Quantification of the Gas-in-Place and Flow Characteristics of Tight Gas-Charged Rocks and Gas-Shale Potential in British Columbia

R.M. Bustin, University of British Columbia, Vancouver, BC, bustin@unixg.ubc.ca

G. Chalmers, University of British Columbia, Vancouver, BC

A.A.M. Bustin, University of British Columbia, Vancouver, BC

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Introduction

Tremendous resources of unconventional gas exist in British Columbia, particularly in rocks generally referred to as gas shales (Bustin, 2008). Even though commercial production from shale is currently minor, industry investment into unconventional gas resources already greatly exceeds two billion dollars in BC through land sale bonuses alone. However, the rapid growth of the unconventional gas industry in general, and in BC in particular, has not been accompanied by increased understanding of either the geological processes that determine gas-in-place, the methods for quantifying gas-in-place or the flow characteristics of the rocks, the consideration of which is critical to economic development. In February 2010, in response to a funding application submitted in 2008, Geoscience BC awarded the authors a two-year grant to investigate those factors that determine the gas-in-place and flow characteristics of gas (and oil) producing shales. The proposed research project targets the Devonian strata in the Horn River Basin and Cordova Embayment, Montney and Doig formations, Gordondale Member (formerly the informal 'Nordegg Member'), Buckinghorse and Shaftesbury formations, and Fort St. John Group, covering a broad area of northeastern BC (Figure 1).

The research has two interrelated components:

- to develop better methodologies for determining gas-in-place capacity in gas shales and the matrix flow characteristics (permeability and diffusivity)
- to quantify the gas-in-place and flow capacities of important gas shales in northeastern BC using established and novel methodologies

Keywords: *gas shale, unconventional gas, reservoir development*

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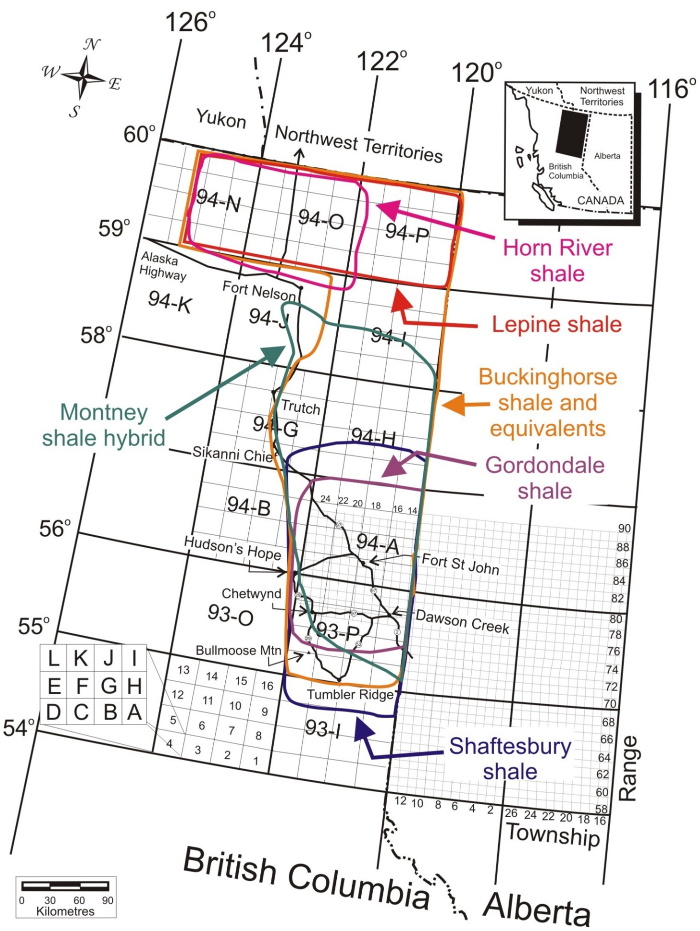

Figure 1. Approximate boundaries or limits of available core for the major potential gas-shale reservoirs in northeastern British Columbia (modified from Mossop and Shetsen, 1994).

