Husky's Response to Board Staff Information Requests for Husky Oil Operations Limited (November 10, 2006)

1. With respect to Husky's October 3, 2006 response to Board Staff information requests of September 19, 2006:

   a) In response 1(b) Husky indicated that it was evaluating the Clearwater depositional environments and internal facies. Provide any additional information that Husky has available on these evaluations.

<u>Husky's Response:</u> Husky continues to evaluate the depositional environments and facies on and adjacent to our lands. Currently we have focused on the eastern lease where our Demonstration project will be located. Additional work on our western lease, as well as EnCana lands (note that both P and NG and Oil Sands rights, Oil Sands Lease 7188110344, are held by EnCana immediately east of Husky's lands) is proceeding. Husky is willing to provide further updates to our interpretation in the future, if the Board so desires.

In the Caribou Lake area the Clearwater sands are part of a broad, northwest-prograding depositional system comprising both deltaic and incised valley fill deposits.
The Clearwater Formation is subdivided into five mappable units: glauconite rich Wabiskaw deposits, MS1 (marine shale 1) pro-delta deposits, regional delta front deposits, incised Valley B fill deposits, and overlying Clearwater offshore marine shale. Note that the valley terminology was previously used by Husky at Tucker Lake, although no direct correlations with Tucker are inferred. Valley B may be a compound fill comprising several valleys, but contacts are ambiguous within the sand-dominated reservoir facies. Note that Valley B described herein, correlates with the Blue Sand of CNRL's Primrose Project terminology.

The lower marine Wabiskaw Formation overlies the McMurray Formation. A regionally extensive silty shale (MS1) at the base of the Clearwater Formation represents prodeltaic sedimentation (Figure 06.11.10 IR1-1, Isopach map of MS1). To the west, MS1 sediments coarsen-upward into thick sand dominated delta front deposits (regional marine deposits). This unit has reduced reservoir quality due to high shale content. In Lease 7188110343, MS1 and associated delta front deposits of the lower Clearwater Formation have been eroded by Valley B (as shown by the isopach thin on Figure 06.11.10 IR 1-1).

Valley B is interpreted as an incised valley trending northwest-southeast. Valley B fill is interpreted as representing deposition within a transgressive, tide-dominated estuarine system (cf. Dalrymple, 1992[1]) and constitutes the main bitumen reservoir on Lease 7188110343. Valley B sediments are capped by shales deposited in an offshore marine environment, subsequent to the transgression of the Clearwater Sea (Figure 06.11.10 IR1-2, Clearwater Shale Isopach map). Note that MS1 and the Clearwater shale isolate the

[1] Dalrymple, R.W., Zaitlan,, B.A., and Boyd, R., 1992, Estuarine facies models: Conceptual basis and stratigraphic implications: Journal of Sedimentary Petrology, v. 62, p. 1130-1146.

Clearwater Formation from the underlying Wabiskaw/McMurray and the overlying Grand Rapids respectively.

The two dominant facies that comprise Valley B are subtidal sand bars and channels. Central basin estuarine deposits form a third, minor facies (equivalent to CNRL's C and D muds). Subtidal sand bars comprise sporadically bioturbated dominantly very fine to medium grained, cross-bedded and planar laminated sands with subordinate thin (mm-cm scale) to thick (dm scale) laminated muds. Tidal channel deposits have an increased shale component but are also sand-dominated. Muds in the subtidal sand bars and channels do not constitute flow boundaries.

Central basin estuarine deposits are comprised primarily of bioturbated, heterolithic muds and silts, and are evident in the valley fill on the eastern edge of Sections 8 and 2, Township 69, Range 4 (Figure 06.10.27 IR 3-1, Shale Isopach map). Central basin deposits have poor reservoir quality but are absent in much of Lease 7188110343.

The Central basin estuarine shale is present in well AA/03-04-069-04W4/00. Core analysis indicates some porosity, permeability and bitumen saturations present throughout the zone. Therefore, this shale zone potentially acts as a baffle more so than a barrier. The isopach map (Figure 06.10.27 IR 3-1) also indicates significant thickness variability from 0 on the western edge to 18m, with a number of thicks and thins, also suggesting the unit is not a major sealing boundary. This notwithstanding, the sands above and below this shale are in direct communication with Valley B sands. The piezometer data confirms pressure movement either across or through this non-continuous shale or along the adjacent sands.

b) In response 3(c) Husky stated it was evaluating any problems that could explain the pressure anomalies at wells 16-7 and 4-6 where the pressure trends measured by some of the piezometers are decreasing while the pressure trends measured by other piezometers in the same well are increasing. Provide any further explanation for these pressure anomalies that Husky has determined.

Husky's Response: Latest piezometer data to Nov. 14, 2006 is attached. Also shown in Table 1, pressures declines measured at discrete points in time corrected to a datum of +210 mSS using the pressure gradient suggested by EnCana of 9.85 kPa/m. These discrete points are the dates when the data was received from the field. Using this pressure gradient, the initial pressure is calculated as 2808 kPa now (instead of the previously reported value of 2800 kPa with 9.50 kPa/m). Again one should note that this is the highest stabilized pressure observed with the piezometers and it occurs at 472.5 m depth on Aug. 28, 2006 in the 04-06 well. It is also clearly seen that this pressure itself has declined by some amount from the actual initial pressure as evidenced by the declining piezometer pressure trend. Consequently, the pressure decline levels reported in Table 1 are likely to be higher when compared with the actual initial pressure and should be taken as declines observed from the initial pressure observed on Aug. 28, 2006. Note that of all 31 piezometers, 25 (81%) recorded monotonically declining pressures of up to

