ 9,578,070
Freehold Mineral Rights Tax	134,000	171,831	145,928
Industry Levies and Licences	259,926	292,060	214,968
Other Revenue	12,159	28,490	33,171
Net Income from Government Business Enterprise	144	13,759	1,343
	9,615,229	9,454,013	9,973,480
Expenses - Directly Incurred (Note 2, Schedules 2 and 4)			
Ministry Support Services	7,814	7,585	7,129
Resource Development and Management	87,633	100,979	104,769
Bioenergy Initiatives	106,000	70,275	68,202
Costs of Marketing Oil	209,616	176,426	173,622
Energy Regulation	229,627	256,827	208,310
Utilities Regulation	38,358	33,741	31,571
Carbon Capture and Storage	147,200	53,914	116,056
Orphan Well Abandonment	15,500	15,760	16,172
Oil Sands Sustainable Development Secretariat	3,161	817	1,527
Settlements Related to the Land-Use Framework	-	4,123	72,267
	844,909	720,447	799,625
Net Operating Results	$ 8,770,320	$ 8,733,566	$ 9,173,855

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at March 31, 2015

(in thousands)

	2015	2014
Assets		
Cash and Cash Equivalents (Note 3)	$ 300,994	$ 690,597
Accounts Receivable (Note 4)	213,239	1,338,555
Inventory (Note 5)	1,226	2,987
Prepaid Expenses	11,530	10,853
Equity in Government Business Enterprise (Schedule 5)	14,475	716
Tangible Capital Assets (Note 6)	101,102	97,099
	$ 642,566	$ 2,140,807
Liabilities		
Accounts Payable and Accrued Liabilities	$ 392,622	$ 228,393
Gas Royalty Deposits (Note 7)	247,777	260,017
Unearned Revenue	74,636	79,327
Security Deposits (Note 8)	122,835	100,211
Tenant Incentives	23,063	23,618
Pension Obligations (Note 9)	3,114	4,056
	$ 864,047	$ 695,622
Net Assets (Liabilities):		
Net Assets at Beginning of Year	$ 1,445,185	$ 624,630
Net Operating Results	8,733,566	9,173,855
Net Financing Provided for General Revenues	(10,400,232)	(8,353,300)
Net (Liabilities) Assets at End of Year	$ (221,481)	$ 1,445,185
	$ 642,566	$ 2,140,807

Contractual Obligations, Contingent Liabilities and Commitments (Notes 10, 11, and Schedule 5)

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

MINISTRY OF ENERGY

CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended March 31, 2015

(in thousands)

	2015	2014
Operating Transactions		
Net Operating Results	$ 8,733,566	$ 9,173,855
Non-cash items included in Net Operating Results		
Amortization (Note 6)	21,035	20,561
Loss on Disposal of Tangible Capital Assets (Note 6)	780	264
	$ 8,755,381	$ 9,194,680
Decrease (Increase) in Accounts Receivable	1,125,316	(356,761)
Decrease in Inventory	1,761	10,443
(Increase) Decrease in Prepaid Expenses	(677)	416
Increase (Decrease) in Accounts Payable and Accrued Liabilities	164,229	(93,380)
(Decrease) Increase in Unearned Revenue	(4,691)	200
(Decrease) in Tenant Incentives	(555)	(666)
(Decrease) Increase in Pension Obligation	(942)	31
Cash Provided by Operating Transactions	$ 10,039,822	$ 8,754,963
Capital Transactions		
Acquisition of Tangible Capital Assets (Note 6)	$ (25,869)	$ (23,518)
Proceeds on Disposal/Sale of Tangible Capital Assets (Note 6)	51	-
Cash (Applied to) Capital Transactions	$ (25,818)	$ (23,518)
Investing Transactions		
(Increase) in Equity in Government Business Enterprise	$ (13,759)	$ (1,343)
	$ (13,759)	$ (1,343)
Financing Transactions		
Net Financing Provided for General Revenues	$ (10,400,232)	$ (8,353,300)
(Decrease) in Gas Royalty Deposits	(12,240)	(77,450)
Increase in Security Deposits	22,624	47,691
Cash Applied to Financing Transactions	$ (10,389,848)	$ (8,383,059)
(Decrease) Increase in cash and cash equivalents	$ (389,603)	$ 347,043
Cash and cash equivalents at Beginning of Year	690,597	343,554
Cash and cash equivalents at End of Year	$ 300,994	$ 690,597

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

NOTE 1 AUTHORITY

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*

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

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

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. Intra-ministry transactions (revenue, expenses, capital, investing and financing transactions, and related asset and liability accounts) have been eliminated.

The Commission is a government business enterprise and is 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 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.

Under the proclamation of portions of the *Responsible Energy Development Act* (REDA) in June 2013, the AER was created and assumed all responsibilities of the ERCB including all assets, liabilities, obligations, commitments and contingencies. In November 2013, additional portions of REDA were proclaimed transferring the public land and geophysical jurisdictions. The remaining portions of REDA were proclaimed in March 2014 which transferred all environmental and water jurisdictions. The transfer of jurisdiction from ESRD to the AER represented the final step in creating a single regulator for upstream oil, oil sands, natural gas and coal development in Alberta.

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

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

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.

Expenses

Directly Incurred

Directly incurred expenses are those costs the ministry 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 are 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.

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

Directly Incurred (cont'd)

- 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 and eligibility criteria, if any, are met.

Incurred by Others

Services contributed by other entities in support of the ministry operations are not recognized and are disclosed in Schedule 4 and are not reflected in the consolidated statements of operations.

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.

Assets acquired by right are not included.

Tangible capital assets of the ministry are recorded 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 in use.

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

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

Liabilities

Liabilities are recorded 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.

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

Net Assets/Net Liabilities

Net assets/net liabilities represent the difference between the carrying value of assets held by the ministry and its liabilities.

Canadian Public Sector Accounting Standards require a "net debt" presentation for the statement of financial position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as "net debt" or "net financial assets" as an indicator of the future revenues required to pay for past transactions and events. The ministry operates within the government reporting entity, and does not finance all its expenditures by independently raising revenues. Accordingly, these financial statements do not report a net asset/debt indicator.

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, advances, accounts payable and accrued liabilities, security deposits, and gas royalty deposits are estimated to approximate their carrying values because of the short-term nature of these instruments.

Measurement Uncertainty
(in thousands)

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 recorded as $989,160, bitumen royalty recorded as $5,049,393, and crude oil royalty revenue recorded as $2,244,745 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 ministry by royalty payers. These costs and volumes could vary significantly from that 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, natural gas and by- products revenue could change by $175,000.

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.

NOTE 3 CASH AND CASH EQUIVALENTS

Cash consists of deposits in the Consolidated Cash Investment Trust Fund which is 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. As at March 31, 2015, securities held by the Fund have a time-weighted rate of return of 1.2% per annum (2014 - 1.2% per annum).

NOTE 4 ACCOUNTS RECEIVABLE

Accounts receivable royalties are secured by a claim against the mineral leases.

NOTE 5 INVENTORY

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

NOTE 6 TANGIBLE CAPITAL ASSETS

(in thousands)

	Land	Leasehold Improvement s	Equipment [1]	Computer Hardware and Software	Total
Estimated Useful Life	indefinite	lease term	3-40 years	3-10 years	
Historical Cost [2]					
Beginning of Year	$ 282	$ 31,929	$ 42,328	$ 223,141	$ 297,680
Additions	-	8,034	4,119	13,716	$ 25,869
Disposals - including write-downs	-	(561)	(289)	(6,288)	$ (7,138)
	$ 282	$ 39,402	$ 46,158	$ 230,569	$ 316,411
Accumulated Amortization					
Beginning of Year	$ -	$ 7,905	$ 27,643	$ 165,033	$ 200,581
Amortization Expense	-	2,106	4,343	14,586	$ 21,035
Effect of Disposals	-	-	(232)	(6,075)	$ (6,307)
	$ -	$ 10,011	$ 31,754	$ 173,544	$ 215,309
Net Book Value at March 31, 20	$ 282	$ 29,391	$ 14,404	$ 57,025	$ 101,102
Net Book Value at March 31, 20	$ 282	$ 24,024	$ 14,685	$ 58,108	$ 97,099

(1) Equipment includes office equipment and furniture and other equipment.
(2) Historical cost includes work-in-progress at March 31, 2015 totaling $454 (2014 - $3,893) comprised of computer hardware and software.

NOTE 7 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 8 SECURITY DEPOSITS

(in thousands)

The ministry encourages the timely and proper abandonment and reclamation of upstream wells, facilities, pipelines, and oilfield waste management facilities by holding various forms of security. At March 31, 2015, the ministry held $122,835 (2014 - $100,211) in cash and an additional $1,707,241 (2014 - $1,595,700) in letters of credit. The security, along with any interest earned, will be returned to the depositor upon meeting specified refund criteria.

NOTE 9 EMPLOYEE FUTURE BENEFITS

(in thousands)

The ministry participates in multi-employer pension plans, Management Employees Pension Plan and Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. The expense for these pension plans is equivalent to the annual contributions of $29,471 for the year ended March 31, 2015 (2014 - $24,771). Departments are not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2014, the Management Employees Pension Plan reported a surplus of $75,805 (2013 - deficiency $50,457), the Public Service Pension Plan reported a deficiency of $803,299 (2013 - deficiency $1,254,678) and the Supplementary Retirement Plan for Public Service Managers reported a deficiency of $17,203 (2013 - deficiency $12,384).

The ministry also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2015, the Bargaining Unit Plan reported an actuarial surplus of $86,888 (2014 - surplus $75,200) and the Management, Opted Out and Excluded Plan an actuarial surplus of $32,343 (2014 - surplus $24,055). 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, 2013. The accrued benefit obligation as at March 31, 2015 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, 2016.

NOTE 9 EMPLOYEE FUTURE BENEFITS (cont'd)

(in thousands)

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

	AER		AUC	
	2015	2014	2015	2014
Accrued benefits obligations				
Discount rate	4.9%	5.3%	4.7%	5.0%
Rate of compensation increase	0% for 2016, 3.5% thereafter	3.8%	3.5%	3.8%
Long – term inflation rate	2.0%	2.3%	2.0%	2.3%
Pension benefit costs for the year				
Discount rate	5.3%	5.0%	5.0%	4.8%
Expected rate of return on plan assets	5.3%	5.0%	5.0%	4.8%
Rate of compensation increase	3.8%	3.8%	3.8%	3.8%
Funded status and amounts				
Market value of plan assets	$ 45,087	$ 37,859	$ 8,092	$ 6,802
Accrued benefit obligation	49,510	43,231	9,384	8,141
Plan (deficit)	$ (4,423)	$ (5,372)	$ (1,292)	$ (1,339)
Unamortized actuarial loss	2,074	2,081	527	574
Pension obligations	$ (2,349)	$ (3,291)	$ (765)	$ (765)
Asset Allocation				
Equity securities	49.9%	49.4%	51.7%	52.4%
Debt securities	38.4%	39.0%	29.4%	29.4%
Other	11.7%	11.6%	18.9%	18.2%
	100.0%	100.0%	100.0%	100.0%
Additional information				
Employer contribution	$ 5,247	$ 2,630	$ 802	$ 717
Employees' contribution	731	507	113	108
Benefit paid	3,350	3,024	420	458

NOTE 10 CONTRACTUAL OBLIGATIONS

(in thousands)

Contractual obligations to outside organizations in respect of contracts entered into before March 31, 2015 amount to $1,267,115 (2014 - $1,420,723). These contractual obligations will become expenses of the ministry when terms of the contracts 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
2016	$ 390,706	$ 11,331	$ 24,863	$ 426,900
2017	157,250	8,508	20,632	186,390
2018	59,290	149	19,368	78,807
2019	49,600	5	12,815	62,420
2020	49,600	5	11,590	61,195
Thereafter	332,460	3	118,940	451,403
	$ 1,038,906	$ 20,001	$ 208,208	$ 1,267,115

NOTE 11 CONTINGENT AND OTHER LIABILITIES

(in thousands)

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

Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate.