Results to Date

During the initial six months of the study, research has focused on refining methods of quantifying porosity and permeability of shales, assembling a representative sample suite for analyses and initiating an analysis program.

Quantifying Gas-in-Place and Flow Characteristics of Gas Shales

The methodologies currently used to characterize the pore systems, gas-storage capacity and flow characteristics of the shale matrix are mainly a hybrid mixture of specialized methods used for coals and conventional reservoir rocks, which have been applied to gas shales with limited consideration of the latter's unique and varied properties (American Petroleum Institute, 1998; Bustin et al., 2008). The tight-rock analysis programs applied to shale by some commercial laboratories date from work on Appalachian shale carried out by the Gas Research Institute (GRI) in the early 1990s (i.e., Luffel et al., 1993); these programs do not take into consideration the potential problems caused by the unique pore-structure characteristics of gas shales, such as molecular sieving or errors in analysis due to gas sorption during porosity, permeability and diffusivity measurements. Additionally, the GRI methods for permeability analysis (Luffel et al., 1993) and porosity determination are carried out under unconfined and low hydrostatic pressures; hence, they assume that no pore compressibility exists and it is likewise assumed that skeletal and grain density are equal. The uncritical application of these methodologies to gas shales has resulted in uncertainty as to the amount of original gas-in-place and flow properties of the rocks; this in turn cascades into poorly formulated numerical simulations and development programs that are inadequately optimized, require ongoing revisions, and which therefore have a major impact on project economics.

As part of this study, the authors have continued to develop instrumentation, theory and protocols to routinely measure effective gas porosity and permeability of core plugs under estimated in situ stress conditions likely experienced by a reservoir during its production life. Testing of core or core plugs under in situ reservoir conditions can significantly reduce uncertainties or errors introduced by sample crushing and zero confining stress. Simultaneous measurement of porosity and permeability on the same sample is also beneficial as it results in a reduction in testing time and requirements for good-quality core samples, which are usually unavailable; it also provides intrinsically consistent correlation of porosity and permeability.

The instrument design developed is based on Boyle's law and a conceptual schematic is shown in Figure 2. A triaxial cell with an internal urethane rubber, forming a pressurization chamber, is used to hold the cylindrical core plugs. Radial or confining stress (S_r) is applied through the hydraulic pressurization chamber inside the cell by a pump and axial stress (S_a) is imposed on both ends of the sample through pistons with a load frame. Either biaxial (S_r ? S_a) or hydrostatic stress ($S_r = S_a$) may be applied to samples being tested. One piston has a port connected so that it enables gas to flow from the external gas cylinder to the sample. The in-

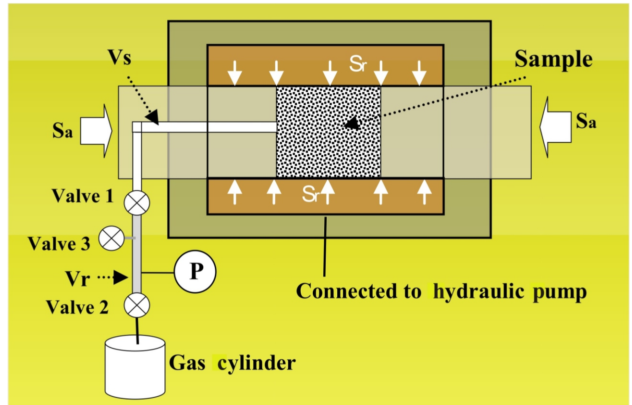

Figure 2. Connectional diagram of instrument designed to measure effective gas porosity of core plugs from study area in northeastern British Columbia. Abbreviations: pressure transducer, P; axial stress, S_a; reference cell void volume, V_r; sample cell void volume, V_s.

ternal open space of the tubes between valve 1 and the sample end, consisting of the sample cell void volume (V_s) and the reference cell void volume (V_r), is defined among valves 1, 2 and 3. A high-precision pressure transducer is connected to the system for measuring gas pressure and ambient temperature. The small cell volumes (approximately 5 cm^3 in total) allow accurate capture of small pressure changes due to gas flow into or out of the sample.

