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PEERING INTO ALBERTA'S DARKENING FUTURE: HOW OIL PRICES IMPACT ALBERTA'S ROYALTY REVENUES

Sarah Dobson

SUMMARY

The price of oil just keeps collapsing — and the fate of Alberta's revenues is buckling with it. Going into March 2015, it seemed as if prices might have finally found a bottom, somewhere between US$48 and US$52. By the second week of March, they began falling again, to the low forties. These are prices the Alberta government had not even ventured to fathom when first putting together its forecasts for the impact of falling oil prices on the province's finances. Come the fourth quarter of the Alberta government's 2014/15 fiscal year, the province's finances will begin to really feel the blow from the plunge in oil, as royalty payments dry up significantly. Come the 2015/16 fiscal year, the situation becomes even bleaker.

In fact, the current fiscal year will seem pleasant compared to the next one. Due to a stronger than expected first half of the year, actual bitumen and crude oil royalties collected in Alberta from April to September 2014 exceeded estimates by $1.3 billion. That will mitigate some of the damage that the continuing slide in prices will cause by the year's end, with the government's third quarter update showing expected year-end crude oil and bitumen royalty revenues falling short of the budget target by $549 million.

So severe has the fall in oil prices been that, in March 2015, the number of barrels of conventional oil that the government collects in royalties could plummet by up to 53,000 barrels from the 2014/15 budget forecast, declining to just 4,100 barrels per day. This suggests that prices may be nearing a point where royalty collection from conventional crude oil production is at risk of being virtually eliminated. Bitumen royalties are not faring much better. Relative to July 2014, per barrel royalties in February 2015 have potentially declined by 60 to 90 per cent.

All told, the combined effect of the changing exchange rate, lower prices, and the lower royalty rates that take effect in this low-price environment, will lead to a potential decline in crude oil and bitumen royalty revenues of 42 to 74 per cent in the 2015/16 fiscal year. This corresponds to a monetary decline of roughly $3.3 billion to $5.8 billion. If oil prices stay below US$45 per barrel, that decline will become even more severe.

The pain for Alberta revenues does not end there. The government will be facing additional losses in land sale revenues, natural gas royalties, and tax revenues.

Still, even the surprisingly strong revenues for the first half of the year suggest a serious problem with government forecasts. By the end of September, the government had collected $5.198 billion in crude oil and bitumen royalties, 33 per cent higher than originally forecast. That government estimates could be so far off the mark raises serious questions about the methods the province is using to forecast royalties. In a province so dependent on resource royalties for its revenues, adding the unpredictability of unreliable forecasting methods can only put its fiscal planning at that much greater risk of instability.

INTRODUCTION

Few individuals outside of the finance and energy industries and government were likely paying close attention to oil prices over the first half of 2014. The price of a barrel of West Texas Intermediate (WTI) crude on Jan. 2, 2014 was $95.14, a modest 1.1 per cent increase over the $93.14 starting price in 2013.[1] Over the first half of 2014, the price of WTI trended upwards (see Figure 1), reaching its 2014 high of $107.95 on June 20. What started as a slow slide through much of the summer of 2014 became a sharp decline towards the end of the year. On Dec. 31, 2014 the price of a barrel of WTI crude was $53.45, a drop of 50 per cent from the end of June and a price not observed since the financial market crisis of 2008 when oil prices bottomed out at just over $30 per barrel. With headlines about falling oil prices dominating the media and with gas prices dropping below $1.00 a litre in many Canadian cities, there were very few individuals who remained unaware of the fate of oil prices over the second half of 2014.

WTI is the North American benchmark for the price of crude oil produced in Canada.[2] As a result, it is the primary price used by the government of Alberta in its budget forecasts.[3] However, it is worthwhile to note that the fall in oil prices is a phenomenon being observed across all types of crude. The global crude oil benchmark, Brent, and the benchmark for Alberta bitumen production,[4] Western Canadian Select (WCS), have both followed similar paths over the course of 2014 (see Figure 1). Brent peaked at a price of $115.19 on June 19, 2014 and fell 52 per cent to a price of $55.27 on December 31. WCS displayed the largest percentage fall of 57 per cent, declining from a 2014 high of $87.08 on June 20 to $37.27 on December 31.

The impact of falling oil prices will be felt hard in Alberta. The province in 2015 will see its economic growth slow significantly, with some forecasters predicting a mild recession.[5] The most wide-reaching impact, however, will most likely be felt through the effect of falling oil prices on government revenues.

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1 For consistency, except where otherwise specified we report all oil prices and per-barrel costs in U.S. dollars.

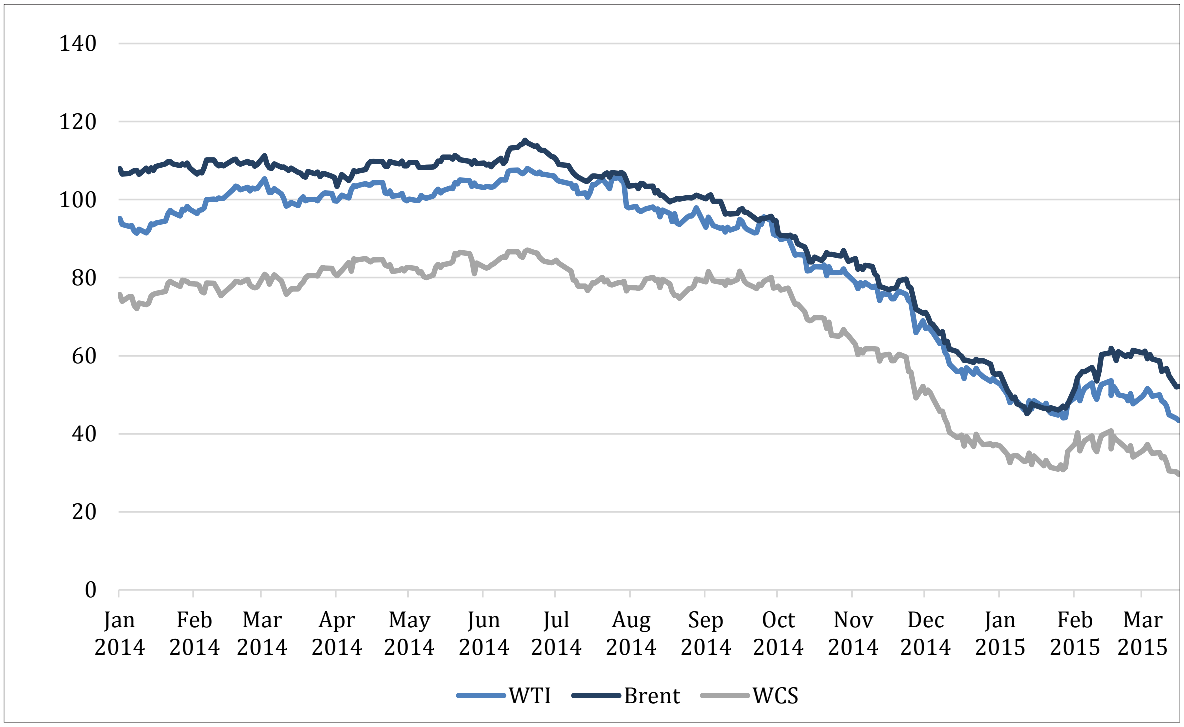
2 There are many different varieties of crude oil streams and blends, all with specific characteristics. Primarily they are classified by density (light/heavy) and sulphur content (sweet/sour). A benchmark price is a reference price that is used by buyers and sellers to determine the price for different crude oil varieties that are produced. A crude oil will be priced relative to the benchmark depending on its quality, transportation costs to move the product from production location to refinery, and other supply and demand conditions in the region in which it is produced. Source: Energy Information Administration, "Benchmarks play an important role in pricing crude oil," October 28, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=18571.

3 The other price used by the government of Alberta is the price of Western Canadian Select (WCS), which is expressed relative to WTI. For example, in the 2014/15 fiscal-year budget, the government of Alberta's WTI forecast was US$95.22 per barrel. The government assumed a WCS/WTI differential of 26 per cent, and an average annual exchange rate of 0.910 (USD/CAD), resulting in a WCS forecast of $77.18 (CAD) per barrel. The government also identifies an average Alberta wellhead price for light, medium and heavy crude, but this price is only referenced in the supporting Economic Outlook document. Source: Canada. Government of Alberta, *Budget 2014: Overview*, March 2014. http://www.finance.alberta.ca/publications/Budget/budget2014/fiscal-plan-overview.pdf; and Canada. Government of Alberta, *Budget 2014: Economic Outlook*, March 2014, http://finance.alberta.ca/publications/budget/budget2014/fiscal-plan-economic-outlook.pdf.

4 Bitumen is produced from the oil sands in northern Alberta. It is heavier, thicker and of a lower quality than most crude oils that are pumped from a well. It also costs more to refine into end consumer products. As a result, it sells at a lower price relative to other types of crude oil.

5 The Conference Board of Canada is currently predicting a contraction in Alberta's real GDP of 1.5 per cent in 2015, while CIBC is predicting a real GDP contraction of 0.3 per cent. Source: CIBC Economics, "Provincial Forecast Update" (February 6, 2015), http://research.cibcwm.com/economic_public/download/pffeb15.pdf; and Conference Board of Canada, "Provincial Outlook Executive Summary 2015" (February 23, 2015), http://www.conferenceboard.ca/e-library/abstract.aspx?did=6885.

FIGURE 1 **SPOT PRICE OF WEST TEXAS INTERMEDIATE (WTI) AND BRENT, CLOSING PRICE OF WCS: JAN. 1, 2014 TO MAR. 20, 2015**



Source: U.S. Energy Information Administration, "Petroleum & Other Liquids: Cushing, OK WTI Spot Price FOB and Europe Brent Spot Price FOB" and Daily Oil Bulletin, "Daily Reports, Selected Oil and Gas Prices."

Falling oil prices directly impact government revenues through bitumen and crude oil royalties, a significant revenue source for the government of Alberta. Over the last five completed fiscal years (2009/10 to 2013/14), bitumen and crude oil royalties have averaged $6.2 billion and contributed just under 16 per cent to government revenues on an annual basis. In its 2014/15 fiscal-year budget, the government was forecasting an annual average of $8.0 billion in bitumen and crude oil royalties over the next three fiscal years (2014/15 to 2016/17) and an increase in the annual share of bitumen and crude oil royalties to over 17 per cent of government revenues.

Falling oil prices will also indirectly impact government revenues through a decline in tax revenue and other non-renewable resource revenue, most notably the revenue from land-lease sales and natural gas royalties. These impacts are indirect as they are more strongly related to other economic consequences of the fall in oil prices. These include lower corporate revenues (particularly in the energy sector), slower economic growth, job losses and declining land values and natural gas prices.

Our objective in this report is to provide insight on the connection between oil prices and government revenues, with a primary focus on the direct impacts on bitumen and crude oil royalties. We start by providing a brief background on the price fall and an overview of its short-term impact in Alberta. We then move on to our focus on bitumen and crude oil royalties. We explain how royalties are calculated, and provide our estimates for the impact of falling oil prices on bitumen and crude oil royalties in the current and upcoming fiscal year. Lastly, using our estimates of bitumen and crude oil royalties, we attempt to unpack the government's estimates of total revenue shortfalls for the 2015/16 fiscal year by looking at the declines by revenue source.

Our estimates suggest the brunt of the price fall will not hit government revenues until the fourth quarter of the 2014/15 fiscal year. The current fiscal-year impact, however, is significantly mitigated by a strong first half of the year that saw both bitumen and crude oil royalties well exceed their targets. While the government is currently forecasting a combined shortfall in bitumen and crude oil royalties of $549 million[6] for the current fiscal year, we expect the shortfall may be even less, at around $300 million.

In the 2015/16 fiscal year, the effects are drastically different. In the 2014/15 budget, the government forecast a WTI price of $94.86, crude oil royalties of $1.852 billion and bitumen royalties of $5.982 billion for 2015/16.[7] With oil prices expected to average $30 to $50 below the government's forecast, our estimates suggest that crude oil royalties could decline by 47 to 78 per cent ($0.9 to $1.4 billion) and bitumen royalties by 41 to 73 per cent ($2.4 to $4.4 billion). These declines make up the majority of the total revenue shortfall that is expected as a result of low oil prices in the 2015/16 fiscal year.

As noted previously, bitumen and crude oil royalties are a significant revenue source for the provincial government.[8] A heavy reliance on royalties, which in turn rely on volatile crude oil prices, creates significant volatility in government revenues. The government recently announced a goal of restructuring the province's current economic model in order to reduce its reliance on resource revenues.[9] Previous papers from The School of Public Policy offer insights and recommendations on how this can be achieved.[10] Similar recommendations, however, are beyond the scope of this work. Rather, the main purpose of this paper is expository. We aim to explain how bitumen and crude oil royalties are calculated, and to offer estimates on how falling oil prices translate into reduced royalties. While we provide a detailed analysis below, we acknowledge from the outset that the accuracy of our estimates is limited by a lack of transparency in the government's assumptions and methods for forecasting royalties. Given the importance of bitumen and crude oil royalties as a revenue source to government, we believe the assumptions and methodology that inform the government's forecasts should be made more transparent in the budget and its supporting documents.

THE CURRENT STATE OF AFFAIRS

Oil is well known for its volatility, and a steep decline in its price is nothing new. The U.S. Energy Information Administration (EIA) provides daily tracking of the WTI price dating back to Jan. 3, 1986 — 28 years of data.[11] During this time, WTI has declined by nearly 50 per cent on five occasions. The steepest decline occurred during the 2008 recession when WTI fell nearly 80 per cent over the course of 120 business days (173 calendar days). The longest decline unfolded from November 1997 to December 1998, when WTI fell 49 per cent over 266 business days (391 calendar days).

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[6] Canada. Government of Alberta, *2014-15 Third Quarter Fiscal Update and Economic Statement*, February 2015, http://finance.alberta.ca/publications/budget/quarterly/2014/2014-15-3rd-Quarter-Fiscal-Update.pdf.

[7] Canada. Government of Alberta, *Budget 2014: Operational Plan*, March 2014, http://www.finance.alberta.ca/publications/budget/budget2014/fiscal-plan-operational-plan.pdf.

[8] Author calculations. Source: Canada. Government of Alberta, Fiscal Plan Tables for Budget 2014, Budget 2013, Budget 2012 and Budget 2011, http://finance.alberta.ca/publications/budget/index.html.

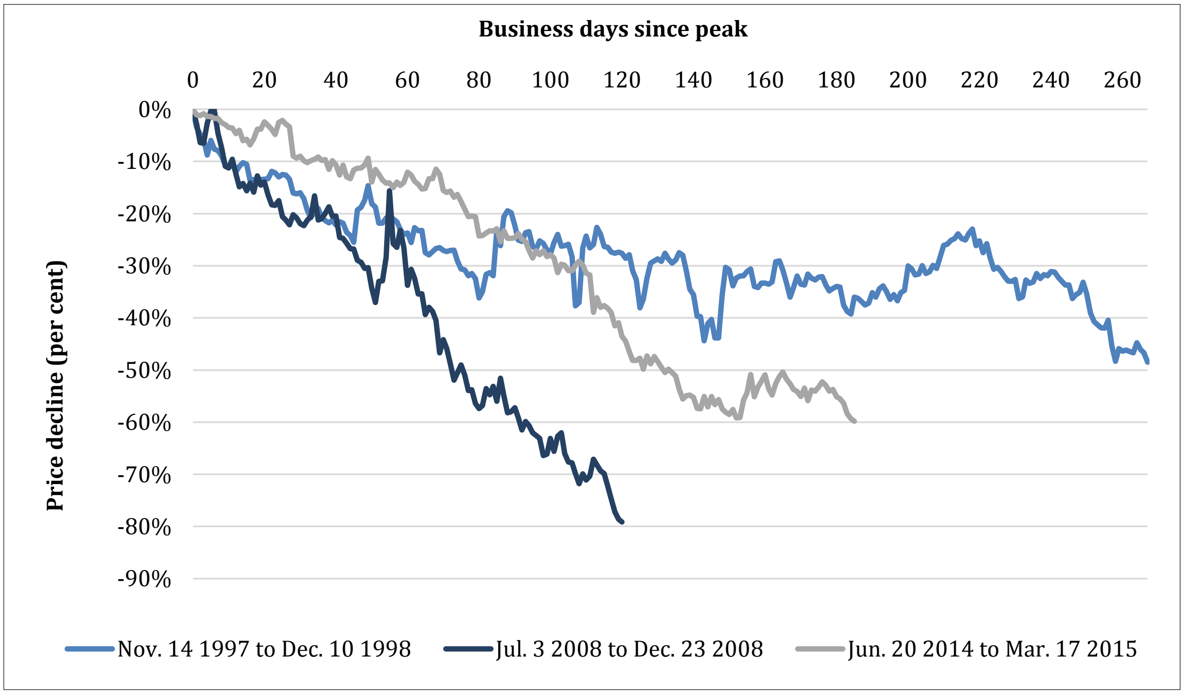
[9] Dean Bennett, "Alberta Premier Jim Prentice, cabinet to take pay reduction," *The Globe and Mail*, January 29, 2015, http://www.theglobeandmail.com/news/alberta/alberta-premier-jim-prentice-cabinet-to-take-pay-reduction/article22714099/.

[10] See for example: Ton van den Bremer and Rick van der Ploeg, "Digging Deep for the Heritage Fund: Why the Right Fund for Alberta Pays Dividends Long After Oil is Gone," University of Calgary School of Public Policy Research Paper 7, 32 (September 2014), http://www.policyschool.ucalgary.ca/?q=content/digging-deep-heritage-fund-why-right-fund-alberta-pays-dividends-long-after-oil-gone; and Philip Bazel and Jack Mintz, "Enhancing the Alberta Tax Advantage with a Harmonized Sales Tax," University of Calgary School of Public Policy Research Paper 6, 29 (September 2013), http://www.policyschool.ucalgary.ca/?q=content/enhancing-alberta-tax-advantage-harmonized-sales-tax.

[11] U.S. Energy Information Administration, "Petroleum & Other Liquids: Cushing, OK WTI Spot Price FOB," http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=D.

The current price fall reached a temporary low of $44.08 on Jan. 28, 2015. Driven in part by a sharp decline in drilling rig counts the price rallied through February, averaging $50.58. It started to drop again in March, however, as production declines have not been realized, inventories continue to rise and storage options are becoming more limited.[12] On Mar. 17, 2015 the WTI price reached a six-year low of $43.39, a fall of nearly 60 per cent from its high of $107.95 on Jun. 20, 2014. While the current price fall is not the absolute steepest and not yet the longest, it is the steepest for its current duration (from Jun. 20, 2014 to Mar. 17, 2015) of 186 business days (270 calendar days) (Figure 2).

FIGURE 2 COMPARISON OF WTI OIL PRICE DECLINES BY DURATION AND STEEPNESS: 1997/98, 2008 AND 2014/15



Source: U.S. Energy Information Administration, "Petroleum & Other Liquids: Cushing, OK WTI Spot Price FOB."

