1

Hein, Frances J., Dale Leckie, Steve Larter, and John R. Suter, 2013, Heavy oil and bitumen petroleum systems in Alberta and beyond: The future is nonconventional and the future is now, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 1 – 21.

Heavy Oil and Bitumen Petroleum Systems in Alberta and Beyond: The Future Is Nonconventional and the Future Is Now

Frances J. Hein

Energy Resources Conservation Board, Suite 1000, 250-5th St., SW, Calgary, Alberta, T2P 0R4, Canada (e-mail: fran.hein@ercb.ca)

Dale Leckie

Nexen Inc., 801-7th Ave. SW, Calgary, Alberta, T2P 3P7, Canada (e-mail: daleleckie@nexeninc.com)

Steve Larter

Geoscience, University of Calgary, 844 Campus Pl. NW, Calgary, Alberta, T2N 1N4, Canada (e-mail: slarter@ucalgary.com)

John R. Suter

ConocoPhillips Canada, PO Box 130, Postal Station M, Calgary, Alberta, T2P 2H7, Canada (e-mail: john.r.suter@conocophillips.com)

ABSTRACT

Global bitumen and heavy-oil resources are estimated to be 5.6 trillion bbl, with most of that occurring in the western hemisphere. In the past decade, significant advances in the development and production of these resources have occurred by way of the critical integration of geology, geophysics, engineering, modeling economics, and transportation.

Bitumen and heavy-oil deposits are mainly unconsolidated sands bound together by biodegraded bitumen. In the case of the world's largest oil-sand and heavy-oil deposit, located in western Canada, the oil sands occur in deposits of low sedimentary accommodation on the distal side of a foreland basin. Hydrocarbons were derived from Mississippian Exshaw and/or Mesozoic source rocks. The hydrocarbons migrated eastward several hundred kilometers to accumulate and become biodegraded on the shallowly buried, low-temperature, northeastern margins of the basin. The hydrocarbons accumulated in tidally influenced fluvioestuarine sediments, midchannel bars, brackish bays, bay-head deltas, and tidal flats. Elsewhere, in another major global heavy-oil resource, the Oficina Formation in Venezuela was similarly deposited in fluvioestuarine to deltaic settings.

Current in-situ oil-sand development focuses on steam-assisted gravity drainage (SAGD) technology and, to a lesser degree, cyclic steam stimulation (CSS). Other emerging technologies being piloted include in-situ combustion, electrothermal dynamic stripping, and passive

DOI:10.1306/13371576St643550

heating-assisted recovery methods. Water supply and disposal is an ongoing critical component for the mines and in-situ development. In the surface mines, hydrotransport, typically using recycled and brackish water, has major requirements for water, whereas fresh to saline water is used to generate steam for the in-situ bitumen heating. The development of oil sands requires a delicate balance between resource extraction regulatory systems, environmental issues, and long-term sustainability. In areas of in-situ SAGD development where overburden is shallow, cap rock integrity is also critical to prevent steam escape from mixed hydrocarbon and steam chambers into ground and surface waters. For surface mines, experimental new bacterial-remedial biotechnology shows promise for reducing sedimentation time of fines and toxin removal from tailings ponds. Thus, to cost-effectively develop oil-sand resources of the world, it is critical that technological innovation continue to develop to minimize environmental impacts and to more efficiently develop these strategic resources.

INTRODUCTION

In 1974, Hills edited a memoir entitled *Oil Sands Fuel of the Future*. At that time, the world conventional crude oil industry was robust, and booked reserves were well ahead of demand, although, since about 1968, remaining reserves were starting to decline. Understanding the geology of oil sands and heavy oil was at a reconnaissance scale, and the experimental development of in-situ technologies was in its infancy. At that time, world estimates of the major oil-sand deposits was 1440 billion bbl in place, with major oil-sand deposits described in a dozen different basins (Walters, 1974). Viscosity variations of bitumen and heavy oil were known on a regional basis; however, neither thorough understanding of the important role of anaerobic oil biodegradation in the development of these resources (Head et al., 2003; Aitken et al., 2004; Adams et al., 2007, 2013; Jones et al., 2008; Larter et al., 2008), or field-scale understanding of the complex mechanisms associated with the natural degradation of hydrocarbons and the impact on recovery process engineering (Larter et al., 2008; Fustic et al., 2013a) existed then. Such complexity results in the compartmentalization of the bitumen and heavy-oil reservoirs (Hubbard et al., 2011; Fustic et al., 2013a, b) and the need for three-dimensional (3-D) modeling of the subsurface reservoir before implementation of in-situ schemes (Deutsch, 2013; Fustic et al., 2013b; Musial, 2013). Environmental issues were not as much of a concern as they are today. At that time, most of the Alberta government studies dealt with the impact of surface mining of the oil sands, and government regulation and royalty schemes were just being extended to deal with the growth in the development of these nonconventional resources (Govier, 1974; Page, 1974).

Presently, world nonconventional energy sources are being increasingly explored, developed, and produced as conventional hydrocarbon reserves become depleted. Two of the strategic major nonconventional hydrocarbon resources are oil-sands and heavy-oil. Recent interest and activity in the vast oil-sand and heavy-oil deposits of the western hemisphere are progressing rapidly to fill this need. Nearly 40 yr of research and development experience has led to better understanding and empirically-based reservoir modeling in the supergiant and giant bitumen and heavy-oil fields of the Canadian oil sands (Hein, 2000, 2011-2012), the Orinoco Heavy Oil belt of Venezuela (Martinius et al., 2007, 2013; Villarroel et al., 2013), the heavy oil on the North Slope of Alaska (Hulm et al., 2013), and the heavy-oil fields of California (Hein, 2013). These areas have served as proving grounds for the commercial development of in-situ recovery (mostly thermal) technologies that will be used to extract most of the remaining non-conventional bitumen and heavy-oil resources.

Bitumen and heavy-oil deposits occur in more than 100 countries and in almost all of the continents of the world (Figure 1). Meyer et al. (2007) recorded nearly 2000 heavy-oil deposits in 192 basins and more than 300 natural bitumen deposits in 89 basins (Figure 1). As other countries begin to explore the commercial development of their own oil-sand and heavy-oil reserves, the Alaskan, Californian, Canadian, and Venezuelan basin experiences may be used as empirical analogs. In addition to the geologic features, commercial development of the other natural bitumen deposits depends on a host of other factors, including (1) the remoteness of the deposits; (2) the costs of development and production in relation to the economic resources of the country; (3) preexisting infrastructure and transportation systems; (4) the existence of favorable economics and government regulatory schemes; (5) the need for a highly technically trained workforce and expert knowledge; and (6) the balance between sustainable development and the country's requirements for conservation, preservation of natural resources, and increasing desire to limit greenhouse gas (GHG) emissions.

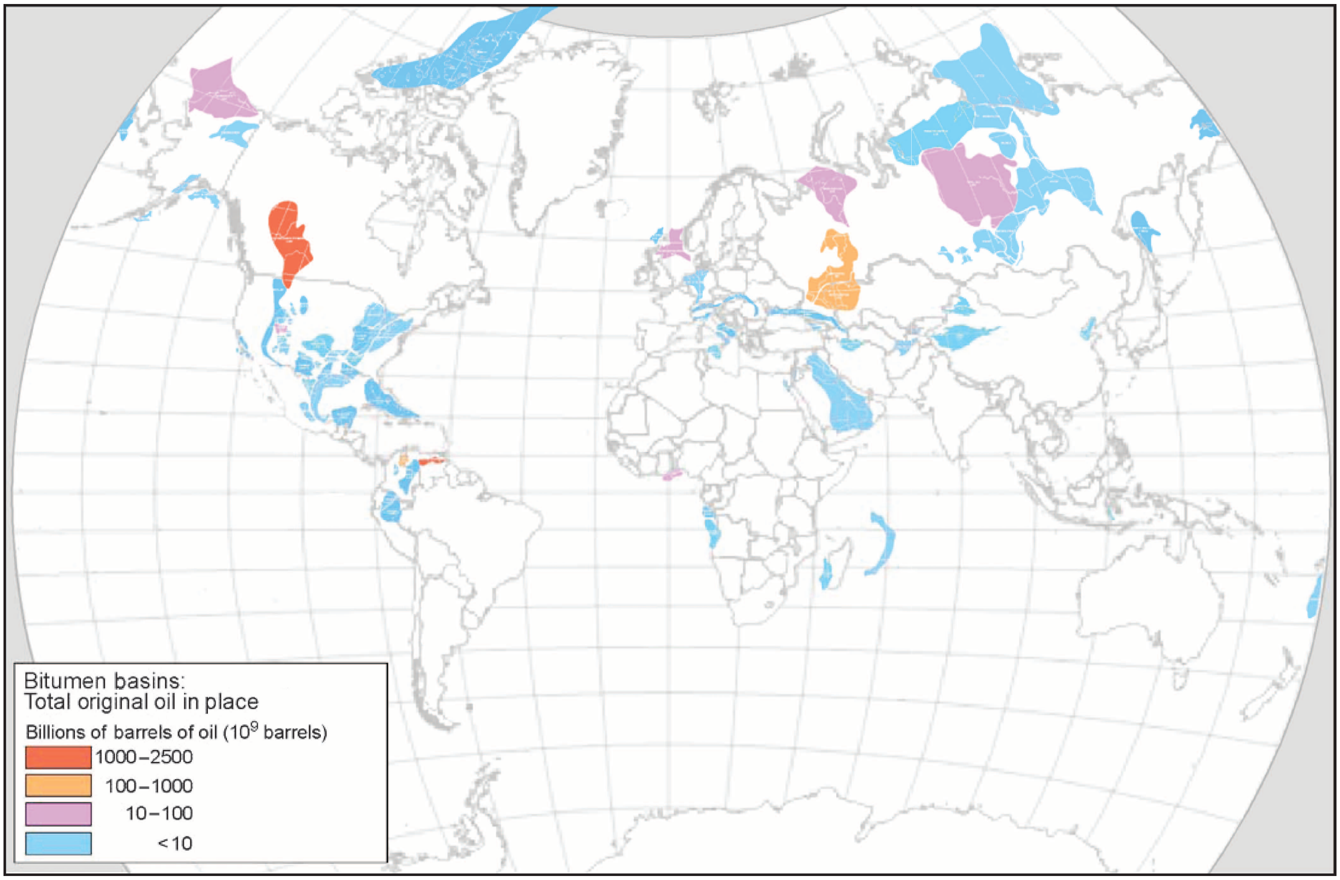

Figure 1. Schematic world map showing natural bitumen basins with total original bitumen in place: pink = 1000 to 2500 billion bbl (10^9) of oil; orange = 100 to 1000 billion bbl (10^9) of oil; yellow = 10 to 100 billion bbl (10^9) of oil; blue = less than 10 billion bbl (10^9) of oil. Mercator projection (based on data given in Meyer et al., 2007).

This AAPG Studies in Geology is a compilation of articles that address all phases of heavy-oil and oil-sand development, many presented at the 2007 AAPG Hedberg Research Conference on Heavy Oil and Bitumen in Foreland Basins: From Processes to Products (Hein et al., 2007; Suter et al., 2007) and at the 2009 Canadian Society of Petroleum Geologists Gussow Conference on Sustainable Development of the Oil Sands (Larter, 2009), both held in Banff, Alberta, Canada. Others were solicited from presentations in oil sands or heavy oil sessions at the World Heavy Oil Congress (2008) held in Edmonton and from recent AAPG annual and international conferences held in Dallas (AAPG, 2004), Calgary (AAPG, 2005, 2010), Long Beach (AAPG, 2007), and Denver (AAPG, 2009). Previous published reviews of the world's major oil-sand and heavy-oil deposits were compiled by Hills (1974), Lewan and Associates, Inc. (1984), Meyer et al. (1984), and Meyer (1987). More recent updates for North America are by Hein (2006) and for the world by Meyer and Attanasi (2003), the U.S. Geological Survey (2006), and Meyer et al. (2007). For Canada, dedicated volumes include the Alberta oil sand core conference proceedings and memoir by Pemberton et al. (1994) and Pemberton and James (1997), a brief overview article of the prospective Saskatchewan oil sands by Schramm et al. (2010), a collection of reprints by Palmgren (2006), and a recent two-volume review of the technologies for oil-sand and heavy-oil recovery by Masliyah et al. (2009, in press).

