

Question

1. On Page 1, CNRL has indicated that there is a compelling evidence for the role of gas drive in the success of CSS. However, what is provided is a reference to a conclusion by Batycky et al based on a proposed mechanistic model of the CSS process. EnCana requests CNRL's history matched field data using this model to confirm the role suggested in the proposed mechanism. What are the relevant parameters with which this model was history matched? What is the evidence based on CNRL's history matched model data that this mechanism will be impacted in the presence of a lower pressure gas zone?

Response

1. The importance of solution gas drive in the success of CSS has been well studied and documented. The conclusions have been supported with field evidence. A history match of the field performance is not a requirement to understanding the mechanism of solution gas drive during a CSS operation. CNRL has not conducted any simulation modeling determining the impact of lower pressure gas zones on CSS performance. CSS is a very difficult process to simulate accurately.

In addition to the references (Batycky et al, and Denbina et al) quoted in the report, the following is additional evidence related to solution gas drive during a CSS recovery process:

- In pages 113 to 114 from the monograph "Thermal Recovery" by Michael Prats ^[1]:

*"By and large, there must be a driving force present in the reservoir initially if cyclic steam injection is to succeed. In other words, it is not sufficient merely to reduce the flow resistance in the reservoir. Gravity drainage and **solution-gas drive** are often highly important in providing driving forces during the production phase"*

- Physical modeling using a 2-D model was carried out by the Alberta Research Council to investigate the effect of initial solution gas on the cyclic steaming process^[2]. With a 10.5 API heavy Cold Lake bitumen, the following is quoted from the conclusions of this research:

*"Live oil, such as that found in some heavy-oil reservoirs, will respond differently to a thermal EOR process than will a similar dead oil. **Live-oil experiments produced significantly more oil than did dead-oil experiments.** This was in spite of a gas content in the live oil that was much lower than that found in many conventional oils".*

In the physical model the live oil case contained 5.0 m³/m³ initial GOR. The actual initial solution gas in the Clearwater Formation is higher (7.4 m³/m³ – 9.8 m³/m³). The impact of solution gas on CSS performance will be even higher than predicted in the model.

- The presence of solution gas improves the flow of bitumen as a result of reduced bitumen viscosity^[3]. Beggs and Robinson suggested the following equation for estimating the viscosities of live oil:

$$\mu = A\mu_{od}B$$

where:

$$A = 10.715(R_s + 100)^{-0.515}$$

$$B = 5.44(R_s + 150)^{-0.338}$$

- The CSS wells in the Primrose area have been producing with a GOR of 40 to 60 m³/m³ (approximately 80% is methane gas) through out the life of CSS operations. This is a clear indication that solution gas drive is always an important part of the recovery mechanisms for CSS production.
- The failure of CSS in the Athabasca McMurray formation is largely due to the lack of solution gas drive. One example of a failed McMurray CSS pilot is the test conducted by Petro-Canada in Hangingstone.

The low pressure in a gas zone, if it is in contact with a bitumen zone, implies that degassing has already taken place in the bitumen. This will reduce the contribution to flow of solution gas drive mechanisms.

Question

2. *In Section 1.1 of the report CNRL notes that a wellhead oil sample obtained from a CSS well “effervesces vigorously exsolving enough gas such that the sample shrinks by almost 50% by volume after all the gas comes out as shown in Figure 1.1.” EnCana requests that CNRL identify the well from which the sample was obtained and provide its producing history, the time at which the sample was taken, and any gas analysis for the gas which was exsolved.*

Response

2. The sample was obtained from:
 UWI: 100/12-25-67-04W4/0
 Well Name: CNRES 8C29 Primrose 12-25-67-4

The production history of this well is shown in Figure 1 below:

