ALBERTA ENERGY AND UTILITIES BOARD

RESCINDING AN ORDER TO PRODUCE DOCUMENTS

IN THE MATTER OF THE *ALBERTA ENERGY AND UTILITES BOARD ACT*, RSA 2000, Chapter A-17;

AND IN THE MATTER OF THE *ENERGY RESOURCES CONSERVATION ACT*, RSA 2000, Chapter E-10;

AND IN THE MATTER OF Proceeding No. 960952 respecting an application by Gulf Canada Resources Limited for an order of the Alberta Energy and Utilities Board that natural gas production from the Wabiskaw-McMurray formation of the Surmont area be shut in and otherwise precluded until the recovery of bitumen is complete.

WHEREAS the Alberta Energy and Utilities Board (the Board) determined during Proceeding No. 960952 that it was necessary to review information from the Dover SAGD Project and the Gulf Surmount Experimental Scheme (the Bitumen Production Information) that was considered confidential under Part 2 of the *Oil Sands Conservation Regulations*; and

WHEREAS the Board issued an Order to Produce Documents on July 8, 1999 that compelled the production of the Bitumen Production Information, named the parties that would have access to the Bitumen Production Information, and established conditions under which the Bitumen Production Information, hearing transcripts from in-camera sessions, and related materials could be used during and after the hearing; and

WHEREAS the Board amended the Order to Produce Documents On April 3, 2000 so that it also applied to the Confidential Edition of EUB Decision 2000-22; and

WHEREAS the Bitumen Production Information no longer qualifies for confidential treatment under Part 2 of the *Oil Sands Conservation Regulations*; and

WHEREAS, the Board has determined that it is no longer in the public interest to maintain the confidentiality of the Bitumen Production Information, hearing transcripts from in-camera sessions, related materials, and the Confidential Edition of EUB Decision 2000-22; and

WHEREAS the Board wrote to interested parties on July 10 and August 9, 2006 and informed them of its intention to rescind the Amended Order to Produce Documents; and

WHEREAS no interested party objected to the Board’s proposal to rescind the Amended Order to Produce Documents.

THEREFORE the Board, Pursuant to section 16 of the *Energy Resources Conservation Act*, being Chapter E-10 of the Revised Statutes of Alberta, 2000, hereby orders that:

1. The Order to Produce Documents dated July 8, 1999, and amended on April 3, 2000, relating to Proceeding No. 960952 is hereby rescinded.

Made at the City of Calgary, in the Province of Alberta, this 15th day of February, 2007.

Alberta Energy and Utilities Board

Original Signed by Neil McCrank

M. Neil McCrank, Q.C., P. Eng.
Chairman

Proceeding No. 960952

ALBERTA ENERGY AND UTILITIES BOARD

IN THE MATTER OF THE *ALBERTA ENERGY AND UTILITES BOARD ACT*, RSA 2000, Chapter A-17;

AND IN THE MATTER OF THE *ENERGY RESOURCES CONSERVATION ACT*, RSA 2000, Chapter E-10;

AND IN THE MATTER OF Proceeding No. 960952 respecting an application by Gulf Canada Resources Limited for an order of the Alberta Energy and Utilities Board that natural gas production from the Wabiskaw-McMurray formation of the Surmont area be shut in and otherwise precluded until the recovery of bitumen is complete.

RESCINDING ORDER

Gulf Canada Resources Limited

Request for the Shut-in of Associated Gas
Surmont Area

March 2000

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(continued)

(continued)

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(continued)

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EXECUTIVE SUMMARY

In November 1996, the Alberta Energy and Utilities Board (EUB/Board) received a submission from Gulf Canada Resources Limited (Gulf) requesting that the Board order the shut-in of associated gas production from the top of the Wabiskaw Member to the base of the McMurray Formation (Wabiskaw-McMurray) on its Surmont oil sands leases. Gulf submitted that pressure depletion of the gas pools in association with the oil sands zones would adversely affect the recovery of bitumen by the steam-assisted gravity drainage (SAGD) process to the extent that the bitumen might not be recoverable. Prior to dealing with Gulf's request, the Board held a general inquiry into the matter and issued its *Gas/Bitumen Inquiry Report* (inquiry report) in March 1998. Gulf subsequently amended its request to include the shut-in of associated gas from wells within a three-section buffer area surrounding its Surmont leases. Petro-Canada Oil and Gas (Petro-Canada) made a submission in support of Gulf's request, while the Surmont Producers Group (SPG) made a submission opposing Gulf's request. The Anzac Metis Local No. 334, Chipewyan Prairie Dene First Nation, and Fort McMurray No. 468 First Nation made submissions regarding the encroachment of oil and gas activity on their traditional way of life, the need for consultation between them and the oil and gas industry, and opportunities for employment. A hearing to consider Gulf's request was held during April to September 1999.

The Board believes that the bitumen resources on Gulf's Surmont leases are in the order of 15 billion barrels. If 35 to 50 per cent of the bitumen is ultimately recoverable, as suggested by Gulf, this would result in the production of 5.25 billion to 7.5 billion barrels of bitumen. To put this into perspective, about 12 billion barrels of light-medium crude oil had been produced in Alberta to the end of 1998. Hence, the bitumen resources on Gulf's Surmont leases represent a significant energy resource for the province, which the Board believes warrant consideration for protection for future development. The estimates for remaining recoverable gas reserves in the requested gas shut-in area range from 95 billion to 180 billion cubic feet, which on an energy basis (i.e., 17 million to 32 million barrels of oil equivalent) is much less than the potentially recoverable bitumen, in the order of half of one per cent.

The Board believes that all the Wabiskaw-McMurray gas being produced by wells on the Gulf Surmont leases is or has the potential to be associated with the underlying bitumen, either through direct vertical continuity or indirectly through lateral continuity of the gas and water zones. This is based on the Board's view that, notwithstanding the presence of interbedded sands and muds, the geological evidence indicates that the occurrence of thick bitumen-saturated sands in direct communication with overlying gas and water zones is extensive and randomly distributed. It is also based on the Board's consideration of the vertical permeability data and the temperature, pressure, production, and seismic data for the Surmont SAGD pilot. With respect to the Dover SAGD pilot site, the Board believes it is not an appropriate geological analogue for the Surmont area and hence the extent of the steam rise observed at the Dover SAGD pilot cannot be relied on to determine the extent of steam rise at Surmont. Also, the Board believes that the gas being produced by many of the wells in the three-section buffer area is or has the potential to be indirectly associated with the bitumen on Gulf's Surmont leases through lateral continuity of the gas and water zones in the buffer area with the gas and water zones on Gulf's Surmont leases.

Because of the limited amount of applicable field experience, the Board believes that reservoir modelling is the best tool available at this time to evaluate the effect of associated gas production on SAGD bitumen recovery. The Board believes that reservoir modelling reasonably demonstrates that producing associated gas in the Surmont area would likely have a detrimental effect on SAGD bitumen recovery and that the detrimental effect increases with decreasing gas pool pressure. The magnitude of the detrimental effect could be significant and is dependent on several factors, including the specific reservoir situation, the operating strategy, the abandonment pressure of the gas pools, and the economic circumstances. The Board also believes that the model predictions may underestimate the effect of associated gas production on SAGD bitumen recovery, since the models do not account for all the risk factors identified by Gulf and Petro-Canada. The Board recognizes that there are uncertainties with reservoir modelling and that having a model that has been history matched to field data would provide more confidence in the model predictions. However, there are only limited data available from the Surmont SAGD pilot, and although additional data are continuing to be obtained, the Board believes that it is not acceptable to wait for these additional data before deciding on Gulf's request because waiting would involve a significant risk to future bitumen recovery.

With respect to the geomechanical effects (i.e., compaction and lateral displacement of overlying sediments) of gas pool depressurization and/or repressurization and any subsequent SAGD operations, the Board is not convinced that they would have a significant impact on wellbore integrity at Surmont. Also, the Board believes that they would not likely lead to a reduction in the sealing capability of the overburden.

The Board is not prepared to rely on repressuring depleted gas zones by gas injection as a reason to allow continued gas production until it has been demonstrated that this is feasible and practical. Considering the uncertainty regarding the lateral extent of the gas and water zones and the resulting potential for leak-off, the Board is not convinced that repressuring is viable. Even if it were technically feasible, the Board believes that the time needed to repressure a potentially large region of influence could have a significant negative impact on the economics of a SAGD project. The Board is also not convinced that repressuring with water is a viable option, considering the results from reservoir modelling regarding the effect on SAGD bitumen recovery, the volume of water that could be required, and the concern about water compatibility.

The Board accepts that as the steam chamber pressure is decreased below about 800 kilopascals absolute, artificial lift becomes increasingly more difficult, until at pressures below 400 to 600 kilopascals absolute it is not technically feasible. The Board concludes that minimizing the depressuring of the overlying gas zones will better ensure successful SAGD operations, both in terms of maximizing bitumen recovery and minimizing the costs and technical difficulties of artificial lift.

The Board acknowledges that the SAGD process could result in a loss of associated gas into the bitumen zone and the loss of evolved solution gas from the bitumen zone into the overlying gas zone. However, because there was very little evidence submitted to the hearing on this issue, the Board is not in a position to draw any conclusions at this time. The Board believes that this issue should be dealt with in any future applications to the Board for SAGD schemes.

The Board does not accept the SPG's argument that the potential for sterilization of the bitumen resource should not be a matter for the public interest, since this could result in the Board not considering many situations where resources could be effectively sterilized under any reasonably foreseeable economic conditions. The Board recognizes that it could take in the order of 100 to

200 years to produce the bitumen resources on Gulf's Surmont leases. However, as stated in the inquiry report, the Board does not believe that it is reasonable and prudent to "force" bitumen development by requiring leaseholders to demonstrate, along with performance requirements, commitments to bitumen projects within a given time frame. Conceivably, this might cause ill-timed investment in bitumen projects and, in any event, such a requirement would imply that the public interest is driven by specific operators' plans for bitumen projects. The Board believes that its conservation role must consider a broader set of issues than the immediate plans of any one company or industry sector. The Board acknowledges the risk associated with the commercial application of relatively unproven technology. However, the Board accepts that the potential value of the bitumen resources significantly exceeds the value of the remaining gas reserves in the Surmont area and believes that it would not be in the public interest to accept the possibility of sterilizing a vast bitumen resource by allowing continued gas production. The Board acknowledges that shutting in gas production at Surmont would have a significant impact on the SPG and might require some complementary action. The Board notes that Section 91 of the Oil and Gas Conservation Act provides that the Lieutenant Governor in Council may direct the Board to proceed to prepare a scheme to compensate persons who are injured or suffer a loss by reason of any orders made pursuant to the Act.

With respect to the concerns raised by the Metis and First Nations, the Board expects that energy operators will consult with them in a meaningful way. The Board intends to follow up on the concerns about impacts and opportunities from future developments to determine if ongoing regional initiatives may be of assistance.

After considering all the evidence submitted to the hearing, the Board concludes that continued production of associated gas presents a significant risk to future bitumen recovery from the Gulf Surmont oil sands leases. Accordingly, the Board grants Gulf's request in part. The Board will order the shut-in of Wabiskaw-McMurray gas production effective May 1, 2000, from 146 of the 183 wells that Gulf requested be shut in.

The Board's decision results in the following considerations and requirements:

1) The Board recognizes that there will be practical implications to its decision and that it may be necessary to put in place follow-up processes to deal with these implications. These follow-up processes would deal with matters relating to well suspensions/abandonments, pipeline issues, and other matters resulting from the Board's decision.

2) The Board will require Gulf to submit annual reports on the management of the resources on its Surmont leases, including the continued assessment of the effect that the pressure of the overlying gas zone has on SAGD bitumen recovery. Also, if requested, the Board is prepared to work with the interested parties to assist in the development and implementation of a pressure-monitoring program in the Surmont area.

3) The Board will not shut in 22 of the Wabiskaw-McMurray gas wells in the three-section buffer area that Gulf requested be shut in because the Board does not believe that the gas being produced is associated with the bitumen resources on Gulf's Surmont leases. However, the Board believes that the gas being produced by these wells and other gas wells in the Surmont and geologically similar areas could be associated with and present a risk to underlying bitumen. The Board therefore intends to review the appropriateness of continued

gas production from these wells and may require the licensees to submit reports to the Board that address this issue.

The Board does not have a concern with the remaining 15 wells requested by Gulf to be shut in because, according to the EUB's records, they are not completed in the Wabiskaw-McMurray.

PREFACE

The Alberta Energy and Utilities Board (EUB/Board) determined in the course of the hearing on Gulf Canada Resources Limited's request for the shut-in of associated gas in the Surmont area that certain confidential information was necessary and relevant to the Board's further deliberations and decision. The Board believed that information from the Dover steam-assisted gravity drainage (SAGD) experimental scheme and from the Gulf Surmont SAGD experimental scheme, then in the possession and/or control of participants before the Board and others, should be produced at the hearing. The parties possessing the information did not agree to produce it voluntarily, as it was commercially sensitive and had proprietary value.

As a result, the Board issued an Order to Produce Documents on July 8, 1999 (Appendix 10). The order identified the persons entitled access to the information and the conditions upon which limited access would take place.

It was decided to issue two editions of the decision report. The confidential edition, containing the Board's review and consideration of the confidential information, is being made available to only those parties who are signatories of the Declaration and Undertaking Not to Disclose, as described in the order. In this edition the confidential material is in bold type.

The public edition, available to all the hearing participants and the public, presents only a summary of the Board's views and conclusions in those parts where confidential information was considered.

GULF CANADA RESOURCES LIMITED
REQUEST FOR THE SHUT-IN OF ASSOCIATED GAS
SURMONT AREA

Decision 2000-22
Proceeding No. 960952

1 DECISION

After considering all the evidence submitted to the hearing, the Alberta Energy and Utilities Board (EUB/Board) concludes that continued production of associated gas presents a significant risk to future bitumen recovery from the Gulf Canada Resources Limited (Gulf) Surmont oil sands leases. Accordingly, the Board grants Gulf's request in part. Specifically, the Board will order the shut-in of associated gas production from the top of the Wabiskaw Member to the base of the McMurray Formation (Wabiskaw-McMurray) effective May 1, 2000, from the 146 wells listed in Appendix 1. An order requiring the shut-in of gas production will be issued shortly.

The Board's decision results in the following considerations and requirements:

1) The Board recognizes that there will be practical implications to its decision to shut in gas production and that it may be necessary to put in place follow-up processes to deal with these implications. Also, it may be necessary for the Board to consider requests for relief from some of its regulatory requirements. For example, there are requirements related to the suspension and abandonment of wells, pipelines, and other field facilities. There are also requirements pertaining to long-term inactive wells that can trigger liability management considerations. In light of the unusual circumstances that may arise, the Board is prepared to consider special requests.

2) The Board will require Gulf to submit annual reports on the management of the resources on its Surmont leases, including the continued assessment of the effect that the pressure of the overlying gas zone has on the recovery of bitumen by steam-assisted gravity drainage (SAGD). The Board will work with Gulf and other interested parties to determine the details of this process, including the information requirements. Also, if requested, the Board is prepared to work with the interested parties to assist in the development and implementation of a pressure-monitoring program in the Surmont area.

3) Appendix 2 lists 22 of the Wabiskaw-McMurray gas wells in the three-section buffer area requested by Gulf to be shut in. These wells are not being shut in at this time because the Board does not believe that the gas being produced is associated with the bitumen resources on Gulf's Surmont leases. However, the Board believes that the gas being produced by these wells and other gas wells in the Surmont and geologically similar areas could be associated with and present a risk to underlying bitumen. The Board therefore intends to review the appropriateness of continued gas production from these wells and may require the licensees to submit reports to the Board that address this issue.

Appendix 3 lists the remaining 15 wells requested by Gulf to be shut in about which the Board does not have a concern because, according to the EUB's records, they are not completed in the Wabiskaw-McMurray.

The reasons for the Board's decision are provided in the following sections of this report.

2 INTRODUCTION

2.1 Submissions and Background

On November 12, 1996, the EUB received a submission from Gulf requesting that the Board order that associated gas production from the Wabiskaw-McMurray on its Surmont oil sands leases be shut in immediately on a temporary basis while the Board held formal proceedings to review the effect of associated gas production on SAGD bitumen recovery on its leases. Gulf further indicated that as part of such a review it would request that the Board order that associated gas production on its leases be shut in until oil sands development was completed. Gulf submitted that pressure depletion of gas pools in association with oil sands zones would adversely affect SAGD bitumen recovery to the extent that the bitumen might not be recoverable.

The EUB subsequently requested submissions from the petroleum and natural gas (P&NG) leaseholders affected by Gulf's request and, upon review of the information provided, denied Gulf's request for the immediate and temporary shut in of associated gas production on its leases. However, recognizing the broad implications of the issues and the possible impacts on existing and future gas and bitumen operations, the EUB convened a general meeting of interested parties on January 21, 1997, to discuss the scope of a general review. On the basis of the information provided at the meeting and the submissions received, the Board issued a Memorandum of Decision on February 19, 1997 (Appendix 4) advising that it intended to hold a general inquiry into the issues raised and that it would reconsider Gulf's request upon completion of the inquiry.

The inquiry was conducted between May 29 and June 20, 1997, and on March 25, 1998, the Board issued the *Gas/Bitumen Inquiry Report*[1] (Appendix 5: Inquiry Report Executive Summary). The Board concluded that sufficient evidence exists to suggest that associated gas production could have a detrimental effect on bitumen resources to the extent that significant volumes might never be recoverable. In that regard, the Board further concluded that

- for all wells drilled and/or completed in the defined oil sands strata after July 1, 1998, an operator must submit an application and obtain approval from the EUB before any associated gas can be produced; and

- for wells completed in the defined oil sands strata prior to July 1, 1998, an application for approval to produce gas would not be required. These wells would be allowed to continue to produce, subject to the resolution of any concerns that might be raised by oil sands leaseholders or by the EUB on its own initiative.