56% since Aug. 28, 2006. If the two highest points are excluded the mean decline on Nov. 14, 2006 from assumed initial pressure is 5.8% with a standard deviation of 3.8% and a median of 4.6% (see Figure 1). If one looks at the pressure decline during this 2.5 month period alone then the mean pressures decline is 12.6% with a standard deviation of 16.1% and a median of 6.7% (Figure 2). Based on this data, our conclusion is that rapid pressure communication is occurring through out the bitumen zone due to adjacent gas production. Our geological mapping indicates that the top water zone is areally more extensive than both the overlying gas zone in the east and south and the underlying shale zone in the east. The pressure is communicated from the adjacent gas production to the bitumen through two means: (i) pressure transient travels from the gas zone to the top water zone and from there to the bitumen zone laterally and vertically, (ii) where there is no top water zone, pressure transmitted directly from the gas cap to the bitumen vertically and laterally.

04-06 Well: It appears that the bottom two piezometers took longer to stabilize in this well than the shallower ones. One can see that these two piezometers stabilized around mid August. The pressure decline trend from this point on can clearly be seen in the latest data for all the piezometers in this well.

16-07 Well: The two lowest piezometers appear to be still behaving in an unexpected manner. The pressure gauges are enclosed in a permeable protective casing. This casing is normally saturated with water during installation to provide capillary continuity between the reservoir and the recorder. The behaviour is suggestive of initially partially saturated protective casing which becomes more saturated with time. Husky's investigation still continues. The formation at 466 m appears to have higher pressure than at 473. While investigation into the instrument malfunction continues, another explanation may be that these pressures reflect the hydraulic diffusivity of the path that is travelled by the pressure transient to these particular piezometers. This path is reflective of the complex bedding of highly variable sands and shales.

04-09 Well: The two shallower piezometers have taken a longer time to stabilize possibly due to the initial partial saturation of the protective casing. However, the saturation process appears to be coming to an end because the pressure increase has slowed down considerably. It is quite possible that the decline trend will be established in the near future based on the current behaviour. The deepest piezometer in this well declines steadily.

2. With respect to Husky's October 27, 2006 response to Board Staff information requests of October 13, 2006:

   a) In response 1 Husky provided Figure IR1-1 illustrating a 3 km region of influence.

      i) Provide a revised figure that more clearly shows the region of influence.

Husky's Response: 3 km ROI is posted on Figure 06.11.10 IR 2-1. Essentially all of Husky's land is enclosed within a 3 km ROI. Husky is of the opinion that a 3km radius is a minimum region of influence. Ultimately, the areal extent of the region of influence may be much broader as additional pressure data are collected. It is currently impossible to definitively map the areal extent of the region of influence

ii) Provide a discussion of the basis for the extent of the region of influence; in particular, explain why the region of influence does not contain the entire extent of the gas pools and top water zones.

Husky's Response: It is worth noting that a true region of influence has not been determined for the Clearwater bitumen pool within Husky lands. What can be said with confidence is that the region of influence extends at least 3 km beyond the edge of the gas pools. There is no reason for the pressure transient to stop 3 km away from the gas pools. In fact, our geological model suggests that the area of actual pressure depletion is larger than 3 km. Therefore, there is rapid pressure communication between the gas pools and the bitumen zone over the entire interval through the pressure pathways that are mentioned above in 1 (b). The original ROI shown on Figure 06.10.27 IR 1-1 encompassed only Husky lands. Figure 06.11.10 IR 2-1 expands the original ROI to include all affected lands.

b) With respect to response 2:

i) Where Husky has not previously provided the information, provide annotated logs (Gamma Ray, Neutron-Density, SP, and Resistivity) over the Clearwater Formation for all of the wells within the boundaries of Husky's gas pools as defined on Figure IR1-1 and for one well per section within the 3 km boundary surrounding the gas pools. The composite well logs should identify:

- Formation and facies tops.
- All gas pay, water zone, and bitumen pay intervals.
- All perforated and cored intervals.

Husky's Response: Data is included on the attached CD

ii) Composite well logs were provided showing, among other things, gas pay, water zones and bitumen pay intervals. In reviewing these composite well logs, it appears that the log characteristics of wet zones in the 6-2, 6-3, and 6-4-70-5W4 wells are very similar to the log characteristics of the intervals underlying the gas zones in the 13-27 and 02/16-28-68-5W4 wells and for the interval 490-491.5 m KB in the 10-35-68-5W4 well.

- Comment on why these example intervals are not interpreted to be wet in the composite log sections.

Husky's Response: Husky concurs that the intervals indicated in 13-27 and 02/16-28 -68-5W4 represent very thin water zones. The interval outlined in 10-35 may also represent a water zone. These zones provide pathways for depleted gas pressures to be transmitted to the bitumen zone.

- List the log parameters Husky uses to determine if a zone is wet.

Husky's Response: Resistivity below 10 ohm, with clean gamma (generally less than 75 API), and Neutron density is an indication of porosity. Note that rigorous application of these parameters resulted in the identification of other wells with water zones. A revised Water Isopach map is included as Figure 06.11.22 IR 2-2. Therefore, where top water is present the pressure depletion effects from the overlying gas pool will travel easily to the edge of the water zone, and from there laterally and vertically to the bitumen zone. This is proven by our piezometer data

iii) Figure IR6b-1 indicates Husky has interpreted gas pay to be present in the 6-3 and 6-4-70-5W4 wells. The composite logs of these wells indicate the gas zones to be above the red dashed line. There is a thin neutron kick over the interpreted gas interval. However the resistivity of the gas zone is about the same as the resistivity of the underlying water zone, and the gas is structurally lower than the gas/water contact in the adjacent 6-2-70-5W4 well. Explain why Husky has interpreted there to be gas pay in the Clearwater in these two wells. If there is gas pay in these two wells, would the differing gas/water contacts indicate separate pools? Explain.

