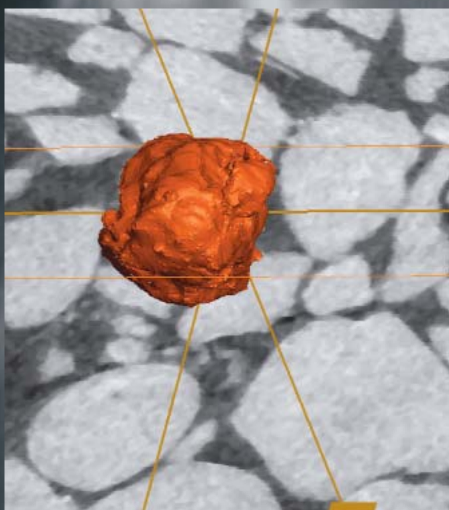
InSite

CWLS Magazine
Nov 2009 Issue 2 Volume 29



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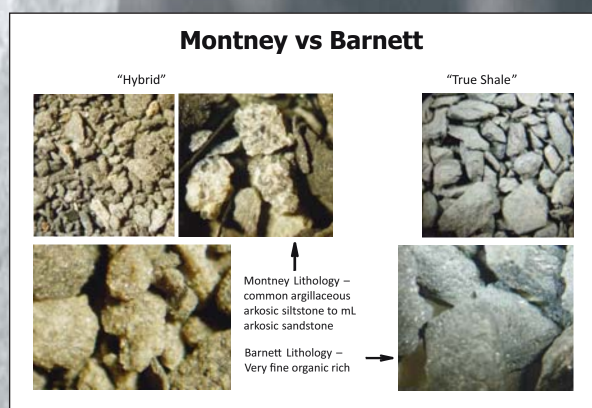

InSite

CWLS Magazine **Nov 2009**

Issue 2 **Volume 29**

The CWLS InSite is printed by Little Rock Document Services Ltd. of Calgary, Alberta, Canada four times annually which is included as a part of your yearly membership fees.

The InSite is an informal magazine with technical content. The material is not subject to peer review. The opinions expressed are those of the individual authors.

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Photos: If you have a photos that the CWLS can use on its next InSite please send a high resolution jpeg format version to kusuma1@slb.com or naladani@suncor.com. Include a short description of the photo with your submission.

The 2009 - 2010 CWLS Executive:

Back row (l - r): Simon Corti, Dave Shorey, David Ypma, Garry Drebit, Agus Kusuma.
Front row (l - r): Maggie Malapad, Roy Benteau, Vern Mathison, Nabil Al-Adani.

President's Message

Summer's over it seems, or is it? We live 9 months of the year just to see warm weather and then we get what we get, such is life. Some would say the same ideology applies to the oil and gas industry in Western Canada as well. Cycles, whether it is at the top or the bottom, dictate the health of the industry. Are we through the worst of it and heading back up or not? Only time and patience will tell for sure. Some survive others don't, some get leaner others get meaner and a few excel which is the nature of the business.

Gas is the life blood of the WCSB and at the time of writing of this message it sits at about $3.95/mcf which is enough for small producers to turn a profit but not enough for the large companies. Either way it does not matter since shale gas has created an over capacity of gas and storage is full. We pray for hurricane season and a cold winter but relying on Mother Nature is never a good business plan. Producers will have to wait for the markets to correct and this is going to take time, perhaps longer than some can wait, and this is where the survival mode kicks in.

These lean times also affect the various societies tied to the industry, CWLS, CSPG, and CSEG to name a few. We have seen sponsorship drop off as well as membership, and profits from the last convention. The CWLS executive has taken measures to reduce costs, as it should, and the society remains in a good financial position. On that note the society has renegotiated its contract with the Fairmont Palliser Hotel to continue holding our luncheons at this venue. The lunches are still heavily subsidized by the CWLS, to the tune of about $10.00 per plate. Attendance to the luncheons has been excellent and this can be attributed to past vice president, Doug Hardman, and current V.P. Dave Shorey who have done an outstanding job soliciting talks focused on current interests. Increased attendance does not however mean that we make money on the technical talks, since the price per plate remains the same. We still offer the lowest price for our lunch tickets but don't be surprised if it increases for the next term to try and reduce the subsidy.

The 2010 GeoCanada Convention is next on the radar. It is now only eight months away and we need to get some good papers submitted. The volunteer staff, headed by John Nieto and Reigh MacPherson, are doing an excellent job as is Nicole Lehocky who is in charge of the Short Course Committee. If you have a paper you would like to submit let these people know or if you have a short course suggestion please contact Nicole.

The 2010 Convention is being hosted by several societies this year and this will again affect our revenues so we will try to offset this by running more short courses. Due to the economic times a lot of people and companies are looking closer to home rather than travelling to these courses and talks. Once again if you have any suggestions please let us know.

I am well into my third year now with the CWLS, first two as treasurer, and it has been an awesome adventure. I have met a lot of interesting people and have worked with many more. It is an honor to be part of this great society and I only hope I am living up to the standards set by those before me and creating a path for others to follow. The society has seen a lot of transitions in the last three years. We now participate in the annual conventions with the CSPG and CSEG which has spawned the Joint Annual Convention Committee (JACC) to coordinate this event. A new web page has been created and online "e-voting" has been added. The DST database has been partially redone in Excel to make it more user-friendly and this is an ongoing project. Overall the society is in great shape and with continued support from our members and sponsors will continue to be this way. As president of the CWLS I thank you for your continued support and I am proud to serve you.

Sincerely,
Vern Mathison
CWLS President

CWLS 2009 to 2010 Executive

President
Vern Mathison
Enseco
500, 1111 – 11th Avenue SW
Calgary, AB T2R 0G5
(403) 988-0446 (Cell)
(403) 806-0084 (Fax)
vmathison@enseco.ca

Past President
Roy Benteau, P.Geol.
EOG Resources Canada Inc.
1300, 700 – 9th Avenue SW
(403) 297-9191 (Office)
Roy_Benteau@eogresources.com

Vice President
Dave Shorey
Baker Hughes – INTEQ
(403) 461-5290 (Cell)
(403) 537-3786 (Office)
dave.shorey@bakerhughes.com

Secretary
David Ypma
Tucker Wireline
900, 444 – 5th Avenue SW
Calgary, AB T2P 2T8
(403) 990-0876 (Cell)
(403) 232-1720 (Office)
(403) 264-2118 (Fax)
dypma@tuckerenergy.com

Treasurer
Simon Corti, P.Eng.
ALCOSS Enterprises Ltd.
Box 549
Beiseker, AB T0M 0G0
(403) 620-7733
Simon.corti@gmail.com

Chair of Committees
Maggie Malapad, E.I.T.
Schlumberger Data & Consulting Services
525 – 3rd Avenue SW
Calgary, AB T2P 0G4
(403) 509-4419 (Phone)
(403) 509-4220 (Fax)
mmalapad@slb.com

Membership Chair
Gary Drebit
(403) 680-4267
gdrebit@shaw.ca

Publications Co-Chairs
Nabil Al-Adani, P.Eng.
Suncor Energy
150 – 6th Avenue SW
Calgary, AB T2P 3E3
(403) 296-5046 (Phone)
(403) 296-6736 (Fax)
naladani@suncor.com

Agus Kusuma
Schlumberger
525 – 3rd Avenue SW
Calgary, AB T2P 0G4
(403) 852-1770 (Cell)
(403) 509-4127 (Office)
Kusuma1@slb.com

The State of Fluid Saturation in Tight-Gas Reservoirs: Insights and Implications from the Rocky Mountain Basins

May 13th 2009 CWLS luncheon presentation

Keith Shanley has indicated that the conventional log-based petrophysical analysis in evaluating water saturation profile does not correctly describe the water distribution in tight gas reservoirs. He suggested that the issue may be due to two possible reasons: 1) The usage of electrical logs in deriving saturation which is heavily based on the electrical parameters assumptions made in saturation models. These assumptions in many cases may not represent tight gas electrical properties. 2) The underlying assumption of that water is in capillary drainage state in these reservoirs. He challenged this assumption through a thorough tight gas reservoir study in the green basin river of Wyoming.

He alleged that the basin was charged early with gas then structurally uplifted and re-organized. At the time of hydrocarbon charging the reservoirs were not tight sands and hence the porosities and permeabilities were likely very high. During the burial process pore volumes were decreased and gas columns were increased. Similar phenomena occurred during uplift and re-orientation of the basin. Tight gas reservoirs were formed with capillary departion from drianage to imbibation state as a result of burial and uplift.

This means today's many tight gas reservoirs will have a steep imbibition capillary curves and gas saturations (non-wetting phase) at residual condition. At pore level, gas is not connected due to formation of complex porosity structure during burial and uplift process. Discontinuity of gas in pores results in zero capillary pressure in these reservoirs.

Based on the above theory, perhaps the petrophysical electrical parameters assumed nowadays for tight gas may not be far from the truth. This means the estimated saturation may not be far from actual volumes. However, these do not explain productivity.

The paradigm shift is required in defining pay based on saturation only. New innovative measurements might be required to evaluation gas connectivity to evaluate accurate pay.

Nabil Al-Adani
Publication Co-Chairs

Development of a Predictive Tool for Estimating Well Performance in Horizontal Shale Gas Wells in the Barnett Shale, North Texas, USA

June 10th 2009 CWLS luncheon presentation

Russell Spears discussed the possibility of evaluating gas reserves in the Barnett shale in using basic logs only. The technique he and his coauthor have applied in evaluating the well logs was a traditional approach where, a probabilistic volumetric estimation of lithology and total porosity is performed using open hole log data. Free gas content and Kergoen are estimated using log data and lab derived core data. Using this approach gas desorption was assumed to be the main source of free gas. It was additionally assumed that there was enough pressure draw down in borehole while production.

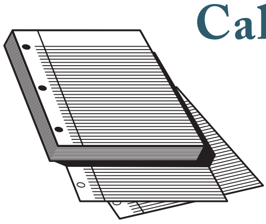
Geologically he indicated that the Barnett Shale underwent uplift and thrust faulting which contributed to the formation of today's shale gas reservoirs. This has produced a wide range of shale gas kerogen maturity.

In the Barnett Shale the gamma ray (mainly Uranium) reading is directly proportional to kerogen content. This does not apply to all shale gas reservoirs.

The reservoir is brittle, which is indicated by frequent smooth caliper readings. It was observed that higher quartz content is directly proportional to kerogen content. In addition, high resistivity and slow sonic readings are the characteristic of Barnett shale as well. The assumption is that these indicators might be used to evaluate TOC with low cost log data. The speaker indicated that geochemical logs did not add significant value in identifying the pay zones in Barnett shale compared to basic logs.

In horizontal well cases, the ultimate recovered gas volumes diminish with penetration length of the well. This indicates longer horizontal wells are not required to increase the production of in the Barnett Shale.

Nabil Al-Adani
Publication Co-Chairs



Call for Papers

The CWLS is always seeking materials for publication. We are seeking both full papers and short articles for the InSite Magazine. Please share your knowledge and observations with the rest of the membership/petrophysical community. Contact publication Co-chair: Agus Kusuma - kusuma1@slb.com or Nabil Al-Adani - naladani@suncor.com

CWLS Best Thesis Student Award

June 10th 2009 CWLS luncheon presentation

The CWLS best thesis student award was presented at the luncheon meeting on 10th June 2009 to Chad Glemser from the University of Saskatchewan. His thesis title was "Petrophysical & Geochemical Characterization of Midale Carbonate using Synchrotron Microtomography". This work was supervised by Dr. Tom Kotzer.

The Canadian Well Logging Society (CWLS) announces yearly awards for engineering and earth sciences undergraduate and graduate students in Canada. The purpose of these awards is to raise interest and awareness of careers in Petrophysics and Formation Evaluation. Formation Evaluation and Petrophysics are the studies of rocks and their fluid properties as they pertain to the oil and gas industry.

Two $2,000 awards will go to students who submit abstract proposals of a thesis that critically examines some aspects of well logging, formation evaluation or petrophysics. Abstracts should be submitted to the CWLS in their final year of study. The CWLS will select award winners by March 31 of each year. An additional $5,000 will be awarded for the best thesis related to Formation evaluation and submitted to CWLS upon graduation. The final thesis can be submitted at any time in the year of graduation. The award winner will be selected in January of the following year. The winner of this award will be invited at the expense of the CWLS to make a presentation at a lunch meeting of CWLS in Calgary.

Nabil Al-Adani
Publication Co-Chairs

New Members

John Clark, Renegade Oil and Gas Ltd
Parsegh Oksayan, Bnbkennel
Bruce Palmer, Birchcliff Energy Ltd.
Ian Smith, Telluric Petrophysical Consulting Ltd.
Reigh MacPherson, Devon Canada Corp
Norm Hopkins, Fairmount Energy Inc.
Clark Strong, Datalog
Andriano Lalang, Datalog Technology
Patrick McLellan, Weatherford Advanced Geotechnology
Tyler Klatt, EnCana
Omar Sabbah, Natural Resources Authority, Petroleum Directorate
Jason Montpetit, Caltex Energy Inc.
Shaun Rhyno, Sunshine Oilsands
Garett Nykipilo, Athabasca Oil Sands Corp.
Wade Hansen, Arsenal Energy Inc.
David Graham, Univerra Resouces Ltd.
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David McPhee, Voltage Wireline Inc.
Bill Boykin, NuTech Energy Alliance
Megha Singh, 24X7 Well Log Digitizing Services
Temitope Olabode, Tucker Wireline Services Canada
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Zhaoli Wu, Bonnett's Energy Service
Tom Sneddon, APEGGA
Deborah Glover, NAL Resources
Jacky Szeto, Weatherford
Okechukwu Moronu, Halliburton Energy Services
Mark Welty
Barrett Summers, Shell Exploration and Production
Nicholas Austin, Imperial Oil
Botao (Todd) Li, Epic Consulting Services Ltd
Chryss Zhao, Tanganyika oil company
Jay Guilmette, Devon Canada
Irvan Novikri, Saudi Aramco
Charles Ozobeme
Sheldon Ligad, ConocoPhillips Canada
Kevin Mutterback, Mutterback Consulting Inc.
Brian Hunter, Windy Field Ltd.
Agatha Sparks, Wellness
Paul Picco, Tucker Wireline
Neal Alexander, EnCana Corp
Mimoza Pumo, MEG Energy Corp.
Kristy Weiss, Core Lab
Peter Arhebamen, Petronas Carigali Sdn Bhd
Dean Bull, Outrider Energy Ltd.
William Moore, Schlumberger Oilfield Services
Alessandra Simone, Shell
Lyle Green, Atlantic Directional Inc.

New Members – Student

Anthony Raimondo
Christopher Steinhoff
Mike Gierach
Carissa Struksnes
Anthony Stadnyk
Tyler Clark
Dalbir Dev
Julia Saar
Gunmar Danelak
Kenneth Goode
Peter Tanchak
Laura Keirstead
Azim Dhulla
Travis Mueller
Aman Gill
Monica Robichaud
Waldo Volschenk
Scott Grant
Karthik Nandula
Azat Latypov
Atif Asif
Kyle Milz
Gabriel Mesquita
Ramsey Yuen
Sepideh Espiar
Spencer Cook
Nick Corcoran
Janice Tran
Dan Forget
Matthew Freich
Mayan Hattab
Mustaali Raj
Artiz Arrizabalaga

Digital Rock Physics for Oil Sands and Gas Shales

Guoping Li, Elizabeth Diaz, Avrami Grader, Meghan Armbruster and Amos Nur, Ingrain Inc.

Abstract

Advanced digital rock physics employs state-of-the-art high-resolution CT scanning techniques, special image processing, and efficient computational algorithms realized on super-computing platforms. The use of modern technologies makes it possible to commercially deliver accurate and fast results of computed rock properties and multiphase fluid flow characteristics such as porosity, absolute and relative permeability, and capillary pressure, as well as to visualize, in a high-fidelity manner, the internal pore geometry and grain matrix structure of the rocks under investigation. All of these rock features provided through virtual experiments are valuable information in effective reservoir management, advanced reservoir simulation, and exploration risk reduction. Compared to the physical experiments in conventional laboratories, digital rock physics offers obvious and tremendous advantages: (a) virtual experiments involve a non-destructive process, i.e., no rocks need to be crushed, or homogenized; (b) computed results can be obtained fast and accurately; (c) digital rock volumes can be re-used as many times as desired; and (d) the whole process of measuring rock properties is transparent, and 3-D internal structure of the rock is revealed. Digital rock physics works effectively not only for conventional plays, but also for unconventional resources plays, either on cores, sidewall plugs, or drill cuttings, the latter of which would be difficult, if not impossible, to work on in a traditional physical lab because of small sizes and random shapes. In this article, we wish to introduce the reader to the basic steps and instruments used in a digital rock physics lab, explain briefly the science behind this increasingly popular technology, and illustrate its effectiveness by a few examples of practical applications to oil sands and gas shale plays.

Introduction

Unconventional resource plays, as the increasingly more attractive new sources of energy, require the use of novel technologies to help better characterize reservoirs, improve reserves estimates and production efficiency, and mitigate all the associated risks. In particular, two such play types, oil sands and gas shales, have attracted tremendous attention from the industry and a high level of interest in the investing community.

Digital rock physics is one such innovative technology born to meet the demand and challenges of unconventional resource exploration and development. As a new branch of geoscience, it has developed quickly during the last decade into a commercial application, as a result of recent advances in massive scientific computing power, high-resolution computed tomography (CT) scanning instrumentation, as well as exponentially growing knowledge and experience in rock physics theory development and experiments [Mavko *et al.*, 1998; Tiab and Donaldson, 2004].

Currently, rock physics is widely used not only in geophysical exploration and reservoir characterization, but also in petroleum engineering areas, such as improved recovery, wellbore management, and advanced reservoir simulation. Rock physics is a powerful means to derive critical information about key reservoir characteristics and transport properties, including porosity, permeability, elastic and mechanical properties, and pore-scale fluid flow processes. Obtaining this information is even more important for unconventional plays because of their geological complexities and high demand in capital costs.

Traditionally, rock physics analysis has been made in a physical laboratory. Physical measurements of rock properties rely on the availability of cores. However, obtaining cores is expensive for unconventional plays for which often hundreds to thousands of wells need to be drilled in a field to produce at an economical scale. In many cases, coring can be problematic because it leads to potential delays in drilling and carries the danger of damaging or even losing a well [Blackbourn, 2009]. Drill cuttings from a well are available all the time but they are found difficult to handle in the physical lab that requires a certain size and regular shape of the samples under measurement. In addition, friable rocks, like oil sands, simply cannot be properly treated in the physical lab due to the necessity of applying cleaning or homogenizing processes, making it a big challenge to keep the rock's pore structure intact and to provide reliable results [Dvorkin et al., 2008]. Moreover, modern reservoir modeling and simulations demand that physical properties of rocks be obtained not for tens of samples but for thousands or even tens of thousands of samples, which will be extremely hard to realize using a physical measurement approach that is slow and cumbersome. All these difficulties and even impossibilities encountered in a physical lab environment, nevertheless, can be handily overcome by the emerging digital rock physics methodology.

Table 1 lists all the physical properties and multiphase transport characteristics that can be obtained in virtual experiments today, for all different rock types (sandstone, carbonate, tight gas sand, shale and oil sands), either on cores, sidewall plugs, or

Continued on next page…

Digital Rock Physics for Oil Sands and Gas Shales *continued…*

cuttings. With digital rock physics advancing further and rapidly, we also envision that, in the near future, complicated natural pore-scale processes (fine particle migration, formation damage, diagenesis, and chemical reactions) will be virtually simulated in a detailed actual pore space.