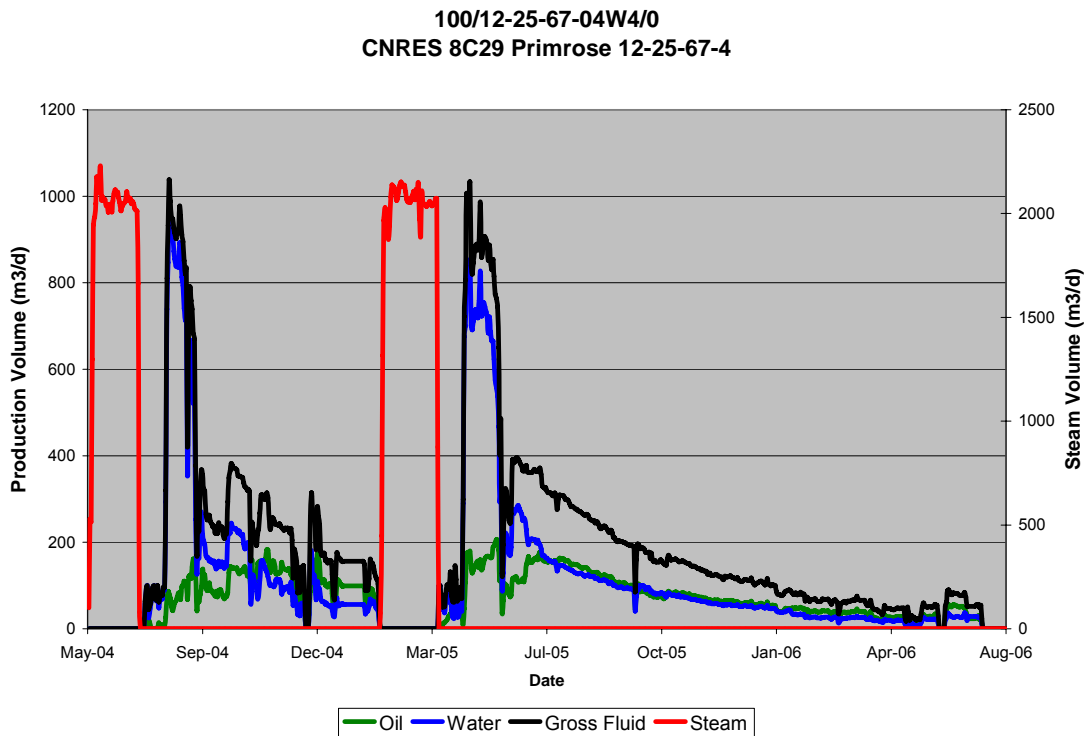


Figure 1 – 100/12-25-67-04W4M Production Plot

The sample was taken in June 2006 at a temperature of 69 C and no gas analysis was taken.

Question

3. *In Section 1.1 of the report CNRL states “The Clearwater Formation of greater than 10m thickness has generally been targeted for CSS development, but recent improvements in technology are expanding feasible development to intervals as thin as 7m.” What net pay cutoff criteria have CNRL used in determining the 10 m and 7 m values? Do these values reflect vertically continuous zones or what thickness of vertical discontinuities is acceptable within the zones for viable CSS operations?*

Response

3. Net pay in the Clearwater Formation is defined as greater than 7 m of continuous sand with less than 10% bioturbated mud interbeds and greater than 6 average weight percent bitumen. These values reflect vertically continuous zones.

Question

4. *In Figure 1.2 an oil viscosity vs. depth plot is presented. EnCana requests that CNRL provide the data used to prepare this graph including the wells sampled, how the samples were obtained and details of the oil analysis. Does CNRL have any data that indicates a corresponding variation in solution gas oil ratio with depth?*

Response

4. The detailed oil analysis reports for all wells used in Figure 1.2 of the July 4th, 2006 submission are included in Appendix A. CNRL does not have any direct data on solution gas variation with depth.

Question

5. *Figure 1.3 presents data from a Burnt Lake primary production pilot in the Clearwater Formation. EnCana requests that CNRL identify the wells in this pilot and if production and pressure data for the wells are not available on the public record provide this data.*

Response

5. Table 1 gives the List of Burnt Lake Primary Wells

Table 1 – List of Burnt Lake Primary Production Wells

| List of Primary Wells |
|------------------------------|
| 00/02-14-067-03W4/0 |
| 00/05-14-067-03W4/0 |
| 00/06-14-067-03W4/0 |
| 00/07-14-067-03W4/0 |
| 00/10-12-067-03W4/0 |
| 00/11-10-067-03W4/0 |
| 00/11-11-067-03W4/0 |
| 00/11-13-067-03W4/0 |

| |
|---------------------|
| 00/12-14-067-03W4/0 |
| 00/14-14-067-03W4/0 |
| 02/03-14-067-03W4/0 |
| 02/10-14-067-03W4/0 |
| 04/04-14-067-03W4/0 |
| 05/02-14-067-03W4/0 |
| 05/07-14-067-03W4/0 |
| 07/03-14-067-03W4/0 |
| 07/08-14-067-03W4/0 |
| 08/06-14-067-03W4/0 |

All related data is available in public records.

