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Abstract

Formation waters of the Beaufort-Mackenzie Basin, Arctic Canada, show a broad range of salinity and water chemistry. Three main water types are defined: freshwaters related to a gravity-driven flow system, original trapped seawater with minor diagenetic alteration, and low TDS – high alkalinity waters. High alkalinity waters are isolated in overpressured fault blocks characterized by rapid sedimentation and burial. The high alkalinities (up to 9000 mg/l) are interpreted to be related to *in situ* CO_2 generation through anaerobic methanogenesis during burial.

Introduction

The late Cretaceous-Cenozoic Beaufort-Mackenzie Basin (BMB) represents a post-rift infill of more than 14 km of sediments in a rapidly subsiding deltaic and marine depositional environment in northern Canada (Dixon *et al*., 1992). Early exploration, including 250 wells drilled (Fig. 1), defined extensive petroleum reserves of 744 x 10^9 bbls (277.3 x 10^6m^3) recoverable crude oil and 11.74 tcf (332.4 x 10^9m^3) recoverable natural gas (Dixon *et al*., 1994). However these have not yet been produced due to lack of infrastructure. Recent increased demands for natural gas and crude oil in North America and worldwide have sparked new interests in the search for additional petroleum resources in the BMB (Bergquist *et al*., 2003), and discussions are in place to build a multi-billion dollar pipeline to bring gas to market. To aid exploration efforts and environmental impact assessments, a large project has been conducted to re-examine data collected during previous exploration. As part of this work we examined formation waters to better understand the fluid flow history of the basin and the nature and distribution of formation waters and their relation to hydrocarbon migration. Hitchon *et al*. (1990) previously examined the regional hydrogeology of the BMB using drill stem test (DST) data and suggested extensive meteoric water flushing occurred. However, their analyses did not include data from many wells that were confidential at the time, and they did not examine the spatial variability in formation water chemistry. Our more complete analyses show strongly compartmentalized zones with distinct water types, with evidence for significant anaerobic biodegradation within the BMB controlled by burial and thermal history.

Regional geology

The regional geological setting of the BMB is described by Lane (1998) and Dixon *et al*. (1994). Basin tectonics has been well studied at the regional scale (e.g. Lane and Deitrich, 1995; Lane, 1998 and 2002). Lane and Dietrich (1995) mapped several fault zones in BMB, three of which are particularly important to this study (Fig. 2). The Eskimo Lakes Fault Zone, striking NE-SW, marks the southeast margin of the Jurassic-Early Cretaceous rift system. The Taglu Fault Zone (TFZ), parallel to the ELFZ, controls the late Cretaceous to middle Tertiary depo-centers in the Mackenzie Delta. The Tarsiut-Amauligak Fault Zone (TAFZ), running nearly E-W, defines the southern boundary of the post-Miocene depositional center. Movement along the TFZ is associated with significant and rapid deposition of Taglu Sequence. Figure 3 provides a simplified stratigraphy, illustrating the major regional aquifers and stratigraphic intervals with significant petroleum discoveries. Major Tertiary age aquifers include the Fish River, Aklak, Taglu, Kugmallit and Iperk sequences. Data for the Fish River and Aklak sequences are limited to the south because of burial depths in most of the study area. The Richards Sequence is shaly and is considered a localized aquitard (Dixon *et al*., 1992). The Oligocene Kugmallit and Eocene Taglu sequences are widely distributed in the study area. Among the 52 significant petroleum discoveries, 38 are from the Tertiary Taglu and Kugmallit sequences, accounting for about 77% and 70% of total discovered gas and oil reserves, respectively.

Methods

Formation water analyses from petroleum well DSTs in the Northwest Territories become available in the public domain after a confidentiality period. We examined all 2583 DST analyses reported from the 250 wells drilled in the basin. Several culling techniques were used to identify poor quality or suspect samples (e.g. Bachu *et al*., 1987; Hitchon and Brulotte, 1994). Data in the Appendix is coded to indicate potential data quality issues. Culling of incomplete or suspect quality data reduced the initial database by 90% (typical data reduction for DST analyses), leaving 255 samples from 98 wells. Despite the large data cull, the remaining wells still show good spatial distribution over the study area (Fig. 1). The remaining data where then classified by Principle Component Analysis (PCA) based on major ion chemistry.

