

AAPG Energy Minerals Division
Bitumen and Heavy Oil Committee Annual Commodity
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Vice-Chairs

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Executive Summary

Bitumen and heavy oil deposits occur in more than 70 countries across the world. The global in- place resources of bitumen and heavy oil are estimated to be 5.9 trillion barrels [938 billion m³], with more than 80% of these resources found in Canada, Venezuela and the United States. Globally there is just over one trillion barrels of technically-recoverable unconventional oils:

434.3 billion barrels of heavy oil, including extra-heavy crude, and 650.7 billion barrels of bitumen. These bitumens are commonly interpreted as degraded conventional oils (Head et al., 2003; Bata et al., 2015, 2016; Bata, 2016; Hein, 2016; Bata et al., 2018). The two most important processes that act on light oil to produce heavy oil are biodegradation (hydrocarbon oxidation process involving the microbial metabolism of various classes of compounds, which alters the oil's fluid properties and economic value) and water washing (the removal of the more water-soluble components of petroleum, especially low molecular weight aromatic hydrocarbons such as benzene, toluene, ethylbenzene and xylenes) (Palmer, 1993).

Virtually all the bitumen being commercially produced in North America is from Alberta, Canada, making it a strategic source of bitumen and of the synthetic crude oil obtained by upgrading bitumen. Estimated remaining established reserves of in-situ and mineable crude bitumen is 165 billion bbls [26.3 billion m³]. To date, about 5% of Canada's initial established crude bitumen has been recovered since commercial production began in 1967. In-situ production overtook mined production for the first time in 2012 and continued to exceed mined production in 2013 (AER, 2015). The Faja Petrolifera del Orinoco (Orinoco Heavy Oil Belt) in eastern Venezuela is the world's single largest heavy oil accumulation. The total estimated oil in-place is 1.2 trillion barrels [190 billion m³] of which 310 billion barrels [49.3 billion m³] is considered technically-recoverable. Currently, the United States is producing commercial quantities of heavy oil from sand deposits in two principal areas, the San Joaquin Basin of

central California and the North Slope of Alaska. California has the second largest heavy oil accumulations in the world, second only to Venezuela.

California's oil fields, of which 52 each have reserves exceeding 100 million bbls [15.9 million m³], are in the central and southern parts of the state. As of 2014, the proved reserves were 2,854 million barrels [453.7 million m³], nearly 65 % of which is heavy oil in the southern San Joaquin Basin. In addition to the heavy oil accumulations that are being produced, California has numerous undeveloped shallow bitumen deposits and seeps, a resource is estimated to be as large as 4.7 billion bbls [0.74 billion m³].

Alaska's heavy oil and bitumen deposits on the North Slope are very large (24 to 33 billion bbls, or 3.8 to 5.2 billion m³) and they hold promise for commercially-successful development. Heavy oil constitutes approximately 13.1% of the total Russian oil reserves, which official estimates place at 22.5 billion m³ or 141.8 billion bbls. Recoverable heavy oil occurs in three principal petroleum provinces, the Volga-Ural, Timan Pechora and the West Siberian Basin. In all regions of sustained production, the industry is steadily improving in situ recovery methods and reducing environmental impacts of surface mining of bitumen and heavy oil.

Introduction

This commodity commonly consists of bitumen and heavy oil principally in unlithified sand. However, heavy oil reservoirs can also include porous sandstone and carbonates. Oil sands petroleum includes those hydrocarbons in the spectrum from viscous heavy oil to near-solid bitumen, although these accumulations also can contain some lighter hydrocarbons and even gas. These hydrocarbons are denser than conventional crude oil and considerably more viscous (Fig. 1), making them more difficult to recover, transport and refine.

Heavy oil is just slightly less dense than water, with specific gravity in the 1.000 to 0.920 g/cc range, equivalent to API gravity of 10° to 22.3°. Bitumen and extra-heavy oil are denser than water, with an API gravity less than 10 °. Extra-heavy oil is generally mobile in the reservoir, whereas bitumen is not. At ambient reservoir conditions, heavy and extra-heavy oils have viscosities greater than 100 centipoise (cP), the consistency of maple syrup. Bitumen has a gas-free viscosity greater than 10,000 cP (Danyluk et al. 1984; Cornelius, 1987), equivalent to molasses. Many bitumens and extra-heavy oils have in-reservoir viscosities many orders of magnitude large. There are a variety of factors that govern the viscosity of these high-density hydrocarbons, such as their organic chemistry, the presence of dissolved natural gas, and the reservoir temperature and pressure. The viscosity of a heavy oil or bitumen is only approximated by its density.

Some heavy oils are the direct product of immature (early) oil maturation. However, bitumen and most heavy oils are the products of in-reservoir alteration of conventional oils by water washing, evaporation (selective fractionation) or, at reservoir temperatures below 80°C, biodegradation (Blanc and Connan, 1994), all of which reduce the fraction of low molecular weight components of the oil. These light-end distillates are what add commercial value to an oil. Thus, in addition to being more difficult and costly to recover and transport than conventional oil, heavy oil and bitumen have lower economic value. Upgrading to a

marketable syncrude (also called synthetic crude or “synoil”) requires the addition of hydrogen to the crude to increase the H/C ratio to values near those of conventional crudes. Heavy oil and bitumen normally contain high concentrations of NSO compounds (nitrogen, sulfur, oxygen) and heavy metals, the removal of which during upgrading and refining further discounts the value of the resource. Heavy and some extra-heavy oils can be extracted in situ by injection of steam or super-hot water, CO₂, or viscosity-reducing solvents, such as naphtha. Bitumen normally is recovered by surface mining and processing with hot water or solvents.

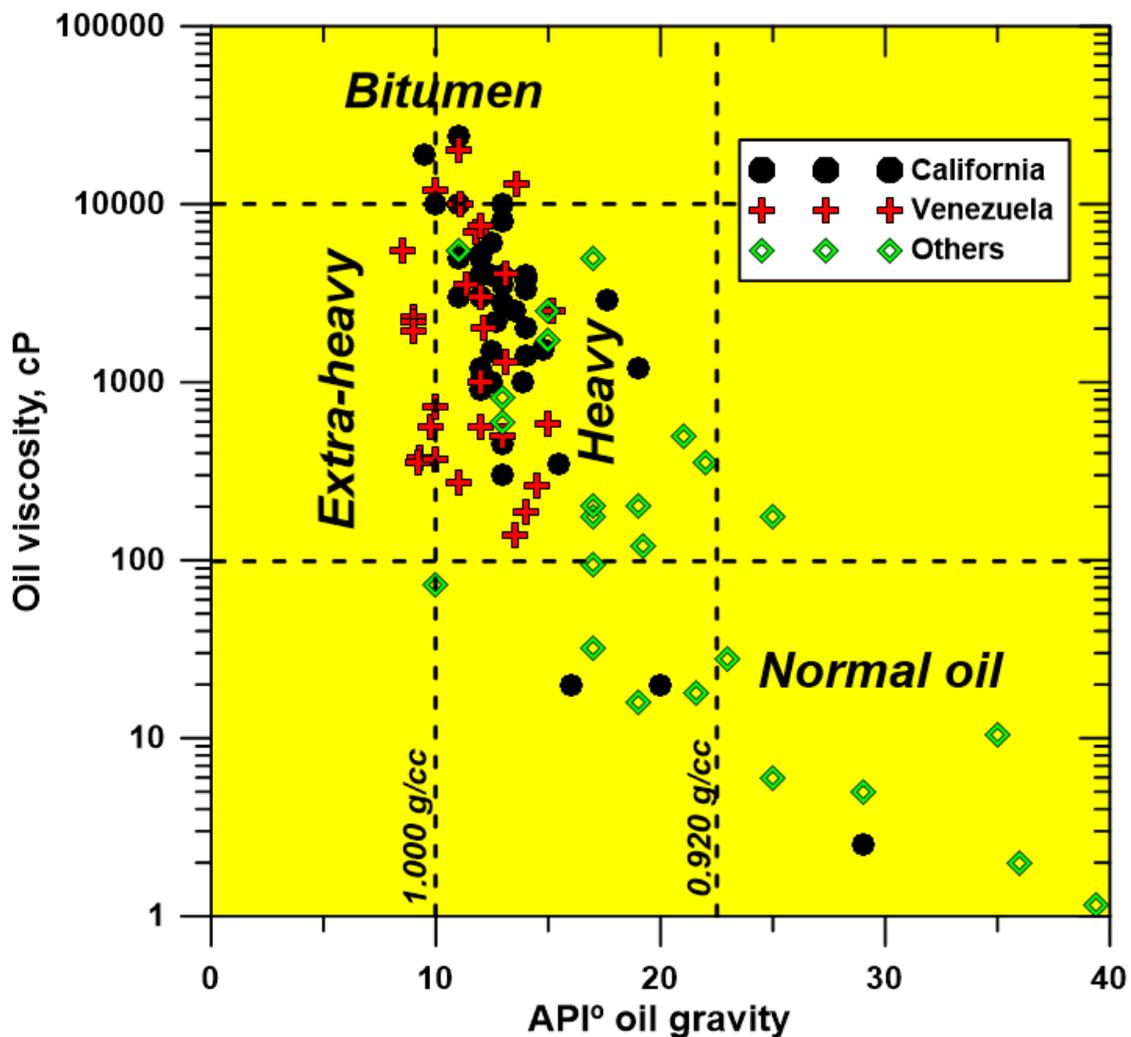


Figure 1: Cross-plot of oil density versus viscosity indicating the fields represented by bitumen, heavy and extra-heavy oils. Actual properties are plotted for a variety of oils from producing oil sand accumulations (data from Oil & Gas Journal, April 2, 2012).

Resources and Production

Resources and Production – Global

The International Energy Agency estimates the total world oil resources are between 9 and 13 trillion barrels, of which just 30% is conventional crude oil. The remaining 70% of unconventional crude is divided 30% oil sands and bitumen, 25% extra-heavy oil, and 15% heavy oil. Heavy oil and bitumen deposits occur in more than 70 countries across the world.

Meyer et al. (2007) notes that heavy oils are found in 192 sedimentary basins and bitumen accumulations occur in 89 basins. However, these unconventional oils are not uniformly distributed (Table 1). The global in-place resources of bitumen and heavy oil are estimated to be 5.9 trillion barrels [938 billion m³], with more than 80% of these resources found in Canada, Venezuela and the United States (Meyer and Attanasi, 2003; Hein, 2013).

The largest oil sand deposits in the world, having a combined in-place resource of 5.3 trillion barrels [842 billion m³], are along the shallow up-dip margins of the Western Canada sedimentary basin and the Orinoco foreland basin, eastern Venezuela. Western Canada has several separate accumulations of bitumen and heavy oil that together comprise 1.7 trillion barrels [270 billion m³]. The Orinoco Heavy Oil Belt is a single extensive deposit containing 1.2 trillion barrels [190 billion m³] of extra-heavy oil. Both basins have extensive world-class source rocks and host substantial conventional oil pools in addition to the considerably larger resources within shallow oil sands.

Globally there is just over one trillion barrels [159.0 billion m³] of technically-recoverable unconventional oils (Table 1), 434.3 billion barrels [69.1 billion m³] of heavy oil, including extra-heavy crude, and 650.7 billion barrels [103.5 billion m³] of bitumen (Meyer and Attanasi, 2003). South America, principally Venezuela, has 61.2% of the heavy oil reserves and North America, mainly western Canada, has 81.6% of the bitumen reserves.

Table 1: Estimated global in-place heavy oil and bitumen resources and technically-recoverable reserves. The table also shows the percentage of global reserves occurring in each region. The heavy oil category includes extra-heavy oil. Source: Meyer and Attanasi (2003).

REGION	HEAVY OIL (BBO)			BITUMEN (BBO)		
	Resources	Reserves	%	Resources	Reserves	%
N. America	185.8	35.3	8.1	1659.1	530.9	81.6
S. America	2043.8	265.7	61.2	1.1	0.1	0.0
Europe	32.7	4.9	1.1	1.4	0.2	0.0
Russia	103.1	13.4	3.1	259.2	33.7	5.2
Middle East	651.7	78.2	18.0	0.0	0.0	0.0
Asia	211.4	29.6	6.8	267.5	42.8	6.6
Africa	40.0	7.2	1.7	430.0	43.0	6.6
Western Hemisphere	2315.4	301.0	69.3	1659.4	531.0	81.6
Eastern Hemisphere	1025.4	133.3	30.7	920.8	119.7	18.4
World total	3340.8	434.3		2580.1	650.7	

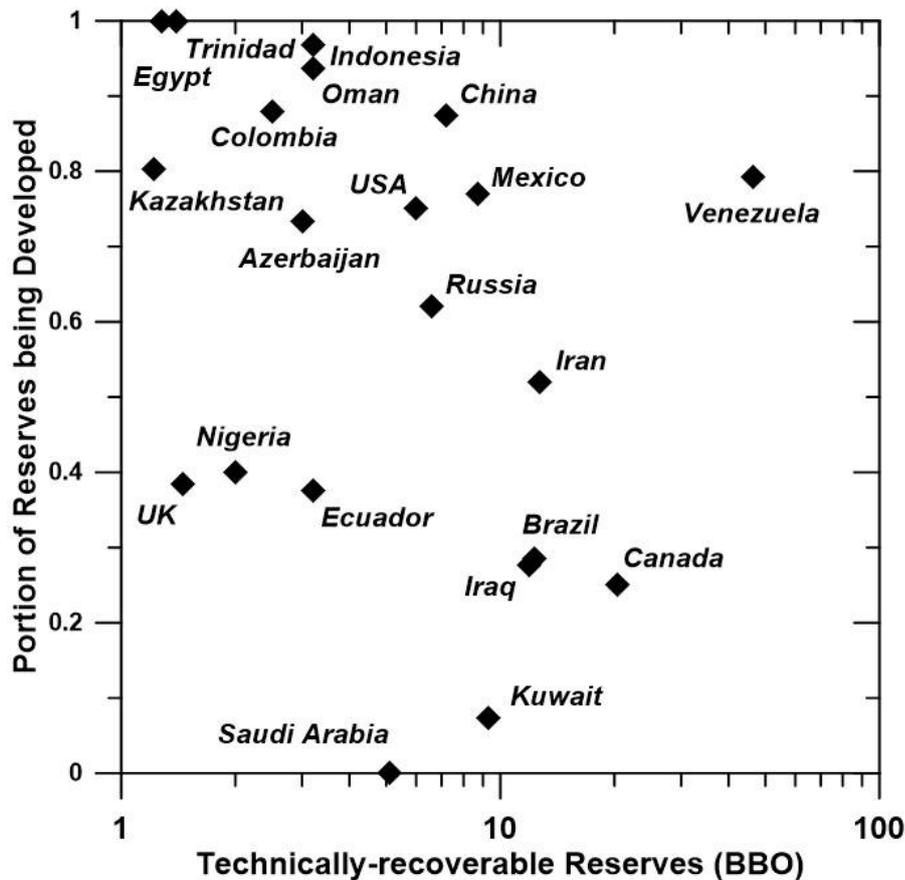


Figure 2: By country, the estimated technically-recoverable heavy and extra-heavy reserves vs. the portion of the reserves in production or development. Sources: Meyer and Attanasi (2003).