The primary contributing factors to the current decline can be tracked back to the basics of supply and demand — a rapid increase in global oil production that has been countered by only moderate growth in global demand. In the U.S. in particular, crude oil production has surged. Driven primarily by increased production in shale oil plays, weekly production estimates averaged over 8.5 million barrels a day in 2014, an increase of 14 per cent over the average 7.5 million barrels per day of production in 2013.[13] While final 2014 production numbers in Canada are not yet available, as of January 2015 the National Energy Board is estimating that Canadian production will have increased by 8.0 per cent, from 3.5 million barrels per day in 2013 to an estimated 3.8 million barrels per day in 2014.[14] This increase is driven in large part by the rapidly expanding oilsands sector; from 2013 to 2014, non-upgraded bitumen

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[12] Grant Smith and Moming Zhou, "Oil slumps to six-year low as U.S. production seen filling tanks," *The Globe and Mail*, March 16, 2015, http://www.theglobeandmail.com/report-on-business/international-business/oil-slumps-to-six-year-low-as-us-production-seen-filling-tanks/article23468077/.

[13] U.S. Energy Information Administration, "Petroleum & Other Liquids: Weekly U.S. Field Production of Crude Oil," http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WCRFPUS2&f=W.

[14] Author calculations. Source: Canada. National Energy Board, "Estimated Production of Canadian Crude Oil and Equivalents," https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/stmtdprdctn-eng.html; and Canada. National Energy Board, "ARCHIVED - Estimated Production of Canadian Crude Oil and Equivalent," https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/archive/stmtdprdctnrchv-eng.html.

production is expected to increase by 20 per cent, from 1.01 to 1.21 million barrels per day.[15] Upgraded bitumen production increased by only 2.5 per cent (23,000 barrels per day)[16] as it is constrained by available upgrader capacity, which increased by only 17,000 barrels per day in 2014.[17,18]

The growth in global oil production is more modest — current estimates show 2014 production averaged 93.3 million barrels of oil per day, an increase of 2.1 per cent over the 91.4 million barrel per day average of 2013.[19] However, more significantly, it is growing at over twice the pace of demand, which increased by only 0.8 per cent from 2013 to 2014.[20] Furthermore, the International Energy Agency (IEA) reports that, as of the first quarter of 2014, world oil production is exceeding world oil demand.[21]

In recent history, a falling price of oil has typically been backstopped by a production decline from the Organization for Petroleum Exporting Countries (OPEC). Since June, however, OPEC production has remained relatively steady, hovering close to its production target of 30 million barrels of oil per day. Following its most recent production meeting on Nov. 27, 2014, OPEC announced it would be maintaining its current production level, leading to the largest one-day drop in the price of WTI — a $7.76 decline — in nearly six years.

OPEC's resistance to cutting production has many observers comparing the current oil price decline to the final stage of the oil price crash of the 1980s. Through the early 1980s, OPEC made a series of production cuts in a failed attempt to support a falling world price.[22] In early 1986, OPEC's strategy reversed. In an attempt to regain market share it started to expand production again and prices plummeted, hitting an average monthly low of $11 per barrel in July 1986. A slow recovery started in late 1986 but, when measured in real dollars,[23] it would be 20 years later (in 2005) before the oil price returned to 1985 levels of $27 per barrel.[24]

This time around OPEC has essentially committed to maintaining its production share from the start of the price fall, leading to speculation that oil prices are unlikely to recover to their recent highs anytime soon.[25] Rather, current expectations are that real prices will likely settle below $100 per barrel in the

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15 Author calculations. Source: ibid.

16 Author calculations. Source: ibid.

17 Author calculations. Source: Junewarren-Nickels, "Alberta Oil Sands Industry Quarterly Update: Winter 2015," 2015, http://albertacanada.com/business/statistics/oil-sands-quarterly.aspx.

18 Upgraded bitumen is bitumen that has been converted into synthetic crude oil either through the removal of carbon (coking) or the addition of hydrogen (hydroconversion) at upgrader plants in Alberta before being refined into an end-consumer product. Non-upgraded bitumen is shipped to refineries as a blended bitumen product. The bitumen is typically blended with diluent (a diluting agent such as condensate or sweet crude) for ease of transport, but the chemical structure of the bitumen is not changed. Source: Junewarren-Nickels, "Alberta Oil."

19 International Energy Agency, "Oil Market Report: World Oil Supply and Demand" (February 2015), https://www.iea.org/media/omrreports/tables/2015-02-10.pdf.

20 ibid.

21 ibid.

22 In early 1981, oil prices reached a high of just under $40 per barrel. As high prices weakened demand and accelerated non-OPEC production the price dropped steadily over the next five years, falling to a price that hovered around $27 per barrel for most of 1985. Over this same period, OPEC steadily cut its production — decreasing output from an average 26 million barrels per day in 1980 to 16 million barrels per day in 1985, and dropping its global market share over the same period from over 40 per cent to under 30.

23 Real dollars are dollars that have been adjusted to remove the impact of inflation.

24 U.S. Energy Information Administration, "Short-Term Energy Outlook: Real Prices Viewer," http://www.eia.gov/forecasts/steo/realprices/.

25 David Sheppard, "Oil to stay lower for longer; Chinese demand growth to slow — Goldman," Reuters, January 27, 2015, http://www.reuters.com/article/2015/01/27/us-oil-goldman-currie-idUSKBN0L024220150127.

medium to long term (2016 and beyond).[26,27] Analysts are noting that the price in recent years has been a test of the market — one that reveals that $100 oil makes viable virtually all sources of high-cost production and leads to too much global supply relative to global demand.[28]

Not surprisingly there is division on where the price of oil will go in the short term. In mid-fall 2014, a price as low as $65 per barrel was being predicted.[29,30] The WTI price hit this level in early December and some experts are now predicting the price could fall as low as $20 or $30.[31,32] Projections of the average annual oil price for 2015 are similarly varied, although like the "bottom-out" price, they have been trending downwards with the oil price. This is most evident in the EIA projections that are updated every month. In October 2014 the EIA was forecasting an average price of $94.58 a barrel for 2015.[33] That projection dropped to $77.75 per barrel in November 2014, $62.75 in December 2014 and $54.58 in January 2015. With the small price recovery recently observed in early February, the EIA's price projection for 2015 stabilized in its February 2015 outlook, increasingly slightly to $55.02.[34] The March 2015 outlook, however, brought another decline to $52.15.[35] The EIA is currently projecting prices will bottom out in the second quarter of 2015, before starting a slow climb back up over the remainder of the year.[36] Other recent forecasts for 2015 have similarly been cut, with the most optimistic forecast tending to put prices in the mid- to high-fifties range.[37,38] In early March 2015, the government of Alberta's current forecast for 2015 was a WTI price of $55.11.[39]

THE IMMEDIATE ALBERTA IMPACT

One area in which analysts are in agreement is that the falling price of oil is unlikely to significantly affect current production levels. We define the breakeven price of ongoing production as the price a

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26 Mark Shenk and Grant Smith, "Oil heads for bear market as supply pushes price to six-year low," *The Globe and Mail*, March 17, 2015. http://www.theglobeandmail.com/report-on-business/international-business/oil-heads-for-bear-market-as-supply-pushes-price-to-six-year-low/article23493362/.

27 Michael Wittner, "Oil Price Collapse 2015: Where Do Prices Bottom Out?" (Presentation to the Conference Board of Canada Oil and Gas Summit, Societe Generale, January 20, 2015), http://www.conferenceboard.ca/Libraries/CONF_PRES_PUBLIC/15-0095_presentationp1_wittner.sflb.

28 ibid.

29 BNN, "Oil prices haven't hit rock bottom, could hit $65: Trader," November 4, 2014, http://www.bnn.ca/News/2014/11/4/Oil-prices-havent-hit-bottom-could-hit-65-Trader.aspx.

30 Derek Thompson, "It's Coming: $65 Oil," *The Atlantic*, October 28, 2014, http://www.theatlantic.com/business/archive/2014/10/its-coming-65-oil/382025/.

31 Kyle Bakx, "Calgary oil analyst offers dim outlook for 2015," CBC News, January 20, 2015, http://www.cbc.ca/news/business/calgary-oil-analyst-offers-dim-outlook-for-2015-1.2919669.

32 Bloomberg News, "Oil prices could plunge to $20 and this might be 'the end of OPEC': Citigroup," *Financial Post*, February 9, 2015, http://business.financialpost.com/2015/02/09/oil-could-plunge-to-20-and-this-might-be-the-end-of-opec-citigroup/?__lsa=0949-9f9b.

33 U.S. Energy Information Administration, *Short-Term Energy Outlook (STEO)* (October 2014), http://www.eia.gov/forecasts/steo/archives/Oct14.pdf.

34 U.S. Energy Information Administration, *Short-Term Energy Outlook (STEO) Archives* (October 2014, November 2014, December 2015, January 2015 and February 2015), http://www.eia.gov/forecasts/steo/outlook.cfm.

35 U.S. Energy Information Administration, *Short-Term Energy Outlook (STEO),* (March 2015), http://www.eia.gov/forecasts/steo/archives/Mar15.pdf

36 ibid.

37 Bakx, "Calgary oil."

38 Scotiabank, "Global Forecast Update," February 26, 2015, http://www.gbm.scotiabank.com/English/bns_econ/forecast.pdf.

39 Canada. Alberta. Alberta Energy, *Oil Sands Monthly Royalty Rates Information, Production Month: February 2015*, March 2015, http://www.energy.alberta.ca/OilSands/pdfs/MonthlyRoyaltyRatesReport_February2015.pdf..

company must receive per barrel of production in order to recover its ongoing costs and continue with operations. Recent reports from BMO Capital Markets and TD Securities estimate the WTI breakeven price of production from in situ[40] and mining[41] projects in the ranges of $16 to $51 and $34 to $54 per barrel respectively.[42,43] While WTI prices have hovered close to the upper end of these ranges for much of the first quarter of 2015, a decision to stop production must also consider fixed costs associated with shutting down and restarting an oilsands project, as well as the negative impact that a temporary shutdown could have on the productivity of a reservoir.[44] In a February 2015 interview with Bloomberg News, the Canadian Energy Research Institute suggested prices would have to fall to between $30 and $35 per barrel, and remain there for six months before production is stopped.[45]

Despite the expectation that current production levels will continue, Alberta will feel a significant short-term impact of the price drop through declining royalty payments to the provincial government. Royalty payments account for a significant portion of Alberta's budget every year. In the 2013/14 fiscal year, bitumen royalties were equal to $5.2 billion and crude oil royalties were equal to $2.5 billion. At a combined total of $7.7 billion they accounted for 17 per cent of the provincial government's total revenues in 2013/14.[46] When the budget for 2014/15 was released in March 2014, the government was forecasting crude oil and bitumen royalties of $7.6 billion for the current fiscal year and $7.8 billion for 2015/16.[47]

Due to a stronger than expected first half of the year (actual bitumen and crude oil royalties exceeded estimates by nearly $1.3 billion), when the government released its second-quarter update in November 2014 it still expected to exceed its combined bitumen and crude oil royalty target for the year. However, that was based on an updated WTI price forecast for the 2014/15 fiscal year of $88.88 per barrel.[48] Since then, oil prices have continued their downward slide. When the third-quarter update was released in February 2015, the government had revised its WTI price forecast for the fiscal year down to $79.24 per barrel. It also no longer expected to meet its royalty target. Rather, crude oil and bitumen royalties are forecast to fall short of the budget target by $549 million.[49]

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40 In situ projects extract deep underground oil sands deposits that are greater than 75 metres from the surface. In situ recovery uses drilling methods that pump bitumen to the surface after being heated underground with steam or through cold extraction technology. Source: Canada. Government of Alberta, *Oil Sands: The Resource* (2013), http://oilsands.alberta.ca/FactSheets/Resource_FSht_Sep_2013_Online.pdf.

41 Mining projects extract oil sands deposits that are less than 75 metres from the surface. Shovels extract the oil sand and then trucks move it to a cleaning facility where the bitumen is separated from the sand. Source: Canada. Government of Alberta, *Oil Sands*.

42 The TD Securities calculation assumes a WTI price of $50 and an exchange rate of 0.81 (USD/CAD). The breakeven price includes operating costs, royalties, transportation costs, sustaining capital costs, the cost of diluent and product differentials. Sustaining capital costs refer to costs related to capital repair, maintenance and replacement that are incurred by a firm on an ongoing basis to sustain its capital stock. Source: Menno Hulshof, Tyler Irving and Jin Yan, *Oil Sands Breakeven WTI Oil Prices: We're close…and in Some Cases Already There* (TD Securities, January 28, 2015).

43 The BMO Capital Markets calculation assumes an average WTI/WCS differential of 22 per cent in 2015 and an exchange rate of 0.85 (USD/CAD). The breakeven price includes all operating cash costs, the cost of diluent and product differentials. Source: Randy Ollenberger and Jared Dziuba, *Oil & Gas: E&P – Canada* (BMO Capital Markets, February 2, 2015).

44 Menno Hulshof et al., *Oil Sands*.

45 Robert Tuttle, "Canadian Oil Sands Output Growth Defies Plunge in Prices: Energy," Bloomberg News, February 19, 2015, http://www.bloomberg.com/news/articles/2015-02-20/canadian-oil-sands-output-growth-defies-plunge-in-prices-energy.

46 Canada. Government of Alberta, *Budget 2014: 2014-15 Second Quarter Fiscal Update and Economic Statement,* November 2014, http://www.finance.alberta.ca/publications/budget/quarterly/2014/2014-15-2nd-Quarter-Fiscal-Update.pdf.

47 Canada. Government of Alberta, *Budget 2014, Fiscal Plan Tables*, March 2014, http://finance.alberta.ca/publications/budget/budget2014/fiscal-plan-tables.pdf.

48 Alberta Finance, *2014-15 Second Quarter.*

49 Alberta Finance, *2014-15 Third Quarter.*

Looking further ahead, Premier Jim Prentice has announced that oil prices of $65 a barrel in 2015 will drop projected resource revenue by $6 to $7 billion.[50] If prices stay below $50 then the expected drop in revenue will be $10 billion.[51] This would come from a decrease in royalties as well as a fall in taxes, natural gas royalties and land-lease revenue. With current annual government revenues hovering around $45 billion, these scenarios represent significant revenue declines of 15 to 22 per cent, leading Premier Prentice to term the current financial situation in Alberta the "most serious" in 25 or even 50 years.[52]

For our immediate purposes, we focus on the impact of the fall in oil prices on bitumen and crude oil royalty payments. The primary reason the Alberta government is seeing significant declines in royalty payments, even as short-term production remains relatively unchanged, is that the royalty payment for both bitumen and crude oil is doubly tied to the price of oil. First, in Alberta's royalty regime, as the price of oil falls companies pay a lower royalty rate. Second, the value of the royalty payments that companies continue to pay is reduced by the lower price. In the sections that follow we consider the specific impact of falling royalty payments from both crude oil wells and bitumen projects.

CONVENTIONAL CRUDE OIL ROYALTIES

Crude oil companies pay royalties in accordance with the Petroleum Regulatory Regime, 2009 (AR 222/2008). Royalty rates for conventional[53] crude oil are well-specific and are applied to all production that is owned by the Crown (referred to as Crown production).[54] The royalty rate for a specific well varies between zero and a maximum value of 40 per cent, and is equal to the sum of two components: a quantity component that varies from -28 per cent to 30 per cent, and a price component that varies from -4 per cent to 35 per cent.[55]

The quantity component of the royalty rate is determined by the average productivity of the well. The price component is determined by the category-specific "par price" of the crude oil produced by the well — the average sale price minus transportation costs and quality adjustment. The par price is set monthly by the government of Alberta for four categories of crude oil: light, medium, heavy and ultra-heavy. The royalty rate a company pays increases with both the price of oil and the quantity of oil being produced from a well. For conventional oil, the royalty is paid entirely in kind — that is, the Alberta government receives a share of crude oil production (determined by the royalty rate) in lieu of cash payments.[56] The Alberta Petroleum Marketing Commission is then responsible for marketing the government's share of crude oil production.

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50 CBC News, "Alberta now facing $500M deficit due to dropping oil prices," January 8, 2015, http://www.cbc.ca/news/canada/edmonton/alberta-now-facing-500m-deficit-due-to-dropping-oil-prices-1.2894583.

51 CBC News, "Alberta finances the worst in 25, even 50 years, premier says," January 9, 2015, http://www.cbc.ca/news/canada/edmonton/alberta-finances-the-worst-in-25-even-50-years-premier-says-1.2895912.

52 CBC News, "Alberta finances."

53 The Alberta government defines "conventional" crude oil as crude oil produced by drilling wells. Source: Canada. Alberta. Alberta Energy website, "What is Oil," http://www.energy.alberta.ca/Oil/765.asp.

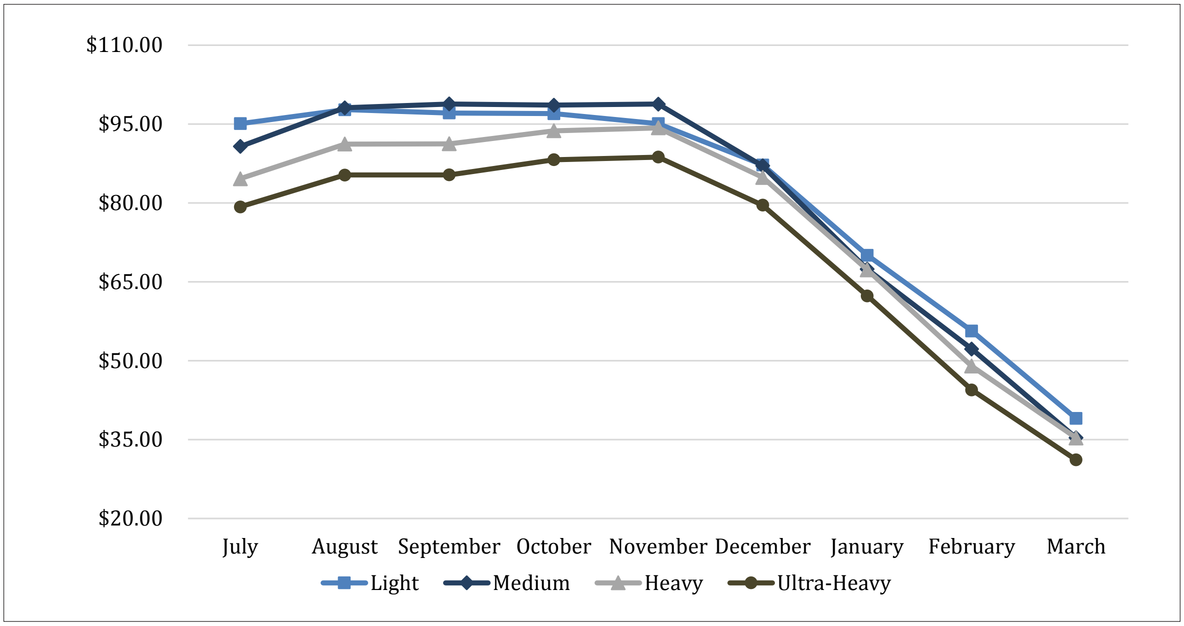
54 Crown production occurs from subsurface petroleum and natural gas rights owned by the province (as opposed to freehold rights, owned by private individuals, companies or the federal government). Crown-owned mineral rights correspond to about 81 per cent of Alberta's land area. Source: Canada. Alberta. Alberta Energy website, "Tenure Facts," http://www.energy.alberta.ca/Tenure/863.asp.

55 If the price and quantity component of the royalty rate sum to greater than 40 per cent, then the royalty rate assumes its maximum value of 40 per cent. If the price and quantity components sum to less than zero, then the royalty rate assumes its minimum value of zero per cent.

56 Canada. Government of Alberta, *Alberta Petroleum Royalty Guidelines: Principles and Procedures* (December 2013), http://www.energy.alberta.ca/Oil/pdfs/Petroleum_Royalty_Guidelines.pdf.