[1] EUB Inquiry, *Gas/Bitumen Production in Oil Sands Areas*, March 25, 1998.

On February 3, 1999, the Board issued *Interim Directive 99-1,*[2] which further outlined the requirements regarding gas/bitumen production in the oil sands areas. These requirements were subsequently included in regulations enacted under the Oil and Gas Conservation Act (Alberta Regulation 47/99) and the Oil Sands Conservation Act (Alberta Regulation 48/99), effective March 31, 1999.

Following the release of the inquiry report, the EUB received submissions from Gulf requesting that the Board reconsider its original request as amended. Gulf requested that

- gas production from the Wabiskaw-McMurray on its Surmont oil sands leases and surrounding three-section buffer area, shown in Figure 1, be shut in until oil sands development is completed (Gulf's list of 183 wells requested to be shut in is shown in Appendix 6), and

- any further drilling for gas production from the Wabiskaw-McMurray on its Surmont oil sands leases and surrounding area be prohibited until oil sands development is completed.[3]

The EUB subsequently received submissions from the Surmont Producers Group (SPG) opposing Gulf's request. The SPG is a group of gas producers (listed in Appendix 9) with interests in the Surmont area. The EUB also received submissions from Petro-Canada Oil and Gas (Petro-Canada) supporting Gulf's request. Petro-Canada holds the oil sands rights for some of the land in the area surrounding the Surmont leases for which Gulf has requested that gas production be shut in. The EUB also received submissions from the Anzac Metis Local No. 334, Chipewyan Prairie Dene First Nation, and Fort McMurray No. 468 First Nation, which were generally in support of Gulf's request. Letters were received from several other parties expressing an interest in the matter.

2.2 Pre-hearing Meeting and Rescheduling of Hearing

The Board held a pre-hearing meeting on November 5, 1998, in Calgary, Alberta, to obtain input from interested parties regarding the schedule for filing of submissions and hearing commencement and any other matters related to the hearing procedure. The Board issued a letter on November 9, 1998 (Appendix 7) advising parties of its decisions resulting from the pre-hearing meeting.

Approximately one week prior to the originally scheduled date for commencement of the hearing, the Board received a request from the SPG for an adjournment. The Board agreed that a short adjournment was warranted, and the commencement date of the hearing was rescheduled.

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[2] EUB *Interim Directive 99-1: Gas/Bitumen Production in Oil Sands Areas—Application, Notification, and Drilling Requirements*, February 3, 1999.

[3] In light of the issuance of EUB *Interim Directive 99-1*, Gulf subsequently withdrew this request at the hearing.

2.3 Motion for Dismissal of Gulf's Request

On February 5, 1999, the EUB received a Motion for Dismissal (Motion) of Gulf's request from the SPG. The Motion requested that the Board dismiss Gulf's request on the following grounds:

- The statutory authority that Gulf requests be exercised or that the Board may purport to exercise is neither disclosed nor obvious.

- The Board lacks the jurisdiction and authority to grant the relief requested by Gulf.

The Board requested submissions respecting the Motion from other interested parties and received responses dated February 25, 1999, from Gulf, Petro-Canada, and Amoco Canada Petroleum Limited. Upon consideration of all the submissions, the Board issued a letter on March 4, 1999 (Appendix 8) confirming its position that it has the statutory authority to hear Gulf's request and take whatever action within the EUB's jurisdiction that it deemed necessary.

Further to the decision of March 4, 1999, the Board reiterates that the referenced legislation clearly establishes that a fundamental part of the EUB's mandate is to ensure that Alberta's energy resources are developed in an efficient and orderly manner that, to the greatest extent possible, eliminates all economically avoidable waste. Conservation, in this sense, was the impetus for the EUB's original creation. In carrying out its responsibilities regarding conservation, orderly development, and the avoidance of waste, the Board is entitled to consider the impact that one resource development may have on another. Section 15 of the Energy Resources Conservation Act provides additional authority to the EUB and reflects the necessary flexibility and responsiveness required to address a variety of issues that may arise with respect to the conservation and orderly and efficient development of Alberta's energy resources.

The SPG subsequently filed an application with the Court of Appeal of Alberta for leave to appeal the Board's decision regarding the SPG's Motion. The Court granted this leave to appeal but suspended the leave until the Board issues its final decision regarding Gulf's request.

2.4 Hearing

A public hearing on Gulf's request began on April 28, 1999, in Calgary, Alberta, before F. J. Mink, P.Eng., J. D. Dilay, P.Eng., and W. J. Schnitzler, P.Eng. The hearing, which concluded on September 24, 1999, involved 47 sitting days, 459 exhibits (including 83 confidential exhibits), and approximately 7200 pages of transcript. The Board heard representations from the Anzac Metis Local No. 334, Chipewyan Prairie Dene First Nation, and Fort McMurray No. 468 First Nation in Fort McMurray, Alberta, on May 13, 1999. Durando Resources Corporation did not actively participate in the evidentiary portion of the hearing but did provide some closing remarks. A list of the hearing participants is provided in Appendix 9. The Gulf Surmont leases and other areas that were discussed at the hearing are shown in Figure 2.

In a letter dated April 9, 1999, and again at the hearing, the SPG requested that the Board visit the Syncrude Oil Sands Mine to directly see and hear representations on the inclined heterolithic stratification (IHS) layer, viewable at the Syncrude mine site, and its significance to potential future SAGD schemes. The Board agreed to the SPG's request and on May 12, 1999, the Board panel visited the Syncrude mine site. Also participating in the visit were EUB staff and representatives from the SPG, Petro-Canada, Gulf, and the Anzac Metis Local No. 334.

From May 19 to 21, 1999, a "technical conference" was held involving EUB staff and representatives from the SPG, Petro-Canada, and Gulf to attempt to reach some consensus among the hearing participants regarding the pressure data submitted to the hearing. The Board hoped that the hearing participants could agree on what the pressure values should be and focus on the interpretations resulting from the data. As a result of the technical conference, a report (Exhibit No. 104) was submitted at the hearing indicating where consensus had been reached among the parties regarding the pressure data.

During the course of the hearing, some of the participants referred to confidential information that they suggested could be of significant assistance to the Board in making a decision on Gulf's request. Given the broad public-interest implications of Gulf's request, the Board determined that certain information from the Dover SAGD experimental scheme and Gulf Surmont SAGD experimental scheme was necessary and relevant to the Board's further deliberations and decision respecting Gulf's request. Therefore, on July 8, 1999, the Board issued an Order to Produce Documents (Appendix 10), requiring that information specified in the order be produced. However, recognizing the commercial sensitivity and proprietary value of the information, the Board, in consultation with the SPG, Petro-Canada, and Gulf, developed an in camera process (outlined in the order) in which only the Board panel and persons who had signed and filed a Declaration and Undertaking Not to Disclose would be permitted to participate. The evidentiary portion of the in camera process was conducted from August 31 to September 11, 1999, and closing arguments for the in camera process were given on September 24, 1999.

3 ISSUES

The Board considers the issues with regard to Gulf's request to be as follows:

- extent of affected resources/reserves;
- reservoir and aquifer continuity;
- effect of associated gas production on SAGD bitumen recovery;
- geomechanical effects;
- feasibility of artificial repressuring;
- feasibility of artificial lift;
- production of associated gas by SAGD wells;
- economics; and
- regional issues.

4 EXTENT OF AFFECTED RESOURCES/RESERVES

4.1 Views of Gulf

Gulf estimated that out of more than 17 billion barrels (10^9 bbl) (2703 million cubic metres [10^6 m^3]) of bitumen in place on its Surmont leases, approximately 15 10^9 bbl (2385 10^6 m^3) are suitable for development using SAGD technology. It further estimated that approximately 5.25 10^9 to 7.5 10^9 bbl (835 10^6 to 1193 10^6 m^3) of this bitumen, or 35 to 50 per cent, is recoverable. Gulf identified prospective commercial bitumen resources on its Surmont leases using reservoir rock cutoffs of 20 m continuous bitumen pay thickness, 12 per cent bulk weight bitumen, and 30 per cent porosity. On the basis of the distribution of bitumen resources by net pay thickness across its Surmont leases, Gulf contended that if pressure depletion of gas caps limits economic SAGD operations to only those areas that are over 30 to 40 m thick, upwards of 7 10^9 bbl (1113 10^6 m^3) of potential bitumen resources would be lost. It further contended that there is a risk of reduced recovery in even the thickest bitumen due to pressure depletion of gas caps.

Gulf estimated that there were approximately 273 billion to 280 billion cubic feet (bcf) (7644 10^6 to 7840 10^6 m^3) of original recoverable gas reserves in the Wabiskaw-McMurray in its application area. Of these gas reserves, approximately 179 bcf (5012 10^6 m^3) had been produced as of June 30, 1998. Therefore, there were approximately 95 to 105 bcf (2660 10^6 to 2940 10^6 m^3) of remaining recoverable gas reserves, or 17 10^6 to 19 10^6 bbl (2703 10^3 to 3021 10^3 m^3) of oil equivalent, in its application area as of June 30, 1998.

4.2 Views of Petro-Canada

Petro-Canada provided only a bitumen resource estimate and gas reserve estimate for a portion of its Chard leases (i.e., Chard A Bitumen Prospect).

4.3 Views of the SPG

The SPG did not provide an estimate of the bitumen resources on Gulf's Surmont leases. However, it suggested that Gulf might have overestimated these resources as a result of the methodology used. The SPG also pointed out that Gulf had not yet booked any probable, undeveloped, or proven bitumen reserves on its Surmont leases.

The SPG estimated that 124 bcf (3472 10^6 m^3) of proved producing gas reserves and 180 bcf (5040 10^6 m^3) of proved and probable producing gas reserves were still economically recoverable from the application area as of January 1, 1999.

4.4 Views of the Board

The Board notes that although the SPG questioned Gulf's estimate of the bitumen resources on the Surmont leases, it did not counter with an estimate of its own. On the basis of the evidence submitted to the hearing, the Board believes that the bitumen resources on Gulf's Surmont leases are in the order of 15 10^9 bbl (2385 10^6 m^3). Therefore, if 35 to 50 per cent of these resources are ultimately recoverable, as suggested by Gulf, this represents a significant energy resource for the province. To put this into perspective, on the basis of EUB production statistics, approximately 12 10^9 bbl (1908 10^6 m^3) of light-medium crude oil had been produced in Alberta as of year-end

1998. Accordingly, the Board believes that the bitumen resources on the Surmont leases warrant consideration for protection for future development.

The Board notes that Gulf and the SPG estimated the remaining recoverable gas reserves in the area for which gas is requested to be shut in to be 95 bcf (2660 10^6 m^3) and 180 bcf (5040 10^6 m^3) respectively. The Board concludes that the amount of bitumen potentially recoverable from the Surmont leases is significantly greater on an energy basis than that of either estimate of the remaining recoverable gas reserves.

5 RESERVOIR AND AQUIFER CONTINUITY

5.1 Regional-Scale Hydrogeology and Aquifer Systems

5.1.1 Views of Gulf

Gulf contended that extensive vertical and lateral hydraulic continuity exists in the Cretaceous Mannville Group in the Surmont area. On the basis of basin-scale distribution maps of hydraulic heads and total dissolved solids for the Upper and Lower Mannville Groups, Gulf submitted that the Athabasca area, hence the Surmont leases, is geographically located in the discharge area of a basin-scale flow system driven by topography from southwestern to northeastern Alberta. This system is present in the Devonian strata that underlie the Cretaceous McMurray Formation. Local flow systems are superimposed over the regional-scale flow system and are present mainly in the Mesozoic strata that overlie the Devonian.

Gulf interpreted the flow of formation water to be driven on a local scale by topography from recharge at the Stony Mountain uplands, west of the Surmont leases, to discharge at the outcrop of the McMurray Formation along the Christina River some 45 kilometres (km) north of the Surmont leases. Gulf submitted that the flow of formation water in the study area is downward from the Upper Mannville (Grand Rapids Formation) to the Lower Mannville (McMurray Formation) strata and upward from the Devonian Beaverhill Lake Group. Gulf interpreted the observed flow pattern as comprising local systems that drive the flow of fresh meteoric water downward across Cretaceous strata and an underlying regional-scale system that drives the flow of basinal brines updip in the strata of the Devonian Beaverhill Lake Group. The two systems converge toward the McMurray Formation in the Athabasca area, including the Surmont leases, with limited mixing between them. Gulf submitted that the basin-scale and local flow systems discharge along the Clearwater and Christina River valleys to the north of the Surmont leases where both Cretaceous and Devonian strata outcrop. On the basis of distributions of salinity, anions, and cations in formation waters, Gulf contended that there is likely hydraulic communication between the underlying Devonian Beaverhill Lake Group and the overlying Upper McMurray member[4] (Upper McMurray) across the bitumen-saturated McMurray Formation. Gulf submitted that the entire stratigraphic succession in the Surmont area, from the surface down to the Devonian Beaverhill Lake Group, is in hydraulic continuity on a geological

[4] Gulf and Petro-Canada both recognized the more formal designation of Upper, Middle, Lower, and Basal members of the McMurray Formation. The SPG, however, only recognized the lower as being the lower part, the middle as the middle part, and the upper as the upper part of the McMurray Formation. The distinction between the two usages of these terms is as follows: when used in uppercase, the Basal, Lower, Middle, and Upper refer to stratigraphic designations; when used in lowercase, the basal, lower, middle, and upper refer to that relative portion of the McMurray Formation at a given location.

time scale both vertically and laterally. Gulf contended that the migration, accumulation, and biodegradation in place of hydrocarbons into bitumen is further evidence of permeability and flow systems that must have existed and are still present in the McMurray Formation.

Gulf submitted that the Upper McMurray in the Surmont area is an aquifer with lateral water flow. Gulf defined lateral hydraulic continuity within the water sands of the Upper McMurray on the basis of its interpretation of the depositional environment, areal extent, and thickness of sand bodies, fluid contacts (i.e., gas-water-bitumen), and hydraulic head distribution. Gulf submitted that the individual hydraulically continuous regions are in hydrodynamic communication through interregion strata of lesser transmissivity, such that the entire Upper McMurray is laterally continuous overall. Regarding repressuring of the gas pools in the Upper McMurray with water from the Grand Rapids and Clearwater aquifers, Gulf asserted that the observed underpressuring in these aquifers indicates that they are not in good hydraulic communication with the ground surface and that they will not be continuously replenished because of the intervening shales. Furthermore, on the basis of water mass balance, Gulf estimated that the permeability of the Clearwater shales must be in the order of 1 millidarcy (mD). Gulf stated that on a production-time scale there are no pressure effects in the Upper McMurray from water injection in the Basal McMurray. Regarding the bitumen-saturated strata, Gulf stated that at in situ reservoir conditions the bitumen filling the pore space has asphaltlike properties.

On the basis of pressure-versus-elevation plots, Gulf showed that the natural hydrodynamic system in the Surmont area is underpressured with respect to the present-day topography. Gulf interpreted the observed underpressuring as being the result of flow in a system characterized by low-permeability strata upstream at vertical recharge in the Stony Mountain uplands and high permeability of the Upper McMurray at downstream lateral discharge. The low hydraulic heads, hence pressures, at outcrop along the Christina and Clearwater River valleys have propagated upstream through the high-permeability Upper McMurray up to and beyond the Surmont leases, with an average regional hydraulic gradient of 2.4 to 3.5 m/km.

Gulf interpreted nonlinear pressure/compressibility factor (p/z)-versus-cumulative-production plots and water influx in producing gas pools with and without "mappable" water in the Surmont area as further evidence that the gas pools in the Surmont area are supported/underlain by an extensive aquifer. Gulf acknowledged that the support is weak and attributed it to extremely low recharge rates through low-permeability strata upstream in recharge areas, rather than to hydrodynamic discontinuity.

Gulf concluded that the sediments in the Surmont area exhibit both vertical and lateral hydraulic continuity from the surface to the pre-Cretaceous unconformity (i.e., top of the Devonian) and that the aquifer has achieved equilibrium with the discharge point. Moreover, the lateral hydraulic continuity within the Upper McMurray is extensive.

5.1.2 Views of Petro-Canada

To address the issue of flow systems in the area of the Surmont and Chard leases, Petro-Canada performed a regional-scale hydrogeological analysis of the entire Mesozoic succession (i.e., surface to the Devonian) for a large area defined by Townships 74 to 95 and Ranges 4 to 19, West of the 4th Meridian. Petro-Canada used drillstem tests (DST) and absolute open flow (AOF) tests to construct potentiometric surfaces (i.e., maps of hydraulic head distributions) for four aquifers, which are, in descending order from the surface, Grand Rapids, Clearwater, Wabiskaw-Upper McMurray, and Basal McMurray-Devonian. The hydraulic heads mapped by Petro-Canada for these aquifers reach highs of 540 m in the Grand Rapids in the southeastern portion of the study area and in the Basal McMurray-Devonian at Stony Mountain uplands in the centre of the study area, shown in Figure 3. The lowest mapped hydraulic heads are about 350 m in the Wabiskaw-Upper McMurray and Basal McMurray-Devonian aquifers in the southwest and along the Christina River in the north, also shown in Figure 3.

