AAPG Energy Minerals Division

Oil Sands Committee

Biannual Commodity Report - November, 2014

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Contents

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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 m^3], 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. Virtually all of 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 167 billion bbls [26.6 billion m^3]. To date, just 5.4% 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, 2014). 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 m^3] of which 310 billion barrels [49.3 billion m^3] 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 m^3], are located in the central and southern parts of the state. As of 2012, the proved reserves were 2,976 million bbls [473.2 million m^3], 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 m^3]. 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 m^3) and they hold promise for commercially-successful development. 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 10º to 22.3º. 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 80ºC, 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 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 naphta. Bitumen normally is recovered by surface mining and processing with hot water or solvents.

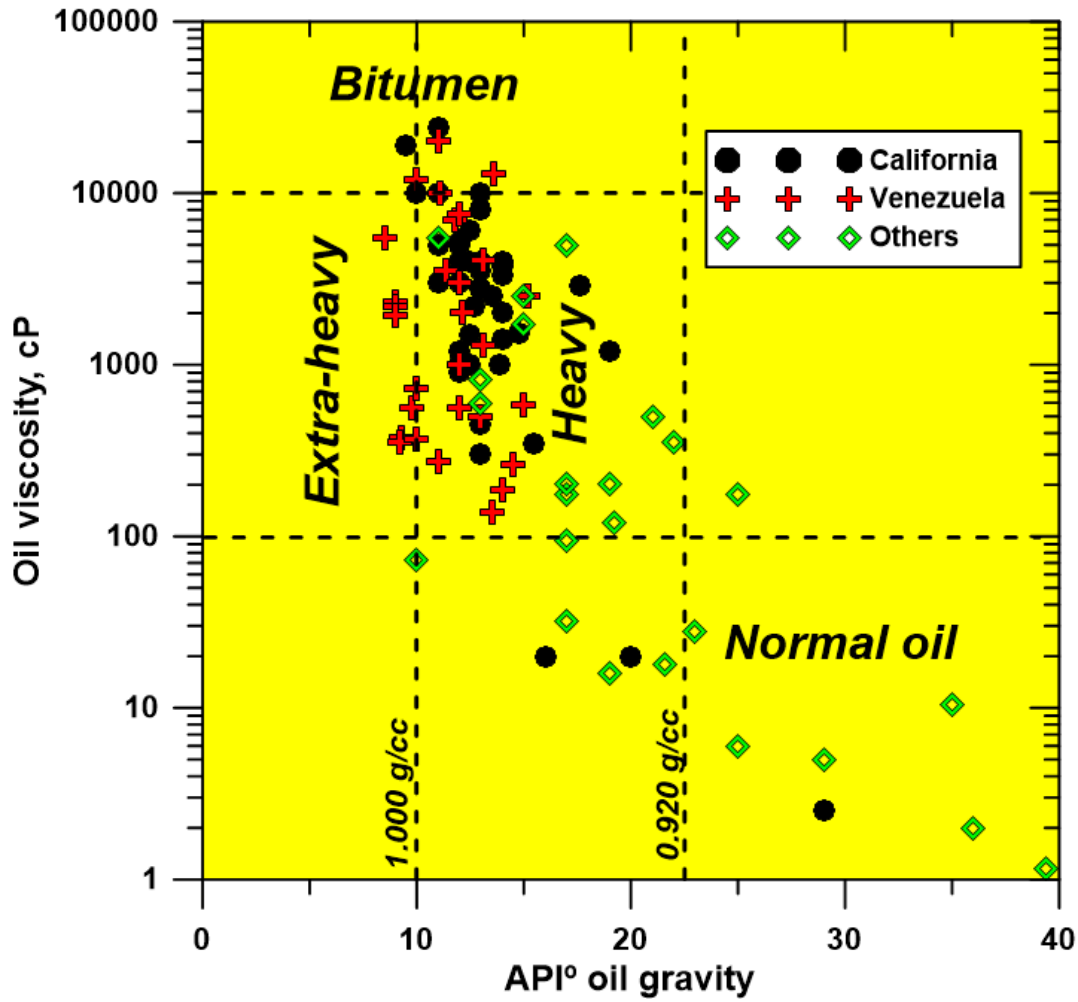


Figure 1: Cross-plot of oil density versus viscosity indicating the fields represented by bitumen, heavy and extra-heavy oils. Actual properties are plotted for a variety of oils from producing oil sand accumulations (data from Oil & Gas Journal, April 2, 2012).

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) note 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 m^3], 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 m^3], 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 m^3]. The Oronoco Heavy Oil Belt is a single extensive deposit containing 1.2 trillion barrels [190 billion m^3] 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.

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	

Globally there is just over one trillion barrels [159.0 billion m^3] of technically-recoverable unconventional oils (Table 1), 434.3 billion barrels [69.1 billion m^3] of heavy oil, including extra-heavy crude, and 650.7 billion barrels [103.5 billion m^3] 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.

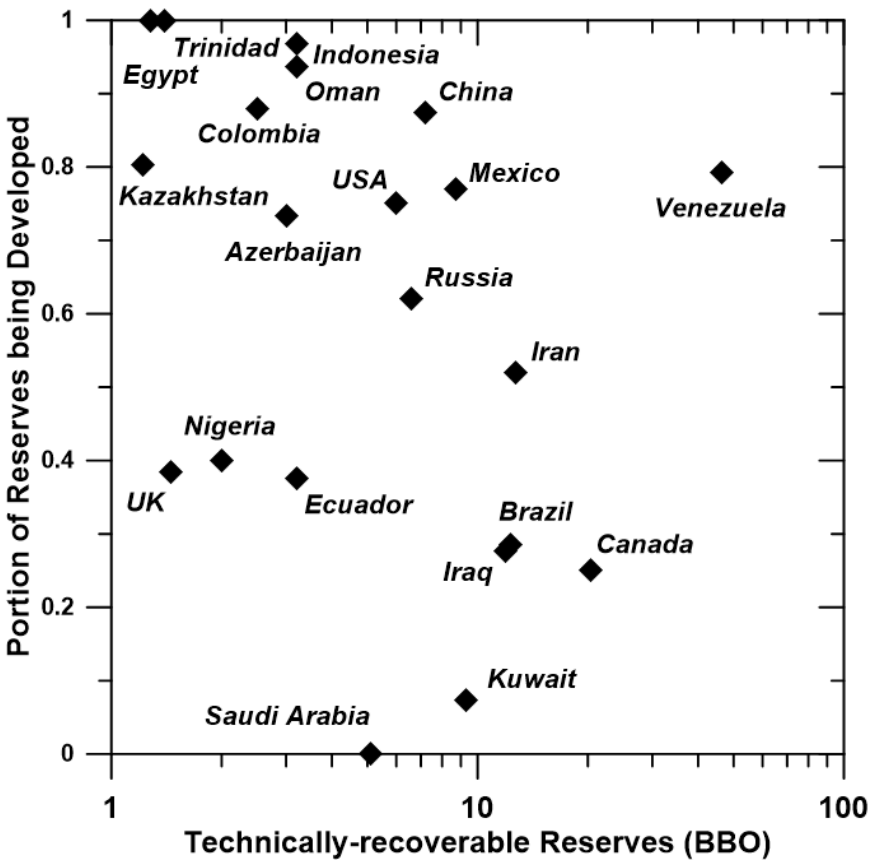


Figure 2: By country, the estimated technically-recoverable heavy and extra-heavy reserves vs. the portion of the reserves in production or development. Sources: Meyer and Attanasi (2003), and other.

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 of 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 2013 (AER, 2014).