The Alberta Petroleum Marketing Commission is also responsible for setting the monthly par prices for each category of crude oil. Par prices are announced through an information letter approximately five weeks prior to the month in which they will determine royalty rates. For example, par prices that determined the royalty rates for March 2015 were announced on January 23, 2015. The par price is based on contract prices for the month that falls in between the month in which they are announced and the month in which they will determine royalty rates. For example, the par prices for March 2015 are based on monthly average contract prices for production due to be sold in February 2015. March 2015 par prices ranged from $31.15 per barrel for ultra-heavy oil to $39.01 per barrel for light oil.

FIGURE 3 2014–15 CRUDE OIL PAR PRICES



Source: Alberta Energy, "2014 Par Prices: December" and "2015 Par Prices: March."

The delay between oil prices that determine par prices and the production month in which the par price applies to the royalty calculation is providing significant insulation to crude oil royalties for the 2014/15 fiscal year. In its 2014/15 budget, the government forecast an average Alberta wellhead oil price for light, medium and heavy crude of $88.02 per barrel.[57] Figure 3 shows the actual monthly par prices for all categories of crude oil from July 2014 to March 2015. Despite oil price declines starting in July, the monthly par price for medium, heavy and ultra-heavy crude increased from July to November and the average crude oil price hovered close to the government's forecast. The impacts of the price fall first started to become apparent in December, when par prices fell between eight and 12 per cent, dropping below $88 per barrel on all types of crude. Thus, while the government was facing lower market oil prices starting in early fall, prior to December the royalty rate was still being determined by per-barrel prices that were not reflecting the price fall.

The impact of the price fall on the government's royalty rate is significantly more pronounced for the final quarter of the 2014/15 fiscal year. As shown in Figure 3, relative to November, the March par prices are $56 to $64 lower per barrel, corresponding to price falls of 59 to 65 per cent. This corresponds to a reduction in the price component of the royalty rate of approximately 25 per cent across all categories of crude oil.[58] The reduction in the overall royalty rate, however, is well-specific and depends heavily on the production rate of a well, which determines the quantity component of the royalty rate.

57 Government of Alberta, *Economic Outlook*, 101.

58 The exact reductions in the price component of the royalty rate are 23.9 per cent for light, 26.0 per cent for medium, 25.2 per cent for heavy, and 25.7 per cent for ultra-heavy.

Alberta Energy maintains a historical data set that provides annual Crown production grouped by 34 ranges of well production.[59] However, it does not provide any information on the number of wells in each production range, or the average well-productivity rate. To approximate the quantity component of the royalty rate in each production range we therefore assume average productivity is equal to the midpoint productivity of the range. Table 1 provides a summary of the Alberta Energy data and our royalty rate estimates. For ease of exposition we amalgamate the 34 production ranges into seven production groups. For each production group, the royalty rates we report are equal to the weighted average (by production share) of the royalty rates for each production range included in the production group.[60] We calculate the average royalty rate at the government's forecast 2014/15 fiscal-year price of $88.02 (for light, medium and heavy crude), as well as at the average par prices for light, medium and heavy crude in January, February and March 2015. Lastly, we also report the average decline in the royalty rate from the government's forecast price to the average par price for light, medium and heavy crude in March 2015. The full data table by production range, including our estimate of average well productivity in each range, is provided in Appendix A.

TABLE 1 CRUDE OIL WELLS IN ALBERTA BY AVERAGE PRODUCTIVITY: IMPACT OF PRICE DECLINE ON CRUDE OIL ROYALTY RATES

Well Productivity (Barrels/Day)	Share of Crown Production	Average Royalty Rate at Forecast Price ($88.02)	New Average Royalty Rate after Price Fall			Royalty Rate Decline (from Forecast to March)
			Jan ($68.24)	Feb ($52.28)	Mar ($36.54)	
0.02–6.19	8.8%	3.3%	0.0%	0.0%	0.0%	-3.3%
6.20–12.40	14.2%	9.8%	4.0%	0.0%	0.0%	-9.8%
12.41–20.68	14.0%	18.8%	12.9%	4.3%	0.0%	-18.8%
20.69–33.09	13.8%	28.0%	22.2%	13.6%	4.5%	-23.5%
33.10–51.71	12.8%	35.1%	29.2%	20.7%	11.5%	-23.5%
51.72–82.74	11.5%	40.0%	36.5%	28.0%	18.9%	-21.2%
82.75–118.37	7.2%	40.0%	40.0%	33.3%	24.2%	-15.8%
> 118.37	17.7%	40.0%	40.0%	40.0%	32.4%	-7.6%

Author calculations. Source: Alberta Energy, "New Royalty Framework Royalty Volumes 2014."

Note: Well productivity in Alberta Energy's original data set is reported in cubic metres per month. For consistency with production forecasts, which are measured in barrels per day, as well as per-barrel prices, we convert the well-productivity ranges to barrels per day and report the results rounded to two decimal places.

As shown in Table 1, small wells producing 6.19 barrels or less per day contributed just under nine per cent to Alberta's Crown crude oil production in 2013. At the government's forecast price, oil royalty rates for wells in this lowest production range typically fell in the range of zero to five per cent, with an average of 3.3 per cent. As the minimum royalty rate is zero, these low-productivity wells are less impacted by the falling price, with all wells in this category seeing their royalty rates fall from a maximum of five per cent to zero in January, and remaining there in February and March. On the other end of the spectrum, large wells producing more than 118.37 barrels per day contributed just under 18 per cent to Alberta's Crown crude oil production in 2013. With higher flow rates they face higher

59 The full data set provides total Crown production by well-productivity range for production from 1994 to 2013. The share of Crown production we calculate and report is equal to the average of the annual Crown production shares from 2009 through to 2013 (the last five years of available production data). Source: Alberta Energy website, "New Royalty Framework," http://www.energy.alberta.ca/About_Us/3073.asp.

60 For example, the well-productivity group 6.20–12.40 barrels per day (bpd) includes three production ranges: 6.20–8.26 bpd; 8.27–10.33 bpd; and 10.34–12.40 bpd . Production shares within the group are 35.3, 33.3 and 31.3 per cent respectively, and royalty rates at the forecast price are 7.35, 9.95 and 12.55 per cent respectively. We report an average royalty rate at the forecast price for the production group of 9.8 per cent, which is equal to the sum of the royalty rate for each production range multiplied by the production range's share of production within the production group.

royalties — at forecast prices they were paying the maximum royalty rate of 40 per cent in 2014. These wells continued paying the maximum royalty rate until March 2015, when the royalty rate for all wells in this group fell by 7.6 per cent. Royalty rates for wells in the mid-productivity ranges, producing between 6.20 and 118.37 barrels per day, contribute over 70 per cent to Alberta's production and are most impacted by the price fall. The average wells in these ranges will see monthly reductions in their royalty rates of zero to six per cent in January, an additional two to nine per cent in February, and an additional zero to nine per cent in March. Relative to the forecast royalty rate, at the average March par price, the cumulative royalty rate decline for these wells varies from seven to 24 per cent.

The production forecast for crude oil wells in Alberta in 2014 was 583,000 barrels per day.[61] From 2009 to 2013, an average of 79 per cent of total crude oil production was Crown production that was royalty eligible.[62] Assuming this same proportion holds in 2014, the Crown production portion of the government's production forecast is 460,600 barrels per day. Statistics from the Alberta Energy Regulator suggest approximately 149,600 barrels of this production is from new horizontal and vertical wells that qualify for a maximum five per cent royalty rate (for a limited number of years).[63,64] We again assume 79 per cent of this new production, or 118,200 barrels per day, is Crown production. This leaves 342,400 barrels of established Crown production that pays royalty rates according to the standard royalty schedule. This production will be most impacted by the price fall since, as the price component of the royalty rate changes, the final royalty rate value can vary over its full range from zero to 40 per cent.[65]

To estimate the impact of falling oil prices on crude oil royalties in the 2014/15 fiscal year, we start by backing out the approximate number of royalty barrels the government was expecting to collect. The government's royalty forecast for the 2014/15 fiscal year was $2.019 billion. At the forecast average wellhead price of $88.02, this roughly suggests the government was expecting to collect, on average, 62,800 barrels of oil per day from the approximate 460,600 barrels per day of Crown production.[66] If we assume the 118,200 barrels per day of new production follows a similar well-productivity distribution to

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61 Government of Alberta, *Budget 2014: Operational Plan*.

62 Canada. Alberta. Alberta Energy website, "Conventional Oil Production and Royalties," http://www.energy.alberta.ca/About_Us/3073.asp.

63 Alberta Energy Regulator, "ST98: Alberta's Energy Reserves and Supply/Demand Outlook: Crude oil data set ST98-2014," http://aer.ca/data-and-publications/statistical-reports/st98.

64 We define a new horizontal well as one that had new production in 2013 or 2014, and a new vertical well as one that had new production in 2014. We include two years of expected new production for horizontal wells as new horizontal wells are eligible for the five per cent flat-rate royalty for up to four years (depending on the depth of the well) and we assume the average length is two years. We include only a single year for vertical wells, as new vertical wells are only eligible for the reduced royalty rate for a single year. The numbers for new production are equal to the forecast production numbers for horizontal and vertical wells for 2013 and 2014 from the crude oil data sets for the Alberta Energy Regulator's ST98-2013 and ST98-2014 reports (http://www.aer.ca/data-and-publications/statistical-reports/st98).

65 The government of Alberta also offers a royalty reduction through the Enhanced Oil Recovery and Deep Oil programs. We do not account for these reductions, as we do not have an estimate of how much Crown production qualifies for these programs. Historical data from Alberta Energy, however, suggest that both programs are relatively quite small, with royalty reductions averaging 2,500 barrels per day over the last three years. As a comparison, the New Well Royalty Program averaged royalty reductions of 35,500 barrels per day over the last three years. Source: Canada. Alberta. Alberta Energy website, "Net Oil Royalty Volumes 2014," http://www.energy.alberta.ca/About_Us/3073.asp.

66 This will be a slight underestimate as the forecast average wellhead price of $88.02 is for light, medium and heavy crude. It does not include the price of ultra-heavy crude, which sells for a lower price.

all Crown production, then the government could expect to collect royalties of 5,700 barrels per day from new production.[67] The remaining 57,100 royalty barrels must then be attributable to Crown production that pays royalties according to the regular royalty rates.

If we assume that Crown production paying royalties according to the regular royalty rates also follows a similar well-productivity distribution to the entire province, then at the average March par price for light, medium and heavy crude of $36.54, we estimate the government's royalty collection on regular production will decline by approximately 53,000 barrels per day below forecast levels, to 4,100 barrels per day.[68] This suggests the fall in prices has the potential to virtually eliminate royalty collection from conventional production. Evaluated at the average price forecast for the year of $88.02, this corresponds to a drop in royalties of $145 million per month. This is the decline that is attributable to a lower royalty rate. We estimate an additional drop of $6 million per month can be attributed to the government selling the royalty share that it still collects (4,100 barrels per day) for prices that are significantly less than forecast.

Lastly, there will also be a decline in royalties collected on new production that qualifies for the maximum five per cent rate. The lowest-productivity wells will see their rates decline by up to five per cent (falling to zero) and the royalty share collected from the larger wells will be sold at lower prices. We estimate this decline at $12 million per month. The combined effect is an estimated drop in royalties in March of $163 million.

The government's 2014/15 forecast for crude oil royalties, $2.019 billion, corresponds to an average royalty collection of $168 million per month. As of the third-quarter fiscal update it had already exceeded this total amount with actual royalties collected of $2.024 billion.[69] This is largely due to a much stronger than forecast first half of the fiscal year. At the end of September 2014, the government had collected $1.462 billion in crude oil royalties — over $300 million or 30 per cent higher than forecast.[70] In addition, with the brunt of the oil price fall not hitting par prices and royalty rates until the January production month, average royalties in October through December still remained above forecast levels, averaging $187 million per month.

A forecast that was off by 30 per cent over the first half of the fiscal year raises valid questions about the government's forecasting method for crude oil royalties. An unforeseen benefit of the low forecast, however, is that it has provided the government with a more than sufficient cushion to weather the severe drop off in crude oil royalties — potentially upwards of $163 million per month by March — that will likely be observed in the fourth quarter.

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67 If we assume that new production follows the same productivity distribution as all Crown production in the province, then, as shown in Table A1 in Appendix A, 91.2 per cent of new production (107,800 bpd) will pay the maximum new-well royalty rate of five per cent, corresponding to 5,400 bpd in royalties, at the forecast average wellhead price of $88.01. The remaining production from lower-productivity wells pays a royalty rate of zero (0.25 per cent production share), 0.2 per cent (0.8 per cent production share), 2.1 per cent (3.2 per cent production share) and 4.8 per cent (4.6 per cent production share). Based on production share and royalty rates, the expected approximate royalty contribution of these lower-producing wells is 300 bpd.

68 We calculate the total decline in royalty collection by summing across the decline in each production range, which we estimate using the share of Crown production and the reduction in royalty rate for the average well provided in Table A1 in Appendix A. For example, we estimate the well-productivity range of 118.38–206.88 barrels per day will see a total decline in royalty payments as a result of the price fall of 2,360 barrels per day. This is equal to total established Crown production impacted by the price fall (342,400 barrels) multiplied by the production range's share of total production (9.1 per cent) and the reduction in royalty rate for the average well from the price fall (-7.6 per cent).

69 Government of Alberta, *2014-15 Third Quarter.*

70 Government of Alberta, *2014-15 Second Quarter.*

BITUMEN ROYALTIES

Oilsands companies pay royalties in accordance with the guidelines to the *Oil Sands Regulatory Regime, 2009* (AR 233/2008).[71] Specific projects are classified into one of three types: pre-payout, post-payout and non-project.

A “pre-payout” project is one where a project’s cumulative capital and operating costs over its lifetime are greater than its cumulative revenues. A “post-payout” project, alternatively, is one where a project’s cumulative capital and operating costs over its lifetime are less than its cumulative revenues. Both projects pay royalties in cash (as opposed to “in kind”),[72] but each type of project faces a distinct royalty regime, the specifics of which are discussed below. A key commonality between both royalty regimes is that the royalty rate is calculated using a WTI price in Canadian dollars. This means both the WTI price in U.S. dollars and the Canada-U.S. exchange rate influence the prevailing royalty rate. As the Canada-U.S. exchange rate has been falling along with the WTI price, it also means the impact of the recent price fall on the royalty rates for both project types is partially offset. This impact will also be explored in more detail below.

“Non-project” refers to a bitumen well that is not associated with an approved oil sands project. From 2011 to 2013, production from non-project wells averaged 27,600 barrels per day, representing only 1.5 per cent of total oil sands production.[73] Non-project wells pay royalties in accordance with the royalty structure for conventional crude oil wells and therefore face royalty rates that are generally higher than the pre- and post-payout project royalty rates. As a result, non-project wells contributed an average of 2.6 per cent to annual bitumen royalties collected from 2011 to 2013. While this contribution is not insignificant, we do not calculate the decline in royalties for non-project production. This is primarily because we do not have data on the number of non-project oilsands wells or average well-productivity rates. Without this information we are unable to approximate the quantity component of the royalty rate and, as a result, we also cannot approximate the royalty rate at either forecast or current prices. This is another instance of how improved transparency on the part of the government is important for improving our understanding of how changes in the price of oil influence government revenues.

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71 For complete guidelines see: Canada. Alberta. Alberta Energy, *Alberta Oil Sands Royalty Guidelines*, *Principles and Procedures* (2012), http://www.energy.alberta.ca/OilSands/pdfs/Royalty_Guidelines.pdf.

72 The government has announced plans for a bitumen royalty-in-kind program, which would see it collect a portion of its bitumen royalty in barrels of bitumen, as opposed to cash payments. While the program is announced, and supply agreements for the government’s portion of bitumen production have been established, the government does not currently collect any of its bitumen royalty in kind.

73 Canada. Alberta. Alberta Energy website, “Royalty Archive — Oil Sands,” http://www.energy.gov.ab.ca/About_Us/1702.asp.

PRE-PAYOUT PROJECTS

A pre-payout project has cumulative revenues over its lifetime that are less than its cumulative costs; i.e., they are projects that are typically still paying off their initial capital investments. These projects are also allocated a monthly return allowance, equal to the rate of return on long-term Canada bonds, on the excess of cumulative costs over cumulative revenues. In pre-payout status, a project pays monthly royalties on its gross revenues according to the following royalty rate schedule:

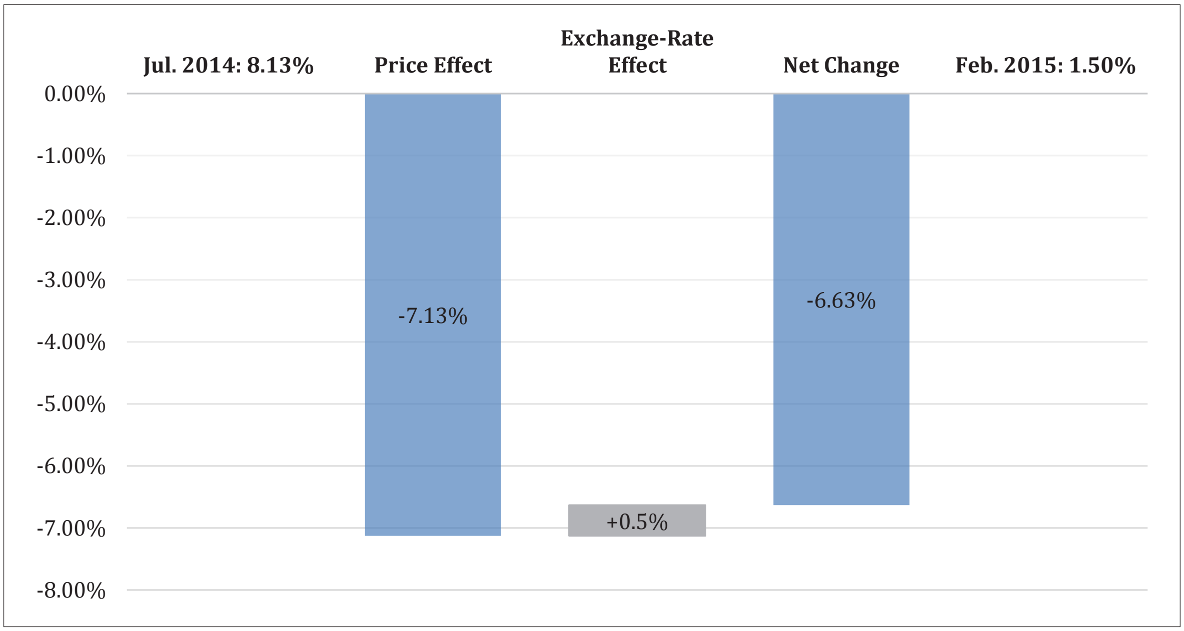
$$
\begin{array}{ll}
WTI_{CAD} < \$55 & R_{Gross} = 1\% \\
\$55 < WTI_{CAD} < \$120 & R_{Gross} = 0.01 + \dfrac{0.08}{65}\left(WTI_{CAD} - 55\right) \\
WTI_{CAD} > \$120 & R_{Gross} = 9\%
\end{array}
$$

The monthly royalty rate is calculated using the previous month's average WTI price in Canadian dollars, while the WTI price conversion from U.S. to Canadian dollars is completed using the current month's average exchange rate. For example, the royalty rate for pre-payout projects in December 2014 was 4.99 per cent, which is based on a WTI price of $87.43 (CAD). The WTI price in Canadian dollars is equal to the average WTI price in November 2014 (US$75.81), divided by the average U.S.-Canada (USD/CAD) exchange rate for December 2014 (0.867 USD/CAD).