Petro-Canada noted that the flow in the Grand Rapids and Clearwater aquifers appears to be entirely controlled by the ground surface elevation, with a pattern of flow from topographic highs in the southwest and Stony Mountain uplands to lows along the valleys of the Athabasca, Clearwater, and Christina rivers. With regard to the Wabiskaw-Upper McMurray and Basal McMurray-Devonian aquifers, Petro-Canada noted that the flow continues to be controlled by topography over much of the study area, except for the southwestern corner, where the flow is directed toward and controlled by the Devonian Grosmont drain in the southwest. Petro-Canada further noted that hydraulic heads in the Basal McMurray-Devonian are up to 100 m lower than in the Wabiskaw-Upper McMurray, which in turn are up to 100 m lower than in the Clearwater. Petro-Canada attributed local upward hydraulic gradients, identified on potentiometric maps on the basis of pressure measurements, to the local existence of the remnants of a fossil flow system that did not reach equilibrium with the present-day topography. Petro-Canada submitted that the generally decreasing hydraulic heads from the Grand Rapids to the Basal McMurray-Devonian and the general similarity between the various potentiometric surfaces and the ground surface, albeit increasingly muted with depth, are proof of a single dynamic flow system in hydraulic communication on a geologic time scale from the Grand Rapids Formation to the Devonian System.

Petro-Canada submitted that the low salinity in the McMurray Formation and adjacent strata is proof that the original seawater present at deposition was flushed out or diluted by fresh meteoric water. On the basis of this evidence, Petro-Canada asserted that potential vertical permeability barriers (i.e., shales and bitumen-saturated sand) do not prevent vertical hydraulic communication. Petro-Canada estimated that the regional-scale permeability of the intervening shale beds in the area must be in the order of 1 mD. Petro-Canada concluded that an overall hydrodynamic system exists in the Chard and Surmont areas that extends from the ground surface to the base of the McMurray Formation. Petro-Canada submitted that the petroleum history of the Athabasca area and the emplacement of bitumen and gas are further proof that interconnected permeability has been in place in the past and must be present today. However, Petro-Canada recognized that the issue of hydraulic continuity needs to be qualified by a time frame of the process under debate. In this context, Petro-Canada attributed the observed aquifer hydraulic heads in the Basal McMurray-Devonian higher than in the Wabiskaw-Upper McMurray at Gulf's Surmont pilot and a few other locations to a relic of a fossil flow system whose regime, hence pressures, have not adjusted yet to the present ground surface elevation.

With regard to the Wabiskaw-Upper McMurray, Petro-Canada asserted that it forms a continuous aquifer. Petro-Canada submitted that the water influx occurring in gas pools demonstrates that they are underlain by and communicate through an active aquifer.

In addition to the regional-scale study, Petro-Canada presented a detailed hydrogeological analysis regarding fluid flow and lateral hydraulic continuity at a local scale in the Wabiskaw-

Upper McMurray for its Chard A Bitumen Prospect area. Petro-Canada interpreted the virgin potentiometric surface, which slopes generally from west to east over the Chard A Bitumen Prospect area, as an indication of eastward flow of formation water in an aquifer that is part of a regional-scale dynamic system.

5.1.3 Views of the SPG

The SPG submitted that the Clearwater and Grand Rapids aquifers that overlie the McMurray Formation are areally extensive, hydrostatic (i.e., no flow) with constant potentiometric surfaces, and unaffected by topography. The SPG further submitted that there is no communication between these aquifers, as demonstrated by the differences in hydraulic heads and by the lack of discernible pressure effects in one from gas production or water injection in the other. The SPG referred specifically to Gulf's 03/10-31-83-6 W4M water disposal well, where water is being injected into basal McMurray water sands at pressures significantly above the formation virgin pressure with no observed pressure effects in the overlying bitumen-saturated and upper McMurray strata. The SPG contended that the Clearwater and Grand Rapids aquifers have equilibrated with the present topography, while the strata of the underlying Wabiskaw-McMurray, separated from the aquifers above by the intervening Clearwater shales, have not. The SPG submitted that the hydrogeological regime of the overlying Grand Rapids and Clearwater aquifers and of the underlying Devonian System (i.e., Calumet limestone) are different from and independent of that of the Wabiskaw-McMurray aquifer and, therefore, irrelevant.

The SPG contended that the gas- and water-saturated sands in the Wabiskaw-McMurray are relatively small in area and that they are not part of a single hydrogeological system (i.e., they are compartmentalized and isolated). On the basis of drilling results, the SPG submitted that the water is found under gas pools, but in general does not extend between them.

The SPG used the linear behaviour of p/z-versus-cumulative-production plots and material balance calculations for gas pools to support its contention that the gas pools produce as volumetric reservoirs with no water drive. The SPG stated that this interpretation is supported by the absence of discernible upward movement of the gas/water contact in producing gas pools, but it did not produce any evidence to support this contention. The SPG interpreted the water produced occasionally in gas wells as originating internally from the gas pool, but not from lateral sources (i.e., from outside the gas pool). Such internal sources of water are either one or a combination of the following: from below the gas zone (i.e., coning); from cusping along an inclined impermeable bed; or from trapped and perched water within the reservoir. In addition, the SPG submitted that another possible origin of produced water could be the Clearwater Formation above the gas pools, where hydraulic heads are higher than in the Wabiskaw-McMurray. The SPG stated that water production is not the consequence of aquifer support. It interpreted any nonlinear behaviour of p/z-versus-cumulative-production plots to be due to the heterogeneity of the gas reservoirs, and not to water influx (i.e., aquifer support).

On the basis of its interpretation of water pods and the lack of aquifer support in the upper McMurray, the SPG contended that there is no continuous aquifer underlying the Wabiskaw-McMurray gas pools in the Surmont area through which pressure could be transmitted. The discontinuous water-saturated sands are each under different hydrostatic conditions, although not in equilibrium with the present-day topography. The SPG submitted that natural recharge and repressuring in a system with no underlying aquifer is inherently impossible. It also noted that neither Gulf nor Petro-Canada provided estimates of rates and time frames for flow in the Mannville Group aquifers to support its submission of a dynamic flow system.

5.1.4 Views of the Board

The Board notes that both Gulf and Petro-Canada submitted that local pressure changes caused by gas production from Wabiskaw-McMurray gas pools propagate across the Surmont area and beyond through a continuous and dynamic underlying aquifer and that the SPG disagreed with them, maintaining that the water sands underlying Wabiskaw-McMurray gas pools are discontinuous and static. Because the rate and distance of propagation of a pressure change depend on the hydraulic communication in the Cretaceous strata in the Surmont area, the Board needs to establish the extent of hydraulic communication across the Cretaceous strata in the area.

On the basis of the maps of salinity and hydraulic head distributions (i.e., potentiometric surfaces) submitted by Gulf and Petro-Canada, the Board believes that the flow of formation waters of connate origin in the Devonian strata in the Athabasca area is driven in a basin-scale flow system from southern and southwestern Alberta that discharges at outcrop along the Athabasca River and its tributaries and at the northeastern edge of the basin, shown in Figure 4. Formation water of meteoric origin flows in the Cretaceous strata in the area, driven by topography in local flow systems from recharge at topographic highs to discharge at topographic lows along river valleys, also shown in Figure 4. The Board believes that limited mixing takes place between the Devonian and Cretaceous flow systems at the pre-Cretaceous unconformity where the two meet because of buoyancy effects caused by significant salinity differences.

The Board recognizes that the Cretaceous succession comprises four sandy aquifers, which are, in ascending order from the pre-Cretaceous unconformity, Basal McMurray, Wabiskaw-Upper McMurray, Clearwater, and Grand Rapids. The Board agrees with Gulf that the underpressuring observed in all Cretaceous aquifers is caused by low permeability upstream at recharge and high permeability downstream at discharge.

On the basis of the regional-scale potentiometric maps, shown in Figure 3, and corresponding pressure data submitted by Petro-Canada, the Board believes that the Cretaceous aquifers are separated by regional-scale strong aquitards,[5] as indicated by

- large, up to 100 m, hydraulic head differences between aquifers across aquitards up to tens of metres thick;
- a pattern of lateral flow that differs locally from aquifer to aquifer, particularly between the McMurray aquifers and the overlying Grand Rapids and Clearwater aquifers;
- hydraulic heads in the McMurray aquifers in the west-southwest that reach values as low as 350 m, lower than the topographic elevation of the Athabasca River; and

[5] Aquitards are low-permeability units from which water cannot be produced through wells, but where the vertical flow is significant enough to feed adjacent aquifers through leaking.

- reversal in places of the potential for vertical flow between various adjacent aquifers from the generally downward to the upward direction.

On the basis of the submitted data and applying Darcy's law for flow in porous media, the Board believes that the regional-scale permeability of the Cretaceous aquitards must be less than 1 mD to sustain vertical hydraulic gradients in the order of 10^0 to 10^1 m/m (10^3 to 10^4 m/km), compared with lateral hydraulic gradients in the order of 2 to 3 m/km in the sandy aquifers, whose permeability all the hearing participants estimated to be in the order of 1000 mD.

The Board accepts that there are no pressure effects in the Wabiskaw-Upper McMurray aquifer as a result of gas production from gas pools in the overlying Clearwater Formation, which demonstrates again that the intervening Clearwater shaly aquitard is strong. The Board believes that the lack of pressure effects in the Wabiskaw-Upper McMurray aquifer from water injection in the underlying Basal McMurray aquifer indicates that the intervening bitumen-saturated Middle McMurray aquitard is also strong. The Board accepts Gulf's submission that at normal in situ temperatures the bitumen has asphaltlike properties and acts as a solid with elasto-plastic properties. The irreducible water present in the pore space does not allow fluid flow and pressure transmission because of zero relative permeability. Locally, pressure changes could be transmitted through a bitumen zone if the water saturation, however small, is greater than the irreducible saturation.

The Board believes that the Wabiskaw-Upper McMurray aquifer is weak, most probably because of slow recharge in a low-permeability environment, as indicated by the distribution of hydraulic heads in the area and by the downstream underpressuring observed in the aquifer. The Board accepts that the aquifer provides little (i.e., weak) support to the gas pools, as submitted by Gulf.

The Board concludes that

- on a production-time-scale, the Cretaceous aquitards do not allow natural fluid flow and pressure communication between adjacent aquifers;

- the Wabiskaw-Upper McMurray strata form a regional-scale, hydraulically continuous weak aquifer that is isolated from the overlying and underlying aquifers by the strong Clearwater and Middle McMurray aquitards; and

- the Wabiskaw-Upper McMurray aquifer is in hydrodynamic equilibrium with recharge and discharge areas.

The Board needs to establish on a local scale the extent of lateral continuity of the Wabiskaw-Upper McMurray aquifer to address the issue of the transmission across the Surmont area of pressure changes caused by gas production. This issue is addressed in Section 5.4.

5.2 Depositional Models

5.2.1 Geology at Surmont

5.2.1.1 Views of Gulf

Gulf stated that the complex nature of the geology at Surmont is reflected in bitumen being concentrated in laterally discontinuous fluvial and estuarine channel sands of the Lower and Middle McMurray. Top gas and/or top water thief zones overlie the bitumen and are concentrated in hydrodynamically continuous tidal flat and tidal channel sediments of the Upper McMurray, as illustrated in Gulf's type well shown in Figure 5.

Gulf described the Lower McMurray as being composed of a coarse- to fine-grained, poorly sorted fluvial channel sand. The fluvial channel sand, deposited in topographic lows on the Devonian, forms an important component of the bitumen reservoir. Silty and muddy interfluve deposits dominated sedimentation on the flanks and tops of Devonian topographic highs. Gulf distinguished these fluvial McMurray sediments from other sediments based on grain size and the absence of bioturbation.

Gulf described the Middle McMurray bitumen reservoir as being composed of very fine- to fine-grained sand deposited as stacked channel point bars in a widespread estuarine system. The stacked channel point bars form an important bitumen pay interval. Gulf distinguished estuarine McMurray sediments from other sediments based on grain size and/or by the presence of abundant small trace fossils of low population diversity. It presented an estuarine model to demonstrate that upstream, where tidal influences are weak, there is a predominance of sand with minor shales, while downstream, where tidal influences are greatest, there is an increase in mud and a decrease in sand. Gulf indicated that Surmont was located in the upstream portion of the estuary during Middle McMurray time, whereas Dover was located downstream, where tidal influences were greater. Gulf further described the Middle McMurray as consisting of a complex series of multiple-stacked channels that incised into each other both laterally and vertically, thus forming vast complex heterogeneous channel systems. A complete fining-upward sequence was rarely preserved. These sequences are laterally noncorrelatable, discontinuous, and sand dominant, as indicated from cores and logs.

Gulf stated that shale stringers from 10 to 15 cm thick (infrequently ranging up to 3 m thick) occasionally break the vertical continuity of the oil sand column. These shales, interpreted to be overbank muds, are likely of limited lateral extent (i.e., less than 100 m) due to the dominance of lateral accretion in a meandering estuarine system. Gulf also stated that the vertical continuity of the bitumen pay may have been broken by 10 to 15 cm thick (occasionally ranging up to 5 m thick) layers of shale rip-up clasts suspended in a bitumen sand matrix. Gulf indicated that it does not expect the small lateral extent of the shale beds or the presence of rip-up clasts to adversely affect SAGD recovery. Gulf referred to these shale stringers and clasts as heterolithic stratification (HS). Shales and muds within the sand-dominated HS are generally bioturbated. Gulf described bioturbation as the churning of sediments and disturbing of bedding by organisms, which generally increases porosity and permeability. Gulf contended that its depositional model illustrates, and core and log data confirm, that sand-dominant facies are present at Surmont. The HS is thin, bioturbated, and not areally extensive. Also, as demonstrated by the hydrocarbon model, every available pore space, including the pore spaces within the bioturbated shales and muds, is occupied with gas, water, or bitumen.

Gulf adopted Petro-Canada's chimney model, which is defined as a series of stacked channel sands that may have some minor HS and where bitumen is in communication with either water or gas. Gulf pointed to the 02/12-24-083-7W4 observation well as an example of a chimney well at Surmont. The core showed clean sand with some minor discontinuous HS. The logs showed a clean gamma ray, generally clean spontaneous potential, compensated neutron formation density logs tracking each other, and resistivity curves almost tracking each other. High gamma ray or high spontaneous potential reflected the presence of breccia. Gulf also used log data to identify wells with bitumen in direct contact with overlying water. The 00/10-24-81-7W4 well had similar core and log responses. Gulf looked for other wells with similar log patterns to the two wells discussed above. In total, it identified 45 wells that met the criteria for chimneys and 47 wells that were very close to being chimneys.

Gulf submitted that it disagreed with the SPG's lithofacies classification and its determination of an average of 24.3 m of HS derived from all of the cored wells at Surmont. Gulf stated that the lithofacies classification is biased and the cutoffs used enhance the presence of muds. Gulf contended that different cutoffs would identify a thick sand reservoir at Surmont. It stated that using the SPG's 5 m sand cutoff would result in a 4.5 m cross-bedded sand with thin mud laminae at the top and base to be classified as sandy HS, rather than as cross-bedded sand. Gulf further contended that the SPG inconsistently applied the classification between Dover and Surmont, so that the reservoir at Dover would appear to be better than at Surmont. Gulf also disagreed with the SPG's claim that it incorrectly relied on logs to characterize reservoirs in the absence of core. Gulf stated that the SPG was inconsistent in its reliance on log data and that some of its members used logs as a lithology indicator. Gulf further pointed out that Northstar Energy Corporation had acquired, based solely on log data, four sections of oil sands leases adjacent to Surmont, an area that the SPG claims is uneconomic for SAGD development.

Gulf described the Upper McMurray as being tidally influenced, with features such as rhythmic lamination, planar lamination, ripple bedding (all of which was later referred to as HS), and an abundance of very small bioturbated structures. The tidally influenced sediments occur as sands, silts, and shales. Gulf interpreted these lithologies to have been deposited in a tidal flat environment, which includes tidal channel and creek, mud tidal flat, sand tidal flat, and mixed tidal flat composed of silty sand and shale interbeds. Gulf interpreted the tidal channels and flats to be laterally continuous, extending several kilometres in length and several hundred metres in width. The Upper McMurray tidal flat environment is more laterally continuous and extensive than the underlying laterally discontinuous estuarine and fluvial channels. These Upper McMurray sands contain the associated gas and/or water pools. Gulf stated that the muddy portions of these Upper McMurray facies are highly bioturbated, resulting in increased porosity and permeability and thus allowing for hydrodynamic communication of fluids. Gulf submitted that the literature indicates that the degree of bioturbation varies from moderate to extensive in the shales and muds of the tidal flats and HS facies. Gulf further stated that this would allow fluid movement and pressure communication from one gas pool or water zone to another.

Gulf hypothesized that the coincidence of the gas- and water-bearing sands with relatively thick underlying McMurray channel sands is likely the result of differential compaction in the shale-rich McMurray section. The gas accumulation resulted from biodegradation of the bitumen. The competence of the sand relative to the compressibility of the shale could lead to structural entrapment of gas in Upper McMurray tidal flat and tidal channel sands directly overlying bitumen-rich stacked channel sands of the Middle and Lower McMurray.

5.2.1.2 Views of Petro-Canada

Petro-Canada used its Chard A Bitumen Prospect, which is located adjacent to Gulf's Surmont leases, as an example of how pressure depletion of gas caps in association with oil sands zones would adversely affect SAGD bitumen recovery. Petro-Canada submitted that its Chard A Bitumen Prospect is an area impacted by gas production within the Gulf application area and is an area for which it has considerable data. Petro-Canada further submitted that, given its proximity to the Gulf Surmont leases, the Chard A Bitumen Prospect provides valuable analogous information concerning the processes and impacts associated with pressure depletion both at Chard and at Surmont.

