Distribution of total dissolved solids in McMurray Formation water in the Athabasca oil sands region, Alberta, Canada: Implications for regional hydrogeology and resource development

Benjamin R. Cowie, Bruce James, and Bernhard Mayer

ABSTRACT

Total dissolved solids (TDS) concentrations of 258 Lower Cretaceous McMurray Formation water samples in the Athabasca oil sands region (54 to 58°N and 110 to 114°W) were mapped using published data from recent government reports and environmental impact assessments. McMurray Formation waters varied from nonsaline (240 mg/L) to brine (279,000 mg/L) with a regional trend of high salinity water approximately following the partial dissolution front of the Devonian Prairie Evaporite Formation. The simplest hydrogeological explanation for the observed formation water salinity data is that Devonian aquifers are locally connected to the McMurray Formation via conduits in the sub-Cretaceous karst system in the region overlying the partial dissolution front of the Prairie Evaporite Formation. The driving force for upward formation water flow is provided by the Pleistocene glaciation events that reversed the regional Devonian flow system over the past 2 m.y. in the Athabasca region. This study demonstrates that a detailed approach to hydrogeological assessment is required to elucidate TDS concentrations in McMurray Formation waters at an individual lease-area scale. The observed heterogeneity in formation water TDS and the potential for present day upward flow has implications for both mining and in situ oil sands resource development.

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AUTHORS

Benjamin R. Cowie ~ *University of Calgary, Department of Geoscience, 2500 University Drive NW, Calgary, Alberta, T2N 1N4, Canada; Harvard University, Department of Earth and Planetary Sciences, 20 Oxford Street, Cambridge, Massachusetts, 02138; cowie@fas.harvard.edu*

Ben Cowie is a postdoctoral fellow in the Earth and Planetary Sciences Department at Harvard University. He completed his Ph.D. at the University of Calgary in 2013 and previously received B.Sc. (2006) and M.Sc. (2008) degrees from McMaster University in Hamilton, Canada. He is particularly interested in developing new isotopic approaches to studying complex Earth systems through time.

Bruce James ~ *Suncor Energy Inc., 150 6 Ave SW, Calgary, Alberta, Canada T2P 3Y7; bjames@suncor.com*

Bruce James is a senior reservoir engineering advisor at Suncor Energy Inc. He has a B.A.Sc. in geological engineering from the University of Waterloo, a M.S. in engineering economic systems and operations research from Stanford University, and a Ph.D. in geological engineering from the University of British Columbia.

Bernhard Mayer ~ *University of Calgary, Department of Geoscience, 2500 University Drive NW, Calgary, Alberta, T2N 1N4, Canada; bmayer@ucalgary.ca*

Bernhard Mayer is a professor of isotope geochemistry in the Department of Geoscience at the University of Calgary. He received his M.Sc. (Diploma) and Ph.D. from the Ludwig-Maximilians University in Munich (Germany) in 1987 and 1993, respectively. His Applied Geochemistry group uses tracer tools to conduct innovative research on geological CO_2 sequestration (including EOR), shale gas and oil sands development and its environmental impacts, among others.

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DATASHARE 57

Table 2 is available in an electronic version on the AAPG website (www.aapg.org/datashare) as Datashare 57.

INTRODUCTION

The Athabasca oil sands region (AOSR) in northeastern Alberta, Canada is a region of significant hydrocarbon development, representing 170 billion barrels of heavy oil and bitumen reserves (Government of Alberta, 2013). Rapid development of bitumen resources by surface mining or in situ extraction by steam-assisted gravity drainage (SAGD) requires water-intensive extraction and separation processes that will strain Northern Alberta's water supply over the coming decades (Griffiths et al., 2006). The major mining projects in the Athabasca region are sufficiently close to the Athabasca River to draw from its vast surface water resources; however, the majority of in situ extraction facilities must draw upon groundwater resources for industrial use (Hayes, 2013). The Lower Cretaceous McMurray Formation is the primary petroleum-bearing unit in the Athabasca region. However, it is also a significant aquifer where it is not saturated with bitumen, and it provides water sources for most in situ resource development projects (Government of Alberta, 2013; Hayes, 2013; Wills, 2013). McMurray Formation water is poorly suited for most domestic water use in the AOSR due to its proximity to bitumen and resulting naturally elevated concentrations of dissolved hydrocarbons (Lemay, 2002; Hayes, 2013). However, due to its high permeability and relatively shallow depth, the McMurray Formation is an ideal aquifer for industrial water supply. Therefore, these water systems have economic value despite their relatively poor water quality (George, 2013). Detailed characterization of aquifer geochemical properties may be beneficial to identify the highest quality water for industrial processes (Robertson, 2013). Therefore, understanding the heterogeneity of the McMurray Formation water salinity is important for hydrogeological interpretation, reservoir characterization, and building appropriate facilities to treat saline water extracted from the McMurray aquifer for industrial use.