OIL-SAND AND HEAVY-OIL RESOURCES AND RESERVES

Historically, there has been much confusion in the literature regarding the terms and different classifications applied to oil sands, heavy oil, and bitumen (Kashirtsev and Hein, 2013). Depending on their API gravity ([in degrees] = [141.5/specific gravity]-131.5), many of the extra heavy oils of Venezuela would be considered oil sands in Canada, also called tar sands in the United States. Meyer and Freeman (2006) and Meyer et al. (2007) provided a good description

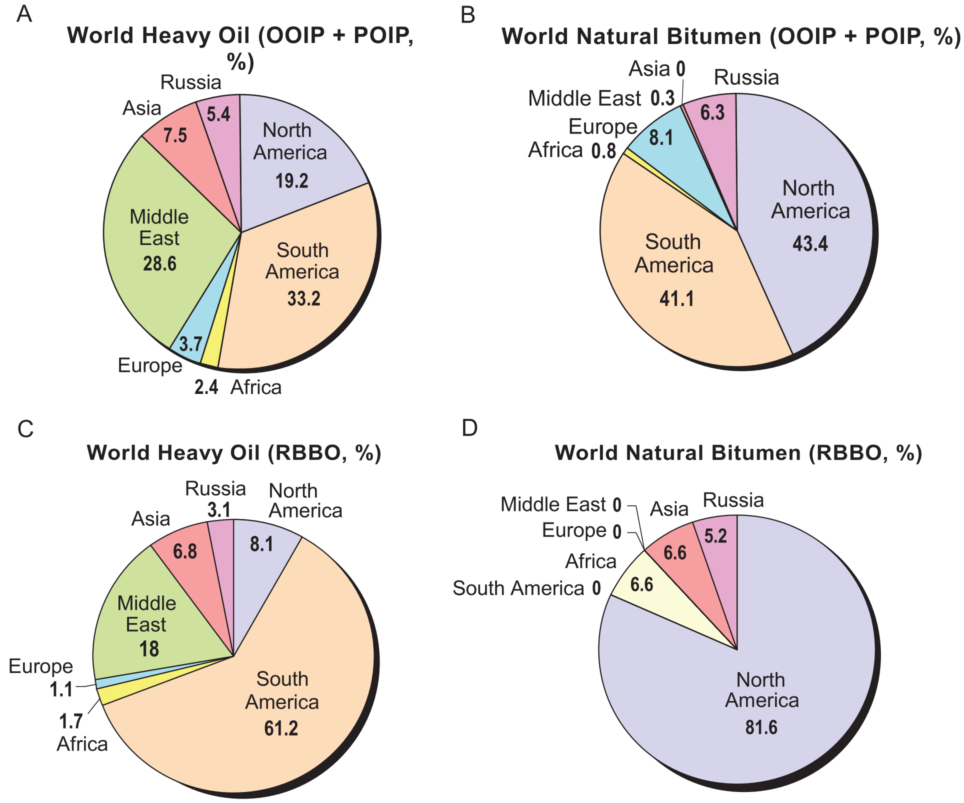

Figure 2. Pie charts of world (A) heavy oil and (B) bitumen expressed as a percentage of discovered plus prospective original oil in place (OOIP + POIP); (C) heavy oil and (D) bitumen expressed as a percentage of technically recoverable amounts in billions of barrels of oil (RBBO). Recovery factors range from 0.10 to 0.20 for heavy oil; 0.13 to 0.32 for natural bitumen. Values plotted are percentages of the total world technically recoverable heavy oil (434.3 RBBO) and natural bitumen (650.7 RBBO) (see Tables 1, 2) (based on data in part from Meyer and Attanasi, 2003; Meyer et al., 2007).

of the different classifications, with comparisons with the terminologies used in North America. Heavy oil is defined as oil with 10 to 20° API and a viscosity of more than 100 cp. Bitumen includes extra heavy oil as well as oil (tar) sands with less than 10° API and viscosity of more than 10,000 cp. The main distinction between the terms is that the high viscosity of natural bitumen prevents it from flowing to a wellbore under in-situ reservoir conditions, whereas extra heavy and heavy oil will flow to the wellbore under the same conditions.

Oil sand is unconsolidated sand containing high saturations of highly to severely biodegraded oil (heavy oil or bitumen). Conventionally, the term ‘‘oil sand’’ refers to those highly viscous oil-containing reservoirs in which the oil at reservoir conditions is too viscous to flow to a wellbore and, as such, is uneconomic to produce in volumes without technological intervention. In situ, the viscosity of bitumen exceeds 10,000 cp under natural reservoir conditions. For heavy oil, the in-situ viscosity ranges from tens of centipoise to less than 10,000 cp, which can allow some primary production under natural reservoir conditions. In surface mining operations, the bitumen is separated from the sand (mostly by hot-water separation processes) and the residuum of loose sand is disposed of in tailings ponds. A large part of the tailings from oil-sand mines consists of the original quartz-sand component of the oil sands.

World resources of bitumen and heavy oil are estimated to be 5.6 trillion bbl (Hein, 2006), with more than 80% occurring in Canada, Venezuela, and the United States. The bulk of the original oil in place (OOIP) and prospective oil in place (POIP) for heavy oil (>50%) and natural bitumen (>80%) is in the western hemisphere (Meyer et al., 2007) (Figure 2A, B; Table 1). Most of the recoverable billions of barrels of oil (RBBO) for heavy oil are in South America, mainly within the lower Miocene Orinoco Heavy Oil Belt of Venezuela (Figure 2C; Table 2). The largest recoverable billions of barrels of oil for natural bitumen are in North America (Figure 2D; Table 2), mainly hosted within the Lower Cretaceous oil sands and carbonate-bitumen deposits of Alberta, Canada (Meyer and Attanasi, 2003; Buschkuehle et al., 2006; Barrett et al., 2007; Marsh et al., 2009; Energy Resources Conservation Board, 2010).

The largest oil-sand deposit in the world is located in the Western Canada sedimentary basin, at its shallow updip margin against the Precambrian shield (Figure 3). To date, most of the exploration and development has been in Alberta, with preliminary assessments of contiguous oil-sand occurrences in northwestern Saskatchewan (Schramm et al., 2010). The oil sands of Alberta occur in three main areas: Athabasca, Cold

Table 1. Regional distribution of TOOP (OOIP + POIP)* for heavy oil and natural bitumen in billions of barrels of oil and percentage of world occurrences.**

Region	Heavy Oil (TOOP, BBL**)	Heavy Oil (%)	Natural Bitumen (TOOP, BBL**)	Natural Bitumen (%)
North America	651	19.2	2391	43.4
South America	1127	33.2	2260	41.1
Africa	83	2.4	430	0.8
Europe	127	3.7	46	8.1
Middle East	971	28.6	0	0
Asia	254	7.5	14	0.3
Russia	182	5.4	347	6.3
Total	3395	100	5505	100

*TOOP = total original oil in place; OOIP = original oil in place; POIP = prospective oil in place; BBL = billions of barrels of oil.
**Modified from Meyer et al. (2007).

Lake, and Peace River. Of these, the Athabasca has the largest reserves, with estimated remaining established reserves of 152.21×10^6 m^3 (Energy Resources Conservation Board, 2010).

During the past decade, increased development and production of bitumen from the Alberta oil sands have been reported (Rahnama et al., 2013). To date, only 4% of the initially established total crude bitumen reserves of Alberta (28.09×10^9 m^3) has been commercially produced since 1967 (Energy Resources Conservation Board, 2010). Of the remaining bitumen reserves, most of the bitumen (78%) is in areas of thick overburden where in-situ (mainly thermal) technologies will have to be used to recover the resource.

REGIONAL OIL EMPLACEMENT MODELS AND VISCOSITY TRENDS

Most of the large-scale accumulations of heavy oil and natural bitumen occur mainly in stratigraphic traps along the shallow updip margins of foreland basins or within closed interior basins associated with convergent plate boundaries (Meyer et al., 2007). Other medium and small heavy-oil and natural bitumen deposits occur within faulted subbasins, such as the strike-slip California continental borderland or Laramide Basin and Range province of the Western Interior of the United States (Hein, 2006; Schamel, 2013). Many of these medium- and small-scale deposits are within combined structural-stratigraphic traps.

In the western Canada sedimentary basin, petroleum generation from source rocks began near the present-day eastern edge of the Canadian Cordillera, with updip migration to the northeast for 200 to 350 km (124–218 mi) where hydrocarbons were pooled against the craton of the Precambrian shield (Figure 3). Here, the reservoired oil degraded in place, forming the world's largest oil-sand and heavy-oil deposit. The source rocks for this vast hydrocarbon accumulation remain controversial, with some workers advocating a mainly single-charge history from the Mississippian

Table 2. Regional distribution of estimated technically recoverable oil from heavy oil and natural bitumen in billions of barrels of oil and percentage of world occurrences.*

Region	Heavy Oil (RBBO, BBL)**	Heavy Oil (%)	Bitumen (RBBO, BBL)**	Bitumen (%)
North America	35.3	8.1	530.9	81.6
South America	265.7	61.2	0.1	0
Africa	7.2	1.7	43	6.6
Europe	4.9	1.1	0.2	0
Middle East	78.2	18	0	0
Asia	29.6	6.8	42.8	6.6
Russia	13.4	3.1	33.7	5.2
Total	434.3	100	650.7	100

*Data updated from Meyer and Attanasi (2003).
**RBBO = technically recoverable amounts in billions of barrels of oil; BBL = billions of barrels of oil.

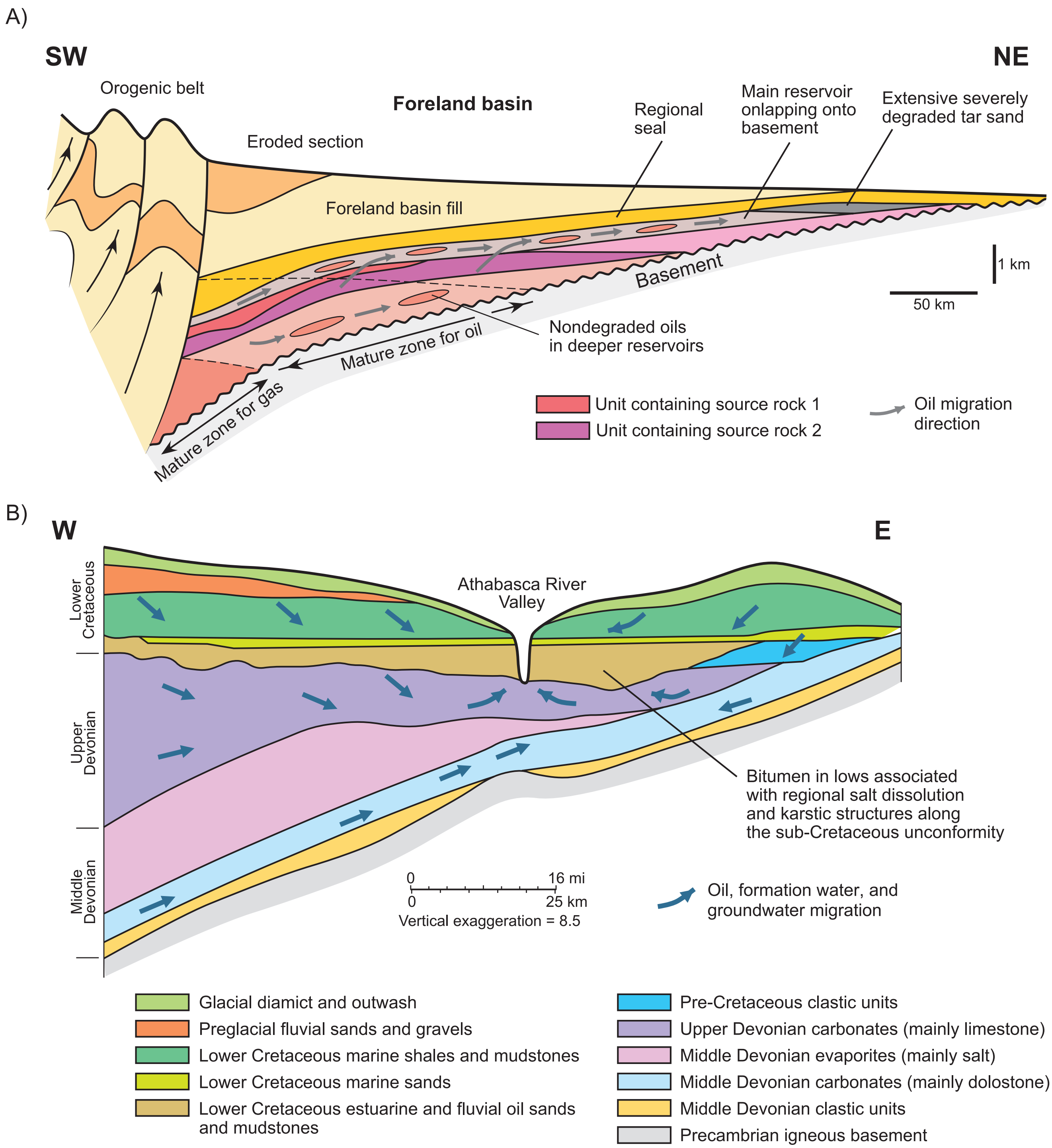

Figure 3. Schematic cross sections. (A) Regional southwest-northeast emplacement model for the Alberta oil sands of the Western Canada sedimentary basin. (B) Detailed west-east subsurface flow of hydrocarbons, formation, and groundwater in the Athabasca River valley that contributed to the charging and biodegradation history of the oil sands, northeastern Alberta, Canada (from Head et al., 2003; p. 1974, published in Hein, 2006).