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 844	11 357	71.5	9 504	337	94	103
Initial established reserves	28 092	177	2 863	18.0	5 384	191	35	38
Cumulative production	1 294	8.1	2 617	16.5	4 377	155	1.49	1.64
Remaining established reserves	**26 798**	**169**	**246**	**1.5**	**1 007[b]**	**35.7[b]**	**33**	**37**
Annual production	101	0.637	28.4	0.179	111	3.9	0.030[d]	0.033[d]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[c]	223[c]	620	683

[a] Expressed as "as is" gas, except for annual production, which is at 37.4 megajoules per cubic metre; includes coalbed methane natural gas.
[b] Measured at field gate (or 34.7 trillion cubic feet downstream of straddle plant).
[c] Does not include unconventional natural gas.
[d] Annual production is marketable.

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 m^3] (AER 2014, p. 3). Estimated remaining established reserves of in-situ and mineable crude bitumen is 167 billion BBLs [26.6 billion m^3]; only 5.4% of the initial established crude bitumen has been produced since commercial production began in 1967 (Table 2) (AER 2014, p. 9). Cumulative bitumen production for Alberta in 2013 was 9.6 billion bbls [1,527 million m^3]. The bitumen that was

produced by surface mining was upgraded; *in-situ* bitumen production was marketed as non-upgraded crude bitumen (ERCB 2012). Alberta bitumen production has more than doubled in the last decade, and is expected to increase to greater than 3 million bbls per day [> 0.48 million m^3] over the next decade. 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.

Crude bitumen is 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).

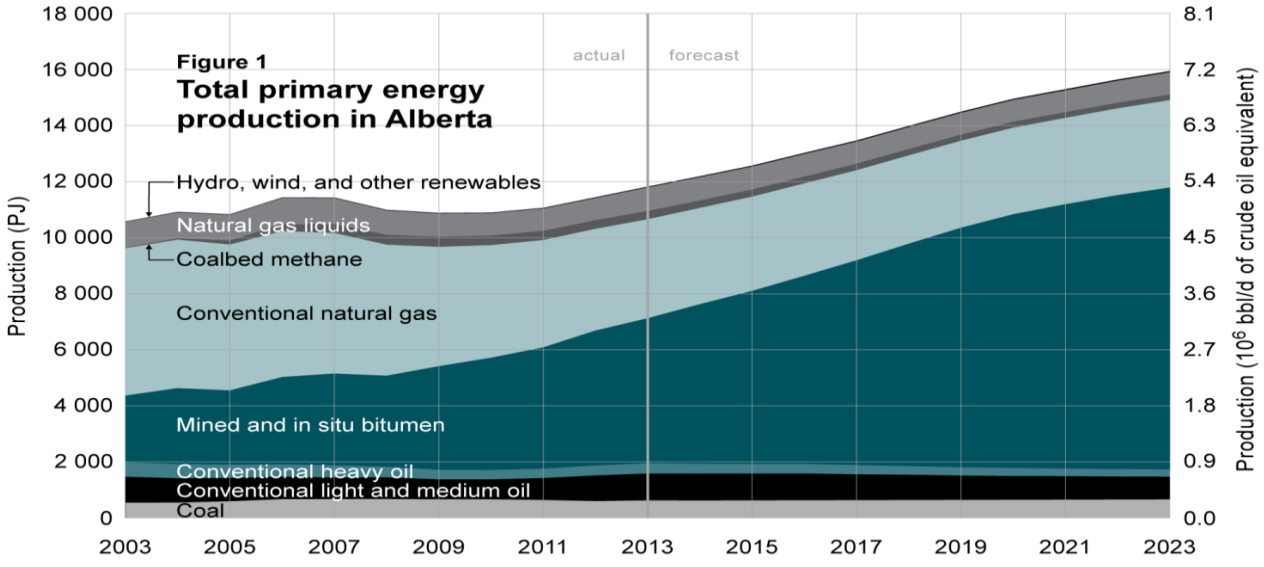


Figure 3: Total primary energy production in Alberta (AER, 2014).

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, 2014).

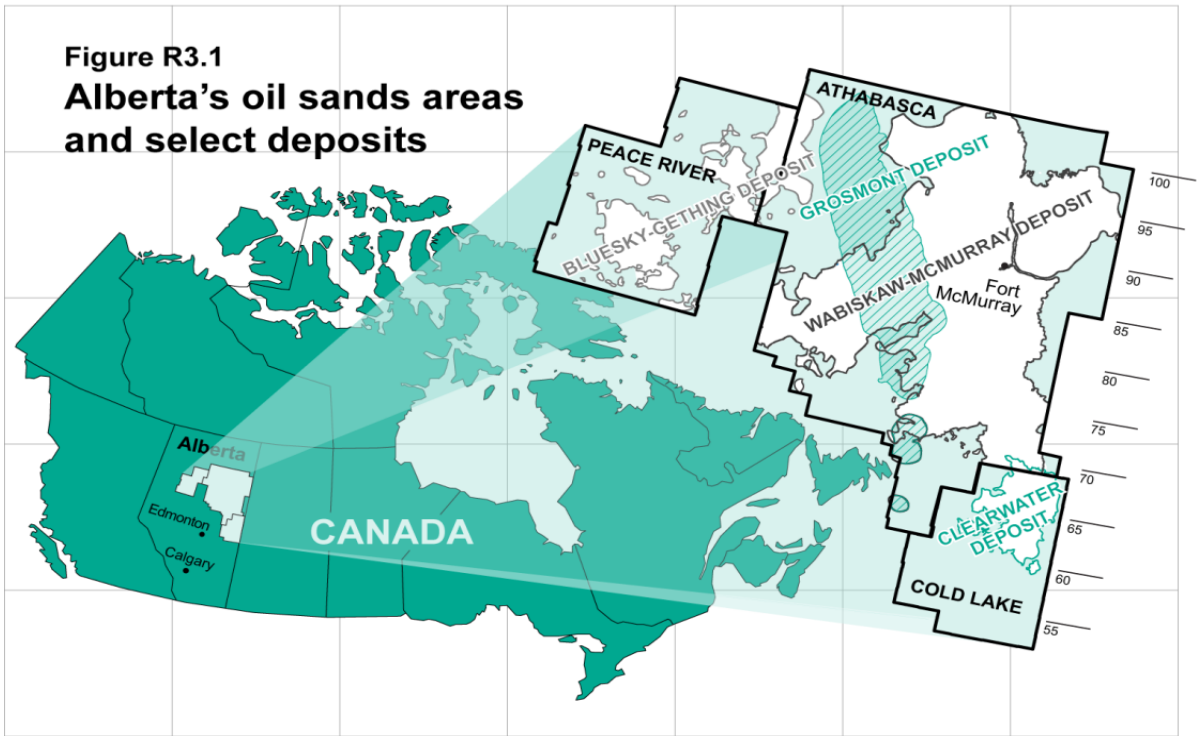


Figure 4: Alberta's Peace River, Athabasca and Cold Lake oil sands areas, highlighting the main deposits (AER, 2014).

A number of 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 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, 2013 (AER, 2014).

Table R3.3 Initial in-place volumes of crude bitumen as of December 31, 2013

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	9.0	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	8.0	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	**21 560**					
Total	**293 125**					

[a] ha = hectare.

Alberta is Canada's largest producer of marketable gas (69% in 2013) and of crude oil and equivalent production, 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 northwestern Saskatchewan, as yet these have not been brought to

commercial production. In Alberta, of the 2013 primary energy production, bitumen accounted for 80% of the total crude oil and raw bitumen production, with production increasing by 5% in surface mining areas, and by 12% from in-situ areas from the previous year. During this same time crude oil production increased by 5%, total marketable natural gas declined by 3%, total natural gas liquids production increased by 6%, and coal production declined by 3%. 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, 2013 (AER, 2014).

