CHARACTERIZATION OF MULTIPHASE FLOW PROPERTIES FOR TERTIARY IMMISCIBLE DISPLACEMENT PROCESSES IN AN OIL-WET RESERVOIR

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ABSTRACT

This paper presents results of a comprehensive laboratory study of a double displacement process (DDP) involving gas injection following a waterflood. The experimental program was designed and implemented for evaluating the DDP for the Hibernia field in East Canada. The objectives were to determine the feasibility of gas storage in a reservoir that had been undergoing waterflooding and to assess the potential for incremental oil recovery.

The scope of the laboratory study consisted of the following tests: double displacement, gas-oil and water-oil relative permeability and capillary pressure, wettability, interfacial tension, and rock and fluid characterization.

The DDP test was performed at reservoir conditions (210°F, 4500-psi pore pressure, and 4000-psi net confining stress) with live reservoir fluids using a Hibernia composite core. It consisted of: (1) injection of water and oil simultaneously at a ratio of 9:1 until a steady-state condition was established and (2) injection of gas until gasflood residual oil saturation was achieved.

The results demonstrate that reservoir-condition testing is necessary in order to simulate the prevailing wettability and interfacial tension in the reservoir, and that gas injection into previously waterflooded zones of Hibernia reservoir produces excellent potential for gas storage and may result in an incremental oil recovery.

INTRODUCTION

The Hibernia field is situated 315 km ESE of St. John's, Newfoundland in 80 m of water. The field was discovered in 1979. Oil production commenced in 1997, and development drilling has continued since then. A total of 27 oil producers, 18 water injectors, and 6 gas injectors had been drilled and completed by the end of 2005 with a cumulative oil production of 455 MBO.

There are two productive Cretaceous reservoir units, shallow and deep. Over 97% of the field's production to date has come from the deep Hibernia Formation. The Hibernia

Formation was deposited in a series of amalgamated and incised braided fluvial channels (Arthur *et al.*, 1982, Hurley *et al.,* 1992). Details of Hibernia's regional setting within the Jeanne d' Arc petroleum basin can be found in Magoon *et al.,* 2005.

The primary reservoir interval in the Hibernia Formation ranges from 150 to 200 m in total thickness with a net/gross ratio averaging around 50%. Reservoir sand units are highly fault compartmentilized such that the primary mode of field development has been to drill producer-injector pairs within individual fault blocks (Figure 1).

Future reservoir depletion plans remain dynamic and require a combination of proactive and reactive management based on prudent surveillance data collection and evergreen geologic and reservoir modeling. One concept being considered in this process is to convert some of the current Hibernia Formation waterflood blocks into gas storage/gasflood when the secondary recovery is complete. Such a double displacement process (DDP) might have benefits both from a reservoir management/operational perspective and from the ultimate recovery consideration. As a result, this proactive special core analysis study was commissioned to understand the effects of three-phase fluid displacement processes within the Hibernia Formation.

In this study, a laboratory DDP experiment was performed at reservoir conditions using a Hibernia composite core and live reservoir fluids. The following tests were performed to provide data for use in reservoir simulation to help interpretation of the DDP test results:

- Two-phase water-oil imbibition and secondary drainage relative permeability[*]
- Two-phase gas-oil drainage and imbibition relative permeability in the presence of immobile water,[†] including studies of:
  - effect of gravity
  - effect of interfacial tension by varying pore pressure or test fluids
- Water-oil imbibition capillary pressure
- Gas-oil drainage capillary pressure in the presence of immobile water
- Interfacial tensions between water-oil, gas-oil, and gas-water
- USBM wettability
- Crude oil characterization
- Thin section petrography
- Scanning electron microscopy
- Mercury injection capillary pressure

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[*] In this paper, for a water-oil system, the term “imbibition” refers to water-displacing-oil, whereas “drainage” refers to oil-displacing-water, regardless of the rock wettability.

[†]In a gas-oil system, the term “drainage” refers to gas-displacing-oil, whereas “imbibition” refers to oil-displacing-gas.

CORE MATERIAL

The cores were obtained from the B-16 17 well drilled in the Hibernia Formation V-block in late 1999 (Figure 2). The V-block cores are considered representative of other blocks that may be suited for gas injection following waterflood. The majority of the productive Hibernia sandstones are fine- to medium-grained, quartz-dominated, and fully consolidated. The only significant diagenesis is rimming silica cement growth. Average core properties are 15-20% porosity and 500-5000 md permeability. Figures 3 and 4 show the thin-section photomicrograph and the mercury injection capillary pressure data of a typical core sample.

Horizontal core plugs (3.8 cm in diameter and 5.0 cm in length) were taken from the whole cores. The plugs were extracted with toluene and dried, their routine core properties measured, and x-ray CT scan images taken in order to select suitable samples for the special core analysis (SCAL) tests.

Table 1 lists the ten core plugs used in the SCAL tests, along with their routine properties. The ten plugs all had similar properties. They contained more than 95% quartz, with an average porosity of 18% BV and permeability of 1800 md. All samples showed characteristics of uniform, narrow pore size distribution with an average pore aperture diameter of about 43 μm.

