

Three-dimensional characterization of the total dissolved solids concentration and stable isotope composition of porewater extracted from Athabasca oil sands drill core

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Summary

Total dissolved solids (TDS) concentrations in McMurray Formation waters range from 220 to 280 000 mg/L in the Athabasca Oil Sands Region (AOSR) (Cowie et al., 2014). The observed variability in TDS concentrations within a reservoir or across a lease area influences measurements of resistivity that are required for resource assessment. Here we present a robust, low-cost method to characterize the geochemical composition of reservoir pore fluids from drill core derived porewater. The methods reveals the heterogeneity of TDS concentrations and the stable isotope compositions ($\delta^2\text{H}$, $\delta^{18}\text{O}$) of reservoir porewater, both vertically within a core, and laterally across a field. Analysis of water samples extracted directly from drill core provides a significant advance in the ability to characterize the properties of reservoir porewater, but requires corrections to account for drilling fluid contamination. Our new technique utilizes two end-member mixing relationships between the stable isotope compositions of drilling fluids and formation waters from multiple samples within a single reservoir, and does not require

measurement of drilling fluids to calculate formation water properties. The new method revealed that water derived from drill cores in several preliminary reservoirs had significant variability in TDS (860 to 45 000 mg/L), $\delta^2\text{H}$ (–172 to –149‰) and $\delta^{18}\text{O}$ (–22.4 to –19.3‰). These values are consistent with regional trends in formation water salinity and stable isotope composition, and illustrate the wide range of TDS values that can be found in McMurray Formation waters. A detailed characterization of the Suncor-Firebag lease area revealed both lateral and vertical heterogeneity in TDS and stable isotope compositions of McMurray Formation waters, thus providing a three-dimensional approach to water characterization within these oil sands reservoirs. This new methodology provides a tool to understand the origin and movement of reservoir water due to natural groundwater flow, and may be able to detect anthropogenic influence by steam injection. Additionally, novel in-situ extraction technologies that utilize electromagnetic or radio wave heating systems may also benefit from detailed characterization of aqueous reservoir fluids to accurately determine the resistivity and water properties of the reservoir.

Athabasca Oil Sands Regional Groundwater System

The regional groundwater system in the AOSR is complex, particularly in the bitumen-bearing McMurray formation. Recent research has proposed areas of upward formation water flow from Devonian aquifers into the McMurray Formation along the partial dissolution edge of the Prairie Evaporite Formation (Cowie et al., in review). Within this narrow geographic band trending from northwest to southeast across the AOSR, upward formation water flow occurs locally via karst conduits in the Devonian units, creating considerable heterogeneity in McMurray Formation waters. In addition, the presence of many Quaternary channels that down-cut into the McMurray Formation (Andriashek and Atkinson, 2007) provides a mechanism for locally increased modern groundwater recharge into the McMurray Formation. These hydrogeological processes have resulted in highly variable salinity in McMurray Formation waters at a lease-area scale. TDS concentrations in McMurray Formation waters can range from 1 000 to 100 000 mg/L within tens of kilometres (Cowie et al., in review). Therefore detailed characterization of McMurray Formation waters at high spatial resolution is desirable to infer hydrogeological processes and to improve interpretation of resistivity log measurements. The objective of this research was a proof-of-concept study to demonstrate the effectiveness of the porewater technique for measuring reservoir properties in the Athabasca Oil Sands Region.

Method Description

Drill core samples from oil sands reservoirs were frozen at the wellsite before transport to the laboratory. Between five and twelve 500 g subsamples were taken for analysis from each core, at depth intervals of two to five metres between samples. Porewaters were mechanically extracted via the Plunger technique (Gushor, Schlumberger Inc., US Patent #8495921). Water yield was typically less than 15 mL for each 500 g of core, however some core samples yielded no water. Porewaters squeezed from core materials were centrifuged, decanted and filtered to remove particulate material. Hydrogen and oxygen isotope ratios ($\delta^2\text{H}$ and $\delta^{18}\text{O}$) were determined using a Los Gatos Research DLT-100 Isotope Ratio Infrared Spectrometer. Concentrations of major cations (Na, K, Ca, Mg) were analyzed by ICP-OES, and concentrations of major anions (Cl, SO_4) were measured using an ion chromatography system. Laboratory alkalinity (determined as bicarbonate) was determined using a Thermo Orion 960 autotitration system. Total dissolved solids were calculated for each sample by taking the sum of the concentrations of major cations and anions in each sample.

