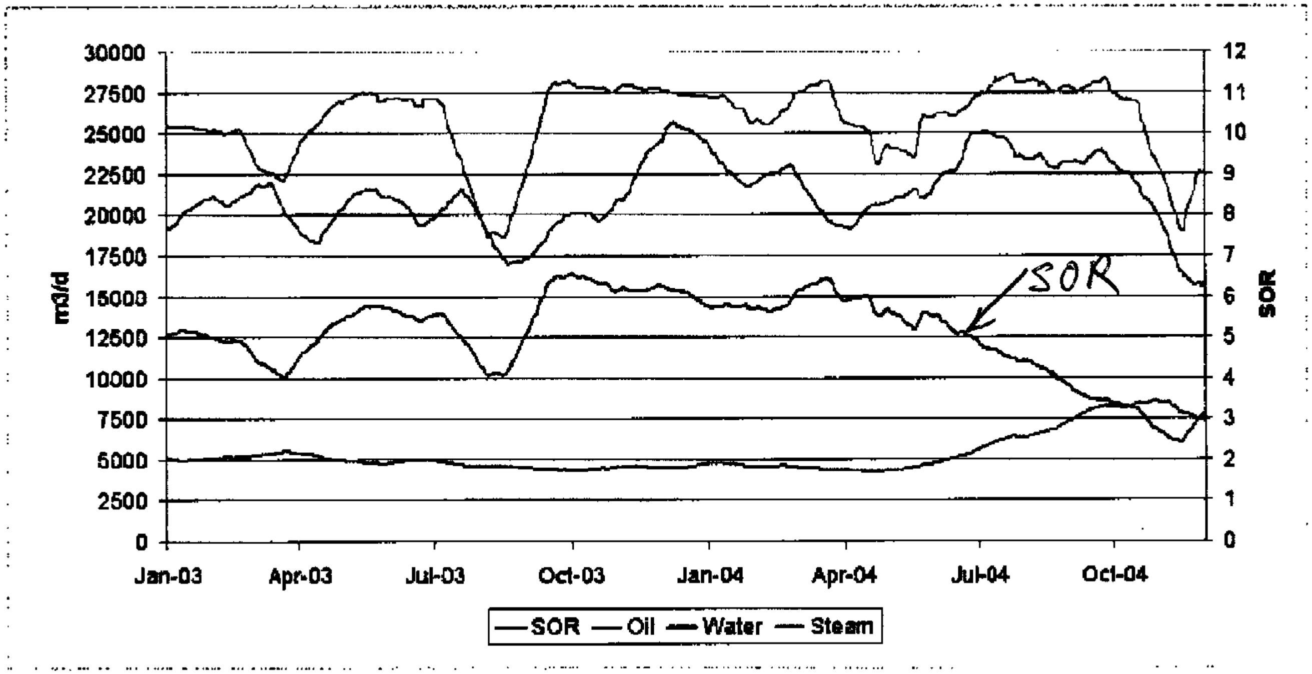
C-9

Undertaking 1. Regarding Primrose SOR: Between October 2003 and April 2004, SOR reported to be at or near 6. Confirm this from Jan 7, 2005 Annual Presentation to EUB, Slide #16. (Transcript Reference: Line 00632 – 23)

Response: The answer is yes. However, the performance shown in this slide (see attachment #1) is from the entire area (400+ horizontal wells) of the Primrose Cyclic Steaming Stimulation (CSS) operations. The variation of SOR during the operation is of cyclic features, depending on steam schedule. High SOR during this particular period is due to the shutin of a number of high productive wells for steaming. It can be seen from the graph that oil production increases and SOR drops. In addition, most wells in Primrose South are in the late stage of the CSS operation. Average steam quality at Primrose is about 72%.

Primrose Production



Attachment #1 #16

Jan 7, 2005, CNRL Annual Presentation to EUB

Canadian Natural

Undertaking 2. Regarding Virgin Pressures in the Upper Mannville in the Kirby Area: What does CNRL believe is the Virgin Pressure / Range of Pressures? (Transcript Reference: Line 00652 – 19)

Response:

The following data was obtained from the SSG Supporting Material (SSG CD) of the 2nd Interim Proceeding (Proceeding No. 1347004).