The ministry has been named in one claim (2014 - one) of which the outcome is not determinable. The claim has a specified amount of $7,000 (2014 - $15,000).

The ministry has been jointly named with other entities in seven claims (2014 restated - five). Five of these claims have specified amounts totaling $14,350,000 (2014 restated – four claims totaling $2,922,500) and two claims (2014 restated - one) with no amounts specified.

Of the total specified claims, two claims totaling $10,007,000 (2014 restated - two claims totaling $587,500) are partially or fully covered by the Alberta Risk Management Fund.

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

NOTE 12 TRUST FUNDS UNDER ADMINISTRATION

(in thousands)

The ministry administers trust funds which are regulated funds consisting of public money over which the Legislature has no power of appropriation. Because the Province has no equity in the funds, and administers them for the purpose of various trusts, they are not included in the ministry's financial statements.

As at March 31, trust funds under administration were as follows:

	2015	2014
Oil and Gas Conservation Trust	$ 4,463	$ 4,364

NOTE 13 RELATED PARTY TRANSACTIONS

(in thousands)

The ministry paid $6,843 (2014 - $4,351) to various other Government of Alberta departments, agencies or funds for grants, supplies and/or services during the fiscal year and received $127 (2014 - $148) as revenue.

Accommodations, legal, business services, and certain financial costs were provided to the ministry by other government organizations at no cost. However, services contributed by other entities in support of the ministry operations are disclosed in Schedule 4.

NOTE 14 ROYALTY REDUCTION PROGRAMS

(in thousands)

The ministry provides twelve 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, 2015, the royalties received under these programs were reduced by $1,441,451 (2014 - $1,191,501).

NOTE 15 BITUMEN CONSERVATION

(in thousands)

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 $26,374 (2014 - $43,266).

NOTE 16 APPROVAL OF FINANCIAL STATEMENTS

The financial statements were approved by the Senior Financial Officer and the Deputy Minister.

MINISTRY OF ENERGY **Schedule 1**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Revenues

Year ended March 31, 2015

(in thousands)

	2015		2014
	Budget	**Actual**	**Actual**
Non-Renewable Resource Revenue			
Bitumen Royalty	$ 5,579,000	$ 5,049,393	$ 5,222,178
Crude Oil Royalty	2,019,000	2,244,745	2,475,992
Natural Gas and By-Products Royalty	823,000	989,160	1,102,999
Bonuses and Sales of Crown Leases	623,000	476,331	588,108
Rentals and Fees	153,000	172,489	172,719
Coal Royalty	12,000	15,755	16,074
	9,209,000	8,947,873	9,578,070
Freehold Mineral Rights Tax	134,000	171,831	145,928
Industry Levies and Licenses	259,926	292,060	214,968
Other Revenue			
Other	9,359	26,596	31,910
Interest	2,800	1,894	1,261
	12,159	28,490	33,171
Net Income from Government Business Enterprise	144	13,759	1,343
Total Revenue	$ 9,615,229	$ 9,454,013	$ 9,973,480

MINISTRY OF ENERGY **Schedule 2**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Expenses - Directly Incurred Detailed by Object

Year ended March 31, 2015

(in thousands)

	2015		2014
	Budget	Actual	Actual
Salaries, Wages and Employee Benefits	$ 254,995	$ 285,076	$ 238,639
Supplies and Services	298,761	272,462	266,401
Grants	253,200	122,543	183,846
Amortization of Tangible Capital Assets (Note 6)	23,088	21,035	20,561
Orphan Well Abandonment	15,500	15,760	16,172
Settlements Related to the Land-Use Framework	-	4,123	72,344
Financial Transactions and Other	120	67	2,406
Total Expenses before Recoveries	845,664	721,066	800,369
Less Recovery from Support Service Arrangements with Related Parties (a)	(755)	(619)	(744)
Total Expenses	$ 844,909	$ 720,447	$ 799,625

(a) The ministry provides financial services to the Ministry of Environment and Sustainable Resource Development. Costs incurred by the ministry for these services are recovered from the Ministry of Environment and Sustainable Resource Development and are distributed between salaries and supplies.

MINISTRY OF ENERGY **Schedule 3**

SCHEDULE TO FINANCIAL STATEMENTS

BUDGET RECONCILIATION

Year ended March 31, 2015

(in thousands)

	2014-15 Estimate	Adjustments to Conform to Accounting Policy	2014-15 Constructed Budget
Revenues			
Operational Revenue			
Non-Renewable Resource Revenue			
Bitumen Royalty	$ 5,579,000	$ -	$ 5,579,000
Crude Oil Royalty	2,019,000	-	2,019,000
Natural Gas and By-Products Royalty	823,000	-	823,000
Bonuses and Sales of Crown Leases	623,000	-	623,000
Rental and Fees	153,000	-	153,000
Coal Royalty	12,000	-	12,000
	9,209,000	-	9,209,000
Freehold Mineral Rights Tax	134,000	-	134,000
Industry Levies and Licenses	259,926	-	259,926
Other Revenue			
Interest	2,800	-	2,800
Other	9,359	-	9,359
	12,159	-	12,159
Net Income from Commercial Operations	144	-	144
	$ 9,615,229	$ -	$ 9,615,229
Expenses - Directly Incurred			
Operational Programs			
Ministry Support Services	$ 7,814	$ -	$ 7,814
Resource Development and Management	87,633	-	87,633
Biofuel Initiatives	106,000	-	106,000
Costs of Marketing Oil	209,616	-	209,616
Oil Sands Sustainable Development Secretariat	3,161	-	3,161
Energy Regulation	229,627	-	229,627
Utilities Regulation	38,358	-	38,358
Carbon Capture and Storage	3,400	143,800	147,200
Orphan Well Abandonment	15,500	-	15,500
	$ 701,109	$ 143,800	$ 844,909
Net Operating Results	$ 8,914,120	$ (143,800)	$ 8,770,320
Capital Spending	$ 174,515	$ (143,800)	$ 30,715
Financial Transactions	$ 57,700	$ -	$ 57,700

MINISTRY OF ENERGY **Schedule 4**

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Allocated Costs

Year ended March 31, 2015

(in thousands)

	2015					2014
		Expenses Incurred by Others				
Program	**Expenses [1]**	**Accommodation Costs [2]**	**Legal Services**	**Business Services [3]**	**Total Expenses**	**Total Expenses**
Ministry Support Services	$ 7,585	$ 518	$ 1,624	$ -	$ 9,727	$ 7,978
Resource Development and Management	100,979	5,600	2,479	3,443	112,501	$ 118,559
Bioenergy Initiatives	70,275	43	-	-	70,318	$ 68,269
Costs of Marketing Oil	176,426	-	-	-	176,426	$ 173,622
Energy and Utilities Regulation [4]	256,827	-	-	-	256,827	$ 216,663
Utilities Regulation	33,741	-	-	-	33,741	$ 31,571
Carbon Capture and Storage	53,914	87	-	-	54,001	$ 116,115
Orphan Well Abandonment	15,760	-	-	-	15,760	$ 16,172
Oil Sands Sustainable Development Secretariat	817	36	-	-	853	$ 1,611
Settlements Related to the Land-Use Framework	4,123	-	-	-	4,123	$ 72,267
	$ 720,447	$ 6,284	$ 4,103	$ 3,443	$ 734,277	$ 822,827

(1) Expenses - Directly Incurred as per Statement of Operations.
(2) Costs shown for Accommodation are allocated by budgeted Full-Time Equivalent Employment.
(3) Costs shown for Business Service include charges for IT support, vehicles, air transportation, internal audit services and other services are allocated by costs in certain programs.
(4) As of November 30, 2013, the Ministry of Environment and Sustainable Resource Development (ESRD) has transferred responsibility of upstream oil, oil sands, natural gas and coal development in Alberta to the Alberta Energy Regulator (AER). As a result, the 2014 restatement included an additional $8.35 million to reflect the transfer of costs incurred by ESRD on the behalf of AER.

MINISTRY OF ENERGY Schedule 5

CONSOLIDATED SCHEDULES TO FINANCIAL STATEMENTS

Equity in Government Business Enterprise

Year ended March 31, 2015

(in thousands)

	2015	2014
Accumulated surpluses (deficit)		
Opening accumulated surplus - Alberta Petroleum Marketing Commission	$ 716	($ 627)
Revenues		
Marketing of Oil	7,681	6,315
Financing Transactions	12,738	-
Total revenue	20,419	6,315
Total expense	6,660	4,972
Net income for the year	13,759	1,343
Accumulated surpluses at end of year	$ 14,475	$ 716
Represented by		
Assets		
Cash and short-term investments	$ 5,919	$ 16,166
Due from the Department of Energy	3,346	-
Term Loan	237,738	-
Other assets	42,202	225,084
Total assets	289,205	241,250
Liabilities		
Accounts payable	13,443	24,212
Due to Government of Alberta	226,426	-
Due to the Department of Energy	34,861	216,322
Total liabilities	274,730	240,534
	$ 14,475	$ 716
Accumulated surpluses at end of year		
Alberta Petroleum Marketing Commission	14,475	716
Equity in commercial enterprises at end of year	$ 14,475	$ 716

COMMITMENTS *(in thousands)*

a) North West Redwater Partnership

On November 8th, 2012 the North West Redwater Partnership (the "Partnership") 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 the Partnership 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. The Partnership 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 fee-for-service toll comprised of operating, debt, equity, and incentive fee components on 37,500 barrels per day of bitumen (75% of the project's feedstock) for 30 years. The toll includes both flow through costs as well as costs of facility construction, the latter of which is estimated to be $8.5 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 debt component of the toll incurred to date. The term of the commitment begins upon the commencement of commercial operations, expected September 2017. No amounts have been paid under this agreement to date.

b) North West Redwater Partnership Monthly Toll Commitment

The Commission has used judgement 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 interest rates, estimates for factors including future operating costs, oil prices (West Texas Intermediate ["WTI"] and light/heavy differentials), refined product prices, gas prices and foreign exchange. The toll under the processing agreement, assuming a $8.5 billion facility capital cost, market interest rates and 2% operating cost inflation rate, is estimated to be:

Fiscal 2015-16	$ -
Fiscal 2016-17	$ 85,000
Fiscal 2017-18	$ 256,000
Fiscal 2018-19	$ 708,750
Fiscal 2019 -20	$ 827,000
Beyond Fiscal 2019-20	$ 24,133,250

c) Term Loan Provided To North West Redwater Partnership

As part of the Subordinated Debt Agreement with the Partnership, the Commission committed to loan up to $324 million over three years beginning in 2014. 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.

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.