A detailed hydrostratigraphic description of the Athabasca region was provided by Bachu and Underschultz (1993), and this model is the basis for the simplified hydrostratigraphic delineation in Figure 1. Throughout the Athabasca region, the Cretaceous-aged McMurray Formation, which bears the majority of the oil sands deposits, has a complex depositional history with fluvial and estuarine components (Fustic et al., 2012). The McMurray Formation overlies a major unconformity that spans from the Upper Devonian to the Lower Cretaceous. Underlying the sub-Cretaceous unconformity is a thick Devonian carbonate and evaporite succession. Formation waters in Devonian strata in the AOSR have typically high salinity total dissolved solids (TDS) >35,000 mg/L) because of the dissolution of halite and

Era	Period	Stratigraphy		Hydrostratigraphy
Cenozoic	Quaternary	Pleistocene unconsolidated sediment		aquifer
Mesozoic	Cretaceous	Colorado Group		aquitard
		Mannville Group	Grand Rapids	aquifer
			Clearwater	aquitard
				aquifer
			McMurray-Wabiskaw	aquifer
		sub-Cretaceous unconformity		
Paleozoic	Devonian	Wabamum-Winterburn		aquifer
		Ireton		aquitard
		Waterways		aquifer
		Prairie Evaporite		aquiclude
		Keg River (Methy)		aquifer
Precambrian		aquiclude		

Figure 1. Regional hydrostratigraphy in the Athabasca oil sands region (modified after Bachu and Underschultz, 1993).

anhydrite-containing evaporite units, including the Prairie Evaporite Formation (Hackbarth and Nastasa, 1979; Bachu and Underschultz, 1993; Grasby and Chen, 2005; Gue, 2012). Overlying the McMurray Formation is the Cretaceous Clearwater Formation, considered to be a regional aquitard (Bachu and Underschultz, 1993). A second unconformity exists from the Upper Cretaceous through to the Pleistocene. The Pleistocene glaciation resulted in the incision of deep valleys that sporadically cross-cut the McMurray Formation, which were subsequently infilled with Quaternary sediments (Andriashek and Atkinson, 2007). These channels often have aquifer properties and may permit connectivity between shallow groundwater and deeper formation waters.

Frequently cited regional flow models have provided somewhat differing interpretations of the sub-Cretaceous hydrogeology. Several models suggest very long flow paths with formation waters originating far to the south in Montana or far to the west in the Rocky Mountains (Bachu, 1995; Anfort et al., 2001; Barson et al., 2001; Michael et al., 2003). However, mixing between fluids in Devonian and Cretaceous aquifers has been suggested to occur across the sub-Cretaceous unconformity in the AOSR, where the McMurray Formation overlies the Devonian aquifers (Bachu and Underschultz, 1993). However, the precise spatial location and extent of flow across the sub-Cretaceous interface in the oil sands region remains unconstrained.

Springs in Devonian strata are common along the banks of the Clearwater and Athabasca Rivers, indicating that these river valleys are areas of groundwater discharge. Spring waters are often brackish to saline, with stable isotope compositions that are indicative of recent meteoric recharge (Grasby and Chen, 2005; Gue, 2012). Recent work has also quantified the saline groundwater flow into the Athabasca River from groundwater sources (Jasechko et al., 2012). However, very few groundwater samples have ever been obtained from below the sub-Cretaceous unconformity in the AOSR, and the hydrogeological nature of the unconformity has not been studied in great detail in this region. Samples that have been obtained from Devonian strata (Hackbarth and Nastasa, 1979) indicate that formation water TDS is greater than that of seawater, with elevated concentrations of Ca and SO_4, suggesting anhydrite dissolution as a likely source of dissolved SO_4.

There are many indications suggesting that upward vertical flow, originating from the sub-Cretaceous strata, is an important regional-scale hydrogeological process that may impact water quality in some areas of the McMurray Formation in the AOSR. These lines of evidence include drill stem pressure tests that indicated Devonian hydraulic head values exceeding those measured in the McMurray Formation (Nexen Inc. and OPTI Canada Inc., 2007), reported McMurray Formation waters with salinity values greater than seawater (Hackbarth and Nastasa, 1979; WorleyParsons, 2010a, b), and a reported eruption of an H_2S-bearing saline fluid from a planned mine tailings pond that was attributed to connectivity with artesian Devonian aquifers (Cooper, 2011).

Water saturation in oil sands systems is calculated according to Archie's law (Archie, 1942) or the Waxman-Smits equation (Waxman and Smits, 1968) that relate the conductivity of a fluid-saturated rock to the conductivity of water, which is directly related to its dissolved ion content and composition. Therefore, geophysical tools used to determine bitumen and water saturation in the McMurray Formation are influenced by variable salinity of formation waters, and changes in salinity across a bitumen play may lead to incorrect estimates of bitumen saturation with possible economic implications. Additionally, the steam-generation process for bitumen recovery requires removal of dissolved solids from the water source, and elevated salinity in the source water adds substantial costs to this process (Robertson, 2013). Therefore, there is significant economic benefit to be gained by understanding salinity variations in formation waters within an oil sands reservoir.