Heavy oil, in general, is more easily produced, transported and marketed than bitumen. Consequently, it tends to be in a more advanced stage of development than bitumen deposits. Figure 2 shows the relative intensity of heavy oil exploitation for countries with substantial heavy oil reserves. Note that countries with very large reserves of conventional crude oil, particularly Saudi Arabia and Kuwait, have been slow to develop their heavy oil resource, whereas countries with small or dwindling conventional oil reserves are exploiting heavy oil to a greater degree.

Resources and Production - Canada

Nearly all the bitumen being commercially produced in North America is from Alberta, Canada. Canada is an important strategic source of bitumen and of the synthetic crude oil (SCO) obtained by upgrading bitumen. Bitumen and heavy oil are also characterized by high concentrations of nitrogen, oxygen, sulfur and heavy metals, which results in increased costs for extraction, transportation, refining, and marketing compared to conventional oil (Meyer and Attanasi, 2010).

Research and planning are ongoing for transportation alternatives for heavy crude, bitumen, and upgraded bitumen using new and existing infrastructure of pipelines and railways. Such integration has been called a virtual “pipeline on rails” to get the raw and upgraded bitumen to U.S. markets (Perry and Meyer, 2009). SCO from bitumen and (or) partially upgraded bitumen is being evaluated for potential long-distance transport to refineries in the Midwest and Gulf states of the USA and to existing or proposed terminals on the west coast of North America. Associated concerns include effects on the price of crude oil, and the environmental impacts that are associated with land disturbance, surface reclamation, habitat disturbance, and oil spills or leaks with associated potential pollution of surface and ground waters.

Table 2: Summary of Alberta’s energy reserves, resources, and production at the end of 2015 (AER, 2016).

	Crude bitumen		Crude oil		Natural gas ^b		Raw coal	
	(million m ³)	(billion barrels)	(million m ³)	(billion barrels)	(billion m ³)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 845	13 171	82.9	9 880	351	94	103
Initial established reserves	28 092	177	3 032.9	19.1	5 654	201	34.8	38.4
Cumulative production	1 808	11.4	2 752.1	17.3	4 772	169	1.63	1.8
Remaining established reserves	26 284	165	280.7	1.8	882^a	31.3^c	33.2	36.6
Annual production	146.6	0.923	30.6	0.193	109.0 ^d	3.9 ^d	0.027 ^e	0.030 ^e
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276 ^f	223 ^f	620	683

Excellent sources of information on Alberta oil sands and carbonate-hosted bitumen deposits are the resource assessments and regulatory information by the Alberta Energy Regulator (<http://www.aer.ca/data-and-publications/statistical-reports/st98>). Estimated in-place resources for the Alberta oil sands are 1845 billion barrels (bbls) [293.1 billion m³] (AER 2016). Estimated remaining established reserves of in-situ and mineable crude bitumen is 165 billion bbls [26.3 billion m³]; about 5% of the initial established crude bitumen has been produced since commercial production began in 1967 (AER 2015).

Cumulative bitumen production for Alberta in 2015 was 11.4 billion bbls [1,808 million m³]. The bitumen that was produced by surface mining was upgraded; in-situ bitumen production was marketed as non-upgraded crude bitumen (ERCB 2012). Despite the significant weakness in crude oil prices, crude bitumen production in Alberta rose in 2015 and is projected to continue to increase over the next 10 years, reaching 3.8 million barrels of marketable bitumen per day by 2025 (AER 2015). Over the last 10 years, the contribution of bitumen to Alberta’s total primary energy production has increased steadily. A breakdown of production of energy in Alberta from all sources, including renewable sources, is given in Figure 3.

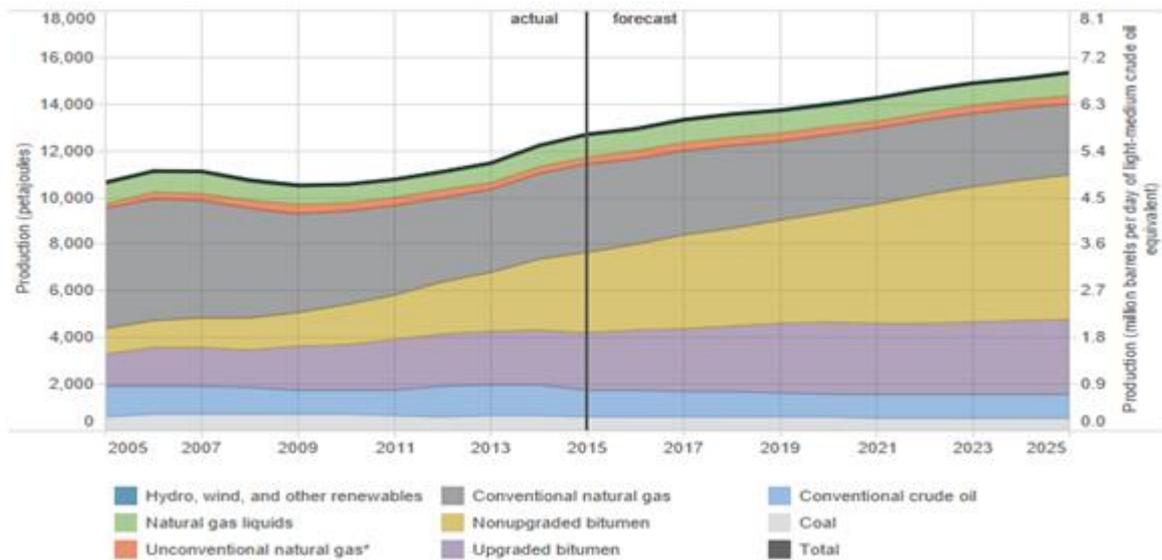


Figure 3: Total primary energy production in Alberta (AER, 2016).

“Crude bitumen” includes heavy and extra heavy oil that at reservoir conditions has a very high viscosity such that it will not naturally flow to a well bore. Administratively, in Alberta, the geologic formations (whether clastic or carbonate) and the geographic areas containing the bitumen are designated as the Athabasca, Cold Lake or Peace River oil sands areas (Fig. 4). Most of the in-place bitumen is hosted within unlithified sands of the Lower Cretaceous Wabiskaw-McMurray deposit in the in-situ development area (Table 3), followed by the Grosmont carbonate-bitumen deposit, and the Wabiskaw-McMurray deposit in the surface mineable area (Table 3).

Included in the initial in-place volumes of crude bitumen (Table 3) are reassessments for the Athabasca-Grosmont carbonate-bitumen (done in 2009) and the Athabasca-Grand Rapids oil sands and Athabasca-Nisku carbonate-bitumen deposits (done in 2011). The Nisku reassessment resulted in a 57% increase in initial bitumen volume in place. The Nisku Formation, like the Athabasca-Grosmont carbonate-bitumen deposit, is a shelf carbonate that has undergone significant leaching and karstification, with the creation of an extensive vug and cavern network. Conventional oil migrated and infilled the paleocave deposits and then

degraded in place to form the bitumen. Other prospective carbonate-bitumen reservoirs are being explored west of the town site of Fort McMurray, with initial industry estimates indicating that bitumen pay zones may exceed 100 m [328 ft] in thickness, hosted primarily within the Leduc Formation carbonates (AER, 2015).

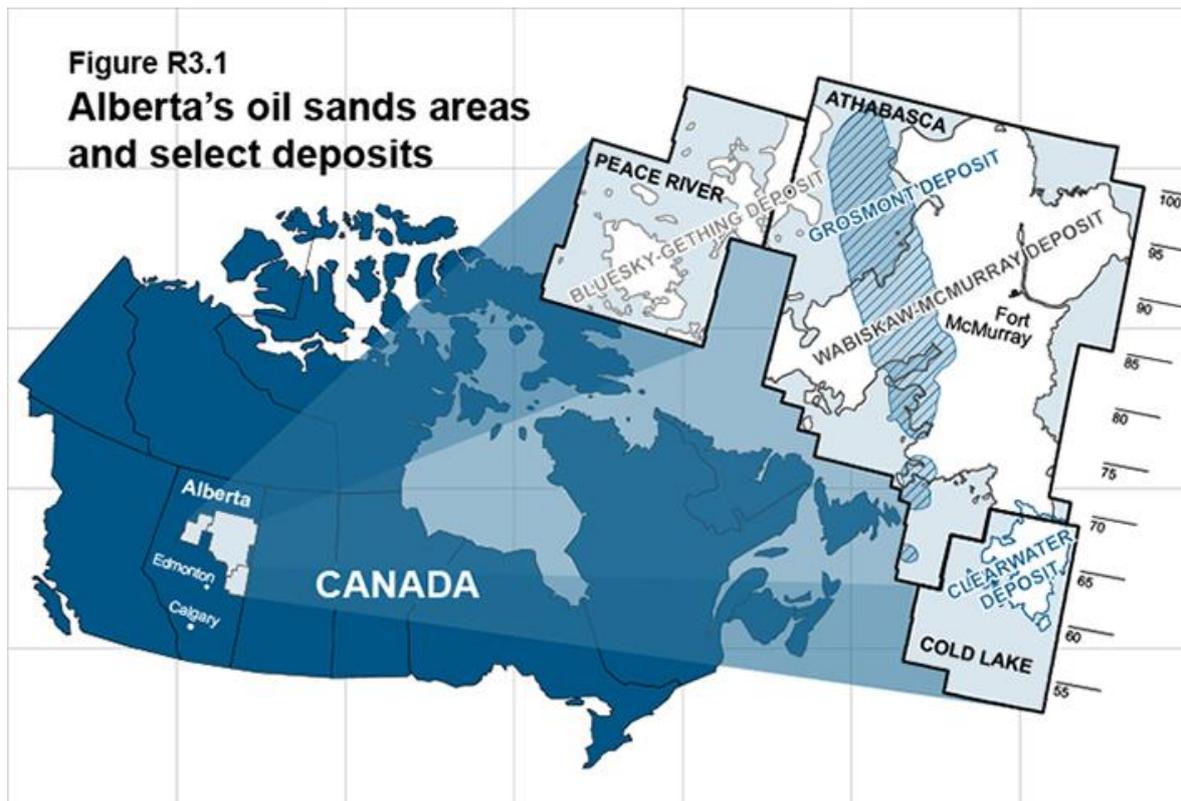


Figure 4: Alberta's Peace River, Athabasca and Cold Lake oil sands areas, highlighting the main deposits (AER, 2016).

Many factors (including economic, environmental and technological criteria) are applied to the initial in-place volumes of crude bitumen to attain the established reserves. In Alberta, there are two types of reserves for crude bitumen – those that are anticipated to be recovered by surface mining techniques (generally in areas with < 65 m [< 213 ft] of overburden in the Athabasca area), and those to be recovered by underground in-situ and largely thermal technologies in areas with more than 65 m [213 ft] of overburden. The principal in-situ technology of choice for Athabasca is Steam-Assisted Gravity Drainage (SAGD), for

Cold Lake it is Cyclic Steam Stimulation (CSS), and for Peace River it is thermal and primary recovery. (Tables 4 and 5).

Table 3: Initial in-place volumes of crude bitumen as of December 31, 2015 (AER, 2016).

Oil sands area Oil sands deposit	Initial volume in-place (10 ⁶ m ³)	Area (10 ³ ha) ^a	Average pay thickness (m)	Average reservoir parameters		
				Mass (%)	Pore volume oil (%)	Average porosity (%)
Athabasca						
Upper Grand Rapids	5 817	359	8.5	9.2	58	33
Middle Grand Rapids	2 171	183	6.8	8.4	55	32
Lower Grand Rapids	1 286	134	5.6	8.3	52	33
Wabiskaw-McMurray (mineable)	20 823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131 609	4 694	13.1	10.2	73	29
Nisku	16 232	819	14.4	5.7	68	20
Grosmont	64 537	1 766	23.8	6.6	79	20
Subtotal	242 475					
Cold Lake						
Upper Grand Rapids	5 377	612	4.8	9	65	28
Lower Grand Rapids	10 004	658	7.8	9.2	65	30
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.1	8.1	62	28
Subtotal	29 090					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14	5.3	52	23
Subtotal	21 560					
Total	293 125					

Alberta is Canada's largest producer of marketable gas (68% in 2015) and of oil and equivalent production (80% in 2015), and the only producer of upgraded bitumen (also called 'SCO') and non-upgraded bitumen. Heavy oil is produced in both Alberta and Saskatchewan. Although there are oil-sands resources in north-western Saskatchewan, as yet these have not been brought to commercial production. In Alberta, of the 2015 primary energy production, bitumen accounted for 8% of the Alberta's total oil production, with production increasing by 11.9% in surface mining areas, and by 7.8% from in-situ areas from the previous year (Fig. 3). While there was an overall raw bitumen production increase in 2015, conventional crude oil production was impacted by low prices, decreasing by 10.6%. Total marketable natural gas increased by 2.2%, total natural gas liquids production increased by 7.0%, and coal production

declined by 9.8%. By comparison, only about 0.2% of energy is produced from renewable energy sources, such as hydro and wind power.

Table 4. Mineable crude bitumen reserves in Alberta for areas under active development as of December 31, 2016 (AER, 2016)

Development	Project area* (ha)	Initial mineable volume in-place (10 ⁶ m ³)	Initial established reserves (10 ⁶ m ³)	Cumulative production (10 ⁶ m ³)	Remaining established reserves (10 ⁶ m ³)
CNRL Horizon	28 482	834	537	42	495
Fort Hills	17 864	556	382	0	382
Imperial Kearn	19 674	1 324	872	16	856
Shell Muskeg River	13 581	672	419	101	318
Shell Jackpine	7 958	361	222	30	192
Suncor	19 155	990	687	365	322
Syncrude	44 037	2 071	1 306	504	802
Total	150 751	6 826	4 425	1 058	3 367

Technological advances, such as horizontal, multi-stage drilling with hydraulic fracturing and/or acidization continues to enhance the development of crude oil in Alberta. Along with this technologically-driven enhancement of crude oil production, the ERCB (Rokosh et al. 2012; Beaton et al. 2013) conducted a regional resource assessment of crude oil in six of Alberta’s shale and siltstone-dominated formations, that pointed to a vast potential (best in-place estimates of 423.6 billion bbls).

