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PHASE 3 FINAL PROCEEDING
BITUMEN CONSERVATION
REQUIREMENTS

RESPONSE SUBMISSION
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NEXEN INC.

Nexen Response Submission
GB 2003-28
Phase 3 Final Proceeding
Bitumen Conservation Requirements
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I. Introduction and Summary of Submission

Nexen Inc. (“Nexen”) is a bitumen producer in the Athabasca Oil Sands area through its interests at Long Lake. In addition to the ongoing development at Long Lake, Nexen is the operator of bitumen leases at Leismer (Jackfish) and in the Corner-Hangingstone area and is actively developing these leases. Nexen also holds working interests in bitumen leases at Corner, Chard and Hangingstone.

Paramount Energy Operating Corp. (“PEOC”) seeks to have the Board approve 203 wells and/or intervals for gas production from the Wabiskaw-McMurray Formation. These wells occur across the Revised ID 99-1 Application Area within the Athabasca, including in areas where Nexen is either the operator of bitumen leases or holds a working interest in the bitumen rights.

PEOC’s submissions to Proceeding No. 1347905 consist of a number of numerical simulations. PEOC states, in its Submission of Evidence Cover Letter, dated February 14, 2005:

In conclusion, PEOC’s position as stated in the Interim Hearings remains unchanged. The results of our detailed analysis covering a wide spectrum of geology and fluid configurations, all reach the same conclusion, namely that continued gas production poses no risk to bitumen recovery, and therefore PEOC hereby requests that that [sic] the Board change the production status of the interval(s) of the wells listed in Schedule “A” from “shut-in” to “produce”.

Schedule A lists 203 wells in the Kirby, Glover, Hardy, Leismer, Thornbury, Corner, Hangingstone, Newby, Divide and Resdeln Fields. Therefore, it is clear that the results of the simulations are meant to apply to a broad area, including areas where Nexen holds the bitumen rights. Accordingly, Nexen has examined the submissions of PEOC.

In summary, Nexen has examined the approach and conclusions of PEOC and finds that PEOC’s conclusions are incorrect, as set forth in greater detail in this Response Submission:

- PEOC asserts that it applied the RGS stratigraphy within the Wabiskaw-McMurray. However, contrary to the RGS stratigraphy, PEOC finds preserved marine shorefaces with basal marine muds within the areas where pervasive McMurray channelling, vertically and laterally through the section, have removed the McMurray regional mudstones. (This area is hereafter referred to as “the main channel trend” in this submission.) The majority of the 203 wells or intervals that PEOC seeks to have placed on production are located in the main channel trend where the Board has previously found in the Leismer/Chard Decision, the Interim Decision, and where the RGS has similarly concluded, that no regional barriers exist and that the Wabiskaw-McMurray geology is heterogeneous;

- PEOC has presented 4 separate simulation studies over gas pools in the Corner-Hangingstone area. The gas pools are located within or adjacent to the main channel trend. Bitumen development has not yet occurred in these areas. The existing wells were drilled for natural gas on gas well spacing. However, the occurrence of thick bitumen-saturated sands in direct communication with overlying gas zones in the main channel trend is extensive and randomly distributed;
- PEOC uses a maximum of 14 wells in any of the four separate simulations. These wells were drilled primarily on gas well spacing. Geostatistics cannot be properly applied when well spacing is inadequate to sample the full range of geological possibilities within a heterogeneous depositional environment. Further, the effect of utilizing a small number of wells is to artificially limit the geological variability to that encountered within the small well set;
- The PEOC simulations are intended to model the area in which no regional McMurray mudstones occur, however, the models are constructed from wells in which the McMurray A2 regional mudstone is present;
- Within its geostatistical models, PEOC shows limited vertical permeability. The PEOC models exaggerate the presence of low permeability facies in the upper McMurray, however, the simulations do provide permeable vertical pathways for communication between McMurray A1 gas and underlying bitumen. Yet, the simulations conclude that there is no communication. It is unclear how this could result;
- In PEOC's study area, PEOC fails to properly utilize wells that have high permeability pathways that would allow communication between overlying gas and top water thief zones and underlying bitumen. Numerous "chimney" wells (even on the sparse drilling data) exist within the study area that have not been utilized;
- Within its simulations, PEOC employs wells that have limited bitumen resource. In the result, it is not surprising that the simulations show uneconomic bitumen;
- As demonstrated in PEOC's responses to Nexen's Information Requests, when the petrophysical characteristics of wells showing good channel development are used as inputs into the simulator, the result is markedly increased bitumen production rates and established commerciality; and,

- Finally, PEOC uses the results of the 4 simulation studies in the Corner-Hangingstone area, and one reservoir engineering study in the Hardy area, to submit that 203 wells and/or intervals across the Athabasca should be allowed to produce. It is incorrect to draw such sweeping conclusions from PEOC's limited and, in Nexen's view, incorrect, simulation studies.

II. The PEOC Simulation Studies are Flawed

PEOC ignores the regional geologic framework as established by the Leismer/Chard Decision, the RGS and the Interim Hearing in its simulation studies.

By using the following inputs, PEOC ignores the heterogeneity of the McMurray:

- Each study utilized a small number of wells;
- These wells were drilled primarily on gas well spacing; bitumen delineation drilling has not yet taken place in these areas;
- Only a small number of cores, also from wells drilled on gas well spacing, were used to describe the facies present.

The inputs to PEOC's studies are further flawed by the following methodologies:

- Three of the four studies include wells that contain preserved McMurray A2 regional mudstone, as established by the RGS, although PEOC states in its evidence that its studies used wells in which the RGS interpreted that no regional mudstones were present;
- Facies determined from the small core set were applied to non-cored wells. Given that the facies cannot be distinguished reliably using the stated methodology (Discriminant Function Analysis), this approach is flawed;
- "Manual reassignment" of facies was used to attribute marine muds and marine shoreface sands to the non-cored wells, despite that these facies cannot be distinguished from other facies based on petrophysical properties. The presence of such facies could only be established through core examination of sedimentary structures and ichnology;
- The gas-bearing sands in the upper McMurray in the main channel trend wells were entered into the simulation as "interbedded muds";
- The facies assignment in the PEOC models exaggerates the presence of low permeability facies in the upper McMurray yet some proportion of permeable facies exists through the upper McMurray in three of four models. Thus, pressure communication between McMurray A1 gas and underlying bitumen should occur in at least three of the four models.

Having utilized the above inputs, PEOC then runs the simulations and draws two conclusions:

- There is no communication of bitumen with overlying gas, and there is no significant risk of communication; and,
- There is no economic bitumen in the Athabasca.

It is unclear how, when the models are put into the simulator, no communication between overlying gas and bitumen can result given that three of the four models permit communication. These erroneous conclusions, drawn from the flawed studies, are then inappropriately extended to 203 wells situated across the Athabasca.

III. The PEOC Studies Use Incorrect Inputs¹

(a) PEOC Ignores the Regional Geologic Setting

PEOC continues to assert that continued gas production poses no risk to bitumen recovery due to the presence of sealing shales in the form of preserved regional marine shorefaces. In doing so, PEOC fails to acknowledge the heterogeneity of the McMurray Formation and the fact that rapid lithological changes occur over extremely short distances. This has been established in the Leismer/Chard Decision, the RGS and the Interim Hearing. Any credible geologic presentation of the Athabasca Oil Sands Area must acknowledge that the dominant geologic event is channelling and that channelling removes pre-existing sediments, including shorefaces.

As was established at the Leismer/Chard hearing, the McMurray within the main channel trend was deposited in a fluvial-estuarine setting characterized by the occurrence of stacked and intercut channel facies. It was also established that channelling creates sand-on-sand contacts, that channelling can occur anywhere within the McMurray resulting in discontinuous mudstones, and that the McMurray is lithologically heterogeneous.

PEOC does not recognize and adhere to the regional geologic framework as established by the Leismer/Chard Decision, the RGS and the Interim Hearing. The 203 wells or intervals that PEOC seeks to have placed on production are located in the main channel trend or are gas zones in communication with the main channel trend, where the Board has previously found in the Leismer/Chard Decision, the Interim Decision, and where the RGS has similarly concluded, that no regional barriers exist and that the Wabiskaw-McMurray geology is heterogeneous.

¹ In the following discussion of PEOC's geostatistical modelling work, the PEOC Corner McMurray C Pool study will be used as a specific example, and page references will apply to that study, unless otherwise indicated. However, it should be recognized that the comments apply equally to the other three studies.