For a pre-payout project, the effects of changes in the oil price are immediate and strong. The first effect we consider is the falling royalty rate. As shown in Figure 4, from July 2014 to February 2015 the monthly royalty rate for pre-payout projects fell from 8.13 to 1.50 per cent — a fall of over 80 per cent. It is worth noting however that this fall was softened by the declining U.S.-Canada exchange rate. The average exchange rate in July 2014 was 0.931; in February 2015 it had fallen 14 per cent to 0.800. Had the exchange rate stayed constant, then the royalty rate in December would have fallen an additional 0.5 per cent to its minimum threshold of 1.0 per cent. We can therefore divide the royalty rate fall into two components — a negative price effect (-7.13 per cent) and a positive exchange-rate effect (0.5 per cent).[74] The relative magnitudes of these effects are shown in Figure 4.

[74] The negative price effect decreased the royalty rate by 7.13 per cent (to 1.0 per cent), while the positive exchange-rate effect brought the royalty rate back up by 0.5 per cent (to 1.50 per cent).

FIGURE 4 BREAKDOWN OF CHANGE IN ROYALTY RATE FOR PRE-PAYOUT PROJECTS (AS A PERCENTAGE OF GROSS REVENUES), JULY 2014 TO FEBRUARY 2015



The next effect we consider is the falling monetary value of the royalty paid to government. To consider this effect we assume a project's gross revenue per barrel of production is equal to the price of Western Canadian Select (WCS).[75] In July, the average WCS price was $82.73. At a royalty rate of 8.13 per cent and U.S.-Canada exchange rate of 0.931, the average per-barrel royalty in July 2014 was $7.22 (CAD). As shown in Figure 6, by February 2015 the average per-barrel royalty had declined to $0.70 (CAD), a fall of 90 per cent. The lower royalty represents the combined effect of a lower royalty rate (1.50 per cent), a lower WCS price ($37.54) and a lower exchange rate (0.800). The fall in the monetary value of the royalty can therefore be divided into three components: a negative royalty-rate effect (-$5.89), a negative price effect (-$0.73) and a positive exchange-rate effect (+$0.10). The royalty-rate effect measures the decline in the royalty payment assuming the WCS price and exchange rate remained constant from July to February. The price effect measures the incremental decline in the royalty from the decline in the WCS price from July to February, leaving the exchange rate constant. Finally, the exchange-rate effect measures the incremental increase in the royalty from the decline in the exchange rate from July to February. The relative magnitudes of these effects are shown in Figure 6.

[75] The Alberta Oil Sands Royalty Guidelines define a project's gross revenue as project revenue minus the cost of diluent (the diluting agent used to create a bitumen blend that is shipped to refiners). Project revenue is the sum of all quantities of oil sands products produced by a project multiplied by their unit price. WCS is a benchmark price for blended bitumen produced in the oil sands. It contains both condensate and sweet crude diluents, which have a higher price than bitumen. As a result, the WCS price, which is a weighted average of the price of bitumen and the price of diluents, will overestimate a company's gross revenue per barrel of bitumen. In 2014, the per-barrel price difference between WCS and the implied price of a barrel of pure bitumen ranged from 10 to 38 per cent, with an annual average difference of 17 per cent (Author calculations. Source: Canada. Alberta. Alberta Energy website, "Bitumen Methodology Valuation Components 2014" and "BVM Model Calculator," http://www.energy.alberta.ca/OilSands/1542.asp). While we acknowledge this difference, we still opt to use the WCS price as an approximation, as the government does not provide a bitumen-specific price, or information on its assumptions for calculating a bitumen-specific price, in the budget documents.

FIGURE 5 IMPACT OF OIL PRICE ON PRE-PAYOUT PROJECT ROYALTIES

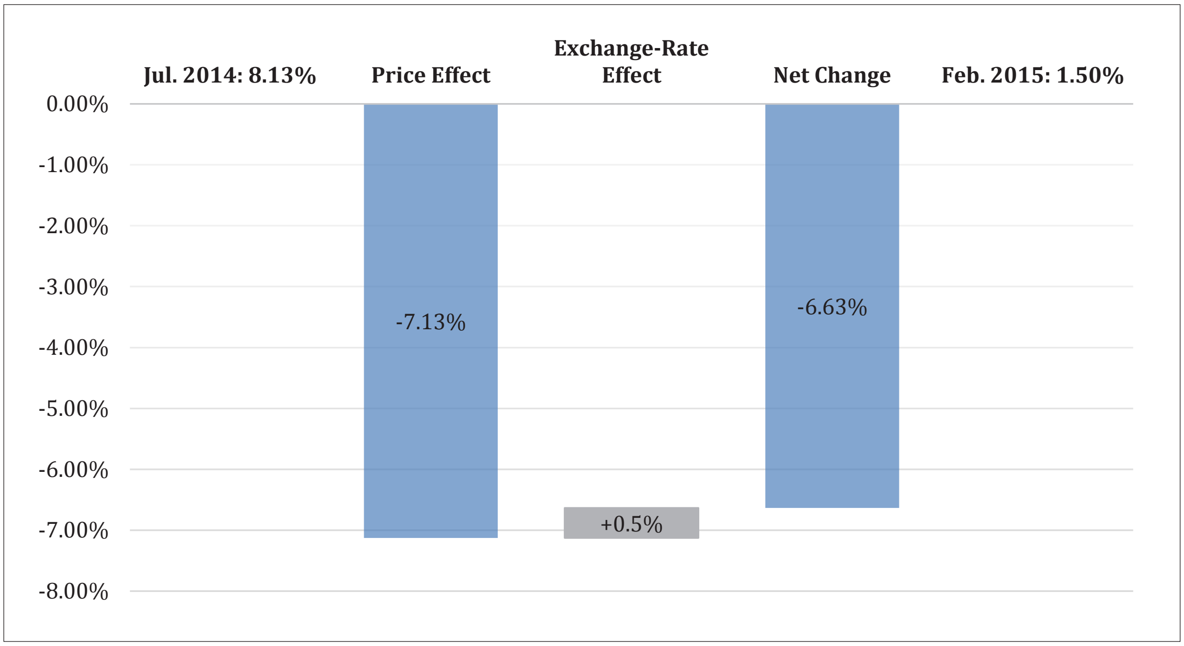
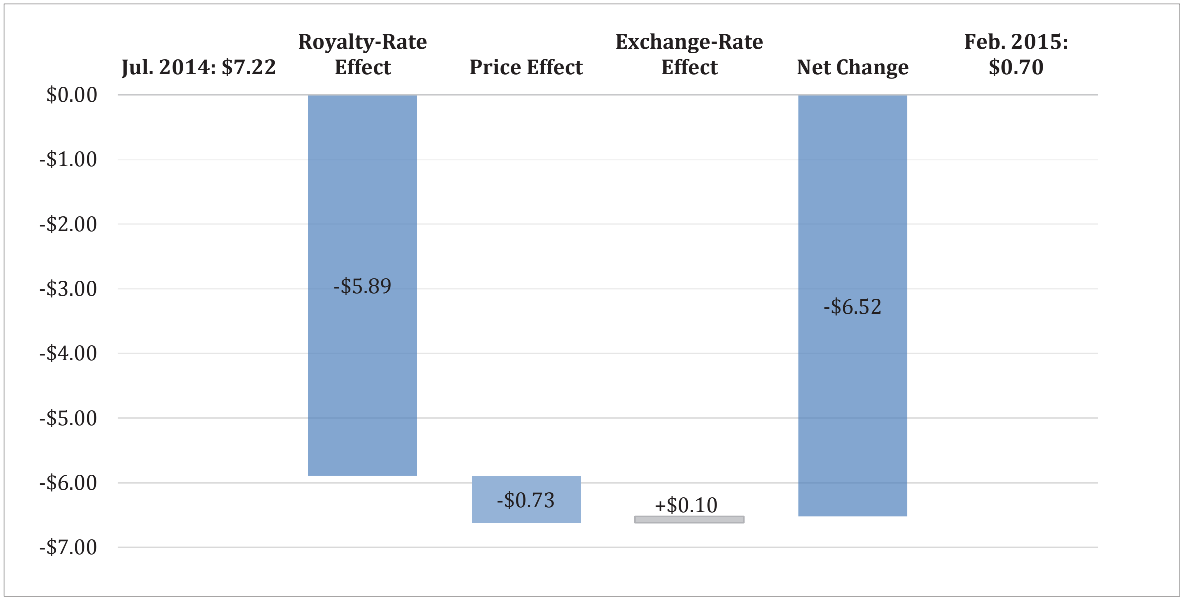


FIGURE 6 BREAKDOWN OF CHANGE IN PER-BARREL ROYALTY FOR PRE-PAYOUT PROJECTS, JULY 2014 TO FEBRUARY 2015



POST-PAYOUT PROJECTS

A post-payout project has cumulative costs over its lifetime that are less than its cumulative revenues; i.e., it is typically a project that has paid off its initial capital investment and only needs to cover its operating and sustaining capital costs going forward. Unlike pre-payout projects that pay a monthly royalty, a post-payout project pays an annual royalty each calendar year. The royalty is paid through monthly instalments based on the expected annual royalty rate. The expected annual royalty rate is calculated based on the expected price and expected exchange rate for the year. It is updated each month with the actual WTI price and exchange rate that is observed.

The annual royalty rate is calculated using an average annual WTI price that is equal to the average of the average monthly WTI prices in Canadian dollars over the course of the year. The average price for each production month is equal to the average WTI price from the previous month, converted to Canadian dollars using the production month's exchange rate. For example, the average price for January 2015 was $71.83 (CAD). This is equal to the average December 2014 WTI price ($59.29) divided by the average monthly U.S.-Canada exchange rate for January 2014 (0.825).

Whereas a pre-payout project will always pay royalties that are a fixed percentage of gross revenues, a post-payout project will pay the higher of royalties calculated using two possible rates: (1) a gross-revenue rate that calculates the royalty owing as a percentage of gross revenues; or (2) a net-revenue rate that calculates the royalty owing as a percentage of net revenues.

The gross-revenue rate follows the same schedule as the gross-revenue rate for pre-payout projects, but is calculated using the average annual WTI price as opposed to the average monthly WTI price. The net-revenue rate is calculated according to the following schedule:

$$
\begin{aligned}
WTI_{CAD} &< \$55 & R_{Net} &= 25\% \\
\$55 < WTI_{CAD} &< \$120 & R_{Net} &= 0.25 + \frac{0.15}{65}\left(WTI_{CAD} - 55\right) \\
WTI_{CAD} &> \$120 & R_{Net} &= 40\%
\end{aligned}
$$

Table 2 is a reproduction of the government of Alberta's royalty rate table for January 2014, July 2014 and December 2014. It shows how the annual gross-revenue and net-revenue royalty rate for post-payout projects updates over the course of the year.

We next consider how falling prices are impacting the royalty rate and royalties owing for a post-payout project. As the applicable royalty rate depends on a company's net versus gross revenues, we conduct our analysis assuming a representative company that has net revenues equal to 20 per cent of gross revenues.[76] As post-payout projects pay an annual royalty rate, we first consider how the expected annual royalty rate and payments changed from July to December of 2014, and then we consider how the royalty rate and payments are currently expected to change from 2014 to 2015.

[76] We use the assumption of a representative company having net revenues equal to 20 per cent of gross revenues as this is the scenario used in the post-payout royalty calculation examples found in the government of Alberta's *Alberta Oil Sands Royalty Guidelines: Principles and Procedures* document.

TABLE 2 POST-PAYOUT ROYALTY CALCULATION

	JANUARY			JULY			DECEMBER		
	Act/Est	Price (USD)	USD/CAD	Act/Est	Price (USD)	USD/CAD	Act/Est	Price (USD)	USD/CAD
January	**Act**	**$97.89**	**0.9139**	Act	$97.89	0.9139	Act	$97.89	0.9139
February	Est	$94.86	0.9750	Act	$94.86	0.9046	Act	$94.86	0.9046
March	Est	$97.49	0.9750	Act	$100.68	0.9003	Act	$100.68	0.9003
April	Est	$96.71	0.9750	Act	$100.51	0.9098	Act	$100.51	0.9098
May	Est	$95.80	0.9750	Act	$102.03	0.9180	Act	$102.03	0.9180
June	Est	$94.85	0.9750	Act	$101.79	0.9233	Act	$101.79	0.9233
July	Est	$93.87	0.9750	**Act**	**$105.15**	**0.9312**	Act	$105.15	0.9312
August	Est	$92.90	0.9750	Est	$102.39	0.9100	Act	$102.39	0.9151
September	Est	$92.00	0.9750	Est	$98.17	0.9100	Act	$96.08	0.9081
October	Est	$91.21	0.9750	Est	$97.32	0.9100	Act	$93.03	0.8919
November	Est	$90.54	0.9750	Est	$96.73	0.9100	Act	$84.34	0.8829
December	Est	$89.92	0.9750	Est	$96.21	0.9100	Act	$75.81	0.8671
Annual Avg	Est	$94.00	0.9700	Est	$99.48	0.9126	**Act**	**$96.21**	**0.9055**
Gross Royalty Rate	Est	6.15938%		Est	7.64738%		Act	7.30769%	
Net Royalty Rate	Est	34.67485%		Est	37.46385%		Act	36.82692%	

Source: Alberta Energy, "Monthly Royalty Rates: January 2014, July 2014 and December 2014."

As shown in Figure 7, in July 2014 our representative company expected to face an annual gross-revenue royalty rate of 7.65 per cent. In December 2014, the year-end annual gross-revenue royalty rate had declined to 7.31 per cent while the year-end annual net-revenue royalty rate was equal to 36.83 per cent. For a company with net revenues equal to 20 per cent of gross, the net-revenue rate corresponds to a gross-revenue rate of 7.37 per cent, higher than the year-end annual gross-revenue royalty rate of 7.31 per cent. Our representative company therefore faces the net-revenue royalty rate at year-end, and pays a royalty rate of 7.37 per cent on gross revenues from all 2014 production. This is a decline of only three-tenths of a percentage point, or less than four per cent, relative to what our representative company was expecting to pay in July. This small decline is a result of the royalty rate calculation depending on the average annual WTI price, which through to December is still propped up by the higher WTI prices that were observed over the first half of 2014.

The effect of the price fall on royalties for post-payout projects is more fully realized in 2015, when a new period for royalty rate calculations and payments begins. From December 2014 to February 2015 the annual WTI price used in the royalty rate calculation dropped by 40 per cent, from $106.25 (CAD) (the actual average WTI price in 2014 of $96.21 divided by the actual average exchange rate of 0.906 USD/CAD) to $63.25 (CAD) (the government of Alberta's projected average WTI price in 2015 of $55.11 divided by the projected average exchange rate of 0.871 USD/CAD).[77] As shown in Figure 7, this leads to a fall in the gross-revenue royalty rate of our representative company of two percentage points, or nearly 30 per cent. As with the changing royalty rates for pre-payout projects, the fall in the royalty rate includes both a negative price effect (-2.09 per cent) and a positive exchange-rate effect (+0.11 per cent) (shown in Figure 8).

[77] Canada. Alberta. Alberta Energy, *Oil Sands Monthly.*

FIGURE 7 IMPACT OF OIL PRICE ON POST-PAYOUT PROJECT ROYALTIES

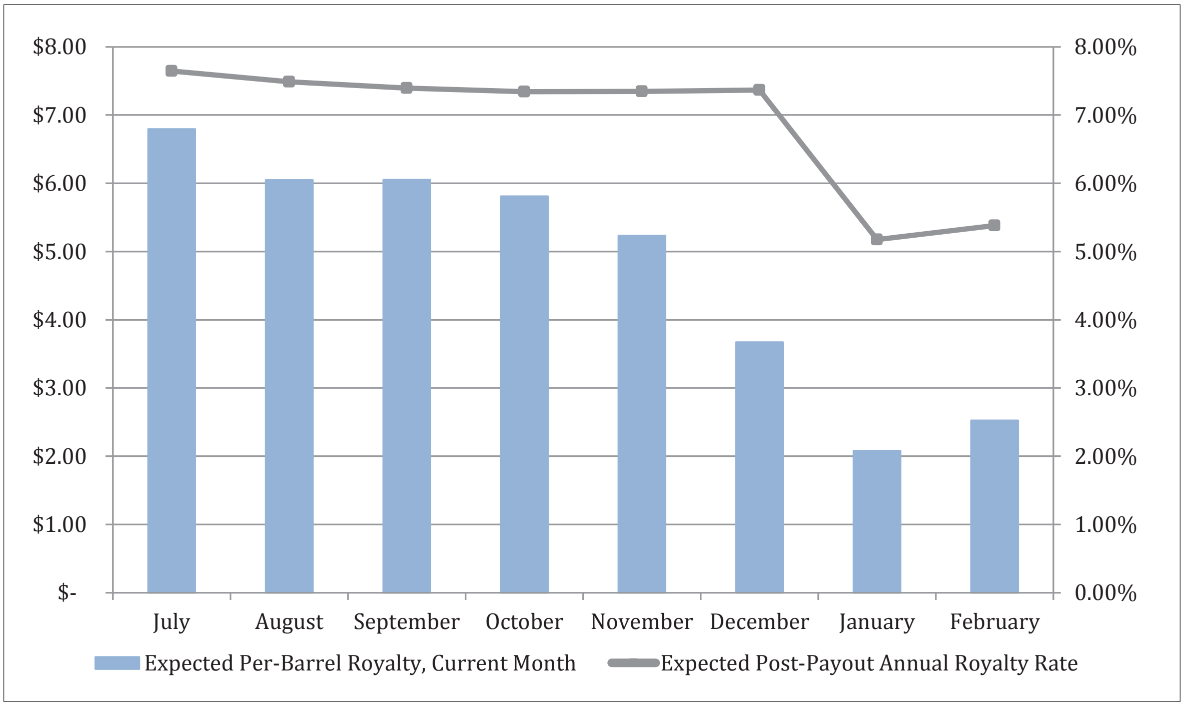
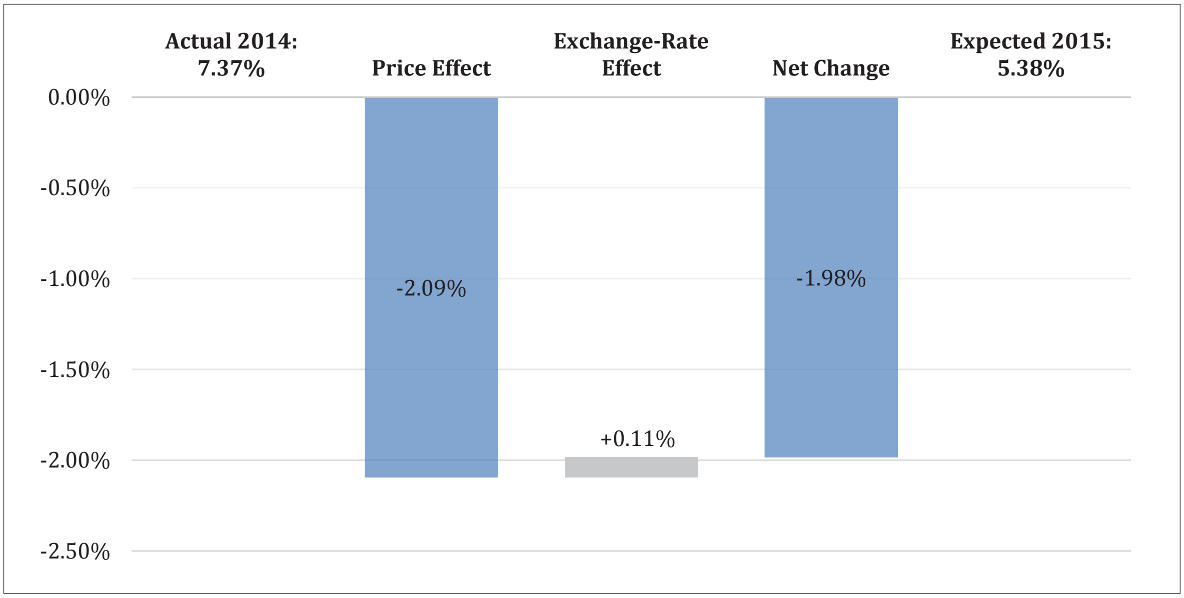


FIGURE 8 BREAKDOWN OF CHANGE IN ROYALTY RATE FOR POST-PAYOUT PROJECTS (AS A PERCENTAGE OF GROSS REVENUES), 2014 ACTUAL TO 2015 EXPECTED



The next effect we consider is the falling monetary value of the royalty paid to government. As the change in the royalty rate over the latter half of 2014 is small, the change in the royalty per barrel in 2014 — falling from an expected value of $6.79 per barrel in July to $3.67 in December — is driven by the falling price. It is important to note however that while the change in the royalty rate is small, the annual royalty rate calculated in December applies to production and revenues over the entire 2014 calendar year. That is, there will be a royalty rate adjustment that applies to the royalties that were paid in instalments in previous production months. For example, in July, our representative company was expecting to face an annual royalty rate of 7.65 per cent of gross revenues. At the final year-end royalty rate of 7.37 per cent of gross revenues, the actual royalty the company owes on July production is $6.54 (CAD) per barrel, representing a decline of $0.25 per barrel.

