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The Fiscal Pulse of Canada's Oil and Gas Industry

A Review of Capital Flows and Activity

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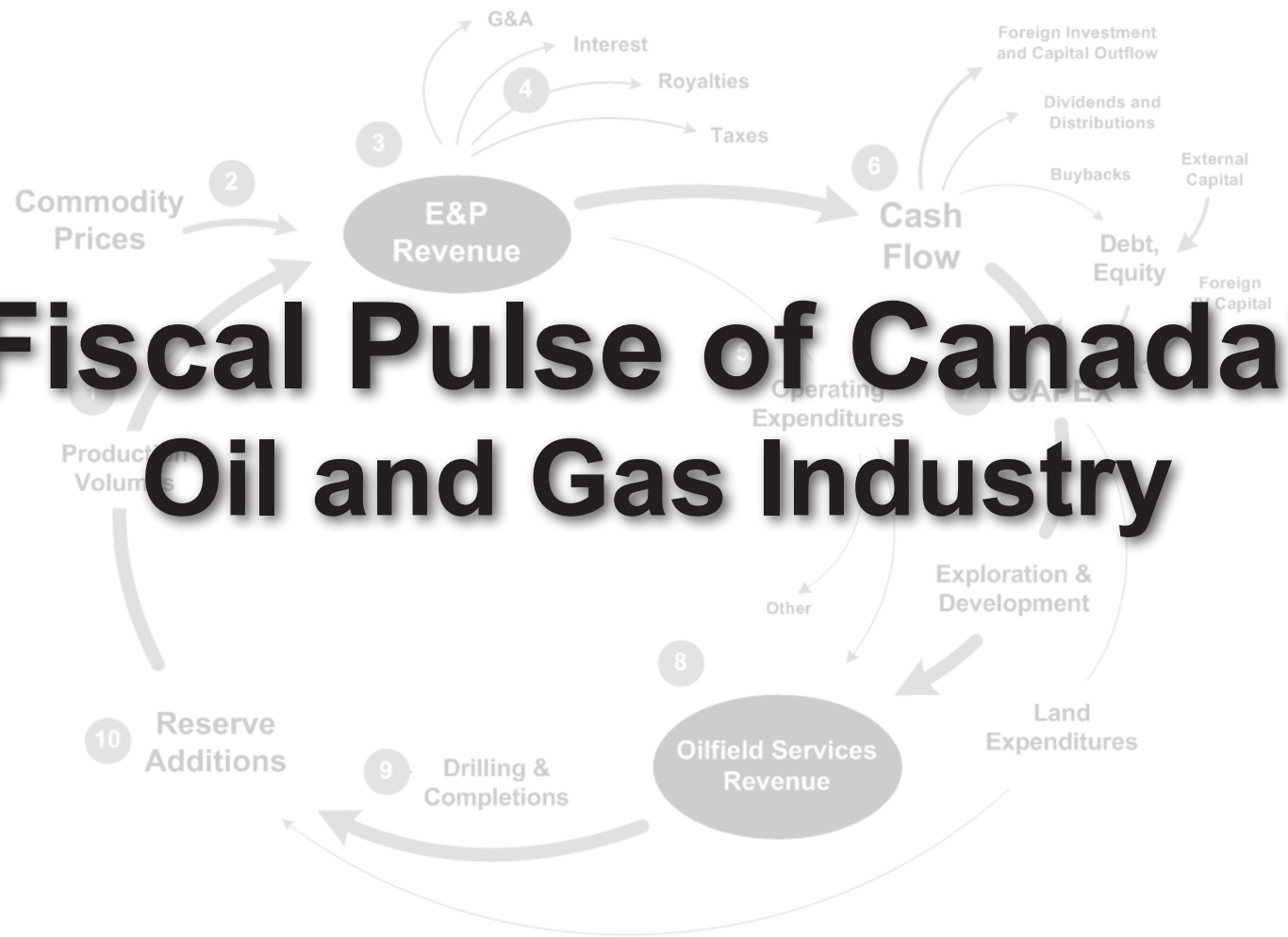
Fiscal Pulse of Canada's Oil and Gas Industry



About ARC Financial Corp. and the Authors

ARC Financial Corp.

ARC Financial Corp. ("ARC") is an energy-focused private equity firm based in Calgary, Alberta, Canada, with $5.3 billion of capital across eight ARC Energy Funds. Leveraging off the experience, expertise, and industry relationships of more than 25 investment professionals, ARC invests in upstream oil and gas, oilfield services and energy infrastructure.

ARC offers world-class research, analysis and assessment established through technical and operating industry experience. Through this deep domain knowledge and energy capital markets expertise, ARC plays a valuable role in the companies we finance and in the Canadian oil and gas industry as a whole. Employing best practices in corporate governance and business processes, ARC builds successful companies through transactional advice, deal sourcing and evaluation support.

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Acknowledgements and Disclaimer

Author's Note

ARC Financial Cop. ("ARC") has been publishing economic data and analysis of the Canadian oil and gas industry for over 25 years. This summary report is an adjunct to ARC's weekly publication, the *ARC Energy Charts* commentary found at www.arcenergyideas.com. As well, the analysis contained within is a continuation of a less periodic series of industry reports published by ARC over the years.

The authors wish to thank the many industry contributors to this ongoing effort of providing an objective characterization of the fiscal variables that make the Canadian oil and gas industry go around. In particular, thanks go to the partners of ARC Financial Corp. who support the effort, and specifically to Megan Lancashire, Marcus Rocque and Jackie Forrest who helped assemble, edit and publish this material. Special thanks to staff at the Canadian Association of Petroleum Producers who helped collect and provide raw data.

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Executive Summary

Economists and analysts have been trying to find historical comparisons to the lengthy oil price downturn that began 21 months ago. As bad as 1998? 1985? Or even the 1890s? Regardless, the dual impact of oil and natural gas prices falling by more than 50% since late 2014 has led to a severe contraction in the Canadian oil and gas industry. In this report we examine the ongoing impact of the downturn on capital flows, production levels and field activity since our last review, one year ago.

We assess the financial health of Canada Oil and Gas Limited (COGL) – a fictitious company that represents a financial consolidation of all upstream oil and gas companies operating across the country – through our model called the "Fiscal Pulse." Trends in product volumes, prices, costs, money flows, profitability and capital efficiencies are tracked and analyzed. Data comes from many sources, but dominantly from information published by the Canadian Association of Petroleum Producers (CAPP) and company financial reports.

With the first quarter behind us, the highlights of our 2016 diagnosis are summarized below; details are to be found in the subsequent pages.

- **Nominal cash flow lowest since the 1990s** - Cash flow is the dominant source of capital for investment in the drilling, completion of new wells, and requisite production infrastructure. In 2016 we expect a token $18.6 billion from all hydrocarbons. That's down 30% from 2015, and a staggering 75% from 2014 (page 26). On average, COGL runs at cash-flow-break-even at $30/B WTI – a level tested in Q1 2016. By the end of 2016, two years of low oil and gas prices will have taken $65 billion out of Canada's oil and gas economy.
- **Investment reduced to legacy spending** - COGL has two divisions: Oil Sands and Conventional Oil and Gas. Cash flow running at near break-even levels in early 2016 means that there won't be much of a Fiscal Pulse for investment this year. Bankruptcies and 100,000+ layoffs validate the issue under a harsh light. Nominal CAPEX for the conventional side of the business will be as low as the mid-1990s, reducing field activity to a crawl. Like last year, the $30.5 billion in total CAPEX is largely being driven by spending on several late-stage oil sands projects, the last of which is expected to be completed by 2017 - 2018.
- **Declining production** - The calculus in the oil and gas business is fairly simple: declining investment equals declining production. But there is a lag in the equation, which is one reason why production declines had not yet been recorded a year ago. In 2016, conventional oil as well as natural gas output is expected to drop. Light and medium grades of high-decline, tight oil are already off by 17% or 120,000 B/d from the 2014 peak. Western Canadian natural gas production is increasing in some prolific, low-cost regions, but on balance total volumes are expected to decline by the end of the year. In the absence of more clarity on the wildfire damage, oil sands production is expected to grow by about 85,000 B/d this year, a lagging consequence of late-stage projects coming to fruition.
- **Contracting oilfield service capacity** - Rig activity is down to levels not seen in decades (page 28). Utilization of equipment this past winter was as low as the idle "spring breakup" period in normal years. By the end of 2015 the lack of an investment pulse on the conventional side of COGL began causing market death of oilfield service companies. Bankruptcies, layoffs and cannibalization of good equipment for spare parts all represent a contraction of field capacity that may be insufficient to serve COGL on a price rebound.
- **Falling costs (for now)** - Declining investment continued to create a labour and service surplus in 2016. As well, producing companies doubled their emphasis on improving logistics and innovating for operational efficiencies. The result was a further lowering of year-over-year capital and operating costs. Existing production is now costing 15 to 25% less than the peak of 2014. Drilling and completing new wells is 20 to 30%

cheaper. Wages for Western Canadian oilfield workers are down between 10 and 15% from peak, though Alberta's wages are stickier on the downside than BC and Saskatchewan. More cost reductions are unlikely. Service companies are running at or below breakeven. Commodities are showing some strength going into Q2. Any rebound in investment by COGL will be served by less equipment and fewer people.

- **Tighter capital markets** - COGL was able to raise $17.1 billion in new debt and equity in 2015, a level that was surprisingly resilient to the downturn. However, much of that was in the first half of the year. By late 2015 capital markets were shunning the industry. Only $1.2 billion of external capital came into the business in Q1 2016, a trickle by historical standards. Rebound in financings will be wholly dependent on rising commodity prices; however new debt and equity will remain scarce until there is belief in the sustainability of a recovery. We expect only $8.5 billion of financings in 2016, half of last year (page 26).
- **Price arbitrage drives market access** - Oil price discounts relative to global prices have historically plagued COGL, especially between 2010 and 2013 when rising production across North America began clogging up pipelines. But price discounts created market inefficiencies that represented opportunity for arbitrage. An aggressive build out of railroad loading/unloading facilities, combined with expansions of existing pipelines added over 1.0 MMB/d of oil transport to North American markets. It didn't solve Canada's "only-one-customer" problem, but the added capacity to the US market has diminished both the size of the discount and price volatility (page 29).

- **Governments feel the fiscal pain of contraction** - Last year was the first year since 1998 that COGL reported an income statement loss ($20.1 billion). The loss in 2016 will be even greater, estimated at ($26.4 billion). Negative earnings means that corporate income taxes from oil and gas producers to provincial and federal governments will be net zero. Service companies and many other peripheral businesses are unlikely to be taxable this year either. Royalties are based on a variety of factors, but dominantly revenue. Royalty income to provinces is expected to total $3.0 billion in 2016, the lowest level in decades.

As in last year's report, the grids on pages 31 through 33 show the sensitivity of key fiscal metrics-Revenue, Cash Flow, CAPEX and Well Count- as a function of average annual oil and gas prices. At the moment, commodity prices are still leaning into the lowest case scenario. However, because the industry's production is 64% weighted to oil by volume, the metrics are more sensitive to oil price than natural gas. Potential oil price appreciation into the latter half of 2016 will tend to improve the Fiscal Pulse of the industry, though a guarded return to investment may see oilfield activity numbers lag by several quarters.

None of the indicators for 2016 are looking positive. However, the air of unsustainability is not unique to Canada's oil and gas industry. The charts and tables in this report represent a window into the challenges facing oil and gas producing entities around the world. Contraction of productive capacity across the world's supply chain – from producers to service companies – has a momentum in 2016 that will not be reversed without meaningful price recovery. That by itself is a self-referential, positive indicator for future prices. In short, the world can look to Canada's exceptionally weak Fiscal Pulse as a transparent case study for inevitable commodity price recovery.

The Fiscal Pulse of the Upstream Oil and Gas Economy

On the following page we show a simple model diagram of how capital flows into and out of the Canadian upstream oil and gas economy, or as we term it the Fiscal Pulse. On pages 10 and 11 we show the Fiscal Pulse for COGL's two divisions separately: Conventional Oil and Gas and the Oil Sands. Within each division, the industry is segmented into two broad sectors: Exploration and Production (E&P) and Oilfield Services. Each sector is depicted as a black oval.

E&P companies determine where to explore for oil and gas. Oilfield service companies are contracted to do the physical prospecting, drilling and delivery to market. Once additional reserves are found, E&P companies manage the production and sale of their oil and gas from their newly added reserves. Capital flows through both the E&P and the oilfield service sectors, which work closely together to create value for stakeholders.

The mechanics of the accompanying capital flow diagrams represent an accounting of the dollars and product volumes flowing through the industry. *Production Volumes* ❶ are multiplied by *Commodity Prices* ❷ to yield gross *E&P Revenue* ❸. *Interest* and *General and Administrative (G&A)* expenses are deducted, as are *Royalties* and *Taxes* ❹. Royalties are mostly dependent on commodity prices, but well type, depth and production output are also major determinants. Taxes are mostly a function of net income, owed both federally and provincially.

Managing and operating the base of production is labour, capital and energy intensive. *Operating Expenditures* ❺ have fixed and variable components that adapt to commodity prices.

A large portion of *Cash Flow* ❻ is typically allocated to investment; this is the *CAPEX* pool ❼. To leverage capital and gain cycle momentum, the *CAPEX* pool is supplemented with *Debt and Equity*. During periods of healthy cash flow, debt may be paid down and equity repurchased through *Buybacks*, *Dividends and Distributions*, and changes to working capital account for any remaining cash flow.

A certain amount of capital also 'leaks' out of the system as multi-national companies seek to repatriate their Canadian-earned cash flow or reinvest it abroad. This dynamic is difficult to capture and is represented in *Foreign Investment and Capital Outflow*. Counterbalancing leakage, *Foreign Joint Venture (JV) Capital* is another stream of funding that emerged in 2009, primarily from Asian investors.

Capital in the domestic CAPEX pool can be rationed a number of different ways: oil versus natural gas drilling, exploration versus development, oil and liquids versus oil sands, and so on.

In our chart, we broadly segment capital spending into two: *Exploration and Development* and *Land*.