Table 1. Physical properties and transport characteristics that can be computed from 3-D digital rocks at present
Physical Properties
Porosity (total, effective, and non-connected)
Absolute permeability (matrix and fractures) in x-y-z directions
Elastic properties in x-y-z directions
Formation factor (resistivity) in x-y-z directions
Mechanical strength
Fluid flow characteristics
Relative permeability in x-y-z directions
Capillary pressure
Irreducible water saturation
Residual oil saturation
Oil-water wettability
Rock characterization
Type of grains (quartz, feldspar, carbonate, etc)
Pore size distribution
Grain size distribution
Surface area and volume of grains
Grain sphcrity and roundness
Clay mineralogy analysis
Total organic carbon contact (connected and non-connected)
Silt fraction
Bedding plane orientation
Geologic settings and origin of rock

Compared to the traditional physical lab methodology, the digital approach is characterized by the following advantages and impacts:

(1) It drastically speeds up and increases the massiveness and reliability of routine and special core analyses;

(2) It reconstructs a 3-D structure of real pore space from rocks in a non-destructive manner. Once created, it can be re-used as many times in numerical experiments as needed;

(3) It eliminates the use of hazardous materials (such as mercury) commonly used in a physical lab;

(4) It makes quasi real-time permeability logging directly from wells possible;

(5) It allows the rigorous link of computed properties to well logging data;

(6) It enables integration of computed rock properties and well logs with seismic data to predict rocks away from the well ("drilling virtual wells");

(7) It now provides opportunities to digitally realize those challenging physical processes that would be only dreamed of in a physical lab environment.

In the sections below, we will introduce the concept of a commercial digital rock physics laboratory, provide the basic working procedure and equipment as required to conduct virtual experiments, explain the science behind this technology, and finally demonstrate its effectiveness with some real-case examples. Specifically, applications to two North American conventional resource plays, oil sands and gas shales, will be discussed.

Digital Rock Physics Laboratory

A digital rock physics laboratory is where virtual (or numerical) experiments are performed, in which an actual rock sample is scanned using high-resolution CT scanner. A 3-D digital image representing the rock is created, a true pore space is separated from the solid matrix through special image processing, and then, rock properties and fluid flow values are computed. A commercially functional digital physics lab, involves at least four key components:

(1) High-precision scanning instruments that should effectively work on all rock types: sandstones, carbonates, oil sands, tight gas sands, and shales. A full resolution spectrum is available, from macro- (>10 μm*), to micro- (0.1 to 10 μm), to nano-level (2 to 50 nm*) resolutions (*Here, μm denotes microns or 10^{-6} m, while nm denotes nano-meters or 10^{-9} m).

(2) Access to cluster-based supercomputing power for massive computations of rock properties and multiphase flow simulations.

(3) Proprietary image processing and computational algorithms.

(4) Specially trained geologists who have acquired knowledge and skills to operate scanning instruments, conduct special rock analysis, process 3-D images, and compute rock properties. They are also assisted with other useful devices such as scanning electron microscopy (SEM), x-ray diffraction (XRD) and energy-dispersive X-ray spectrometry (EDS).

To make a digital rock physics experiment successful, a well-designed procedure must be followed, including:

- Rock preparation
- CT scanning and imaging
- Image segmentation
- Rock property computation
- Integration

Once rock samples, whether in the form of cores, sidewall plugs, drill cuttings, or fresh oil sands, are delivered to the lab, a geologist is responsible for creating a database for each sample and preparing the sample for scanning (Figure 1a). No sam-

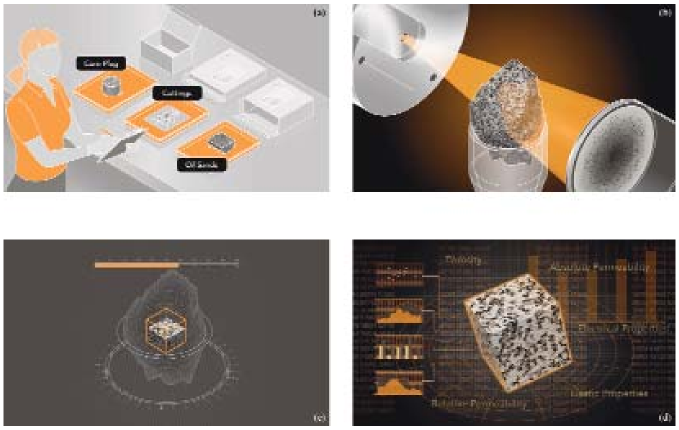

Figure 1. Basic workflow for a virtual experiment in digital rock physics lab. (a) Preparing rock samples and creating database; (b) CT scanning of rock sample; (c) Generating vRock, a 3-D digital rock volume; and (d) Computing rock properties from vRock.

ple cleaning or fluid injection is needed. The rock's original saturation status will be preserved. In addition to computed rock properties, detailed geological information associated with the input sample, including rock type, mineralogy, depositional environment, age and location, is logged into the database. For a particular rock type, the size of the sample for scanning depends on the resolution needed to resolve its pores and grains, and therefore adjustments of sample sizes may be necessary.

Imaging starts at a macro-level resolution: that is, the entire input core, core plug or drill cutting is macro-CT scanned. The resulting macro image does not contain sufficient details for changes at pore scale, but enough information about spatial variations of heterogeneity, bedding and/or zoning of the scanned rock, from which smaller samples may be selected and prepared for scanning at higher, i.e., micro-level, resolution. In the cases of tight rock types such as shales, an even higher, nano-level, resolution is required to scan an even smaller sample. Thus, rock sample sizes for scanning generally decrease in every step where an increase in resolution is required. During CT-scanning, the rock sample is scanned omni-directionally (Figure 1b). Hundreds, even over a thousand, of 2-D slices are generated and later combined to create a 3-D digital representation of the actual rock volume (Figure 1c). The CT-scanners use x-rays as a energy source. Therefore the energy emerging from the other side of the sample placed within the scanner is converted into visible light and recorded as a digital image, which shows the variations in density (or intensity) corresponding to the rock compositions. For instance, low-density pore space and saturating fluids may be represented by dark colors in the image whereas higher-density grains and mineral solids may be in light gray to white colors (Figure 1d).

After scanning, the geologist uses specially designed image processing software to segment the resulting 3-D image in order to separate the pore space (filled with fluids and other particles) from the solid matrix (grains, clays and other hard materials), based on the density variations and mineralogy analysis on SEM, XRD and/or EDS. The bulk density for some common minerals and fluids is given in Table 2. The final

Table 2. Bulk densities of some common minerals and fluids

Minerals and Fluids	Bulk Density (g/cc)	Chemical Symbol
Calcite	2.710	Ca(CO3)
Dolomite	2.870	CaMg(CO3)2
Quartz	2.650	SiO2
Feldspar	2.570	KAlSi3O8
Gypsum	2.320	CaSO4*2(H2O)
Anhydrite	2.960	CaSO4
Pyrite	5.010	FeS2
Illite	2.780	K.8Al1.6Fe.2Mg.2Si3.4Al.6O10OH2
Kaolinite	2.620	Al4(Si4O10)(OH)8
Clay	2.770	
Water (brine)	1.076	
Bitumen (@15degC)*	1.015	
Light crude oil	0.881	
Air (@20degC and 1 atm)	0.0012	
Methane (at 20degC and 1 atm)	0.000668	CH4
Organic matter	1.000	
Kerogen	1.400	

Sources: Canadian Association of Petroleum Producers: Alberta Oil Sands Bitumen Valuation Methodology, December 2008; Schlumberger online database

segmented 3-D volume is called a virtual rock (or vRock), which is a complete digital capture of the actual fabric of the original rock sample. Figure 2 shows an example of image segmentation for a tight gas sand. In the vRock (Figure 2a), the porosity is shown in blue, the calcite is in white, while the fine grains are in grays. The pore geometry, in this case, is found to be similar to the shape of calcite cement/crystals. So dissolution of the calcite is interpreted to be a possible origin of the porosity. Figure 2b highlights the porosity after eroding away the solid matrix. The entire pore space in Figure 2c is shown as a 3-D object, where connected and isolated pores can be further characterized. The vRock provides the basis for computing rock properties and multi-phase flows.

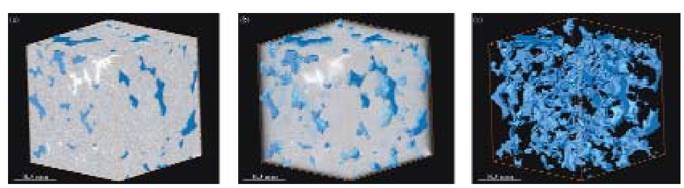

Figure 2. A 3-D digital image created from tight gas sand. (a) The vRock. Porosity – blue, calcite – white, grains – gray. (b) Highlighted pore space with eroded matrix. (c) Pore space separated from grain matrix. Scale at 0.3 mm.

To account for the rock's heterogeneity, a number (say, 3 or more) of sub-samples may be taken from different regions of each rock being scanned and properties are computed on each sub-sample [Dvorkin and Nur, 2009]. Heterogeneity of the sedimentary rocks occurs at every scale of samples taken for

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Digital Rock Physics for Oil Sands and Gas Shales *continued…*

analysis. Therefore, useful reservoir information, whether from direct measurements or computations on cores, plugs or drill cuttings, or from indirect inference of well logs and seismic observations, needs to integrate. Upscaling from small to large scales is a necessary part of integration. Only when a full-scale and multi-disciplinary integration is successfully done, can the reservoir model, thus reservoir simulations, be complete and reliable. Detailed discussions of upscaling and integration, though, are beyond the scope of this article.

Once created, the vRock can be stored permanently in a secure online database, along with the computed results, which the user can access repeatedly any time. At the user's option, multiple analyses can be done on the same digital rock to test parameters and changing conditions, and to observe the resulting sensitivities. Additionally, the vRock can be used in the future to re-analyze the rock for new properties of interest.

Computations of the Physical Properties of Rocks

At present, key reservoir properties (porosity, absolute and relative permeability) can be computed accurately and fast, through the use of advanced 3-D CT scanning and scalable high-performance computing capabilities. Historically, relative permeability could take physical labs many months, or even years, to measure, let alone its questionable quality. However, computing relative permeability in a digital lab takes only a few days.

To compute a rock property, rigorous physical laws and processes are strictly followed to provide the basic principles [Keehm *et al.*, 2001; Dvorkin *et al.*, 2008]. Next we will briefly explain how some of the important reservoir properties are computed.

Porosity

Porosity is commonly defined as the ratio of the void volume in the rock to the total volume of the rock. In digital rock physics, porosity is directly calculated from vRock where the ratio of the number of voxels that fall into the pore space to the total number of voxels occupying the entire digital rock yields the total (or absolute) porosity of that rock.

The task of separating the pores from grains and minerals is accomplished through image segmentation. The main technical challenge is the gradual transition from dark to light shade of gray at the edges of pore space. Proprietary image-processing abilities are adopted to address this issue so that pore space is accurately separated from mineral matrix and reliable porosity is computed.

As shown in Figure 2c, natural rocks contain interconnected pores as well as isolated pores. Only the connected porosity contributes to reservoir fluid flows. By the digital approach, both connected and non-connected pores can be visualized in 3-D display. Total, effective, and isolated porosity are computed respectively.

Permeability

Absolute permeability (or simply, permeability) measures the capability of a rock to transmit a single fluid phase (oil, gas, or water) through its pore structure. It is difficult to measure permeability directly in a well. Traditionally, it is measured in a physical laboratory on regularly shaped core samples.

Fluid flow through actual pore space of a vRock is numerically simulated. The simulations can be conducted rapidly and massively on rock samples of any shapes and sizes that are almost impossible to handle in the physical lab.

The numerical tool used is the lattice-Boltzmann method (LBM), which accurately mimics the Navier-Stokes equations for slow viscous flows in porous media. The LBM can easily accommodate the boundary conditions on a complex realistic pore surface, such as in a natural rock [Keehm et al., 2001; Dvorkin et al., 2008].

Permeability is computed in a manner analogous to a laboratory measurement. In a virtual experiment, a pressure head (or body force) is virtually applied to a digital rock. The resulting fluid flux is calculated and linearly related to the pressure drop between the two faces of the sample, which, through Darcy's equation, yields permeability. Virtual permeability can be obtained in any three orthogonal axes.

Permeability depends not only on porosity but also on grain (or pore) size, tortuosity and connectivity of pore space. Obviously, accurate characterization of rock's pore/grain geometry is prerequisite for delivering accurate permeability values.

Relative Permeability

Relative permeability copes with multiphase (say, oil-water) viscous fluid flow through a porous rock. It has been notoriously difficult to physically measure relative permeability in a laboratory. The main reason is that, when multiple fluid phases flow through friable rocks such as oil sands, it is extremely difficult, if not impossible, and time-consuming to ensure stable saturations, unless the rock's texture is completely destroyed for such purposes.

Virtual experiments provide a unique and pragmatic way for simulating multiphase flows in any rocks, with irregular shapes, and with fluids of any viscosity and wettability, as long as the physical laws are satisfied. Again, the lattice-Boltzmann method is used to simulate the Navier-Stokes equations in the case of slow multiphase viscous flows.

LBM directly simulates static and dynamic configurations of the contacts between the fluid phases and the pore walls by taking into account surface tension and contact angle, formed at an interface between fluid and mineral. A wetting angle is larger than 90 degrees if the fluid is wetting, and smaller than 90 degrees if the fluid is non-wetting. Key parameters that are needed to define the wetting (or contact) angle, and thus affect relative permeability computations, include:

- Pore-space geometry (distribution of large and small conduits and their sizes);
- Viscosity of the fluids;
- Wettability of the mineral surfaces; and
- The surface tension between the fluid phases, and between fluid and minerals.

Like absolute permeability, relative permeability can be obtained in any three orthogonal axes. In addition, the virtual experimentation makes it possible to estimate other transport properties such as capillary pressure, irreducible water saturation and residual hydrocarbon saturation, or to simulate pore-scale processes like dynamic drainage and imbibitions.

Figure 3 shows the results of LBM simulations for hydrocarbon imbibitions [from (a) to (c)] into a fully brine-saturated carbonate. It is then followed by water flooding [from (d) to (f)] within the same rock. The digital 3-D pore space used was created from a Middle East carbonate sample. As a result, relative permeability, along with irreducible water and residual hydrocarbon saturations, were computed.

Formation Factor

The same virtual object, vRock, as used to compute porosity, absolute and relative permeability, is used to digitally derive electrical properties: conductivity and/or resistivity. Conductivity is the rock's capacity to transmit electrical current. The powerful finite element (FEM) computational engine, which numerically solves the Laplace equation, is used to calculate the electrical current responding to an imposed potential field inside a digital rock. The electrical current field in the pores is computed and then summed up to generate the total current through the sample. The effective conductivity of the rock sample is simply the ratio of this current to the potential drop per unit length.

If the rock is fully saturated with conductive fluid (e.g., brine), which is easy to realize in a virtual experiment, the formation factor, F, can be computed as the ratio of the wet sample's resistivity to that of the brine. If the rock is partially saturated with hydrocarbon, which is usually a dielectric, the water saturation S_w is calculated as $S_w = (FR_w/R_t)^{1/n}$, where R_w is the resistivity of brine, R_t is total resistivity, and n is the saturation exponent.

Elastic Properties

An elastic property of a rock measures its tendency to deform non-permanently in various directions when a stress is applied. Once again, the same virtual rock is used to deform digitally. Upon applying stresses to the faces of the digital rock, strains in the rock frame can be computed locally using the finite element method (FEM). By relating the strain to the stress, we obtain the effective elastic properties, including bulk modulus, shear modulus, Young's modulus and Poisson's ratio. Assuming that linear elasticity laws are satisfied within the sample (normally true for natural rocks), elastic moduli can be converted into seismic velocities V_p and V_s. All these elastic properties are computed in x-, y-, and z-directions.

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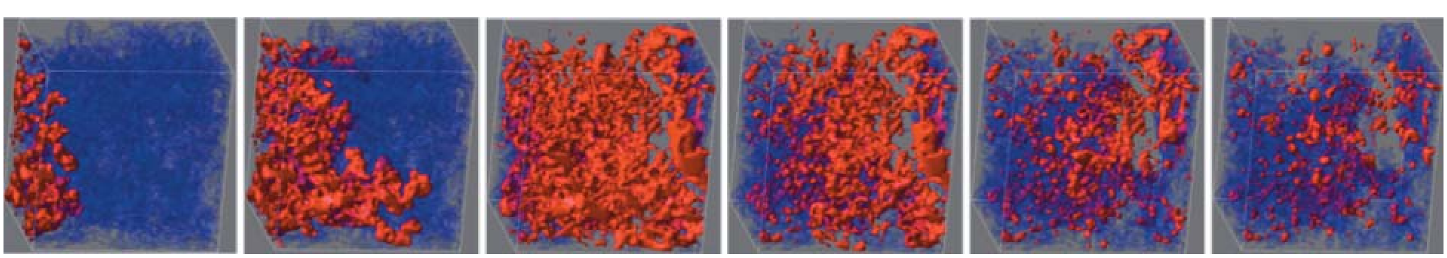

Figure 3. Results of numerical simulations on a Middle East carbonate rock saturated initially with brine: hydrocarbon imbibition [(a) to (c)]; and subsequent water flooding [(d) to (f)]. Oil – red; brine – blue.

Digital Rock Physics for Oil Sands and Gas Shales *continued…*

Using the virtual rock, we can further investigate the dependence of elastic properties on porosity, pore/grain geometry and mineralogy. The advantage is that virtual experiments for different purposes can be simultaneously conducted on a shared digital object, vRock.

Nevertheless, one of the technical challenges posed in digital rock physics is: How to accurately quantify the controls of minerals on the elastic and electrical properties, especially if conductive minerals (e.g., pyrite and porous clay), or sub-resolution particles (clay or micrite) are present in the rock? Currently, as discussed in Dvorkin *et al*. (2008), this challenge is addressed through (1) acquiring additional information from SEM and XRD analyses, and specific petrological and mineralogical knowledge; (2) utilizing ultra-high resolution scanning instruments such as nano-CT scanner for mapping sub-resolution particles; and (3) applying expertise and common sense.

Applications to Canadian Oil Sands

Canadian oil sands are shallow, massive viscous petroleum deposits that consist of unconsolidated sediment and viscous petroleum or bitumen. They are naturally occurring mixtures of sand, clay, water, and bitumen with viscosity of up to one million centipoises or higher. Essentially, almost no compaction and diagenesis have occurred within these rocks.

Developing the enormous oil sand reserves (>175 billion barrels) is extremely costly. To produce the virtually immobile bitumen, open-pit mining and in-situ thermal heating are two main approaches commonly in use. In the case of thermal operations, which are only suitable for relatively deep deposits, expensive steam is injected underground either continuously as in SAGD (steam assisted gravity drainage), or periodically as in CSS (cyclic steam stimulation). Because large amouonts of capitals and high operating costs are involved, risk mitigation is a profound challenge in the business. Effective reservoir characterization and cost management is crucial. A better understanding of reservoir properties and multiphase flow characteristics is required for accurate and reliable reservoir simulations.

However, friable oil sands often cannot be delivered *intact* from the subsurface to the laboratory. Furthermore, because bitumen within oil sands acts as the load-bearing framework, handling the core samples for such rock in a physical lab is very difficult, or even impossible, without destroying the samples' texture. For instance, cleaning and transportation may be necessary for fluid flow experiments, where more than one fluid phase is required to flow through the rock sample. Removing the bitumen would cause the rock to collapse, its internal pore structure completely destroyed, resulting in unreliable measurements of important reservoir parameters like relative permeability.

Digital rock physics is needed to avoid such artifacts (Armbruster *et al*., 2009). In a virtual experiment, the entire oil sand core, once delivered to the digital lab, would be macroCT scanned at >10 µm resolution. In Figure 4, a piece of conventional core, 16.5 cm long and 6.5 cm wide, placed within a plastic sleeve, is x-ray scanned. At this low resolution, the image only shows some significant spatial variations of the rock, i.e., three different zones: a low-density dark-colored zone with many variations (zone 3), a high-density light-colored zone with little variation (zone 2), and an intermediate zone (zone 1)

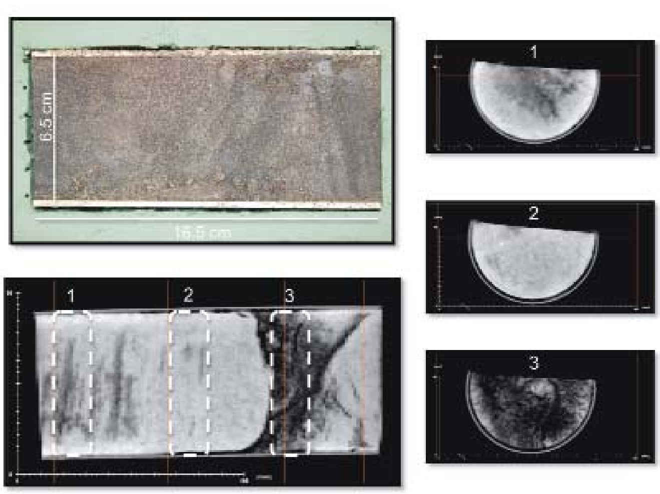

Figure 4. (a) Conventional oil sand core within a plastic sleeve. (b) Image after macroCT scanning of the original core. (c) Three disks of MacroCT images cut from the three zones marked in (b).