Petro-Canada submitted that subsequent to the deposition of the Lower McMurray in the lowest spots on the Devonian, the deposition of the Middle McMurray occurred in a dynamic interruptible fluvial estuary system with superimposed events. Trough cross-bedded to massive sandstones were deposited in the high-energy bedload-dominated channels. The sands that contain associated lags or breccias are remnants of the erosive nature of the channel margins. IHS and mudstones offlap and overlie the massive sandstones. Petro-Canada stated that IHS is indicative of an alternating energy system. Sands were deposited during flood stage or high-river discharge, muds settled during quiet or falling water periods, and abandoned channel fills (commonly mudstones) occurred at the end of channel evolution. Younger channels would cut across an earlier deposited system. The younger channel could represent a new generation of fill after an erosive event had cut down into an older deposit or it could be a separate, more contemporary channel meandering back over the area occupied by the first channel. Petro-Canada noted a number of areas where these cut-and-fill processes of the fluvial estuarine system occurred within the Middle McMurray at Surmont.

Petro-Canada suggested that two fundamental processes likely were at work during deposition of the Middle McMurray to account for the multistoried, high net-sand content of the bitumen pay and the creation of chimneys. Petro-Canada defined chimneys as the direct sand-on-sand contact of the bitumen interval with the overlying top water and/or top gas thief zones. The vertical stacking of the cross-bedded to massive sandstone of the younger channel on top of the older channel, where the IHS/HS beds are not preserved, could result in the formation of a chimney. Petro-Canada also noted that the deposition of a chimney could occur by vertical growth, called "aggradation," in a high-energy bedload-dominated system with straight or low sinuosity channels. Channel energy remained high to the top of the interval or thief zone. These deposits are dominated by massive to cross-bedded sandstones, sand-dominated breccia, or sand-rich IHS.

Petro-Canada acknowledged that it did not have an example of a cored chimney well at Chard but that the AA/11-30-80-6W4 well was the closest example it had to a cored chimney well. Petro-Canada indicated that it had relied on the regional database to improve its understanding where there was limited core control. It used areas with high well density (i.e., MacKay River, Gregoire Lake), outcrops, and the Syncrude Mine site to better understand the lithological and depositional relationships to define chimneys in the Chard area. It noted that it was general industry practice to use cored wells to calibrate noncored wells.

Petro-Canada used the terms "bitumen pay" and "bitumen zone" in its mapping, as illustrated in its type well shown in Figure 6. It defined bitumen pay intervals as massive cross-bedded sandstones with porosities greater than 27 per cent, true resistivity greater than 40 ohm-metres, and mud interbeds less than or equal to 2 m thick. These intervals have high vertical permeability that does not impede steam flow and consist of massive sandstones, breccias, thinly interbedded bioturbated mudstones, and thicker mudstones with limited correlation lengths and sand-dominated IHS. Petro-Canada defined bitumen zones as sandstone intervals with less than 27 per cent porosity, a gamma ray response less than shale, and resistivity values usually greater than 15 ohm-metres. The bitumen zone has lower vertical permeability than bitumen pay. Petro-Canada contended that the interbedded nature of the bitumen zone would slow steam chamber growth relative to the bitumen pay but would not stop it. The combined analytical parameters, along with the regional understanding of the geology of the Middle McMurray, resulted in the reservoir characterization into these two mappable units.

Using the above methodology, Petro-Canada identified bitumen pay in the central portion of its Chard prospect, where highly permeable chimneys consisting of amalgamated stacked channels are found (e.g., 00/09-24-080-07W4 well) and where the IHS is correspondingly thin or absent. In the eastern portion of its Chard prospect, Petro-Canada interpreted the bitumen zone to be present between the bitumen pay and the top water and top gas zones. On the basis of its mapping, Petro-Canada noted the association of the gas pools and water zones with the thickest bitumen deposits. This observation led it to believe that the presence of a chimney with high vertical permeability would render the area vulnerable to pressure effects due to gas production.

Petro-Canada noted that the geographic location of chimneys is better defined as well control increases. It presented a cross-section through its MacKay River lease and a photo of the southwest corner of the Syncrude North Mine to illustrate the presence of chimneys. It noted that the rich bitumen sands offset and overlie IHS beds and that the mud beds are discontinuous. It emphasized that mud-dominated IHS is discontinuous and could not be relied upon to stop steam chamber growth. Using the Syncrude mine and the Horse River outcrop photos, Petro-Canada contended that IHS is not always present between the Upper McMurray top water and the bitumen pay of the Middle McMurray. Petro-Canada submitted that these examples demonstrate that direct communication through chimneys would occur.

With respect to the SPG's argument that IHS represents an effective seal segregating the bitumen resources from the effects of the depletion of the overlying gas pools, Petro-Canada submitted that IHS beds are typically 1 to 15 cm thick and are usually interbedded with laterally discontinuous sands and silts. Petro-Canada contended that, therefore, the heterogeneities within the IHS are baffles and not barriers to flow. It stressed that although IHS beds could be mapped as distinct lithofacies units, mapping does not capture the internal heterogeneities of IHS beds. If the mechanics of the formation of IHS were examined, it would show that there were many variables during deposition, resulting in the existence of different scales of continuity that could create many pathways for communication. In support of this theory, Petro-Canada presented literature references illustrating that IHS beds were produced by unsteady, nonuniform flows that never repeated from day to day or from flow event to flow event.

Petro-Canada further submitted that the bioturbation and the presence of microfaults (observed at the Syncrude mine and other McMurray outcrops) result in communication pathways. Petro-Canada presented a photo of Willapa Bay along the coast of Washington State that illustrated that surface discontinuities were formed as a result of internal drainage. When preserved in the subsurface, these discontinuities create opportunities for sand-on-sand contact by cutting across thin shale beds present within the IHS beds. Petro-Canada presented the shale-dominated Bay of Fundy to illustrate that bioturbation could result in vertical communication pathways. It noted that the top of the Middle McMurray contains similar densities and bioturbation types to those observed at the Bay of Fundy. Petro-Canada presented outcrop examples of the McMurray from the Steepbank and Christina Rivers as examples of the subsequent erosion of pre-existing IHS deposits by younger channel events resulting in sand-on-sand contacts. It further presented photos from the Syncrude mine field trip showing sand-on-sand contacts. Petro-Canada also noted that the shales extended laterally a few metres to over a 100 m but none extended as thick, continuous, impermeable top seals on the scale of a SAGD horizontal well.

To illustrate the relationship between the Upper and Middle McMurray, Petro-Canada presented photos of the Steepbank and the Horse River outcrops. The Steepbank River outcrop showed that the bioturbated tidal flat sediments of the Upper McMurray truncated the IHS of the Middle McMurray. Petro-Canada submitted that fluids would migrate along the inclined bitumen saturated sands within the IHS directly into the Upper McMurray. The Horse River outcrop showed that wet Upper McMurray sediments are in direct contact with bitumen-saturated sand and mud-dominated IHS beds of the Middle McMurray. Petro-Canada further submitted that these examples demonstrate that direct communication through the IHS would occur between the Middle McMurray and the overlying Upper McMurray.

Petro-Canada interpreted the Upper McMurray to comprise bioturbated silty sandstones deposited in a tidal flat setting and sandstones deposited in tidal channels. It noted that the Upper McMurray was more bioturbated than the Middle McMurray, creating pathways for horizontal and vertical communication.

5.2.1.3 Views of the SPG

The SPG consistently maintained that the pervasive IHS layer at Surmont is a barrier that separates the upper McMurray gas sands from the middle McMurray bitumen sands. From its examinations of available cores from Surmont and Chard, the SPG separated cross-bedded sandstone and breccia beds from IHS/HS packages if the thickness of the cross-bedded and breccia intervals exceeded 5 m. Otherwise, the cross-bedded sandstone and breccia beds less than 5 m were included as part of the IHS/HS package. Using these facies distinctions, the SPG noted that there is an average of 24.3 m of IHS/HS at Surmont/Chard. On the basis of its core work, the SPG concluded that interbedded sands and muds (i.e., IHS/HS) are present between the bitumen reservoirs and the overlying gas and water zones throughout the entire Surmont area. The SPG claimed that neither Gulf nor Petro-Canada addressed the degree and significance of impact that IHS and interbedded sands and muds would have on steam rise and SAGD.

The SPG concurred with Gulf and Petro-Canada that the McMurray Formation at Surmont/Chard was deposited within a fluvial estuarine system. Specifically, the SPG interpreted the McMurray Formation as being deposited within tidally influenced meandering channels located within an estuarine setting. The SPG pointed to the presence of dipping beds of sand and mud as being key to the interpretation of this depositional environment.

The SPG submitted that it relied on analogs from modern environments to develop a facies model for the origins of IHS and to further understand the facies associations within the McMurray Formation. According to the SPG facies model, IHS is common in meandering fluvial-estuarine channel deposits, particularly within upper estuarine settings. IHS is also common in meandering tidal creeks located in mixed tidal flats, and the orientation of these IHS beds differs from those created within major meandering estuarine channels. The SPG further submitted that tidal creek IHS commonly caps the main estuarine channel IHS at Surmont.

The SPG stated that Surmont was probably in the transition point between the upper estuarine complex and middle estuarine area. Although the SPG recognized that the Surmont pilot site is very sandy, it noted that in areas to the east and to the south of the pilot area there are many reservoir heterogeneities in the form of dipping mud beds. The SPG stated that this suggested a trend towards a more landward setting. Contrary to Gulf's assertions, the SPG characterized the upper estuary by an abundance of mud deposits found within an estuarine channel and associated muddy tidal flat settings.

The dominant consistent pattern within the McMurray Formation occurs within the middle McMurray, where lithofacies are stacked and create thick (30-45 m), fining-upward successions. The lower zone is a more homogenous, trough cross-bedded, highly porous, permeable and bitumen-saturated, fine to granular sandstone with common intervals of mudstone intraclast breccia and rare in situ mudstone interbeds. Overlying this are the IHS packages of interbedded sand and mudstone, commonly with dips from 5 to 12°, which the SPG suggested may extend laterally over distances of at least 2 km. On the basis of outcrop observations, the SPG noted that the thickness of the dipping interbedded sandstone and mudrock lithologies are commonly 10 to 25 m. The SPG also noted that these beds are volumetrically the dominant component of channelized McMurray successions at Surmont. The SPG further contended that the individual sandstone and mudstone beds might be 150 m long. However, based on published Dover cross-sections, it stressed that the IHS package of interbedded sandstone and mudstone is a much more areally extensive unit, extending for a minimum of 500 m. The SPG submitted that while the length and continuity of any individual sand or mudstone bed is difficult to determine, it is clear that the package of interbedded sands and muds can be found in every cored well at Surmont.

The SPG maintained that these muddy interbeds above the thick channel sands in the fining-upward successions are barriers to the flow of fluids. The SPG further noted that the number and thickness of these barriers generally increase upward within any channellized McMurray succession, with the result that this body of dipping interbedded layers forms a regionally extensive package of rock. According to the SPG interpretation, internally within this package dipping mudstones create flow barriers both laterally and vertically. The SPG maintained that these dipping mudstone interbeds would ultimately act as confining layers, limiting the vertical and lateral migration of the steam chamber. These mud beds would not only significantly inhibit the potential for steam rise but, more important, the potential for bitumen to drain down would ultimately be curtailed.

The SPG concurred that it was possible to interpret the occurrence of the superposition of a younger channellized tract over pre-existing deposits from the lithological character observed in cores. The SPG acknowledged that in its work it did not attempt to actually go through every individual core at Surmont and try to break out the different possible channellized successions that may or may not be seen in any given well.

The SPG characterized the upper McMurray as poorly sorted, muddy, highly bioturbated interbedded sands and muds, which it interpreted as having been formed within mixed tidal flats that border tidally influenced estuarine channels. The SPG described the upper McMurray as a complex and variable mixture of sand lenses, mud, and silt. It interpreted the sand bodies, which form both the gas and water reservoirs, to be locally developed and bounded by muds and silts. It noted that the centres of the gas pools are predominantly distributary facies of a channel type with upward-fining successions. The SPG interpreted the variable pool patterns present in some Surmont pools as being a combination of several channel sequences.

Overall, the SPG noted that the middle and upper McMurray are situated in a very marginal marine environment with some marine influences, including facies indicative of tidal flat, distributary channel, transgressive sands, shorelines, and lower shoreface settings. The SPG noted that locally the McMurray marine sands, which are up to 5 m thick, cap the channel sand sequence. The SPG further noted that these marine sands are most commonly underlain by shale. It pointed out that in the Surmont gas pools the areal extent of the marine sand component is usually greater than the channel sand component; consequently, the peripheral portions of the gas pool(s) usually consist of the marine sand overlying an appreciable shale and silt section. The shale section between the top of the channel sand and the base of the marine sand generally thickens toward the periphery of the gas pool. Consequently, away from the core of the gas pool, the basal portion of the channel sand (usually water bearing) is often separated from the overlying marine sand (usually gas bearing) by an appreciable shale thickness. The SPG also noted that in the upper McMurray, the marine sand and channel sand zones are correlative; however, it was not possible to correlate individual interbeds of shale.

5.2.1.4 Views of the Board

The Board has reviewed the models, interpretations, and supporting evidence presented by the participants relating to the geology. The Board believes that the integration of all available geological information (outcrop, core, logs, modern-day analogs, and other subsurface examples in areas of more closely spaced drilling) is required to postulate a depositional model for the Surmont area. The Board accepts that the evidence provided by Petro-Canada from its Chard leases is analogous to Gulf's Surmont leases based on its proximity and the similar geologic character of the McMurray Formation. The Board notes that the geological models proposed by all participants consisted of a similar geological setting, that being a fluvial estuarine environment. The significant difference between the Gulf and Petro-Canada models and that of the SPG is in the interpretation of the degree and significance of the impact that IHS/HS (interbedded sands and mudstones) would have in isolating and protecting bitumen reservoirs from the overlying potential water and gas thief zones.

To assess the SPG's argument that an average of 24.3 m of IHS/HS is present in every cored well at Surmont, the Board has reviewed the cutoff arguments and examined the submitted core photos. The Board believes that the distribution of cross-bedded interval and HS strata is cutoff dependent and that using a different thickness cutoff would result in different facies distribution. The Board notes that the methodology used by the SPG would, with the identification of a single mud layer of any thickness, render large sand intervals to its HS classification. In the Board's view, this method overemphasizes the presence of mudstone. As a result, the Board does not believe that the characterization of an average of 24.3 m of IHS/HS is representative; it believes that the actual number is lower.

With respect to the SPG's contention that thick, laterally extensive packages of HS are present between the bitumen reservoirs and the overlying gas and water zones throughout the entire Surmont area, the Board has reviewed the submitted core and log data. The Board notes that although HS intervals are recognized in the core, they are not consistently present at the top of the bitumen-bearing interval. For example, the Board found that the cores at 02/12-24-83-7W4 and 00/8-3-83-6W4 demonstrate the existence of thick intervals of clean bitumen sand in communication with the overlying water and gas sands. The Board also recognizes the necessity to rely on log data in the absence of core. Some examples of logs that the Board believes show continuous bitumen sands in communication with overlying gas and water zones are located at 00/09-24-80-7W4, 00/15-2-81-6W4, and 00/15-36-83-6W4.

Cross-sections from the densely drilled MacKay River and Gregoire Lake areas and McMurray outcrop examples, supported by modern-day analogs, suggest that rapid lithological changes occur over very limited geographic distances in depositional environments such as the Middle McMurray. Additionally, within the closely spaced wells in the Surmont pilot area, the sands and muds could not be correlated. As a result, the Board believes that the chimney hypothesis advanced by Petro-Canada and the position advanced by both Gulf and Petro-Canada that the mud beds are not laterally extensive over a distance of a SAGD well pair have considerable merit.

In its assessment of the evidence, the Board notes that channel sediments and HS intervals can be observed repeatedly throughout the Middle McMurray successions within a single core or outcrop exposure. This repetition results from the stacking of channels. The inability to correlate these channel sands and HS intervals between closely spaced wells suggests that the younger channels are incising and removing the sediments (channel sand or HS) of a pre-existing channel. This is confirmed by outcrop exposures that show the erosional contacts and replacement by a new channel. The Board believes that this process creates sand-on-sand contacts and does not preserve laterally extensive HS units.

On the basis of its review of the well logs and core at Surmont, the Board has determined that the occurrence of thick bitumen-saturated sands in direct communication with overlying gas and water zones is extensive and randomly distributed.

On the basis of the above, the Board concludes that

- the Middle McMurray was deposited in a fluvial estuarine environment, resulting in heterogeneous sediment distribution;
- the Middle McMurray consists of clean cross-bedded sands (including breccias) and HS units;
- the average HS thickness is less than that characterized by the SPG;
- HS, although present, is not consistently at the top of the bitumen sands at Surmont; and

- core and logs demonstrate that thick bitumen sands can be in contact with the overlying gas and water zones.

5.2.2 Use of Dover as an Analog for Surmont

5.2.2.1 Views of Gulf

Gulf submitted that it does not view the geology at the Dover Phase B pilot as being analogous to Surmont for the following reasons:

- **differences in depositional environment and the resulting lateral continuity;**
- **presence of Unit B at Dover and its absence at Surmont;**
- **presence of laterally continuous Facies 5/IHS at Dover and its absence at Surmont;**
- **lack of a thief zone at Dover; and**
- **lack of chimneys at Dover.**

Gulf stated that log and core data showed that the McMurray Formation at Dover is 30 m thick and consists of a simple solitary fining-upward sequence of limited areal extent. Gulf further stated that the McMurray at Dover was deposited in a more tidally influenced portion of the estuary system present during McMurray time and that each of the facies present is easily identified on logs and core and is laterally correlatable across Dover. The lowermost unit is a cross-bedded sand within which there are some IHS/HS facies, such as breccia. An inclined interbedded sand mud unit (Facies 5) overlies this unit, Unit B overlies the whole sequence, and the Wabiskaw gas sand overlies Unit B.

