

Question

1. *With respect to the wells requested to be shut-in.*
 - a) *Provide a list of the wells that CNRL is requesting shut the EUB to shut in and specify the intervals that CNRL wants shut in.*

Response

1.a) The list of wells CNRL with perforation intervals is as follows:

Table 1 – Requested Shut-in Wells and Specific Shut-in Intervals.

Well	Interval (mKB)
100/10-26-68-04W4/0	492 – 494.5
100/02-24-68-04W4/2	482 – 485
100/05-18-68-03W4/2	489 – 491
100/08-13-68-04W4/0	480 – 481
100/03-25-68-04W4/2	486 – 488
100/16-12-68-04W4/0	481 – 482
100/11-06-68-03W4/0	454.5 – 455
100/07-16-68-03W4/2	495 – 497
100/05-15-68-03W4/2	491 – 493
100/10-21-68-03W4/2	472.5 – 476.5
100/15-29-68-03W4/2	483 – 486
100/07-31-67-03W4/0	435 – 437
100/06-32-67-03W4/0	434.5 – 438
100/10-33-68-04W4/2	485 – 486
100/05-17-68-03W4/0	483 – 484
100/10-22-67-05W4/0	448 – 511
102/12-09-68-03W4/0	475 – 476
100/10-08-68-03W4/2	474 – 478 *

* Perf interval not listed in public database interval given corresponds to entire gas interval on logs.

Response

- b) *In its August 5, 2005 submission, CNRL included wells 5-10-69-4W4M and 3/8-3-69-4W4M on the list of wells it wanted shut in, but these wells are not included in CNRL's July 4th, 2006 submission which supersedes CNRL's previously submitted evidence. Explain why CNRL is no longer requesting shut in of these two wells.*

Response

b) The 5-10-69-4W4M and 103/8-3-69-4W4M wells were included in the August 5th, 2005 submission because they were originally mapped in the same gas pool as the 10-33-68-4W4M well. Subsequent work demonstrated that these two wells are not in the same gas pool as the 10-33-68-4W4M well. At this time, CNRL is seeking the shut-in of all Clearwater gas production wells that are either located in sections where CNRL owns the oil sands rights or are part of pools that extend onto lands where CNRL is the oil sands rights holder. Pending the EUB decision on this initial hearing, CNRL may make application to shut-in further gas pools which have a region of influence (defined by Section 3.2 of CNRL's July 4th, 2006 evidence) extending onto lands where CNRL is the oil sands rights holder. CNRL continues to view Clearwater gas production as endangering future bitumen recovery.

Question

2. On Page 1 of its submission, 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." Provide information to support this statement.

Response

2. Figure 1 is a graph of the Phase 17 D column wells showing CSS performance in an area where the average thickness is 7 metres.

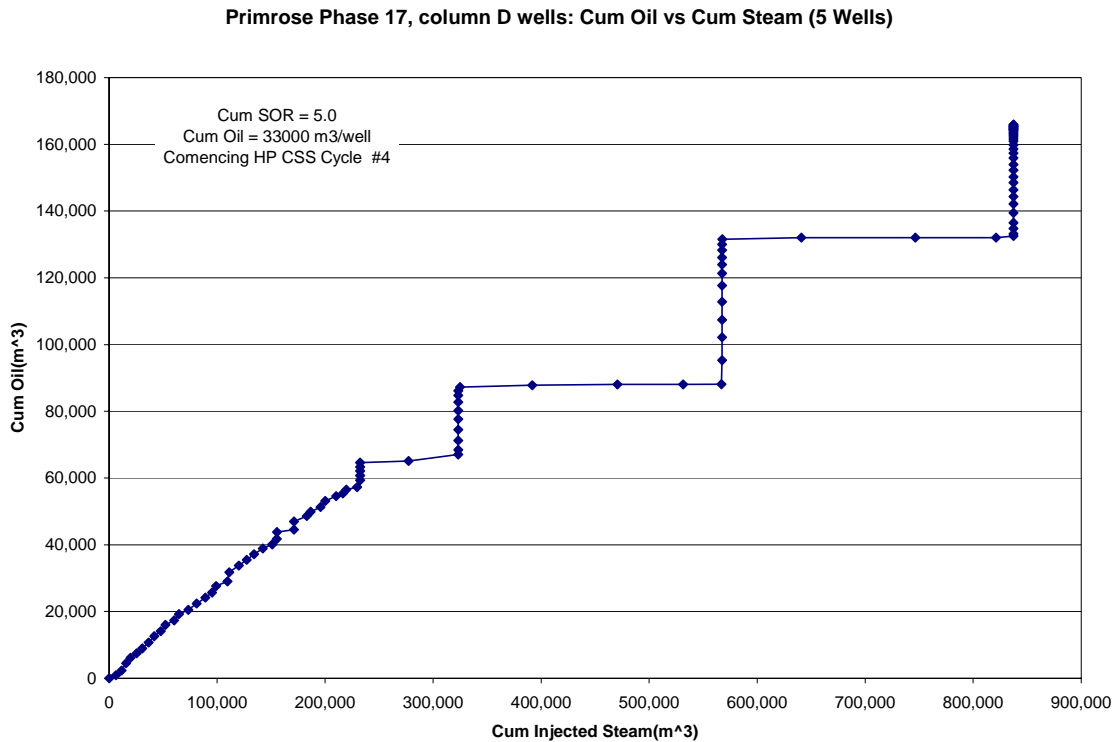


Figure 1 – Primrose Phase 17, Column D: Cum Oil vs. Cum Steam (5 Wells).

The D column in Phase 17 has produced 33,000 m³/well with a cumulative SOR of 5.0, using 600 metre horizontal CSS wells. The new Phase 27 wells which are drilled in approximately 8 metres of reservoir (see Figure 2 below), are 2.7 times longer (1600 metres) and are expected to produce over 90,000 m³/well (560 MM bbls/well) based on the production performance of Phase 17 D column.