Table R3.4 Mineable crude bitumen reserves in areas under active development as of December 31, 2013

Development	Project area[a] (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	26	511
Fort Hills	17 864	556	382	0	382
Imperial Kearl	19 674	1 324	872	1.4	871
Shell Muskeg River	13 581	672	419	86	333
Shell Jackpine	7 958	361	222	18	204
Suncor	19 155	990	687	331	356
Syncrude	44 037	2 071	1 306	468	838
Total Joslyn North	8 604	274	139	0	139
Total	**159 355**	**7 100**	**4 564**	**930**	**3 634**

[a] The project areas correspond to the areas defined in the project approval.

Starting in 2010, the downward trend of total crude oil production in Alberta was reversed, with light-medium crude oil production increasing due to technological advances, such as horizontal, multi-stage drilling with hydraulic fracturing and/or acidization. This resulted in an increase of total crude oil production by 5% in 2013 (AER, 2014). Along with this technologically-driven increase in 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 [67.3 billion $m^{3]}$ of crude oil; 3,424 trillion cubic ft [97 trillion m^3]of natural gas; and 58.6 billion

BBLs [9.3 billion m^3] 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; but, how these relate to the total energy resource endowment of the province is not known until it is addressed if they are technologically or economically feasible to produce at large scales with existing or near-future resource technologies.

Table 5: In situ crude bitumen reserves in Alberta for areas under active development as of December 31, 2013 (AER, 2014).

Table R3.5 In situ crude bitumen reserves in areas under active development as of December 31, 2013[a]

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	11.8	13.7
Primary recovery schemes	375.0	10	37.5	17.6	19.9
Subtotal[c]	**438.7**		**63.0**	**29.4**	**33.6**
Athabasca Oil Sands Area					
Thermal commercial projects	391.8	50	195.9	149.2	46.7
Primary recovery schemes	1 026.2	5	51.3	25.4	25.9
Enhanced recovery schemes[d]	(289.0)[e]	10	28.9	26.1	2.8
Subtotal[c]	**1 418.0**		**276.1**	**200.7**	**75.4**
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[f]	1 212.8	25	303.2	256.0	47.2
Thermal commercial (SAGD)[g]	33.8	50	16.9	4.6	12.3
Primary recovery schemes	6 257.5	5	312.9	106.0	206.9
Subtotal[c]	**7 504.1**		**633.0**	**366.6**	**266.4**
Total[c]	**9 360.8**		**972.1**	**596.7**	**375.4**

[a] Thermal reserves are reported only for lands on which thermal recovery is approved and drilling development has occurred.

[b] Includes amendments to production reports.

[c] Any discrepancies are due to rounding.

[d] Schemes currently on polymer injection or waterflooding in the Brintnell-Pelican area. Previous primary production is included under primary recovery schemes.

[e] The in-place number is that part of the initial volume available for primary recovery schemes that will see incremental production due to polymer injection or waterflooding.

[f] Cyclic steam stimulation projects.

[g] Steam-assisted gravity drainage projects.

Investment in expansion of existing mines and start up of new mine and SAGD projects is continuing at pace. Four new projects have been announced for 2014 (World Oil, February 2014) that involve a total C$43.4 billion in capital investment and that will add a projected 742,000 bopd in new production capacity by 2015, or shortly thereafter.

In situ oil sands production continues to be the largest growth area. 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, largely due to improvements in multi-stage hydraulic fracturing from horizontal wells that are targeting these previously uneconomic, but potentially large, resources. Alberta Energy Regulator predicts that *in situ* production will overtake that from surface mining in 2015.

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 m^3] of which 310 billion barrels [49.3 billion m^3] is considered technically-recoverable (Villarroel et al., 2013). The Faja is 55,314 km^2 [21,357 mi^2] 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, were Neogene-age sediments overlie the crystalline basement of the Guayana Shield. To the north, in the foothills of the Serrania del Interior, there are numerous conventional oil fields, the majority in structural traps within the thrust belt.

Extra-heavy oil having an average API gravity of 8.5º is reservoired 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 esturine complexes on the south rim of the foreland basin (Martinius et al., 2013). Upper Miocene marine shales of the Freites 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.

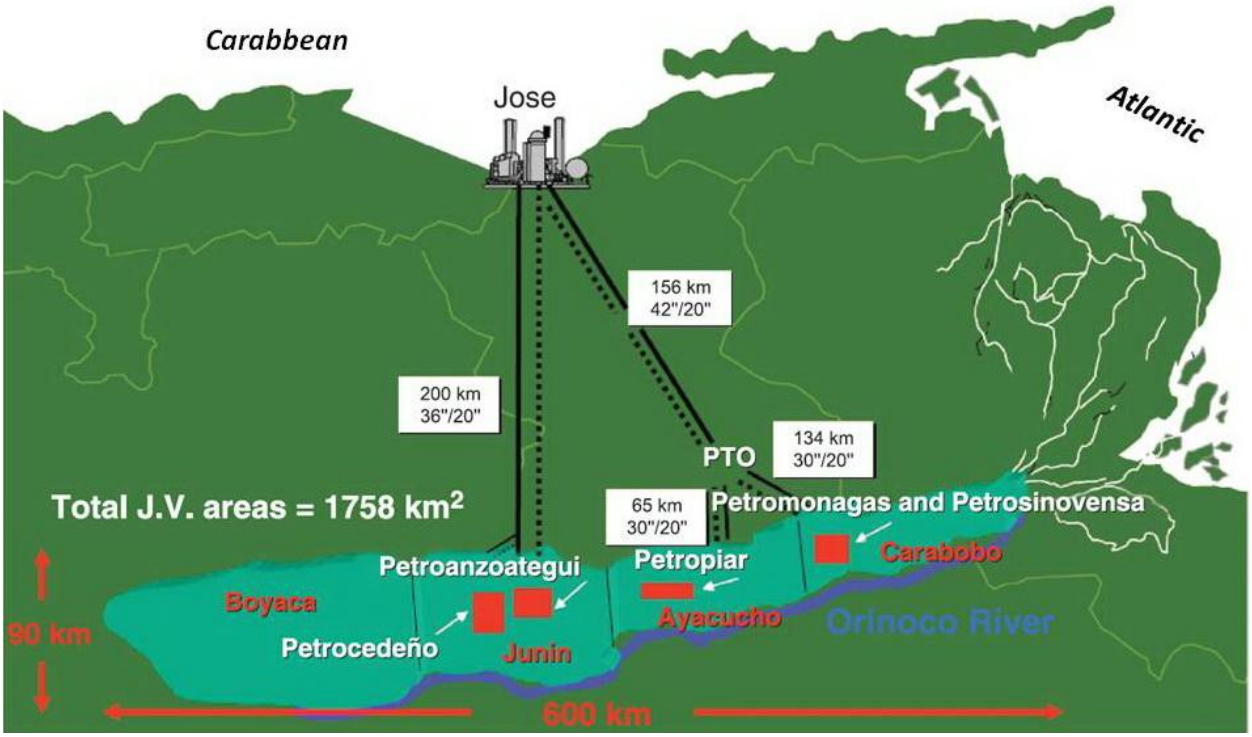
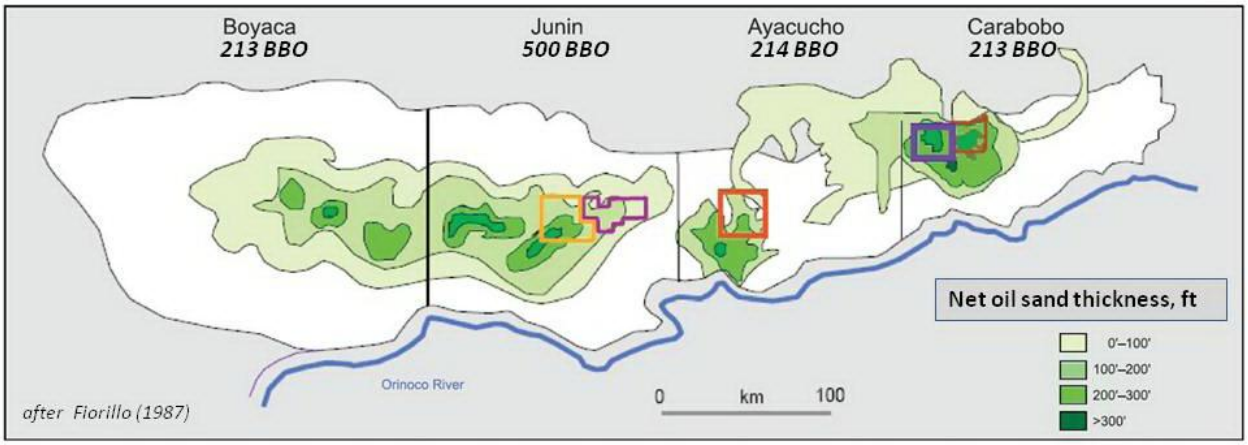