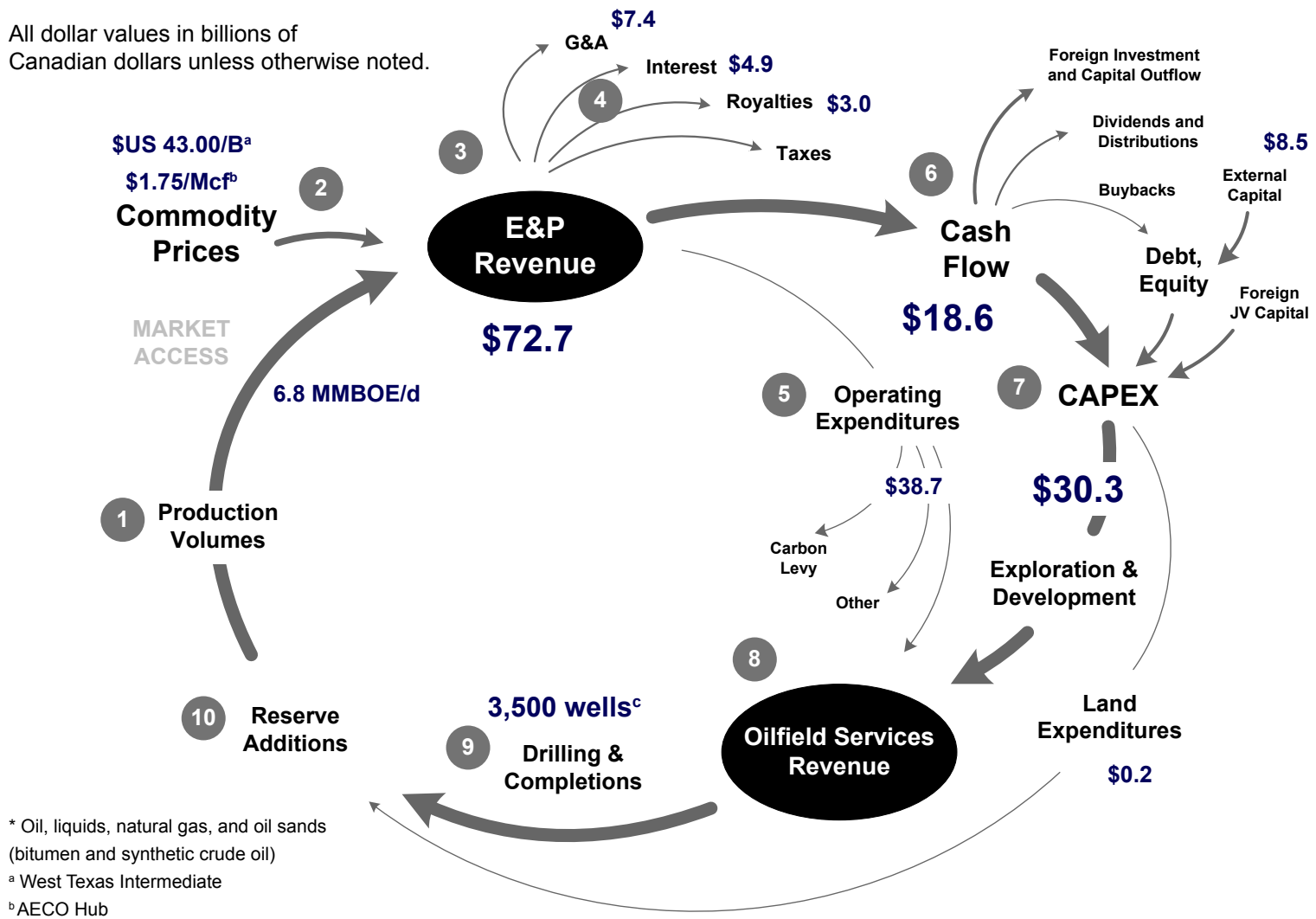
Oilfield Services Revenue ❽ is largely dependent on domestic E&P spending, over 50% of which is typically allocated to drilling. Note that not all E&P capital spending goes to the oilfield services sector. There are many *Other* peripheral expenditures for goods and services that percolate into the Canadian economy.

Drilling and Completions ❾ yield oil and gas *Reserve Additions* ❿, which are often placed into production as soon as is technically and financially feasible. Productive capacity – the ability of a reservoir to produce hydrocarbons – declines over time, similar to diminishing product inventory. To replenish depleting reserves, the entire cycle of capital flow starts over again.

How well Canada's oil and gas capital cycle performs in the face of many internal and external forces determines profitability of the industry. Delivering stable, long-term financial returns has always been challenging amidst a backdrop of volatile commodity prices, competitive challenges, constrained labour pools, geologic risk, and cost considerations. Offsetting negative forces, new oilfield technology and innovation has been a strong positive across the industry.

Availability of high quality statistics at points around our diagram enable us to model capital flows with a reasonable degree of confidence; enough to determine the magnitude and direction of the most important economic trends and financial measures.

The 2016 Fiscal Pulse by the Numbers - All Segments*



* Oil, liquids, natural gas, and oil sands (bitumen and synthetic crude oil)

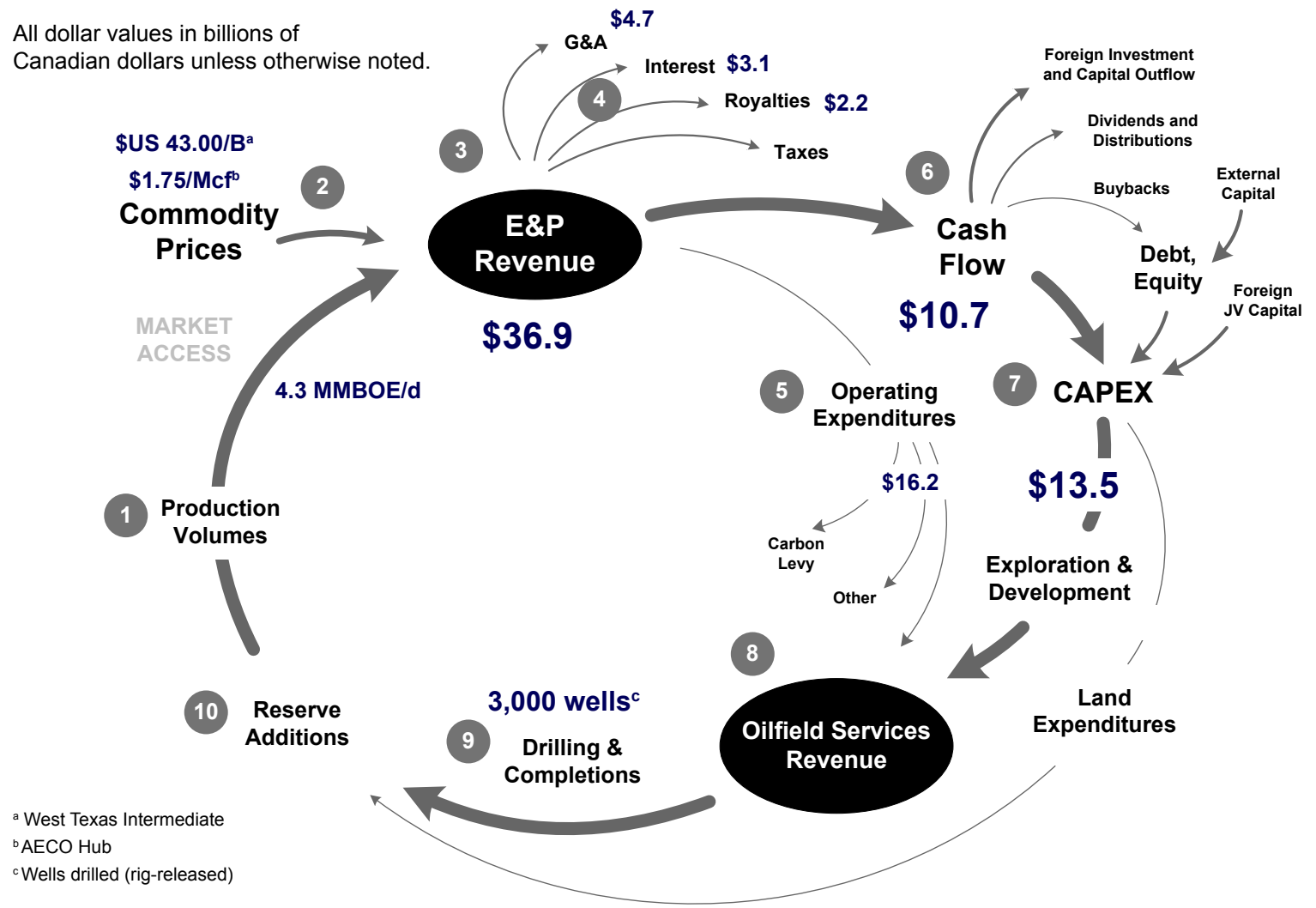
[a] West Texas Intermediate

[b] AECO Hub

[c] Wells drilled (rig-released)

Source: ARC Financial Corp.

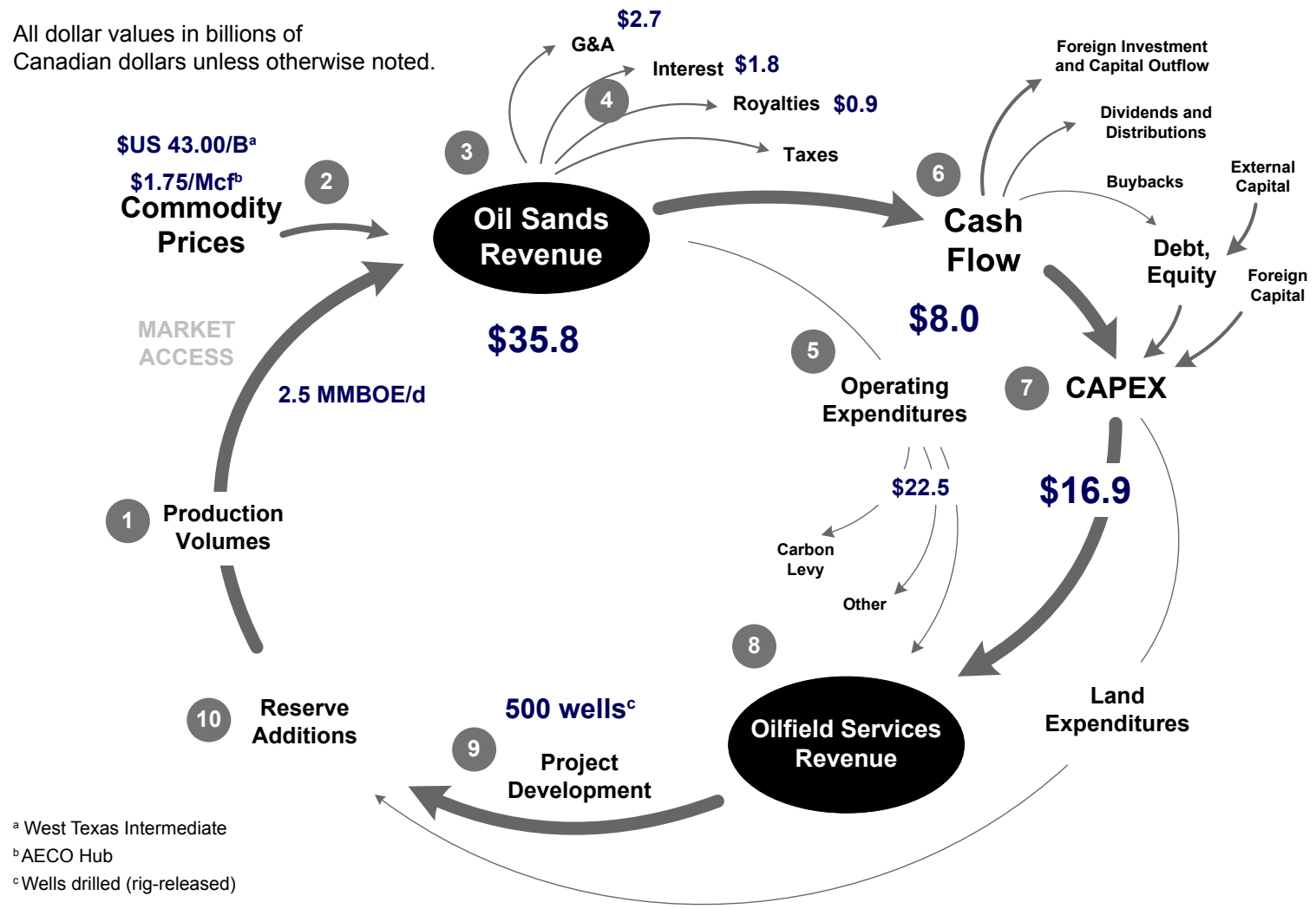
The 2016 Fiscal Pulse by the Numbers - Conventional Only



[a] West Texas Intermediate
[b] AECO Hub
[c] Wells drilled (rig-released)

Source: ARC Financial Corp.

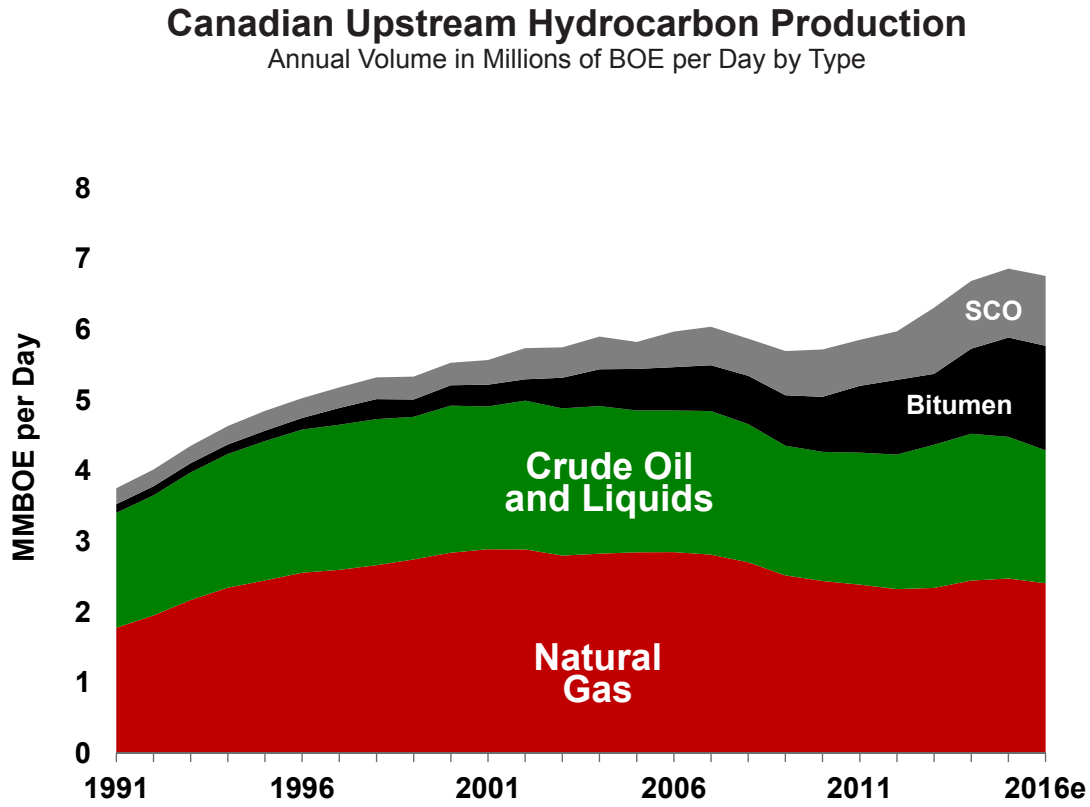
The 2016 Fiscal Pulse by the Numbers - Oil Sands Only



[a] West Texas Intermediate
[b] AECO Hub
[c] Wells drilled (rig-released)

Source: ARC Financial Corp.