Water chemistry

Digital DST water and gas analyses are compiled in the Appendix. Formation waters in the BMB show a broad range of salinity, from 1 to 40 g/l. Unlike typical basin profiles, waters from the BMB do not show any systematic increase in salinity with depth. Brackish waters are observed down to 4 km. Sodium is the dominant cation in all waters. High salinity end-members are Cl dominated, but lower salinity waters are dominated by alkalinity, with some of the highest alkalinity values reported (up to 9000 mg/l). PCA analyses of the major ion chemistry show waters are characterized by three end members, defined as: 1) brine, 2) low TDS-high alkalinity water, and 3) fresh water. We also define a fourth group as ‘mixed’ waters between these end members.

Figure 4 plots Na values against the conservative Cl ion along with a theoretical dissolution/evaporation trend for seawater. All waters are enriched in Na relative to seawater, a typical trend observed in formation waters due to water/rock reactions during burial (Hannor, 1996). Brine waters show Cl values similar to seawater concentrations whereas high alkalinity and fresh waters have very low Cl values. The remaining waters all plot on a mixing trend between the two end members. We plot in Figure 5 the four water types as a function of the deviation of formation pressure at depth of sampling from expected hydrostatic (measured pressure – calculated hydrostatic). Here we see that brines and fresh waters are all at or near hydrostatic values. In contrast high alkalinity waters and mixed waters have significant overpressures. Spatially the four water types also show distinct distribution patterns. Fresh waters are largely restricted to higher stratigraphic levels and southern onshore areas, brines are largely restricted to the Tuktoyaktuk Peninsula. High alkalinity waters are restricted to north of the TFZ where rapid and thick Tertiary deposition occurred.

Discussion

PCA indicates at least three different waters in the BMB, with a complex mixing relationship between these end members. Brines are most likely original trapped seawaters that have undergone relatively minor water/rock interaction that increased Na levels.

Freshwaters are likely related to a gravity-driven flow system in the southwest and southeast margins as inferred from the regional pressure distribution (Chen *et al*., 2006). Given the low current topographic profile, we argue that this freshwater event was likely related to earlier uplift events, when the southern basin margin was inverted and topographic drive was more significant than present. Partial dissolution of quartz and chert grains and a lack of quartz overgrowth in reservoir intervals of the Niglintgak field are consistent with a significant freshwater flux through the reservoir prior to gas charge (Shell, 2004).

High alkalinity waters appear to be trapped freshwaters that have undergone significant alteration during burial. These waters are spatially separated from low alkalinity freshwaters by the TFZ, and are generally restricted to areas where rapid and thick deposition occurred. The high alkalinity waters are also typically highly overpressured indicating they are distinct from low alkalinity freshwaters related to the gravity-driven flow system. The source of the alkalinity is thus most likely related to *in situ* generation of CO_2.

Anaerobic biodegradation produces significant CO_2 and methane gas through the reaction:

$$CH_3COO^- + H_2O \rightarrow HCO_3^- + CH_4$$

Aitken *et al*. (2004) were able to use the isolation of metabolites from a large number of biodegraded oil fields to show that anaerobic biodegradation is more common than previously thought, and can occur at temperatures up to 80 ^oC. Recently Horsfield *et al*. (2006) have also demonstrated that the habitable zone of microorganisms can overlap with the onset of abiotic thermal degradation of buried organic matter, which produces oxygenated compounds and hydrogen that form substrates for methanogenesis. This is consistent with high alkalinity waters being present at depths of up to 4 km. However, high alkalinity waters are restricted to sediments that have not been exposed to burial temperatures greater than 100 ^oC. Industry gas analyses have not included stable isotopes, making it difficult to confirm a biogenic origin as suggested by this model. However when we plot the dry gas index (C_1/C_1-C_6) in Figure 6 against vitrinite reflectance, it shows that significant biogenic gas was likely generated in sediments that have not been buried in excess of 100 ^oC, similar to the occurrence of high alkalinity waters and consistent with the paleopasturisation model of Wilhelms *et al.* (2000).