(b) PEOC Incorrectly Extrapolates Marine Shoreface Units across the Main Channel Trend

PEOC does not recognize and adhere to the regional geologic framework as previously established. PEOC interprets the presence of a trace fossil that is characteristic of the marine shallow shelf environment, rather than of the brackish, fluvial-estuarine McMurray depositional setting. PEOC uses this interpretation to support a further interpretation of sands in the upper McMurray main channel trend as regional marine shoreface units.

i. PEOC Misinterprets Trace Fossil Evidence in the McMurray Formation

The trace fossil *Helminthopsis* is considered to be a common element of the trace fossil assemblages that are characteristic of normal marine shallow shelf environments². Within the McMurray cores examined in the context of its simulations, PEOC interprets “marine mud” intervals with “dominantly *Teichichnus* and *Helminthopsis*” trace fossil assemblages. The implication of this interpretation is a more prevalent marine influence in the McMurray Formation than found to date in the previous submissions of Nexen or in the RGS.

In Nexen-PEOC-2, Nexen requested that PEOC indicate the depths at which the trace fossil *Helminthopsis* was noted in PEOC’s examinations in all cores referenced within Appendix 5: Core Logging Plots. In response, PEOC provided a listing of the core intervals in which the occurrence of *Helminthopsis* was interpreted within the McMurray. Nexen examined the cores and intervals, and makes the following comments.

According to S. G. Pemberton *et al*³, the trace fossil *Heminthopsis* is described as follows:

Regular meandering (*Helminthoida*), or irregularly meandering (*Helminthopsis*), smooth-walled burrows which never branch, interpenetrate or cut across one another. In cross-section, the burrows are elliptical to sub-circular and are generally horizontal. Fill tends to be dissimilar from the surrounding matrix. In core, *Helminthoida/Helminthopsis* commonly appears as tiny dark spots (transverse section) 1 – 3 mm in diameter, or dark lines (longitudinal sections).

The following figures are reproduced from the same reference to illustrate the above description of the meandering character of the burrows as seen in horizontal section:

² S. G. Pemberton, M. Spila, A. J. Pulham, T. Saunders, J. A MacEachern, D. Robbins, I. K. Sinclair; *Ichnology and Sedimentology of Shallow to Marginal Marine Systems: Ben Nevis and Avalon Reservoirs, Jeanne d’Arc Basin*, Geological Association of Canada, Short Course Volume 15, 2001, page 298:

Environmental Consideration: *Helminthopsis* is a common element of the distal *Cruziana* ichnofacies and proximal *Zoophycos* ichnofacies on a normal marine shallow shelf. In some instances, *Helminthopsis* can be associated with low energy, fine-grained bay environments.

³ *Ibid.*

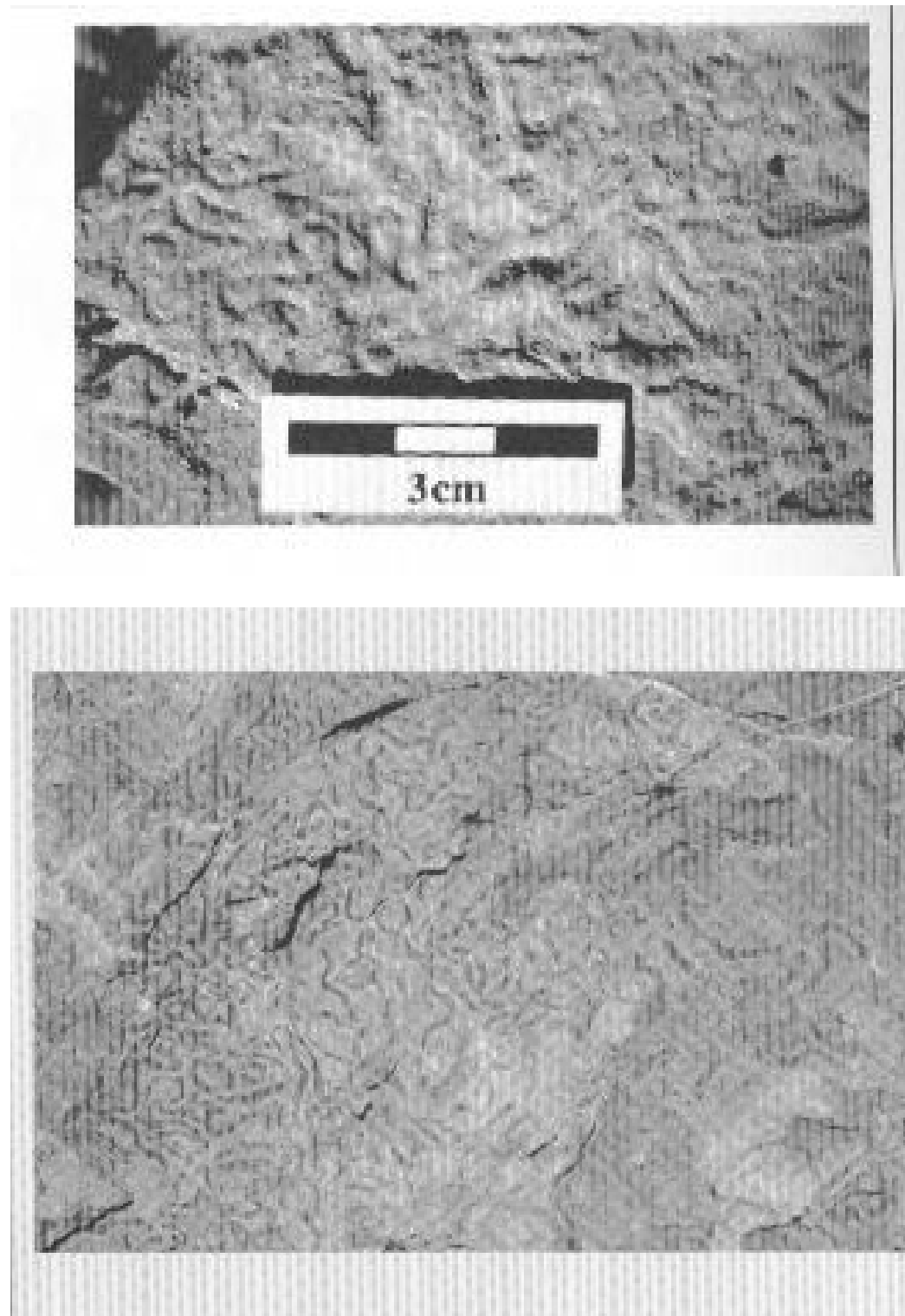


Figure 1: Core photographs demonstrating “Regular meandering (*Helminthoida*) or irregular meandering (*Helminthopsis*), smooth-walled burrows” on horizontal section of core, from Pemberton *et al*; page 298 (top photo) and page 299 (bottom photo).

The wells and intervals indicated by PEOC as containing *Helminthopsis*, and examined by Nexen, are as follows:

1. 100/06-25-081-09W4

- i. 432.4 -435.15m (1418.63 -1427.75 ft) Core 2, Box 3 to Core 2, Box 5

The interval noted contains the McMurray A2 mudstone unit. The strata show light to moderate bioturbation with local high levels of bioturbation. Within the basal transgressive mudstone unit of the McMurray A2, are occasional small, darker spots, measuring 1-3 mm in diameter, visible in two dimensions on the slabbed core surface, which are suggestive of, and might conceivably be misconstrued as *Helminthopsis* or *Helminthoida*. However, examination of both fresh and older horizontal surfaces through the core fail to reveal the “regular meandering (*Helminthoida*) or irregularly meandering (*Helminthopsis*)” burrows which would lead to a conclusive identification of this trace fossil.

- ii. 445.6 – 446.48m (1462.0 -1464.9 ft) Core 3, Box 6

There is no evidence of *Helminthopsis* or *Helminthoida*, using the identification criteria provided by Pemberton *et al*, in this core interval. While some gray, mud-filled burrows, 5-6 mm in diameter, were noted, the characteristic regular or irregular meandering burrows of *Helminthopsis* or *Helminthoida* are absent.

- iii. 448.52 – 451.05m (1471.6 – 1479.8 ft) Core 4, Box 2 to Core 4, Box 3; also Figure 1 in PEOC reply to Nexen-PEOC-1

This interval includes the transgressive McMurray B2 mudstone interval. Nexen’s observations are the same as (ii) above.

PEOC, in its reply to Nexen-PEOC-1, provides two photographs within this interval as “example(s) of marine mud where individual burrows of *Helminthopsis* (He) and *Teichichnus* (Te) can be more easily discerned.” The 6-25-81-9W4 core intervals shown in the photos were examined by Nexen. The intervals represented in both photos show small, dark, mud-lined burrows that might be suggestive of *Helminthopsis* or *Helminthoida* when viewed in two dimensions on the slabbed core surface. However, extensive examination of both fresh and old horizontal surfaces through the core, within and immediately above and below the photographed intervals, reveals no evidence of the characteristic meandering burrow traces of *Helminthopsis*/*Helminthoida*.