KIRBY FIELD
UPPER MANNVILLE POOLS
PRE-PRODUCTION PRESSURES

Pool Name	Field Code	Pool Code	No. of Wells	No. of Pressures	Lowest Pressure	Highest Pressure
Upper Mannville I	527	250009	189	57	1721	2257
Upper Mannville J	527	250010	21	7	2062	2152
Upper Mannville S	527	250019	2	3	2057	2060
Upper Mannville II	527	250035	4	3	2110	2210
Upper Mannville RR	527	250044	1			
Upper Mannville XX	527	250050	2	2	2065	2428
Upper Mannville YY	527	250051	1	2	2070	2090
Upper Mannville U/D-381	527	250098	1			
Upper Mannville YYY	527	250725	3	12	1224	2143
Upper Mannville U2U	527	250747	31	4	2129	2211
Upper Mannville V2V	527	250748	36	4	2117	2125
Upper Mannville O3O	527	251115	13	6	2008	2172
Upper Mannville Z3Z	527	251126	9	2	2100	2139
Upper Mannville A4A	527	251127	1			
Upper Mannville B4B	527	251128	7	1	2093	2093
Upper Mannville C4C	527	251129	1	1	2358	2358
Upper Mannville D4D	527	251130	1	1	2288	2288
Upper Mannville E4E	527	251131	1	2	2083	2083
Upper Mannville F4F	527	251132	4	4	2045	2148
Upper Mannville G4G	527	251133	1			
Upper Mannville H4H	527	251134	1			

- If the two lowest pressures are excluded as possibly being invalid pressure data, then the range of virgin pressures for the Kirby Upper Mannville Pools is 2008 to 2428 kPaa. The difference from lowest to highest is 420 kPaa.

- Correcting the 3-21-74-7W4 February 13, 1994 static gradient pressure of 1841 kPag for:

    - overnight buildup in surface pressure (1848 – 1815 = 33 kPa)
    - pressure difference between the surface dead weight gauge and the downhole gauges at surface depth (1815 – 1728 = 87 kPa)
    - correction to absolute pressure (93 kPa)

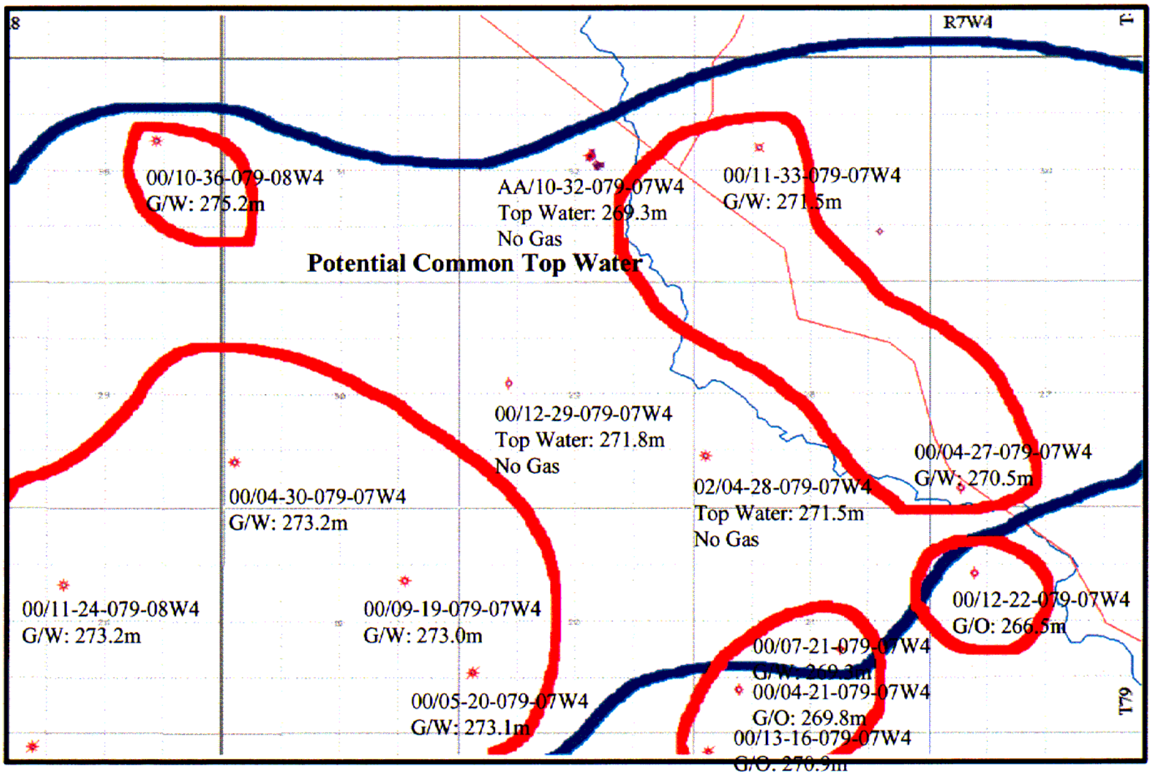
  results in a bottomhole pressure of 1841 + 33 + 87 + 93 = 2054 kPa. This pressure is within the range of Kirby Upper Mannville virgin pressures.