Recent research is suggestive of active karst processes in the Athabasca region as a result of the dissolution of evaporite and carbonate rocks below the McMurray Formation (Broughton, 2013). These proposed karst processes have substantial implications for McMurray Formation hydrogeology, as the conduit-style preferential flow paths generated in a karst system can create unpredictable water flow paths in groundwater systems (e.g., Ford and Williams, 2007), potentially generating conduits for upward vertical flow into the McMurray Formation. Further complicating the system is the influence of meltwater from the Pleistocene glaciation events that have been identified as a major influence in Devonian aquifer systems by geophysical pressure models, geochemical analysis, and stable isotope studies (Grasby and Chen, 2005; Gue, 2012). Elevated hydraulic head created by several kilometers of glacial ice has generated overpressured fluids in the Devonian aquifers that underlie the McMurray Formation (Grasby and Chen, 2005). These glaciogenic fluids containing ions dissolved from Devonian evaporites discharge at outcrops along the Clearwater and Athabasca Rivers (Gue, 2012). The McMurray Formation hydrogeology is further influenced by anthropogenic activities via steam injection and groundwater withdrawal. This complex interplay of geological phenomena and anthropogenic activities has created significant variability in the salinity of the McMurray Formation that requires further investigation.

The purpose of this study was to map total dissolved solids in waters of the McMurray Formation across the AOSR. Understanding heterogeneity in McMurray Formation water salinity on a regional scale will help to gain a better understanding of the regional hydrogeological flow system and, as a consequence, to improve the efficiency of oil sands operations, and help to manage the risk of negative environmental impacts during resource development.

METHODS

Total dissolved solids data for McMurray Formation waters were obtained from a large body of government and industry technical reports including environmental impact assessments, Cumulative Environmental Management Agency (CEMA) documents, Oil Sands Research and Information Network (OSRIN) reports, and Alberta Geological Survey (AGS) reports. Details of the data source, location, and a TDS value for each individual formation water sample are available as an Appendix (AAPG Datashare 57, www.aapg.org/datashare). These samples were obtained from groundwater wells with major cation and anion concentrations determined by commercial laboratories, resulting in a detailed and high-quality data set compared to previous formation water samples from drill stem tests or those that use electrical conductivity to estimate TDS.

Sample access was biased toward the bitumen-bearing commercial lease areas, resulting in an uneven spatial distribution across the AOSR. Data were excluded from the database if they were noted in the report as contaminated by drilling fluids or cement (typically resulting in $K^+ > 1000$ mg/L or pH > 10.0). All reported TDS values were generated from water samples having analysis of major and minor cations with a charge balance of less than ±10%. Many groundwater wells were sampled multiple times over the past 20 years by different companies. When duplicate sampling dates were identified, only data from the most recent sampling date were included. A wide spatial distribution of groundwater TDS data was obtained, and 258 total data points were included in this study.

RESULTS

McMurray Formation water TDS data were evaluated by considering the Athabasca region as a whole and also by dividing the data spatially into three subregions. These subregions were delineated by the Athabasca and Clearwater Rivers, which are incised deep into the geologic strata and act as major hydrogeological flow barriers in the region (Bachu and Underschultz, 1993; WorleyParsons, 2010b). The West subregion consists of all areas west of the Athabasca River; the Northeast subregion consists of the area east of the Athabasca River and north of the Clearwater River, and the Southeast subregion consists of all areas east of the Athabasca River and south of the Clearwater River.