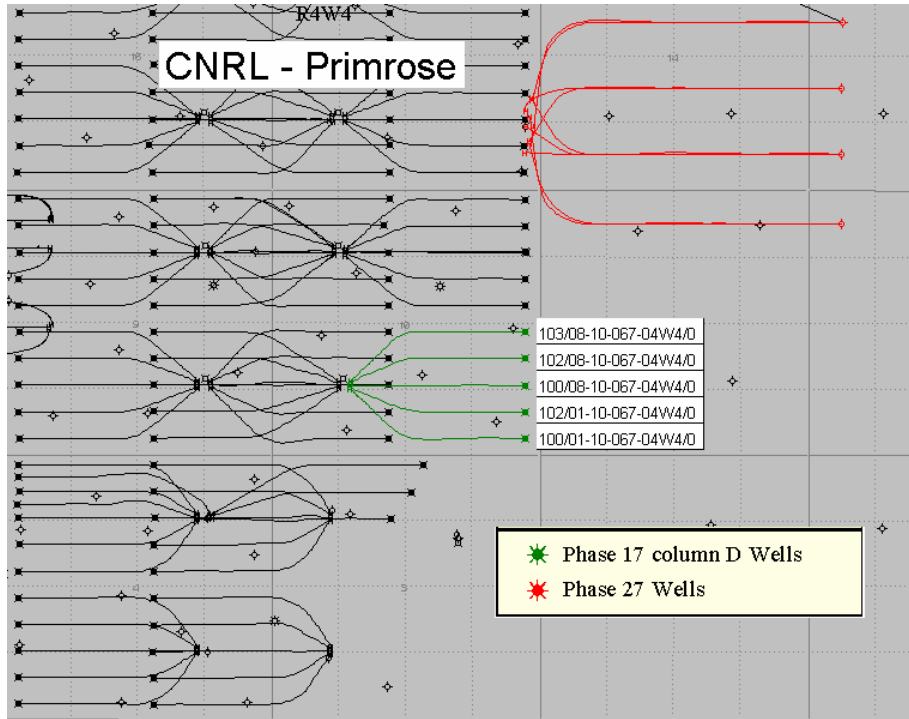


Figure 2 – CNRL Primrose Phase 17 D Column and Phase 27 Well Map.

Question

3. On page 2, CNRL states, “A primary recovery pilot was conducted at Primrose East Burnt Lake pilot in the early 1990’s. Here primary oil rates were 10-30 m³/d well.”
 - a) Provide a comparison of the reservoir and bitumen properties for the Primrose East Burnt Lake Pilot and area 5 on Figure 6.1.

Response

3. a)

Bitumen Properties

The only well drilled in area 5 on Figure 6.1 of the July 4th, 2006 submission is 1AA/06-04-068-03W4/00. The viscosities from this well match with the trend of viscosity vs. distance from the Clearwater top presented in Figure 1.2 of the July 4th, 2006 submission. Figure 3 below displays the data from Figure 1.2 in blue with the viscosity data from the 1AA/06-04-068-03W4/00 well displayed in pink.

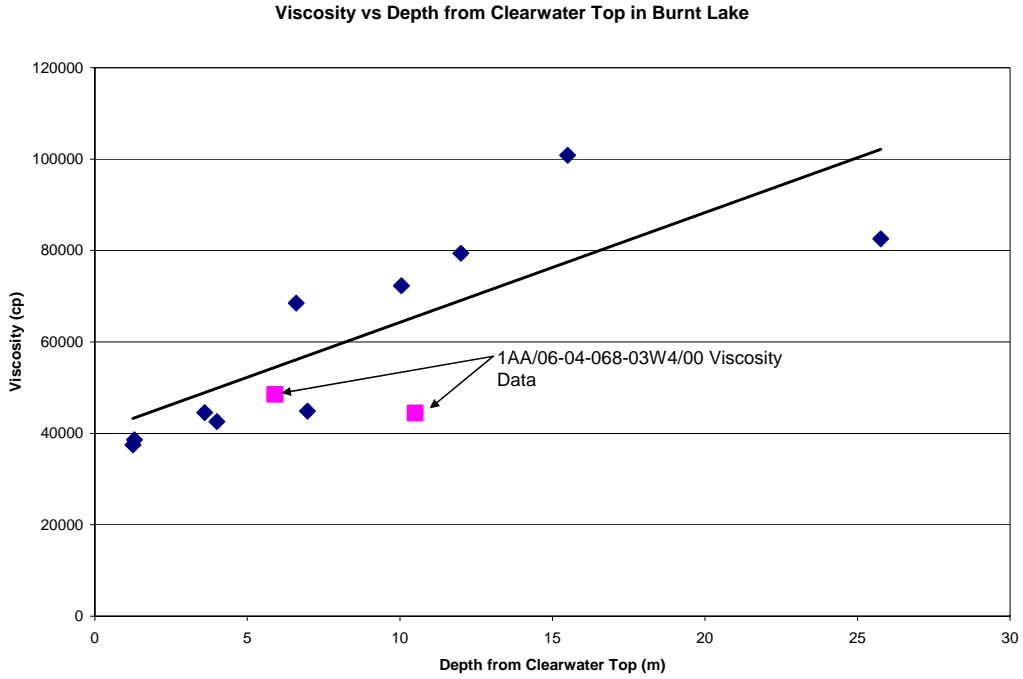


Figure 3 – Viscosity vs. Depth from Clearwater Top in Burnt Lake and Area 5 of Table 6.1 of the CNRL July 4th, 2006 Submission

Reservoir Properties

Table 2 – Comparison of Burnt Lake Pilot Geology to Area 5 of Figure 6.1 of CNRL’s July 4th, 2006 Submission.

Yellow sand	H (m)	Bitwt (%)	Porosity (%)	Sw
BL Pilot	20.1	10.2	32	0.35
Area 5	6.0	8.9	32	0.43

Question

- b) Provide the cumulative oil production data for the Primrose East Burnt Lake pilot.

Response

b) Figure 4 below shows the cumulative oil production for the Burnt Lake Pilot:

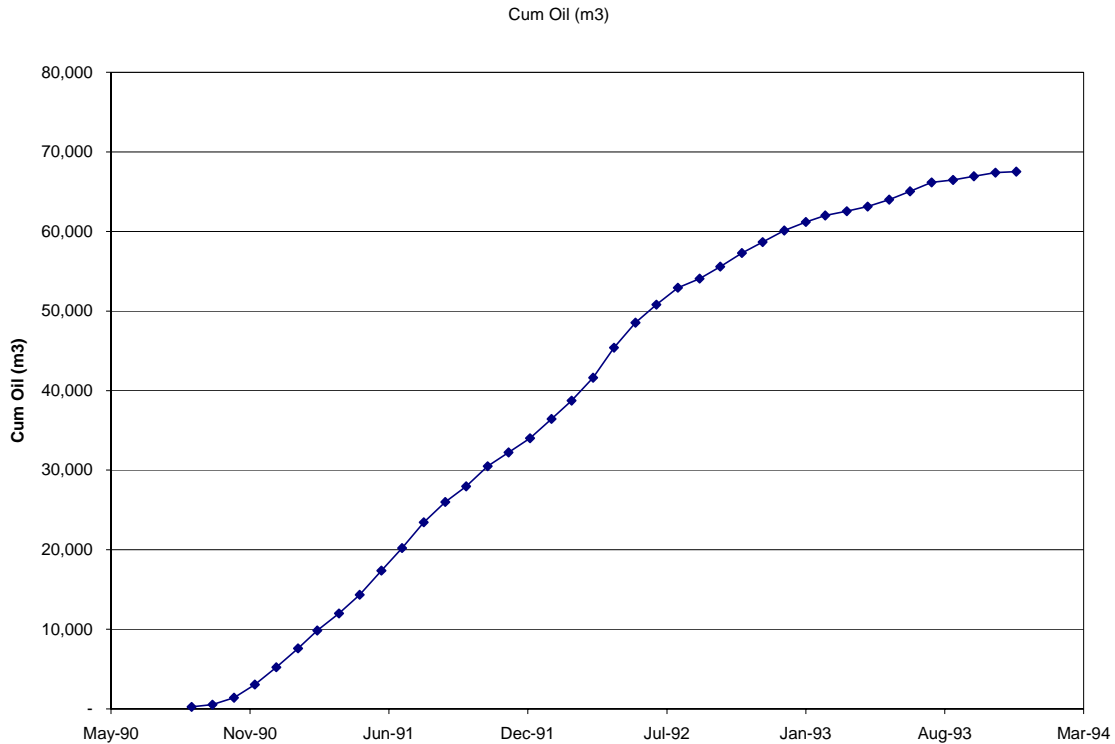


Figure 4 – Cumulative Oil Production from the Burnt Lake Pilot

Question

c) *Discuss the impact that current completions practices and technology might have had on the primary production from the pilot area.*

Response

c) The use of current technology in primary production should increase the production efficiency of the Clearwater Formation. Over the past 15 years improvements in sand handling and improvements in well stimulation, through the use of coil tubing, should increase the primary productive capability of the wells located in specific areas within the Clearwater Formation.

Question

4. *With respect to thermally induced cold flow:*

a) *On page 3, thermally induced cold flow at North Tangleflags is used as an analogy for the Primrose Blue Valley sand facies assemblage E. Provide a comparison of the reservoir and fluid properties for the tow areas and explain why the analogy is appropriate.*

Response

4. a)

Bitumen Properties

The reservoir fluid properties of the two areas can be compared as follows in Table 3:

Table 3 – Reservoir Fluid Comparison of Clearwater and GP Formations

Area	Formation	°API	Viscosity (cp)*
North Tangleflags	GP (General Petroleum)	11	100,000
Primrose Blue Valley	Clearwater (FAE)	11	100,000

* At original reservoir conditions

The bitumen in Facies Assemblage E and in the GP in North Tangleflags both require heat to be produced. The reservoir fluids in both locations are identical, from a viscosity point-of-view, and therefore production through conductive heating in the GP is believed to be an appropriate analogy for production using conductive heating in FAE.

Reservoir Properties

Table 4 – Comparison of Facies Assemblage E (Blue Sand) and GP in North Tangleflags

Area	H (m)	Bitwt (%)	Porosity (%)	Sw
FAE (Blue sand)	2.0	9.2	32	0.41
GP (NTF)	2.5	12.5	32	0.17

Table 4 shows the reservoir properties for both FAE (Blue sand) and the GP in North Tangleflags are the same and only differ slightly in bitumen saturation.

Question

b) *Provide an explanation, with a sample calculation if possible, of how the curves shown on Figure 1.4 were generated.*

Response

b) Facies Assemblage E will be conductivity heated by CSS operations in Facies Assemblage A&B. Assuming that during the life of CSS the upper portion of FAB has an average temperature of 150C. Temperatures above FAB can be calculated by simple 1-D heat conduction assuming a thermal heat diffusivity of 8e-7 m2/s. The data for these calculations is included on the attached CD in the Excel file “CNRL Response to EUB Question 4-b.xls”.

Question

c) *With respect to Figures 1.6 and 1.7, show the location of the thermal area relative to wells 14/15-23-53-25W3M and 41/5-23-52-25W3M.*

Response

c.) Figure 5 below shows the thermal operations area at North Tangleflags. The 14/15-23 well is located near the centre of the thermal project and 41/05-23 is located on the western edge of the thermal project.

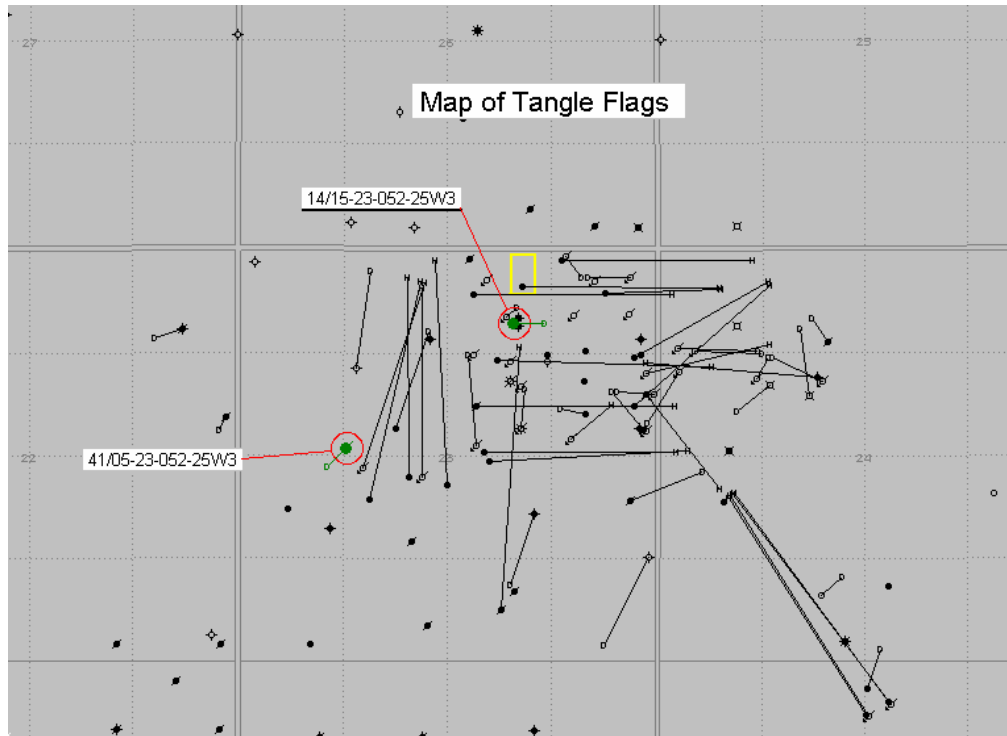


Figure 5 – Map of Tangleflags Thermal Project

Question

5. *With respect to geological data and analysis:*
- a) *Provide annotated logs (Gamma Ray, Neutron-Density, SP, and Resistivity) over the Clearwater Formation for all wells within the region of influence as defined in the application. The composite well logs should identify:*
 - i) *Formation and facies tops.*
 - ii) *All gas pay, water zone, and bitumen pay intervals.*
 - iii) *All perforated and cored intervals.*
 - iv) *Location of piezometers.*

Response

5. a) Annotated logs are provided in Appendix A.