- The pressure of 1918 kPaa (October, 2001) in 11-33-74-7W4 was accepted as a virgin pressure and not a depleted pressure. The 11-33 pressure is less than the 3-21 pressure, even when only the correction to absolute pressure is used.

- In addition to the above variations in virgin pressure for the Kirby Upper Mannville pools, there is the DST from 11-23-74-7W4 taken in February 1980 prior to any production from Upper Mannville pools in the Kirby area. The DST pressure for the Upper Mannville zone was 1595 kPaa. This is well below the accepted virgin pressure for the area and there is no explanation for it.

Undertaking 3. Regarding 10-32, 11-33 and 10-36-79-8W4 Pooling Map: Provide a pooling map to demonstrate CNRL's interpretation of depletion at 11-33. (Transcript Reference: Line 00660 – 10)

Response:



Having examined the fluid contact data for 11-33-79-7W4 and 10-36-79-8W5 CNRL recognizes a Gas / Water contact difference of 3.7m. This means that these two wells cannot be directly connected through the gas, but may communicate through a common top water. Similarly, the gas cannot be directly connected to gas in 9-19-79-7W4, 5-20-79-7W4 and 4-30-79-7W4, but again these wells may share a common top water connection.

The point of CNRL's submissions, which has been reinforced through the course of this hearing, has been that there are a variety of possible explanations for the pressure data recorded at 11-33-79-7W4. As the interpretation put forth by Petro Canada is neither definitive, nor even the most likely, the material submitted cannot be considered evidence that the McMurray regional shales are not a seal. CNRL believes that the evidence continues to support the conclusion of the Board that the regional McMurray muds do act as a seal.

Undertaking 4. Regarding Wabiskaw B Valley fill Wt% bitumen: What weight % does CNRL believe more accurately accounts for 50% bitumen saturation for the Wabiskaw B Valley Fill? (Transcript Reference: Line 00661 – 23)

Response:

Weight Percent Bitumen (WTAR) is calculated as follows:

$$\text{WTAR} = \frac{(\text{PHIE*SO*RHOHY})}{((1\text{-VSH-PHIE})\text{*RHOMA}+(\text{VSH*RHOSH})+\text{PHIE*}(\text{SO*RHOHY}+\text{SW*RHOF})}$$

Where:

SO - Oil Saturation
SW - Water Saturation
PHIE - Effective Porosity
VSH - Volume of Shale
RHOMA - Matrix Density
RHOSH - Shale Density
RHOHY - Hydrocarbon Density
RHOF - Fluid Density

Kirby Wabiskaw B Valley Fill Parameters (Core Porosity)

SO =0.5
SW =0.5
PHIE =0.34 (Median value from core analysis)
VSH =0.3 (Clavier corrected from 6 sample Kirby wells)
RHOMA =2650 kg/m^3
RHOSH =2300 kg/m^3
RHOHY =1000 kg/m^3
RHOF =1000 kg/m^3

WT TAR Frac =0.086

Although the PHIE of 34% is statistically robust due to the large sample involved, it suffers from the problem that core derived porosity are potentially higher than in situ. Observed porosity values from a more limited suite of logs range from 27 to 35%, with estimated average of approximately 31%. Substituting this value in the calculations:

Kirby Wabiskaw B Valley Fill (Log Porosity)

WT TAR Frac =0.076

Based on these observations CNRL believes that 50% saturation in the Wabiskaw B Valley fill would be equivalent to a Wt Tar of approximately 7.6%. CNRL also notes that using these same calculations the RGS cutoff of 6 Wt %

Tar equates to a bitumen saturation of approximately 39%. This is likely to be part of the overestimation of pay documented by CNRL.