Question

6. *In section 1 of the report and Table 6.2, CNRL indicates that it believes cold production and thermally induced cold production is commercially viable and indicates a recovery factor of 10%. EnCana requests that CNRL provide any field data or well test data in the Clearwater zone to support these positions.*

Response

6. CNRL believes that recovery of 10% is achievable under primary recovery through the production of the Burnt Lake Primary Production Pilot. The cum production for the deviated primary wells (well list included in question 5) varies between 10 m3 and 14373 m3 with an average of 3751 m3 production. Based on the 25 well, ¼ section pattern used in the Burnt Lake pilot the recovery achieved using the average per well production would be 2.9% and using the maximum per well production recovery would be 11%. Based on this abbreviated pilot, CNRL believes that using current primary production technology, including improved sand handling techniques and advances in stimulation, that 10% recovery is an achievable primary recovery volume.

Question

7. *EnCana requests that CNRL provide details of the installation programs for the piezometers in 02/9-29-67-3W4 and 10-32-68-4W4, details of any completions in these wellbores and any verifications of cement integrity that have been performed.*

Response

7. Completions data is included in Appendix B. There was no cement integrity tests performed after these piezometers were installed.

Question

8. *Figure 2.9 indicates that a piezometer is hung at a depth of 375.5 m in the 13-33-67-3W4 well, Figure 2.12 indicates that a piezometer is hung at a depth of 482.5 m in the 11-2-68-4W4 well and Figure 2.13 indicates that a piezometer is hung at a depth of 491.7 m in the 13-10-68-3W4 well. EnCana requests that CNRL provide details of any completion intervals in these three wells including all completion and workover reports.*

Response

8. Completions data is included in Appendix B. There have been no workovers completed on these wells after initial completions.

Question

9. *CNRL had previously provided piezometer pressure data to April 28, 2005. EnCana requests that CNRL provide pressure data from all piezometers in the Application area from April 29, 2005 to the current time. If any pressures have been measured in these wells in addition to the piezometer data EnCana requests that CNRL provide copies of this pressure data.*

Response

9. Updated pressure data is included in the Excel file on the attached CD.

Question

10. *In section 3.1 (page 23) of the report CNRL states "Diffusivity of this large magnitude suggests that pressure transmits through a mobile water phase in the Clearwater Formation of the Cold Lake and Primrose area." and in section 4.2.1 (page 28) of the report CNRL states "Large regions of the Clearwater Formation are in pressure communication through the mobile water phase." EnCana requests that CNRL provide the criteria (and any supporting lab or field data) it uses to determine if water is a mobile phase in various intervals of the Clearwater sands at initial reservoir conditions. EnCana also requests that CNRL provide any information it has on the effect of mobile water on bitumen net pay determination and recovery levels and any mapping it has prepared of mobile water zones.*

Response

10. The average bitumen saturation in the Clearwater Formation at Primrose is approximately 60% of the pore volume. The field evidence reported in this submission has demonstrated that the water in the Clearwater Formation is mobile at the initial reservoir conditions, as a result of 40% water saturation. The criteria to determine if water is a mobile phase at the initial reservoir condition can be based on the following questions:

1. Does the reservoir have initial injectivity?
2. Can pressure be transported through the reservoir over an extended distance?
3. Will injected water move ahead of the heated zones?

The vast majority of bitumen in the Clearwater Formation has limited mobility at the initial reservoir condition. To meet any of the above criteria, water phase must be mobile. In addition to the evidence provided in the July 4th, 2006 submission, the following is additional evidence related to field performance or tests:

- During primary production water is produced immediately when the well is put on production.
- The first cycle of CSS in the Clearwater Formation at Primrose has a typical steam injection rate of 100 to 200 m³/d when at low pressure injection (lower than fracturing pressure).
- In the laboratory, the initial water saturation which can be achieved in the model packed with fine Ottawa sands by displacing water by bitumen is usually less than 20% ^[4].

The mapping of mobile water zones is not necessary because the water is mobile in all permeable bitumen regions within the Clearwater Formation. The thermal efficiency will decrease with the increase of mobile water due to the requirement to heat the additional water volume for the same amount of oil recovery.

Question

11. *In section 3.1 (page 23) of the report CNRL states, “Independent measurements of the Clearwater Formation hydraulic diffusivity have been made in the Primrose area using pressure response data from a 1992 pilot of Combined Drive Drainage”. EnCana requests that CNRL supply all of the documentation provided by the independent consultants and identify the wells involved in these tests.*

Response

11. Independent measurements of the Clearwater diffusivity were conducted by CNRL using the CDD pilot data. Figure 2 is a plan view of the area.