Exshaw and equivalents, and others indicating mostly Mesozoic sources with a more complex charge history. Molecular and isotopic geochemical analysis of north-central Alberta Lower Cretaceous oils identifies variable source contributions to the oil sands from the Exshaw, Gordondale, and Duvernay source rocks. Cold Lake and southern Athabasca oils are most likely derived from the Exshaw, with minor contributions from the Duvernay, whereas west to east across the Peace River region, sulfur content, isotopic composition, and biomarker and molecular marker geochemistry show a mixing zone of Gordondale (west)- and Exshaw (east)-sourced oils (Creaney et al., 1994; Adams et al., 2007, 2013; Higley and Lewan, 2013).

Bitumen is the lowest grade of naturally occurring oil and is a result of biodegradation of former lighter oil hydrocarbon reservoirs. Biodegradation is dominantly anaerobic (Head et al., 2003; Aitken et al., 2004)—biodegradation resulting in the transition to heavy oil or natural bitumen. The principal biodegradation mechanisms are via methanogenesis, with large volumes of methane and CO_2 being produced as oil is degraded for millions of years. For the western Canada sedimentary basin, Adams et al. (2007, 2013) used standard source facies assessments and geochemically assessed levels of biodegradation of the oils (Peters and Moldowan, 1993; Peters et al., 2005), along with total ion current (TIC) chromatograms of type oils singly sourced from various source rocks, and compared these with similar analyses of the Alberta heavy oil and oil sands. Their work indicated that a dominant source can account for the origin of much of the Alberta heavy-oil and oil-sand accumulations in the Athabasca area (Figure 3A) and that much of the observed viscosity variation is caused by variations in the balance between mass transport and physical mixing processes of new oil charge to the reservoirs versus the biological processes of anaerobic degradation driven from highly water-saturated reservoir zones. These factors, along with bounding in-situ reservoir paleotemperatures of more than 80°C at which organisms are pasteurized or sterilized, account for much of the regional- as well as field-scale viscosity variations that are observed in the western Canada sedimentary basin (Adams et al., 2007, 2013; Larter et al., 2008).

In other four-dimensional models of the western Canada sedimentary basin, source rock oil generation kinetics derived from hydrous pyrolysis (HP) and Rock-Eval (RE) analysis of presumed source rock samples yield variable results (Higley and Lewan, 2013). Their HP model indicates that most of the oil in the northern Alberta oil sands was sourced from type IIS kerogen derived from Fernie Group source rocks. By contrast, their RE-based source rock kinetic model for the western Canada sedimentary basin does not indicate a major contributor to the oil sands from this unit, with the most likely source being the Poker Chip A shale (Higley and Lewan, 2013). Differences in their two results are attributed to variations in the laboratory techniques between the RE and HP models, from which Higley and Lewan (2013) thought that the HP model gave more representative results regarding the kinetics of potential source rocks and matched more closely the high-sulfur content of the Alberta heavy oil and oil sands. Unconstrained basin models cannot resolve the issue as Adams et al. (2013) summarize well recent developments in assessing high-sulfur oil charge from the Jurassic source rock section to the Peace River and other accumulations. It is clear that multiple source rocks are involved and oil mixing is a key component of oil-sand origins.

In Russia, earlier work on natural bitumens in the Olenek uplift of eastern Siberia indicated that all of the surface bitumen, regardless of age of the host rocks, was likely generated from a single source rock. It now appears from geochemistry (carbon-isotope and biomarker distributions) that multiple source rocks contributed at different times to the accumulation of the bitumen deposits (Kashirtsev and Hein, 2013). Vendian bitumen has light carbon-isotope compositions, typical of ancient Siberian oils; whereas the younger Cambrian- and Permian-hosted bitumens have a wide range of carbon-isotope compositions and biomarkers that differ from the Vendian bitumen. Source rocks appear to have been in the paleo-Verkhoyansk Basin, with subsequent migration updip to the Olenek uplift of eastern Siberia (Kashirtsev and Hein, 2013).

Processes of in-reservoir crude oil biodegradation are complex, and observed gradients of in-situ oil viscosities relate to the paleotemperatures and oil charge history of the degraded oil-containing reservoirs, controls on the biological processes (supply of nutrients from high water-saturation zones, redox conditions, pH, possible formation of biofilms, etc.), physicochemical and microbial interactions between the degrading oil and any associated bottom water, top water, gas, or shallow groundwater aquifers (Head et al., 2003; Larter et al., 2003, 2006, 2008; Adams et al., 2007, 2013; Jones et al., 2008). In some cases, internal reservoir compartmentalization and local fill-spill effects in relation to the charge history of the degrading oils result in further factors impacting in-situ viscosity gradients (Fustic, et al., 2013a). These vertical and lateral oil viscosity gradients are ubiquitous in heavy-oil and oil-sand reservoirs and have been proposed to have large impacts of subsequent oil recovery process engineering (Gates et al., 2007a, b, 2008; Larter et al., 2008).

Understanding oil emplacement mechanisms and the variable controls on oil biodegradation can aid in (1) targeting prospective heavy-oil and natural bitumen deposits for commercial development, (2) design of optimal well placement for in-situ (mostly thermal) schemes, (3) optimization of recovery and production schemes (Adams et al., 2007, 2013; Gates et al., 2007a, b, 2008; Larter et al., 2008). Because the reservoir heterogeneity distributions within bitumen reservoirs ultimately control the oil emplacement and degradation models, understanding the 3-D geologic framework of porosity and permeability distributions is necessary to fully understand and predict the local and regional gradients in oil viscosity distributions. This understanding and documentation is one of the raison d'être for assessing the regional- and local (field)-scale facies models for the oil-sand and heavy-oil deposits.

GEOLOGIC MODELS AND FACIES CHARACTERIZATION

Although the existence of oil sands in Alberta and the heavy oil of Alaska's North Slope and Venezuela have been known for decades (and centuries for the Alberta deposits), it was not until considerable technological development evolved that commercial projects became possible. Well-to-well steam flood and steam drive have been used for more than 60 yr in California for the production of heavy oil (in-situ oil viscosity <10,000 cp) (Mongold and Allan, 2007; Dusseault, 2013). Initial development of the bitumen recovery methods began in the oil sands of Alberta in the 1920s, with the first commercial production of oil sands by a variety of methods since the 1980s (Hein, 2000, 2001-2012).

Concomitant with the development of in-situ thermal recovery technology was a regional characterization of the geology of the oil sands and heavy oil, with the goal of identifying prospective areas for oil-sand and heavy-oil exploitation.

Geologic characterization of the oil-sand and heavy-oil deposits has been done at two scales, regional, for broad-scale understanding of the resource, mainly done by government and university research consortia, and local, mainly by industry and university workers, to aid in the layout and configuration of infrastructure for surface mines and the in-situ (mainly steam-assisted gravity drainage [SAGD] and cyclic steam stimulation [CSS]) plants. Decades of research, field development, and production in the giant and supergiant accumulations (40+ yr for various operators in the Albertan oil-sand areas; 12+ yr for Petrocedeño (ex-Sincor) for the Orinoco Heavy Oil belt, Venezuela; and 30+ yr in the Alaskan North Slope) have led to refined geologic facies reservoir models and understanding of the sedimentary and oil viscosity variation architecture in three dimensions.

In all cases, characterization of the reservoir geologic lithofacies, along with their 3-D geometric relationships to one another in the subsurface, is necessary for proper reservoir characterization and development of these important bitumen deposits. Facies models developed in areas of dense-core coverage (e.g., in the Athabasca oil sands or the Petrocedeño for the Orinoco Heavy Oil belt) can be used in new frontier areas of oil-sand and heavy-oil development for the prediction and assessment of appropriate in-situ thermal schemes. In addition, such facies characterization can be used to constrain geostatistical models (i.e., to populate block cells or to assign reservoir properties to geobodies) that are used to help optimize well placement during development phases of in-situ schemes (Bellman, 2007; Phillips and Wen, 2007; Deutsch, 2010, 2013; Fustic et al., 2013a, b; Martinius et al., 2013; Musial et al., 2013).

Regional Geology and Facies Models

The regional geologies of the world's largest heavy-oil and oil-sand deposits are remarkably similar. Depositional models of the Petrocedeño field, early Miocene Oficina Formation in the Orinoco Heavy Oil belt, Venezuela, show that most of the deposits are in fluvioestuarine to deltaic settings (Figure 4A) (Martinius et al., 2013). Using chronostratigraphic correlations, eight main facies associations are organized into 11 sequences from different regional systems tracts that have been superimposed on one another and are separated by major unconformities or disconformities. Facies distribution and net-to-gross maps for each sequence were used for optimization of cold production and the implementation of enhanced oil recovery techniques. The sequence-stratigraphic approach showed that the Oficina depositional systems evolved from sandy fluvial braid plain at the base to sandy sinuous rivers and eventually to mixed-fluvial-tidal delta and upper delta-front environments (Figure 4B). Following maximum by a low-gradient, tide-dominated delta that eventually drowned, forming a delta platform that provided regional seals to the underlying heavy-oil reservoirs.

Depositional models of the Athabasca oil sands, Early Cretaceous Wabiskaw-McMurray succession, Alberta, show that most of the deposits are in fluvial to fluvioestuarine or marginal marine settings, including tidally influenced estuarine channels and bars, swamps, brackish bays and lagoons, with local bay-head deltas and tidal flats (Figure 5) (Demchuk et al., 2007; Dolby et al., 2013; Hubbard et al., 2011; Hein et al., 2013). Similar to the heavy-oil deposits of the Oficina, use of a chronostratigraphic sequence-stratigraphic approach illustrates that the main facies associations occur in at least eight different successions from different regional systems tracts that have been superimposed on one another in this low-accommodation position of the basin. The deposits from the different systems tracts are separated by major to minor unconformities or disconformities, from which incised-valley fills have locally removed stratigraphy, amalgamating channel complexes, and, in some cases, taken away local