2. 100/06-08-081-09W4

- i. 440.18 – 441.47 m (1444.2 – 1448.4 ft) Core 3, Box 6 to Core 3, Box 7

Again, Nexen’s detailed examination of the 6-8-81-9W4 core intervals indicated above failed to disclose the characteristic meandering burrows of *Helminthopsis/Helminthoidea*, as would be seen in a horizontal section, if present.

3. 100/09-29-081-09W4

- i. 437.02 – 437.82m (1433.8 – 1436.42 ft) Core 3, Box 4 to Core 3, Box 5
- ii. 444.44 – 442.88m (1453.0 – 1458.15 ft) Core 4, Box 2 to Core 4, Box 3
- iii. 446.2 – 447.88m (1463.95 – 1470.4 ft) Core 4, Box 3 to Core 5, Box 1

As above, detailed examination by Nexen of the 9-29-81-9W4 core failed to disclose the characteristic meandering burrows of *Helminthopsis/Helminthoidea*, as would be expected to be visible in horizontal sections if the trace fossil was present.

4. 10-11-81-10W4

- i. 435.51 – 436.47m (1428.85 -1432.0 ft) Core 1, Box 5

This core interval shows low angle, dipping (at approximately 5 degrees), muddy inclined heterolithic stratification (IHS), interbedded with sandier strata, and containing abundant subvertical burrows of *Cylindrichnus*. This type of deposition and trace fossil assemblage is characteristic of estuarine channel sedimentation within the McMurray. Within this core interval, there is not even the suggestion of the presence of *Helminthopsis/Helminthoidea*, nor of the depositional facies in which it would be expected to occur, if it was present in the McMurray.

5. 100/3-34-80-10W4

The right side of Figure 9 within PEOC’s submission shows Core 10, Box 2 of 100/3-34-80-10W4, which is described by PEOC as “Marine Mud: burrowed silty mud, dominantly *Teichichnus* and *Helminthopsis*”.

Nexen has examined this core interval and, while it agrees that *Teichichnus* is present, finds PEOC’s interpretation of *Helminthopsis* to be unsubstantiated. Again, this is due to the absence of detectable meandering burrow traces in horizontal section. The same statement applies to Nexen’s examination of the core interval presented on the left side of Figure 9, which is Core 13, Box 1, approximately 427.3m.

Nexen suggests that PEOC may be mistakenly interpreting small preserved remnants of mud linings or muddy *spreiten* associated with other trace fossils, such as the abundant *Teichichnus*, as *Helminthopsis*.

6. Review of PEOC References

PEOC appears to rely heavily on the 2001 Ranger – Caplan paper⁴, and the 2003 Ranger-Gingras guidebook⁵ for support for its interpretation of significant marine influence in the McMurray.

Nexen has reviewed these references. From the Caplan-Ranger paper, Figure 2 (following) shows a core description for the 1AA/10-10-80-7W4 well.

⁴ M. Caplan, and M. Ranger, *Description and Interpretation of Coarsening-Upward Cycles in the McMurray Formation, Northeastern Alberta: Preliminary Results*, Canadian Society of Petroleum Geologists, Rock the Foundation Convention, 2001, page 010-7.

⁵ M. J. Ranger and M. K. Gingras, *Geology of the Athabasca Oil Sands: Field Guide and Overview*, 4th Edition, Canadian Society of Petroleum Geologists, 2003.

In the Caplan-Ranger figure, *Helminthopsis* is noted in the Wabiskaw Sand interval, along with *Diplocraterion*. The McMurray A2 and B2 mudstones (“Facies A”) are noted as containing *Planolites* and *Teichichnus*. It should be noted, that, in going to the 2003 report, the same core is referenced, but the “Facies A” trace fossil assemblage is now noted as “including *Teichichnus* and *Helminthopsis*”. As noted, *Helminthopsis* was not indicated within the McMurray in the 2001 paper, it was indicated only in the Wabiskaw. No reason is given for what would be an abrupt interpretational change.

Nexen examined the 1AA/10-10-80-7W4 core and detected no trace fossils that were suggestive of *Helminthopsis* within the intervals of the McMurray A2 and B2 mudstones (Core 11, Box 1, Core 12, Box 1, Core 18, Boxes 1 and 2). In the absence of further explanation from the authors, Nexen assumes the change from the 2001 reference to the 2003 reference may represent a typographical error in which the word, *Helminthopsis*, was substituted for the word, *Planolites*, in the 2003 reference. In support of this position, Dr. Murray Gingras, co-author of the 2003 guidebook, reported to Nexen (*pers. comm.*) that he has not observed *Helminthopsis* in the McMurray.

In light of its examination, Nexen disagrees with PEOC’s interpretation of the occurrence of *Helminthopsis* within the McMurray in the referenced core examples. In any event, even if *Helminthopsis* was correctly identified within the McMurray, Pemberton *et al.* note that, “In some instances, *Helminthopsis* can be associated with low energy, fine-grained bay environments”⁶, and in such circumstances, is not indicative of the normal marine shallow shelf conditions in which it commonly occurs.

Further, it is Nexen’s opinion that PEOC overstates the marine influence within the McMurray by invoking an interpretation of *Helminthopsis* and the inference of the depositional environment (normal marine shallow shelf) with which it would normally be associated. To do so, PEOC relies on incorrect trace fossil identification to overstate the marine influence within the McMurray A2 mudstone, as represented in the 100/06-25-81-09W4 core. The A2 mudstone is acknowledged to record a transgressive event which was then followed by the progradational deposition of brackish shorefaces. While the interpretation of the basal unit as fully marine, rather than brackish, is not of overwhelming significance in itself, the same mistaken trace fossil interpretation is then used by PEOC to attempt to support the continuity of marine shoreface deposits across the main channel trend (as represented by the 100/06-08-81-09W4, 100/09-29-81-9W4, 10-11-81-10W4 and 100/3-34-80-10W4 cores).

Nexen does not agree with PEOC’s observations of *Helminthopsis* nor with the associated implication of continuous marine units occurring within the main channel trend. PEOC puts forth this interpretation in spite of the fact that the previous decisions of the Board have accepted that any regional mudstones within the main channel trend have been cut by channels and removed by erosion.

⁶ *Supra*, note 2.

ii. PEOC Incorrectly Interprets the Presence of Marine Shorefaces within the Main Channel Trend

One of the eight facies described in PEOC’s simulations is “marine sand”, as follows:

“Regionally developed but prone to erosion by autocyclic or allogenic processes; occurs in the upper part of the McMurray, and therefore commonly a gas reservoir. These facies are interpreted as a prograding shoreface.” (ID 99-1 Application, Core and Facies Identification, within Corner McMurray C Pool study); and,

Figure 8 is captioned “Core Photo of Marine Sand; 3-34-80-10W4” (same reference as above); and,

“In particular, unequivocal muds at the base of marine sand intervals were judged to have a high probability of being a regional marine mud based on observations from wells where core is available.” (ID 99-1 Application, Corner McMurray C Pool study, page 29 of 81)

It is clear in its determination of “marine sand” that PEOC refers to regional marine shoreface units (coarsening-upward sands with regional marine mudstones at the base).

In addition to the 3-34-80-10W4 well given as an example, PEOC also attributes marine shorefaces to sands in the following non-cored wells:

- 02/3-34-80-10W4; “marine sand” is indicated down to 435m, 17m into the McMurray;
- 11-19-81-9W4; “marine sand” is indicated down to 432.5m, well below base of the McMurray A1;
- 6-27-81-9W4; “marine sand” is indicated down to 429.5m, well below base of the McMurray A1.

All of the referenced wells are situated in the main channel trend, where the McMurray A2 and B2 regional shorefaces are absent. However, PEOC is interpreting that prograding marine shoreface units extend across the main channel trend. This is illustrated in response to Nexen-PEOC-1. PEOC supplied the depths for the core photo intervals indicated in Figure 8 as “Marine Sand”:

Figure 8:

Left figure: 3-34-80-10W4 428.4 – 429.15m Core 13, Box 2

Middle figure: 3-34-80-10W4 418.25 – 419.75m Core 10, Box 1

Right figure: 3-34-80-10W4 432.35 – 433.85m Core 15, Box 2 & Core 16,
Box 1

Nexen examined the core intervals in Figure 8, and discusses them below in order of increasing depth:

Middle figure: 3-34-80-10W4 418.25 – 419.75m Core 10, Box 1

The core interval shown in the middle part of Figure 8 (Core 10, Box 1; 418.25 – 419.75m) contains predominantly fine-grained sand that displays parallel-laminated, low angle diverging beds that are suggestive of hummocky cross stratification (HCS). This is consistent with descriptions of the McMurray A shoal unit, which occurs as the final depositional filling event within the McMurray main channel trend, as shown in Nexen’s previously submitted core descriptions (see Nexen’s Supplemental Intervenor Submission, October 23, 2001 and Exhibit 999-11, Leismer/Chard Proceeding). Within the RGS, this unit is referred to as the McMurray A1. There are no indications in the core that would define the sands within this unit as having been deposited under fully marine conditions as opposed to brackish conditions.