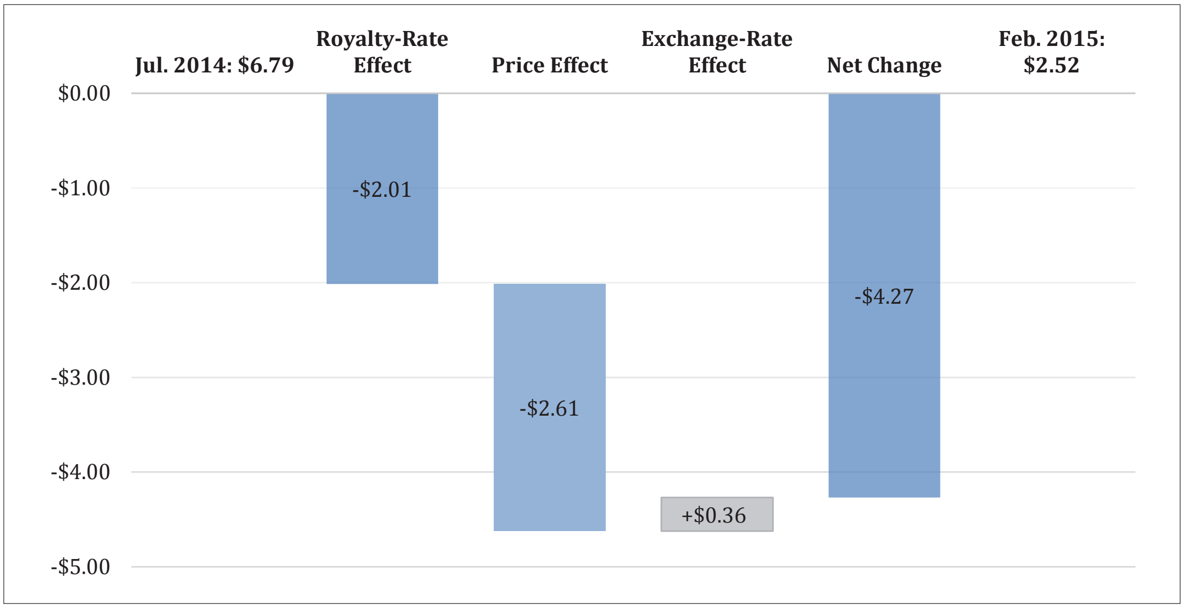
Table 3 provides a summary of the expected royalty rate and expected per-barrel royalty for each 2014 production month in the 2014/15 fiscal year, the year-end actual per-barrel royalty owed and the month-specific adjustment. While the per-barrel effects in each month are small, they add up over the course of the year. More specifically, a rough approximation suggests that from April to November 2014, companies in post-payout status may have overpaid royalties by $68.8 million.[78] While this is only 1.4 per cent of total royalties paid by all companies from April to December 2014, it comprises over 12 per cent of the current projected shortfall in bitumen royalties for the 2014/15 fiscal year.

TABLE 3 SUMMARY OF PER-MONTH ROYALTY-RATE EFFECTS ON 2014 PRODUCTION

Month	Expected Royalty Rate	Expected Per-Barrel Royalty	Actual Per-Barrel Royalty	Rate Effect
April	7.52%	$6.57	$6.44	-$0.13
May	7.77%	$7.00	$6.64	-$0.36
June	7.99%	$7.49	$6.91	-$0.59
July	7.65%	$6.79	$6.54	-$0.25
August	7.49%	$6.05	$5.95	-$0.10
September	7.40%	$6.06	$6.03	-$0.02
October	7.34%	$5.81	$5.83	$0.02
November	7.35%	$5.23	$5.24	$0.01
December	7.37%	$3.67	$3.67	$0.00

[78] We note this calculation is a rough approximation as it assumes that all companies in post-payout status have a cost structure where gross revenues are equal to 20 per cent of net revenues. We further assume there is 1.443 million barrels per day of post-payout production, divided into 830,000 barrels per day of bitumen with gross revenue per barrel approximated by the WCS price and 613,000 barrels per day of synthetic crude oil with gross revenue per barrel approximated by the WTI price. The monthly rate effects provided in Table 3 are for bitumen production. The monthly rate effects for synthetic crude oil production will be 1 to 10 cents greater as the WTI price is greater than WTS. Further explanation and justification of these assumptions is provided at the start of the next section and in footnotes 84 and 85.

FIGURE 9 **BREAKDOWN OF CHANGE IN PER-BARREL ROYALTY FOR POST-PAYOUT PROJECTS, JULY 2014 TO FEBRUARY 2015**



It is again the start of 2015 before the effect of the price fall on the monetary value of royalties is more fully realized. As shown in Figure 9, the expected average per-barrel royalty on February production is $2.32 (CAD), a fall of 63 per cent from July's high. As with the pre-payout project, the lower royalty represents the combined effect of a lower royalty rate (5.38 per cent of gross revenues), a lower WCS price ($37.54) and a lower exchange rate (0.800). The fall in the monetary value of the royalty can therefore be divided into three components: a negative royalty-rate effect (-$2.01), a negative price effect (-$2.61) and a positive exchange-rate effect (+$0.36) (shown in Figure 9).

THE CURRENT FISCAL-YEAR IMPACT

Through the first half of the current fiscal year (April 1 to September 30, 2014) the government collected $3.736 billion in bitumen royalties, exceeding its forecast by nearly $1.0 billion or almost 35 per cent.[79] This surplus was driven by both a higher-than-forecast average WTI price of $100.08 (forecast was $95.22) and a lower-than-forecast WTI/WCS differential of $20.09 (forecast was $25.00).[80] Despite this strong position, with oil prices falling, the government revised its forecast bitumen royalty for the year in its second-quarter fiscal update — dropping it from $5.549 billion to $5.419 billion. Accompanying this were declines in the forecast fiscal-year WTI price to $88.88, the exchange rate to 0.905 CAD/USD and the WTI/WCS differential to $18.16.

The government's third-quarter update for 2014/15 contained both good and bad news with respect to bitumen royalties for the current fiscal year. On the good side, despite falling oil prices, the government collected $1.079 billion in bitumen royalties in the third quarter of the fiscal year, bringing its current fiscal-year total to $4.815 billion. On the less promising side, the government once again revised downwards its fiscal-year WTI price forecast, dropping it to $79.24 per barrel. The forecast WTI/WCS differential fell to $17.49, and the forecast exchange rate fell to 0.883 USD/CAD. These adjusted

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79 Canada. Government of Alberta, *2014-15 Second Quarter.*

80 ibid.

forecasts suggest the government is expecting WTI to average $44 per month in the fourth quarter, the WTI/WCS differential to average $15.40 and the exchange rate to average 0.820 USD/CAD.

Most significantly, the government also dropped its 2014/15 forecast for bitumen royalties to $4.935 billion. There is no question that royalty payments will see a large drop-off in the fourth quarter — oil prices fell through January, and February's small recovery has not been sustained. In addition, post-payout projects are starting a new royalty period and will face a significantly lower royalty rate that is more reflective of current prices. However, the government's current forecast for fourth-quarter bitumen royalties is $120 million, working out to an average royalty collection of $40 million per month.[81] This seems curiously low and is not supported by the price assumptions currently being provided by the government.

Using the government's assumptions, we perform a back-of-the-envelope calculation of expected royalties for the third and fourth quarter of the current fiscal year. As falling oil prices are not expected to impact current projects, we assume in our calculations that production for the remainder of the 2014/15 fiscal year continues at the government's initial estimate of 2,347,000 barrels per day. Of this production, we assume 2,303,000 barrels per day is Crown production,[82] divided into 2,279,000 barrels per day of project production and 23,500 barrels of non-project production for which we do not estimate royalties due to a lack of data on well productivity.[83] Of the project production we assume 968,000 barrels is upgraded to synthetic crude oil, with gross revenue per barrel approximated by the WTI price.[84] We assume the remainder of production is non-upgraded bitumen, with gross revenue per barrel approximated by the WCS price. Lastly, we assume the production split between pre- and post-payout projects is 36.7/63.3 per cent for both upgraded and non-upgraded bitumen.[85,86]

We first apply our "back-of-the-envelope" model using known prices from the third quarter. Our estimate of third-quarter royalties, shown by month in Figure 10, is $1.080 billion, an overestimate of 0.1 per cent relative to actual third-quarter bitumen royalties of $1.079 billion. Using the government's projected prices for the fourth quarter, we estimate fourth-quarter royalties of $354 million, exceeding the government's forecast of $120 million by 195 per cent. Such a massive swing in how well our model

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81 This estimate should not include any adjustment for royalties that were overpaid by companies in post-payout status in 2014. This is because the monthly instalments that post-payout companies pay are adjusted each month to reflect any over- or under-payment of royalties that occurred in previous months of the calendar year. As a result, the final monthly instalment paid for the December production month should equal the final amount of royalties owing for the entire calendar year.

82 The estimate of total Crown bitumen production is equal to the government's production estimate minus our estimate of annual freehold bitumen production. Our estimate of annual freehold bitumen production is equal to the average of total annual freehold oil production minus total annual freehold conventional crude oil production from 2011 through to 2013. Sources: Canada. Alberta. Alberta Energy website, "Freehold Mineral Tax Statistics," http://www.energy.alberta.ca/Tenure/900.asp; Alberta Energy website, "Conventional Oil."

83 The estimate of non-project Crown production is equal to the average annual non-project Crown production from 2011 through to 2013. Source: Alberta Energy, "Royalty Archive — Oil Sands."

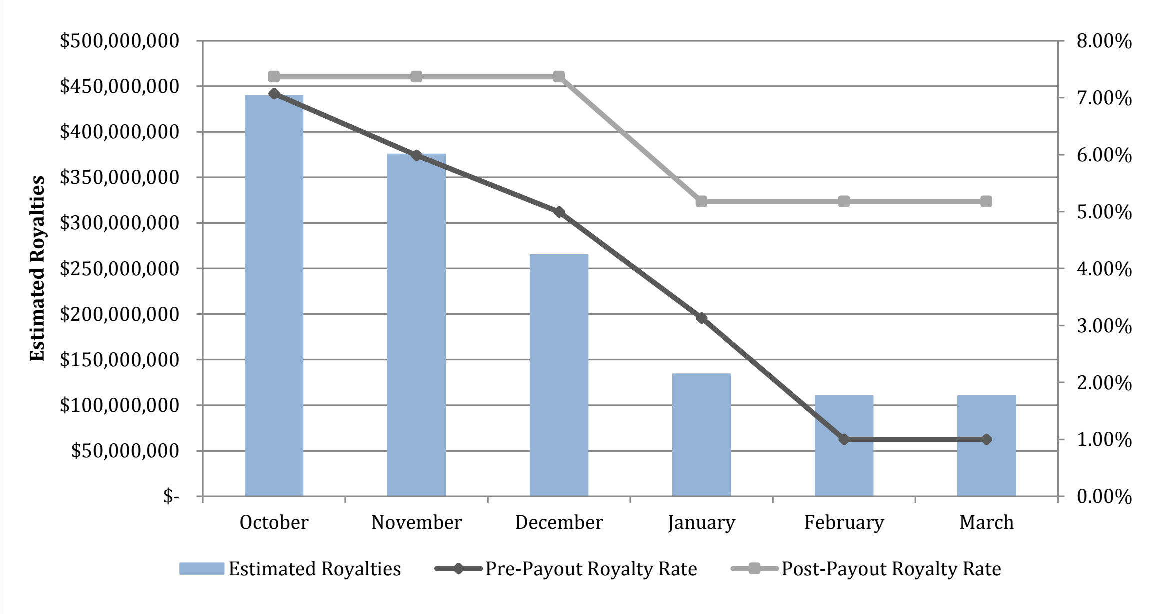
84 The assumption of 968,000 barrels per day of synthetic crude oil is based on the Alberta Energy Regulator's forecast for 2014 production of Alberta upgraded bitumen. Source: Alberta Energy Regulator, "ST98: Alberta's Energy."

85 Our estimate for the production split between pre- and post-payout projects was based on the 2013 production split of 34/66 per cent (701,000/1,364,000). We then calculated the average growth in post-payout production over the previous five years (2009 to 2013), equal to 5.77 per cent. Assuming post-payout production grows at this rate from 2013 to 2014, we arrive at our estimate of a 2014 production split of 36.7/63.3 per cent for pre- and post-payout projects.

86 As a check of our assumptions regarding production splits and per-barrel gross revenues, and the accuracy of our "back-of-the-envelope" model relative to the government of Alberta's forecast methodology, we estimate total royalties for the 2014/15 fiscal year using the government's 2014/15 budget forecasts. Specifically, using a WTI price of $95.22 per barrel, a WCS/WTI differential of 26 per cent and an exchange rate of 0.91 (USD/CAD) we estimate annual royalties for 2014/15 of $5,317 million, 4.7 per cent lower than the government of Alberta's forecast of $5,579 million. As we are not estimating non-project royalties, which have accounted for (on average) 2.6 per cent of annual royalties in recent years, that puts the estimate from our "back-of-the-envelope" model within approximately 2.1 per cent of the government of Alberta's forecast. This suggests our assumptions are not unreasonable.

tracks actual royalties versus forecast royalties suggests that it is missing a critical piece (or pieces) of information for the fourth-quarter forecast. This reflects a significant lack of transparency in the government's forecast methods.

FIGURE 10 ESTIMATED ALBERTA BITUMEN ROYALTIES FOR SECOND HALF OF 2014/15 FISCAL YEAR



THE MEDIUM-TERM (2015) IMPACT

A sustained recovery in oil prices will require a resolution to the current imbalance between global oil supply and demand. While a positive demand response can be expected with lower prices, it is unlikely to be strong enough to instigate a price recovery. In the United States, the EIA estimates the price elasticity of motor gasoline at only -0.02[87] — that is, it forecasts a 10 per cent decrease in price will lead to only a 0.2 per cent increase in gasoline demand. Globally, the IEA forecasts world oil demand in its Oil Market Report released every month. The demand outlook for 2015 has yet to reflect an increase in demand in response to falling prices. Rather, even with oil prices declining there has been a steady series of cutbacks to the forecast — from July 2014 to January 2015 the IEA's estimate of global oil demand in 2015 declined by nearly 750,000 barrels per day.[88]

With global oil demand still not returning to previously anticipated growth levels, most analysts are in agreement that the turnaround in the oil price fall will need to be driven by the supply side. Since the November 27 OPEC meeting, ministers from both Saudi Arabia and the United Arab Emirates have reaffirmed on multiple occasions that the organization has no intention of cutting back supply, even if

87 Michael Morris, "Gasoline prices tend to have little effect on demand for car travel," U.S *Energy Information Administration: Today in Energy* (December 15, 2014), http://www.eia.gov/todayinenergy/detail.cfm?id=19191.

88 International Energy Agency, *Oil Market Report* Archives (July 2014 to Jan 2015), https://www.iea.org/oilmarketreport/omrpublic/.

oil falls to as low as $20 or $40 per barrel.[89,90] This suggests the required cutback in supply will need to come from non-OPEC sources.

Falling oil prices are not yet having a significant impact on current non-OPEC production. Rather, in the United States and Canada, production is still on an upward trajectory. From June 2014 to February 2015, average monthly U.S. crude oil production increased by 8.4 per cent, rising from an average of 8.5 million barrels per day in June to 9.3 million barrels per day in February.[91] Looking specifically at shale oil, the EIA reports that from February to March 2015, production is expected to increase by 68,000 barrels per day.[92] In Alberta, production of bitumen and crude oil is also sharply up, increasing by 6.7 per cent or 181,000 barrels of oil per day from June to December 2014.[93]

While companies are moving forward with current projects it is also becoming evident that they are approaching new projects with caution. December 2014 and January 2015 brought a flood of announcements from Canadian companies planning to cut back their capital expenditures in 2015.[94] In the oilsands these included Husky Energy ($3.4 billion/-42 per cent), Penn West ($215 million/-26 per cent), MEG Energy ($895 million/-75 per cent), White Cap Resources Inc. ($115 million/-32 per cent), Bonavista Energy ($150 million/-30 per cent),[95] ARC Resources Ltd. ($125 million/-14 per cent),[96] Cenovus Energy (-$1.2 billion/-38 per cent),[97] Canadian Natural Resources Ltd. ($2.4 billion/-28 per cent)[98] and Suncor ($1 billion/-13 per cent).[99] Industry-wide in Western Canada, the Canadian Association of Petroleum Producers (CAPP) is forecasting a decline in capital investment of $23 billion from 2014 to 2015, falling 33 per cent from $69 to $46 billion. A shallower decline of 24 per cent is anticipated for the oil sands, where CAPP forecasts capital investment to fall from $33 billion in 2015 to $25 billion in 2015.[100]

Current expectations are that cutbacks in capital spending will begin to translate into reduced production growth in the second half of 2015. Looking again at the United States, between November 2014 and

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89 Andrew Critchlow, "OPEC to keep pumping 'even if oil falls to $40 per barrel,'" *The Telegraph*, December 14, 2014, http://www.telegraph.co.uk/finance/newsbysector/energy/oilandgas/11292837/Opec-willing-to-push-oil-price-to-40-says-Gulf-oil-minister.html.

90 Andrew Critchlow, "Oil plummets after Saudis say $20 crude is possible," *The Telegraph*, December 22, 2014, http://www.telegraph.co.uk/finance/newsbysector/energy/11308952/Opec-Oil-plummets-after-Saudis-says-20-crude-is-possible.html.

91 U.S. Energy Information Administration, "Petroleum & Other Liquids: Cushing."

92 U.S. Energy Information Administration, *Drilling productivity report: For key tight oil and shale gas regions* (February 2015), http://www.eia.gov/petroleum/drilling/pdf/dpr-feb15.pdf.

