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Research paper

Impact of reservoir heterogeneity on oil migration and the origin of oil-water contacts: McMurray Formation type section, Alberta, Canada

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ABSTRACT

This study documents and attempts to describe the processes leading to the formation and preservation of exposed oil, water, and paleo-gas contacts at the McMurray Formation type section, Alberta, Canada. The McMurray Formation type section, a part of the Athabasca Oil Sands Deposit (AOSD), the largest exhumed oil reservoir on Earth, is unparralled, still underutilized, natural laboratory for veryfing and refining existing, and developing new concepts, for oil migration and post oil-emplacement fluid diffusion and biodegradation processes in a sedimentologically complex reservoir setting.

Exposures, coupled with adjacent borehole data, provide a three-dimensional insight into reservoir heterogeneities and their influence on oil migration, entrapment, post-emplacement fluid mixing, and biodegradation processes and products, in a hierarchical and chronological order from early charge to present-day conditions.

The principles of oil above water and of horizontal or tilted oil/water contacts are challenged by outstanding examples of: (i) centimetre to decimetre scale inter-fingering oil-water stringers/contacts, created by capillary pressure differences and partial charge; (ii) irregular oil-water contacts in both clean and heterogeneous reservoirs characterized by gravitational effects caused by severe biodegradation that caused the formation of extra heavy-oil commonly referred to as “bitumen” that sank through the water column; (iii) occurrences of multiple metre-scale intervals with less than 50% oil saturation, commonly referred to as lean zones that formed during microbial gas generation following oil entrapment.

Studied contacts provided excellent opportunity to study oil migration and charging mechanisms from pore and sedimentary bed to reservoir scale at various stages of oil migration into the reservoir, as well as oil, water, and gas re-migration within the reservoir (trap).

Described exposures can play an additional role in advancing geoscience education, petroleum exploration, reservoir characterization, field development, and production optimization studies.

1. Introduction

Reservoir charge concepts have been outlined by England and co-workers (England, 1989, 1994; England et al., 1987, 1991; Stainforth, 2004). Petroleum migrating into a trap will normally fill the coaser beds first where the capillary entry pressures are lowest. This is characterized by a dendritic network that essentially demarcates the coarser grained parts of the reservoir within the trap. Petroleum saturation of the reservoir increases as more petroleum enters with the resulting increase of buoyant pressure causing petroleum to replace water from successively smaller pores (e.g. England et al., 1991). Later, gravity segregation occur, and gas will occupy the top of the trap, oil in the middle and water at the base. Additionally, the contacts between them are expected to be horizontal or slightly tilted due to active hydrodynamics (Dahlberg, 1995).

In the Athabasca oil sands deposit, a number of petroleum entrapment schemes have been proposed to explain how the bitumen accumulated through different trapping mechanisms. These include regional scale anticline and stratigraphic traps (Ranger, 1994; Ranger and Gingras, 2006; Tozer et al., 2014); a diagenetic trap formed by the

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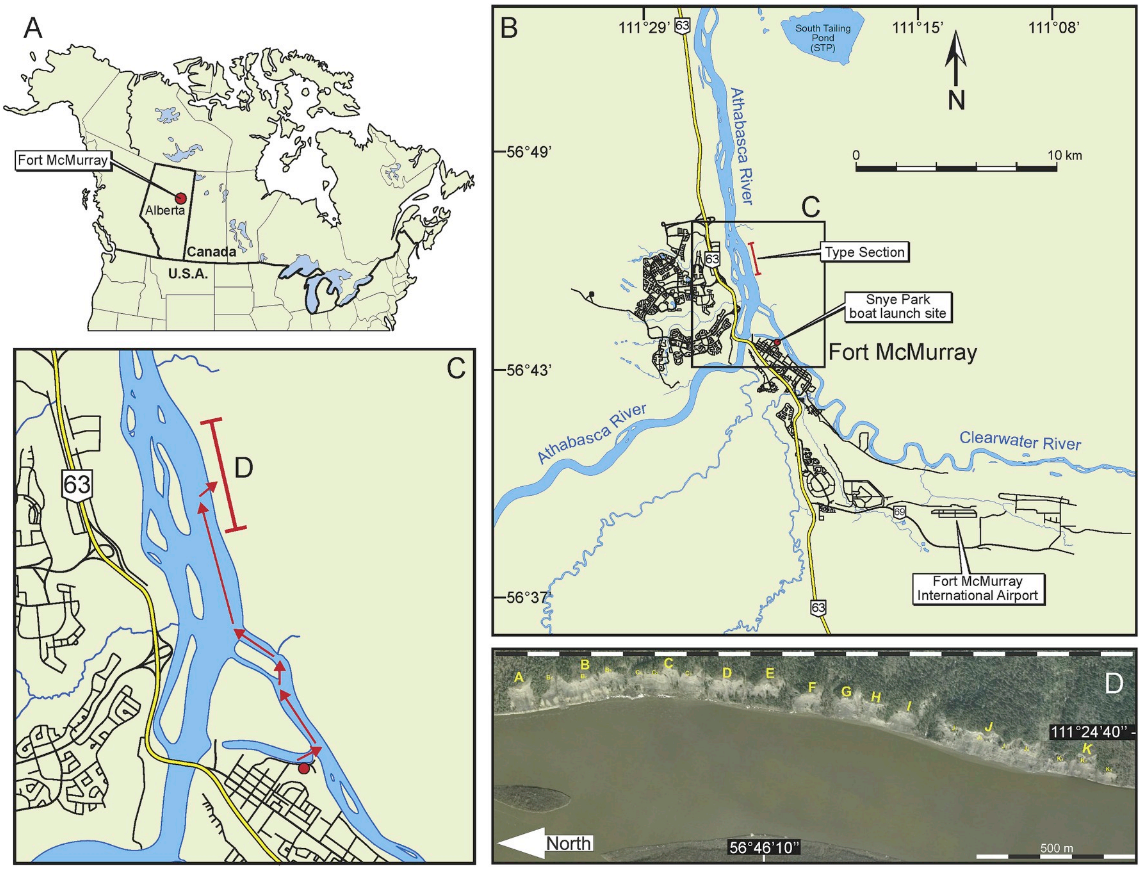

Fig. 1. **(A)** Location map showing Fort McMurray, Canada. **(B)** Fort McMurray city map. Annotated are locations of the international airport, boat launch site at Snye Park and location of the outcrop. **(C)** Zoom in on location of the boat launch site and the McMurray Formation type section outcrop. Red arrows shows boat route. **(D)** Google Earth image of type section (Image courtesy of Google Earth, © DigitalGlobe); A to K (yellow letters) is informal geographic subdivision of the outcrop; Studied oil-water contacts are on B2, I, J2, J3 and K2-3 parts of the outcrop. Modified after Fustic et al. (2018). (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

evolving properties of oil as it is biodegradation produces highly viscous and immobile bitumen which may act as a seal (Mossop, 1980; Higley et al., 2009). Although some controversies remain, the common belief is that the Clearwater shale provided regional seal, and that oil within the McMurray migrated intercompartmental fill-and-spill controlled by complex stratigraphy and reservoir architecture (Fustic et al., 2012a).

Recent regional oil characterization subsurface studies suggest that bitumen viscosity ranges from 1 to 10 million cP at 20 °C, API density from 6 to 8 with biodegradation level of 6–9 on the PM scale (Peters and Moldovan, 1993), and that basin was charged with low maturity oil generated in an early oil-generation window (Adams et al., 2013; Fustic et al., 2013a). The presence of reduced naphthoic acids (Aitken et al., 2004), polar lipid membranes (Oldenburg et al., 2009) and methanomicrobiales (Hubert et al., 2011) suggests that petroleum in the Athabasca region is degraded by anaerobic biodegradation. The major byproduct of anaerobic biodegradation pathways is a significant amount of biogenic gas generated along the oil-water contacts (Larter et al., 2006). Based on the observed crude oil biodegradation levels, the stoichiometry of methanogenic biodegradation, and selected conversion rates, Huang and Grasby (2015) calculated that approximately $141.3 \times 10^{12}\,m^3$ (4991 Tcf) of secondary biogenic methane was generated from Athabasca oil sands deposit. While about 2% of generated gas is still retained in reservoir, its vast majority leaked into the atmosphere (Huang and Grasby, 2015; Osadetz et al., 2018).

Compartment-scale reservoir charge and in reservoir fluid mixing including migration of in situ generated secondary biogenic gas were used to explain various oil-water contacts in Athabasca Oil Sands Deposits (Fustic et al., 2012a, 2013a). These studies suggests that i) top water and other highly water-saturated zones are related to the formation and the subsequent depletion of gas caps likely derived from microbial gas generation that followed petroleum entrapment; ii) multiple decimeter-scale oil-water contacts are due to the dendritic pattern of oil within partially charged reservoir zone. Additionally, these studies suggested that top water (depleted gas caps) - oil contacts are expected to be horizontal whereas basal oil – water contacts are likely undulated since caused by the denser biodegraded bitumen sunk into the basal water. Since based on sparse core and wireline data these principles remain debatable.

At the McMurray Formation type section, the very-low mobility of bitumen provides an opportunity to examine virtually “frozen in-place” geometries of oil-saturation and its relationship with characteristics and architecture of the reservoir rocks from sub-milimeter (pore) to hundreds of meters (reservoir development) scales. The overall aim of the work is to describe and interpret various oil-water contacts in geological and petroleum systems context. The objectives of this study are as follows:(i) describe and interpret various oil, water, and gas contacts, document geometries of fluid geobodies and contacts, and interpret processes leading to their formation; (ii) compare and contrast observation and findings with existing petroleum system concepts, (iii) demonstrate vailidity and importance of presented concepts for reducing subsurface interpretation and reservoir development risks.

2. Geological setting

The Athabasca Oil Sands Deposit located in northeast Alberta is estimated to have 1.53 trillion barrels of oil ($242475*10^6$ m^3; Alberta Energy Regulator, 2015). It occupies 140,200 km^2 (54132 mi^2), representing an area approximately of the size of England (130,373 km^2; 50,337 mi^2). These oil sands, hosted primarily in the Lower Cretaceous McMurray Formation, crop out along the modern Athabasca River and its tributaries. Many of these outcrops have been the focus of sedimentological, reservoir, and stratigraphic studies describing marginal marine depositional systems. However, to the best of authors' knowledge, these outcrops remained undocumented in petroleum system literature.