Question

- b) *Provide core photos and core analysis for all cored wells used in the cross-sections in the application.*

Response

- b) Core photos and analysis are provided in Appendix B.

Question

- c) *Section 2 of the application provides a general description of the Clearwater depositional environments and internal facies. Provide a detailed description of the Clearwater*

depositional environments and the internal facies description for each of the Blue, Yellow and Orange Sands. Include appropriate figures (i.e. type logs and core photographs).

Response

c) Yellow valley sand is composed of two sequences, CS50 and CS60 each of which hosts three and five facies associations respectively. Below is a description of these facies in ascending stratigraphic order.

CS50 is characterized by three facies associations (CS50A10, CS50A20, and CS50A30). CS50A10 cleans upwards from as high as 50% mud to 10% mud and is dominated by mud couplets and lenticular bedding. Ichnospecies include *Planolites*, *Skolithos*, *Palaeophycus*, *Teichichnus*, *Thalassinoides*, *Rosselia*, *Arenicolites*, *Asterosoma*, *Chondrites*, *Rhizocorallium*, *Subphyllochora*, *Terebellina*, *Helminthopsis*, *Zoophycus*. CS50A20 and CS50A30 on average consist of 2 – 5 % and is dominated by low angle planar bedforms. Ichnospecies include *Planolites*, *Skolithos*, *Palaeophycus*, *Diplocraterion*, *Teichichnus*, *Thalassinoides*, *Rosselia*, *Arenicolites*, *Asterosoma*, *Chondrites*, *Rhizocorallium*, *Subphyllochora*, *Terebellina*. Overall the mud content varies from up to 50% at the base to 2% at the top of the succession, with an associated variation in ichnoassemblages from a lower more diverse marine to an upper less diverse brackish nature. CS50 is interpreted to represent an overall cleaning upward progradational deltaic succession reaching up to 26 m in thickness. A representative core photo illustrating these facies associations and their stratigraphic succession is shown in Figure 6 - Yellow Sand (CS50) type core.

The younger CS60 sequence is composed of five facies associations (CS60A50, CS60A40, CS60A30, CS60A20, and CS60A10). CS60A10 consists of 2- 10% bioturbated mud interbeds with predominantly low angle planar and wave ripple bedforms. The ichnospecies present here are *Planolites*, *Skolithos*, *Palaeophycus*, *Diplocraterion*, *Teichichnus*, *Thalassinoides*, *Cylindrichnus*, *Rosselia* and *Arenicolites*. CS60A20 is represented by 3-15% bioturbated mud interbeds and 10-15% mud clasts and is dominated by trough cross-bedding bedforms. Ichnospecies present are *Planolites*, *Skolithos*, *Palaeophycus*, *Diplocraterion*, *Gyrolithes*, *Teichichnus*, and *Thalassinoides*. CS60A30 is characterized by 7-32% mud interbeds and mud couplets with lenticular bedforms. Ichnospecies associated with this facies are similar to that of CS60A20. CS60A40 is dominated by 4-10% mud interbeds and low angle planar and wave ripple bedforms. Ichnospecies present here are more marine and consists of an assemblage similar to CS50A10. CS60A50 consists of less than 5% mud interbeds and predominantly low angle planar bedforms. Ichnospecies present are *Planolites* and *Skolithos*.

The interpreted depositional environments of these facies associations vary from subtidal bar complexes (CS60A20), to brackish bay deposits (CS60A30 and CS60A40), to possible tidal inlet deposits (CS60A50). A type log of the Yellow valley is provided in Figure 7 - Yellow Sand (CS60) type core.

The contact between CS50 and CS60 is interpreted to be a sequence boundary based on vertical and lateral stratigraphic correlations from core data.

In total, six of the eight facies associations constitute reservoir in the Yellow valley. The base of the reservoir is either the erosional base of the CS60 sequence or the gradational contact between facies associations CS50A20 and CS50A10 of the older CS50 sequence (see Figure 8 –

Yellow Sand Type Log). The highlighted green-filled curve (calculated bitumen weight) represents the reservoir interval while the black bar along the log indicates the cored interval.

Orange Sand

The Orange Sand (CS40) is composed of two facies associations, CS40A20 and CS40A10 (previously referred to as O10 and O30 respectively) (see Figures 9 & 10 – Orange sand type log and Orange Sand type core). CS40A10 consists of a cleaning up succession from 15 to 20 % mud. The cleaning upward trend is developed on the scale of 4 to 5m, as well as 15 to 20 m. Some mud drapes occur with starved ripples. Both wave and current ripples with low angle planar cross beds occur but much of the fabric is disturbed by bioturbation. In the muddier intervals *Planolites*, *Palaeophycus*, *Diplocraterion*, *Cylindrichnus*, and possible *Rosselia* constitute a diverse brackish water ichnoassemblage.

CS40A20 represents the reservoir facies association within the Orange Sand and contains approximately 1% to 5% mud. Low angle planar cross beds and some steepening upward planar cross beds (interpreted as trough cross beds) characterize the upper sandier portion of the Orange Sand. *Planolites* and *Palaeophycus* constitute the low diversity ichnoassemblage in the upper facies.

The overall cleaning upward succession and its low diversity brackish water ichnoassemblage suggest an Orange Sand progradation. A possible interpretation is as a strongly prograding subtidal bar assemblage or a brackish bay delta. The mud-rich, bioturbated facies that occurs in some of the northeastern Orange Sand may represent an autocyclic flooding event.

Blue Sand

The Blue Sand occurs in a stratigraphic unit older than that containing the Orange and Yellow Sand and has had five distinct facies identified within it (Figure 11 – Blue Sand type core) which are described below in ascending stratigraphic order.

CS3010 (previously referred to as FAA) cleans upwards from as high as 27% mud to 5% mud with a thickness generally ranging from <1 to 6 m but attaining a maximum of 12 m. Bedforms include low angle planar cross beds, current ripples and steepening upward planar cross beds interpreted as trough cross beds (these occur in the cleaner sand intervals). In the muddier intervals, some remnant mud drapes occur but these have been extensively disrupted by bioturbation. Ichnospecies represent a brackish water assemblage including *Planolites*, *Palaeophycus*, *Teichichnus*, *Diplocraterion*, *Thalassinoides*, possible *Cylindrichnus* and *Asterosoma*. A variation on Facies A occurs sporadically, contains relatively little mud, and is characterized by the occurrence of the authigenic clay berthierine.

The brackish progradational succession of CS30A10 has been variably interpreted as an upper shoreface, or as a sand bar as part of a delta at the mouth of a tidal or fluvial channel entering a brackish bay.