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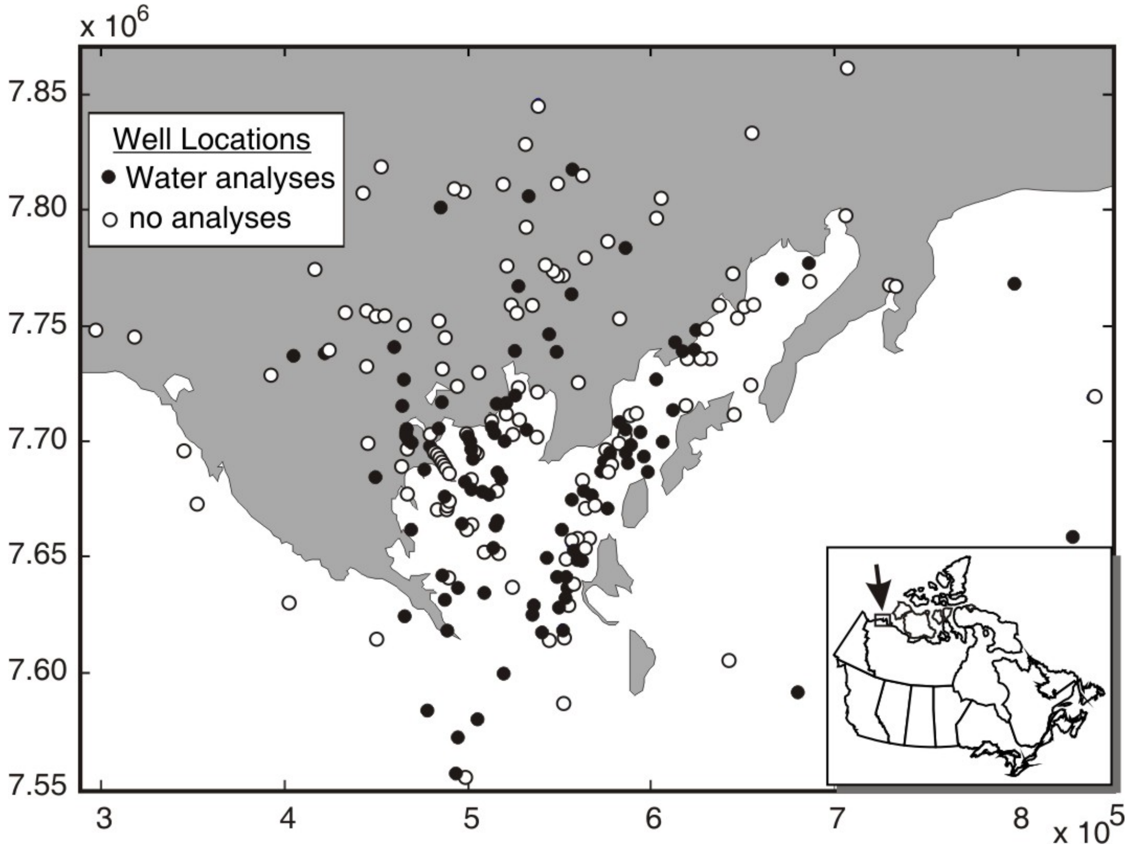

Figure 1. Location of exploration wells drilled in the Beaufort-Mackenzie region. Wells marked 'no analyses' indicate DST samples ~~are~~ of poor data quality that were not used for further analysis.