Husky's Response: Neutron-Density cross-over was used to identify gas zones. In Husky's opinion, the low resistivity in both wells is related to tool response limitations due to thin beds. The variation in gas/water contact elevation is significant and reflects more than the accuracy of logging/drilling data. The 6-3 and 6-4 wells may well be in separate pools. This interpretation is reflected on the revised pool structure map Figure 06.11.10 2-8**.**

c) In response 3 Husky has provided a Clearwater shale map in which the shale is interpreted to be continuous to the east of Husky's oil sands leases. There is no indication on the Clearwater shale map of shale to the west of range 4, but there appear to be many zones in the composite well logs provided for wells west of range 4 which have comparable log characteristics to the identified shale intervals in the wells east of range 4.

i) List the log parameters used to determine the presence of a shale interval.

Husky's Response: In decreasing order of reliability: Core descriptions, Resistivity log, porosity and gamma/SP logs. In many instances more than one of these tools can be applied

ii) Comment on the criteria used to determine if a shale is continuous.

Husky's Response: Our ongoing facies and depositional environment interpretation is and will be useful in determining shale continuity. The depositional interpretation is key in evaluating shale continuity. Given the heterogeneous depositional environment, shale, if present, may not be continuous. Shale that may be correlatable from well to well does not confirm shale continuity over a large area

iii) Comment on the depositional environment of a continuous shale and its expected areal extent.

Husky's Response: As discussed in our response to IR 1a, the shale outlined in Figure 06.10.27 IR 3-1 represents a central basin deposit. The isopach illustrates a variation in thickness over the map, suggesting significant variability in the deposit. This shale may have some continuity over the mapped area, but as indicated in the response to IR 1a, core analysis data from 00/03-04-69-04W4 indicates some porosity and permeability exist at least at this location. This, combined with the cutting by Valley B (as suggested by the sharp western edge shown on the isopach map, and discussed in IR 1a) of the central basin estuarine shale would result in sand to sand communication avenues into Valley B sands, transmitting pressure changes into bitumen reservoir sands both above and below the central basin estuarine shale. In regard to areal extent, the central basin estuarine shale is likely not regionally extensive (sections rather than townships)

iv) Comment on why there is no interpreted continuous shale west of range 4.

Husky's Response: Figure 06.11.20 2-3, West Shale Map outlines the distribution of continuous shale to the west of Range 4. This shale, as discussed in IR 1a, represents a marine prodelta shale, and is not depositionally related to the central basin estuarine shale mapped in 06.10.27 IR Figure 3-1. The west shale is also sharply cut by Valley B, again producing sand to sand avenues for pressure communication. Note the shale does represent a top seal in some areas, as evidenced by structurally trapped gas reserves (eg 00/11-33-068-05w4/0, 462-463m, 02/16-28-068-05W4/0, 464.5-465.5m and 00/5-13-69-4W4/0, 476-480m). However, potential mechanisms for pressure communication across this shale include direct transfer along a wellbore, either due to poor cement bond, or due to commingling of the two Clearwater gas zones. (as is occurring at the 2 CLWR DD wells listed above, where gas reservoirs above and below the prodelta shale are perfed). Lateral pressure transmission will also occur along the bitumen zones above and below the prodelta shale.

In terms of areal extent, the marine prodelta shale is mapped over much of 69-4W4. Well density is sparser than over Husky lease 7188110343 and as such, does not preclude the presence of other bitumen bearing Clearwater incised valleys. Additional valleys would provide the mechanism for transmission of pressure changes to bitumen bearing zones above and below the shale, due to sand on sand contacts. Two additional figures are attached. Figure 06.11.10 2-4 is a bitumen net pay map (using >20% porosity and <50% Sw) for the section above the west shale. Figure 06.11.10 2-5 is a bitumen net pay map (using the same cutoffs) for the interval between the base of west shale and the top of the MS1 shale.

d) In response 5 Husky provides a table of pressure data in response to the EUB Staff's request for a tabulation of the pressure data for pools that Husky is requesting to be shut-in. Husky appears to have provided pressure data only for the wells that it has requested to be shut-in but not for all of the wells in the pools.

i) Publicly available information indicates that there are segregated pressure data for wells not included in Husky's table and that there are more segregated pressure data for the wells that are included in Husky's table than are shown in the table. Explain why all of the data were not included or provide the additional pressure data.

<u>Husky's Response:</u> The additional pressures are included in Table 2, the new material balance plots and decline analysis plots are included in Appendix A.

ii) Comment on whether or not the pressure data supports Husky's interpretation that the 5-16, 6-21 and 5-22-70-5W4 wells are part of the pool shown on Figure IR1-1 as the CLWR MU #2 pool. Refer also to question 2e(iv).