Four of the plugs were used for the centrifuge capillary pressure tests. The other six plugs were used to construct a 30-cm-long composite core. The composite core was used for the relative permeability tests and the double displacement study. Table 2 shows the properties of the composite core.

Because the cores were cut with oil-based drilling fluid, their wettability might have been altered by filtrate invasion and therefore become unsuitable for direct use in the SCAL tests. In order to restore the native wettability, the selected plugs were further cleaned by injection with a series of solvents (THF, chloroform/methanol, and methanol), and then the plugs were aged with crude oil at the reservoir temperature and representative connate water saturation for a prolonged period of time (a minimum of eight weeks).

Figure 5 shows the USBM wettability test results (Donaldson *et al.*, 1969) for a typical Hibernia core plug after restoration by cleaning and aging. The slightly negative USBM wettability index (W) indicated that the restored plugs had oil-wetting tendency. The oil-wet conclusion was further substantiated by the observations of a significant amount of spontaneous oil imbibition (18.3% PV) and no spontaneous water imbibition (≤ 1% PV).

TEST FLUIDS

The synthetic Hibernia brine contains 102,435 ppm of total dissolved solids, which include 90,400 ppm NaCl, 9,970 ppm $CaCl_2$, 1,290 ppm $MgCl_2$, 430 ppm KCl, and 345 ppm Na_2SO_4. This composition is consistent with formation water recovered in MDT samples and also with that produced at first breakthrough in the waterflood.

Stock tank oil was used in all centrifuge capillary pressure tests and in the USBM wettability tests. The oil was dewatered, degassed, and filtered prior to use in these tests.

A recombined reservoir oil sample and its equilibrated gas sample were prepared at 210°F and 4500 psig (the bubble point pressure of the oil) for use in core-flooding experiments. The oil, brine, and gas were pre-equilibrated with one another prior to the core-flooding experiments. Table 3 shows the assay of the oil sample.

Table 4 lists the viscosity, density, and interfacial tensions of the fluid systems used in the centrifuge and the core-flooding experiments. The interfacial tension measurements were performed using the pendant drop method.‡

CAPILLARY PRESSURE AND RESIDUAL OIL SATURATION BY CENTRIFUGE

Centrifuge tests were performed on individual core plugs to measure capillary pressure as a function of saturation and to determine the "ultimate" residual oil saturation in both the water-oil system and the gas-oil system. The tests were conducted with degassed stock tank oil at 150°F, ambient pore pressure, and 4000 psi net confining stress.

Figure 6 shows a typical water-oil imbibition capillary pressure curve for the core samples. The "ultimate" residual oil saturation by water displacement was only 1.0% PV.
Figure 7 shows a typical gas-oil drainage capillary pressure curve for core samples in the presence of irreducible water saturation. The "ultimate" residual oil saturation by gas displacement was also very small, about 0.9% PV.

TWO-PHASE GAS-OIL RELATIVE PERMEABILITY

Gas-oil relative permeability measurements were conducted with live reservoir fluids under reservoir conditions (210°F, 4500-psi pore pressure, and 4000-psi net confining stress) on the composite core using the steady-state method in both drainage and imbibition directions. An unsteady-state gasflood was added as the last step of the drainage test to extend the oil relative permeability curve near the residual oil saturation.

At the end of the imbibition cycle (*i.e.,* the end of oil-flooding), a consistency check was conducted for quality control by measuring the trapped gas saturation and comparing it with that from material balance calculations.
Figure 8 shows the measured relative permeability data when the core was vertically orientated and the gas and oil injected downward into the core. Note that the oil relative permeability curves are the same in both directions, indicating no hysteresis in the wetting phase relative permeability. The gas relative permeability curves, however, are

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‡ The pendant drop method is a method for measuring interfacial tension between immiscible fluids based on the shape of a static drop or bubble. In this method, the interfacial tension is derived from the drop shape, size, and fluid densities.

very different, indicating strong hysteresis in the non-wetting phase relative permeability.

Unlike the conventional unsteady-state gasflood method, the steady-state method used in this study made it possible to obtain gas relative permeability in the low gas saturation region. Such data are needed for predicting gas breakthrough in the gasflooding process. The steady-state method also provided accurate measurements of saturation endpoints and the corresponding endpoint relative permeability.

In the gas-displacing-oil process, the critical gas saturation was 0.243 fraction PV in the composite cores. The gas relative permeability increased from zero and remained below 1×10^{-5} until the gas saturation increased to about 0.26 PV. The gasflood yielded a residual oil saturation of 0.065 fraction PV at the core outlet face after more than 1000 PV of gas injection. Extrapolation of the oil relative permeability curve yields an asymptotic residual oil saturation of 0.009 fraction PV, identical to that determined from the centrifuge test.

In the oil-displacing-gas process, the trapped gas saturation at the end of oil flooding was 0.448 fraction PV and the corresponding oil relative permeability was 0.136 fraction $k_{o,iw}$.

Effect of Gravity

The gas-oil relative permeability test was repeated by orienting the core upside-down and injecting fluids from the bottom of the core.

Figure 9 compares the relative permeability curves obtained by injection from the bottom with those obtained by injection from the top. The results are quite similar, indicating that gravity effects in this system are insignificant compared to the capillary forces.

