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QUIC RESEARCH REPORT

Energy & Utilities

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Onshore Oil & Gas Fields in North America

A Geographical Analysis of the Energy Space

Introduction

North America is a crucial hub for oil and gas (O&G) production. The United States and Canada produce the world's most and fifth most petroleum products, respectively, while also producing the first and third most natural gas respectively. Clearly, the two countries combine to have a major impact on global supply and demand levels. As a result, the Energy team decided it would be prudent to perform an in-depth analysis of the supply side of this equation by providing a geographical breakdown and analysis of this North America production.

The goal is to assess the various O&G basins on a number of key metrics: percentage oil vs gas, quality of oil produced, well economics and growth outlooks. Ultimately this will be used to determine whether particular fields stand-out as attractive, from which we can then identify the major companies that are levered to these plays.

QUIC Research Reports focus on emerging investment themes that affect current portfolio companies and companies under coverage.

Industry Terms

Geographical Areas

The focus of this report is to develop a better understanding of the different oil and gas (O&G) producing geographical areas in the United States and Canada. In order to do this, it is first important to understand some fundamental terminology.

In conventional production, an oil well extracts oil from a subsurface pool. Oil pools that group together become a field. These fields form plays that are comprised of a specific type of hydrocarbon accumulations. Finally, these plays tend to be grouped into basins. A basin is a depression in the crust of Earth where sediments typically accumulate.

Types of Production

Oil production can broadly be classified in terms of conventional and unconventional production.

A conventional play is a reservoir in which buoyant forces keep hydrocarbons in place below a sealing caprock.

The contrasting type of production is broadly classified as unconventional. Unconventional production differs in that the hydrocarbons are spread throughout the basin as opposed to being trapped in one location. Furthermore, they are often embedded in low permeability formations.

The first type of unconventional production is tight oil. This is crude oil stored in shale that requires modern drilling and recovery techniques to extract.

The second type is oil shale. This is a petroleum precursor that requires cooking to get the oil out.

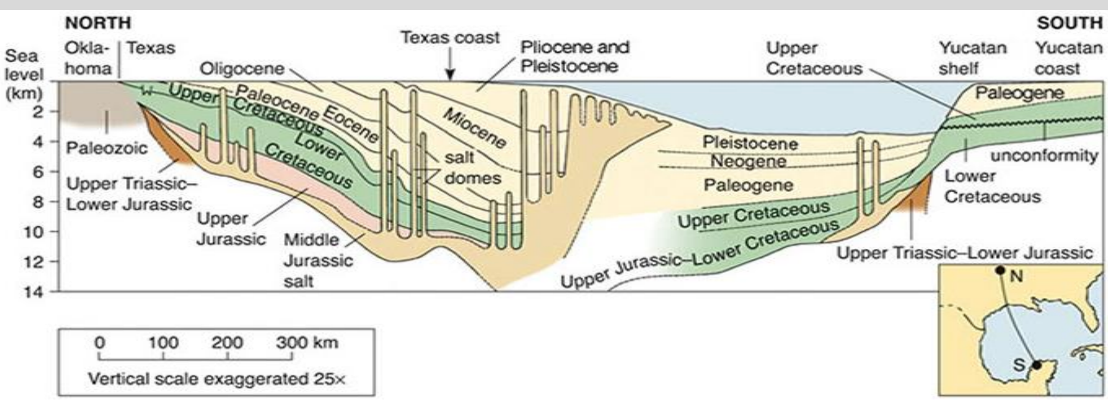
For natural gas it is a little bit simpler. There are two types: wet gas and dry gas. The difference is simply that wet gas also produces associated products like ethane, which can be sold at a higher cost than the gas, effectively lowering the breakeven of wet gas compared to dry gas.

General

For simplicity we will avoid in-depth discussions regarding the technical geological terms and formations; however if desired, a diagram can be viewed below (see Exhibit I)

One final concept that is important to understand is that every oil well produces an associated amount of gas, and that every gas well produces an associated amount of oil. In the case of oil associated with gas production, it is classified as condensate.