The ERCB (Rokosh et al. 2012; Beaton et al. 2013) conducted a regional resource assessment of crude oil in six of Alberta’s shale and siltstone-dominated formations, that pointed to a vast potential (best in-place estimates of 423.6 billion bbls [67.3 billion m³] of crude oil; 3,424 trillion cubic ft [97 trillion m³] of natural gas; and 58.6 billion bbls [9.3 billion m³] of natural gas liquids) in tight formations, which until now were considered uneconomic due to challenges related to production from these low-permeability reservoirs. To date, these hydrocarbon resource estimates identify other (non-bitumen) unconventional resources in the province. How these relate to the total energy resource endowment of the province will not be known until the resources are assessed for technological and commercial feasibility at large scales with existing or pending recovery technologies.

Table 5: In situ crude bitumen reserves in Alberta for areas under active development as of December 31, 2015 (AER, 2016)

Development	Initial volume in-place (10 ⁶ m ³)	Recovery factor (%)	Initial established reserves (10 ⁶ m ³)	Cumulative production ^b (10 ⁶ m ³)	Remaining established reserves (10 ⁶ m ³)
Peace River Oil Sands Area					
Thermal commercial projects	63.7	40	25.5	12.5	13.0
Primary recovery schemes	375.0	10	37.5	22.8	14.7
Subtotal^c	438.7		63.0	35.3	27.7
Athabasca Oil Sands Area^d					
Thermal commercial projects	799.8	50	399.9	237.5	162.4
Primary recovery schemes	1 026.2	5	51.3	28.2	23.1
Enhanced recovery schemes ^e	(365.0) ^f	15	54.8	34.7	20.1
Subtotal^c	1 826.0		506	300.3	205.6
Cold Lake Oil Sands Area					
Thermal commercial (CSS) ^g	1 212.8	25	303.2	284.7	18.5
Thermal commercial (SAGD) ^h	33.8	50	16.9	7.6	9.3
Primary recovery schemes	6 257.5	5	312.9	121.2	191.7
Subtotal^c	7 504.1		633.0	413.6	219.4
Total^c	9 768.8		1 202.0	749.2	452.7

Expenditures related to the oil sands are projected to decrease significantly in 2016. This is due to weak crude oil prices and capital budget reductions resulting in delays and cancellations in the development of projects. In situ oil sands production continues to expand. Compared to surface mining, in situ operations, such as SAGD, involve lower capital costs, a smaller “footprint” and reduced environmental impacts. A modest increase in both conventional and tight-formation development is expected. This largely is due to improvements in multi-stage hydraulic fracturing from horizontal wells that target previously uneconomic, but potentially large, resources.

The collapse of crude oil prices in 2015 was a result of significant production growth and slowing global demand for crude oil. Despite this, the growth of bitumen production in 2015 is the result of new projects coming on-stream that had been initiated before price drop. Production growth is forecast to continue as more of these projects (where capital has already been committed or spent) are developed and brought on production. Other expansions and new projects that have not progressed as far are being deferred or cancelled. Bitumen projects involve large, long-term investments making them is less vulnerable to near-term price

fluctuations. Producers have chosen to continue operating since halting steam flows to curtail production can not only be costlier to start up later on, but may potentially damage the reservoir and limit future recovery. The temporary shut down or rate reduction at oil sands production sites due to the fires at Fort McMurray from May and June 2016, will impact the next year's production reporting. The EIA estimates that disruptions to oil production in May averaged about 0.8 million barrels per day.

Resources and Production – Venezuela

The Faja Petrolifera del Orinoco (Orinoco Heavy Oil Belt) in eastern Venezuela is the world's single largest oil accumulation. The total estimated oil in-place is 1.2 trillion barrels [190 billion m³] of which 310 billion barrels [49.3 billion m³] is considered technically-recoverable (Villarroel et al., 2013). The Faja is 55,314 km² [21,357 mile²] in size and extends 600 km in an east-west arcuate band that is up to 90 km wide (Fig. 5). The deposit lies immediately north of the Orinoco and Arauca rivers in the southern portions of the states of Guarico, Anzoategui and Monagas. The Faja follows the extreme up-dip edge of the foreland basin of the young Serrania del Interior thrust belt, the source of the oil, where Neogene-age sediments overlie the crystalline basement of the Guyana Shield. To the north, in the foothills of the Serrania del Interior, there are numerous conventional oil fields in structural traps within the thrust belt.

Extra-heavy oil having an average API gravity of 8.5° is reservoided in stratigraphic traps within the highly porous and permeable sands of the lower and middle Miocene Oficina Formation. These sands were carried off the Guayana Shield by river systems flowing north and northeastward to be deposited in fluvio-deltaic and estuarine complexes on the south rim of the foreland basin (Martinius et al., 2013). Upper Miocene marine shales of the Freitas Formation form the top seal to the Faja oil accumulation. The net thickness of oil-impregnated

sands is highest within the paleo-deltas (Fig.6), giving rise to a highly irregular distribution of resource richness within the Faja.

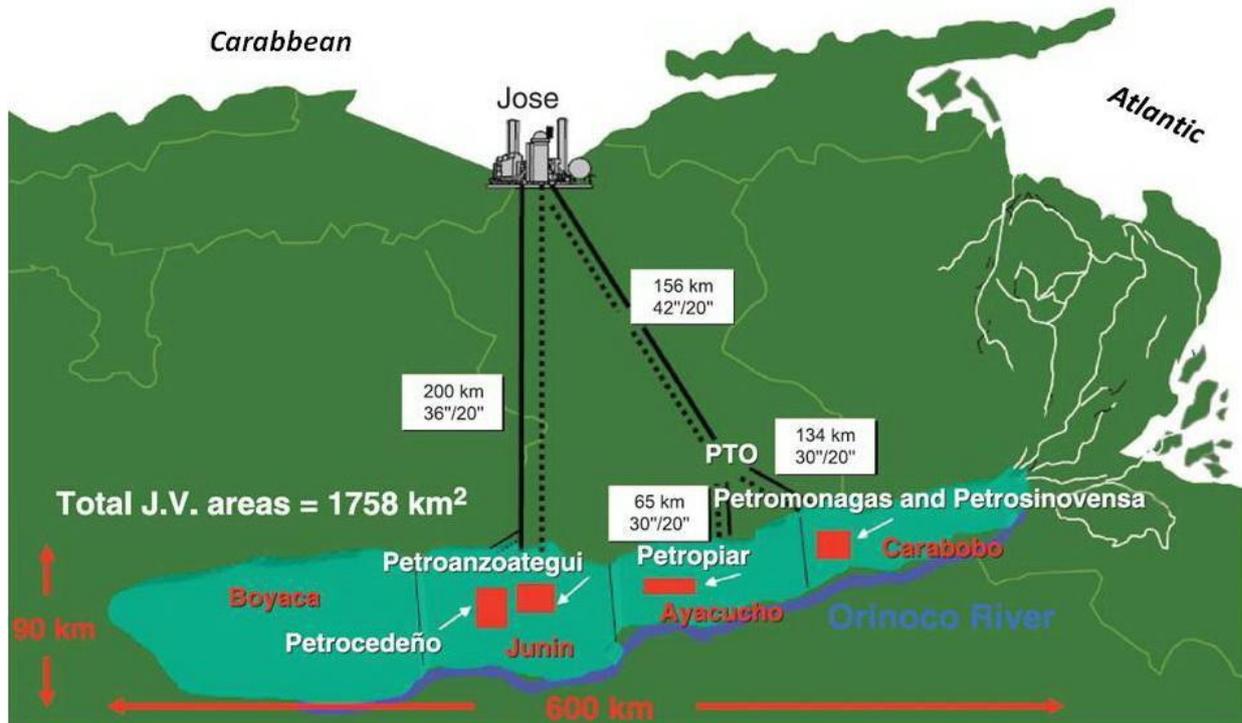


Figure 5: The Faja Petrolifera del Orinoco in eastern Venezuela (light green) showing the four production units (red text), four current production projects (white text), and pipelines connecting the projects to the Jose upgrading facility on the coast. (Villarroel et al., 2013)

At present, there are four active heavy oil recovery projects operating in the Faja (Fig. 5), each begun in successive years between 1998 and 2001. Petroleos de Venezuela SA (PDVSA) is the sole owner/operator of Petroanzoategui and is the senior joint-venture partner in the other three projects, usually with a partner as the operator: BP (now replaced by Rosneft) in Petromonagas, Chevron in Petropiar, and Total with Statoil (Equinor) in Petrocedeño. In what is referred to as the “first stage” of development, the projects were producing collectively about 640,000 bopd using cold production methods (Villarroel et al., 2013). Cold production was possible due to the highly porous and permeable properties of the reservoir sands (Fig. 6) and the gas-charged and foamy character of the extra- heavy oil. The dissolution of dissolved natural gas in the oil during production aids in propelling the oil from the sand and towards the

wellbore. The foaming of the oil and reservoir temperatures of about 50°C, help overcome its viscosity, which is on the order of thousands of centipoises (Fig. 6). The oil is extracted from horizontal wells up to 1.5 km long with the aid of down-hole progressive cavity pumps and multi-phase pumps at the well head. A major challenge is the optimal placement of the long horizontal wells in these complex heterogeneous fluvial-deltaic sands (Martinius et al., 2013).

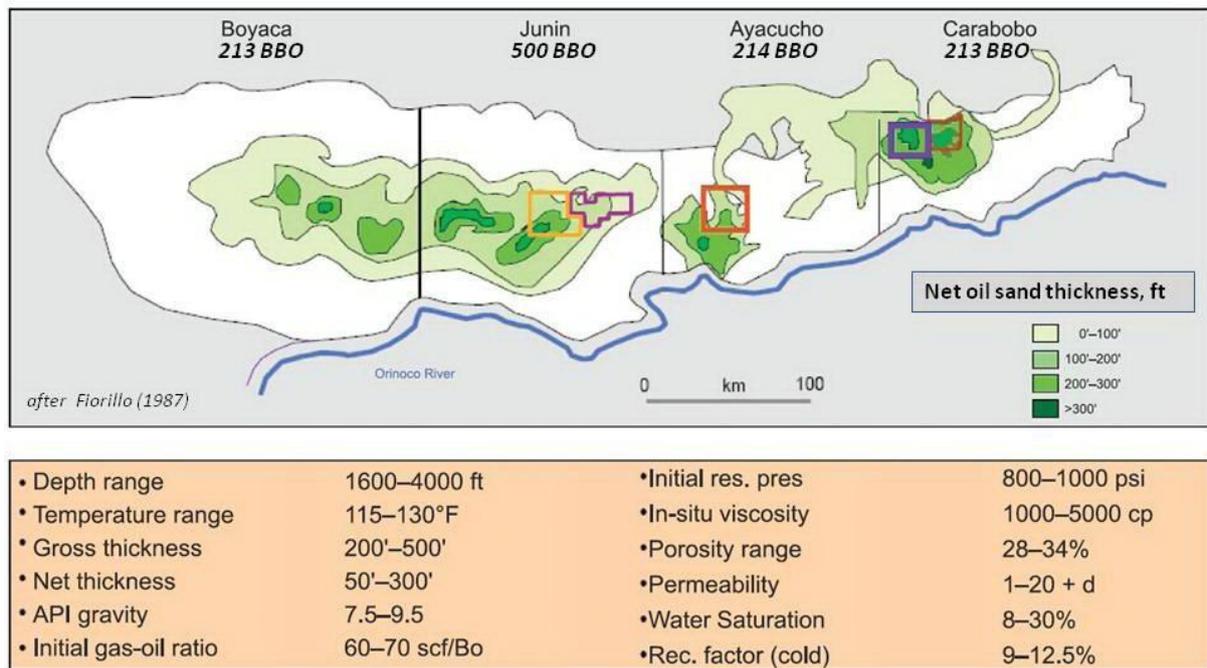


Figure 6: Map showing the net oil sand thickness, which approximates the distribution of oil sand richness. The currently active development projects are within or proximal to the net oil sand thicks. The table lists the average reservoir and oil properties of the deposit. Source: Villarroel et al. (2013).

To enhance production, a 50° API naphtha diluent is commonly injected into the horizontal wells to further decrease viscosity. The recovery factor for cold production is about 10%. The naphtha-charged oil is transported about 200 km to the Jose upgrading facility on the Caribbean coast (Figs. 5 and 7). Here the naphtha is separated from the oil and returned to the projects via dedicated diluent pipelines (Fig. 6). The oil is upgraded in one of four delayed coking units to a 32° API syncrude that is exported as “Zuata Sweet”, until recently principally to refineries in Texas. As the projects prepared for the next phase of development, a variety of established

EOR technologies were tested in pilots, including thermal methods (SAGD, CSS) and reservoir flooding using polymer-viscosified water. Eventually, more heavy crude was being produced than could be processed in the Jose and other upgraders, which were designed for just 700 bopd and were nearly two to three decades old.