<u>Husky's Response:</u> As a result of an expanded review with all the requested well pressure data from all the wells in each pool, a better interpretation is now available. Husky is now in agreement with the public available data in that, wells 5-16, 6-21 and 5-22-70-5 W4 are part of a separate Clearwater S pool. Husky recompiled and evaluated pressure data for the Clearwater S and B gas pools and generated a combined P/z plot as shown in the appendix. It is evident that the Clearwater S pool is isolated in a separate pressure system. Husky confirms that Clearwater B and S are separate pools.

iii) Figure IR6b-1 shows the 6-28 well as currently producing from the Clearwater formation. Publicly available information indicates that in the 6-28-69-4W4 well the interval that Husky has asked to be shut-in is below a cemented bridge plug and that the interval has never produced. Publicly available information also shows that the pressure data submitted by Husky for the 6-28 well is from the Grand Rapids zone. Clarify why Husky has indicated the 6-28 well is currently producing from the Clearwater formation and why it has included the pressure data from the Grand Rapids zone in the table.

Husky's Response: The 00/06-28-069-04W4/0 well Clearwater perfs are below a cement bridge plug and not currently producing, as publicly available data indicates. The pressure data was included in error. Husky deems it prudent to retain the well on our Shut in list, as the Clearwater interval at 00/06-32-069-04W4/00 and /02 well, owned and operated by EnCana, was also isolated by a cement bridge plug (412-420m, 1988-02-11), but later re-entered, re-perfed (430–434m, 2000-03-19), and subsequently put on production. Note that an amended and updated Shut-in list is included as Figure 06.11.10 IR 2.6. The table includes all wells currently producing from the Clearwater Formation within the ROI (Figure 06.11.10 IR 1-1), resulting in pressure decline within Bitumen resources on both Husky and EnCana lands. A second table (Figure 06.10.11 IR 2.7) includes wells within designated Clearwater gas pools that contain Clearwater gas, but are not currently perfed in the Clearwater. These wells should never be allowed to produce from the Clearwater as, again, pressure reduction and subsequent decline in bitumen recovery would ensue.

iv) Publicly available information also shows that the pressure data submitted by Husky for the 5-13-69-6W4 well is for an interval different than the interval that Husky has requested to be shut-in. Clarify why Husky has included this data in the table.

Husky's Response: The pressure data was incorrectly submitted by Husky for the 5-13 well. The pressures submitted were for the deeper McMurray zone which is abandoned in the wellbore. Based on a recent public data review, no pressure data was available for the Clearwater interval.

e) With respect to response 6:

i) In response 6(a) Husky states that the trapping mechanism for the gas pools includes structural, stratigraphic and bitumen "elements". However, in response 3 Husky states that gas cap depletion effects will be transmitted throughout the bitumen reservoir. How can bitumen be a trapping mechanism for gas if gas cap depletion effects are transmitted throughout the bitumen reservoir?

Husky's Response: Structural and Stratigraphic aspects are deemed to be the trapping mechanism. The original response including bitumen proved to be incorrect. As an example, core analysis for AA/3-4-69-4W4/00 indicates zero bitumen saturation at the top of the gas zone (i.e. 488.70-489.45m), confirming that bitumen is not part of the trapping mechanism. Husky piezometer data also illustrates that bitumen is a pressure conduit, and does not act as a barrier.

ii) In response 6(b) Husky notes that its gas pool outlines were modified after new well data were input and additional wells were reviewed. Identify the new data that were input and the additional wells that were reviewed. Also provide isopach maps for the new pool outlines.

Husky's Response: Data for the following wells were added:

00/12-17-069-05W4/0	RR 2006.01.23
00/16-27-068-05W4/0	RR 2006.03-15
00/14-34-069-04W4/0	RR 2006.01.24
00/10-03-070-04W4/0	RR 2006.02.01
00/06-17-070-05W4/0	RR 2006-01-26

Note that numerous LAS curves were also added to supplement existing vector logs. Figure IR 06.11.10 2-9 is an updated Gas Pay isopach map using the new pool outlines.

iii) Also in response 6(b) Husky indicates that the Clearwater MU #2 and Clearwater EE pools have tilted gas/water contacts. Explain the mechanism which would result in a tilted gas/water contact in a gas pool with good permeability.

Husky's Response: In our previous work, we relied commercially available public data. However, due to confusion of stratigraphic nomenclature and our interpretation of pool definitions, we grouped wells together in error. Subsequent evaluation of EUB pooling rulings has clarified this issue. An updated map, included as Figure 06.11.10 2-8, definitively shows the Clearwater S Pool does not have a tilted gas water contact. Figure 06.11.2-9 provides an updated isopach map of the gas pools utilizing the pool outlines of Figure 2-8. The table below updates OGIP calculations for Clearwater B and Clearwater S pools (replacing the Clearwater MU #2 calculation presented in 2006.10.27 IR 7). Updated P/Z graphs are included in Appendix A.

iv) In response 6(c) Husky states that the Clearwater MU #2 pool is commingled with Grand Rapids production, and therefore pressure data is of no use in isolating the Clearwater reservoir. Publicly available information indicates that within the Clearwater MU #2 pool shown on Figure IR1-1, the Clearwater zone is not commingled with any other zone. Clarify why Husky believes that the Clearwater MU #2 pool is commingled with the Grand Rapids zone. If Husky agrees that the Clearwater zone is not commingled with any other zone, discuss the use of pressure data for pooling of the wells in the Clearwater MU #2 pool shown on Figure IR1-1.

Husky's Response: With an expanded review of the all the well pressure data and subsequent clarification of the AEUB's pool designations and commingling orders, Husky is in agreement that the Clearwater B pool is not commingled with any zone in this area. Further to this Husky has prepared the analysis of all the Clearwater Pools as shown in Appendix A.

Husky recompiled and evaluated pressure data for the Clearwater S and B gas pools and generated a combined P/z plot. As shown in Appendix A. It is evident that the Clearwater S pool is isolated in a separate pressure system. Husky confirms that Clearwater B and S are separate pools.

f) In response 8 Husky states that a conservative estimate for the bitumen recovery in the primary development area is 27 % with a potential to go as high as 50 % if the HSAGD technology works. What is the basis for these recovery estimates? Discuss the effect of pressure depletion of the gas zones on these recoveries.