93 Alberta Energy Regulator, "Oil: Supply and Disposition," *ST3: Alberta Energy Resource Industries Monthly Statistics* (December 2014), http://aer.ca/data-and-publications/statistical-reports/st3.

94 Announced cutbacks include both reductions relative to 2014 expenditures, as well as reductions relative to previously announced 2015 expenditure plans.

95 Claudia Cattaneo, "Canadian oil producers brace for long downturn as Husky, MEG Energy, Penn West axe budgets," *Financial Post*, December 17, 2014, http://business.financialpost.com/2014/12/17/canadian-oil-producers-brace-for-long-downturn-as-husky-meg-energy-penn-west-axe-budgets/?__lsa=d351-9c89.

96 Reuters, "Canada's ARC Resources latest to cut budget as oil prices fall," January 7, 2015, http://www.reuters.com/article/2015/01/07/us-arc-resource-spending-idUSKBN0KG2BA20150107.

97 Bertrand Marotte, "Cenovus slashes 2015 spending by additional $700-million on low oil," *The Globe and Mail*, January 28, 2015, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/cenovus-slashes-2015-spending-by-additional-700-million-on-low-oil-prices/article22671621/.

98 *Calgary Herald*, "CNRL cuts $2.4 billion from 2015 capital spending plan," January 12, 2015, http://calgaryherald.com/business/energy/cnrl-cuts-2-4-billion-from-2015-capital-spending-plan.

99 Dan Healing, "Suncor cuts 1B in capital spending, plans to chop 1,000 positions," *Calgary Herald*, January 14, 2015, http://calgaryherald.com/business/energy/suncor-cuts-1b-in-capital-plans-to-chop-1000-positions.

100 Canadian Association of Petroleum Producers, "Increased access to markets remains critical despite recent oil price decline," News Release, January 21, 2015, http://www.capp.ca/aboutUs/mediaCentre/NewsReleases/Pages/access-to-markets-remains-critical.aspx.

March 2015, the EIA revised slightly upwards its production forecast for the first quarter of 2015 (+1.3 per cent). Its production forecast for the second quarter remained constant while the forecasts for the third and fourth quarters declined by 1.4 per cent and 3.0 per cent respectively.[101] U.S. production is still expected to grow in 2015 but only by 230,000 barrels per day as opposed to 660,000. In Canada, CAPP is expecting western Canadian oil production to increase by 150,000 barrels per day in 2015, with all of the increase coming from the oil sands (conventional oil production is expected to remain flat). This is a decline in growth of 65,000 barrels per day over CAPP's previous forecast.[102]

Most analysts are expecting a gradual recovery in oil prices to start in the second half of 2015 when slower production growth is realized. Current forecasts are unsurprisingly varied but generally predict the WTI price to average in the $50 to $55 range over the course of the year, rising back to $60 to $65 per barrel by the end of the year.[103,104]

THE 2015/16 FISCAL-YEAR IMPACT IN ALBERTA

Even more so than currently, in the 2015/16 fiscal year, Alberta will feel the brunt of the fall in oil prices through decreased government revenues. In its 2014/15 budget, the government's revenue forecast for WTI and Alberta wellhead prices (for light, medium and heavy crude) in the 2015/16 fiscal year were US$94.86 and $87.61 (CAD) respectively.[105] At these prices, crude oil royalties would range from zero to 40 per cent depending on the productivity of the well. At a forecast exchange rate of 0.91 CAD/USD the expected bitumen royalty rates in 2015/16 were 7.0 per cent of gross revenues for companies in pre-payout status and 36.3 per cent of net revenues for companies in post-payout status. The Alberta government also forecast crude oil production to fall slightly to 571,000 barrels per day in 2015/16 and bitumen production to expand to 2,548,000 barrels per day in 2015/16.[106] With these estimates, the government targeted $7.814 billion in crude oil and bitumen royalties in 2015/16.[107] The government has not provided a formal update on this target since the oil prices started declining, although as noted previously, Premier Prentice has stated that low oil prices could lead to government revenue shortfalls — which include the fall in bitumen and crude oil royalties, other non-renewable resource revenue and taxes — in the range of $6 to $10 billion.[108,109] We provide our estimates of the fall in each of these components below.

FISCAL YEAR 2015/16: CRUDE OIL ROYALTIES

The decline in conventional crude oil royalties is challenging to calculate since there are four categories of conventional oil, and the royalty rate for each well depends both on the oil category price and the volume of oil that is pumped from the well on a monthly basis. The government does not provide information in the budget documents on its assumptions with respect to well distributions, average well

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101 U.S. Energy Information Administration, *Short-Term Energy Outlook (STEO),* (March 2015).

102 Canadian Association of Petroleum Producers, "Increased access."

103 U.S. Energy Information Administration, *Short-Term Energy Outlook (STEO)* (March 2015).

104 Wittner, "Oil Price Collapse."

105 Government of Alberta, *Economic Outlook*

106 ibid.

107 Government of Alberta, *Budget 2014: Operational Plan*.

108 CBC News, "Alberta now."

109 CBC News, "Alberta finances."

productivity, or the average well royalty rate. With respect to pricing, the government provides only its assumption on the average wellhead price for light, medium and heavy crude. There is no information on the assumed price for ultra-heavy crude, nor any indication of the distribution of production across the different types of crude. Lastly, while the government provides an estimate of total crude oil production, it does not provide any information on its assumptions with respect to what percentage of total production is Crown production, how much Crown production qualifies for the new-well royalty rate, and the average productivity of these new wells. All of this information is relevant to constructing the forecast, and despite the historical data made available by Alberta Energy, we have not been able to accurately reconstruct the government's crude oil royalty forecast in the absence of this information.

We attempt a rough approximation of crude oil royalties for 2015/16 using three methods that are summarized below, and described in detail in Appendix B. For each method we look at the per cent decline in royalties from the government's forecast average wellhead price of $87.61 to average wellhead prices of $40, $45, $50, $55 and $60 (all CAD).[110] We focus on the percentage as opposed to the absolute decline since none of the methods we consider replicate the government of Alberta's forecast from the 2014/15 budget of crude oil royalties of $1,812 million in the 2015/16 fiscal year.

A summary of the estimates from each of the methodologies is provided in Table 4. Method 1 forecasts royalties based on average well productivity for all wells in the province. Method 2 divides wells in the province into two categories — low-production wells producing less than 6.20 barrels of oil per day (and often paying a zero royalty) and high-production wells — and estimates royalties separately for each category. Finally Method 3 uses Alberta Energy's historical data on Crown production distribution to estimate royalties by production ranges.

TABLE 4 2015/16 FISCAL-YEAR CRUDE OIL ROYALTY ESTIMATES

Average Wellhead Price (CAD)	Method 1: Average Well Productivity		Method 2: High and Low Production		Method 3: By Production Range	
	Expected Royalties	Per Cent Decline	Expected Royalties	Per Cent Decline	Expected Royalties	Per Cent Decline
$87.61	$1,845 million	-	$2,134 million	-	$2,821 million	-
$60.00	$647 million	-64.9%	$890 million	-58.3%	$1,492 million	-47.1%
$55.00	$381 million	-79.4%	$645 million	-69.8%	$1,240 million	-56.0%
$50.00	$87 million	-95.3%	$430 million	-79.8%	$1,021 million	-63.8%
$45.00	$0	-100.0%	$201 million	-90.6%	$804 million	-71.5%
$40.00	$0	-100.0%	$0	-100.0%	$618 million	-78.1%

As shown in Table 4, the three methodologies we employ lead to a large range in both the estimates of royalties and the percentage decline in royalties at lower oil prices. This highlights the sensitivity of crude oil royalties to the forecasting methodology and the need for greater transparency from the government of Alberta on its forecasting methods.

What should be the most accurate method — Method 3 — is actually the least accurate, resulting in an overestimate of royalties of 56 per cent relative to the government's forecast. There are three possible explanations for this. First, we assume in Method 3 that new production that qualifies for a reduced royalty rate follows the same well-productivity distribution as existing production. We make this assumption in the absence of better data on the well-productivity distribution of new production. However, it is admittedly a poor one as new production is predominantly coming from horizontal wells that tend to have higher production rates than that of existing vertical wells; i.e., relative to our current estimates, the distribution of new production is actually more heavily weighted towards higher-productivity wells. This implies that a greater number of high-production wells qualify for the

110 We use average wellhead prices of $40, $45, $50, $55 and $60 (CAD) as these correspond to percentage declines from the government's forecast average wellhead price of $87.61 that match, approximately, the decline in the government's forecast WTI price of US$94.86 to levels of US$45, US$50, US$55, US$60 and US$65.

five per cent royalty rate, a reduction typically in the range of 20 to 35 per cent relative to what they would otherwise pay.[111] Second, we use only the government's forecast average wellhead price in our estimates, which is the average for light, medium and heavy crude. Ultra-heavy crude, which accounts for approximately 18 per cent of Alberta's Crown crude oil production, will sell for a lower price, decreasing both the royalty rate for ultra-heavy oil wells and the value of the royalty collected.[112] Finally, if we look back to earlier in the 2014/15 fiscal year, crude oil royalties collected in the first half of the fiscal year were 30 per cent higher than the government's forecast. This suggests the possibility that the government's forecasting methodology may have a tendency to underestimate crude oil royalties.

While methods 1 and 2 come significantly closer to replicating the absolute value of the government's 2015/16 forecast, they both face an inherent shortcoming. More specifically, Alberta's production profile is characterized by a large number of wells producing a small proportion of oil. In 2013, 44.4 per cent of Alberta's wells — 17,443 in total — pumped fewer than 6.20 barrels of oil per day, contributing just under nine per cent to total production.[113] This large number of low-productivity wells pulls down the average well-productivity rate across the province. In Method 1 this creates an inherent underestimate of the royalty rate and results in an estimate of zero royalties at prices of $40 and $45. Method 2 partially addresses this problem by separating out the lowest-producing wells, but an estimate of zero royalties at a price of $40 indicates that an inherent underestimation of the royalty rate still exists.

As a result, despite the inaccuracy of Method 3 in replicating the absolute value of the government's 2015/16 forecast for crude oil royalties, we believe it is the most accurate for predicting relative changes and use the percentage declines from only this method to estimate the decline in the government's forecast. A summary of these estimates is provided in Table 5. Applying the percentage fall at each price level to the government's forecast crude oil royalties of $1,812 million, we find the monetary value of the decline in forecast royalty payments from lower oil prices in 2015/16 could range from $853 to $1,415 million.

TABLE 5 ESTIMATES OF CRUDE OIL ROYALTY DECLINES FOR 2015/16

Average Wellhead Price (CAD)	Per Cent Decline in Royalties	Decline in Government Crude Oil Royalty Estimate
$60.00	-47.1%	-$853 million
$55.00	-56.0%	-$1,016 million
$50.00	-63.8%	-$1,156 million
$45.00	-71.5%	-$1,295 million
$40.00	-78.1%	-$1,415 million

Note: The government of Alberta's forecast value from the 2014/15 fiscal-year budget for crude oil royalties in the 2015/16 fiscal year was $1,812 million. The value of the decline in the government's crude oil royalty estimate is equal to this amount multiplied by the percentage decline at each price level.

111 As a check of this explanation we estimated royalties assuming that total Crown production followed the distribution implied by Alberta Energy's historical data, but that new production only comes from wells with a productivity rate of 20.69 barrels per day or higher. Using this method our royalty estimate decreases by $500 million. We do not formally report these results, as the minimum production threshold we choose for new wells is arbitrary. However, it points towards the impact of underestimating the number of high-productivity wells that qualify for the new-well royalty reduction rate.

112 Alberta Energy website, "Conventional Oil."

113 Alberta Energy Regulator, "Crude-oil data set"; and Alberta Energy website, "New Royalty Framework."

FISCAL YEAR 2015/16: BITUMEN ROYALTIES

At current oil prices, the government's bitumen royalties for the 2015/16 fiscal year will fall far short of its $5.942 billion target from the 2014/15 fiscal-year budget. This is due to five contributing factors. The first three are the primary contributors discussed before — a negative royalty-rate effect that reflects the impact of a lower royalty rate, a negative price effect that reflects the impact of lower WTI/WCS prices and a positive exchange-rate effect that reflects the impact of a falling exchange rate. The remaining two factors are relevant only in the medium to long term and have a secondary impact. The status effect reflects the impact of companies earning lower gross revenues and remaining in pre-payout status, and paying lower royalties, for a longer period of time. Finally, the production effect reflects the fact that, as companies decrease capital investment, anticipated growth will slow, and actual production will likely fall short of forecasts.

A summary of the impact of the first three factors, for an average WTI price in 2015 ranging from $45 to $65 per barrel, and assuming an average exchange rate of 0.800 USD/CAD and a WTI/WCS differential of 27 per cent, is provided in Table 6.[114] To estimate royalties we use the same back-of-the-envelope model that we previously used to estimate bitumen royalties for the remainder of the 2014/15 fiscal year. As was the case previously, we are required to make significant assumptions in our estimates due to a lack of information from the government on key variables that influence the royalty forecast. Specifically, in our calculations we assume bitumen production grows as forecast to 2,548,000 barrels per day in 2015/16. Of this production, we assume 2,504,000 barrels per day is Crown production,[115] divided into 2,480,000 barrels per day of project production and 23,500 barrels of non-project production.[116] We again do not estimate non-project royalties due to a lack of data. Of the project production we assume 1,001,000 barrels are upgraded to synthetic crude oil, with gross revenue per barrel approximated by the WTI price.[117] We assume the remainder of production is non-upgraded bitumen, with gross revenue per barrel approximated by the WCS price. Lastly, we assume the production split between pre- and post-payout projects is 38.5/61.5 per cent for both upgraded and non-upgraded bitumen.[118,119]

Applying the above assumptions in our back-of-the-envelope model, we calculate the percentage decline in royalties from the government's initial forecast WTI price (from the 2014/15 budget) for the 2015/16 fiscal year of $94.86 to WTI prices ranging from $45 to $65 per barrel. We then apply the percentage declines to the government's initial royalty estimate for 2015/16 of $5.942 billion and calculate the expected monetary value of the decline in the government's royalty estimate.

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114 The average exchange rate was chosen to match the average exchange rate in February 2015. The value of the differential matches the government's forecast for 2015/16 from its 2014/15 budget. Source: Government of Alberta, *Budget 2014, Fiscal Overview*.

115 We estimate total Crown bitumen production using the same methods described in footnote 82.

116 We estimate total non-project Crown bitumen production using the same methods described in footnote 83.

117 The assumption of 1,001,000 barrels per day of synthetic crude oil is based on the Alberta Energy Regulator's forecast for 2015 production of Alberta upgraded bitumen. Source: Alberta Energy Regulator, "ST98: Alberta's Energy."

118 Our estimate for the production split between pre- and post-payout projects was based on the 2013 production split of 34/66 per cent. We then calculated the average growth in post-payout production over the previous five years (2009 to 2013), equal to 5.77 per cent. Assuming post-payout production grows at this rate from 2013 to 2014 and 2014 to 2015 we arrive at our estimate of a 2014 production split of 38.5/61.5 per cent for pre- and post-payout projects.

119 The government's forecast value for bitumen royalties in 2015/16 was $5,962 million. As a check of our assumptions regarding production splits and per-barrel gross revenues, and the accuracy of our estimation method relative to the government of Alberta's forecast methodology, we estimate total royalties for the 2015/16 fiscal year using the 2015/16 forecast price and exchange-rate values from the government's 2014/15 budget. Specifically, using a WTI price of $94.86 per barrel, a WCS/WTI differential of 27 per cent and an exchange rate of 0.91 (USD/CAD), we estimate annual royalties for 2015/16 of $5,670 million, 3.3 per cent lower than the government of Alberta's forecast. As we are not estimating non-project royalties, which have accounted for (on average) 2.6 per cent of annual royalties in recent years, that puts our estimate within approximately 0.7 per cent of the government of Alberta's forecast. This suggests our assumptions and estimation method can provide a reasonable estimate of changes in 2015/16 fiscal-year royalties.

As shown in Table 6, relative to the government's target for the 2015/16 fiscal year, the combined effect of lower royalty rates, lower prices and a lower exchange rate will lead to a potential decline in royalty revenues of 41 to 74 per cent, corresponding to a monetary drop of $2,440 to $4,371 million. The declining royalty rate has the largest impact on the decrease in royalties and, as expected, this effect grows as the expected WTI price declines. The magnitude of the price effect gradually increases when moving from a WTI price of $65 to $50, and then declines slightly at the lowest WTI price of $45. This small decline in the price effect is reflective of the relative strength of the royalty-rate effect. With significantly lower total royalties being paid at a WTI price of $45, the effect of the lower price on the value of these remaining royalties is smaller. Lastly, the exchange-rate effect consistently declines as the expected WTI price declines. This reflects the positive exchange-rate effect applying to a lower royalty total at lower prices.

The status effect and production effect are more difficult to isolate, but their impacts will also be secondary. Table 7 summarizes the extreme case of no production growth in 2015/16 and no transition of projects from pre- to post-payout status. Considering the same average WTI price range of $45 to $65, the combined status and production effects reduce estimated royalties by an additional $211 to $374 million, or 3.6 to 6.3 per cent. The two effects move in different directions with the status effect getting larger as the price falls and the production effect getting smaller. This is because the difference between the royalty rates for pre- and post-payout projects increases as the price falls (increasing the status effect), while the actual royalty paid falls, reducing the value of lost production (and decreasing the production effect).

TABLE 6 ESTIMATES OF BITUMEN ROYALTY DECLINES FOR 2015/16: ROYALTY-RATE, PRICE AND EXCHANGE-RATE EFFECTS

WTI Price (US)	Per Cent Decline in Royalties	Decline in Government Royalty Estimate	Royalty-Rate Effect	Price Effect	Exchange-Rate Effect
$65.00	-40.9%	-$2,440 million	-$1,444 million	-$1,422 million	+$426 million
$60.00	-50.2%	-$2,994 million	-$1,837 million	-$1,516 million	+$359 million
$55.00	-58.7%	-$3,500 million	-$2,229 million	-$1,569 million	+$298 million
$50.00	-66.4%	-$3,959 million	-$2,622 million	-$1,580 million	+$252 million
$45.00	-73.3%	-$4,371 million	-$3,014 million	-$1,549 million	+$192 million

Note: The government of Alberta's forecast value from the 2014/15 fiscal-year budget for crude oil royalties in the 2015/16 fiscal year was $5,962 million. The value of the decline in the government's bitumen royalty estimate is equal to this amount multiplied by the percentage decline at each price level. The calculation of the per cent decline in royalties assumes an average exchange rate for the 2015/16 fiscal year of 0.800 (USD/CAD), an average WTI/WCS differential of 27 per cent, and average project Crown production of 2,480,000 barrels per day.