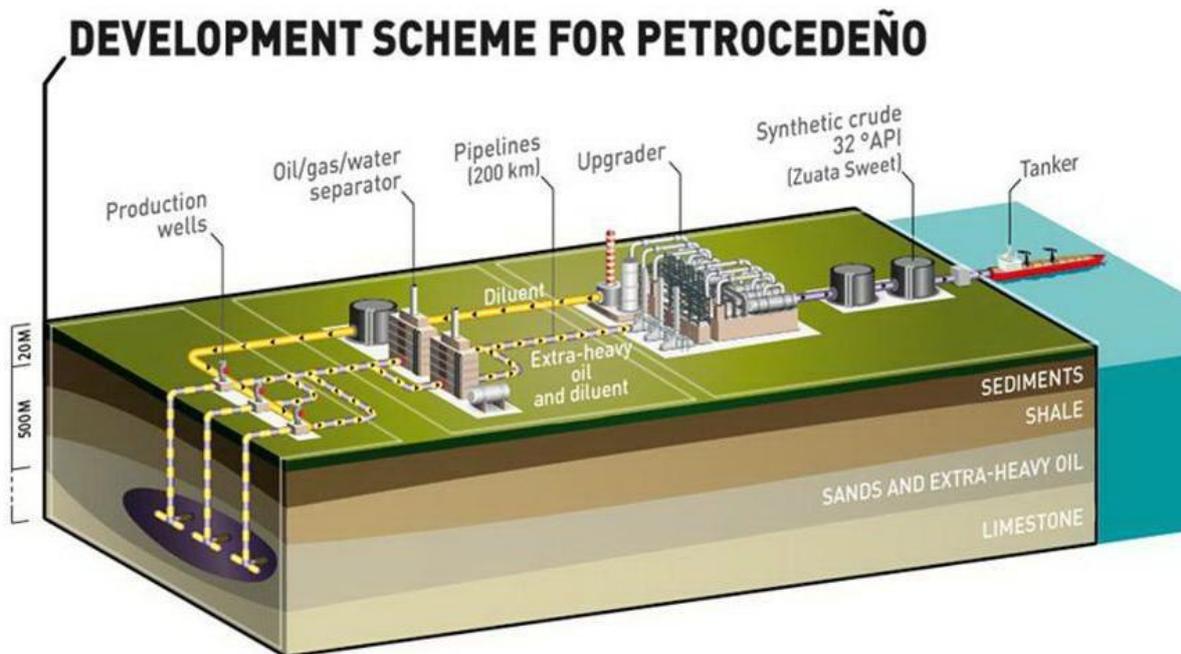


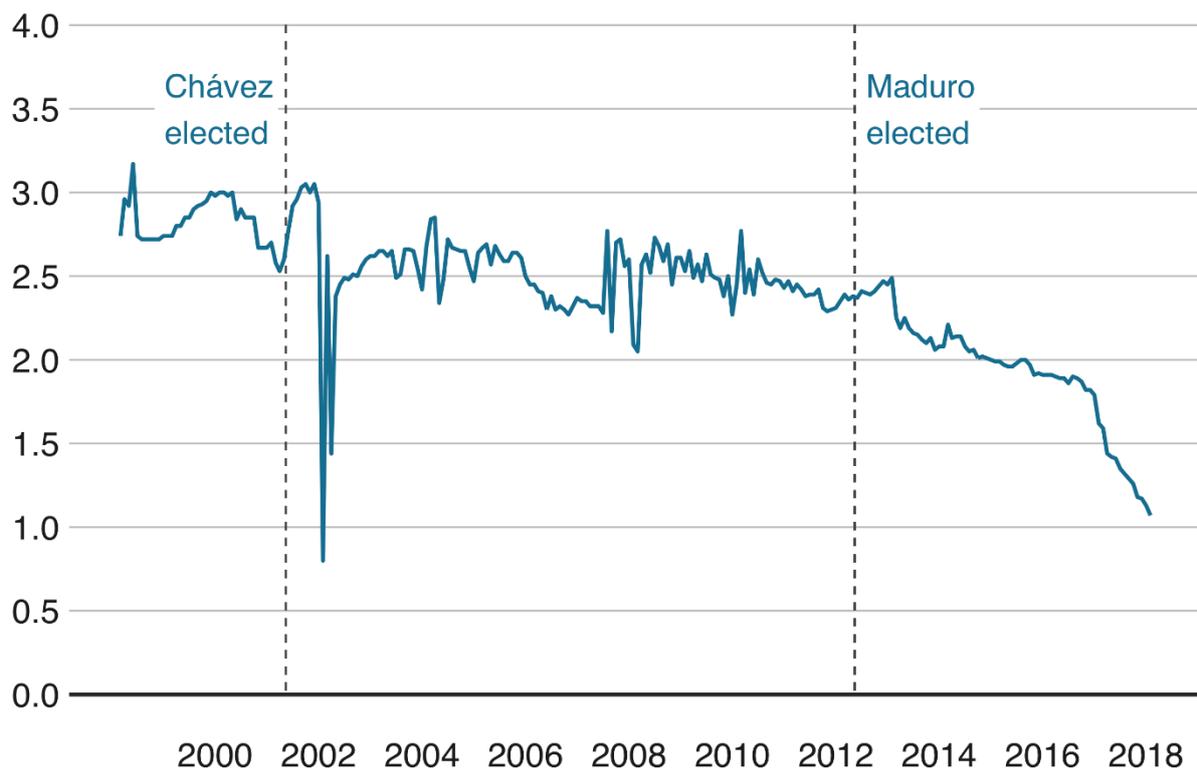
Figure 7: Process for recovery, transport and upgrading of extra-heavy oil from the Faja Petrolifera del Orinoco at the Petrocedeño project. Source: Total

However, for nearly two decades, since shortly after the election of Hugo Chavez, Venezuela oil production has steadily declined from near historic highs exceeding 3.0 million barrels per day (Fig. 8). On taking office, Chavez replaced key PDVSA corporate managers and operating staff and he began diverting profits from oil sales to other government programs. Lack of funds halted planned field and facility expansions and hindered routine maintenance of the oil fields, pipelines and upgraders. Under President Maduro the decline in oil production has accelerated (Fig. 8) due to combined low global crude oil prices, gross government mismanagement of and corruption within the national petroleum industry, and since 2017 ever-tightening financial

sanctions imposed by the Trump administration. Before sanctions, refineries on the Texas Gulf Coast had been the principal destination for Zuata Sweet syncrude. But by January 2018 Venezuelan syncrude imports actually fell below syncrudes imported from Alberta, 455,000 b/d versus 463,000 b/d, respectively (The Globe and Mail, April 4, 2018). For the first quarter

Oil production is falling

Millions of barrels per day



Source: OPEC



Figure 8: Steadily declining Venezuelan oil production over the past two decades accelerated after Maduro assumed the Presidency in 2012 and the Trump administration began imposing economic sanctions in 2017.

of 2018 exports had fallen to 1,252,000 bopd with just 32.3% going to the United States versus 45.7% to Asia (mainly China and India) and 22.0% to the Caribbean and elsewhere. With recognition of an alternative government of Venezuela and imposition of additional U.S. sanctions in January 2019 by mid-March all oil shipments to the United States had ended along with imports from the U.S. of diluents critical to the extraction and transport of the extra-heavy

crude. That month oil exports declined still further to 980,355 bopd, 74% of which was shipped to Asia (Reuters Business News, April 2, 2019).

Resources and Production – United States

The goal of the United States to move towards sustained energy independence includes production from known domestic oil sand deposits using surface mining or in-situ extraction. Historically, oil sand production had been principally for local use on roads and other paved surfaces. This is due mainly to the different character and scale of the U.S. deposits compared to Canada and Venezuela, but in part it is because, outside of the producing heavy oil fields in California and Alaska, the infrastructure required to exploit oil sands as a commercially-viable fuel source is wanting. Schenk et al. (2006) compiled total measured, plus speculative, estimates of bitumen in-place of about 54 billion barrels [8.6 billion m³] for 29 major oil sand accumulations in Alabama, Alaska, California, Kentucky, New Mexico, Oklahoma, Texas, Utah, and Wyoming (Table 6). However, these estimates of total oil sand resources provide only limited guidance for the potential commercially viable, environmentally-responsible development of the bitumen and heavy oils. The resources in each of the states have distinct characteristics that influence current and/or future exploitation.

Table 6: Previous estimates of bitumen-heavy oil resource-in-place, measured and total, including speculative, in the United States.

<i>State</i>	<i>No. deposits</i>	<i>°API range</i>	<i>Measured, MMB</i>	<i>Total, MMB</i>
Utah	10	-2.9 to 10.4	11,850	18,680
Alaska	1	7.1 to 11.5	15,000	15,000
Alabama	2	na	1,760	6,360
Texas	3	-2.0 to 7.0	3,870	4,880
California	6	0.0 to 17.0	1,910	4,470
Kentucky	4	10	1,720	3,410
New Mexico	1	12	130	350
Wyoming	2	na	120	145

Data from Schenk and others, 2006

California has the second largest exploited heavy oil reserves in the world, second only to Venezuela (Hein 2013). California's oil fields, of which 52 each have reserves greater than 100 million barrels [15.9 million m³], are located in the central and southern parts of the state (Fig. 9). As of the end of 2017, California's proved reserves were 2,204 million barrels [350.4 million m³] (U.S. Energy Information Administration, Nov. 28, 2018). The dominantly heavy oil fields of the southern San Joaquin basin had 2014 proved reserves of 1,824 million barrels [290.0 million m³]. Most of the fields were discovered and put into primary production in the period 1890 - 1930. However, with the introduction of water flooding, thermal recovery, and other EOR technologies starting in the 1950s and 1960s, oil recoveries improved dramatically, and the proved reserves increased several fold (Tennyson 2005).

from fields in the southern San Joaquin basin (Fig. 9; Table 7).

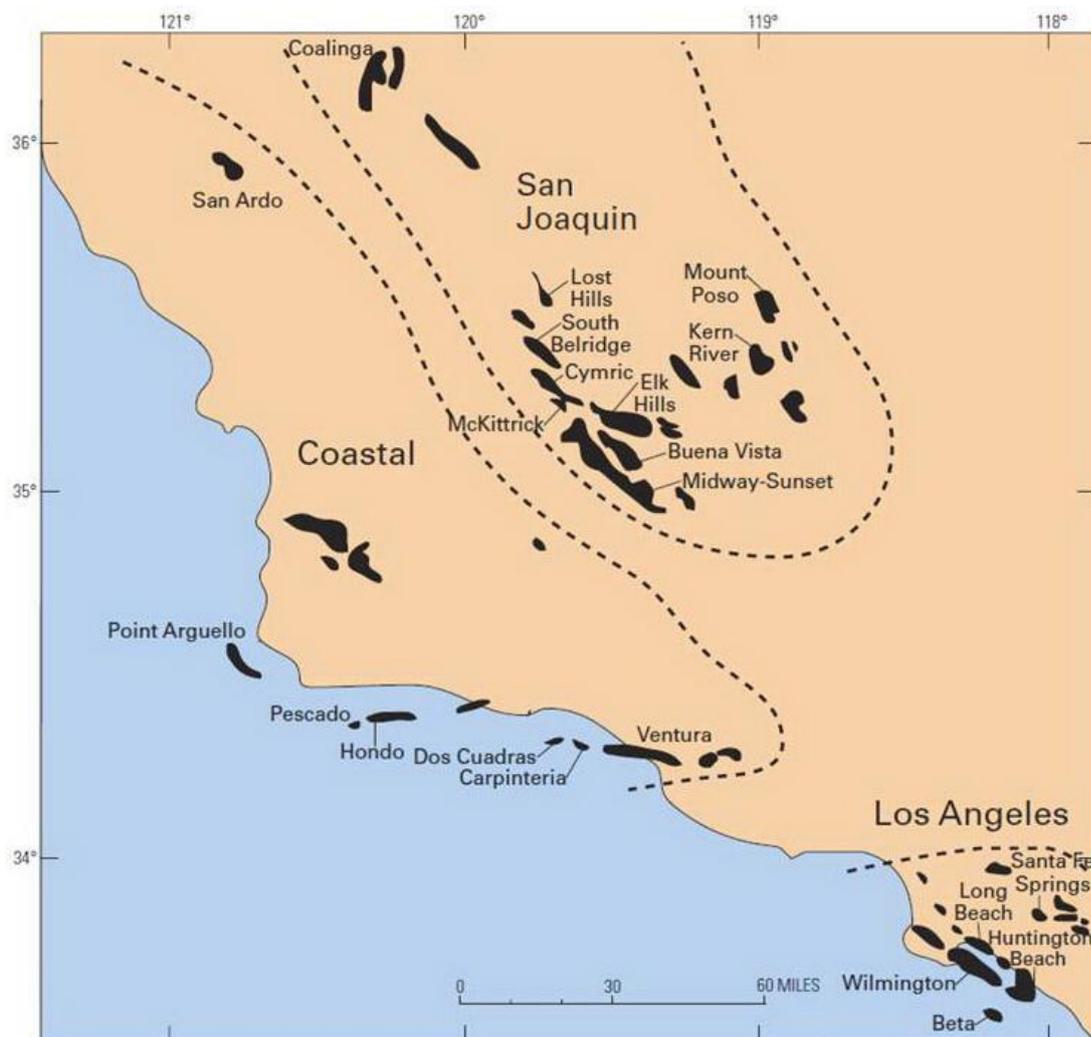


Figure 9: Principal oil fields of California (Tennyson, 2005)

Nearly all the oil is sourced from organic-rich intervals within the thick Miocene-age Monterey Formation diatomite, diatomaceous mudstone, and carbonate. Due to a combination of Type IIS kerogen, modest burial and thermal heating, and generally shallow depths of oil pools, the oil tends to be heavy and relatively viscous. These are thermally immature, partially biodegraded oils. Approximately 40% of the oil is produced by steam flooding, cyclic steam stimulation (CSS), or other thermal recovery methods. Thermally-produced oil comes mainly

In general, the reservoirs are poorly- or un-consolidated sandstones intercalated within or immediately overlying the Monterey Formation. However, the South Belridge field produces

from diagenetically-altered, highly fractured Monterey diatomite. The Coalinga field produces from sandstones in the Temblor Formation underlying the Monterey Formation. Here the source rock is the Middle Eocene Kreyenhagen Formation, which at the field is unconformably overlain by the Temblor Formation.

Table 7: Principal California 1 oil fields produced by thermal recovery methods. The fields are arranged by 2017 total oil yield; the volume of associated gas is indicated by the gas-oil ratio (GOR) in units of SCF gas/barrels oil. Also shown are the characteristic oil gravity, oil viscosity, and reservoir or in-situ oil temperature of the fields.

<i>Field</i>	<i>2017 Oil, MMBO</i>	<i>2017 GOR</i>	<i>° API</i>	<i>Oil viscosity, cp</i>	<i>Oil temp., ° F</i>
Midway-Sunset	22.090	204	11 to 14	1000 - 10000	85 - 130
Kern River	21.935	468	13	4000	90
South Belridge	21.166	383	13 to 14	1500 - 4000	95
Cymric	16.160	171	11 to 14	1000 - 2000	95 - 105
Lost Hills	9.504	469	12.7 to 13.9	1500 - 4000	75 - 82
San Ardo	7.234	140	11 to 12	1000 - 3000	125 - 130
Coalinga	6.575	39	9 to 13	2000 - 28000	84 - 105
Poso Creek	4.419	172	13 to 14.8	1500	80 - 95
Kern Front	3.684	15	13	2800	110
McKittrick	3.004	49	10 to 12	13000 - 51000	83
Placerita	0.575	0	13	10000	90
Edison	0.559	215	14	2000	90
North Antelope Hills	0.259	0	14	1400	80

Data from California DOGGR 2017 production statistics and Oil & Gas Journal, April 2, 2012

With the exception of Poso Creek, all of the principal thermal oil fields in the San Joaquin basin (Table 7) experienced oil production declines in the three-year period 2015-2017 on the order of 2.4% (Cymric) to 35.1% (Placerita). The three largest fields experienced declines of 7.6% (South Belridge), 14.6% (Kern River) and 21.6% (Midway- Sunset). The Cymric and Coalinga fields, which earlier in the decade saw respectable increases in production, had the smallest three-year declines of 2.4% and 3.0%, respectively. Even the young (1952) San Ardo field immediately west of the San Joaquin basin (Fig. 8), which had been expanding, saw a 7.2% decline in 2015-2017.