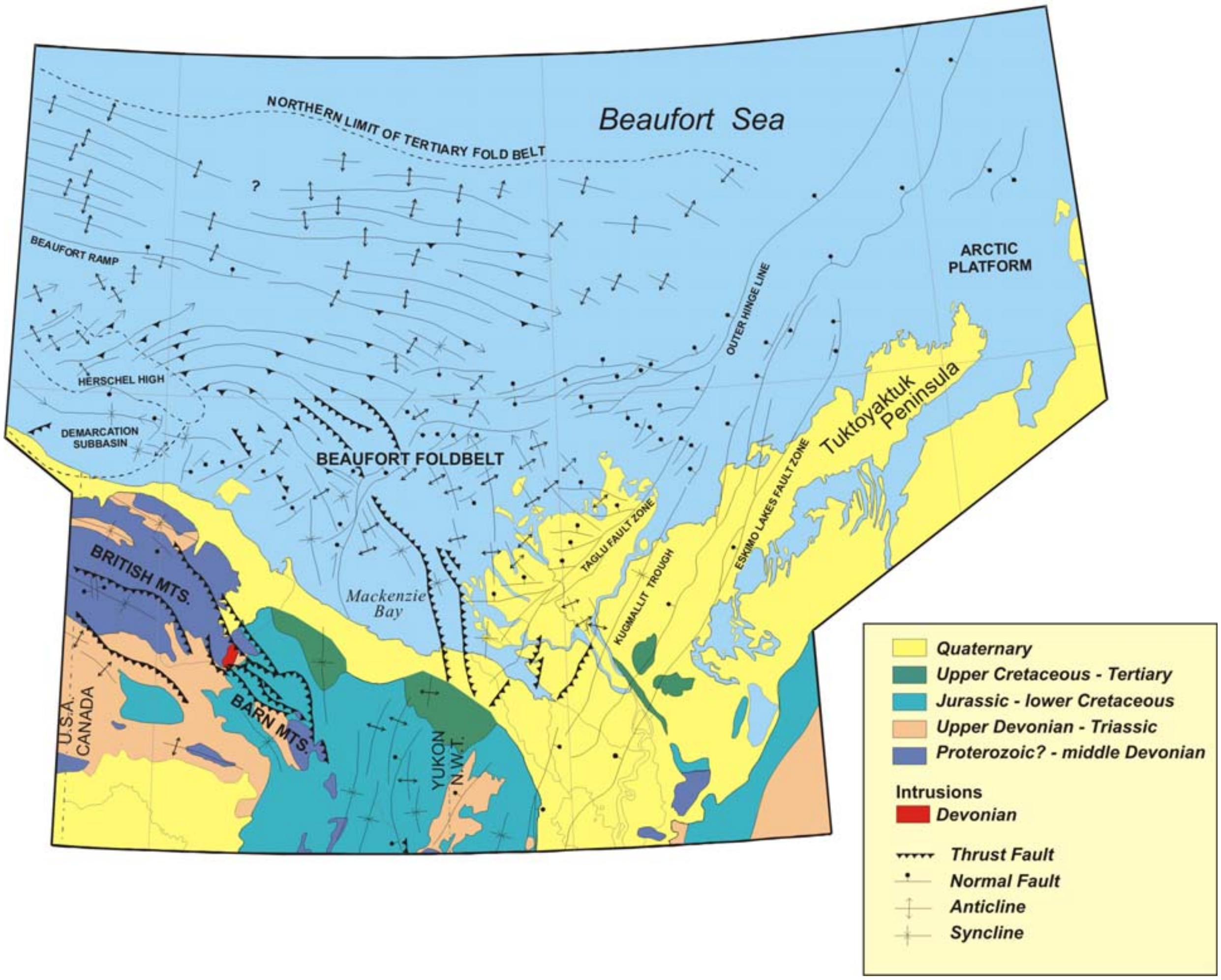

Figure 2. Geology of the Beaufort-Mackenzie Basin (after Lane and Dietrich, 1995).

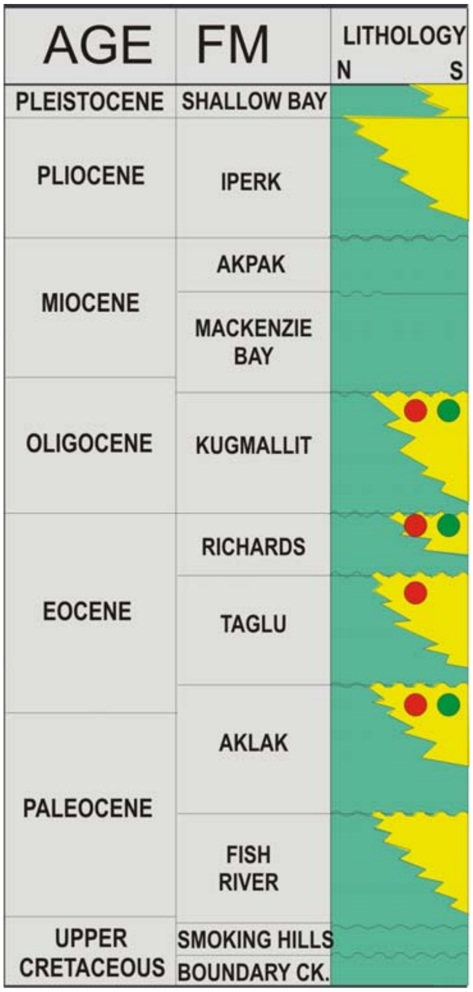

Figure 3. Simplified stratigraphy of the Beaufort-Mackenzie Basin showing zones of oil (green dot) and gas (red dot) discoveries.