Figure 5: The Faja Petrolifera del Orinoco in eastern Venezuela (light green) showing the four production units (red text), four current production projects (white text), and pipelines connecting the projects to the Jose upgrading facility on the coast. (Villarroel et al., 2013).

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 (PDVSA), 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 in Petromonagas, Chevron in Petropiar, and Total with Statoil in Petrocedeño. In what is referred to as the "first stage" of development, the projects are now producing collectively about 640,000 bopd using cold production methods (Villarroel et al., 2013). These methods are 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 50ºC, help overcome its viscosity, which is on the order of thousands of centipoise (Fig. 6). The oil is extracted from horizontal wells as long as 1.5 km 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).



• Depth range	1600–4000 ft	•Initial res. pres	800–1000 psi
• Temperature range	115–130°F	•In-situ viscosity	1000–5000 cp
• Gross thickness	200'–500'	•Porosity range	28–34%
• Net thickness	50'–300'	•Permeability	1–20 + d
• API gravity	7.5–9.5	•Water Saturation	8–30%
• Initial gas-oil ratio	60–70 scf/Bo	•Rec. factor (cold)	9–12.5%

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 50º API naphtha diluents is commonly injected into the horizontal wells to further decrease viscosity. The recovery factor for cold production is about 10%. The naphta-charged oil is transported about 200 km to the Jose upgrading facility on the Carabbean coast (Figs. 5 and 7). Here the naphta 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 32º API syncrude that is exported as "Zuata Sweet". As the projects prepare for the next phase of development, a variety of established EOR technologies are being tested in pilots, including thermal methods (SAGD, CSS) and reservoir flooding using polymer-viscosified water.

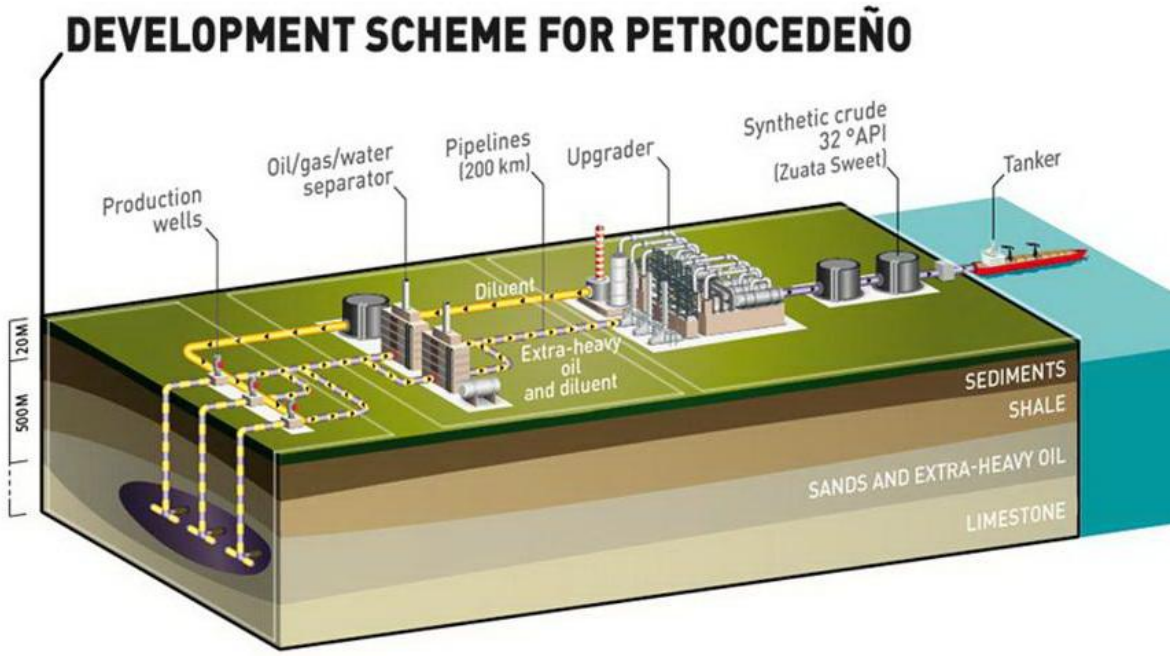


Figure 7: Process for recovery, transport and upgrading of extra-heavy oil from the Faja petrolifera del Orinoco at the Petrocedeño project. Source: Total

In November 2005 PDVSA began the "Magna Reserva" study to determine and certify the remaining oil reserves in each of 28 blocks delineated in the four operating regions (Fig. 5). This evaluation is ongoing, but early reports point to the possibility of as much as 100 billion barrels being added to proven reserves. To increase the rate of extra-heavy oil production by expanding operating areas, PDVSA has entered into joint-venture partnerships with various national or quasi-national oil companies: Gasprom and Lukoil (Russia), CNPC (China), Petrobras (Brazil), Rapsol (Spain), ENI (Italy), ONGC (India), PetroPars (Iran), and PetroVietnam. However, at present more heavy crude is being produced than can be processed in the Jose upgraders, which are more than a decade old. The lack of investment funds have prevented PDVSA from adequately maintaining and expanding the pipelines and upgrading facility.

Resources and Production – United States

The goal of the United States to move towards greater energy independence could include production from existing U.S. oil sands deposits using surface mining or *in-situ* extraction. Current U.S. bitumen production is mainly for local use on roads and similar surfaces. This is due mainly to the different character and scale of the deposits compared to Canada and

Venezuela, but in part it is because, outside of California and Alaska, the U.S. has not developed the infrastructure required to produce oil sands as a fuel source. Schenk et al. (2006) compiled total measured, plus speculative, estimates of bitumen in-place of about 54 billion barrels [8.6 billion m^3] for 29 major oil sand accumulations in Alabama, Alaska, California, Kentucky, New Mexico, Oklahoma, Texas, Utah, and Wyoming (Table 6). However, these older estimates of total oil sand resources provide only limited guidance for commercial, environmentally-responsible development of the oil sand deposits. Additionally, the estimates do not factor in commercially-viable heavy oil resources. The resources in each of the states have distinct characteristics that influence current and future exploitation.

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

State	No. deposits	°API range	Measured, MMB	Total, MMB
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 heavy oil reserves in the world, second only to Venezuela (Hein 2013). California's oil fields, of which 52 have reserves greater than 100 million barrels [15.9 million m^3], are located in the central and southern parts of the state (Fig. 8). As of 2011, the proved reserves were 3,009 million barrels [478.4 million m^3], nearly 65 % of which were in the southern San Joaquin basin (U.S. Energy Information Administration, 2013). 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).