Viscous heavy oil also is found in the Los Angeles basin, but it is not exploited. As a pilot project, a small portion of the supergiant Wilmington field (Figure 9) was produced

successfully by steam flood using two pairs of parallel horizontal injector and producer wells. The test soon was stopped due to surface subsidence problems at the ports of Los Angeles and Long Beach that overlie the field. Additionally, air quality issues associated with steam generation have severely limited the implementation of thermal recovery methods across the entire Los Angeles basin.

Although California is the third largest U.S. oil producing state, it imports about 70% of the oil it consumes. Consequently, California heavy oil is exceptional in that it sells at a substantial premium above the West Texas Intermediate (WTI) benchmark. In January 2019, when the average price of WTI was \$44.06, the Midway-Sunset 13° API benchmark crude was priced at \$56.39 (EIA, California Midway-Sunset First Purchase Price, 4/1/2019). In the existing heavy oil fields of California, where natural gas burned to generate steam is the principal operational cost, a dramatic drop in oil price may reduce new capital expenditures, but rarely ongoing oil production.

During the past three decades, oil production in California has steadily declined (U.S. Energy Information Administration, 2019). Peak production of 1,109 thousand bpd was reached in February 1986, but in January 2019 it had fallen to 458 thousand bpd. The total production state wide in 2017 was 174.0 million bbls [27.7 million m³], a 6.8% decrease from 2016 (2017 Annual Report of California Oil and Gas Production). However, before the recent fall in oil price, the rate of decline was being slowed and reversed in many fields through the application of fully integrated reservoir characterization and improved recovery technologies that resulted in higher recovery factors (Dusseault 2013), up to 70- 80% in some fields.

In addition to the heavy oil accumulations that are being produced, California has numerous shallow bitumen deposits and seeps that are not currently exploited. The total resource is estimated to be as large as 4.7 billion barrels [747.3 million m³] (Kuuskraa et al. 1986). Five of the six largest tar sand deposits are in the onshore Santa Maria basin (central

Coastal zone in Fig. 8), covering a total area of over 60 square miles [155 km²]. In general, the deposits are in the Sisquoc Formation, which overlies and is a seal to the oil-generating Monterey Formation. An additional major deposit is in the onshore Ventura basin (extreme southeast of the Coastal zone). Minor bituminous sand deposits and surface seeps are scattered throughout all the oil-producing areas of California, normally overlying or up-dip from known oil fields.

Alaska's heavy oil and bitumen deposits on the North Slope are very large (24 to 33 billion barrels; 3.8 to 5.2 billion m³) and they hold promise for expanded commercially successful development. Since early 1980s (Werner 1987), two very large, shallow heavy oil impregnated sands have been known to overlie the Kuparuk River field and underlie the 1,800 ft [549 m] thick permafrost (Fig. 10). These are the Ugnu Sands (8-12 °API) at depths of 2,000-5,000 ft [610-1,524 m] and the West Sak/Schrader Bluff Formation (16-22 °API) at 2,300-5,500 ft [701-1,676 m]. The size of the heavy oil deposits (Fig. 10) is well defined by the numerous wells tapping underlying conventional oil fields. For the Lower Ugnu Sands and West Sak/Schrader Bluff Formation the resources are 12-18 billion bbls [1.9-2.9 billion m³] and 12 billion bbls [1.9 billion m³], respectively (Attanasi and Freeman, 2015). The reservoirs are fluvial-deltaic sands deposited during the Late Cretaceous-earliest Paleocene in the north and northeast prograding Brooks Range coastal plain (Hulm et al., 2013).

Alaska Viscous & Heavy Oil Resource

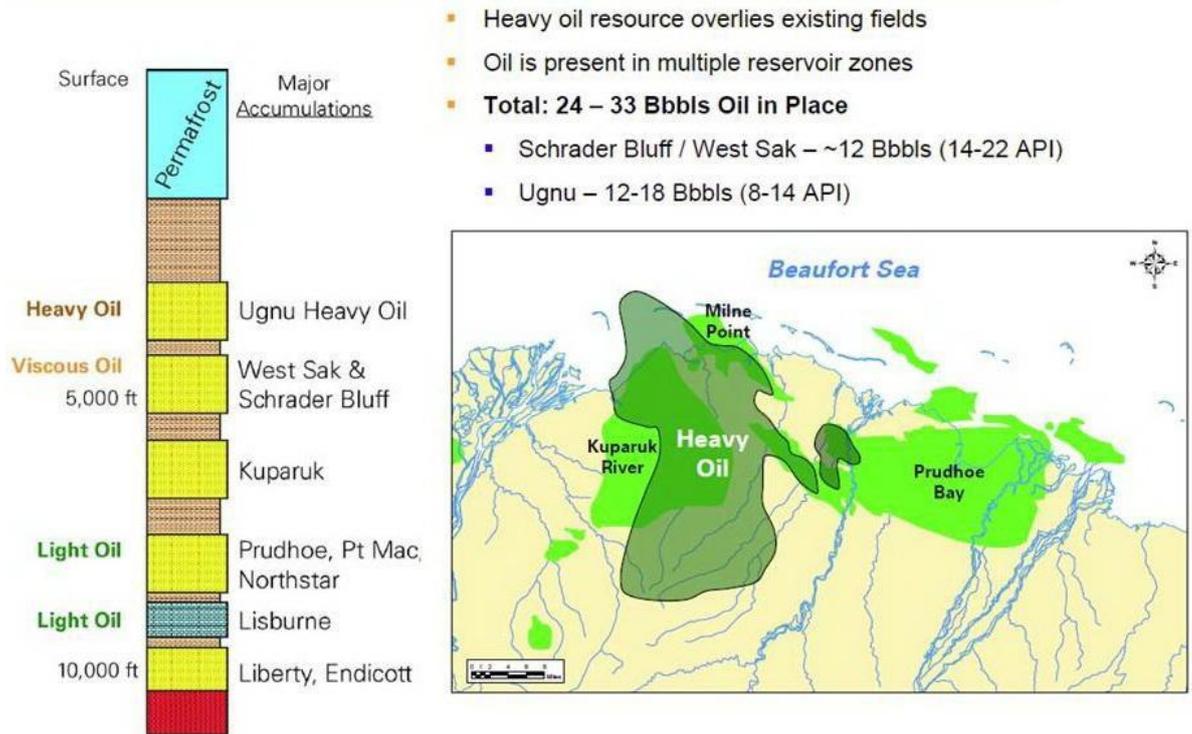


Figure 10: Location of shallow, heavy oil accumulations on the North Slope of Alaska. Heavy oil deposits overlie the Kuparuk field and parts of the Prudhoe and Milne Point fields and occur in sands within the Ugnu, West Sak and Schrader Bluff formations. Source: Gordon Pospisil, BP Exploration (Alaska) Inc., January 6, 20.

Extraction of viscous oils from beneath a thick permafrost layer precludes the injection of hot water or steam that would liquify the sediments adjacent to the injector and production wells leading to ground instability. Were it not for this constraint, the heavy oils of the North Slope would have been exploited to a greater extent than at present (Attanasi and Freeman, (2015).

Production of viscous (50-5000 cp) heavy oil from the Scharader Bluff/West Sak pools began in the early 1990s, reaching the current level of 4,000-5,000 bbls [636-795 m³] of oil per day in 2004. (Fig. 11). To date, over 100 million bbls [15.9 million m³] have been recovered from the formation using a combination of vertical wells and water flood. The heavy

KUPARUK RIVER, WEST SAK OIL

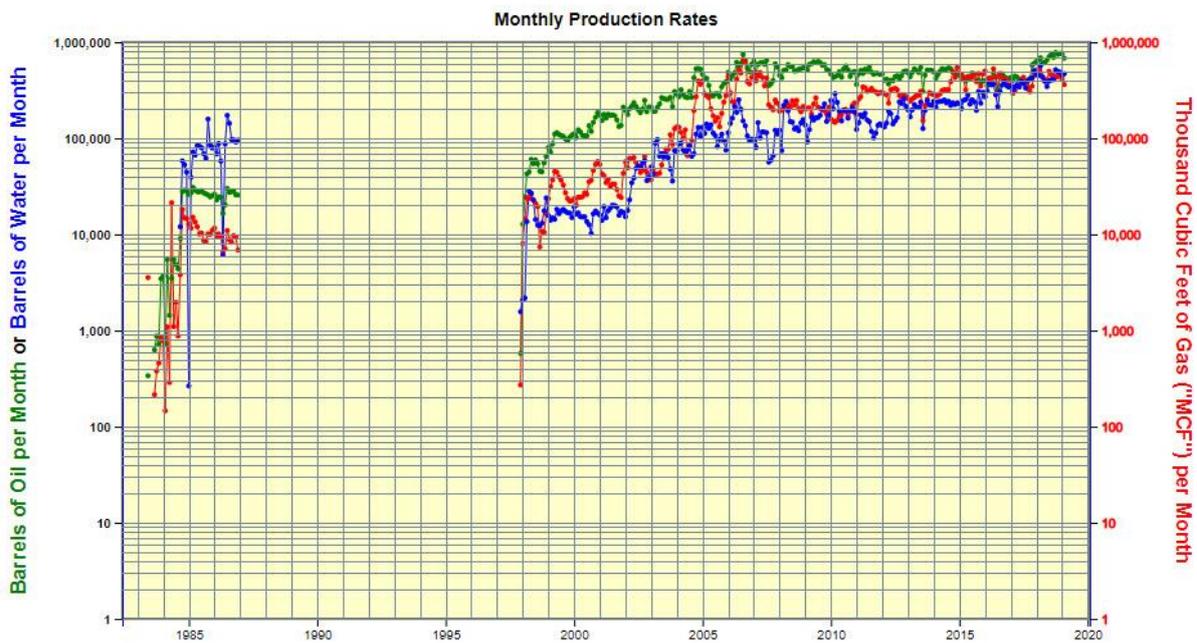


Figure 11: Monthly production of the heavy oil (green) from the West Sak oil pool in the Kuparuk River block. Source: Alaska Oil and Gas Conservation Commission Pool Statistics

oil in the Ugnu Sands presents a much greater technical challenge due to its higher viscosity (5,000 to over 20,000 cp) and the extreme friability of the reservoir sand (Chmielowski, 2013). At its Milne Point S-Pad Pilot (Fig. 10), BP Alaska tested two different recovery strategies in the Ugnu Sands. One pilot pumped from the heel of a cased and perforated horizontal well, which early in 2013 successfully produced heavy oil at a rate of 350 bbls [55.6 m³] of oil per day (Newsminer, January 16, 2013). The other is a test of the CHOPS ('cold heavy oil production with sand') recovery process (Young et al. 2010; Mathur, 2017). BP Alaska had suspended the test program in 2013 after encountering operational problems in the CHOPS mechanical procedure that required frequent maintenance (Alaska Journal of Commerce, July 2015). There has been no commercial exploitation of the highly viscous Ugnu Sands oil (Attanasi and Freeman, 2015).

Utah's bitumen and heavy oil deposits are found throughout the eastern half of the state (Schamel 2009; Schamel 2013a, b). In northeast Utah, the largest accumulations are located along the southern margin of the Uinta Basin where they underlie vast portions of the gently

north-dipping East and West Tavaputs Plateaus. This highland surface on either side of the Green River (Desolation Canyon) and above the Book and Roan Cliffs is supported by sandstone and limestones of the Green River Formation (lower Eocene). Here the bitumen/heavy oil resource-in-place is at least 10 billion bbls [1.6 billion m³], nearly all of it reservoirized in fluvial-deltaic sandstone bodies within the lower member of the Green River Formation.

On the northern margin of the Uinta Basin, viscous heavy oil occurs in a variety of Mesozoic and Tertiary reservoirs on the hanging wall of the Uinta Basin Boundary Fault. The proven resource is less than 2.0 billion bbls [0.32 billion m³], but the potential for additional undiscovered heavy oil and bitumen is great. In both areas, the source of the heavy oil is organic-rich lacustrine calcareous mudstone in the Green River Formation. These naphthenic oils have API gravities in the 5.5 to 17.3° range, are only weakly biodegraded in the subsurface, and are sulphur-poor (0.19 to 0.76 weight %). The known oil sand reservoirs are lithified and oil-wet.

New resource-in-place estimates for the major deposits are determined from the average volume of bitumen/heavy oil measured in cores distributed across the deposit, as delineated by wells and surface exposures (Table 8). The deposits on the south flank of the basin are large and extensive, but the actual concentrations (richness) of resource are small. For the vast P. R. Spring–Hill Creek deposit, the average richness is just 25.9 thousand bbls [4.1 thousand m³] per acre. Richness is only slightly higher for the entire Sunnyside accumulation west of the Green River. However, in small portion of the Sunnyside deposit having unusually large net reservoir sand thickness within a monoclinical structure trap the measured average richness is as great as 638.3 thousand bbls [101.2 thousand m³] per acre. The two principal deposits on the north flank of the basin, Asphalt Ridge and Whiterocks, are relatively small, but both contain high concentrations of viscous heavy oil (Table 8).

Table 8: Estimated resource size and richness of the principal heavy oil-bitumen deposits in Utah. Abbreviations:MMB, million barrels; MB, thousand barrels.

<i>Bitumen-heavy oil deposit</i>	<i>Resource estimate MMB</i>	<i>Areal extent square miles</i>	<i>Richness, average MB/acre</i>	<i>° API gravity</i>	<i>Reservoir unit</i>
P.R. Spring - Hill Creek	7,790	470	25.9	5.9 to 13.8	lower Green River ss
Sunnyside	3,500 - 4,000	122	45 - 51	7.1 to 10.1	lower Green River ss
<i>Sunnyside 'core'</i>	1,160	2.7	638.3		lower Green River ss
Asphalt Ridge	1,360	16	132.9	10.0 to 14.4	Mesaverde ss (U Cret.)
Whiterocks	98	0.45	338	11.4 to 13.5	Navajo Ss (Tr.-Jr.)
Tar Sand Triangle	4,250 - 5,150	198	33.5 - 40.6	-3.6 to 9.6	White Rim Ss. (L. Perm)
<i>TST 'core'</i>	1,300 - 2,460	30 - 52	67.7 - 73.9		White Rim Ss. (L. Perm)
<i>Data from Schamel (2013a) and Schamel (2013b)</i>					

In the southeast quadrant of Utah, there are numerous shallow bitumen accumulations on the northwest and west margins of the Pennsylvanian-Permian Paradox Basin. The deposits are hosted in rocks of late Paleozoic and early Mesozoic age. Except for the Tar Sand Triangle and Circle Cliffs deposits, most accumulations are small and/or very lean. Normally, the oils are heavier than 10° API and highly biodegraded. In contrast to the Uinta Basin deposits, this bitumen is derived from a marine source rock and is aromatic with high sulphur content (1.6 to 6.3 wt.%), but low nitrogen (0.3 to 0.9 wt.%).

