237 (2024) 212807

Contents lists available at ScienceDirect

Geoenergy Science and Engineering

journal homepage: www.sciencedirect.com/journal/geoenergy-science-and-engineering

Effects of matrix on oil sands texture and bitumen distribution in the Cretaceous McMurray Formation, Alberta, Canada

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ARTICLE INFO

Keywords:
Matrix effect
Oil sands texture
Biodegradation degree
Bitumen distribution
McMurray formation

ABSTRACT

With the depletion of world energy resources, unconventional energy sources such as heavy oil and oil sand are attracting widespread attention. The Lower Cretaceous McMurray Formation in Athabasca has abundant oil sand resources, and the relationship between reservoir characteristics and bitumen heterogeneity has always been a research hotspot. However, the effect of interstitial material (matrix) in oil sand on the distribution and properties of bitumen is often overlooked. In this study, thin-section petrography, fluorescence microscopy, scanning electron microscopy (SEM), X-ray diffraction (XRD), porosity and permeability gas measurements, organic matter extraction and separation of group components, and gas chromatography-mass spectrometry (GC-MS) were used to investigate the oil sands of a well in the Mackay River area. The results indicate that the matrix has a significant influence on the physical properties, support mode, and storage space of oil sands. The oil sands can be identified into three types according to the matrix content and texture: arenite (<15% matrix content), grain support, and predominantly intergranular pores; L-wackes (15–25% matrix content), grain support, dominated by intergranular pores and matrix micropores; H-wackes (>25% matrix content), matrix support, matrix micropores and micro-fractures as the main storage space. Geochemical surveys and biodegradation evaluation, indicate that arenites have good connectivity, but are vulnerable to formation water and microbial degradation, with most of the hydrocarbons being consumed by serious biodegradation. The tight matrix layers in H-wackes limit initial oil charging, resulting in poor oil interval. L-wackes contain an appropriate amount of matrix, which does not limit initial oil charging, and the matrix can absorb and protect hydrocarbons, reducing the degree of biodegradation. Therefore, considering matrix can further consummate the formation mechanism of water, oil, and poor oil interval in oil sand reservoir, provide more comprehensive information for predicting the distribution and quality of bitumen, and optimize well-site deployment and bitumen recovery.

1. Introduction

Oil sands and heavy oil have become important unconventional hydrocarbon resources in recent years, and the technology of exploration and recovery processes has therefore received increasing attention (Hein, 2006, 2017; Hein et al., 2013b; Rodriguez et al., 2022, 2023). The relationship between oil sand reservoir characteristics and bitumen distribution has long been a focus of research (Day-Stirrat et al., 2021; Fustic et al., 2006). Many previous studies have shown that the mineral composition (Osacky et al., 2013a), mineral chemistry (Osacky et al., 2013b), and clay minerals content of oil sands (Day-Stirrat et al., 2021), as well as their porosity and permeability (Babak and Resnick, 2016), are closely related to the distribution of bitumen.

It is well known, that oil sands are primarily composed of inorganic materials, water, and bitumen, but their interactions and arrangements are complex (Czarnecki et al., 2005; Doan et al., 2012; Takamura, 1982). Early experiments using sieve analysis determined that fine sand grains have higher bitumen contents than coarse sand grains, but the bitumen content of silt and clay sand grains is very low (Carrigy, 1959). Subsequent research also considered the degree of sorting and found that the average bitumen content of well-sorted fine-grained sand was greater than that of poorly-sorted silt (Carrigy, 1962). There have also been

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https://doi.org/10.1016/j.geoen.2024.212807
Received 27 August 2023; Received in revised form 25 January 2024; Accepted 29 March 2024
Available online 3 April 2024

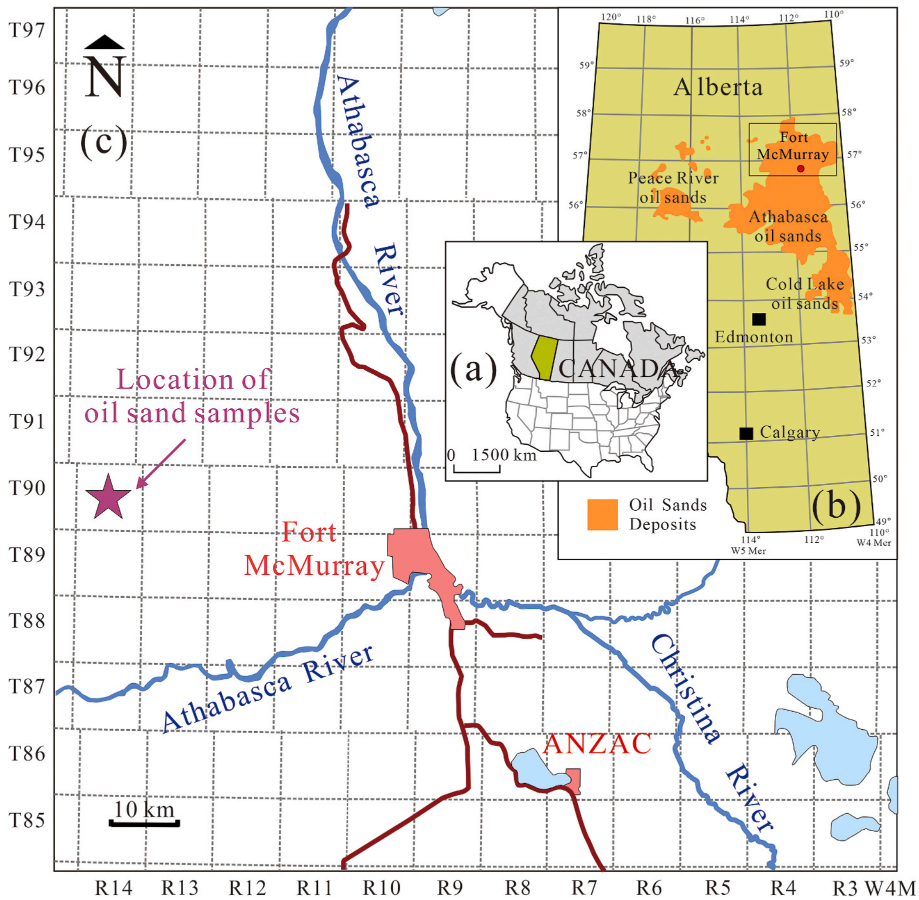

Fig. 1. Location of the research area, modified after (Fustic et al., 2013). (a) Location of the Alberta Basin (yellow part) in Canada. (b) Distribution of the oil sands deposits (orange part) in the Alberta Basin. (c) The location of sampling well in the Mackay River area is indicated by the purple star, approximately 35 km northwest of Fort McMurray.

reports that the bitumen content of oil sands decreases as medium-diameter grains decrease, and decreases with an increase in the proportion of clay grains (Czarnecki et al., 2005). In addition, clay materials have a crucial impact on the structure, composition, and bitumen content of oil sands. For example, the content of clay in oil sands is negatively correlated with the recovery rate of bitumen, while there is a strong positive correlation between clay content and the proportion of silt (Day-Stirrat et al., 2021; Oh and Jo, 2021; Osacky et al., 2013b). In recent studies, the Athabasca oil sands have been described as loose, unconsolidated, and different from conventional reservoirs. The detrital microscopic characteristics, including size, roundness, sorting, distribution, weathering, and diagenesis, combine to determine the bitumen contents of oil sands (Abram and Cain, 2014; Czarnecki et al., 2005; Doan et al., 2012).

Most studies have focused on the relationship between detrital characteristics and bitumen content, neglecting the effect of matrix on the texture of oil sands. Matrix is a type of interstitial material, defined as interstitial material with grain sizes less than 0.03 mm that is mechanically deposited with sand and gravel in clastic rock (Dickinson, 1970). The significance of matrix in the fields of petroleum and geology has been widely recognized, as it affects the rock structure, reservoir physical properties, and on-site development (Aschwanden et al., 2019; Wong and Maini, 2007). In addition, the secondary alteration of crude oil by biodegradation is considered one of the main reasons for diversity in bitumen distribution and properties in the study area (Brooks et al., 1988; Head et al., 2003; Larter et al., 2003). The factors controlling biodegradation levels include reservoir physical properties (Fustic, 2007; Larter et al., 2005), temperature (Zekri and Chaalal, 2005), nutrients (Chaineau et al., 2005), and microorganisms (Morozova et al., 2011). As a storage space for bitumen, the texture of the oil sand and the degree of biodegradation suffered by bitumen have not been fully considered.

For this study, oil sand samples from the Cretaceous Upper McMurray Formation in the Mackay River area of Athabasca were selected. The role of matrix in oil sands is analyzed based on thin-section petrography and petrophysical data. The effect of matrix on the distribution of bitumen within oil sands and its mechanisms are discussed in combination with the molecular composition of saturated and aromatic hydrocarbons. All samples are from the same formation in the same well, and there are three reasons for this: It excludes significant lithological differences; there is no interference from complex diageneses; and it avoids differences between source rocks and variations in maturity.

2. Geological settings

Canada has the richest oil sands resources in the world. Oil sands are found in the Athabasca, Pease River, and Cold Lake regions of the Alberta Basin (Broughton, 2013; Flach and Mossop, 1985; Mossop, 1980) (Fig. 1a and b). Most of Athabasca's oil sands are in the Lower Cretaceous Mannville Group sandstone, which includes the Aptian McMurray Formation (114 Ma) and the Albian Wabiskaw, Clearwater, and Grand Rapids Formations (107 Ma) (Labrecque et al., 2011; Musial et al., 2012). The McMurray Formation in the Mannville Group is the most promising oil sand reservoir, with an average burial depth of no more than 200 m and an average thickness of 40–60 m (Ranger, 1996). The McMurray Formation unconformably overlies Devonian carbonate rocks. Above the McMurray Formation is the Clearwater Formation, which consists of marine shales and contains glauconite sandstone