Left figure: 3-34-80-10W4 428.4 – 429.15m Core 13, Box 2

This core interval contains predominantly very fine grained sand in which the dominant sedimentary structure is climbing ripples. Climbing ripples occur when heavily sand-laden currents flow into quiet water. The change in flow velocity causes the sediment load to fall out of suspension as the current slows. The abundance of sediment causes the forming ripples to “climb” onto the backs of other ripples, rather than to be distributed in a more horizontal fashion, as would be caused if current speed was maintained. The predominant climbing-rippled sections are underlain by inclined heterolithic stratification (IHS) with abundant soft sediment deformation and abundant small rip-up clasts of mud, and additional sections of climbing rippled sands and IHS. Climbing ripples are not typically characteristic of shoreface deposits, but are common in estuarine fill depositional settings.

Right figure: 3-34-80-10W4 432.35 – 433.85m Core 15, Box 2 & Core 16, Box 1

This core interval consists of fine grained sand in which the sedimentary structures consist predominantly of ripple cross-beds. The trace fossil assemblage and character indicate high stress, consistent with brackish water and/or high sediment load. Cross bedding may occur in a shoreface setting, but the overall context does not support a shoreface interpretation. The sedimentary structures, faunal assemblages and character, and log motifs through the entire photographed interval are consistent with fluvial/estuarine-filling of the McMurray main channel trend. Within the McMurray A1 unit (middle part of Figure 8; Core 10, Box 1; 418.25 – 419.75m), the depositional character and log character are consistent with fluvial/estuarine-filling of the McMurray

main channel trend, and there is no compelling evidence to interpret it as a marine shoreface.

Below the McMurray A1 unit, the entire interval down to the Devonian is also consistent with fluvial/estuarine filling of the McMurray main channel trend by sediments deposited by fluvial-estuarine channels, tidal flats and tidal shoals. The sedimentary structures observed in the 3-34-80-10W4 core are consistent with this interpretation (climbing ripples, IHS, ripple cross-bedding, rip-up clasts, and a stressed faunal assemblage). The 3-34-80-10W4 well has been mapped in the main channel trend by the RGS, and this conclusion is supported by core and logs. Again, there is no supportable reason to interpret marine shorefaces within this well.

The absence of shoreface units in the 3-34-80-10W4 core and logs is made strikingly clear when compared to the core and logs from the AA/10-10-80-7W4 well (which, as indicated above, was also examined). The McMurray A2 and B2 regional shoreface units at AA/10-10-80-7W4 show the characteristic features documented in Nexen's previous submissions and in the RGS, namely: a basal mudstone interbedded with white silts and bioturbated by *Teichichnus* and *Planolites*, grading up into hummocky cross stratified, very fine-grained sandstones and to wave-rippled fine-to-very fine grained sands with syneresis cracks; displaying a well-defined coarsening-up character on logs, and with the basal mudstones displaying characteristic gamma ray readings as compared to the Wabiskaw Shale interval, and occurring at predictable distances down from the Wabiskaw Shale datum. The 3-34-80-10W4 well lacks these attributes in core and on logs. By comparison to the AA/10-10-80-7W4 well, it is unclear how the 3-34-80-10W4 cored intervals can be considered to represent shoreface deposition.

Nexen does not agree with PEOC's interpretation of "marine shoreface" sands within the McMurray main channel trend. As demonstrated, PEOC is incorrectly describing sands in the representative core as "marine" in origin. PEOC incorrectly describes the sands as "shorefaces", then, as discussed in following sections, applies this incorrect facies assumption to non-cored wells. In spite of the fact that it has been accepted that both the regional mudstones and regional shoreface units have been removed by channelling in the main channel trend, PEOC continues to promote the existence of regional marine shorefaces within the McMurray main channel trend.

(c) Geostatistics are Used Incorrectly

The primary difference between PEOC's simulations and simulations submitted by other gas producers is the use of geostatistical modelling to distribute facies and a facies-dependent determination of porosity and permeability, laterally and vertically, in the intervals between well control.

Geostatistical modelling can be a valuable technique when the data set contains the full range of geological situations present in the area, and an accurate assessment of the frequency of occurrence of each geological facies and its distribution in the stratigraphic column. In a heterogeneous environment such as the McMurray, geostatistical

modelling would be more properly applied when bitumen delineation drilling has resulted in a well density sufficient to fully evaluate the bitumen resource. For example, a minimum of 8 wells per section, with core, and 3-D seismic is required to delineate the bitumen resource sufficiently for EUB approval of a bitumen project. In the absence of 3-D seismic, the minimum number of wells for project approval is 16 per section. In contrast, the PEOC models use a small number of wells, distributed on gas well spacing.

PEOC's use of geostatistical modelling with wells drilled on gas well spacing is a clear misapplication of the technique since the heterogeneity of the McMurray deposition cannot be adequately assessed, statistically, by a small number of non-cored wells on gas well spacing.

i. PEOC Incorrectly Models the Presence of Regional Mudstones

In submitting the simulations, PEOC attempts to support a case that no vertical communication would occur between gas and underlying bitumen, even in the McMurray main channel trend where regional mudstones are absent. PEOC states the following in three of the four simulation reports⁷, with respect to the wells used in the models:

“It should be noted that the geostatistical modeling methodology utilized...the RGS geological interpretation” (page 9 of 81, Corner McMurray C Pool Submission); and,

“The RGS indicates all wells contain the McM A1 Sequence. The RGS identified McM Channel sequences in all wells. *The RGS interprets that there are no regional mudstones present that act to separate the overlying McM A1 Sequence gas from the underlying McM Channel gas.*” (Page 11 of 81, Corner McMurray C Pool Submission) [Emphasis added]

⁷ The exception is the PEOC Hangingstone McMurray KKK Pool Submission.

To examine these statements, Nexen requested that PEOC list the wells used to generate the geocellular model for each simulation (Nexen-PEOC-5a), and was provided with the following:

Corner McMurray G Pool Simulation	Hangingstone McMurray X Pool Simulation	Corner McMurray C Pool Simulation	Hangingstone McMurray KKK Pool Simulation
100/09-10-081-09W4M	100/16-18-081-09W4M	100/07-26-080-10W4M	100/12-28-081-10W4
100/13-11-081-09W4M	100/07-19-081-09W4M	100/14-27-080-10W4M	
100/02-14-081-09W4M	100/11-19-081-09W4M	100/14-28-080-10W4M	
100/11-14-081-09W4M	100/12-30-081-09W4M	100/09-33-080-10W4M	
100/04-15-081-09W4M	100/10-25-081-10W4M	100/11-34-080-10W4M	
100/10-23-081-09W4M	100/10-26-081-10W4M	100/05-35-080-10W4M	
100/06-25-081-09W4M		100/08-35-080-10W4M	
100/07-25-081-09W4M		100/14-35-080-10W4M	
100/07-26-081-09W4M		100/03-36-080-10W4M	
100/06-27-081-09W4M		100/08-04-081-10W4M	
		100/10-08-081-10W4M	

However, the Petrel inputs to the studies consist of the following wells, which in some cases, differ from PEOC's response. It is unclear why PEOC's response provides different wells than the wells shown in Petrel as the input wells.

Corner McMurray G Pool Simulation	Hangingstone McMurray X Pool Simulation	Corner McMurray C Pool Simulation	Hangingstone McMurray KKK Pool Simulation
100/09-10-081-09W4M	100/16-18-081-09W4M	100/14-27-080-10W4M	100/12-28-081-10W4
100/13-11-081-09W4M	100/07-19-081-09W4	100/14-28-080-10W4M	
100/02-14-081-09W4M	100/11-19-081-09W4	100/09-33-080-10W4M	
100/11-14-081-09W4M	100/12-30-081-09W4M	102/03-34-080-10W4	
100/12-16-081-09W4M	100/05-24-081-10W4M	100/11-34-080-10W4M	
100/04-15-081-09W4M	100/10-25-081-10W4M	100/05-35-080-10W4M	
100/10-23-081-09W4M	100/10-26-081-10W4M	100/08-35-080-10W4M	
100/10-24-081-09W4M		100/14-35-080-10W4M	
100/06-25-081-09W4M		100/03-36-080-10W4M	
100/07-25-081-09W4M		100/03-03-081-10W4M	
100/07-26-081-09W4M		100/08-04-081-10W4M	
100/06-27-081-09W4M		100/08-05-081-10W4M	
100/10-28-081-09W4M		100/10-11-081-10W4M	
100/09-29-081-09W4M			

In the examination of the input wells, Nexen reviewed the RGS maps and geology, and noted the following:

1. In PEOC's Corner McMurray G Pool Simulation, the RGS interpreted the McMurray A2 mudstone as being present in 8 of the 14 wells used in this simulation (100/09-10-081-09W4M, 100/13-11-081-09W4M, 100/02-14-081-09W4M, 100/12-16-081-09W4M, and 100/10-24-081-09W4M, 100/06-25-081-09W4M, 100/07-25-081-09W4M, and 100/09-29-081-09W4M);
2. In PEOC's Hangingstone McMurray X Pool Simulation, the RGS interpreted the McMurray A2 mudstone as being present in 1 of the 7 wells used in this simulation (100/16-18-081-09W4M);
3. PEOC's Hangingstone McMurray KKK Pool simulation is based on the 100/12-28-81-10W4 well, and uses the facies distribution from the McMurray C Pool. The RGS interpreted the 12-28 well as containing the McMurray A2 mudstone. This is the only simulation in which PEOC acknowledges the presence of a regional mudstone.
4. PEOC's Corner McMurray C Pool simulation is the only simulation in which all the wells used are located within the main channel trend, and, consequently, does not have the regional mudstone present within it.