Bitumen in the Tar Sand Triangle deposit, located south of the junction of the Green River with the Colorado River, is reservoirized in several-hundred-foot-thick aeolian sandstone of Lower Permian age. Across an area of 84 square miles [217 km²], the thickness of bitumen-impregnated sandstone exceeds 100 ft (30 m). The API gravity of the bitumen is less than 8° at the surface and just over 10° in the subsurface. Schamel (2013b) estimated the total in-place bitumen resource is between 4.25 and 5.15 billion bbls [0.67 and 0.82 billion m³] in a deposit slightly less than 200 square miles [518 km²] in size. At a richness equal to or greater than 60 thousand bbls [9.5 thousand m³] per acre, the resource ranges between 1.30 to 2.46 billion bbls [0.21 to 0.39 billion m³] in an area of 30 to 52 square miles [78 to 135 km²], respectively. Approximately half of the deposit is in the Glen Canyon National Recreation Area, where exploitation could be severely limited. The rest of the deposit is on land managed by the U.S. Bureau of Land Management and the Utah State Lands Trust. The Circle Cliffs deposit, holding

an estimated 1.73 billion bbls [0.27 billion m³], lies completely in the Capitol Reef National Park and Grand Staircase- Escalante National Monument, areas off limits to development.

The Uinta Basin heavy oils and bitumens are highly viscous; the Tar Sand Triangle bitumen is only slightly less viscous. Both groups of oils have viscosity that is orders of magnitude greater than that of the 13 °API heavy oil produced by steam flood in the southern San Joaquin Basin, California and that of the 9° API extra-heavy oil in Alberta recovered by surface mining and SAGD steam injection. So far, the Utah ‘tar sands’ have resisted attempts at commercial development. During a period of improving oil price, both Calgary-based U.S. Oil Sands (Utah) Inc. and Toronto-based MCW Energy Group Limited announced resumption of their oil sands pilot projects at PR Spring and the Asphalt Ridge deposits, respectively. Both companies proposed to surface mine the shallow oil sands and produce bitumen/heavy oil by similar closed-loop solvent extraction processes. The 2015 drop in oil price had impact on both companies. In September 2017 U.S. Sands (Utah) Inc. went into receivership; a sale solicitation process was initiated Court of Queen’s Bench of Alberta on February 23, 2018. MCW Energy Group, restructured as Petroteq Energy Inc., announced in an April 25, 2018 press release that a new oil extraction facility at the existing Temple Mountain mine at the south end of Asphalt Ridge had been completed. Commercial production was scheduled to begin in May 2018, but that has not yet happened. There has been no economically-successful exploitation of the large oil sand resources anywhere in Utah.

The Southwest Texas Heavy Oil Province (Ewing, 2009) is located on the northeastern margin of the Maverick Basin, northeast of Eagle Pass. Bitumen is hosted in early to middle Campanian carbonate grainstone shoals (Anacacho Formation) and in late Campanian-Maastrichtian sandstone (San Miguel, Olmos, and Escondido Formations). The largest accumulation is in the San Miguel ‘D’ Sandstone with a reported 3.2 billion bbls [0.51 billion m³] in an area of 256 square miles [663 km²] (Kuuskraa et al., 1987). The bitumen is highly

viscous and sulfur-rich (10%) with an API gravity of -2° to 10° API. The average resource grade of the deposit is less than 20 thousand bbls [3.2 thousand m^3] per acre. Only a very small part of the deposit has a grade more than 40 thousand bbls [6.4 thousand m^3] per acre.

In the late 1970s and early 1980s, Exxon and Conoco produced from pilot plants at this deposit 417,673 bbls [66,405 m^3] of bitumen, but since then there has been no successful exploitation of the deposit. The shallow Anacacho deposit contains an estimated 550 million bbls [87.4 million m^3] resource in an area of 36.6 square miles [94.8 km^2]. The average resource grade is 23.5 thousand bbls [3.7 thousand m^3] per acre. The deposit has been mined since 1888 for asphaltic road paving.

In northwest Alabama, bitumen-impregnated Hartselle Sandstone (Mississippian) occurs sporadically along a 70 mile [113 km] -long belt extending east-southeast across the Cumberland Plateau from near the Alabama-Mississippi border to the front of the Appalachian thrust belt. To the south of this outcrop belt, bitumen is observed in wells penetrating the Hartselle Sandstone. The Alabama Geological Survey (Hooks and others, 2016; Wilson, 1987) speculated that there could be 7.5 billion bbls [1.2 billion m^3] of bitumen in an area of 2,800 square miles [7,252 km^2], of which 350 million bbls [55.6 million m^3] is at depths shallower than 50 feet [15 m].

Despite the large potential resource, the deposit is lean, with an average bitumen-impregnated interval of 14 feet [4.3 m] and an average richness of only 4.3 thousand bbls [0.68 thousand m^3] per acre. In 2014, the Geological Survey of Alabama and the State Oil and Gas Board of Alabama established the Alabama Oil Sands Program (AOSP) to provide an updated resource assessment for the potential development of oil sands in Alabama (Hooks, 2015). This includes a review of data, fieldwork, testing new technologies to locate bitumen concentrations in the Hartselle sandstone, and reservoir models and reserves estimates to be recalculated.

The oil sand deposits of western Kentucky form an arcuate belt along the southeast margin of the Illinois Basin. The estimated oil-in-place is 3.36 billion barrels [533.8 million m³] (Bowersox, 2016). The heavy oil is hosted in fluvial sandstones, some filling paleovalleys, of Late Mississippian-Early Pennsylvanian age (May, 2013; Bowersox, 2016). The area is crossed by the east-west trending Rough Creek and Pennyryle fault systems that aid in trapping the heavy oil pools and may have been the conduits for eastward oil migration from hydrocarbon kitchens at the juncture of Illinois, Indiana and Kentucky. The largest deposit, hosted in the Big Clifty Sandstone, extends in 5 to 10 miles [8 to 16 km] wide and 50 miles [80 km] long situated north of Bowling Green. This deposit holds an estimated 2.26 billion bbls [359.9 million m³] of 10° API oil, but it is very lean, just 6.21 thousand barrels per acre, with thickness of the oil-impregnated sands from a few to just over 50 feet (Noger, 1999). The smaller deposits further to the west are in the Hardinsburg Sandstone and Caseyville Formation hold estimated in-place resources of 0.357 and 0.740 billion bbls [56.8 and 117.7 million m³], respectively, with API gravities of 10° to 17°. These deposits also are very lean at 2.84 and 6.31 thousand bbls per acre.

At present, there is no commercial exploitation of the deposits for liquid hydrocarbons, although at least one operator has announced plans to do so. Arrakis Oil Recovery, a subsidiary of Imperial Petroleum, Inc. has applied for a U.S. Army Corps of Engineers permit to strip mine the Big Clifty Sandstone at a 144-acre site in Logan County, west of Bowling Green. The application is being opposed by various environmental groups as destructive to existing wetland habitats and water resources. In 2018 Indago Energy drilled, cored and production tested, unsuccessfully, a pilot well in the Big Clifty Sandstone using an injected solvent (HCD Multi-Flow) in an attempt to reduce the viscosity of the heavy oil (Indago Energy Limited 2018 Annual Report; www.indagoenergy.com).

Oil sand accumulations in east-central New Mexico have total in-place measured and speculative resources of 130 million bbls [20.6 million m³] and 190 to 220 million bbls [30.2 to 35 million m³], respectively (IOCC, 1983; Schenk et al., 2006). The oil accumulations are within Triassic Santa Rosa Sandstone at depths of less than 2,000 ft [610 m]. (Broadhead, 1984). Speculative in-place oil sand resources total 800 million bbls [127.2 million m³] for Oklahoma (IOCC, 1983; Schenk et al., 2006). Oil sands are located mostly within Ordovician Oil Creek Formation sandstones and Viola Group limestones, with lesser accumulations in Mississippian through Permian sandstones (IOCC, 1983). A bibliography of Oklahoma asphalt references through 2006 (B. J. Cardott, compiler) can be downloaded from

http://www.ogs.ou.edu/fossilfuels/pdf/bibOkAsphalt7_10.pdf

In-place resources for two oil sand accumulations in Wyoming total 120 million bbls [19 million m³] measured and 70 million bbls [11.1 million m³] speculative (IOCC, 1983; Schenk et al., 2006). The larger accumulation is within Pennsylvanian-Permian sandstones of the Minnelusa Formation in northeastern Wyoming, and the smaller is within Cretaceous sandstones in the Wind River Basin, central Wyoming (IOCC, 1983).

Resources and Production – Russia

Heavy oil constitutes approximately 18% of the total Russian oil reserves and estimates at 3.6 billion cubic meters (22.6 billion barrels). Recoverable heavy oil occurs in four principal petroleum provinces, (1) the southern, up-dip portion of the West Siberian Basin, (2) the Volga-Ural Basin, (3) Timan-Pechora Basin, and (4) Eastern Siberian Basin (Fig. 12, Table 9). There are 71.7 million m³ (451.5 MMBO) of annual heavy oil production in 2016 in Russia (Prischepa O.M. and Borovinshikh A.P., 2016). Resource and reserve summaries of the deposits within these principal petroleum provinces are described herein.

Table 9: Russian heavy oil and bitumen resources regional distribution (Bazhenova T.K., 2015)

Basin	Region	Resource, Bm3	Resource, BBO	The share of total heavy oil, %
West-Siberian basin	Khanty-Mansiysky Region	1.69	10.64	25.7
	Yamalo-Nenets Region	1.03	6.51	15.7
Volga-Ural basin	Republic of Tatarstan	0.85	5.35	12.9
	Republic of Bashkortostan	0.36	2.29	5.5
	Udmurt Republic	0.32	2.01	4.8
Timan-Pechora basin (North-West)	Komi Republic	0.41	2.56	6.2
	Nenets Region	0.36	2.26	5.4
East-Siberian basin	Krasnoyarsk Region	0.34	2.15	5.2
Offshore		0.21	1.34	3.2
Total		5.57	35.11	84.6

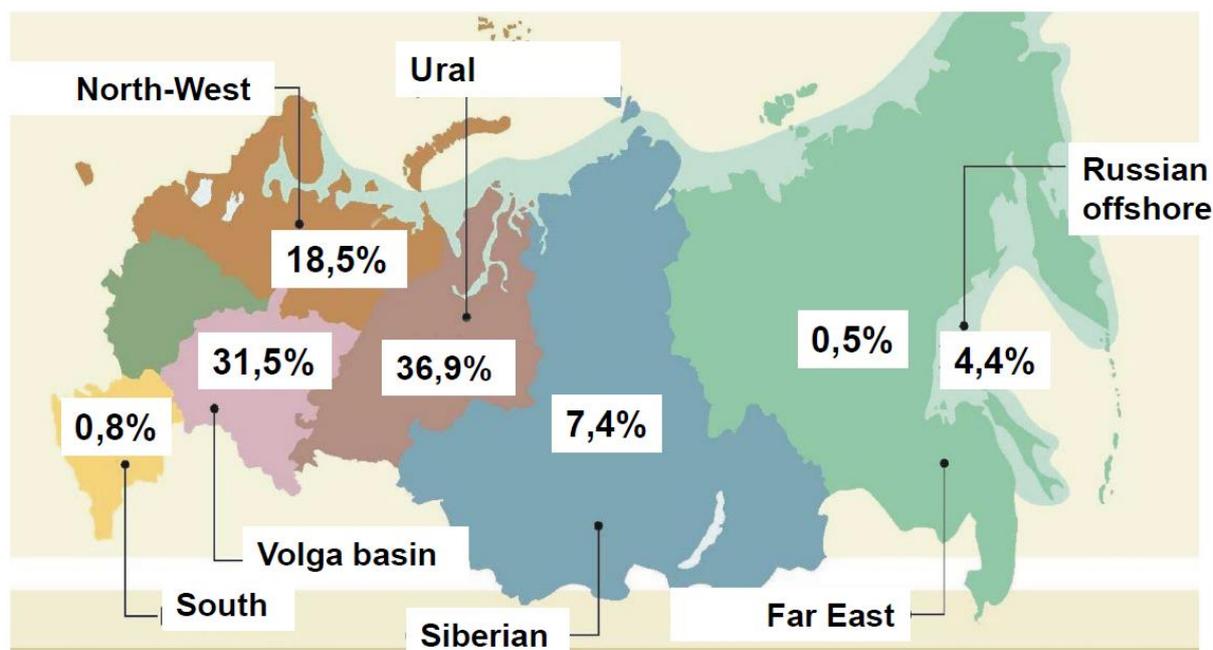


Figure 12: Heavy Oil and Bitumen Reserves Regional Distribution (VNIGRI, 2017)

In the southern up-dip portion of the West Siberian basin, heavy oils occur in Jurassic Cretaceous sandstone where oil pools have been infiltrated by meteoric water and biodegraded. Additionally, bitumen deposits have been discovered along the southeast flank of the Ural Mountains. West Siberian basin's reserves are mainly represented by the Russkoye,

Tazovskoye, and Vanyeganskoye heavy oil fields (Table 10, Figure 13). Recoverable reserves of the biggest Russkoye field are estimated at 458.3 MMm³ (2,649 MMBO).

Table 10: Parameters of main heavy oil fields in the West-Siberian basin (Prischepa O.M. and Borovinshikh A.P., 2016)

Field	Depth, m	Density, API ⁰	Reserves, MMm ³	Reserves, MMBO
Russkoye	664	19.7	458.3	2649
S.-Komsomolskoye	1056	19.0	217.2	1256
Van-Eganskoye	893	16.8	169.7	1069
Tazovskoye	1162	19.4	92.9	454
V.-Messoyakhskoye	834	17.0	370.9	2144
Z.-Messoyakhskoye	834	17.0	140.5	812



Figure 13: Siberia and Far East of Russia (Source: IEEJ)

In Eastern Siberia, extremely large bitumen and heavy oil resources are reported at various locations on the Siberian Platform (Fig.13). The principal bitumen-containing formations in Eastern Siberia are within Vendian – Cambrian, Silurian, Carboniferous, and Permian formations. These deposits are poorly characterized and the resources may not be recoverable at present. The Siberian platform in the Eastern Siberia is in tectonic contact with dominantly siliciclastic sedimentary basins. These bitumen-bearing basins are the Yenisey-Khatanga, Lena- Anabar Basins (northern margin), Verkhoyansk Basin (northeastern margin), and the Lena- Vilyuy Basin in the (eastern margin), as shown in Figure 14.