Canadian Hydrocarbon Production



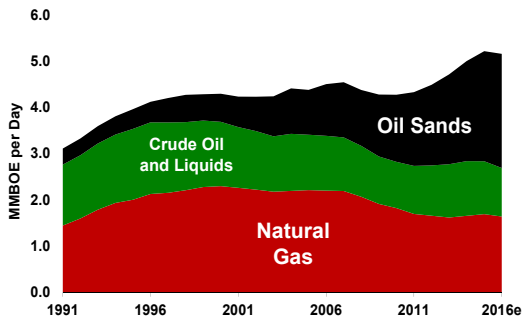
Source: CAPP, ARC Financial Corp.
Note: Natural gas volumes are converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (mcf) of gas to one barrel (bbl) of oil.

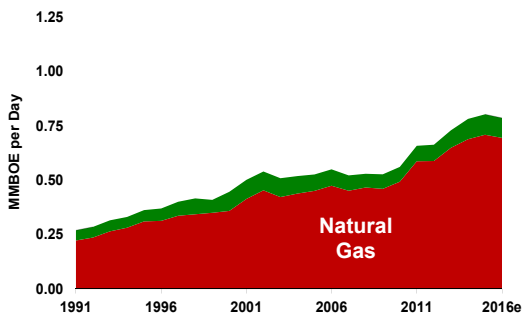
Total Canadian upstream oil and gas production is expected to decline in 2016.

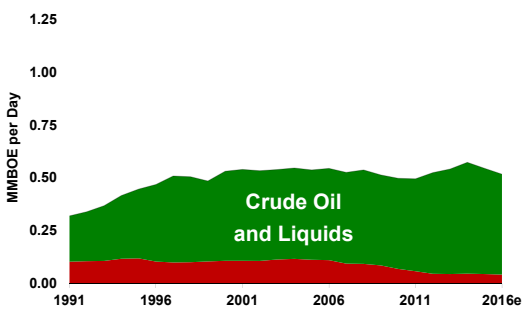
For the most part, hydrocarbon production in Canada has been on an upward trajectory for more than half a century. Despite the severe downturn in commodity prices since 2014, and the subsequent reduction in capital expenditures and drilling programs, Canadian production hit a record high in 2015 of 6.9 MMBOE per day. Most of the growth in the last decade has come from the oil sands. Since 2005, production of bitumen and synthetic crude oil (SCO) more than doubled, from just under 1.0 MMB/d in 2005 to 2.4 MMB/d last year. Another 85,000 B/d of oil sands production is expected in 2016.

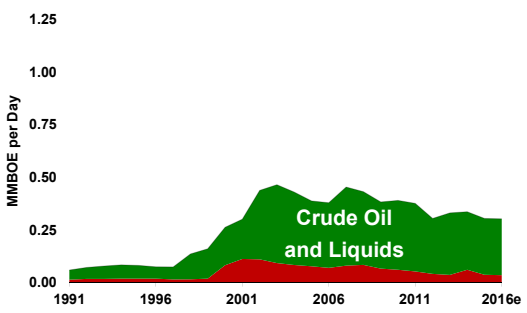
Innovations like multi-stage hydraulic fracturing have unlocked new resources of light tight oil (LTO) and shale gas. After two years of growth, total crude oil and liquids production (excluding oil sands) rolled over in 2015 and is expected to decline in 2016. Natural gas production, saw a short three-year spurt in activity ending in 2015. Declines will continue in 2016 as low prices suppress investment and market share is lost to new US exports to Eastern Canadian markets. As such, COGL is becoming progressively 'oilier'. Oil and liquids plus oil sands will account for about 64% of the hydrocarbon mix in 2016.

Canadian Hydrocarbon Production by Province









Source: CAPP, ARC Financial Corp.
Note: Vertical scale differences.

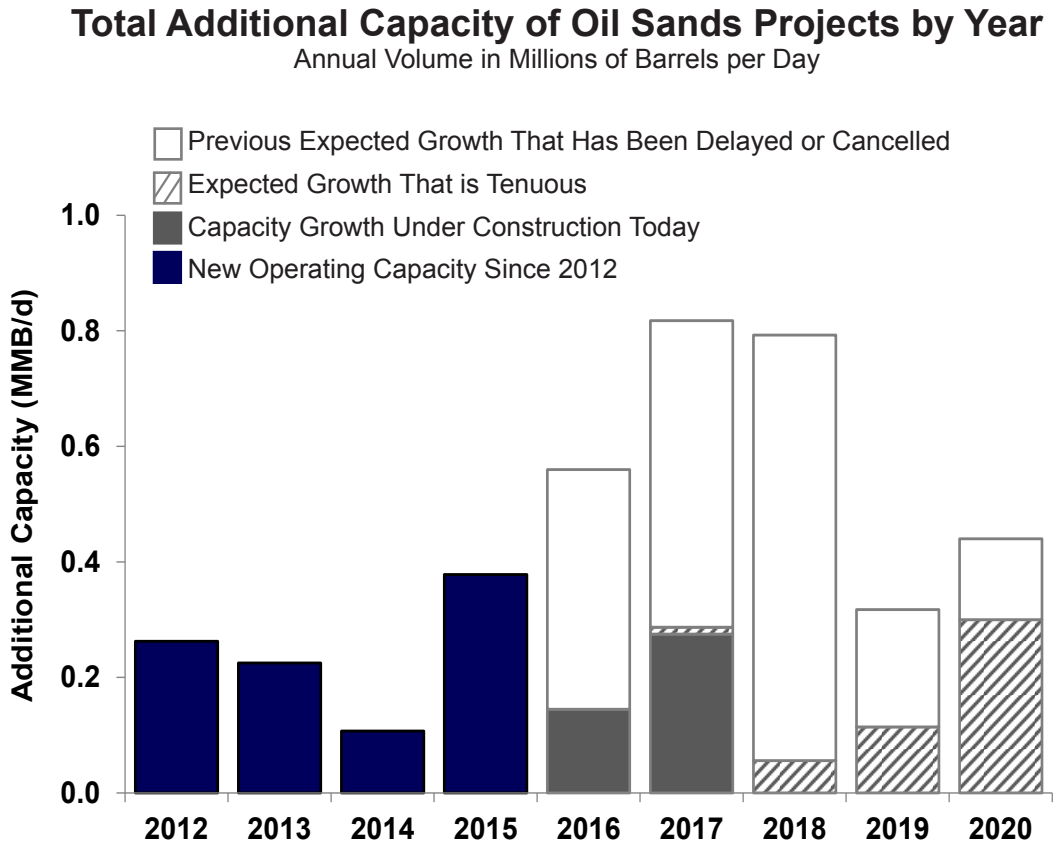
Alberta remains Canada's dominant hydrocarbon producer representing 76% of output. Growth continues to be dominated by the oil sands segment, however low oil prices have led to the cancellation and delay of at least 17 large projects. Growth in the oil sands is expected to level out by 2020. In the meantime, lack of investment is leading to broad production declines in conventional oil and gas across Western Canada.

British Columbia's Montney and Horn River resource plays grew the province's natural gas production by 44% between 2010 and 2015. Today's weakness in natural gas prices, combined with high transportation tolls, is reversing recent growth.

Saskatchewan is oil-weighted with attractive resource plays like the Viking. But like Alberta, light and medium oil production is trending downward due to lack of investment.

Production from the rest of Canada (ROC) comes mostly from Atlantic Canada. Newfoundland and Labrador produces mostly oil which is in decline, though some offset is expected in 2017 when Hebron comes on-line. Nova Scotia's natural gas production continues to decline, unable to compete with inexpensive gas from US shale gas plays.

Oil Sands Projects



Source: Government of Alberta, ARC Financial Corp.

Long term growth plans in the oil sands have been curtailed due to the collapse in oil prices.

Canada's oil sands are amongst the largest proven reserves in the world and rank third behind Venezuela and Saudi Arabia at 166 billion barrels. These multibillion dollar mega-projects require long lead times and have productive lifespans measured in decades. Since 2000, over $250 billion has been spent on building and maintaining approximately 2.2 MMB/d of new output capacity.*

Most projects not sanctioned before the oil price crash have been suspended or cancelled until oil prices recover. The empty white bars show the capacity impact of those cancellations over the next five years – in other words, what's been taken out of expected growth due to low prices.

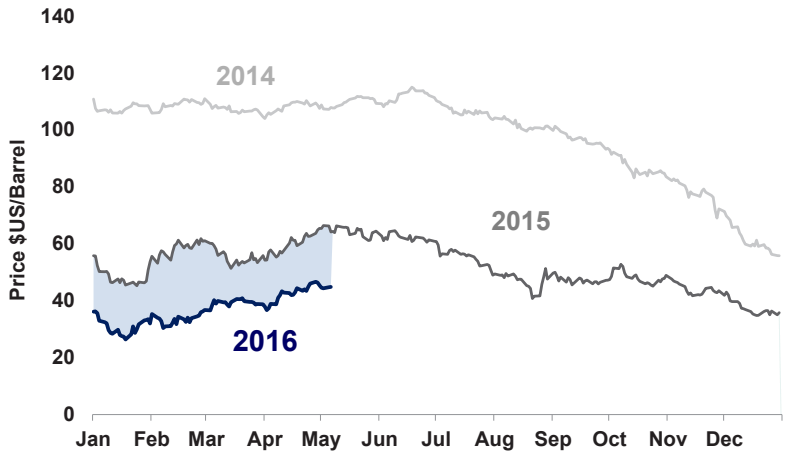
The solid grey bars represent 0.42 MMB/d of capacity that is under construction today. The hatched grey bars denote capacity that is still expected but unlikely to be built in the absence of sustainable price appreciation. Companies in the region will need to place emphasis on process innovation, carbon reduction, cost management and smaller modular expansion plans to drive future growth.

**Capacity is defined as 100% utilization; not actual production.*

Global Commodity Reference Prices

Global Oil Prices

Dated Brent Oil; Select Calendar Years



Source: Bloomberg, ARC Financial Corp.

Approximately two-thirds of all crude oil contracts around the world reference Brent as the pricing benchmark making it the most widely used indicator for global oil prices. Brent is a light sweet blend (although with a slightly higher sulfur content than WTI) that originates from offshore oilfields in the North Sea.

The blue shaded area shows the daily price gap between 2015 and 2016. The price of Brent crude averaged $US 34.50/B in Q1 2016, down 36% from the same period a year prior. After testing fiscally unsustainable sub-$US 30/B levels back in January, the price of a barrel of Brent is on a positive uptrend into Q2.

Global Natural Gas Prices

UK NBP Natural Gas; Select Calendar Years

Source: Bloomberg, ARC Financial Corp.

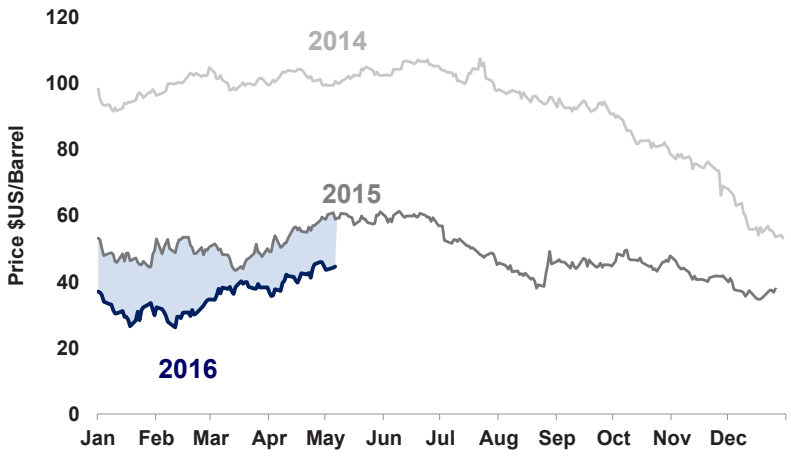
NBP stands for National Balancing Point and is Europe's longest established natural gas market. Unlike Henry Hub, NBP is not a physical hub, but instead a virtual trading location. This allows gas anywhere within the national transmission system to trade as NBP gas whether it is sourced from the UK, imported by pipeline from Norway or shipped by LNG tankers from global markets.

Although still trading at a premium of 2.0 to 2.5x higher than Henry Hub, European gas prices have also fallen since 2014 amid a global supply glut. In Q1 2016, the price of natural gas at NBP averaged $US 4.40/MMBtu, down 40% compared to a year earlier.

Commodity Prices

Near-Term WTI Crude Oil Price

Select Calendar Years



Source: Bloomberg, ARC Financial Corp.

The benchmark for North American oils, West Texas Intermediate (WTI), hit a low of $US 26.21/B in February, a price level not seen since 2002.

While we expect oil prices to continue the uptrend and surpass $US 50/B in the latter half of 2016, a ramp up in oilfield activity is likely to be slower than previous rebounds. Considerable damage has been done to balance sheets and the ability of producers to access capital markets has been sharply reduced.

Ultimately, commodity price is the dominant factor influencing a company's propensity to generate cash flow, raise capital and invest back into maintaining (and growing) productive capacity.