PEOC's statement to have modelled wells in which the McMurray regional mudstones are absent is incorrect. The McMurray A2 regional mudstone is present, as interpreted by the RGS, in the input wells in 3 of the 4 simulations. Accordingly, the petrophysical characteristics of the regional mudstone units (McMurray A2 and B2 regional mudstones) have actually been incorporated into the geostatistical models. The presence of the regional mudstones in these wells influences the facies distributions toward muddier facies. As a result, the stated purpose of the geostatistical modelling - to model the area where regional mudstones are absent - has not been achieved. Therefore, the results are invalid because the input wells contain regional mudstones.

ii. PEOC's Assignment of Facies to Non-Cored Wells

Some of the major flaws noted by Nexen in PEOC's approach to geostatistical modelling relate to the assignment of facies to non-cored wells. The methodology used is presented in Section 5.2: 3D Reservoir Modelling (Corner McMurray C Pool Submission). The methodology begins with comparing facies from the original 10 cored wells to logs for the same wells. Then, Discriminant Function Analysis is used to derive relationships between the described facies and the gamma ray, neutron porosity, density porosity and deep resistivity readings for the wells. Facies are then ascribed to non-cored wells using the logs from the wells, and the previously-determined log-to-core relationships from the cored wells.

Nexen does not agree that facies can be reliably determined by the described methodology. Even if the methodology of Discriminant Function Analysis could be

successfully employed to assign facies to non-cored wells, in Nexen's view, the data preparation used by PEOC detracts from the validity of its application. In respect of data preparation, PEOC states:

Data preparation is a vital step before the Discriminant Analysis procedure can be implemented. Cores from the control wells must be carefully depth corrected to their corresponding wireline logs. This is achieved by standard methods of using carbonate-cemented beds and sharp bedding contacts. Any uncertainty in this step may be sufficient to exclude that well as a control well. (Page 27 of 81; Corner McMurray C Pool Submission)

After stating the importance of careful data preparation, Nexen notes the following instances where PEOC appears to have allowed significant uncertainties into the data set⁸:

- Full core recovery is indicated in only one of the 10 examined cores (8-35-80-10W4). Missing core is indicated on the Core Logging Plots for the remainder of the examined cores. Particularly large intervals of missing core (greater than 3m) are noted on the Core Logging Plots for 1AA/07-26-080-10W4, 4-15-81-9W4, 6-25-81-9W4, and 3-36-80-10W4. Full core recovery for only one of the cores examined diminishes the reliability of the data set.
- There are significant discrepancies between core description and log character on the Core Logging Plots that suggest that rigorous depth correction was not done during core description. For example:
 - Limestone is indicated at approximately 471.5m (1546') on the 4-15-81-9W4 Core Logging Plot, whereas logs indicate the top of the Devonian at approximately 476.8m (1564'). This indicates a 5.5m discrepancy in facies correlation to logs.
 - The Wabiskaw-McMurray contact is indicated at 428m (1404') on the Core Logging Plot at 6-8-81-9W4, whereas it occurs on logs at approximately 426.2m (1398'). This indicates a 1.8m discrepancy in facies correlation to logs.
 - Also on the 6-8-81-9W4 Core Logging Plot, a mud interval is indicated from 433.7m (1423') to 438.5m (1438'). This does not match logs. The comparable log interval would appear to be from approximately 431.7m (1416') to 436.6m (1432'). This indicates a 2.0m discrepancy in facies correlation to logs.
 - An "uncertain" Wabiskaw-McMurray contact is indicated at 429m (1407') on the Core Logging Plot at 10-26-81-10W4, whereas it occurs on logs at approximately 426.2m (1398'). This indicates a 2.8m discrepancy in facies correlation to logs.
- The Core Logging Plot for the 1AA/10-11-81-10W4 core is plotted on the logs from the 100/10-11-81-10W4 well. This apparent error has resulted

⁸ For the purposes of the discussion of PEOC's assignment of facies to non-cored wells, the Corner McMurray C Pool data inputs have been examined. No inference should be made that Nexen is in agreement with the data inputs of the other simulations.

in gross miscorrelation between facies and log character on the Core Logging Plot.

- For the well 100/08-05-081-10W4, shale volume (Vsh) calculations for the interval from approximately 419.4 to 431m appear to be incorrect. In other wells with similar gamma ray and neutron-density readings, Vsh varies from 0 to 20%, and effective porosity (Phie) is 25-35%. In the 8-5 well, Vsh values range from 20% to 80% and Phie is as low as 0%. It appears that the Vsh resulting from the neutron-density separation was used, rather than the minimum Vsh.

It is evident that the rigorous approach to data accuracy that would be indicated for an appropriate application of Discriminant Function Analysis, and for appropriate application of statistical techniques in general, has not been achieved within the study inputs. Nonetheless, Discriminant Function Analysis was applied to determine facies in the non-cored wells, as follows:

“Four log curves were used to derive the Discriminant Function: the Gamma Ray log, the Neutron and Density logs (both in sandstone porosity units), and the Deep Resistivity log.” (page 27 of 81, Corner McMurray C Pool)

The studies fail to provide data that demonstrates that facies can be reliably distinguished on the basis of gamma ray, neutron porosity, density porosity and deep resistivity in the original 10 cored wells. However, the shortcomings of the methodology used for facies determination are apparent from examination of the statistical analysis of Vsh for different facies on the original and upscaled logs, since shale volume would be expected to have a relationship to facies.

Facies	V _{sh} Original Logs			V _{sh} upscaled Logs		
	Min	Max	Mean	Min	Max	Mean
Marine Mud	0.000	1.000	0.511	0.272	0.773	0.516
Marine Sand	0.000	0.290	0.029	0.000	0.045	0.019
Interbedded Mud	0.000	0.820	0.346	0.000	0.653	0.275
Interbedded Sand	0.000	0.410	0.076	0.000	0.193	0.073

Table 19: Basic Statistics of V_{sh} for Different Facies-Original and Upscaled Logs, A1 Sequence

Facies	V _{sh} Original Logs			V _{sh} upscaled Logs		
	Min	Max	Mean	Min	Max	Mean
Marine Mud	0.000	0.590	0.243	0.000	0.486	0.222
Marine Sand	0.000	0.050	0.002	0.000	0.029	0.002
Interbedded Mud	0.000	0.800	0.233	0.000	0.809	0.220
Sand	0.000	0.290	0.047	0.000	0.229	0.043
Breccia	0.050	0.230	0.138	0.061	0.188	0.124
Mud Plug	0.050	0.690	0.420	0.146	0.665	0.411
Interbedded Sand	0.000	0.500	0.107	0.000	0.468	0.106

Table 20: Basic Statistics of V_{sh} for Different Facies-Original and Upscaled Logs, Lower McMurray

Figure 3: Tables 19 and 20 showing statistics of Vsh for all facies; Corner McMurray C Pool study, Appendix 8: Geological Modelling Report.

Tables 19 and 20 (above) from the Corner McMurray C Pool study, show that “marine mud”, “interbedded mud”, “interbedded sand”, “marine sand” and “sand” facies all have a minimum Vsh value of zero in both the original facies-to-log assignment, and in the upscaled logs. The same is true within the McMurray Corner G (Tables 20 and 21), and Hangingstone McMurray X Pool (Tables 17 and 18) studies.

In fact, all facies have minimum Vsh values of zero in the McMurray G Pool study. In the McMurray C Pool study, only the “breccia” and “mud plug” facies have minimum values of Vsh greater than zero, and for those facies, the minimum Vsh value is only 0.05 or 5%. In the Hangingstone McMurray X Pool study, only breccia has a minimum Vsh value greater than zero (0.09, or 9%).

The effect of using the Discriminant Function Analysis to apply facies to non-cored wells is:

- The marine mud and interbedded mud facies may be assigned to a log interval that shows clean sand on log analysis (0% Vsh);
- The mud plug facies may be assigned to a log interval that shows 0% Vsh or as little as 5% or 9% Vsh.
- Interbedded sand may also be assigned to a log interval that shows 0% Vsh.