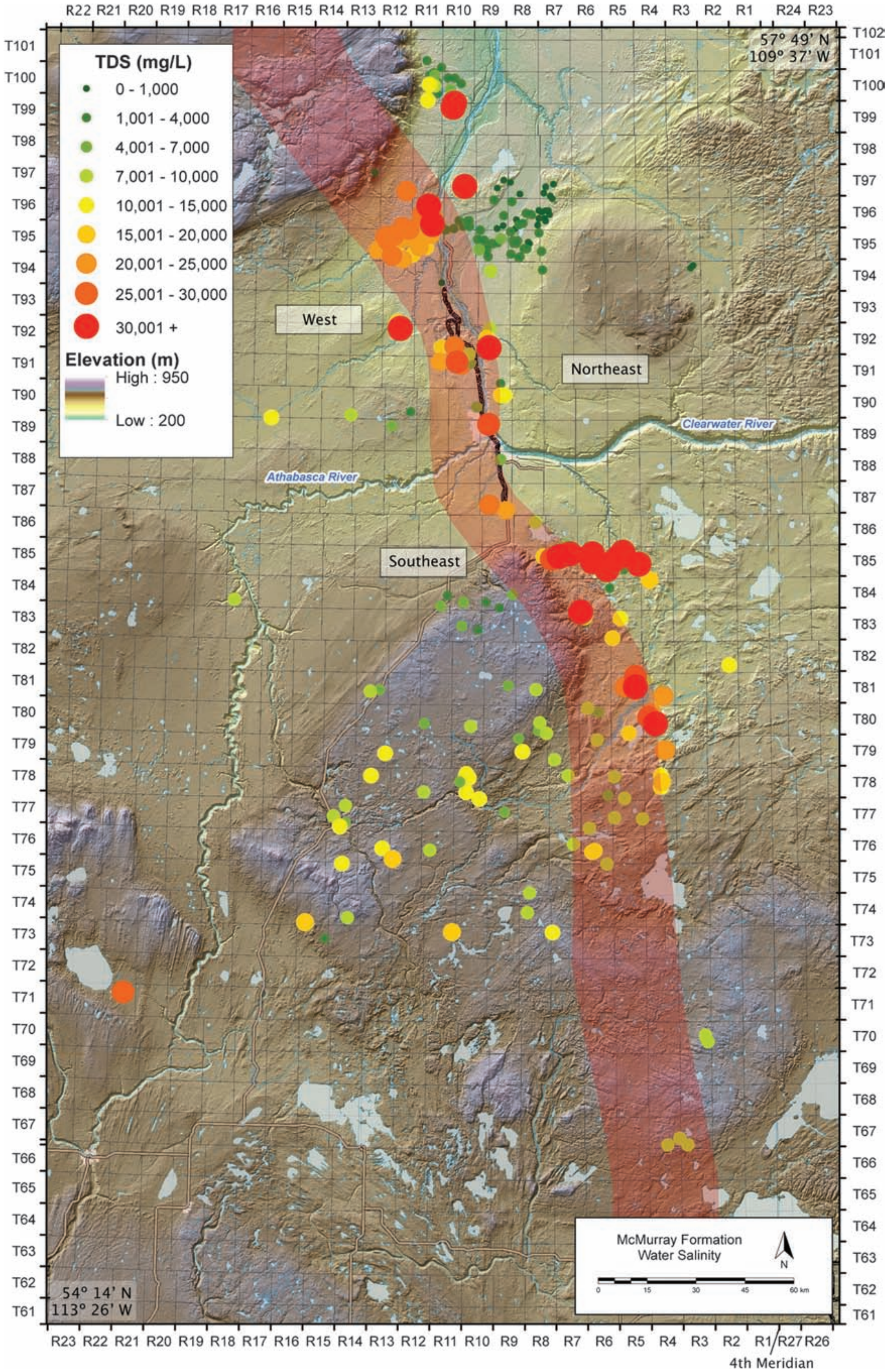
Data from this study were plotted in two different ways to illustrate the observed heterogeneity in the data set. A map of McMurray Formation water TDS was plotted on a regional surface topography map in Figure 2, and histograms of the regional and subregional TDS values for formation waters were plotted in Figure 3. These data illustrate major differences among the subregions, and broad variations in formation water TDS emerged.

Athabasca Region

Summary statistics of observed McMurray Formation water TDS values are reported in Table 1. Eighteen formation waters had TDS values greater than 30,000 mg/L, and ten formation waters had values greater than 50,000 mg/L. Spatially across the Athabasca region, there was a trend of high formation water TDS values (>20,000 mg/L) observed in a trend overlying the partial dissolution front of the Prairie Evaporite Formation. This high salinity region transcends the regional hydrogeological barriers of the Athabasca and Clearwater Rivers, with TDS values above 20,000 mg/L observed in all three subregions (Figure 2). Within 10 km (6.2 mi) of the Prairie Evaporite Formation partial dissolution front, the highest TDS values in the region are observed. However, McMurray Formation water TDS values from wells drilled near the evaporite edge are not exclusively high, suggesting that local heterogeneity, rather than wide-scale regional processes, are responsible for the observed variability.

The histogram of TDS values for the Athabasca region (Figure 3A) shows a strongly skewed distribution toward low TDS values (<5000 mg/L), with a long tail of data in the upper range of values (>20,000 mg/L). While the majority of TDS values plot on the lower end of the distribution, there is a significant group of outliers that require attention due to the challenges posed by high salinity waters in oil sands reservoirs. It should be noted, however, that the distribution of McMurray Formation water TDS

Figure 2. Distribution of total dissolved solids in McMurray Formation waters in the Athabasca oil sands region. The partial dissolution front of the Prairie Evaporite Formation is indicated by red shading (derived from Grobe, 2000 and Broughton, 2013).