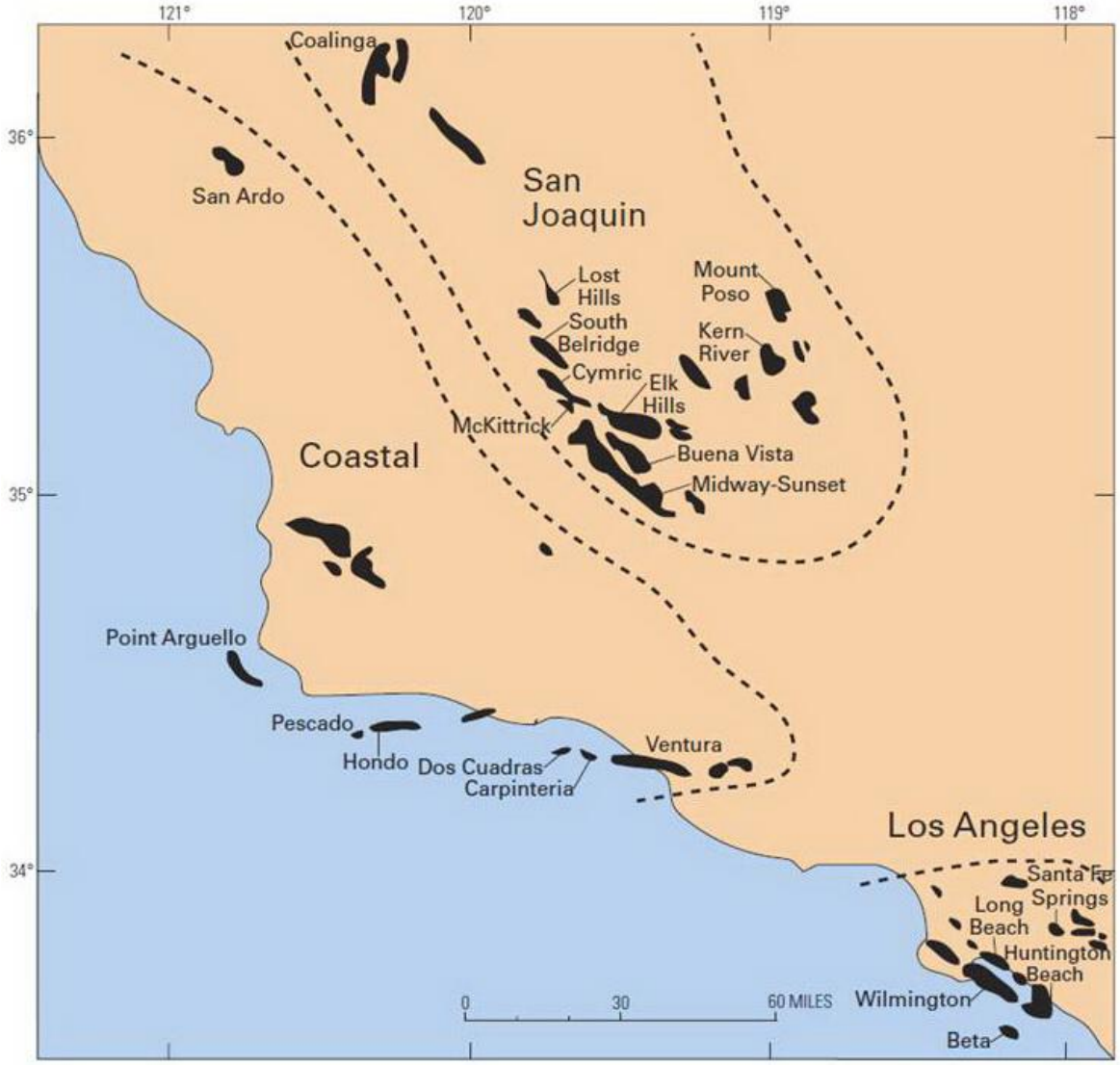


Figure 8: Principal oil fields of California (Tennyson, 2005).

Nearly all of the oil is sourced from organic-rich intervals within the thick Miocene-age Monterey 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, or other thermal recovery methods. Thermally-produced oil comes mainly from fields in the San Joaquin basin (Fig. 8, Table 7). In general, the reservoirs are poorly- or un-consolidated sandstones intercalated within or overlying the Monterey Formation. However, the South Belridge field produces from diagenetically-altered, highly fractured diatomite. The Coalinga

field produces from sandstones in the Temblor Formation underlying the Monterey Formation; the source rock is the Middle Eocene Kreyenhagen Formation, which is unconformably overlain by the Temblor Formation.

The larger thermal oil fields (Table 7) have experienced oil production declines in the five-year period 2008-2012 on the order of 11.2% (Kern River) to 24.4% (Cymric). Smaller fields have had little or no declines. The young (1952) San Ardo field immediately west of the San Joaquin basin (Fig. 7) has actually doubled production in this period. A small portion of the supergiant Wilmington field in the Los Angeles basin was produced by steam flood using two pairs of parallel horizontal injector and producer wells. The project was stopped because of surface subsidence problems. With the exception of this successful pilot, air quality issues associated with steam generation have limited the expansion of thermal recovery methods in the Los Angeles basin. The California heavy oils are exceptional in that they sell with little or no discount compared to WTC. Since 2011, the price of benchmark Midway-Sunset 13º API crude has remained near $100/barrel (EIA, Domestic Crude Oil First Purchase Price, 3/3/2014).

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 m^3] (Kuuskraa et al. 1986).
Five of the six largest tar sand deposits are in the onshore Santa Maria basin (central Coastal zone in Fig. 7), covering a total area of over 60 square miles [155 km^2]. 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 tar sand deposits and surface seeps are scattered throughout the oil-producing areas of California normally overlying or up-dip from known oil fields.

During the past decade, oil production in California has steadily declined (U.S. Energy Information Administration, 2014). The rate of decline is being slowed, and may be reversed, through the application of fully integrated reservoir characterization and improved recovery technologies that are resulting in higher recovery factors (Dusseault 2013), up to 70-80% in some fields.

Table 7: California oil fields produced by thermal recovery methods. The fields are arranged by 2013 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.

Field	2013 Oil, MMBO	2013 GOR	ºAPI	Oil viscosity, cp	Oil temp., ºF
Midway-Sunset	28.820	172	11 to 14	1000 - 10000	85 - 130
Kern River	25.739	2	13	4000	90
South Belridge	23.531	372	13 to 14	1500 - 4000	95
Cymric	14.459	228	11 to 14	1000 - 2000	95 - 105
Lost Hills	10.763	839	12.7 to 13.9	1500 - 4000	75 - 82
San Ardo	7.232	155	11 to 12	1000 - 3000	125 - 130
Coalinga	5.524	41	9 to 13	2000 - 28000	84 - 105
Poso Creek	2.798	4	13	2800	110
Kern Front	3.447	0	13 to 14.8	1500	80 - 95
McKittrick	2.513	824	10 to 12	13000 - 51000	83
Placerita	0.942	0	13	10000	90
Edison	0.790	6	14	2000	90
North Antelope Hills	0.243	83	14	1400	80

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

Alaska's heavy oil and bitumen deposits on the North Slope are very large (24 to 33 billion barrels, or 3.8 to 5.2 billion m^3) and they hold promise for 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 a 1,800 ft [549 m] thick permafrost (Fig. 8). These are the Ugnu Sands (8-12 ºAPI) at depths of 2,000-5,000 ft [610-1,524 m] and the West Sak Formation (16-22 ºAPI) at 2,300-5,500 ft [701-1,676 m]. The size of the deposits is well defined with the numerous wells tapping the underlying conventional oil fields. For the Lower Ugnu Sands and West Sak Formation the resources are 12-18 billion bbls [1.9-2.9 billion m^3] and 12 billion bbls [1.9 billion m^3], respectively. 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).