Test procedures of a typical porosity and permeability run consist of:

1) precise grinding in a milling machine of the ends of an orientated core plug cut from representative core;
2) mounting of the sample in the confinement cell and application of desired confining (S_r) and axial stress (S_a);
3) flushing of the sample with experimental gas;
4) obtainment of initial equilibrium pressure in the sample cell (P_s) with valve 1 closed;
5) establishment of a higher or lower reference cell pressure (P_r) relative to P_s; and
6) opening of valve 1 for gas dosing between the sample and reference cells and monitoring of pressure variation with time of the mixed system until final equilibrium pressure (P_m) is obtained.

A typical data set of a test is shown in Figure 3. Detailed discussion of the analytical methodology may be found in Cui et al. (2010).

Porosity Determination

Sample pore volume (V_p) under the specified S_r and S_a is calculated as:

$$V_p = [(V_s + V_r)\rho_m - (V_s\rho_s + V_r\rho_r)]/(\rho_s - \rho_m)$$

where ρ is real gas density and its subscripts *s*, *r* and *m* represent the initial sample and reference cells gas densities, and the final equilibrium density, respectively, at pressures

P_s, P_r and P_m and corresponding temperatures. Then the porosity is determined as:

$$= V_p/V_b$$

where V_b is the sample bulk volume under the applied stress condition.

Permeability Determination

Effective gas permeability k (mD) under the applied stress is given as:

$$k = 0.10327 \cdot S \cdot \ \cdot c \cdot \mu / b^2$$

where c and μ are gas compressibility (1/MPa) and viscosity (MPa·s) values, respectively, and b is the first root of the transcendental equation:

$$b \cdot \cot(b \cdot l) = -h$$

where l is the length of the sample (cm), h is given by:

$$h = A \cdot \ /(V_r+V_s)$$

and A is the sample cross-sectional area. As shown in Figures 2 and 3 (left), S (1/second) is the slope of the straight-line part of the semi-log plot of the dimensionless density ($_D$) versus time t, after gas mixing, and $_D$ is calculated as:

$$_D = [(\ - \ _s)(1+h \cdot l)-(\ _e - \ _s)]/[(1+h \cdot l) \cdot (\ _e - \ _s)]$$

where

$$_e = (\ _sV_s + \ _rV_r)/(V_s+V_r)$$

Testing of the instrumentation and analysis protocols are ongoing.

Reservoir Characteristics of Northeastern BC Shales

Doig and Montney Formations

During the initial stage of this study, the reservoir characteristics of the Doig and Montney formations were targeted due to industry interest, ready availability of samples (core) and complexity of the reservoir facies, which provides an opportunity to study the impact of reservoir lithology and fabric on gas-storage mechanics and flow properties. The specific objectives of the study are to

- understand the influence sedimentology has on the total-organic-carbon–content distribution, mineralogy, porosity and the pore-size distribution;
- understand the influence of mineralogy on the porosity and the pore-size distribution; and
- identify the controls on the matrix permeability.