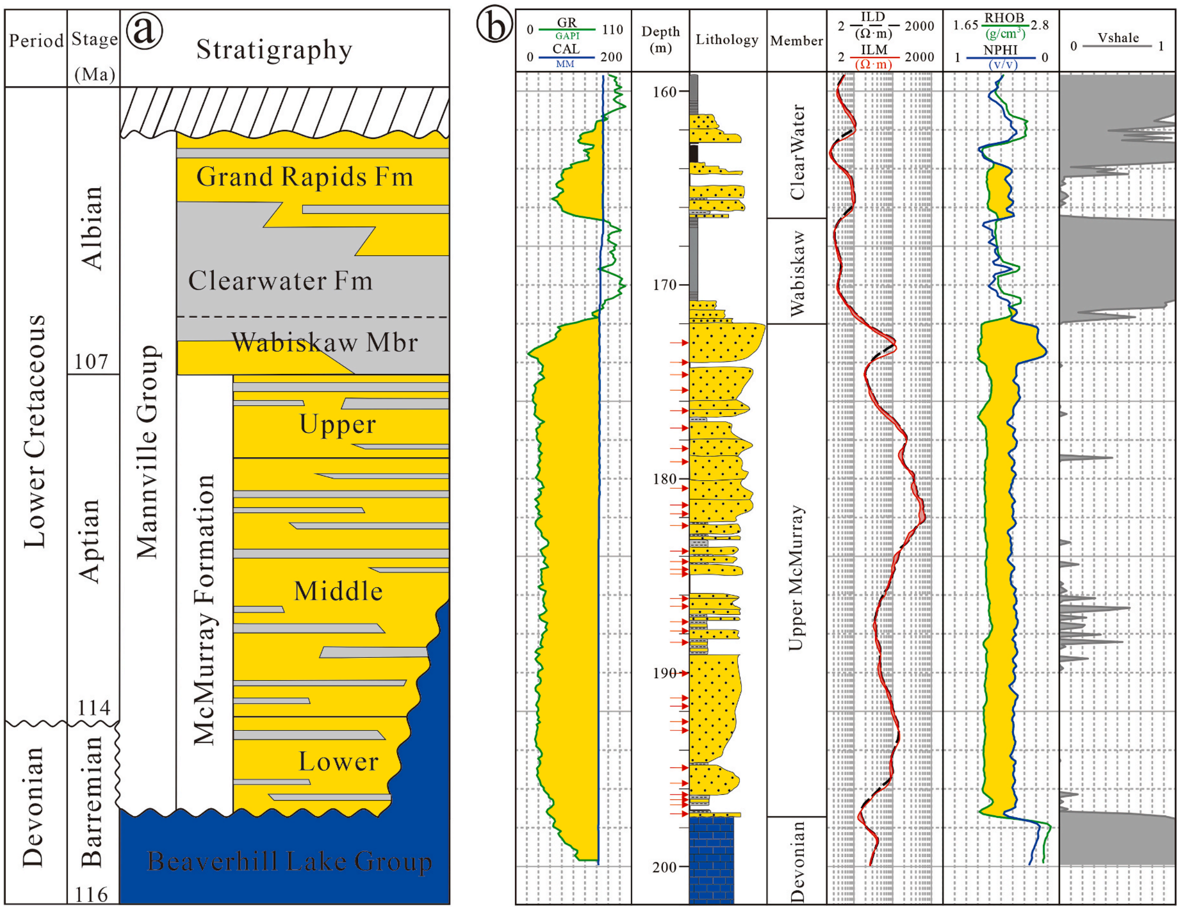

Fig. 2. Athabasca stratigraphy (a) and stratigraphic columns of sampling well in Mackay River area (b). As shown in (a), gray indicates non-reservoir shale, yellow indicates sand reservoir, and the intersection of gray and yellow indicates the presence of complex Inclined Heterolithic Stratification (IHS). Devonian carbonate rocks are shown dark blue. The oil sand reservoir of this well is the Upper McMurray Formation, with a depth range of 171.9–197.5 m. Stratigraphic information and logging data were provided by Brion Energy Corporation. The sampling locations are indicated by the red arrows in (b).

(Mossop, 1980).

The McMurray Formation is usually informally divided into three units, upper, middle, and lower. The lower McMurray Formation is dominated by fluvial deposits, the middle McMurray Formation by estuarine deposits, and the upper McMurray Formation by estuarine-shallow marine deposits (Baniak and Kingsmith, 2018; Hein and Langenberg, 2003; Mossop, 1980) (Fig. 2a). The Upper McMurray Formation is affected by the dual effects of tide and river, and is dominated by tidal sandbar and sand flat, with mixed flat deposits on both sides. There are millimeter-level discontinuous horizontal muddy interlayers developed in the reservoir, which mostly extend less than 10 m (Yin et al., 2020).

Although the mineralization model of the McMurray Formation oil sands is still controversial, the process described here is generally accepted as the most likely scenario. During the Cretaceous period, the Rocky Mountains on the western side of the Alberta Foreland basin were subjected to east-west compression caused by subduction of the Pacific plate to the east under the North American plate (Cant and Stockmal, 1989). As a result, the reservoirs in the Lower Cretaceous Mannville Group in the northeast of the basin have never been deeply buried and diagenesis is weak (Connan, 1984; Fowler et al., 2001; Monger et al., 1982). However, the Devonian to Jurassic source rocks in the western part of the basin were deeply buried (Berbesi et al., 2012; Higley et al., 2009; Moshier and Waples, 1985), with large amounts of oil and gas migrating long distances from west to east through unconformities and permeable sand bodies, forming reservoirs in the McMurray Formation (Higley et al., 2009; Leenheer, 1984). Due to the shallow depth of the McMurray Formation, the crude oil in the reservoir suffered oxidation, water washing, and biodegradation, eventually forming oil sands (Flach and Mossop, 1985; Plint et al., 2022).

This study focuses on the upper McMurray Formation oil sands in the Mackay River area (Fig. 1c), east of Athabasca, which covers an area of 760 km^2 (Hein et al., 2013a). The burial depth of the reservoir range is mostly from 160 m to 180 m, and its average thickness is 18 m (Ranger, 1996). The reservoir is mainly composed of unconsolidated sand with an average effective porosity of 32% and an average permeability of 6.5 Darcies (Hein, 2006).

3. Samples and methods

3.1. Samples

A total of 32 oil sand samples were collected from the Cretaceous Upper McMurray Formation in the Mackay River region of Athabasca. Representative samples (of 5 cm length and width) were obtained by sampling the 30 m thick oil sand reservoir every 1 m (Fig. 2b). The samples are almost all composed of dark brown to black sand (high bitumen saturation) and sand interbedded with laminated shale, with burial depths ranging from 169 to 198 m. The samples were cut from the core column using professional cutting tools, wrapped in tin paper, and packaged in clean sample bags to prevent contamination (all tools were cleaned with dichloromethane).

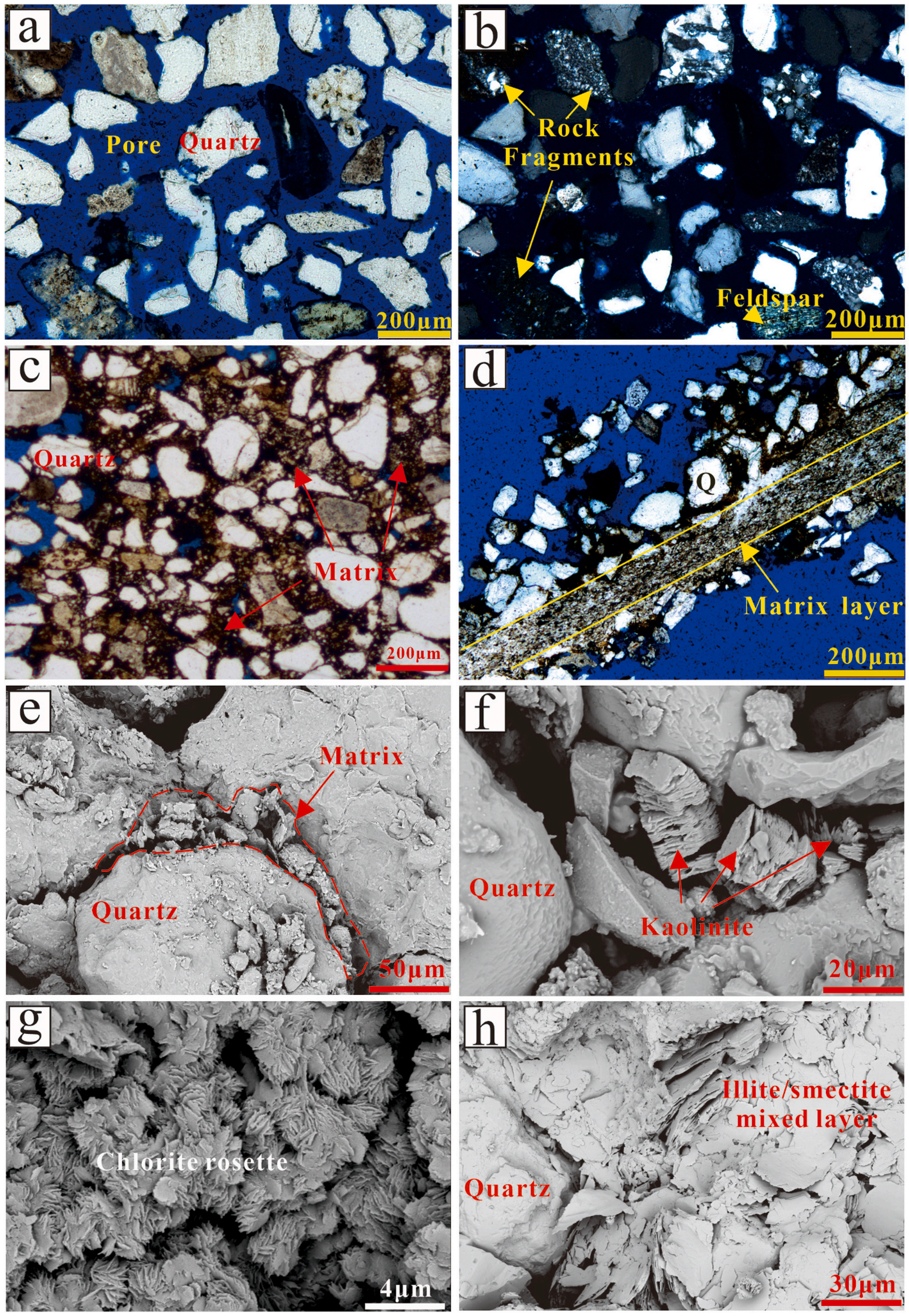

Fig. 3. Micrographs show the characteristics of detrital grains and interstitial material in the oil sands. (a) In PPL (173.82 m), the oil sands framework is composed of abundant quartz, with small amounts of feldspars and rock fragments. There is basically no interstitial material, and the detrital grains contact mode is floating. (b) In XPL, the rock fragments are mostly composed of sedimentary and metamorphic fragments. The feldspar are mostly potassium feldspar and albite. (c) In PPL (193 m), a mixture of matrix and bitumen is filled between detrital grains. Some intergranular pores are blocked. (d) In PPL (188.37 m), due to the high content of matrix, tight matrix layers are formed in the oil sands. (e) The main components of the matrix are clay grains and silt. (f) SEM shows that layered kaolinite is the most common clay mineral, and that (g) Rosette chlorite and (h) amorphous lamellar illite-smectite mixed layer appear on mineral surfaces or in the form of clay bridges between detrital grains.

3.2. Methods

3.2.1. Petrographic analyses

Thin sections were prepared (before extracting organic matter) by impregnating the oil sand samples with blue epoxy resin in a vacuum and observed using a plane and cross-polarized light under a Leica microscope equipped with a transmission polarization light and a reflection fluorescence system. Bitumen distribution was identified by fluorescence color, brightness, and luminescence. Thin-section photomicrographs were obtained and statistically analyzed using the point counting method (no less than 350 points per thin section) to obtain data of their detrital components, grain size and sorting, interstitial materials, and cements. The open-source software imageJ is used for further quantitative analysis of photomicrographs. After the thin sections point counting work was completed, grayscale values of the images of detrital grain, bitumen, and interstitial materials were calibrated, and then the data of grain size, matrix content, and pore space proportion were analyzed using statistical analysis software (Doan et al., 2012).

Oil sand samples were dried (without removing bitumen) in an oven at 50 °C and gold-plated in a vacuum. A FEI Quanta 650F scanning

Table 1
Detrital composition and petrophysical data of the McMurray Formation oil sands in the Mackay River area.