(in thousands)

d) North West Redwater Partnership Processing Agreement Assessment

The Commission performs an annual assessment to determine if the North West Redwater Partnership Processing Agreement (the "Processing Agreement") gives rise to unavoidable costs of the obligations exceeding the economic benefits expected to be received. If such an assessment results in a negative net present value over the expected term of the contract, the Commission will recognize an expense on the statement of operations and a liability on the statement of financial position. The Commission uses a model to calculate the present value of future cash flows under the Processing Agreement. Variables used in the model 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 actual operating performance compared to capacity.

Technical inputs may be estimated with reasonable certainty for the operating plan; however revenues and costs that depend upon market prices are subject to the use of professional judgement in the estimates, particularly over long future time periods such as the 30 year Processing Agreement term. In order to perform the cash flow analysis the Commission 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 performed as at December 31, 2014, the Commission determined the present value of future cash flows under the Processing Agreement to be positive and has not recognized a liability.

e) Energy East Pipeline Project

The Commission has signed a Transportation Service Agreement (TSA) with Energy East Pipeline Limited Partnership to purchase firm capacity for a term of 20 years to transport volumes of crude oil. The construction of the pipeline is dependent upon obtaining regulatory approval. Under the take-or-pay obligation, the Commission has a minimum obligation to pay $3.4 billion in tolls over the 20 year term. Additional tolls will be incurred depending on the volumes transported through the pipeline. The pipeline is expected to be in service as early as 2018.

Fiscal 2015-16	$ -
Fiscal 2016-17	$ -
Fiscal 2017-18	$ 42,500
Fiscal 2018-19	$ 170,000
Fiscal 2019-20	$ 170,000
Beyond Fiscal 2019-20	$ 3,017,500

DEPARTMENT OF ENERGY

FINANCIAL STATEMENTS
For the year ended March 31, 2015

AUDITOR GENERAL Alberta

Independent Auditor's Report

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, 2015, and the statements of operations 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, 2015, and the results of its operations and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

June 3, 2015
Edmonton, Alberta

DEPARTMENT OF ENERGY

STATEMENT OF OPERATIONS

Year ended March 31, 2015

(in thousands)

	2015		2014
	Constructed Budget (Schedule 3)	Actual	Actual
Revenues (Schedule 1)			
Non-Renewable Resource Revenue	$ 9,209,000	$ 8,947,873	$ 9,578,070
Freehold Mineral Rights Tax	134,000	171,831	145,928
Other Revenue	500	18,458	24,415
	9,343,500	9,138,162	9,748,413
Expenses - Directly Incurred (Note 2(b) and Schedule 2)			
Ministry Support Services	7,814	7,585	7,129
Resource Development and Management	87,633	101,125	104,844
Bioenergy Initiatives	106,000	70,275	68,202
Cost of Marketing Oil	209,616	176,426	173,622
Oil Sands Sustainable Development Secretariat	3,161	817	1,527
Energy Regulation	19,800	19,800	36,300
Settlements Related to the Land-Use Framework	-	4,123	72,267
Carbon Capture and Storage	147,200	53,914	116,056
	581,224	434,065	579,947
Net Operating Results	$ 8,762,276	$ 8,704,097	$ 9,168,466

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

DEPARTMENT OF ENERGY

STATEMENT OF FINANCIAL POSITION

As at March 31, 2015

(in thousands)

		2015		2014
Assets				
Cash and Cash Equivalents (Note 3)	$	112,374	$	536,100
Accounts Receivable (Note 4)		204,880		1,338,999
Inventory (Note 5)		1,226		2,987
Tangible Capital Assets (Note 6)		30,635		34,483
	$	349,115	$	1,912,569
Liabilities				
Accounts Payable and Accrued Liabilities (Note 7)	$	344,848	$	196,152
Gas Royalty Deposits (Note 8)		247,777		260,016
Unearned Revenue		72,580		76,356
	$	665,205	$	532,524
Net Assets (Liabilities)				
Net Assets at Beginning of Year	$	1,380,045	$	564,879
Net Operating Results		8,704,097		9,168,466
Net Financing Provided for General Revenues		(10,400,232)		(8,353,300)
Net (Liabilities) Assets at End of Year	$	(316,090)	$	1,380,045
	$	349,115	$	1,912,569

Contingent Liabilities and Contractual Obligations (Notes 9 and 10)

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

DEPARTMENT OF ENERGY

STATEMENT OF CASH FLOWS

Year ended March 31, 2015

(in thousands)

	2015	2014
Operating Transactions		
Net Operating Results	$ 8,704,097	$ 9,168,466
Non-cash Items included in Net Operating Results		
Amortization (Note 6)	7,771	7,274
	8,711,868	9,175,740
Decrease (Increase) in Accounts Receivable	1,134,119	(375,783)
Decrease in Inventory	1,761	10,443
Increase (Decrease) in Accounts Payable and Accrued Liabilities	148,696	(67,302)
(Decrease) in Unearned/Deferred Revenue	(3,776)	(1,286)
Cash Provided by Operating Transactions	9,992,668	8,741,812
Capital Transactions		
Acquisition of Tangible Capital Assets (Note 6)	(3,974)	(6,305)
Proceeds from Disposal of Tangible Capital Assets (Note 6)	51	-
Cash (Applied to) Capital Transactions	(3,923)	(6,305)
Financing Transactions		
Net Financing Provided (for) General Revenues	(10,400,232)	(8,353,300)
(Decrease) in Gas Royalty Deposits	(12,239)	(77,451)
Cash (Applied to) Financing Transactions	(10,412,471)	(8,430,751)
Increase (Decrease) in Cash and Cash Equivalents	(423,726)	304,756
Cash and Cash Equivalents at Beginning of Year	536,100	231,344
Cash and Cash Equivalents at End of Year	$ 112,374	$ 536,100

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

NOTE 1 AUTHORITY

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

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND REPORTING PRACTICES

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

a) **Reporting Entity**

The reporting entity is the Department of Energy, which is part of the Ministry of Energy and for which the Minister of Energy is accountable. Other entities reporting to the Minister are the Alberta Petroleum Marketing Commission (APMC), the Alberta Energy Regulator (AER) and the Alberta Utilities Commission (AUC). The activities of these organizations are not included in these financial statements. The ministry annual report provides a more comprehensive accounting of the financial position and results of the ministry's operations for which the minister is accountable.

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.

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 recorded as unearned (deferred) 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 filling.

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.

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

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

Revenues (cont'd)

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.

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 are 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 and eligibility criteria, if any, are met.

Incurred by Others

Services contributed by other entities in support of the department operations are not recognized and are disclosed in Schedule 6 and allocated to programs in Schedule 7.

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 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.

Tangible capital assets of the department are recorded 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 in use.

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

Liabilities

Liabilities are recorded 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.

Net Assets/Net Liabilities

Net assets/net liabilities represent the difference between the carrying value of assets held by the department and its liabilities.

Canadian Public Sector Accounting Standards require a "net debt" presentation for the statement of financial position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as "net debt" or "net financial assets" as an indicator of the future revenues required to pay for past transactions and events. The department operates within the government reporting entity, and does not finance all its expenditures by independently raising revenues. Accordingly, these financial statements do not report a net debt indicator.

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, accounts payable and accrued liabilities, and gas royalty deposits are estimated to approximate their carrying values because of the short-term nature of these instruments.

Measurement Uncertainty
(in thousands)

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 recorded as $989,160, bitumen royalty recorded as $5,049,393, and crude oil royalty revenue recorded as $2,244,745 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. These costs and volumes could vary significantly from that 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, natural gas and by-products revenue could change by $175,000.

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.

NOTE 3 CASH AND CASH EQUIVALENTS

Cash consists of deposits in the Consolidated Cash Investment Trust Fund which is 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. As at March 31, 2015, securities held by the Fund have a time-weighted rate of return of 1.2% per annum (2014 - 1.2% per annum).

NOTE 4 ACCOUNTS RECEIVABLE

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

	2015			2014
	Gross Amount	Allowance for Doubtful Accounts	Net Realizable Value	Net Realizable Value
Royalties	$ 165,857	$ -	$ 165,857	$ 1,118,128
Due from APMC	34,861	-	34,861	216,322
Bioenergy Grant Recoveries	1,406	1,294	112	499
Alberta Energy Regulator	4,050	-	4,050	4,050
	$ 206,174	$ 1,294	$ 204,880	$ 1,338,999

NOTE 5 INVENTORY

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.

NOTE 6 TANGIBLE CAPITAL ASSETS

(in thousands)

	Equipment (1)	Computer Hardware and Software	Total
Estimated Useful Life	3-40 years	3-10 years	
Historical Cost (2)			
Beginning of Year	$ 26,788	$ 94,120	$ 120,908
Additions	1,186	2,788	3,974
Disposals, Including Write-downs	(183)	-	(183)
	$ 27,791	$ 96,908	$ 124,699

NOTE 6 TANGIBLE CAPITAL ASSETS (cont'd)
(in thousands)

	Equipment [1]	Computer Hardware and Software	Total
Accumulated Amortization			
Beginning of Year	$ 18,503	$ 67,922	$ 86,425
Amortization Expense	3,194	4,577	7,771
Effect of Disposals	(132)	-	(132)
	$ 21,565	$ 72,499	$ 94,064
Net Book Value at March 31, 2015	$ 6,226	$ 24,409	$ 30,635
Net Book Value at March 31, 2014	$ 8,285	$ 26,198	$ 34,483

(1) Equipment includes office equipment and furniture and other equipment.
(2) Historical cost includes work-in-progress at March 31, 2015 totaling $0 (2014 - $1,771) for computer software.

NOTE 7 ACCOUNTS PAYABLE AND ACCRUED LIABILITIES
(in thousands)

	2015	2014
Trade	$ 169,183	$ 133,160
Overpayments of Royalties	172,319	62,992
Due to APMC	3,346	-
	$ 344,848	$ 196,152

NOTE 8 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 9 CONTINGENT LIABILITIES

(in thousands)

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

Accruals have been made in specific instances where it is likely that losses will be incurred based on a reasonable estimate.

The department has been named in one claim (2014 - one) of which the outcome is not determinable. The claim has a specified amount of $7,000 (2014 - $15,000).

The department has been jointly named with other entities in seven claims (2014 restated - five). Five of these claims have specified amounts totaling $14,350,000 (2014 restated – four claims totaling $2,922,500) and two claims (2014 restated - one) with no amounts specified.

Of the total specified claims, two claims totaling $10,007,000 (2014 restated - two claims totaling $587,500) are partially or fully covered by the Alberta Risk Management Fund.

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

NOTE 10 CONTRACTUAL OBLIGATIONS

(in thousands)

As at March 31, 2015, the department had contractual obligations totaling $1,058,907 (2014 - $1,221,567).

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
2016	$ 390,706	$ 11,331	$ 402,037
2017	157,250	8,508	165,758
2018	59,290	149	59,439
2019	49,600	5	49,605
2020	49,600	5	49,605
Thereafter	332,460	3	332,463
	$ 1,038,906	$ 20,001	$ 1,058,907

NOTE 11 TRUST FUNDS UNDER ADMINISTRATION

(in thousands)

The department administers the Oil and Gas Conservation Trust which is a regulated fund 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, 2015, the funds in the Oil and Gas Conservation Trust was $4,463 (2014 - $4,364).