EXHIBIT I: Geological Formations



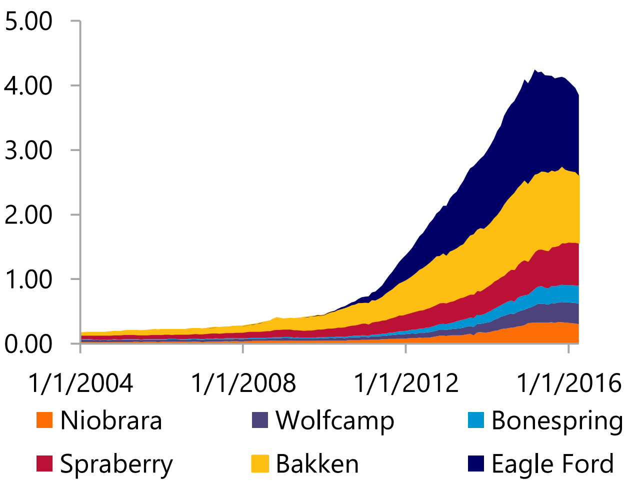
U.S. Onshore Oil and Gas Basins

Major Basins

The U.S. has for years been the largest producer of both oil and natural gas. In 2014 it produced just over 14 Mmboe/d, including both onshore and offshore production, far exceeding both Saudi Arabia and Russia with approximately 11 Mmboe/d.

The three biggest oil basins in the U.S. are the Western Gulf (Eagle Ford Tight Oil), the Permian (Straberry, Wolfcamp, Bone Springs), and as of recently, the Williston (Bakken). These three basins account for more than half of U.S. onshore oil production (see Exhibit II)

EXHIBIT II: U.S. Tight Oil Production

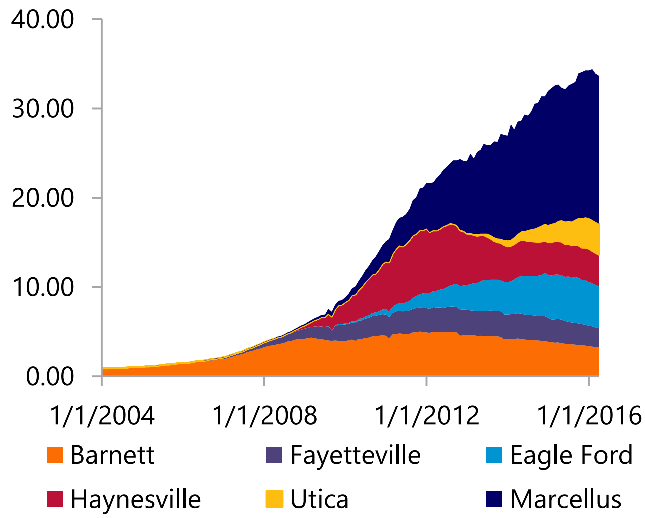


Source: EIA

The three biggest gas basins in the U.S. are the Appalachian (Marcellus Shale), Fort Worth (Barnett Shale, and Western Gulf (Eagle Ford Shale) These areas all offer varying economic conditions, growth prospects, and are operated by hundreds of different Exploration and Production companies (see Exhibt III).

It is worth noting that the Utica and Marcellus together form the Appalachian basin and that they alone are responsible for 85% of the natural gas production growth that occurred between 2012-2015.

EXHIBIT III: U.S. Shale Gas Production



Source: EIA

Overall Production

The massive spikes in both unconventional oil and unconventional gas production that occurred in the past decade essentially created the oil supply gut that has resulted in a price slump for approximately two years.