Thus, it is apparent that the Discriminant Function Analysis results in an almost total lack of discriminatory ability to differentiate between facies on the basis of shale

content. This is simply incorrect. The effect within the simulation is to allow an almost random assignment of facies to non-cored wells.

iii. PEOC's Manual Reassignment of Facies is Flawed

PEOC uses “manual reassignment” of facies to attribute marine muds and marine shoreface sands to the non-cored wells, despite that these facies have no distinction based on petrophysical properties. The presence of such facies, as distinct from other sands and muds, could only be established through core examination of sedimentary structures and ichnology, thus the presence of these facies cannot be reliably established in non-cored wells. The only characteristic offered to distinguish “marine sands” on logs is a “coarsening upwards” character, however this character is generally absent within the intervals designated as marine sand. Nonetheless, PEOC states:

In this study, it was judged important to differentiate marine (shoreface) sand from non-marine (channelised or bar) sands due to probable differences in sand body geometry. This proved not to be possible using the Discriminant Function. Therefore, sand intervals in the upper part of the McMurray Formation were reassigned manually based on their Gamma Ray log signature (i.e. coarsening upwards); and,

Similarly it was not always possible to differentiate channel abandonment mud (mud plug) from regional marine mud using the Discriminant Function, yet it was critical that these be differentiated in the reservoir model. Therefore these too were manually re-assigned based on geological experience. (page 29 of 81, ID 99-1 Application, Corner McMurray C Pool Submission)

Examination of the input data where marine sand and marine mud have been manually assigned to non-cored wells shows no justification for doing so on the basis of log parameters. The following wells illustrate this point. (See Appendix 1, attached, for open hole logs and PEOC Petrel input data for the following wells.)

1) 14-28-80-10W4

In the 14-28-80-10W4 well, PEOC has manually assigned marine mud to the obvious gas zone interval from 428.2-428.8m (0.6m), despite the fact that PEOC's log analysis for this zone shows 0% Vsh, and Phie of 27%. The neutron and density porosity readings for this interval clearly indicate that the gamma ray response is due to radioactive minerals in the sand, not to mud.

2) 5-35-80-10W4

In the 5-35-80-10W4 well, PEOC has manually assigned marine mud to the intervals from 423-423.2m (0.2m) and 425.2-426.6m (1.4m), despite the fact that PEOC's log analysis for this zone shows no distinction from the “interbedded mud” intervals above and below the zones. The “marine mud” intervals have Vsh ranging from 0-28% and

Phie ranging from 22-28%. The interbedded mud intervals above and below it show Vsh from 0-27% and Phie from 19-28%. Clearly, there is no distinction in shale volume or effective porosity that would serve to distinguish “marine mud” from “interbedded mud”, and thus the designations of marine mud are essentially random.

3) 3-3-81-10W4

In the 3-3-81-10W4 well, PEOC has manually assigned “marine sand” over the interval from 422-423.6m in the McMurray A1. Log analysis through the marine sand shows Vsh from 0-11% and Phie from 29-34%, while intervals designated as “sand” (i.e. channel sand) from 446.6-463.8m have Vsh from 0-11% and Phie of 33-36%. As there is no clear distinction between Vsh in these units and both have extremely high effective porosity, it is unclear why “marine sand” should be assigned to the upper interval, rather than sand.

4) 3-36-80-10W4

In the 3-36-80-10W4 well, PEOC has manually assigned marine mud to the interval from 421-422.2m (1.2m), despite that log analysis shows Vsh of 8-20%, and Phie from 25-31%. Clearly, this facies assignment does not agree with the log analysis values.

5) 10-11-81-10W4

In the 10-11-81-10W4 well, logs show a gas zone from 424-428.5m. However, the PEOC facies assignment denotes this interval as marine mud, in spite of the fact that log analysis shows a maximum of 2% Vsh and a minimum of 28% Phie. Again, the manual reassignment of this interval to the marine mud facies is not supportable.

Clearly, as demonstrated in these examples, manual reassignment of the marine mud facies does not correlate to log properties and appears to be essentially random.

In relation to marine sand, PEOC manually introduces this facies sparingly (see below, The Gas Prone Upper McMurray is Simulated as Interbedded Muds). The result of manually assigned “marine sand” as opposed to “sand” is to impose a mean vertical permeability that is approximately one-eighth that of “sand” (channel sands). A comparison of mean Vsh between marine sand and sand reveals no basis for this permeability difference. The mean Vsh in marine sand is 0.002 or 0.2%, and the mean Vsh in sand is 0.049 or 5%. However, despite the lower mean Vsh in the marine sand, the mean vertical permeability in marine sand is 464 md while it is 3812 md in sand. The most likely cause of vertical permeability reduction in sands is shale content, however, marine sand displays lower mean shale content than channel sand in PEOC’s estimation. The assignment of low vertical permeability to marine sand is unsupported by log parameters and therefore its validity is questionable.

The overall effect of manual facies reassignment in the McMurray Corner C Pool study is to decrease the distribution of sand and interbedded sand in the upper, productive,

gas-bearing sands of the McMurray by introducing a manually assigned marine mud facies. Where marine sand is assigned, vertical permeability is severely hampered, as compared to an assignment of channel sand. The overall result is a biasing of the facies distribution in the upper part of the McMurray toward lower permeability facies.

iv. The Gas Prone Upper McMurray is Simulated as Interbedded Muds

PEOC notes that the upper part of the McMurray is commonly a gas reservoir. The evidence of the productivity of the upper gas zones is clear from the gas production volumes shown on the Structural Pool Schematic provided in Appendix 1: Cross Sections and Pool Schematic (Corner McMurray C Pool Submission). The wells along the cross section (which represent all the wells in the model with the exception of the dry and abandoned 3-36-80-10W4 well) are shown to have produced 21 Bcf of gas. However, examination of the input logs to the model shows the gas pay intervals have largely been assigned the interbedded mud facies as opposed to any sand facies, despite that log parameters do not support this facies determination. Given that the mean horizontal and vertical permeabilities of interbedded mud in the McMurray, within the Corner McMurray C Pool model, are 94md and 70md respectively, it is clear that gas zones composed largely of interbedded mud could not support the economic gas rates that have occurred, and therefore, in Nexen's opinion, the model is flawed.

Examination of the input data to the Corner McMurray C Pool study shows this to be true. PEOC uses a pessimistic definition of "interbedded mud" within its facies definition. In response to Petro-Canada's Information Request #1, for a quantitative definition of reservoir parameters for each facies type, PEOC replies as follows:

Interbedded sand: 10% - 30% mud
Interbedded mud: 10% - 70% sand
"interbedded": Sand-mud couplets 1m or less in genetic thickness.
Mud: <10% sand laminae.

Thus, an interval containing 70% sand would be classified by PEOC as "interbedded mud", and assigned only 94md mean horizontal permeability and 70md mean vertical permeability (Table 5: McMurray Zone Facies Properties; ID 99-1 Application, page 34 of 81), as compared to 761md and 508md mean horizontal and vertical permeability for "interbedded sand". By comparison, Nexen defines interbedded sand (Sandy IHS facies) as containing between 10% and 50% mud, and interbedded mud (Muddy IHS facies) as containing between 50% and 90% mud. Thus, a portion of the strata that Nexen, as a bitumen producer, considers to be reservoir, would be designated as non-reservoir, low permeability strata by PEOC. It is clear that in its basic facies definitions, PEOC exaggerates the proportion of low permeability facies within the McMurray.

PEOC's exaggeration of the proportion of low permeability facies is demonstrated by an examination of the input wells to the Corner McMurray C Pool study. (See Appendix 1, attached, for open hole logs and PEOC Petrel input data for the following wells.)

1. 5-35-80-10W4

In the 5-35-80-10W4 well, there is a perforated gas zone from 426m-428m. PEOC log analysis shows this zone to have Phie ranging from 26-31% and Vsh ranging from 0-10%. However, PEOC has assigned only 0.6m of interbedded sand and marine sand (from 427.4-428.0m). The remainder of the zone is interbedded mud and marine mud. Thus, over a 2m gas zone, only 0.6m of permeable facies (e.g. sand, marine sand, interbedded sand) is assigned in the model.

Similarly, across the perforated gas zone from 429m-430m, PEOC log analysis shows Phie ranging from 25-28% and Vsh ranging from 0-2%. PEOC has assigned only 0.4m of interbedded sand and marine sand (429.4-429.8m). Thus a 1m gas zone with high porosity and clean sand is assigned only 0.4m of permeable facies.

2. 100/08-04-081-10W4

In the 100/08-04-81-10W4 well, across the gas zone from 432m-435m (2m), PEOC log analysis shows Phie ranging from 26-29% and Vsh ranging from 0-0.01%. However, PEOC has assigned the interbedded mud facies across this entire zone. Thus, 2m of gas zone is unrepresented in the inputs to the model.

