



Hunt Oil Company of Canada, Inc.

Applications to Amend Enhanced Recovery Scheme
Approval No. 10848 and Pool Delineation
Kleskun and Puskwaskau Fields

December 23, 2008

ENERGY RESOURCES CONSERVATION BOARD

Decision 2008-130: Hunt Oil Company of Canada, Inc., Applications to Amend Enhanced Recovery Scheme Approval No. 10848 and Pool Delineation, Kleskun and Puskwaskau Fields

December 23, 2008

Published by

Energy Resources Conservation Board
640 – 5 Avenue SW
Calgary, Alberta
T2P 3G4

Telephone: 403-297-8311
Fax: 403-297-7040
E-mail: Publications@ercb.ca
Web site: www.ercb.ca

CONTENTS

Decision	1
Examiner Report	3
1 Recommendation	3
2 Introduction.....	3
2.1 Applications.....	3
2.2 Intervention.....	3
2.3 Hearing	3
3 Background.....	4
4 Issues.....	4
5 Pool Delineation.....	5
5.1 Views of Hunt.....	5
5.2 Views of Galleon.....	5
5.3 Findings of the Examiners.....	6
6 Need for and Location of Additional Injectors in Hunt’s Waterflood Scheme	6
6.1 Views of Hunt.....	6
6.2 Views of Galleon.....	10
6.3 Findings of the Examiners.....	12
7 Potential for Hunt’s Proposed Injectors to Impact Galleon’s Producers	15
7.1 Views of Hunt.....	15
7.2 Views of Galleon.....	17
7.3 Findings of the Examiners.....	18
Appendix 1 Hearing Participants	21
Table 1 Hunt’s Reservoir Simulation Results	8
Table 2 Galleon’s Reservoir Simulation Results	12
Figure 1 Location map.....	22

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

**HUNT OIL COMPANY OF CANADA, INC.
APPLICATIONS TO AMEND ENHANCED RECOVERY
SCHEME APPROVAL NO. 10848 AND POOL DELINEATION
KLESKUN AND PUSKWASKAU FIELDS**

**Decision 2008-130
Applications No.
1554799 and 1578005**

DECISION

The Energy Resources Conservation Board has considered the findings and recommendation set out in the following examiner report, adopts the recommendation, and directs that Applications No. 1554799 and 1578005 be approved.

Dated in Calgary, Alberta, on December 18, 2008.

ENERGY RESOURCES CONSERVATION BOARD

<original signed by>

Dan McFadyen
Chairman

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

**EXAMINER REPORT RESPECTING
HUNT OIL COMPANY OF CANADA, INC.
APPLICATIONS TO AMEND ENHANCED RECOVERY
SCHEME APPROVAL NO. 10848 AND POOL DELINEATION
KLESKUN AND PUSKWASKAU FIELDS**

**Decision 2008-130
Applications No.
1554799 and 1578005**

1 RECOMMENDATION

Having considered all of the evidence, the examiners recommend that Applications No. 1554799 and 1578005 be approved.

2 INTRODUCTION

2.1 Applications

In Application No. 1554799, Hunt Oil Company of Canada, Inc. (Hunt) applied to the Energy Resources Conservation Board (ERCB/Board), pursuant to Section 39 (1)(a) of the *Oil and Gas Conservation Act (OGCA)*, to amend its enhanced recovery (ER) scheme, Approval No. 10848 (Hunt's waterflood scheme), by adding two water injection wells located at the second location exception of Legal Subdivision 12, Section 33, Township 71, Range 26, West of the 5th Meridian (02/12-33-071-26W5/0) (02/12-33 well) and 00/06-04-072-26W5/0 (6-4 well) in the Kleskun Beaverhill Lake A Pool (A Pool) that would inject saline water.

In Application No. 1578005, Hunt applied to the ERCB, pursuant to Section 33 of the *OGCA*, to include the 00/06-03-072-26W5/0 (6-3), 00/11-03-072-26W5/0 (11-3), 00/16-03-072-26W5/2 (16-3/2), and 00/16-04-072-26W5/0 (16-4) wells, currently designated to the Puskwaskau Beaverhill Lake C Pool (C Pool), in the A Pool.

2.2 Intervention

Galleon Energy Inc. (Galleon) filed an objection to Application No. 1554799 on the basis that the proposed 02/12-33 and 6-4 injection wells could result in premature water breakthrough because of high-permeability channels in the A Pool, and that injecting water into updip wells in a reservoir where there is an oil-water contact could result in reduced sweep efficiency. Galleon is the licensee of the 00/16-32-071-26W5/0 (16-32) and 00/08-05-072-26W5/3 (8-5/3) A Pool wells and holder of ER scheme Approval No. 10827A (Galleon's waterflood scheme) in the A Pool.

2.3 Hearing

The Board held a public hearing in Calgary, Alberta, which commenced on September 29, 2008, and concluded on October 2, 2008, before Board-appointed examiners G. W. Dilay, P.Eng. (Presiding Member), T. R. Keelan, P.Eng., and J. R. MacGillivray, P.Geol. Those who appeared at the hearing are listed in Appendix 1.

At the close of the hearing, Galleon was required to complete a number of undertakings. The undertakings were completed on October 8, 2008, and therefore the examiners consider the hearing to have been closed on that date.

3 BACKGROUND

Figure 1 is a location map that shows the areas referred to in Applications No. 1554799 and 1578005 and in Galleon's objection.

The A Pool is a conventional oil pool that was discovered in November 2005 and is being competitively operated with two separate waterflood schemes, which are shown in Figure 1. Galleon operates a waterflood scheme in the southwestern part of the A Pool and Hunt operates a waterflood to the east of Galleon's waterflood. Galleon started water injection in June 2007, while Hunt started water injection in October 2007. Currently the A Pool contains the 16-32, 02/12-33, 00/13-33-071-26W5/0 (13-33), 00/01-04-072-26W5/0 (1-4), 6-4, 00/14-04-072-26W5/0 (14-4), and 8-5/3 wells. Of these seven wells, four (02/12-33, 13-33, 1-4, and 6-4) are within Hunt's waterflood scheme, two (16-32 and 8-5/3) are within Galleon's waterflood scheme, and one (14-4) lies outside the existing waterflood schemes. Galleon is currently injecting water into the 00/06-32-071-26W5/2 (6-32/2) Kleskun Beaverhill Lake D Pool (Kleskun D Pool) well and the undefined 00/08-32-071-26W5/2 (8-32/2) well, while Hunt is currently injecting water into the 00/06-33-071-26W5/0 (6-33) Kleskun Beaverhill Lake E Pool (E Pool) well. All of the injection is into a common aquifer associated with the A Pool. The Kleskun D Pool and the E Pool have no producing wells at this time.

The C Pool, also shown in Figure 1, was discovered in March 2006 and is operating under primary recovery. This pool consists of the 6-3, 11-3, 16-3/2, and 16-4 wells. All of these wells are licensed to Hunt.

4 ISSUES

The examiners consider the issues respecting the applications to be

- pool delineation,
- the need for and location of additional injectors in Hunt's waterflood scheme, and
- the potential for Hunt's proposed injectors to impact Galleon's producers.