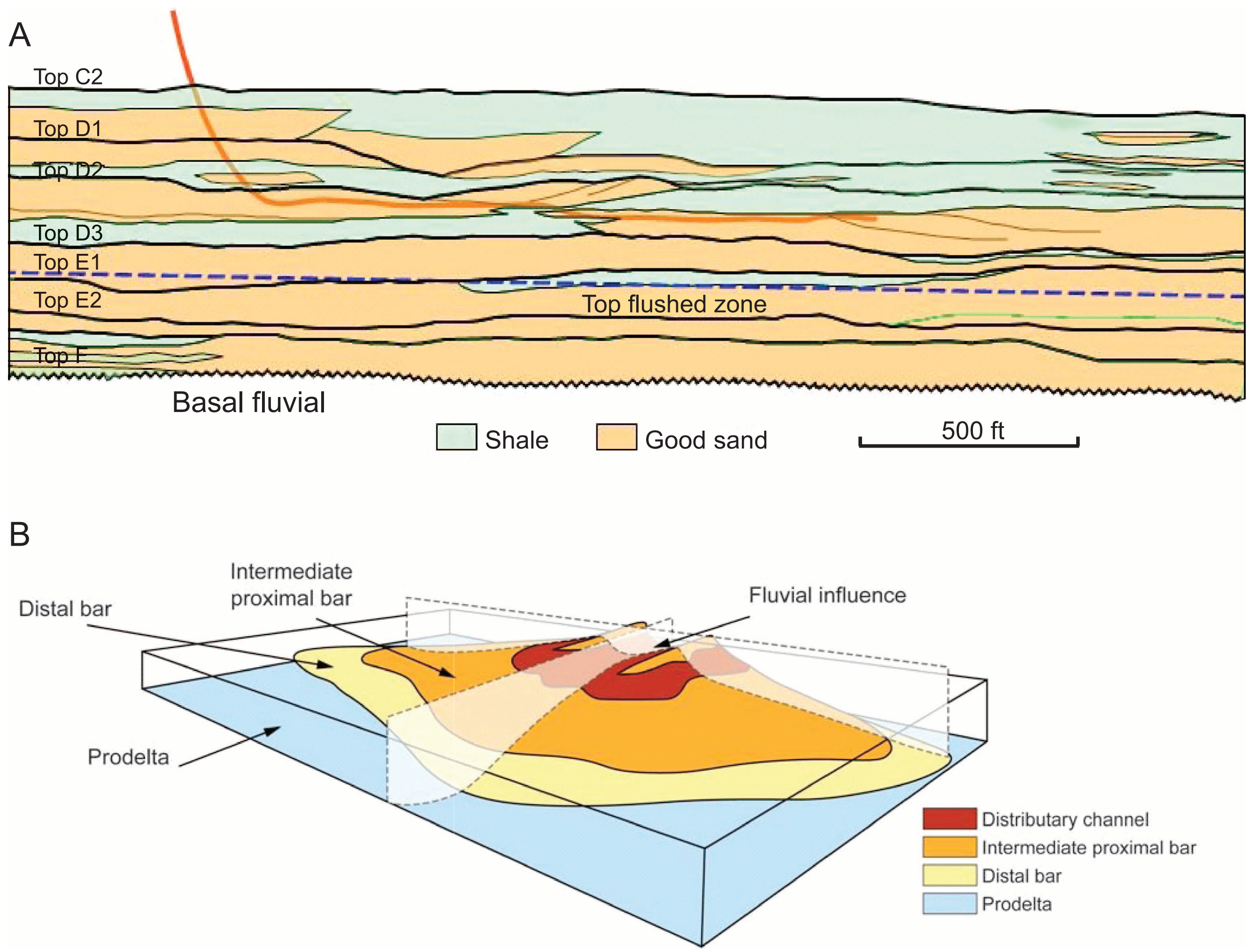

Figure 4. (A) Representative chronostratigraphic correlation of third-order sedimentary packages in the Petrocedeño (formerly called Sincor) field, early Miocene Oficina Formation in the Orinoco Heavy Oil belt, Venezuela, with the timeline tops labeled on the left; orange line indicates the optimal trajectory of horizontal wells for the development of the field. Orange = amalgamated channel sands; orange with gold dipping lines = inclined point bar deposits; green = fine-grained overbank, delta plain, and prodelta deposits. (B) Block diagram showing the geometry of fluvially influenced distributary channels, distributary mouth bars, and prodelta deposits for the upper deltaic successions of the Petrocedeño field. Modified from Labourdette et al. (2008) and Martinius et al. (2013). 500 ft (152.4 m).

cap rocks above bitumen reservoirs. These geologic factors make management of the coproduction of bitumen and overlying gas reservoirs difficult (Hein et al., 2013) and, in shallow overburden areas of Alberta, have compromised the integrity of cap rocks above bitumen reservoirs, which in one case, resulted in steam release to the surface from an in-situ bitumen production scheme (Hein and Fairgrieve, 2013). The sequence-stratigraphic interpretations show that the Wabiskaw-McMurray depositional systems evolved from lowstand, sandy, fluvial braided to meandering plains at the base to mixed, tidally influenced, sinuous rivers, with large fluvioestuarine channel-point bar complexes and eventually to bay-fill–lagoonal–marginal marine settings with bay-head deltas, tidal flats, and bay-shore environments. Following maximum transgression, the main reservoir fluvial-tidal complexes were overlain by more marine to fully marine mudstones and shales of the Clearwater Formation that provided regional caps to the underlying oil-sand–bitumen reservoirs (Demchuk et al., 2007; Dolby et al., 2013; Hein et al., 2013).

Other areas that have had recent regional analysis of oil-sand and heavy-oil deposits include assessments of unconventional oil resources of the Unita Basin, Utah (Schamel, 2013); integrated reservoir descriptions of the Ugnu heavy-oil accumulation, North Slope, Alaska (Hulm et al., 2013); geologic assessment and

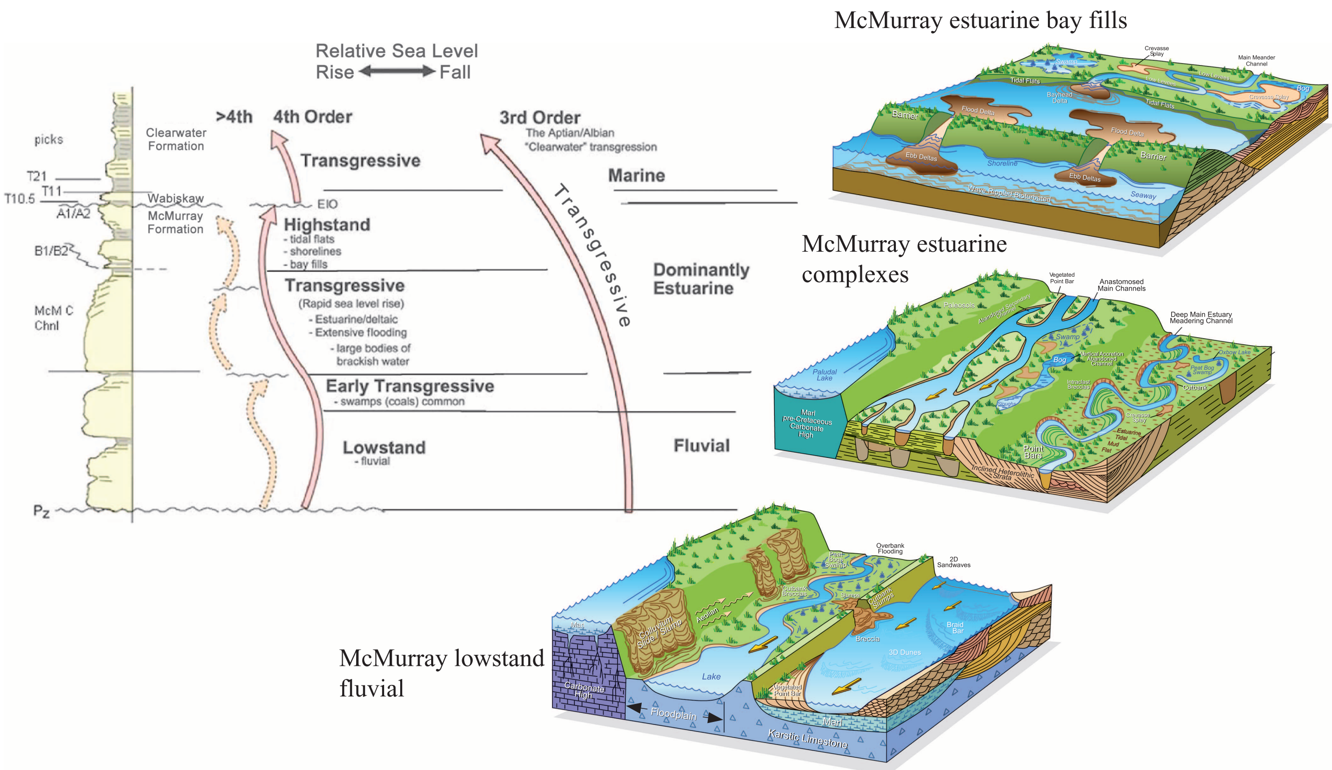

Figure 5. Sequence-stratigraphic model and detailed facies models for the Athabasca-Wabiskaw-McMurray succession of oil sands showing the successive stacking of deposits from different systems tracts separated by major unconformities and disconformities. Modified from Hein et al. (2013).

historical development of oil-saturated Mississippian–Pennsylvanian sandstones of south-central Kentucky (May, 2013); and an overview of the natural bitumen fields of the Siberian platform, Olenek uplift, eastern Siberia, Russia (Kashirtsev and Hein, 2013).

Local (Field-scale) Reservoir Geology and Engineering

Detailed local (field-scale) reservoir geology and facies characterization mostly relate in the surface mines to the mapping of ore versus non-ore (bench) zones and for in-situ operations to the prediction of oil saturation and reservoir connectivity, including permeability and barrier or baffle locations. In both situations, the understanding of the mine- or field-scale distribution of geologic facies aids in more efficient and effective development of the resource. Some of the most intensive drilling of bitumen reservoirs occurs in the heavy-oil Petrocedeño field, Venezuela, and in the surface and in-situ areas of the Canadian oil-sand and heavy-oil deposits.

For the Petrocedeño field, the heavy-oil deposits are in braided fluvial channels, meandering fluvioestuarine channels, and incised-valley fills, with smaller accumulations in the distributary channels, mouth bars, and crevasse splay sands associated with channel levees and deltas (Figure 4B) (Martinius et al., 2007, 2013). In the Athabasca oil sands, as discussed earlier, a variety of fluvioestuarine and marginal marine deposits are represented (Demchuk et al., 2007; Hubbard et al., 2011; Dolby et al., 2013; Hein et al., 2013). On a field scale, local paleogeographic interpretations range from giant wave-dominated bars in tidal embayments (Broughton, 2013) to individual or stacked, multistory, fluvioestuarine channel–point bar and/or distributary channel-crevasse splays (Ranger and Gingras, 2007; Hubbard et al., 2011; Strobl, 2013); and, on a broader multifield or mine scale, incised valleys, infilled with deposits from fluvial-to-estuarine or marginal marine systems tracts, with local paleosols, lagoons, swamps, and coals (Demchuk et al., 2007; Nardin et al., 2007, 2013; Stancliffe and Chen, 2007; Dolby et al., 2013; Hein et al., 2013). In all field, multifield, and mine case studies, these have to be put into a regional context to fully understand the depositional controls on sedimentation (including relative base level fluctuations and resultant chronostratigraphy) (Hein et al., 2007; Nardin et al., 2007, 2013) and ultimately the porosity and permeability distributions of the geologic framework comprising and enclosing the heavy-oil and bitumen reservoirs.

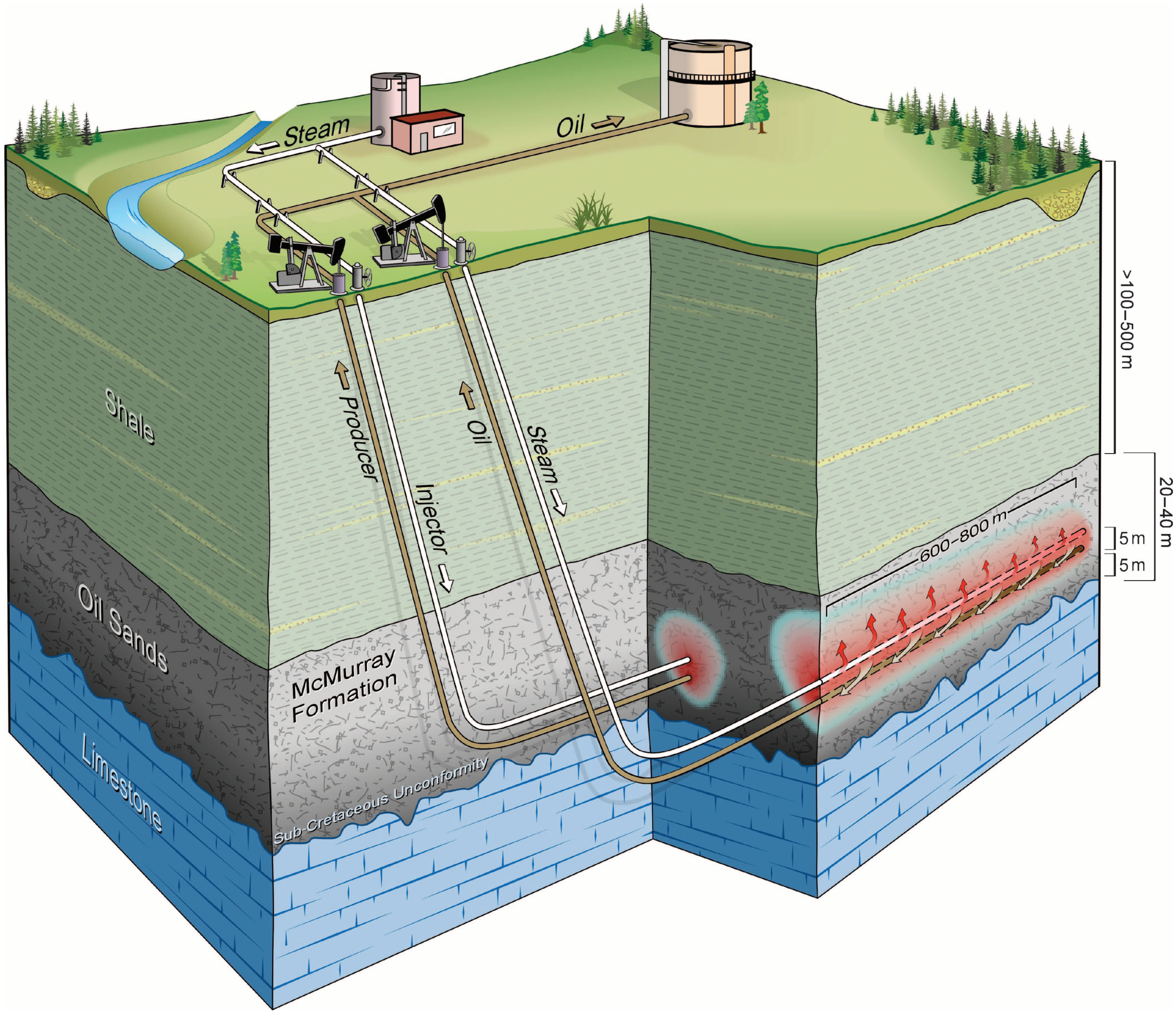

Figure 6. Schematic diagram, drawn to scale, of optimal conditions for steam-assisted gravity drainage in-situ schemes used in the Athabasca oil-sand area. Most of the bitumen production is from the McMurray Formation. The horizontal injector and producer wells commonly have 5 m (16.4 ft) of vertical separation, extend for 600 to 800 m (1969 – 2625 ft) from toe to heel in the reservoir, are commonly placed 5 m (16.4 ft) above basal water zones along the sub-Cretaceous unconformity, and have more than 100 to 500 m (328 – 1640 ft) of overburden.