The Triassic Doig and Montney formations in the Fort St. John graben and Groundbirch field of northeastern BC are

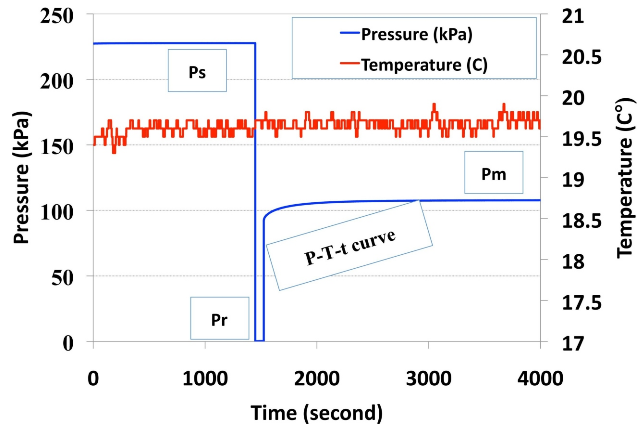

Figure 3. Typical pressure and temperature data of porosity and permeability analyses carried out on core from the study area in northeastern British Columbia (after Cui et al., 2010). Abbreviations: initial equilibrium pressure in sample cell, P_s; reference cell pressure, P_r; final equilibrium pressure, P_m.

being studied in a series of wells (Figure 4). A schematic stratigraphic cross-section showing the general stratigraphy and facies changes is presented in Figure 5; Figure 6 shows the detailed stratigraphy.

Preliminary results for well 16-2-78-22 (Figure 6) are summarized below.

Mineralogy

Quartz content in well 16-2-78-22 averages 23% and ranges between 10 and 38%. Quartz content shows no significant downhole trends, but does show abrupt variations between 15–25%. There is a subtle decrease in quartz content from the top of the Montney Formation into the lower and middle members of the Doig phosphate zone (Figure 6). The carbonate content varies between 5 and 47%, with an average content of 20%; it also shows an increasing trend towards the top of the phosphate zone and several large peaks at 3118 m and 3075 m within the F member of the Montney Formation. Feldspar content shows a subtle decreasing trend towards the top of the Doig phosphate zone, similar to the quartz content and contrary to the carbonate content. Dolomite content peaks where quartz and feldspar content decreases. The highly radioactive phosphate zone appears to have lower quartz and feldspar and higher carbonate and dolomite contents compared to the Montney Formation. Illite content remains low throughout the profile. The average apatite content is 2.9% and varies between zero and 17%. Apatite content is the greatest within this well, compared to the other wells, and peaks just below the phosphate zone. Feldspar content averages 26% and ranges between 15 and 42%.The average pyrite content is 1.6% and varies between 0.1 and 3.5%.

Porosity

Total porosity to helium (He), based on measurement of bulk density by mercury (Hg) immersion and skeletal density using a Boyle's Law apparatus and Hg porosimetry, are summarized for well 16-2-78-22 in Figure 7. Average pycnometry derived porosity for well 16-2-78-22 is 5.5%, with porosity ranging between 3 and 8.5%. Average porosimetry-derived porosity is 4.4% and ranges between 3 and 5.8%. Above average porosimetry-derived porosity is more common within the Montney Formation than in the lower and middle members of the Doig phosphate zone, while the pycnometry-derived porosity values alternate above and below average throughout both the Doig and Montney formations. The separation between the porosimetry- and pycnometry-derived porosity, particularly in the upper Montney (F member) and the Doig phosphate zone, may be an indication that there is an increase in the fine meso- and microporosity (0.26 to 3 nm) within the shale.

A positive trend exists between porosimetry-derived porosity and quartz content (r = 0.61; Figure 8), whereas a negative relationship exists between the carbonate content and porosimetry-derived porosity (r = -0.61). No other minerals show a correlation or relationship with pycnometry- or porosimetry-derived porosity.