Husky's Response: Husky's preliminary single well numerical simulation model of the HSAGD yields recoveries of over 70% for the primary development area which can be expected from better areas of the lease. Assuming that there will be more geological detail in the field than those included in the simulation model, a high estimate of the recovery factor in the field from the whole lease will be in the 50% range. This also happens to be a midway number between generally expected CSS and a SAGD recovery factors. The CSS development would be analogous to the Primrose project to the south. The expected recovery from this project is 20 % based on 160 to 188 m spacing between the wells[2]. This region is thinner than Husky lands. Assuming a denser development of 100 m between the wells an improved recovery factor of 25% (note that 27% was a typographical error) was determined for the best case (conservative) reserves estimate. However, it is obvious that by experimenting with the HSAGD technology, we are attempting to improve recoveries beyond CSS levels.

Husky is concerned that continued pressure depletion and the existence of high water saturation zones in the reservoir will cause injected steam losses (resulting in higher steam oil ratios) through induced flow channels, poor distribution of steam in the reservoir, daily oil rate reduction and recovery reduction. As a result, our design choices will be severely limited and the project economics may suffer. Presently, Husky is establishing a generic Caribou gas-over-bitumen model to investigate the impact of gas pool depletion to adjacent HSAGD, SAGD and/or CSS operations. We are using the recently acquired piezometer data from Caribou to calibrate the flow properties of this model. Results and more details will be submitted as they become available.

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[2] Canadian Natural Resources Limited , "Application for the Primrose In Situ Oil Sands Project – Primrose East Expansion", Jan. 24, 2006

The adverse effects of lower pressures on CSS have been well documented[3]. In order to improve project economics, high pressure CSS is the technology applied in the Primrose project to the south. There will be additional risks in a depleted reservoir with imposed pressure gradients that would result from continued gas production if Husky has to apply high pressure CSS technology in our leases as well.

g) With respect to response 9:

i) Husky has indicated that it wants five wells in the Clearwater MU #2 pool shut-in. Publicly available information indicates there are five wells (5-21, 6-32-69-4W4, 8-36-69-5W4, 10-6-70-4W4 and 6-12-70-5W4) producing from the Clearwater MU #2 pool in addition to the 5 wells that Husky has requested to be shut-in. The information also shows that Clearwater gas pay has been assigned by the EUB for a total of 24 wells (see the attached table for well locations and intervals) in the Clearwater MU #2 pool shown on Figure IR1-1. Explain why Husky has not requested that all intervals in the pool with assigned gas pay not be allowed to produce.

<u>Husky's Response:</u> As outlined in our response to IR 2e iii, we have corrected our pool designations. Husky lists of wells required to be shut in to prevent detrimental pressure impacts on bitumen resources are presented as Figures 06.11.10 2-6 and 2-7.

ii) Husky has indicated that it wants three wells in the Clearwater D pool shut-in. Publicly available information shows that Clearwater gas pay has been assigned by the EUB for a total of six wells in the Clearwater D pool (see the attached table for well locations and intervals). Explain why Husky has not requested that all intervals in the pool with assigned gas pay not be allowed to produce.

<u>Husky's Response:</u> Husky concurs that all wells present in the pool with assigned gas pay should not be allowed to produce. See response to IR 2g (i) above and Figures 06.11.10 2.6 and 2.7, that summarize updated requests for wells required to be shut in or not be allowed to produce from the Clearwater Formation.

iii) Husky has indicated that it wants two wells in each of the Clearwater CC and DD pools shut-in. Publicly available information shows that Clearwater gas pay has been assigned by the EUB for a total of four wells in each of the Clearwater CC and DD pools (see the attached table for well locations and intervals).

[3] Batycky J.P. et al., "A Mechanistic Model of Cyclic Steam Stimulation", SPE 37550, February 1997.

Explain why Husky has not requested that all intervals in the pools with assigned gas pay not be allowed to produce.

Husky's Response: Husky concurs that all wells present in the pool with assigned gas pay should not be allowed to produce. See response to IR 2g (i) above and Figures 06.11.10 2.6 and 2.7, that list updated requests for wells required to be shut in or not be allowed to produce from the Clearwater Formation.

iv) Husky has requested that two gas bearing intervals in the 02/16-28 and 11-33-68-5 W4 wells be shut in.

- What is the horizontal trapping mechanism for the lower gas zones in these wells?

Husky's Response: The lower gas is trapped below the prodelta shale illustrated in Figure IR 06.11.10 2-3. Figure IR 06.11.10 2-12 is a structure map on the base of the prodelta shale and illustrates a closed high around these wells. Hence, the lower gas is structurally trapped. Note that this structural high is the result of drape over an interpreted bitumen saturated McMurray channel. As discussed in our response to IR 2c, this shale is laterally extensive, but again, unmapped Clearwater incised valleys, combined with wellbore communication, could result in pressure transfer between the bitumen reservoire above and below the marine shale unit.

- What is the vertical trapping mechanism separating the two gas zones in these wells?

Husky's Response: : The two zones are separated by prodelta shale as mapped in IR 06.11.10 2-3 that provides top seal, and acts as the vertical trapping mechanism. Note though that both gas zones are producing concurrently at these two wells, allowing for intraformational pressure communication. Pressure communication will also occur laterally through each sand (above and below the shale), and negatively impact bitumen recovery in the adjacent Valley B reservoir.