In reaching the findings contained within this examiner report, the examiners considered all relevant materials constituting the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this report to specific parts of the record are intended to assist the reader in understanding the examiners' reasoning relating to a particular matter and should not be taken as an indication that the examiners did not consider all relevant portions of the record with respect to that matter.

5 POOL DELINEATION

5.1 Views of Hunt

Hunt applied to add the following four wells to the A Pool: 6-3, 11-3, 16-3/2, and 16-4. These wells are located to the northeast of the A Pool, as shown in Figure 1, and are currently within the C Pool. Hunt's pooling interpretation was based on there being pressure communication between wells in the A Pool and the subject four wells, which was indicated by the similarities in the declining pressure trends. Hunt acknowledged that pressure differences existed between wells in the applied-for expansion area and suggested that these differences were due to permeability differences in the pool. Hunt submitted that the structure of the reservoir and seismic data supported its pool interpretation. It noted that while seismic data were not definitive, they aided in pool delineation.

With respect to the northeast edge of the expanded A Pool, Hunt interpreted there to be pressure communication between the A Pool and the Puskwaskau Beaverhill Lake D Pool (Puskwaskau D Pool) but because fluid flow appeared to be poor in that area, Hunt pooled them separately.

With respect to the southwest edge of the A Pool, Hunt interpreted that the 6-32/2, 8-32/2, and 6-33 wells were not within the A Pool. This was based on the poor pressure communication between the three wells and the A Pool and Hunt's interpretation that the oil-water contacts in these wells were different than its interpreted oil-water contact for the A Pool. Hunt inferred the oil-water contact in the A Pool to be at -2434 metres subsea (mss) from the transition zones at the bases of the 16-32 and 02/12-33 wells. Hunt interpreted the oil-water contacts in the 6-32/2 and 6-33 wells to be at -2441.5 mss and -2427.5 mss (based on the corrected 6-33 well log depth) respectively. Hunt did not interpret any commercial oil pay at the 8-32/2 well because of the lack of oil recovery from the well.

5.2 Views of Galleon

Galleon had no objection to the pool delineation changes applied for by Hunt and included the four wells within its isopach map of the A Pool. In addition, Galleon's mapping of the A Pool extended into the Puskwaskau D Pool.

With respect to the southwest edge of the A Pool, Galleon interpreted the 6-32/2, 8-32/2, and 6-33 wells to be within the A Pool. This interpretation was based on pressure data and geological and geophysical maps that, in Galleon's view, indicated the A Pool was continuous through Section 32 and most of Section 33-71-26W5M. Galleon stated that Hunt incorrectly defined the oil-water contact for the A Pool by using bulk volume water over shaly intervals in the 16-32 and 02/12-33 wells. Galleon's interpretation was that there were no oil-water contacts in the 16-32 and 02/12-33 wells. Instead, Galleon stated that the 6-32/2 and 8-32/2 wells correctly defined the oil-water contact for the A Pool to be at -2442 mss, based on both log and production data. Galleon interpreted an oil-water contact at -2427 mss in the 6-33 well as the result of there being, in its view, a small perched aquifer in the vicinity of the 6-33 well. Galleon stated that it would be submitting an application to the ERCB to include the 6-32/2 and 8-32/2 wells in the A Pool.

5.3 Findings of the Examiners

The examiners agree with Hunt and Galleon that the geological and pressure data indicate that the 6-3, 11-3, 16-3/2, and 16-4 wells are part of an expanded A Pool and recommend that these wells be added to the existing A Pool. With respect to the possible continuation of the expanded A Pool farther to the northeast, as shown in Figure 1, while both Hunt and Galleon have indicated that this may be a possibility, neither requested such a pooling change and no supporting evidence was presented at the hearing. Therefore the examiners recommend that the A Pool not be extended beyond Section 3 at this time.

With respect to the different interpretations between Hunt and Galleon regarding the southwest edge of the A Pool, the examiners note that while Galleon mapped the 6-32/2, 8-32/2, and 6-33 wells in the A Pool, it did not request a pooling change. Both Hunt and Galleon agreed that the existing injectors encounter a common aquifer to the A Pool that provides at least some pressure communication between the injectors and the A Pool. Therefore, in deciding on Hunt's application to amend its waterflood scheme, the examiners believe that the issue of the continuity of the oil pay is not as relevant as the continuity of the aquifer associated with the A Pool. As a result, the examiners recommend that the existing pooling in the southwest area remain unchanged at this time.

6 NEED FOR AND LOCATION OF ADDITIONAL INJECTORS IN HUNT'S WATERFLOOD SCHEME

Hunt and Galleon agreed that additional water injection was required in the expanded A Pool, but they had different views on where the additional injectors should be located to optimize recovery.

6.1 Views of Hunt

Hunt submitted that its existing 6-33 injection well and Galleon's existing 6-32/2 and 8-32/2 injection wells provided minimal pressure support to the A Pool through a poorly connected aquifer. All three had lost injectivity and pressured up, despite attempts by both operators to stimulate the wells. Hunt stated that in August 2008 the pressure in the main part of the A Pool was about 18 megapascals (MPa), which was about 5 MPa below the bubble-point pressure. Hunt pointed out that all the producers in its waterflood scheme, except the 13-33 well, were currently shut in to maintain a voidage replacement ratio (VRR) of 1.0.

To evaluate the impact of additional injector locations on pool recovery, Hunt conducted a reservoir simulation of several cases, starting with a base case of the current operations. The simulator included all wells currently drilled within Hunt's mapped A Pool, as shown in Figure 1, and the existing water injectors at 6-32/2, 8-32/2, and 6-33 that injected into the aquifer associated with Hunt's A Pool. The simulator consisted of 122 cells by 49 cells by 10 layers with each cell being 50 m by 50 m and averaging 1.1 m in thickness. It was oriented northeast-southwest, parallel to the regional depositional trend and along the flow direction.

Hunt incorporated a geological model into the simulator that divided the pool into two depositional events, event A and event B. The events were identified at existing well locations based on well logs, and each event was divided into five equal intervals, with an average porosity

determined for each interval. Using these interval values to represent individual layers, Hunt populated the cells of the model's ten layers with porosity values using a geostatistical technique, with the exception of a region identified as low porosity, where it set a constant value of 6.5 per cent for all cells. The low-porosity region corresponded to an interpreted poor-quality reservoir region that provided limited communication between the existing aquifer injectors and the southernmost A Pool producers. Once porosity values were established in all cells, those with porosities of less than 6 per cent were made inactive.

To populate the model's cells with permeability values, Hunt constructed four trend lines from porosity-permeability cross-plots. Based on core analysis data from the 6-32/2 well, two trend lines were used to populate the A and B events in areas of the model that Hunt interpreted to have high permeability based on well test, production, and seismic data. Based on core analysis data from the 11-3, 16-4, and 12-11-72-26W5 (12-11) wells, the other two trend lines were used to populate the A and B events in the lower-permeability areas of the model. All permeabilities were reduced by half to adjust air permeabilities from cores to in situ permeabilities.

Hunt believed that populating the porosity and permeability values in this way would produce a model that would realistically represent the complexity and heterogeneity of the reservoir within each of the various regions.

Hunt assigned initial water saturation values of either 20 per cent or 100 per cent, depending on whether the cell was interpreted to be in the pay zone or the aquifer respectively. Hunt chose not to input variable water saturations because it did not have sufficient data.