Number	Samples depth (m)	Porosity (%)	Permeability (mD)	S_B (%)	S_W (%)	Total clay content (%)	Detrital component (%)			Interstitial material (%)	
							Quartz	Feldspar	Rock fragments	Matrix	Cement
1	173.56	36.82	>10000	2.40	77.41	5.37	78.00	10.00	12.00	9.00	3.00
2	174.06	35.35	>10000	3.91	76.62	4.40	87.00	8.00	5.00	2.00	/
3	174.74	37.32	7511.00	5.29	76.15	8.52	82.00	8.00	10.00	2.00	/
4	175.54	31.00	4039.00	12.15	47.33	6.14	80.00	8.00	12.00	20.00	/
5	176.57	37.17	7817.00	9.59	44.22	8.23	81.00	6.00	13.00	15.00	/
6	177.44	34.58	5506.00	14.64	17.34	9.70	88.00	5.00	7.00	23.37	1.00
7	178.44	33.63	4127.00	10.33	20.72	6.32	76.00	9.00	15.00	17.00	/
8	179.14	33.27	4267.00	12.54	10.21	7.52	83.00	7.00	10.00	21.00	/
9	180.46	37.22	3327.00	14.04	21.73	7.32	80.00	8.00	12.00	24.00	/
10	181.36	32.00	3532.21	14.17	11.03	6.07	73.00	9.00	18.00	29.00	/
11	181.86	33.40	3682.00	13.50	14.71	9.42	74.00	12.00	14.00	23.52	/
12	182.31	34.53	3582.00	12.91	10.99	8.20	81.00	10.00	9.00	20.00	1.00
13	183.83	34.27	4346.00	11.93	12.91	7.33	75.00	13.00	12.00	19.00	1.00
14	184.35	33.12	3013.54	14.24	17.08	8.22	72.00	9.00	19.00	27.00	/
15	184.57	33.27	3254.17	12.47	22.23	7.52	75.00	7.00	18.00	29.65	1.00
16	184.91	33.06	3920.00	7.29	22.08	7.62	85.00	7.00	8.00	19.00	/
17	186.23	34.45	2857.64	7.95	35.40	7.36	72.00	7.00	21.00	35.00	1.00
18	186.67	32.06	2934.72	11.92	43.85	9.10	76.00	6.00	18.00	32.50	/
19	187.47	32.17	2751.36	7.12	41.30	8.24	78.00	8.00	14.00	42.00	/
20	187.97	35.56	8481.00	8.05	38.54	9.54	86.00	6.00	8.00	13.00	1.00
21	188.37	31.34	3092.55	6.26	38.48	10.31	75.00	12.00	13.00	39.00	1.00
22	190.02	33.92	4362.00	5.89	34.79	7.42	79.00	6.00	15.00	9.30	/
23	191.13	36.75	4455.00	12.91	18.12	8.23	69.00	10.00	21.00	21.85	/
24	191.80	34.39	4621.00	10.07	13.33	5.41	82.00	8.00	10.00	19.57	1.00
25	192.30	34.23	5113.00	6.12	27.05	7.08	76.00	10.00	14.00	2.00	/
26	193.00	35.23	6611.00	12.53	23.81	5.05	81.00	6.00	13.00	23.28	/
27	194.97	35.71	6611.00	11.78	36.14	9.20	76.00	10.00	14.00	21.00	1.00
28	195.77	33.39	4101.00	13.44	34.47	5.38	73.00	11.00	16.00	21.00	/
29	196.37	36.32	7357.00	5.75	50.77	7.62	85.00	9.00	6.00	6.82	/
30	196.57	35.38	7529.00	4.90	50.12	5.92	79.00	8.00	13.00	5.33	1.00
31	197.07	37.62	8231.00	6.19	63.82	6.05	83.00	7.00	10.00	5.36	3.00
32	197.20	38.28	9039.00	2.98	76.84	3.32	88.00	7.00	5.00	2.00	/

S_B (%): Bitumen saturation of bulk mass; S_W (%): water saturation of bulk mass.

electron microscope (SEM) was used to observe pore structures and bitumen distribution. The acceleration voltage was 5–10 kV and a back-scattered electron detector was used.

Petrophysical data (porosity and permeability) of the oil sands were obtained by lab measurement. Porosity was measured by a CMS-300 helium porosimeter and a Hasler sleeve core holder. Permeability was measured using nitrogen as a steady-state flowing gas and was not corrected by the Klinkenberg equation.

After extracting bitumen with dichloromethane, the sand was crushed to less than 200 mesh in an agate mortar, and the mineral composition and clay mineral contents were measured by using an Olympus innov-X X-Ray Diffractometer (XRD) with Cu-Kα radiation. Testing was conducted in air-dry conditions, with the powdered samples soaked in ethylene-glycol and saturated, then heated at 300 °C for 1 h. The scanning rate was 1° 2θ/min from 2° to 50° 2θ. Based on the peak area, empirical factors and weighted calculations were used to semi-quantitatively estimate the mineral compositions of the oil sands, and the results were normalized (Oliveira et al., 2002).

3.2.2. Bitumen geochemical analysis

The molecular composition of bitumen was used to determine the relative degradation degree of the oil sand samples. In order to improve accuracy, the outermost layer was removed, then a clean knife was used to cut 3–5 g of fresh oil sands. Organic matter (bitumen) was extracted using dichloromethane (CH_2Cl_2) in a Soxhlet apparatus for more than 72 h. After extraction, the asphaltenes in the bitumen were precipitated by petroleum ether (A mixture of pentane and hexane), and the remaining solution was separated into saturated hydrocarbons, aromatics hydrocarbons, and resins (NSO compounds) using activated silica gel column chromatography (Xiao et al., 2021).

An Agilent 5975i gas chromatography-mass spectrometry (GC-MS) was used to determine the characteristics of saturated and aromatic hydrocarbons. For more information on experimental equipment, reagents, conditions, and heating programs, please refer to references (Xiao et al., 2019). All sample pretreatment, experiments, and analysis were conducted in the National Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum (Beijing).

4. Results

4.1. Petrology and physical properties

4.1.1. Petrological characteristics

Point counting revealed that the average detrital composition of the oil sands is quartz (80.7%), feldspar (9.45%) and rock fragment (9.85%). Most quartz grains are monocrystalline quartz, with no obvious quartz over-growth. The content of feldspar is relatively low, mainly potash feldspar and plagioclase. Most of the feldspar has undergone varying degrees of secondary alteration, but fresh feldspar grains still occur (Fig. 3a and b). The rock fragments are mainly sedimentary and metamorphic fragments, including flint, metamorphic quartz, occasionally biotite, and rarely volcanic fragments (Table 1). The detrital grain size is predominantly fine-grained (0.1–0.25 mm), with a very small proportion being medium-grained (0.25–0.5 mm). The sorting ranges from well to moderately sorted, with shapes ranging from sub-angular to subrounded. The contact mode is mostly floating or point contact, and there are no obvious traces of mechanical compaction.

Besides detrital grains, interstitial material is one of the most important components of oil sands and has a significant effect on the oil sand texture (Dickinson, 1970). The burial depth of the McMurray

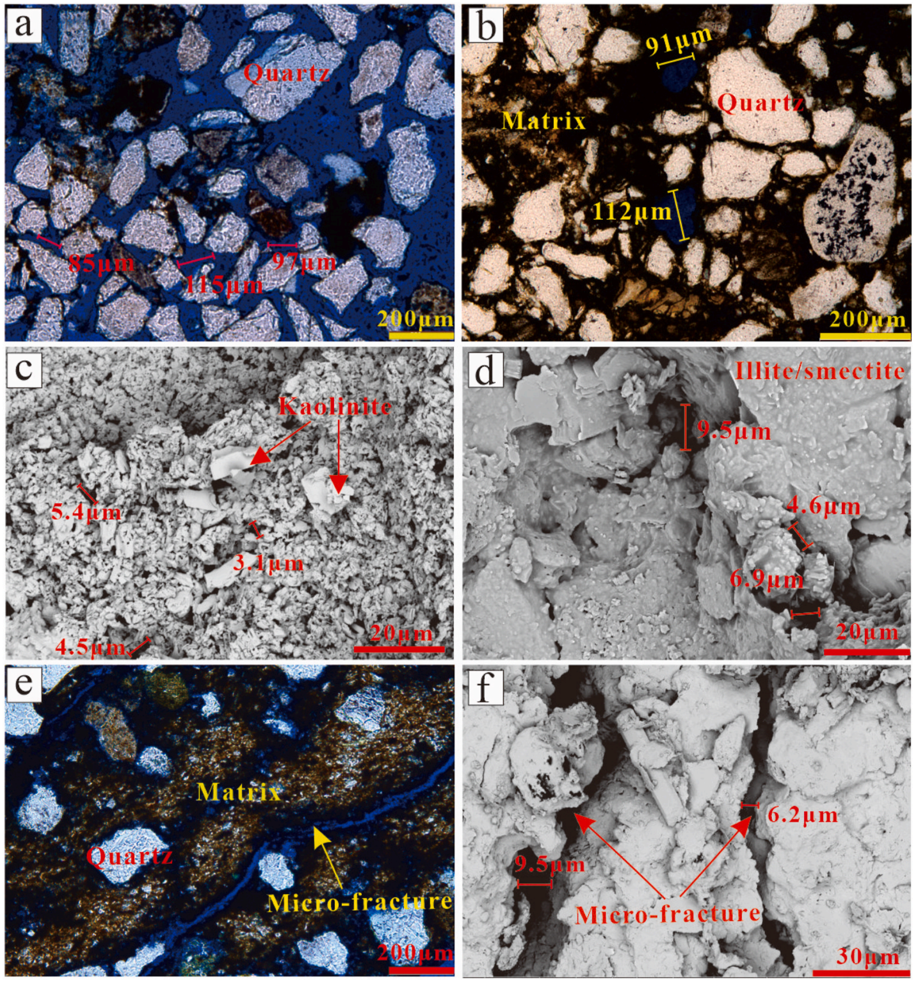

Fig. 4. Micrographs of pore characteristics and bitumen distribution in oil sand. (A) In transmitted light, bitumen mainly appears on the surface of debris grains or in the matrix. (B) Intergranular pores in oil sands, with pore sizes ranging from 0.1 to 2 mm. (C) Clay minerals micropores composed of kaolinite minerals, with spaces of 4–5 μm (D) Inter-crystalline micropores composed of illite, with pore size generally less than 10 μm. (E) Illite intergranular porosity adsorbs a large amount of bitumen. (F) Bitumen is adsorbed in the layered structure of kaolinite. (Q: quartz; RF: rock fragment; P: pore; K: kaolinite; I/S: Illite and montmorillonite mixed layer; B: bitumen; I: illite).

Formation reservoir is shallow and crude oil was charged in the early period of sedimentation (Adams et al., 2013), so cement is basically not developed. The differences in oil sand texture are therefore largely determined by the content and distribution of matrix. As shown in (Fig. 3a), oil sand is mainly composed of detrital grains with almost no matrix. The detrital grains of most oil sands are evenly filled with brownish-black matrix, which is mixed with bitumen (Fig. 3c). In some samples it was also observed that, due to the high content of matrix and its susceptibility to compaction, tight matrix layers formed (Fig. 3d). The matrix between detrital grains is mostly composed of clay minerals grains and silt, with an average grain size of less than 30 μm.

The clay minerals are of three types: kaolinite, chlorite, and illite-smectite mixed layer. As shown in (Fig. 3f), layered kaolinite grains are common in all the oil sand samples. In addition, rosette chlorite grains (Fig. 3g) and amorphous lamellar illite-smectite mixed layer (Fig. 3h) are distributed on the surfaces of the detrital grains or form clay bridges between the grains. The XRD results show total clay mineral content (Table 1) ranges from 3.32 to 10.31%, average 7.29%. The proportion of clay minerals in the overall mineral composition of oil sands is not significant, but there are obvious differences.

Mineral identification and grayscale calibration were carried out under a microscope, and matrix content of the oil sands were analyzed using ImageJ software. The matrix contents of McMurray Formation oil sands range from 2% to 39%, with an average of 19.09%. There are two modes of matrix occurrence in oil sands. When the content of matrix is less than 25%, it is usually evenly filled between detrital grains (Fig. 3a–c). When the content of matrix is more than 25%, it usually forms a tight matrix layer with a thickness of 200–500 μm (Fig. 3d).