- What is the lateral extent of this vertical trapping mechanism?

Husky's Response: See response to IR 2c iv, and Figure 06.11.10 2-12.

h) With respect to Figure IR3-1, provide separate net bitumen pay maps for the bitumen above and below the shale shown in Figure IR3-1, at a scale of 1:50 000. The bitumen pay should be based on the bitumen saturation being equal to or greater than 50 % pore volume and the net pay values for each well should be posted on the maps. Also provide the cutoffs (resistivity, porosity) used by Husky to determine the net pays.

Husky's Response: Net bitumen pay maps are attached as Figures 06.11.20 06.11.10 2-11 and 2-12.. As with previous OBIP calculations (refer to 06.10.03 IR 1b), resistivity cutoffs are not applied, instead Sw calculations are made using a modified Simandoux shaley sand equation. A porosity cutoff of 20% was applied, and Sw cutoff of 50%.

As previously stated, the presence of this central basin estuarine shale does not preclude pressure communication between the bitumen zones above and below the shale. The presence of Valley B results in cross shale communication due to sand on sand contacts. Husky piezometer data also confirms this. The entire 1.1 billion barrel of resources outlined in 06.10.03 IR 1d is in pressure communication with the EnCana gas pools required to be shut in.

i) With respect to Figure IR7-1:

i) The plot shows three data points for the Clearwater G Pool (well 6-20-69-5W4) but the pressure table on page 2 shows five pressure measurements at different dates. Why are only three data points plotted on Figure IR7-1?

Husky's Response: With the expanded review of all the well pressure data, a revised P/Z plot for the Clearwater G Pool including all usable data points is included in Appendix A.

ii) The plot shows a cumulative gas production at the last pressure point of about 45 E6 m^3 but the publicly available information indicates a cumulative gas production for the 6-20 well of only 33 E6 m^3 in September 2006. Explain why the cumulative gas production at the last pressure point is greater that the current cumulative gas production from the well.

Husky's Response: The publicly available completion data was interpreted as the Clearwater G Pool and the Grand Rapids J were commingled. The pool completion data has subsequently been reviewed and corrected to show that the Clearwater zone is isolated at 6-20.

Table 1 Pressure Decline from "Initial" Pressure of 2808 kPa

Date		**Aug. 28, 2006** Decline	**Sep. 26, 2006** Decline	**Nov. 14, 2006** Decline
	Depth			
	(m KB)			
well 03-04	516	0.51%	0.64%	0.80%
	509	1.89%	2.04%	2.21%
	496	51.96%	52.12%	52.15%
	491.5	55.30%	55.66%	56.04%
well 03-07	493	5.00%	5.07%	5.28%
	487.5	4.05%	4.12%	4.22%
	483	4.34%	4.45%	4.64%
	479	4.40%	4.53%	4.73%
	474	2.83%	2.98%	3.18%
well 04-06	493.5	1.05%	1.08%	1.18%
	489	1.20%	1.26%	1.41%
	484	0.43%	0.51%	0.66%
	487	3.90%	3.94%	4.07%
	472.5	0.00%	0.03%	0.08%
well 04-09	492	1.60%	1.66%	1.75%
	474	10.91%	10.51%	10.27%
	470	10.87%	10.37%	10.10%
well 10-05	503.5	4.331%	4.348%	4.354%
	499	3.77%	3.89%	4.02%
	494	5.85%	5.97%	6.17%
	489	7.64%	7.77%	8.17%
	480	7.65%	7.79%	8.02%
well 16-07	483	9.79%	9.69%	9.36%
	478	8.50%	9.33%	9.03%
	473	9.12%	9.26%	9.50%
	466	5.69%	5.82%	6.02%
	460	6.51%	6.99%	7.34%
well 14-9	520.5	3.81%	3.93%	3.55%
	503.5	2.56%	2.36%	2.27%
	497	9.11%	9.54%	9.78%
	491.5	15.62%	16.05%	16.35%