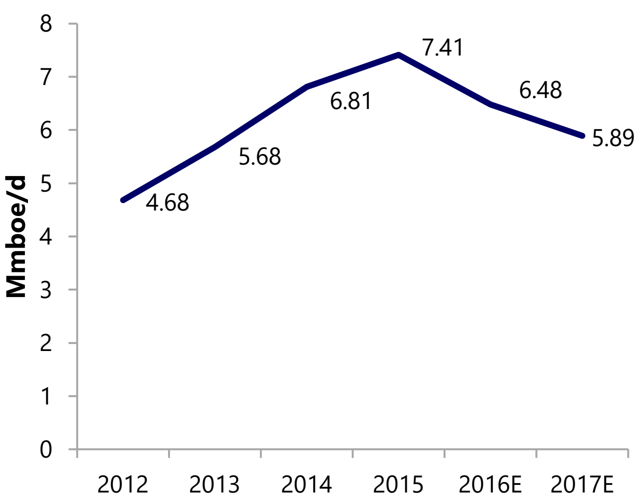
However, as attractive as these unconventional methods were when oil was $100/barrel, many are now no longer economically viable. These plays have recently come to comprise the majority of our onshore O&G production, and as such , the resulting declines in production from these sources have had and will have a major impact on overall U.S. O&G production. For the first time in more than four years, oil production in the U.S. is expected to decline year-over-year. In 2015 U.S. onshore oil production was 7.41 Mmboe/d and in 2016 the U.S.

U.S. Onshore Oil and Gas Basins

Overall Production Continued

is expected to produce only 6.48 Mmboe/d (see Exhibit IV).

EXHIBIT IV: U.S. Onshore Oil Production



Source: EIA

Outlook

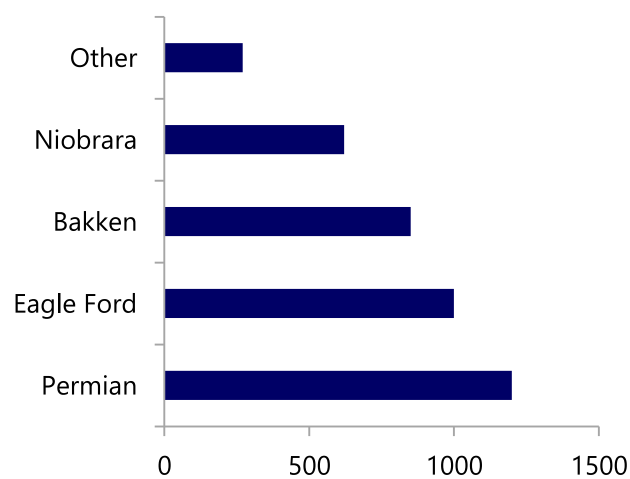
The general outlook for U.S. onshore production is bleak. As will be evident from the next page, some areas are likely to fare better than others, but in general there are several significant headwinds for the major basins that need to be discussed.

The first of these is drilled and uncompleted wells (DUCs). DUCs are wells that have been drilled but have yet to be fracked. They are very concentrated with more than 90% of them located in four basins: Permian, Western Gulf (Eagle Ford), Williston (Bakken), and Niobrara (see Exhibit V). Since one of biggest costs associated with new oil wells is the cost of drilling the expensive horizontal wells, these DUCs have essentially already sunk that cost and as such can come online at much lower prices. It is worth noting that the increase in production from these wells won't be precluded by the rig count jump that many analysts are carefully looking watching.

It is also worth highlighting that while the EIA is usually a reliable source, they are currently forecasting a much steeper decline in production than other sources. Unconventional oil plays have done a truly remarkable job of lowering costs in the face of the current downturn, and with oil currently hovering at $50, many of the major plays do in fact breakeven. While the next year or two may be painful for the companies operating fields in these areas, the majority will likely survive and come out as a much leaner, more efficient versions of their former selves.

The next slide will highlight the individual basins and plays along with the conclusions the QUIC energy team has reached regarding their respective investment attractiveness.

EXHIBIT V: DUCs by Play



Source: EIA

U.S. Onshore Oil and Gas Basins

Oil

The table below (see Exhibit VI) highlights the 3 key oil basins based on a number of important metrics. It is worth noting that all the basins produce very high quality oil (light sweet) with the Bakken having a little bit of a range. However, this is not the reason it trades at a discount, but rather it is more of a transportation bottleneck with all the heavy oil also trying to come down from the north to Oklahoma. Furthermore, you can see the well economics for specific plays vary from $36 top quartile to $61 at Eagle Ford and the Bakken respectively. On the whole, the Eagle Ford East appears to be the lowest cost producer, with Three Forks and Wolfcamp Midland being among the highest cost producers. Based off of this, companies like EOG and Devon, who are trying to focus on core plays like the Eagle Ford East, appear attractive.