The McMurray Formation is formed by an upward transition from fluvial deposits to fully marine deposits and is interpreted to be formed in an overall transgressive setting (Carrigy, 1959; Flach, 1984; Flach and Mossop, 1985; Ranger, 1994; Ranger and Pemberton, 1997; Hein and Cotterill, 2006). Sedimentological, ichnological and palynological studies suggest that the majority of the preserved sediments are of tidal-fluvial origin (Hubbard et al., 2011) in settings where brackish water was present either as a result of marine influence (Wightman and Pemberton, 1997; Gingras et al., 2011, 2016) or due to the syndepositional discharge of saline groundwaters into the McMurray drainage system (Broughton, 2018; Hein and Dolby, 2018). In contrast, based on the morphology of the channels revealed by high-resolution seismic data (Smith et al., 2009; Hubbard et al., 2011; Fustic et al., 2012a, 2012b; Labrecque et al., 2011; Durkin et al., 2017) Blum (2017) suggests a fluvial setting, landward of the backwater zone.

The McMurray Formation type section is located 3 km downstream from the confluence of the Athabasca and Clearwater rivers and extends 1.6 km along the east bank of the Athabasca River (Fig. 1). Access to the outcrop is via boat, ideally during the period from the end of May to early October (when the Athabasca river is not frozen). The McMurray Formation type section is part of a major, tens of kilometers wide, north-northwesterly oriented paleo-valley system, commonly referred to as the Main Valley (Keith et al., 1990; MacGillivray et al., 1992; Fustic et al., 2012b), that was draining a large part of the North American Craton (Benyon et al., 2014; Blum and Pecha, 2014), into the Boreal Sea during the Early Cretaceous (Aptian-Albian).

Since the first documentation of oil sands along the Athabasca River by Peter Pond in 1778, qualitative geological descriptions of this outcrop were presented by Bell (1884), McConnell (1893), Ells (1914), McLearn (1917) followed by descriptive logging (Carrigy, 1959). Carrigy's (1959) outcrop log included the contact between the McMurray and the overlying Clearwater Formation, the informal subdivision of the McMurray Formation into a lower, middle and upper members, and a sedimentological description of grain size, mineralogy, cement types, induration and bitumen saturation. Although regularly visited by many geologists in recent decades, the type section was not formally documented until Hein et al. (2001) who measured four detailed logs. These included a description of sedimentary facies and provided interpretation of the depositional environment and a refined stratigraphic subdivision. Detailed correlation between their logged locations and reservoir architecture mapping was not included. Based on detailed outcrop mapping, logs from thirty boreholes and six cores from wells located behind the outcrop, Fustic et al. (2018) created a three-dimensional surface-based model (Fig. 2) for the study area. It was proposed that within the study area the McMurray Formation, comprises three major vertically-stacked stratigraphic units, each characterized by distinct depositional styles and separated by laterally extensive sub-horizontal erosion surfaces (Figs. 2–3). This interpretation is consistent with the recently proposed stratigraphic framework for the ConocoPhillips operated in situ oil-sands property located 80 km south of the outcrops (Chung et al., 2013). Thus, Chung et al. (2013) subdivision of the McMurray Formation into Early, Late and the Latest units is adopted in this study (Figs. 2–3). The Early McMurray is interpreted as multiple small-scale stacked and inter-fingered thin (3–7 m thick) meandering channel deposits (Fig. 4); the Late McMurray is interpreted as a single large-scale meander-belt deposit (up to 40 m thick and 5 km wide). Both meander intervals comprise cross-bedded sandstones in lower point bar deposits that transition into alternating finer-grained sandstone and mudstone in the form of inclined heterolithic stratification (IHS; sensu Thomas et al., 1987; Smith, 1985, 1988; Wightman and Pemberton, 1997). The sandstone-dominance is caused by a combination of high-energy flow processes that dominate the lower-point bar environment, whereas the transition to finer-grained deposits reflects an up-dip waning in flow energy during low river flow (Jablonski and Dalyrmple, 2016), velocity and stream capacity (Bridge, 2003). The Latest McMurray as low-sinuosity late-stage channel incisions formed in response to base level drop (Fig. 2; Fustic et al., 2018). All three Units belong to the middle member of the McMurray Formation (Flach pers. comm. 2018).

3. Methods

The McMurray Formation type section is sub-divided into individual "bowls" that are exposures separated by natural gullies (Figs. 1D and 3). Downstream (North) to upstream (South) the bowls are termed A to K. Some bowls are further divided into closely spaced exposures, such as bowl B which is subdivided into B1, B2 and B3.

Six long (up to 80 m long) outcrop logs collected at A, B2, D, I, J2 and K3 (Fig. 3) where used to correlate major stratigraphic surfaces such as contacts between Early, Late, and the Latest McMurray as well as between lower and upper point bar deposits within the Late McMurray (Fig. 3). Additionally, a twelve shorter (10–40 m long) detailed logs where collected through intervals of various geological interest geology above and below all fluid contacts described in this study. At each accessible parts of exposure, bed thicknesses and clast-size were estimated using a Jacob's staff or "pogo stick" (1.5 m-long wooden rod with 0.1 m subdivision, used for fast measure of true stratigraphic thickness at outcrops) and scale (0.2 m-long with 0.05 m and 0.01 m subdivisions); while a 10× magnifying lens and a grain-size chart were used to visually estimate grain-size and sorting.

Outcrop logs, integrated with scaled photo-montages and line-drawings of various geological and fluid contact allowed for creation of a detailed two-dimensional outcrop map created with the use of a Gigapan ™ (Fig. 3).

4. Results and interpretation

Five distinct oil-water contacts exposed at bowls B2 (two), I, J2 to J3, and K3-4 (Fig. 3) are described in detailed and interpreted applying a range of petroleum system concepts employed in reservoir geology context.

4.1. ***Exposure 1 (B2)***. *very-poorly consolidated oil-stained clean sand interval, Early McMurray*

UTM coordinates (56°46′35.40″N; 111°23′52.00″W)

4.1.1. *Description*

The exposure of interest is at the very base of the B2 outcrop exposure (Fig. 3). Vertically, features include a few meters thick, ripple-laminated, bitumen-saturated sandstone, ~1 m thick, very-poorly consolidated, upper-fine-grained, ripple-laminated bitumen-free, but oil-stained sandstone, ~0.4 m thick, light grey (when freshly exposed) or brown (when weathered) mudstone, and ~12 m thick fine-grained stacked channelized sandstone with individual channel units < 5 m thick, and a 1–2 m thick weathered mudstone layer, which is overlain by Late McMurray (Fig. 5). The same features are sporadically exposed at the base of bowl B3.

The lower boundary of the bitumen-free sandstone is a very sharp horizontal contact with bitumen-saturated sandstone. Core analysis from wells behind the outcrop (Appendix 1) suggests that oil saturation in bitumen cemented and poorly consolidated sands is 80% and 5–10%,