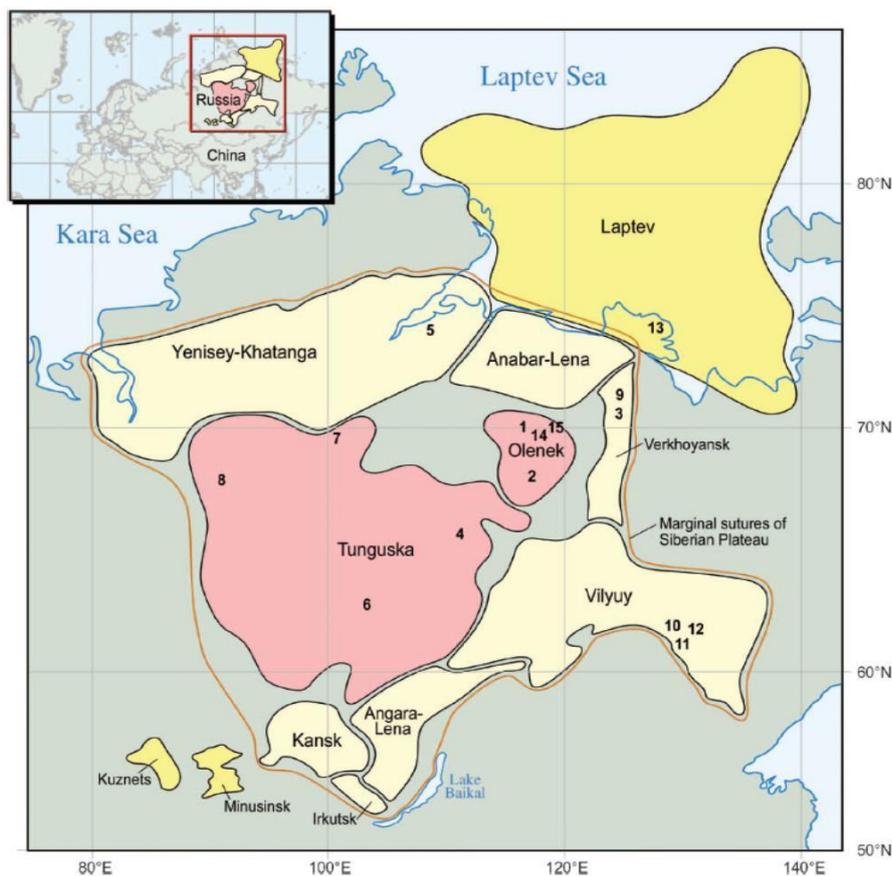


Figure 14: Eastern Siberia. Map of the sedimentary basin of the Siberian platform, Russia. Main heavy-oil and bitumen deposit locations: (1) Olenek; (2) East Anabar; (3) Chekurovka; (4) Siligir-Markha; (5) Rassokha; (6) Chun'ya; (7) Medvezh'ye; (8) Turukhan; (9) Bulkur; (10) Tuolba; (11) Amga; (12) Sina; (13) Ust-Lena; (14) Kuoyka; and (15) Sololisk. Dark pink color denotes uplift areas; yellow color denotes basins (Meyer and Freeman, 2006; modified from St.John, 1996). (Source: Kashirtsev and Hein, 2013).

The heavy oil and bitumen accumulations of the Volga-Ural province, Russia's second largest oil producing region, are within Carboniferous-Permian age reservoirs on or flanking the enormous Tatar dome. There are 194 known heavy oil-bitumen fields, most of which are reservoirs within shallow Permian-age rocks in the central and northern parts of the province. Tatarstan holds Russia's largest natural bitumen resources; there are 450 deposits in Upper Permian sandstones with 1.163 billion cubic meters [7.3 BBO] of resource in place (Fig. 15). The heavy oil and bitumen of this province have high sulphur content (up to 4.5%) and contain rare earth metals (Ni, Mo). A very large portion of the total oil reserves is heavy oil. The heavy oil comprises 35% of the reserves in Tartarstan, 58% in the Perm Region, 83% in the Udmurt Republic and all the reserves of the Ulyanovsk Region.



Figure 15: Location of Komi and Tatarstan Republics on the east of the Ural Mountains showing the location of the principal heavy oil production areas and fields in red within the inset maps.

In the Volga-Ural basin, the Ashalchinskoye and Mordovo-Karmalskoye heavy oil fields are the oldest produced shallow fields of the Cheremshano-Bastrykskaya Area (Fig. 15). Tatarstan is the most dynamic heavy oil producer which increased near ten times heavy oil production in last 5 years (Fig.16). The Yaregskoye and Usinskoye heavy oil fields are the same for the Timano – Pechora one (Fig. 15). As an example of a quality of reserves, parameters of typical fields in the Volga-Ural and Timano – Pechora basins are shown in the Table 11.

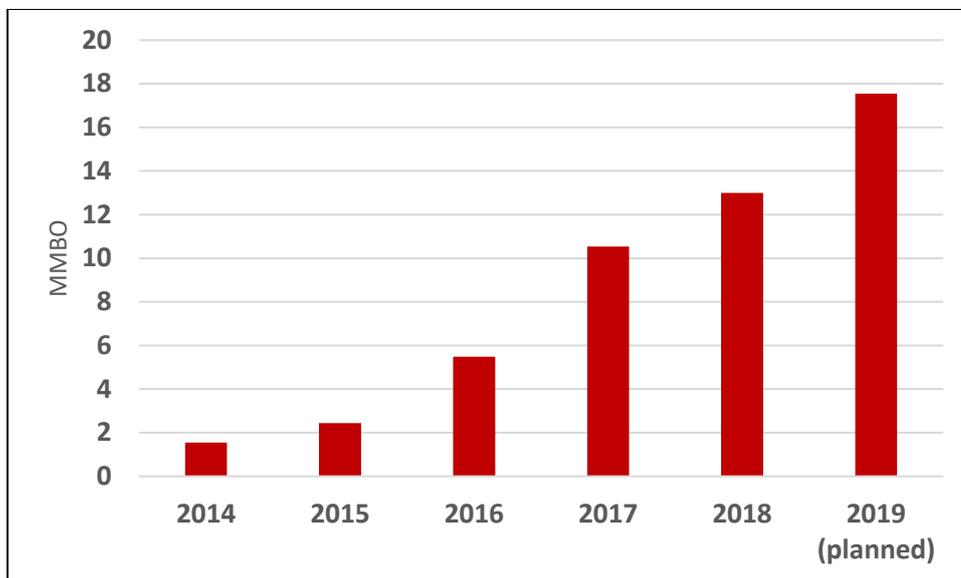


Fig.16 Annual Tatarstan heavy oil production, MMBO

In the Timan-Pechora basin, the heavy oil and bitumen resources occur in shallow pools on the Timan arch that is in the southwest part of the basin. Some of the fields are in production. The Yaregskoye oil field is located in East-Pechora Swell, and the Usinskoye oil field is located in the Kolvino Swell. The Yaregskoye field in the Komi Republic, containing about 375 million cubic m [4292 MMBO] of heavy oil proved recoverable reserves in Devonian formation, is the largest field in the Timan-Pechora petroleum province. The second largest is the Usinskoye

oil field which contains proved reserves around 67.0 million cubic m [472 MMBO] of heavy oil in Permian – Carboniferous age reservoir.

Table 11: A comparison of parameters between typical heavy oil fields in the Volga-Ural and the Timano-Pechora basins

	Ashalchinskoye	Mordovo-Karmalskoye	Yaregskoye	Usinskoye
Formation rock type	<u>Silicaclastic</u>	Silicaclastic	Silicaclastic	Carbonate
Depth, m	80	88.5	165	1100
Thickness, m	25	26.5	26	320
Permeability, d	3	1.06	2.5	0.38-10
Oil density, kg/m ³ (°API)	970 (14,4)	961 (15,7)	945 (18.2)	955-968(14.5-16.7)

Four biggest offshore heavy oil fields contain heavy oil. Three of them, namely Medynskoye sea, Prirazlomnoye, and Dolgunskoye are located in the south part of the Barents Sea. There is the fourth field named Arkutun-Daginskoye in offshore Sakhalin island. Total offshore proved reserves of heavy oil are 440 million cubic m [2,542 MMBO].

Resources and Production – Colombia

Although significant heavy oil and bitumen resources long had been known to be present in various parts of Colombia, it has only been in the past decade that this resource has an impact on the country’s production profile. Heavy oil from a single cluster of fields in the east-central part of the country has been responsible for a reversal of total oil production from a slow decline to just 550 thousand barrels per day prior to 2008 to a rapid increase reaching about one million barrels per day in 2014. Three factors facilitated the development of heavy oil resource in Colombia: (1) the restructuring of the petroleum industry opening the country to foreign investment and partial ownership of resources, (2) political agreements that sharply reduced guerrilla attacks on petroleum personnel and infrastructure, and (3) the decline of production from the mature conventional oil fields together with lack of success in replacing reserves through exploration. In nearly all instances of increased heavy oil production, the former

national oil company, Ecopetrol S.A., has retained half or greater interest in the field being developed with foreign investors and operators. There are four regions of Colombia where heavy oil production is now occurring on a commercial scale.

The Heavy Oil Belt in the extreme southwest portion of the Middle Magdalena basin, west of Bogota, has been known since the earliest days of exploration in the region. The heavy oil (11°-13° API) occurs in unconsolidated late Tertiary fluvial sands intercalated in mudstone. The reservoir unconformably on-laps basement rocks of the Central Cordillera on the extreme up-dip tapered margin of the basin. Over time small quantities of heavy oil were produced “cold” from vertical wells in a narrow band of fields (Moriche, Nare, Abarco, Girasol, Jasmine, Teca- Cocorná) centered on Puerto Boyaca. The Teca-Cocorná field has produced over 100 million barrels of heavy crude, but the cumulative production for the other fields been considerably less. The heavy oil belt is immediately up-dip from the Valásquez-Palagua field, which has yielded over 300 million barrels of intermediate gravity crude from the same reservoir sands.

Ecopetrol has partnered with Mansarovar Energy Colombia, Ltd. and other foreign operators to implement enhanced recovery methods in the Heavy Oil Belt. Heavy oil is now recovered by cyclic steam stimulation (CSS) in horizontal (!) wells carefully positioned in the stacked 10 to 20-foot-thick oil-bearing sands (Cuadros et al., 2010). In the Girasol field, optimal recovery is realized by placing the 2,500 ft horizontal legs 3 to 10 ft above the lower bounding mudstone for each sand reservoir bed (Cuadros et al., 2012).

Immediately south of Villavicencio, on the eastern margin of the Eastern Cordillera and within the Llanos foothills, there is a cluster of large oil fields that for many decades have produced intermediate gravity oil from Cretaceous sandstone reservoirs (K1 and K2). These are the anticlinal Castilla, Chichimene, Apiay, Suria and Libertad fields. As oil rates from the Cretaceous reservoirs declined, Ecopetrol began recovering heavy and extra-heavy oil from

shallower, Tertiary-age sands in the San Fernando Formation (T2). The general San Fernando reservoir characteristics of the two largest fields in the cluster, Castilla and Chichimene, are high porosity (16-22%) and permeability (0.5-10.0 D), relatively low oil viscosity at reservoir temperatures (about 150 cp), low initial water saturation (15%), and a strong artesian water drive resulting in an inclined oil-water contact for the oil pools (Piedrahita R. et al., 2012); Guarin Arenas et al., 2010). Oil is recovered from the fields by “cold production” merely with the assist of electric submersible pumps providing artificial lift. The heavy and extra-heavy oil component is providing a significant contribution to the several-fold increase in oil rates obtained in the fields over the past decade.

The Llanos basin is the broad foreland depression stretching between the Eastern Cordillera and the Guyana Shield. Its eastern margin, where Tertiary sands unconformably on-lap Paleozoic and older basement rocks, is geologically like the Orinoco oil sands belt in Venezuela. However, it lacks proximity to a major petroleum kitchen as exists in the Serrania del Interior thrust belt. Here the heavy oil deposits are considerably smaller than in Venezuela and less thoroughly investigated. The largest of the accumulations that have been developed is the Rubiales field, which has an extent of about 5,600 km², not including its several small satellite fields.

The Rubiales field was discovered in 1981 and first put into major production by Pacific Rubiales Energy and operating partner Ecopetrol S.A. in 2006. The field initially had an estimated 4.6 billion bbls [0.73 billion m³] of heavy oil-in-place. But by 2008 the total proven recoverable reserves had been revised to 4.38 billion bbls [696 million m³] and 22.8 million bbls [3.63 million m³] had been produced. By 2011, cumulative production from the field was 163 million barrels [25.9 million m³] and the daily oil rates were continuing to climbing above 180 thousand bbls per day falling off slightly to 132,000 bbls per day in 2017. On July 1, 2016 Ecopetrol became the sole owner and operator of the field. The reservoirs are unconsolidated

sands of Tertiary Carbonera Formation (unit C7) and Areniscas Basales having a combined thickness of 20 to 80 feet. The oil has a density of 11° to 14° API and at reservoir temperature (147°F) a viscosity between 310 and 730 cp. There is an aquifer water drive that, in most instances, initially supported “cold production” of the oil. Presently, the preferred production method involves radial arrays of 5 horizontal wells forming a near-circular drainage area with a radius of 1,200 ft. (Florez Anaya et al., 2012). The projected recovery factor for this well configuration is between 21% and 23%.

The Quifa field, an extension of Rubiales presently operated by Frontera Energy, was discovered in 2008. By 2011 it was producing at a rate of 39.4 thousand bbls per day. Discoveries of new heavy oil pools continue to be made throughout the Llanos basin, some of which have estimated oil-in-place approaching that of the Rubiales field.

The Caguan-Putumayo basin in southern Colombia is the northern extension of the oil-rich Oriente basin in Ecuador. Except for its southern fringe, the Putumayo is still a frontier basin, relatively inaccessible and consequently little explored. However, in recent years heavy oil discoveries have been made in the Andean foothills on the northwest margin of the basin. As in the Llanos foothills fields, the heavy oil is entrapped in faulted anticlines. The Capella extra-heavy oil field was discovered by Emerald Energy and Canacol Energy Ltd. in 2008 (Valbuena et al., 2014). The principal reservoir is the lower Tertiary Mirador Sandstone, which is a friable quartz arenite 120 ft thick that is both very porous (33%) and permeable (3 to 10 D). The gravity of the oil is 9° API and at reservoir temperatures it is quite viscous (2500-4000 cp). Secondary reservoir targets are heavily fractured Paleozoic sandstone and crystalline basement (Ramon et al., 2014). To date, recovery of the heavy oil has been by “cold production” through horizontal wells. By this method, the recovery factor is estimated to be less than 10%. But cyclic steam stimulation has been attempted in pilot wells with a short-lived four-fold increase in oil rates (Ramon et al., 2014). It is anticipated that through steam flood

in horizontal wells sustained oil recovery can be increased to 30% to 50%. Recently, other heavy oil discoveries have been made in the Putumayo foothills (Porrás et al., 2013), but they are not yet developed.