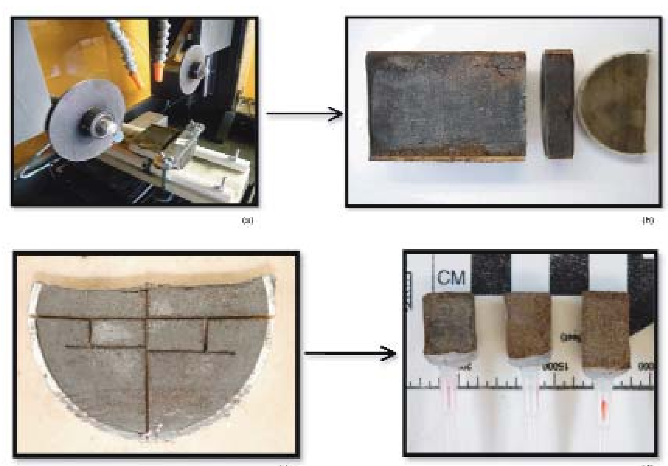

Figure 5. (a) A diamond wire saw used to cut small samples; (b) Disks cut from oil sand core; (c) The side view of the core showing where the samples are cut from; and (d) Three samples with 1-cm diameter used for microCT scanning.

showing laminations. But no pores can be seen at this resolution. Nevertheless, the strong heterogeneities provide clear evidence to guide us to further sample the rock for higher-resolution imaging. Three thin disks, representing zones 1 to 3, are thus taken, as shown in Figure 4c.

A diamond wire saw is used to cut core (Figure 5a). This tool has a high precision (~150 µm) such that smaller samples are precisely cut without collapsing the soft oil sands. These small samples, called micro-samples, typically have a size of 1-cm width and 1.5-cm length. Three of them, from zones 1-3 of Figure 4, will be microCT scanned.

MicroCT scanning on micro-samples provides a resolution ranging from 0.1 µm to 10 µm. Figure 6 shows a micro-CT image of an oil sand sample. Here, grains are represented by light gray, pore space by dark gray and black, and higher-density minerals by white. The pores are filled with air, bitumen and some fine particles, determine by their respective densities

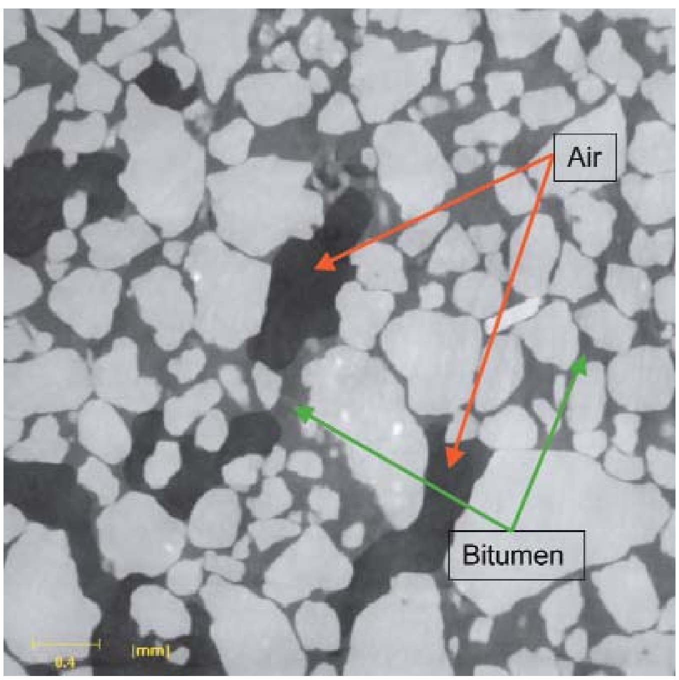

Figure 6. MicroCT image of oil sand sample showing fluid-filled pores, sand grains and minerals. Scale at 0.4 mm.

(Table 2). Grains, having variable sizes and shapes, are basically immersed in, and partially supported by, bitumen. The huge contrast in grain geometry implies poor sorting during deposition. A 3-D image (vRock) created from image segmentation on the rock sample is given in Figure 7. In this 3-D display, we can clearly see the pores well connected through pore throats, both of which are saturated by bitumen (green) and air (black).

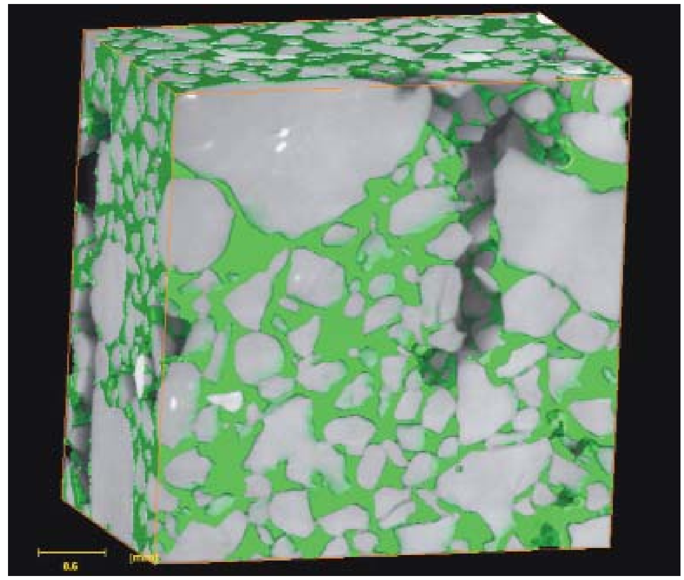

Figure 7. 3-D digital image of oil sand sample showing bitumen- (green) and air- (black) saturated pore space surrounding grains (gray) and some minerals (white). Scale at 0.6 mm.

If water were to occur in the pore space and had sufficient density contrast from bitumen, this high-resolution image would produce volumetric values for each of the fluids saturating the pore space.

Once the volumes for pore space and grain/mineral matrix are calculated, respectively, from a virtual rock, physical properties and flow characteristics can then be computed. Figure 8 shows the total porosity, absolute permeability and formation factor, in x-, y- and z-directions, computed on the three micro-

Sample Name	1	2	3
Porosity			
Total Porosity (%)	34.6	28.6	40.5
Permeability (D)			
Directional Permeability (X)	5266	1687	12176
Directional Permeability (Y)	5651	1659	13556
Directional Permeability (Z)	6128	1531	13642
Formation Factor			
Formation Factor (X)	6.2	7.0	4.4
Formation Factor (Y)	6.0	7.1	4.0
Formation Factor (Z)	6.3	7.7	4.3

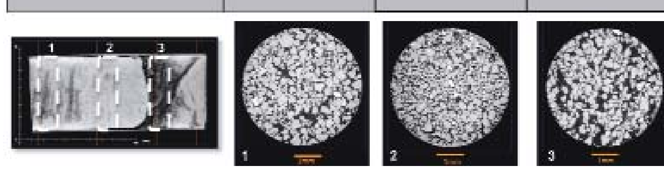

Figure 8. Computed porosity, permeability and formation factor from the microCT images (lower right) representing the samples within each of the three marked zones in Figure 4.

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Digital Rock Physics for Oil Sands and Gas Shales *continued…*

samples as described in Figures 4 and 5. Some interesting observations can be made. Firstly, the rock properties, i.e., porosity, permeability, and formation factor, vary as a function of grain size, shapes and sorting. For example, zone 2 exhibits generally smaller grains but more grain size variations than zones 1 and 3, and it yields lower porosity, lower permeability, and higher formation factor. On the other hand, grains in zone 3 almost do not contact each other. Secondly, there are some weak changes in directional permeability. Lastly, macro and micro images are correlated well, and both are good indicators of porosity and permeability variations. In another words, the grain sizes and shapes appearing on micro-images and the density changes appearing on macro-images combined could indicate the high or low values of porosity and permeability. This may be helpful in a multi-scale integration from micro-sample to macro-core to well logs.

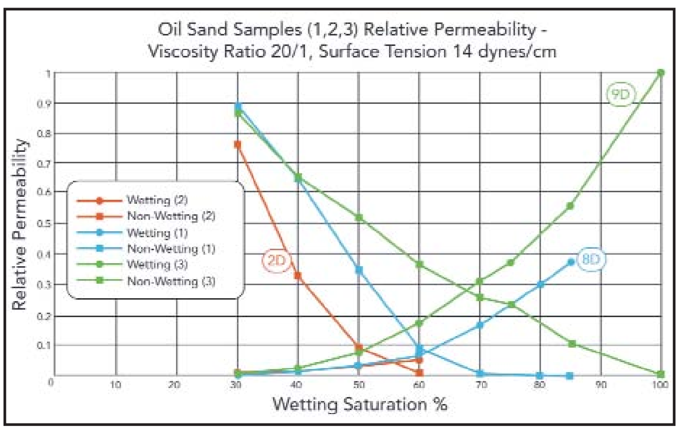


Figure 9. Relative permeability computed at a 240 °C temperature for three oil sand samples with 2-, 8-, and 9-Darcy permeability, respectively.

Figure 9 shows the results of relative permeability computed at 240 °C on three oil sand samples. Key input reservoir parameters include fluid viscosity, wettability, surface tensions, reservoir pressure and temperature. Normally done within just a few days, the computations of relative permeability, residual oil saturation and irreducible water saturations, can be obtained for high temperatures encountered in thermal operations, yet hard to reach by physical laboratories.

Grain size distribution and grain shape (sphericity and angularity) can be readily computed. Shown in Figure 10 is a virtual sand grain from an oil sand sample. Surface area, volume, and aspect ratios can be obtained for individual as well as a set of grains. Figure 11 shows the grain size distributions as histograms for the three samples discussed above.

Unnatural features such as artificial cracks could be easily introduced into oil sand cores, without being noticed. Care must be taken and solutions must be found before such features lead to unreliable measurements. Figure 12 provides one such case, where the original oil sand core only shows some lamination features (Figure 12a), but the x-ray image (Figure 12b) shows additional vertical linear features that cannot be seen at all with

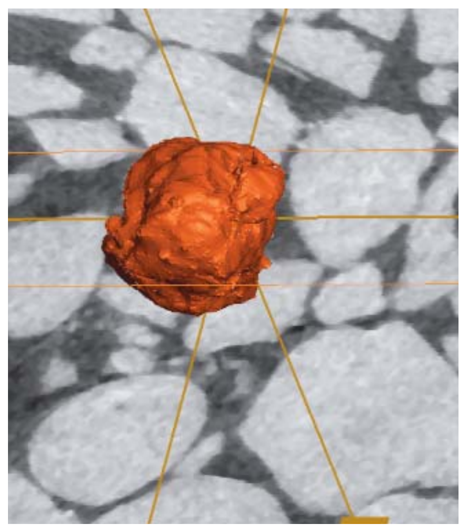


Figure 10. A virtual sand grain.

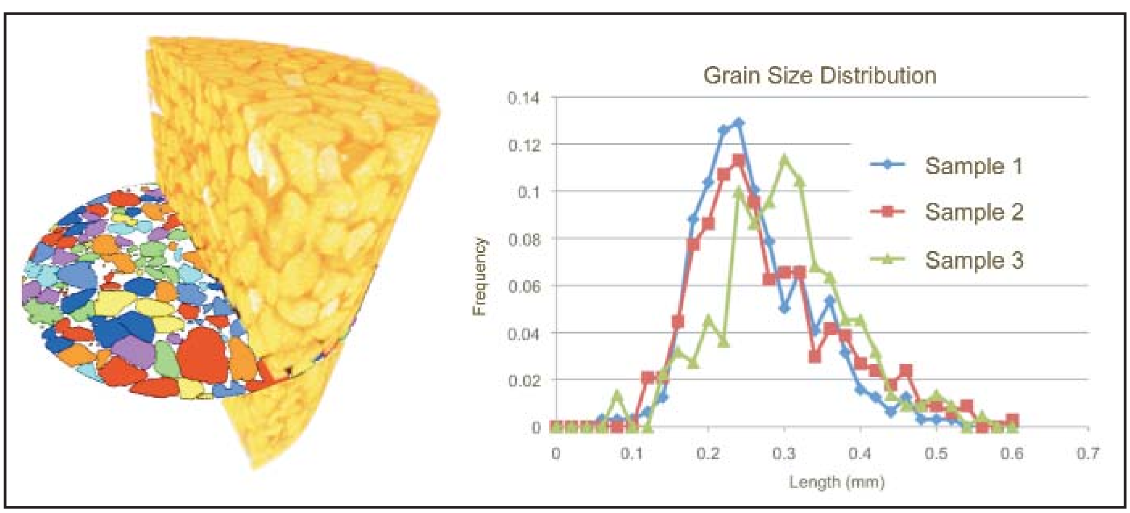


Figure 11. Grain size distribution in histograms.

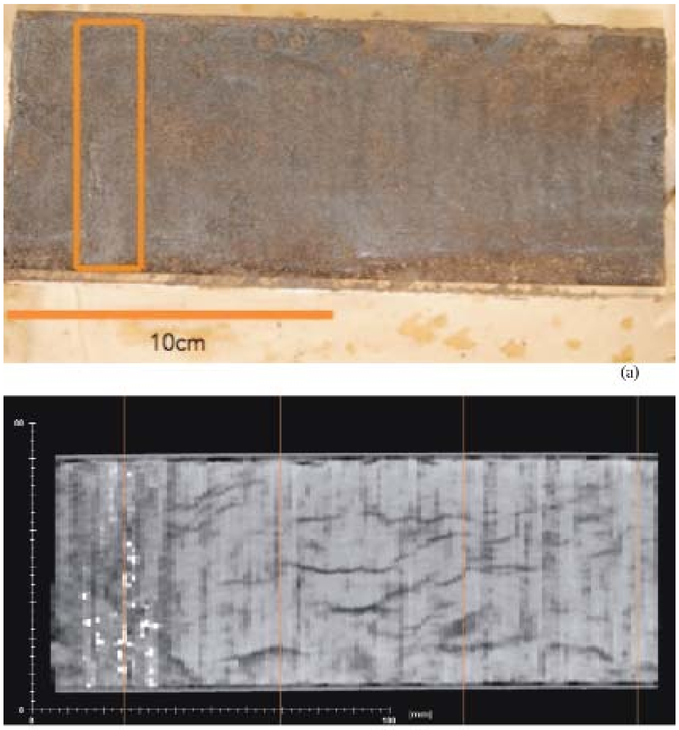
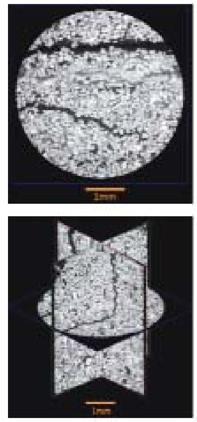


Figure 12. (a) An oil sand core. (b) Its macroCT x-ray image showing artificial cracks, invisible in the original core, induced due to drying.



Sample Name	Core 9 Sample 1-A
Porosity	
Total Porosity (%)	31
Permeability (mD)	
Directional Permeability (X)	975
Directional Permeability (Y)	269
Directional Permeability (Z)	811
Formation Factor	
Formation Factor (X)	6.7
Formation Factor (Y)	15
Formation Factor (Z)	7.8

Figure 13. Computed rock properties for the oil sand sample with induced cracks displayed in micro-CT image and 3-D volume.

naked eye. These features are even better seen in 2-D micro image and 3-D volume (Figure 13). These additional features are artificial cracks interpreted as a result of drying after the core was brought to the ground.

Clearly, if including these artificial features in measurements, the results would be severely biased. As illustrated in Figure 13, the permeability and formation factor values change drastically, depending on the direction of measuring (in this case, computation). Digital rock physics provides enough flexibility in dealing with this kind of problems: We can either take a smaller virtual sample to avoid the cracks, or we can directly '*heal*' them digitally.

Applications to Gas Shales

Over the recent decade, shale has become an important source of natural gas and oil, especially in North America. Canada alone is estimated [Bustin, 2005] to hold gas resources of over 1,000 TCF in its massive shale deposits. Famous gas shale plays include Barnett, Fayetteville, Marcellus, and Hayneville in the United States, and Montney, Horn River (Muskwa), and Utica in Canada, to name a few.

In sharp contrast to oil sands, shale is a fine-grained, organic-rich sedimentary rock whose original constituents are clay minerals or muds. Shale acts as the source, the reservoir and the seal for hydrocarbons and ordinarily does not have sufficient matrix permeability to allow significant fluid flow to a wellbore. Shale permeability is much lower than 1 mD and commonly in the nano-Darcy range.

Although they typically are thick (10's to 100's meters), extensive and continuous, shales can show remarkable heterogeneities that extend to the nano-meter pore size scale. Hence, each shale reservoir requires unique treatment and systematic analysis before analogs from proven producing reservoirs or fields can be directly applied [Ross and Bustin, 2008].

Therefore, proper studies of rock physical properties and, perhaps more importantly, fluid flow characteristics in such ultra-low permeability rocks are essential to investigate heterogeneities. Because shales possess extremely small grains and pores, rock samples used for high-resolution CT imaging and analyses tend to be small. Figure 14 shows an example, in a mi-

Figure 14. A black shale sample ready for nanoCT scan. Scale at 500 Ìm.

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Digital Rock Physics for Oil Sands and Gas Shales *continued…*

cro-sample, of North American black shale, a thinly bedded shale rich in sulfides such as pyrite and organic materials. Common dimension of a micro sample for shale ranges from 100 μm to 350 μm.

For a typical shale gas reservoir, parameters of importance include organic matter type (oil- vs gas-prone kerogen) and abundance, vertical and lateral extent, depth of burial (affecting reservoir temperature, pressure and thermal maturity), porosity (including pore-size distribution), and mineralogical composition (affecting natural fracture genesis and design for fracture stimulation).

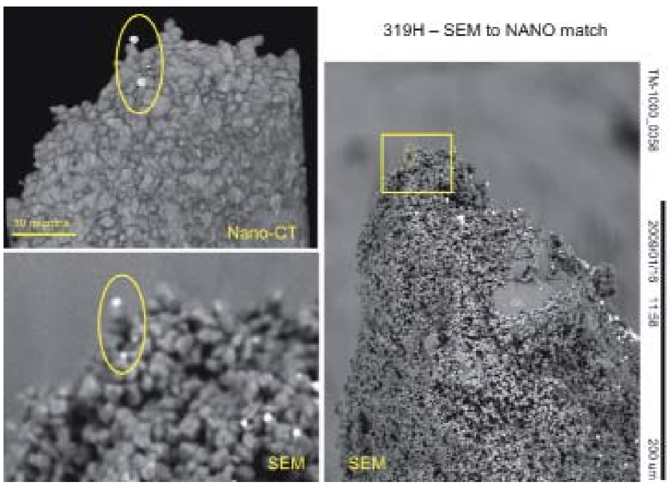

Figure 15. Black shale shown on nanoCT image in comparison to SEM image.

SEM and XRD are often used to analyze and determine qualitatively shale minerals but they cannot be used for quantitative rock property computations. A nanoCT scanner is used due to its superior resolution (50-100 nm) and ability to provide 3-D image. Figure 15 demonstrates the difference between an SEM and a nanoCT in image resolution on the same shale.

Minerals like calcite and pyrite are important because they sometimes act as the filling materials healing open fractures, a crucial parameter for effective gas productivity in shale reservoirs. Pyrite in the organic-rich sediments, though, rarely exceeds 1% in quantity, as suggested in Ross and Bustin's [2008] study of Devonian-Mississippian shales in Western Canada, such as the Horn River Group and Muskwa shales. Figure 16 shows the 3-D distribution of framboidal pyrites in the black shale.