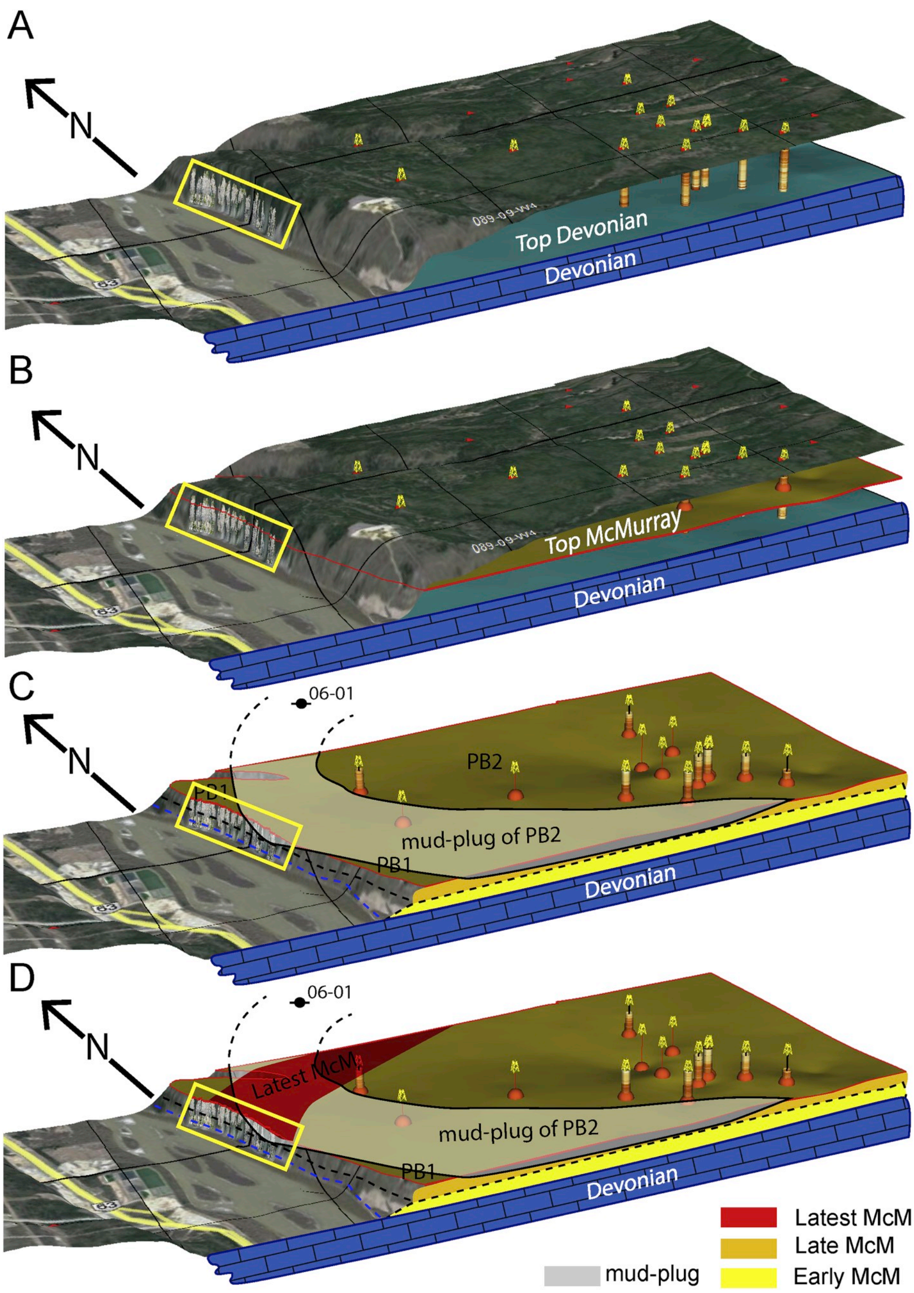

Fig. 2. Three dimensional visualization of type section outcrop along the right bank of the Athabasca River (flowing northwards), including nearby well locations, stratigraphic subdivision and major architectural elements **(A)** Surface based three-dimensional model (vertical exaggeration 5 times) showing the outcrop exposure relative to well locations, topography and underlying Devonian carbonates. Surface image is a combination of (i) google map, (ii) high-resolution aerial photo provided by Spatial Energy and (iii) terrestrial Lidar of outcrop exposure. All three surfaces are snapped on EMD topographic surface. **(B) A**s A with McMurray Formation top mapped in logs and outcrop. **(C)** As B with post-McMurray taken away and McMurray Formation sub-division into “Early” and “Late”. NOTE: “Late McMurray” is comprised of point bar 1 [PB1], point bar 2 [PB2] and mud-plug of PB2. **(D)** As C with added interpretation of the “Latest McMurray” channel incision. Point bar 2 is younger than (erodes laterally into) PB1. Yellow square shows location of detailed panorama image shown in Fig. 3. Black squares in A and B shows legal sub-division into sections, each section is 402 m by 402 m (0.25 miles by 0.25 miles). Red arrow shows well-location with geochemical log (Appendix 1). Modified after Fustic et al. (2018). (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

respectively.

4.1.2. Interpretation

The sandstone is very-poorly consolidated due to the lack of bitumen, which acts as a cement in both the underlying and the overlying sandstones. The same lithology throughout the lower two intervals coupled by absence of diagenetic changes suggest that the saturation contact is not controlled by porosity or permeability changes. The boundary between bitumen-free and bitumen saturated intervals represents a paleo-fluid contact between gas and oil legs, whereas the overlying mudstone acted as an intra-reservoir seal that separated the over- and under-lying hydrocarbon-charged sandstones. The present day basal oil-water contact at this location is covered, but its presence is inferred from nearby outcrop observations (Exposures 3 and 5) and petrophysical logs (Appendix 1).

Following migration of oil into the sandstone, it was partially displaced by microbial gas generated during the biodegradation process along an inferred underlying oil-water contact. The gas on its upward journey was entrapped by the intra-reservoir mudstone seal below which gas accumulated thus causing downward displacement of oil until gas reached a lateral spill point. The spill point defined both the lateral edge of the gas column and the elevation of a sharp horizontal (paleo-) gas-oil contact. When the closure was filled by gas, excess gas “spilled” laterally then migrated upward from the spill point thus limiting the height of the gas cap. When the transformation of oil to bitumen by biodegradation was complete, and the gas escaped, the former gas-leg was re-saturated with water. The suggested geohistory is similar to that described based on subsurface data by Fustic et al. (2013a). The ~1 m thickness of the lean zone suggests that closure provided by the overlying mudstone was quite gentle and/or of limited extent.

4.2. *Exposure 2 (B2): irregular paleo-oil-water contact, at the base of the Late McMurray*

UTM coordinates (56°46′35.48″N; 111°23′51.60″W)

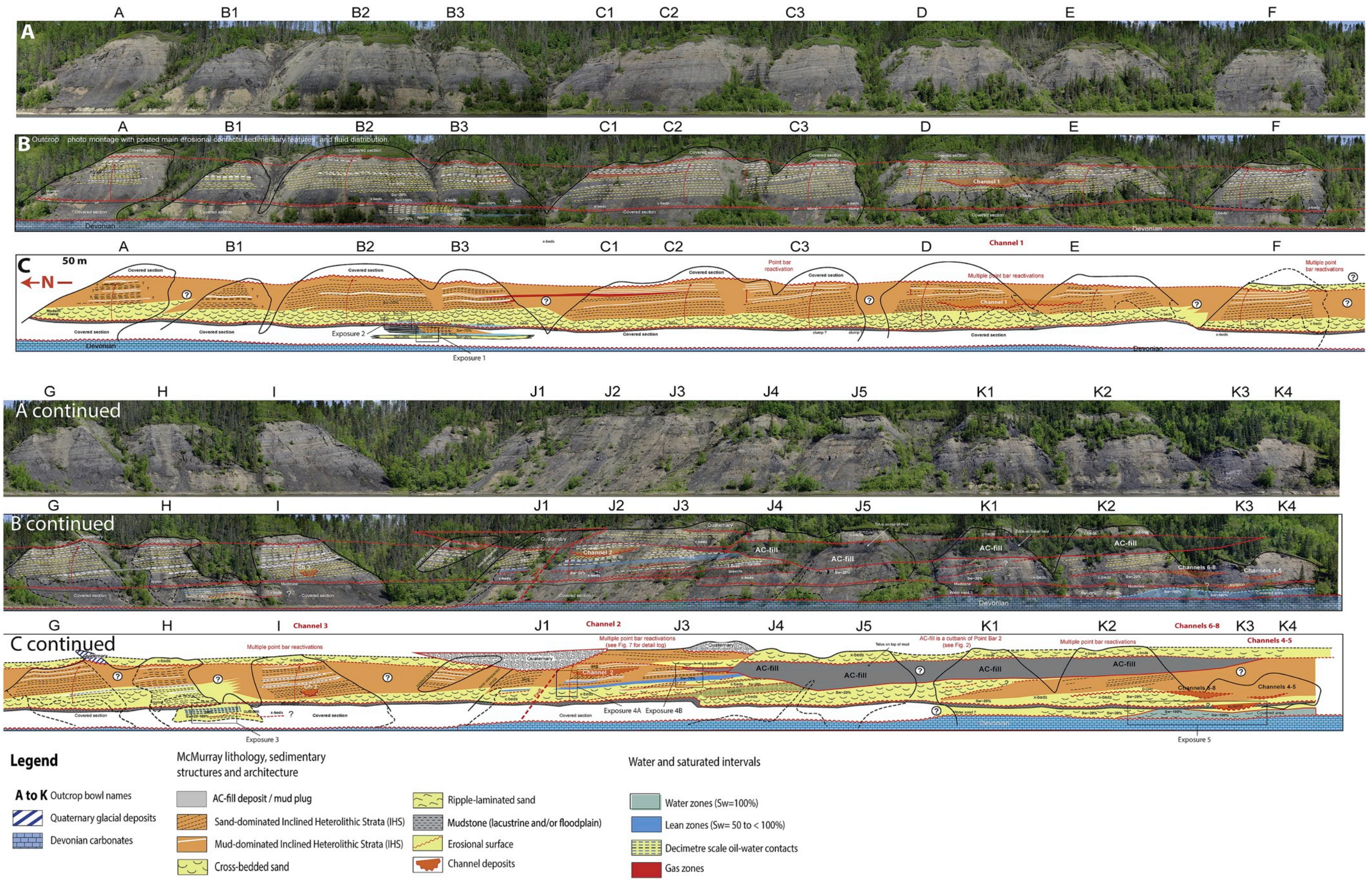

Fig. 3. McMurray Formation type section (A) High-resolution panorama image. (B) and (C) Interpretation of A. Studied exposures (Labelled as Exposures 1–5 on C) are on B2 (Exposures 1–2), I (Exposure 3), J2 (Exposure 4A), J3 (Exposure 4B) and K3-4 (Exposure 5). Modified after Fustic et al. (2018).

4.2.1. Description

The exposure of interest is immediately above the main erosional surface that marks the contact between Early and Late McMurray (Fig. 6A–C). Oil-water contacts are characterized by a step-like pattern (Fig. 6D–E). Detailed investigation of the rock-oil-water contacts reveals that horizontal parts of the contact (Fig. 6E) are marked by thin

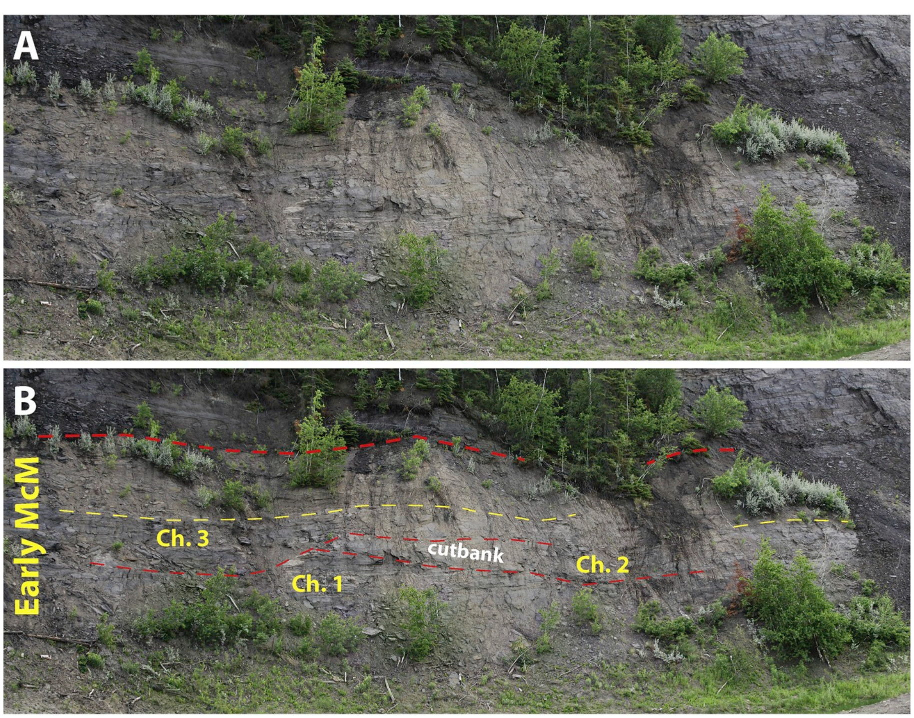

Fig. 4. (A) Superb exposure of the Early McMurray between bowls H and I (black box in Fig. 3), **(B)** Interpretation of A shows multiple stacked and interfingering small-scale channel deposits conformably overlain by continuous, weathered and/or vegetated fine mudstone dominated lacustrine and/or floodplain deposit (above yellow line), which is further overlain by Late McM large-scale point bar (above top red dashed line). Ch. – channel. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