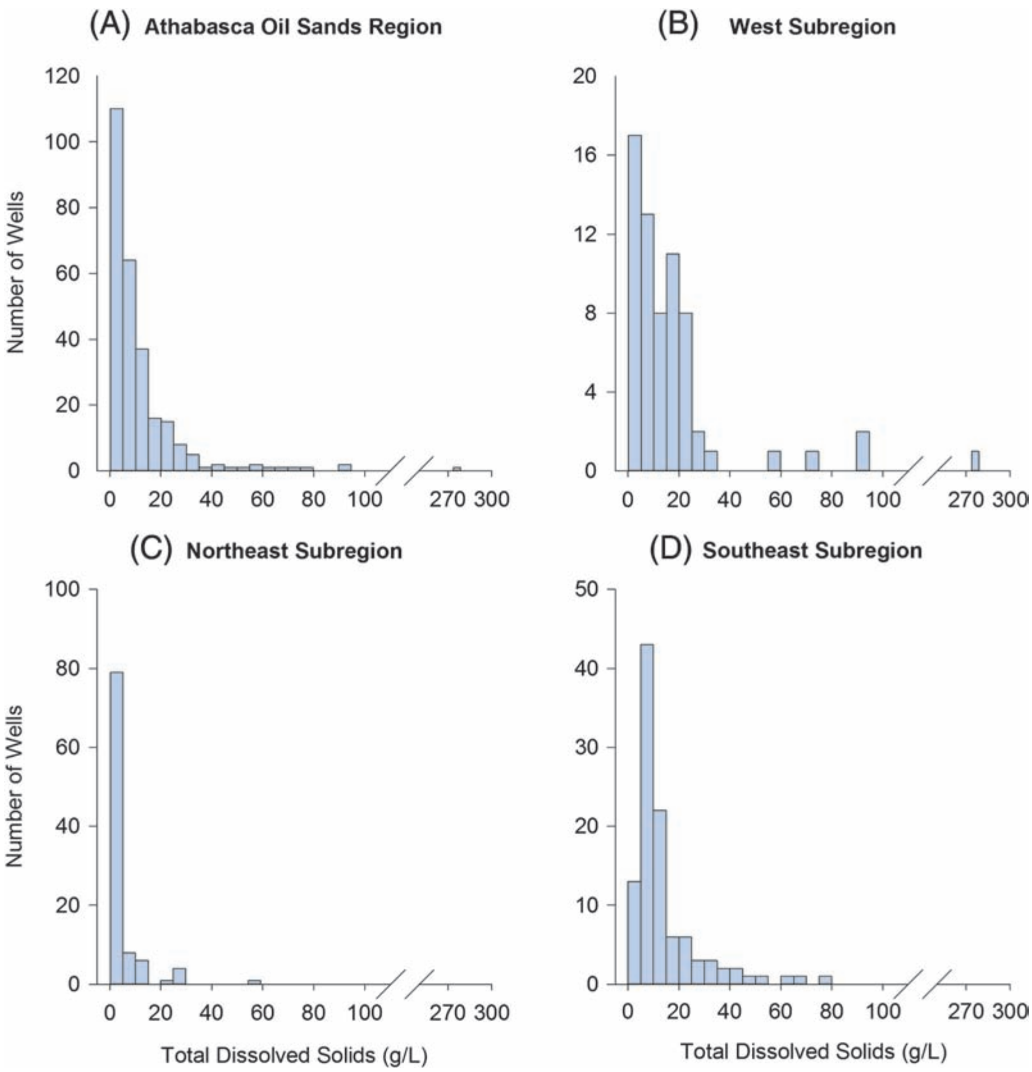


Figure 3. Distribution of total dissolved solids concentrations in McMurray Formation waters for (A) the Athabasca oil sands region, (B) West subregion, (C) Northeast subregion, (D) Southeast subregion. Histogram bin size is 5000 mg/L in all diagrams.

values in the AOSR as a whole deviates substantially from those of the subregions (Figure 3). Hence, an evaluation of the TDS data by subregion is desirable.

West Subregion

The distribution of TDS values observed in the West subregion was primarily from the mining regions of the AOSR. Six of the data points in this subregion had TDS values greater than 30,000 mg/L, and the highest salinity value observed in any of the subregions was found in the West subregion (279,000 mg/L). The highest TDS sample was observed in Township 96, Range 11W4 and was measured by two different researchers on different sampling dates. Brines with comparably elevated salinity have been previously noted in the AOSR in deeper Devonian aquifers (Grasby and Chen, 2005). Within the same township as the brine outlier, TDS values less than 1000 mg/L were also observed in McMurray Formation waters, demonstrating substantial local heterogeneity. Spatially, the data in the West subregion were highly variable with few discernible trends apart from the primary regional trend of elevated formation water salinity along the Prairie Evaporite dissolution front. In the northernmost mining area (Teck Frontier, Twp 99, Rng 10W4), the Teck-Frontier lease is approximately 20 km (12.4 mi) east of the mapped Prairie Evaporite dissolution edge and overlies large sinkholes in the Devonian surface (Grobe, 2000; Broughton, 2013). Most TDS values of McMurray Formation waters in the Teck lease were low (mean TDS = 4700 mg/L, n = 28) compared to those observed at the southern

Table 1. Summary Statistics for McMurray Formation Water Total Dissolved Solids in the Athabasca Oil Sands Region*

Region	No. of Samples	Minimum	25th Percentile	Median	75th Percentile	Maximum
Athabasca	258	240	2,400	7,000	14,000	279,000
West	65	332	5,400	14,000	22,000	279,000
Northeast	96	240	730	1,900	3,700	59,000
Southeast	97	750	6,900	9,100	16,000	77,000

*All total dissolved solids (TDS) values in mg/L.

mines. However, two observation wells within the Teck lease had formation waters with significantly higher TDS (~90,000 mg/L) than the rest of the samples. West of the Athabasca River and south of Fort McMurray, there were fewer available public data from which to draw interpretations. Water samples from available wells showed variable TDS ranging from 4000 to 25,000 mg/L.

The histogram of the West subregion (Figure 3B) depicts a skewed distribution with 17 TDS values greater than 20,000 mg/L. The tail of high TDS values extended to 279,000 mg/L, with sporadic high TDS values dotting the upper range of formation water TDS values.