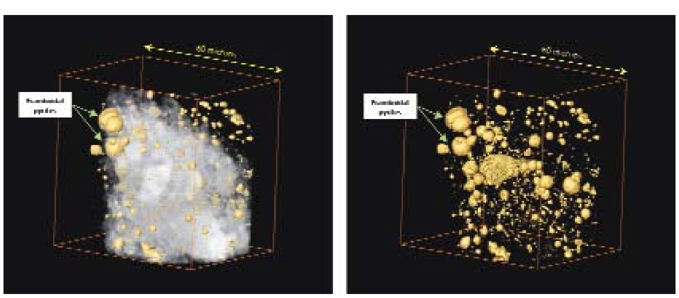

Figure 16. (a) Grain matrix and pyrites in a black shale. (b) Pyrites only.

Total Ornagic Carbon

Shale gas (mainly methane) is generated from organic matter (kerogens) and stored within the source rock itself. The knowledge of the quantities and spatial distributions of total organic carbon (TOC) contents within a shale reservoir plays a critical role in determining its potential gas capacity and identifying potential favorable completion zones. The TOC normally ranges between 0.5% and 6% (wt), but can go up to 20%. Shale gas is stored in a reservoir in three manners: 1) adsorbed gas adhered onto organic matter and mineral surfaces; 2) free gas in the micro-pores and fractures; and 3) solute gas within water and/or bitumen. Often the solute gas is accounted for in adsorbed gas due to the difficulty to differentiate both [Ross and Bustin, 2008].

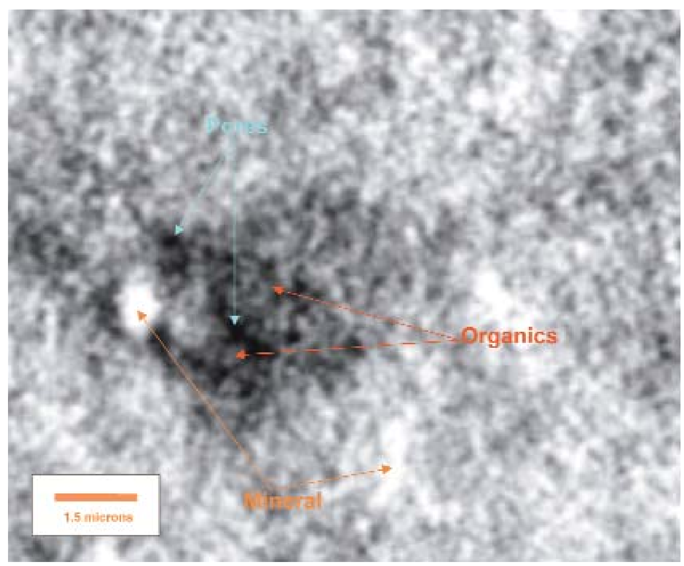

Figure 17. Organic matter, pores and minerals identified in a nanoCT image for a black shale sample.

The bulk density of organic matter is significantly higher than free gas or air in the pores but much lower than some common minerals such as quartz, carbonate and clays (Table 2). So these constituents can be well differentiated in a high-resolution nanoCT image. Shown in Figure 17 is a 2-D nano slice for the black shale sample in Figure 14. The white areas represent high-density grains and minerals (>2.5 g/cc). The dark gray areas represent organic matter at a ~1.0 g/cc density. Clearly distinguishable, the black areas represent the pores perhaps filled with free gas at extremely low density (0.0007 g/cc). A detailed characterization based on a 3-D nano vRock, as in this case, allows for accurate computations of TOC content, mineral volume, and porosity. Figure 18 displays a 3-D distribution of the silt fraction (high-density materials), whereas Figure 19 shows the TOC distribution, superimposed on the silt fraction, both computed from the shale sample.

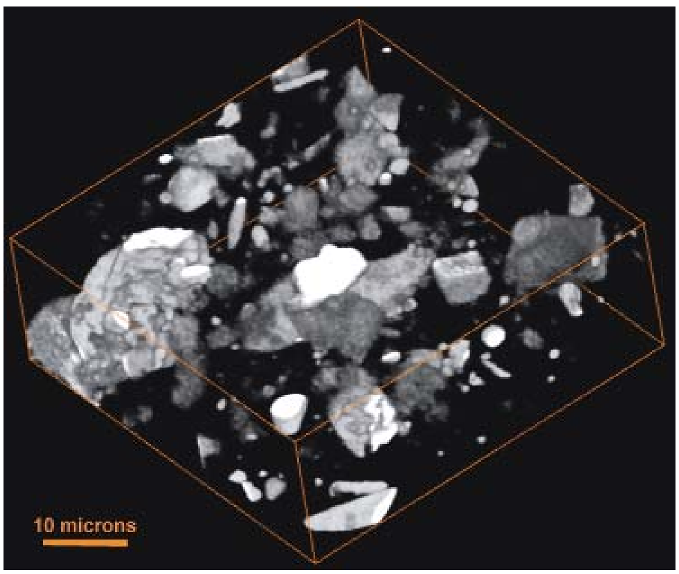

Figure 18. Black shale silt fraction.

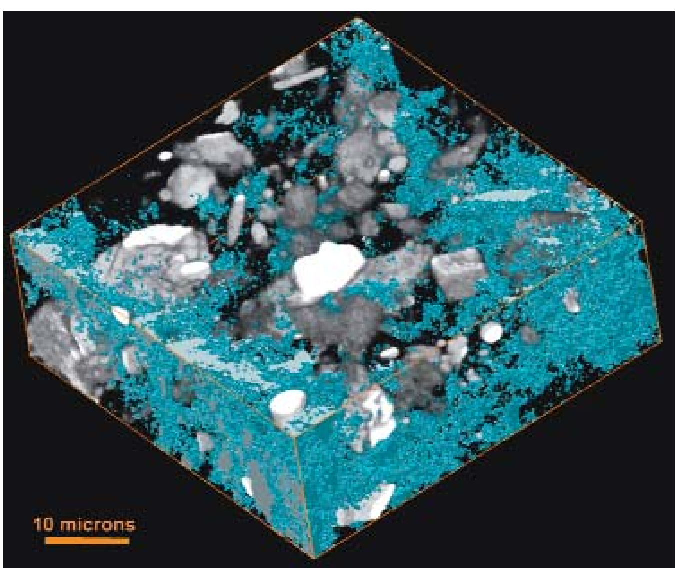

Figure 19. Black shale TOC distribution along with silt fraction.

Porosity & Permeability

A substantial proportion of the total gas of a shale reservoir is indeed free gas stored in pore space and open fractures [Jenkins and Boyer II, 2008; Ross and Bustin, 2008]. Porosity is a key parameter for quantifying the free gas amount and estimating the matrix permeability of the shale. Although fracture porosity is a very important reservoir parameter, it contributes only approximately 10 percent to the bulk reservoir volume. Therefore, matrix porosity is the main storage space.

Because the pores in fine-grained shales are so small, it would be remarkably difficult in physical labs to accurately quantify the storage characteristics of the shale matrix and its gas flow properties using cores, in particular using drill cuttings. Hence, quantifying porosity (especially effective porosity) and matrix permeability through the digital approach makes a great sense.

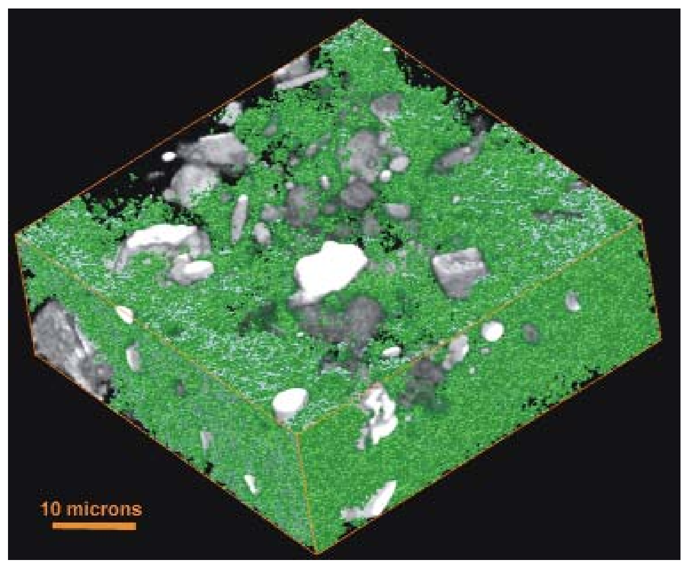

Figure 20. Black shale porosity distribution along with silt fraction.

Shale rock property computations, based on vRock, are similar to oil sands, as discussed earlier. Figure 20 shows a spatial distribution of matrix porosity computed for the black shale in Figure 14, superimposed on the silt fraction distribution. For this particular sample, the total computed porosity is 4.1%, the permeability is 0.023 mD and the formation factor is 510. Since no open fractures are observed in this sample, it is therefore believed that the computed permeability is the matrix permeability.

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Digital Rock Physics for Oil Sands and Gas Shales *continued…*

Elastic/Mechanical Properties

For a gas shale play to be commercially successful, the impermeable rocks need to be mechanically stimulated in order to introduce enough fracture permeability so that the gas can flow freely to the wellbore. Industry experiences show that shale gas wells are not hard to drill, but they are difficult to complete. The critical technologies for completion depend on the degree of reservoir heterogeneity, the mechanical properties, and the type of fluids present in the shale rocks.

So obtaining accurate results of elastic and mechanical properties is very important. Digital rock physics allows for creating such rock properties in three orthogonal axes so that not only average values, but also anisotropy, if present, can be determined. Computed elastic/mechanical properties for shales include: bulk modulus, shear modulus, Young's modulus, Poisson's ratio, V*p* and V*s*.

Reservoir Management

More sophisticated numerical reservoir simulation has become popular with unconventional resource plays [Jenkins and Boyer II, 2008]. Here multi-disciplinary information from different scales of study, such as core analysis, well log evaluations, 3-D seismic interpretation, geological models and well tests, can be integrated to help quantify proved reserves, manage wellbore behavior, test economical and risk sensitivities, and maximize reservoir production performance. In this case, knowledge of local reservoir characteristics through computations of rock properties can play a vital role, by assessing the effects of changes in key reservoir parameters like directional permeability, saturation and elastic properties. Incorporating such unique components can be very useful in addressing development and production strategies including reservoir model updating, well pattern, well spacing, and hydraulic stimulation design.

Drill Cuttings

Another challenge confronted by the industry is that obtaining cores from a shale reservoir is very costly, and often coring quality is questionable. A cost-effective alternative is drill cuttings, which are available anyway during a drilling program. The ability to analyze cuttings for gas shale is a major advantage made possible only by virtual experimentation [Dvorkin *et al.*, 2008], which imposes no requirements on shape and size of the samples being measured.

Figure 21 shows a gas shale cutting sample in a nanoCT image, where high-density calcite grains are shown surrounded by organic matter (blue), open pores (bright white), and other filling particles (dark colors). A few micro-fractures on the grains can be seen. A 3-D view of the sample's porosity is given in Figure 22. Although the pores are arranged in a few clouds (or clusters), they are barely connected. The computed total porosity is 2.5% without little effective porosity. Micro-fractures present in the sample are interpreted to be mineralized. We found, though, that the TOC covers a larger space, and much of the TOC is interconnected. The overall properties computed are given in Table 3. Their spatial relationships with the isolated open pores can be viewed in a 3-D image.

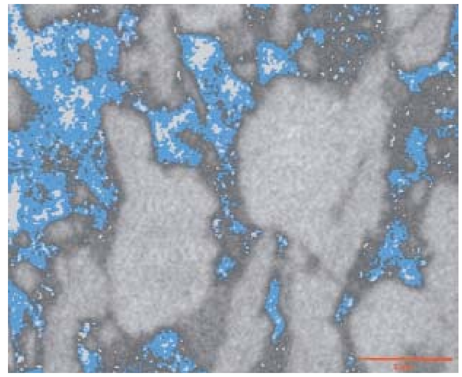

Figure 21. A nanoCT image of a shale drill cutting sample.

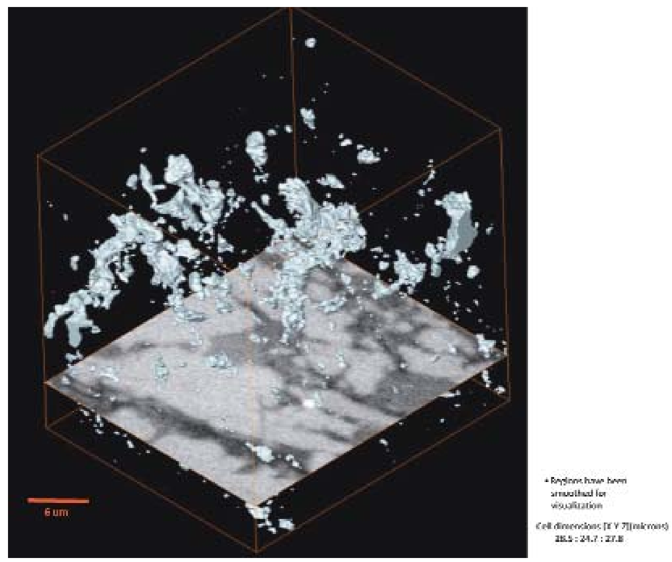

Figure 22. 3-D view of porosity from the shale cutting sample of Figure 21. The computed total porosity value is 2.5% with zero connectivity.

Table 3. Computed properties for drill cutting sample A

Sample ID	Total CT Porosity	TOC	Connected TOC	Non-connected TOC
Shale Cutting A	2.50%	11.00%	9.90%	1.10%

Sub-resolution Imaging

The computational accuracy may be affected, to a certain degree, if and only if sub-resolution grain particles, smaller than the nano-CT resolution limit (50 nm), are present in a sufficient amount. These tiny particles will not be resolved by nanoCT imaging and thus will not contribute to the property contributions.

To effectively address this issue, a newer scanning device with an improved resolution limit (2 to 3 nm) is used. This device, called FIB-SEM (focused ion bean and scanning electron microscopy), combined with proprietary image processing capability, allows for reconstruction of a 3-D digital image from shale samples at much higher resolutions, and provides reliable computed micro-porosity and matrix permeability in nano-Darcy range. Figure 23 shows a comparison of an FIB-SEM image of a shale sample with a nanoCT image created from the same sample.

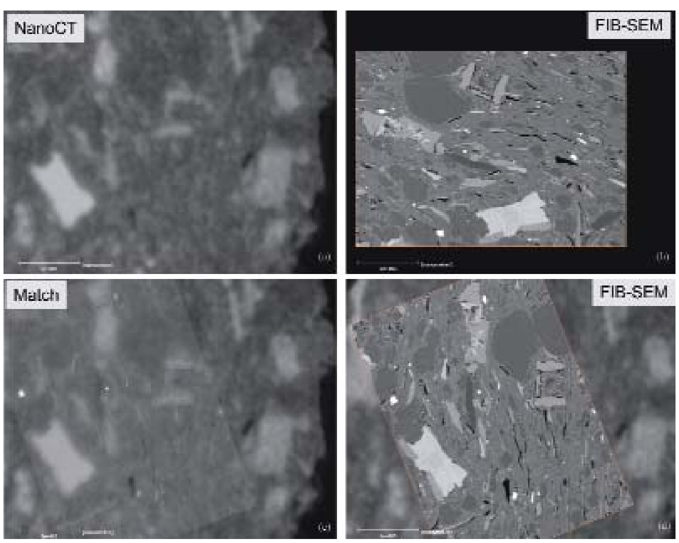

Figure 23. (a) A shale sample in a nanoCT image. (b) An FIB-SEM image. (c) Rotation of the FIB-SEM image. (d) FIB-SEM image matched with nanoCT image.

In Figure 23a, a portion of the nanoCT image shows a few obvious features: high-density calcite, black pores, and grain matrix. But on the FIB-SEM image in Figure 23b, we not only see those same features in Figure 23a more clearly, but also a lot more details of the much smaller pores, grains, organic materials, and other features that are not resolved in Figure 23a. It is these sub-resolution features that may make important contributions to micro-porosity and nano-Darcy matrix permeability. Figures 23c and 23d show the FIB-SEM image registered and integrated with the nanoCT image, after image translation and calibration. A 3-D FIB-SEM digital image reconstructed this way can be used to compute shale rock properties, in much the same way as for other types of rocks.

Conclusions

Digital rock physics is a new technology that is born to meet the high demand and challenges facing the oil and gas industry. It has been applied to the pursuit of economical opportunities in exploring for and developing unconventional resource plays such as oil sands and gas shales. To mitigate all the associated risks, effective reservoir characterization and field performance management requires accurate, detailed, and fast information about reservoir rock physical properties and multiphase fluid flow characteristics. To this end, digital rock physics places itself in a perfect position to make possible many difficult solutions or impossible practices in traditional physical laboratory measurements on oil sands and gas shale rocks. In this paper, we have demonstrated with real-case examples that digital rock physics through its virtual experiments allows for obtaining important reservoir parameters including porosity, permeability, grain geometry and pore structure on oil sand rock samples without destroying their texture; reliable and fast relative permeability values at high temperatures not possible in a physical lab environment; or matrix porosity, permeability, and total organic carbon contents for gas shales without crushing the rock samples. All these are realized because of the use of efficient CT-scanners covering from macro-, micro- to nano-level resolution, massive supercomputing power, and proprietary image processing and rock property computational algorithms.

Acknowledgements

The authors wish to thank the management of Ingrain Inc. for their support and encouragement. The excellent and enduring work performed by Ingrain Operations and Technical teams on all the samples presented in this article, as in many other commercial projects, is deeply appreciated. We would also like to express our sincere gratitude to our anonymous clients for permission to publish some of the results obtained from their samples. Finally but not least, we want to thank the anonymous reviewers for carefully reviewing and editing the manuscript of this article.

Continued on next page…

Digital Rock Physics for Oil Sands and Gas Shales *continued…*

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About the Authors

Guoping (Gabriel) Li, PGeoph, works as Country Manager (Canada) with Ingrain Inc., a Digital Rock Physics service company based in Houston, Texas. He brings twenty-six years of experiences to Ingrain, most of which was spent in the Canadian petroleum industry as an interpreting geophysicist. He previously worked with Canadian E&P companies including EnCana Corp, Canadian Natural Resources Ltd, Talisman Energy Inc. and Canadian Hunter, and was involved in domestic as well as international exploration and development projects. His areas of specialization are 3D seismic interpretation, 4D monitoring, integration of rock physics in quantitative seismic interpretation, inversion, and borehole seismology. He has extensive experience in carbonate plays and oil sands development. Guoping received his BSc. in geophysics from Tongji University in Shanghai, China and an MSc. in geophysics from the University of Calgary. He is a registered Professional Geophysicist with APEGGA and also an active member of SEG, CSEG, AAPG and EAGE. He has published and presented numerous technical papers.

Elizabeth Diaz currently works with Ingrain Inc. as Chief Geoscientist. She is an expert in the application of rock physics and quantitative seismic interpretation techniques, evaluating and risking the presence of reservoir rocks and hydrocarbons on multiple exploration and appraisal projects worldwide (Nigeria, Brazil, Libya, Kazakhstan, Yemen, Peru, Ecuador, USA, and Colombia). Prior to Ingrain, Elizabeth was senior geoscientist with Shell International Exploration and Production Inc. Previously, she held technical roles at Occidental Oil & Gas, Halliburton, and Grant Geophysical. At Stanford Rock Physics Laboratory, she conducted rock physics research on the effect of glauconite on the elastic properties, porosity, and permeability on reservoir rocks. She is a member of the Society of Exploration Geophysicists, American Association of Petroleum Geologists, and the Society of Petroleum Engineers. Mrs. Diaz holds a B.S. in Geology from Universidad Industrial de Santander and an M.S. in Geophysics from Stanford University.