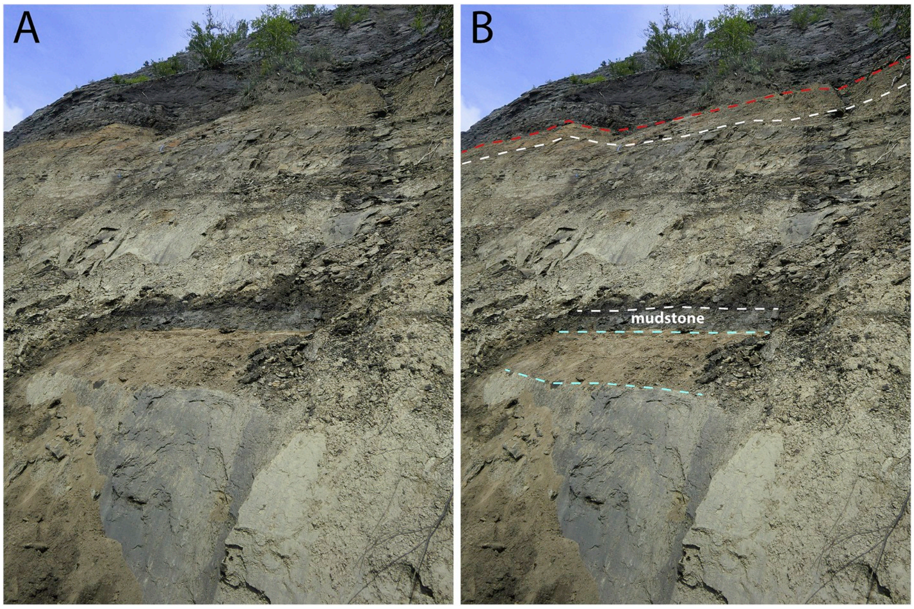

Fig. 5. Stop 1. (A) The lower part of B2 bowl (B) Interpretation of A. The bitumen-free zone is between blue dashed lines. Red dashed line, about 20 m above the base of the outcrop, is the base Late McMurray. White dashed lines bound bitumen-saturated small-scale stacked channel deposits. Continuous, ripple laminated, fine-grained, well-sorted sandstone is in both bitumen-free and bitumen-saturated intervals below thin mudstone to the base of the exposure. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

discontinuous fine-grained strata, interpreted as fluid mud dune bottomsets deposited under high-energy conditions (*sensu* Féniès et al., 1999; Dalrymple, 2010; Mackay and Dalrymple, 2011) at the bottom of a ~40 m deep river characterized by transport of high suspended sediment concentrations (Fustic et al., 2013d). Fig. 6D, F-G show decimetre-scale sharp lateral oil-water contact between black (bitumen saturated) and beige (bitumen free) poorly consolidated sandstone. In contrast to light grey colored sandstone at Exposure 1, the beige colored sandstone at this outcrop is free of oil-staining (Fig. 6D, F-H).

4.2.2. Interpretation

The lack of oil-staining suggests that the sandstone was never charged with oil. As oil migrates it rises under buoyant force through a more dense water column. However, once trapped below a seal top-down filling occurs, promoting downward migration as a part of the infill process. In clean reservoirs, the oil column becomes thicker, but oil remains on the top of the water, maintaining horizontal contact. However, low-permeability layers in heterogeneous reservoirs may locally stop downward infilling and promote lateral migration along bedding (Fig. 6D–F). Further downward migration may occur when heavy oil (denser than water) sinks under gravitational force. Thin, discontinuous fine-grained layers that mark horizontal segments of a step-like oil-water contact are likely to have significantly lower porosity and permeability than the overlying coarser grained sandstones. Hence, the fine-grained layers represent localized under-seals, which impede downward oil migration and promote lateral oil migration along the low-permeability bedding surface (Fig. 6G–E). To produce the step-like oil-water contact (Fig. 6) density driven gravitational forces must have exceeded the buoyant force.

4.3. **Exposure 3 (I)**: multiple closely-spaced, intra bed-scale oil-water contacts in stacked channel deposits, Early McMurray

UTM coordinates (56°46′7.70″N; 111°23′30.36″W)

4.3.1. Description

The area is characterized by small-scale (3–7 m thick) channel stacking and inter-fingering, including exposure of channel cutbank (Fig. 4). The exposed section is about 5–10 m vertically above the river level (Fig. 7A). Stacked channels consist of various scales of stacked cross-beds at the base (Fig. 7B–D) with IHS dominant in the upper parts (Figs. 4 and 7B). Three types of oil-water contact are present. 1) Decimetre-scale oil-water contacts prevail within the IHS with only the coarsest grained sandstone dominated units of IHS being oil saturated (the central part of Fig. 7B). 2) Decimeter-scale, inter-layered, predominantly sub-parallel and sub-horizontal, oil-water contacts within lithologically homogenous, stacked decimeter-scale cross-beds (~0.2 m thick; Fig. 7C) where oil saturation is controlled by grain-size variations. 3) Irregular oil-water contacts within lithologically homogenous, highly permeable, meter-scale, cross-bedded sandstone (Fig. 7 D).

4.3.2. Interpretation

Three variations in oil-water contacts are observed within meters of each other, which are typical of the early-phase reservoir charge of heterogeneous reservoirs where variations in hydrocarbon saturation are controlled by bed-scale reservoir characteristics. Thus oil-water contacts 1 (Figs. 7B) and 2 (Fig. 7C) are interpreted from the early stages of oil migration into the reservoir, where a buoyant oil charge preferentially migrates into the intervals with best reservoir quality. Oil migration remains confined within relatively thin layers by capillary pressure in the adjacent finer-grained strata (England, 1989, 1994; England et al., 1987; Stainforth, 2004; Fustic et al., 2013a). Following cessation of oil migration, oil remained entrapped in the high quality reservoir units and was biodegraded in place to form bitumen (Fig. 7B–C).

The third type of oil-water contact (Fig. 7D) is interpreted as partially charged, high-permeability, meter-scale cross-bedded sandstone. Unlike the previous oil-water contacts, the inferred relatively homogenous grain-size within individual cross-beds minimizes differences in capillary pressure and resulted in unconstrained oil migration. In this case, following the cessation of oil migration, oil biodegraded rapidly and because of increased density, migrated downward under gravity. Due to the lack of underseals (described in Exposure 2) downward migration continued until the oil was completely immobilized. Gravity-driven sinking of oil formed a sharp, but highly irregular oil-water contact (Fig. 7D), also observed in some cores (Fig. 7E).

At this exposure, different types of oil-water contacts show the impact and inter-play of bed-scale reservoir heterogeneity, capillary pressure variations and rapid in-reservoir biodegradation on reservoir charge and inherited oil-saturation variations. Correlation with subsurface cores indicate that multiple stacked, decimetere-scale oil-water contacts are laterally extensive for hyndreeds of meters. These are important for volumetric calculations, reservoir characterization, and particularly field-development risk assessment.