Effects of Test Fluids, Pore Pressure, and Interfacial Tension

The gas-oil relative permeability data were obtained using live fluids at the reservoir conditions, under which the interfacial tension (IFT) between the gas and oil was quite low (1.82 dyne/cm). As demonstrated below, changes in pore pressure or in fluid compositions altered the IFT, and the resulting gas-oil relative permeability varied correspondingly.

Figure 10 compares the gas-oil relative permeability data obtained on the same Hibernia core with different fluids at various conditions. The base case is the live fluid system at the reservoir conditions (210°F, 4500 psig) with an immobile water saturation of 0.030 fraction PV. The second case is the equilibrated reservoir fluids at the same temperature (210°F) but at a reduced pressure (500 psig) with an immobile water saturation of 0.097 fraction PV. The third case is the nitrogen/white oil system at 88°F and 1000 psig with different levels of immobile water saturation (S_{wi} = 0.000, 0.102, and 0.180, respectively). Note that the gas relative permeability is plotted against the total liquid saturation, whereas the oil relative permeability is plotted against the oil saturation, regardless of the level of the immobile water saturation.

The results in Figure 10 show that the relative permeability behaviors in the second case and the third case were very similar because the gas-oil IFTs were comparable in the two systems (15.1 and 20.3 dyne/cm, respectively). The relative permeability in the first case, however, was dramatically different because the IFT was substantially lower (1.82 dyne/cm). The low interfacial tension resulted in a higher critical gas saturation and a lower residual oil saturation.

TWO-PHASE WATER-OIL RELATIVE PERMEABILITY

Water-oil relative permeability measurements were conducted on the same composite core with live reservoir fluids at the reservoir temperature (210°F) and a pore pressure (4800 psig) slightly higher than the bubble point of the oil. The composite core was oriented horizontally. Steady-state measurements were taken on both the imbibition and secondary drainage paths. An unsteady-state waterflood or oilflood was added as the last step on each path to obtain more data near the residual oil or residual water saturation.

At the end of the secondary drainage cycle, a consistency check was conducted for quality control by measuring the volume of oil in the core and comparing it with that from material balance calculations.

Figure 11 shows the measured relative permeability results. Note that the oil relative permeability curves are the same in both directions (*i.e.*, no hysteresis). The water relative permeability data, however, are very different (*i.e.*, strong hysteresis). At the end of the secondary drainage cycle, the residual water saturation was very high (about 36% PV), and the corresponding end-point oil relative permeability was very low (only 14.5% $k_{o,iw}$). These observations indicate that the Hibernia core tested was oil wet, which is consistent with the USBM test results (Figure 5).

DOUBLE DISPLACEMENT EXPERIMENT

The DDP experiment was conducted on the same composite core at the reservoir conditions (210°F, 4500-psig pore pressure, and 4000-psi net confining stress). Because the previous two-phase water-oil relative permeability test ended at a very high residual water saturation (about 0.36 PV) in the secondary drainage cycle, a low initial water saturation was reestablished by the centrifuge method before the core was reused in the DDP experiment.

Initial Water Saturation

To establish the initial water saturation, the live oil in the composite core was first replaced with dead oil. The composite core was disassembled, and each plug was centrifuged under air at 3200 rpm for three days. The composite core was then reconstructed from the plugs in their original order and orientations. The volume of the void space in the core was measured, and then the core was saturated with crude oil.

Prior to the DDP experiment, the initial volume of oil in the core was determined. The initial water saturation (S_{wi2}) was 0.122 fraction PV. Note that the initial water saturation for the DDP experiment (S_{wi2}) was established by centrifuging the oil-wet core, which contained both oil and water, whereas that for the two-phase relative permeability measurements (S_{wi}) was established by centrifuging the water-wet core containing 100% water.

The Post-Waterflood Condition

DDP testing involves gas injection initiated at a late stage of the waterflood—for example, when the produced water and oil at the production wells have reached a ratio of 9:1. In this laboratory experiment, this late-stage condition was established by simultaneously injecting water and oil into the core at a ratio of 9:1 until a steady-state condition was reached. The water saturation, the relative permeability to oil, and the relative permeability to water at the steady-state condition were determined.

The remaining oil saturation at the post-waterflood condition was 0.446 fraction PV. The corresponding oil relative permeability and water relative permeability were 0.0250 and 0.1550 fraction $k_{o,iw}$, respectively.

Gas Injection

In the second stage of the experiment, the composite core was placed vertically, and pre-equilibrated gas was injected into the top of the core. The core effluent was collected in a three-phase separator, and the produced gas was recycled for injection. The volumes of the produced oil and produced water and the pressure drop across the core were recorded as functions of time. The gas injection rate was initially 4 cc/min and later increased to 75 cc/min in five steps during the gasflood.

Corrections for Losses of Connate Water and Residual Oil

As part of the quality-control procedures, at the end of the experiment, the gas in the core was compressed into solution and removed by flooding with oil under high pressure. The amount of gas removed was measured and compared with the total liquid production during the gas injection. Moreover, the volume of residual water in the core was measured by two independent methods: first by measuring the volume of oil using the solution-gas liberation method and second by measuring the void pore space after the oil was removed by flushing with liquid propane. These measured values were compared with that from material balance calculations.