Dr. Avrami Grader is Chief Scientist with Ingrain Inc. He is an expert in multi-phase flow in porous media and formerly a professor at PennState in the Department of Energy and Mineral Engineering. Dr. Grader's research focused on two- and three-phase flow in porous media, transient pressure analysis with its effect on well testing and on reservoir engineering water influx problems, and multi-phase flow dynamics in the near wellbore domain including wellbore mechanics. He has provided consulting services in the field of X-ray CT imaging and image processing and analysis worldwide. Dr. Grader holds a Ph.D. in petroleum engineering from Stanford University and is a member of the Society of Petroleum Engineers of AIME.

Meghan Armbruster is a Senior Geologist at Ingrain Inc., specializing in imaging, image processing, and geological interpretation of digital images for rock physics computations. She holds a B.S. in geology from Northern Arizona University.

Amos Nur is the Wayne Loel Professor of Earth Sciences and Professor of Geophysics at Stanford University (ret.) and the CTO of Ingrain Inc.

Amos received his Ph.D. in Geophysics from M.I.T. in 1969 and has been a professor at Stanford University since 1970. He served twice as a chairman of the Stanford Geophysics

Department and between 2000 and 2005 as director of the Stanford University wide Overseas Studies Program.

Amos is an elected member of the USA National Academy of Engineering (NAE). He is also the recipient of the American Geophysical Union's J. D. Macelwane Award in 1974, is a Fellow of the American Geophysical Union (1976); Fellow, Geological Society of America (1980); Fellow, California Academy of Science (1990); and an honorary member of the Society of Exploration Geophysics (1996), and served as distinguished lecturer for the Society of Exploration Geophysics in 1997 and the American Association of Petroleum Geologists in 1998.

Amos' research is in the areas of (a) the physics of rocks and applications to the exploration and production of oil and gas. At Stanford's geophysics department he has been leading for 30 years a continuous research program funded by a global consortium of 25 oil and oilfield service companies; and (b) rock mechanics, earthquake mechanics and earthquake physics. For over twenty years, he has been investigating the temporal and spatial patterns of earthquakes throughout history to find clues useful for earthquake prediction. He is a cofounder and presently chief technology officer of Ingrain – a computational rock physics service company based in Houston, Texas.

Amos has published several books, over 240 papers including a dozen related to earthquakes and archaeology, and one prize-winning documentary.

"No Such Thing as Objective Truth"

By Kathy Chernipeski, P. Geol. July 9, 2009

David Finch, a noted local historian and outdoor enthusiast, graciously shares his informed and unique perspective on the current state of our industry in context of the history of the oil patch. Part 1 of the interview will be shared here, watch for Part 2 in the next edition of the InSite.

Part 1

While David Finch was growing up, he "saw firsthand how much power, influence and control" Venezuela had been able to gain from its oil, and subsequently how petroleum really changed that country. And though he had always been interested in History and English in school, this was one of the reasons he became interested particularly in oil patch history.

Coming back to live in Western Canada, he satisfied his curiosity about the place he had always been told he came from, but that he was now seeing for the first time, and from an outsider's perspective. He was surprised by the differences between Canada's provinces and regions, in the way that people perceive themselves and each other, especially the contrast between the consuming and producing regions. "In the international scope of things, if the West were anywhere else in the world, it would be a member of OPEC."

There are not many who choose to follow a path such as he has blazed for himself as a public historian of the Canadian West. But he has no regrets. For him "the unexpected serendipitous story that comes out when you don't expect it" is one of his favourite parts of the process, and he continually looks for "new projects to work on, and new ways of looking at society" for fear of being bored. He is just getting going in true "Outlier" fashion, and his expectation is that in thirty years he'll have only more perspective. He writes for "many different clients and in that way works to remain as independent and impartial as possible."

So what is a public historian? "The job of the public historian is to...study the past, and we research and re-write in a way...to find the stories to help illuminate where we've been" and make it accessible to the public.

Though having variously been "criticized for not being academic enough" being "in the pocket of industry", or being "too much of an environmentalist," his twenty + books and countless magazine and newspaper articles speak for themselves on his commitment to detailed research and documentation, his own personal journey of identity and discovery and interest in the story, and most importantly, the people behind the headlines.

He looks "for the deep themes behind [the story], the economic developments, the political developments, the technological developments." For example, "if all you say is until 1924 they used cable tool rigs and then they put in steel rigs, then rotary, well 'so what did that mean?' It's finding the story that helps bring that to life," to reach the people behind the statistics.

How does a historian verify the validity of a story or stay objective? Surprisingly, "there is no such thing as 'objective truth' when it comes to history." Nor are historians unbiased or objective! For example, "if you have three people in a room, they will all remember [an] incident in a different way." The person with the most power in a situation (ie. the winners) are usually the ones who record the history. "And the losers, well, maybe not! And so it's worthwhile understanding that historical information has some facts in it, but the facts could be interpreted in different ways, that it's always told from a point of view from whomever is telling it, and it's always told for a reason...If the point you want to make is 'such and such a point', then you will tell the story so that it arrives at that conclusion...It doesn't mean that historical fact, information, isn't reliable, it just means you have to take it at face value. It's that person's point of view...and so an honest historian will [also] say 'I come to this topic from this point of view.'" And since your truth can be very different from mine, "what we search for is different points of view, we try to get the record as best we can...People that say they have no biases are disillusioned, they don't know what their biases are or they are not admitting it."

Continued on next page…

"No Such Thing as Objective Truth" *continued…*

And we would all agree that we should be able to get at least the dates and names correct. But what about fact versus myth? "One of the wonderful prevalent myths in the west is that the National Energy Program (NEP) of the 1980s caused the economic downturn of 1983, 84, and 85...Strangely enough, the people in the US have...never heard that the NEP in Canada created the economic downturn around the whole world." It was worldwide, and that's a situation where the NEP was passed, two banks in Alberta went bankrupt, and because one thing happened, and then another, there was an assumption of causality. When what had happened in perspective was that "AB had boomed in the 1970s and it overdeveloped, and it really had gotten itself into some troubles."

The CWLS, and societies and organizations like it, "plays an important role in the Canadian petroleum industry. The oil patch is about more than just competition and the bottom line. "The purpose of organizations such as the CWLS is to do something that no one else can do." They "are a catalyst" allowing peers to come together, providing a common ground for working in collaborative ways, rather than just competitively. "Society works best when we work together," even if we have our own personal goals. "I do really believe that organizations like this particular society are extraordinarily important and play a role that no other agency can play. Not government, not industry, and not academia."

In addition to opportunities for collaboration, documentation of that collaboration is also important. Technological innovations can be recorded through publications, and even "how thought and education has changed around topics over the years. Particularly in scientific materials, or ideas, they're always open to challenge and to change and to honing and improvement." It then becomes "so important for an organization to have it's records available so that it's members can use them," and Mr. Finch thinks that we (the CWLS) "do an extraordinarily good job of that." And he would know the importance of appropriate record-keeping, as he has had to uncover stories by using only such information as injury and death records, statististics, annual reports, government documents, newspaper clippings, local community hand-written histories, society publications archives, photographs, and rare and valuable first-hand accounts (interviews of old-timers for example).

"For historical research a hundred years ago, the easiest thing to do is to go to the newspaper because most everybody from a hundred years ago is dead." However, we know from today that the newspapers are "always under enormous pressure," with deadlines, trying to find the headlines, and competition with other media types. "They work really hard to give as accurate information as they can within the time frame that they have" but often "these forces do not provide much time for careful thought, reflection, research and looking at the big picture." On top of this, it is always "biased in that media reflects the mainstream views of society" in order to try to sell papers. In addition, "there's a certain kind of person who is writing the story in the newspaper. Here in Calgary we had two newspapers, we had the Calgary Herald and we had the Calgary Albertan. And they each had different political slants. But they were all being written by people who were in the better-educated class. So that's their point of view as well. So you don't get a lot of information from the newspaper from the working class point of view for example."

For those wishing to do their own historical research about the oil industry, the place to go is the Glenbow Archives. In addition to all of Mr. Finch's own research and documentation (interviews and so on), more and more organizations are also depositing their archival material there, such as photos and publications. So sometimes, though towns or companies may disappear, hopefully the memory of them and the lessons learned will not.

Why is history so important? All companies have accountants, and the reason for that is "the accounts of a company are a unique record of that company." Intellectual property such as "Trademarks and patents are also very important for companies," to protect the integrity of discoveries and innovations of the company. But "what most companies don't realize is that their history is also almost equally important and it can be a very very powerful tool because it can show how a company has evolved... and it's corporate culture. Oftentimes a company can learn just as much from its failures as from its successes." Who are we and where did we come from? History "sets the present in context so we can understand it better." And that is key (in the author's opinion). "History can't predict the future, but why make the same mistakes as in the past?"

The other thing history can help us do is gain perspective. "If you get out of university with a geology degree, and you get a job and you work for ten years and everything's going well, and all of a sudden half the geologists are layed off, it's like wait, this has never happened before, because it's never happened to you! Wait a minute, there was an economic downturn in the 1930s, there was another in the 1960s, there was an economic downturn and geologists were being layed off, there are stories of geologists on the street corners selling apples. And then there was another downturn in the 1980s. And so, this industry is cyclical, and if we have too narrow a view" we will miss it. "That's why history's important."

Stelmach's royalty review last year illustrates the point again about perspective. He didn't create the $147 barrel of oil, nor did he create the $29 barrel. These prices are controlled by "much bigger conditions than what he did." Industry was saying don't raise the royalties, as the "royalty review is unfair, and if you raise the royalties it will kill the goose that layed the golden egg and the end of the world will happen...Short-term realities and a narrow perspective tend to dominate the discussion of the royalty rates." People were also saying "this has never happened before...But the fact of the matter is that from 1942 on, almost every ten years the Alberta government has done a royalty review and almost every time industry has said 'don't raise the royalties, it will kill the economy, and this has never happened before' just crying wolf...And every time the gov't has done it somewhat differently. But what we do know from studying the history of the royalty reviews, is that neither the companies nor the government were able to accurately predict what was going to happen over the next ten years or even five years. So what we DO know to be true is that it's very hard to predict the future."

Can the future not be predicted from the past? "I have a hard enough time predicting the past, the way I put it....there are plenty of challenges in working with the complexities of the past. Sure, I can predict the future; I can predict that unpredictable things will happen and that just when you think one thing will happen, another thing will happen.. the booms will go bust and the busts will go boom."

"Conventional oil replaced coal as the main fuel source in Canada in 1950, but about two or three years ago, synthetic oil from the oil sands replaced conventional oil as the major fuel source in Canada. And you know, sometimes these things happen, and nobody even notices...It gets increasingly hard to find conventional oil and gas and shale gas and so on, but the oil sands are there....The industry will probably change in substantive ways because of this shift in emphasis...a change as big as that one from coal to conventional oil."

"The merger of PetroCanada and Suncor speaks to that" as well, because twenty or thirty years ago, the oil sands were considered insubstantial. Now there is "an oilsands company buying a major conventional oil company" to create the largest energy company in Canadian history." Of course exploration companies still remain relevant, as they "have all kinds of tools that are necessary to develop something like the oilsands, but innovation and change follow where industry really needs to go."


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Shale Gas Petrophysics – Montney and Muskwa, are they Barnett Look-Alikes?

John Nieto, Robert Bercha and Jim Chan,
(CANBRIAM Energy Inc, Calgary)

This paper was prepared for presentation at the SPWLA 50th Annual Logging Symposium held in The Woodlands, Texas, June 21-24, 2009.

Abstract

Shale gas reservoirs have rapidly become the focus of exploration and production throughout the Continental USA and Canada. These shale gas reservoirs invariably have two factors in common, namely, the need for quality petrophysical work and the implementation of innovative drilling and completion technology. In the past 5 years the Barnett shale has become the benchmark for both petrophysical and completion technology work, a huge success story for the United States. With this, there has almost been a requirement to compare "your" shale with the Barnett shale, to provide a comfort level for both management and non industry financiers.

This work compares two shales of very different character. They are both in British Columbia, Canada and are themselves the focus of exponential growth, associated land prices having increased 10 fold in 2008 alone. In addition, they have both at one time, been cited by industry commentators as Barnett look-alikes.

Net pay mapping of the shales is key to purchasing the best land and drilling the best wells. First and foremost, it is important to understand the geological environment of deposition of each of the shales. We demonstrate that the depositional setting for the Montney and Muskwa shales is very different, giving rise to equally different rocks. Both are fundamentally deep basinal environment, however the Montney has well sorted sediment influx in the form of submarine flows or turbidites. Once this is understood, the rock work, including thin sections, XRD, SEM and core analysis (TOC, porosity, permeability, Dean-Stark saturation and grain density) can be effectively integrated into the petrophysical evaluation and more reliable net pay maps can be produced.

This paper illustrates the predictive capability of a well calibrated wireline log in estimating petrofacies, porosity, and TOC. Net pay, porosity and TOC maps are presented in the paper. Further, we show that although both are prolific gas producing formations, only one, the Muskwa, can truly be called a Barnett look alike. The Montney can be termed a hybrid shale, comprising thinly laminated shale, organic material and siltstone. The Montney has much lower TOC than the Muskwa, 1 to 3 percent compared to 5 to 10 percent, but has intrinsically higher permeability than the Muskwa because of its coarser, more granular siliciclastic composition. In this regard, the Muskwa is similar to the Barnett shale. An understanding of the rock fabric and the differing petrophysical properties of the two shales leads to different completion strategies for optimum gas production.

Introduction

The focus areas, both in N.E. British Columbia, are shown in Figure 1. The Montney formation is pervasive throughout a large area of British Columbia (B.C.) trending North West from the Alberta border towards Fort St. John. The Muskwa formation studied in this paper, is located in the Horn River Basin close to the Northern Eastern B.C. border with The Northwest Territories. The Barnett needs little introduction and will be used as a benchmark with which to compare and contrast the two Canadian 'shales'.

Figure 1. Location of Focus Areas in N.E. British Columbia.

Fundamental in fully evaluating these 'shales' is a solid understanding of the rocks themselves and their environment of deposition. Figure 2 illustrates a generalized stratigraphic section showing the Montney formation and Muskwa member. (From B.C Ministry of Energy and Mines and Petroleum Resources)

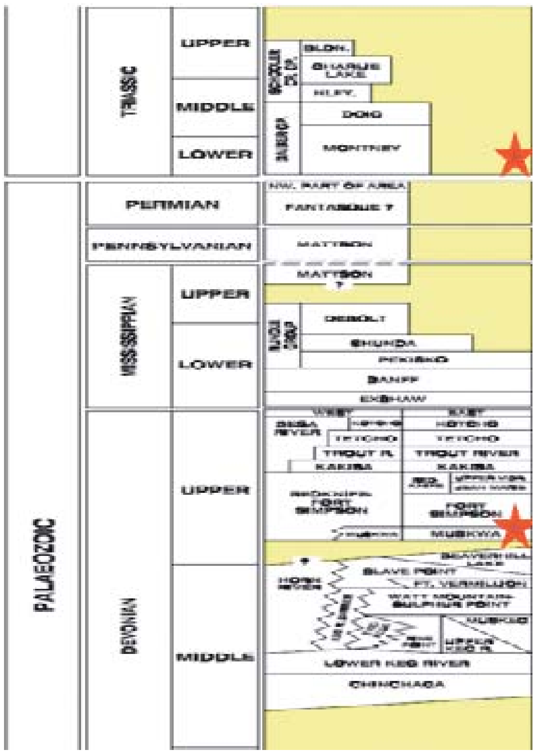

Figure 2. Generalized Stratigraphy of N.E.B.C. (M.E.M.P.R).

Geological Overview – Montney Formation

The Triassic Montney formation is approximately 240 million years old. It was deposited in a continental-ramp basinal setting (Moslow et al, 1997). The depositional environment ranged from proximal inner continental shelf to distal deep water outer shelf, similar to that currently seen in modern offshore North Africa (Davies, 1997a). This modern day analogy is shown in Figure 3. The Montney consists predominantly of aeolian derived and pelagic marine sediment. Deposition of this sediment occurred though suspension fallout (Davies, 1997b) and was further re-worked by submarine mass-wasting events along the continental-ramp edge which dipped basin-ward to the west, at ~2.0° (Moslow et al, 1997). During Montney deposition the Peace River Embayment continued to be a depo-center with the Dawson Creek Graben Complex, a complicated series of grabens and half-grabens, at its core (Barclay et al, 1990).

The aeolian sediments were sourced in an arid desert type environment to the east of present day Alberta. The sediment was transported to the west by wind and deposited on the continental shelf. Coarser grained sediment was deposited closer to the shoreline and finer grained material was carried further out. The aeolian derived sediment is characterized by extremely well sorted quartz-dominant grains with some detrital feldspar,

Figure 3. Modern day analog setting for the Montney formation, N.E.B.C. (photos from NASA, Earth from Space).

dolomite and mica (Davies, 1997b). A second source of sediment was pelagic material that rained down through the water column. These pelagic sediments consist of fine mud and organic material – the source of the hydrocarbons in the Montney. As water depth increased the proportion of pelagic material increased relative to the sediment. The effect of this is that sediment further from the shoreline is muddier and richer in organic material with less clastic material. Another effect of increasing water depth is abundant accommodation space. This combined with continuous sediment supply resulted in potential reservoir intervals which are hundreds of meters thick in some localities.

In addition, either tectonic activity, sediment loading and/or cyclic shock caused sediment flow and slumping off the continental-ramp edge into the westerly ocean (Moslow et al, 1997). This sub-marine slumping has been characterized by mass sediment transport or 'turbidites' fed by structurally controlled feeder channels on the shelf. Turbidites are efficient at transporting sediments far offshore; "turbidity currents can carry relatively coarse-grained sediment over large distances into deeper water, basinal settings, especially if the flow is channelized. Several hundred kilometers in oceanic basins is not uncommon. In intra-cratonic basins, long-distance transport of 100 km is also not uncommon." (Posamentier 2009, pers comm).

Consequently, reservoir quality in the Montney is variable. As the water deepens away from the shelf, the intrinsic reservoir quality deteriorates as the predominantly deep water very fine grained 'pelagic rain' and finer grained aeolian sediment take precedence at the expense of the coarser nearer shore/source

Continued on next page…

Shale Gas Petrophysics *continued…*

quartz sand/silt grains. Inter-fingered into this background sedimentation are numerous turbidite deposits. These coarser grained turbidite deposits provide elongate, thin and continuous reservoir fairways which make attractive exploration targets. In addition the enhanced permeability associated with these deposits allows for the drainage of large areas and thicknesses of poorer quality rock. We will be concentrating on the upper half of the Montney formation, immediately below the Doig phosphate member – termed the "Upper-Montney". The Upper Montney is layered with depositional cycles having coarsening-up siliciclastic material interbedded with highly radioactive more organic layers or flooding surfaces. These will be discussed further under the petrophysical section.

Geological Overview – Muskwa Shale

The Devonian age Muskwa Shale Member is part of the 370 million year old Horn River Formation. Figure 1 illustrates the approximate extent of the Muskwa Shale in British Columbia and Figure 2 shows its relative position in the stratigraphic column. The Muskwa is 130 million years older than the Montney formation, and much closer in age, around 40 million years, to the Barnett Shale. In the Horn River Basin, Middle Devonian age shallow water carbonates of the Presqu'ile Complex grade westward into the organic rich basinal shales of the Horn River Formation (Morrow et al, 2002). The Muskwa is the upper member in the Horn River Formation and its deposition is diachronous with an abrupt sea level rise which resulted in the drowning of the fringe reefs on the edge of the Presqu'ile Complex (Williams, 1983).

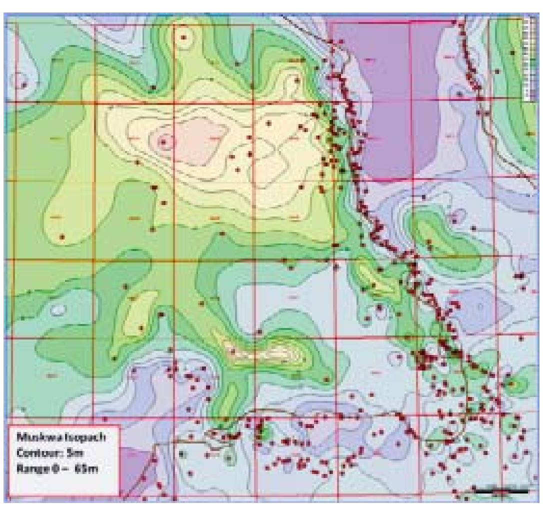

Figure 4. Horn River Basin, N.E.B.C., Muskwa formation isopach map. (Warmer colours are thicker)

The thickest Muskwa is found within the Horn River Basin where it is a black bituminous shale with abundant pyrite and high radioactivity on gamma ray logs (Griffin, 1965) Its isopach ranges from 65m in the center of the Horn River Basin to as thin as 5m to the East and South, where it overlaps the Presqu'ile Barrier Complex. (Williams, 1983). This is shown in the Muskwa isopach map in Figure 4.