Hunt indicated that its reservoir model achieved a good overall history match. The cumulative gas production was matched to within about 4 per cent after the critical gas saturation was set at 4 per cent. The permeabilities around specific wells were adjusted to achieve history matches for those wells. The pressure match on a well-by-well basis was very good, except for the 6-3 well, which Hunt stated would not impact recovery from Galleon's wells due to its location. Hunt noted that its history match of water production was fair, with water production underforecast by the model on a well-by-well basis. This was due to the model's inability to account for recovery of load water produced following well workovers. With cumulative and instantaneous water cuts below 2 per cent, the water cuts predicted by the model could be considered to be within measurement accuracy. Hunt found that use of Galleon's oil-water contact of -2441 mss for the A Pool, rather than Hunt's oil-water contact of -2434 mss, gave results that would not be close to a history match without other major and unreasonable changes to the model.

Table 1 provides a summary of the various cases run by Hunt using its reservoir simulator.

Table 1. Hunt's reservoir simulation results

Case	Description	Pool oil recovery factor (%)
Hunt Case 1	Base case (currently approved schemes) – injection at 6-32/2, 8-32/2, and 6-33	29.9
Hunt Case 2	Base case plus injection at 02/12-33 and Hunt scheme expanded to include 14-4	36.0
Hunt Case 2a	Case 2 with reduced injection at 02/12-33	35.3 ¹
Hunt Case 3	Case 2 plus injection at 6-4	37.9
Hunt Case 3a	Case 3 without injection at 02/12-33	38.3 ¹
Hunt Case 4	Case 2 plus injection at 13-33	37.2
Hunt Case 5	Case 2 plus injection at 1-4	37.0
Hunt Case 6	Case 2 plus injection at Galleon's 16-32 well	37.2 ¹
Hunt Case 7	Case 3 with 6-4 overinjecting to increase pool pressure to bubble point	41.9 ¹
Hunt Case 8	Case 7 plus injection at 6-3 (Hunt scheme expanded to include wells in Section 3)	47.3
Galleon Case 1	Base case – injection at 6-32/2, 8-32/2, and 6-33	30.0
Galleon Case 2	Base case plus injection at 6-3, 11-3, 16-3, 14-4, and 16-4 ("fringe water injection scheme")	40.0

¹ Exhibit B-37 provides recovery factors for all the cases except 2a, 3a, 6, and 7. Recovery factors for these cases were calculated by dividing the total predicted oil production for the cases by Hunt's original oil in place (OOIP) of $2.734 \times 10^6 \text{ m}^3$, consistent with Exhibit B-37.

Hunt believed that the model results supported its applied-for injector locations, represented as Case 3:

- Case 3 and Case 3a gave the highest recovery for those cases that did not include overinjection or expansion of the waterflood into Section 3-72-26W5M (Section 3). Hunt considered these two cases to have virtually the same recovery, given the accuracy of the model, but believed that the 02/12-33 injector offered the only opportunity to effectively sweep oil from the southwest flank of Hunt's lands. Hunt acknowledged that if it were only allowed to convert one more well to injection, Case 3a might be more reasonable than Case 3. However, when further expansion of the waterflood was considered, Case 3 would be a better option than Case 3a.
- Hunt considered the 02/12-33 well to be a good injector choice based on its physical location. Hunt submitted that the 02/12-33 well was proximal to both the pool edge and to the surface location for Hunt's water source well and that the water pipeline to the well was in place.
- Hunt believed that because the 6-4 well was horizontal, it would be a good injector even if its injectivity were to drop, as it had at the existing injectors. Hunt submitted that the location of the 6-4 injection well would create a pattern similar to an inverted nine-spot and therefore would provide pressure support and displacement of oil towards Hunt's 13-33, 1-4, and 14-4

wells, along with Galleon's 16-32 and 8-5/3 wells. Hunt stated that uniform patterns were usually required to get the best areal sweep for waterflood recovery and that its inability to install a pattern waterflood would dramatically reduce overall resource recovery. Further, Hunt believed that the 6-4 well would provide areal sweep in Section 3 and the northeast corner of Section 4-72-26W5M (Section 4) and be compatible with an expansion of a pattern waterflood to Section 3 in the future.

Hunt rejected Cases 2, 2a, 4, 5, and 6 as follows: Cases 2 and 2a did not provide sufficient voidage replacement. Case 4 used the 13-33 well as an injector, which was in close proximity to the lease line with Galleon and created the potential for offsetting licensee concerns. Case 5 used the 1-4 well as an injector, which Hunt believed was not suitable based on its poor reservoir quality compared to that in the 13-33 and 6-4 wells. Case 6 would require Galleon's 16-32 well to be used as an injector and would result in a lower recovery than Case 3.

Hunt's Cases 1 to 6 controlled production to maintain a VRR of 1.0 within the waterflood schemes. In all these cases, production also occurred from wells in Section 3 under a maximum rate limitation with gas-oil ratio (GOR) penalties, and their voidage was not replaced. For this reason, Cases 1 to 6 showed a significant drop in pool pressure. Therefore, Case 7 was run to investigate the impact on recovery of overinjection, and Case 8 was run with overinjection and expansion of the waterflood into Section 3. Both of these cases resulted in a significant increase in recovery over Cases 1 to 6, due largely to improved sweep towards Section 3 producers. However, Hunt stated that it did not intend to apply for expansion of the waterflood into Section 3 until the results of injection at 02/12-33 and 6-4 could be analyzed.

Hunt viewed Galleon's Case 2 as being comparable to Hunt's Case 8 in that it expanded the waterflood to Section 3. However, Hunt rejected Galleon's Case 2 because it required oil to be swept over 3 kilometres from the upper corner of the expanded A Pool. Hunt believed that sweep efficiency over such a long distance would be poor and that Galleon's model overcame this by imposing arbitrary permeability barriers to direct the injection. Hunt's model did not have these barriers and gave a much lower recovery for Galleon's Case 2 compared to Hunt's Case 8.

Hunt also argued that because Galleon's Case 2 converted all the producers in Section 3 to injection, it would be virtually impossible to incorporate future learnings about the A Pool and this would hinder Hunt's ability to optimize its waterflood. In addition, Hunt stated that Galleon's Case 2 would be less economic than Hunt's proposed Case 3, since it progressed more slowly due to poorer quality injectors and would have an incremental capital cost of up to \$3.25 million due to the additional well conversions and infrastructure.

Hunt stated that its model was superior to Galleon's because it incorporated a geological model that was based on more core data and was more representative of the reservoir geology, particularly with respect to representing heterogeneity. In Hunt's view, its use of a geostatistical technique resulted in more random permeabilities than the more uniform permeabilities predicted by Galleon's mapping. Hunt argued that its model achieved a better history match of both GORs and bottomhole pressures than Galleon's and that it used all of the available pressure data in its history match. It believed that because Galleon's model did not incorporate a representative geological model, Galleon was required to make many adjustments to its model input values, including the use of some arbitrary transmissibility barriers and some unrealistic values of porosities and permeabilities. Hunt also did not believe that there was faulting within the A Pool.