4.1.2. Pore types and distribution

The pore types in the McMurray Formation oil sands include intergranular pores, matrix micropores, and microfractures. As shown in (Fig. 4a and b), a large number of detrital grains in point contact result in well-preserved primary intergranular pores, which is the most common pore type in oil sands, with a pore size range of 70–120 μm. Matrix micropores include micropores formed by sediment weathering and contraction, as well as intragranular pores formed by clay mineral recrystallization; for example, irregular micropores formed by disorderly arrangement of kaolinite grains (Fig. 4c) and intragranular pores formed by layered stacking of thin illite-smectite mixed layer. (Fig. 4d). The average size of matrix micropores is less than 10 μm, and they are numerous in the matrix.

Due to the influence of texture and supporting modes, microfractures are generally formed in the oil sand samples with high matrix content, with widths ranging from 20 to 50 μm. These form the main reservoir spaces and fluid channels in the tight matrix layer (Fig. 4e). SEM shows that clay minerals cannot provide the same support as rigid minerals, being prone to compaction and densification. Intergranular pores are

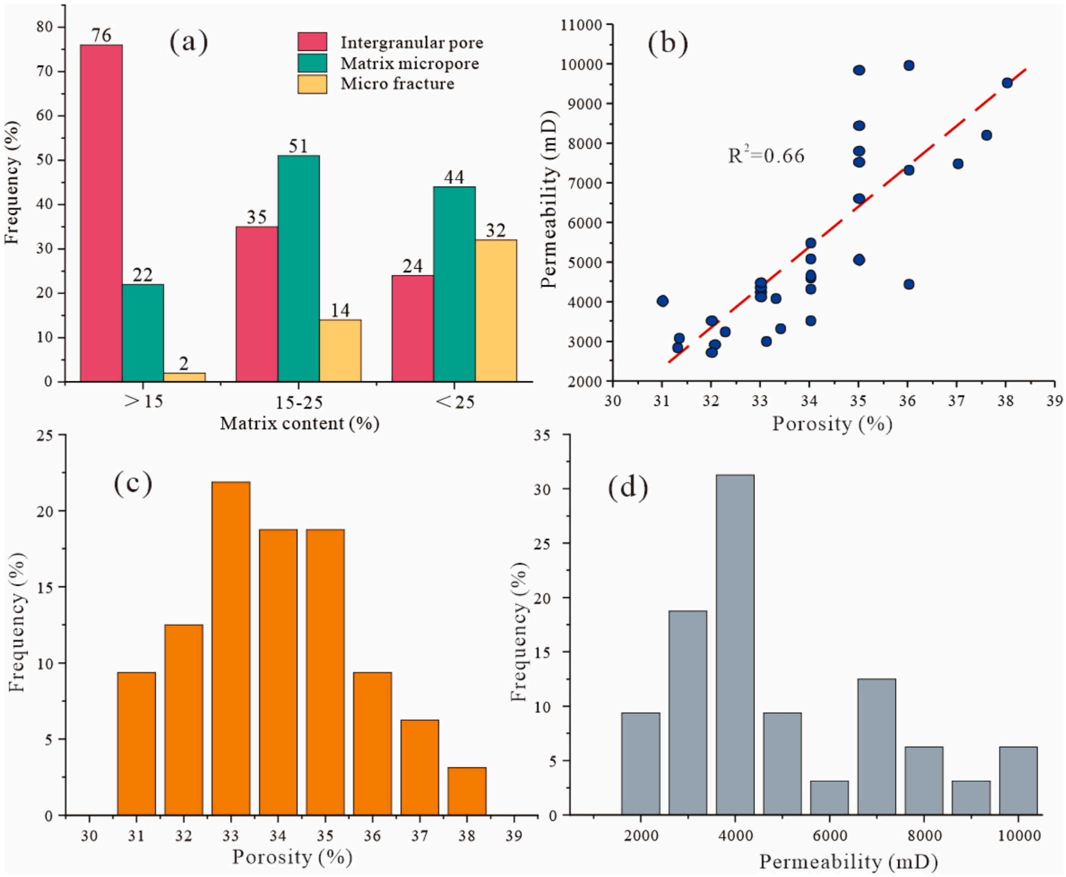

Fig. 5. Pore distribution and physical properties of oil sands. (a) The relationship between the matrix content in oil sands and the distribution of pore types. (b) The porosity and permeability of oil sands are positively correlated. (c) Porosity exhibits a unimodal distribution, concentrated between 33% and 35%. (d) Strong heterogeneity of permeability, with an average of 5179.13 mD.

replaced by large numbers of matrix micropores and microfractures.

The proportions of the different pore types are closely related to the matrix content of oil sands (Fig. 5a). Intergranular pores predominate in oil sands with low matrix content (<15%), with an average proportion of 76% and almost no microfracture. The pores of oil sands with moderate matrix content (15–25%) are mainly matrix micropores (average 51%) and intergranular pores (average 35%), and there are few microfractures (average 14%). Oil sands with high matrix content (>25%) are dominated by matrix micropores (average 44%) and microfractures (average 32%) due to the frequent formation of tight matrix layers.

4.1.3. *Petrophysical properties*

The petrophysical results show a positive correlation between porosity and permeability of the oil sands (Fig. 5b). Porosity exhibits a unimodal distribution, ranging from 31.3% to 38% with an average of 34.01%, mostly concentrated between 33% and 35% (Fig. 5c). The heterogeneity of permeability is strong, ranging from 2751.36 to 10000 mD, with an average of 5179.13 mD (Fig. 5d). It is worth noting that the porosity of all samples exceeds 30% and the lowest permeability still exceeds 2000 mD, indicating that, although there is heterogeneity, all oil sand reservoirs have extremely high porosity and permeability (Babak and Resnick, 2016). The variable physical properties (porosity and permeability) of oil sands may be related to their petrological characteristics (Cade et al., 1994).

4.2. *Geochemical characteristics of bitumen*

4.2.1. *Group composition*

Bitumen in oil sand reservoirs is a product of biodegradation of crude oil (Tissot and Welte, 1984). Secondary alteration of crude oil caused by biodegradation is reflected in two ways: the group composition and the molecular composition of bitumen (Connan, 1984). The consumption order of the various hydrocarbons is: first, saturated hydrocarbons, then aromatic hydrocarbons, resulting in an increase in the proportion of compounds containing nitrogen, sulfur, and oxygen in the residual bitumen, which increases viscosity and reduces economic value (Peters and Moldowan, 1993). However, the degradation process is extremely complex, and different types of bacteria selectively consume the hydrocarbons, so analyzing the molecular composition of hydrocarbons is a good method to evaluate the degree of biodegradation. But it is difficult to distinguish samples with similar biodegradation levels within the same oil column, and accurate information for optimizing production is generally not available (Larter et al., 2012).

The bitumen content is represented as the percentage of the weight of extracted organic matter relative to the weight of the oil sand. The results show that the bitumen content of the McMurray Formation oil sand reservoir ranges from 2.40 to 14.64%, with an average of 9.86% (Fig. 6). In addition, the proportion of group components exhibits strong heterogeneity, with saturated hydrocarbon contents ranging from 17.06% to 23.43%, with an average of 20.44%. The range of aromatic hydrocarbon content is 18.06–31.32%, with an average of 24.30%. The range of resin content is 18.64–29.88%, with an average of 24.01. The range of asphaltene content is 25.04–40.85%, with an average of 31.25%. The ratio of saturated plus aromatic hydrocarbon fractions to resin plus asphaltene fractions is used to quantify differences in bitumen composition, with values ranging from 0.63 to 1.23, with an average of 0.88.

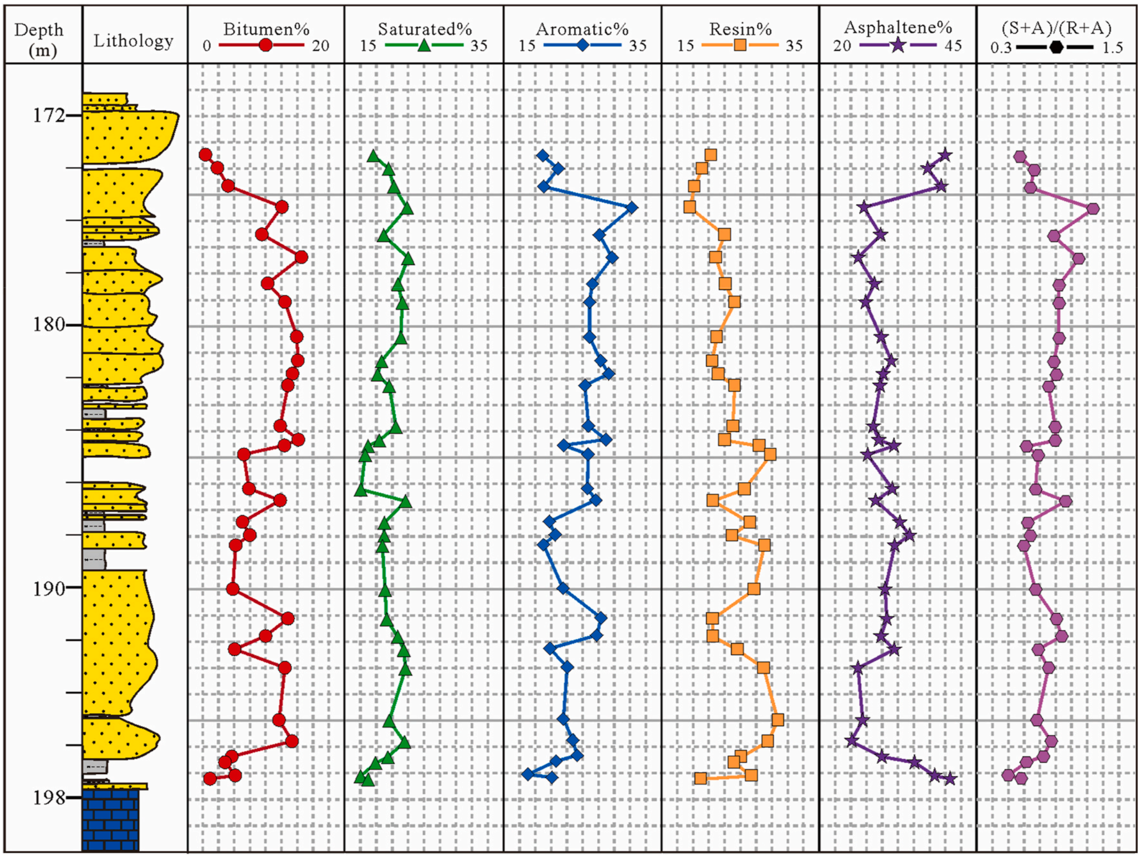

Fig. 6. Bitumen content and group compositions of oil sands bitumen in the McMurray Formation. Using (S + A)/(R + A): (saturated + aromatic hydrocarbon fraction)/(resin + asphaltene fraction) represent variation in bitumen components.

4.2.2. *Molecular composition of bitumen*

The degradation characteristics of bitumen are determined by analyzing the molecular composition of saturated hydrocarbon and aromatic hydrocarbon fractions (Connan, 1984). The saturated hydrocarbon total ion chromatograms (TIC) of all samples show an absence of n-alkanes, and the baselines of the chromatograms exhibit obvious 'humps' (unresolved complex mixture, UCM) (Fig. 7), which is a typical indicator of severe degradation (Peters and Moldowan, 1993). The relative abundance of hopanes indicates that there are differences in the degrees of degradation of these samples.