Figure 5 below shows the regional extent of the Muskwa shale. It is clear at the outset, that the Muskwa is a deep water ultra-fine grained basinal deposit with associated increase in clays and organic material, much like the Barnett formation (Givens and Zhao, 2008). This contrasts with the more siliciclastic rich, coarser grained Montney formation.

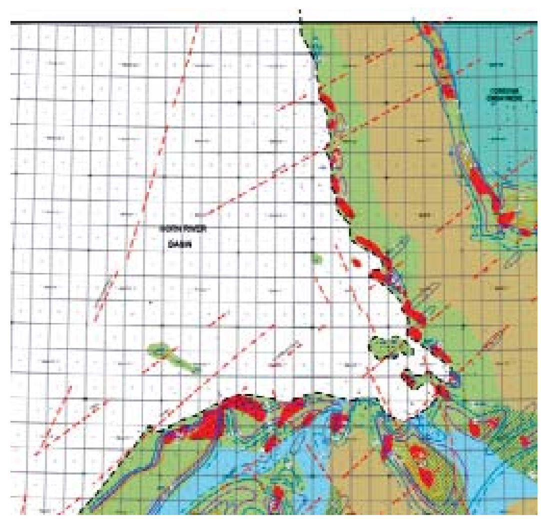

Figure 5. Horn River Basin, N.E.B.C., showing the shale basin and approximate Slave Point Formation edge. (Courtesy, Petrel Robertson).

Petrophysical Overview – Montney Formation

Lithology Determination – Petrofacies

A solid understanding of the rock and its geological background and environment of deposition is the key to a good petrophysical evaluation. Given that the Montney is not a 'true shale' but has a higher siliciclastic content, it can be termed a 'hybrid' formation. Figure 6 illustrates the distinct difference in texture and mineralogy from cutting samples taken from Montney and Barnett wells. Relative proportions of clay, silt, fine sand and organic material vary with proximity to the sediment source in the East. As a general statement, towards the border with Alberta, the grain size becomes coarser and the organic content less. In some localities, there are Montney turbidite feeder channels which appear more like good quality

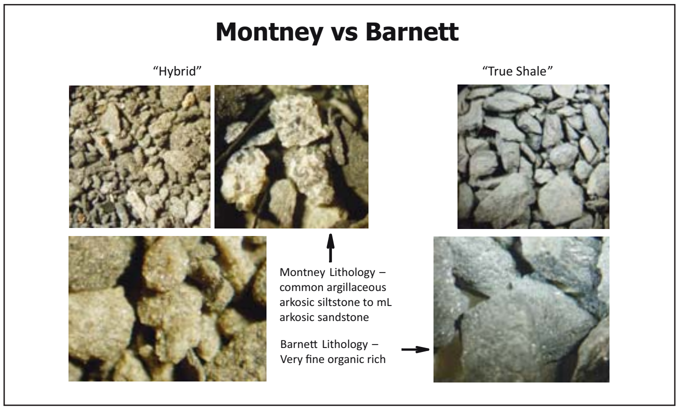

Figure 6. Montney formation compared to the Barnett Shale.

conventional channel sand reservoirs with excellent permeability. The majority of the Montney however, is made up of extremely low permeability highly laminated organic clay, silt and fine sand. The Montney formation, as discussed previously, is layered in cycles on a scale of metres in thickness.

These cycles, separated by very radioactive phosphatic 'layers' can be correlated over much of the N.E.B.C. basin. These layers are thought to represent flooding surfaces with rapid rise in sea

level leaving organic rich layers. These separate coarsening upwards cycles of more active sedimentation through turbidite sources from the East. The type logs shown in Figure 7 below illustrate these depositional cycles.

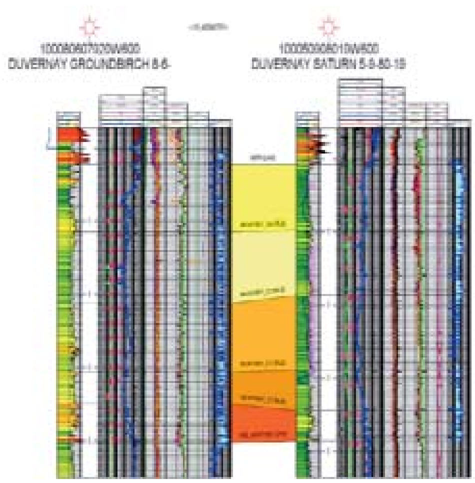

Figure 7. Montney depositional cycles, type wells.

It is important to recognize the direction of sediment influx in the Montney. Closer to the source (East, present day Alberta), grain size is generally coarser. Moving west, basinward and distally from the sediment source, sediment becomes more laminated with a finer grain size. Our work has indicated that there are at least 3 basic petrofacies or 'rock-types' in the Montney. Based on cuttings and thin section work, it is clear that log responses can easily be used to predict these basic rock types. The basic rules for these petrofacies are shown in Figure 8. As a general statement, Petrofacies 1 tends to be coarser grained to the east, finer to the west and could be further sub-divided, as discussed later. The important point from our work is that an understanding of how these petrofacies vary at pore level is key to understanding the development and completion of the Montney formation in general and will be further explained.

Petrofacies 1 Siliciclastic Montney
Gamma Ray <90API
Resistivity <90ohmm (<2% TOC)
Petrofacies 2 Organic-rich Montney
Gamma Ray <90API
Resistivity >90ohmm (>2% TOC)
Petrofacies 3 Phosphatic Montney
Gamma Ray >90API

Figure 8. U. Montney Petrofacies (Rock-types) from log & sample data.

In addition to sample description work, we have made hundreds of Rockeval Total Organic Carbon (TOC) measurements with thin sections and X-Ray diffraction (XRD) measurements. For the Montney, we have found that TOC is the most useful measurement. Thermal maturity index R_o, determined from picking T_{max} is less useful as the S2 peak is not well developed. This leads to unreliable R_o measurements.

We have found that there is a strong correlation with our Petrofacies and increased TOC. The samples show this clearly, illustrated in Figure 9

When the depth-matched TOC data are plotted against a variety of wireline measurements, resistivity appears to give the best correlation. The Delta-logR method (Passey et al, 1999) using sonic and resistivity doesn't give any advantage over using resistivity alone for TOC prediction in the Montney.

It is likely that the organic material is having a greater order effect on rock conductivity by plugging some of the pores and that porosity change in the Montney, on average, is a second order effect. Our Montney resistivity-based

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Shale Gas Petrophysics *continued…*

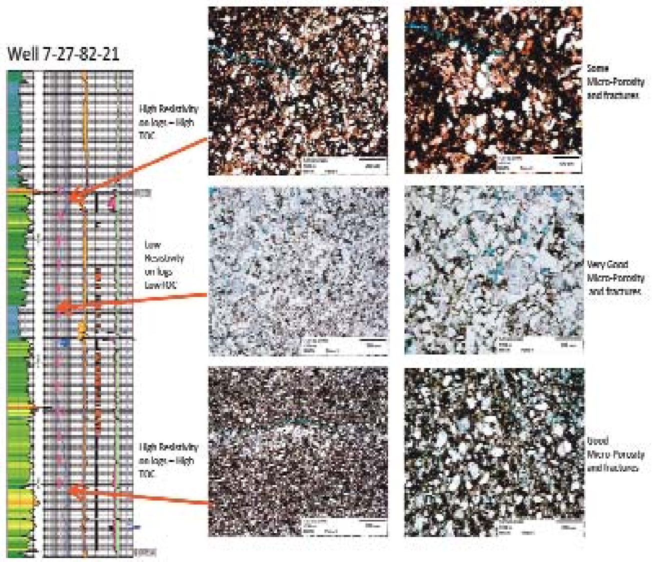

Figure 9. U. Montney Petrofacies (Rock-types) from log & photomicrograph data. Note increased TOC (dark material) in higher resistivity layers.

TOC prediction method, equation 1, is included in the appendix. TOC prediction in a typical well is shown in Figure 10. Both the Passey method in pink and the R-TOC method, in green are plotted in track 2 with the core derived TOC points and their values. The 90ohmm petrofacies discriminator is equivalent to a TOC of 2% using this method, which adequately captures the differences we are seeing from samples and thin section work.

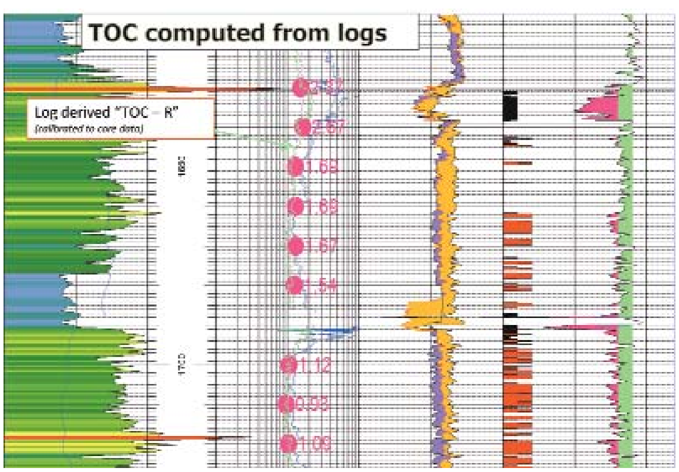

Figure 10. Montney TOC prediction using R-TOC method, Equation in the Appendix.

Kerogen typing from Rockeval work indicates that the Montney is predominantly type III, mature, in the gas window.

Consequently, the importance of TOC prediction becomes clear, the higher TOC rock, Petrofacies 2, is likely to have poorer permeability, 10 – 100 micro-Darcies compared to 100 – 500 micro-Darcies in Petrofacies 1, by virtue of both pore throat plugging by the increased organic material and overall finer grain size. There are both higher and lower permeability laminae within Petrofacies 1 & 2, with Petrofacies 2 having more fine grained and organic material. This leads to a more Barnett-like completions strategy due to this lower intrinsic permeability. This will be addressed in a later section. (It is clear however, that the permeability of the Montney is several orders of magnitude higher than the "true shales", Barnett and Muskwa, which have permeabilities measured in nanoDarcies.) As many wells have resistivity logs, as mandated by the B.C. Oil and Gas Commission (O.G.C.), it is easy to predict TOC across a wide area. TOC mapping can facilitate the identification of different petrofacies and their extents in the Upper Montney, leading to more informed completion decisions later.

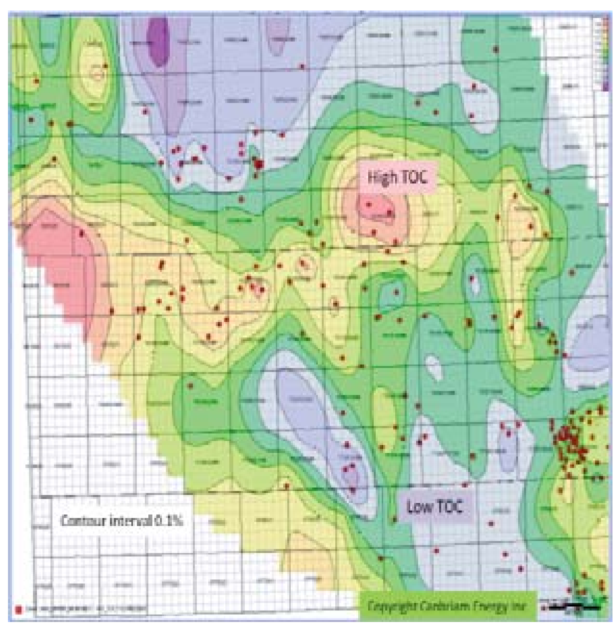

Figure 11. Average TOC Mapping in the U.Montney (High TOC in warmer colours, contour interval 0.1%).

Figure 11 indicates where average TOC becomes higher, up to 2.0%, which, because of lower intrinsic permeability, might require a different completion type.

Porosity Determination

Montney porosity is predominantly intergranular porosity, with some micro-porosity. Figure 12 illustrates the distinct changes in grain size within Petrofacies 1 using backscatter SEM work. The SEM photo illustrates the genesis of the micro-porosity, including micro-porosity between kaolinite booklets.

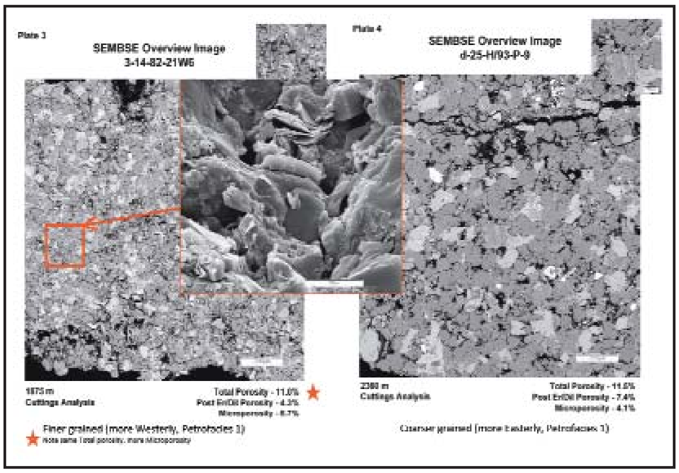

Figure 12. SEMBSE and SEM photos contrasting grain size moving basin-ward in the U. Montney (Total porosity >11% in both samples).

In any event, porosity is notably higher than either the Barnett or Muskwa shales. As discussed, the Montney sediments are highly laminated, with laminations in the order of microns thick in some cases. Conventional logging suites therefore provide an average of petrophysical properties over both silty-sandy and shaly-more organic layers. Core plugs used for core analysis are also affected in the same way. Core analysis is extremely important in calibrating the wireline measurements so that they can be used quantitatively. Our experience has been that core laboratories are applying conventional core analysis techniques to extremely low porosity and permeability unconventional core. Though all Operators' core data is available through the O.G.C. in B.C., it must therefore be used judiciously. Our preferred technique is to calibrate density and sonic porosity logs directly to core data, using where possible, petrofacies as a discriminator, Nieto (2002), Nieto et al, (2004, 2006, 2008).

The initial step is to compaction correct the core porosity data, (Nieto, 1990) before depth matching to the wireline log data. Histograms are made of grain density measurements from core analysis to identify the matrix point in the porosity equation. A crossplot is made of compaction corrected core porosity versus wireline bulk density. A fixed point and centroid regression is performed on the data, the fixed point being at the 0% porosity or the matrix point as defined by the core grain density histogram. The regression defines the 100% porosity, or fluid density point (RHOFL) in the density porosity equation. If there is sufficient core analysis data, this process is performed for each Petrofacies. A matrix density and fluid density is produced for each petrofacies. A similar procedure can be performed where there is no RHOB log in a well using the sonic travel time (DT). The DT is substituted for the RHOB on the X-axis of the cross plot. Figure 13 below illustrates the process.

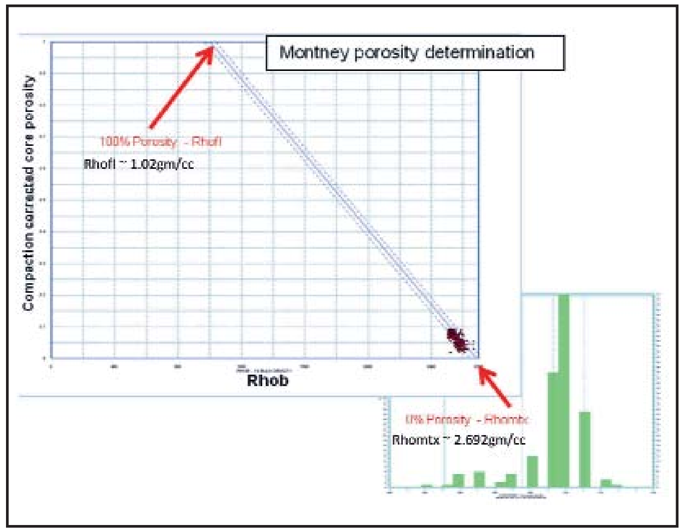

Figure 13. Porosity determination in the Montney – core calibration.

Equation 2 in the Appendix gives a relationship to calculate porosity in the Montney formation. (Petrofacies 1 & 2 combined). Approximate RHOMATRIX is 2690kg/m^3 and RHOFL 1000kg/m^3. We have noted that for the limited core porosity data in Petrofacies 2, the matrix density is similar, 2690 kg/m^3 depending on how much phosphatic and dolomitic material is present. The fitting parameter, RHOFL in the regression is however slightly lower, around 850kg/m^3, due to the increased organic material in this rock. The porosity equation for Petrofacies 2 will be updated as we acquire more core analysis data. Where TOC > 2%, (~90ohmm) therefore, the lower value for RHOFL should be substituted.

Core calibrated porosity works well over much of the Upper Montney, especially in Petrofacies 1, where there are many laminations with fair intergranular porosity. We have noted that within the Montney, the process benefits from very high resolution density and also borehole image logging, though these logs are not commonly available in the area. The method uses cut-offs for net to gross at a 2 inch scale, to determine which layers have intergranular porosity and which have more finer

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Shale Gas Petrophysics *continued…*

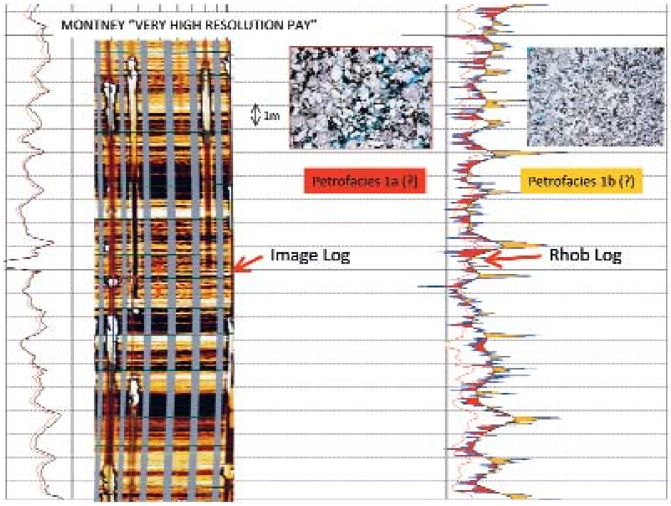

Figure 14. Porosity determination in the Montney – high resolution (Nieto & Bujor 2005).

grained, cemented laminae. This method will be useful in further sub-dividing Petrofacies 1, given sufficient log data. (Nieto and Bujor, 2005). Figure 14, illustrates the concept.

Permeability Determination

Although permeability in the Montney is several orders higher than that in the Muskwa (or Barnett), Montney permeability measurement using 'conventional' core analysis is still limited to all but the best quality turbidite channel lithofacies. If left to their own devices in the Montney, core laboratories will report pages of Perm <0.01mD, attempting to use low resolution 'steady state' measurements. We have found that "Pulse Decay Permeameters" (PDP) give good, repeatable permeability measurements in the Montney. Core permeability data can be readily found as the B.C. O.G.C. require all data to be submitted. Much of these data are unfortunately limited at 0.01, 0.02 or 0.03mD because of the measurement resolution limits. Consequently, they are of limited use for prediction of permeability from porosity using conventional poro-perm crossplots as there are large porosity variations for the same permeability value. Figure 15 illustrates some of these permeability data and the difficulty in performing a regression.