NOTE 12 BENEFIT PLANS

(in thousands)

The department participates in the multi-employer pension plans: Management Employees Pension Plan and Public Service Pension Plan and Supplementary Retirement Plan for Public Service Managers. The expense for these pension plans is equivalent to the annual contributions of $10,150 for the year ended March 31, 2015 (2014 - $9,710). Departments are not responsible for future funding of the plan deficit other than through contribution increases.

At December 31, 2014, the Management Employees Pension Plan reported a surplus of $75,805 (2013 - surplus of $50,457), the Public Service Pension Plan reported a deficiency of $803,299 (2013 - deficiency $1,254,678) and the Supplementary Retirement Plan for Public Service Managers reported a deficiency of $17,203 (2013 - deficiency of $12,384).

The department also participates in two multi-employer Long Term Disability Income Continuance Plans. At March 31, 2015, the Bargaining Unit Plan reported an actuarial surplus of $86,888 (2014 - surplus $75,200) and the Management, Opted Out and Excluded Plan an actuarial surplus of $32,343 (2014 - surplus $24,055). The expense for these two plans is limited to the employer's annual contributions for the year.

NOTE 13 ROYALTY REDUCTION PROGRAMS

(in thousands)

The department provides twelve 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, 2015, the royalties received under these programs were reduced by $1,441,451 (2014 - $1,191,501).

NOTE 14 BITUMEN CONSERVATION

(in thousands)

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 $26,374 (2014 - $43,266).

NOTE 15 APPROVAL OF FINANCIAL STATEMENTS

The financial statements were approved by the Senior Financial Officer and the Deputy Minister.

DEPARTMENT OF ENERGY **Schedule 1**

SCHEDULE TO FINANCIAL STATEMENTS

REVENUES

Year ended March 31, 2015

(in thousands)

	2015		2014
	Budget	Actual	Actual
Non-Renewable Resource Revenue (Note 13)			
Bitumen Royalty	$ 5,579,000	$ 5,049,393	$ 5,222,178
Crude Oil Royalty	2,019,000	2,244,745	2,475,992
Natural Gas and By-Products Royalty (Note 14)	823,000	989,160	1,102,999
Bonuses and Sales of Crown Leases	623,000	476,331	588,108
Rentals and Fees	153,000	172,489	172,719
Coal Royalty	12,000	15,755	16,074
	9,209,000	8,947,873	9,578,070
Freehold Mineral Rights Tax	134,000	171,831	145,928
Other Revenue	500	18,458	24,415
Total Revenue	$ 9,343,500	$ 9,138,162	$ 9,748,413

DEPARTMENT OF ENERGY **Schedule 2**

SCHEDULE TO FINANCIAL STATEMENTS

EXPENSES - DIRECTLY INCURRED DETAILED BY OBJECT

Year ended March 31, 2015

(in thousands)

	2015 Budget	2015 Actual	2014 Actual
Grants	$ 269,600	$ 142,343	$ 220,146
Salaries, Wages and Employee Benefits	82,895	83,715	80,823
Supplies and Services	222,776	196,665	197,698
Amortization of Tangible Capital Assets	6,588	7,771	7,274
Settlements Related to the Land-Use Framework	-	4,123	72,267
Other	120	67	2,483
Total Expenses before Recoveries	581,979	434,684	580,691
Less Recovery from Support Service Arrangements with Related Parties [1]	(755)	(619)	(744)
	$ 581,224	$ 434,065	$ 579,947

(1) The department provides financial services to the Department of Environment and Sustainable Resource Development. Costs incurred by the department for these services are recovered from the Department of Environment and Sustainable Resource Development.

DEPARTMENT OF ENERGY
SCHEDULE TO FINANCIAL STATEMENTS
BUDGET RECONCILIATION
Year ended March 31, 2015
(in thousands)

Schedule 3

	2014-15 Estimate	Adjustments to Conform to Accounting Policy	2014-15 Constructed Budget
Revenues			
Operational Revenue			
Non-Renewable Resource Revenue			
Bitumen Royalty	$ 5,579,000	$ -	$ 5,579,000
Crude Oil Royalty	2,019,000	-	2,019,000
Natural Gas and By-Products Royalty	823,000	-	823,000
Bonuses and Sales of Crown Leases	623,000	-	623,000
Rental and Fees	153,000	-	153,000
Coal Royalty	12,000	-	12,000
	9,209,000	-	9,209,000
Freehold Mineral Rights Tax	134,000	-	134,000
Other Revenue	500	-	500
	9,343,500	-	9,343,500
Expenses - Directly Incurred			
Operational Programs			
Ministry Support Services	7,814	-	7,814
Resource Development and Management	87,633	-	87,633
Bioenergy Initiatives	106,000	-	106,000
Cost of Marketing Oil	209,616	-	209,616
Oil Sands Sustainable Development Secretariat	3,161	-	3,161
Energy Regulation	19,800	-	19,800
Carbon Capture and Storage	3,400	143,800	147,200
	437,424	143,800	581,224
Net Operating Results	$ 8,906,076	$ (143,800)	$ 8,762,276
Capital Spending	$ 150,115	$ (143,800)	$ 6,315
Financial Transactions	$ 57,700	$ -	$ 57,700

DEPARTMENT OF ENERGY **Schedule 4**

SCHEDULE TO FINANCIAL STATEMENTS

LAPSE/ENCUMBRANCE

Year ended March 31, 2015

(in thousands)

	Voted Estimate (1)	Supplementary Estimate (2)	Adjusted Voted Estimate	Voted Actuals (3)	Unexpended (Over Expended)
Program - Operational					
Program - Ministry Support Services					
1.1 Minister's Office	$ 740	$ -	$ 740	$ 729	$ 11
1.2 Associate Minister's Office	250	-	250	-	250
1.3 Deputy Minister's Office	511	-	511	497	14
1.4 Communications	1,383	-	1,383	958	425
1.5 Corporate Service	4,930	-	4,930	5,401	(471)
	7,814	-	7,814	7,585	229
Program - Resource Development and Management					
2.1 Revenue Collection	45,703	-	45,703	44,316	1,387
2.2 Resource Development	35,307	-	35,307	45,946	(10,639)
	81,010	-	81,010	90,262	(9,252)
Program - Bioenergy Initiatives					
3 Bioenergy Initiatives	106,000	-	106,000	70,275	35,725
	106,000	-	106,000	70,275	35,725
Program - Cost of Selling Oil					
4 Cost of Marketing Oil	209,616	-	209,616	176,426	33,190
	209,616	-	209,616	176,426	33,190
Program - Energy Regulation					
5 Oil Sands Sustainable Development Secretariat	3,157	-	3,157	817	2,340
	3,157	-	3,157	817	2,340
Program - Energy Regulation					
6 Energy Regulation	19,800	-	19,800	19,800	-
	19,800	-	19,800	19,800	-
Total	$ 427,397	$ -	$ 427,397	$ 365,165	$ 62,232
Lapse/(Encumbrance)					$ 62,232
Program - Capital					
Program - Ministry Support Services	$ -	$ -	$ -	$ 127	$ (127)
Program - Resource Development and Management	6,315	-	6,315	3,847	2,468
Total	$ 6,315	$ -	$ 6,315	$ 3,974	$ 2,341
Lapse/(Encumbrance)					$ 2,341
Financial Transactions					
Settlements Related to the Land-Use Framework	$ -	$ 57,700	57,700	8,814	$ 48,886
Total	$ -	$ 57,700	$ 57,700	$ 8,814	$ 48,886
Lapse/(Encumbrance)					$ 48,886

(1) As per "Operational Vote by Program", "Voted Capital Vote by Program" and "Financial Transaction Vote by Program" page of 2014-15 Government Estimates.

(2) Per the Supplementary Supply Estimates approved on March 10, 2015.

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

DEPARTMENT OF ENERGY **Schedule 5**

SCHEDULE FOR FINANCIAL STATEMENTS

SALARY AND BENEFITS DISCLOSURE

Year ended March 31, 2015

(in thousands)

	2015				2014
	Base Salary [1]	Other Cash Benefits [2]	Other Non-cash Benefits [3]	Total	Total
Deputy Minister [4]	$ 280	$ -	$ 61	$ 341	$ 411
Executives					
Assistant Deputy Minister - Oil Sands and Energy Operations	181	-	47	228	302
Assistant Deputy Minister - Strategy [5]	196	-	49	245	251
Assistant Deputy Minister - Corporate Services	182	-	46	228	275
Assistant Deputy Minister - Electricity & Sustainable Energy [6]	182	-	47	229	232
Assistant Deputy Minister - Policy Management Office [5] [7]	98	-	25	123	118
Assistant Deputy Minister - Resource Development Policy [8]	174	-	45	219	250
Assistant Deputy Minister - Resource Revenue & Operations	196	-	32	228	250
Assistant Deputy Minister - Strategic Initiatives	196	-	50	246	251
Assistant Deputy Minister - Regulatory Enhancement Project [9]	-	-	-	-	269

Total salary and benefits relating to a position are disclosed.

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

(2) Other cash benefits include vacation payouts and lump sum payments. There were no vacation payouts or bonuses in 2015.

(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, car allowances, health spending account expense, and professional memberships and tuition fees.

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

(5) On July 2, 2014 the Deputy Minister announced an executive team shuffle of two individuals. The shuffle occurred between the positions of Assistant Deputy Minister - Strategy and Assistant Deputy Minister - Policy Management Office.

(6) This position was occupied by one individual and one acting for 6 weeks of the fiscal year.

(7) The incumbent's services are shared with the Department of Environment & Sustainable Resources Development which contributes its own share of the cost of salary and benefits. Only 50% of the full salary and benefits are disclosed in this Schedule.

(8) This position was occupied by one individual until February 16, 2015.

(9) This project ended in July 2013. This position no longer exists.

DEPARTMENT OF ENERGY **Schedule 6**
SCHEDULE TO FINANCIAL STATEMENTS
RELATED PARTY TRANSACTIONS
Year ended March 31, 2015
(in thousands)

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 in the Department.

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 recorded 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	
	2015	**2014**	**2015**	**2014**
Accounts Receivable	$ 38,911	$ 220,372	$ -	$ -
Accounts Payable	$ 3,346	$ -	$ -	$ -
Expenses - Directly Incurred				
Grants	19,800	36,300	-	105
Other services	145	75	3,203	1,360
	$ 19,945	$ 36,375	$ 3,203	$ 1,465
Contractual Obligations	$ -	$ -	$ -	$ -

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 recorded in the financial statements and are disclosed in Schedule 6.

	Entities in the Ministry		Other Entities	
	2015	**2014**	**2015**	**2014**
Expenses - Incurred by Others				
Accommodation	$ -	$ -	$ 6,284	$ 6,548
Legal	-	-	4,103	4,424
Business Services	-	-	4,082	3,877
	$ -	$ -	$ 14,469	$ 14,849

DEPARTMENT OF ENERGY **Schedule 7**

SCHEDULE TO FINANCIAL STATEMENTS

ALLOCATED COSTS

Year ended March 31, 2015

(in thousands)

	2015					2014
		Expenses -Incurred by Others				Total
Program	Expenses [1]	Accommodation Costs [2]	Legal Services [3]	Business Services [4]	Total Expenses	Expenses (Restated)
Ministry Support Services	$ 7,585	$ 518	$ 1,624	$ -	$ 9,727	$ 7,978
Resource Development and Management	101,125	5,600	2,479	4,082	113,286	118,634
Bioenergy Initiatives	70,275	43	-	-	70,318	68,269
Cost of Marketing Oil	176,426	-	-	-	176,426	173,622
Oil Sands Sustainable Development Secretariat	817	36	-	-	853	1,611
Carbon Capture and Storage	53,914	87	-	-	54,001	116,115
Settlements Related to the Land-Use Framework	4,123	-	-	-	4,123	72,267
Energy Regulation	19,800	-	-	-	19,800	36,300
	$ 434,065	$ 6,284	$ 4,103	$ 4,082	$ 448,534	$ 594,796

(1) Expenses - Directly Incurred as per 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, air transportation, internal audit services and other services are allocated by costs in certain programs.