Similarly, across the gas zone from 436m-437m (1m), PEOC log analysis shows Phie ranging from 26-29% and Vsh ranging from 0-4%. However, PEOC has assigned only 0.2m of interbedded sand (436.2-436.4m) and has designated the remainder as interbedded mud. Thus, a 1m gas zone is diminished in the model inputs to 0.2m of permeable facies.

3. 100/09-33-80-10W4

Similarly, the logs for this well show a 10m gas cross-over extending from 424m to 435m. However, PEOC diminishes the gas zone thickness and facies representation by assigning interbedded mud to the gas-bearing interval from 424-424.6m, despite the fact that Phie ranges from 28-29% and Vsh is 0%. Interbedded Mud is also assigned to the interval from 425-425.6m (0.6m; 26-28% Phie, 0-8% Vsh) and from 431-432.8m, (1.8m; Phie of 28-30% Phie and 0-2% Vsh). Thus, a 10m gas zone is diminished in the model to 7m of permeable facies.

4. 11-34-80-10W4

In the 11-34-80-10W4 well, logs show a thin, perforated zone of gas cross-over at approximately 427-427.2m (0.2m). PEOC has assigned interbedded mud to this zone, even though the PEOC log analysis shows that Phie is 29% and Vsh is 3%. Thus, this thin gas zone is unrepresented in the original log input to the model.

The logs also show a perforated gas zone from 432.3m to 436m (3.7m). PEOC has assigned interbedded mud over the interval from 432.3 to 434m (1.7m), despite the fact

that the PEOC log analysis shows that Phie is 23-30% and Vsh is 0-9%. Thus, a 3.7m gas zone is reduced to 2.0m of permeable facies in the model.

5. 14-28-80-10W4

The 14-28-80-10W4 logs show a perforated gas zone from 417-418.8m (1.8m). PEOC has assigned interbedded sand only over 0.2m of this interval (417.4-417.6m). The remainder is assigned marine mud and interbedded mud. Thus, a 1.8m gas zone is reduced in the model to only 0.2m of permeable facies.

Logs also show a thin, perforated zone of gas cross-over at approximately 422m-422.2m (0.2m). PEOC has assigned interbedded mud to this zone, despite that the PEOC log analysis shows that Phie is 28% and Vsh is 0%. This thin gas zone is therefore unrepresented in the original log input to the model.

As well, the major gas interval between 425.5-433m (6.0m of gas cross over) is minimized in the PEOC facies assignment. Interbedded sand and sand are assigned to the intervals from 426-426.4m (0.4m), 428.8-430m (1.2m), and 430.4-433 (2.6m). The remainder is interbedded mud and marine mud. Thus, the 6.0m gas zone is reduced in the model to only 4.2m of permeable facies.

In the examples above, a cumulative thickness of 23.5m of gas pay from logs is reduced to 6.9m of permeable facies in the model inputs.

As demonstrated, the overall effect of facies assignment in the McMurray Corner C Pool study is to sway the distribution of facies in the upper, productive, gas-bearing sands of the McMurray away from sand and interbedded sand facies, and towards interbedded mud and marine mud. The sand facies – sand, interbedded sand, marine sand – have relatively high mean vertical permeabilities in PEOC’s model - 3812 md, 366-508 md, and 465-583 md, respectively. Interbedded mud and marine mud have relatively low vertical permeabilities in PEOC’s model – 70-148md and 2-95md respectively. In the end result, it is no surprise that the upper McMurray interval in the model consists largely of the interbedded mud facies, as shown on the Vertical Facies Proportions for the original logs (Figure 11, Appendix 8: Geological Modelling Report, page 17).

v. The Presence of Continuous Mudstones Within PEOC’s Simulations

PEOC states in its Submission of Evidence Cover Letter, dated February 14, 2005, which prefaces all of its simulation binders, that: “No continuous mudstones are introduced into the geostatistical models.” An examination of the vertical facies proportion diagrams for the geostatistical models demonstrates that this statement is incorrect in two of the four studies. The use of the Discriminant Function Analysis to assign facies to non-cored wells, the assignment of the interbedded mud facies to a significant proportion of the upper McMurray gas zones, the manual reassignment of facies to insert marine mud into the model, and the manual reassignment of “marine sand” in place of higher permeability “sand”, appear to result in the creation of

continuous mudstone layers in two of the models. Prior to running the simulations, the vertical facies proportions for the models were smoothed, and thus the continuous mud layers were made less continuous in all models. In the result, despite the statistical probability of permeable facies occurring in any layer through the upper McMurray channel section, there is still no communication between McMurray A1 gas and underlying McMurray channel bitumen in the simulations. It is unclear how this result can occur.

1. Corner McMurray C Pool

Examination of the Vertical Facies Proportions diagram across the Lower McMurray zone for the original logs reveals that PEOC's facies determination methodology did, in fact, result in a 100% probability that 2 separate layers of interbedded mud would extend across the entire model within the upper 17 layers of the model (Figure 11: Vertical facies proportions – Original logs, lower McMurray, Appendix 8 Geological Modelling Report, page 17).

It is only due to the fact that slight smoothing was applied to the facies distributions, on the version chosen for the simulation run, that the probability of continuous mud across the entire model, in one or more layers, ended up at slightly less than 100%. The Lower McMurray Vertical Facies Proportions diagram, that represents the actual input chosen for the simulation (Figure 30; 3-D Reservoir Modelling, page 27, Corner McMurray C Pool Submission), shows a 98% probability that one zone of interbedded mud will be continuous across the entire model, and a 93% probability that a second zone of interbedded mud and marine mud will be continuous across the entire model within the upper 28 layers in the Lower McMurray. (The mean vertical permeabilities for interbedded mud and marine mud, are 70md and 94m, respectively, in this model.) Thus, the actual inputs to the model result in essentially continuous mudstones across the model area. It is hardly surprising that the result of the simulation, using this geostatistical model, is no communication between McMurray A1 gas and underlying bitumen.

2. Hangingstone McMurray X Pool

For the Hangingstone McMurray X Pool, the Lower McMurray vertical facies proportion that was chosen for the simulation (Figure 30; 3-D Reservoir Modelling, page 25) demonstrates a 76% probability that marine mud and/or interbedded mud will occur within the uppermost 3 layers in the Lower McMurray, immediately below the McMurray A1 sequence. Despite a 24% probability that permeable facies will occur, even in the most permeability-restricted layers, the result of the simulation is no communication between McMurray A1 gas and underlying bitumen. It is unclear how this can occur, given the presence of permeable facies in the input.

3. Corner McMurray G Pool

For the Corner McMurray G Pool, the Vertical Facies Proportions diagram for the Lower McMurray chosen for the simulation (Figure 30, 3-D Reservoir Modelling, page 28) shows a minimum probability of approximately 48% that permeable facies will occur in the uppermost 16 layers. However, in spite of the apparent probability that there will be pressure communication between the McMurray A1 gas zone and the underlying channel sands (via the presence of permeable facies), the result – no communication – is the same as in the previously discussed models. It is unclear how a model that demonstrates a statistical probability of pressure communication can, nonetheless, result in no communication.

4. Hangingstone McMurray KKK Pool

In the McMurray KKK Pool study, the 12-28-81-10W4 well was apparently added into the facies distribution generated by the Corner McMurray C Pool study. Similar to the Corner C McMurray Pool study, the resulting vertical facies proportions diagram for the Lower McMurray upscaled logs (Figure 11, 3-D Reservoir Modelling, page 12) shows a 100% probability of encountering marine mud or interbedded mud across the entire pool area within what appears to be Layer 6. Thus, the overall facies designation methodology did, in fact, result in a continuous mudstone across the entire pool.

Again, it is only due to the fact that smoothing was applied to the facies distributions, on the version chosen for the simulation run, that the probability of continuous mud, in one or more layer, across the entire model, ended up at less than 100%. The Lower McMurray Vertical Facies Proportions chosen for the simulation (Figure 12; 3-D Reservoir Modelling, page 16, Hangingstone McMurray KKK Pool study) shows approximately 22% minimum probability of permeable facies in the upper 10 layers of the model. However, the result of the simulation is no communication between McMurray A1 gas and underlying bitumen.

In summary, examination of the models submitted by PEOC shows that the facies designation methodology results in a continuous mudstone layer across the entire pool area in 2 of the 4 models. Subsequent smoothing of vertical facies proportions in the versions chosen as simulation inputs resulted in at least a small statistical possibility of vertical communication between McMurray A1 gas and bitumen. However, all simulations resulted in no pressure communication between McMurray A1 gas and underlying McMurray bitumen sands. It is unclear how a model that demonstrates a statistical probability of pressure communication can, nonetheless, result in no communication. For this reason, in Nexen's opinion, the results of the simulations are invalid.