Northeast Subregion

The Northeast subregion contains data from both mining and in situ energy developments. There was only one well that had a TDS value greater than 30,000 mg/L. Spatially, the highest TDS values observed in this subregion were close to the Athabasca River and the Prairie Evaporite partial dissolution front (Figure 2). Formation waters with lower TDS values were observed to the east of the partial dissolution front. No formation waters with TDS greater than 4000 mg/L were identified more than 10 km (6.2 mi) east of the Athabasca River. Formation waters with higher TDS values are found within 10 km (6.2 mi) of the Athabasca River. However, these data are interspersed with low-TDS formation waters, indicating local, instead of regional geochemical influence on the formation water salinity in the McMurray Formation.

The histogram for the Northeast subregion (Figure 3C) is skewed toward the low-TDS end of the spectrum, with a large majority of the values ($n = 79$) falling into the lowest histogram bin (<5000 mg/L). However, four TDS values ranging from 20,000 to 59,000 mg/L were identified for McMurray Formation waters in the Northeast subregion.

Southeast Subregion

Distinct from the other two subregions that contain mining and in situ operations, the southeast subregion consists entirely of in situ energy developments, as the oil sands deposits in this area are too deep to mine. In the Southeast subregion, 12 wells yielded formation water with TDS values greater than 30,000 mg/L. Examining the spatial distribution of TDS in the Southeast subregion, the values were highest in the east and lower in the west and central portions of the subregion. The lowest TDS values in the Southeast subregion were observed on the topographic high, centered at Township 84, Range 9W4 (Figure 2). The easternmost part of the Southeast subregion was characterized by very elevated TDS values up to 77,000 mg/L. This region of high salinity is consistent with the broader regional trend of the Prairie Evaporite edge (Figure 2), and in the Southeast region, the evaporite edge also coincides with the eastern edge of bitumen-bearing McMurray Formation.

The histogram for the Southeast subregion (Figure 3D) was different from those of the other subregions in that the modal peak was in the second histogram bin (5000–10,000 mg/L), indicating that fewer waters with low TDS were present in the Southeast subregion (Figure 3D). Similar to the other two subregions, the Southeast subregion exhibited a long tail toward the high end of TDS in formation water data distribution, with 21 TDS values >20,000 mg/L.

DISCUSSION

Conceptual models of groundwater flow in the McMurray Formation have described groundwater flow paths as primarily local in nature, driven by topographic recharge (Bachu and Underschultz, 1993; Anfort et al., 2001; WorleyParsons, 2010a, b). However, exclusive downward flow does not satisfactorily explain the variation observed in formation water salinity across the AOSR. While topographically driven flow plays an important role in the AOSR, additional factors such as interactions with fluids from the Devonian units below the sub-Cretaceous unconformity provide a better explanation for the observed variability in TDS. This hypothesis is based on two key principles that have recently been described in the literature: (1) There are widespread karst features underlying the McMurray Formation in the Devonian carbonate and evaporite units (Broughton, 2013), providing conduit-style preferential flow paths between Devonian aquifers and the McMurray Formation that directly overlies the karst structures. (2) Injection of meltwater from Pleistocene ice sheets into the Devonian aquifers that underlie the McMurray Formation (Grasby and Chen, 2005; Gue, 2012) has created elevated hydraulic head thus providing a driving force for upward flow of saline formation waters into the oil sands reservoirs where conduits exist to enable flow. Hence, a conceptual model is proposed that incorporates both downward and upward groundwater flow into the McMurray Formation to explain the present-day distribution of formation water TDS.

Mixing between fluids from Devonian aquifers and overlying Cretaceous formation waters was first suggested as a possibility by Bachu and Underschultz (1993); however, at the time their study was published, there were insufficient data to identify the extent and magnitude of this process. Massive-scale karst caused by carbonate and evaporite dissolution below the sub-Cretaceous unconformity was recently demonstrated to underlie much of the AOSR (Broughton, 2013). Deep, karst-style closed depressions (sinkholes) are apparent throughout the region in the Devonian structural surface, and the continued subsidence of several of these sinkholes has been demonstrated to occur on timescales from pre-Cretaceous to modern (Broughton, 2013). Further evidence of the presence of sinkholes is provided by geological models developed for environmental impact assessments of many oil sands operations where units above the sub-Cretaceous unconformity have been structurally altered since deposition, suggesting continued subsidence after deposition of these units (e.g., Petro Canada, 2001; Nexen Energy Inc. and OPTI Canada Inc., 2007; Teck Resources Ltd., 2011; Broughton, 2013). Karst hydrogeological systems consist of dual porosity matrix flow and a network of conduits that can result in groundwater flow rates of up to kilometers per day during periods of high flow (Ford and Williams, 2007). This unique type of hydrogeology that is characterized by preferential flow of fluids through conduits creates significant challenges for modeling groundwater flow. The preferential flow paths generated by karst provide the necessary connectivity to explain the highly localized nature of cross-formation flow between Cretaceous and Devonian units. Because the McMurray Formation directly overlies the karst topography of the Devonian system, it should be directly connected to Devonian aquifer systems where open conduits exist. Karst hydrogeology provides an explanation consistent with formation waters measured in wells separated by several kilometers with TDS values varying by orders of magnitude (Figure 2). The highly localized nature of proposed upward fluid flow from Paleozoic strata is apparent in the northernmost part of Figure 2 (Township 100, Range 10W4). In this area, there are groundwater wells drilled into the McMurray Formation that have TDS values ranging from non-saline water (<4000 mg/L) to those approaching brine concentrations (~90,000 mg/L) over a distance of tens of kilometers. These locally high TDS values of formation waters are most consistent with hydraulic connectivity between Devonian and Cretaceous hydrostratigraphic units; however, not all the McMurray Formation waters within this area have high salinity. Therefore, the best explanation for the observed variability is that conduits between Cretaceous and Devonian hydrogeological systems exist within the areas of McMurray Formation water with the highest salinity, resulting in high TDS values in some areas, but not necessarily in adjacent wells.