The *m/z* 191 and *m/z* 217 mass chromatogram of saturated hydrocarbon fractions show the distribution characteristics of tricyclic terpanes (TT), hopanes (H) and steranes (S) (Fig. 8). The characteristic peak of TT in bitumen is complete, dominated by C_{23} TT, and the distribution characteristics of all samples are similar, indicating that these compounds are less affected by degradation. Although most of the hopanes can be identified, there are differences in the distribution characteristics of samples, mainly reflected in the relative abundances of C_{30}H and C_{31-35}H. The distribution characteristics of diasteranes in most samples are basically consistent, and are less affected by degradation. Regular steranes are significantly affected by degradation, with generally low overall abundance, and slight differences in the relative distributions of $C_{27\text{-}29}$ steranes (Fig. 8a, b, c).

The *m/z* 192 and *m/z* 180 mass chromatogram of aromatic components show the distribution characteristics of methylphenanthrene (MP) and methylfluorene (MFlu) (Fig. 9). The naphthalene series in oil sands are mostly degraded and cannot be identified. There is a significant difference in the relative abundances of MP and MFlu with three ring structures (Fig. 9a, b, c). According to their relative abundance, indicating whether the bitumen has suffered light, moderate, or heavy degradation.

5. Discussion

5.1. *Classification of texture*

In previous petrological studies of the Athabasca oil sands, most of the classification criteria have been based on end member quartz, feldspar, and rock fragments, or the size of detrital grains (Carrigy, 1962; Hein et al., 2013a). However, this classification method focuses on the detrital grains and ignores the influence of matrix on the distribution of oil sand and bitumen.

The relative contents of matrix and detrital grains determine the internal support mode of oil sands, either matrix or grain support which has a critical impact on the physical properties of the sands (Dott, 1964). In order to fully consider the support effect of matrix, Pettijohn's classification method (Pettijohn, 1975) was adopted in this study, combined with observation of micrographs, and the addition of a boundary at a matrix content of 25%, the point at which the support mode switches from grain support to matrix support (Fig. 10). Oil sands with low matrix content (<15%) are defined as arenites, while oil sands with high matrix content (>15%) are defined as wackes. The wackes are further subdivided into two types at the support mode boundary: L-wackes (15–25%) and H-wackes (>25%). It should be noted that if the matrix content is greater than 75%, then the rock is mudstone. However, in this study, the highest matrix content is 42.2%, and all samples are therefore within the range of sandstone.

The average size of arenite detrital grains is relatively large, with an average of 0.28 mm, and they are mostly well-sorted (Fig. 10a). The matrix content is less than 15% and total clay content is relatively low, with an average of 6.52%. The contact modes of the detrital grains are mostly floating or point contact. Rigid detrital grains dominate and support the oil sands' texture.

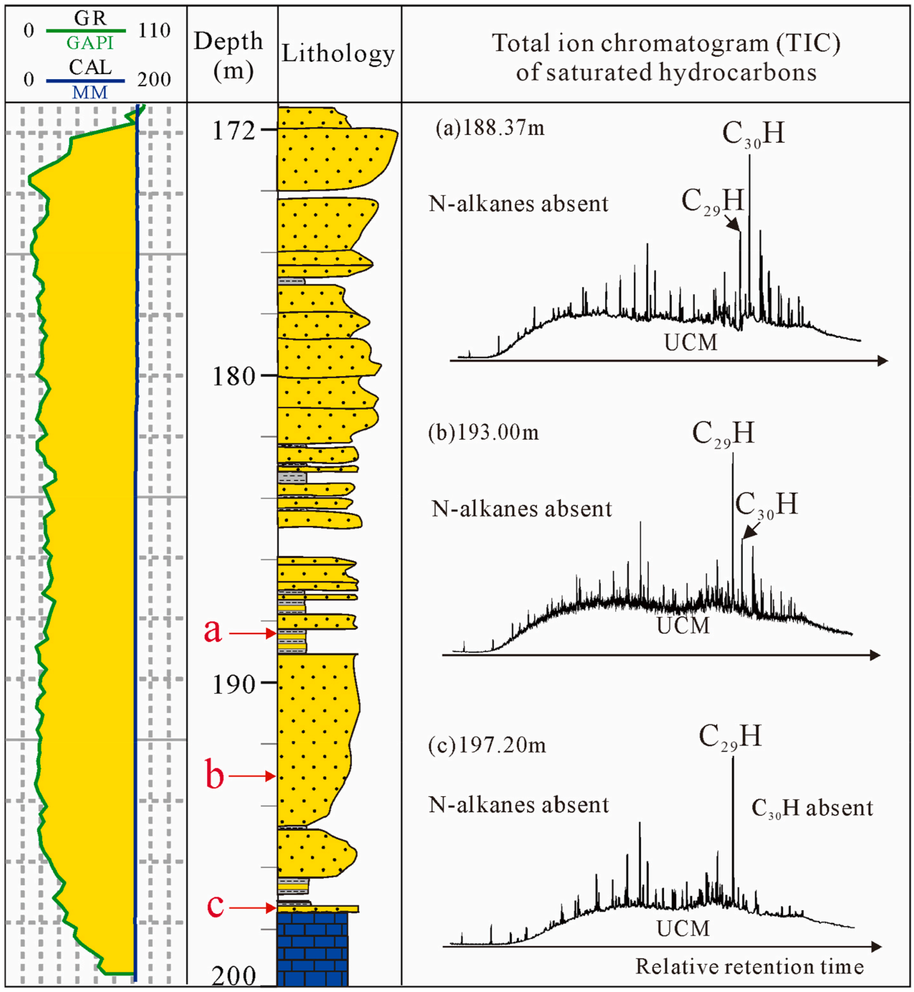

Fig. 7. Total ion chromatogram of saturated hydrocarbons fraction in bitumen from oil sands. Relative abundances of n-alkanes and acyclic isoprenoids are below detection limits and exhibit unresolved complex mixture (UCM) 'humps'. Differences in relative abundances of hopanes series compounds are also observed.

The average size of L-wackes detrital grains is 0.25 mm, and sorting ranges from well to moderately sorted (Fig. 10b). Matrix content ranges from 15 to 25%. Total clay content is moderate, with an average of 7.41%. Matrix composed of clay and silt grains is filled between the detrital grains. Rigid detrital grains are still the framework of oil sands, with grain support being the main support mode.

The detrital grains size of H-wackes is the smallest among the three types, with an average of 0.22 mm, mostly moderately sorted (Fig. 10c). The matrix content is greater than 25%, usually forming a matrix layer inside the oil sands. The total clay content is relatively high, with an average of 8.12%. Detrital grains are usually wrapped in a large amount of matrix and appear in a floating state. Rigid detrital grains are not the main load-bearing minerals, and the support mode is mainly matrix support.

5.2. Evaluation of biodegradation degree

Varying degrees of biodegradation may be the main reason for the differences in group and molecular composition of bitumen. Evaluation of degrees of biodegradation of bitumen is therefore an essential practice. Peters and Moldowan classified levels of biodegradation from PM1 (lowest) to PM10 (highest) based on the different resistance abilities of compound types to microbial degradation, this classification is now been widely used (Head et al., 2003; Larter et al., 2003; Peters and Moldowan, 1993). The total ion chromatogram of saturated hydrocarbons in bitumen from the Upper McMurray Formation shows highly similar features (Fig. 7), with a clear 'hump' in the baseline. Normal alkanes and acyclic isoprene are basically unrecognizable. The distributions of TT, pregnanes, and diasteranes in the saturated hydrocarbons show no significant changes, while the distribution characteristics of hopanes and regular steranes are different due to degradation (Fig. 8). The distributions of methylphenanthrene and methylfluorene series compounds in aromatic hydrocarbons show significant differences, while there is no obvious change in triaromatic steranes (Fig. 9). According to these molecular composition characteristics, the biodegradation level of the oil sands of the Upper McMurray Formation is in the range of PM 6–7. Many previous reports determined the biodegradation level of the Athabasca oil sands as being in the range of PM 5–9 (Adams et al., 2013; Bennett et al., 2006). The samples in this study all come from the same well in the Mackay River area, so the variations in degradation degree are relatively small.

Although the PM method can be used to evaluate the level of biodegradation, there are still two issues that cannot be ignored. Firstly, the PM method is more suitable for light or moderate degradation; its identification of severely degraded bitumen is unreliable. Secondly, the PM method has insufficient resolution to distinguish between similar degradation levels. In order to accurately evaluate the degree of degradation, this study used the Manco method for calculations. This process involves the selection of eight compounds with different sensitivities to biodegradation, and conducting semi-quantitative evaluation based on changes in relative abundance combined with linear and power functions. For the detailed calculation process, refer to the original

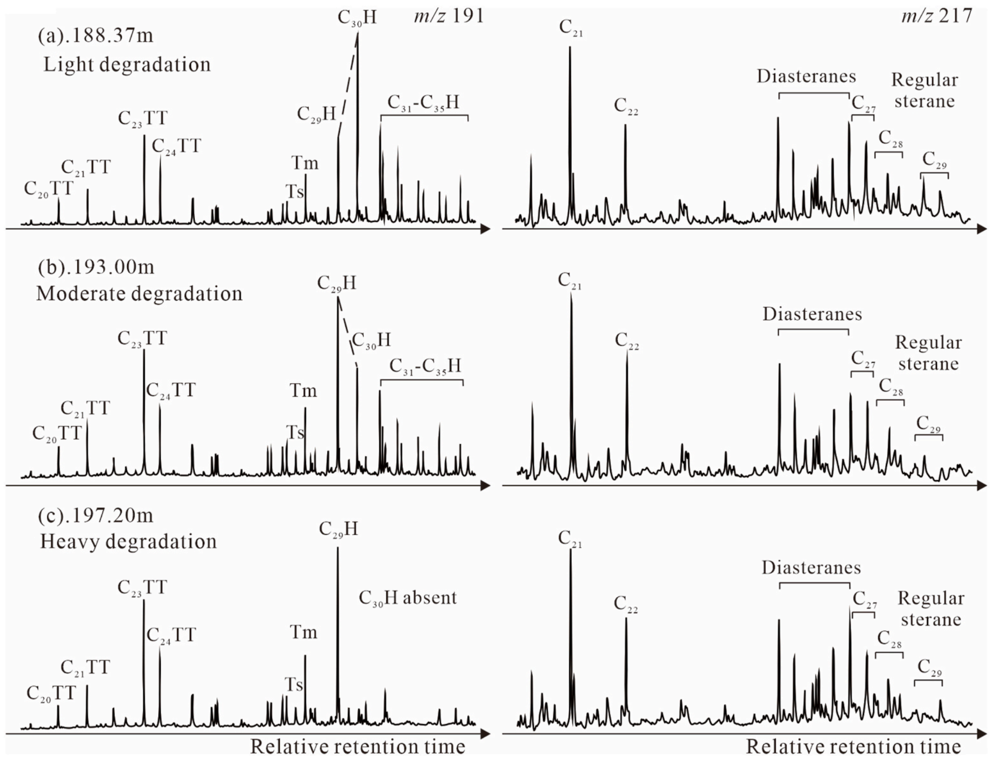

Fig. 8. Mass chromatogram of m/z 191 and 217 saturated hydrocarbons fractions in bitumen from oil sands. The distribution characteristics of tricyclic terpanes (TT) and diasteranes are similar, but there are differences in the distributions of hopanes and regular steranes.