6.2 Views of Galleon

Although Galleon objected to Hunt's applied-for injector locations, it recognized that additional injector locations were needed to replace voidage and optimize pool recovery. The issues for Galleon were where the injectors should be located and what injection volumes would be reasonable. Galleon acknowledged that it had also had injectivity problems with its two injectors, but it did not agree with Hunt that its injectors were in poor communication with the A Pool. It believed that the injection problems were due to scaling issues and were being managed with solvent treatments.

Galleon conducted its own reservoir simulations of several of Hunt's cases, as well as two of its own. As with Hunt's simulation model, Galleon's model included all wells currently drilled within Hunt's mapped A Pool, as shown in Figure 1, and the existing water injectors at 6-32/2, 8-32/2, and 6-33. However, Galleon's model extended the A Pool to include the existing injectors and used an oil-water contact at -2441 mss, compared to Hunt's A Pool oil-water contact at -2434 mss. The simulator consisted of 126 cells by 84 cells by 3 layers, with each cell being 50 m by 50 m, and was oriented east-west. Layer 1 averaged about 2 m in gross thickness, while layers 2 and 3 averaged about 3 m and 4.5 m respectively.

For each of the 3 layers of its model, Galleon created deterministic porosity maps based on a layer average determined at each well by detailed petrophysical analysis of the well logs. Each cell of each layer of the simulation model was then populated with the corresponding value from the porosity maps, rather than using geostatistical techniques as Hunt had done. Galleon stated that while there was tremendous heterogeneity between the layers of the reservoir, the porosity distribution within a single layer was not that variable and the smooth porosity contours were reasonable. Galleon believed that Hunt's geostatistical approach resulted in too much porosity variability between adjacent cells, while Galleon's deterministic mapping resulted in smooth porosity contours within layers that were likely not variable enough, and it agreed with Hunt that the actual porosity distribution was somewhere in between the two approximations.

The net thickness based on a porosity cutoff of 6 per cent at a particular location was based on Galleon's deterministic mapping of the net-to-gross ratio. Therefore, unlike Hunt's geostatistical approach, no cells within the net thickness zero-edge were made inactive.

To populate the model's cells with permeability values, Galleon constructed two trend lines from porosity-permeability cross-plots. A higher-permeability trend line was generated using core analysis data from the 6-32/2 well and was used to populate interpreted high-permeability areas in layer 2 that were encountered by wells 16-32, 13-33, and 6-3. A lower permeability trend line that represented the rest of the reservoir was generated using core analysis data from the 12-11 and 12-13-072-26W5M wells and was used to populate the remainder of layer 2 and all of layers 1 and 3.

Galleon assigned initial water saturation values based on a deterministic analysis of initial water saturations derived from its detailed petrophysical analysis. It identified a number of different regions within the reservoir correlating to regions of fairly constant bulk volume water, and applied differing initial water saturations and endpoint relative permeability values within those regions. Galleon stated that this had the effect of introducing some heterogeneity into the model.

Galleon attached an aquifer to the southwest edge of its model just below the 6-32/2 well. Although Galleon did not do any sensitivity runs to determine the aquifer size, it acknowledged that the aquifer was not fully active, considering that the pressure in the A Pool had dropped from about 33 MPa to about 20 MPa.

Galleon stated that its reservoir model achieved a reasonable history match. Galleon submitted that modifications had to be imposed on its model, but that no excessive or nonphysical changes had to be made to make the model match historical performance. Galleon added transmissibility barriers that were in some cases aligned with fault lines interpreted by Galleon. However, Galleon acknowledged that in some areas transmissibility barriers not evident on seismic mapping were imposed as part of the history matching process. Galleon also used porosity and permeability multipliers in local areas around some wells to allow for adequate fluid movements during history matching. However, Galleon acknowledged that some of the permeabilities in its model were hundreds of times greater than the values determined by core analysis and that such large adjustments were not made in Hunt's model.

Galleon stated that although Hunt's model achieved a closer history match of GORs, Galleon's model was better able to match water production. With respect to pressure data, Galleon acknowledged that its history match of the injection pressures for the 6-32/2 and 8-32/2 wells were about 30 MPa and 20 MPa too low respectively. Regarding its match of the pool average pressure, Galleon agreed that it was not as good as Hunt's history match and that it did not use all of the data points. However, Galleon believed that many of the reported pressures were not built up, particularly the 13-33 pressures. Nevertheless, Galleon acknowledged that its own model showed there was very little difference between the producing and shut-in pressures at 13-33 due to its very high permeability.

Galleon pointed out that the preferred method of improving a model's history match was to review the geology and look for another viable interpretation, but time constraints had prevented this approach. Galleon also used the lack of time to explain the absence of a descriptive well-by-well analysis of its history match.

Table 2 provides a summary of Galleon's reservoir simulation runs.

Galleon believed that its Case 2 represented the optimum flood design for the A Pool based on analyses done to date. The only comparable full pool development case was Hunt's Case 8. Galleon's model predicted 45.9 per cent recovery for its Case 2, compared to only 42.2 per cent for Hunt's Case 8. Galleon believed its Case 2 achieved the highest recovery factor by using a "fringe water injection scheme" that swept oil from existing edge injectors in the south and from converted edge injectors at 6-3, 11-3, 16-3, 14-4, and 16-4. Galleon argued that this provided better sweep efficiency and reduced water breakthrough. However, Galleon acknowledged that its use of permeability barriers not evident on seismic served to interfere with sweep efficiency in Hunt's Case 8.

Table 2. Galleon's Reservoir Simulation Results

Case	Description	Pool oil recovery factor (%)
Hunt Case 1	Base case (currently approved schemes) – injection at 6-32/2, 8-32/2, and 6-33	35.4
Hunt Case 2	Base case plus injection at 02/12-33 and Hunt scheme expanded to include 14-4	40.7
Hunt Case 2a	Galleon did not run this case	
Hunt Case 3	Case 2 plus injection at 6-4	43.9
Hunt Case 3a	Galleon did not run this case	
Hunt Case 4	Case 2 plus injection at 13-33	36.6
Hunt Case 5	Case 2 plus injection at 1-4	42.8
Hunt Case 6	Galleon did not run this case	
Hunt Case 7	Galleon did not run this case	
Hunt Case 8	Case 7 plus injection at 6-3 (Hunt scheme expanded to include Section 3 wells)	42.2
Galleon Case 1	Base case – injection at 6-32/2, 8-32/2, and 6-33	33.3
Galleon Case 2	Base case plus injection at 6-3, 11-3, 16-3, 14-4, and 16-4 ("fringe water injection scheme")	45.9

Galleon believed that its model showed that its Case 2 would not be detrimental to Hunt's or Galleon's oil production and that it would provide cost saving benefits since the model results showed that less injection water was required for Galleon's Case 2 than for Hunt's Case 8, as well as lower water production. It disagreed with Hunt's estimate of the cost of converting the five Hunt wells to injectors. Galleon estimated that the cost would be about \$4.5 million, compared to Hunt's estimate of about \$6 million. In addition, Galleon argued that since Hunt's Case 3 and Case 8 involved injecting more water than Galleon's Case 2, the operating costs for Hunt's cases would be higher than for Galleon's Case 2 by about \$6 million.