In areas of mature development, a multidisciplinary approach using extensive and stratigraphic coverage of cores tied to wire-line logs, engineering, geotechnical and seismic analysis addresses the two-dimensional (2-D) and 3-D characterization of the geologic framework for the deposits (Chalaturnyk, 1996; Bellman, 2007; Sarzalejo and Hart, 2007; Hubbard et al., 2011; Dumitrescu and Lines, 2013; Dusseault, 2013; Fustic et al., 2013a, b; Hein, 2013; Hein et al., 2013; Hulm et al., 2013; Martinius et al., 2013; Musial et al., 2013; Sarzalejo Silva and Hart, 2013).

For oil sands, the most commonly used in-situ technologies for the recovery of bitumen are SAGD (Figure 6) and CSS, both of which have high demands for water and energy to produce steam. Other extraction technologies for viscous oil production (either heavy oil or bitumen) include cold production with or without sand, solvent-based or solvent-enhanced methods, pressure pulsing technology, steam flood or steam drive, and anoxic pyrolysis and in-situ combustion (Gates et al., 2007a, b, 2013; Dusseault, 2013; Hein, 2013).

For most of the in-situ processes to be effective, a need exists for good vertical and horizontal permeability, relatively thick pay zones (generally >10 m [32.8 ft]), an absence of thick barriers (>5 m [16.4 ft]), such as cemented or continuous shales, and a lack of significant top gas or bottom water thief zones (Gates et al., 2007a, b, 2013; Dusseault, 2013; Hein et al., 2013; Strobl, 2013; Villarroel et al., 2013). Recently, it has been proposed that in-situ technology sequencing, using screening criteria based on geologic factors and hybrid approaches, may be appropriate to maximize efficiency and recovery of these resources (Dusseault, 2013). In some cases, in-situ technology sequencing may be used to revitalize old oil fields. In California, old oil fields may be further developed using horizontal drilling with CSS or SAGD to access bypassed pay in heavy-oil zones. This production may be augmented by new horizontal drilling and production by CSS or SAGD for shallow oil-sand zones overlying the heavy-oil reservoirs and multistage, multifracing for the deeper source rocks underlying the heavy-oil reservoirs (Hein, 2013). For most of the future development of heavy oil and bitumen, a convergence of disciplines is needed to support this understanding, integrating the results from the geologic and geomechanical perspectives, in addition to the engineering issues related to development (Chalaturnyk, 1996; Dusseault, 2013).

In general, through time, the average steam oil ratios of in-situ bitumen developments using SAGD and CSS have increased because more complex compartmentalized reservoirs have been produced, suggesting that new technologies are urgently needed. The higher upstream emissions of bitumen production over conventional oils and a growing concern over GHG emissions associated with fossil fuel production and especially oil-sand production (Bergerson and Keith, 2010) also drive us toward the need for new, more geologically tolerant bitumen recovery processes and better integration of the geoscience and engineering disciplines associated with bitumen recovery.

RESERVOIR MODELS AND GEOSTATISTICS

Reservoir models and geostatistics are commonly used to predict and optimize the recovery of bitumen from surface mines or heavy oil or bitumen from subsurface reservoirs by in-situ technologies. To constrain the models to give more predictive results, an empirical correlation with relevant geologic and engineering models should exist. To do this, multiple-scale geologic models are used to characterize the heavy-oil and bitumen reservoirs (Deutsch, 2013). Data from well logs, cores, core photographs, high-resolution image logs, and porosity and permeability measurements are tied to geologic facies, which are then related to geologic environments, as determined from outcrop-subsurface correlation or correspondence to seismic facies in the subsurface (Langenberg et al., 2002; Martinius et al., 2007, 2013; Sarzalejo and Hart, 2007; Hubbard et al., 2011; Fustic et al., 2013a, b; Musial et al., 2013; Sarzalejo Silva and Hart, 2013). Such empirical correlations are assigned to individual facies and facies associations or to blocks in object-based models, which are then put into geologic models for realizations of the 2-D and 3-D porosity and permeability frameworks of the reservoir.

For realizations to be representative, empirical geologic data must be used to constrain the geobodies used in the stochastic and deterministic simulations (Deutsch, 2010, 2013; Fustic et al., 2013a, b; Martinius et al., 2013; Musial et al., 2013). In addition, data should be analyzed with multiple reservoir model realizations and with further iterations as more empirical data become available. It may be useful to model the porosity or permeability first on a small scale (micromodeling and minimodeling), the results of which may be more representative for scaling up to a full reservoir and attaining the best models of vertical and horizontal permeability distributions (Deutsch, 2010, 2013). In many cases, iterative workflow processes incorporating seismic attributes and simulations, along with the geobody simulations, have been effective in modeling these complex reservoirs (Gray et al., 2006; Ren et al., 2006; Bellman, 2007; Phillips and Wen, 2007; Fustic et al., 2013a, b).

ENVIRONMENTAL AND SUSTAINABILITY ISSUES

Environmental and sustainability issues connected to oil-sand development mostly relate to CO_2 emissions and water use balanced with the protection and conservation of water resources; reclamation of disturbed land, wetlands, and forests; and reduction of non-CO_2 air emissions. In Alberta, the Energy Resources Conservation Board shares these responsibilities with Alberta Environment on environmental issues. Set against the need for more sustainable approaches to the development of nonconventional hydrocarbon resources has been the development of a regulatory system that compliments and enhances sustainability interests, in addition to the promotion of the industries in light of a favorable royalty regime—a delicate balance between industry, academia, and government. Recent reviews conducted by the Royal Society of

Canada (Gosselin et al., 2010) and others have criticized the performance and fragmented nature of monitoring in the oil sands region of Alberta. These reports were considered by expert panels assembled by both the Alberta and Canadian federal governments, resulting in a several recommendations to resolve perceived issues. In February 2012, the federal and provincial governments announced a joint implementation for monitoring in this region. This plan is intended to be consistent with the ongoing efforts of Alberta to establish a provincewide envrionmental monitoring system.

In recent years, the increasing need for sustainable development of hydrocarbon resources, initially focused on issues related to climate change initiatives, has been reported.

Current research and development initiatives include the development of mature fine-tailings remediation technologies with lessened environmental footprints (Mikula, 2013); the function of bioremediation in tailings management (Kostenko and Martinuzzi, 2013); the reduction of GHG emissions; the development of in-situ combustion and electrothermal (ET) technologies (McGee and MacDonald, 2009); and cogeneration and use of geothermal technology (shallow formation water and uranium) for heat generation (Majorowicz et al., 2013). Reservoir preconditioning approaches have also been proposed to reduce energy input and CO_2 emissions associated with bitumen recovery (Larter et al., 2006). Bergerson and Keith (2010) summarize emission and technology options for oil-sand developments. In Alberta, because most of the leases for deep oil sands have been acquired, in-situ development has migrated to more marginal areas with thinner overburden, near the surface minable area. Concerns for in-situ bitumen development in areas of shallow overburden relate mostly to cap rock integrity issues and possible communications between steam chambers and associated groundwater and surface water.

Cap Rock Integrity

In the Athabasca oil-sand deposit, the most commonly used in-situ technology is SAGD (Figure 6). Although many SAGD schemes exist in northern Alberta, limited empirical production history is present on which to develop and recommend best practices for optimal design and well placement for the efficient recovery of the bitumen resources at depth. There needs to be isolation of bitumen reservoirs from any overlying or adjacent thief zones, including associated gas and/or water. In-situ thermal bitumen development requires that cap rock integrity is not compromised by the occurrence of faults and fractures, the presence of coarser sandy interbeds, and/or the removal of cap rock units by younger channels (Hein and Fairgrieve, 2013). Beyond the technical recovery aspects of the bitumen at depth, other environmental concerns are associated with in-situ thermal production of bitumen in the subsurface. Locally, the occurrence of young Quaternary bedrock channels may, in some cases, completely remove cap rock and put bitumen reservoirs in direct contact with present-day aquifers for potable water in the region (Andriashek and Atkinson, 2007).

In areas of shallow cap rock, a need exists for good understanding of the geologic framework of the bitumen resource as well as the geologic framework of the enclosing sedimentary sequence, that is, the under rock and the overburden (Hein and Fairgrieve, 2013). In cases where the enclosing geologic framework is poorly defined, instances may result in the loss of cap rock integrity, with release of steam or bitumen beyond the steam chamber.

In SAGD, elevated pressures and temperatures associated with steam injection alter the rock framework, creating rock stresses to cause shear failure within and around the subsurface steam chamber. This shear failure increases porosity, permeability, and transmissibility of the rock framework, to further enhance the growth of the steam chamber and to increase communication between the steam chamber and the producing horizontal well (Chalaturnyk, 1996; Collins, 2005; Nasr and Ayodele, 2005).

The geomechanical effects associated with the SAGD process are directly dependent on the properties of the rock framework that is being sheared, specifically, the interbedding of the unconsolidated oil sands and the surrounding more competent and/or cemented shales and mudstones and their continuity or discontinuity in the subsurface. What affects subsurface injection of steam and flow of recovered bitumen is not only the distribution of high-porosity and high-permeability lithofacies but also the occurrence of the low-porosity and low-permeability lithofacies and their spatial relationships to one another (Fustic et al., 2013a, b; Martinius et al., 2013; Musial et al., 2013; Strobl, 2013).

One further complication in dealing with oil-sand cap rock systems is that it is likely that they have been leaking gas for some time. Generation of large amounts of methane during oil biodegradation and the absence of large gas caps indicate that the system is open on a geologic time scale (Adams et al., 2013). Furthermore, the rapid encroachment and very rapid removal of kilometer-thick ice sheets during the last few hundred thousand years likely results in the McMurray

Formation becoming overpressured and on ice sheet removal undergoing fracturing (S. Grasby, I. Gates, S. Larter, personal communication, 2012). Certainly, the common occurrence of oil in cap rocks and the absence of gas in most places suggest that the McMurray Formation was poorly sealed for most of its history.

Tailings Remediation

More environmentally sensitive methods of extraction, production, and upgrading of oil sands are required for surface mining. Work needs to be done regarding reclamation of tailings and remediation of open-pit-mine sites. In the surface mines of the Athabasca oil sand area, bitumen is separated from the sand mainly by a hot-water separation process. The residuum of this separation process are the tailings—a mix of produced water, unrecovered bitumen and oil, polycyclic aromatic hydrocarbons, organic matter, suspended sediment, quartz sand, clays, arsenic, mercury, salt, and trace metals (such as vanadium, nickel, and sulfur, among others). As regulated by Alberta Environment, the tailings are put into ponds for settling, consolidation, and subsequent remediation. Eventually, mature fine tailings, with 30% solids, form a slurry at the bottom of the ponds, and without the addition of other coagulants, biological polymers or other minerals (such as gypsum) could take 125 to 150 yr to naturally settle out and consolidate in the ponds (Eckert et al., 1996). Newer technologies, including consolidated tailings (CTs), speed up the process, with slurries dewatered to 30 to 35% solids in a few weeks; however, the CT and released water commonly contain toxic elements that exceed environmental standards (Chalaturnyk et al., 2004; Mikula, 2013). Most recently, the function of anaerobic microbial biofilms has been proposed as an environmentally friendly technology to dewater or densify the tailings and to detoxify the solid residuum and expelled water (Bordenave et al., 2010; Kostenko and Martinuzzi, 2013).