Canadian Dollar Currency Exchange

Relative to the US Dollar

Source: Bloomberg, ARC Financial Corp.

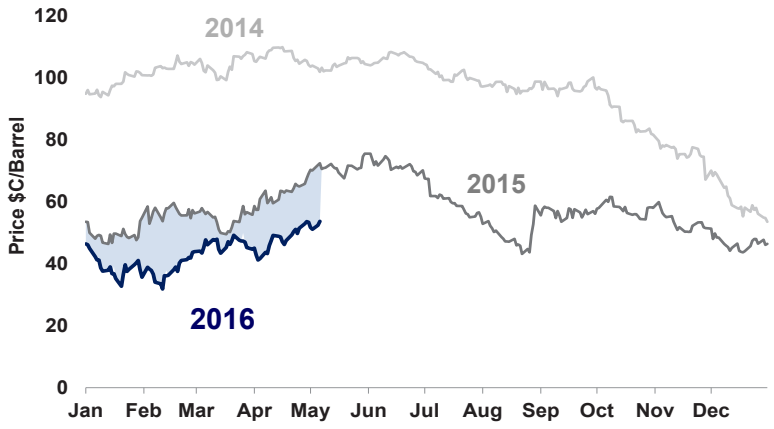
Since last trading at parity with the US dollar in 2013, the Canadian dollar has fallen due to several factors; a strengthening US economy, diverging cross border monetary policy, weak global economic outlooks and falling oil prices. The latter is the most influential variable. In February, the Loonie traded below 70 cents; the first time in nearly thirteen years.

Benchmark oil and gas are priced in US dollars, making currency fluctuations impact prices received for Canadian exports. A one-cent, sustained change in the exchange rate equates to a change of $0.65/B and $0.02/Mcf for Edmonton Light and AECO prices respectively. Recently trading just a few pennies below 80 cents, the Loonie is likely to appreciate to the low-to-mid 80s with an oil price rebound to $US 60/B (WTI).

Commodity Prices

Canadian Light Oil Price

Edmonton Light; Select Calendar Years



Source: Bloomberg, ARC Financial Corp.

Edmonton Light is the benchmark Canadian light (40° API gravity) sweet (low sulfur) crude oil price. Because of the close proximity to the US market, the price of Edmonton Light tends to mimic that of WTI, adjusted for factors such as currency exchange, transportation costs, relative quality and regional demand.

In Q1 2016, Edmonton Light averaged $41/B, down 22% from the comparable quarter in 2015. This report assumes an annual average Edmonton Light price of $50.35/B for 2016.

Canadian Heavy Oil Price

Western Canadian Select (WCS); Select Calendar Years

Source: Bloomberg, ARC Financial Corp.

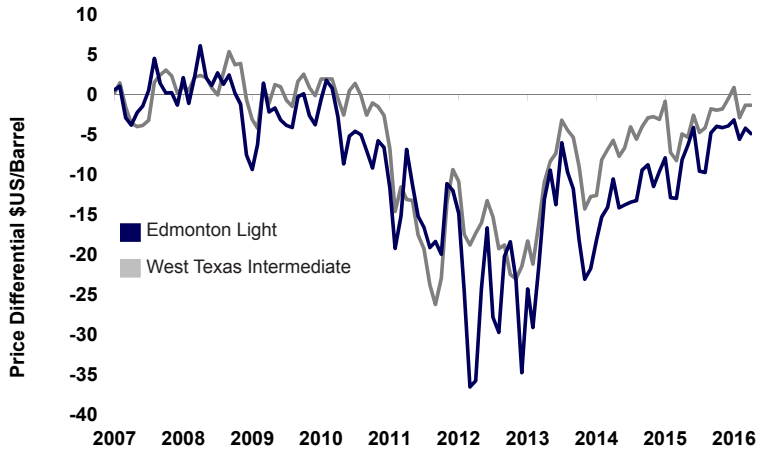
Western Canada Select (WCS) is the Canadian heavy oil benchmark priced at Hardisty, Alberta and is one of North America's largest heavy crude oil streams. Launched in 2004, WCS is a blend of conventional heavy and bitumen crude oils blended with sweet synthetic and condensate diluents.

The drop in global light oil prices has pushed down the whole price complex, including the heavier grades. WCS averaged just over $20/B in Q1 2016, down 42% from Q1 2015. Industry revenues and cash flows were severely impacted as this price level is below cash costs of many oil sands producers. This report assumes an annual WCS price average of $37.10/B for 2016.

Commodity Prices

North American Light Oil Differentials

Relative to the Global Oil Price (Brent)

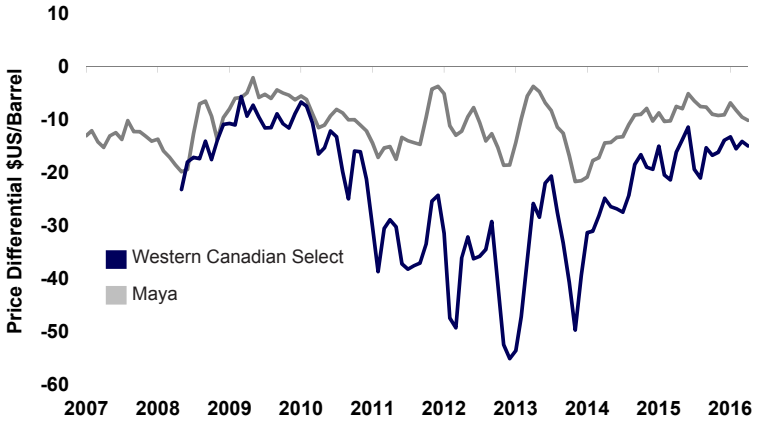


Source: Bloomberg, ARC Financial Corp.

Up until the onslaught of the US shale oil boom in 2010, WTI and Edmonton Light traded tightly, within a few dollars of the international benchmark, Brent. Thereafter North American prices were steeply discounted as US and Canadian production growth exceeded continental infrastructure resulting in regional supply gluts. In 2014, North American differentials narrowed significantly as capacity increases in pipe and rail infrastructure relieved the bottleneck. The US crude oil export ban was lifted in December 2015, which narrowed US and Canadian discounts relative to Brent and other international markers. In Q1 2016, price discounts for light oil compared to Brent averaged $US 1.10/B and $US 4.30/B for WTI and Edmonton Light respectively.

North American Heavy Oil Differentials

Relative to the Global Oil Price (Brent)



Source: Bloomberg, ARC Financial Corp.

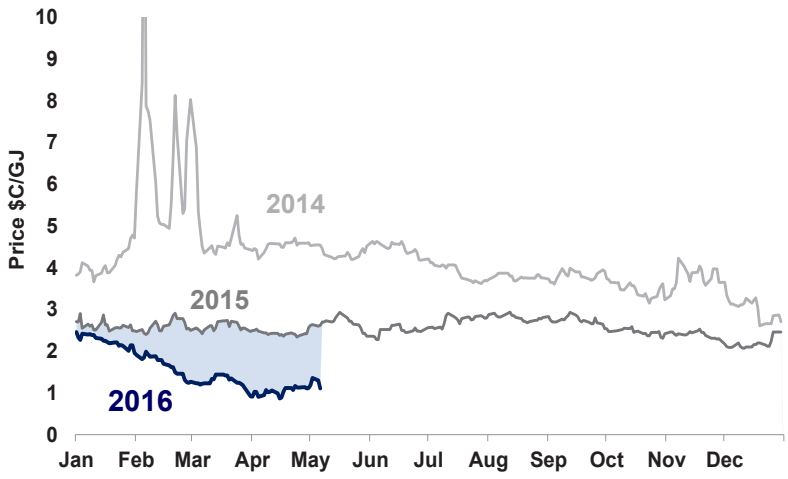
Heavy oils trade at a discount to WTI due to the higher cost of transportation and refining into petroleum products, such as gasolines, jet fuel, kerosene, and diesel. The heavy oil that is most similar in specifications and often compared to WCS is Mexican Maya.

Canadian heavy oil price differentials 'blew out' a few years ago because of limited takeaway capacity. Since then, Canadian access to the US Gulf Coast has improved with increasing pipeline capacity and the option of rail. Unlike WCS, Maya is not land locked and is available to the US Gulf Coast hence the fairly consistent range of discount over the same time period. The Canadian heavy discount averaged $US 14.30/B in Q1 2016.

Commodity Prices

Near-Term Alberta Natural Gas Prices

AECO; Selected Calendar Years



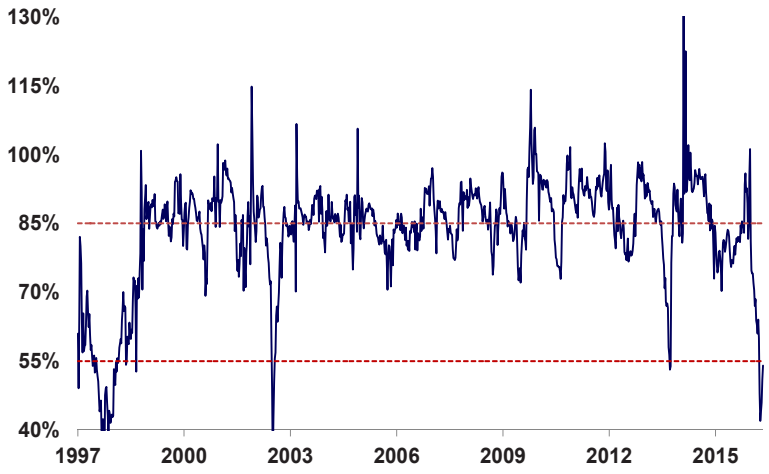
Source: Bloomberg, ARC Financial Corp.

Stubbornly high natural gas production levels and ballooning storage levels on both sides of the border kept AECO prices under $3.00/GJ for most of 2015. Price has deteriorated even further in 2016 as surplus molecules are going into storage rather than flowing on pipelines. At the time of writing, AECO was trading under the $1.00 /GJ mark, a level not seen in over two decades.

On many measures, this dual oil-gas price hit is why the industry's Fiscal Pulse right now is the weakest it's been in decades. This report assumes an average AECO price of $1.65/GJ for 2016.

AECO Basis Differential

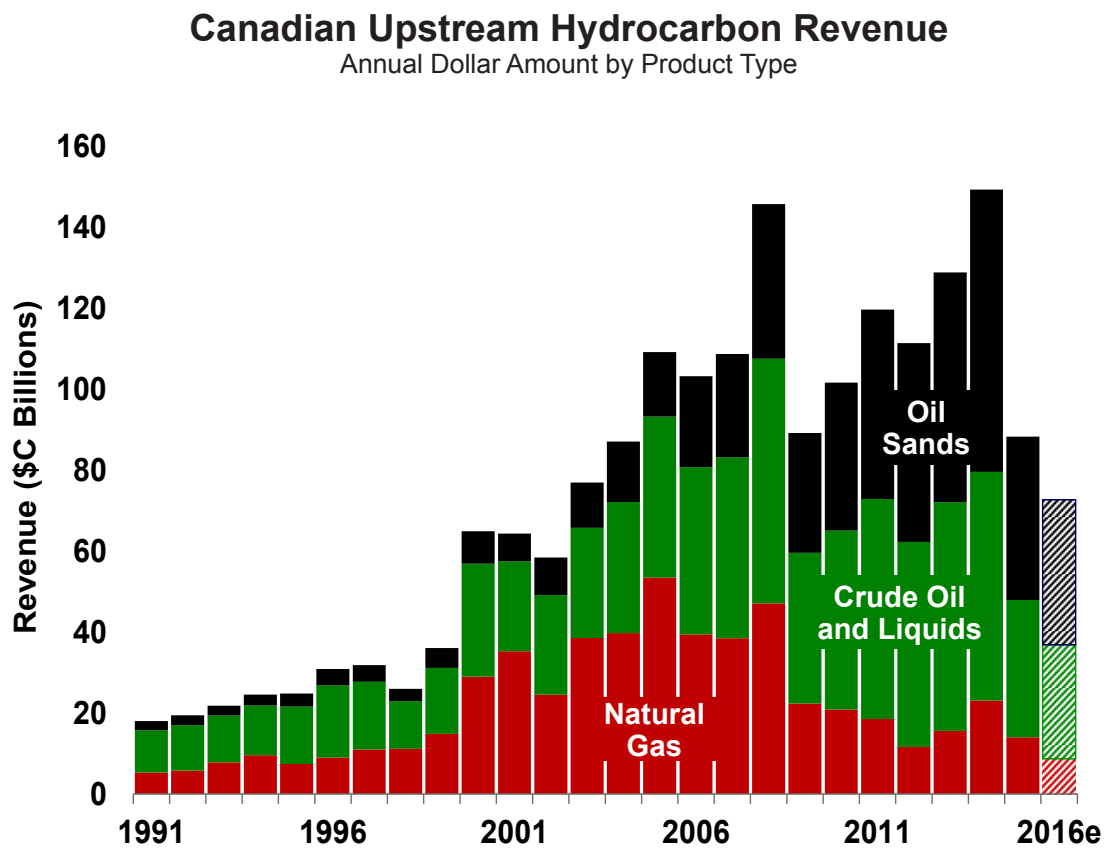
AECO as a Percentage of Henry Hub in US Dollars



Source: Bloomberg, ARC Financial Corp.

In a balanced market, the difference between US and Canadian gas prices typically reflects the transportation toll costs between hubs. Historically, gas priced at AECO traded (on average) at about 85% of Henry Hub (in US dollars). However seasonality, regional imbalances and the complexities of continental pipeline flows all impacted differentials. Today high volumes of domestic production, record storage and shrinking export markets are the catalysts for periodically suppressed AECO prices. Year to date, AECO has traded at an average 61% of Henry Hub, sinking as low as 38%. The market has historically remedied continental gas arbitrages through greater pipeline capacity and/or lower production volumes. LNG exports off of Canada's west coast are not expected before the early 2020s.

Canadian Upstream Industry Revenue



Source: CAPP, ARC Financial Corp.

Canadian upstream revenues have evolved to be mostly dependent on oil prices.

Oil and gas companies produce many different hydrocarbon products of varying type and quality. Eight different product classifications are used to estimate aggregate upstream revenue: light and medium oil, heavy oil, bitumen, synthetic crude oil, natural gas liquids, pentanes, condensates and natural gas.