The results of these checks revealed a loss of connate water and residual oil from the composite core over the large throughput of gas injection (133,800 cc or 2,143 PV). This loss was the natural result of evaporation because the pressure at the pump head and the pressure inside the composite core were slightly different. The evaporation was rather slow because the injected gas had been pre-equilibrated with the water and oil before use.

The DDP experimental results were corrected for evaporation losses based on the assumption that the losses were linearly proportional to the gas throughput. The experimental results discussed below should be free from effects of evaporation during the first 160 PV, as the corrections were less than 0.010 fraction PV and less than 0.0023 fraction PV for the residual water saturation and the residual oil saturation, respectively.

Discussion of Double Displacement Experimental Results

Figures 12 and 13 show the early production histories during the gas injection. Initially, water and oil continued to produce at a 9:1 ratio. An oil bank arrived at the core outlet when 0.205 PV of gas had been injected. As the oil bank arrived, the fractional flow of oil increased from 0.100 to 0.925. Later the gas breakthrough occurred when 0.280 PV of gas was injected, at which point the fractional flow of oil immediately dropped from 0.925 to 0.205. After the gas breakthrough, the production of both oil and water gradually decreased, but oil continued to produce at a much higher rate than water.

Figure 14 shows that a late-stage secondary oil bank arrived after 11.0 PV of gas had been injected. This oil bank is attributed to the reconnection of isolated oil ganglia and production via the film drainage mechanism. The peak fractional flow in the secondary oil bank was only 3.5×10^{-3}. However, the production was protracted over more than 2,000 PV of gas injection.

Additional Oil Recovery by Gas Injection in Double Displacement Experiment

Prior to gas injection, the oil recovered by waterflooding at a water-oil ratio of 9:1 was 54% of the original oil in place (OOIP). Figure 15 shows that the injection of gas yielded an additional 14% OOIP after one pore volume (1 PV), and 18.5% OOIP after 11 PV of injection. Further injection of gas created the secondary oil bank, which ultimately produced an extra 15.6% OOIP after 2,143 PV of injection.

Discussion of Wettability and Spreading Coefficient in the Hibernia System

Multi-phase relative permeability behaviors in porous media are affected by several parameters, including wettability and spreading coefficient. These two parameters are of the same nature. They reflect interfacial phenomena acting at solid/liquid and liquid/liquid interfaces, respectively (Kalaydjian *et al*. 1993).

In the Hibernia system, oil is the wetting phase relative to water. This fact is evidenced by the two-phase water-oil relative permeability test results presented earlier in this paper. Oren and Pinczewski (1994) have concluded that oil recovery of waterflood residual oil by immiscible gasflooding is highest for oil-wet displacement (both positive and negative spreading systems), due to the presence of highly continuous oil-wetting films.

The spreading coefficient is defined as a balance of interfacial tensions:

$$S_{o/w} = \sigma_{wg} - (\sigma_{og} + \sigma_{ow}) \quad (1)$$

For the Hibernia system,

$$S_{o/w} = 39.9 - (1.82 + 21.4) = 16.7 > 0 \quad (2)$$

where the IFTs of the two-phase pairs were measured with fluids under the three-phase equilibrium conditions. The positive spreading coefficient in Equation (2) indicates that, even in a water-wet core, the Hibernia oil can spread between the water and the gas, forming continuous oil films. Oil recovery for a positive spreading system was reported to be significantly higher than that for the corresponding negative spreading system in a water-wet porous media (Oren *et al.,* 1992).

In summary, from both wettability and spreading considerations, oil recovery efficiency as a result of gas injection is expected to be high in the Hibernia system, which has been confirmed by experimental observations in this study.

CONCLUSIONS

Characterization of two- and three-phase flow properties under reservoir conditions was successfully completed for studying the Hibernia double displacement process. Gas-oil relative permeability data measured under reservoir conditions were significantly different from those obtained with mineral oil under ambient conditions. Interfacial tensions and wettability were shown to have significant effects on the performance of the DDP process. The results of the DDP experiment demonstrate that gas injection into previously waterflooded zones has potential not only for gas storage but also for incremental oil recovery from the oil-wet reservoir.

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Table 1. Properties of Hibernia B 16-17 Core Samples Used in the SCAL Tests

Core Sample	Depth (m)	Net Confining Stress = 4000 psi		SCAL Test
		K_{inf} (md)	Porosity (%BV)	
Centrifuge Plug No. 10	4039.71	1705	0.1795	W-O Imb. Pc
Centrifuge Plug No. 12	4039.79	1752	0.1787	G-O Dr. Pc
Composite Core No. 1	4041.09 4039.83 4040.96 4041.04 4041.13 4041.00	1919	0.1789	SS G-O kr SS W-O kr Double Displacement
Centrifuge Plug No. 20	4041.17	1602	0.1752	W-O Imb. Pc
Centrifuge Plug No. 21	4041.22	1681	0.1777	G-O Dr. Pc