TABLE 7 ADDITIONAL ROYALTY IMPACT FROM STATUS EFFECT AND PRODUCTION EFFECT

WTI Price (US)	Additional Per Cent Decline	Decline in Government Royalty Estimate	Additional Decrease	Status Effect	Production Effect
$65.00	-6.3%	-$2,814 million	-$374 million	-$171 million	-$203 million
$60.00	-5.5%	-$3,323 million	-$329 million	-$178 million	-$151 million
$55.00	-4.8%	-$3,787 million	-$287 million	-$181 million	-$106 million
$50.00	-4.2%	-$4,207 million	-$248 million	-$181 million	-$67 million
$45.00	-3.6%	-$4,583 million	-$211 million	-$178 million	-$33 million

FISCAL YEAR 2015/16: OTHER NON-RENEWABLE RESOURCE REVENUE

In addition to the bitumen and crude oil royalty, Alberta also receives significant non-renewable resource revenue from its natural gas and byproduct royalty and from sales of Crown land leases. In the 2014/15 budget, the government targeted revenues from these categories for the 2015/16 fiscal year of $823 million and $623 million respectively. With the natural gas price also falling below the government's initial forecasts, and with land leases becoming less valuable to companies facing lower oil and gas prices, both of these sources of revenue will also be impacted by the oil price fall.

Considering first the impact on land-lease revenue, the average lease price per hectare from October 2014 through February 2015 is $309.61. This is a 28 per cent decrease from the average price of $428.01 over the same time horizon from one year earlier (October 2013 through February 2014). The largest single month differential is in February. The average lease price per hectare in February 2015 of $201.21 is nearly 55 per cent lower than the average price of $440.70 from February 2014. These numbers do not yet point to any clear trends as land-lease revenue and sale prices tend to fluctuate quite heavily from one year to the next, even in the absence of significant volatility in the oil price, as they will depend heavily on the expected quality of the resource on the land that is put forward for lease. However, if current patterns persist, then this roughly indicates the government could be facing a 25 to 55 per cent decrease in forecast land revenues. This corresponds to a decline that could range from $156 to $343 million.

The EIA's February 2015 price forecast for WTI is $55.02, a decline of approximately $40 from the government of Alberta's forecast WTI price for the 2015/16 fiscal year of $94.86. As a rough approximation we assume that a $40 decline in the WTI price will result in a 40 per cent decline in land revenue (the midpoint of the 25 to 55 per cent range we just identified). If we further assume the percentage decline in land-lease revenues decreases linearly with the fall in the WTI price, then we can roughly approximately the fall in land-lease revenue at WTI prices ranging from $45.00 to $65.00. These results are summarized in Table 8. All of the revenue declines fit within the range of $156 to $343 million that we previously identified.

TABLE 8 LAND-LEASE REVENUE DECLINES, 2015/16 FISCAL YEAR

WTI Price	Decline in Land-Lease Revenue	
	Per cent	Value
$65.00	-30.0%	-$187 million
$60.00	-35.0%	-$218 million
$55.00	-40.0%	-$249 million
$50.00	-45.0%	-$280 million
$45.00	-50.0%	-$311 million

Note: The government of Alberta's forecast value from the 2014/15 fiscal-year budget for land-lease revenue in the 2015/16 fiscal year was $623 million. The value of the decline in land-lease revenue is equal to this amount multiplied by the per cent decline at each price level.

Finally, with the impact of falling oil prices spilling over into lower natural gas prices, we very briefly consider the potential decline in natural gas royalties. Natural gas royalties are calculated similarly to crude oil royalties in that they depend on both a price component and a quantity component that is determined by the productivity of the natural gas well. The royalty rate is well specific and equal to the sum of the price and quantity components. It has a minimum value of five per cent and a maximum value of 36 per cent.

In the 2014/15 fiscal-year budget the government forecast natural gas royalties of $823 million for the 2015/16 fiscal year. This target was based on a 2015/16 fiscal-year natural gas price of $3.73 (CAD) per gigajoule (GJ), which corresponds to a price component of the royalty rate of -3.5 per cent. As of early March 2015, the average natural gas price in Alberta for 2015 is forecast at $2.69 (CAD) per GJ, which corresponds to a price component of the royalty rate of -8.2 per cent.[120] At current prices, the government is therefore facing declines in the natural gas royalty rate of zero to 4.7 per cent below its forecast.[121]

As was the case with crude oil royalties, the exact decrease in the royalty rate for each natural gas well will depend on the quantity component of the royalty rate, which in turn depends on the productivity of the natural gas well. We have not looked for data on the distribution of natural gas wells in Alberta by productivity since the decline in natural gas prices is not the focus of this report. Therefore, to calculate the potential decline in natural gas royalties we instead use the government's sensitivity to fiscal-year assumptions from the 2014/15 budget. The sensitivity for the price of natural gas states that a 10-cent decline in the natural gas price (measured in Canadian dollars per GJ) will result in an $8 million decline in total government revenues. Allocating the entirety of this decline to natural gas royalties, we estimate that at a natural gas price of $2.69 (CAD) per GJ (a $1.04 (CAD) decline below the forecast value of $3.73), natural gas royalties will decline by $83.2 million.

FISCAL YEAR 2015/16: TAX REVENUE

The primary source of a decline in taxes will be the decline in corporate tax revenue from oil and gas companies. Alberta currently has a corporate tax rate of 10 per cent of a company's taxable income, which (loosely) is equal to its gross revenues minus deductible expenses. Revenues of oil and gas companies will decrease dramatically with lower oil prices. Suncor, for example, announced in early February 2015 an 81 per cent drop in earnings for the fourth quarter of 2014 relative to 2013.[122] While the tax rate that companies face will not change, the fall in taxable income will mean lower taxes paid to both the provincial and federal government.

Alberta will also absorb an indirect tax impact from a slowdown in economic growth. Alberta has led the country in GDP growth for the past 20 years with an annual average growth rate of 3.5 per cent.[123] Despite falling oil prices over the second half of 2014, most economic outlooks are currently forecasting that 2014 real GDP growth will exceed this average, ranging from 3.5 to 4.3 per cent.[124] However, these same outlooks also suggest Alberta's real economic growth will fall by over three percentage points from 2014 to 2015, leaving it hovering around 0.5 to one per cent, and that the unemployment rate will rise by between 0.5 and 1.0 percentage points, increasing to between five and six per cent.[125] The slower growth rate and higher unemployment rate will lower corporate and personal income taxes across the province, and thereby lower taxes that the province collects outside of the oil and gas sector as well.

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120 GasAlbertaInc., "Market Prices," http://www.gasalberta.com/pricing-market.htm.

121 Small natural gas wells with relatively low flow rates face a flat royalty rate of five per cent and will not be impacted by falling prices. Natural gas wells qualifying for one of the province's natural gas royalty reduction programs will also be less impacted by falling prices.

122 Geoffrey Morgan, "Suncor Energy Inc profit shrinks more than 80% amid oil rout," *Financial Post*, February 5, 2015, http://business.financialpost.com/2015/02/05/suncor-energy-inc-profit-shrinks-more-than-80-amid-oil-rout/?__lsa=ec4f-3589.

123 Canada. Government of Alberta, "Alberta Canada: Economic Results," http://albertacanada.com/business/overview/economic-results.aspx.

124 The low forecast of 3.5 per cent real GDP growth rate in 2014 is from BMO Capital Markets, while the high forecast of 4.3 per cent is from National Bank. Source: Canada. Government of Alberta, "Budget 2015: Economic forecasts," http://alberta.ca/budget-economic-forecasts.cfm.

125 Canada. Government of Alberta, "Budget 2015: Economic forecasts."

Estimating the decline in taxes is a much more difficult task than estimating the decline in royalties and is beyond the scope of this paper. However, we can back out the expected tax losses by looking at what's accounted for in the government's total by our estimates of the bitumen royalty, crude oil royalty and other non-renewable resource revenue declines. These breakdowns are provided in the next section.

FISCAL YEAR 2015/16: BREAKDOWN OF ANTICIPATED REVENUE DECLINES BY SOURCE

Throughout the first quarter of 2015, Premier Prentice has been conditioning Albertans to expect a significant decline in government revenues in the 2015/16 fiscal year. As noted previously, he has stated an average WTI price of $65 in the 2015/16 fiscal year will drop projected government revenues by $6 to $7 billion, while a WTI price below $50 will drop projected revenues by up to $10 billion. To obtain more accurate estimates of the government's expected revenue shortfall, we estimate the shortfall at various oil prices using the government's original forecasts for 2015/16, and the sensitivity assumptions from the government's 2014/15 fiscal-year budget. This information is summarized in Table 9.

TABLE 9 GOVERNMENT REVENUE SENSITIVITIES TO FISCAL-YEAR ASSUMPTIONS

Variable	Forecast Value for 2015/16	Change in Forecast	Revenue Impact
Oil Price (WTI $US/bbl)	$94.86	-$1.00 (US)	-$215 million
Exchange Rate (US cents/CAD)	0.91	+1 cent	-$179 million
Natural Gas Price ($Cdn/GJ)	$3.73	-10 cents	-$8 million
Household Income	6.2%	-1 per cent	-$141 million

Source: Alberta Finance, "Budget 2014: Operational Plan."

Note: The "Change in Forecast" and "Revenue Impact" columns are taken directly from the Operational Plan of the 2014 budget. The revenue impact is the change in government revenue from a one-unit change in the forecast. For example, according to these sensitivities, a $1 decline in the WTI price will result in a $215 million decline in total government revenues.

Our calculations of estimated government revenue shortfalls in the 2015/16 fiscal year are provided in Table 10. We calculate government revenue shortfalls at WTI prices ranging from $45 to $65, assuming the natural gas price is fixed at $2.69 (a $1.04 decline below forecast), household income growth is fixed at 3.1 per cent (a 3.1 per cent decline below forecast)[126] and the exchange rate is fixed at 0.800 (an 11 cent decline below forecast).[127] While the decline in natural gas and household income is expected to result in a government revenue shortfall of $83 million and $47 million, the decline in the exchange rate is expected to increase government revenues by $2.651 billion.[128] The net change in government revenues from these fixed components is therefore an increase in revenues of $2.131 billion. Once accounting for the decreasing WTI price, however, the net change in government revenues is a significant decline at all price levels, ranging from -$4.319 billion at a WTI price of $65 to -$8.619 billion at a WTI price of $45.

Interestingly, our estimates fall approximately $2.0 billion short of the revenue shortfalls that have been announced by Premier Prentice at the various WTI price levels. We expect this is due to our assumption of an average exchange rate in the 2015/16 fiscal year of 0.800 CAD/USD. This is significantly lower

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126 The government announced in its third-quarter 2014/15 fiscal update that it is expecting household income growth to slow to 3.1 per cent in the 2015/16 fiscal year. Source: Government of Alberta, *Budget 2014: Third Quarter.*

127 We use an exchange rate of 0.800 as this was the average exchange rate in February 2015.

128 The change in government revenue attributable to each source is equal to the change in the value of the source from forecast multiplied by the revenue impact for a one-unit change from Table 9. For natural gas royalties only, the change from forecast needs to be converted to units of 10 cents to match the unit for natural gas prices in Table 9. More specifically, a decline of $1.04 in the natural gas price is equivalent to a decline of 10.4 "10-cent" units. The government revenue shortfall attributable to natural gas is therefore equal to -10.4 multiplied by $8 million, which equals -$83.2 million.

than the government's current exchange-rate assumption for 2015 of 0.883 CAD/USD.[129] Using the government's exchange-rate assumption, our estimate of the government revenue shortfall at each WTI price level increases by exactly $2.0 billion. We choose to use the lower exchange-rate forecast as all indications are that the exchange rate is unlikely to rise over the 2015/16 fiscal year. Rather, most forecasters are expecting it to decline even further, potentially reaching 0.750 USD/CAD by the end of 2015.[130]

TABLE 10 ESTIMATE OF GOVERNMENT REVENUE SHORTFALLS, 2015/16 FISCAL YEAR

WTI Price		Natural Gas Price		Household Income Growth		Exchange Rate		Estimated Government Revenue Impact
Value	Change from Forecast	Value	Change from Forecast	Value	Change from Forecast	Value	Change from Forecast	
$65.00	-$30.00	$2.69	-$1.04	3.1%	-3.1%	0.800	$0.11	-$4.289 billion
$60.00	-$35.00	$2.69	-$1.04	3.1%	-3.1%	0.800	$0.11	-$5.364 billion
$55.00	-$40.00	$2.69	-$1.04	3.1%	-3.1%	0.800	$0.11	-$6.439 billion
$50.00	-$45.00	$2.69	-$1.04	3.1%	-3.1%	0.800	$0.11	-$7.514 billion
$45.00	-$50.00	$2.69	-$1.04	3.1%	-3.1%	0.800	$0.11	-$8.589 billion

Note: The estimated government revenue is the sum of the individual revenue impacts from the change in the WTI price, natural gas price, household income growth and exchange rate.

Using the calculations from earlier in this paper, Table 11 provides a summary of the breakdown in anticipated government revenue shortfalls by source. Figure 11 provides a graphical representation of the breakdown at a WTI price of $55, the closest to the government of Alberta's March 2015 projection for the price of WTI in 2015.[131]

At all WTI price levels we find the majority of the decline, as expected, is attributable to the fall in crude oil royalties and bitumen royalties. Interestingly, however, the relative share of crude oil and bitumen royalties to the overall revenue shortfall declines as the price of oil falls. Specifically, at a price of $65 we find crude oil and bitumen revenue declines account for 79 per cent of the revenue shortfall, while at a WTI price of $45 they account for 67 per cent of the shortfall.

The contribution of other non-renewable resource revenue is relatively constant under our assumptions. As a result, as the contribution of crude oil and bitumen royalties to the total government revenue shortfall declines, the remaining shortfall, which we attribute to the decline in taxes, grows. At a WTI price of $65 we estimate taxes accounts for 12 per cent of the government revenue shortfall. The tax contribution rises to 28 per cent at a price of $45. This likely reflects the indirect economic impacts from the oil price fall — most notably increased unemployment and slower economic growth — which become more pronounced at lower oil prices and have an increasingly larger effect on tax revenues.

[129] The government has not formally announced an updated exchange-rate assumption for the 2015/16 fiscal year. However, in its monthly royalty-rate bulletins for oilsands projects, it identifies its estimated exchange rate for all upcoming months in the remainder of the royalty year, as this information is required for calculating the expected annual royalty rates for post-payout projects. In the February 2015 royalty-rate bulletin, posted on March 2, 2015, the government estimates a monthly exchange rate of 0.883 for March 2015 through to December 2015. Source: Alberta Energy, *Oil Sands Monthly.*

[130] Scotiabank and Royal Bank are both currently forecasting an exchange rate of 0.752 for the fourth quarter of 2015. Sources: RBC Economics, "Keeping an open mind," *Financial Markets Monthly* (March 6, 2015), http://www.rbc.com/economics/economic-reports/pdf/financial-markets/fmm-March2015.pdf; and Scotiabank, *Foreign Exchange Outlook* (March 2015), http://www.gfx.gbm.scotiabank.com/Chart_Feed/fxout.pdf.

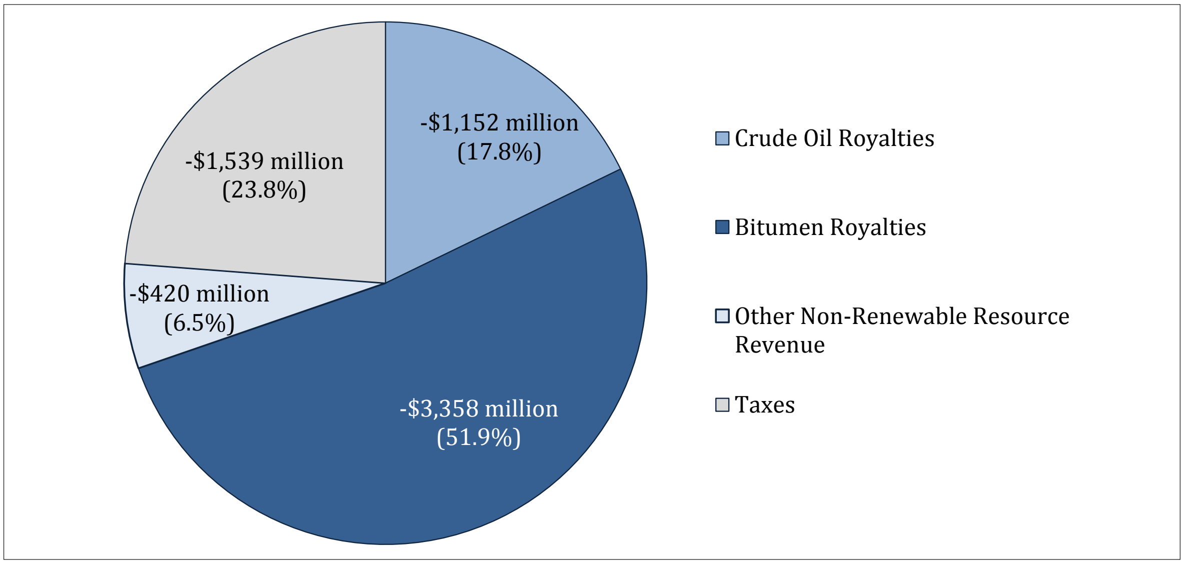
[131] Source: Alberta Energy, *Oil Sands Monthly.*

TABLE 11 BREAKDOWN OF EXPECTED GOVERNMENT REVENUE SHORTFALLS FOR 2015/16 FISCAL YEAR BY REVENUE SOURCE ($ MILLION)

WTI Price	Estimated Government Revenue Impact	Crude Oil Royalties		Bitumen Royalties		Other Non-Renewable Resource Revenue		Taxes	
		Value	Share	Value	Share	Value	Share	Value	Share
$65.00	-$4,289	-$853	19.9%	-$2,440	56.9%	-$270	6.3%	-$725	16.9%
$60.00	-$5,364	-$1,016	18.9%	-$2,994	55.8%	-$301	5.6%	-$1,054	19.6%
$55.00	-$6,439	-$1,156	18.0%	-$3,500	54.4%	-$332	5.2%	-$1,451	22.5%
$50.00	-$7,514	-$1,295	17.2%	-$3,959	52.7%	-$363	4.8%	-$1,897	25.2%
$45.00	-$8,589	-$1,415	16.5%	-$4,371	50.9%	-$394	4.6%	-$2,409	28.0%

Note: At each WTI price level the value of the decline in taxes is equal to the estimated government revenue impact minus the contributions of crude oil royalties, bitumen royalties and other non-renewable resource revenues.

FIGURE 11 BREAKDOWN OF ESTIMATED $6.4 BILLION DECLINE IN GOVERNMENT REVENUES FOR AN AVERAGE 2015/16 WTI PRICE OF $55



CONCLUSION

With the bottom-out point of oil prices still unknown, there remains little certainty over the exact degree of the impact on Alberta. Given how far oil prices have already fallen however, we do know that it will be significant — particularly the decline in government revenues — and that it will grow and persist as oil prices continue to fall, and the longer they stay low. Our objective in this report was to explain Alberta's crude oil and bitumen royalty system, and provide insight as to how declining oil prices will likely impact government revenues in the 2014/15 and 2015/16 fiscal years.

The reality of unpredictable oil prices creating volatility in Alberta's government revenues is nothing new. Rather, it is a reality that Alberta has sometimes struggled with, and at other times benefited from, over the course of the last 30 years. Through this report we aimed to clarify how volatility in oil prices transfers to volatility in government revenues by explaining how royalties are calculated and providing estimates of the decline in bitumen and crude oil royalties at a range of lower oil prices. We found that constructing our estimates of changes in royalties required us to make significant assumptions beyond those provided by the government in the budget. Specifically, while the government clearly states its assumptions for WTI price, average Alberta wellhead price, exchange rate, WTI/WCS differential and base crude oil and bitumen production, it fails to provide further key information that is significant in determining royalties. Among the information that is missing are assumptions regarding the allocation of bitumen production between pre- and post-payout projects, the production split between upgraded and non-upgraded bitumen, the crude oil production split between the light, medium, heavy and ultra-heavy categories, the proportion of crude oil production that qualifies for a royalty discount, the proportion of crude oil and bitumen production that is Crown production, or any information on the average productivity of crude oil wells (necessary for calculating the quantity component of the crude oil royalty rate).