The muddier variety of CS30A10 is consistent with the bar model. The generally cleaner, but commonly berthierine-rich, variation of CS30A10 is consistent with a fluvial deposit.

CS30A20 (previously referred to as FAB) contains mud clasts and fines upwards. In some wells, 10 cm thick intervals occur with 50% mud clasts, but more characteristically sparsely distributed clasts constitute only 2% of the interval. Bedforms include low and high angle planar cross beds, and steepening upward planar cross beds interpreted as trough cross bedding. Mud drapes and lenticular bedding tend to occur toward the top of the facies suggesting an overall fining upward succession. Trace fossils are restricted to *Planolites*, and possible *Teichichnus*. The tidal influence suggested by mud drapes, presence of clasts, and fining upward succession are consistent with a tidal channel origin for the facies.

CS30A30 (previously referred to as FAC) commonly has a sharp boundary with CS30A20 and is predominantly mud (80% to 85%) interbedded with 1 to 3 cm thick sand beds. Both muds and sands are highly bioturbated with robust *Teichichnus*, *Planolites*, *Palaeophycus*, *Terebellina*, and some possible *Chondrites*. This brackish assemblage and mud rich nature of the deposits are suggestive of a brackish bay depositional environment. This facies tends to occur on the eastern side of the Blue Sand unit. Where Facies C and D are not developed, Facies B is described to the top of the Blue Sand from its contact with the lower Facies A.

CS30A40 (previously referred to as FAD) is gradational from CS30A30 with mud content at the basal contact of no less than 85% and sanding upward to a decreased mud content of 40%. Some vestigial mud drapes are preserved but most are disrupted by bioturbation. The ichnoassemblage is similar to that of CS30A30 suggestive of a brackish environment. Bioturbation has disrupted most bedforms but some current ripples are preserved. CS30A40 has been interpreted as a flood tidal delta washing sand into the brackish bay of CS30A30.

CS30A50 (previously referred to as FAE) has a sharp lower contact with CS30A40 with an associated abrupt increase in grain size. In places, a lag of rip up clasts and woody fragments has been observed at this contact. CS30A50 fines upward with increasing proportions of silt and mud in burrowed interbeds. These grain size changes are not in all cases readily identifiable on logs due to factors such as the occurrence of mud clasts in otherwise coarser sands at the base of CS30A50. The clasts can make the logs appear "muddy" thereby masking the fining upward trend which can be seen in core. Ichnospecies are limited to *Planolites*, *Thalassinoides*, and *Skolithos*. CS30A50 has been interpreted as a tidal inlet deposit.

In total, two of the five facies associations constitute the primary reservoir in the Blue valley. The base of the reservoir is either the erosional base of CS30A20 or CS30A10 (see Figure 12 – Blue Sand Type Log).

Question

- d) Provide bitumen net pay maps, at a scale of 1:75000, for the following sands based on bitumen saturation equal to or greater than 50% pore volume with the net pay values for each well posted on the maps. Include the cutoffs (resistivity, porosity) used by CNRL to determine the net pays.

- i) *The Clearwater Orange Sand.*
- ii) *The Clearwater Yellow Sand.*
- iii) *The Clearwater Blue Sand.*
- iv) *Facies A/B of the Blue Sand.*
- v) *Facies E of the Blue Sand.*

Response

- d) Net pay maps are provided in Appendix C.

Question

- e) *Provide the reservoir parameters (area, porosity, water saturation, oil volume formation factor) used to calculate the original bitumen in place values shown on table 6.2.*

Response

- e)

Table 5 – Reservoir Parameters Used to Calculate Original Bitumen In Place for Table 6.2 in CNRL’s July 4th, 2006 Submission

Location	Location Description		Net Pay				
			ROI			Porosity (%)	Sw
area (m2)	H (m)	Bitwt					
1	>7m yellow (net)	east of Moore A, B, C	34646599.9	7.6	8.65	32.0	0.45
		Moore A Moore B & C Moore U					
2	>7m blue (net) FAA + FAB FAE	west of Fisher K	422467.1	18.4	9.17	32.0	0.41
		west of Fisher K Fisher K					
3	>7m orange (net) >7m blue (net)	south of Fisher A	5956568.5	9.2	9.94	32.0	0.37
		east of Fisher A Fisher A	2673243.6	8.1	8.95	32.0	0.43
4	>7m blue (net)	west of Fisher E & F	36826074.5	2.4	9.00	32.0	0.43
		Fisher E and F					
5	<7m yellow	east of Moore A, B, C	2603805.1	6.0	8.94	32.0	0.43

Question

- f) *Provide a map showing the thickness of any water zones associated with the gas or bitumen zones.*

Response

- f) Water zone map is provided in Appendix D.

Question

- 6. *With respect to the calculation of the regions of influence:*
 - a) *On page 23 of its submission CNRL states that simulation of the pressure data for the Orange Sand observation well yields a good match using a diffusivity of $1.5 \cdot 10^{-3} \text{ m}^2/\text{s}$.*

However, Figure 3.1 shows the simulated pressures diverging from the measured pressures at later times. Did CNRL do any sensitivity calculations using different diffusivity values to try to get better match of the later time data? If yes, provide the results. If not, why not?

Response

6. a) A sensitivity study was conducted which resulted in $1.5 \times 10^{-3} \text{ m}^2/\text{s}$ giving the best match. Late time data on the orange sand observation well did not match likely due to some small localized shear failure on the horizontal well during thermal operations changing the apparent inter-well distance for pure pressure single phase pressure diffusion. The early time data gives the most confidence in the mechanism.

Question

b) Did CNRL simulate the pressure data for the Blue Sand observation well? If yes, provide the results. If no, why not?

Response

b) Figure 13 is the match of both the Orange and Blue sand observation well. The early time slope is similar for both orange and blue pressure response indicating that diffusivities are similar in the two zones.