Production of viscous (50-5000 cp) oil from the West Sak pools began in the early 1990s, reaching the current level of 4,000-5,000 bbls [636-795 m^3] of oil per day in 2004. To date, over 100 million bbls [15.9 million m^3] have been recovered from the formation using a combination of vertical wells and water flood. The heavy oil in the Ugnu Sands presents a much greater

technical challenge due to its higher viscosity (5,000 to over 20,000 cp) of and the friability of the reservoir sand. At its Milne Point S-Pad Pilot, BP Alaska is testing two different recovery strategies in the Ugnu Sands. One pilot is pumping 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 m^3] 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) with results not yet announced.

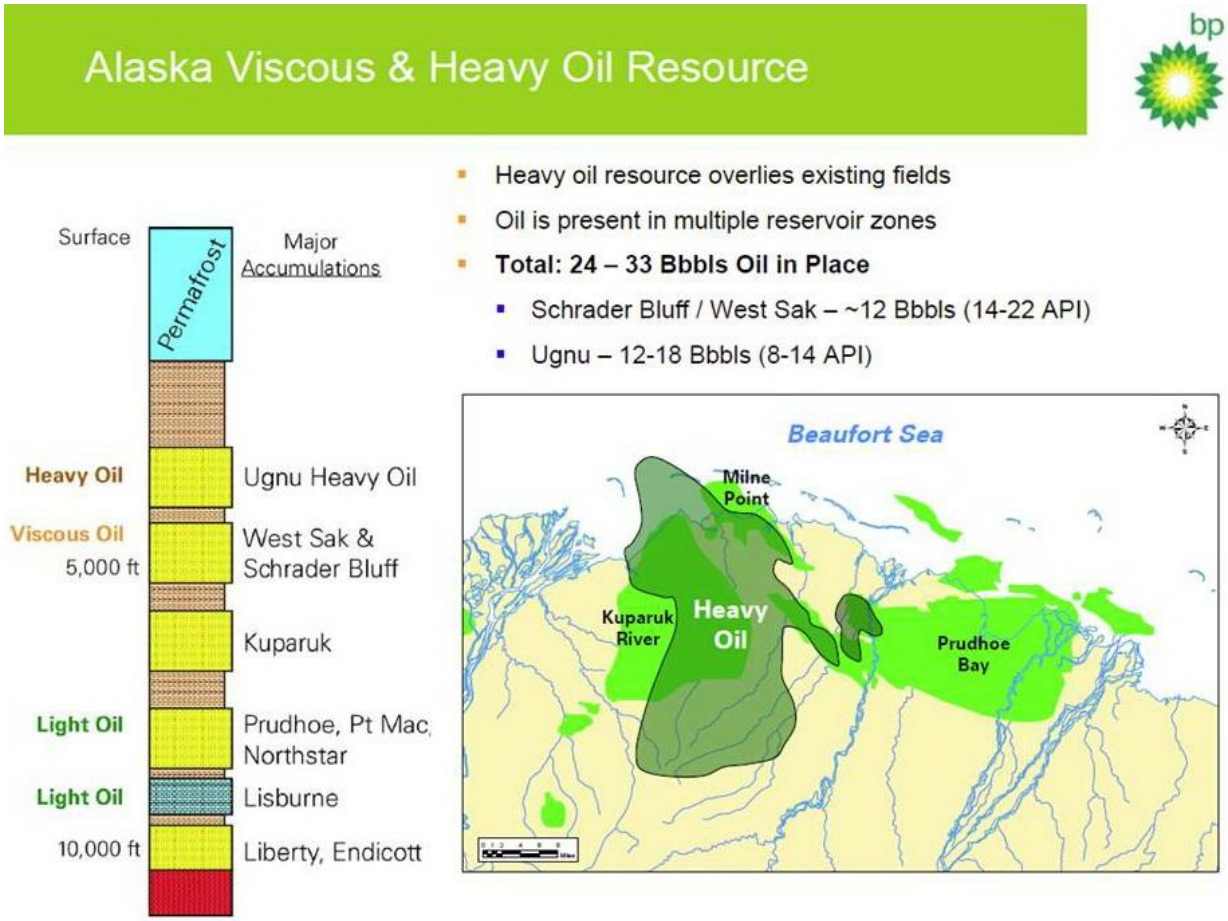


Figure 9: Location of shallow, heavy oil accumulations on the North Slope of Alaska. Heavy oil deposits overlie the Kuparuk field and parts of the Prudhoe and Milne Point fields and occur in sands within the Ugnu, West Sak and Schrader Bluff formations. Source: Gordon Pospisil, BP Exploration (Alaska) Inc., January 6, 2011.

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 underlying vast portions of the gently north-dipping East and West Tavaputs Plateaus. This highland surface above the Book and Roan Cliffs

on either side of the Green River (Desolation) Canyon is supported by sandstone and limestones of the Green River Formation (lower Eocene). Here the resource-in-place is at least 10 billion barrels [1.6 billion m^3], nearly all of it reservoired in fluvial-deltaic sandstone bodies within the lower member of the Green River Formation. On the northern margin of the Uinta Basin, 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 m^3], 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 17.3º range, are only weakly biodegraded in the subsurface, and are sulfur-poor (0.19 to 0.76 wt%). 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 extensive and large, 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 m^3] per acre; it is only slightly higher for the entire Sunnyside accumulation west of the Green River. However, a small portion of the Sunnyside deposit having unusually thick reservoir sands within an monoclinal trap has a measured average richness of 638.3 thousand bbls [101.2 thousand m^3] per acre. The two principal deposits on the north flank of the basin, Asphalt Ridge and Whiterocks, are relatively small, but they contain high concentrations of heavy oil (Table 8).

Table 8: Estimated resource size and richness of the principal heavy oil-bitumen deposits in Utah.

Bitumen-heavy oil deposit	Resource estimate MMB	Areal extent square miles	Richness, average MB/acre	º API gravity	Reservoir unit
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
Sunnyside 'core'	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)
TST 'core'	1,300 - 2,460	30 - 52	67.7 - 73.9		White Rim Ss. (L. Perm)

Data from Schamel (2013a) and Schamel (2013b)

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. With the exception of the Tar Sand Triangle and Circle Cliffs deposits, most accumulations are small and/or very lean. Normally, the oils are heavier than 10º 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 sulfur 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 reservoired in a several-hundred-foot-thick eolian sandstone of Lower Permian age. Across an area of 84 square miles [217 km^2], the thickness of bitumen-impregnated sandstone exceeds 100 ft (30 m). The API gravity of the bitumen is less than 8º at the surface and just over 10º 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 m^3] in a deposit just less than 200 square miles [518 km^2] in size. However, at a resource threshold equal to or greater than 60 thousand bbls [9.5 thousand m^3] per acre, the resource ranges between 1.30 to 2.46 billion bbls [0.21 to 0.39 billion m^3] in an area of 30 to 52 square miles [78 to 135 km^2], respectively. Approximately half of the deposit is in the Glen Canyon National Recreation Area, where exploitation could be severely limited. The Circle Cliffs deposit, with an estimated 1.73 billion bbls [0.27 billion m^3], 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 ºAPI heavy oil produced by steam flood in the southern San Joaquin Basin, California. So far, the Utah ‘tar sands’ have resisted attempts at commercial development. However, starting in 2015 a U.S. Oil Sands pilot at Seep Ridge in the P.R. Springs deposit is designed to produce liquids from surface-mined oil sand using a closed-loop solvent extraction process.