ALBERTA ENERGY REGULATOR

FINANCIAL STATEMENTS
For the year ended March 31, 2015

Independent Auditor's Report

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, 2015, and the statements of operations 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, 2015, and the results of its operations, its remeasurement gains and losses, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

May 14, 2015
Edmonton, Alberta

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

	2015		2014
	Estimates (Schedule 3)	**Actual**	**Actual**
Revenues			
Industry levies and assessments	$ 222,268	$ 258,278	$ 181,668
Provincial grant	19,800	19,800	36,300
Information, services and fees	8,759	8,260	7,431
Investment	2,500	1,654	1,023
	253,327	287,992	226,422
Expenses			
Energy regulation (Schedule 1)	229,627	256,827	208,310
Orphan abandonment (Note 3)	15,500	15,760	16,172
	245,127	272,587	224,482
Annual operating surplus (Note 12)	$ 8,200	$ 15,405	$ 1,940

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

ALBERTA ENERGY REGULATOR
STATEMENT OF FINANCIAL POSITION
As at March 31
(in thousands)

	2015	2014
Assets		
Cash and cash equivalents (Note 4)	$ 54,040	$ 42,055
Security deposits (Note 6)	122,835	100,211
Accounts receivable	12,245	3,892
Prepaid expenses and other assets	10,353	9,660
Tangible capital assets (Note 7)	63,211	54,972
	$ 262,684	$ 210,790
Liabilities		
Accounts payable and accrued liabilities	$ 33,511	$ 21,582
Grant payable to Orphan Well Association	15,055	10,750
Security deposits (Note 6)	122,835	100,211
Deferred revenue (Note 9)	2,056	2,971
Deferred lease incentives (Note 10)	23,023	23,535
Pension obligations (Note 11)	2,349	3,291
	198,829	162,340
Net Assets		
Accumulated operating surplus (Note 12)	63,855	48,450
	63,855	48,450
	$ 262,684	$ 210,790

Contractual obligations (Note 13)

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

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

		2015		2014
Operating transactions				
Annual operating surplus	$	15,405	$	1,940
Non-cash items included in net operating results				
Amortization of tangible capital assets (Note 7)		11,836		12,045
Loss on disposal and write-down of tangible capital assets		779		-
Change in pension obligations		(942)		31
Amortization of deferred lease incentives (Note 10)		(1,430)		(1,370)
		25,648		12,646
(Increase) in accounts receivable		(8,353)		(412)
(Increase)/decrease in prepaid expenses and other assets		(693)		431
Increase in accounts payable and accrued liabilities		11,929		2,601
Increase in grant payable to Orphan Well Association		4,305		1,778
(Decrease)/increase in deferred revenue		(915)		1,486
Additions to deferred lease incentives (Note 10)		918		748
Cash provided by operating transactions		32,839		19,278
Capital transactions				
Acquisition of tangible capital assets (Note 7)		(20,854)		(13,870)
Cash applied to capital transactions		(20,854)		(13,870)
Increase in cash and cash equivalents		11,985		5,408
Cash and cash equivalents at beginning of year		42,055		36,647
Cash and cash equivalents at end of year	$	54,040	$	42,055

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

ALBERTA ENERGY REGULATOR
NOTES TO THE FINANCIAL STATEMENTS
March 31, 2015
(in thousands)

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 (REDA)* . The AER's mandate provides for the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes the conservation and management of water, the disposition and management of public lands and protection of the environment.

The AER was established on June 17, 2013 to supersede the Energy Resources Conservation Board (ERCB). The AER is responsible for the historic regulatory functions of the ERCB as well as certain functions of Alberta Environment and Sustainable Resource Development that relate to public lands, water and the environment.

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 recorded as deferred revenue.

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

Provincial grants, without terms for the use of the transfer, are recorded 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) 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 AER are limited to financial claims, such as advances to and receivables from other organizations.

Tangible capital assets are recorded at historical 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 - 5 years
Computer software - purchased	Straight line	4 - 5 years
Computer software - developed	Declining balance	5 years

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 expense in the Statement of Operations.

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

(d) Liabilities

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

(e) Net assets

Net assets represent the difference between the carrying value of assets held by the AER and its liabilities.

PSAS requires a “net debt” presentation for the Statement of Financial Position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as “net debt” or “net financial assets” as an indicator of the future revenues required to pay for past transactions and events. The AER operates within the government reporting entity, and does not finance all its expenditures by independently raising revenues. Accordingly, these financial statements do not report a net debt indicator.

(f) 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	Amortized cost and cost
Accounts receivable	Amortized cost
Security deposits	Amortized cost
Accounts payable and accrued liabilities	Cost
Grant payable to the Orphan Well Association	Cost

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, accounts payable and accrued liabilities, grant payable to the Orphan Well Association and security deposits are estimated to approximate their carrying values.

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.

(g) Pension

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.

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 8.3 years.

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

Defined contribution plan accounting is applied to the Government of Alberta multi-employer defined benefit pension plans as the AER has insufficient information to apply defined benefit plan accounting. The AER is not responsible for future funding of the plan deficit other than through contribution increases.

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

(h) 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.

(i) 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 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.

(j) Changes in accounting policy

Liability for contaminated sites

In June 2010, the Public Sector Accounting Board issued an accounting standard, Liability for contaminated sites, effective for fiscal years starting on or after April 1, 2014. Contaminated sites are a result of contamination being introduced into air, soil, water or sediment of chemical, organic, or radioactive material, or live organism that exceeds an environmental standard. The AER adopted this accounting standard retroactively as of April 1, 2014 but without restatement of prior period results. The adoption of the standard did not have an impact on the AER’s financial statements.

Note 3 Orphan 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 abandonment revenues (levy and application fees) to the Orphan Well Association. During the year ended March 31, 2015, the AER collected $15,000 (2014 - $15,242) in levies and $760 (2014 - $930) in application fees.

Note 4 Cash and cash equivalents

During 2015, the AER transferred its cash and cash equivalents from the Consolidated Cash Investment Trust Fund (the Fund) to a Premier Investment Account. The account earns interest calculated based on the average monthly cash balance. The funds are able to be withdrawn upon request. During the year ended March 31, 2015, the AER earned interest at the rate of 1.3%.

As at March 31, 2014, the Consolidated Cash Investment Trust Fund was comprised of high quality short-term and mid-term fixed income securities with a maximum term to maturity of three years and securities held by the Fund had a time-weighted return of 1.2% per annum. The Fund is managed by the Province of Alberta to provide interest income at competitive rates while maintaining maximum security and liquidity of depositors' principal.

(in thousands)

Note 5 Financial instruments

The AER has the following financial instruments: accounts receivable, accounts payable and accrued liabilities, grant payable to the Orphan Well Association and security deposits.

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. As at March 31, 2015, the amount of financial assets that were past due was not significant and there were no material uncollectible receivable balances.

Note 6 Security deposits

The AER encourages the timely and proper abandonment and reclamation of upstream wells, facilities, pipelines, mines, mine sites and oilfield waste management facilities by holding various forms of security. At March 31, 2015, the AER held $122,835 (2014 - $100,211) in cash and an additional $1,707,241 (2014 - $1,595,700) in letters of credit. The security, along with any interest earned, will be returned to the depositors upon meeting specified refund criteria.

Note 7 Tangible capital assets

	Land	Leasehold improvements	Furniture and equipment	Computer hardware and software	Total
Estimated useful life	Indefinite	Term of the lease	5-12 years	4-5 years	
Historical cost					
Beginning of year	$ 282	$ 28,593	$ 13,330	$ 115,154	$ 157,359
Additions	-	8,023	2,925	9,906	20,854
Disposals, including write-downs	-	(561)	(101)	(1,061)	(1,723)
	282	36,055	16,154	123,999	176,490
Accumulated amortization					
Beginning of year	$ -	$ 6,004	$ 8,291	$ 88,092	$ 102,387
Amortization expense	-	1,736	1,032	9,068	11,836
Disposals, including write-downs	-	-	(96)	(848)	(944)
	-	7,740	9,227	96,312	113,279
Net book value at March 31, 2015	$ 282	$ 28,315	$ 6,927	$ 27,687	$ 63,211
Net book value at March 31, 2014	$ 282	$ 22,589	$ 5,039	$ 27,062	$ 54,972

Historical cost includes work-in-progress at March 31, 2015 totaling $454 (March 31, 2014 - $2,122) comprised of: computer hardware and software $321 (March 31, 2014 - $1,507) and leasehold improvements $133 (March 31, 2014 - $615).

(in thousands)

Note 8 Revolving line of credit

During 2015, the AER entered into 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, 2015, the outstanding balance for the revolving line of credit was $nil.

Note 9 Deferred revenue

	2015	2014
Balance at beginning of year	$ 2,971	$ 1,485
Received during year	347	3,758
Less amounts recognized as revenue	(1,262)	(2,272)
Balance at end of year	$ 2,056	$ 2,971

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.

	2015			2014
	Leasehold improvement costs	Reduced rent benefits and rent-free periods	Total	Total
Balance at beginning of year	$ 19,275	$ 4,260	$ 23,535	$ 24,157
Additions during the year	237	681	918	748
Amortization	(1,181)	(249)	(1,430)	(1,370)
Balance at end of year	$ 18,331	$ 4,692	$ 23,023	$ 23,535

Note 11 Pension

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, 2015, the expense for these pension plans is equal to the contribution of $17,325 (2014 - $13,194). Pension expense recorded is comprised of employer contributions to the plans that are required for its employees during the year, which are calculated based on actuarially determined amounts that are expected to provide the plans' future benefits.

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.

The effective date of the most recent actuarial funding valuation for SEPP was December 31, 2013. The accrued benefit obligation as at March 31, 2015 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, 2016.

Pension plan assets are valued at market values. During the year ended March 31, 2015 the weighted average actual return on plan assets was 11.7% (9.2% in 2014).