Table 2. Properties of Hibernia B 16-17 Composite Core No. 1

Composite Core:	
Pore volume, PV (cm^3)	62.42
Bulk volume, BV (cm^3)	348.99
Length, L (cm)	31.17
Cross-sectional area, A (cm^2)	11.20
Porosity @ NCS = 4000 psi, ϕ (fraction BV)	0.179
Grain density, ρ_{ma} (g/cm^3)	2.644
Klinkenberg corrected gas permeability, K_{inf} (md)	1917
Absolute brine permeability, $K_{b,abs}$ (md)	1964
Harmonic average of core plug K_{inf}'s @ NCS = 800 psi, (md)	2270
Initial water saturation, S_{wi} (fraction)	0.030
Effective gas permeability at initial water saturation, $k_{g,iw}$ (md)	1870
Effective oil permeability at initial water saturation, $k_{o,iw}$ (md)	1771

Note: All permeability and porosity measurements were made under 4000 pci net confining stress unless otherwise noted.

Table 3. Hibernia Crude Oil Assay

Bubble Point Pressure at 210°F (psig)	4489
Gas/Oil Ratio at 250 psig and 70°F (scf/bbl)	1473
Stock Tank Oil Gravity (°API)	31.8
Acid Number (mg KOH/g)	0.03
Base Number (mg KOH/g)	1.33
SARA Analysis of Pentane Insolubles	
Saturates (wt%)	65.80
Aromatics (wt%)	22.76
Resins (wt%)	10.84
Asphaltenes (wt%)	0.60

Table 4. Hibernia Fluid Properties

Fluid	Density (g/cc)	Viscosity (cp)	Interfacial Tension (dyne/cm)
Core-flooding Conditions at 210°F and 4500 psig:			
Brine	1.0793	0.411	
Gas	0.2278	0.0293	
Oil	0.6716	0.597	
Oil and Gas			1.82
Oil and Brine			21.4
Gas and Brine			39.9
Centrifuge Conditions at 150°F and 0 psig:			
Brine	1.0515	0.567	
Air	0.00100	0.0190	
Oil	0.8185	2.86	
Oil and Brine			22.0

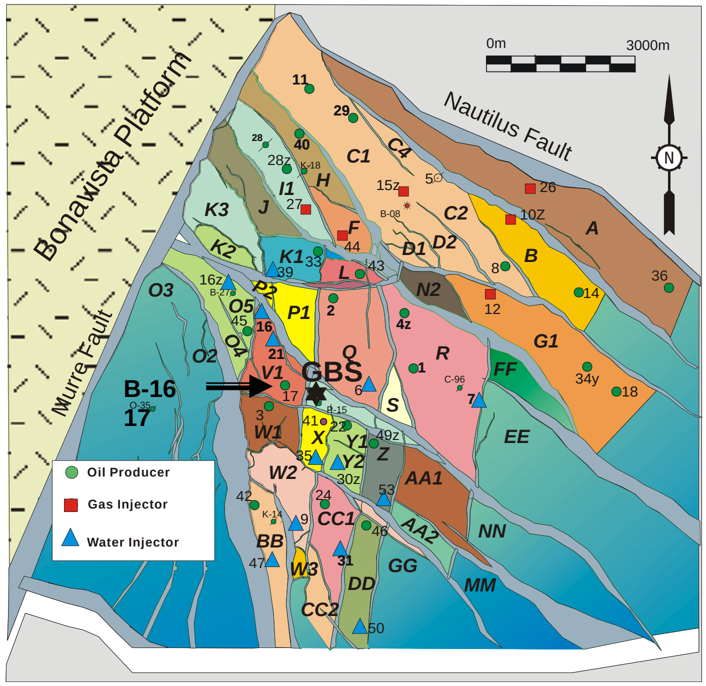

Figure 1. Hibernia Field Map showing platform location (GBS), well locations, fault blocks and the location of the B-16 17 well from which the core in this study was recovered. The northern fault blocks (A, B, C, G, F, H, and I) are supported by gas injection, central and southern blocks with water injection.

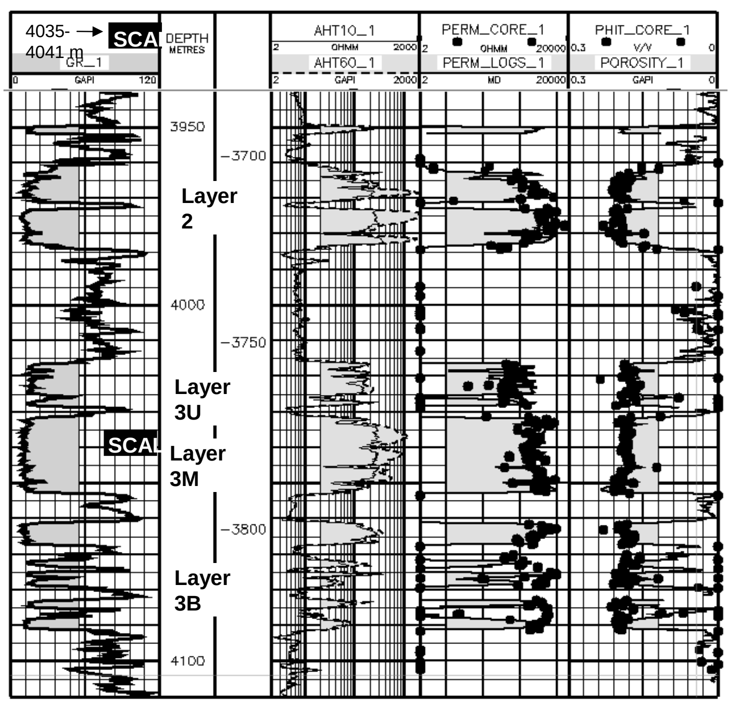

Figure 2. Hibernia Formation Log and Core Data from B-16 17 wellbore from which the SCAL plugs analyzed in this study were obtained. The samples studied were from Layer 3M and are considered representative of the high quality rock which dominates all primary reservoir layers in the region of the field being considered for DDP.