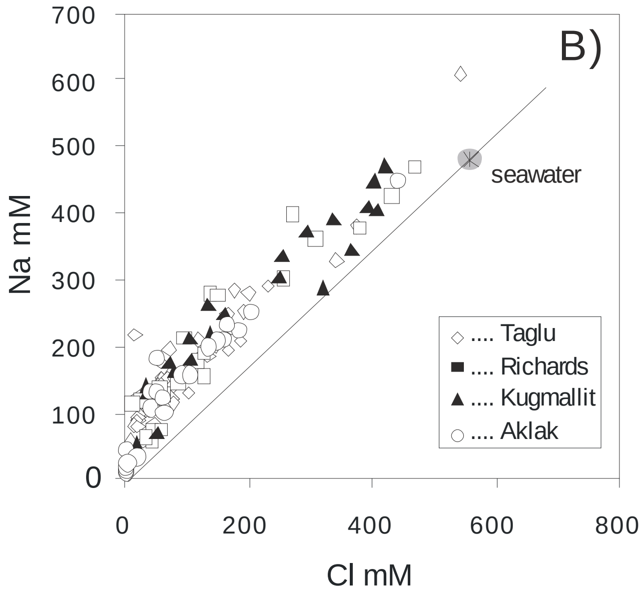

Figure 4. Plot of Na-Cl values for DST analyses.

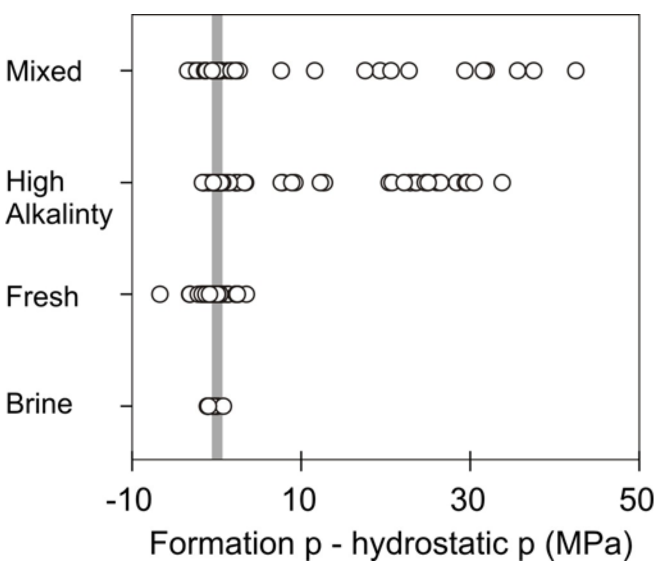

Figure 5. Plot of water type (based on PCA results) versus pressure.

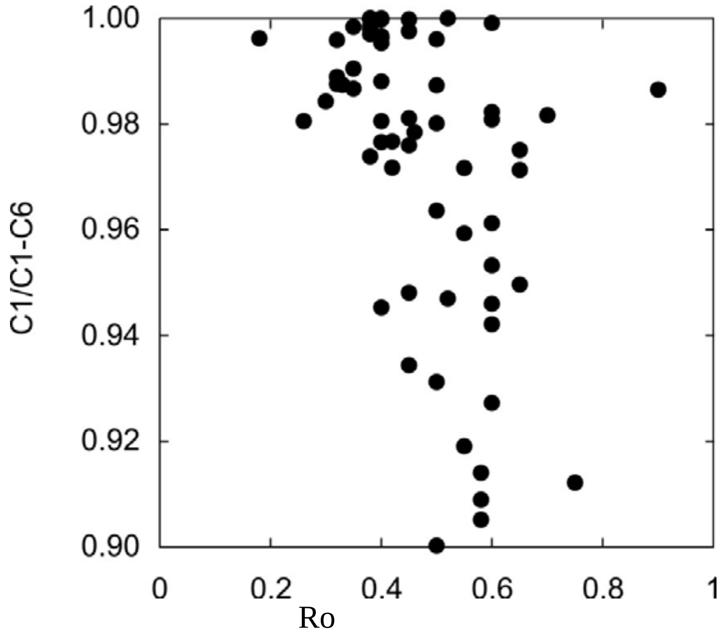

Figure 6. Plot of dry gas index versus Ro from vitrinite reflectance (reflectance data are from Stasiuk, pers. com., 2006).