Galleon believed that its reservoir model was at least as good as Hunt's and in some respects superior. Galleon pointed out that its model included the oil leg in the 6-32/2 well and the well was an oil producer before it was converted to an injector in July 2007, while Hunt's model did not include these aspects of the 6-32/2 well. Galleon also stated that its geological model was more applicable to the reservoir geology than Hunt's, due to the use of more appropriate oil-water contacts, properties that were based on a detailed petrophysical analysis, interpretation of faulting within the reservoir, and Galleon's use of variable initial water saturations. Galleon believed that because Hunt did not do detailed petrophysical analysis, Hunt's porosity and net pay values were approximations. Further, Galleon believed that Hunt's use of null cells resulted in random barriers that were without geological basis.

6.3 Findings of the Examiners

The examiners agree with Hunt and Galleon that additional water injection is needed in the part of the A Pool operated by Hunt in order to optimize oil recovery. Because of the limited water injectivity of Hunt's existing injector at 6-33, a significant amount of oil production is currently shut in. Additional water injection would allow Hunt to increase its oil production and maintain voidage replacement.

The examiners note that while Hunt's application to add two injectors is best represented by Hunt's Case 3, Galleon has proposed an expansion to a pool-wide waterflood as its preferred alternative, represented by Galleon's Case 2. Hunt's Case 8 is the only full pool waterflood case that Hunt ran on its reservoir simulator. Before the examiners discuss their views on Hunt's application to add two injectors, the examiners first deal with the comparative merits of Hunt's Case 8 and Galleon's Case 2.

Two different approaches for a full pool waterflood were proposed by Hunt and Galleon. In its Case 8, Hunt proposed to build upon its applied-for Case 3 through the conversion of the 6-3 well to injection and the repressuring of the A Pool to the bubble-point pressure. Case 8 would therefore consist of edge well injection (6-32/2 8-32/2, 6-33, 02/12-33, and 6-3) and injection into the central part of the A Pool (6-4). Galleon's proposal involved a "fringe water injection scheme" where, in addition to the existing edge injectors, the proposed injectors would be placed in the lower-quality rock closer to the edges of the A Pool at 6-3, 11-3, 16-3, 14-4, and 16-4.

Both Hunt and Galleon used reservoir simulation to assess the merits of their proposed additional injectors. While the examiners believe that reservoir simulation is a useful tool to assess the merits of different injector locations, they note that at this time there has been very little water production from the A Pool. Since there is very little water production data to use in the history match, it is not possible at this time to adequately test the ability of the models to predict water production. History matching is therefore limited to mainly matching the pressure and GOR data for the A Pool. The examiners believe Hunt's model was better able to match these data than was Galleon's model. Also, Hunt made fewer changes to the geological input to its model in order to obtain the better history match. The examiners note that Galleon acknowledged it would have liked to revisit the geology around several of the wells where it had made changes to the reservoir properties in order to try to get a reasonable history match. The examiners believe that in order to achieve a history match, Galleon's addition of transmissibility barriers in areas of the A Pool where it did not interpret faults to be present results in a model that is likely not representative of the geology of the reservoir. Although Hunt and Galleon both characterized the A Pool as being heterogeneous, the examiners believe that in generating the geological models, Hunt best captured the heterogeneity through geostatistical modelling, compared to Galleon's deterministic modelling, notwithstanding Galleon's use of variable initial water saturations. Based on the above, the examiners have more confidence in the predictions from Hunt's model than from Galleon's model.

Hunt's model predicted that its Case 8 had better oil recovery than Galleon's Case 2 (47.3 per cent versus 40.0 per cent of Hunt's OOIP for the expanded A Pool), while Galleon's model predicted that its Case 2 had better recovery than Hunt's Case 8 (45.9 per cent versus 42.2 per cent of Galleon's OOIP for the expanded A Pool). Since the examiners have more confidence in Hunt's model predictions than those of Galleon's model, when reservoir modelling is used as the assessment method, the examiners believe that Hunt's proposed approach of including water injection in the central part of the A Pool as well as near the edges of the pool is preferred over Galleon's proposed approach of just using injectors closer to the edges of the A Pool.

In addition to the examiners' preference for Hunt's approach for waterflooding the A Pool based on reservoir modelling predictions, the examiners have two concerns about the waterflood expansion proposed by Galleon. First, Galleon's proposal involves using injectors that would be located in the lower-quality rock. This raises the concern that there could be problems with

attaining adequate water injectivity, as has been experienced with the existing injectors near the edges of the A Pool. Second, Galleon's proposal involves converting all the wells in Section 3 to injectors, such that there would be no producers in the section. Any oil in Section 3 displaced by the injectors would have to be captured by the producers in Section 4. As pointed out by Hunt, some of the oil in Section 3 would have to be swept over a long distance.

With respect to the different estimates made by Hunt and Galleon regarding the extra capital costs associated with Galleon's proposed Case 2 and Galleon's argument that the increased capital costs would be offset by lower operating costs because less water injection would be required, the examiners believe that a more detailed economic analysis would be required to definitively determine the difference in the costs between Hunt's Case 8 and Galleon's Case 2.

In addition to the examiners' assessment of the reservoir modelling done by Hunt and Galleon, the examiners' concerns about Galleon's proposed waterflood expansion add to the examiners' conclusion that Hunt's proposed approach is preferred over Galleon's proposed approach.

Having concluded that Hunt's approach is preferred over Galleon's approach on a pool basis, the examiners need to consider whether both the 02/12-33 and 6-4 wells should be approved as injectors for Hunt's currently approved waterflood scheme, which only includes part of the A Pool, as illustrated in Figure 1. The examiners note that while Hunt's application to add two injectors was best represented by Hunt's Case 3, that case also expanded the waterflood scheme to include the 14-4 well, for which Hunt did not apply. However, in all of Hunt's cases, the 14-4 well contributed very little production (up to 0.3 per cent of Hunt's OOIP). Therefore, the examiners believe that Case 3 would reasonably approximate Hunt's application case.

The examiners believe that water injection at 6-4 is required in order to provide proper sweep of the central part of the A Pool and to provide adequate water injectivity. With respect to the need for injection at the 02/12-33 well in addition to the 6-4 well, the examiners note that Hunt's model predicted that Case 3a, which only involved converting the 6-4 well to water injection, had slightly higher oil recovery than Case 3, which involved converting both the 6-4 and 02/12-33 wells to water injection. Although the slightly higher oil recovery predicted for Case 3a over Case 3 (38.3 per cent versus 37.9 per cent of Hunt's OOIP for the expanded A Pool) is within the accuracy of the model, Case 3a involved injecting and producing significantly less water than Case 3 (10.1 million $[10^6]$ m³ and 8.8 10^6 m³ of water injection and production respectively for Case 3a compared to 13.6 10^6 m³ and 12.3 10^6 m³ for Case 3). This indicates that Case 3a would be a more efficient waterflood. However, the examiners note that in Case 3a, the forecast production plots for the 02/12-33 and 13-33 wells suggest the wells were produced at the same time. This is not consistent with the existing quarter-section spacing for the A Pool, and Galleon indicated that it would likely object to an application to reduce the spacing, since it believed two wells were not needed to drain the quarter section. Hence, the examiners believe that Hunt's Case 3a is not necessarily a realistic case.