Pilot and Emerging Technologies

Other piloted and emerging technologies are mostly being developed for in-situ subsurface recovery and partial upgrading of bitumen and heavy oil. Two of these technologies are in-situ combustion (Nasr and Ayodele, 2005) and electrothermal dynamic stripping (McGee and MacDonald, 2009). In-situ combustion (Figure 7) is like SAGD (Figure 6) in that it uses heat to reduce the viscosity of the bitumen so it will flow to the producing well. The heat is generated by the underground combustion of part of the bitumen ore body. Air is injected underground in an injection well that is then ignited to generate a firewall of embers that burns the oil underground in the bitumen reservoir. The heavier bitumen components are burned to coke, with the lighter components flowing by gravity ahead of the firewall to the producing well. This process uses minimal water and has a fairly small surface footprint, has partial upgrading of the bitumen underground, and keeps the coke and toxic emissions sequestered, eliminating the need for surface ponds for processed water. This process is being field tested in the Athabasca oil sands, south of Fort McMurray, by Petrobank Energy and Resources, Ltd., using their patented toe-and-heel air injection (THAI™) (Ayasse et al., 2005; Nasr and Ayodele, 2005).

The Electro-Thermal Dynamic Stripping Process™ (ET-DSP™) is being field tested in the Athabasca oil-sands area in close proximity to the town site of Fort McMurray by E-T Energy, Ltd. (McGee and MacDonald, 2009). In this case, the ET-DSP™ process heats the bitumen by passing an electric alternating current through the connate water in the bitumen reservoir. During the past decade, this technology has been used commercially for remediation of contaminated soils. In the case of bitumen recovery, targeted to those reservoirs with 6 to 250 m (20–820 ft) of overburden, multiple three-electrode arrays are installed at equidistant spacing in a grid fashion, such that they are in electrical communication with one another. Three-phase electrical power is used. Within a three-electrode array, a different phase of the three-phase power is applied to each of the electrodes. This is done to create a voltage potential between the electrodes that results in uniformly heating the bitumen in the reservoir. The heated bitumen is then pumped to the surface using vertical production wells. The volume of bitumen produced is replaced by injecting produced and makeup water back down into the reservoir through the electrodes. Water is injected to cool the electrodes and to enhance subsurface heating of the reservoir. A proof-of-concept test was completed to demonstrate the technical and economic viability of the process, with ongoing expanded field tests to experiment with well spacing, electrode-extraction ratios, and completion strategies (McGee and MacDonald, 2009). Like the in-situ combustion process, the ET-DSP™ process has a minimal footprint, has minimal water usage (compared with CSS and SAGD), keeps toxic by-products underground, and also has the advantage of being able to be deployed in areas where overburden is too thin for sufficient containment of underground SAGD steam chambers. Initially, wells were completed with rod-pumping jacks; subsequently, it was found that artificial lift, using progressive cavity pumps, was needed to bring the heated bitumen to the surface.

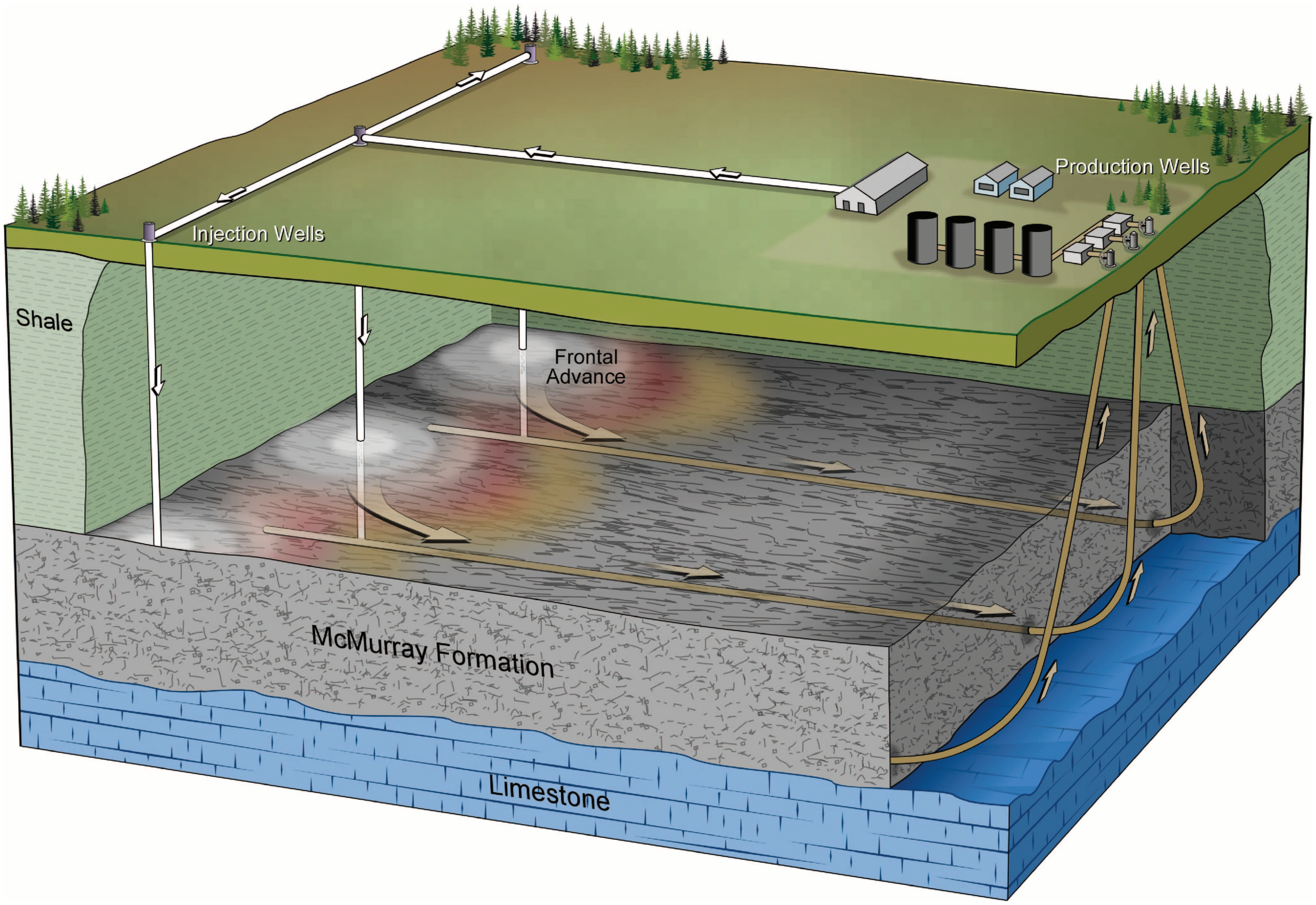

Figure 7. Schematic diagram, drawn to scale, of optimal conditions for in-situ combustion schemes being piloted in the Athabasca oil-sands area. Most of the bitumen production is from the McMurray Formation. Air is injected down vertical injector wells, which is then ignited to form a firewall of burning embers in the bitumen, which leads to a mobile oil zone that advances in front of the coke zone to the multilateral horizontal production wells.

Other alternative strategies for in-situ heavy-oil and bitumen recovery include passive heating-assisted recovery method (PHARM™), being laboratory tested by Laricina Energy, Ltd. This process uses vertical wells to passively heat the bitumen reservoir before SAGD and is being proposed to be piloted on the carbonate-bitumen deposits that underlie the Athabasca oil sands in the Saleski area (Barrett et al., 2007; Cimolai et al., 2010). This process has the advantage of preheating the bitumen reservoir before production without the use of secondary solvents or other working fluids (such as steam during circulation phases of SAGD) before production and may improve economics and efficiencies of subsequent SAGD recovery (Cimolai et al., 2010). Until the more experimental and pilot schemes are proven to be effective for scaled up in-situ bitumen extraction, water and energy demands continue to be concerns for in-situ recovery of bitumen.

Water, Steam, and Alternate Energy Sources

One of the main concerns regarding sustainable development of bitumen relates to water usage and the energy requirements, where both surface mines and in-situ operations use significant amounts of water. In surface mines, one of the newer methods for ore transport is hydrotransport technology, wherein a slurry of oil sand and water is created, which is then transported by pipeline to the extraction plant. Recycled water from tailings ponds is commonly used for hydrotransport. At the extraction plants, recycled water is also used for bitumen separation, with some makeup water from other brackish or freshwater sources, as needed. To extract bitumen from oil sands, a hot-water separation process is used in the surface mines north of Fort McMurray, Alberta, and energy is needed to heat the recycled water for this process. On average, for all surface mine operations in the area, about 0.7 m^3 (25 ft^3)

of recycled water is needed for extraction per ton of processed ore.

The other major use of water is for generation of steam for the in-situ thermal operations. The in-situ extraction of the bitumen resource is energy intensive. Under more favorable conditions, it takes, on average, about 3 bbl of water to produce the steam to extract 1 bbl of oil by in-situ thermal heating of the bitumen. By accounting for present recycling of water, the ratio becomes less than 1 bbl of water per 1 bbl oil-produced bitumen. For SAGD, an average steam/oil ratio of 2 to 3 is needed to recover more than 50% of the initial crude volume of bitumen in place. During the past few years, there has been research interest in the deep geothermal energy sources (>150°C) below the surface minable oil-sand area of Alberta as alternate energy sources to the burning of natural gas to generate steam (Majorowicz et al., 2013). Other proposals include using low-temperature shallow geothermal heating systems for preheating water in oil-sand processing facilities, to use an integrated system of geothermal energy along with carbon capture and storage (Grobe, 2010), or to use hybrid systems of both natural gas and solar energy to heat water for steam (Terrell, 2011).

CHALLENGES IN THE DEVELOPMENT OF WORLD HEAVY-OIL AND BITUMEN RESOURCES

Several ongoing challenges concern the development of the world oil-sand and heavy-oil resources. Although the U.S. Geological Survey has conducted a world survey of these unconventional deposits, one of the pressing needs is a detailed assessment of the reserves and delineation of the resources in relation to existing and developing infrastructure, technology, and transportation issues on a country-by-country basis. Coupled with the infrastructure and technology developments are the complex issues of sustainable development of the oil sands and heavy oil in relation to environmental impacts, remediation, and GHG emission concerns.

In the near-term, some of the more strategic prospective deposits for commercial development of bitumen include those in the Western Interior of the United States—the Colorado Plateau, the Paradox Basin, and most notably, the Uinta Basin in Utah (Schamel, 2013); the Black Warrior Basin, Alabama; the Maverick Basin, southwest Texas; the borderland basins of California (Hein, 2013); the Eastern Interior and Appalachian basins of Illinois and Kentucky (May, 2013); and the tri-state mid-continent region of Kansas, Missouri, and Oklahoma. With further development of infrastructure and transportation in the Arctic and Asia, the huge natural bitumen reserves of eastern Siberia are forecast to become a leading future supplier of synthetic crude oil (Kashirtsev and Hein, 2013), along with increased supply from the North Slope of Alaska (Hulm et al., 2013). Other prospective areas include the natural bitumen and heavy oil of Canada's High Arctic (Fowler et al., 2010) and the vast heavy-oil resources of China, most notably in the Liaohe Basin, northeastern China (Koopmans et al., 2002; Huang et al., 2004). Although the occurrence of world oil-sand and heavy-oil deposits outside of the main commercially developed areas (Alberta, Venezuela, Alaska, and California) has been known for a long time, it is only with the increasing demand for synthetic crude oil from nonconventional resources, along with favorable economics and improving in-situ technologies and infrastructure that these other occurrences will be more attractive. In all cases, a multidisciplinary approach of geology, engineering, and modeling, along with economics and transportation, must be used by teams of experts. In the 200 yr of emerging world economies, the huge historical gap is dwindling between the west and the rest of the world. A new approach of aid, trade, and world green technology will hopefully fund the future development of the vast unconventional bitumen and heavy-oil resources as the large Asian and Russian giant fields come on stream as future suppliers of world energy needs.

ACKNOWLEDGMENTS

Support is acknowledged from the Energy Resources Conservation Board, Calgary, Nexen Inc., the University of Calgary, and Conoco Phillips Canada. We thank Kevin Parks and Doug Boyler for helpful suggestions to improve the manuscript and Dan Magee for digital graphics. Any use of trade, product, or firm names is for descriptive purposes only and does not imply endorsement by the industry or the Alberta government.