Undertaking 5. Regarding SAGD Calculations: Provide calculations as per P. 1 and 2 of April 11, 2005 IR response to Board Staff for each of three phases of SAGD, namely Steam Chamber Rising, Spreading and Falling. (Transcript Reference: Line 00666 – 23)

Response:
Figure 7 presented in CNRL's submission on February 14th already showed the three phases of SAGD production. I have reproduced the Figure 7 with more points in phase 1 (see attachment 2). Due to a10-meter pay, steam takes less than one year to reach the top. Therefore, the phase 1 is relatively short. Phases 2 and 3 are relatively longer. However, if the reservoir is thicker, phase 1 production will be longer.

As an example, the parameters used for calculation of Wabiskaw SAGD (attachment #2) are listed below:

k(Perm.)	1.6×10^{-12} m^2		M (Viscosity Coefficient)	3.4
α(Thermal Diffusivity)	5.38×10^{-7} m^2/s		Ts (Steam Temp.)	212 °C
ΔSo (Mobil Oil Sat.)	0.51 (0.61-0.10)		Tr (Reservoir Temp.)	15 °C
ϕ (Porosity)	0.32		h(Reservoir Height)	10 m
νs (Viscosity at Ts)	8.3×10^{-6}(m^2/s)$^{-1}$		K(Thermal Conductivity)	2.0 W/m °C
ρ (Density of Rock)	2600 kg/m^3		C (Heat Capacity)	840 J/kg °C
W (Well Spacing)	100 m		L (Well Length)	700 m

Based on the equations described in April 11, 2005 IR response to Board Staff, steam chamber needs about 10 months to reach the top of the reservoir and requires about 4.2 years to reach the boundary (50 meters from each side of the horizontal well). Taking above parameters into related equations, oil production rates from three phases of the SAGD process can be predicted.

For rising chamber, oil rate

$$Q=0.1294\ t^{1/3}$$

t is production time in seconds.

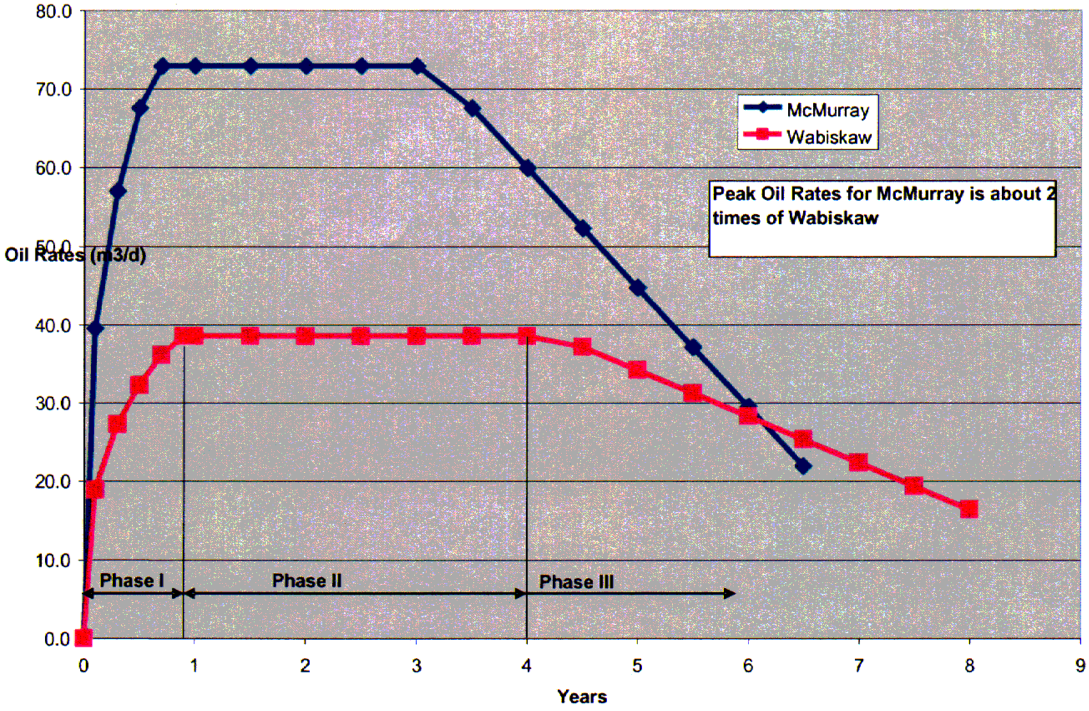
For spreading chamber, oil rate is constant:

$$Q=38.55\ \mathrm{m^3/d}$$

For falling chamber, oil rate is determined by drainage height h:

$$Q=12.19\ \mathrm{sqrt}\ (h)$$

Attachment #2 Comparison of SAGD Oil Production Rates
(10 m Pay, 100 m Spacing and 700 Horizontal Length)



Peak Oil Rates for McMurray is about 2 times of Wabiskaw

Undertaking 6. Regarding 0.4 Coefficient from Dr. Roger Butler's work: Provide reference from CIM paper, (1994?) for use of this coefficient. (Transcript Reference: Line 00669 - 3)

Response:

In the steam chamber, two-phase flow takes place: oil and water. To estimate the flow rate of oil and water, a relative permeability for each phase is required. A coefficient of 0.4 is used to calculate the effective permeability to oil phase. For Athabasca bitumen, the reasonable average coefficient is 0.4, although it could be higher or lower depending on the water/oil ratio. The theory behind this is illustrated in Figure 11.12 (see attachment #3) of Page 178 from Dr. Butler's book "Horizontal Wells for The Recovery of Oil, Gas and Bitumen", monograph of the Petroleum Society of CIM 1994.

Attachment #3

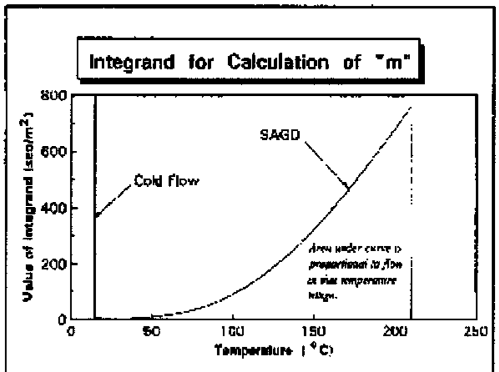


FIGURE 11.11

$$\text{theo.}\,q = 1.004 \times 10^{-3}\ \text{m}^3/\text{s}$$
$$= 86.76\ \text{m}^3/\text{d}$$
$$= 546\ \text{B/d}\ (0.33\ \text{B/ft d}).$$

Calculate Front Advance Rate at Start at y/h=1/√3

$t_c = 1.11 \times 10^8$ s = 1281 days from equation (11.27)

$U = 1.77 \times 10^{-7}$ m/s = 0.015 m/d equation (11.28)

ξ (for $T^* = 0.5$) = ln(2) α/U = 2.1 m equation (11.6)

The frontal advance rate is slower for this example than for that in Table 11.1, largely because the value of mv_s is higher for these conditions.

Average Relative Permeability for Flow of Oil

In the preceding equations, k is the effective permeability for the flow of oil. To allow for the effect of the simultaneous flow of condensate with the steam, it is usual to assume a relative permeability of 0.4 for the oil, i.e., k is taken as 40% of the absolute permeability.

This value was arrived at in the original analysis by the following argument.

The fractional flow of water, fw, is related to the viscosities and relative permeabilities by:

$$f_w = \frac{1}{1 + \frac{\mu_w}{\mu_o}\,\frac{k_{ro}}{k_{rw}}} \tag{11.29}$$

In clean sands, relative permeabilities are approximately cubic functions of the mobile saturations.