(in thousands)

Note 11 Pension (continued)

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

	March 31, 2015	March 31, 2014
Accrued benefit obligations		
Discount rate	4.9%	5.3%
Rate of compensation increase	0% for 2016, 3.5% thereafter	3.8%
Long-term inflation rate	2.0%	2.3%

	2015	2014
Pension benefit costs for the year		
Discount rate	5.3%	5.0%
Expected rate of return on plan assets	5.3%	5.0%
Rate of compensation increase	3.8%	3.8%

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

	March 31, 2015	March 31, 2014
Market value of plan assets	$ 45,087	$ 37,859
Accrued benefit obligations	49,510	43,231
Plan (deficit)	(4,423)	(5,372)
Unamortized actuarial loss	2,074	2,081
Pension obligations	$ (2,349)	$ (3,291)

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

	2015	2014
Current period benefit cost	$ 3,625	$ 2,022
Interest cost	2,394	2,030
Expected return on plan assets	(2,110)	(1,786)
Amortization of actuarial losses	396	395
	$ 4,305	$ 2,661

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

	2015	2014
AER contribution	$ 5,247	$ 2,630
Employees' contribution	731	507
Benefits paid	3,350	3,024

(in thousands)

Note 11 Pension (continued)

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

	March 31, 2015	March 31, 2014
Equity securities	49.9%	49.4%
Debt securities	38.4%	39.0%
Other	11.7%	11.6%
	100.0%	100.0%

Note 12 Accumulated operating surplus

Accumulated operating surplus is comprised of the following:

	Investments in tangible capital assets [(a)]	Unrestricted net assets	Accumulated surplus
Balance at beginning of year	$ 35,697	$ 12,753	$ 48,450
Annual operating surplus	-	15,405	15,405
Net investment in capital assets	9,183	(9,183)	-
Balance at end of year	$ 44,880	$ 18,975	$ 63,855

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

Note 13 Contractual obligations

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:

2016	$ 21,271
2017	17,825
2018	16,762
2019	12,598
2020	11,590
2021 - 2086	118,940
	$ 198,986

(in thousands)

Note 14 Related party transactions

Related parties are those entities consolidated or accounted for on the modified equity basis in the Province of Alberta's financial statements.

The AER had the following transactions with related parties recorded 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		Other entities	
	2015	2014	2015	2014
Revenues				
Provincial grant	$ 19,875	$ 36,300	$ -	$ -
Information, services and fees	150	146	136	144
	$ 20,025	$ 36,446	$ 136	$ 144

	Entities in the Ministry		Other entities	
	2015	2014	2015	2014
Expenses				
Computer services	$ 2,122	$ 2,154	$ 1,167	$ 1,197
Buildings	-	-	600	553
Administrative	-	275	933	617
Consulting services	82	153	321	173
	$ 2,204	$ 2,582	$ 3,021	$ 2,540
Receivable from	$ 10	$ 86	$ 4	$ 15
Payable to	$ 4,460	$ 4,571	$ 669	$ 605

Note 15 Comparative figures

The AER was established on June 17, 2013 to supercede the ERCB. The 2014 comparative figures combine 77 days of ERCB operations from April 1, 2013 to June 16, 2013 with the balance of the fiscal year being those of the AER.

Note 16 Approval of financial statements

These financial statements were approved by the AER Board of Directors on May 14, 2015.

ALBERTA ENERGY REGULATOR **Schedule 1**

SCHEDULE TO THE FINANCIAL STATEMENTS

Energy Regulation Expenses

Year Ended March 31

(in thousands)

	2015	2014
Personnel	$ 178,510	$ 136,564
Consulting services	19,990	21,962
Buildings	18,016	14,660
Computer services	15,912	12,710
Amortization of tangible capital assets	11,836	12,045
Travel and transportation	5,582	5,076
Administrative	3,771	3,161
Abandonment and enforcement	1,258	1,024
Equipment rent and maintenance	1,173	1,108
Loss on disposal and write-down of tangible capital assets	779	-
	$ 256,827	$ 208,310

ALBERTA ENERGY REGULATOR **Schedule 2**

SCHEDULE TO THE FINANCIAL STATEMENTS

Salaries and Benefits Disclosure

Year Ended March 31

(in thousands)

	2015				2014 Restated [h]
Position	**Base salary [a]**	**Other cash benefits[b]**	**Other non-cash benefits [c]**	**Total [d]**	**Total[e]**
Board of Directors					
Chairman	$ 285	$ -	$ 6	$ 291	$ 255
Board Director 1	116	-	15	131	97
Board Director 2	112	-	17	129	96
Board Director 3	113	-	14	127	94
Board Director 4	115	-	4	119	100
Board Director 5	116	-	1	117	102
Board Director 6	107	-	1	108	92
Board Director 7 [f]	28	-	1	29	94
Executives					
President and Chief Executive Officer	527	77	106	710	558
Chief Hearing Commissioner[g]	209	7	45	261	212
Executive Vice-President, Corporate Services [h]	274	75	62	411	290
Executive Vice-President and General Counsel [h] [i]	274	76	68	418	305
Executive Vice-President, Operations [h] [i]	316	65	68	449	270
Executive Vice-President, Stakeholder & Government Relations[h]	274	93	65	432	260
Executive Vice-President, Strategy & Regulatory [h] [i]	274	69	71	414	304

(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, health and pension benefits, and vehicle and relocation allowances. The 2015 balances include 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, Alberta and AER pension plans, health benefits or payments made for professional memberships and tuition fees. If automobiles were provided, no amount is included in these figures.

(d) Salaries and benefits for the Board of Directors are presented in descending order.

(e) Total 2014 compensation reflects compensation earned by members of the Board of Directors and Executives appointed subsequent to June 16, 2013 as a result of the proclamation of REDA.

(f) The incumbent left the position effective June 26, 2014.

(g) This position was held by two individuals in the current period.

(h) The 2014 figures have been restated to include short term incentive payments made to Executive Vice-Presidents as other cash benefits in 2014. These short term incentive payments were approved on May 8, 2014. Restated figures for Executive Vice-Presidents are provided below:

	2014			
Position	**Base salary**	**Other cash benefits**	**Other non-cash benefits**	**Total**
Executive Vice-President, Corporate Services	195	30	65	290
Executive Vice-President and General Counsel	205	50	50	305
Executive Vice-President, Operations	192	34	44	270
Executive Vice-President, Stakeholder & Government Relations	166	38	56	260
Executive Vice-President, Strategy & Regulatory	206	49	49	304

SCHEDULE TO THE FINANCIAL STATEMENTS

Salaries and Benefits Disclosure

Year Ended March 31

(in thousands)

(i) 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.

	2015			2014
Position	**Current service cost**	**Prior service and other costs**	**Total**	**Total**
Executive Vice-President and General Counsel	$ 36	$ 6	$ 42	$ 29
Executive Vice-President, Operations [j]	51	1	52	-
Executive Vice-President, Strategy & Regulatory	24	16	40	34

(j) Pension expense is determined at the beginning of the fiscal period. As this employee became a member of the AER's pension plans on August 12, 2013 the estimated pension expense in fiscal 2014 was $nil.

Position	**Accrued obligation April 1, 2014**	**Changes in accrued obligation**	**Accrued obligation March 31, 2015**	**2014**
Executive Vice-President and General Counsel	$ 301	$ 102	$ 403	$ 301
Executive Vice-President, Operations [k]	44	81	125	44
Executive Vice-President, Strategy & Regulatory	869	239	1,108	869

(k) The accrued obligation at March 31, 2014 is an estimate only as the March 31, 2014 accounting disclosure is based on a December 31, 2012 valuation extrapolated to March 31, 2014.

ALBERTA ENERGY REGULATOR **Schedule 3**

SCHEDULE TO THE FINANCIAL STATEMENTS

Estimates

Year Ended March 31, 2015

(in thousands)

	Plan			
	Estimates[(a)]	**Changes**	**Authorized budget**	**Actual**
Revenues				
Industry levies and assessments	$ 222,268	$ 35,900	$ 258,168	$ 258,278
Provincial grant	19,800	-	19,800	19,800
Information, services and fees	8,759	-	8,759	8,260
Investment	2,500	-	2,500	1,654
	253,327	35,900	289,227	287,992
Expenses				
Energy regulation	229,627	34,600	264,227	256,827
Orphan abandonment	15,500	-	15,500	15,760
	245,127	34,600	279,727	272,587
Annual operating surplus	8,200	1,300	9,500	15,405
Capital				
Capital investment	22,900	1,300	24,200	20,854
Less: Amortization	(14,700)	-	(14,700)	(11,836)
Loss on disposal and write-down of tangible capital assets	-	-	-	(779)
Net capital investment	8,200	1,300	9,500	8,239
	$ -	$ -	$ -	$ 7,166

(a) Estimates are based on the AER Business Plan for the year ended March 31, 2015. The Estimates and Changes have been approved by the Treasury Board of the Government of Alberta as the Authorized budget.

ALBERTA UTILITIES COMMISSION

FINANCIAL STATEMENTS
For the year ended March 31, 2015

Independent Auditor's Report

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, 2015, and the statements of operations 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, 2015, and the results of its operations, its remeasurement gains and losses, and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

May 5, 2015
Edmonton, Alberta

ALBERTA UTILITIES COMMISSION
STATEMENT OF OPERATIONS
Year Ended March 31, 2015

	2015		2014
	Budget (Schedule 3)	Actual	Actual
	(in thousands)		
Revenues			
Administration fees	$ 37,658	$ 33,782	$ 33,300
Investment income	300	240	238
Professional services	100	92	207
	38,058	34,114	33,745
Expenses			
Utility regulation (Schedule 1)	38,358	33,810	31,639
Annual operating surplus (deficit)	$ (300)	$ 304	$ 2,106

Contractual obligations (Note 8)

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF FINANCIAL POSITION
As at March 31, 2015

	2015	2014
	------(*in thousands*)------	
Assets		
Cash and cash equivalents (Note 4)	$ 11,745	$ 12,231
Accounts receivable	174	322
Prepaid expenses	1,176	1,192
Capital assets (Note 5)	7,256	7,643
	$ 20,351	$ 21,388
Liabilities		
Accounts payable and accrued liabilities	$ 3,268	$ 4,566
Accrued pension liability (Note 6)	765	765
Deferred lease incentive	40	83
	4,073	5,414
Net Assets		
Accumulated operating surplus (Note 7)	16,278	15,974
	$ 20,351	$ 21,388

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

ALBERTA UTILITIES COMMISSION
STATEMENT OF CASH FLOWS
Year Ended March 31, 2015

	2015	2014
	-----------------------*(in thousands)*------------------------	
Operating transactions		
Annual operating surplus	$ 304	$ 2,106
Non-cash items		
Amortization of capital assets	1,428	1,242
Pension expense	802	717
Loss on write down and disposal of capital assets	1	264
Decrease in accounts receivable	148	76
Decrease (increase) in prepaid expenses	16	(14)
(Decrease) increase in accounts payable and accrued liabilities	(1,298)	119
	1,401	4,510
Capital transactions		
Acquisition of capital assets	(1,042)	(3,343)
	(1,042)	(3,343)
Financing transactions		
Pension obligations funded	(802)	(717)
Lease incentive paid	(43)	(44)
	(845)	(761)
(Decrease) increase in cash and cash equivalents	(486)	406
Cash and cash equivalents at beginning of year	12,231	11,825
Cash and cash equivalents at end of year	$ 11,745	$ 12,231

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

ALBERTA UTILITIES COMMISSION
NOTES TO THE FINANCIAL STATEMENTS
March 31, 2015
(in thousands of dollars)

Note 1 Authority

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

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. 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 9 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.

Capital assets
Capital assets of the AUC are recorded at historical cost and amortized using the following methods:

Computer software	Declining balance - 30 per cent per year
Furniture and equipment	Straight line - four to 40 years
Computer hardware	Straight line - four to five years
Leasehold improvements	Straight line - lease term

Contributed assets are recorded at their fair value. The threshold for capitalizing all capital assets is $1.5 unless they are included in certain capital asset pools.

Valuation of financial assets and liabilities
Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities are recorded at amortized cost. As the AUC does not carry any financial assets or liabilities at fair value and has no derivatives and no unsettled exchange gains or losses, a statement of remeasurement gains or losses is not included in these financial statements.