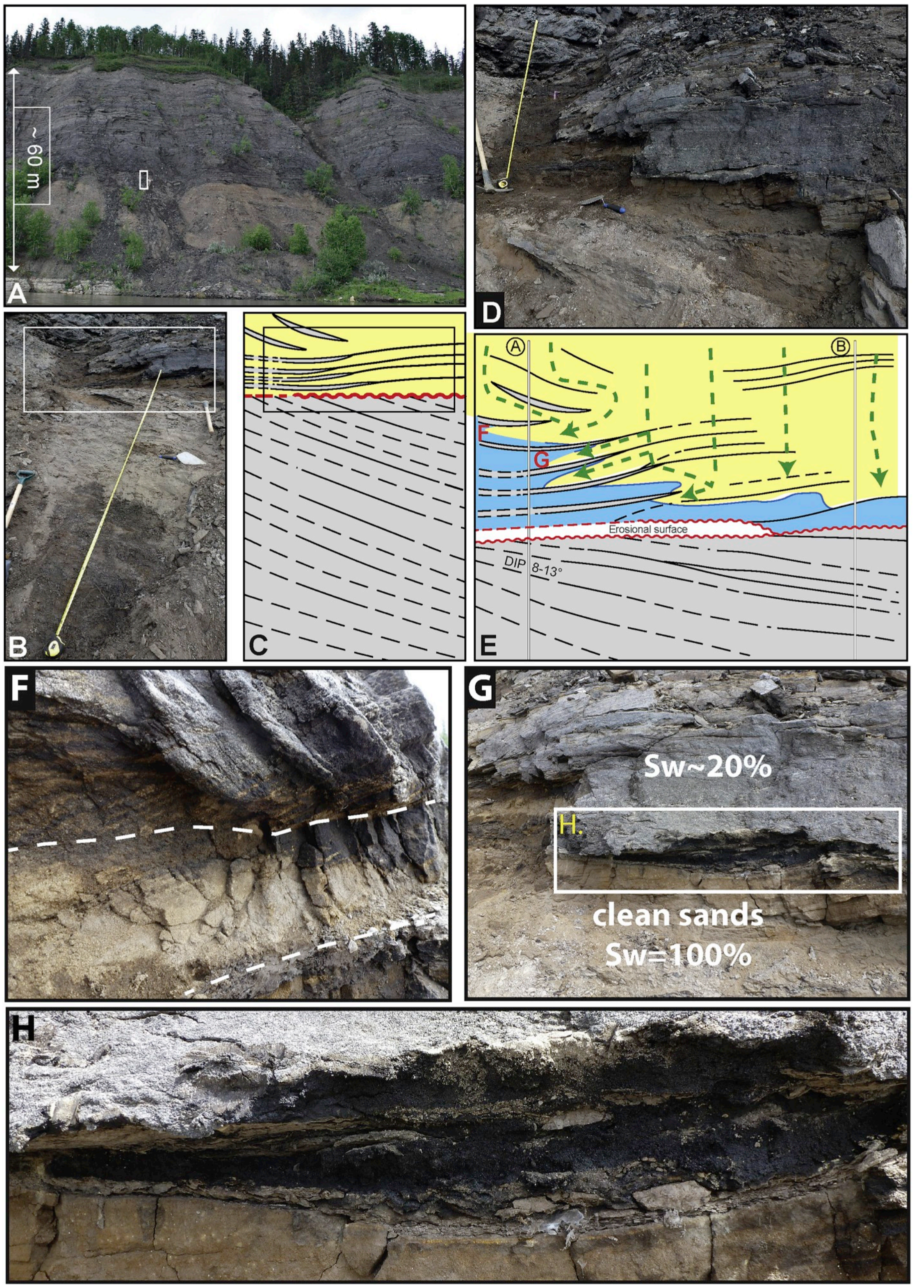

Fig. 6. Stop 2. (A) Bowl B2 (see location in Fig. 3); small white box shows location of exposure of interest. (B) Close-up view along the erosional contact of the large-scale point bar (Late McMurray) and underlying mud-dominated inclined heterolithic strata, interpreted as small-scale abandoned channel fill deposits (Early McMurray). (C) Schematic interpretation of B. (D) A close-up view of depositional beds immediately above the major erosional surface (channel base). Note how from right to left the thin (mm scale) silt dune-troughs evolve into thicker (up to 0.05 m) mud deposits. (E) Interpretation of D, showing oil-water contacts. KEY: blue: water, yellow: bitumen saturated sandstone, grey: mudstone, green arrows: top-down oil migration. The A and B locations represent placement of hypothetical wells. (F) Close up view showing how oil attempted to migrate sideways through ~0.2 m thick dune cross-bed (between two white dashed lines), but oil occupied only the most proximal parts (to the right) to areas where mudstone is stacked (as illustrated in E.) and progressively thins away until pinches out (to the left). It occupies the top part of the bed suggesting it was lighter than water. The stripe-pattern in the overlying dune cross-bed is due to partial charge limited to coarse grained foresets. (G) Close up view of contact showing how thin mud layer (grey below black) acted as under-seal for oil migration. In contrast to F, the oil occupies the lower part of the bed first, inferring it was more dense than water. Estimated water saturation (Sw) is 100% and up to 20% in bitumen-free and bitumen-saturated intervals, respectively. (H) Close up view of contact in G. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

4.4. ***Exposure 4A (J2) and 4B (J3)***: *poorly consolidated oil-stained sand intervals beneath IHS, Late McMurray*

UTM coordinates (56°45′57.78″N, 111°23′28.29″W) and (56°45′53.07″N, 111°23′24.25″W)

4.4.1. Description (J2)

Six stacked fining-upward cycles in fine-to-medium grained sandstone occur along the 35 m of exposure (Fig. 8A–C). The intervals of specific interest are between 10 and 12 m and 15.5–16 m on the sedimentary log (Fig. 8B) where, respectively two intervals of grey, oil-stained but not oil-saturated (lean zones), poorly consolidated sandstone are overlain by IHS and underlain by black bitumen-saturated sandstone (Fig. 8D, C).

4.4.2. Description (J3)

At the base of the exposure, black, bitumen-saturated sandstone is sharply overlain by grey, oil-stained (lean zones) very-poorly consolidated sandstone, which in turn is overlain by highly weathered, partially-vegetated and/or slumped IHS (Fig. 9). To the south is a large, 500 m wide and up to 25 m thick exposure of mudstone and fine-grained filled abandoned channel deposit (Figs. 3 and 9).

4.4.3. Interpretation

The 35 m thick exposure (J2) is interpreted as a single large-scale Late McMurray point bar deposit, and the overlying cliff forming bitumen saturated cross-bedded sandstone as the Latest McMurray (Figs. 3 and 9). Point-bar reactivation is suggested by truncation of underlying strata by inclined (northerly dipping) erosional surfaces (Figs. 3 and 8A-C). Northerly dipping inclined heterolithic strata (IHS) at the top of each cycle are interpreted as downstream accretion sets (Ghinassi et al., 2016). A single occurrence of southerly dipping IHS from 21 to 25 m (Fig. 8B) is part of an embedded channelized feature described by Fustic et al. (2013b) and Fustic et al. (2018) as localized short-lived chute channel deposits.

The base of lower lean zone between J2 and J3 (Figs. 8E and 9) is

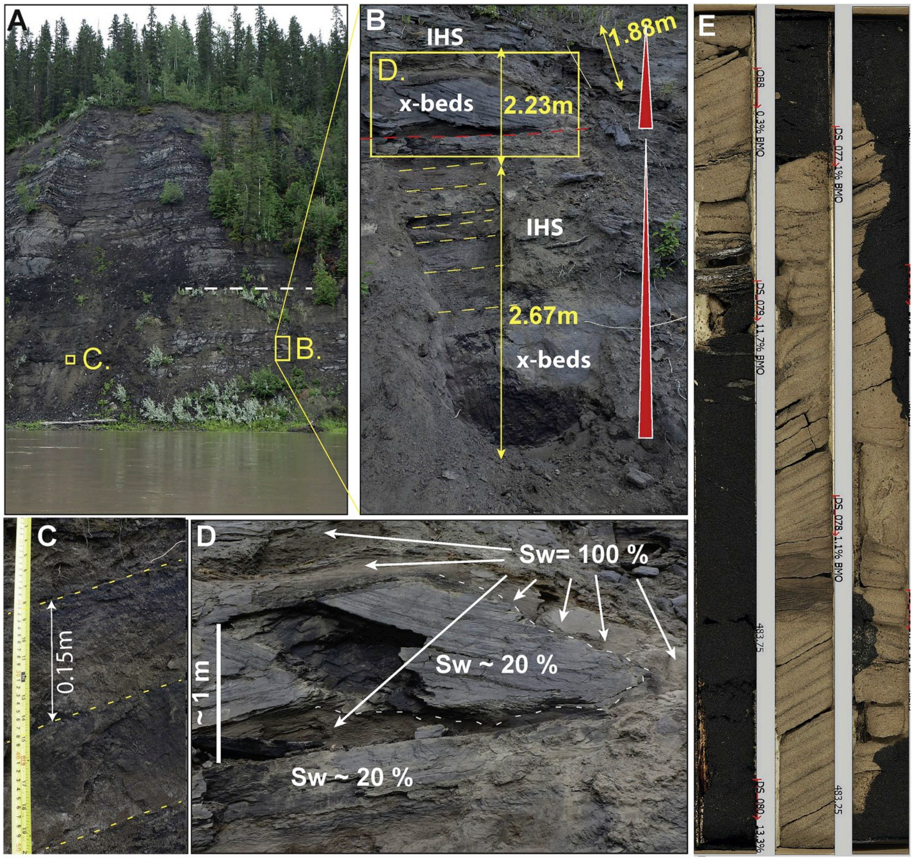

Fig. 7. Stop 3. (A) Complete outcrop exposure on bowl H (see location in Fig. 3). White dashed line shows exposed contact between Early and Late McMurray (B) Close up view of decimeter-scale oil-water contacts. The bitumen saturated sand appears black (fresh excavated surface) while the water saturated sand appears buff in color. Yellow dashed lines shows major IHS surfaces; red dashed line shows the base of meter-scale cross-bed. (C) Stacked ~0.15 m thick cross-beds (between yellow dashed lines), black – oil saturated coarser dune foreset grains, buff – fine-grained bitumen free dune lower and bottom set sands, and transition between the two. (D) Close up view of the sharp contact between bitumen saturated and bitumen-free sands within single cross-bed deposit characterized by high porosity and permeability and the absence of low permeability layers. Note that the sharp contact between bitumen (Sw ~20%) and water saturated (Sw = 100%) sands (i.e. thin white dashed line) occurs at multiple elevations and within a single cross-bed. (E) Potentially analogue core from an undisclosed location in the Athabasca Oil Sands area. Key: IHS – inclined heterolithic strata; x-beds – cross–beds; Sw – water saturation. Sw values are visual estimates based on analogy with core analysis. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

observed to be horizontal (Fig. 3) indicating its origin as a gas-cap. The limited lateral continuity of the lean zones is controlled by closure created by the combination of overlying IHS and the mud-plugged channel acting as a seal.

Considering the petroleum charge concept that in geological closures (traps), fluids honour basic physics principles that lower density fluids replaces higher density fluids (e.g. oil replaces water, and gas replaces oil; Gussow, 1954) outcrop data, such as pervasive oil stain on all sand grains, suggest that following cessation of oil migration, all sandstone above the basal oil-water contact contained reservoired oil. Subsequently some oil was displaced as microbial gas was mostly generated along the inferred underlying basal oil-water contact (Fustic et al., 2013a; Adams et al., 2013; Huang and Grasby, 2015). Gas migrated upward and was entrapped by a combination of the low-permeability mudstone of IHS and the mud-plug for which the spill point was determined by the lateral extent of the two lithofacies (Fustic et al., 2013a). An example of the spill point, identified as pinch-out or "zero" thickness of lower lean zone, is seen at J1 (Fig. 3; 56°46′0.01″N, 111°23′27.40″W). From thickness measurement of the lower lean zone, the relief of the closure was up to at least 4 m as seen at Bowl J3. Spill and fill of gas pervaded the section and formed new gas caps below successively shallower seal lithologies where closure was present, for example, at 16 m atop the lower lean zone (Fig. 8B–D). The lateral closure is likely provided by progressively finer-grained sands and associated porosity reduction along the same gentle dipping bed (~9°), representing a bed-scale stratigraphic trap, phenomena typical for IHS in both lateral and downstream accretion sets in point-bars.

Gas caps become lean zones when gas escaped during exhumation of the strata and was replaced by water. Adjacent oil could not migrate into the formerly gas-saturated volumes because by then the oil had biodegraded into a very-low mobility bitumen that has similar density to water. The suggested geohistory is similar to that described based on subsurface data by Fustic et al. (2013a).

4.5. *Exposure 5 (bowls K2-K3) - lateral oil-water-oil contacts in thick, laterally continuous, cross-bedded sandstone, Early McMurray*

UTM coordinates (56°45′45.45″N, 111°23′23.17″W)

4.5.1. *Description*

The interval of interest is about 5–15 m vertically above river level. Unlike the succession described at Stop 3, where the Early McMurray is characterized by stacked, thin and laterally discontinuous channelized sandstone with abundant IHS, here the Early McMurray is dominated by 10–12 m thick cross-bedded sandstone (Figs. 3 and 10). From a distance lateral color change from black (bitumen saturated) to grey (bitumen-free) sandstone is obvious (Fig. 10). Cross-bedded sandstone is overlain by a few meters of thick, laterally extensive mudstone dominated unit that regionally overlies sand-dominated facies of Early McMurray (Flach, pers. comm. 2018, Figs. 3, 4 and 10). The same mudstone was described at B2 exposure and is likely mapped across the outcrop (Fig. 3). An additional feature at K3 is a narrow channel incision, labelled as "Incision" that locally erodes the mudstone (Fig. 10A).