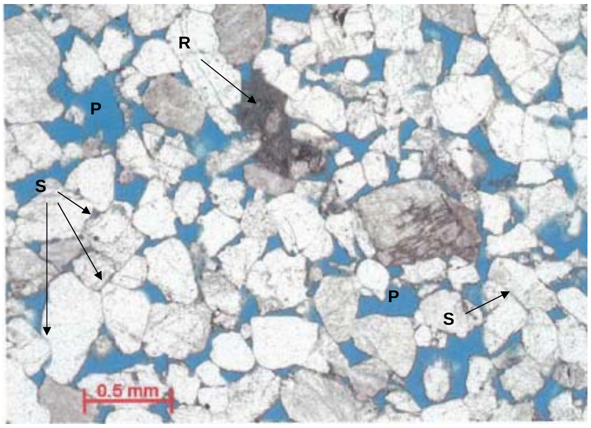

Figure 3. Hibernia Formation Photomicrograph from 4039.7 m MD. Core plug measured 18.8 % porosity and 2396 md permeability to air. Section is representative of the well sorted, medium-grained, quartz-dominated sandstone which dominates the field's performance. Occassional rock fragments (R) and Incipient silica cement growth (S) along some grain boundaries are depicted on the photo. The light grey, intergranular space (P) is porosity.

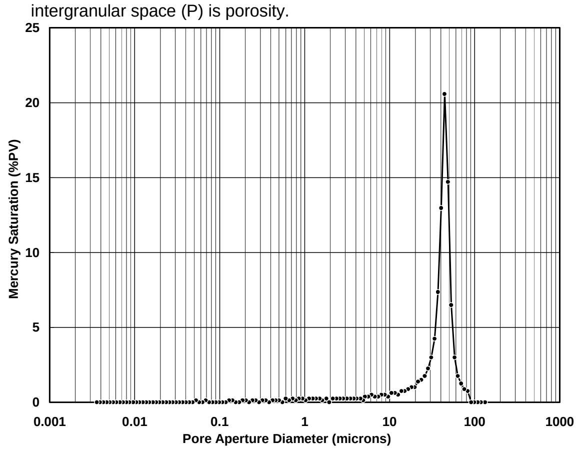

Figure 4. Hibernia Formation Mercury Injection Data from 4039.7 m MD, showing characteristics of uniform, narrow pore size distribution with an average pore aperture diameter of about 43 microns.