(d) The PEOC Simulations Disregard the Presence of Commercial Bitumen

PEOC takes a small sample of widely-distributed wells, ascribes facies in a manner that exaggerates the nonreservoir portion, and then performs simulations that show

uneconomic bitumen rates and no communication between McMurray A1 gas and underlying bitumen. In doing so, PEOC uses wells that generally contain poorer quality channel sands, and when a well with better channel quality sands is included, it represents only a small fraction of the data set. PEOC then applies the conclusions derived from this flawed study to say that bitumen is uneconomic in the Athabasca. Nexen notes that this is clearly incorrect.

PEOC states in its Submission of Evidence Cover Letter:

The simulations incorporating the most probable geostatistically-generated geology predicted very poor SAGD performance from the Wabiskaw-McMurray within the region of influence of all of the gas pools reviewed with low average oil production rates of 0.01 to 0.02 m³/d/m of horizontal wellbore and average stabilized rates of 2-12 m³/d/well pair, low cumulative bitumen recoveries and high steam/oil ratios of well above 4 which is considered an economic cut-off by industry...

Nexen has shown that PEOC's models do not represent the most probable geostatistically-generated geology. PEOC ignores the findings of the regional geologic setting that has been established by the Leismer/Chard Decision and by the RGS. In doing so, PEOC ignores the heterogeneity of the McMurray Formation and the finding that channelling can occur anywhere within the McMurray and that channels are extensive and randomly distributed, and result in discontinuous mudstones. Such extensive and randomly distributed channels place bitumen-saturated sands in direct communication with overlying gas zones. PEOC's models do not include wells that exhibit good channel development in the upper part of the section, or where such wells are included, permeable gas-bearing strata are given the facies designation of interbedded mud. In ignoring the past findings on the geology of the McMurray, it is clear that PEOC's geostatistically modelled geology is flawed and does not represent a realistic basis on which to make conclusions on the economics of bitumen, or on the potential for communication between gas and bitumen.

Nexen notes many examples of "chimney" wells in the vicinity of the PEOC pool studies which demonstrate that very well-developed channel sands may exist anywhere vertically within the McMurray section. These wells clearly show that vertical communication will exist between the McMurray A1 unit, the underlying McMurray channel, and throughout the McMurray. Some examples are:

100/05-31-080-09W4
100/12-32-080-09W4
100/07-14-080-10W4
100/16-24-080-10W4
100/10-23-081-09W4
100/06-27-081-09W4
100/12-13-081-10W4

These wells were encountered on sparse drilling on gas well spacing. Since such channels sands are extensive and randomly distributed, it can be expected that bitumen delineation drilling will discover many more.

Numerous wells exist in the Corner-Hangingstone area in the vicinity of PEOC's pool studies that display well-developed channel sands and economic thicknesses of bitumen. For example:

100/05-31-080-09W4
100/12-32-080-09W4
100/15-03-080-10W4
100/15-10-080-10W4
100/10-13-080-10W4
100/07-14-080-10W4
1AA/04-24-080-10W4
100/16-24-080-10W4
100/05-35-080-10W4
100/10-23-081-09W4
100/12-13-081-10W4

These wells were also encountered on sparse drilling on gas well spacing, and clearly show the likelihood that delineation drilling will result in economic bitumen projects in this area.

In Nexen-PEOC-5e, Nexen requested that PEOC comment on the SAGD bitumen production rates that would result if some of the above-noted wells in the same area were used as the basis for the model instead of the ones chosen for the models. PEOC did not construct a new model using these wells as inputs, but provided a qualitative estimation of the SAGD bitumen production rate for these wells, as follows:

100/15-03-080-10W4:	175 m3/d
100/15-10-080-10W4:	12-25 m3/d
100/10-13-080-10W4:	160 m3/d
100/07-14-080-10W4:	180-185 m3/d
1AA/04-24-080-10W4:	180-185 m3/d
100/05-35-080-10W4:	175 m3/d

PEOC's response clearly demonstrates that the Corner-Hangingstone area contains excellent potential for economic bitumen production, and that PEOC's assessment of uneconomic bitumen, derived from the simulations, is incorrect.

The bitumen potential in the Corner-Hangingstone area, and in the Athabasca Oil Sands as a whole, has been demonstrated by the recent flurry in oil sands lease acquisition and oil sands evaluation drilling. The increased oil sands leasing activity has occurred primarily on the basis of regionally sparse gas well drilling. Given that few new

gas wells have been drilled in the Wabiskaw-McMurray Application Area of the Athabasca Oil Sands since the date of the gas well shut in, oil sands leases are being acquired on the basis of much the same well control as prior to the Leismer/Chard Hearing. Contrary to the simulations submitted to this hearing by PEOC, industry has not written off the economic potential of oil sands on the basis of sparse well control and the heterogeneity of the McMurray Formation.

Paramount Resources has taken part in the activity, and is the lease holder for oil sands rights beneath the Corner McMurray G Pool. The oil sands rights were purchased on the basis of the same gas wells, on sparse gas-well spacing, that are modelled by PEOC in its McMurray G Pool simulation. Paramount Resources also holds the oil sands rights immediately east of, and adjoining, the Hangingstone McMurray X Pool. These rights were purchased recently (February 9, 2005). Where PEOC finds the bitumen resource uneconomic as the result of its simulation studies, Paramount Resources continues to hold bitumen rights and acquires additional bitumen rights on the basis of existing sparse well control. The flurry of oil sands leasing activity has been accompanied by increasing lease prices. What appears to be a record price for oil sands leases (\$5,903 per hectare) was recently set in the Corner-Hangingstone area by Paramount Resources and its partner⁹.

The high levels of oil sands leasing activity and bitumen evaluation drilling by industry send a clear message that bitumen potential cannot be written off on the basis of sparse well control, nor on the basis of unfavourable simulation studies founded on incorrect geological models.

IV) Conclusion

PEOC's approach to simulating the geology of the McMurray in the main channel trend is incorrect and, therefore, PEOC's conclusions should not be accepted for the reasons set forth in this submission:

- PEOC does not recognize and adhere to the regional geologic framework of the McMurray by continuing to extrapolate marine shoreface units across the main McMurray channel trend where no regional barriers exist;
- PEOC ignores the heterogeneity of the McMurray by presuming that wells on typical gas well spacing provide a statistically complete representation of the McMurray geology. Geostatistical modelling methods are misapplied because the heterogeneity of the McMurray cannot be adequately assessed by the small numbers of widely-spaced wells used in the models;

⁹ The 9-section block consisting of Sections 4, 5-7, and 18 in Township 83, Range 9W4M and Sections 1, 12, 13, and 24 in Township 83, Range 10W4M was acquired by Paramount Resources and North American Oil Sands Corporation (NAOSC) for a price of \$5,903 per hectare. Paramount and NAOSC licensed 11 oil sands evaluation wells in 2004 and 89 in 2005 on oil sands leases in the Corner (including those lands underlying the McMurray Corner G Pool), Hangingstone and Surmont areas.

- PEOC sets out to model the main channel trend in the McMurray but includes wells that contain the McMurray A2 regional mudstone in the models;
- PEOC's assignment of facies to non-cored wells using Discriminant Function Analysis, a pessimistic definition of interbedded mud, and manual facies assignment, results in predominantly low permeability facies in the gas-bearing reservoir sand section of the upper McMurray;
- PEOC's simulations disregard the presence of commercial bitumen by using wells that generally contain poorer quality channel sands;
- PEOC utilizes the 4 simulation studies in the Corner-Hangingstone area study to submit that 203 wells and/or intervals across the Athabasca should be allowed to produce. It is incorrect to draw such sweeping conclusions from PEOC's limited and, in Nexen's view incorrect, simulation studies;
- Numerous wells exist on gas well spacing in the Corner-Hangingstone area that exhibit well developed channel sands at various stratigraphic levels within the McMurray, and with economic thicknesses of bitumen;
- The potential for economic bitumen projects is high in the Corner-Hangingstone area, as is communication between overlying depleted gas and bitumen;
- It is the nature of simulation modelling that if PEOC had constructed a model primarily from wells containing well developed bitumen-filled channel sands, the end result of a proper simulation would be economic bitumen production rates, and, if the model incorporated, and correctly assigned facies to, wells with well developed sands in the upper part of the McMurray, the result would be communication between the McMurray A1 gas and underlying bitumen;
- The PEOC simulations do not present a valid scientific basis on which to reverse the Board's previous decisions to shut in gas.

Therefore, Nexen continues to seek the relief sought in its February 14th, 2005 Submission, and requests that the Board uphold the previous decision to disallow gas production from the 203 wells and/or intervals that PEOC is currently disputing.

All of which is respectfully submitted by Lori Skulski on behalf of Nexen Inc. this 9th day of May, 2005.

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