EXHIBIT VI: U.S. Onshore Oil Analysis

Field	Production	Proved Reserves	Field Type		Field Quality		Field Economics				Major Players		
			Oil %	Gas %	API Gravity	(Discount)	Top-Quartile Breakeven	Standard Breakeven	Top Quartile Payback Period	Standard Payback Period	1	2	3
Eagle Ford East / West (Western Gulf)	1.25 Mmboe/d	5172 Mmboe	82%	18%	40	0	$36/$41	$49/58	0.8/1.7	3.7/7	EOG Resources	Devon Energy	Conoco Philips
Spraberry/Wolfcamp Deleware/Wolfcamp Midland/Bone Springs (Permian)	1.26 Mmboe/d	772 Mmboe	64%	36%	40	0	$41/$42/$51/ $43	$51/$49/$49/ $57	2.2/2.8/5.4/2.7	5.2/4.9/5/7	Occidental	Conoco Philips	Apache
North Dakota Bakken / Three Forks (Williston)	1.04 Mmboe/d	5972 Mmboe	80%	20%	36-44	(1.33)	$41/$41	$55/$61	2.6/2.6	7/7	Whiting Petroleum	Continental Resources	Hess Corp.

Gas

On the natural gas front it is truly remarkable to note how much larger the Marcellus is than any other gas play. It has the potential to completely change the supply side of the equation and will likely keep prices lower for a long time. Looking at it from the cost side of things, if you want to be invested in gas, it is undoubtedly more appealing to be in the Marcellus play due to the far better growth potential and well economics. Marcellus Shale has a breakeven of $1.20 for wet gas and $2.20 for dry gas – the lowest of any of the major plays. Considering the attractiveness of the play, there is a potential for Chesapeake or Range Resources to become good investment opportunities, depending on their respective valuation. Another potential idea is to lever the portfolio towards an infrastructure build out in the Appalachian basin as that will undoubtedly become necessary in the coming years.

EXHIBIT VII: U.S. Onshore Gas Analysis

Field	Production	Proved Reserves	Field Economics				Major Players		
			Wet	Dry	Wet	Dry	1	2	3
Appalachian (Marcellus Shale)	4.9 Tcf/d	84.5 Tcf	$1.2	$2.2	2.5 years	3.0 years	Chesapeake	Range Resources	Anadarko
Fort Worth (Barnett Shale)	1.8 Tcf/d	24.3 Tcf		$4.0		8.0 years	Devon	Chesapeake	XTO
Western Gulf (Eagle Ford)	2.0 Tcf/d	23.7 Tcf	$3.2	$5.0	6.2 years	8.0 years	EOG Resources	Chesapeake	Encana

Conventional Canadian Production

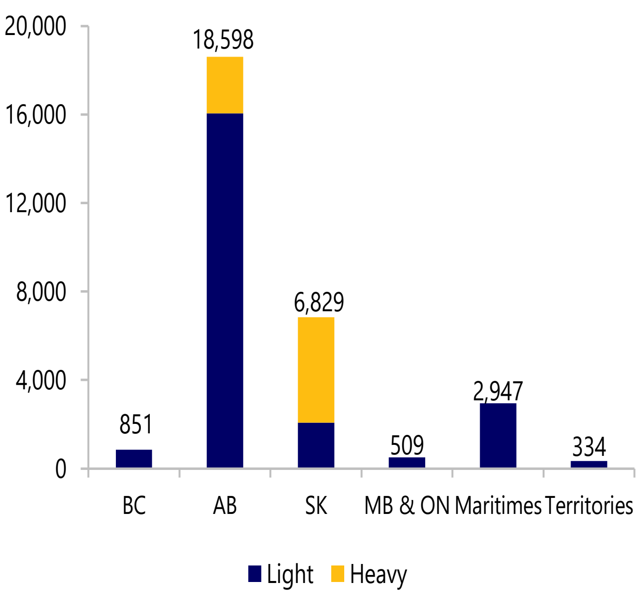
Overview

As mentioned earlier, a conventional play is a reservoir of the resource where it essentially pools together underground. These geographical formations are rather easy to develop and have been developed in Canada since the 1890's (with conventional natural gas production beginning in the early 1900's).