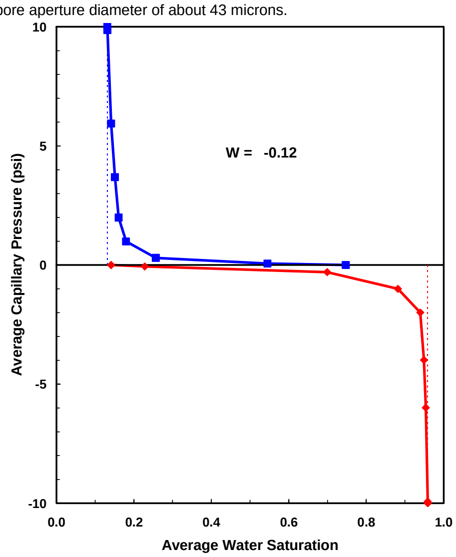

Figure 5. USBM Wettability Test, Plug 10

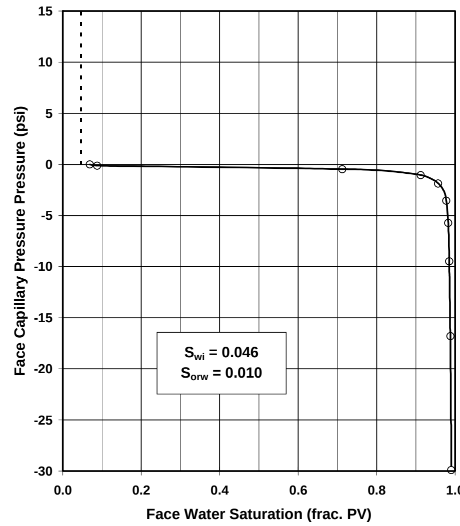

Figure 6. Water-Oil Imbibition Capillary Pressure Plugs 10

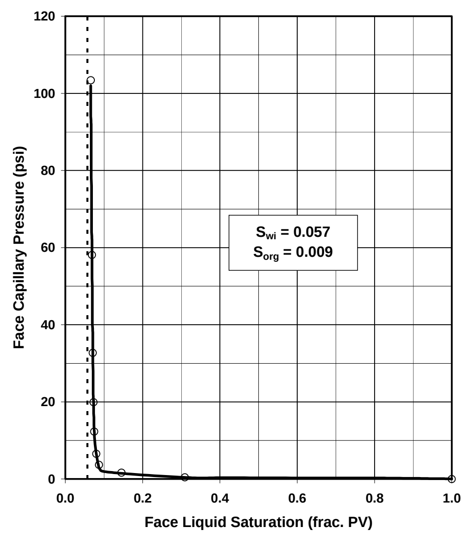

Figure 7. Gas-Oil Drainage Capillary Pressure Plugs 12

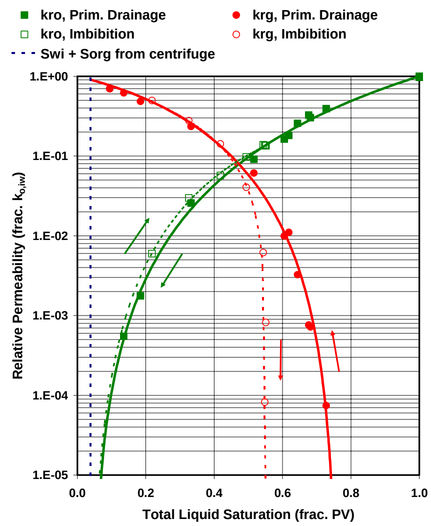

Figure 8. Two-Phase Gas-Oil Relative Permeability

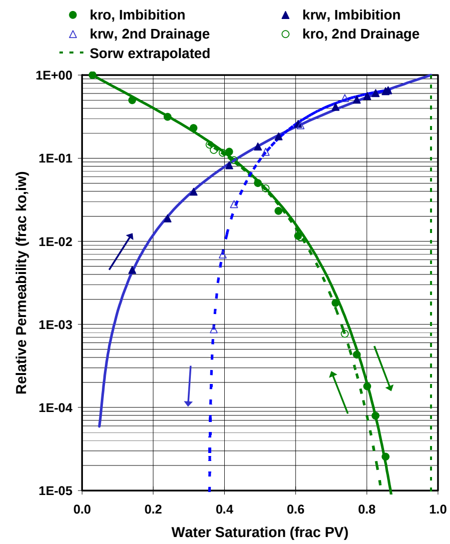

Figure 11. Two-Phase Water-Oil Relative Permeability

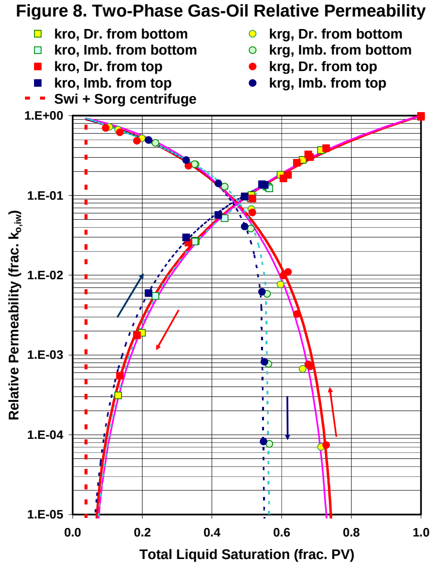

Figure 9. Effect of Injection Direction on Gas-Oil Relative Permeability