Future Work

This research project is in its early stages: instrumentation development and testing are in progress and sample collection and analysis are ongoing. Studies to date have focused

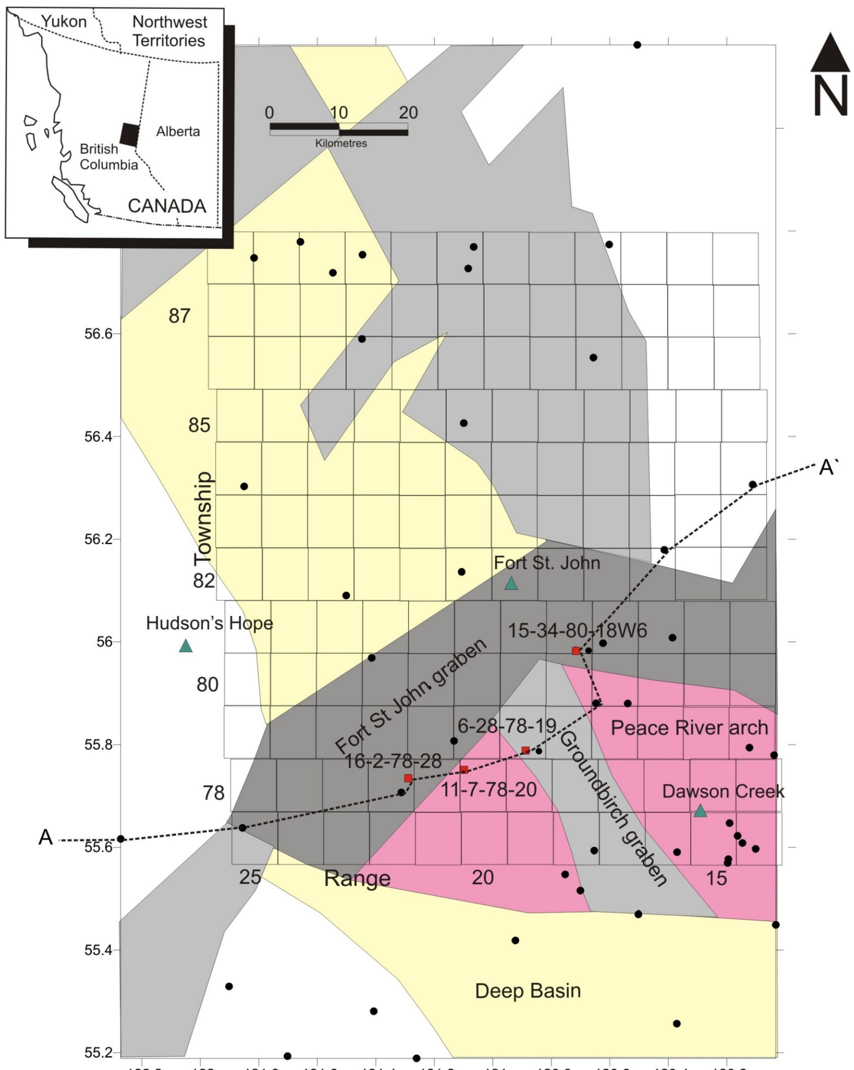

Figure 4. Index map showing the location of the Doig and Montney formations, and the location of cross-section A–A` in northeastern British Columbia (Figure 5). Red squares represent wells that are sampled for this project and green triangles, the locations of cities and towns. The structural elements for the area are modified from Berger et al. (2008), with both the darker and lighter grey areas representing the Fort St. John and Groundbirch graben system. Black circles represent the locations of wells used in this study to date.