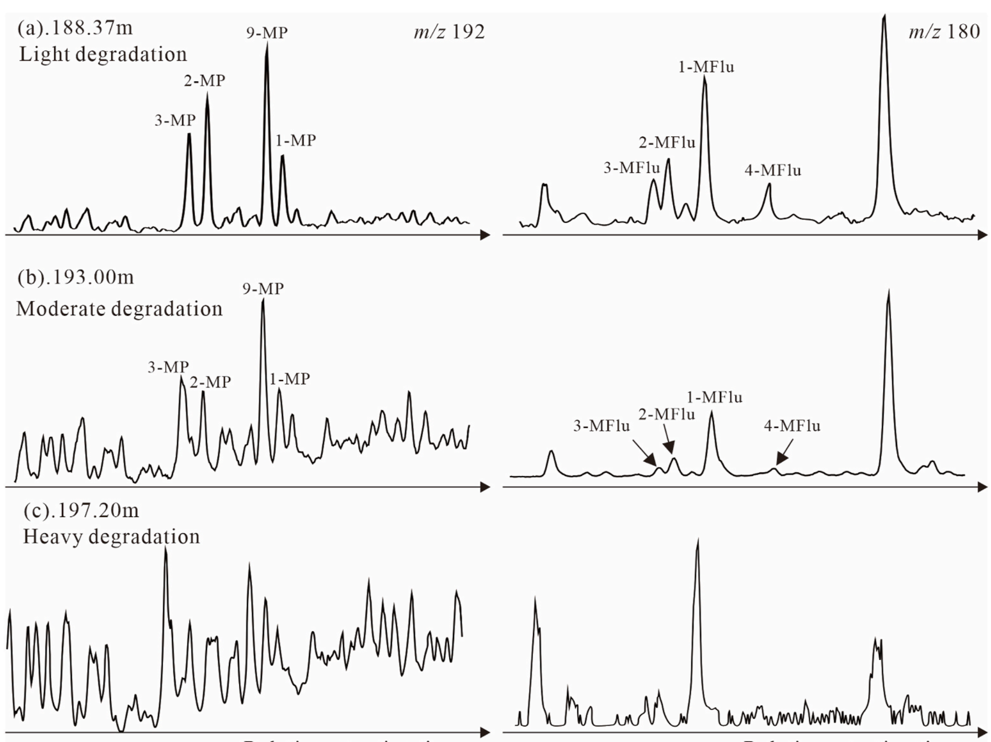

Fig. 9. Mass chromatogram of m/z 192 and 180 aromatic hydrocarbon fractions in bitumen from oil sands. Most naphthalene series compounds with two ring structures cannot be identified. There are differences in the relative distribution characteristics of methylphenanthrene (MP) and methylfluorene (MFlu) with three ring structures.

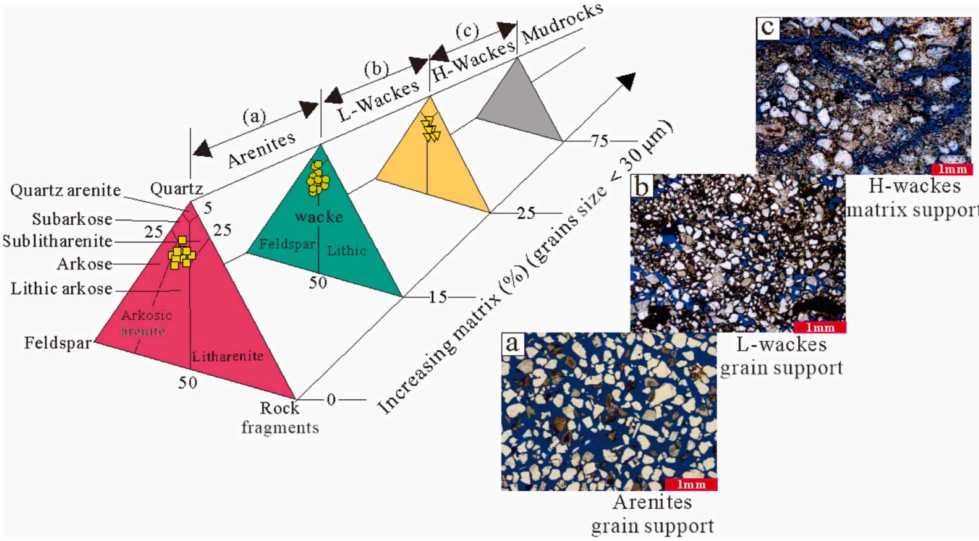

Fig. 10. Textural classification of oil sands in the McMurray Formation (modified after Pettijohn, 1975). (a) Matrix content (<15%), arenite. The wackes are further identified as (b) matrix content (15–25%), L-wackes. and (c) matrix content (25–75%), H-wackes. Matrix content (>75%), mudstone.

Table 2
The degree of biodegradation of 32 oil sand samples was evaluated using the Manco method, and the degree of biodegradation was found to be positively correlated with the MN2 value. In general, as the degree of biodegradation increases, the bitumen content decreases, and the proportion of resin and asphaltene fractions increases.

Number	Depth (m)	MP	DMP	TMP	MFlu	MDBT	MDBF	C_{30}H	Sterane	MN2	Bitumen (%)	R + A (%)
1	173.29	4	4	4	3	3	3	2	1	909.93	2.40	61.36
2	173.82	4	3	3	3	3	3	1	1	899.18	3.91	57.47
3	174.84	4	4	4	4	4	3	2	1	910.41	5.29	58.65
4	175.54	3	2	2	2	2	2	1	0	782.37	12.15	45.76
5	176.57	3	2	2	2	3	3	1	0	793.89	9.59	52.85
6	177.44	1	1	1	1	1	0	0	0	518.18	14.64	48.13
7	178.44	2	2	2	2	1	1	0	0	646.24	10.33	51.93
8	179.14	3	3	2	2	2	1	0	0	657.46	12.54	51.71
9	180.46	3	3	3	2	1	0	0	0	534.85	14.04	51.93
10	181.36	2	2	2	1	0	0	0	0	407.16	14.17	44.94
11	181.86	3	3	2	2	1	0	0	0	532.82	13.50	52.42
12	182.31	3	3	2	1	1	1	0	0	643.93	12.91	54.00
13	183.83	3	3	2	2	2	1	1	0	771.27	11.93	52.72
14	184.35	2	2	2	1	0	0	0	0	407.16	14.24	45.55
15	184.57	3	3	3	1	0	0	0	0	419.07	12.47	50.37
16	184.91	3	3	3	3	2	1	1	1	893.95	7.29	56.62
17	186.23	3	3	2	1	1	0	0	0	521.78	7.95	49.25
18	186.67	3	3	2	2	1	0	0	0	532.82	11.92	45.55
19	187.47	3	3	2	2	1	0	0	0	532.82	7.12	51.14
20	187.97	4	4	4	3	2	1	1	1	893.97	8.05	58.41
21	188.37	3	3	2	2	2	0	0	0	572.31	6.26	52.15
22	190.02	4	4	4	4	3	3	2	1	910.01	5.89	57.30
23	191.13	3	3	3	3	3	1	0	0	669.33	12.91	52.26
24	191.80	3	3	2	2	1	1	1	0	768.85	10.07	51.41
25	192.30	4	4	4	4	4	4	2	2	950.09	6.12	56.62
26	193.00	3	3	3	2	1	1	0	0	646.83	12.53	54.19
27	194.97	3	3	3	3	2	2	1	0	782.88	11.78	56.76
28	195.77	3	4	4	3	2	0	0	0	580.75	13.44	53.60
29	196.37	4	4	4	4	3	3	2	2	948.64	5.75	55.13
30	196.57	4	4	4	4	4	3	2	2	948.88	4.90	59.41
31	197.07	4	4	4	4	3	3	2	1	910.01	6.19	64.89
32	197.20	4	4	4	4	4	4	4	3	983.54	2.98	60.86

MP: methylphenanthrene; DMP: dimethylphenanthrene; TMP: trimethylphenanthrene; MFlu: methylfluorene; MDBT: methyldibenzothiophene; MDBF: methyldibenzofuran; C_{30}H: C_{30}H hopanes; Steranes: regular steranes; R + A: resin plus asphaltene fractions.

report (Larter et al., 2012). In this study, the biodegradation levels of most samples were PM 6–7. It is more effective to track the degree of biodegradation using aromatic hydrocarbons with structures containing three or more rings. Therefore, eight compounds with progressive anti-degradation ability were screened: methylphenanthrene (*m/z* 192), dimethylphenanthrene (*m/z* 206), trimethylphenanthrene (*m/z* 220), methylfluorene (m/z 180), methyldibenzothiophene (*m/z* 198), methyldibenzofuran (*m/z* 182), C_{30} hopanes (*m/z* 191), and regular steranes (m/z 217).

The calculation formulae for the Manco method are as follows:

$$MN1 = \sum \left(m_i \times 5^i\right) \tag{1}$$

$$MN2 = \left[n + \left(\log_5(MN1) \times Smax\text{-}1\right)\right]/n \tag{2}$$

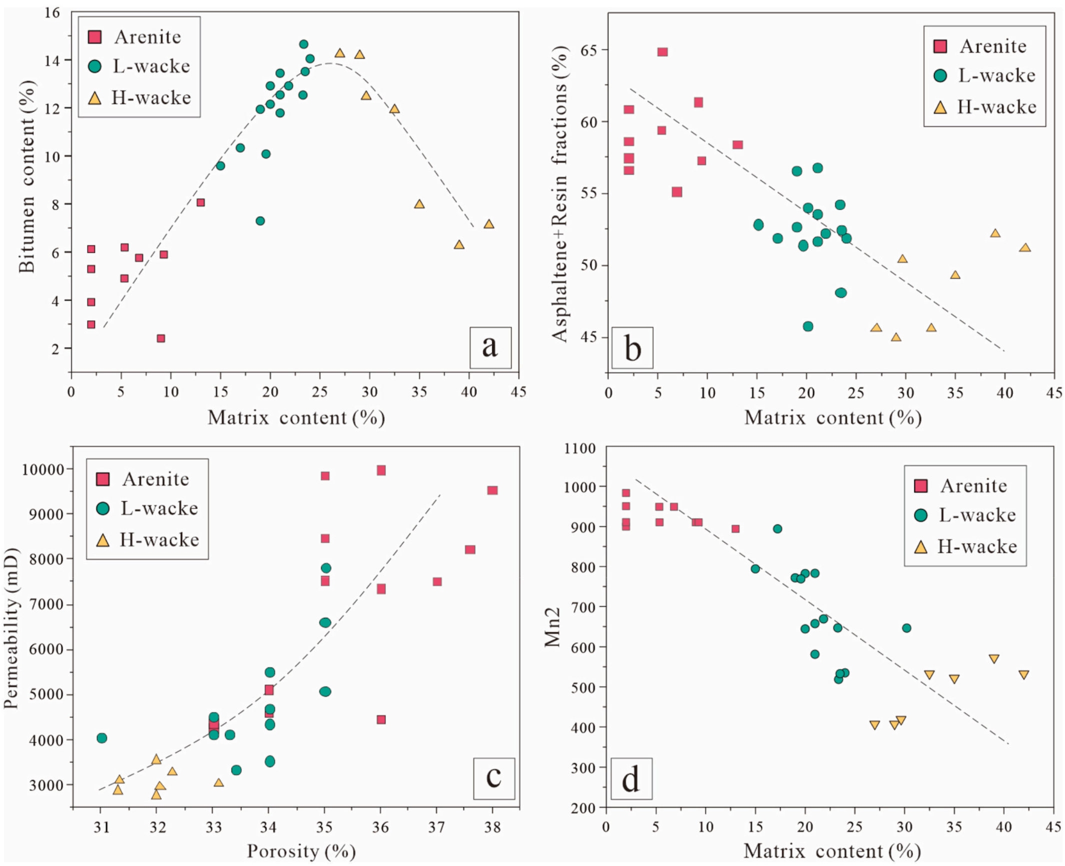

Fig. 11. The relationship between matrix and bitumen distribution, physical properties, and degradation degree. (a) The bitumen content shows a trend of first increasing and then decreasing with an increase in the matrix content. (b) There is a negative correlation between matrix content and resin plus asphaltene fractions. (c) Matrix content is negatively correlated with the physical properties of oil sands. (d) Matrix content is negatively correlated with the degree of degradation. Matrix affects the content and properties of oil sands bitumen by controlling the physical properties reservoir of the reservoir.

in equation (1), i is the number of the selected reference compound, with a value range of 0–7. m is the degree of degradation of the evaluation reference compound, assigned from 0 to 4 in order of no degradation, light degradation, moderate degradation, severe degradation, and complete consumption of the reference compound. In equation (2), the number of benchmark compounds selected for evaluation is represented by n. There are eight selected compounds, so n is assigned a value of 8. Smax is the maximum value of MN2 and, in order to have sufficient resolution to characterize the degradation degree, Smax is given a value of 1000.