Table 2: Clearwater Pool Pressures

Well ID	Pool	Pressure Interval		YYYY	MM	DD	Type	Shut-in	Datum P	Press Data Used
		Top, mKB	Bot, mKB					hrs	kPaa	kPaa
00/03-11-070-06W402	CLWR Undef	437.0	438.0	2006	3	26	SG	25.8		2582.87
00/05-10-069-04W402	CLWR D	500.3	501.3	1997	12	20	SG	25.5	2134	2030.17
				1998	6	28	SG	20.9	1349	1346.8
				1998	10	3	SG			
		500.7	501.7	1991	3	14	SG	116	2548	2429.76
				1991	3	14	BU	104	2552	2564.3
		500.3	504	2005	1	13	SG	3.8	926	908.95
				2005	1	13	Duplicate			
00/05-13-069-06W400	CLWR EE	499	501.5	NO PRESSURE DATA AVAILABLE						
00/05-16-070-05W400	CLWR S	425	425.5	2002	3	13	SG	212.5	1796	
00/05-22-070-05W400	CLWR S	422.5	423.5	2000	3	15	SG	192.7	2151	2150.4
00/06-20-069-05W400	CLWR G	445.2	446.5	1997	12	20	SG	23.4	1860	1860.11
				1998	3	14	SG	25.6	1631	1629.91
				2001	1	28	SG	26.3	1383	1383.64
		444.6	446.5	1991	1	22	SG	0	2619	2616.13
				1991	1	29	SG	72.4	2682	
				1991	1	29	BU	70.4	2603	
		445.2	446.5	2005	1	1	SG			823.22
				2005	1	1	UN	18	0	
00/06-21-070-05W400	CLWR S	417	422	1995	3	14	SG	31	1814	2449.8
				1997	12	20	SG	stable press	2357	2356.8
				1998	12	29	SG	stable press		
				1999	11	1	SG	stable press	2138	2138.09
				2002	2	25	SG	60.4	1794	1794.07
		417	422	2005	1	12	SG	29	795	
				2005	1	12	BU	29	795	
00/06-28-069-04W402	CLWR B	407	410	NO DATA FOR THIS INTERVAL						
00/11-33-068-05W400	CLWR CC	450.5	463	NO DATA FOR THIS INTERVAL						
00/11-33-068-05W400	CLWR DD	450.5	563	2000	2	29	SG	stable press	2665	2663
00/12-04-070-04W400	CLWR B	427.9	428.4	1991	3	10	SG	stable press	2460	2460.54
		427.8	428.3	1997	12	21	SG	354.2	1528	1528.29
				1998	10	4	SG	4000		
				1999	2	9	SG	47.7	1741	1741.24
				1999	11	1	SG	16.5	1488	1457.99
				2001	1	8	SG	27.6	1222	1197.9
		427.8	428.4	1991	3	18	BU	57.2	2457	2457
02/16-28-068-05W400	CLWR CC	453.5	465.5	2002	2	9	SG	218	2377	2474.97
02/16-28-068-05W400	CLWR DD									
03/08-03-069-04W402	CLWR D	495.5	497.5	2005	1	3	SG	27		975.44
				2001	3	19	SG	98		2036.35
00/10-33-068-04W402	CLWR D	485	486	1998	1	25	SG	no prod	2481	2482.48
				1998	1	27	SG	41.1	2481	2481.43
				1998	1	27	BU	41.1	2483	2483.41
00/08-26-069-05W400	CLWR Undef	435.5	436.5	1991	2	4	SG	no prod	2446	2458.5
				1991	2	5	SG	9.7	2455	2469.4
				1991	2	5	BU	9.7	2425	2429.9
				2001	1	11	SG	stable press	1347	1346.7
00/11-13-070-05W400	CLWR Undef	NO PRESSURE DATA								
00/08-36-069-05W400	CLWR B	441	444	2001	1	9	SG	28.4	1233	1232.77
				1991	1	24	SG	no prod	2431	2459.34
				1991	2	1	SG	76	2443	2445.84
				1991	2	1	BU	76	2466	2447.84
00/06-32-069-04W402	CLWR B	430	434	1988	2	8	SG	0	2475	2487.29
				1988	2	8	BU	44	2511	2523.17
				2000	6	29	AWS	47.3	34	35.01
				2002	1	19	SG	26	1164	1071.78
				2003	12	22	SG	26.4	837	837.4
00/06-19-069-04W402	CLWR B	440.8	441.8	1991	2	2	SG	74.6	2452	2452.82
				1991	2	9	BU	72.6	2454	2455.79
				1991	2	9	SG	72.6		2460.21
				1998	5	2	SG	24		1487.62
00/05-29-069-04W400	CLWR B	435.4	438	1999	10	25	SG	18.5	1632	1539.25
				2003	9	24	SG	29.4	749	749.85
				1991	3	5	SG	stable press	2455	2466.59
				1991	3	18	SG	196.5	2459	2460
				1991	3	18	BU	195.2	2469	2466.54
				1994	12	8	SG	9.5	2044	2044.36
02/10-35-069-05W400	CLWR B			NO PRESSURE DATA AVAILABLE						
00/05-21-069-04W400	CLWR B	443.5	449	2002	2	24	SG	26.1	1119	1118.88
				2003	12	22	SG	2	1165	1164.86
				1999	2	3	SG	24		1749.91
				1998	3	12	SG	24.4	1525	1526.52
00/06-17-069-04W400	CLWR B	444.9	446.9	1991	2	8	SG	1991	2433	2454.02
				1991	2	19	SG	90	2436	2459.02
				1991	2	19	BU	90	2444	2468.66
				1998	3	20	SG	29.2	1547	1546.78
				1986	12	1	SG	0	2493	2495.56
				1986	12	1	bu	48	2476	2478.56
				1994	12	8	SG	7.5	1934	1930.48
				1997	12	20	SG	552	1572	1573.13
				1998	6	7	SG	1631	1570	1570.55
				1999	2	2	SG	12.8	1814	1806.51
				2003	12	22	SG	2689	949	949
00/06-12-070-05W400	CLWR B	434	440	1998	1	23	SG	720	1531	1531.77
				1998	3	7	SG	57.5	1573	
				1998	3	7	BU	57.5	1521	
				2003	9	29	AWS	34.6	26	
		433.5	439.5	1991	3	4	SG	stable press	2458	2456.5
				1991	3	13	SG	150	2460	2460.26
				1997	12	23	SG	stable press	1538	1539.2
				1998	3	25	SG	3348	1527	
00/10-06-070-04W400	CLWR B	428.4	437.2	1991	2	11	SG	stable press	2448	2447.62
				1991	2	18	SG	429	2451	2466.01
				1991	2	18	BU	139.7	2450	2464.08
				1998	2	24	SG	24	1488	
				1998	10	3	SG	48		1488.65
				1998	2	24	BU	26	1559	