Gulf described Facies 5 as an IHS interval having a thickness of 5 m to the west, grading laterally to greater than 15 m to the east. It occurs either below a combination of abandoned channel muds and Unit B or directly below Unit B. The muds of Facies 5 vary from nonbioturbated to moderately bioturbated.

Gulf described Unit B as a flat-lying, wavy to lenticular unit that is typically mud dominated, representing deposition in the upper offshore environment. Unlike the inclined nature of interbedded sands and muds of the estuarine point bar deposits, these types of marine depositional facies are commonly flat lying and widespread. Unit B muds are distinctly greater barriers than anything in the McMurray. Sand beds present in Unit B are very lenticular and commonly do not extend across the width of the core. Horizontal sand-filled burrows characterize trace fossils of Unit B. Gulf contended that these horizontal burrows would have little or no impact on vertical permeability. Dover core photographs of Unit B show a significantly lower degree of burrowing than the underlying Facies 5. Gulf further noted that the physical structures and lateral extent of this marine facies provide significant vertical permeability limits and, as such, it is an effective barrier. Unit B at the Dover site is a barrier between the underlying McMurray bitumen zone and

the overlying Wabiskaw gas sand. It is a marine deposit that is laterally continuous and correlatable across the pilot. There is no equivalent correlatable unit found within the Surmont area.

Gulf noted that Facies 5/IHS is also a laterally correlatable unit present in every well at Dover. It contended that this unit was deposited on a single point bar and has been preserved. It further noted that point bar deposits such as this may have been deposited at Surmont but not preserved in their entirety due to the complex depositional environment at Surmont. The lateral migration and incision of channels would have removed the point bar deposits, replacing them with channel deposits. Where any point bar facies was preserved, only a portion would likely be present at Surmont.

Gulf contended that there is no thief zone at Dover. The Unit B mudstone is laterally continuous and is a competent barrier, sealing the Wabiskaw gas sand from the underlying McMurray. Therefore, the Wabiskaw gas sand at Dover is not a potential thief zone. Gulf did not accept the SPG's horizontal permeability data obtained from core analysis of Unit B or its implication that these permeabilities are comparable to Gulf's criteria for thief zones. Gulf questioned the reliability of the SPG's measurements, since the samples were taken as small plugs from old core that was not properly stored, resulting in microfractures. Gulf contended that the horizontal permeability measurements of 100 mD are not representative of the petrophysical properties of Unit B. Gulf stated that Dover confidential data to date showed that the steam chamber has not hydraulically communicated with the Wabiskaw water disposal sand and was unlikely to do so.

Finally, Gulf stated that chimneys are present all across Surmont, they could be identified with logs, and they would act as breakthrough columns. It stated that chimneys are not present at Dover due to the presence of Facies 5/IHS and the presence of Unit B over the Phase B pilot.

5.2.2.2 Views of Petro-Canada

Petro-Canada interpreted the Dover Phase B pilot to be located on the flank of a channel system where there is an abundance of IHS and, consequently, chimneys are not present. The bitumen resource is within amalgamated stacked channels, which are porous and permeable, with minor amounts of mud-clast breccia and sand-dominated IHS. Overlying the bitumen resource is Facies 5/IHS, characterized by bioturbated interbedded sands and mudstones. Sediments overlying Facies 5 are predominantly tidal flat deposits (Facies 3 and 4). A thin overlying transgressive sand deposit (Facies 2) could overlie Facies 3, 4, and 5. Facies 2 occurs at the base of the overlying Wabiskaw Member of the Clearwater Formation. A sandy marine mudstone equivalent to the Wabiskaw B (Unit B) occurs above these facies and isolates what the SPG described as a potential Wabiskaw C thief zone from the underlying McMurray bitumen. The Wabiskaw B is laterally continuous across the Dover Phase B pilot and ranges from 5 to 10 m thick.

Petro-Canada interpreted the bitumen pay interval at both Dover and Surmont/Chard to be developed in fluvial estuarine deposits of the Middle McMurray. The thick pay intervals occur in amalgamated stacked channel sequences at both locations and contain the common representative facies of massive sandstones, mud-clast breccias, thinly interbedded bioturbated mudstones, thicker mudstones with limited correlation lengths, and sand-dominated IHS. The best examples of this are the 02/12-24-83-7W4 well at Surmont and the BT4 well at Dover. Petro-Canada further submitted that the breccias, mudstones, and IHS within the bitumen pay at Dover do not slow steam rise or steam movement, and as a result similar geologic facies present within chimneys at Surmont/Chard would not limit or prevent steam flow. Examples of such facies occur in the Dover BT4 and BT6 wells, the Surmont 02/12-24-83-7W4 and 05/12-24-83-7W4 wells, the Chard 00/9-24-80-7W4 well, and the MacKay River AA/6-4-93-12W4 well.

Petro-Canada submitted that it considers Facies 5 at Dover to be equivalent to its bitumen zone at Surmont/Chard. It noted that at Dover steam had risen 8 m into Facies 5 and as a result it expected the bitumen zones at Surmont/Chard to act as baffles, not barriers. Petro-Canada also noted that a similar zone to Facies 5 exists at Surmont but is not always present. The bitumen zone at both locations is more interbedded and by its geologic characteristics would slow steam chamber growth relative to the bitumen pay section. Where the zone is thin to absent at Surmont, a chimney exists with bitumen pay directly underlying the Upper McMurray top water and gas.

Petro-Canada noted that there is no McMurray thief zone at Dover. There is a continuous shale (Unit B) separating the underlying McMurray bitumen from the gas and water present in the Wabiskaw C sand, which acts as an effective barrier. Petro-Canada had similar arguments to Gulf's respecting the reliability of the SPG's permeability measurements from core analysis of Unit B. In comparison, Petro-Canada contended that at Surmont/Chard thief zones exist where the bitumen pay zone is in direct communication with the overlying top water and gas zones. This communication is due to the presence of chimneys. Chimneys occur where amalgamated stacked channels with high vertical permeability are preserved to the top of the Middle McMurray. Chimneys do not exist at Dover because of its location on the flank of a channel system.

Petro-Canada further noted that Phase B at Dover is areally small, covering 13.5 hectares (ha), and therefore does not demonstrate the susceptibility of a 250 to 750 ha SAGD commercial operation to the impact of chimneys. It maintained that the limited area and depositional setting minimize the probability of encountering a chimney at Dover.

5.2.2.3 Views of the SPG

The SPG maintained that the lithologies, vertical succession of rock types, reservoir architecture, and depositional processes are similar at Dover and Surmont. Specifically, the same materials of sand and mud, in an interbedded fashion, reside above the bitumen hosts in both areas. The SPG stated that interbedded mudstones and sandstones would confine the steam chamber at Surmont analogously to those interbedded mudstones and sandstones that confine the steam chamber at Dover. It stated that both Dover and Surmont have water-bearing zones above bitumen-bearing beds.

The SPG noted that the basic vertical succession at Dover consists of fluvial estuarine channel deposits within the main bitumen host at the bottom and interbeds above that, capped by tidal flat deposits, with a total McMurray thickness of 25 to 35 m. Of that, the IHS zone is 10 m thick on average. The mud interbeds are found within and above the main bitumen zone in every core. The SPG observed extensive burrowing in many of the mud beds and stated that the vast majority of the mud beds are less than 0.1 m in thickness. Despite the bioturbation intensity and the relatively thin nature of the mud beds, the SPG contended that steam has not passed through any mud bed over 15 cm in thickness. It noted that zones rich in mudstone clasts also block steam rise in some wells for many years (e.g., BTP04 well). The SPG also noted that a vertical permeability of 100 mD for the IHS, with movement of the impermeable barrier down into the interbedded Facies 5/IHS zone, is required to history match the Dover pilot performance. The SPG submitted that Unit B is not a shale, nor is it impermeable. It displays attributes ascribed by Gulf to potential thief zones with its measured permeability values of over 100 mD, average porosity over 28 per cent, and water saturations exceeding 60 per cent.

The SPG contended that as mud beds thinner than 15 cm and breccia beds block steam rise at Dover, the use of log-based assessments of vertically continuous pay at those sites and at the Surmont pilot must be considered inaccurate. It maintained that Gulf's numerical reservoir model should be adjusted to reflect the reality of reservoir architecture at Surmont and reservoir heterogeneity performance at Dover. The definition of bitumen pay proposed by Petro-Canada, which forms the basis for the presence of chimneys, does not properly define the actual pay at Dover and is not reasonable for commercial SAGD projects. Therefore, the SPG concluded that the speculative concept of the chimney had not yet been proven to exist with real SAGD field data.

The SPG acknowledged that the McMurray bitumen reservoirs at Surmont generally have more reservoir heterogeneities than the same deposits at Dover. It observed that the average thickness of IHS at Dover is 10 m, compared with an average IHS thickness based on cores in the Surmont pilot of 24.3 m. The SPG acknowledged that Dover is a single channel, which is different from Surmont. However, it described the McMurray at Surmont as consisting of a number of Dover-type units stacked on top of each other. It noted that each of those stacked channels at Surmont contains numerous interbeds of sands and muds within and at the tops of the bitumen columns. The blocks of clean sand at Surmont do not occur in the same stratigraphic location.

The SPG stated that the number and thickness of the mudstone interbeds are far greater and that the McMurray is 2.5 to 3 times thicker at Surmont than at Dover. It further noted that for potential zones at Surmont to be impacted by steam chambers, steam must travel through a vertical package of muddier sediments far thicker than the entire Dover McMurray section.

5.2.2.4 Views of the Board

To determine whether the geology at Dover is an appropriate analog for the Surmont area, the Board must assess

- whether Unit B has similar properties to potential thief zones of the Upper McMurray at Surmont;
- the potential for Unit B to isolate the bitumen resource from the overlying Wabiskaw gas sand;

- **whether direct communication of clean bitumen sands with an overlying thief zone exists at Dover; and**

- **whether it is appropriate to use information from the limited geographic area at Dover (i.e., 13.5 ha) and apply these observations to the entire Surmont area.**

The Board notes that the SPG did not dispute Gulf's position that proper storage of old core is required to obtain reliable measurements of porosity and permeability within water-saturated fine-grained sediment. The Board accepts that if core of this nature is not properly stored, exposure to atmosphere will allow evaporation to occur, resulting in desiccation. The Board believes that this will enhance porosity and permeability. As a result, the Board does not believe that the core measurements presented by the SPG regarding Unit B are reliable, and therefore it is not possible to assess from these core-permeability data whether Unit B has similar properties to potential thief zones of the Upper McMurray at Surmont.

To assess whether Unit B has similar properties to potential thief zones of the Upper McMurray at Surmont, the Board relied upon the submitted core photographs and log information of Unit B. The Board found mudstone to be present in all the core photographs of Unit B. Additionally, the Board notes the following log responses over the Unit B interval: a gamma ray in excess of 75 American Petroleum Institute (API) units; a neutron-density porosity separation of 15 or more porosity units; a shaly spontaneous potential response; and true resistivities less than 10 ohm-metres. These observations indicate to the Board that Unit B at Dover is mudstone and is an effective barrier that isolates the bitumen resource.

As stated in Section 5.2.1.4, the Board believes that bitumen can be in direct communication with overlying gas and water zones at Surmont. This association is lacking at Dover, due to the presence of Unit B, an impermeable barrier extending across the Phase B pilot area.

Additionally, as stated in Section 5.2.1.4, the Board believes that there is heterogeneous sediment distribution in the Middle McMurray at Surmont. The evidence shows that completely preserved channel deposits such as at Dover are not present at Surmont due to the incision of subsequent channelling. As a result, the Board believes that the application of observations from a limited geographic area such as Dover to the highly heterogeneous, much larger geographic Surmont area is inappropriate.

On the basis of the above, the Board concludes that the geology at Dover is not an appropriate analog for the Surmont area.

5.3 Vertical Continuity

5.3.1 Steam Rise at Surmont Pilot and Dover Phase B Pilot

The Surmont pilot involves two SAGD well pairs and five temperature observation wells, with two of the observation wells located along one SAGD well pair and the other three located along the second SAGD well pair. The Dover Phase B pilot involves three SAGD well pairs and 29 temperature observation wells located along, between, and around the SAGD well pairs.

5.3.1.1 Views of Gulf

Gulf submitted that in the absence of noncondensable gas the definition of a steam chamber is clear. In terms of saturations, the steam chamber is the portion of the reservoir containing a gas phase, which can only be saturated steam. In terms of temperature, it is the portion of the reservoir at saturated steam temperature, which is uniquely determined by the pressure in the steam zone. In this situation, the steam chamber can readily be determined by temperature measurements in observation wells.

When noncondensable gas is present, the definition of a steam chamber is not as clear. In terms of saturations, the steam chamber is the portion of the reservoir containing a gas phase that includes significant steam vapour but may also contain noncondensable gas. In terms of temperature, the steam chamber includes the portion of the reservoir at saturated steam temperature where only steam is present, as well as a portion of the reservoir at lower temperatures because of partial pressure effects where there is noncondensable gas present in addition to steam. The boundary of the steam chamber is not precise because the steam saturation gradually falls to a low value toward the boundary and the temperature is no longer uniquely related to the pressure. In this situation, it can be difficult to determine the extent of a steam chamber based on temperature measurements in observation wells. The apparent top of a steam chamber, based on the highest elevation of the saturated steam temperature in an observation well, gives only the extent of the steam chamber containing close to 100 per cent steam saturation.

Surmont Pilot

Gulf stated that at the Surmont pilot only one of the five observation wells had shown the development of a steam chamber. The observations at these five wells are summarized as follows:

- **At one observation well, the steam chamber rose about 18 m above the production well in a year, which included rising through a 2 m IHS layer. The apparent steam chamber subsequently fell to about 9 m above the production well, which Gulf attributed to the buildup of noncondensable gas at the top of the steam chamber. Gulf stated that the noncondensable gas was likely solution gas, but some of it could be gas that was inadvertently injected during well operations.**

- **Gulf attributed the lack of evidence of steam chambers at two of the observation wells to the lateral separation of the observation wells from the SAGD wells (9 to 14 m) and to the lowest thermocouple in one of the observation wells being 35 m above the injection well.**

- **A fourth observation well showed an early temperature response, but the temperature soon fell to about 100°C, which indicated that water had entered the well through a casing leak and was refluxing. A subsequent "rough" temperature log indicated an** apparent steam chamber (possibly containing noncondensable gas) between the horizontal injector and producer.

- The lack of development of a steam chamber at the fifth observation well, which had a surveyed location close to one of the SAGD well pairs, was attributed by Gulf to several possible factors, the most likely being that the bottomhole survey location was incorrect. Gulf submitted that if the survey location is correct, conduction heating alone would have resulted in a higher temperature than that measured at the observation well.

Gulf stated that it is considered normal that some parts of a SAGD well pair will take a long time to develop a steam chamber. Gulf submitted that Surmont is still a young pilot with an effective operating time of just 1.6 years, if allowance is made for reduced performance due to facilities work. On the basis of the temperature data from the observation wells, Gulf concluded that there had been no indication that the steam chambers had communicated with the overlying thief zone.

Gulf also provided material balance calculations from which it estimated the average height of the steam chamber, assuming the steam chamber was rectangular. The average height ranged from 13.7 m (assuming that three-quarters of the well pairs were active and the aspect ratio[6] was 2.0) to 24 m (assuming that one-half of the well pairs were active and the aspect ratio was 1.0). Gulf submitted that the substantial bitumen produced at the Surmont pilot (24 625 m^3 from one well pair and 23 519 m^3 from the other well pair) demonstrated that even though the horizontal wells were drilled into HS, according to the SPG's interpretation, the HS was not a barrier to steam rise or bitumen production.

Gulf provided four-dimensional seismic evidence from the Surmont pilot to indicate that steam was rising through the McMurray and spreading along the well pairs in a fashion that supported its geologic model and reported production rates from both well pairs. It stated that the observed gas seismic response indicated that development of steam was occurring both vertically and longitudinally along the well pairs. In response to the SPG assertion respecting the effects of precipitation on seismic response during acquisition from year to year, Gulf did not believe that the effects would be significant since the geophones were buried 9 m below the surface.

Dover Phase B Pilot

Gulf argued that steam had gone through or around muds, breccia, and IHS present in the cross-bedded sands at Dover and that the steam had risen at a rate of 18 to 28 m per year in the cross-bedded sands. The apparent top of the steam chamber had risen into the IHS zone, located above the cross-bedded sands, between 1 and 8 m at the observation wells. The steam rise rate through the IHS zone was up to 2 m per year. Gulf stated that Dover is not geologically analogous to Surmont and therefore the steam rise rates from the IHS zone at Dover could not be imported to Surmont. It argued that if steam rise rates from Dover were to be applied to Surmont, they should be from the cross-bedded sands and not from the IHS zone.

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[6] Aspect ratio is the ratio of the average width of the steam chamber to the average height of the steam chamber.