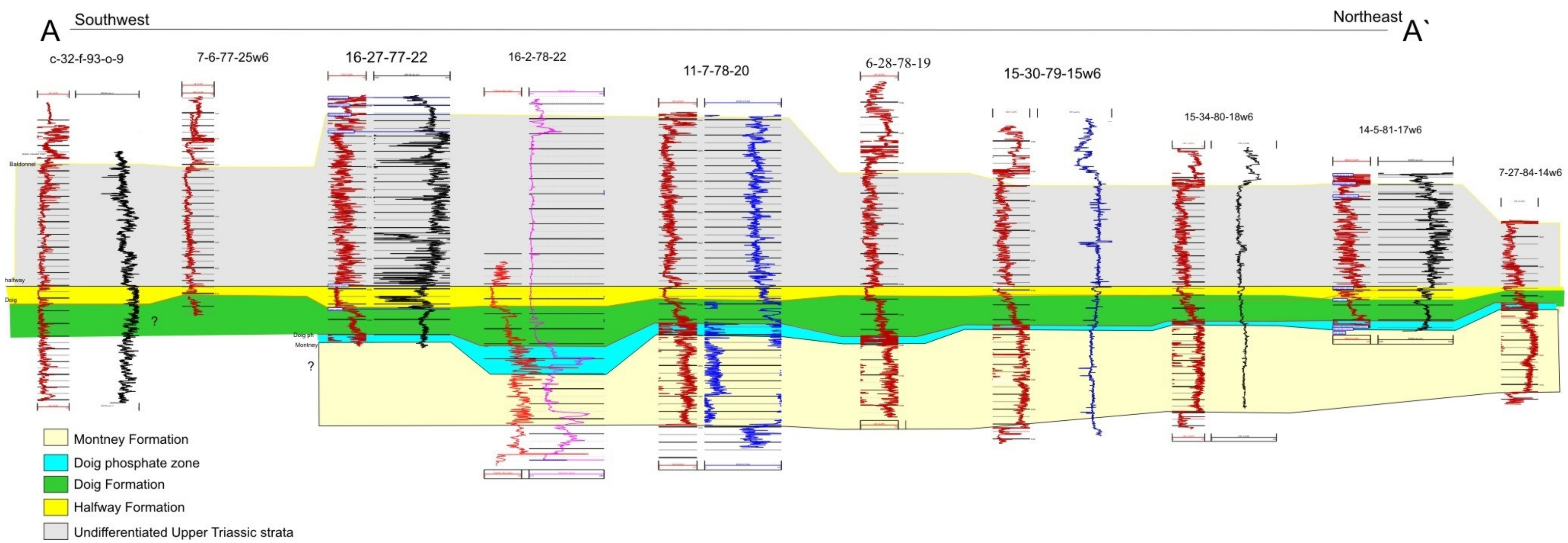

Figure 5: Cross-section A–A` showing the stratal geometries of the Triassic sediments sampled from wells located along the depositional dip in the study area, in northeastern British Columbia. Geophysical logs include gamma ray (red curve), bulk density (black curve), sonic density (blue curve) and gas content (magenta curve).