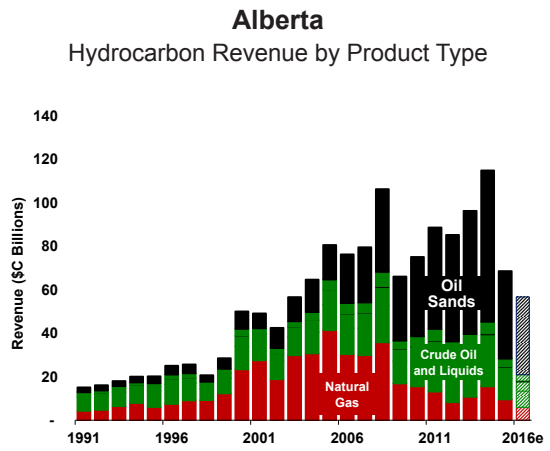
To derive this chart, each commodity's production volume is multiplied by the average annual price that was, or is expected to be realized by all producers (excluding any hedging gains which are likely to add some revenue to 2016 figures).

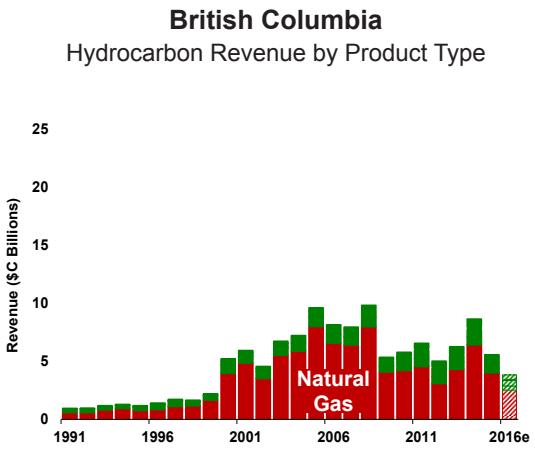
Beginning in 2000, the sharp rise in commodity prices catapulted upstream revenue to over $100 billion in 2005, reaching a record of $145 billion in 2008. This previous record was surpassed in 2014, only to collapse a year later to levels on par with the 2009 Financial Crisis.

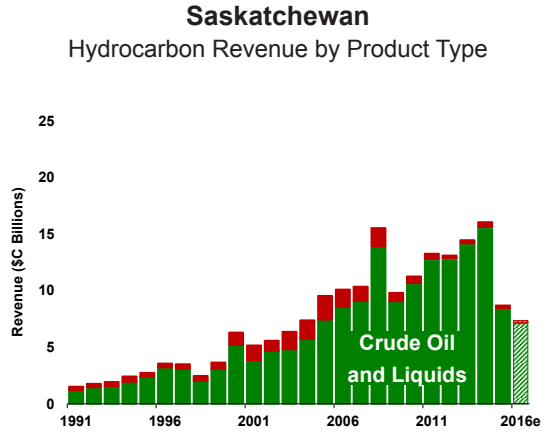
Based on price and production outlooks, total upstream revenues are estimated at $73 billion for 2016. Total revenue loss would be much greater if not for over 1.0 MMB/d of oil sands production growth since 2009.

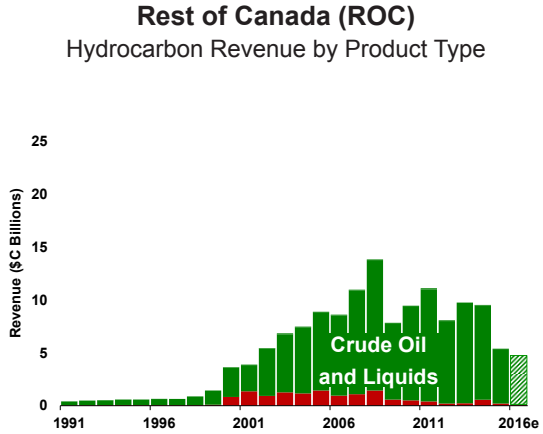
Canadian upstream revenues are dominantly dependent on oil prices. Oil-generated revenues account for almost 90% of total revenues.

Canadian Upstream Industry Revenue by Province









Source: CAPP, ARC Financial Corp.
Note: Vertical scale differences.

Across all producing provinces in Canada, upstream industry revenue is expected to fall again in 2016. A lower Canadian dollar will be insufficient to offset the combination of declining production volumes and lower commodity prices.

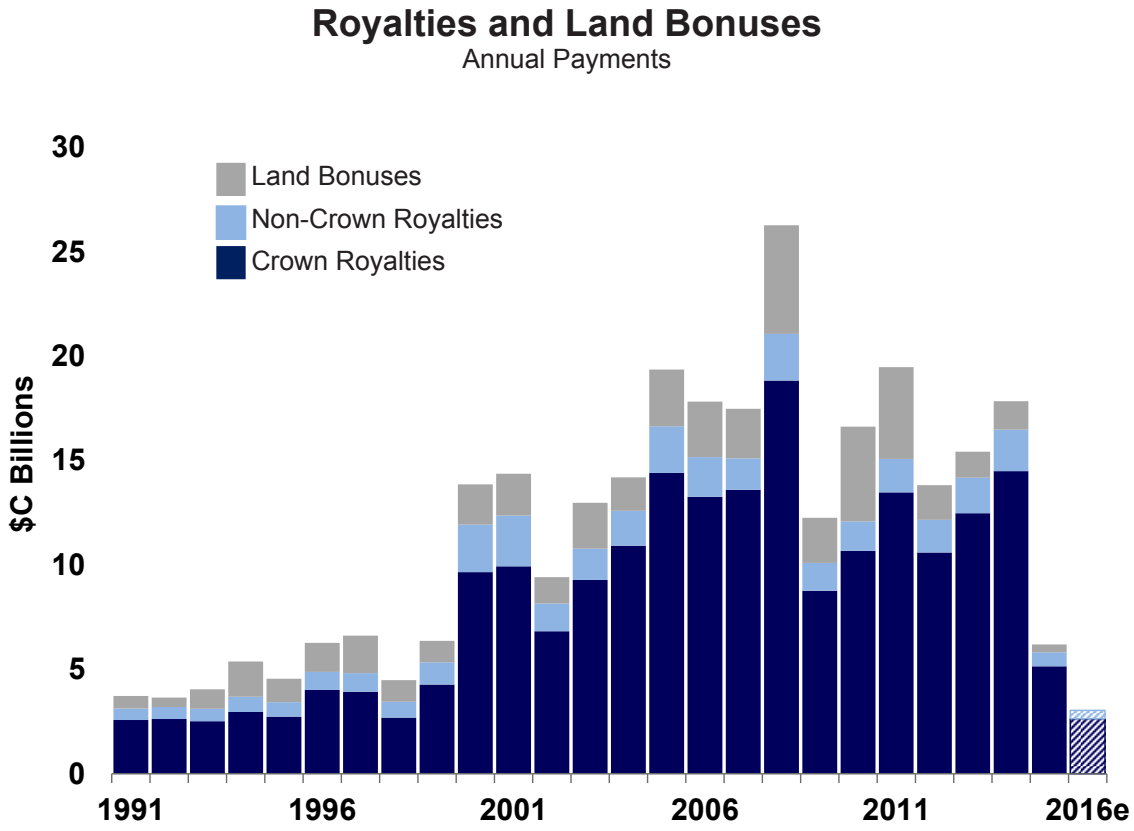
Over 78% of industry revenue is generated in Alberta. Notwithstanding the impact of wildfires, oil sands volumes are still rising, but not enough to keep consolidated product sales level with 2015.

Gas-biased BC is expected to struggle to keep its revenue flat. Gas prices are likely to be lower longer than oil, inhibiting investment. BC production is unlikely to rise as aggressively as between 2010 to 2015 until there is greater certainty on the future of west-coast LNG exports.

Saskatchewan is dominantly oil. Investment into fast-cycle tight oil plays like the Viking is likely to respond quickly on any oil rebound above $US 50/B (WTI). But production will grow only if the rebound sustains.

In the rest of Canada, oil revenue from Newfoundland and Labrador is also expected to fall in 2016. Declining natural gas revenue from offshore Nova Scotia will continue to be minimal to the industry at large.

Total Royalties and Land Bonuses



Source: CAPP, Statistics Canada, ARC Financial Corp.

Total Royalties are expected to be down to $3.0 billion in 2016, the lowest level since 1993. Land bonuses are expected to be at record lows as well.

Provincial government royalties are mostly a function of commodity price and volume produced. So, there is a strong correlation between royalties and oil and gas revenue. Land bonuses are indicative of the industry's appetite to lease more prospective acreage from the provinces. Both suffer if commodity prices are low.

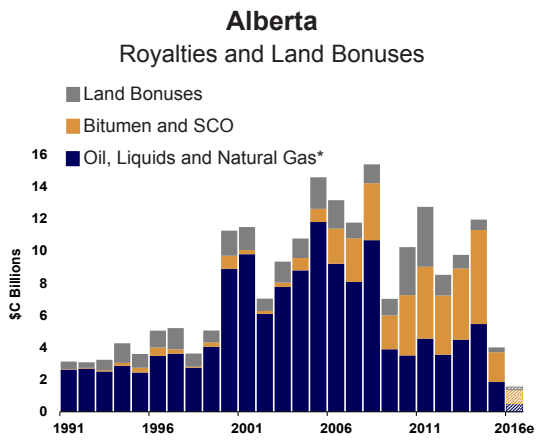
The high watermark for royalties and land bonuses was in 2008, when prices and production volumes were high – over $25 billion was paid by the industry to the producing provinces.

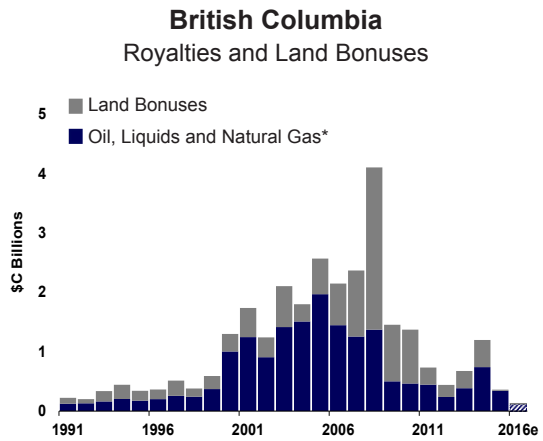
Rapidly falling oil and gas prices, combined with declining production volumes due to a dearth of investment, has been mirrored in royalty payments and land bonuses.

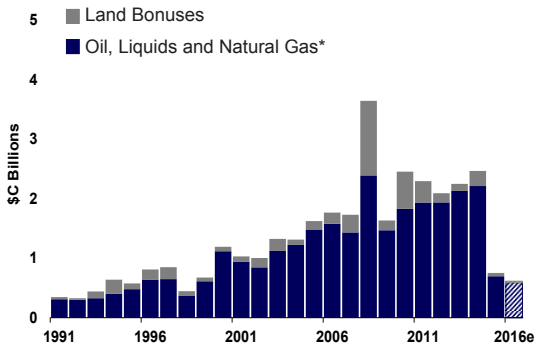
In 2015, government take – dominantly in BC, Alberta, Saskatchewan and Newfoundland and Labrador – was down over $10 billion, or 65% relative to 2014. Another 40% to 50% leg down is expected in 2016, to bring absolute royalties down to levels not seen since the 1990s.

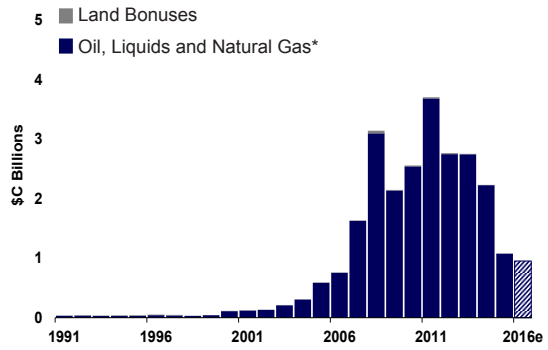
The good news? Royalties have significant upward leverage when commodity prices rebound.

Total Royalties and Land Bonuses by Province









Source: CAPP, ARC Financial Corp.
Note: Vertical scale differences
**Includes crown and non-crown royalties*

Alberta's provincial take from royalties and land bonuses peaked at $15.4 billion in 2008. The combined decay of oil and natural gas prices over the past two years has affected the largest producing province of both commodities.

Total Alberta take in 2016 is forecast to only be $1.3 billion, the lowest in over 25 years. Land sales are de minimis, due to an oversupply of prospective lands acquired by companies over the past several years.

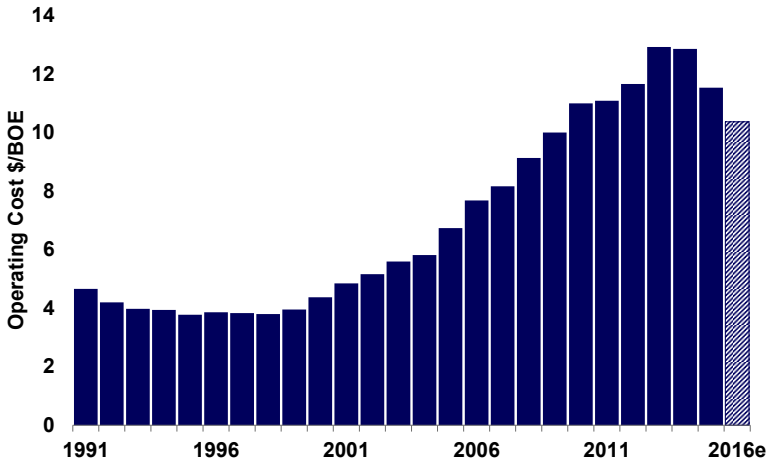
British Columbia experienced a royalty and land sale boom between 2000 and 2008, but the activity quickly deflated due to depressed continental natural gas prices. BC has the widest dynamic range of royalty and land bonus payments: 30:1 between what is expected in 2016 versus 2008.

Oil-biased Saskatchewan has seen its royalties rise over the past 20 years, in tandem with output growth and price appreciation. But there is no hiding from a 50% price drop in oil. The same downward price pressure affects the ROC namely, Newfoundland and Labrador.

Average Annual Operating Costs

Operating Cost per Unit of Production

Conventional Oil and Natural Gas



Source: CAPP, ARC Financial Corp.