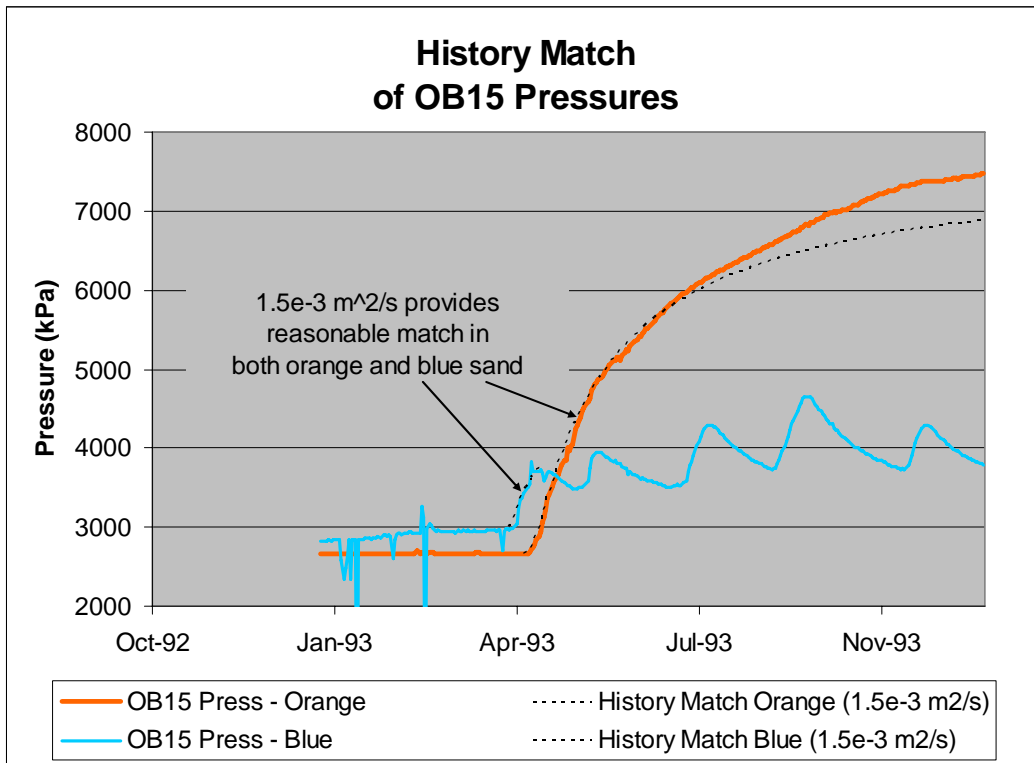


Figure 13 – History Match of OB15 Pressure

Question

- c) *Provide the input information used to generate the curves presented on Figure 3.2 and, if possible, provide a sample calculation showing how the curves were generated.*

Response

- c) The data for from this test is included on the attached CD in the Excel file "CNRL Response to EUB Question 6-c.xls".

Question

7. *With respect to the methodology of CNRL's gas pool analysis described on page 28 of its submission where CNRL states that in interpreting the P/Z plots, early time data were used to delineate an "initial decline" curve which was extrapolated to yield and "Original OGIP" and this was compared to a "later decline" curve delineated by later time data which was extrapolated to yield a "Recoverable Gas in Place".*

- a) *Comment on the reliability of extrapolating the early time data considering the amount of data that are available for the pools and CNRL wants the EUB to shut in.*

Response

7. a) In the pools that have early data, CNRL believes this third party static gradient data must be honoured creating the initial decline. This "early decline data" makes up between 1/3 and 1/2 of the current cumulative production of the subject gas pools which CNRL considers of substantial importance.

In pools where there is no early data a straight line P/Z can be drawn but this does not prove pure depletion drive (See Section 4.2.1 of CNRL's July 4th, 2006 Submission). In these cases the initial decline can be inferred using the data from volumetrics and decline analysis.

Question

- b) *Comment on whether the data actually show two distinct trends or whether there is a just scatter in the data around a single trend.*

Response

b). It is CNRL's position is that in a gas reservoir with 2 – 3 Darcy permeability, pressure variation of more than approximately 100 kPa are unlikely to occur. In the cases where there is sufficient early pool pressure data available to demonstrate an initial decline drawing a straight line P/Z between the initial data and most recent data would require accepting deviation of 300 kPa from the pressure tests to the P/Z line, something that is not likely given reservoir permeability. This conclusion is also supported by the fact that many of these pools have, or will produce volumes greatly in excess of their volumetric OGIP. This means that when the entire dataset is considered data scatter cannot explain the current phenomenon which must be bitumen degassing.

CNRL analysed each pool using the aggregation of all data available including volumetrics, material balance (P/Z), and decline analysis. The following quotation from the July 4th, 2006 submission details the analysis methodology:

"The analysis methodology described below, and used for each gas pool (Section 5) in this submission, involves collecting and analyzing a wide range of data recognizing that all data is subject to imprecision and other limitations. It is in weighing all

the pertinent data and evidence that the best (and most likely) explanation is derived."

Question

8. Section 5.0 has a number of plots showing pressure and production data and analysis.
- a) Provide a tabulation of well location, type of test date of pressure test and shut-in time for each static gradient and AOF test for each of the pools in Section 5.

Response

8. a) The well test tabulation can be found in Appendix E.

Question

- b) On page 31, in reference to Figure 5.4, CNRL states that, "the sum of the current declines for the wells (dotted red line) indicates that the pool will make 350 E6m³". Explain how the dotted red line is supported by the production data after a cumulative production of about 120 E6M³.

Response

- b) The dotted red line is the sum of the individual well rate vs. cumulative production decline matches.

Question

- c) On Page 14, it is stated, "The 10-22 well is currently shut-in by Canadian Natural...". EUB records indicated that the 10-22-67-5W4 well produced full hours in April 2006. When did CNRL shut-in the well?

Response

- c) The 10-22-67-5W4M well was shut-in on April 3rd, 2006. The production hours in the public database for the month of April were in error and have been corrected.

Question

9. With respect to the pressure monitoring wells:
- a) Provide an electronic tabulation of the pressure data in excel format for each piezometer in the pressure monitoring wells.

Response

9. a) The data requested is included on the attached CD in the Excel file "CNRL Response to EUB Question 9-a.xls".

Question

- b) The data on most the pressure monitoring wells does not appear to be current. Update the pressure monitoring well plots with current data if additional data is available.

Response

b) The updated pressure plots are included in Appendix F.

Question

c) *It appears that some of the piezometers are set in the gas and/or bitumen zones while other piezometers are “hung” in the wellbores (i.e. wells 13-33-67-3W4M, 13-10-68-3W4M, and 11-12-68-4W4M). Explain how each of the piezometers were installed, and indicate how the wells are completed and which zones are being monitored by each of the piezometers.*

Response

c) See Appendix G for installation and completion information. The table below details which zone is monitored by each individual piezometer.

Table 6 – Piezometer Depth and Monitored Facies

Well	Depth (mKB)	Monitored Facies
11-12-68-4W4M	482.5*	Blue Sand Facies Assemblage E
13-10-68-3W4M	491.7*	Yellow Sand
7-13-68-4W4M	476.8	Fisher E/F Gas Cap
7-13-68-4W4M	492.5	Blue Sand Facies Assemblage B
7-13-68-4W4M	497.3	Blue Sand Facies Assemblage B
102/9-29-67-3W4M	438	Yellow Sand
102/9-29-67-3W4M	440	Yellow Sand
9-16-67-5W4M	452.3	Orange Sand
9-16-67-5W4M	448.7	Orange Sand
10-32-68-4W4M	478.5	Blue Sand Facies Assemblage E
10-32-68-4W4M	476.2	Blue Sand Facies Assemblage E
13-33-67-3W4M	375.5*	Yellow Sand

* - Indicates hung piezometer.