4.5.2. *Interpretation*

Absence of oil-staining in the grey sandstone intervals supports the inference that it has never been charged with oil i.e. 100% water saturated. In laterally continuous reservoirs in which the only heterogeneity is cross-bedding (Fig. 10) and there is a lack of any obvious barriers to lateral or vertical fluid flow, a horizontal oil-water contact is expected.

The channel incision at K3 (Fig. 10A) is a linear feature (Fig. 10F) that acted as a conduit for oil migration and hydraulic continuity between the Early and Late McMurray. When the Late McMurray was charged, the mudstone acted as an extensive under-seal that prevented downward filling of the oil column except through narrow erosive incisions (Fig. 10F). When oil migrated into the Early McMurray it

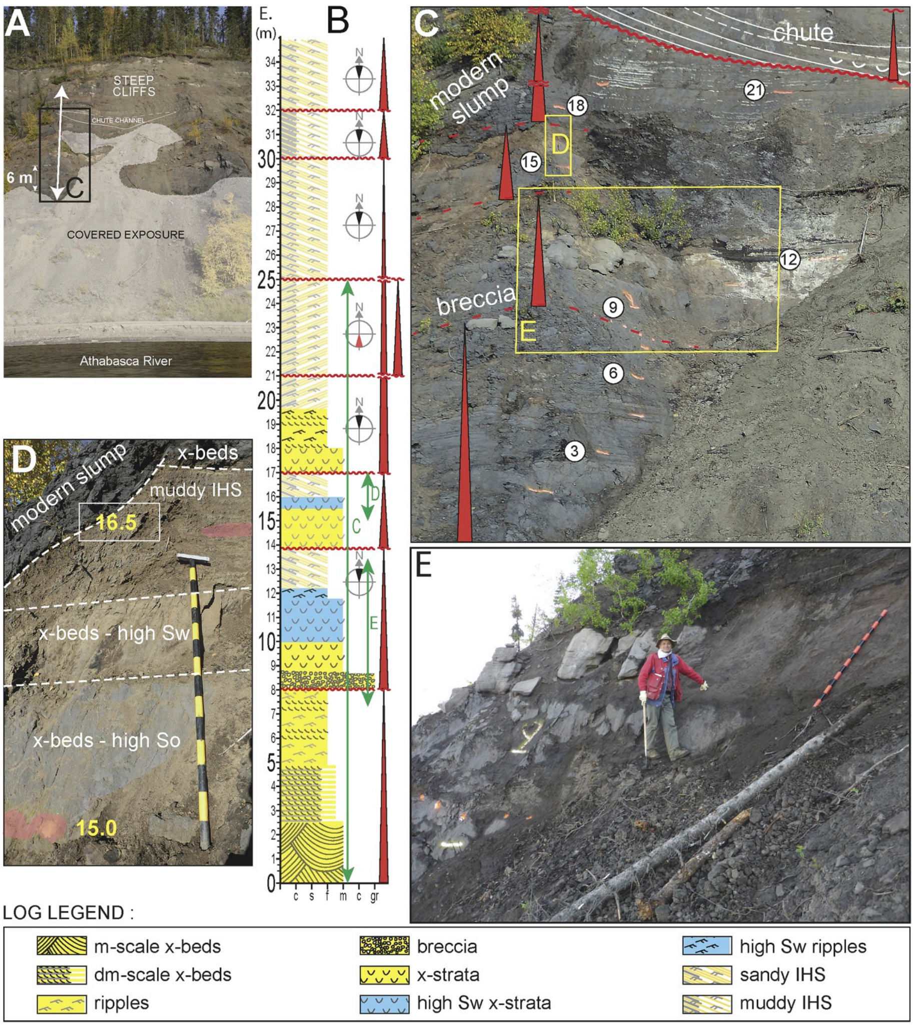

Fig. 8. Stop 4A. (A) Bowl J2. Thick white line shows approximate position of detailed log shown in B. (B) Detailed outcrop log. The lower and the upper lean zones shown in blue. Stratigraphic position of images shown in C-E indicated by double green arrow lines. (C) Close up view of the bottom 25 m of interpreted large-scale (35 m thick) point bar deposits. Numbers 3–21 shows vertical elevation in meters from the base of the channel. Thin red dashed lines shows interpreted intra-point bar reactivation surfaces; red wavy line is a base of chute channel. (D) Close up view of the "upper lean zone" at elevation of 16 m [underlying muddy IHS with underlain decimeter-scale cross-beds]. (E) Close up view of the "lower lean zone" at elevation of 10–12 m [underlying sandy IHS and underlain by decimeter-scale cross-beds. Key: IHS – inclined heterolithic strata; x-beds – cross – beds; Sw – water saturation (Sw is a visual estimate based on analogy with core analysis); E. – elevation; m – meters. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

migrated laterally and occupied the uppermost parts of the Early McMurray below the mudstone, which in this case acts as a top-seal. Lateral migration is limited by cessation of charge and the continued increase in oil density caused by biodegradation. When the oil became more dense than water then downward migration occurred, driven by gravity. Undulose contacts form when the mobility of the bitumen becomes so low that migration stops (Fig. 10).

5. Discussion

Presented cases coupled with core and log data from drillholes adjacent to the outcrop (Fig. 2; Appendix 1) suggests that almost entire Late McMurray sandstone has high oil saturation. The exceptions include localized and volumetrically insignificant low-bitumen saturation zone (Bowls J2-J3; Figs. 8 and 9) interpreted as localized depleted gas-cap and a thin bitumen free interval (Bowl B2; Fig. 6) interpreted as very localized bottom water and/or by-passed interval that remained not charged perhaps due to cessation of charge and bottom-channel reservoir heterogeneities that acted as local under-seals for petroleum migration (Fig. 6). Overall, in petroleum charge context (England, 1989, 1994; England et al., 1987, 1991; Stainforth, 2004) the Late McMurray can be considered completely charged. In contrast, (i) centimeter to decimeter scale oil-water interfingering features (Fig. 7) suggesting that the overall oil saturation in this area did not exceed 50% to overcome capillary pressure (England, 1994); (ii) thick intervals of bitumen-free cross-bedded sand characterized by an undulated lateral oil-water contact (Fig. 10); and (iii) log data from wells behind the outcrop (Appendix 1) documented in Early McMurray suggests that this unit is only partially charged.

A very narrow ratio range averaging 0.35 of biodegradation resistant tri- and mono-aromatic steroids throughout the Early and Late McMurray (Appendix 1) suggests that both units were receiving oil from the same pulse and likely simultaneously. Some oil migrated from the Later to Early McMurray because of localized gaps in the mudstone between the two intervals (Fig. 10).

The main trapping mechanism was provided by the overlying Clearwater Formation that acted as a regional seal (Fig. 11). Intraformational reservoir heterogeneities impacting the oil entrapment at the type section include: (i) laterally extensive [multi-kilometer scale] mudstone at the top of the Early McMurray (Figs. 3, 10 and 11); (ii) smaller-scale [hundreds of meters scale] mudstone layers within the Early McMurray (Fig. 5); (iii) a fine-grained-filled, large-scale channel within Late McMurray (Figs. 2–3, 9 and 11 [a curvi-linear hundreds of meters wide feature]) that likely acted as a local lateral seal during reservoir charge allowing oil to move into the next point bar deposits via the spill point at its base (Fig. 11A); (iv) fine-grained dune bottomsets [meter-scale] mudstone (Fig. 6); (v) bed-scale (decimeter-scale), grain-size variations and associated capillary pressure differences (Fig. 7).

Following reservoir charge, reservoir heterogeneity continued to play an important role for entrapment of in situ generated biogenic gases including varied scale closures: (i) mudstone layers interpreted as localized, partially preserved floodplain deposits within the Early McMurray (Fig. 5); (ii) IHS (Figs. 3, 8 and 9); (iii) a combination of IHS