On March 22, 2013, BLM Principal Deputy Director Neil Kornze signed the Record of Decision (ROD) for the Oil Shale and Tar Sands Programmatic EIS, finalizing the Proposed Land Use Plan Amendments for Allocation of Oil Shale and Tar Sands Resources on Lands Administered by the BLM in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement (OSTS PEIS) that was released in November 2012. The ROD opens 130,000 Federal acres (52,609 ha) of designated tar sands in Utah for leasing and development. Federal lands in adjacent Wyoming and Colorado, also covered by this ROD for oil shale leasing, hold no oil (tar) sand deposits. Further information is available at: http://ostseis.anl.gov/documents/.

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 m^3] in an area of 256 square miles [663 km^2] (Kuuskraa et al., 1987). The bitumen is highly viscous and sulfur-rich (10%) with an API gravity of -2º to 10ºAPI. 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 in excess of 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^2] 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 (Wilson, 1987) speculated that there could be 7.5 billion bbls [1.2 billion m^2] 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] and an average richness of only 4.3 thousand bbls [0.68 thousand m^3] per acre.

The heavy oil deposits of western Kentucky form an arcuate belt along the southeast margin of the Illinois Basin. The heavy oil is hosted in fluvial sandstones, some filling paleovalleys, of Late Mississippian-Early Pennsylvanian age (May, 2013). The area is crossed by the east-west trending Rough Creek and Pennyrile 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 (2.1 billion bbls; or 3.3 billion m^3) extends in a zone 5 to 10 miles [8 to 16 km] wide and 50 miles [80 km] long situated north of Bowling Green. This deposit, hosted in the Clifty Sandstone, generally is lean with thickness of the oil-impregnated sands from a few to just over 50 feet (Noger, 1999). The API gravity of the heavy oil is 10º. Other deposits are considerably smaller and have API gravities of 10º to 17º. Kentucky's oil sand total oil-in-place is estimated to be 3.42 billion bbls [0.54 billion m^3] (Noger, 1999). At present, there is no commercial exploitation of the deposits for liquid hydrocarbons, although at least one operator has announced plans to do so.

Oil sand accumulations in east-central New Mexico have total in-place measured and speculative resources of 130 million bbls [20.6 million m^3] and 190 to 220 million bbls [30.2 to 35 million m^3], respectively (IOCC, 1983; Schenk et al., 2006). The oil accumulations are within Triassic Santa Rosa Sandstone at depths of less than 2,000 ft [3,219 m]. (Broadhead, 1984). Speculative in-place oil sand resources total 800 million bbls [127.2 million m^3] 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 m^3] measured and 70 million bbls [11.1 million m^3] 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).

Resource Technology

As of December, 2013, Alberta bitumen reserves under active development (mainly by surface mining, compare cumulative production in Tables 3 and 4) accounted for only 5.4% of the remaining established reserves of 167 billion barrels [2.66 billion m^3] since commercial production began in 1967 (Table 2) (AER, 2014). Figure 9 shows the production in 2013 for each oil sands area for surface mining and in-situ recovery. In 2013, in-situ production from all three oil sand areas in Alberta grew by 11.7%, compared with a 5.0% 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).

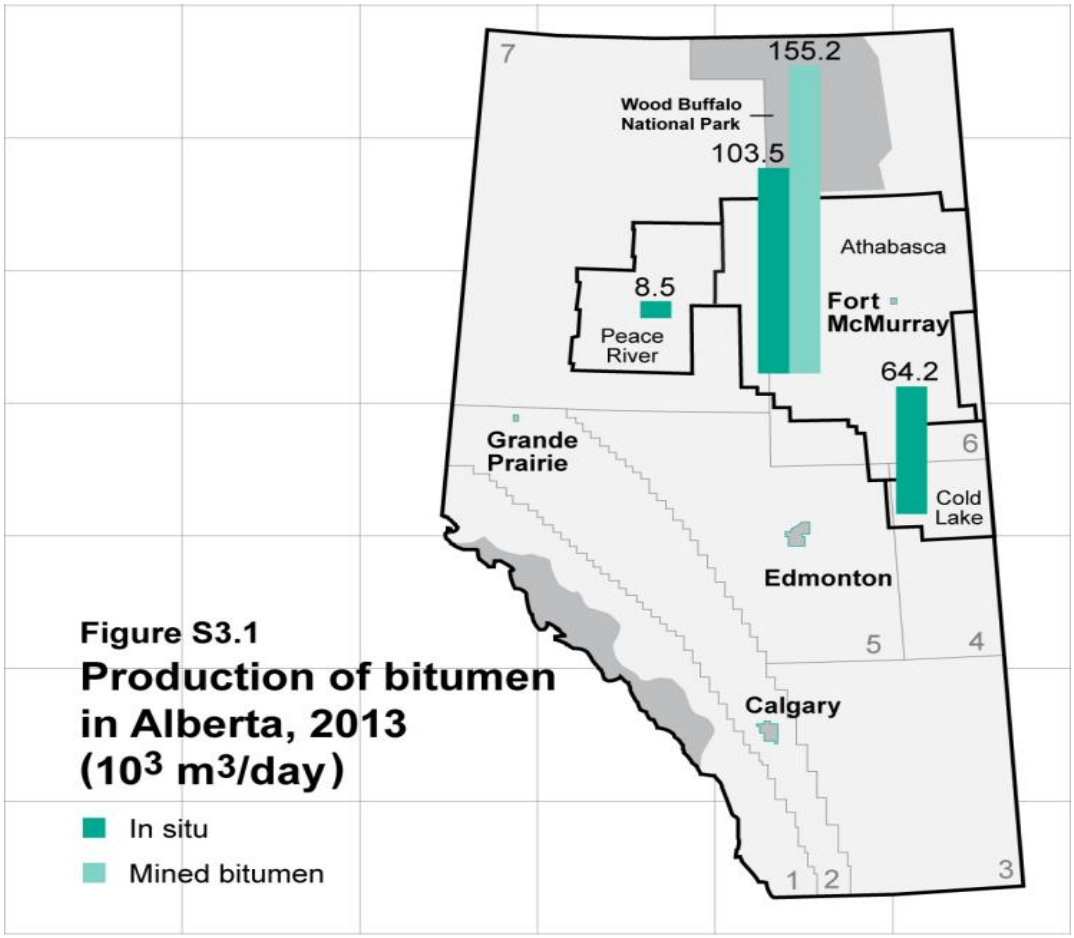


Figure 9: Production of bitumen in Alberta in 2013 (AER, 2014)

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), and an absence of barriers (cemented zones, thick laterally-continuous shales) and the lack of significant top/gas, top/lean or bottom water thief zones. 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 covers 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 CO_2 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. In early February 2009, the Energy Resources Conservation Board (ERCB) issued Directive 074 that outlines new cleanup rules and harsh penalties for non-compliance regarding tailings ponds regulations for the oil sands areas. This directive resulted from the ERCB acknowledgment that, although operators invested heavily in improved tailings reduction strategies, targets set out in the original development applications have not been met. Firm performance criteria are defined for reclaiming the tailings ponds, with performance inspections, and subsequent penalties due to neglect, omission, or commission.

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). New sources of heat for steam generation are being tested. For instance, in the San Joaquin Basin two solar steam heavy oil recovery demonstration projects have been operating since 2011. One is a Chevron-Bright Source Energy partnership at the Coalinga field (Fig. 7). The other is a Berry Petroleum Co.-GlassPoint Solar collaboration, the 21Z Project, in a portion of the McKittrick field.

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) CO_2 emissions. Current greenhouse gas emissions are decreasing and remaining emissions are compensated for by carbon trading and (or) CO_2 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 CO_2 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).