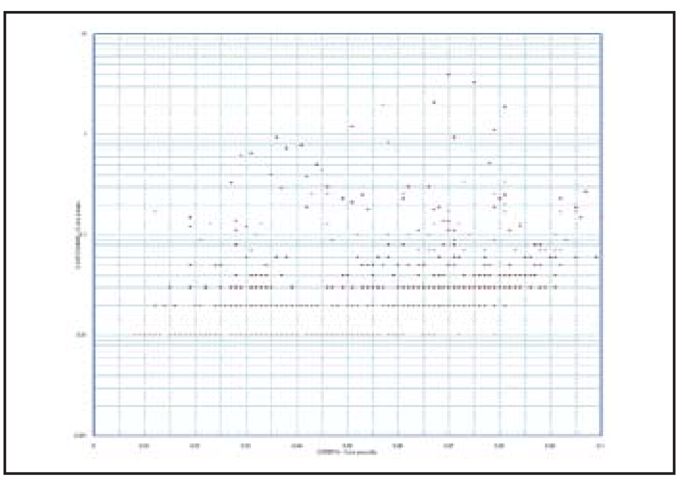

Figure 15. Permeability data (courtesy of OGC database) in the Montney.

We have made several (more on the way) PDP measurements and though not definitive, they are at least more representative of the lower permeabilities seen in the Montney.

Figure 16 shows 'a provisional relationship' for the Montney. Equation 3 in the Appendix details this relationship.

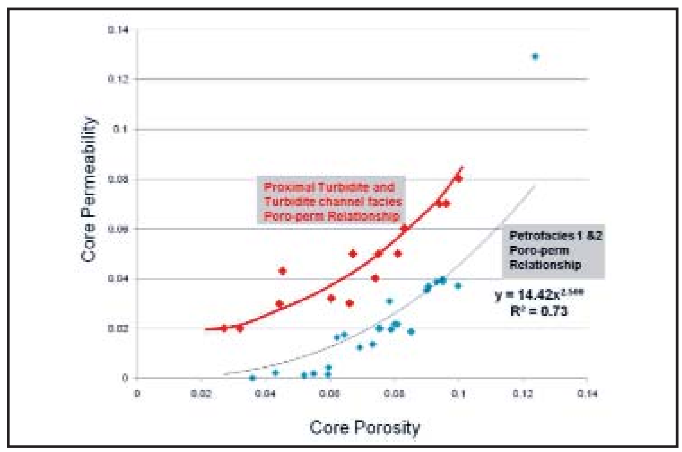

Figure 16. Permeability data in the Montney, selected samples.

Note, that the better quality turbidite channel facies samples, (defined by the red line on Figure 16) have been excluded from the regression.

The Petrofacies 1 & 2 relationship above is work-in-progress and will be updated and refined with future PDP and other 'unsteady-state' permeability measurements as they become available. In addition, given enough reliable permeability data, we see the possibility to sub-divide Petrofacies 1 further (i.e. 1a and 1b), using predicted permeability as one of the discriminating rules in each well as identified in Figure 14. Equation 3, (Appendix), has been used to predict permeability in the Montney using core-calibrated density porosity. Figure 17 illustrates a typical Montney core permeability map and again, might be used to select different completion types when used in conjunction with other data. The contour interval on Figure 17 is 0.001mD and the range of data shown is from 0 to

0.02mD. (Note that this is the interval geometric average for the Upper Montney and includes both petrofacies types where present).

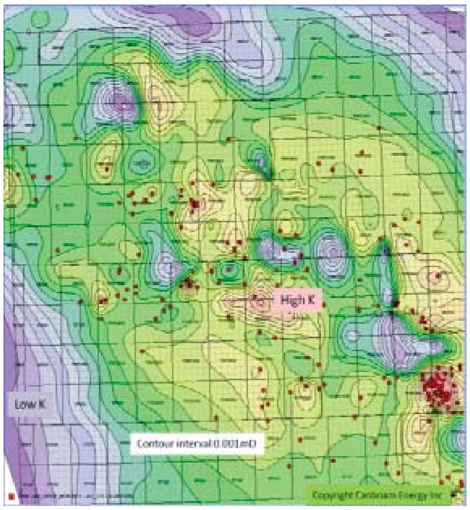

Figure 17. Average Permeability mapping over the Upper Montney, warmer colours are higher permeability, contours at 0.001 mD interval.

Water Saturation determination

Water saturation determination in the Montney is different to the 'true shales' as most of the gas is 'free gas' contained in the pore system. Very little gas is contained in an adsorbed state as the TOC in these rocks is generally quite low, 1-2%. Reservoir pressures would have to be reduced to extremely low levels to desorb any adsorbed gas at all. We will therefore not cover Montney adsorbed gas saturation in this section, though a typical value is included in the Formation Summary, Figure 29. Given that the gas is contained in the pore system, a conventional Archie water saturation method has been used by many operators. This is fraught with difficulties, as the Montney is anything but an "Archie rock". The standard log analysis approach, using the "Archie" equation, has several important difficulties.

Archie Parameters that cannot be used with confidence are:-

Rw, formation water resistivity. There is no free water in this basin-centred deposit. Rw cannot be determined with any accuracy. Produced water (at least in B.C.), is either 'frac water' or water of condensation.

Rt, true formation resistivity. The rock fabric of the Montney is highly laminated, down in some instances to micron size. No resistivity device can resolve this level of bedding.

'n', saturation exponent. This can be measured, but as with any laminated system suffers from curvature on the resistivity index vs Sw plot. Consequently, 'n' changes with saturation. In the data analyzed, 'n' has a large range, from 1.3 to 2.9. A composite average 'n' from the data is 1.78.

We are reasonably confident with both porosity and 'm', cementation exponent, given enough lithology data and core analysis data to apply to different petrofacies types. A composite average 'm' from the data analyzed was 1.81.

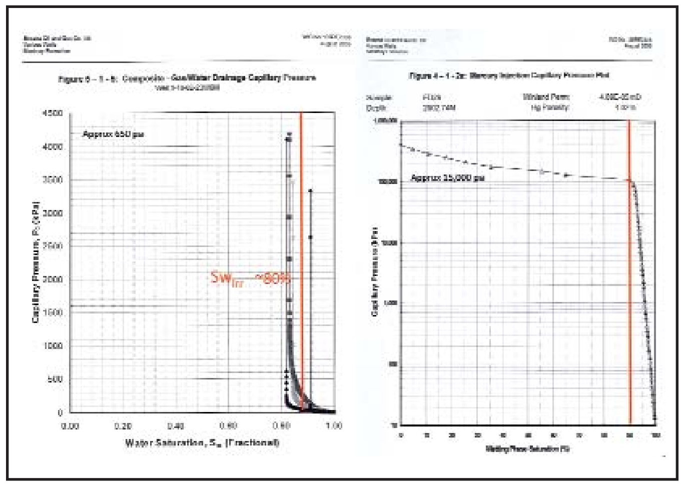

Figure 18. Air-Brine and Mercury injection Capillary pressure data, U.Montney, Petrofacies 1. Experimental constraints are evident using these techniques on very low permeability rock.

As a result, the Authors prefer to use a core analysis based method. We have tried capillary pressure-based Sw methods, but have found that mercury cannot enter the smallest pores in the system, but do however, give an approximate pore-size distribution, which is useful in characterizing the rock. Porous plate techniques are limited by their maximum pressure and cannot fully desaturate the core, leading to high estimates of water saturation. Figure 18 is taken from the Government database, the laboratory measurements shown were made by another Operator. It illustrates several samples taken from an air-brine capillary pressure test and, if taken literally, the resulting irreducible water saturation would be around 80%. Dynamic methods of hydrocarbon-in-place (GIIP) determination, such as P/Z (decline) plots cannot be reconciled with the correspondingly low GIIP that would be required if 80-90% Sw were used.

Consequently, we have tried Dean-Stark water saturations using oil-based mud systems. Our job preparation was rigorous,

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Shale Gas Petrophysics *continued…*

we sealed and froze the core at the well-site. The core was shipped frozen and plugs cut immediately after they were received at the core laboratory. These plugs were weighed and placed in the D-S pots within 2 minutes of cutting. Control pots were left empty to measure ambient water in the toluene-based cleaning mixture. (This proved to be a key step, as the empty pots did indeed contain water from the Lab's solvent!). In previous D-S work we have noticed that rapid desiccation can occur, even if left in a freezer over the weekend. Our results were good and we plan to expand our D-S database with more samples from both Petrofacies 1 & 2 as we move ahead. Currently however, we have established a preliminary relationship between core porosity and Dean-Stark saturation which is resistivity independent. This relationship is shown in Figure 19.

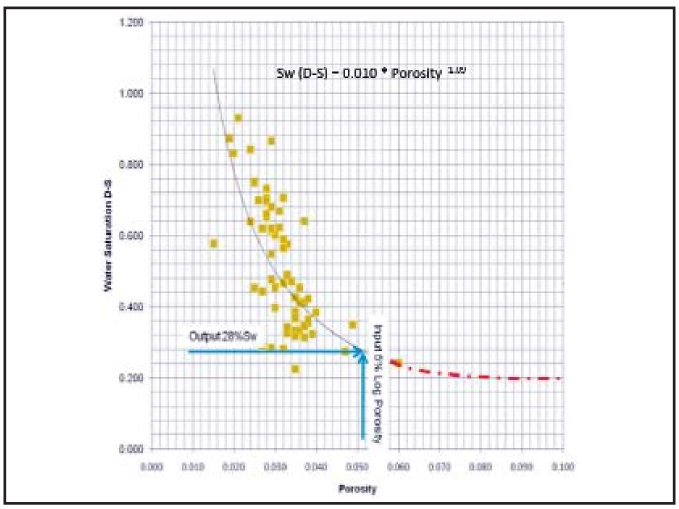

Figure 19. Dean-Stark Water Saturation determination in the U. Montney, mostly petrofacies 2. (Equation in the Appendix)

The equation generated from this limited dataset, (Equation 4), is included in the Appendix.

Currently we have been unable to find any other D-S measurements in the O.G.C. database and look forward to making our relationship more robust should any other operating companies also use D-S measurements. Water saturation averages based on this relationship are used for GIIP determination, together with independent estimates from decline methods, with good agreement.

Net Pay Determination

Net pay in the Upper Montney uses an 'industry standard' 3 pu porosity cut-off. This is largely to take into account all gas bearing petrofacies types in the Montney. Production will prove the validity of this cut off as we establish production history and decline curves in current wells. Figure 20 illustrates the overall thickening of Montney pay, basin-ward to the Southwest. Consequently, the Isopach Map in the bottom corner of Figure 20 has similarities to the 3pu Net Pay map.

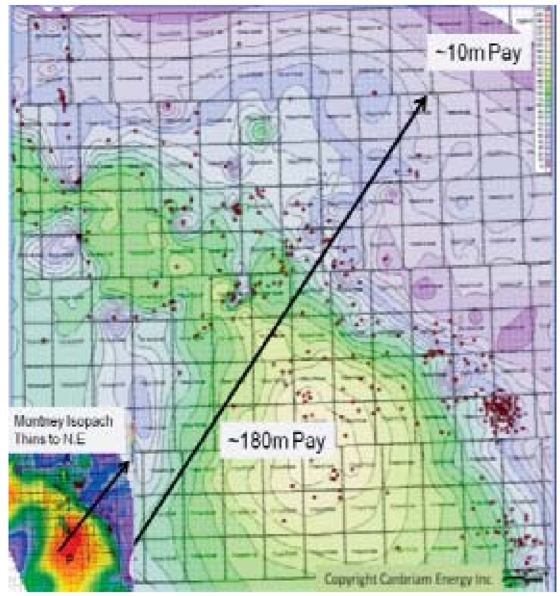

Figure 20. Net Pay Mapping in the Upper Montney, using only a 3pu porosity cutoff. (Warmer colours – higher net pay thickness, contour interval 10m)

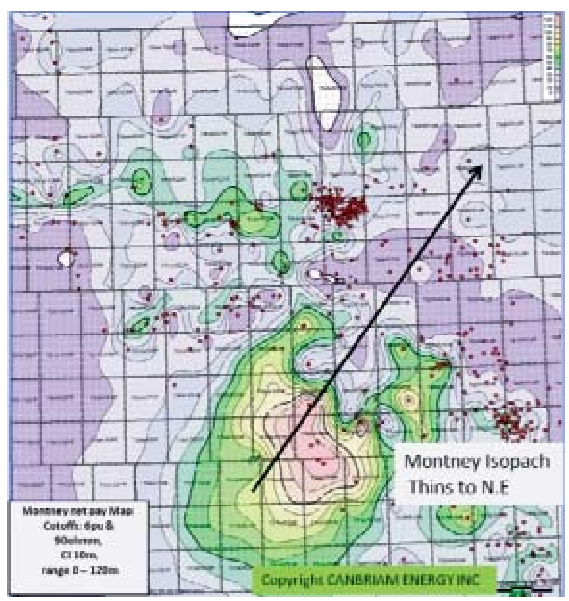

Figure 21. Net Pay Mapping in the Upper Montney, using both 6pu porosity and 2% TOC cutoffs. (Warmer colours – higher net pay thickness, contour interval 10m)

Good quality Montney reservoir is present to the Northeast, as it is closer to the sediment source and paleo-shoreline, however the Montney isopach thins in this direction. Toward the Alberta border, the Montney is eroded away and there is a NNW – SSE trending sub-crop edge. Other Net Pay maps with different cut-offs have been made. Figure 21 shows the approximate extent of Montney Petrofacies type 1 and uses both 6pu porosity and 2% TOC (approx 90ohmm resistivity) cut-offs.

Petrophysical Overview – Muskwa Formation

Lithology Determination

Lithology determination, as per the Montney formation is key to a good petrophysical evaluation. The Muskwa formation unlike the Montney, is a 'true' shale, similar in composition to the Barnett shale of Texas. Figure 22 illustrates the similarities between the two shales from samples. Texturally they are similar, though differ in the details of mineralogy which can be seen from XRD data later, in Figure 23. In contrast to the Montney, most porosity in the Muskwa and Barnett is micro-porosity and gas is contained in the rock in a predominantly adsorbed state. Workers in the Barnett such as Jarvie, (2004), have observed micro-fracturing, possibly as a result of in-situ hydrocarbon cracking of the shale.

Figure 22. Muskwa Shale and Barnett Shale illustrating similarities between the two.

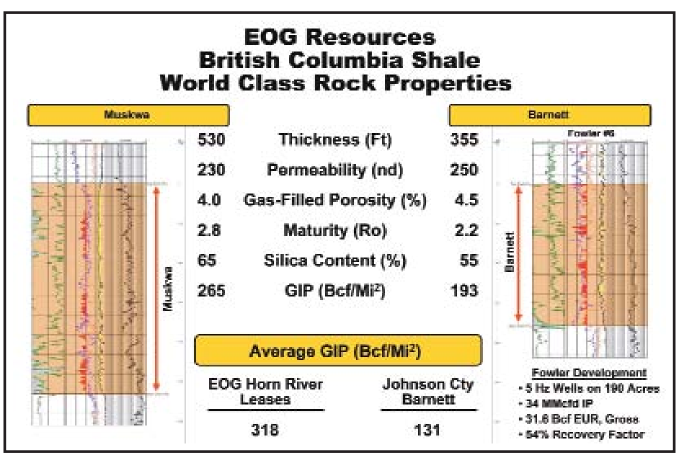

Figure 23. Muskwa Shale and Barnett Shale illustrating similarities between the two. (Courtesy EOG website 2008)

This adds to porosity and permeability of the shale and therefore increases possible free gas content and gas deliverability. We have not seen such micro-fractures in the Muskwa, but have had very limited exposure to Muskwa thin section samples.

Additionally, EOG has published some results on their website, illustrating the similarities between the Muskwa and the Barnett in terms of petrophysical properties, Figure 23. Their work shows notable similarities in permeability, 100 – 300nD, and gas-filled porosity, with up to 5% in each case. (largely micro-porosity, with pore throat size < 0.5 microns). Mineralogy of the two shales is similar, though we recognize that the Muskwa has a higher overall Quartz content, up to 85% in some layers, (Source; OGC database).

Petrofacies work (Lithofacies from wireline log responses) has been performed in the Barnett by Jarvie, (2004) and by Ross and Bustin, (2008) in the Muskwa formation. Similar comparisons have been performed by these workers on TOC and gas contents of the two shales.

XRD results shown in Figure 24 illustrate some of the similarities and differences between the Muskwa and Barnett. These volume fraction values are average values over the Muskwa interval.

X-Ray Diffraction — Mineralogy

	MUSKWA		BARNETT	
	DENSITY	Av VOL FRACTION	DENSITY	Av VOL FRACTION
QUARTZ	2.65	52.00	2.65	40.00
K-FELDSPAR	2.58	2.00	2.58	1.00
PLAGIOCLASE	2.63	1.00	2.63	2.00
CALCITE	2.71	2.00	2.71	8.00
DOLOMITE	2.84	2.00	2.84	1.00
PYRITE	5.00	5.00	5.00	9.00
KAOLINITE	2.65	8.00	2.65	9.00
ILLITE/MICA	2.75	28.00	2.75	30.00

•Note similarities in Clay content
•Barnett has more Calcite
•Barnett has less Quartz

Sources; Jarvie (2004) and B.C MEMPR (2007)

Figure 24. Muskwa Shale and Barnett Shale average XRD mineralogy illustrating similarities between the two, used in the petrophysical modeling.

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Shale Gas Petrophysics *continued…*

The Muskwa type-logs in Figure 25 below show that there is considerable heterogeneity with the Muskwa formation. Quartz and Calcite content especially can vary by +/- 20%. The XRD mineralogy is extremely useful however, in setting up the petrophysical model to be used for porosity determination. However, the extremely fine grained, nano-Darcy permeability of the Muskwa, leads to somewhat subjective core analysis.

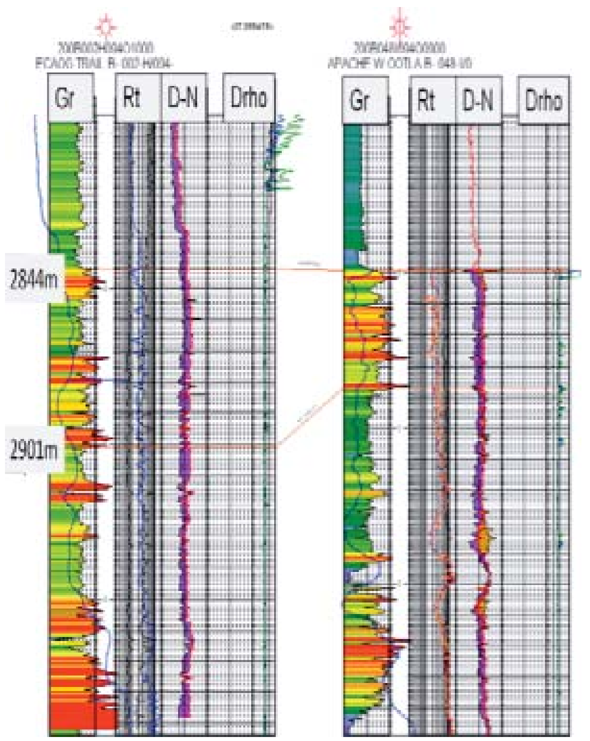

Figure 25. Muskwa Shale Type logs, Horn River basin, illustrating thinning of the section towards the basin edge. (Ootla area)

Because of this, a sample-based, lithology modeled, wireline log approach to determining porosity, using core analysis porosity as a guide, is preferred.

Porosity Determination

Porosity in the Muskwa is largely micro-porosity with possibly some micro-fracturing (per the Barnett shale). Porosity measurement in the Muskwa is problematical as it is so impermeable. The standard helium porosimeter has been used with mixed results. Porosity is frequently under-estimated as the helium takes too long to enter the pore system. In addition, cleaning and drying of true shale cores destroys clays (Figure 26) in the pore system. Helium porosimetry in shales often involves using uncleaned, undried core, which would again under-estimate porosity. Luffel and Guidry, (1992) overcame this with a technique which involves crushing of the core sample, then measuring porosity. This leads to higher (more realistic?) porosity measurements. We intend to run some comparative tests on both these methods, as in our view, the difference between the two could be an indicator of 'producible or free gas' porosity versus 'total' porosity. Some helium porosity measurements are available and these have been used to guide the log analysis based models. To determine porosity in the wells, we have used a 'matrix inversion' technique solving for porosity as the unknown parameter. (Wallace, 2004). In order to minimize error, the matrix inversion model must have more known elements (log responses) than unknown elements (porosity and lithologies). The method optimizes and combines petrophysical response equations from several log measurements using geologically constrained matrices, such as core descriptions, cutting descriptions and XRD measurements. Key to a successful outcome are the correct lithological inputs discussed above. A conventional set of input logs, resistivity array, gamma ray, density-neutron, PEF and sonic are used in the model. Output logs from the matrix inversion include reconstructed input logs to determine at which depths the model fits the lithology and porosity results or not. This is used as a quality control step on the model. Figure 26, illustrates the scale of the porosity in the 'true-shales'. Pores can be less than 0.1 micron in size.