The evaluation results shown in (Table 2) that the MN2 value is positively correlated with the degree of degradation. The range of MN2 values is 407.16–983.54, and the degree of degradation of each sample can be identified. The MN2 value is negatively correlated with the content of bitumen in the oil sand, and positively correlated with the proportion of resin and asphaltene fractions in the bitumen. Previous studies have shown that there is a good linear relationship between MN2 value and the viscosity and content of crude oil, which depends largely on the consumption of saturated and aromatics hydrocarbons, and the increase in the proportion of non-hydrocarbon species (Connan, 1984; Larter et al., 2006; Larter et al., 2012; Peters and Moldowan, 1993). The relationship between the MN2 value and bitumen content and components in this study is consistent with the previous description of the biodegradation process, which confirms that using MN2 values to characterize the degree of biodegradation is a reliable approach.

5.3. Role of matrix

As the matrix content of oil sand increases, the bitumen content shows a trend of first increasing and then decreasing (Fig. 11a), while the proportion of resin plus asphaltene fractions gradually decreases (Fig. 11b). Arenites have the lowest bitumen contents and the highest average proportion of resin plus asphaltene fractions. The bitumen content of L-wackes is the highest, and their average proportions of resin plus asphaltene fractions are moderate. The bitumen content of H-wackes is slightly lower than that of L-wackes, and they have the lowest average proportion of resin plus asphaltene fractions. The distribution and quality of bitumen are closely related to the matrix contents of oil sands.

High matrix content is usually a manifestation of low maturity in sandstone structure, which has a destructive effect on the physical properties of reservoirs (Aschwanden et al., 2019; Wong and Maini, 2007). The porosity and permeability of the oil sands of the Upper McMurray Formation are positively correlated (Fig. 11c). The physical properties of the oil sands are, from best to worst, arenites, L-wackes and H-wackes. Good connectivity in a reservoir is considered to be one of the necessary conditions for biodegradation (Head et al., 2003; Larter et al., 2003). There is a strong negative correlation between matrix content and MN2 value, which characterizes the degree of biodegradation. The degradation degree of arenites is the highest, that of H-wackes is the lowest, with the L-wackes between the two. Matrix may therefore affect the degree of biodegradation by altering the physical properties of oil sands, thereby controlling the distribution of bitumen. There are large amounts of black bitumen (Fig. 12e and f) distributed in layered and lamellar clay mineral grains, which proves that micropores of clay grains can provide favorable conditions for bitumen accumulation. Clay minerals have more specific surface features and micropores than detrital grains, enhancing the exchange frequency of cations, which is

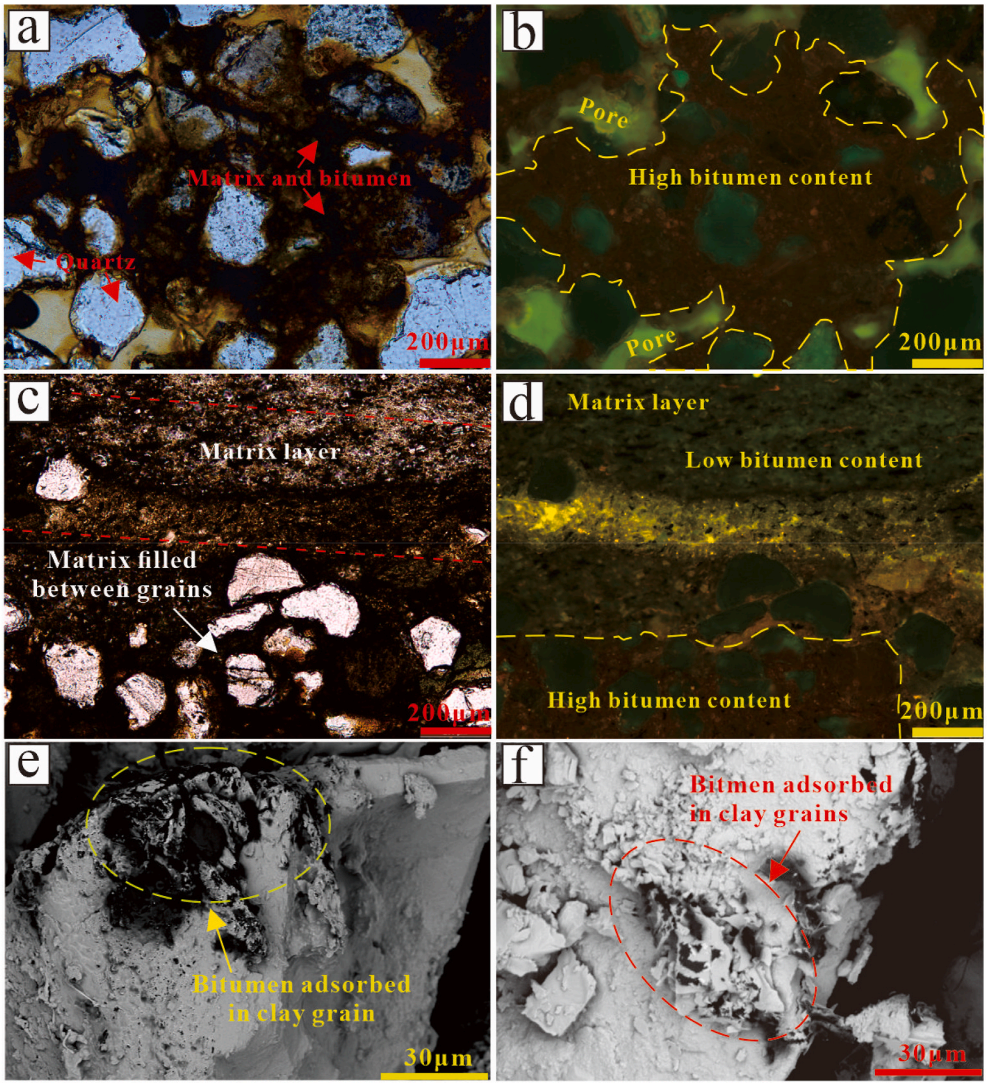

Fig. 12. Fluorescence and transmission light micrographs of bitumen distribution in oil sands. (a) L-wackes under transmitted light. The mixture of matrix and black bitumen is filled between the detrital grains, and (b) areas with high bitumen content display brown. (c) In transmitted light, matrix layers are unevenly distributed in H-wackes. (d) The bitumen content of the tight matrix layer in H-wackes is low, but the matrix with grain support shows high bitumen content. (e), (f) Clay mineral grains in the matrix absorb a large amount of bitumen, which may explain the high bitumen content of L-wackes.

considered to have a strong adsorption and preservation effect on hydrocarbons (Day-Stirrat et al., 2021; Osacky et al., 2013a).

The micrographs of transmission light and fluorescence provide more direct evidence for the distribution of bitumen in oil sands. The detrital grains appear silver-white under transmitted light, with the matrix between the detrital grains adsorbing a large amount of black bitumen. (Fig. 12a). Due to the sensitivity of fluorescence to hydrocarbons, fluorescence reactions are common in all the oil sand samples. The L-wackes generally show a strong fluorescence response (Fig. 12b), the detrital grains are dark green, the pores are bright green due to good light transmission qualities, and the areas with high bitumen content are brown. The overall fluorescence image of arenites is yellow-green, with only a few areas showing brown, indicating low bitumen content. However, H-wackes generally exist in two extreme states (Fig. 12c and d), showing low fluorescence in the tight matrix layer, and brown with high bitumen content where the structure is supported by detrital grains. The low average bitumen content of H-wackes may be because the frequent occurrence of matrix layers restricts the charging of crude oil, but the positions supported by grains still have high bitumen contents.

In summary, the mechanisms and effects of matrix on, the distribution of bitumen in oil sands can be summarized in three modes. Arenites with matrix content less than 15% have good physical properties (Fig. 13a1), with crude oil charging and reaching saturation more easily (Fig. 13a2). However, better physical properties can also lead to stronger water washing, oxidation, and degradation, leading to severe consumption of hydrocarbons and an increase in the proportion of resin and asphaltene fractions (Fig. 13a3). H-wackes have high contents of clay and silt grains (Fig. 13c1), which are easy to be compacted to form tight matrix layers (Fig. 13c2). Microfractures are the only fluid channels in the matrix layer, leading to poor physical properties. Reservoirs composed of H-wackes charge with crude oil only with difficulty, but the degradation degree of the hydrocarbons is the lowest in the three rock type (Fig. 13c3). Although the physical properties of L-wackes with matrix contents of 15–25% are poorer than arenites, the matrix only serves as interstitial material, with detrital grains providing the support (Fig. 13b1). In addition to intergranular pores, the uncompacted matrix can also serve as reservoir space for the adsorption and preservation of bitumen (Fig. 13b2). Therefore, the hydrocarbons adsorbed in the L-wackes matrix suffer relatively little degradation, resulting in high average bitumen contents (Fig. 13b3).