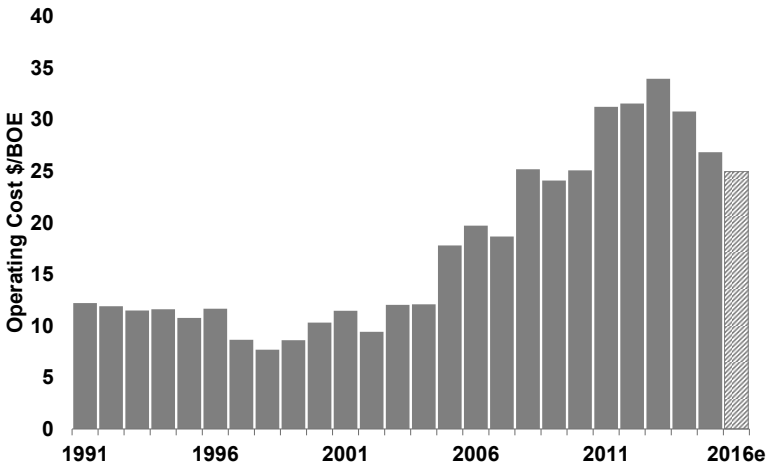
Operating costs typically rise in tandem with commodity prices and level of investment. The 8.0% CAGR* of costs between 2000 and 2014 is far in excess of other price indices due to the hard pull on labour and services by the industry during periods of growth. This cost-as-a-function-of-price dynamic is not exclusive to the Canadian oil and gas industry. However it is more acute in Canada, due to the limited availability of local labour and services as a function of exploitable resource size.

Costs are continually adjusting. Best available data suggests that costs outside the oil sands have declined by 15 to 25% on average between 2014 and 2016. Technology and operational efficiency have helped, but oversupply of service capacity is the dominant driver.

**compound annual growth rate*

Operating Cost per Unit of Production

Oil Sands - Bitumen and Synthetic Crude Oil



Source: CAPP, ARC Financial Corp.

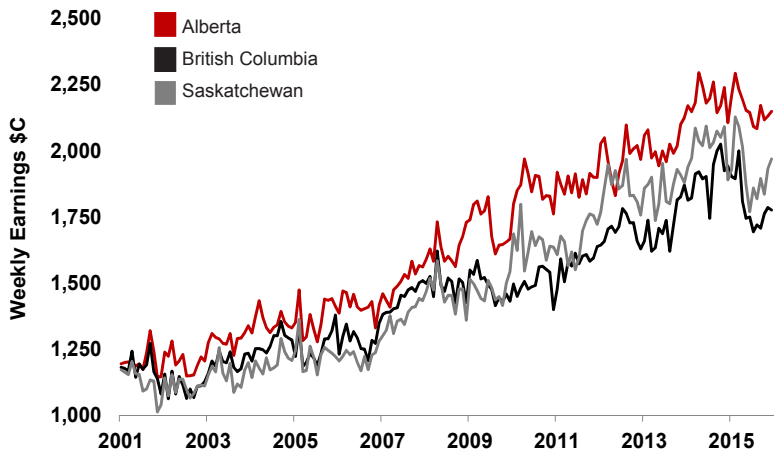
The massive scale of oil sands project development has been responsible for inflating costs over the past decade. Within the region, the inflationary CAGR has been 9.8% over the past decade, a period which saw over $200 billion in cumulative investment. Since the peak, costs have come down by almost $10 per barrel as companies have improved logistics and processes to adapt to lower prices.

Notwithstanding longer term impacts of wildfires, the region may not see such rapid inflation as in the past – over 17 projects have been cancelled or indefinitely delayed. A more balanced labour and service pool in the oil sands also has the potential to mitigate cost inflation on the conventional oil and gas side of the industry.

Other Costs

Average Weekly Labour Rates

Mining,Quarrying & Oil and Gas Extraction

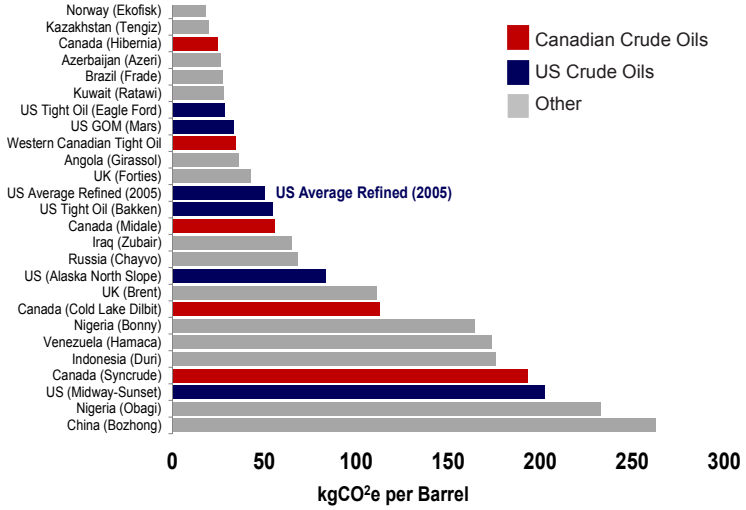


Source: Statistics Canada, ARC Financial Corp.

Wage inflation associated with oil and gas activity has been acute over the past decade, especially in Alberta, driven largely by booming oil sands development. Weekly average earnings of oil patch workers in Alberta rose at a rate of 5.5% per year between 2007 and 2014. Cancellation of 17 oil sands projects combined with broader job losses of over 100,000 workers has reversed the uptrend – wages have fallen by 10 to 15% from the peak across the western provinces. Wages are often sticky on the way down, especially in Alberta. And, top-quality workers can still command a premium. More downside may not be forthcoming. However, much slower investment into the oil sands suggests that wage inflation may be much softer than the long-term average on price recovery.

GHG Emissions for a Set of Crude Oils

From Production and Upgrading Only



*Source: Crude Oil Investing in a Carbon Constrained World, ARC Financial Corp.**

The above data shows the greenhouse gas (GHG) emissions associated with extracting and upgrading a sample of heavy and light crude oil streams. The average crude oil refined in the U.S. (2005) is highlighted as it is a commonly quoted yardstick for comparing crude oil GHG emissions intensities.

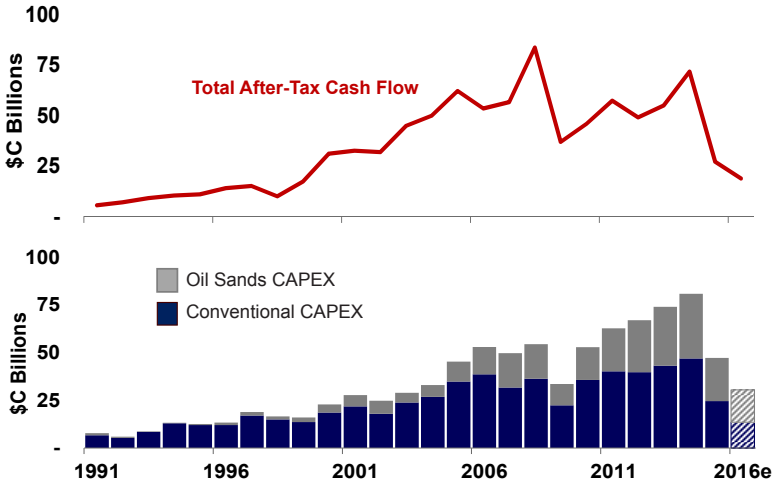
To learn more about the ARC method for assessing, reporting and comparing the GHG intensity of crude oil production, the report *Crude Oil Investing in a Carbon Constrained World* can be found at: http://www.arcfinancial.com/research

* *(using input data from the Global Oil Climate Index, IHS and DOE/NETL, and using publically available models from Stanford University and the University of Calgary).*

Cash Flow, Capital Spending and Financings

Cash Flow and Capital Expenditures

CAPEX Stacked by Industry Segment

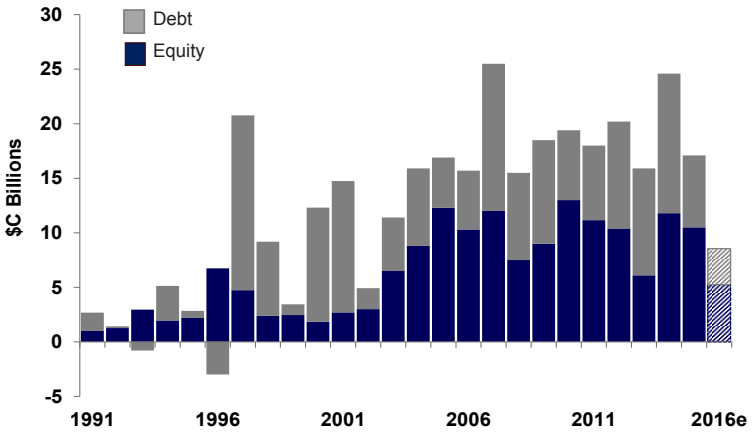


Source: CAPP, ARC Financial Corp.

Since 2010 the industry has invested 100% of its cash flow, plus additional capital raised from debt and equity markets. Outspending cash flow was largely driven by access to cheap capital that was chasing capital-intensive oil sands projects and the new set of growth opportunities presented by horizontal drilling and multi-stage hydraulic fracturing. Cash flow is currently insufficient to support debt-servicing and the required spending to offset production declines. Companies are focusing on remedying cash shortages by reducing costs, selling assets, downsizing staff and deferring projects. Despite factoring in three consecutive years of declining operating costs, COGL's cash flow for 2016 will be down another 30% from last year, and a staggering 75% relative to 2014.

Canadian Oil and Gas Financings

Annual Inflow of Debt and Equity Capital



Source: Sayer Energy Advisors, CanOils, ARC Financial Corp.

New resource plays in North America have an attractive risk-return profile relative to elsewhere in the world. Fast payback periods are an important element of the appeal. The near record capital infusion into the Canadian upstream industry in 2014 of $24.6 billion validated that sentiment. As prices slid in 2015, financings fell by 30%. Nevertheless, $17.1 billion in capital was still raised last year to fund capital programs and bolster battered balance sheets, before prices fell under $40/B.

In 2016, capital markets have largely shut access to new funding. In Q1 2016 only $1.2 billion of debt and equity was raised – down 84% compared to Q1 2015. Capital markets will be highly selective, preferentially funding the best companies. We expect $8.5 billion in financings for 2016.

Capital Spending Cuts

Capital Expenditure Cuts - Three Year Trend
Conventional Oil and Gas Directed Capital Spending

Company		CAPEX ($C MM) 2014	2015	2015 YOY Chg. $	%	CAPEX ($C MM) 2016e	2016 YOY Chg. $	%
Advantage Energy	Mar-16	237.0	165.0	-72.0	-30.4%	**120.0**	-45.0	-27.3%
Apache Canada	Feb-16	600.0	273.3	-326.7	-54.4%	**244.4**	-28.9	-10.6%
ARC Resources	Feb-16	945.5	541.6	-403.9	-42.7%	**390.0**	-151.6	-28.0%
Athabasca Oil Sands	Mar-16	199.9	176.0	-24.0	-12.0%	**52.5**	-123.5	-70.2%
Baytex Energy	Mar-16	700.0	71.3	-628.7	-89.8%	**12.3**	-59.1	-82.8%
Bonterra Energy	Mar-16	155.6	58.5	-97.1	-62.4%	**40.0**	-18.5	-31.6%
Bellatrix	Mar-16	504.0	155.2	-348.8	-69.2%	**92.0**	-63.2	-40.7%
Birchcliff Energy	May-16	450.0	250.0	-200.0	-44.4%	**103.5**	-146.5	-58.6%
BlackPearl Resources	Feb-16	235.4	68.5	-166.9	-70.9%	**12.5**	-56.0	-81.8%
Bonavista Energy	Feb-16	533.0	313.9	-219.1	-41.1%	**167.5**	-146.4	-46.6%
Cardinal Energy	Jan-16	36.0	30.0	-6.0	-16.7%	**25.0**	-5.0	-16.7%
Cdn Natural Res.	Mar-16	2,960.0	1,093.0	-1,867.0	-63.1%	**547.5**	-545.5	-49.9%
Cenovus	Feb-16	870.0	244.0	-626.0	-72.0%	**152.5**	-91.5	-37.5%
Cequence	Nov-15	29.4	22.0	-7.4	-25.3%	**17.0**	-5.0	-22.7%
Chinook	May-16	96.6	44.3	-52.3	-54.1%	**10.1**	-34.2	-77.2%
Crescent Point	Mar-16	2,095.6	1,561.8	-533.8	-25.5%	**950.0**	-611.8	-39.2%
Crew Energy	Mar-16	307.0	135.0	-172.0	-56.0%	**70.0**	-65.0	-48.1%
Encana	Feb-16	1,225.4	465.5	-759.9	-62.0%	**277.8**	-187.7	-40.3%
Enerplus	Feb-16	308.0	157.7	-150.3	-48.8%	**50.0**	-107.7	-68.3%
Freehold Royalty Trust	Mar-16	33.7	22.3	-11.4	-33.8%	**7.0**	-15.3	-68.6%
Husky Energy	Dec-15	3,029.0	2,200.0	-829.0	-27.4%	**1,100.0**	-1,100.0	-50.0%
Journey Energy	Mar-16	260.9	49.0	-211.9	-81.2%	**9.0**	-40.0	-81.6%
Kelt Exploration	May-16	266.0	181.0	-85.0	-32.0%	**83.0**	-98.0	-54.1%
Lightstream	Mar-16	472.0	95.0	-377.0	-79.9%	**32.0**	-63.0	-66.3%
Northern Blizzard	Feb-16	262.8	80.0	-182.8	-69.6%	**40.0**	-40.0	-50.0%
Nuvista	Mar-16	315.0	273.2	-41.8	-13.3%	**125.0**	-148.2	-54.3%
Painted Pony	Apr-16	270.5	106.7	-163.8	-60.6%	**178.0**	71.3	66.8%
Paramount Resources	Apr-16	857.4	438.0	-419.4	-48.9%	**80.4**	-357.6	-81.6%
Pengrowth	Jan-16	769.0	200.0	-569.0	-74.0%	**65.0**	-135.0	-67.5%
PennWest	Mar-16	732.0	470.0	-262.0	-35.8%	**50.0**	-420.0	-89.4%
Peyto Energy	Mar-16	690.0	593.8	-96.2	-13.9%	**525.0**	-68.8	-11.6%
Raging River	Mar-16	273.9	171.0	-102.8	-37.5%	**155.0**	-16.0	-9.4%
Rock Energy	Mar-16	118.9	37.7	-81.2	-68.3%	**20.0**	-17.7	-46.9%
RMP Energy	Mar-16	186.2	96.6	-89.7	-48.1%	**60.0**	-36.6	-37.9%
Seven Generations Energy	Jan-16	N/A	1,309.0	N/A	N/A	**925.0**	-384.0	-29.3%
Storm Resources	Feb-16	106.0	90.7	-15.3	-14.4%	**80.0**	-10.7	-11.8%
Suncor	Feb-16	1,685.0	1,325.0	-360.0	-21.4%	**889.0**	-436.0	-32.9%
Tamarack Valley Energy	Feb-16	154.0	120.0	-34.0	-22.1%	**48.5**	-71.5	-59.6%
TORC Oil and Gas	Mar-16	141.8	99.3	-42.5	-30.0%	**90.0**	-9.3	-9.3%
Tourmaline	Mar-16	1,563.6	1,450.0	-113.6	-7.3%	**610.0**	-840.0	-57.9%
Whitecap Resources	Apr-16	482.0	234.8	-247.2	-51.3%	**148.0**	-86.8	-37.0%
Surge	Apr-16	149.6	76.7	-72.8	-48.7%	**55.0**	-21.7	-28.3%
Trilogy Energy	Mar-16	426.7	80.9	-345.8	-81.0%	**75.0**	-5.9	-7.3%
Twin Butte	Mar-16	140.0	80.2	-59.8	-42.7%	**17.0**	-63.2	-78.8%
Vermilion Energy	Feb-16	337.0	202.0	-135.0	-40.1%	**73.0**	-129.0	-63.9%
Sum of Released Budgets		**26,211.2**	**14,600.5**	**-11,610.7**	**-44.3%**	**8,874.5**	**-7,035.1**	**-44.2%**

Source: Company Reports, ARC Financial Corp.