In all the heavy oil fields, the increasingly large water cut, requiring investment in treatment plants and disposal wells, is proving to be a problem that is restricting expansion of some recovery operations. As oil rates decline in “cold production”, increased oil rates and recovery factors will require investments in thermal and other EOR facilities. Additionally, there are many new, undeveloped heavy oil discoveries that will be competing for investment funds. It is economics, not the availability of resource that will control the future of heavy oil production in Colombia.

Recently discovering and developing additional oil and resources has taken on an urgency for Colombia. There have been no new discoveries of significance since 1992 and exploration in all basins has slowed dramatically. In 2014 the proven oil reserves were 2.31 billion bbls [0.37 billion m³]. The current (2019) proven reserves are 1.78 billion bbls [0.28 billion m³], the equivalent to just 5.7 years of current consumption. There is only an 11 year supply of proven natural gas reserves. The national Hydrocarbon Agency (ANH) will try to stimulate additions to the reserves by tendering more than 20 E&P licences for at least 20 blocks, mainly in the Llanos and Magdalena basins (18), but also in the offshore (2). This licence round, announced in February 2019 is the first since 2014.

Resources in Nigeria.

Extensive oil sands occur in Nigeria along an East-West belt, stretching over an area of 120 km x 6 km, across Lagos, Ogun, Ondo and Edo states in south-western Nigeria (Fasasi et al., 2003). These oil sands which are mostly associated with the Cretaceous Afowo Formation are under exploited at present, but it is a potential source of future revenue for Nigeria. Bata et al.

(2015) also reported the occurrence of a Cretaceous oil sand (Bima Oil Sand) in the Nigerian sector of the Chad Basin. This Bima Oil Sand which extends into the Gongola Arm of the Upper Benue Trough is another potential source of revenue for Nigeria (Bata et al., 2017).

Resource Technology

As of December 2015, Alberta bitumen reserves under active development (mainly by surface mining, compare cumulative production in Tables 3 and 4) accounted for about 5% of the remaining established reserves of 165 billion barrels [26.3 billion m³] since commercial production began in 1967 (AER, 2016). Figure 17 shows the production in 2015 for each oil sands area for surface mining and in-situ recovery. In-situ production from all three oil sand areas in Alberta grew by 7.8%, compared with a 11.9% increase in production for mined bitumen. In-situ production overtook mined production for the first time in 2012, continued to exceed mined production in 2013 and is expected to continue going forward (AER, 2014).

Unlocking the huge potential of the remaining bitumen resources in Alberta will require enhancing other in-situ technologies. The most commonly used in-situ technologies are SAGD and CSS. SAGD and CSS utilize considerable energy and water to produce steam; also required are good permeability (both vertical and horizontal), relatively thick pay zones (> 10 m; 32.8 ft),

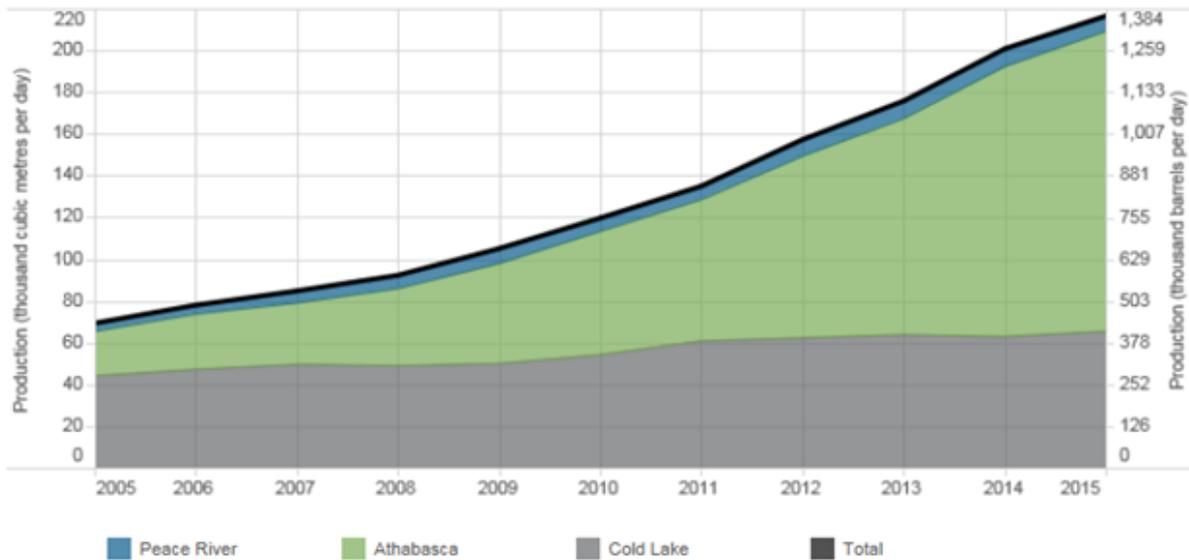


Figure 17: Production of bitumen in Alberta in 2015 by oil sands area (AER, 2016)

Generally, the cross-bedded sands of lower point bar depositional environments are characterized by vertical permeability ranging from 2 to 6 D. Associated inclined heterolithic stratification (IHS) from upper point bar deposits exhibits a 2 to 3 order of magnitude decrease in permeability, and siltstone in abandoned channel and point bar strata also exhibits a 2 to 3 order-of-magnitude decrease in permeability (Strobl et al., 1977; Strobl, 2007, Strobl, 2013). Depositional heterogeneities at vertical and lateral scales influence bitumen recovery from in-situ processes.

A comprehensive, two-volume edition book entitled: “Handbook on Theory and Practice of Bitumen Recovery from Athabasca Oil Sands” (Masliyah et al., 2011) focuses on the extraction of bitumen from oil sands mainly using surface mining methods, and also includes a chapter on in-situ processes. Volume I cover the basic scientific principles of bitumen recovery, froth treatment, diluents recovery, and tailings disposal; Volume II is devoted to industrial practices (editor, Jan Czarnecki, at jc7@ualberta.ca). Some of the focus of recent in-situ technology and advances includes:

- Integration of future oil sands technology with that of emerging oil shale co-production in the western United States.
- New developments concerning in-situ recovery and underground refining technologies for oil sands in western Canada include underground combustion and refining.
- Use of Cold Heavy Oil Production with Sand (CHOPS) as a specialized primary type of production where progressive cavity pumps assist in lifting bitumen and sand to the surface, and utilize this sand production to create wormholes in the strata to increase permeability in the reservoir. Liberatore et al. (2012) examined alternative seismic methods for in-situ monitoring of CHOPS heavy oil recovery. Seismic modeling indicates that signature of wormholes developed during CHOPS production can be detected.
- Search for alternative sources of energy for steam production, including the use of nuclear energy in conjunction with in-situ oil sands production plants (Peace River, Alberta).
- Further development and integration of technologies that include solvent co-injection, electro-magnetic heating, wedge (in-fill) wells, in-situ combustion, hot-solvent gravity drainage, Supercritical Partial Oxidation (SUPOX), and various hybrid developments, including CO2 flooding (Rudy Strobl, Nov. 14, written communication).

Critical technology needs include enhancing current methods and developing new more- environmentally-friendly methods of extraction, production, and upgrading of oil sands. Emphasis of surface mining operations is on reclamation of tailings and consolidated tailings, and on re-vegetation of open-pit mine sites. On March 13, 2015, the Government of Alberta released the Tailings Management Framework for Mineable Athabasca Oil Sands (TMF) for monitoring and managing long-term fluid tailings accumulation and reclamation in the Lower Athabasca Region.

On July 14, 2016, the Alberta Energy Regulator (AER) released Directive 085: Fluid Tailings Management for Oil Sands Mining Projects and rescinded and Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes. The new directive released sets out the new application and performance reporting for fluid tailings volume, and management plans, which is part of a phased approach to implementing the TMF. This is an evolution and ensures management of tailings accumulation and risk, and innovation.

Most of the operations extracting bitumen resources in-situ utilize thermal technologies, such as Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS). Because there is significant co-production of greenhouse gases with bitumen production and upgrading, critical technology needs involve research into: 1) alternative sources of heat for generation of steam (e.g., geothermal, nuclear, burning of slag); 2) methods to reduce the viscosity of the bitumen so it will flow to the well bore or through pipelines more easily (such as use of diluents, catalysts, microbial and nanotechnology); 3) underground in-situ extraction, refining, and upgrading; and 4) co-sequestration of greenhouse gases by injection into abandoned reservoirs or other deep geologic sites. There was in the past an excess supply of produced sulfur, above what was used in agricultural and other markets. Excess sulfur is stockpiled from bitumen and sour gas production and refining. Produced and stored sulfur is sold to various markets, the largest being China, mainly converted to sulfuric acid for use in manufacturing phosphate fertilizer (ERCB, 2012).

In California, where the principal thermal recovery methods currently are steam flood and CSS, an emphasis is being placed on increasing in-situ recovery factors through fully integrated reservoirs characterization and improvements in thermal recovery technologies to make them effective, as well as more energy-efficient and less polluting (Dusseault, 2013). In the supergiant Kern River field, Beeson and others (2014) have demonstrated the utility of 3D earth models in identifying by-passed oil in already heated reservoir sands.

In heavy oil fields in the San Joaquin Valley, California, and in southern Oman, there have been several successful projects demonstrating the feasibility of solar energy for thermal oil recovery (Agarwal and Kavscek, 2013; Dittrick, 2018). The solar power facilities generate steam directly that is injected into sandstone reservoirs to lower the viscosity of otherwise normal crude oils, thereby increasing oil rates and ultimate recoveries. Previously, steam was produced in large natural gas-fired boilers. The solar generated steam is delivered to the injection wells using the existing insulated distribution pipes. In Chevron's Coalinga field in central California, BrightSource Energy adapted its "power tower" technology to generate steam for thermal EOR extracting viscous crude oil from sandstone reservoirs. A field of large tracking mirrors reflect solar power onto a boiler mounted on a 327-foot-tower (BrightSource, 2018). This 29 Mw project, operated from 2011 to 2014, was a technical success, but it proved to be expensive to construct and operate on such a small scale.

The technology that appears more promising is one that involves banks of inexpensive parabolic mirrors enclosed in a protective glass structure (GlassPoint, 2018). The trough-shaped mirrors track the sun, focusing heat onto pipes at the parabolic focus through which water flows. Concentrated sunlight boils the water generating steam. Protecting the mirrors in a glasshouse lowers construction and maintenance costs, especially in the harsh environments common to oil fields. In McKittrick field, central California, the GlassPoint Solar facility was built in less than six weeks in 2011 and has been a technical and commercial success.

At the same time, a similar demonstration project was constructed to support TEOR in the Amal West field, southern Oman. The solar-heated water is used to improve oil rates by hot water flood. This operation is presently being expanded to a one gigawatt solar-thermal facility that also will generate electricity (Dittrick, 2018). At the South Belridge heavy oil field in central California, Aera Energy LLC has announced a \$250 million investment in a GlassPoint Energy solar thermal facility that will generate 12 million barrels of steam per year

to maintain TEOR of the aging field another 20 years (Dittrick, 2018). The GlassPoint Energy “enclosed trough” technology is modular, having the advantage of being easily scaled up or down to accommodate the demand for steam or hot water.

Although the capital expenditure for solar-thermal facilities is larger than that for construction of conventional natural gas-fired steam generators, operating costs are minimal and virtually no greenhouse gases are emitted (Kovscek, 2012; Sandler and others, 2014). The daily and seasonal variations in heat injection rates associated with solar-TEOR has been shown through reservoir modeling and demonstration projects to have minimal effect on oil recovery (Agarwal and Kovscek, 2013).

Electrical heating using electrodes placed in the reservoir and electromagnetic or radio frequency (RF) heating, which is comparable to embedding a microwave oven within an oil-impregnated reservoir, generally are considered too expensive for deployment in oil fields. Although they are successful and widely used technologies for small scale cleanup of surface spills of hydrocarbons into the shallow vadous zone, they have not been found to be economic for field-scale oil recovery.

There is one process under development by the Harris Corporation that shows promise for recovery of shallow heavy oil deposits. This process combines solvent injection with RF heating (Nugent and others, 2014; Rassenfoss, 2012), Enhanced Solvent Extraction Incorporating Electromagnetic Heating (ESEIEH, “easy”). The RF antenna, the solvent (propane) injector, and the producer are all placed together in a single unit that can be lowered in a conventional well bore to the appropriate depth in the reservoir. The antenna can be constructed to lengths equal to the thickness of the target zone. The device can be adapted for deployment in vertical and horizontal wells. A four-month field trial of the heating capabilities of the RF antenna, carried out at the North Steepbank oil sands mine in Alberta, was considered successful in heating the sand reservoir (Trautman and Macfarlane, 2014). A full pilot project

with solvent injection into a heavy oil or bitumen-impregnated reservoir sand remains to be done.

Environmental Issues

The primary environmental issues relate to the balance among greenhouse gas emissions and water/energy usage and the recovery, production and upgrading of bitumen. Specifically, the critical environmental focus is how to cleanly, efficiently, and safely extract, produce, and upgrade the bitumen. Goals include reducing (1) energy required to heat the water to steam and (2) CO₂ emissions. Current greenhouse gas emissions are decreasing and remaining emissions are compensated for by carbon trading and (or) CO₂ sequestration; and (3) improving the economics and processes of extraction, production and upgrading of the bitumen. Some of the areas of focus include:

- Land reclamation in surface mining
- Tailings and consolidated tailings disposal and reclamation
- Bitumen upgrading and co-production of other products from tailings (such as vanadium, nickel, and sulfur)
- In-situ recovery
- Underground refining.

The growing size or “footprint” of the surface mines and their tailings ponds is an environmental problem needing to be addressed. To this end, Syncrude Canada Limited is preparing to build a C\$1.9 billion centrifuge plant at its Mildred Lake mine, which when operational in 2015 will reduce the waste slurry from the separators to a less-hazardous, near-dry sediment requiring far less surface storage (World Oil, February 2014).

Oil sand developers in Canada largely have been successful in reaching the goal of reducing CO₂ emissions by 45% per barrel, as compared to 1990 levels. Also in Canada, developers are legislated to restore oil sand mining sites to at least the equivalent of their

previous biological productivity. For example, at development sites near Fort McMurray, Alberta, the First Nation aboriginal community, as part of the Athabasca Tribal Council, and industry have worked together to reclaim disturbed land (Boucher, 2012) and industry has reclaimed much of the previous tailings pond areas into grasslands that are now supporting a modest bison herd (about 500-700 head).

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