It is currently estimated that Canada has approximately 174 billion barrels of oil reserves, 169 billion of which are in the oil sands or other "unconventional production" methods.

Unlike unconventional production, there are conventional production operations all across the country, from the Pacific to Atlantic coast. The majority of production is based around Alberta and Saskatchewan as demonstrated in Exhibit VIII below, which shows total historical reserves by location (in millions of BOE).

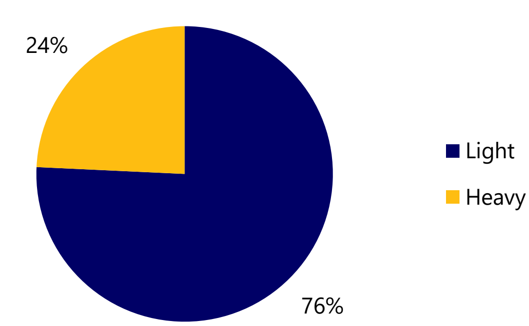
EXHIBIT VIII: Conventional Oil Prod. Breakdown



Source: National Energy Board

The chart additionally segments the production into two different types of oi: Light and Heavy. Due to the nature of its environment, oil often comes in different forms and compositions. One common method used to describe oil is by its weight, or its API Gravity. API Gravity is a measurement used when measuring a petroleum product's density in comparison to water and one must note that it is an inverted scale (lower the value, higher the density and vice versa). An API Gravity value of 22.3° is generally considered the dividing mark between "light" and "heavy" products. Conventional Canadian production is primarily "light" as seen in Exhibit IX below.

EXHIBIT IX: Conventional Oil Prod. Breakdown



Source: National Energy Board

Oil can additionally be classified as "sweet" or "sour" depending on its sulphur content. Oil is considered "sweet" when it has less than 0.5% sulphur which makes it much more attractive as it generally becomes easier to process. However in the past decade, special technology has actually made "sour" oil more profitable in certain areas of the United States, which will be discussed further on the next page.

Conventional Canadian Production

The table at the bottom (Exhibit X) of the page highlights the four largest conventional oil basins in Canada. As alluded to earlier, one can note that each of these plays produce light oil and each trades at a discount to the WTI due to the additional cost of transportation as it is much more expensive to transport oil from Alberta to the Gulf Coast than to ship it from Mexico. In recent years, the low sulfur content, or "sweetness" of the oil has actually hurt its demand, contrary to what one would think. The reason is due to the development of refineries in the US Golf Coast which are now able to convert the heavy crude "bottoms" into high value products and actually increases their refining margins above those with their sweet refining processes.

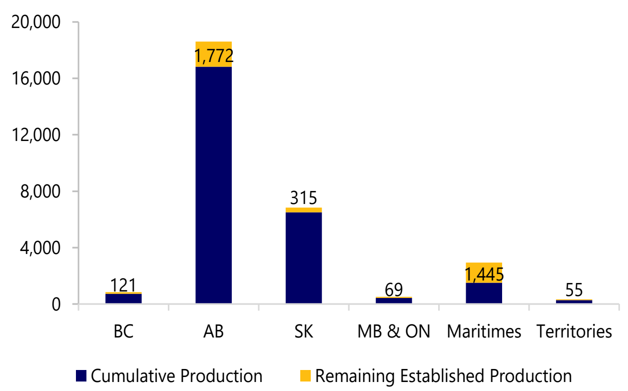
Unlike Canada's unconventional plays, these basins are near break even levels due to the easier and lower cost methods of extraction. This BEP is also extremely attractive as it is well below analyst's outlook for the next two years.

As Exhibit X shows, the Cardium Field has the largest proven reserves yet the production levels are the second lowest. This is because there are very few wells in currently in the area and multiple companies are still testing areas around the field for more reserves, with a strong success rate. With this in mind, companies like Talisman, Bonavista, and Husky become more attractive as the Cardium field is positioned to ramp up production in the future.