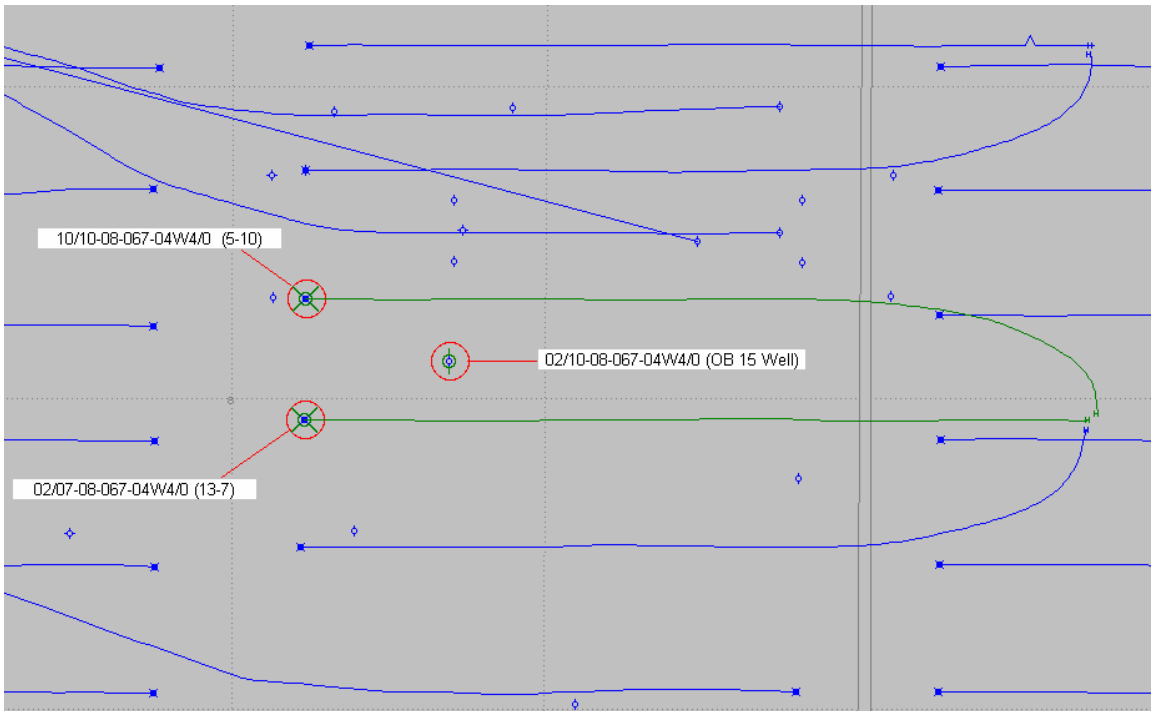


Figure 2 – Plan View of CDD Pilot Area

The wells included in the test are shown in the figure above. The data for from this test is included on the attached CD in the Excel file “CNRL Response to ECA Question 12.xls”.

Question

12. *On Page 24, Figure 3.1 states “Pressure Diffusion in CDD Pilot (During Steam Injection) gives simulation match with hydraulic diffusivity of 1.5e-3 m²/s.” EnCana requests that CNRL provide the simulation dataset that was used in the simulation study.*

Response

12. The data is included on the attached CD in the Excel file "CNRL Response to ECA Question 12.xls".

Question

13. In section 5 of the report volumetric gas in place calculations are provided for each gas pool. EnCana requests that CNRL provide the methodology and assumptions used to determine net gas pay and water saturations by well and by pool and the compressibility factors used in the calculations.

Response

13. The Volumetric OGIP was calculated using the following formulas:

$$OGIP = A * H * \phi * (1 - S_w) * B_g$$

OGIP = Volumetric Original Gas In Place (m³)

A = Area (m²)

H = Height (m)

φ = Porosity

S_w = Water Saturation

B_g = Formation Volume Factor of Gas

$$B_g = \frac{P_{sc} * Z * T_r}{T_{sc} * P_r}$$

B_g = Formation Volume Factor of Gas

P_r = Reservoir Pressure (kPa_a)

T_r = Reservoir Temperature (K)

T_{sc} = Surface Temperature (K)

P_{sc} = Surface Pressure (kPa_a)

Z = Compressibility Factor

The compressibility factor used in the calculation was 0.964, the average compressibility for all of the pools. To determine net gas pay, well logs were analyzed for density/porosity crossover in the presence of sand intervals.