REFERENCES CITED

AAPG, 2004, Embrace the future, celebrate the past: Annual Meeting, Dallas, Texas, April 18–21, Abstracts Volume (CD-ROM): http://www.searchanddiscovery.net/documents/2004/av/index.htm (accessed August 1, 2011).

AAPG, 2005, Exploring energy systems, global roundup: Annual Meeting, Calgary, Alberta, Canada, June 19–22, Abstracts Volume (CD-ROM): http://www.aapg.org/calgary05/index.cfm (accessed August 1, 2011).

AAPG, 2007, Understanding earth systems, pursuing the checkered flag: Annual Meeting, Long Beach, California, April 1–4, Abstracts Volume (CD-ROM): http://www.aapg.org/longbeach (accessed August 1, 2011).

AAPG, 2009, Image the past, imagine the future: Annual Meeting, Denver, Colorado, June 7–10, Abstracts Volume (CD-ROM): http://www.aapg.org/denver/index.cfm (accessed August 1, 2011).

AAPG, 2010, Frontiers of unconventional thinking: Saddle up for the ride: International Conference and Exhibition, Calgary, Alberta, Canada, Abstracts Volume (CD-ROM): http://www.aapg.org/calgary (accessed August 1, 2011).

Adams, J., B. Bennett, H. Huang, T. Koksalan, D. Jiang, M. Fay, I. Gates, and S. Larter, 2007, Controls on the variability of fluid properties of heavy oils and bitumens in foreland basins: A case history from the Albertan oil sands, *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, September 30–October 3, 5 p.

Adams, J., S. Larter, B. Bennett, H. Huang, J. Westrick, and C. van Kruisdijk, 2013, The dynamic interplay of oil mixing, charge timing, and biodegradation in forming the Alberta oil sands: Insights from geologic modeling and biogeochemistry, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 23–102.

Aitken, C. M., D. M. Jones, and S. R. Larter, 2004, Anaerobic hydrocarbon biodegradation in deep subsurface oil reservoirs: Nature, v. 431, p. 191–194, doi:10.1038/nature02841.

Andriashek, L. D., and N. Atkinson, 2007, Buried channels and glacial-drift aquifers in the Fort McMurray region, northeast Alberta: Alberta Energy and Utilities Board/Alberta Geological Survey, Earth Sciences Report 2007-01, 170 p.

Ayasse, C., C. Bloomer, E. Lyngberg, W. Boddy, J. Donnelly, and M. Greaves, 2005, First field pilot of the toe-and-heel air injection process: 6th Annual Canadian International Petroleum Conference (56th Annual Technical Meeting), Calgary, Alberta, June 7–9, Petroleum Society's CIPC Paper 2005-107.

Barrett, K. R., J. Hopkins, K. N. Wilde, and M. E. Connelly, 2007, The origin of matrix and fracture mega-porosity in a carbonate bitumen reservoir, Grosmont Formation, Saleski, Alberta, *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 2 p.

Bellman, L. W., 2007, Oil sands reservoir characterization: A case study at Nexen/Opti Long Lake, *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 3 p.

Bergerson, J. A., and D. W. Keith, 2010, The truth about dirty oil: Is CCS the answer?: Environmental Science and Technology, v. 44, p. 6010–6015, doi:10.1021/es903812e.

Bordenave, S., V. Kostenko, M. Dutkoski, A. Grigoryan, R. J. Martinuzzi, and G. Voordouw, 2010, Relation between the activity of anaerobic microbial populations in oil sands tailings ponds and the sedimentation of tailings: Chemosphere, v. 81, p. 663–668, doi:10.1016/j.chemosphere.2010.07.058.

Broughton, P. L., 2013, Depositional setting and oil sands reservoir characterization of giant longitudinal sandbars at Ells River: Marginal marine facies of the McMurray Formation, northern Alberta Basin, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 313–357.

Buschkuehle, B. E., F. J. Hein, and M. Grobe, 2006, An overview of the geology of the Upper Devonian Grosmont carbonate bitumen deposit, northern Alberta, Canada: Natural Resources Research, v. 16, no. 1, p. 3–16, doi:10.1007/s11053-007-9032-y.

Chalaturnyk, R. J., 1996, Geomechanics of the steam assisted gravity drainage process in heavy oil reservoirs: Ph.D. thesis, Department of Civil Engineering, University of Alberta, Edmonton, Alberta, Canada, 576 p.

Chalaturnyk, R. J., J. D. Scott, and B. Ozum, 2004, Oil sands tailings production for environmental disposal, *in* Y. Wang, S. Ge, and G. Guo, eds., Mining science and technology: London, United Kingdom, Taylor and Francis Group, p. 653–659.

Cimolai, M. P., S. C. Solanki, and N. R. Edmunds, 2010, Passive reservoir heating for improved bitumen recovery: Journal of Canadian Petroleum Technology, v. 49, no. 11, p. 30–42.

Collins, P. M., 2005, Geomechanical effects on the SAGD process: Society of Petroleum Engineers International Thermal Operations and Heavy Oil Symposium, Calgary, Alberta, Canada, November 1–3, Society of Petroleum Engineers/Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum/Canadian Heavy Oil Association (SPE/PS-CIM/CHOA) Paper 97905, 11 p.

Creaney, S., J. Allan, K. S. Cole, M. G. Fowler, P. W. Brooks, K. G. Osadetz, R. W. Macqueen, L. R. Snowdon, and C. L. Riediger, 1994, Petroleum generation and migration in the Western Canada sedimentary basin, *in* G. D. Mossop and I. Shetsen, compilers, Geological atlas of the Western Canada sedimentary basin, Calgary: Canadian Society of Petroleum Geologists and Alberta Research Council, p. 455–469.

Demchuk, T. D., G. Dolby, D. J. McIntyre, and J. R. Suter, 2007, The utility of palynofloral assemblages for the interpretation of depositional paleoenvironments and sequence-stratigraphic systems tracts in the McMurray Formation at Surmont, Alberta, *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 5 p.

Deutsch, C., 2010, Estimation of vertical permeability in the McMurray Formation: Journal of Canadian Petroleum Technology, v. 49, no. 12, p. 10–18.

Deutsch, C. V., 2013, Multiple-scale geologic models for heavy oil reservoir characterization, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 531–544.

Dolby, G., T. D. Demchuk, and J. R. Suter, 2013, The significance of palynofloral assemblages from the Lower Cretaceous McMurray Formation and associated strata, Surmont and surrounding areas in north-central Alberta, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 251–272.

Dumitrescu, C. C., and L. Lines, 2013, Spectral decomposition in a heavy oil and bitumen sand reservoir, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 605–623.

Dusseault, M. B., 2013, Screening criteria and technology sequencing for in-situ viscous oil production, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 655–668.

Eckert, W. F., J. H. Masliyah, M. R. Gray, and P. M. Fedorak, 1996, Prediction of sedimentation and consolidation of fine tails: American Institute of Chemical Engineers Journal, v. 42, p. 960–972, doi:10.1002/aic.690420409.

Energy Resources Conservation Board, 2010, Alberta's energy reserves 2009 and supply/demand outlook 2010–2019, ST98-2010, p. 1–A35: http://www.ercb.ca/docs/products/sts/st98_current.pdf (accessed October 1, 2010).

Fowler, M., T. Brent, K. Dewing, and M. Obermajer, 2010, Origin and significance of surface hydrocarbon seeps on Melville Island, Canadian Arctic archipelago for Sverdrup Basin petroleum systems (abs.): AAPG International Conference and Exhibition, Calgary, Alberta, Canada, September 12–15 (CD-ROM), Paper 819101: http://www.aapg.org/calgary (accessed October 1, 2010).

Fustic, M., B. Bennett, S. M. Hubbard, H. Huang, T. Oldenburg, and S. Larter, 2013a, Impact of reservoir heterogeneity and geohistory on the variability of bitumen properties and on the distribution of gas- and water-saturated zones in the Athabasca oil sands, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 163–205.

Fustic, M., D. Candiou, D. Thurston, A. Al-Dilwe, and D. A. Leckie, 2013b, Modeling by constraining stochastic simulation to deterministically interpreted three-dimensional geobodies: Case study from lower Cretaceous McMurray formation, long lake steam-assisted gravity drainage project, northeast Alberta, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 565–604.

Gates, I. D., J. J. Adams, and S. R. Larter, 2007a, The impact of oil viscosity heterogeneity on the production, *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 2 p.

Gates, I. D., S. Larter, and J. Adams, 2007b, Design of geotailored recovery processes to produce oil sand reservoirs (abs.), *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 3 p.

Gates, I. D., J. J. Adams, and S. R. Larter, 2008, The impact of oil viscosity heterogeneity on the production characteristics of tar sand and heavy oil reservoirs: Part II. Intelligent, geotailored recovery processes in compositionally graded reservoirs: Journal of Canadian Petroleum Technology, v. 47, no. 9, p. 40–49.

Gates, I. D., M. Cokar, and M. S. Kallos, 2013, Fundamentals of heat transport at the edge of steam chambers in cyclic steam stimulation and steam-assisted gravity drainage, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 625–638.

Gosselin, P., S. E. Hrudey, M. A. Naeth, A. Plourde, R. Therrien, G. van der Kraak, and Z. Xu, 2010, The Royal Society of Canada expert panel: Environmental and health impacts of Canada's oil sands industry: Ottawa, ON, Canada: The Royal Society of Canada, 414 p.

Govier, G. W., 1974, Alberta's oil sands in the energy supply picture, *in* L. V. Hills, ed., Oil sands fuel of the future: Canadian Society of Petroleum Geologists Memoir 3, p. 35–49.

Gray, F. D., P. F. Anderson, and J. A. Gunderson, 2006, Prediction of shale plugs between wells in heavy oil sands using seismic attributes: Natural Resources Research, v. 15, no. 2, p. 103–109, doi:10.1007/s11053-006-9009-2.

Grobe, M., 2010, Energy alternative: Geothermal energy continues to gain momentum, but slowly: Oil Week, July 2010, p. 18.

Head, I. M., D. M. Jones, and S. R. Larter, 2003, Biological activity in the deep subsurface and the origin of heavy oil: Nature, v. 426, p. 344–352, doi:10.1038/nature02134.

Hein, F. J., 2000, Historical overview of the Fort McMurray area and oil sands industry in northeast Alberta: Alberta Energy and Utilities Board/Alberta Geological Survey, Earth Sciences Report 2000-05, 32 p. (CD-ROM).

Hein, F. J., 2006, Heavy oil and oil (tar) sands in North America: An overview and summary of contributions: Natural Resources Research, v. 15, no. 2, p. 67–84, doi:10.1007/s11053-006-9016-3.

Hein, F. J., ed., 2011-2012, Canadian Heavy Oil Association: The first quarter century of knowledge sharing and business networking: Calgary, Alberta, Canada: Canadian Heavy Oil Association 25th Anniversary Volume, 75 p.

Hein, F. J., 2013, Overview of heavy oil, seeps, and oil (tar) sands, California, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 407–435.

Hein, F. J., and B. Fairgrieve, 2013, Joslyn Creek steam-assisted gravity drainage: Geologic considerations related to a surface steam release incident, Athabasca oil sands area, northeastern Alberta, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 747–772.

Hein, F., D. Leckie, J. Suter, and S. Larter, 2007, Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference Core Conference Proceedings, Calgary Alberta, Canada, October 4, 55 p.

Hein, F. J., G. Dolby, and B. Fairgrieve, 2013, A regional geologic framework for the Athabasca oil sands, northeastern Alberta, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 207–250.

Higley, D. K., and M. D. Lewan, 2013, Comparison of oil generation kinetics derived from hydrous pyrolysis and Rock-Eval in four-dimensional models of the Western Canada sedimentary basin and Its northern Alberta oil sands, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 145–161.

Hills, L. V., ed., 1974, Oil sands fuel of the future, Canadian Society of Petroleum Geologists Memoir 3, 263 p.

Huang, H. P., B. F. J. Bowler, T. B. P. Oldenburg, and S. R. Larter, 2004, The effect of biodegradation on polycyclic aromatic hydrocarbons in reservoired oils from the Liaohe basin, NE China: Organic Geochemistry, v. 35, no. 11-12, p. 1619–1634, doi:10.1016/j.orggeochem.2004.05.009.

Hubbard, S. M., D. G. Smith, H. Nielsen, D. A. Leckie, M. Fustic, R. J. Spencer, and L. Bloom, 2011, Seismic geomorphology and sedimentology of a tidally influenced river deposit, Lower Cretaceous Athabasca oil sands, Alberta, Canada: AAPG Bulletin, v. 95, p. 1123–1145, doi:10.1306/12131010111.