Given the significance of royalties as a revenue source for Alberta it is important for the government to provide more information on how royalties are forecasted and the assumptions that are used. This will significantly increase the transparency behind a vital revenue source to Alberta at a time when it is crucial to understand how that revenue source is changing.

APPENDIX A:DISTRIBUTION OF CRUDE OIL WELLS IN ALBERTA BY PRODUCTION RANGES

TABLE A1 CRUDE OIL WELLS IN ALBERTA BY AVERAGE PRODUCTIVITY: IMPACT OF PRICE DECLINE ON CRUDE OIL ROYALTY RATES

Well Productivity (Barrels/Day)	Share of Crown Production	Average Well Productivity	Royalty Rate at Forecast Price for 2014.15 ($88.02)	New Royalty Rate after Price Fall			Royalty Rate Decline (From Forecast to March)
				Jan. ($68.24)	Feb. ($52.28)	March ($36.54)	
0.02–1.02	0.25%	0.52	0.0%	0.0%	0.0%	0.0%	0.0%
1.03–2.06	0.79%	1.55	0.2%	0.0%	0.0%	0.0%	-0.2%
2.07–4.13	3.18%	3.09	2.1%	0.0%	0.0%	0.0%	-2.1%
4.14–6.19	4.59%	5.17	4.8%	0.0%	0.0%	0.0%	-4.8%
6.20–8.26	5.01%	7.24	7.4%	1.5%	0.0%	0.0%	-7.4%
8.27–10.33	4.73%	9.31	10.0%	4.1%	0.0%	0.0%	-10.0%
10.34–12.40	4.44%	11.38	12.6%	6.7%	0.0%	0.0%	-12.6%
12.41–14.47	4.01%	13.45	15.2%	9.3%	0.7%	0.0%	-15.2%
14.48–16.54	3.61%	15.52	17.8%	11.9%	3.3%	0.0%	-17.8%
16.55–18.61	3.32%	17.59	20.4%	14.5%	5.9%	0.0%	-20.4%
18.62–20.68	3.07%	19.65	23.0%	17.1%	8.5%	0.0%	-23.0%
20.69–22.75	2.76%	21.72	25.6%	19.7%	11.1%	2.0%	-23.5%
22.76–24.81	2.57%	23.79	26.8%	20.9%	12.4%	3.3%	-23.5%
24.83–26.88	2.40%	25.86	27.8%	21.9%	13.4%	4.3%	-23.5%
26.89–28.95	2.14%	27.93	28.8%	22.9%	14.4%	5.3%	-23.5%
28.96–31.02	2.00%	30.00	29.8%	23.9%	15.4%	6.4%	-23.5%
31.03–33.09	1.92%	32.07	30.8%	24.9%	16.4%	7.3%	-23.5%
33.10–35.16	1.75%	34.14	31.8%	25.9%	17.4%	8.3%	-23.5%
35.17–37.23	1.65%	36.21	32.8%	26.9%	18.4%	9.3%	-23.5%
37.24–39.30	1.59%	38.27	33.8%	27.9%	19.4%	10.3%	-23.5%
39.31–41.37	1.45%	40.34	34.8%	28.9%	20.4%	11.3%	-23.5%
41.38–51.71	6.34%	46.55	37.0%	31.1%	22.5%	13.4%	-23.5%
51.72–62.05	4.83%	56.89	40.0%	34.6%	26.0%	16.9%	-23.1%
61.06–71.40	3.71%	67.24	40.0%	37.3%	28.7%	19.6%	-20.4%
72.41–82.74	2.97%	77.58	40.0%	38.8%	30.2%	21.1%	-18.9%
82.75–93.09	2.48%	87.93	40.0%	40.0%	31.7%	22.6%	-17.4%
93.10–103.43	2.16%	98.27	40.0%	40.0%	33.2%	24.1%	-15.9%
103.44–118.37	2.59%	110.89	40.0%	40.0%	35.0%	25.9%	-14.1%
118.38–206.88	9.08%	162.62	40.0%	40.0%	40.0%	32.4%	-7.6%
206.89–413.77	5.85%	310.33	40.0%	40.0%	40.0%	32.4%	-7.6%
413.78–620.66	1.35%	517.22	40.0%	40.0%	40.0%	32.4%	-7.6%
620.67–827.55	0.53%	724.11	40.0%	40.0%	40.0%	32.4%	-7.6%
827.56–1034.44	0.22%	931.00	40.0%	40.0%	40.0%	32.4%	-7.6%
1034.45–2068.89	0.65%	1,551.67	40.0%	40.0%	40.0%	32.4%	-7.6%

Author calculations. Source: Alberta Energy, "New Royalty Framework Royalty Volumes 2014."

Note: The original data set from Alberta Energy measures well productivity in cubic metres per month. We assume average productivity in each production range is equal to the midpoint of the production range when measured in cubic metres per month. As a result, due to rounding, the average productivity numbers reported here in barrels per day do not always correspond to the exact midpoint of the reported production ranges.

APPENDIX B: METHODS FOR ESTIMATING CRUDE OIL ROYALTIES

The following methods are used to estimate crude oil royalties for the 2015/16 fiscal year. Results are summarized in the main text in Table 4. For each method we start by estimating crude oil royalties at the government's initial 2015/16 forecast of an average wellhead price of $87.61 (CAD) and production of 571,000 barrels of crude oil per day.[132] These forecast values for 2015/16 are from the 2014/15 fiscal-year budget. Since the government provides only the average wellhead price, we do not distinguish among categories of crude in our calculations. We assume the Crown production percentage is 79 per cent (451,200 barrels per day), equal to the average Crown production percentage from 2009 to 2013.[133] Lastly, we assume 195,000 barrels per day of production from new vertical or horizontal wells, of which 79 per cent (154,100 barrels per day) is Crown production that qualifies for a reduced royalty rate.[134] This leaves 297,100 barrels per day of established Crown crude oil production that pays royalties according to the standard royalty formulas for crude oil.

1. Average Well Productivity

The average well productivity in Alberta in 2013 was 14.8 barrels of oil per day.[135] If we assume average well productivity is not significantly changed in 2015/16 then, at the government's forecast 2015/16 average wellhead price of $87.16, the average established-production well in Alberta would be paying a royalty rate of 16.8 per cent and the average new-production well would be paying a royalty rate of 5.0 per cent. The estimate of expected royalties for the year from all wells is $1,845 million (an overestimate of 1.8 per cent relative to the government of Alberta's initial forecast). As shown in Table B1, at average wellhead prices of $40 to $60 per barrel the royalty rate for the average established-production well declines to between zero and 7.4 per cent. For the average new-production well, the royalty rate remains at 5.0 per cent at prices of $60 and $55, and declines to between zero and 4.2 per cent at lower prices. The estimate of total collected royalties from all wells declines by 65 to 100 per cent.

TABLE B1 CRUDE OIL ROYALTY ESTIMATES FOR 2015/16 FISCAL YEAR: BY OVERALL AVERAGE WELL PRODUCTIVITY

Average Wellhead Price (CAD)	Established Crown Production		New Crown Production		Total Royalties	% Decline in Total Royalties
	Royalty Rate	Expected Royalties	Royalty Rate	Expected Royalties		
$87.16	16.8%	$1,599 million	5.0%	$246 million	$1,845 million	-
$60.00	7.4%	$478 million	5.0%	$169 million	$647 million	-64.9%
$55.00	4.2%	$251 million	4.2%	$130 million	$381 million	-79.4%
$50.00	1.1%	$57 million	1.1%	$30 million	$87 million	-95.3%
$45.00	0.0%	$0	0.0%	$0	$0	-100.0%
$40.00	0.0%	$0	0.0%	$0	$0	-100.0%

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[132] Government of Alberta, *Budget 2014: Operational Plan*.

[133] Alberta Energy, "Conventional Oil."

[134] We define a new horizontal well as one that started production in 2014 or 2015 and a new vertical well as one that started production in 2015. We include two years of expected new production for horizontal wells as new horizontal wells are eligible for the five per cent flat-rate royalty for up to four years (depending on depth of the well) and we assume the average length is two years. We include only a single year for vertical wells as new vertical wells are only eligible for the reduced royalty rate for a single year. The numbers for new production are equal to the expected production numbers for 2014 and 2015 from the data set for the Alberta Energy Regulator's ST98-2014 report (http://www.aer.ca/data-and-publications/statistical-reports/st98).

[135] Author calculations. Source: Alberta Energy Regulator, "Crude-oil data set."

2. Average Well Productivity: Low- and High-Producing Wells

In our second method for estimating royalties we separate out the lowest category of production wells — those producing less than 6.20 barrels of oil per day — from both new and established production. We then estimate royalties for four subcategories of wells as shown in Table B2; the average low-production new well, the average low-production established well, the average high-production new well and the average high-production established well. Results of our royalty estimates are shown in Table B3.

TABLE B2 CRUDE OIL ROYALTY ESTIMATE FOR 2015/16 FISCAL YEAR: ESTIMATED PRODUCTION FROM LOW- AND HIGH-PRODUCTIVITY WELLS

Well Productivity	Share of Total Production	Number of Barrels Per Day	
		Established Crown Production	New Crown Production
Low Production (< 0 — 6.19 bpd)	8.8%	26,200	13,600
High Production (> 6.19 bpd)	91.2%	270,900	140,500

TABLE B3 CRUDE OIL ROYALTY ESTIMATE FOR 2015/16 FISCAL YEAR: BY AVERAGE LOW- AND AVERAGE HIGH-PRODUCTIVITY WELLS

Average Wellhead Price (CAD)	Well Category	Established Crown Production		New Crown Production		Total Royalties	% Decline in Total Royalties
		Royalty Rate	Expected Royalties	Royalty Rate	Expected Royalties		
$87.16	High Production	21.9%	$1,896 million	5.0%	$225 million		
	Low Production	1.0%	$9 million	1.0%	$5 million	**$2,134 million**	**-**
$60.00	High Production	12.4%	$736 million	5.0%	$154 million		
	Low Production	0.0%	$0	0.0%	$0	**$890 million**	**-58.3%**
$55.00	High Production	9.3%	$504 million	5.0%	$141 million		
	Low Production	0.0%	$0	0.0%	$0	**$645 million**	**-69.8%**
$50.00	High Production	6.1%	$302 million	5.0%	$128 million		
	Low Production	0.0%	$0	0.0%	$0	**$430 million**	**-79.8%**
$45.00	High Production	3.0%	$132 million	3.0%	$68 million		
	Low Production	0.0%	$0	0.0%	$0	**$200 million**	**-90.6%**
$40.00	High Production	0.0%	$0	0.0%	$0		
	Low Production	0.0%	$0	0.0%	$0	**$0**	**-100.0%**

After separating out the lowest-producing wells, we find that, at the government's forecast 2015/16 average wellhead price of $87.16, the average established high-productivity wells in Alberta will be paying an average royalty rate of 21.9 per cent while the average new high-productivity wells will be paying the maximum royalty rate of five per cent. The low-productivity established and new wells will be paying a royalty rate of one per cent. The estimate of expected royalties for the year from all royalty-eligible wells in the province is $2,134 million (an overestimate of 17.8 per cent relative to the government of Alberta's initial forecast). As shown in Table B3, at average wellhead prices of $40 to $60 per barrel, the royalty rate for the average established high-productivity well declines by 10 to 22 per cent, while the royalty rate for the average new high-productivity well declines by zero to five per cent. For both wells the royalty rate falls to zero at the lowest price of $40. For both new- and established-production low-productivity wells the royalty rate falls to zero at all lower prices. As the price falls our estimate of total collected royalties from all wells declines by 58 to 100 per cent.

3. Average Well Productivity: By Production Category

Our last method of estimating crude oil royalties for 2015/16 is a further refinement of Method 2. Using the data on average well productivity from Table A1, we can estimate the approximate royalties for 2015/16 and the royalty decrease by production range for both new- and established-production wells. Table B4 provides our estimate of 2015/16 production by well-productivity range. Table B5 provides the results of the royalty estimation, although for ease of exposition we amalgamate the 34 production ranges into seven production groups (the same production groups used in Table 1 for the main text). For each production group, the royalty rate is equal to the weighted average (by production share) of the royalty rates for each production range included in the production group. The estimate of expected royalties for the production group is equal to the sum of estimated royalties for each production range included in the production group. [136]

When estimating royalties by production category we find that, at the government's forecast 2015/16 average wellhead price of $87.16, our estimate of expected royalties for the year is $2,232 million (a 40 per cent overestimate). At average wellhead prices of $40 to $60 per barrel the royalty rates by production category decline by up to 22 per cent for regular production and by up to five per cent for new production. The estimate of total collected royalties declines by 47 to 78 per cent.

TABLE B4 CRUDE OIL ROYALTY ESTIMATE FOR 2015/16 FISCAL YEAR: ESTIMATED PRODUCTION BY PRODUCTION RANGE

Well Productivity (Barrels/Day)	Share of Crown Production	Number of Barrels Per Day	
		Established Crown Production	New Crown Production
0.02-1.02	0.25%	642	245
1.03-2.06	0.79%	2,036	775
2.07-4.13	3.18%	8,137	3,097
4.14-6.19	4.59%	11,767	4,479
6.20-8.26	5.01%	12,824	4,881
8.27-10.33	4.73%	12,107	4,608
10.34-12.40	4.44%	11,375	4,330
12.41-14.47	4.01%	10.279	3,912
14.48-16.54	3.61%	9.236	3,515
16.55-18.61	3.32%	8,516	3,241
18.62-20.68	3.07%	7,859	2,991
20.69-22.75	2.76%	7,068	2,690
22.76-24.81	2.57%	6,585	2,506
24.83-26.88	2.40%	6,19	2,341
26.89-28.95	2.14%	5,485	2,088
28.96-31.02	2.00%	5,127	1,951
31.03-33.09	1.92%	4,917	1,871
33.10-35.16	1.75%	4,477	1,704
35.17-37.23	1.65%	4,233	1,611
37.24-39.30	1.59%	4,065	1,547
39.31-41.37	1.45%	3,721	1,416
41.38-51.71	6.34%	16,250	6,185
51.72-62.05	4.83%	12,364	4,706

[136] See footnote 60 from the main text for further information on how the weighted-average royalty rate for each production group is calculated.

61.06-71.40	3.71%	9,491	3,612
72.41-82.74	2.97%	7,617	2,899
82.75-93.09	2.48%	6,362	2,422
93.10-103.43	2.16%	5,534	2,106
103.44-118.37	2.59%	6,644	2,529
118.38-206.88	9.08%	23,253	8,850
206.89-413.77	5.85%	14,988	5,705
413.78-620.66	1.35%	3,470	1,321
620.67-827.55	0.53%	1,359	517
827.56-1034.44	0.22%	551	210
1034.45-2068.89	0.65%	1,676	638

TABLE B5 CRUDE OIL ROYALTY ESTIMATE FOR 2015/16 FISCAL YEAR: BY PRODUCTION GROUP

Average Wellhead Price (CAD)	Well Productivity (Barrels/Day)	Established Crown Production		New Crown Production		Total Royalties	% Decline in Total Royalties
		Royalty Rate	Expected Royalties	Royalty Rate	Expected Royalties		
$87.16	0.02-6.19	3.2%	$27 million	3.2%	$14 million	**$2,821 million**	**-**
	6.20-12.40	9.8%	$132 million	5.0%	$35 million		
	12.41-20.68	18.7%	$249 million	5.0%	$35 million		
	20.69-33.09	27.9%	$366 million	5.0%	$34 million		
	33.10-51.71	35.0%	$425 million	5.0%	$31 million		
	51.72-82.74	40.0%	$437 million	5.0%	$28 million		
	82.75-118.37	40.0%	$275 million	5.0%	$18 million		
	> 118.37	40.0%	$672 million	5.0%	$44 million		
$60.00	0.02-6.19	0.0%	$0	0.0%	$0	**$1,492 million**	**-47.1%**
	6.20-12.40	1.1%	$9 million	1.1%	$5 million		
	12.41-20.68	9.2%	$84 million	5.0%	$24 million		
	20.69-33.09	18.5%	$166 million	5.0%	$23 million		
	33.10-51.71	25.5%	$212 million	5.0%	$22 million		
	51.72-82.74	32.8%	$246 million	5.0%	$19 million		
	82.75-118.37	38.2%	$180 million	5.0%	$12 million		
	> 118.37	40.0%	$460 million	5.0%	$30 million		
$55.00	0.02-6.19	0.0%	$0	0.0%	$0	**$1,240 million**	**-56.0%**
	6.20-12.40	0.0%	$0	0.0%	$0		
	12.41-20.68	6.1%	$51 million	4.3%	$18 million		
	20.69-33.09	15.3%	$126 million	5.0%	$21 million		
	33.10-51.71	22.4%	$170 million	5.0%	$20 million		
	51.72-82.74	29.7%	$204 million	5.0%	$18 million		
	82.75-118.37	35.1%	$151 million	5.0%	$11 million		
	> 118.37	40.0%	$422 million	5.0%	$27 million		

$50.00	0.02–6.19	0.0%	$0	0.0%	$0	**$1,021 million**	**-63.8%**
	6.20–12.40	0.0%	$0	0.0%	$)		
	12.41-20.68	3.1%	$24 million	2.7%	$10 million		
	20.69–33.09	12.2%	$91 million	5.0%	$19 million		
	33.10–51.71	19.2%	$133 million	5.0%	$18 million		
	51.72–82.74	26.5%	$166 million	5.0%	$16 million		
	82.75–118.37	31.9%	$125 million	5.0%	$10 million		
	> 118.37	40.0%	$383 million	5.0%	$25 million		
$45.00	0.02–6.19	0.0%	$0	0..0%	$0	**$804 million**	**-71.5%**
	6.20–12.40	0.0%	$0	0.0%	$0		
	12.41-20.68	1.2%	$8 million	1.2%	$4 million		
	20.69–33.09	9.0%	$61 million	5.0%	$17 million		
	33.10–51.71	16.1%	$100 million	5.0%	$16 million		
	51.72–82.74	23.4%	$131 million	5.0%	$15 million		
	82.75–118.37	28.8%	$102 million	5.0%	$9 million		
	> 118.37	36.9%	$319 million	5.0%	$22 million		
$40.00	0.02–6.19	0.0%	$0	0.0%	$0	**$618 million**	**-78.1%**
	6.20–12.40	0.0%	$0	0.0%	$0		
	12.41-20.68	0.2%	$1 million	0.2%	$1 million		
	20.69–33.09	5.9%	$35 million	4.6%	$14 million		
	33.10–51.71	12.9%	$72 million	5.0%	$14 million		
	51.72–82.74	20.2%	$101 million	5.0%	$13 million		
	82.75–118.37	25.6%	$80 million	5.0%	$8 million		
	> 118.37	33.8%	$259 million	5.0%	$20 million		

About the Author

Sarah Dobson (PhD) is a Research Associate in the Energy and Environmental Policy area at The School of Public Policy. Her research interests are focused on studying the design, implementation and evaluation of energy and environmental regulatory policy. In prior work Sarah has considered such issues as the welfare implications of climate change policy, and the optimal design of regulatory policy to take into account the tradeoff between the economic benefits of resource development and the ecological consequences of management decisions. Sarah holds a PhD and MSc in Agricultural and Resource Economics from the University of California, Berkeley.

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