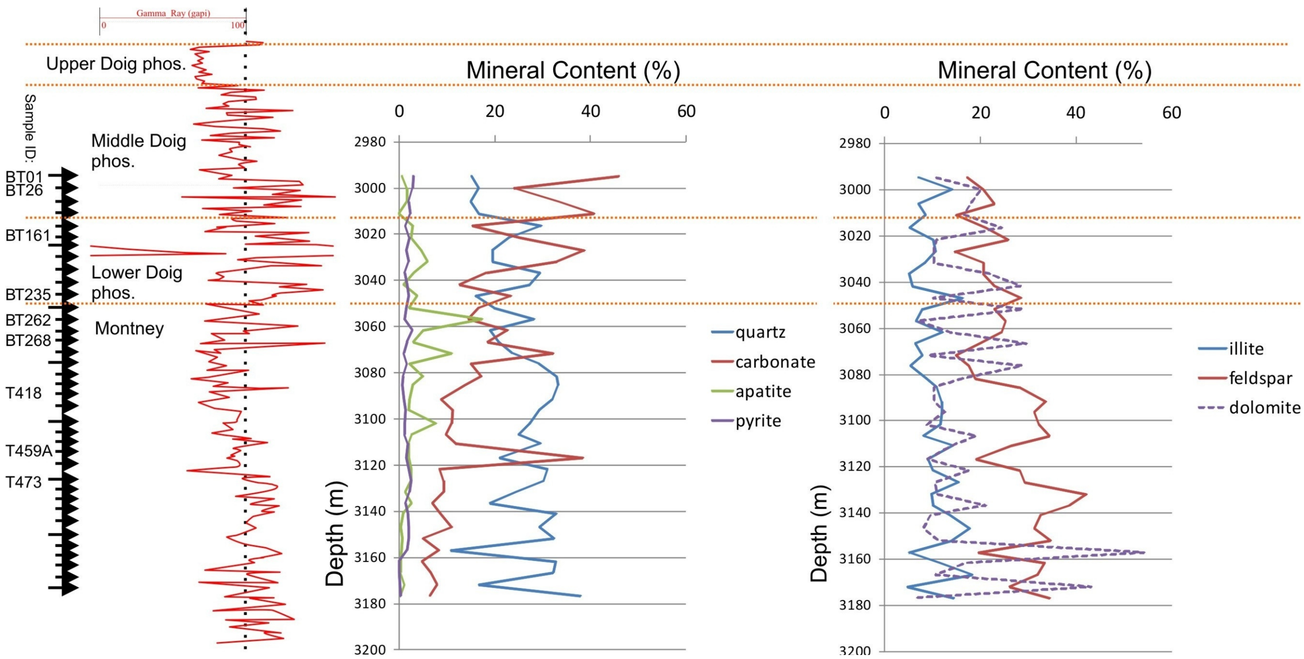

Figure 6. Mineralogical and gamma ray (left) profiles for well 16-2-78-22 in northeastern British Columbia, with samples covering only the Montney Formation and lower member of the Doig phosphate zone. Black arrows indicate sampling locations.