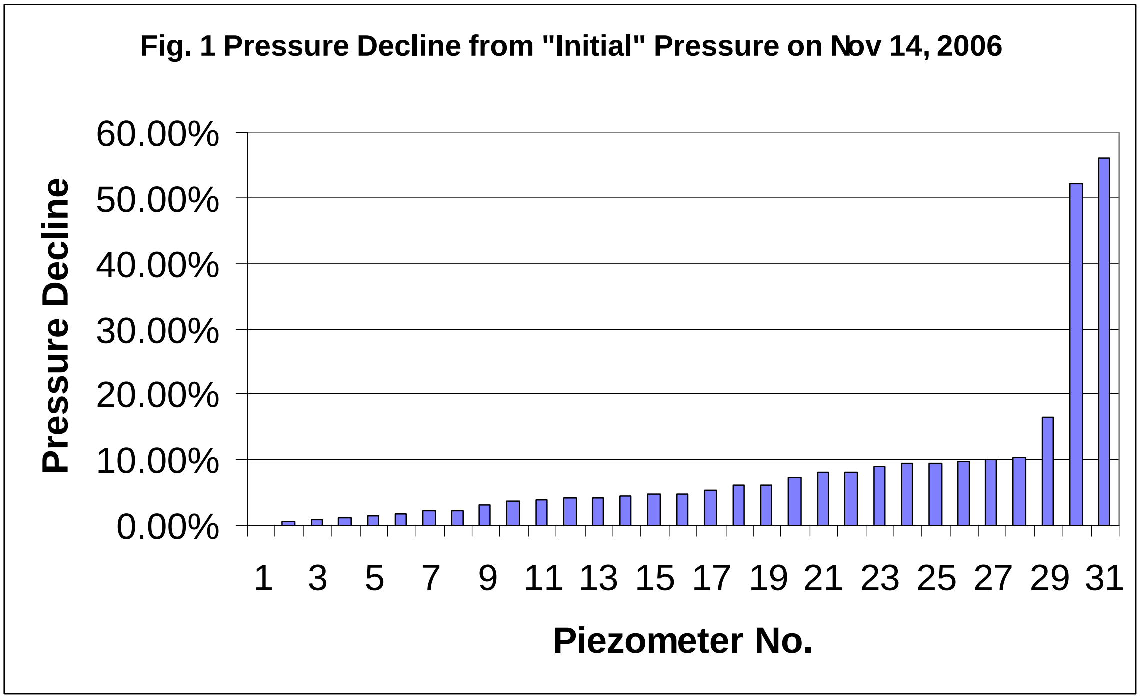
Fig. 1 Pressure Decline from "Initial" Pressure on Nov 14, 2006
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Pressure Decline
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31
Piezometer No.

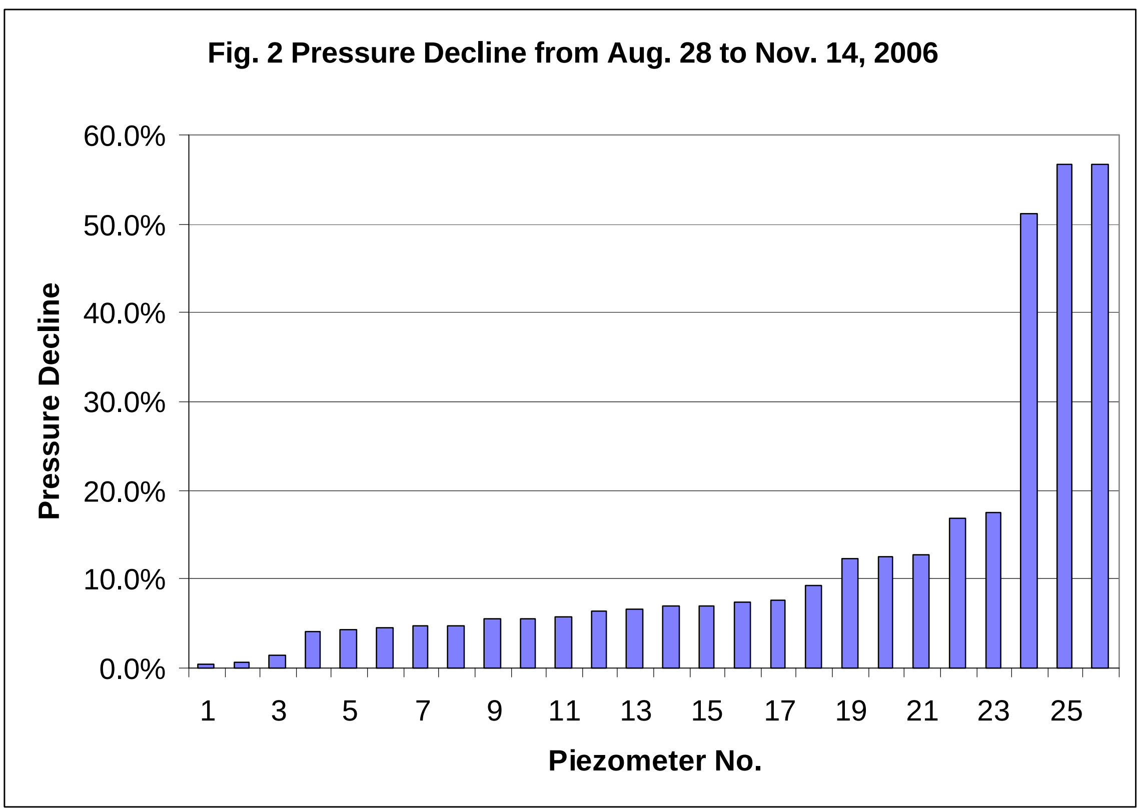
Fig. 2 Pressure Decline from Aug. 28 to Nov. 14, 2006
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Pressure Decline
1 3 5 7 9 11 13 15 17 19 21 23 25
Piezometer No.