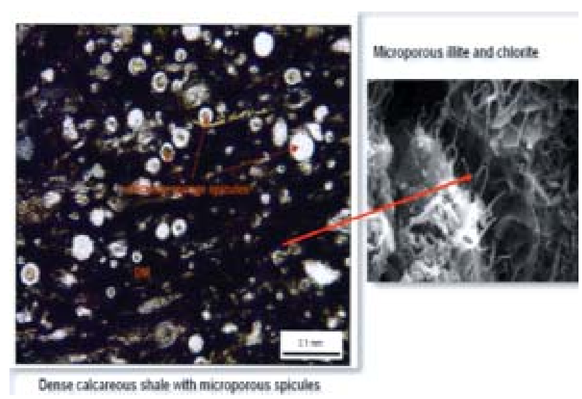

Figure 26. Barnett Shale photomicrograph, illustrating microporosity (courtesy; Hunt Wallace and Associates).

Results of the Barnett porosity modeling, are presented as total porosity – a matrix corrected density porosity and effective (or connected) porosity – a product of the matrix inversion model, using all input logs. These results have been calibrated back to zone production with excellent agreement. (Wallace 2004).

Figure 27 shows the Barnett petrophysical evaluation, with the two types of porosity displayed in track 7.

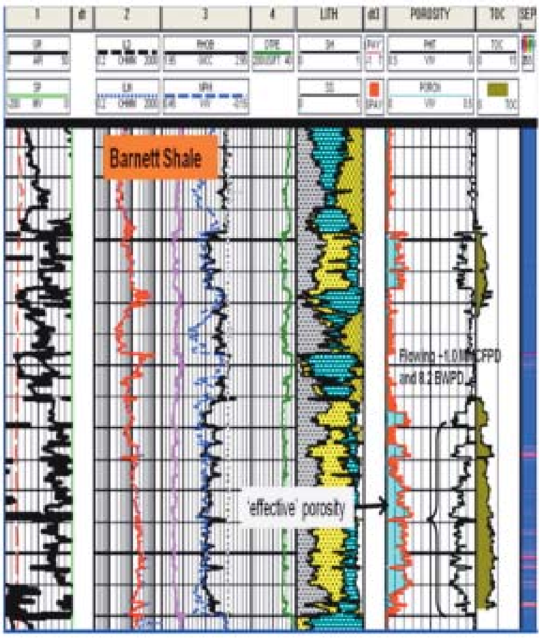

Figure 27. Barnett Shale matrix inversion modeling (courtesy; Hunt Wallace and Associates)

The lower zone in this figure was completed based on the 'effective' porosity, and flowed in excess of 1mmscf/d. In addition, TOC is calculated from logs calibrated to core TOC sample data using a Delta-LogR method. (Passey 1990). Core samples indicate that the Muskwa TOC varies between 1.5 and 8%, though is more commonly in the range of 2-3%. (source; Ross, Bustin (2008) and O.G.C. data.)

A similar model to the Barnett model was run on several Muskwa wells to give the results shown in Figure 28, (see Figure 24 for mineral inputs). TOC (Track 8, green shading), has been calculated in each well and mapped for the Muskwa shale.

Permeability Determination.

Permeability measurement on core has similar difficulties to the Montney, described previously. However, permeabilities are orders of magnitude lower in the Muskwa and Barnett compared to the Montney, so the laboratory equipment and procedural constraints are magnified. There is little PDP permeability available in the public domain. Luffel, (1993), has developed three methods for permeability measurement in 'true' shales, they indicate that micro-fractures whether real or drilling induced, dominate the permeability measurement. Ross and Bustin, (2008) have determined permeability from core analysis in the Muskwa between 80 and 8000 nanoDarcies.

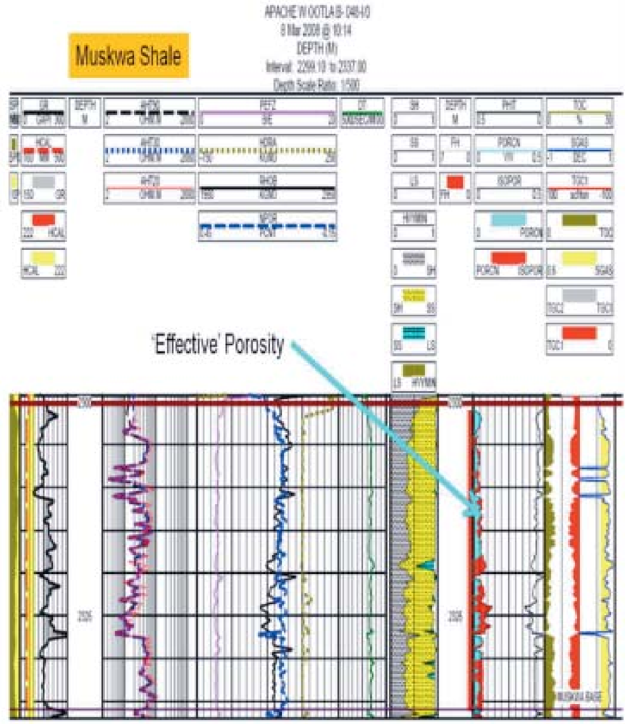

Figure 28. Muskwa Shale matrix inversion modeling. Total and Effective Porosities are shown, track 7, calculated TOC in track 8.

Water Saturation Determination

Water saturation is difficult to determine from core as described in the Montney, again accentuated because of the higher proportion of clay bound water and adsorbed (rather than free) gas found in the Muskwa and Barnett shales. We do not have Dean-Stark data available in the Muskwa or Barnett, so have used a log-analysis based method. This method is calibrated to core derived 'adsorbed' and 'free gas' from desorption work done on a selection of Barnett wells. The estimation of adsorbed gas, and certainly free gas is likely to be under-estimated as some gas will be lost when the core is brought to the surface. Never-the-less, in the Barnett and Muskwa shales, 'gas content', rather than 'water saturation' is determined. Ross and Bustin (2008), have mapped the total gas contents (adsorbed gas plus free gas) in the Muskwa. Their consensus is that 'free gas' liberated within fractures (natural or hydraulic) is more significant than 'adsorbed' gas in the Muskwa as Horn River basin temperatures and pressures are high. For example, the reservoir

Continued on next page…

Shale Gas Petrophysics *continued…*

pressure would have to be extremely low for the adsorbed gas component to be liberated.

Total gas content results run on 5 Muskwa wells, using a Barnett model yield a mean value of 26scf/t, which is in line with other published values for the Muskwa formation. Other petrophysical property results are summarized in Figure 29.

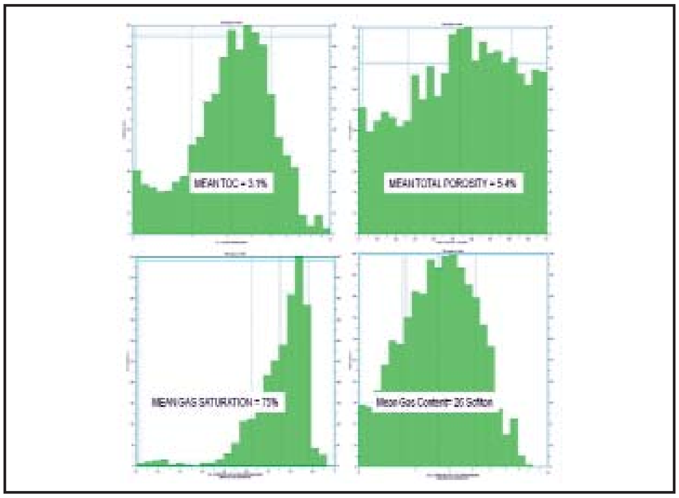

Figure 29. Muskwa Petrophysical results for 5 wells. Note; gas saturation and gas content values.

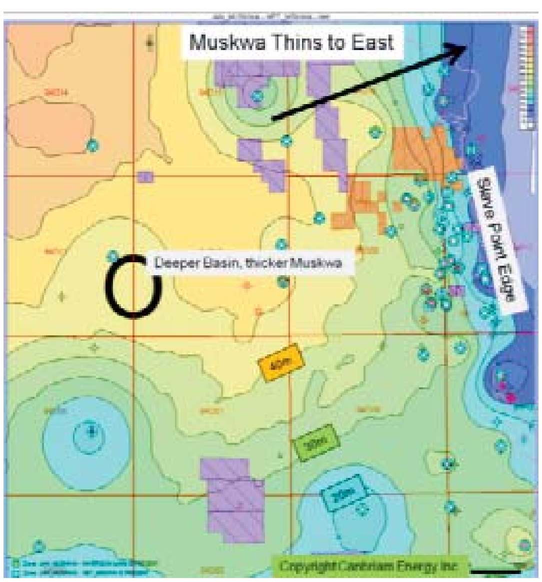

Figure 30. Muskwa Net Pay Map, Horn River Basin. (Using 3 pu 'effective' porosity cut-off.) Note the Muskwa isopach looks similar to the pay map, i.e is thicker in the centre of the basin and thins toward the Slave Point bank edge.

Net Pay Determination

Net pay in the Muskwa is correlated to the overall thickness of the section, as shown by the isopach map, Figure 4. The net pay map (Figure 30) uses a notional 3 pu total porosity cut-off.

Other maps have been made with a 3pu cut-off of 'effective or connected' porosity derived from the inversion modeling of Muskwa wells.

We assume that for rock >3pu, total gas saturations are in the order of 75%, again based upon our petrophysical modeling work, (summarized previously in Figure 29).

Completions

Completions technology has evolved to the point where there are numerous options in methodology and fracture stimulation.

The different methodologies include open-hole external casing packers (ECP) and cemented casing. The E.C.P (i.e. Packers Plus™*, Swell Packers™**, etc) is a system in which external packers and sliding sleeves are ran into the hole with the production casing and set in place via mechanical/hydraulic/swelling packers. The sleeves are opened by dropping different sizes of balls down in the casing. Cemented casing provides different options to perforate, stimulate, and isolate intervals. The options include pump-down plugs, coiled tubing perforation and plug setting, and also tractor-conveyed systems.

Without this new fracture stimulation technology, these tight gas reservoirs would not be economic.

The important element of fracture stimulation is picking the right type of fluid system, which will dictate the proppant selection, for the mineralogy and petrophysics of the reservoir. Currently there are no set rules in place for picking the Frac fluid for a certain type of rock. However, there are a lot of data (e.g. public database, peer collaboration, and published papers) and rules of thumb to help with the selection. The main types of fracture fluid and uses in the industry are:

• **Gelled oil** – is used for water sensitive reservoirs (i.e. swelling clays) and with different sized proppants. It can be energized with N_2 or CO_2 to help with flowback of frac fluid from the reservoir.

• **Gelled water** – is used for reservoirs where water is not an issue in damaging the formation.

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Parameter	Barnett	Muskwa	Montney
Depth, ft	6500 -8500	6000 - 9000	5000 - 6500
Gross Thickness ft	200 - 300	60 - 220	820 - 1380
Net Thickness ft	50 - 100	30 - 160	100 - 275*
Bottom Hole Temperature °F	200	150 - 190	131 - 170
TOC %	4.50%	2.5% - 4.5%	2.0% - 4.5%
Total Porosity %	4% - 5%	3% - 8%	3% - 10% *
Gas Filled Porosity %	2.50%	1% - 4.5%	2.0% - 7%
Water Filled Porosity %	1.90%	1.0% - 2.0%	1% - 3%
Kh md-ft	0.01-2	0.15-1	6 - 16.5
Gas content, scf/ton	105 - 115	10-60	16-48
Adsorbed Gas, %	20	60-85	15
Reservoir Pressure, psi	3,000-4,000	2200-2900	2600 - 3000
Pressure Gradient, psi	0.43-0.44	0.35	0.52-0.63
Well Costs, $1000	1,000	2500-3000	2,200
Completion Costs, $1000	1,250 - 750	1000-3000	2,250
Well spacing, Acres	55-160	80-320	640 - 160
Gas-in-Place, Bcf /Section	30-40	60 - 100**	6 - 60*
Historic Production area basis for data	Wise Co., Texas	N.E.B.C; Canada	Swan, Dawson BC, Canada

Source: GTI report 8305, Montgomery et. al. 2005

* Upper Montney Only

Figure 31. Summary Table of published Barnett, Muskwa and Montney Reservoir Properties.

As per the previous type of Frac, a variety of proppant sizes are available. This is preferable over oil due to cost and can be energized. Initial Montney Fracs, especially in Petrofacies 1 reservoirs, proximal to the sediment source, were done using Emulsified CO_2 or Nitrified Gelled Water. The current thinking is that this type of Frac, which includes the Poly- CO_2 Fracs works well in these reservoirs with intergranular porosity and permeability in the order of hundreds of micro-Darcies.

• **Slickwater** – is used in "tight" reservoirs where the permeability is in the nano-Darcy range. This type of Frac has been refined over the past decade in the Barnett shale. The water that is pumped has no gelling agent in it and the only chemical present is a friction reducer. Due to the limited carrying capacity, smaller sized proppants are used at lower concentration. One benefit of this type of Frac appears to be the rate at which it can be pumped to cause breakdown of the formation. Current industry thinking is that this type of Frac induces bigger Frac wings and 'dendritic' fracture growth in very low permeability reservoirs, which translates to more surface area and connectivity. More recently, Operators have also energized these Fracs with either N_2 or CO_2 to enhance flowback of frac fluid.

Summary

Figure 31 summarizes the salient properties of the three Formations covered in this paper.

Conclusions

We have shown, that though both called 'Barnett-like' shales, the Montney and Muskwa formations are very different rocks. The Montney formation is more of a hybrid – a highly laminated combination of silty-fine sands, organic material and clay minerals. The Muskwa formation on the other hand is a deep water argillaceous, organic shale, very similar in nature to the Barnett in the DFW Metroplex area. Both are highly productive gas reservoirs with different petrophysical properties. These different petrophysical properties, notably permeability, lead to different formation stimulation treatments, which have proved highly effective as stimulation technology advances.

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The authors thank an ex-Mobil colleague, Jim Wallace of Hunt-Wallace and Associates for his invaluable skills and assistance in petrophysical modeling of the Muskwa formation.

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About the Authors

John Nieto is Vice President of Exploration and co-Founder of Canbriam Energy Inc, based in Calgary, Alberta, where he is responsible for Geosciences. Nieto holds a B.Sc. degree (Dual Hons Geology) from London University and a D.M.T from Camborne School of Mines (Geology). He worked as a well-site geologist and wireline logging engineer before joining Britoil (BP) as a petrophysicist. After a 14 year career with Mobil and ExxonMobil, Nieto was global coordinator of Formation Evaluation for the Corporation, based in Houston. He moved to Canada with Anadarko and left APC after 5 years, in the position of Reservoir Characterization Manager for the Company. He is currently a member of, and was previously, 50th President of the Canadian Well Logging Society (CWLS). He was awarded the CWLS President's award for best technical presentation in 2002-2003. He is also an SPWLA and AAPG member. Nieto has authored or co-authored 20 technical papers on formation evaluation and reservoir characterization.

Robert Bercha is a Staff Geologist at Canbriam Energy Inc, based in Calgary, Alberta. He graduated from the University of Calgary with a B.Sc. in Geology in 1991. Upon graduation he worked at Pembina Resources for 5 years in various geological roles. In 1997 he moved to Norcen Energy (which eventually became Union Pacific Resources then Anadarko Canada and now Canadian Natural Resources) as a Senior Geologist. During the next 11 years he worked in both Geological and Petrophysical roles on a wide range of Western Canadian projects including: W4M shallow gas, Hoadley Glauconite, N.E. British Columbia Slave Point & Baldonnel Exploration and Wildriver / Gold Creek Deep Basin Gas. In February, 2008 he moved to Canbriam Energy and is currently employed as a Staff Geologist. His primarily focus is unconventional gas in Quebec and British Columbia. He is currently a member of CWLS, CSPG and APEGGA.

Jim Chan is a Senior Production Engineer at Canbriam Energy Inc, based in Calgary, Alberta. He graduated from the University of Alberta with a B.Sc. in Petroleum Engineering in 1994. Upon graduation he worked for Dowell Schlumberger for 2 years as a Field Engineer and then moved to Canadian Fracmaster as a District Engineer in Grande Prairie, when BJ services took over Fracmaster. After BJ services, he worked for various E&P companies within Calgary on Western Canadian properties including: Enchant, Kaybob, Ansell, Knopcik, Peace River Arch, and N.E. B.C. In April, 2008 he moved to Canbriam Energy and is currently performing production, facilities, and completions engineering duties. He is currently a member of APEGGA.

Appendix

Equations Used In Evaluation

Equation 1 – Montney TOC Prediction.
(R-TOC) Log(ILD) = 0.79972 * TOC + 0.3576

Equation 2 – Montney Density Porosity.
Density Porosity= (-0.000594) * RHOB + 1.5948
(Rhomtx ~ 2690Kg/m^3, Rhofl ~ 1000Kg/m^3)

Equation 3 – Montney Permeability Prediction.
Permeability (Core) = 14.42 * Porosity2.5

Equation 4 – Montney Sw from Log Porosity.
Sw (D-S) = 0.010 * Porosity -1.09

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SPEAKER: **Dr Marc D'Iorio, Director General of Geological Survey of Canada (Atlantic and Western Canada Branch)**

ABSTRACT:

Much progress has been made in the past 20 years in understanding the potential for natural gas production from gas hydrates. Initially identified as a potential drilling hazard and impediment to the transport of hydrocarbons and liquids in pipelines, gas hydrates are now viewed as a new potential clean energy source. Much of the international focus on gas hydrate is the resource assessment of marine deposits (e.g., Korea, India, Japan, Germany). In Canada, research is primarily directed at terrestrial deposits in permafrost regions, with minor activities in marine offshore on all three coasts. In 2008, Canada, in collaboration with Japan and the GNWT, was the first in the world to realize a successful production test by depressurization at the Mallik site located in the Mackenzie Delta.

This talk will present the NRCan / GSC program to map and quantify gas hydrate resources and advance the technical feasibility of *in-situ* natural gas production from gas hydrates. Our goal is to tackle the economic and scientific challenges in order to realize the potential of gas hydrates as part of future energy supply mix, which will change the face of the North American gas market.

BIOGRAPHY

Dr. D'Iorio has had a longstanding career with the Government of Canada, starting in 1988 as a NSERC (Natural Sciences and Engineering Research Council) Post-doctoral fellow. He has worked as a scientist and held a number of executive positions in the Canada Centre for Remote Sensing (CCRS) and in the Geological Survey of Canada. In July 2006, Marc was appointed Director General of the Geological Survey of Canada, Atlantic and Western Canada Branch.

As DG of the Geological Survey of Canada, Dr. D'Iorio is responsible for a suite of Programs that include: natural hazard geoscience research; 24/7 operations of the seismic and geomagnetic networks, and provision of emergency management information related to earthquakes, volcanoes, tsunamis, landslides and geomagnetic storms monitoring Canada; conducting scientific surveys in the Atlantic and Arctic Oceans required to support Canada's claim under the United Nations Convention on the Laws of the Sea (UNCLOS); federal geoscientific research on energy resources , including an international program with Japan on gas hydrates; and federal marine geoscience in Canada.

Dr. D'Iorio's many accomplishments over the years include the creation of the Innovation Acceleration Centre at CCRS, which promoted technology transfer from government labs and generated over $15 M of new revenue for Canadian industry. Internationally he has led technology development projects in Asia and South America and was the Canadian lead in Earth observation for the Canada - European Union S&T Agreement. He has published and presented over 100 papers.

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