Oil Sands Publications and Technical Sessions

AAPG Studies in Geology 64 entitled "Heavy-oil and Oil-Sand Petroleum Systems in Alberta and Beyond" was released in April 2013 (bookstore@aapg.org). It is a combination hard-copy and CD publication, with 160 pages printed (3 chapters), and all 28 chapters in electronic form on the CD-ROM. This oil sands and heavy oils research includes presentations from the 2007 Hedberg conference in Banff, Canada titled "*Heavy oil and bitumen in foreland basins – From processes to products*." Publication editors are Frances Hein, Dale Leckie, Steve Larter, and John Suter. The volume contains 28 chapters (Appendix A) that encompass depositional settings of oil sands and heavy oil accumulations, reservoir characterizations, geochemical characteristics of bitumen and of oil biodegradation, geologic and petroleum system modeling, petroleum reserves and resources, surface mining and in-situ production processes, such as SAGD, for accumulations in Canada, Russia, the U.S., and Venezuela, and oil sands tailings and water use management.

The 2013 SPE Western Region/Pacific Section AAPG Joint Technical Conference in Monterey, California, April 20-25, 2013 included two oral session dealing with heavy oil occurrences and recovery technologies, in addition to and numerous papers on heavy oil issues scattered through the three-day technical program

.

The AAPG International Conference & Exhibition in Cartagena, Colombia, September 8-11, 2013 had as a technical theme "Challenges in Heavy Oil". The program provided for two half-day oral and two half-day poster sessions, a total of 24 papers, focused on heavy oil deposits and recovery methods in the Llanos, Putumayo, Orinoco and Alberta basins.

The SPE Heavy and Extra Heavy Oil Conference: Latin America was held September 24-26, 2014 in Medellin, Colombia. The themes of this conference were the application of innovative technologies to improving ultimate recovery and production rates, and achieving world class levels of ecomonic viability, reliability, energy efficiency, safety in heavy and extra heavy oil fields with minimal environmental impact.

October 14-16, 2014, the Canadian Society of Petroleum Geologists and the AAPG Canada Region held the Oil Sands & Heavy Oil Symposium: A Local to Global Multidisciplinary Collaboration at the Metropolitan Conference Centre, Calgary Alberta. This narratively designed single track technical symposium included 42 technical lectures in 6 sessions, 16 core and/or poster presentations and panel discussions. The unique perspectives covered at multi-scales and multi-disciplines focused on: the global nature of the resource by linking Canadian oil sands with other global "elephants"; a multi-scale look at the deposits and reservoirs; advances in recovery technologies; caprock and reservoir integrity; and contributions to the challenges of environmental protection and social license, as well as driving prosperity and better standards of living for all through sustainable energy development.

The Heavy Oil Latin American Conference and Exhibition was held October 15-17, 2014 on Margarita Island, Venezuela. PDVSA was the organizing sponsor for this annual event.

Heavy Oil Conferences and Workshops Scheduled in 2014-2015

December 10-11, 2014 **AAPG-ACGGP Geosciences Technical Workshop "Expanding Unconventional Resources in Colombia with New Science – From Heavy Oil to Shale Gas/Shale Oil Opportunities**

Hotel Bogotá Royal, Bogota, Colombia http://www.aapg.org/career/training/workshops

February 23-25, 2015 **Heavy Oil Technologies Conference 2015**
Bogota, Colombia For information contact Animesh Rajput animesh@hciex.com

March 24-26, 2015 **World Heavy Oil Congress 2015**
Shaw Conference Centre, Edmond, Alberta http://worldheavyoilcongress.com

June 9-11, 2015 **SPE Canada Heavy Oil Conference**
BMO Centre at Stampede Park, Calgary, Alberta http://www.spe.org/events/choc/2015

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Appendices

<u>Appendix A</u>: Chapter List – Frances J. Hein, Dale Leckie, Steve Larter, and John R. Suter, eds., 2013, Heavy-Oil and Oil-Sand Petroleum Systems in Alberta and Beyond: AAPG Studies in Geology 64.

Table of Contents

Appendix B: Web Links for Oil Sands/Heavy Oil Organizations and Publications

The following provides updates to the Members-Only Webpage located at http://emd.aapg.org/members_only/oil_sands/index.cfm .

Alabama Geological Survey website: http://www.gsa.state.al.us

Alaska Division of Geological and Geophysical Surveys: http://www.dggs.dnr.state.ak.us

Alberta Energy Regulator (AER): www.aer.ca

Alberta Chamber of Resources: www.abchamber.ca

Alberta Department of Energy: www.energy.gov.ab.ca

Alberta Department of Sustainable Resource Development: www.srd.alberta.ca

Alberta Innovates – Energy and Environmental Solutions: www.albertainnovates.ca/energy/

Alberta Environment Information Centre: www.environment.gov.ab.ca

Alberta Geological Survey: www.ags.gov.ab.ca

Alberta Government: www.alberta.ca

Alberta's Industrial Heartland Association: www.industrialheartland.com

Alberta Ingenuity Centre for In Situ Energy: www.aicise.ca

Alberta Innovation & Science: www.aet.alberta.ca

Alberta Research Council: www.arc.ab.ca

Alberta Sulphur Research Ltd.: www.chem.ucalgary.ca/asr

Athabasca Regional Issues Working Group: www.oilsands.cc

Bureau of Land Management – Details on the Oil Shale and Tar Sands PEIS: http://www.blm.gov/wo/st/en/prog/energy/oilshale_2/PEIS_details.html

Canadian Association of Petroleum Producers: www.capp.ca

Canadian Energy Research Institute: www.ceri.ca

Canadian Geoscience Council: www.geoscience.ca

Canadian Heavy Oil Association: www.choa.ab.ca

Canadian Institute of Mining, Metallurgy & Petroleum: www.cim.org

Canadian Petroleum Institute: www.cppi.ca

Canadian Society of Petroleum Geologists: www.cspg.org

Canadian Well Logging Society: www.cwls.org

CanMet Mining and Mineral Sciences Laboratories: www.nrcan.gc.ca

Careers: The Next Generation: www.nextgen.org

Climate Change Central: www.climatechangecentral.com

EnergyInet: www.energyinet.com

Environment Canada: www.ec.gc.ca

Fort McMurray Chamber of Commerce: www.fortmcmurraychamber.ca

Freehold Owners Association: www.fhoa.ca

Geological Survey of Canada: http://gsc.nrcan.gc.ca/

Institute for Sustainable Energy, Environment and Economy: www.iseee.ca

International Energy Foundation: www.ief-energy.org

National Energy Board: www.neb-one.gc.ca

National Research Council's Industrial Research Assistance Program: www.irap-pari.nrc-cnrc.gc.ca

Natural Resources Canada: www.nrcan-rncan.gc.ca

New Mexico Bureau of Geology and Mineral Resources: http://geoinfo.nmt.edu/index.html

Oklahoma Geological Survey http://www.ogs.ou.edu/homepage.php

Oil Sands Discovery Centre: www.oilsandsdiscovery.com

Petroleum Society of Canada: www.petsoc.org , www.spe.org/canada

Petroleum Technology Alliance Canada: www.ptac.org

Petroleum Technology Research Centre: www.ptrc.ca

Saskatchewan Industry and Resources: www.ir.gov.sk.ca

Saskatchewan Government: www.ir.gov.sk.ca

Saskatchewan Research Council: www.src.sk.ca

Seeds Foundation: www.seedsfoundation.ca

Small Explorers and Producers Association of Canada: www.sepac.ca

Society of Petroleum Engineers: www.speca.ca

The Canadian Society of Exploration Geophysicists: www.cseg.ca

The Environmental Association of Alberta: www.esaa.org

U.S. Energy Information Administration: www.eia.doe.gov , http://search.usa.gov/search?affiliate=eia.doe.gov&v%3Aproject=firstgov&query=oil+sands

U.S. Geological Survey: http://www.usgs.gov, http://energy.cr.usgs.gov

U.S. Bureau of Land Management: www.blm.gov

Utah Heavy Oil: http://www.heavyoil.utah.edu/outreach.html; http:/map.heavyoil.utah.edu/