The examiners note that Hunt's application to convert both the 02/12-33 and 6-4 wells to water injection would result in more injectors than producers for Hunt's currently approved waterflood scheme. As calculated by Hunt, the mobility ratio for the waterflood in the A Pool is 0.67. A mobility ratio of less than 1.0 indicates that the water injectivity of an injector is less than the oil productivity of a producer after filling up the gas space in the reservoir. Hence, from a mobility

ratio point of view, more injectors than producers is preferred, which, in principle, supports including both the 02/12-33 and 6-4 wells as injectors.

Another consideration in determining whether the 02/12-33 well should be approved as an injector in addition to the 6-4 well is the problems Hunt has had with the injectivity of its existing 6-33 injector. Including the 02/12-33 well as an injector would assist in supplementing any further reduction in the injectivity of the 6-33 injector.

A final consideration in determining whether the 02/12-33 well should be approved as an injector along with the 6-4 well is whether injecting water at the 02/12-33 well could result in the 13-33 well watering out from that injection before oil can be swept to the 13-33 well by water injection at the 6-4 well. Hunt's model did predict that the water injected at the 02/12-33 well would arrive at the 13-33 well before the water injected at the 6-4 well. However, the model predicted that the 13-33 well was able to continue to produce after the arrival of the water injected at the 02/12-33 well. Hunt calculated that the 13-33 well should be capable of producing an amount of fluid large enough to handle the water production and hence continue to be produced. Based on this information, the examiners do not believe this potential issue would justify not approving the 02/12-33 well as an injector.

The examiners agree with Hunt that approval of the applied-for injectors at 02/12-33 and 6-4 may not be sufficient to waterflood all of the expanded A Pool operated by Hunt and that one or more additional water injectors may be required to expand the waterflood to the northeast. Therefore, the examiners believe that any injectors approved at this time should be compatible with a future expansion of the waterflood. The examiners believe that approving the 02/12-33 and 6-4 wells as injectors would be compatible with a future expansion of the waterflood, as illustrated by Hunt's Case 8, which involved adding the 6-3 well as an injector.

Based on the analysis described above, the examiners conclude that Hunt's application to convert the 02/12-33 and 6-4 wells to water injectors is appropriate, subject to the examiners' views on the potential impact that this could have on Galleon's producers, which is discussed in the following section.

7 POTENTIAL FOR HUNT'S PROPOSED INJECTORS TO IMPACT GALLEON'S PRODUCERS

Galleon identified two concerns regarding Hunt's applied-for injectors: reduced sweep efficiency by injecting into updip wells in a reservoir where there is an oil-water contact and likely contact with an aquifer, and the possibility for premature water breakthrough because of high-permeability channels in the A Pool.

7.1 Views of Hunt

With respect to the concern regarding updip injection, Hunt acknowledged that the A Pool dipped in a northeast to southwest direction. However, Hunt interpreted the dip across the sections in question to be less than 0.5 degree, based on its structure map for the A Pool. Hunt submitted that the fractional flow equation showed that the impact of dip on displacement efficiency was negligible at reservoir dips less than 10 degrees. Hunt pointed out that the reservoir simulation runs that it did, as well as those done by Galleon, showed that the reservoir

dip in the A Pool had no significant effect on oil recovery. Hunt stated that Galleon's concern about updip injection had been undermined by its own model run (Galleon's Case 2), which was predicated on updip injection. Hunt pointed out that Galleon was injecting water at updip locations in its waterflood in the Puskwaskau D Pool. Hunt acknowledged there was no aquifer in that pool but contended that the comparison to the A Pool was appropriate because there was no active aquifer adjacent to the A Pool, based on the large pressure difference between the aquifer and the A Pool and material balance calculations. Hunt further pointed out that updip injection was being done in hundreds of similar pattern waterfloods in western Canada and worldwide.

With respect to the concern about premature water breakthrough, Hunt stated that it was important to clarify the difference between breakthrough and premature breakthrough in a waterflood. Hunt noted that it was an accepted fact that water eventually would break through to producers in a waterflood, so the act of water breaking through to a producer was not necessarily premature. In Hunt's view, premature breakthrough occurred when water arrived at producers without displacing a mobile oil bank in front of it.

Hunt contended that premature water breakthrough would only occur where there was a very thin high-permeability zone surrounded by very low-permeability sands. The zone would have to be very narrow, much narrower than either Hunt or Galleon had mapped.

Hunt stated there was no evidence of high-permeability channels or streaks in the cores or on the logs for the wells in the A Pool. While the core analysis for the 6-32/2 well showed very high permeabilities, Hunt submitted there was no evidence that the permeabilities were continuous or extensive, as indicated by the limited water injectivity of the well. Furthermore, Hunt interpreted the 6-32/2 well to be in a separate pool. With respect to the 16-32 well, Hunt contended that the pressure buildup test indicated that the high-permeability area around the well was likely limited to a radius of 64 m, which did not demonstrate the presence of permeability streaks or channels that could affect sweep efficiency in Galleon's area of the A Pool. With respect to the Davies study,¹ Hunt submitted that the study was done with limited data, did not definitively conclude that channels existed in the area, and only identified nonchannel facies. Hunt stated that there was no evidence of faulting within the A Pool, so faulting was not a consideration.

In the case of the applied-for 02/12-33 injector, Hunt stated that the potential for channelling would be avoided by it injecting water into the low-quality reservoir encountered by the 00/12-33-071-26W5/0 (12-33) horizontal well. Although the applied-for 6-4 injector was located in a high-permeability area, Hunt stated that based on its model predictions, the injected water would flow in essentially a radial fashion from the well to the surrounding producers. Hunt also submitted that the risk of premature water breakthrough would be dramatically reduced with the proposed 6-4 injector, since horizontal injectors had an advantage over vertical injection wells because they distributed the injection pressure over a larger wellbore length, thereby creating greater horizontal displacement efficiency at a much lower local pressure differential.

Hunt calculated the mobility ratio for its waterflood to be very favourable at 0.67. Hunt referred to correlation methods provided in the petroleum engineering literature that indicated that

¹ Both Hunt and Galleon referred to a study titled "Beaverhill Lake Sandstone Oil Play, West-Central Alberta," produced by Graham Davies Geological Consultants and Associates, which is referred to in this report as the "Davies study."

viscous fingering, which could lead to premature water breakthrough, was not a risk at mobility ratios below 1.0.

Hunt stated that there was no indication of premature water breakthrough at the 16-32 or 8-5/3 wells in any of the model runs done by it and Galleon, including Galleon's runs of Hunt's cases. Galleon's own model indicated that the sweep efficiency would be reasonable under all the cases. Hunt argued that Galleon designed its model to include a very large elongated high-permeability region, which from a water movement perspective was a worst-case scenario, yet Galleon's model did not predict premature water breakthrough.

Hunt submitted that water from the aquifer or Galleon's injectors had already arrived at the 16-32 well based on production data, which showed a trend of increasing water production. However, Hunt acknowledged that the water cut was still very low, at about 2 per cent, which may be within the production testing variance. Assuming injection starts in October 2008 and March 2009 at the 02/12-33 and 6-4 wells respectively, Hunt's model predicted it would take until June 2009 for Hunt's injected water to arrive at Galleon's 16-32 well and until July 2010 to arrive at Galleon's 8-5/3 well. In Hunt's view, Galleon would be producing water from the aquifer or its own injectors for more than nine months before the arrival of Hunt's injected water.