The water saturation was calculated using Simandeaux's⁵ and Archie's⁶ Equations. Both equations were run for each well and then averaged for each given pool. Then the Simandeaux and Archie's values were averaged to generate the water saturation by pool. The details of these calculations are included below:

Table 2 – Calculation of Water Saturation using Archie's and Simandeaux's Equations.

| UWI | Simandeaux | | | | Archie's | | | |
|------------------|------------|-------|---------|--------|----------|-------|---------|--------|
| | SoPhiHt | SwPay | Net Pay | PhiPay | SoPhiHt | SwPay | Net Pay | PhiPay |
| 100022406804W400 | 1.10 | 0.14 | 3.60 | 0.35 | 0.92 | 0.28 | 3.60 | 0.35 |
| 100032506804W400 | 0.60 | 0.21 | 2.10 | 0.36 | 0.43 | 0.37 | 1.90 | 0.36 |
| 100051006904W400 | | | | | | | | |
| 100051506803W400 | | | | | | | | |
| 100051706803W400 | 0.25 | 0.31 | 1.00 | 0.36 | 0.16 | 0.45 | 0.80 | 0.36 |
| 100051806803W400 | 0.93 | 0.13 | 3.10 | 0.35 | 0.74 | 0.28 | 3.00 | 0.35 |
| 100063206703W400 | | | | | | | | |
| 100071606803W400 | | | | | | | | |

| | | | | | | | | |
|------------------|------|------|------|------|------|------|------|------|
| 100073106703W400 | 1.56 | 0.23 | 6.00 | 0.34 | 1.26 | 0.33 | 5.60 | 0.34 |
| 100081306804W400 | 0.33 | 0.24 | 1.30 | 0.33 | 0.20 | 0.39 | 1.00 | 0.33 |
| 100100806803W400 | 1.08 | 0.23 | 4.00 | 0.35 | 0.78 | 0.39 | 3.60 | 0.35 |
| 100102106803W400 | 1.19 | 0.15 | 3.81 | 0.37 | 0.96 | 0.32 | 3.81 | 0.37 |
| 100102206705W400 | 1.57 | 0.17 | 5.40 | 0.35 | 1.04 | 0.30 | 4.20 | 0.36 |
| 100102606804W400 | 0.56 | 0.21 | 2.00 | 0.35 | 0.47 | 0.34 | 2.00 | 0.35 |
| 100103306804W400 | 0.48 | 0.20 | 1.68 | 0.36 | 0.36 | 0.35 | 1.52 | 0.36 |
| 100110606803W400 | 0.13 | 0.16 | 0.42 | 0.37 | 0.10 | 0.33 | 0.42 | 0.37 |
| 100152906803W400 | 0.25 | 0.29 | 0.91 | 0.38 | 0.18 | 0.49 | 0.91 | 0.38 |
| 100161206804W400 | 0.41 | 0.24 | 1.60 | 0.34 | 0.34 | 0.37 | 1.60 | 0.34 |
| 102120906803W400 | 0.76 | 0.24 | 2.80 | 0.35 | 0.57 | 0.33 | 2.40 | 0.35 |
| 103080306904W400 | | | | | | | | |

| Simandeaux | | |
|------------|------|------|
| | Sw | Phi |
| Fisher A | 0.17 | 0.35 |
| Fisher E/F | 0.19 | 0.35 |
| Fisher K | 0.20 | 0.36 |
| Moore A | 0.23 | 0.34 |
| Moore B/C | 0.23 | 0.36 |
| Moore U | 0.31 | 0.36 |

| Archie's | | |
|------------|------|------|
| | Sw | Phi |
| Fisher A | 0.30 | 0.36 |
| Fisher E/F | 0.34 | 0.35 |
| Fisher K | 0.35 | 0.36 |
| Moore A | 0.33 | 0.34 |
| Moore B/C | 0.38 | 0.36 |
| Moore U | 0.45 | 0.36 |

| Average Simandeaux & Archie's | | |
|-------------------------------|------|------|
| | Sw | Phi |
| Fisher A | 0.24 | 0.35 |
| Fisher E/F | 0.26 | 0.35 |
| Fisher K | 0.27 | 0.36 |
| Moore A | 0.28 | 0.34 |
| Moore B/C | 0.30 | 0.36 |
| Moore U | 0.38 | 0.36 |

After the completion of the July 4th, 2006 submission an error was discovered in the calculation of volumetric OGIP due to computer network issues. The corrected volumetric OGIP numbers are as follows:

Table 3 – Comparison of July 4th, 2006 Volumetric OGIP to Updated Volumetric OGIP.

| | July 4th, 2006 Submission Volumetric OGIP (E6m ³) | Updated Volumetric OGIP (E6m ³) |
|-------------------|------------------------------------------------------------------|------------------------------------------------|
| Fisher A | 70 | 78 |
| Fisher E/F | 259 | 251 |
| Fisher K | 14 | 15 |
| Moore A | 104 | 117 |
| Moore B/C | 242 | 212 |
| Moore U | 2 | 2 |

These changes result in a minor increases and decreases in the volumetric OGIP for each given pool. While the volumetric OGIP is different than that presented in the July 4th, 2006 submission, this does not change the issue that some of these pools have produced greatly in excess of the

volumetric OGIP and all are projected to produce in excess of this value. The table below compares the volumetric OGIP to the current cumulative gas production and the recoverable GIP from the July 4th, 2006 submission.

Table 4 – Updated Volumetric OGIP compared to Cumulative Current Production and Recoverable GIP.

| | Updated Volumetric OGIP (E6m3) | Current Cum Production (E6m3) | Recoverable GIP (E6m3) |
|-------------------|-----------------------------------|----------------------------------|---------------------------|
| Fisher A | 78 | 72 | 132 |
| Fisher E/F | 251 | 209 | 460 |
| Fisher K | 15 | 39 | 67 |
| Moore A | 117 | 290 | 380 |
| Moore B/C | 212 | 339 | 520 |
| Moore U | 2 | 8 | 13 |

Question

14. *In section 5 of the report solution gas volumes have been calculated using a solution gas oil ratio of 9 m³/m³. EnCana requests that CNRL provide any available Clearwater PVT or field data to support this estimate. Is there any evidence of lower than expected producing gas oil ratios in any CSS producing areas offsetting the gas pools*

Response

14. The value of 9 m³/m³ is supported by published data, which places the Clearwater GOR between 7.4 – 9.8 m³/m³. The following papers give the values:

Mehrotra and Svreck, "Properties of Cold Lake Bitumen Saturated with Pure Gases and Gas Mixtures", The Canadian Journal of Chemical Engineering, Vol. 66, August 1988.
Buckles, "Steam Stimulation Heavy Oil Recovery at Cold Lake, Alberta", Society of Petroleum Engineers 7994, April 1979.

There are no wells that are currently producing from the areas offsetting any of the significant gas pools in the application area.

Question

15. *In section 5 of the report and in Table 6.2 original oil in place is calculated for a number of bitumen zones. EnCana requests that CNRL provide the cut-offs used to determine the net bitumen pay, porosity, and water saturation used in these calculations.*

Response

15. Net pay is defined as greater than 7 m of continuous sand with less than 10% bioturbated mud interbeds and greater than 6 average weight percent bitumen. The average bitumen weight percent and thickness are based on a calculated algorithm, which has been calibrated to the Dean Stark analyses, using a greater than 6% average bitumen weight cut off over the thickest continuous interval of sand. Water saturations are also based on a calculated algorithm using Archie's Water Saturation equation. An average porosity of 32% is used for the Clearwater in the Primrose area.

Footnotes:

1. Michael Prats, "Thermal Recovery", pages 113-114 of Monograph Volume 7, Henry L. Doherty Series, Second Printing, Society of Petroleum Engineers, Henry L. Doherty Memorial Fund of AIME, New York, Dallas, 1986.
2. Frauenfeld, T.W.J., Ridley, R.K., and Nguyen, D.M., "Effect of an Initial Gas Content on Thermal EOR as Applied to Oil Sands", Journal of Petroleum Technology, March 1988.
3. Section of Thermal Recovery on "Petroleum Engineering Handbook", pages 46-31 to 46-34, Second Printing, Society of Petroleum Engineers, Richardson, TX, U.S.A., 1987.
4. Jiang, Q. "Recovery of Heavy Oil and Bitumen using Vapex Process in Homogeneous and Heterogeneous Reservoirs", Ph.D. thesis, University of Calgary, March 1997.
5. Simandoux, P., "Mesures dielectriques en milieu poreux, application a mesure des saturations en eau", Etude du Comportement des Massifs Argileux, Revue de l'institut Francais du Petrole, Supplementary Issue, 1963.
6. Archie, G.E., "The electrical resistivity log as an aid in determining some reservoir characteristics", Petroleum Technology, v.5, p. 54 – 62, 1942.