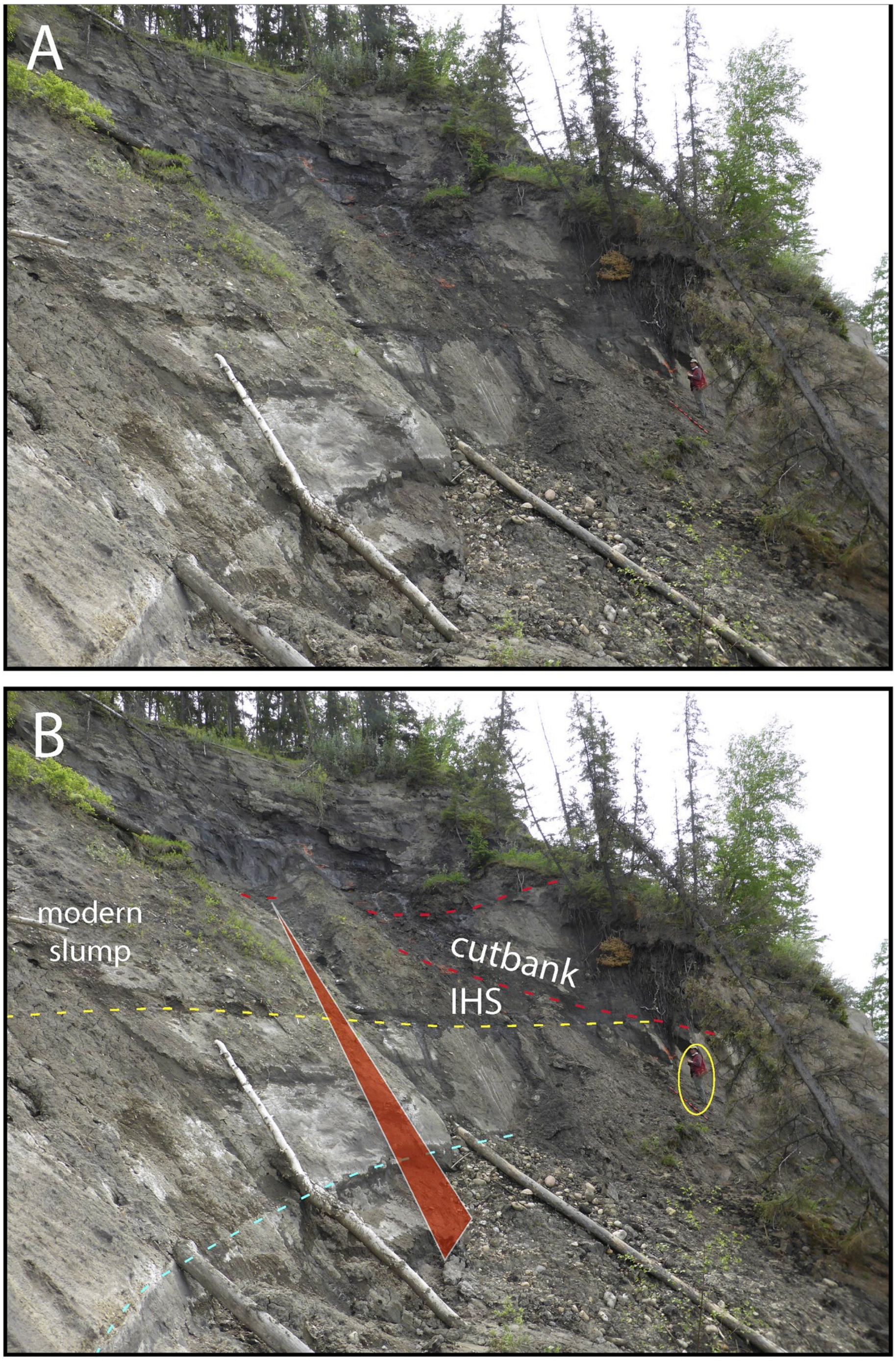

Fig. 9. Stop 4B. (A) Bowl J3 - the upper most part of the exposure from about 40 m vertically from river level to the top. (B) Interpretation of A. Key: Light blue line - base of grey-colored unconsolidated sand interpreted as "lower lean zone"; yellow dashed line - the base of sandy IHS interpreted as top of depleted gas cap; red dashed lines: (lower) cutbank low-permeability fine-grained and mudstone filled abandoned channel deposit which also acts as lateral seal for depleted gas-cap and (upper) erosional base of cross-bedded sand interpreted as the Latest McM (Fig. 2); man in yellow circle for scale. Red triangle shows overall fining upwards grain distribution. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

as vertical seal and a fine-grained mudstone dominated abandoned channel fill deposit as lateral seal (Figs. 9 and 11B-C); inferred lateral lithology changes along gently dipping IHS beds (i.e. lean zone 2 at Exposure 4A). Gas caps evolve into lean zones when gas escaped and the space is re-occupied by water (Figs. 5, 8, 9 and 11D). Adjacent oil could not re-occupy the former gas cap because, by that time, the oil was immobilized by biodegradation (*sensu* Larter et al., 2006; Bennett et al., 2006; Adams et al., 2013; Fustic et al., 2013a. A suggested geohistory is illustrated in Fig. 11.

6. Implications to reservoir developments

This outstanding, 1.6 km long exposure, clearly demonstrates the range of risks of interpreting geological heterogeneities between wells drilled as close as 400 m apart. Analysis of this outcrop provides tools and concepts for improved understanding of subsurface data. Additionally, it is an analogue for scales of reservoir challenges that are commonly encountered over the life cycle of steam assisted gravity drainage (SAGD) well-pairs and thus provides a field example to help conceptual considerations for optimizing wells via scab-liner, steam-split and other approaches employed when steam encounters barriers, baffles and/or lean zones. SAGD is a common method of choice for producing bitumen. Pairs of horizontal wells placed about 5 m apart are used; steam is injected into the upper well, heating the bitumen, thereby reducing viscosity and resulting in flow through slots in the lower well, where it is pumped to the surface. Over time steam chamber, driven by buoyancy grows vertically until reaching continuous low-permeability layers such as IHS (Strobl et al., 1997; Strobl,

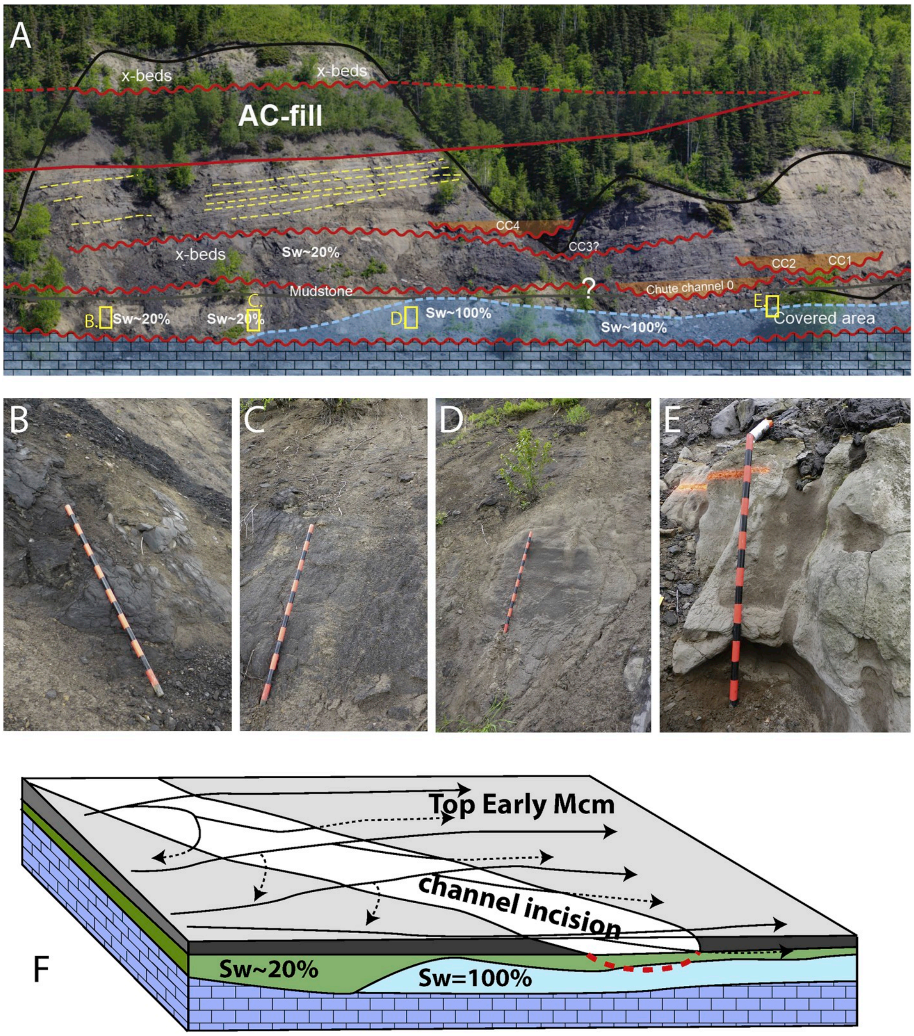

Fig. 10. Stop 5. (A) Bowls K2-4. Yellow squares show location of zoomed in images shown in the B-E. Red wavy lines are major erosional surfaces. The second wavy line from the bottom is the base of a large-scale channel deposit, underlain by a couple of meters thick mud except in orange colored area (labelled "Chute Channel 0") where it is eroded. The third wavy line is interpreted as intra-point bar reactivation surface. Blue dashed line shows oil-water contact. (B) and (C) Black colored, bitumen saturated cross-beds. (D) Buff colored bitumen-free sand. (E) Vertical oil-water contact within cross-bedded sandstone. (F) Schematic three-dimensional visualization with top Early McMurray and proposed oil-migration pathways. Key: x-beds – cross – beds; Sw – water saturation. Sw is a visual estimate based on analogy with core analysis; grey – fine-grained and/or mudstone deposit; green – bitumen saturated cross-beds; blue – water saturated cross-beds, blue brick pattern – Devonian carbonates. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

2013).

The fact that a 0.4 m thick mudstone acted as an effective seal for gas (Fig. 5) implies that in analogous reservoirs, similar thin mudstone can be a localized seal during fluid migration and also a significant vertical barrier for oil flow during production, particularly in energy-intensive thermal recovery processes. In thermal oil-recovery processes, lean zones, which have a higher mobility fluid fill (water) than the bitumen-saturated zones (Figs. 8 and 9), impair production by causing steam losses (Fustic et al., 2013a, 2013c), while IHS lithofacies commonly act as a barrier to vertical steam rise and thus may limit the height of the steam chamber that can develop (Strobl et al., 1997; Strobl, 2013). IHS acted as a seal for insitu generated biogenic gas likely suggests it being a barrier for steam growth too. Extrapolating bitumen-water contacts in partly-charged reservoirs and/or compartments (Figs. 6, 7 and 10) using sparse well control is likely a significant risk when calculating oil in place, and doing field development.

7. Conclusions

The outcrop observations of bitumen-saturated, bitumen-free and high-water saturated (lean zones) sands and their context with respect to reservoir heterogeneity provide an unparalleled portal for conceptual studies of the geological controls on the interplay of oil migration, entrapment, in-reservoir mixing, and biodegradation through space and time. The compartmentalized and heterogeneous nature of the reservoir (Figs. 2–3) complicated oil migration and led to formation of multiple isolated oil-water contacts.

7.1. Documented examples of oil water contacts include

(i) centimetre to decimetre scale inter-fingering oil-water stringers/contacts, created by capillary pressure differences and partial charge;
(ii) irregular oil-water contacts in both clean and heterogeneous reservoirs characterized by gravitational effects caused by severe biodegradation that caused the formation of extra heavy-oil commonly referred to as "bitumen" that sank through the water column;
(iii) occurrences of multiple metre-scale intervals with less than 50% oil saturation, commonly referred to as lean zones that formed during microbial gas generation following oil entrapment.

The interpreted inherited contacts are useful for improved understanding of reservoir development risk assessment, including well-placement planning and production optimization in complex reservoirs.