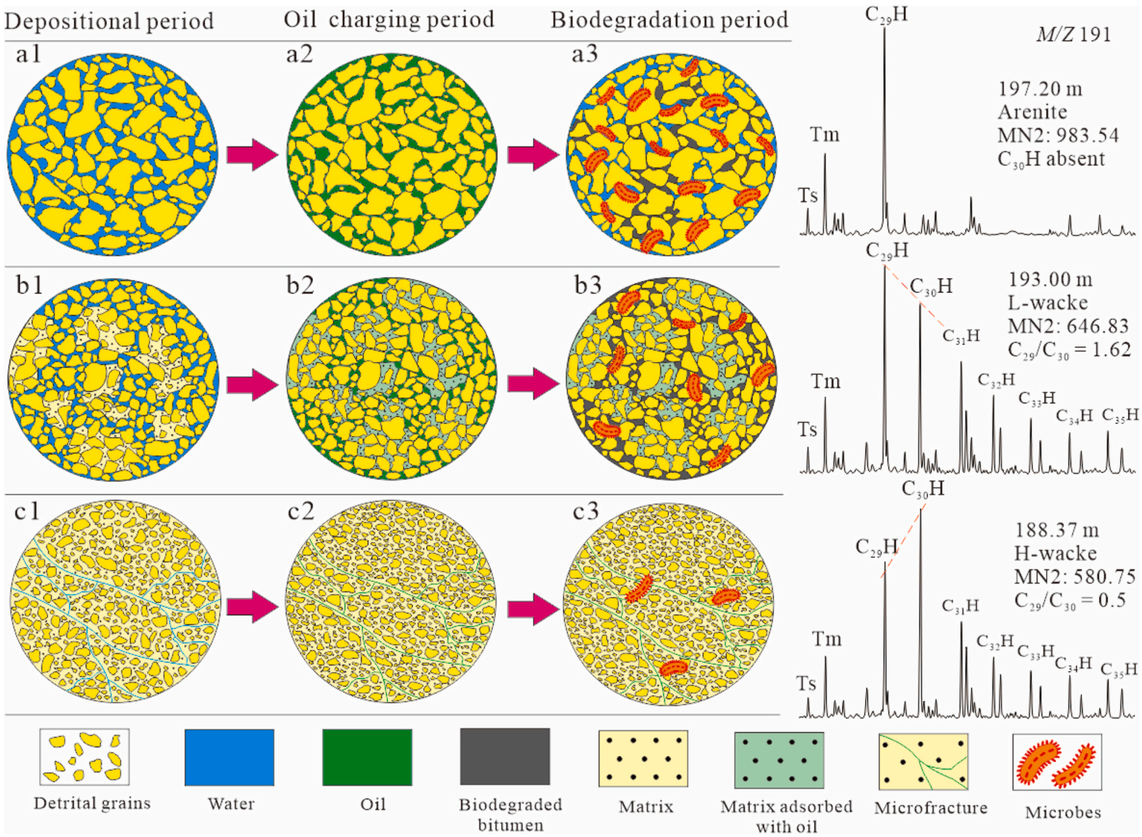

Fig. 13. Matrix controls the distribution of bitumen by affecting the physical properties and biodegradation degree of oil sands. There are three modes. (13a) Arenites (matrix <15%) have good physical properties and a strong degree of degradation, resulting in severe consumption of hydrocarbons. (13c) The support mode of H-wackes (matrix >25%) is matrix support, resulting in the formation of tight matrix layers inside. Although the degree of biodegradation is relatively low, crude oil fully charges only with difficulty. (13b) L-wackes have moderate matrix content, which can absorb and protect hydrocarbons against biodegradation, while not limiting oil charging.

5.4. Implications for bitumen recovery

The strong heterogeneity of bitumen distribution in the oil sand reservoirs is reflected in the variability of bitumen contents and properties, which greatly reduces the efficiency of bitumen recovery (Martinius et al., 2017). The heterogeneity is the result of a combination of multiple factors, including variability of oil sands petrology characteristics, oil-water layer distribution, degrees of degradation, and the initial charging amounts of petroleum (Adams et al., 2013; Fustic et al., 2013, 2019; Larter et al., 2006). The distribution of oil-water intervals in oil sand reservoirs can be evaluated through logging data, oil-water saturation, and shale content (Yang et al. 2023). The control effect of matrix on the oil sands' physical properties can further understand the origin of the formation of oil-water interval, and its implication for bitumen recovery.

The variation of bitumen content in oil sand reservoirs depends on local geological characteristics, such as the position of the oil-water contact, Lateral or vertical barriers caused by reservoir compartments, and physical properties of the reservoir (Fustic et al., 2013). In reservoirs with good physical properties and high saturation of water, the degree of bitumen degradation is more serious (Fustic et al., 2011). The matrix content of oil sands can establish a possible mechanism for the relationship between petrological characteristics, reservoir physical properties, biodegradation degree, oil charging, and oil-water interval formation origin.

Reservoirs with low matrix contents (arenites) have good physical properties but are more likely to be degraded and filled with formation water. This process may occur simultaneously with the disappearance of the top gas and the recharging of the formation water (Fustic et al., 2019). This type of reservoir has a significantly lower hydrocarbon content, and water saturation often exceeds oil, forming water intervals that have little development value. (Fig. 14 shown blue). The physical properties of the reservoirs with high matrix contents (H-wackes) are the worst of the three types. Although tight matrix layers reduce the degradation of hydrocarbon, they also limit initial charging with crude oil, resulting in low average oil contents. This type of reservoir also has high average clay contents and poor connectivity, so the recovery rate of bitumen is very low. They are usually regarded as poor oil intervals (Fig. 14, shown green with white stripes). In reservoirs with moderate matrix contents (L-wackes), the matrix does not seriously limit initial oil charging and also plays a role in the adsorption and preservation of hydrocarbons. These are usually regarded as the most promising oil intervals for development (Fig. 14, shown green).

The average bitumen content of favorable oil intervals is 1.13 times that of the poor oil intervals and 2.33 times that of the water intervals. The spacing between water, oil, and poor oil intervals is usually within the range of meters to centimeters. Identification of drilling locations should therefore focus on oil intervals as far as possible from water intervals, with selective development of poorer oil intervals to provide higher bitumen recovery efficiency.

It is generally accepted that, in sandstone, good physical properties are the primary indicators of high-quality reservoirs. However, for reservoirs like oil sands that have undergone severe biodegradation, the primary consideration is the preservation of hydrocarbons. The content of matrix determines whether it plays a 'promoting' or 'limiting' role in hydrocarbon accumulation and preservation.

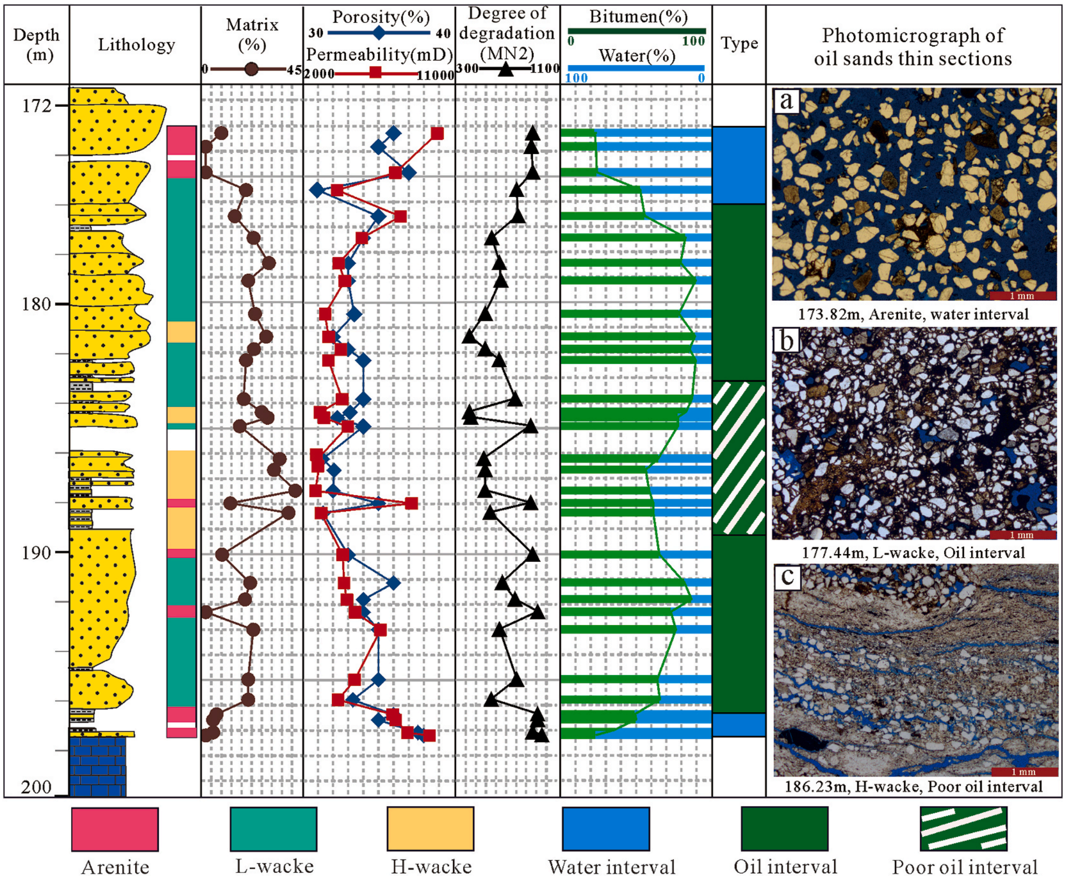

Fig. 14. Characteristics and origin of water, oil and poor oil intervals in the oil sand reservoir of McMurray Formation in the Mackay River area. Although there are a few exceptions, the water interval is primarily composed of arenite (a), the oil layer is mainly composed of L-wacke (b), and the poor oil layer is mostly made up of H-wacke (c). Differences in the degradation degree and oil charging caused by petrology differences are one of the factors contributing to the formation of the water, oil and poor oil interval.

6. Conclusions

This study demonstrates that the distribution of bitumen in oil sand reservoirs is influenced by many factors, such as petrology characteristics, biodegradation degree and original oil charging amount. As the interstitial material for oil sands, the control effect of matrix on oil sands texture and bitumen distribution is often ignored. Too much or too little matrix content is detrimental to the formation of high-quality oil sands reservoirs. A combination of sedimentary petrology and organic geochemistry can further the understanding of the origin of bitumen heterogeneity in oil sand and the factors controlling it. This will provide more comprehensive guidance for on-site management and well position strategies to optimize bitumen recovery rates in future oil sand development work.

1. Diagenesis of the oil sands in the McMurray Formation is weak, the interstitial material is matrix primarily composed of clay and silt grains, and cement is rare. Three types of oil sands with different textures are distinguished according to their matrix contents: arenites (matrix content<15%), L-wackes (matrix content 15–25%) and H-wackes (matrix content>25%).
2. Matrix content is negatively correlated to the physical properties of oil sands. Arenites and L-wackes predominantly feature grain support, and intergranular pores and matrix micropores are the main pore types. H-wackes generally feature matrix support, and matrix micropores and microfractures are the main pore types.
3. The content of matrix controls the texture of oil sands and determines whether they have a "promoting" or "limiting" effect on the distribution of bitumen. Clay and silt grains in the matrix play an adsorption and protection role for hydrocarbons, reducing degradation. However, high matrix content results in the formation of tight matrix layers, which limit initial charging with crude oil. Therefore, the appropriate amount of matrix is a prerequisite for forming high-quality oil sand reservoirs.
4. The reservoirs with the best physical qualities are not those with the highest bitumen contents. A high-quality oil sand reservoir requires both high initial charging and long-term hydrocarbon preservation. The texture of oil sand and its degree of bitumen degradation are effective indicators for evaluating water, oil, and poor oil intervals in reservoirs. The precise location of the oil intervals and avoiding water intervals allow for more efficient bitumen recovery.

CRediT authorship contribution statement

Junhao Ren: Conceptualization, Data curation, Formal analysis, Writing – original draft, Writing – review & editing. **Meijun Li:** Conceptualization, Funding acquisition, Methodology, Project administration, Supervision. **Xiaofa Yang:** Data curation, Project administration, Resources, Supervision, Validation. **Chengyu Yang:** Conceptualization, Formal analysis, Methodology, Supervision, Validation. **Guoqing Ma:** Data curation, Formal analysis, Investigation, Methodology. **Jixin Huang:** Project administration, Resources, Supervision. **Bang Zeng:** Conceptualization, Formal analysis, Methodology. **Ningning Zhong:** Conceptualization, Funding acquisition, Resources, Supervision, Validation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Acknowledgement

This research was supported by CNPC's Research Institute of Petroleum Exploration and Development Project. We sincerely appreciate the collaboration and support of the National Key Laboratory of Petroleum Resources and Engineering, College of Geosciences, China University of Petroleum (Beijing), and are also grateful to Shengbao Shi and Lei Zhu for their assistance in the geochemical experiments and analysis of all oil sand samples. The authors also wish to thank the anonymous editors and reviewers for their constructive suggestions and comments on this paper.

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