Gulf provided two reasons why the apparent top of the steam chamber generally did not extend far into the IHS layer. Both reasons require that a flow barrier exist above the IHS layer such that a pressure difference between the lower steam chamber and the top of the formation cannot cause flow through the IHS. The first reason is that evolved solution gas builds up at the top of the steam chamber and the actual top of the chamber is higher than the apparent top due to partial pressure effects. This can play a role even at Dover, where the volume of solution gas is relatively small. Gulf submitted that there was noncondensable gas at Dover prior to the injection of gas, and therefore the apparent top of the steam chamber was lower than the actual top. Gulf argued that the apparent hesitation or stoppage of the steam chamber in clean oil sand was due to the presence of noncondensable gas and not millimetre-thick mud, as the SPG contended. The second reason that the apparent top of the steam chamber did not extend very far into the IHS layer is that a balance between heat loss to the overburden and heating upward from the steam chamber results in the apparent top of the steam chamber reaching approximate equilibrium some distance below the overburden in the low-permeability IHS zone.

Gulf stated that the Dover data indicated that it took more than a year (about 2.5 years if the early operations are included) for all observation wells close to the SAGD well pairs to show the presence of steam chambers. Gulf concluded that the Dover data supported its submission that the delayed development of a steam chamber at some of the Surmont observation wells was normal.

On the basis of the material balance calculations for the middle SAGD well pair, Gulf submitted that considerable bitumen recovery must have occurred from the IHS zone even though the apparent top of the steam chamber had only penetrated partway into the IHS zone. Gulf concluded that the apparent top of the steam zone does not define the top of the depleted area in the IHS zone, nor does it indicate that the IHS is an effective barrier. Gulf argued that even though the SPG's material balance calculation for Dover was suspect because it included a large area outside the SAGD pattern area, it also included bitumen drainage from the IHS zone.

Gulf submitted that the apparent low steam rise rate through IHS at Dover was consistent with the SPG's numerical model if the IHS had a no-flow boundary above it. Gulf adapted the SPG's simulation model of Surmont to the Dover situation by placing a no-flow boundary above the IHS instead of a thief zone. This resulted in a low steam rise rate through the IHS layer. Alternatively, the unmodified SPG simulations showed rapid steam rise through IHS when there was a thief zone above the IHS. Gulf also submitted that the modified SPG model predictions were consistent with the strong indication that at Dover considerable bitumen had been recovered from the IHS zone. Even though the apparent top of the steam chamber had risen only partway into the IHS zone, the model predicted that a depleted bitumen area extended into the IHS zone. Gulf stated that this meant that the actual top of the steam chamber in the IHS zone was higher than the apparent top.

Gulf disagreed with the SPG's contention that a flat bitumen production profile meant there would be no further rise of the steam chamber. Gulf stated that the contention was based on a simple analytical model. Also, the SPG's evidence for Dover showed that although the bitumen production rate levelled off in February 1994, the steam chamber rose between January 1994 and January 1995, and even to January 1997.

5.3.1.2 Views of Petro-Canada

Surmont Pilot

Petro-Canada did not provide any direct evidence regarding steam rise at the Surmont pilot.

Dover Phase B Pilot

Petro-Canada submitted that it used the 200°C temperature isotherm to describe steam chamber behaviour at Dover since it reasonably accommodates changes in steam quality, heat losses, and normal operations at Dover. Petro-Canada contended that the use of a specific temperature isotherm would not affect temperature rise calculations provided that it is close to the saturation temperature. Furthermore, it would not affect the determination of steam penetration, since the 200°C temperature isotherm is well above the bitumen mobilization temperature.

Petro-Canada argued that the inflection method used by the SPG for determining the height of the steam chamber was flawed for the following reasons:

- it only provides for the minimum height of the apparent steam chamber;
- it is incapable of recognizing the actual height of the steam chamber because it does not recognize noncondensable gas;
- it does not accommodate the physical reality of mobile bitumen beyond the steam chamber; and
- the use of thermocouple data to locate the steam chamber inevitably results in a potential underestimation of the location of the steam chamber.

Petro-Canada submitted that the Dover pilot data indicated that breccias, shales, and IHS within the bitumen pay did not appreciably slow steam rise. Peak steam rise rates through the bitumen pay were 15 to 20 m per year. Petro-Canada also submitted that the Dover pilot data indicated that IHS was a baffle to steam rise, not a barrier. Peak steam rise rates through the IHS were 1 to 3 m per year, with the highest penetration of steam into the IHS occurring at the toe (8 m) and heel (5 m) of the horizontal well pairs. Petro-Canada contended that had the IHS at these locations been thinner, it would not have prevented steam from breaking through to a potential thief zone. Therefore, extrapolating the short-term data available from Dover over the longer lifetime of a commercial SAGD project led to the conclusion that steam can penetrate the IHS to an overlying thief zone.

Petro-Canada submitted that although there had been an observed reduction in steam rise at Dover since 1997, it would be inappropriate to attribute that reduction solely to the influence of IHS. Factors such as the duration of the steam injection, the location of the steam injection, the pressure of the steam, the injection of noncondensable gas, and natural steam chamber behaviour all significantly impacted the steam rise rate. Petro-Canada asserted that had these other influences on steam rise not occurred, steam penetration into the IHS might have been greater. Petro-Canada further submitted that the steam chamber at Dover was mobile in three dimensions and was constantly changing, making steam confinement difficult. Even steam movement being temporarily delayed did not eliminate the concern over potential communication with a thief zone. Steam chamber growth and movement would continue in other dimensions, creating other opportunities for contact with a thief zone. Petro-Canada maintained that, therefore, the performance at Dover could not be universally applied to predict steam chamber performance in areas where chimneys were present.

Petro-Canada submitted that although the 200°C temperature isotherm provided a reasonable estimate of the steam chamber size at Dover, the 160-180°C temperature isotherms represented a much better material balance fit between observed production and volumetric calculations. Petro-Canada argued that this confirmed that the volume of the reservoir being affected by the steam chamber went far beyond the steam front and that extraction of bitumen from IHS was occurring, contrary to the concept of IHS as a barrier. Petro-Canada asserted that the SPG's volumetric estimate was flawed because it did not take into account bitumen production from the IHS. Furthermore, the SPG's extrapolations of lateral steam propagation rates were flawed since they were based on early data and did not take into account later slower rates.

Petro-Canada used a numerical model to compare the differences in steam rise rates in situations with and without a thief zone. Petro-Canada submitted that by replacing the thief zone present in its model 2 with a shale barrier, the reservoir simulation showed a steam rise rate through the bitumen zone in the order of 3 m per year. When a thief zone was present in the model at the equivalent stratigraphic position as the shale barrier, steam rise rates increased from 3 m per year at the base of the bitumen zone to 10 m per year as it approached the thief zone. Petro-Canada submitted that the steam rise rates observed in the shale barrier model were similar to the observed steam rise rates through the IHS at Dover. It stated that the acceleration of the steam rise rates in the thief zone model was consistent with what would be expected when a thief zone was present. Therefore, steam rise rates calculated for IHS at Dover could not be directly applied to situations where there was a pressure-depleted overlying thief zone.

Petro-Canada submitted that the impact of noncondensable gas injected at Dover had not yet been conclusively observed due to the large size of the steam chamber relative to the volume of gas injected to date, the relatively low noncondensable gas injection rate, and the large space between the thermocouples, which made it difficult to see small changes in temperature.

5.3.1.3 Views of the SPG

The SPG submitted that a steam chamber is identified by a zone of constant saturated steam temperature. There are no substantial pressure gradients within a steam chamber, so the saturation temperature is essentially constant. On temperature versus depth plots this is manifested as a straight up-and-down alignment of temperature readings from thermocouples in observation wells. A sloped temperature response above the zone of constant saturated steam temperature indicates that heat is being transferred by conduction above the steam chamber. The top of the steam chamber is where this sloped temperature response meets the straight up-and-down alignment of the thermocouples (i.e., a sharp inflection). To determine if a steam chamber is rising, sequential thermocouple temperature readings are required to see if there is upward movement of the sharp inflection. The SPG stated that noncondensable gas causes a gradational cooling at the top of the steam chamber. Therefore, the presence of noncondensable gas can be observed on temperature versus depth plots as a blur in the sharp inflection.

The SPG contended that a drawback to using constant temperature isotherms for identifying steam chamber rise is that it can give erroneous upward or downward indications of steam chamber movement. Typically, a temperature that is lower than the saturated steam temperature is used for isotherm analysis. Therefore, the isotherm does not identify the top of the steam chamber, but instead it identifies a location within the conductive heating zone ahead of the steam chamber. Furthermore, because the steam chamber pressure can change over time, isotherms will move up or down even though there has been no movement of the steam chamber top.

The SPG submitted that when a steam chamber is rising and when it has reached the reservoir top could be determined from the production profile. On the basis of theoretical analysis, SAGD productivity is a function of steam chamber height. Therefore, a typical SAGD production profile displays a rapid initial productivity increase as the steam chamber rises, a constant production rate when the reservoir top is reached, and a declining production rate when steam chambers coalesce.

Surmont Pilot

The SPG submitted that the Surmont pilot data, like the Dover pilot data, showed that mud beds stop the rise of steam and that the rise of steam at the Surmont pilot had stopped. The SPG argued that two sets of pilot data were demonstrative in confirming that steam had stopped rising at the Surmont pilot.

First, there was a lack of observable steam chamber development. It submitted that only one observation well had shown traceable steam chamber development and that steam rose fairly rapidly at this well and then stopped at the first mud package evidenced in the core. The SPG refuted Gulf's suggestion that the steam rise stopped due to the injection of noncondensable gas, since the steam stopped rising well before the inadvertent injection of gas in December 1998. One observation well showed early indications of steam chamber development prior to a leak in the casing, but a subsequent temperature log demonstrated that the steam chamber never developed in any significant way. Similarly, there was no indication of steam chamber development at two of the observation wells. The SPG asserted that the most obvious and reasonable explanation for the lack of steam chamber development at the Surmont pilot was the extensive interbedding above and between the injection and production wells.

Second, the production profile from the Surmont pilot showed that the production rate initially increased rapidly and then levelled off. The SPG contended that this indicated that the steam chamber had stopped rising vertically. If the steam chamber had continued to rise, so would have the production rate. The SPG argued that continued production at relatively stable rates was occurring due to lateral, not vertical, steam chamber growth.

With respect to Gulf's 4-D seismic evidence, the SPG did not acknowledge that there had been a change in the seismic response at the Surmont pilot from year to year. The SPG suggested that increased precipitation might have affected the seismic response at the Surmont pilot.

Dover Phase B Pilot

The SPG submitted that the Dover pilot data showed that IHS and, specifically, very thin mud beds stopped the steam from rising. The SPG maintained that although steam rise rates tended to be extremely aggressive through clean sands (up to 29 m per year), the steam stopped rising at the base of the IHS at the majority of the observation wells. At observation wells where steam rise had been observed in the IHS zone, the steam rise was characterized by extended stops and was eventually halted as the frequency and thickness of mud beds increased upward. All the observation wells showed that steam rise had stopped in Facies 3 to 5 and that the steam chamber had not risen to the base of Unit B. The SPG contended that the temperature versus depth plots for the observation wells showed that there was no accumulation of noncondensable gas at Dover until 1999, after the commencement of gas injection in April 1998. Therefore, the steam chamber did not stop rising due to the presence of noncondensable gas. The SPG further submitted that every observation well surveyed within 15 m of a SAGD injection well showed a positive indication of steam within 1.25 years and that the observed lateral steam chamber propagation rate was approximately 17 m per year.

The SPG submitted that the observed steam rise behaviour from Dover was directionally different from what the simulation models predicted. The simulation models predicted relentless steam rise until the steam chamber reaches an impermeable barrier. The SPG argued that because the steam stopped rising in the interbedded zone and not at the base of Unit B, the impermeable barrier must be moved into the interbedded zone to history match the performance at Dover.

The SPG conducted a volumetric analysis to address the suggestions by Gulf and Petro-Canada that bitumen was being produced from the IHS zone above the observed steam chamber at the observation wells. On the basis of this volumetric analysis, the SPG predicted a bitumen recovery of 527 000 m^3, which compares favourably with the actual cumulative recovery of 518 000 m^3. The SPG submitted that both Gulf's and Petro-Canada's volumetric analyses involved drawing boxes within which bitumen drainage was occurring. The SPG maintained that the problem with these confined volumetric calculations is the faulty assumption that steam is somehow confined inside these arbitrary boxes. It stated that this assumption was contrary to the observed lateral steam propagation rates at Dover. The SPG further submitted that because there was no buildup of noncondensable gas in the IHS zone, there was no bitumen drainage occurring from the IHS zone above the observed steam chamber at the observation wells.

5.3.1.4 Views of the Board

Since the Board does not believe that the geology at Dover is analogous to that at Surmont, the Board does not believe that the extent of steam rise observed at the Dover Phase B pilot can be relied on to determine the extent of steam rise at Surmont.

With respect to the steam rise observed at the Surmont pilot, the Board notes that there are limited data available, **since steam has been injected only for about two years. The Board further notes that the available data indicate that a steam chamber has only developed at one of the five observation wells.** However, the Board does not believe that this necessarily means that steam chambers are not developing along the well pairs **for the following reasons:**

- **The lack of evidence of steam chambers at the two observation wells that are laterally 9 to 14 m away from the SAGD well pairs is not unexpected, especially for the observation well with the lowest thermocouple 35 m above the injection well.**

- **Although the casing leak that occurred at one of the observation wells compromised the ability to determine whether a steam chamber had developed at that location, there was an early indication of steam chamber development prior to the casing leak.**

- **Although Gulf's argument that the bottomhole survey location of one of the observation wells is incorrect is perhaps speculative, the Board notes that the piezometer at that location had shown a recent pressure response to steam injection. This is further discussed in Section 5.3.2.**

- **Additionally, and perhaps most significant, the two SAGD well pairs have produced a substantial amount of bitumen, even though, as pointed out by Gulf, four of the five observation wells showed that the SAGD well pairs were drilled through HS, according to the SPG's cross-section. Although the bitumen production rate of the Surmont pilot appears to have levelled off, the Board believes that it is too early to conclude whether this means that there will be no further rise in the steam chamber.**

- **Although the Board understands that seismic can indicate only the presence of a gas phase, it accepts that the gas seismic character at the Surmont pilot represents the steam chamber. The Board also recognizes that enhancement of the seismic reflector through time over an enlarging geographic area is representative of steam chamber expansion. The 4-D seismic evidence provided by Gulf demonstrates the longitudinal and vertical movement of the steam chamber at the Surmont pilot. With respect to the impact of precipitation on seismic response, the Board is unable to make an evaluation, as the participants did not provide any supporting evidence.**

5.3.2 Vertical Pressure Transmission at Surmont

This section deals with two aspects of the evidence regarding vertical pressure transmission at Surmont:

- pressure transmission in the bitumen zone resulting from depletion of gas pool pressures, and

- pressure transmission in the bitumen zone resulting from steam injection at the Surmont pilot.

A third aspect, pressure transmission in the bitumen zone resulting from water injection into the Basal McMurray aquifer, is dealt with in Section 5.1.

5.3.2.1 Views of Gulf

Regarding pressure transmission in the bitumen zone resulting from depletion of gas pool pressures, Gulf submitted the following:

- Pressure data from the three piezometers located at different depths in the bitumen zone in the 06/12-24-83-7W4M well indicated that there was pressure transmission into the bitumen zone to a depth of about 40 m in four years. With respect to the possibility that the pressure transmission could be occurring through the wellbore (presumably due to a bad cement job) rather than through the bitumen zone, Gulf argued that after the start of injection at the Surmont pilot, different pressure responses were recorded at adjacent piezometers. This would not occur if the pressure was being transmitted through the wellbore.

- Pressure data from the AA/10-26-81-7W4M piezometer, which was located in a bottom water zone below the bitumen column, showed a decline of 56 kilopascals (kPa) in a year. Since the piezometer was in an area with no mappable top water and no overlying gas pool, Gulf submitted that the only logical depletion source would be through hydrodynamic continuity with gas pools to the west or north of the piezometer. Gulf acknowledged that there was uncertainty in understanding the pressure data, since they came from a single source. Gulf indicated that the pressure data were not necessarily evidence of pressure communication through the bitumen column; the pressure transmission could have been occurring vertically or laterally.

Regarding pressure transmission in the bitumen zone resulting from steam injection, Gulf submitted that recent pressure data recorded at the middle piezometer (located about 27 m above the injection well) in the 06/12-24-83-7W4M well showed a pressure response to steam injection. This piezometer was at the same location as the temperature observation well that Gulf submitted did not show evidence of a steam chamber because the bottomhole survey location was likely incorrect. Gulf submitted that if the effective start-up date of the Surmont pilot was taken as January 1998, the pressure response at the middle piezometer agreed with Gulf's simulation prediction.

5.3.2.2 Views of the SPG

Regarding pressure transmission in the bitumen zone resulting from depletion of gas pool pressures, the SPG submitted the following:

- The SPG acknowledged that the pressure data from three wells with piezometers located in the bitumen zone showed that there was some transmission of the gas pool pressure depletion into the bitumen zone. However, the SPG submitted that the pressure depletion fell off significantly with increasing depth below the water-bitumen contact and that the depletion

40 m into the bitumen column was negligible. With respect to the piezometers in the 06/12-24-83-7W4M well, the SPG also raised the possibility that the pressure transmission could have been through a passageway in the cement around the piezometers rather than through the bitumen zone.

- The SPG argued that the pressure decline observed at the AA/10-26-81-7W4M piezometer was not due to the pressure depletion of offsetting gas pools being transmitted through the bitumen zone. Rather, it was due to a poorly cemented well that resulted in localized cross-flow in the wellbore between the McMurray bottom water zone and the underlying Calumet limestone zone. This interpretation was based on the SPG's analysis of the piezometer data and the potentiometric surface elevations of the McMurray and Calumet zones. Since the piezometer was cemented in the wellbore, the SPG indicated that it was not possible to conduct any tests to check the integrity of the cement.