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

Deferred lease incentive

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

Net assets/net liabilities

Net assets/net liabilities represent the difference between the carrying value of assets held by the AUC and its liabilities.

Canadian public sector accounting standards require a “net debt” presentation for the statement of financial position in the summary financial statements of governments. Net debt presentation reports the difference between financial assets and liabilities as “net debt” or “net financial assets” as an indicator of the future revenues required to pay for past transactions and events. The AUC operates within the government reporting entity, and does not have the authority to independently raise revenue. Accordingly, these financial statements do not report a net debt indicator.

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 benefit obligations incorporate multiple assumptions. Actual results for amortization and accrued pension obligations may differ from reported values.

Pension

Accrued pension 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 length of service to the time of retirement.

For the purpose of calculating pension benefit liability and 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 the active employees, which is 6.5 years.

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.

Note 3 Accounting changes

PS 3260 liability for contaminated sites

In June 2010 the Public Sector Accounting Board issued this accounting standard effective for fiscal years starting on or after April 1, 2014. Contaminated sites are a result of contamination being introduced into air, soil, water, or sediment of a chemical, organic, or radioactive material, or live organism that exceeds an environmental standard. Management has reviewed this accounting standard and have concluded that the AUC does not have any liability for contaminated sites.

(in thousands of dollars)

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, 2015, securities held by the Fund have a time-weighted return of 1.2 per cent per annum (2014: 1.2 per cent).

Note 5 Capital assets

	March 31, 2015				March 31, 2014
	Furniture and equipment	Computer hardware and software	Leasehold improvement	Total	Total
Historical cost					
Beginning of year	$ 2,209	$ 13,866	$ 3,335	$ 19,410	$ 16,595
Additions	8	1,023	11	1,042	3,343
Disposals	(5)	(5,227)	-	(5,232)	(528)
	$ 2,212	$ 9,662	$ 3,346	$ 15,220	$ 19,410
Accumulated amortization					
Beginning of year	$ 848	$ 9,018	$ 1,901	$ 11,767	$ 10,789
Amortization expense	117	941	370	1,428	1,242
Disposal and write-down	(4)	(5,227)	-	(5,231)	(264)
	$ 961	$ 4,732	$ 2,271	$ 7,964	$ 11,767
Net book value at March 31, 2015	$ 1,251	$ 4,930	$ 1,075	$ 7,256	$ 7,643
Net book value at March 31, 2014	$ 1,361	$ 4,848	$ 1,434	$ 7,643	

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 $1,996 for the year ended March 31, 2015 (2014: $1,867). 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, 2013. The accrued benefit obligation as at March 31, 2015 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, 2016.

Pension plan assets are valued at market values. During the year ended March 31, 2015 the weighted average actual return on plan assets was 11.28 per cent (8.47 per cent in 2014).

(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, 2015	March 31, 2014
Accrued benefit obligations		
Discount rate	4.73%	5.00%
Rate of compensation increase	3.50%	3.75%
Long-term inflation rate	2.00%	2.25%

	2015	2014
Pension Benefit costs for the year		
Discount rate	5.00%	4.82%
Expected rate of return on plan assets	5.00%	4.82%
Rate of compensation increase	3.75%	3.75%

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

	March 31, 2015	March 31, 2014
Market value of plan assets	$ 8,092	$ 6,802
Accrued benefit obligations	9,384	8,141
Plan deficit	(1,292)	(1,339)
Unamortized actuarial loss	527	574
Accrued pension liability	$ (765)	$ (765)

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

	2015	2014
Current period benefit costs	$ 627	$ 574
Interest cost	427	372
Expected return on plan assets	(357)	(309)
Amortization of actuarial losses	105	80
	$ 802	$ 717

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

	2015	2014
AUC contribution	$ 802	$ 717
Employees' contribution	113	108
Benefits paid	420	458

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

	March 31, 2015	March 31, 2014
Equity securities	51.70%	52.41%
Debt securities	29.40%	29.44%
Other	18.90%	18.15%
	100.00%	100.00%

(in thousands of dollars)

Note 7 Accumulated operating surplus

Accumulated operating surplus is comprised of the following:

	Investments in capital assets	Unrestricted surplus	Total
Balance April 1, 2014	$ 7,643	$ 8,331	$ 15,974
Annual operating surplus	-	304	304
Net investment in capital assets	(387)	387	-
Balance March 31, 2015	$ 7,256	$ 9,022	$ 16,278

Note 8 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 operations and maintenance payments

	Total
2016	$ 3,592
2017	2,807
2018	2,606
2019	217
2020	-
Thereafter	-
	$ 9,222

Note 9 Related party transactions

For the year ended March 31, 2015 the AUC received and paid $302 (2014: $105) for services from other government of Alberta organizations. The AUC also received contributed services from other government of Alberta organizations with an estimated value of $9 (2014: $24). The value of these contributed services have not been recognized in the Statement of Operations. All transactions were in the normal course of operations and measured at the amount of consideration agreed to by the related parties.

Note 10 Approval of financial statements

These financial statements were approved by the Commission Members.

ALBERTA UTILITIES COMMISSION Schedule 1

UTILITY REGULATION EXPENSES - DETAILED BY OBJECT

Year Ended March 31, 2015

	2015		2014
	Budget	Actual	Actual
	(in thousands)		
Salaries, wages and employee benefits	$ 26,400	$ 22,851	$ 21,252
Supplies and services	10,158	9,530	8,881
Amortization of capital assets	1,800	1,428	1,242
Loss on disposal and write down of capital assets	-	1	264
	$ 38,358	$ 33,810	$ 31,639

ALBERTA UTILITIES COMMISSION Schedule 2

SALARIES AND BENEFITS DISCLOSURE

Year Ended March 31, 2015

	2015				2014
	Base Salary (1)	Other Cash Benefits (2)	Other Non-cash Benefits (3)	Total	Total
	(in thousands)				
Chair of the Commission	$ 340	$ 28	$ 111	$ 479	$ 491
Vice-Chair	214	50	16	280	272
Commission Member 1	192	20	55	267	251
Commission Member 2	192	7	62	261	254
Commission Member 3	192	43	14	249	242
Commission Member 4	192	39	14	245	243
Commission Member 5	192	42	8	242	233
Commission Member 6	192	29	14	235	255

(1) Includes pensionable base pay.

(2) Includes payments in lieu of vacation, health and pension benefits.

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

ALBERTA UTILITIES COMMISSION
AUTHORIZED BUDGET
Year Ended March 31, 2015

Schedule 3

	Plan			
	Budget (Estimate)	**Authorized Changes**	**Authorized Budget**	**Actual**
	(in thousands)			
Revenues				
Administration fees	$ 37,658	$ -	$ 37,658	$ 33,782
Investment income	300	-	300	240
Professional services	100	-	100	92
	38,058	-	38,058	34,114
Expenses				
Utility regulation	38,358	(790)	37,568	33,810
Net Capital Investment				
Capital investment	1,500	(140)	1,360	1,042
Less:				
Amortization	(1,800)	500	(1,300)	(1,428)
Loss on write down and disposal of capital assets	-	-	-	(1)
	(300)	360	60	(387)
	$ -	$ 430	$ 430	$ 691

Note:

The Budget is based on the AUC Business Plan for the year ended March 31, 2015. 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, 2014

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, 2014, and the statements of income and comprehensive income, changes in net 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, 2014, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Original signed by Merwan N. Saher, FCA
Auditor General

June 4, 2015
Edmonton, Alberta

Alberta Petroleum Marketing Commission

Statement of Financial Position
As at December 31
(thousands of Canadian dollars)

	2014	2013
Assets		
Cash and short term investments (Note 6)	$ 15,182	$ 15,062
Accounts receivable	153,558	206,668
Prepaid expenses	12	12
Intangible assets under development (Note 7)	1,271	-
Term loan (Note 8)	112,500	-
Accrued interest on term loan	7,627	-
	$ 290,150	$ 221,742
Liabilities		
Accounts payable (Note 9)	$ 43,054	$ 51,302
Due to the Department of Energy (Note 10)	123,545	169,708
Short term debt (Note 11)	112,500	-
Accrued interest on short term debt	844	-
	$ 279,943	$ 221,010
Net Assets	$ 10,207	$ 732
	$ 290,150	$ 221,742

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)

	2014	2013
Conventional crude oil marketing operations		
Marketing fee revenue (Note 14)	$ 7,678	$ 5,058
Finance income	219	189
	7,897	5,247
Expense		
Wages and benefits (Note 14)	4,181	3,039
Consulting	666	1,280
Software and maintenance (Note 14)	102	46
Dues and subscriptions	79	46
Travel	79	42
Telephone	19	18
Conferences	17	15
Directors' fees	16	-
Other	35	29
	5,194	4,515
Net income from conventional crude oil marketing operations	2,703	732
Sturgeon Refinery		
Finance income	7,627	-
Finance costs	(844)	-
Trust costs	(11)	-
Net income attributable to Sturgeon Refinery	6,772	-
Net income and comprehensive income	$ 9,475	$ 732

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)

	2014	2013
Operating activities		
Net income and comprehensive income	$ 9,475	$ 732
Non-cash items included in net income		
Accrued interest on term loan	(7,627)	-
Accrued interest on short term debt	844	-
Changes in non-cash working capital		
(Increase) decrease in accounts receivable	53,110	(48,972)
(Increase) decrease in prepaid expenses	-	(12)
Increase (decrease) in accounts payable	(8,248)	8,013
Increase (decrease) in due to Department of Energy	(46,163)	41,734
Net cash from operating activities	1,391	1,495
Investing activities		
Term loan	(112,500)	-
Intangible assets under development	(1,271)	-
Net cash used in investing activities	(113,771)	-
Financing activities		
Proceeds from issuance of short term debt	112,500	-
Net cash from financing activities	112,500	-
Increase in cash and short term investments	120	1,495
Cash and short term investments, beginning of year	15,062	13,567
Cash and short term investments, end of year	$ 15,182	$ 15,062

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)

	2014	2013
Net assets, beginning of year	$ 732	$ -
Net income and comprehensive income	9,475	732
Net assets, end of year	$ 10,207	$ 732

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. In July 2014 two outside directors were added to bring the total number of board members to five.

The Commission's mandate has been enhanced to include assisting in the development of new energy markets, transportation infrastructure and managing the implementation of Alberta's Bitumen Royalty In Kind (BRIK) policy. 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 Energy East Pipeline Project. The Commission has set up 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 4, 2015.

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 agreements with Nexen Marketing (Nexen) and 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 $1,554 is being held in a fiduciary capacity on behalf of the Department at December 31, 2014 ($2,629 as at December 31, 2013). 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 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 balance sheet 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.

(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 income statement and offsetting liability on the balance sheet.

(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 obtained for internal use are capitalized if it is probable that 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. Software under development is reviewed annually for impairment. 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, 2015 and have not been applied in preparing the Financial Statements for the year ended December 31, 2014. 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, 2017, with earlier 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.

(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 and does not anticipate that this standard will result in significant accounting changes.

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 Energy East 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 significant judgment in determining whether it is acting as a principal or 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 additional revenues, expenses and amounts to be transferred to the Department of $2,568,641, $184,085 and $2,384,556 respectively ($2,305,692 revenues, $171,572 expenses and $2,134,120 amounts to be transferred to the Department - 2013).