Outlook

This sector of Canadian energy has become much more attractive in light of the downturn of oil. However, investors face a dilemma. That dilemma stems from the fact that oil and gas is not a renewable resource and is finite in nature. Canada has been refining and producing conventional fields of oil since the ninetieth century and it is running out of resources to develop. As shown in Exhibit XI below, the remaining established production (yellow) pales in comparison to the cumulative production. In fact Canada is actually down to the last 14% of their reserves. Of course, this doesn't include any additional newly discovered reserves like the ones at Cardium, however those will only become more rare as time moves forward.

EXHIBIT XI: Remaining Conventional (MMBOE)



Source: National Energy Board

EXHIBIT X: Economics of Major Conventional Deposits

Field	Production	Proved Reserves	Field Type		Field Quality		Field Economics		Major Players		
	MBOE/d		Oil %	Gas %	API Gravity	(Discount)	Mean / Breakeven	Mean / Payback Period	1	2	3
Alberta Montney	165.6	7.7 BBOE	93%	7%	45	(1.5)	\$51 / \$53	2.9 / 3.2	Seven Gen	XTO	CIOC
Viking	251.6	58 MMBOE	80%	20%	36	(1.5)	\$51 / \$47	2.9 / 2.0	Raging River	Novus	Apache
Bakken	61.4	3.7 BBOE	n.a.	n.a.	42	(1.5)	\$51 / \$48	2.9 / 2.0	Crescent Point	Talisman	PennWest
Cardium	100.0	10.6 BBOE	n.a.	n.a.	45	(1.5)	\$51 / \$48	2.9 / 4.9	Talisman	Bonavista	Husky

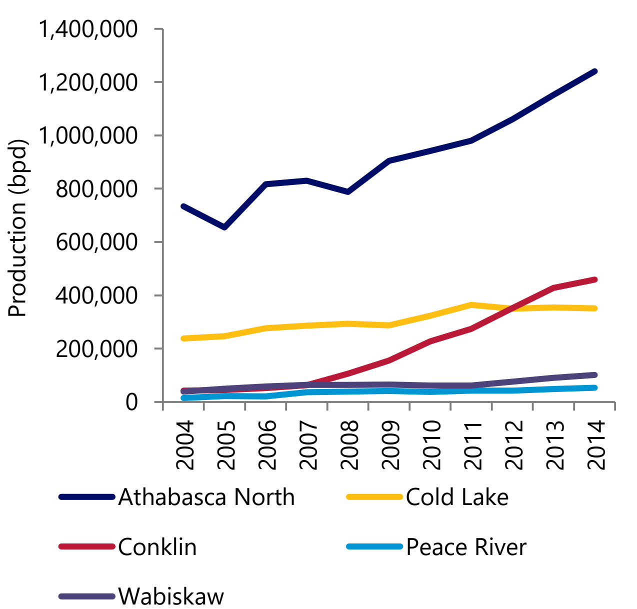
Oil Sands

Oil sands are loose sands containing a mixture of sand, water, clay, and bitumen, and are considered to be a type of unconventional petroleum deposit. Bitumen is an extremely viscous form of petroleum, and is upgraded to synthetic crude oil.

Major Deposits

While there are deposits of oil sands around the globe, the largest are in Canada and Venezuela. Canada's oil sands resources exist in three major deposits: Athabasca (Athabasca North, Conklin, Wabiskaw), Cold Lake, and Peace River, all in Alberta. Together, these deposits produce in excess of 2.2 million bpd as of 2014 (see Exhibit XII). Canadian oil sands are estimated to make up 70.8% of the world's proven bitumen reserves, with 1.75 Tbbl in place.