Therefore, a high degree of variability in formation water TDS values can be expected within the scale of a single oil sands development or lease area.

Connectivity between Cretaceous and Devonian hydrogeological units is insufficient to explain upward flow of high salinity water from underlying units; a driving force is required to move denser, saline water in the opposite direction of gravitational forces. The proposed driving force was previously identified by Grasby and Chen (2005) who provided evidence of subglacial meltwater intrusion into the Devonian carbonate units that underlie the McMurray Formation, and proposed a reversal of the regional groundwater system from a model driven by deep basin flow to one driven by the impact of subglacial recharge. This hypothesis, based on both physical and chemical arguments, demonstrates that modern flow systems are not yet in equilibrium with longer time-scale geological processes. The data from Grasby and Chen (2005) indicate elevated hydraulic pressures during the Pleistocene glacial events that instigated a reversal in the regional flow system at the eastern margin of the Western Canada Sedimentary Basin such that groundwater observed in modern Devonian aquifers was recharged with meltwater of ice sheets in the northeast, rather than through deep basin flow from the Rocky Mountains. Geochemical and stable isotope evidence from springs along the Athabasca and Clearwater Rivers indicates that the discharging water has elevated salinity, but stable isotope compositions (δ^2H, $\delta^{18}O$) that are dissimilar from deep-basin Devonian brines are found elsewhere in Alberta (Connolly et al., 1990; Grasby and Chen, 2005; Gue, 2012). Instead, the isotopic compositions of the discharging brines and saline waters are consistent with mixed inputs from modern recharge and glacial waters that infiltrated into the Devonian formations and dissolved the evaporite units found within the region (Gue, 2012). The hydrogeological response to the removal of the continental ice sheets is the northeastern updip flow of Devonian formation waters toward the edge of the basin. However, in karst-impacted strata, conduit flow paths are exploited, and saline waters from the Devonian system flow directly upward into the McMurray Formation, generating the observed elevated formation water salinity. Our proposed mechanism for upward flow into the McMurray Formation is distinct from other recent studies of glacier-derived Pleistocene recharge into sedimentary basins that resulted in lower salinity in the basin formation waters (e.g., Martini et al., 1996, 1998; McIntosh et al., 2002; Martini et al., 2003; McIntosh et al., 2004; McIntosh and Walter, 2005; Formolo et al., 2008; McIntosh et al., 2011). In the Athabasca region, the presence of undissolved evaporite units and a heavily karst-impacted Devonian system provide a network of conduits for upward flow of high-salinity fluids into the hydrocarbon-bearing McMurray Formation, as opposed to lower salinity glacial waters that are observed elsewhere.

There are other lines of evidence that provide support for the existence of the Pleistocene basin flow reversal. Evidence of blowout structures are described in several locations near the edge of the Western Canada Sedimentary Basin where subsurface pressures exceeded the structural integrity of confining units above the sub-Cretaceous surface. A notable instance of this process is the Howe Lake blowout structure in central Saskatchewan that was described in detail by Christiansen et al. (1982). Recent pressure tests performed for environmental impact assessments provide supporting evidence for upward flow, as several of the wells that were completed in Devonian strata had greater hydraulic head values than wells completed in the overlying McMurray Formation (Nexen Inc. and OPTI Canada Inc., 2007). This evidence suggests that upward flow from the Devonian strata to overlying aquifers has occurred in the recent past and provides a plausible mechanism for upward flow of high-salinity formation water into the McMurray Formation, across the AOSR from the Devonian aquifers, where conduits exist.

The data from this study are most consistent with a model of topographic recharge across the region, coupled with local upward formation water flow into the McMurray Formation from the underlying Devonian units. Exclusively downward flow of groundwater from meteoric recharge does not sufficiently explain the substantial variability and spatial distribution of McMurray Formation waters with elevated TDS values. However, exclusively upward flow does not explain the low salinity values observed throughout the majority of the region. The northwest–southeast-trending linear feature of high formation water TDS values that coincides with the edge of the Prairie Evaporite Formation provides the conditions most likely to generate upward flow of saline water (Figure 2). Along this trend, and east of the dissolution edge, significant karsting has developed, leading to the formation of many sinkholes and conduits associated with karst hydrogeology (Broughton, 2013). Also along this trend are evaporite formations of varying thickness, with both halite and anhydrite to provide high concentrations of solutes in Devonian formation waters (Grobe, 2000). East of the evaporite dissolution front, lower TDS values are observed in Devonian formation waters (Grasby and Chen, 2005). West of the Prairie Evaporite partial dissolution front, the evaporite units are intact, and therefore, the wide-scale karst hydrogeology and conduit system has not yet developed to provide connectivity between the McMurray Formation and underlying Devonian aquifer systems. Therefore, McMurray Formation waters with the highest TDS values are observed primarily adjacent to the Prairie Evaporite partial dissolution front, where karst hydrogeology has created recent conduits. In these locations, elevated hydraulic head values generated by glacial overpressure drive fluid upward into the McMurray Formation waters across the AOSR.