Capital Expenditure Cuts - Three Year Trend
Oil Sands Directed Capital Spending

Company		CAPEX ($C MM) 2014	2015	2015 YOY Chg. $	%	CAPEX ($C MM) 2016e	2016 YOY Chg. $	%
CNRL -Thermal In Situ	Mar-16	1,039.0	314.0	-725.0	-69.8%	**172.5**	-141.5	-45.1%
CNRL - Horizon Oil Sands	Mar-16	3,195.0	2,743.0	-452.0	-14.1%	**2,490.0**	-253.0	-9.2%
Cenovus	Feb-16	2,022.5	1,185.0	-837.5	-41.4%	**765.0**	-420.0	-35.4%
ConocoPhillips	Dec-15	2,461.3	1,602.6	-858.7	-34.9%	**1,066.7**	-535.9	-33.4%
Devon Energy	Feb-16	1,046.7	702.3	-344.4	-32.9%	**243.1**	-459.3	-65.4%
Imperial Oil	Feb-16	5,654.0	3,595.0	-2,059.0	-36.4%	**1,800.0**	-1,795.0	-49.9%
Husky Energy	Dec-15	713.0	200.0	-513.0	-71.9%	**100.0**	-100.0	-50.0%
Athabasca Oil Sands	Mar-16	417.0	114.2	-302.8	-72.6%	**11.0**	-103.2	-90.4%
Suncor Energy	Feb-16	3,456.0	3,881.0	425.0	12.3%	**4,700.0**	819.0	21.1%
Teck Resources	Feb-16	702.0	997.0	295.0	42.0%	**1,005.0**	8.0	0.8%
MEG Energy	Feb-16	1,200.0	257.0	-943.0	-78.6%	**170.0**	-87.0	-33.9%
Sum of Released Budgets		**21,906.5**	**15,591.1**	**-6,315.4**	**-28.8%**	**12,523.2**	**-3,067.9**	**-19.7%**

Oil and gas projects around the world have seen an unprecedented slashing of budgets and deferrals of capital spending over the last couple of years. Globally, several consultancies and agencies are reporting hundreds of billions of dollars in deferred or cancelled projects. As a result, year-over-year worldwide CAPEX cuts of 30% to 40% are expected in 2016, following a 23% decline in 2015. The Canadian oil and gas industry is expecting to see its largest two-year drop in capital spending of 62% since CAPP started keeping track in 1947.

The Canadian oil and gas industry is divided into two distinct sectors: companies primarily operating in the oil sands, and those in conventional oil, liquids and natural gas. We have tabled a select group of publicly-traded Canadian oil and gas companies' 2016 budgets compared to 2015 and 2014. Oil sands producers (above) have announced budget cuts of about 20% this year, while conventional producers have taken a sharper, 44% knife to their proposed 2016 investment.

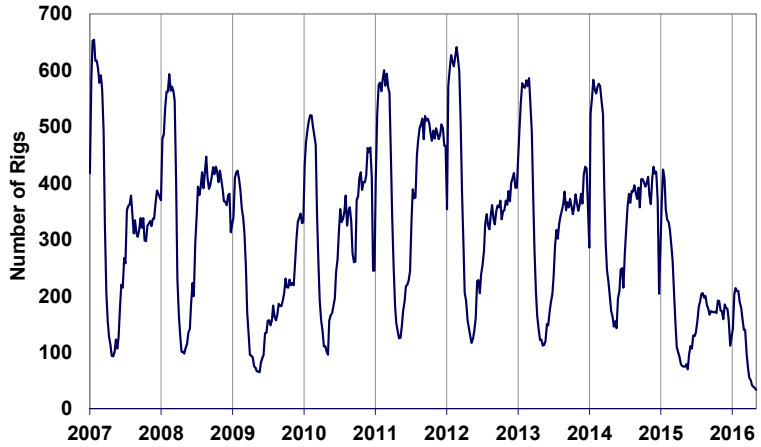
Several oil sands producers will continue to invest in their later-stage projects that are expected to start up over the next couple of years. As such, oil sands budget cuts are not as severe as on the conventional side of the business.

ARC energyresearch institute

Canadian Drilling Activity

WCSB Rig Count

Active Rigs on a Weekly Basis



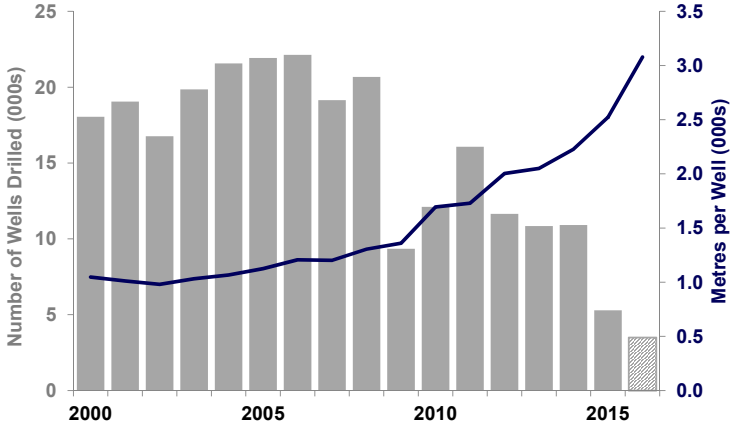
Source: CAODC, ARC Financial Corp.

Oil and gas rig activity "skipped a beat" a year ago and "flat lined" this past winter. Two consecutive years of budget cuts and the onset of an unusually early spring thaw arrested field activity. The first quarter is normally the busiest of the year, but not in 2016. The number of active drilling rigs was down 45% compared to Q1 2015.

Currently rig utilization is close to zero, at just 5%, a record low. The utilization numbers are doubly dire, because the Canadian rig fleet is shrinking. Companies are decommissioning underutilized, older, less efficient rigs or using them for spare parts. Although oil prices have rebounded to the mid-$40/B level, investment will lag. Like last year, the 2016 summer drilling season is expected to be eerily quiet.

Annual Wells Drilled and Metres per Well

Rig-Release Basis



Source: Nickles, ARC Financial Corp.

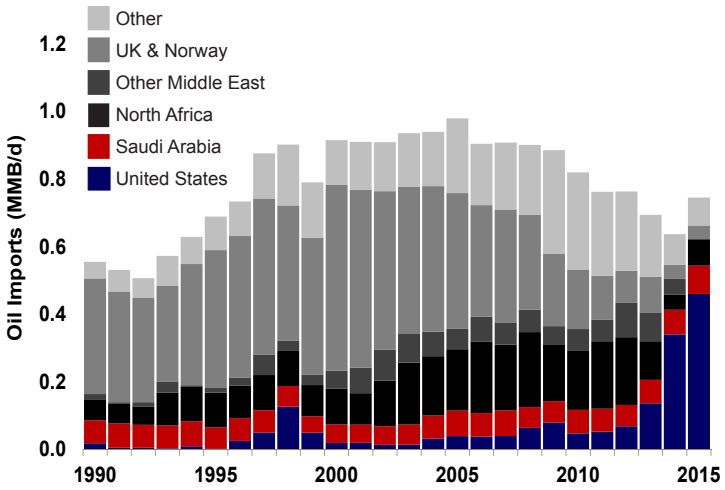
With 45% fewer rigs drilling, it is no surprise that the number of wells drilled has fallen proportionally – 40% less in Q1 2016 than 2015. Counterbalancing the downward well count is increasing well depth, or "meterage." The rigs that are working today are drilling multiple, deeper and longer horizontal wells on "pads." This style of drilling creates cost efficiencies through better logistics and economies of scale. Meterage rose to record lengths last year at over 2,500 meters/well, up 13% from 2014.

Based on the commodity price assumptions of this report and capital spending guidance, we are forecasting the number of wells drilled to be no more than 3,500 in 2016. Based on the first three months of data, the length of each well on average is on track to increase by 20% again.

Market Access

Canadian Crude Oil Imports

From Foreign Sources



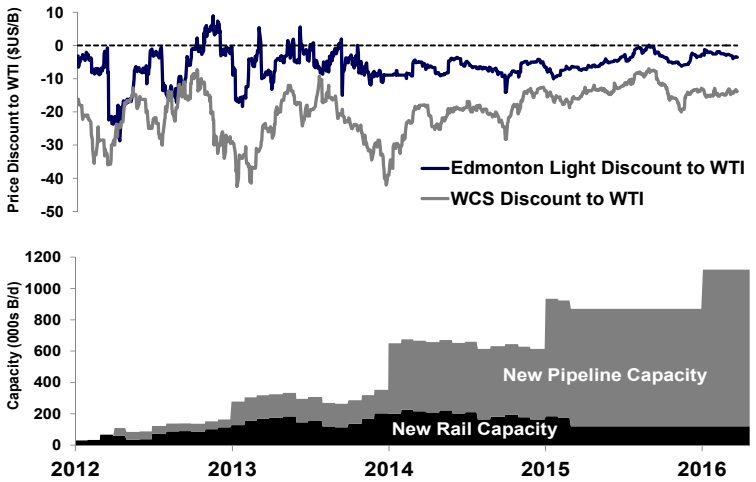
Source: Statistics Canada, ARC Financial Corp.

Historically, refiners on Canada's east coast relied upon imports of waterborne crudes mostly from North Africa, Saudi Arabia, Norway and the United Kingdom.

By 2013, US LTO was growing rapidly and competed for market share at Canadian east coast refineries. By 2015, over 60% of Eastern Canadian oil imports had shifted to US producers. Quebec and Atlantic Canada refineries sourced about 100,000 B/d from Western Canada in 2015 – compared to nothing a few years ago. Recently, Enbridge's Line 9 reversal project began allowing landlocked Western Canadian and US oil to reach Montreal by pipeline. North American oil markets are becoming more self contained, more integrated, and less reliant on overseas sources.

Oil Transport Additions and Price Discounts

Incremental Oil Pipeline and Rail Capacity Since 2012



Source: Bloomberg, Statistics Canada, Enbridge, ARC Financial Corp.

The period between 2012 and 2014 was marked by wide and volatile price discounts for light and heavy oils in Western Canada. At times, barrels of premium light grades were trading at $25/B less than US markets. Static pipeline capacity in the face of rapidly growing oil sands output created bottlenecks that resulted in upstream oversupply. Volume growth in mid-continent US oil plays also clogged up limited pipeline capacity.

By 2014, price distortions had induced more oil takeaway capacity from both railroads and pipeline expansions. Rail took some of the pressure off of pipelines. Existing pipes were able to increase throughput by expansions and improving the logistics of carrying different oils. The result: substantially diminished discounts and volatility, post 2015.

The Fiscal Pulse with Varying Oil and Gas Prices

A Sensitive Industry

Five years from now, hindsight will assuredly prove that any single price forecast in these volatile times will be wrong. If nothing else, uncertain events in large oil producing regions such as North Africa and the Middle East will induce theatrical ups and downs in key metrics like price, revenue, cash flow and therefore capital expenditures.

Commodity prices are the most influential factor in determining the Fiscal Pulse of the business. To see the effect of oil and gas price volatility on key capital metrics for 2016, we have constructed sensitivity tables that are displayed on the following three pages.

We took the mid-point of $US 50/B oil and $2.50/Mcf natural gas as a *Notional Case* (highlighted in the centre, dark blue boxes) to pivot prices around. In the Table on page 31, each offsetting box from the centre adds or subtracts $US 10.00/B off the oil price, and plus or minus $0.50/Mcf off natural gas. In this way we can see the effect of price variations as a function of either one or both commodities.

At time of writing, at the end of Q1 2016, the *Notional Case* for the balance of the year seems optimistic, given that prices in the futures markets at the end of April were indicating closer to the upper left, low case of $US 40.00/B and $2.00/Mcf. That's fine, because none of the nine boxes are meant to be a forecast; the point of the tables is to show sensitivity to an extreme downside, as well as to future price recovery.

The Table on page 32 illustrates the same concept, except the values recorded in each box represent the *differences* from what happened in 2015 (we do the subtractions for you). And the Table on page 33 is the same, except the deviations from 2015 are reported on a percentage basis.

The extreme corners offer the best insights into, "what if?" The most optimistic box is at the bottom right with oil at $US 60.00/B and natural gas at $3.00/Mcf. In such a case, revenue rises to $103.6 billion and cash flow recovers to $45.0 billion. Both these numbers fall well short of the peaks registered in 2014, but they constitute a healthier Fiscal Pulse than what is being realized now, and are at a level that would avoid the labour shortages and cost inflation that plagued the extremes of 2008 and 2014.