Regarding pressure transmission in the bitumen zone resulting from steam injection at the Surmont pilot, the SPG acknowledged that the recent pressure data recorded at the middle piezometer in the 06/12-24-83-7W4 well showed a pressure response. Prior to these data becoming available, the SPG had stated there was an abundance of mud in the form of breccia beds and muddy interbeds in the interval between the injector and the middle piezometer. However, the SPG disagreed with Gulf's statement that the piezometer data confirmed Gulf's simulation results. The SPG argued that since Gulf's model predicted steam rise rates of 10 to 17 m per year, the height of the steam chamber at the 06/12-24-83-7W4M location should be 20 to 30 m above the injector. However, the temperature observation well at the 06/12-24-83-7W4M location indicated that there had not been any steam chamber development.

5.3.2.3 Views of the Board

Regarding pressure transmission in the bitumen zone resulting from depletion of gas pool pressures, the Board notes that some of the depleted gas pool pressure was transmitted a significant distance into the bitumen zone. With respect to the pressure depletion shown by the piezometer located in the bottom water zone at AA/10-26-81-7W4M, the Board believes that there is a great deal of uncertainty about the cause of the pressure depletion. While it is possible that the pressure depletion was due to communication with an underlying zone through a bad cement job, as suggested by the SPG, this cannot be confirmed.

Regarding pressure transmission in the bitumen zone resulting from steam injection at the Surmont pilot, the Board notes that pressure response was observed at the piezometer that is at the same location as the temperature observation well that Gulf believes has an incorrect bottomhole survey location. This pressure response was observed even though the SPG contended that there is an abundance of mud in the approximately 27 m interval between the injection well and the piezometer.

5.3.3 Vertical Permeability Measurements

5.3.3.1 Views of Gulf

Gulf presented vertical permeabilities for HS facies ranging from 20 to100 mD based on routine core analyses of two Surmont wells. Gulf further presented vertical permeabilities to gas for HS facies ranging from 0.731 to 436 mD based on special core analyses of five additional Surmont wells. Gulf stated that bioturbation had caused these HS beds to have effective permeability, which is important in a SAGD process. This effective permeability would allow fluids to move both vertically and laterally. Gulf concluded that the HS facies was a baffle to steam flow but not a barrier.

5.3.3.2 Views of Petro-Canada

Petro-Canada submitted that IHS beds have composite permeability. Citing a reference,[7] it noted that vertical permeabilities range from a low of 0.04 mD in nonbioturbated samples to over 700 mD in bioturbated samples and from 3 to 5 D in ripple laminated sands. Petro-Canada further noted that a permeability of 100 mD for the IHS beds is required to history match the production performance at Dover, verifying that IHS beds are not barriers to flow. Petro-Canada submitted that the whole-layer vertical permeability in Upper McMurray shaly and silty sediments ranges between 7 and 35 mD on the basis of a transform of petrophysical logs in observation wells OB18, OB25, and OB28, drilled at the Gulf Surmont pilot. Petro-Canada also submitted 13 core analyses from the same intervals in these wells, with values ranging from 2.7 to 171 mD. Petro-Canada stated that recent core measurements from Chard exhibited a similar permeability range as that noted by Strobl *et al.* Petro-Canada submitted that it selected samples to represent the more mud-dominated end members of the interbedded units. Vertical permeabilities in these samples ranged from 0.01mD in nonbioturbated mudstone to 170.9 mD in bioturbated siltstone. The vertical permeability measurements at MacKay River have values in the order of 80 to 200 mD.

Petro-Canada also stated that the thief zones display a range of vertical permeabilities similar to the IHS beds and that the flow profile of some of the gas tests suggested the vertical permeabilities are in the order of 125 to 250 mD.

5.3.3.3 Views of the SPG

The SPG stated that although permeability measurements are accurate laboratory results, the results were probably exaggerated due to the mechanical disruption of the cores that occurs upon extraction. The SPG further noted that even though the permeability measurements were being done on full-diameter cores, the disruption factors would be the same. The SPG also expressed concern regarding the size of the core sampled versus the thickness of the IHS layer. The SPG submitted that it would probably be more appropriate to use small-diameter cores to capture individual mudstone layers and measure their respective permeability characteristics, rather than sample and measure full-diameter cores that give composite permeability of interbedded sands

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[7] Strobl, R. S., *et al.*, 1997, "Application of outcrop analogues and detailed reservoir characterization to the AOSTRA underground test facility, McMurray Formation Northeastern Alberta," Pemberton, S. G., and James, D. P., eds., *CSPG Memoir 18:* 375–391.

and mudstones. The SPG submitted that the dipping muddy interbeds have a vertical permeability less than 1 mD, according to published core data from the Dover pilot. By definition, IHS has variable sand and mudstone.

5.3.3.4 Views of the Board

The Board believes that the range of vertical permeabilities derived from HS zones in core presented by Gulf and Petro-Canada indicates that potential exists for effective permeability in the IHS/HS layers.

In summary, with respect to vertical continuity, considering

- the geological evidence that indicates that the occurrence of thick bitumen-saturated sands in direct communication with overlying gas and water zones is extensive and randomly distributed,
- the vertical permeability data, and
- the available temperature, pressure, production, and seismic data for the Surmont pilot,

the Board believes that there is a significant risk of SAGD steam chambers communicating with overlying gas and water zones at Surmont.

5.4 Lateral Continuity

5.4.1 Views of Gulf

Gulf stated that the evidence for resource conflict throughout the Surmont leases is overwhelming. The majority of the McMurray gas at Surmont directly or indirectly overlies the bitumen or the top water zone, which overlies the bitumen. Gulf developed a classification system (see Table 1) for 175 of the wells on its Surmont leases to identify the extent of direct association and to alleviate the need to argue over the areal extent of gas pools and water zones. Gulf submitted that the majority of the wells (i.e., 75.5 per cent) fell within its classification A, indicating that the gas in those wells is in direct hydraulic communication with the underlying bitumen. The classification showed that regardless of the type of mapping and cutoffs used, the conflict between the two resources at Surmont is extensive. In that regard, Gulf contended that the extent of the conflict is self-evident even in the SPG's mapping. Gulf further stated that where a gas zone lies above a thin bitumen zone and the region had not yet been clearly defined, gas production should not be allowed, since moving 200 m laterally can mean moving from off-channel, nonreservoir strata to part of a channel most prospective for SAGD bitumen development.

Definition of Regions of Influence

Gulf defined a region of influence as the extent of a gas pool directly overlying bitumen or the extent of a water zone in the case of gas overlying water overlying bitumen. It stated that the region of influence definition could be modified to include the combined extent of the gas pool and water zone in the case where both gas and top water pools are present. Gulf submitted that a

Table 1. Gulf well classification

Classification	Description	Number of wells (%)
A	**Hydraulic communication with bitumen** - Occasionally thin shale appears to exist on logs at this particular location; however, this thin shale does not extend laterally and is not a pressure barrier between the gas zone and bitumen.	132 (75.5)
B	**Gas well in same pool as an A-type well** - The gas well is in clear communication with an offsetting well that is an A-type well in hydraulic communication with bitumen.	6 (3.0)
C	**Gas separated by thick shale from water and/or bitumen** - Thick shale creates an apparent hydraulic seal between the gas zone and the bitumen. Due to lateral discontinuity, reductions in gas pressure are being communicated to the bitumen.	23 (13.5)
D	**Gas over water with no underlying bitumen** - Hydraulic communication exists between the gas production and bitumen.These wells are only present to the east of Surmont.	14 (8.0)

region of influence is an area of approximately equal hydraulic heads and high transmissivity separated from another region of influence with differing hydraulic heads by an area of lower transmissivity. Gulf defined the areas of lower transmissivity as being areas of lower permeability, estimated to be higher than 1 mD but lower than the value of 1000 mD that it assigned to the clean water sands.

Mapping of Regions of Influence

Gulf stated that the Upper McMurray tidal flat and tidal channel sediments are laterally continuous and provide an effective passageway for pressure transmission across the Surmont leases. Pressure depletion in the Wabiskaw-McMurray due to gas production within a hydraulically continuous region of influence would be transmitted through the saturated phase of the less permeable sediments to neighbouring regions of influence over the time frame of bitumen production. This pressure depletion would be magnified if neighbouring regions of influence are also experiencing gas production. Gulf contended that the cumulative effect of pressure depletion in several or all of the regions of influence at Surmont would be to deplete the pressure across the entire Surmont leases within the time frame of bitumen production.

Gulf stated that the McMurray sands and muds were extensively bioturbated, developing effective porosity and permeability. Gulf further stated that the Athabasca area is a major anticline with a rollover to the east that acts as a major trap and that Surmont is situated along the crest of a structural paleo-high. Residing over this paleo-high are several smaller anticlines. Differential compaction led to draping of the muds and the development of several traps, which was exacerbated to the east of the area by salt solution. The McMurray system was water wet, including the bioturbated muds. The anticlines were subsequently filled with gas to spill points, displacing the formation water that was within the porous sands and the porous bioturbated muds. Oil migration followed and oil displaced most of the water. Some of the Lower McMurray formation waters in the lowermost parts of the channels were not displaced by oil and the sands remained water wet. The oil was biodegraded and became immobile, and the original gas/oil and oil/water contacts remained stationary. Regional tilting and/or breaching of the structures led to partial depletion of the gas caps, which were replenished with formation water, including the pore space in the bioturbated shales. As a result, the gas/water contact is relatively flat, except for capillary effects due to grain size variation, and the water/bitumen and bitumen/water contacts are tilted.

Gulf provided the type well shown in Figure 5 to illustrate its interpretation of the Wabiskaw and McMurray gas zones. Gulf stated that the top of the Wabiskaw is a correlatable pick that it termed the Wabiskaw-McMurray marker. The Wabiskaw marine sand gas and McMurray top gas and top water zones are also identified on this type well log. In most of the wells Gulf identified the presence of two gas zones: marine and channel. It stated that these two zones are vertically separated in many instances but have been perforated and commingled in the wellbore, creating widespread artificial communication between them. Gulf further stated that there are circumstances where natural communication exists between the zones due to incision by channelling.

Gulf mapped its gas pools, top water pools, and prospective bitumen pay using an integrated interdisciplinary interpretation of an independent

- geological assessment of gas and water pool thickness, fluid contacts, bitumen grade, and sedimentology;

- geophysical assessment of 410 km of Gulf proprietary seismic data shot in 1998, 460 km of trade seismic data acquired by Gulf in 1997 and reprocessed to industry standard, and data made available to Gulf by Northstar-Giant Grosmont, all of which Gulf evaluated in regard to prospective sand thickness and to risk of potential top gas thief zones;

- reservoir engineering analysis of gas pool virgin pressures and pressure history; and

- hydrodynamic analysis of channel top water continuity.

Gulf mapped the gas within the marine sands primarily on correlative gas pressures. In the absence of suitable pressure data, it used petrophysical correlation assuming a marine sheet sand.

Specifically, Gulf mapped the tidal flat and channel top gas sands by integrating interpretations from three disciplines:

- Reservoir engineering interwell correlation of virgin gas pressures and pressure history—If virgin pressures between wells or pressure history between wells were not correlative, the wells were assigned to be in different pools. Gulf allowed a margin of error of ±15 kPa.

- Geological correlation of gas/water, gas/shale, and gas/bitumen contacts allowing for a tolerance of ±2 m—In the absence of suitable pressures, Gulf used geological fluid contact correlation to determine if wells were either in separate pools or in the same pool.

- Geophysical identification of gas-induced, bright-spot anomalies—Close spacing of seismic lines (i.e., less than 800 m) facilitated the estimation of the size and shape of gas pools.

Gulf contoured the data as to gas pool shape and size in consideration of a tidal flat depositional environment. As a result, the gas pools range in size from 1 to 17 sections.

Although the volumetric determinations of gas in place performed by the SPG on Gulf's mapped pools showed much larger volumes than Gulf had determined using material balance and decline analysis, Gulf contended that neither determination can be definitively relied upon. Gulf's methodology for mapping the gas pools was based primarily on multidisciplinary input, but it did not adjust the size of the gas pools for material balance reserves. Gulf stated that since the pressure data were often insufficient, it also took into account the geology of the reservoir, the well log data, and the core data.

Gulf disagreed with the SPG's mapping of the gas pools as simple disconnected tanks with straight sides and uniform thickness. Gulf contended that if the gas pools had been contoured to reflect the pay distribution realistically, the lateral extent of the pools would have to be greater than that currently mapped by the SPG to account for the gas volumes presented by the SPG.

Gulf mapped the tidal flat and channel top water sands by integrating interpretations from two disciplines:

- Hydrodynamic analysis of potentiometric surface values (i.e., hydraulic heads) and areas of production-induced drawdown—Gulf determined production-induced drawdown by looking for any producing wells within a 10 km diameter and determining whether those wells were producing prior to the taking of that pressure measurement. Gulf correlated areas as hydraulically continuous on a time scale of gas pool production life if hydraulic head values were within a range of $\pm$3 m.

- Geological correlation of top water/bitumen and water/shale contacts at the base of the channel top water to define the lateral extent of areas interpreted to be hydraulically continuous when suitable pressure data were not available—Gulf defined contacts as correlative if there was a difference of $\pm$2 m. Gulf mapped water only in places where the porosity of the zone exceeded 28 to 30 per cent.

Gulf contoured the data as to top water pool shape and size in consideration of a tidal flat depositional environment and the area of any overlying gas pools.

Gulf disagreed with the SPG's interpretation of 100 m wide water halos beyond the gas pool edges. Gulf contended that even the SPG's hydrocarbon history called for structurally tilted water/bitumen and bitumen/water contacts. Gulf argued that if this were valid, then the halos could not be symmetrical. Gulf submitted that 19 of 30 wells it studied, which encounter water with no gas, are more than 100 m from the edge of the nearest gas pool, proving that the water pools are larger and more pervasive than what the SPG had presented.

Gulf stated that it used pressure data collected from all the publicly available sources. On the basis of the degree of consistency in the data, Gulf determined that, in general, a pressure difference of 30 kPa (i.e., ±15 kPa) would be within acceptable margins of error. Gulf provided a list of factors that it contended affected the margin of error tolerance, such as errors due to measurement, incorrect extrapolation of buildup data, wellbore liquid problems, and commingling of zones. Gulf contended that the impact of induced error resulted in the appearance of a complexity that in fact does not exist. Gulf argued that the SPG's margin of error of ±6 kPa, which was less than the daily barometric variation, was unrealistic. Gulf further stated that the SPG reduced the apparent error in the data by averaging and manipulating the data. Gulf submitted that the effect of using a small margin of error resulted in unrealistically small gas pools.

Regarding the SPG's contention that Gulf had errors in some 60 pressure readings, Gulf acknowledged that this was true. However, upon review of these readings, Gulf determined that they were typically recorded after only 24 to 48 hours of the well being shut in. Therefore, Gulf did not rely on these readings, since they provided no accurate data with respect to average reservoir pressure, as lengthy shut-in times were necessary to assess the complete buildup behaviour due to a variety of factors, such as influx.

Gulf applied its definition of virgin pressure, that is, the pressure prior to any production in the area, to initial pressure data to establish whether the pressure was virgin or depleted.

Gulf stated that the large number of man-induced pressure transients that had been created across Surmont made pressure interpretation very difficult. The interplay of these pressure transients disguised the actual pressure response to any particular pressure change, making accurate pressure interpretation between pools virtually impossible.

Gulf acquired seismic data to aid in determining areas of rich bitumen-bearing sands in the McMurray Formation in the Surmont area. The data were shot with good parameters to evaluate shallow horizons with high-frequency responses. Gulf stated that all seismic data were rigorously calibrated with gas well log data and examined for gas-induced, bright-spot anomalies. Gulf stated that seismic could reliably resolve gas sands greater than 3 m thick. Gas within sands as thin as 1 to 2 m could be seen occasionally but depended on data quality. Gulf further stated that the minimum gas saturation that was visible as a seismic anomaly was approximately 5 per cent. On the basis of these limits, Gulf stated that water sands that are thin and/or have a water saturation of greater than 95 per cent were not detectable by seismic. This was confirmed by numerous wells that had found water and showed no seismic anomaly. Gulf also stated that while seismic lines with no gas anomaly showed the absence of gas, they did not disprove the presence of water. Gulf concluded that it was not possible to seismically map the water correlative to the gas sands.

Pressure Communication Within and Between Regions of Influence

Gulf contended that widespread pressure communication was occurring across the Surmont leases on the basis of the following observations:

- significant pressure declines had already occurred in gas caps;

- significant pressure gradients did not exist across gas caps;

- pressure decline in the underlying water quickly followed the gas cap pressure trend; and

- pressure depletion was quickly transmitted into the underlying bitumen zone.

Gulf stated that the rate of pressure decline in gas caps was directly proportional to gas production and, because significant gas production had occurred, there had already been a significant reduction from virgin pressures across the Surmont leases. Therefore, any further pressure reduction at Surmont would be critical. Gulf stated that the average pool pressure, based on SPG data, had decreased from a virgin pressure of 1578 kPaa to 908 kPaa as of June 30, 1999, a reduction of 670 kPaa. Gulf further estimated that annual decline rates ranged from 89 to 136 kPa. Gulf contended that the SPG misrepresented its decline rates since it only used data from four gas pools that were on production from two to six years.

In looking at three of the large gas pools at Surmont, Gulf determined that significant gas gradients were not evident. For example, Gulf noted that the pool containing the 00/11-19-81-5W4, 00/3-30-81-5W4, and 00/7-23-81-6W4 wells had recorded pressures on April 6, 1999, of 676, 674, and 679 kPaa respectively. Gulf contended that this and other examples showed that the rate of pressure decline within the gas pools was significant and that the magnitude of pressure depletion was essentially uniform across the gas pools. In support of this, Gulf noted that the SPG stated that these pools had been on production for so many years that it was virtually certain that they were under pseudo-steady-state flow and, by definition, pressures were declining at the same rate at any location in a pool.