Karst hydrogeology provides a suitable explanation for other unusual phenomena in the AOSR. For example, in 2010 during excavation of a new tailings pond at its Muskeg River mine, Shell workers excavated a spring that caused sulfide-rich water (reported TDS ~29000 mg/L; Ko, 2012) to discharge into the pond at a very high rate of 2×10^6 liters per hour (Cooper, 2011). The simplest explanation for the occurrence of rapid discharge of saline groundwater is the presence of a large conduit connected to an over-pressured Devonian aquifer. These saline water eruptions may possibly be triggered in areas where resource development reduces the overlying formation pressure, such as that caused by dewatering and digging of an openpit mine facility. This study reveals that the most likely location for saline water intrusion occurs to the east of the dissolution edge of the Prairie Evaporite Formation, and detailed hydrogeological work should be conducted before development of oil sands facilities in these areas.

Topographic recharge remains an important process in the Athabasca regional hydrogeological system. Topographic highs are sites of modern groundwater recharge into the McMurray Formation, and McMurray Formation waters with a significant component of Holocene recharge can be expected to have lower TDS values below 15,000 mg/L (WorleyParsons, 2010a). For example, TDS values measured in the McMurray Formation beneath areas of high surface elevation (e.g., Figure 2, Township 84, Range 9W4) are significantly lower than those of adjacent low-lying areas to the east that are proximal to the evaporite edge (8300–77,000 mg/L; Figure 2., Township 85, Range 7W4). Groundwater recharge into the units above the McMurray Formation (e.g., Pleistocene sediments, Grand Rapids, and Clearwater Formations) are likely driven exclusively by topographic recharge, as these formations are separated from the McMurray and Devonian units by the Clearwater regional aquitard and generally have higher hydraulic head values than the McMurray Formation, indicating downward flow (Bachu and Underschultz, 1993). In this respect, previous hydrogeological work in environmental impact assessments is likely correct in interpreting the subsurface system above the McMurray Formation as topographically driven on a relatively local to subregional scale.

Quaternary incised channels are additional geological features that have the capacity to connect surface water directly to the McMurray Formation, bypassing the regional Clearwater aquitards and enabling downward cross-formation flow. These incised channels occur throughout the region, and their occurrence and distribution are described in detail by Andriashek and Atkinson (2007). Evidence for direct groundwater recharge to the McMurray Formation is present in the low TDS values in the McMurray Formation around the Nexen-Long Lake development (Figure 2: Township 84 and 85, Range 5W4) where the Gregoire Quaternary channel penetrates the McMurray Formation (Nexen Energy Inc. and OPTI Canada Inc., 2007). Proximal to the channel, TDS values in McMurray Formation waters are approximately 2000 mg/L, and distal from the channel, these values increase sharply to >20,000 mg/L. These large changes in salinity should be noted carefully as they provide early indications of connection between shallow groundwater and McMurray Formation water, and caution should be exercised when operating SAGD facilities near these Quaternary channels.

CONCLUSIONS

Highly variable salinity was observed in the McMurray Formation waters throughout the AOSR. Formation water total dissolved solids values ranged from freshwater (TDS = 220 mg/L) to brine fluids (TDS = 279,000 mg/L). There is no TDS value that could be considered typical of McMurray Formation water in the Athabasca region; therefore, all TDS measurements should be examined in a regional spatial context to provide insight into local hydrogeological processes. The observed spatial distribution of formation water TDS in the McMurray Formation is best explained by two processes: (1) topographically driven downward infiltration of meteoric water, and (2) upward flow of saline water via localized karst-derived conduits from Devonian aquifers driven by modern response to the basin-scale flow reversal initiated by the Pleistocene glacial events. Both requirements of this interpretation of upward vertical flow from Paleozoic to Cretaceous formations are met in the AOSR through the heavily karst-influenced sub-Cretaceous strata and elevated hydraulic head in the Devonian aquifers caused by Pleistocene glaciation. Quaternary channels can also facilitate cross-formation flow in the downward direction, bypassing regional aquitards directly connecting recent recharge from precipitation to the McMurray Formation. The result of the groundwater input from Quaternary channels is typically observed as lower TDS values compared to regional McMurray Formation waters. This revised conceptual model for McMurray Formation hydrogeology provides an improved explanation for the observed variability in McMurray Formation water TDS and suggests a mechanism for the surface discharge events that have been observed in the oil sands region. Further investigation is warranted in both the Devonian strata that underlie the McMurray Formation and on the sub-Cretaceous interface itself. Future work describing hydrogeology in oil sands systems could include detailed stable isotope data of water and its dissolved constituents and ion-specific geochemical data to better constrain hydrogeological processes in the AOSR.

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