EXHIBIT XII: Production from Oil Sands by Area



Source: Alberta Energy

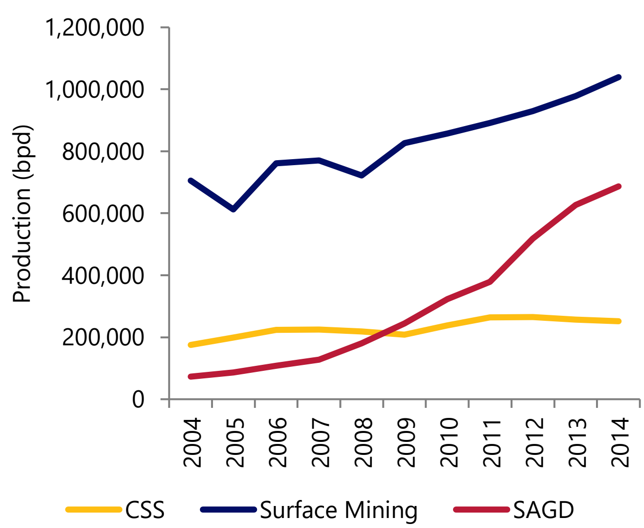
The Athabasca deposit is the largest and most developed deposit in the world, containing 178 billion barrels of economically viable oil, and 1.7 trillion barrels of bitumen in place as of 2014. Cold Lake and Peace River produced 350,473 bpd and 89,397 bpd in 2014, respectively.

The Orinoco Belt in Venezuela is also a major deposit with an estimated 1,200 Gbbl in place, but is far less developed than Canadian oil sands. While Orinoco oil sands contain extra-heavy oil that is easier to produce than Canada's bitumen, Venezuela's oil production has been declining in recent years due to political unrest and economic problems.

Role of Technology

The Athabasca oil sands are the only major oil sands deposits which are shallow enough to surface mine. However, only 20% of oil sands are shallow enough to be recovered through surface mining, and in-situ methods have become increasingly important in the last decade (Exhibit XIII).

EXHIBIT XIII: Production from Oil Sands by Technology



Source: Alberta Energy

Oil Sands

Role of Technology Continued

Two in-situ methods that have allowed for breakthroughs in oil sands mining have been cyclic steam stimulation (CSS) and steam assisted gravity drainage (SAGD). While CSS was popular in the 1980s and is still used in Cold Lake, it was SAGD that truly prompted a revolution and was a contributor to the oversupply that is depressing oil prices today. SAGD is less expensive and more efficient than CSS, recovering 60% of oil in place, and the development of this technology alone quadrupled North American oil reserves. The use of SAGD has a CAGR of 25.4% from 2004-2014, significantly higher than mining (4.7%) and CSS (3.6%), demonstrating just how large of a role technology plays in bitumen extraction.

Outlook

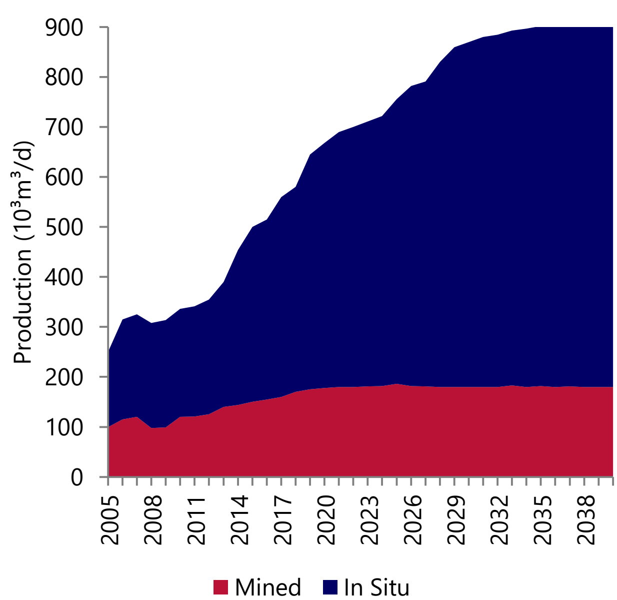
The outlook for oil sands in the medium and long term is bleak, but moderate in the short term. Wildfires at Fort McMurray, in Athabasca have caused shutdowns resulting in one million barrels of lost production per day, and analysts estimate that recovery will present long-term challenges, such as large infrastructure rebuilding costs, and fly-in-fly-out programs for employees who have lost their homes. However, the IEA reports fairly bullish oil sands growth in the short term, with production expected to rise to 3.4 million bpd by 2021. This is because oil sands projects have a very long lead time, and producers are less likely to completely abandon projects in low price environments, or as a result of natural disasters like that in Fort McMurray.