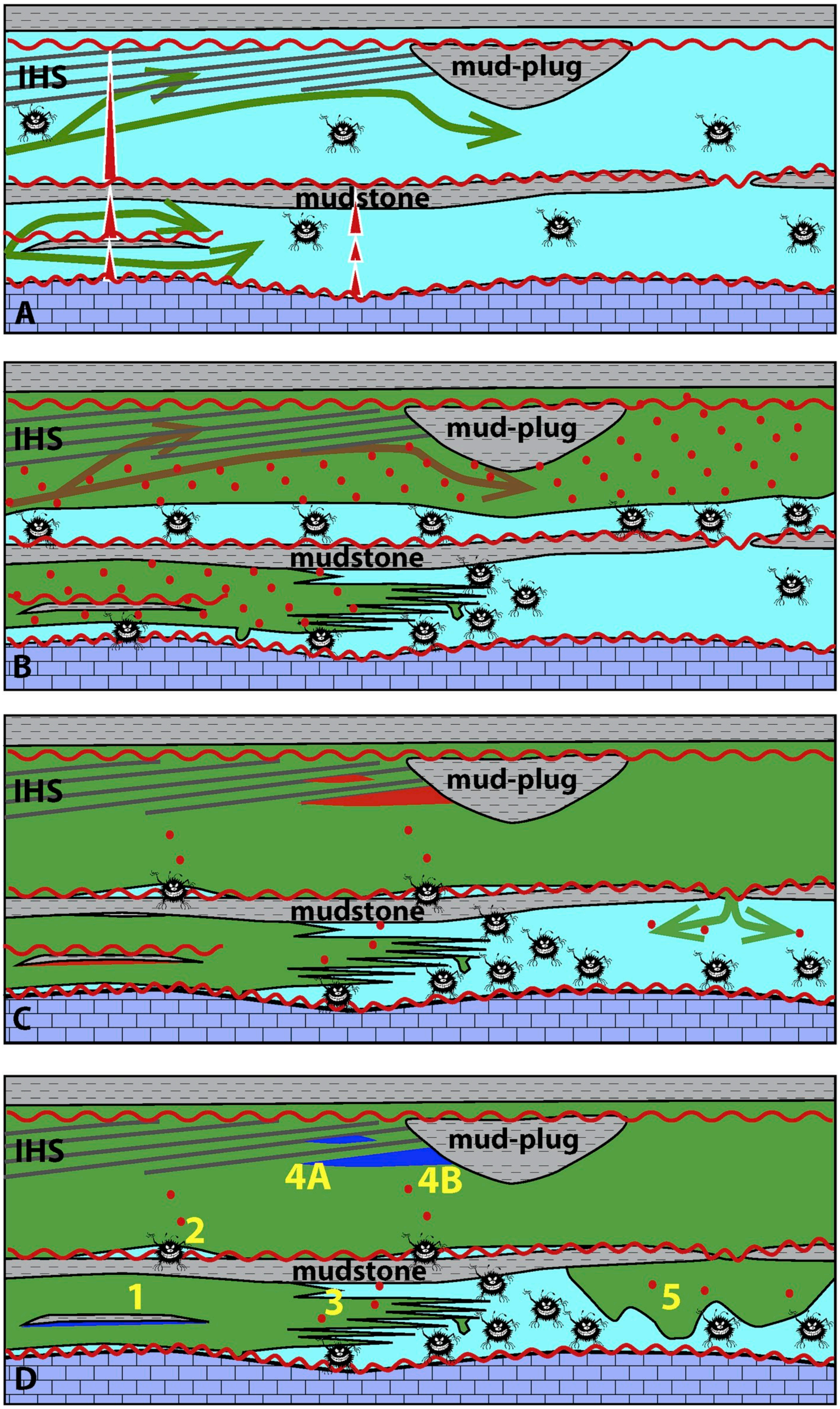

Fig. 11. Conceptual cross-section depicting major geologic features and events contributing to the present-day bitumen accumulation, including reservoir charging, in-reservoir mixing, and biodegradation processes discussed. Simplified geological framework from Figs. 2 and 3. (A) Early stages of reservoir charging. (B) Later stages of reservoir charge and established oil-water contacts along which intensified biodegradation increases oil viscosity and produces biogenic gases (red dots). (C) Biogenic gas accumulated in various closures; the upper compartment virtually filled with minor localized by-passed intervals at the base; excess oil migrates from the upper to the lower compartment. (D) Present-day distribution of bitumen and water (note escaped gas zones are re-occupied by water). IHS = inclined heterolithic strata; Numbers 1–4 schematic study locations. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

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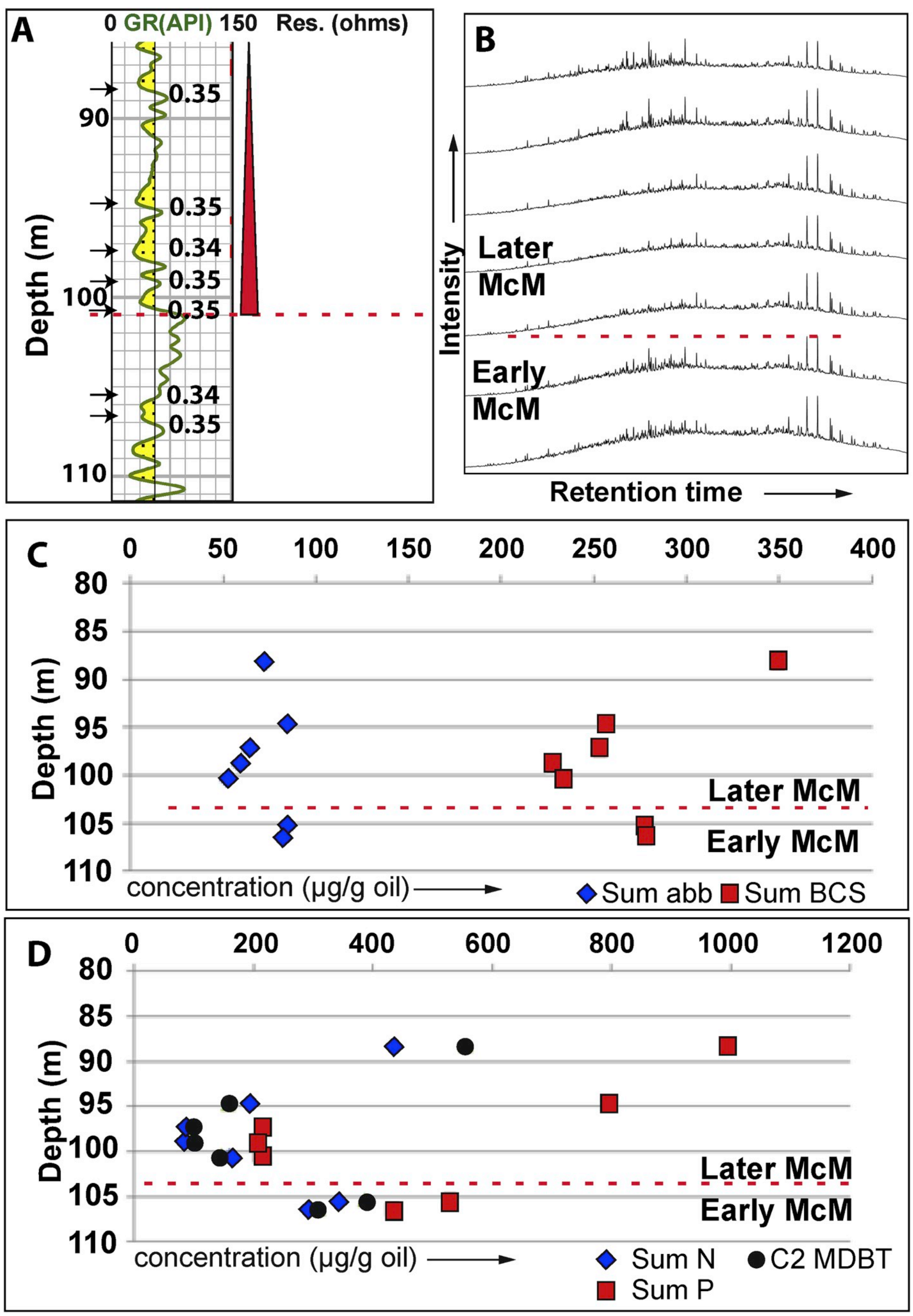
Appendix 1. Petroleum geochemistry

Hydrocarbon compounds in core extracts from drillhole 1AA/14-26-089-09W4M near the outcrop (Fig. 2) were used to assess both the thermal maturity and the extent of biodegradation of the bitumen.

The variation of biodegradation resistant tri- and mono-aromatic steroids shows a very narrow range averaging 0.35. This commonly employed thermal maturity parameter suggests that oil was charged from a single petroleum-generation pulse in the early oil-generation window. These results are consistent with other thermal maturity studies for the McMurray Formation (Adams et al., 2013; Fustic et al., 2013).

Geochemistry of biodegradation susceptible molecular markers utilizes the presence of molecular compositional gradients and breaks to define reservoir continuity and compartmentalization, respectively (i.e. Fustic et al., 2011). Partially reconstructed ion chromatograms and molecular concentration logs of selected saturated and aromatic biodegradation molecular markers show significant concentration variations. Results suggest two stacked vertical molecular concentration gradients, with a break coinciding with the Early and Late McM contact. This confirms that the mudstone at the top of the Early McM acted as an effective barrier for fluid communication between the Early and the Later McM on the geological time scale, impacting both reservoir charge and in-reservoir fluid mixing.

An exception is the localized inter-compartmental communication created by an incising channel which eroded the mudstone as observed at stop 5.



Appendix 1. Fig. caption. Well 1AA/14-26-089-09W4M. **(A)** Gamma-ray and Resistivity logs with posted locations of geochemical samples (black arrows) and ratio of tri- and mono-aromatic [TAS/(TAS + MAS)] steroid concentrations (bold 2 decimal numbers at sampled locations. Gamma-ray (GR) log has colored yellow cutoff at 60 API (American Petroleum Institute units). The resistivity log (Res.) is logarithmic scale with green color cutoff on 20 ohms. Red dashed line – contact between Early and Late McMurray; blue line – OWC; OWC – oil-water contact; red triangle – fining upward sequence of a single point bar deposit. **(B)** Partial reconstructed total ion chromatograms showing the distributions of hydrocarbon compounds in selected core extracts. **(C)** Concentration profile with depth (m) representing selected saturated hydrocarbons. Key: Sum abb = summed C27-C29 abb steranes; Sum BCS = summed C14-C16 bicyclic sesquiterpanes. **(D)** Concentration profile with depth (m) representing alkylaromatic and sulfur compounds. Key: Sum N = summed C0-C5 alkylnaphthalenes, Sum P = summed C0-C2 alkylphenanthrenes, Sum C2 MDBT = summed C2 alkyldibenzothiophenes.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.marpetgeo.2019.01.020.

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