Determination of In Situ Formation Water Properties from Measured Data

During drilling, mud penetrates the borehole and the extracted drill core. However, because bitumen is hydrophobic, it retards the drilling mud from completely obscuring the in situ formation water signal. Hence, the fluid samples obtained from drill core represent mixtures of drilling mud and formation water in variable proportions. Evidence for water samples representing variable mixtures between drilling mud and formation water is based on the following observations:

- The published stable isotope ratios of groundwater from all groundwater wells in the McMurray Formation plot on the Local Meteoric Water Line (LMWL), suggesting that waters within the reservoirs should also plot on the LMWL.
- Porewater samples from all core segments of a given well formed a linear trend in $\delta^2\text{H}$ – $\delta^{18}\text{O}$ space that intercepts the LMWL within the range of water isotope compositions that have been previously published for the McMurray Formation.
- Measured drilling fluids are enriched in ^2H and ^{18}O compared with the porewater obtained from drill core, and from published McMurray Formation water data. The $\delta^2\text{H}$ and $\delta^{18}\text{O}$ values of these drilling fluids plot to the right of the LMWL, suggesting that drilling fluid constitutes the ^2H and ^{18}O enriched end-member of a mixing line with formation water.
- The stable isotope compositions of the water samples extracted from core segments from a single well are also correlated with TDS, either negatively or positively depending on the TDS of formation water compared to the TDS of the drilling mud. This provides a second line of evidence for mixing between formation waters with lower $\delta^{18}\text{O}$ and $\delta^2\text{H}$ values and drilling fluids with elevated $\delta^2\text{H}$ and $\delta^{18}\text{O}$ values.

Based on these observations that water samples extracted from drill core are a mixture of formation fluids and drilling mud, and that the stable isotope composition of McMurray Formation waters fall on the LMWL, the intersection of the regression line formed by the measured isotope data with the LMWL is interpreted as a close approximation of the stable isotope composition of the reservoir waters in the McMurray Formation.

To calculate the original formation water TDS and stable isotope composition, and to determine the viability of this new technique for determining reservoir water properties, porewater $\delta^2\text{H}$ and TDS values were plotted against $\delta^{18}\text{O}$ values for each well. The $\delta^{18}\text{O}$ and $\delta^2\text{H}$ values were closely correlated in each system, displaying a linear array with distinct slopes plotting to the right of the LMWL. These linear trends of isotope compositions are interpreted as two end-member mixing lines between formation waters that plot on the LMWL and drilling fluids that plot to the right of the LMWL. In each of the three wells, the relationship between $\delta^2\text{H}$ and $\delta^{18}\text{O}$ was a linear array that intercepted the LMWL within the range of isotope values that have been previously published for waters in the McMurray Formation (Lemay, 2002; WorleyParsons, 2010; Gibson et al., 2011). The stable isotope composition at the intercept between the mixing array and the LMWL was taken as the reservoir formation water value. In all preliminary cases, TDS values were also correlated with $\delta^{18}\text{O}$ values. Formation water TDS was calculated by substitution of the LMWL-intercept $\delta^{18}\text{O}$ value into the linear equation of the TDS mixing line.

Conclusions

Our approach provides a new method to determine formation water $\delta^{18}\text{O}$, $\delta^2\text{H}$, and TDS values directly from drill core in a bitumen-saturated reservoir by analyzing chemical and isotopic properties of extracted water and correcting drilling fluid contamination. The values calculated by this technique are not dependent on knowing the drilling fluid composition. The stable isotope ratios and total dissolved

solids concentrations of porewater calculated using this method are consistent with regional TDS and stable isotope trends known from groundwater well sampling (Cowie et al., in review), suggesting that accurate values for reservoir formation water can be determined on a well-by-well basis using this technique. Therefore, it is now possible to obtain information about reservoir water salinity and stable isotope composition on a lease-area scale and greatly increase the frequency of TDS measurements within oil sands lease areas.

Applications of this new method are yet to be fully explored. These may include improved calibration of geophysical tools for characterization of water and bitumen saturation, and resultant improvement in efficiency of steam-based bitumen recovery techniques. Future deployment of this method will permit detailed characterization of natural hydrochemical variations in the McMurray Formation, thus assisting with hydrogeological model development. Furthermore, this technique may permit the detection of condensed water from steam injection during in situ energy development, and may assist in the development of new electromagnetic wave heating systems where determining the optimal electrode spacing configuration requires detailed knowledge of formation water salinity in shallow oil sands reservoir systems.

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