In the medium and long term, oil sands face several headwinds, namely increased environmental concerns, lack of pipelines, and policy changes that could restrict investment.

Alberta has recently set a 100 megatonne / year cap on oil sands emissions, and also rolled out a $30 per tonne carbon tax, with additional regulation specific to oil sands operators expected to be enacted in 2017. The objective of these regulations is to force companies to innovate to cut costs, but the IEA reports they do not foresee many companies having sufficient capital to invest in this kind of innovation. Furthermore, companies are being constrained from growing by a shortage of pipelines, and fractious politics over the issue persist.

It is clear that in the face of both economic and political pressure, oil sands producers must become more sustainable in order to survive, both from a cost and environmental perspective, and there will likely be few new projects. IHS reports that 70% of oil sands production expansion will come from existing projects, with 80% of this being from SAGD as opposed to mining (Exhibit XIV)

EXHIBIT XIV: Estimated Oil Sands Production



Source: Wood Mackenzie

Oil Sands

Economics and Analysis

The exhibit below (Exhibit XV) evaluates the three previously discussed basins on a number of metrics. While Venezuelan deposits are comparable to those in Canada, there is far less development, and therefore far less information for these deposits. Bitumen, the product of oil sands, by definition requires a classification of extra heavy (API <10), and is part of the Western Canada Select (WCS) blend, a heavy, sour blend.

It is worth noting that Peace River oil is actually classified as diluted bitumen. Peace River Heavy is mixed with a diluent, usually natural gas condensates, to make it easier to transport. Despite the lower viscosity, it is still classified as a Western Canada Select (WCS) oil. This is likely the reason for the low break even point of <$30, as it can be transported more easily by pipeline.

Economics vary greatly across both technologies and basins, speaking to the previously discussed idea of SAGD being the preferred method of extraction going forward. However, we cannot say that surface mining is absolutely more expensive than SAGD, as this is hugely site-specific. If there is a significant amount of overburden that needs to be removed, then mining may be less expensive, for example.

WCS prices at a discount to WTI not just because it is a lower quality crude, but also because of a transportation differential. The cost to transport one barrel from Alberta to the US Gulf Coast is approximately $10, which translates to at least a $10/ bbl differential. This differential is further widened by pipeline constraints, as briefly discussed in the outlook portion of this report.

While Peace River may seem like the most attractive investment, several projects, such as those piloted by Shell and Andora, in this region were suspended or cancelled in early 2016 due to the initial high costs and low scale. However, Baytex is a major player in the area, and uses cold-heavy production with sand (CHOPS) to extract the oil, a relatively new and rapidly developing production technology.

In terms of larger Athabasca players, Syncrude is the largest producer of oil sands crude, and is a joint venture between five partners: Imperial Oil, Suncor Energy, Sinopec, Nippon Oil Exploration, and Nexen. Suncor's April 2016 purchase of Murpy's stake in Syncrude, and preceding takeover of Canadian Oil Sands, has made them the majority owner with 54% ownership. QUIC currently has a position in Suncor, but it may be worth exploring alternative players, such as Shell, who operate in the Muskeg river and plan to expand their Jackpipe mine over the next 5 years (reaching 500,00 bbl/d).

EXHIBIT XV: Economics of Major Deposits

				Quality		Economics		Major Companies		
Deposit	Location	Production (bpd)	Proven Reserves (million)	API Gravity	Discount	Mining Break Even	SAGD Break Even	1	2	3
Athabasca Oil Sands	Alberta	1,600,000	133,000	7.7-9.0	15.65	$70-$85	$50-$80	Syncrude.	Suncor	Shell
Peace River	Alberta	89,397	7,000	21.5	15.65	$42	< $30	Baytex	Penn West	Murphy Oil
Cold Lake	Alberta	350,473	32,000	9.8	15.65	$75	$40	Canadian Natural Resources	Imperial Oil	Pengrowth

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