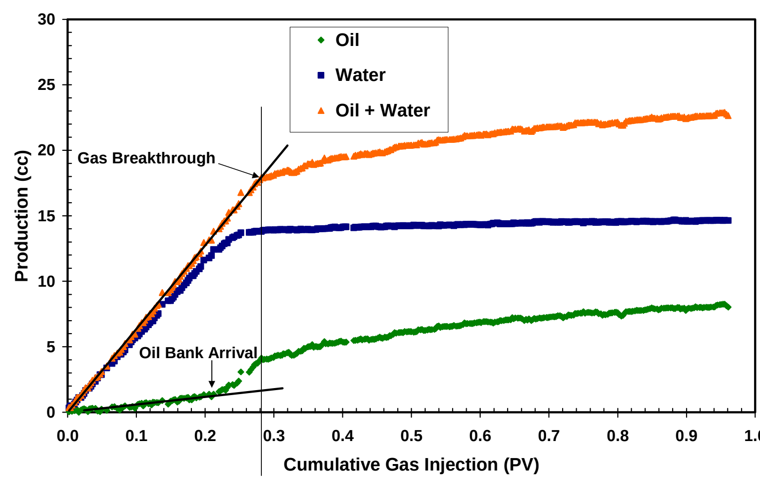

Figure 12. Early Production History During Gas Injection in Hibernia DDP

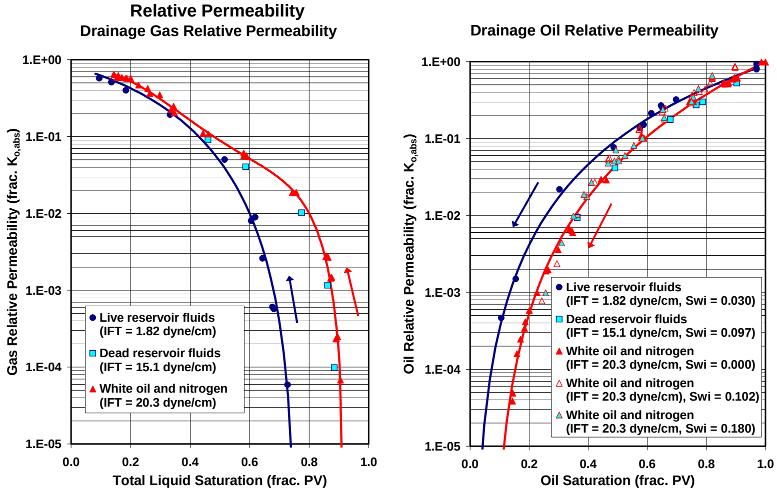

Figure 10. Effects of Interfacial Tension on Hibernia Gas-Oil Drainage Relative Permeability

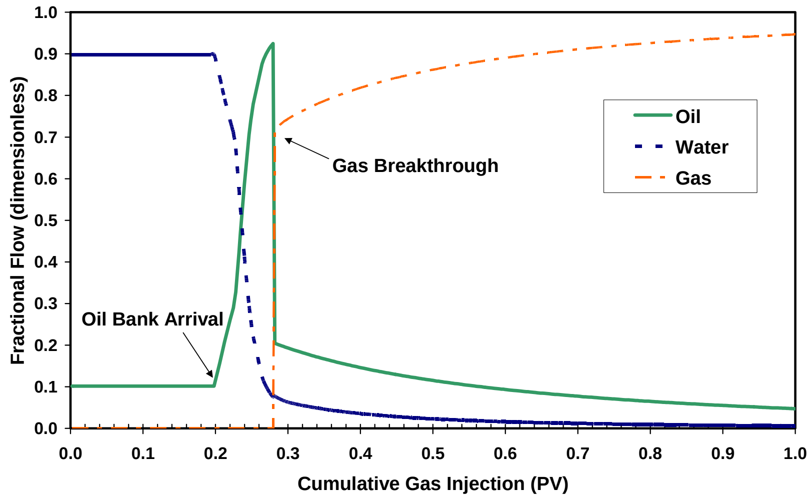

Figure 13. Oil Bank Arrival and Gas Breakthrough During DDP Gas Injection

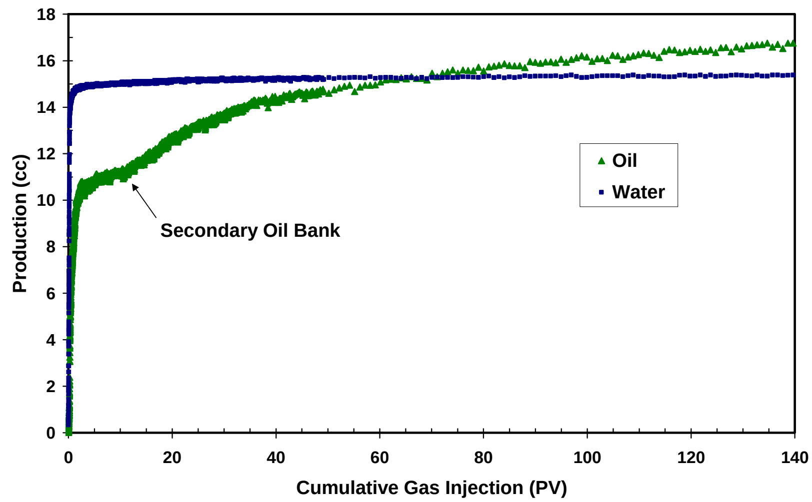

Figure 14. Production at Late Stage of Gas Injection in Hibernia DDP

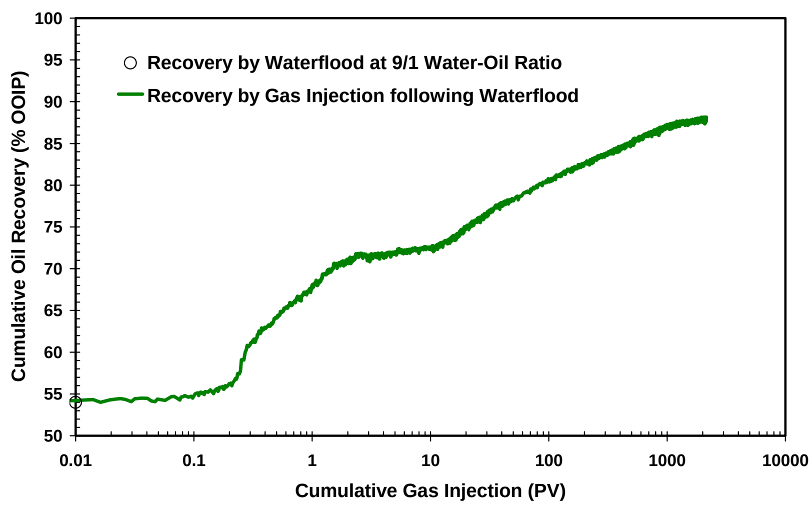

Figure 15. The Ultimate Oil Production by Gas Injection in Hibernia DDP