If premature water breakthrough were to occur, Hunt stated that monitoring would need to be done to determine the source of the water, and this would have to be done jointly with Galleon. Hunt stated that adding tracers to the injected water might be a good monitoring method, but there were other methods that could be considered, such as injection or fluid entry profiling, pulse testing, interwell interference testing, pressure transient testing, and water salinity monitoring. Hunt pointed out that it had collected more pressure data than required by the Board and that it expected to continue to collect such data.

7.2 Views of Galleon

Galleon initially raised a concern about the reduced sweep efficiency that would result from injecting water into updip wells in a reservoir that had an oil-water contact and was likely in contact with an aquifer. Galleon submitted that the structural elevation across the sections in question increased about 28 m over a lateral distance of 3200 m. Although Galleon stated that the dip was significant relative to the 10 m average thickness of the reservoir, it agreed with Hunt that the dip of the reservoir was about 0.5 degrees. Galleon submitted that the ability of the applied-for updip injectors to properly push or sweep oil down the structure through a relatively thin sand was questionable and would not be as efficient as pushing in the direction of a moving aquifer. Galleon acknowledged that updip injection occurred in hundreds of waterfloods, but the majority of these pools were not under active aquifer support. Subsequent to raising its initial concern, Galleon stated that its model study had shown that the inefficiency of updip injection was much less significant compared to the benefit of injecting water into the tighter reservoir rock and sweeping the oil to the centre of the pool in a line drive.

With respect to the concern about premature water breakthrough, Galleon agreed with Hunt that a good definition of premature breakthrough would be where injected water was short-circuited to producers without effectively displacing the oil in the matrix rock. However, Galleon also stated that a case where injected water reached a producer several years earlier than in another case that had higher oil recovery could be considered to be premature water breakthrough.

Galleon interpreted that high-permeability channels were present in the A Pool. This was based on the 8-5/3 well and its quick transition from nonreservoir to reservoir rock, the large variances in productivities of the wells in the A Pool, the blocky log signatures of the 6-32/2, 16-32, 13-33, and base of the 8-32/2 wells, the 6-32/2 core data, and the Davies study. Galleon noted the Davies study's description of a thick downcutting sand in the 6-32/2 well and the statement in the study that channels were part of the regional depositional model. Galleon believed that channelling was supported by its interpretation that there was severe reservoir heterogeneity in the A Pool, as shown by the well test analysis for the 16-32 well, which concluded that outside the high-permeability region near the wellbore region there existed an area of much lower permeability. In Galleon's view, Hunt's 12-33 horizontal well was located either above or below the higher-permeability streak that Hunt was targeting, since seismic data suggested a reasonable likelihood of there being highly porous and permeable rock. Galleon pointed out that its seismic interpretation of the A Pool suggested that an injector at 02/12-33 would be located within an extremely high-porosity/permeability region of the pool, making immediate communication of injected water from the proposed 02/12-33 injector with the nearby producers at 16-32 and 13-33 quite likely. Galleon was also concerned that Hunt's proposed 6-4 injector was located within a high-permeability area and as a result water injection could lead to premature water breakthrough and lower overall pool recovery. Galleon was more concerned about the proposed 6-4 injector than the proposed 02/12-33 injector because of the expected large volume of water to be injected at the 6-4 well.

Galleon interpreted there to be a fault between Hunt's proposed 6-4 injector and Galleon's 16-32 and 8-5/3 producers and a fault between Hunt's proposed 02/12-33 injector and Galleon's 8-5/3 producer. While Galleon acknowledged that the faults would slow down the arrival of injected water at its producers, in its view the faults were not sealing, so the injected water could still find its way to Galleon's producers by a tortuous path.

Galleon acknowledged that its model predicted that there was sweep of oil to the producing wells in all the cases that it ran. However, Galleon submitted that modelling the extremely complex A Pool reservoir may not be very effective at predicting actual water breakthrough. Galleon stated that all models had an idealistic assumption of reservoir sweep based on the porosity and permeability distribution that was input to the model. In Galleon's view, fingering, fracturing, and channelling could all occur and there was no way to effectively model these phenomena without completely manipulating the model to have it predict what was expected to occur.

Galleon acknowledged that its 16-32 well started producing small but measurable amounts of water in November 2007. Galleon argued that Hunt's proposed 02/12-33 and 6-4 injectors in Hunt Case 3 would water-out its 16-32 well much sooner than under Galleon Case 2, which Galleon considered to be premature breakthrough.

Galleon agreed with Hunt that implementing a monitoring program before water breakthrough occurred may not be the best approach to take. If premature water breakthrough were to occur, a tracer program should be implemented. Such a program should be determined by Hunt and Galleon, possibly with the assistance of the Board.

7.3 Findings of the Examiners

The examiners note that Galleon initially identified two concerns regarding Hunt's applied-for injectors: reduced sweep efficiency by injecting into updip wells in a reservoir where there is an

oil-water contact, and the possibility for premature water breakthrough because of high-permeability channels in the A Pool. With respect to the first concern, Galleon subsequently acknowledged that its own model study indicated that updip injection would not be as harmful as Galleon initially thought. Considering that the dip of the A Pool is only about 0.5 degrees and that both the Hunt and Galleon models do not predict an adverse effect due to updip injection, the examiners conclude that updip injection is not a significant concern.

With respect to the concern about premature water breakthrough, the examiners agree with Hunt that it is important to define what is meant by premature breakthrough. As stated by Hunt, water will eventually break through to producers in any waterflood, so water breaking through to a producer is not necessarily premature. The examiners agree with Hunt's definition of premature water breakthrough as being that type of water breakthrough that occurs when water arrives at a producer without displacing a mobile oil bank in front of the injected water. With respect to Galleon's extension of the definition of premature water breakthrough to include the case where injected water reaches a producer several years earlier than another case that has higher oil recovery, the examiners view that case to be more related to optimization of a waterflood rather than to the definition of premature water breakthrough. Considering that the mobility ratio for a waterflood in the A Pool is calculated to be less than 1.0, the type of water breakthrough characterized by Hunt as being premature would likely only occur if there were an extremely narrow conduit or channel connecting a water injector with an oil producer. While Galleon interpreted there to be channels in the A Pool, it did not include in its model any of the extremely narrow channels that would be expected to result in premature water breakthrough. The examiners note that neither the Hunt nor the Galleon models predicted premature water breakthrough as defined above in any of the cases that were run, including Galleon's runs of Hunt's cases, even though Galleon's model included a high-permeability zone that could be considered to be representative of a channel, albeit not an extremely narrow one.

In the absence of specific evidence that there are extremely narrow conduits or channels in the A Pool, the examiners are not convinced that there is sufficient reason to justify denying Hunt's applied-for injectors. However, the examiners acknowledge that there is always the possibility that such narrow conduits could exist. In order to try to mitigate this risk, the examiners believe it would be prudent for Hunt to monitor the performance of the waterflood scheme. Furthermore, if approved, the applied-for injectors would be subject to maximum wellhead injection pressures to prevent fracturing of the reservoir and the waterflood scheme would continue to be subject to a VRR of 1.0, both of which would have to be monitored by Hunt. With respect to Hunt's Case 7 and Case 8, where Hunt injected at a VRR greater than 1.0 to repressure the A Pool to the bubble-point pressure, the examiners note that Hunt would have to submit a separate application to increase the VRR above 1.0.