Assume that $k_{ro} = S_o^{*3}$

and $k_{rw} = (1 - S_o^*)^3 = (1 - k_{ro}^{1/3})^3$

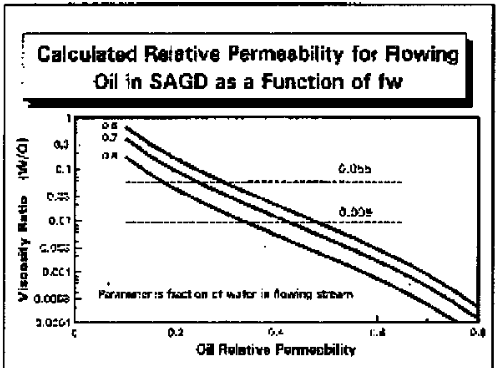


FIGURE 11.12

$$\text{where } S_o^* = \frac{S_o - S_{or}}{1 - S_{or} - S_w}$$

$$\text{Thus, } f_w = \frac{1}{1 + \frac{\mu_w}{\mu_o}\,\frac{k_{ro}}{(1 - k_{ro}^{1/3})^3}} \tag{11.30}$$

This equation allows k_{ro} to be plotted against μ_w/μ_o for various values of the flowing water fraction f_w. In typical SAGD operations, this fraction is in the range of 0.6 to 0.8. In Figure 11.12, curves of μ_w/μ_o are plotted against k_{ro} for f_w = 0.6, 0.7 and 0.8.

The viscosity of water, μ_w = 0.13 mPa.s at 200°C and 0.11 mPa.s at 250°C.

At 200°C, the viscosity of Athabasca bitumen is about 11 mPa.s and at 250°C, the viscosity of Lloydminster crude is about 2 mPa.s.

Thus, the practical range of viscosity ratios is approximately $\mu_w/\mu_o = 0.13/15 = 0.009$ for Athabasca at 200°C and $\mu_w/\mu_o = 0.11/2 = 0.055$ for Lloydminster at 250°C.

These limits are shown as the two dotted lines in Figure 11.12. It can be seen that a reasonable average value to use for the effective relative permeability of oil is 0.4, although it could be somewhat higher or lower.

Comparison of Predicted Drainage Rates for Typical Crude Oils

Calculations similar to that described in the previous numerical example have been carried out for three different crude oils and varying steam temperatures. The results are shown in Figure 11.13. The three crude oils chosen have viscosities typical of those in the Lloydminster, Cold Lake and Athabasca reservoirs. In each case, the parameters shown at the top of the Figure were assumed to be constant. In practice, there is variation in these parameters between reservoirs. For example, in Cold Lake and Athabasca there are many parts of the reservoir that have a height greater than 20 m. The permeability used (0.4 μm²) corresponds to a reservoir permeability

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FEKETE'S UNDERTAKINGS ON BEHALF OF ISH ENGERY LTD.

UNDERTAKING: Volume 5, Page 721:
"UNDERTAKING - TO ADVISE WHAT THE WATER SATURATION OF THE BITUMEN IS IN THE 7-36."

UNDERTAKING: Volume 5, Page 724:
"UNDERTAKING - TO PROVIDE THE SATURATION NUMBERS FOR BOTH THE BITUMEN AND THE WATER AND GAS ZONES WITH REFERENCE TO THE PREVIOUS UNDERTAKING."

RESPONSE:

The water saturation calculated in the Wabiskaw B gas, fizzy water, and bitumen zones is shown in the table below. Note that there is a slight increase in the water saturation moving up from the bitumen zone through to the gas zone.

Interval (mKB)	Zone	Sw
486.5 – 487.5	Wabiskaw B Gas	37
487.5 – 489.0	Wabiskaw B Fizzy Water	35
489.0 – 490.0	Wabiskaw B Bitumen	32

UNDERTAKING: Volume 5, page 728:
"UNDERTAKING - TO ADVISE WHAT THE WATER SATURATION IS IN THE WABISKAW B BELOW THE SECOND GAS ZONE."

RESPONSE:

The water saturation calculated in the Wabiskaw B below the second gas zone is shown in the table below:

Interval (mKB)	Zone	Sw
427.0 – 428.0	Wabiskaw B Bitumen	46