(c) NWRP – Significant Influence

In 2014 APMC lent $112.5 million to NWRP in the form of a term loan. NWRP is a general partnership formed by Canadian Natural Upgrading Limited, a wholly-owned subsidiary of Canadian Natural Resources Limited and by NWU LP, a limited partnership comprised of North West Upgrading Inc. as limited partner and 1726702 Alberta Ltd. (a wholly-owned subsidiary of North West Upgrading Inc.) as general partner. NWRP was formed under the Partnership Act (Alberta) pursuant to a partnership 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 estimated Facility Capital Cost of $8.5 billion. 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 a commercial operations date of September 2017.

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.

The Commission has exercised substantial judgement 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 Commission's financial statements, however will provide summarized NWRP financial information in these notes. See Note 8 for further details.

(in thousands of Canadian dollars unless otherwise stated)

(d) NWRP Monthly Toll Commitment

The Commission has used judgement 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 actual 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.

Note 6 Cash and Short term Investments

Cash and short term investments consist of a deposit in the Consolidated Cash Investment Trust Fund (the "Fund") which is managed by Treasury Board and Finance to provide competitive interest income while maintaining maximum 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, 2014, securities held by the Fund have a rate of return of 1.19% per annum (1.20% per annum – 2013). Due to the short term nature of Fund investments the carrying value approximates fair value.

Note 7 Intangible Assets under Development

	December 31, 2014
Balance beginning of year	$ -
Additions	1,271
Balance, end of year	$ 1,271

(in thousands of Canadian dollars unless otherwise stated)

Note 8 Term Loan

The Commission lent $112.5 million to NWRP as a term loan on April 9, 2014. 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, 2014. This information has been prepared in accordance with IFRS as issued by the IASB.

	NWRP (100% Interest)			
	2014		2013	
Current assets	$	132,235	$	43,270
Non-current assets	$	3,064,235	$	1,403,337
Current liabilities	$	453,475	$	131,660
Non-current liabilities	$	2,145,797	$	701,255
Partners' equity	$	597,198	$	613,692
Revenue	$	-	$	-
Net loss and comprehensive loss attributable to Partners	$	16,494	$	4,946

Non-current assets primarily consist of property plant and equipment, which includes: engineering; procurement activities; site construction costs; module fabrication; and other costs directly attributable to the project. Non-current liabilities chiefly comprise of senior secured long term notes, credit facilities (with both Canadian and U.S. dollar denominated debt) and subordinated debt.

The net loss and comprehensive loss attributable to Partners primarily contains foreign exchange losses and general and administrative costs.

Note 9 Accounts Payable

	December 31, 2014		December 31, 2013	
Trade Payables	$	22,651	$	27,555
GST		20,403		23,747
	$	43,054	$	51,302

(in thousands of Canadian dollars unless otherwise stated)

Note 10 Due to the Department of Energy

	December 31, 2014	December 31, 2013
Due to Department, beginning of year	$ 169,708	$ 127,974
Amount to be transferred	2,384,556	2,134,120
Amount remitted	(2,430,719)	(2,092,386)
Due to the Department, end of year	$ 123,545	$ 169,708

Note 11 Short Term Debt

On April 9, 2014 APMC borrowed monies from Treasury Board and Finance at 1.022% interest, with a due date of April 8, 2015. APMC's intention is to borrow additional short term funds from Treasury Board and Finance when these amounts come due and repay the aggregated amounts over 10 years starting the year after the Sturgeon Refinery start-up. The timing of APMC repaying this debt will match NWRP's repayment of the term loan to the Commission.

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, 2013.

(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 2013 and 2014, a 100 basis point change would have a nominal effect on net income.

There is interest rate risk related to the term loan issued April 9, 2014. APMC earns interest at a rate of prime plus 6%, compounded monthly. A 100 basis point change would have impacted 2014 net income by $870 thousand.

(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, 2014 and December 31, 2013. Any credit losses on accounts receivable would be passed on to the Department.

(in thousands of Canadian dollars unless otherwise stated)

APMC issued a term loan of $112.5 million to NWRP on April 9, 2014. NWRP is an investment grade counterparty. Bonds issued by NWRP received an A- 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 arrangements that 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.

	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	$ 258,806	$ 105,248	$ 153,558
Accounts payable	(153,881)	(110,827)	(43,054)
Net position, December 31, 2014	$ 104,925	$ (5,579)	$ 110,504
Accounts receivable	$ 355,530	$ 148,862	206,668
Accounts payable	(204,919)	(153,617)	(51,302)
Net position, December 31, 2013	$ 150,611	$ (4,755)	$ 155,366

(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. The Commission does not have any externally imposed restrictions on its capital. There has been no change in the Commission's capital management strategy.

(in thousands of Canadian dollars unless otherwise stated)

Note 13 Commitments

	2015	2016	2017	2018	2019	Beyond 2019
NWRP Tolls	$ -	$ -	$ 170,000	$ 684,000	$ 783,000	$ 24,373,000
Energy East Pipeline	$ -	$ -	$ -	$ 170,000	$ 170,000	$ 3,060,000

(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 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.

Under the processing agreement, the Commission is obligated to pay a monthly toll comprised of operating, debt, equity, and profit share components 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 $8.5 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 the commencement of commercial operations. No amounts have been paid under this agreement to date.

The nominal tolls under the processing agreement, assuming an $8.5 billion Facility Capital Cost, market interest rates and 2% operating cost inflation rate, are estimated above. No value has been ascribed to the anticipated refining profits available to APMC over the term of the agreement.

(b) Energy East Pipeline Project

The Commission has signed a Transportation Service Agreement (TSA) with Energy East Pipeline Limited Partnership to purchase 100,000 barrels per day of firm capacity for a term of 20 years to transport volumes of crude oil. The construction of the pipeline is dependent upon obtaining regulatory approval. Under the take-or-pay obligation, once required regulatory and commercial approvals are obtained, the Commission has a minimum obligation to pay $3.4 billion in tolls over the 20 year term. Additional tolls will be incurred depending on the volumes transported through the pipeline. The pipeline is expected to be in service as early as 2018.

(c) NWRP Term Loan

As part of the Subordinated Debt Agreement with NWRP, APMC is committed to loan additional amounts in 2015 of $112.5 million and in 2016 approximately $100 million. These amounts and the accrued interest will be repaid by NWRP beginning one year after commercial start-up of the Sturgeon Refinery. These amounts will be repaid straight line over ten years plus accrued interest.

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 (2014 $2,606, 2013 $2,011) and Software and maintenance (2014 $55, 2013 $0) within the Statement of Income and Comprehensive Income.

(in thousands of Canadian dollars unless otherwise stated)

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.

Note 15 Salaries and Benefit Disclosure

Key management personnel include the Commission's Chief Executive Officer, Executive Director Business Development and Director of Finance. The following amounts in the financial statements relating to board members and key management compensation in 2014 and 2013 are as follows:

	2014				2013
	Base Salary	Other Cash Benefits (3)	Other Non-cash Benefits (4)	Total	Total
Board Members (1)	$ -	$ 16	$ -	$ 16	$ -
Chief Executive Officer	$ 630	$ -	$ 5	$ 635	$ 635
Senior Management					
Executive Director, Business Development (2)	$ 445	$ -	$ 8	$ 453	$ 77
Director of Finance	$ 259	$ -	$ 8	$ 267	$ 262

(1) The Chairman of the Board (Deputy Minister, Department of Energy) and two directors (Assistant Deputy Ministers, Department of Energy) are unpaid. Two outside directors were hired in July, 2014. They receive an annual retainer and meeting fees.
(2) The Executive Director, Business Development began employment November 1, 2013.
(3) Other Cash Benefits for management are performance bonuses. In October, 2014 the employment agreements for all key management personnel were restructured to adjust salaries and eliminate eligibility for performance bonuses.
(4) Included in Other Non-cash benefits are employer contributions to Canada Pension Plan, Employment Insurance, reimbursement of parking and fitness facility membership costs.

Note 16 Subsequent Events

Term Loan to NWRP

On January 2, 2015 APMC issued an additional $112.5 million term loan to NWRP on the same terms and conditions as the term loan issued on April 9, 2014 (see Note 8).

Short Term Debt

On January 2, 2015 the Commission borrowed $112.5 million of short debt from Treasury Board and Finance at an effective interest rate of 1.087% due December 31, 2015.

On April 8, 2015 APMC replaced its short term debt, originally issued April 9, 2014, with new short debt of $113.65 million at 0.696% interest due April 6, 2016.

APMC's intention is to borrow additional short term funds when these amounts come due and repay the aggregated amount straight line over 10 years starting the year after the Sturgeon Refinery start-up.

Energy East Pipeline Project

TransCanada Corp announced April 2, 2015 that it is altering the scope of the Energy East Pipeline project and cancelling the plans for an export terminal at the Port of Cacouna. As a result of these changes the new expected in service date for the pipeline is 2020 and under the terms of the TSA APMC's toll commitments for firm service commence once the pipeline is in service.

POST-CLOSURE STEWARDSHIP FUND

FINANCIAL STATEMENTS
For the year ended March 31, 2015

Independent Auditor's Report

Statement of Operations

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Independent Auditor's Report

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, 2015 and the statement of operations 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, 2015, and the results of its operations and its cash flows for the year then ended in accordance with Canadian public sector accounting standards.

Original signed by Merwan N. Saher, FCA
Auditor General

June 3, 2015
Edmonton, Alberta

POST-CLOSURE STEWARDSHIP FUND

STATEMENT OF OPERATIONS

Year ended March 31, 2015

	2015	2014
Revenue	$ -	$ -
Expenses	-	-
Net Operating Results	$ -	$ -

STATEMENT OF FINANCIAL POSITION

As at March 31, 2015

	2015	2014
Assets	$ -	$ -
Liabilities	$ -	$ -
Net Assets	-	-
	$ -	$ -

The accompanying notes are part of these financial statements.

POST-CLOSURE STEWARDSHIP FUND
NOTES TO THE FINANCIAL STATEMENTS
March 31, 2015

Note 1 Authority and Purpose

The Post-Closure Stewardship Fund operates under the Mines and Minerals Act, chapter M-17.

The fund was established to address any long-term liabilities that may arise from approved projects. Approved projects would inject captured carbon dioxide into subsurface reservoirs for sequestration. No projects have been approved by the Minister of Energy. The fund will be financed by operators of approved projects. The funds would be used for ongoing monitoring costs and any required remediation costs incurred by the Province of Alberta.

The financial statements have nil balances as no projects have been approved by the Minister of Energy for operation.

Note 2 Financial Statement Presentation

A cash flow statement is not provided due to the limited nature of the fund's operations.

Note 3 Approval of Financial Statements

The financial statements were approved by the Deputy Minister and the Senior Financial Officer of the Department of Energy.

Statutory Report

Public Interest Disclosure Act

Section 32 of the *Public Interest Disclosure Act* requires the ministry to report annually on the following parts of the Act:

a. the number of disclosures by the designated officer of the Public Interest Disclosure Office, 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.

In 2014-15, there were no disclosures of wrongdoing filed with the Public Interest Disclosure Office for the ministry.

Other Information

For additional copies, please contact:

Finance and Administration
Business Planning and Performance
Alberta Department of Energy

14th Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6

Tel: 780-427-8050
To call toll free within Alberta, dial 310-0000 first.

The Ministry of Energy Annual Report 2014-2015 is available on the following website:
www.energy.alberta.ca/About_Us/1001.asp

Current information about the organizations that were part of the Ministry of Energy in 2014-2015 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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