Hulm, E., G. Bernaski, B. Kostic, S. Lowe, and R. Matson, 2013, Integrated reservoir description of the Ugnu heavy-oil accumulation, North Slope, Alaska, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 437–480.

Jones, D. M., et al., 2008, Crude oil biodegradation via methanogenesis in subsurface petroleum reservoirs: Nature, v. 451, p. 176–180, doi:10.1038/nature06484.

Kashirtsev, V. A., and F. J. Hein, 2013, Overview of natural bitumen fields of the Siberian platform, Olenek uplift, eastern Siberia, Russia, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 509–529.

Koopmans, M. P., S. R. Larter, and C. M. Zhang, 2002, Biodegradation and mixing of crude oils in Eocene Es3 reservoirs of the Liaohe Basin, northeastern China: AAPG Bulletin, v. 86, p. 1833–1843.

Kostenko, V., and R. J. Martinuzzi, 2013, Potential role of microbial biofilms in oil sands tailings management, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 701–724.

Labourdette, R., J. Casas, and P. Imbert, 2008, 3D sedimentary modeling of a Miocene deltaic reservoir unit, Sincor field, Venezuela: A new approach: Journal of Petroleum Geology, v. 31, p. 135–152, doi:10.1111/j.1747-5457.2008.00412.x.

Langenberg, C. W., F. J. Hein, D. Lawton, and J. Cunningham, 2002, Seismic modeling of fluvial-estuarine deposits in the Athabasca oil sands using ray-tracing techniques, Steepbank River area, northeastern Alberta: Bulletin of Canadian Petroleum Geology, v. 50, no. 1, p. 178–204, doi:10.2113/50.1.178.

Larter, S., 2009, Engineering sustainable oil sands development (abs.): Canadian Society of Petroleum Geologists Gussow Geoscience Conference, Banff, Alberta, Canada, October 5–7 (CD-ROM).

Larter, S. R., A. Wilhelms, I. Head, M. Koopmans, A. Aplin, R. di Primio, C. Zwach, M. Erdmann, and N. Telnaes, 2003, The controls on the composition of biodegraded oils in the deep subsurface: Part 1. Biodegradation rates in petroleum reservoirs: Organic Geochemistry, v. 34, p. 601–613, doi:10.1016/S0146-6380(02)00240-1.

Larter, S. R., H. Huang, J. Adams, B. Bennett, O. Jokanola, T. Oldenburg, M. Jones, I. Head, C. Riediger, and M. Fowler, 2006, The controls on the composition of biodegraded oils in the deep subsurface: Part II. Geological controls on subsurface biodegradation fluxes and constraints on reservoir-fluid property prediction: AAPG Bulletin, v. 90, p. 921–938, doi:10.1306/01270605130.

Larter, S. R., I. D. Gates, J. J. Adams, C. Jiang, L. R. Snowdon, B. Bennett, and H. Huang, 2006, Preconditioning an oilfield reservoir: U.S. Patent Application 20100012331.

Larter, S. R., J. Adams, I. D. Gates, B. Bennett, and H. Huang, 2008, The origin, prediction and impact of oil viscosity heterogeneity on the production characteristics of tar sand and heavy oil reservoirs: Journal of Canadian Petroleum Technology, v. 47, p. 52–61.

Lewan and Associates, Inc., 1984, Major tar sand and heavy oil deposits of the United States: Interstate Oil and Gas Compact Commission, Oklahoma City, Oklahoma, 212 p.

Majorowicz, J., M. Unsworth, T. Chacko, A. Gray, L. Heaman, D. K. Potter, D. Schmitt, and T. Babadagli, 2013, Geothermal energy as a source of heat for oil sands processing in northern Alberta, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 725–746.

Marsh, R. A., J. Farnell, S. L. Harbidge, and F. Hein, 2009, Current resource assessment of the oil sands of Alberta, *in* AAPG Annual Conference and Exhibition, Denver, Colorado, June 7–10, Abstracts Volume (CD-ROM): http://www.aapg.org/denver/index.cfm (accessed June 30, 2009).

Martinius, A. W., J. Casas, M. Exposito, X. Mathieu, R. Mjøs, and J. Peralta, 2007, Sedimentological and stratigraphic analysis for high-resolution reservoir characterization of the Oficina Formation (Sincor field, Orinoco Heavy Oil belt, Venezuela), *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 4 p.

Martinius, A. W., J. Hegner, I. Kaas, C. Beharano, X. Mathieu, and R. Mjøs, 2013, Geologic reservoir characterization and evaluation of the Petrocedeño field, early Miocene, Oficina Formation, Orinoco Heavy Oil belt, Venezuela, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 103–131.

Masliyah, J., J. Czarnecki, and Z. Xu, 2010, Handbook on theory and practice of bitumen recovery from Athabasca oil sands: Volume 1: Theoretical basis: Calgary, Kingsley, 468 p.

Masliyah, J., Z. Xu, and J. Czarnecki, in press, Handbook on theory and practice of bitumen recovery from Athabasca oil sands: Volume 2: Empirical basis: Calgary, Kingsley.

May, M. T., 2013, Oil-saturated Mississippian–Pennsylvanian sandstones of south-central Kentucky, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 373–405.

McGee, B., and C. W. MacDonald, 2009, E-T Energy, Ltd., Poplar Creek 9-13-090-10W4 experimental scheme: ET-DSP™ proof of concept and expanded field test: Energy Resources Conservation Board, Annual Performance Presentation, March 1, 2009, 56 p.

Meyer, R. F., ed., 1987, Exploration of heavy crude oil and natural bitumen: AAPG Studies in Geology 25, 731 p.

Meyer, R. F., and E. D. Attanasi, 2003, Heavy oil and natural bitumen strategic petroleum resources: U.S. Geological Survey, Fact Sheet 70-03, August 2003, online version 1.0: http://pubs.usgs/fs/fs070-03/fs070-03.html (accessed December 1, 2010).

Meyer, R. F., and P. A. Freeman, 2006, Siberian platform: Geology and natural bitumen resources: U.S. Geological Survey, Open-File Report 2006-1316, 24 p.: http://pubs.usgs.gov/of/2006/1316/ (accessed December 1, 2010).

Meyer, R. F., J. C. Wynn, and J. C. Olson, eds., 1984, The future of heavy crude and tar sands: United Nations Institute for Training and Research (UNITAR), 2nd International Conference, Caracas, Venezuela, February 7–17, 1982, 546 p.

Meyer, R. F., E. D. Attanasi, and P. A. Freeman, 2007, Heavy oil and natural bitumen resources in geological basins of the world: U.S. Geological Survey, Open-File Report 2007-1084, 36 p.: http://pubs.usgs.gov/of/2007/1084/OF2007-1084v1.pdf (accessed December 1, 2010).

Mikula, R., 2013, Trading water for oil: Tailings management and water use in surface-mined oil sands, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 689–699.

Mongold, C. L., and M. E. Allan, 2007, Case studies of heavy oil reservoirs: South Belridge field, California (abs.), *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 1 p.

Musial, G., R. Labourdette, J. Franco, and J.-Y. Reynaud, 2013, Modeling of a tide-influenced point-bar heterogeneity distribution and Impacts on steam-assisted gravity drainage production: Example from Steepbank River, McMurray Formation, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 545–564.

Nardin, T., J. Carter, B. Falls, J. Irish, R. Stancliffe, B. Varban, N. Wilson, L. Zabcic, and L. Pratt, 2007, Sequence-stratigraphic and depositional facies framework of the Lower Cretaceous McMurray Formation, Kearl Oil Sands Project, Alberta, *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 2 p.

Nardin, T. R., H. R. Feldman, and B. J. Carter, 2013, Stratigraphic architecture of a large-scale point-bar complex in the McMurray Formation: Syncrude's Mildred Lake Mine, Alberta, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 273–311.

Nasr, T. N., and O. R. Ayodele, 2005, Thermal techniques for the recovery of heavy oil and bitumen: Society of Petroleum Engineers International Improved Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, December 5–6, SPE Paper 97488, 15 p.

Page, H. V., 1974, The environmental impacts of Alberta's tar sands industry, *in* L. V. Hills, ed., Oil sands fuel of the future: Canadian Society of Petroleum Geologists Memoir 3, p. 222–233.

Palmgren, C. (ed.-in-chief), 2006, The CHOA handbook: Canadian Heavy Oil Association, Calgary, 684 p.

Pemberton, S. G., and D. P. James, eds., 1997, Petroleum geology of the Cretaceous Mannville Group, western Canada: Canadian Society of Petroleum Geologists Memoir 18, 486 p.

Pemberton, S. G., D. P. James, and D. M. Wightman, 1994, CSPG Mannville Core Conference: Canadian Society of Petroleum Geologists, Exploration Update 1994, 368 p.

Peters, K. E., and J. M. Moldowan, 1993, The biomarker guide: Englewood Cliffs, New Jersey, Prentice Hall, 363 p.

Peters, K. E., C. C. Walters, and J. M. Moldowan, 2005, The biomarker guide: New York, Cambridge University Press, v. 2, 1155 p.

Phillips, P., and R. Wen, 2007, Defining vertical permeability distribution in a steam assisted gravity drainage project: An integrated multiscale approach to modeling a heavy oil reservoir: Society of Petroleum Engineers Europe/European Association of Geoscientists and Engineers Annual Conference and Exhibition, London, United Kingdom, June 11–14, SPE Paper 107195-PP, 11 p.

Rahnama, F., R. A. Marsh, and L. Philp, 2013, The Alberta oil sands: Reserves and long-term supply outlook, *in* F. J.

Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 133–144.

Ranger, M. J., and M. K. Gingras, 2007, Stratigraphy and sequence-stratigraphic surfaces of the McMurray Formation, *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 4 p.

Ren, W., J. A. McLennan, O. Leuangthong, and C. V. Deutsch, 2006, Reservoir characterization of McMurray Formation by 2-D geostatistical modeling: Natural Resources Research, v. 15, no. 2, p. 111–117, doi:10.1007/s11053-006-9011-8.

Sarzalejo, S., and B. S. Hart, 2007, Visualizing the reservoir distribution of a west-central Saskatchewan heavy oil field by integrating 3-D seismic and well log data (abs.), *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 1 p.

Sarzalejo Silva, E. S., and B. S. Hart, 2013, Advanced seismic-stratigraphic imaging of depositional elements in a Lower Cretaceous (Mannville) heavy oil reservoir, west-central Saskatchewan, Canada, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 359–371.

Schamel, S., 2013, Unconventional oil resources of the Uinta Basin, Utah, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 437–480.

Schramm, L. L., J. W. Kramers, and E. E. Isaacs, 2010, Saskatchewan's place in Canadian oil sands: Journal of Canadian Petroleum Technology, v. 49, no. 11, p. 12–21.

Stancliffe, R. P. W., and Y. Y. Chen, 2007, Palynofacies analysis of the Kearl oil sands project area: A key to resolving the depositional environments of the McMurray Formation of northeastern Alberta, Canada (abs.), *in* J. Suter, D. Leckie, and S. Larter, eds., Heavy oil and bitumen in foreland basins-from processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 1 p.

Strobl, R., 2013, Integration of steam-assisted gravity drainage fundamentals with reservoir characterization to optimize production, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 639–653.

Suter, J., D. Leckie, and S. Larter, 2007, Heavy oil and bitumen in foreland basins: From processes to products: AAPG Hedberg Research Conference, Banff, Alberta, Canada, September 30–October 3, 120 p.

Terrell, H., 2011, What's new in production, solar power enhances recovery in old oil fields, World Oil, v. 232 (March), no. 3, p. 19.

U.S. Geological Survey, 2006, Natural bitumen reserves of the United States, National Assessment of Oil and Gas, Fact Sheet, 2 p.: http://pubs.usgs.gov/fs/2006/3/33/pdf/FS2006-3133-508.pdf (accessed December 1, 2010).

Villarroel, T., A. Zambrano, and R. Garcia, 2013, New progress and technological challenges in the integral development of the Faja Petrolifera del Orinoco, Venezuela, *in* F. J. Hein, D. Leckie, S. Larter, and J. R. Suter, eds., Heavy-oil and oil-sand petroleum systems in Alberta and beyond: AAPG Studies in Geology 64, p. 669–688.

Walters, E. J., 1974, Review of the world's major oil sand deposits, *in* L. V. Hills, ed., Oil sands fuel of the future: Canadian Society of Petroleum Geologists Memoir 3, p. 240–263.

World Heavy Oil Congress, 2008, World Heavy Oil Congress Proceedings and Technical Papers, March 10–12: Edmonton, Alberta, Canada, DMG Media and Hatch (CD-ROM): http://www.heavyoilinfo.com/feature-items/world-heavy-oil-congress-2008 (accessed December 1, 2010).