Recall that commodity price strength and production volumes are now heavily skewed toward oil. Therefore, at an industry level, our matrices show that what happens to oil prices is far more impactful to the Canadian industry than what happens to natural gas. Importantly, at prices below the *Notional Case* the industry is broadly unprofitable and doesn't generate sufficient long-term returns to entice investment of cash flow. This last point stresses the need for vigorous innovation to boost the industry's productivity as an antidote to the potential trauma of ongoing commodity prices that linger at or below *Notional Case*.

Fiscal Health Through Flexibility and Innovation

In today's context, the centre box, the Notional Case, represents metrics afforded to a mostly marginal global oil and gas industry that is capital constrained. Growth is unlikely at $50/B and most producing regions would be unable to arrest declining output.

Yet even if oil and gas prices were to recover to levels beyond the upper limits of our sensitivity tables that follow, we know that a stable, long-term Fiscal Pulse would be fleeting. Forces like competition, substitution, environmental regulations and technological change will pose relentless challenges.

The Canadian oil and gas industry - notionally represented as Canada Oil and Gas Limited in our analysis - has a long history of responding and adapting to forces that have led to extreme downturns. While change is an ongoing expectation in this business, there is one thing that has remained unmoved over time: The industry's 155-year entrepreneurial spirit, combined with the country's vast hydrocarbon resource endowment, has always enabled it to come out with a stronger Fiscal Pulse after every downturn.

Sensitivity of 2016 Canadian Oil and Gas Metrics to Prices

2016 Oil Price Annual Average (WTI $US)

2016 Natural Gas Price Annual Average (AECO $C)		$40.00/B			$50.00/B			$60.00/B		
		Conv.	Oil Sands	Total	Conv.	Oil Sands	Total	Conv.	Oil Sands	Total
$2.00/Mcf	Revenue ($ Billions)	$36.4	$33.1	$69.5	$43.1	$42.7	$85.9	$48.1	$50.2	$98.3
	Cash Flow ($ Billions)	$10.3	$5.5	$15.8	$15.8	$14.1	$29.9	$20.0	$20.7	$40.7
	CAPEX ($ Billions)	$13.0	$16.9	$29.9	$18.2	$16.9	$35.1	$22.0	$18.1	$40.1
	Wells	2,900	500	3,400	4,200	500	4,700	4,950	750	5,700
$2.50/Mcf	Revenue ($ Billions)	$39.1	$33.1	$72.1	$45.8	$42.7	$88.5	$50.8	$50.2	$100.9
	Cash Flow ($ Billions)	$12.4	$5.5	$17.9	$18.0	$14.1	$32.1	$22.2	$20.7	$42.9
	CAPEX ($ Billions)	$15.8	$16.9	$32.7	$20.7	$16.9	$37.6	$24.4	$18.1	$42.4
	Wells	3,600	500	4,100	4,850	500	5,350	5,550	750	6,300
$3.00/Mcf	Revenue ($ Billions)	$41.7	$33.1	$74.8	$48.4	$42.7	$91.1	$53.4	$50.2	$103.6
	Cash Flow ($ Billions)	$14.6	$5.5	$20.0	$20.1	$14.1	$34.3	$24.3	$20.7	$45.0
	CAPEX ($ Billions)	$18.5	$16.9	$35.4	$23.2	$16.9	$40.1	$26.7	$18.1	$44.8
	Wells	4,300	500	4,800	5,500	500	6,000	6,150	750	6,900

Source: ARC Financial Corp.

ARC energyresearch institute

Canadian Oil and Gas Industry Metrics Compared to 2015

2016 Oil Price Annual Average (WTI $US)

2016 Natural Gas Price Annual Average (AECO $C)		$40.00/B			$50.00/B			$60.00/B		
		Conv.	Oil Sands	Total	Conv.	Oil Sands	Total	Conv.	Oil Sands	Total
$2.00/Mcf	Revenue ($ Billions)	-$11.5	-$7.3	-$18.8	-$4.8	$2.4	-$2.4	$0.2	$9.8	$10.0
	Cash Flow ($ Billions)	-$6.1	-$5.1	-$11.2	-$0.6	$3.6	$3.0	$3.6	$10.2	$13.8
	CAPEX ($ Billions)	-$11.6	-$5.7	-$17.3	-$6.4	-$5.6	-$12.0	-$2.6	-$4.5	-$7.1
	Wells	-1,611	-383	-1,994	-311	-383	-694	439	-133	306
$2.50/Mcf	Revenue ($ Billions)	-$8.9	-$7.3	-$16.2	-$2.2	$2.4	$0.2	$2.8	$9.8	$12.6
	Cash Flow ($ Billions)	-$4.0	-$5.1	-$9.1	$1.6	$3.6	$5.2	$5.8	$10.1	$15.9
	CAPEX ($ Billions)	-$8.8	-$5.6	-$14.4	-$3.9	-$5.6	-$9.5	-$0.2	-$4.5	-$4.7
	Wells	-911	-383	-1,294	339	-383	-44	1,039	-133	906
$3.00/Mcf	Revenue ($ Billions)	-$6.2	-$7.3	-$13.5	$0.5	$2.4	$2.8	$5.5	$9.8	$15.3
	Cash Flow ($ Billions)	-$1.8	-$5.1	-$6.9	$3.8	$3.6	$7.3	$7.9	$10.1	$18.1
	CAPEX ($ Billions)	-$6.1	-$5.6	-$11.7	-$1.4	-$5.6	-$7.1	$2.2	-$4.5	-$2.3
	Wells	-211	-383	-594	989	-383	606	1,639	-133	1,506

Source: ARC Financial Corp.

ARC energyresearch institute

Canadian Oil and Gas Industry Metrics Compared to 2015

2016 Oil Price Annual Average (WTI $US)

2016 Natural Gas Price Annual Average (AECO $C)		$40.00/B			$50.00/B			$60.00/B		
		Conv.	Oil Sands	Total	Conv.	Oil Sands	Total	Conv.	Oil Sands	Total
$2.00/Mcf	Revenue	-24.1%	-18.1%	-21.3%	-10.0%	5.9%	-2.8%	0.4%	24.2%	11.3%
	Cash Flow	-37.1%	-48.4%	-41.5%	-3.4%	33.6%	11.1%	22.1%	96.4%	51.2%
	CAPEX	-47.1%	-25.1%	-36.6%	-25.9%	-25.0%	-25.5%	-10.5%	-20.0%	-15.0%
	Wells	-35.7%	-43.4%	-37.0%	-6.9%	-43.4%	-12.9%	9.7%	-15.1%	5.7%
$2.50/Mcf	Revenue	-18.5%	-18.1%	-18.3%	-4.5%	5.9%	0.2%	5.9%	24.2%	14.3%
	Cash Flow	-24.2%	-48.4%	-33.7%	9.8%	33.6%	19.1%	35.3%	96.0%	59.1%
	CAPEX	-35.8%	-25.0%	-30.6%	-15.8%	-25.0%	-20.2%	-0.8%	-20.0%	-10.0%
	Wells	-20.2%	-43.4%	-24.0%	7.5%	-43.4%	-0.8%	23.0%	-15.1%	16.8%
$3.00/Mcf	Revenue	-13.0%	-18.1%	-15.3%	1.0%	5.9%	3.2%	11.4%	24.2%	17.3%
	Cash Flow	-11.0%	-48.4%	-25.7%	22.9%	33.6%	27.1%	48.4%	96.0%	67.1%
	CAPEX	-24.7%	-25.0%	-24.8%	-5.7%	-25.0%	-15.0%	8.8%	-20.0%	-5.0%
	Wells	-4.7%	-43.4%	-11.0%	21.9%	-43.4%	11.2%	36.3%	-15.1%	27.9%

Source: ARC Financial Corp.

ARC energyresearch institute

The Industry's Income Statement

Canada Oil and Gas Limited

Consolidated Income Statement

$C Millions	1998	2009	2010	2011	2012	2013	2014	2015	2016e
Conventional Operations									
Oil and Liquids Sales	11,731	37,242	44,207	54,320	50,633	56,513	56,516	**33,896**	**28,163**
Natural Gas Sales	11,185	22,343	20,897	18,572	11,668	15,581	23,077	**14,034**	**8,718**
Oil and Gas Sales	22,916	59,585	65,104	72,892	62,301	72,094	79,592	**47,931**	**36,881**
Royalties	(3,376)	(7,991)	(8,336)	(10,607)	(8,468)	(9,744)	(10,633)	**(3,964)**	**(2,165)**
Net Revenues	19,540	51,594	56,768	62,285	53,833	62,350	68,959	**43,967**	**34,716**
Operating Expense	6,559	15,899	17,127	17,228	18,001	20,600	21,229	**18,854**	**16,228**
Gross Margin	12,980	35,695	39,642	45,058	35,832	41,750	47,730	**25,113**	**18,488**
Oil Sands Operations									
Bitumen & SCO Sales	3,073	29,583	36,540	46,762	49,088	56,762	69,702	**40,375**	**35,815**
Royalties	(67)	(2,110)	(3,747)	(4,467)	(3,683)	(4,429)	(5,843)	**(1,851)**	**(871)**
Net Revenues	3,005	27,473	32,793	42,295	45,405	52,333	63,859	**38,523**	**34,944**
Operating Expense	1,654	11,781	13,275	18,183	20,089	24,053	24,305	**23,323**	**22,475**
Gross Margin	1,351	15,691	19,518	24,111	25,317	28,280	39,554	**15,200**	**12,469**
Expenses:									
G&A	1,520	5,689	6,442	5,710	6,896	8,796	9,054	**8,360**	**7,411**
Interest	1,905	5,213	4,460	4,507	4,667	4,944	5,139	**5,008**	**4,933**
DD&A	8,831	26,251	29,885	30,020	34,838	35,943	36,187	**36,309**	**34,528**
Other	3,068	2,783	4,409	3,739	8,607	5,022	11,297	**10,707**	**10,508**
Total Expenses	15,324	39,936	45,196	43,975	55,008	54,705	61,678	**60,384**	**57,379**
Earnings Before Taxes	**(992)**	**11,450**	**13,964**	**25,194**	**6,141**	**15,324**	**25,606**	**(20,071)**	**(26,422)**
Current Income Tax	1,006	3,693	2,537	1,740	678	1,509	1,480	**-**	**-**
Deferred Income Tax	(578)	(3,525)	(88)	1,902	134	764	879	*****	*****
Total Taxes	428	168	2,449	3,642	811	2,273	2,359	**-**	**-**
Net Earnings (Loss)	**(1,420)**	**11,282**	**11,515**	**21,552**	**5,330**	**13,051**	**23,247**	**(20,071)**	**(26,422)**

** Due to the severe change in net income, deferred tax is indeterminable at time of writing*

Source: ARC Financial Corp.

Consider this a consolidated Income Statement for our fictitious company called Canada Oil and Gas Limited (COGL), a financial aggregation of all the oil and gas companies operating across the country, from British Columbia to Newfoundland and Labrador.

The numbers expected for 2016 demonstrate another deterioration in financial performance relative to anything seen since 1989, the earliest date for which we keep our Fiscal Pulse model.

Most top line indicators are down by half relative to the period between 2011 and 2014. On the bottom line, the industry is forecast to see its second accounting loss in income since 1998, another indication of the severity of the current situation. The loss has expanded to $26.4 billion, wider than the $20.1 billion last year. The news is not good, but we note that COGL has a wide spectrum of companies, not all of which will have accounting losses or excessive debt in 2016. Companies with quality plays, efficient operations and access to markets will make money, though certainly not as much relative to prior years. These are the companies that will survive this most severe of downturns within COGL, and lead the industry to a healthier Fiscal Pulse in years ahead.

The Industry's Balance Sheet

Canada Oil and Gas Limited

Consolidated Balance Sheet

$C Millions	1998	2009	2010	2011	2012	2013	2014	2015	2016e
Assets									
Current Assets	9,278	35,075	38,708	42,730	44,706	46,961	44,671	33,840	26,645
Property, Plant & Equipment (net)	95,709	294,732	333,236	358,747	395,486	436,688	455,194	456,083	442,062
Other Assets	5,947	41,820	54,684	55,886	69,225	76,177	87,153	87,333	87,469
Total Assets	**110,934**	**371,627**	**426,628**	**457,362**	**509,418**	**559,826**	**587,017**	**577,256**	**556,176**
Liabilities and Shareholders' Equity									
Current Liabilities	10,121	50,653	55,384	59,752	68,066	70,915	57,798	60,273	59,448
Long Term Debt	40,685	68,918	82,530	76,037	90,786	103,865	112,540	115,016	114,191
Future Income Taxes Liability	11,752	25,496	25,408	27,310	27,444	28,207	29,087	27,725	25,643
Other Liabilities	9,235	42,845	43,773	56,737	61,358	59,195	68,254	60,794	60,794
Shareholders' Equity	39,141	183,715	219,532	237,526	261,764	297,644	319,338	313,449	296,101
Total Liabilities and Shareholders' Equity	**110,934**	**371,627**	**426,628**	**457,362**	**509,418**	**559,826**	**587,017**	**577,256**	**556,176**
Ratios									
Debt to Cash Flow	*4.1x*	*1.9x*	*1.8x*	*1.3x*	*1.9x*	*1.9x*	*1.6x*	*4.3x*	*6.1x*

Source: ARC Financial Corp.

The Balance Sheet of COGL has grown impressively over the last two decades. There has been a five-fold increase in assets, mostly coming from an expansion of productive capacity. Assets peaked in 2014 at almost $590 billion. Since then, the value of assets have eroded due to the fall in oil and gas prices. By the end of 2016, we estimate a $30 billion decline in value relative to the 2014 peak. To date, equity holders have shouldered the bulk of the value loss. Creditors could realize greater-than-expected losses if insolvencies accelerate into the latter half of the year.

Current liabilities and long-term debt has grown to an estimated $174 billion. Debt is a major concern for the industry during this severe downturn, with various financial ratios breaking lenders' covenants. COGL's debt-to-cash flow ratio is estimated at 6.1x in 2016, higher than the troubling level of 4.1x in 1998.

Looking into 2017, liabilities will necessarily come down. Upstream bankruptcies will result in debt write-offs. Tighter covenants and a desire to "heal" COGL's balance sheet on price recovery will likely see a significant fraction of incremental cash flows channeled to debt repayment in advance of further investment into productive capacity.