Question

d) *Pressure monitoring well 102/10-33-68-4W4M is referred to on Figure 5.17 regarding CNRL’s Fisher K Pool but only the pressure data for the gas zone are shown. In CNRL’s June 30, 2005 submission, CNRL provided a pressure plot for this well which indicated there are three piezometers in the well. Provide a pressure plot (an electronic tabulation) that shows the data for all three piezometers, explain how the piezometers were installed, and indicate how the well is completed and which zones the piezometers are monitoring.*

Response

d) See Appendix G for installation and completion information. Figure 14 below shows the pressure plot for all installed piezometers in the 102/10-33-68-4W4M well.

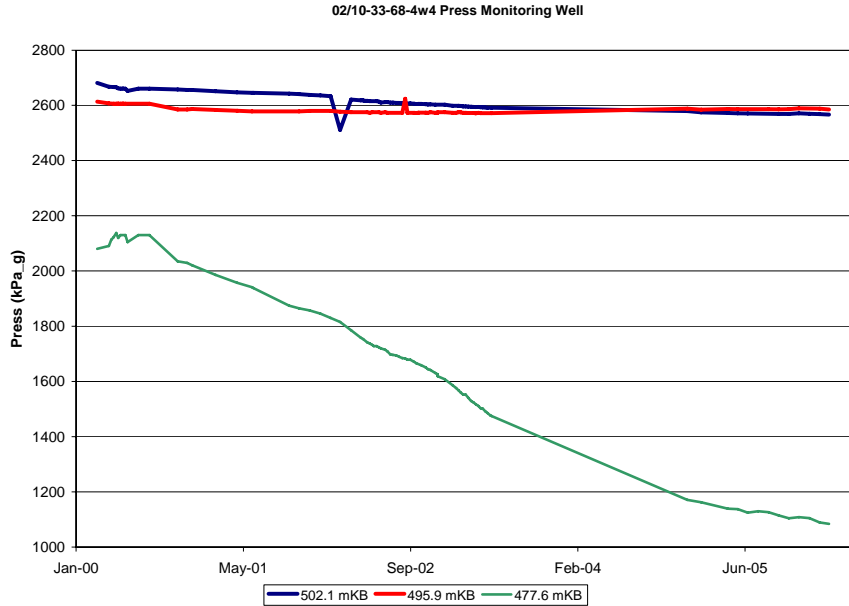


Figure 14 – 102/10-33-68-4W4M Pressure vs. Time Plot.

Table 7 – 102/10-33-68-4W4M Piezometer Depth and Monitored Facies.

Well	Installation Depth (mKB)	Monitored Facies
102/10-33-68-4W4M	477.6	Fisher K Gas Cap
102/10-33-68-4W4M	495.9	Blue Sand Facies Assemblage B
102/10-33-68-4W4M	502.1	Blue Sand Facies Assemblage A

Question

e) *It appears the Figure 5.5 presents the bitumen pressure at the 11-12-68-4W4 well. Provide an explanation why the pressure shown on this plot in 2005 is lower than the gas pressure at that 7-13-68-4W4 well taken in 2005, as shown on Figure 5.6.*

Response

e) In an effort to be consistent with the data presented in the P/Z plots the data presented for the 476.8 mKB piezometer in the 7-13-68-4W4 well is presented in kPa_a, which is not clearly indicated in Figure 5.6. Figure 15 presented below shows the 476.8 mKB piezometer data presented in kPa_g.

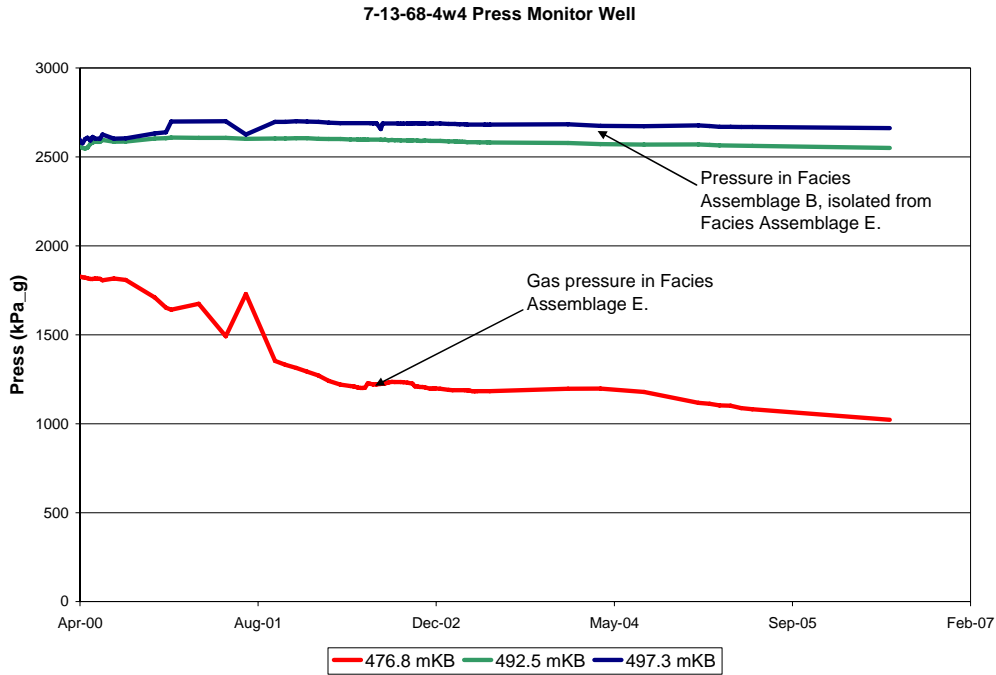


Figure 15 – 7-13-68-4W4M Pressure vs. Time Plot.

When this data is presented more clearly, the 7-13 gas cap piezometer reads 933 kPa_g and the bitumen pressure in the 11-12-68-4W4M is 896 kPa_g, this pressure differential CNRL considers within the range of the instruments. Figure 16 shows the gas pressure from the 7-13-68-4W4M and the bitumen pressure in Facies Assemblage E in the 11-12-68-4W4M.