If premature water breakthrough were to be observed in the A Pool, the examiners believe that it may be advisable to include additional monitoring, such as adding tracers to the injected water to determine where any observed water breakthrough is coming from. The examiners note that Hunt acknowledged that some type of monitoring would be needed, but while using tracers could be a good method, there could be other methods. The examiners agree with Hunt that an effective monitoring program would require a joint effort between Hunt and Galleon. The examiners believe that many details would have to be considered in designing a monitoring program beyond what is normally required by the ERCB, so the examiners do not recommend that the Board require a special monitoring program such as the use of tracers. Nevertheless, the

examiners believe it would be to both Hunt's and Galleon's advantage to jointly develop an appropriate monitoring program if premature water breakthrough is observed. The examiners acknowledge that Hunt has been collecting a great deal of data on its wells, such as by conducting flow and pressure analyses on many of its wells and installing continuous pressure monitoring at its 13-33 well, and the examiners expect that Hunt will continue to collect additional data to assist in ongoing monitoring of Hunt's waterflood scheme.

Dated in Calgary, Alberta, on December 16, 2008.

ENERGY RESOURCES CONSERVATION BOARD

G. W. Dilay, P.Eng.
Presiding Member

T. R. Keelan, P.Eng.
Examiner

J. R. MacGillivray, P.Geol.
Examiner

APPENDIX 1 HEARING PARTICIPANTS

Principals and Representatives
(Abbreviations used in report)**Witnesses**

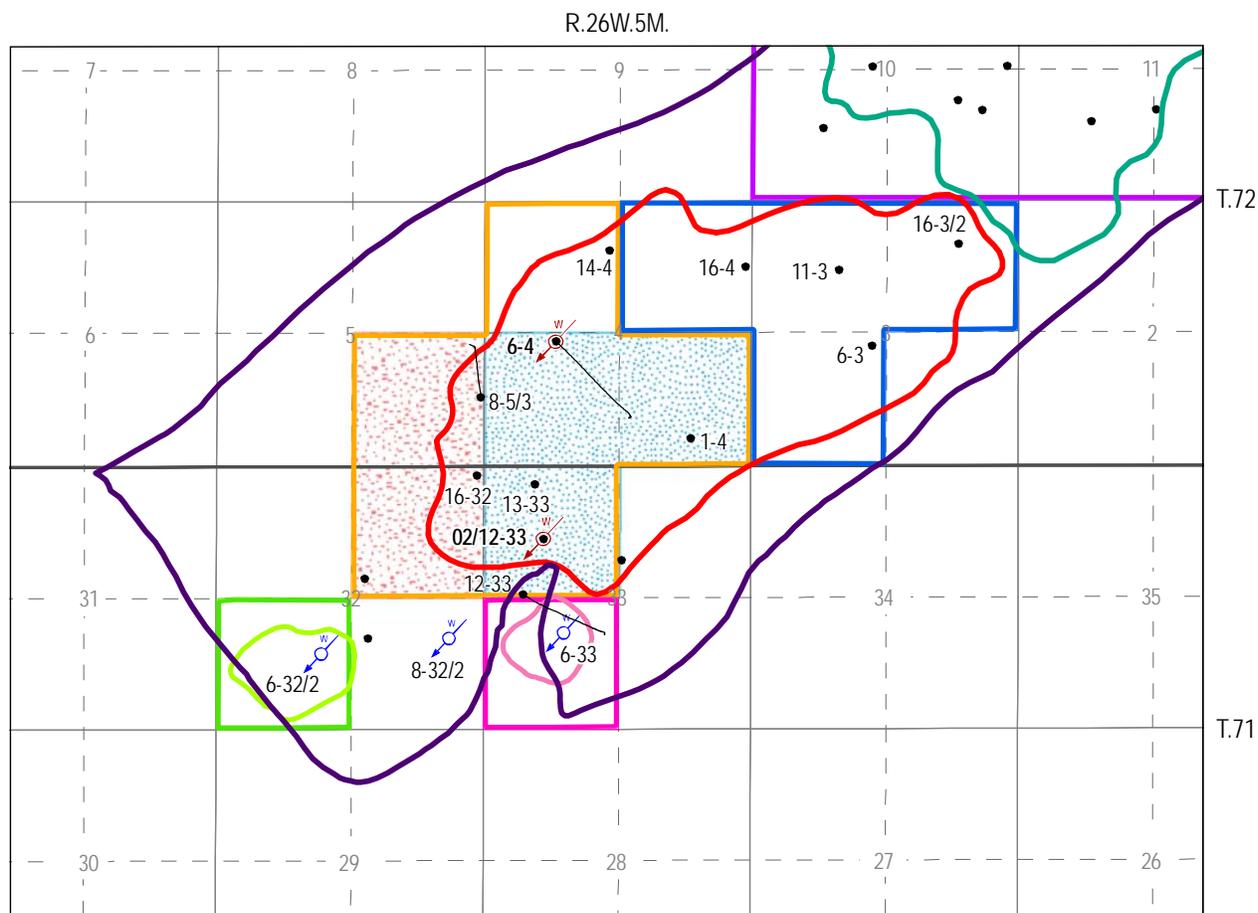
Hunt Oil Company of Canada, Inc. (Hunt)
D. Tupper
G. Matthews

L. A. Engel, P.Geoph.
R. Hannah, P.Geol.
B. J. Hayes, Ph.D., P.Geol.,
President, Petrel Robertson Consulting Ltd.
A. E. Kalmet, P.Eng.
G. J. Low, M.Eng., P.Eng.,
President, Proven Reserves Exploitation
Ltd.
J. D. Macgowan, P.Eng.,
President, J.D. Macgowan & Associates
Ltd.
D. A. Ryder, P.Eng.
S. K. Wong, P.Eng., of
Epic Consulting Services Ltd.

Galleon Energy Inc. (Galleon)
J. E. Lowe

V. Floisand, P.Eng., of
GLJ Petroleum Consultants
K. Gordon, P.Geol.
D. G. Harris, P.Geol.,
Vice President GeoSciences, GLJ
Petroleum Consultants
R. J. Mahoney, P.Geoph.,
President, Mahoney Exploration
Consultants Ltd.
G. McMurren, P.Eng.
A. Williamson, P.Geoph.

Energy Resources Conservation Board staff
K. Stilwell, Board Counsel
N. J. Barnes
L. C. Gagy
T. M. Hurst
R. A. Marsh, P.Geol.
T. K. Rempfer, P.Eng.



Legend

- Well bottomhole
- Direct line, top to bottomhole
- Existing injector
- Proposed injector

Waterflood scheme approval areas

- 10848 - Hunt
- 10827A - Galleon

ERCB pool orders

- Kleskun Beaverhill Lake A
- Kleskun Beaverhill Lake D
- Kleskun Beaverhill Lake E
- Puskwaskau Beaverhill Lake C
- Puskwaskau Beaverhill Lake D

Pool zero edges

- Galleon - Kleskun Beaverhill Lake A
- Hunt - Kleskun Beaverhill Lake A
- Hunt - Kleskun Beaverhill Lake D
- Hunt - Kleskun Beaverhill Lake E
- Hunt - Puskwaskau Beaverhill Lake D

Figure 1. Location map