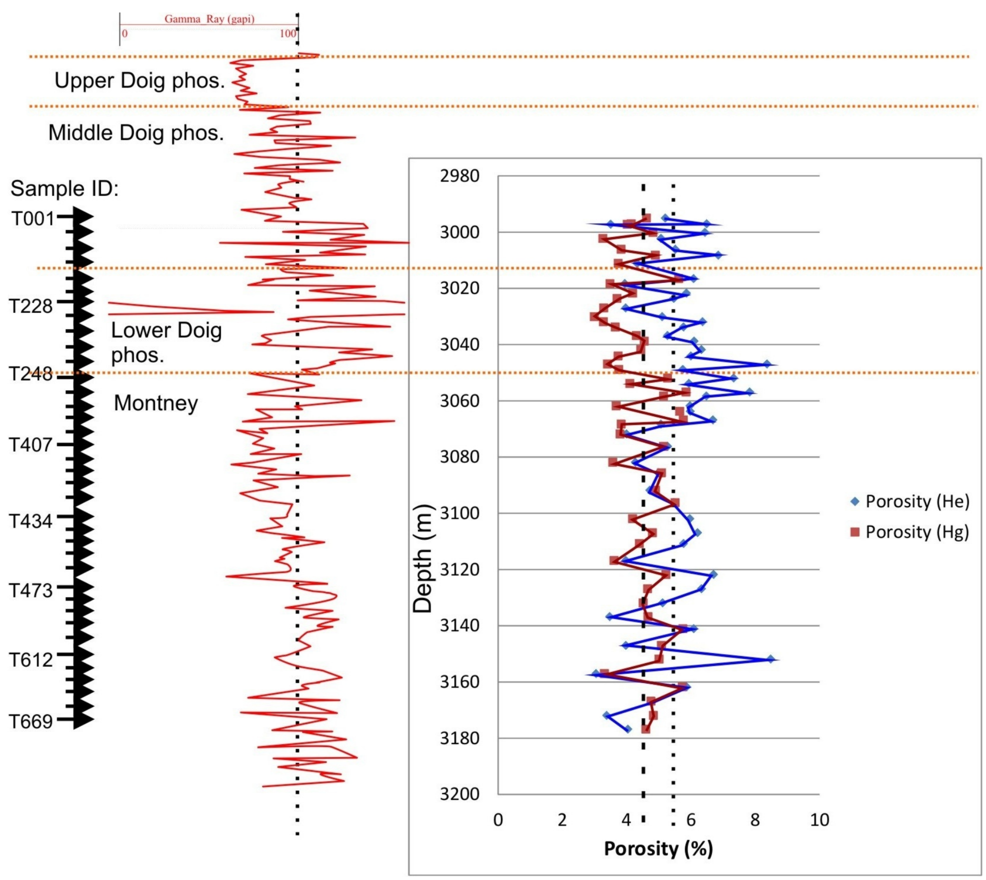

Figure 7. Gamma-ray curve (left) and pycnometry- and porosimetry-derived porosity profile (porosity variation with depth) for well 16-2-78-22 in northeastern British Columbia. Dashed line represents the porosimetry (Hg)-derived porosity and the dotted line, the pycnometry (He)-derived porosity. Black arrows indicate sampling locations. Abbreviations: helium, He; mercury, Hg.

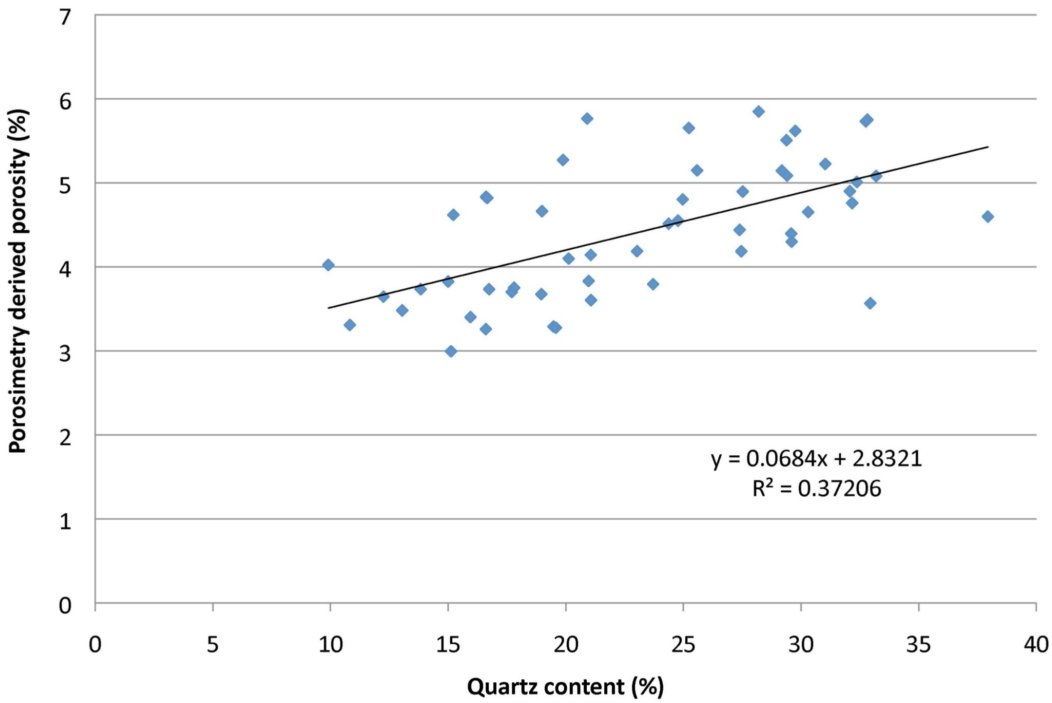

Figure 8. Plot showing positive trend between quartz content and porosimetry-derived porosity for well 16 2-78-22 in northeastern British Columbia.

on the Doig phosphate zone and Montney Formation in a strategic area located in the Fort St. John graben and Groundbirch field, where sample availability is excellent. Sampling will be expanded through the second year of the project, which will include sampling in the last quarter of 2010 of well samples from the Core Facility located at Charlie Lake.

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