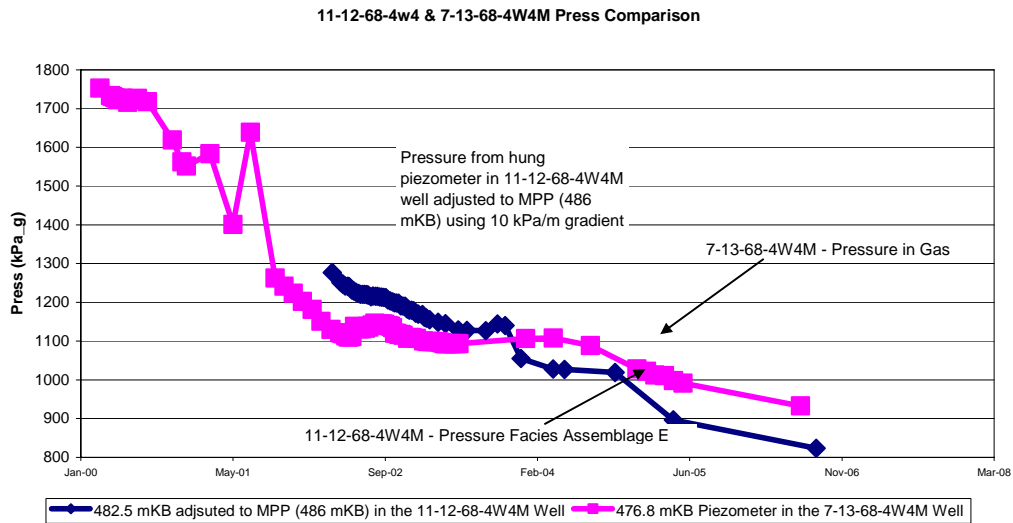


Figure 16 – Pressure Comparison of 7-13-68-4W4M and 11-12-68-4W4M Piezometers.

Question

- f) *Provide the original pressure for the bitumen zone in the area of application and the method use to determine this pressure.*

Response

f) The original pressure of the bitumen zone in the area is approximately 2600 kPa_a because it was in equilibrium with the gas zone. This pressure will vary with depth based on the principle of hydraulic continuity explained in Section 4 of the July 4th, 2006 submission.

Question

- 10. *Provide the basis for CNRL’s gas pool mapping, specifically:*
 - a) *Why is the 11-6-68-3W4M well interpreted to be in CNRL’s Fisher E/R Pool considering that its initial pressure prior to being produced appears to have been lower that the pressures in the other wells in the pool that had already been on production by the time the initial pressure was taken in the 11-6-68-3-W4M well?*

Response

10. a) The initial pressure in the 11-6-68-3W4M well is lower than expected through the hydraulic continuity calculation (defined by Section 4.3 of CNRL’s July 4th, 2006 evidence). This lower initial pressure means that the 11-6-68-3W4M well is in pressure communication with one of the surrounding producing gas pools. There are four possible gas pools that surround the 11-6-68-3W4M which are Fisher E/F, Moore A, and Moore B/C. The pressure differentials between the 11-6-68-3W4M well and the surrounding gas pools in early 2001 are shown in Table 8 as follows:

Table 8 – Pressure Comparison to 11-6-68-3W4M Well

Pool	Initial 11-6-68-3W4M Pressure (kPa_a)	Pool Pressure at the Same Time as Initial 11-6-68-3W4M (kPa_a)	Differential (kPa)
Fisher E/F	1575	1724	149
Moore A	1575	1317	258
Moore U	1575	N/A	N/A
Moore B/C	1575	1483	92

Based on the pressure differentials presented above connection with the Moore A pool can be ruled out, leaving only possible connection to Moore B/C, Moore U, and Fisher E/F.

When a P/Z plot is done using only the 5-17-68-3W4/2 well and the 11-6-68-3W4M well to determine if there is a connection between these two wells, there is a differential of 725 kPa between the initial 11-6 pressure and the P/Z decline line, therefore 11-6 is not in communication with the Moore U Pool.

While the pressure differential for the Fisher E/F pool is slightly higher than CNRL would normally accept but the seismic data presented in Figure 5.2 in the July 4th, 2006 submission shows that the 11-6 well is more likely connected to the Fisher E/F pool than to the Moore B/C pool. This pressure differential might also be explained through the presence of perched water in the area of 11-6-68-5W4M which would allow the well to be connected to the Fisher E/F pool without being exactly the same pressure as the remainder of the pool. It is only when accounting for all of the available data that the best determination of which pool that the 11-6-68-3W4M well is connected to can be determined.

Question

- b) *Why is the 5-17-68-3W4M well interpreted to be in a single well pool rather than being in CNRL's Moore B/C Pool considering that the well appears to have a depleted initial pressure?*

Response

- b) The 5-17-68-3W4M well was interpreted to be a single well pool because of the following information presented in Section 5.6 of CNRL's July 4th, 2006 submission:
The original pressure measured at 5-17 is lower than what would be expected by hydraulic continuity indicating that some pressure depletion has occurred. Recent pressures in the area show that Moore U is 300 kPa higher than Moore B, and 100 kPa higher than Fisher E (but have significant Seismic lows between Moore U and Fisher E, Figure 5.2). It appears that Moore U is a single well pool connected to surrounding gas caps by bottom water.

For further clarification of the location of perched water zones refer to the map provided in the answer for question 5 f).

Question

- c) *Why doesn't CNRL interpret the wells in sections 2,3, and 10-69-4W4M to be in CNRL's Fisher K Pool?*

Response

- c) The wells in Section 3 and 10-69-4W4M were not mapped with the 100/10-33-68-04W4/2 well because they have pressures that vary greatly from the pressure recorded at the 10-33 production well and 102/10-33 piezometer well. CNRL maintains that a pressure differential of greater than approximately 100 kPa are not likely to occur in gas reservoirs with 2 – 3 Darcy permeability.

When the 10-33 production well was drilled it was initially pressure tested at 2481 kPa_a (January 27th, 1998) while the pressure measured at the 5-10-69-4W4M well was measured at 2136 kPa_a (December 20th, 1997), a difference of 346 kPa which means that these two wells are not in the same pool.

When the 103/08-03-69-04W4/2 well was drilled it was initially pressure tested at 976 kPa_a (January 3rd, 2005) and the pressure at the piezometer well 102/10-33 was measured at 1261 kPa_a (January 1st, 2005), a difference of 285 kPa which means these two wells are not in the same pool.

Question

11. *On page 56 of its submission CNRL states that production of the solution gas from the progressively migrating regions of influence will defeat the gas drive mechanism and thereby prevent the recovery of the bitumen. Provide a discussion of why production of the solution gas would prevent the recovery of bitumen rather than reduce the recovery of bitumen.*

Response

- 11.) The production of solution gas will result in a reduction of bitumen recovery. The areas within the region of influence of the gas caps in question are the edges of the currently developable resource base in the Primrose area. The fact that these areas are of marginal economic potential to begin with means that any loss of recovery would result in wells in this area

becoming uneconomic, effectively reducing the recovery to nothing therefore sterilizing the bitumen resource.

Question

12. *Provide copies of references 1, 2, 3, 4, 6, (pages 31-34), 7 and 8.*

Response

12.) The technical papers are included in Appendix H.