Gulf contended that the similar piezometer responses in both the gas and water zones at the AA/9-12-83-7W4 well was clear evidence that the water zone pressure followed the same trend as the pressure in the gas zone overlying it with no time delay. Gulf further contended that the pressure data from the 06/12-24-83-7W4 well demonstrated the downward penetration of depressurization and that the pressure measurements in the bitumen followed the same trend as the gas, lagging by only about six months. The gas zone experienced pressure depletion and rebound, as did the water. Gulf submitted that the water and the bitumen were in communication with the overlying gas. As noted in Section 5.3.2.1, Gulf submitted that it took only four years for the pressure pulse to travel through the water zone and penetrate 40 m into the bitumen zone. Gulf further submitted that subsequent piezometer readings following the start-up of the SAGD process at its pilot showed the separation of pressure responses between the vertically adjacent piezometers. It maintained that this would not exist if the pressure communication existed due to lack of wellbore integrity.

On the basis of piezometers installed to observe pressures in top water with no overlying tidal flat or channel gas, Gulf found that offsetting gas production had drawn down the top water pressure in seven of the nine top water pressure observation wells. Gulf submitted that gas pools that have had little or no production offset the two wells in which the pressure in the top water had not been drawn down.

Gulf interpreted the Wabiskaw-McMurray in the Surmont area to be a hydrodynamically continuous open system. Gulf stated that pressure depletion due to gas production within a region of influence would induce a larger gradient between two neighbouring pools than the existing natural gradient, leading to increased fluid flow between regions of influence. Gulf submitted that high-quality time-series data from piezometers and as shown in Petro-Canada's example of standing wells with a long history of pressure measurements indicated that pressure communication existed between what would normally be considered separate regions of influence.

Gulf installed piezometers into the water zones where no active overlying gas production was occurring to demonstrate that pressure depletion was occurring between regions of influence. Gulf stated that piezometer data from the AA/3-24, AA/4-24, and AA/11-24-82-7W4 wells proved that measurable and significant pressure loss was being experienced below a nonproducing gas cap. Furthermore, data from the AA/3-23, AA/5-23, and AA/9-14-83-7W4 wells proved that similar pressure losses were occurring in an area with top water and no overlying gas. Another example Gulf gave related to the 00/8-3-83-6W4 well (the 8-3 well), which Gulf mapped as a separate water pool from the offsetting 00/10-2-83-6W4 (the 10-2 well) water disposal well into the Upper McMurray. Gulf submitted that the 8-3 well piezometer showed a response to changes in injection rates at the 10-2 well. Gulf contended that the SPG's interpretation and position could not explain these phenomena. In response to the SPG contention that early piezometer data were affected by installation, Gulf stated that the pressure data it relied upon were outside the range of any cement-induced influences.

Gulf stated that in its analysis of reservoir performance it became apparent that most wells would produce free water after any significant period of production. Gulf summarized the pool behaviour as follows:

- some older pools with nonlinear p/z-versus-cumulative-production plots had increasing free water production; and

- some pools with linear p/z-versus-cumulative-production plots also had increasing free water production.

Gulf stated that although it accepted that gas drive depletion reservoirs could have water production problems, this behaviour was better explained for the Surmont gas pools through application of an open reservoir concept (i.e., influx and efflux). Gulf interpreted the influx/efflux, or open pressure system, as further evidence that there was broad cross-lease flow and pressure communication.

Gulf noted that free water production was a common characteristic of Surmont gas wells, even in wells with no water evident on the well logs. Gulf also noted that wells that had watered out had developed standing water columns, which it contended was due to the continued encroachment of water after the wells were shut in. If the wells were coning bottom water, then upon shut-in, they would rapidly release the water back into the reservoirs due to gravity. These observations indicated to Gulf that water influx was occurring.

Gulf submitted that when it attempted to define the gas reserves from material balance for the cases where sufficient data were available, the p/z-versus-cumulative-production plots showed a nonlinear response. Gulf concluded from several of these examples that gas or water influx was sustaining production. Gulf further stated that every examined long-term buildup test indicated composite or composite-bounded reservoir behaviour. It stated that long shut-in times were required to obtain stabilized reservoir pressures and that the tests showing long-term pressure recovery had yet to measure the edge of the total system. Therefore, Gulf concluded that the

Upper McMurray is an infinitely acting system. Gulf also stated that not one long-term test was submitted that indicated a closed reservoir.

Gulf stated that for "weak" water influx behaviour to occur, either the aquifer size had to be limited or low transmissivity was restricting the ability of water to encroach during the period of gas production when it would be necessary to maintain pressure. In the case of limited areal extent, little influx would occur as a result of aquifer expansion. Gulf concluded that undrained gas pools could provide energy to the underlying aquifer since there is dynamic aquifer communication between gas pools, allowing partially drained pools to receive pressure support through the underlying aquifer. Gulf contended that pressure depletion in one gas pool would be transmitted over a much larger area than the gas pool and, due to flux transfer, depressurized gas pools would be partially recharged by offsetting higher pressure gas pools.

Gulf stated that flux transfer is not an instantaneous process and that it can be monitored if sufficient instrumentation is installed in observation wells. Gulf presented the production history of the Westerose South D-3 Gas Unit/Sylvan Lake D-3A Pool as an example of this phenomenon, along with pool history data for the 00/8-1-81-6W4 pool at Surmont. Furthermore, Gulf attributed the pressure rebound observed in the gas cap in the Surmont pilot area after the shut-in of gas production to pressure transmission and equilibration between adjacent gas pools. Local pressure rebound in depleted gas pools took place through the underlying aquifer at the expense of pressure in other gas pools at virgin or higher pressure. Gulf contended that these pressure trends in the channel sands demonstrated weak water influx and that these trends would be documented better over time.

Gulf provided evidence from the Kearl Lake pilot to describe the observed pressure leak-off in the McMurray Formation. The pilot had a lean bitumen sand at the top of the Middle McMurray, which, although not a water zone, behaved as a thief zone due to its high water saturation. The operator was unable to repressure the McMurray Formation beyond 1200 kPa and needed to continue injection to maintain this higher pressure due to the constant pressure leak-off. Gulf contended that this was evidence of continuity in the Upper McMurray.

Gulf stated that the interregion communication and the rate of pressure depletion are dependent on the transmissivity of the material between the regions of influence. On the basis of 110 pressure buildup tests, Gulf determined values for in situ permeability that range in value between 32 and 4000 mD and submitted that the value of 1000 mD, arrived at statistically (i.e., arithmetic average), is representative for the Upper McMurray unconsolidated sands. Gulf adapted a single-phase (i.e., water) hydrogeological model to a two-phase system (i.e., water and gas) by increasing the compressibility of the porous matrix and saturating fluid to that of gas in a gas pool. On the basis of the results of numerical simulations, Gulf submitted that due to hydraulic communication, pressure depletion caused by gas production would occur between neighbouring regions of influence up to a distance of 16 km and within a 30-year time frame. Gulf contended that pressure depletion would be transmitted through low-permeability (i.e., 1 to 10 mD) deposits between regions of influence. In the numerical simulations, Gulf assumed a constant, homogeneous literature value of 5×10^{-9} Pa^{-1} for rock compressibility and used a permeability contrast of two orders of magnitude between the clean sand and the less permeable regions. Gulf stated that the magnitude and time frame of the interregion pressure decrease depended on the transmissivity between the regions of influence. Gulf submitted that the modelling results were comparable to real pressure and hydraulic head data distributions and depletion trends observed in piezometers in recently drilled wells.

Gulf adopted Petro-Canada's argument that geological and pressure data at the 00/7-14-80-7W4 well (the 7-14 well) indicated interregion communication. Gulf stated that, on the basis of gas/water contacts and pressure depletion trends, the 7-14 well appeared to be in the same pool as the offsetting 00/9-24-80-7W4 well (the 9-24 well). Gulf contended that the pressure history for the 7-14 well demonstrated that it experienced pressure decline prior to the 9-24 well beginning production. Gulf agreed with Petro-Canada's conclusion that offset gas production in another producing pool or pools had caused pressure depletion at the 7-14 well. Gulf pointed to the offsetting 00/11-28-80-6W4 pool, approximately 7 km to the northeast, as the most likely source of the depletion.

Gulf submitted that it expected any rebound of pool pressures to be dependent on the energy stored in this open system. It maintained that if all the gas caps were allowed to produce to abandonment, no energy would remain to provide rebound to the abandoned gas pool. Gulf stated that although it was not clear how rapidly pressures would equilibrate across the Surmont leases, its evidence suggested that it could be a minimum of two years within regions of influence. Gulf also pointed out that although no definitive field experience existed, its model suggested that equilibration between regions of influence would occur in some significant measure within five to ten years. However, Gulf submitted that once gas production ceased, it would take a very long time, longer than the time frame envisaged for commercial bitumen production, for pressures to recover naturally to their original (i.e., virgin) values because of weak aquifer support.

On the basis of the distribution of its mapped regions of influence, Gulf contended that all Surmont wells were in direct or indirect communication across the Surmont leases. Therefore, the overall effect of gas production and pressure transmission would be lower pressures over the entire Surmont leases during the time frame of bitumen production.

Gulf suggested that an effective and timely monitoring program should be implemented at Surmont after the shut-in of gas production to determine the sources of pressure depletion, the rates of pressure transmission, and the magnitude of the expected pressure rebound.

5.4.2 Views of Petro-Canada

Petro-Canada noted that most of the gas wells on its Chard leases have gas in direct contact with water that overlies the bitumen. As a result, Petro-Canada contended that any reduction in the gas zone pressure would reduce the pressure in the top water zone.

Definition of Regions of Influence

Petro-Canada defined a region of influence similarly to Gulf, that is, the extent of a gas pool in the case of gas directly overlying bitumen or the extent of a water zone in the case of gas overlying water overlying bitumen. It stated that the region of influence definition could be modified to include the combined extent of the gas pool and water zone in the case where both gas and top water pools were present. Also, Petro-Canada defined a region of influence as an area of high hydraulic continuity and transmissivity. Petro-Canada submitted that hydraulic heads within a region of influence should have similar values throughout as a result of high transmissivity and that areas of widely spaced potentiometric surface contours indicated areas of greatest hydraulic continuity and of large potential regions of influence.

Mapping of Regions of Influence

Petro-Canada stated that its pool outlines relied heavily on the interpretation of geological and pressure data. Delineation of top gas pools and water pools was determined by the correlation of contacts within hydraulically continuous flow units in the Upper McMurray. It considered wells to be in the same gas or water pool if the basal contacts of the top gas or water zone were at the same elevation (i.e., $\pm$1 m) within areas of widely spaced potentiometric surface contours. It separated wells with similar basal contacts into distinct water pools if the hydraulic head data did not support the interpretation of a single pool.

Petro-Canada identified virgin pressures by reviewing the pressure data to determine which pressure measurements had been affected by production. It used the term "production-induced drawdown" to identify production-influenced measurements. In its determination, it reviewed all the wells within a 10 km radius of the test well that could potentially reduce the pressure in a zone, because pressure depletion over large areas would be expected in high-permeability reservoirs such as those encountered at Surmont. It did not consider the pressure measurement to be virgin where it determined pressure effects to exist.

Petro-Canada reviewed over 2000 pressures from the EUB's AOF microfiche files in the area of Petro-Canada's lands. The pressures used for interpretation did not include unsubstantiated pressures from the text in the AOF report, and it compared the AOF preflow data to the postflow data for consistency and reliability. It reviewed static gradient pressures for the presence of water in the wellbore and for reasonableness relative to the well's production performance and perforation intervals.

Due to the differences in vintages of DST measurements (i.e., pre-1980 versus post-1980 gauge accuracy), extrapolation of DST and AOF pressures, and measurement errors in the log contact pick due to incorrect kelly bushing elevation and cable stretch, Petro-Canada used different tolerances for constructing its maps. It used $\pm$51 kPa for its regional hydraulic head maps, $\pm$18 kPa for its local Chard area hydraulic head map, and $\pm$10 kPa for its Chard area gas pools map.

For its hydraulic head mapping, Petro-Canada corrected the pressures down to the base of gas at one of the following fluid contacts:

- gas/water;
- gas/shale where no water was present or where shale separated the gas from top water; and
- gas/bitumen.

On the basis of its hydraulic head mapping, Petro-Canada interpreted the formation water to flow from west to east across its Chard leases. It noted that areas of high hydraulic continuity corresponded to areas where pools of continuous top water or gas could be mapped geologically and where higher net sand was present.

With regard to the SPG's mapping of gas pools, Petro-Canada submitted that the volume of initial gas in place estimated by the SPG to exist in each individual pool could not be contained within the mapped areas unless the pools had flat tops with vertical sides, forming a virtual tank. Petro-Canada contended that this type of geometric pool configuration does not exist in nature and that a more reasonable, natural pool representation would suggest larger pools, creating a situation where the SPG gas pools would either touch or overlap.

Pressure Communication Within and Between Regions of Influence

Petro-Canada challenged the SPG's contention that the top gas pools are isolated. It submitted that the evidence demonstrated active communication between gas pools and between regions of influence in the Upper McMurray. It stated that this was important because it established that the impact of gas production in the Upper McMurray was extensive. In support of its position, Petro-Canada presented its interpretation of the hydrocarbon emplacement model, reservoir modelling results, and historical pressure data from wells in the area of its Chard A Bitumen Prospect.

Petro-Canada submitted that for the Athabasca deposit to accumulate 890 10^9 bbl (141 10^9 m^3) of oil, a high degree of lateral permeability would be required. Petro-Canada argued that the emplacement of gas and oil, the biodegradation of the oil, the leakage of the original gas, and the ongoing accumulation of biogenic gas could not occur in the compartmentalized reservoirs, as postulated by the SPG. It stated that the SPG's isolated pool interpretation could be used for any other formation in the Alberta basin, but not for the McMurray Formation, because it is the superpermeable highway in the basin.

Petro-Canada contended that the observed flow pattern in the Upper McMurray demonstrated that there was interconnected permeability throughout. It submitted that there were no sharp pressure breaks within the aquifer that would indicate the existence of the lateral seals required to create isolated pods of water, as interpreted by the SPG. The widely spaced potentiometric surface contours indicated areas where the transmissivity was high and where flow was unrestricted. Closely spaced potentiometric surface contours indicated areas of flow restriction. Petro-Canada further noted that the magnitude of the hydraulic head drop was indicative of the degree of that restriction.

Petro-Canada submitted that in the area of its Chard A Bitumen Prospect tight hydraulic head contours exist to the west, north, and east of the main pool. The minor hydraulic head drop to the north and east of the main pool indicated that the flow restriction bounding the region of influence was relatively weak. It contended that the data indicated that there was communication between regions of influence on a production time scale at the southern edge of the Surmont leases.

Petro-Canada submitted that the flow restriction between regions of influence was caused by thin sandstones interbedded with mudstone. The boundaries of regions of influence were generally low transmissivity regions comprising interchannel sediments found in the Upper McMurray tidal flat environment. The sediments acted as restrictions that delayed, but did not stop, pressure communication.

Petro-Canada submitted that pressure data for the 7-14 well, the 9-24 well, and the 00/02-36-080-07W4 well (the 2-36 well) within the main region of influence in the area of its Chard A Bitumen Prospect demonstrated pressure communication between regions of influence. Petro-Canada noted that there was pressure depletion at the 7-14 well prior to significant production from any wells defined in its main region of influence pool. On the basis of the pressure data collected at the 7-14 well over five years prior to any production from the main region of influence, Petro-Canada submitted that a pressure drop of approximately 50 kPa had occurred. Additionally, subsequent to the 9-24 well and other wells being placed on production within the main gas pool, a further drop of about 150 kPa was observed at the 7-14 well. Petro-Canada contended that because pressure trends indicated that the 9-24 well was in the same gas pool as the 7-14 well, it would have had the same virgin pool pressure of 1749 kPa. It noted that the initial pressure at the 9-24 well was about 1650 kPa in January 1991, similar to the offset 2-36 well. Both of these initial pressures indicated pressure communication between regions of influence because the pressures were measured prior to any significant production from within the main region of influence. Although the specific source of this depletion could not be confirmed, Petro-Canada noted that there was considerable production since 1987 from 15 wells located to the east and northeast on the Surmont leases.

Petro-Canada argued that the SPG's interpretation of the pressure depletion source for the 7-14 well originating from wells on production in Township 79, Range 6, West of the 4th Meridian, focused on the direction from which the pressure depletion originated and not on the amount of depletion. It further noted that the SPG's depletion source was located 10 km from the 7-14 well and, therefore, was inconsistent with the SPG's description of small, isolated, discontinuous pools. Petro-Canada maintained that, in fact, the SPG's interpretation supported much of its own evidence concerning the nature and mechanisms for pressure communication. On the basis of both Petro-Canada's and the SPG's interpretations, the region of influence containing the 7-14 well had been depleted from a source located at a considerable distance from the well.

Petro-Canada stated that it had not observed any other cases of communication between regions of influence for the following reasons:

- Extensive preproduction pressure history data were not commonly collected (i.e., the 7-14 well had the only available data set).

- Pressure response through the aquifer was buffered by offsetting nonproducing gas pools by their own energy storage. Strong communication could therefore have existed between pools through the aquifer, yet pressures would not have changed appreciably in the early stages. This could have resulted in initial pool pressure measurements being mistaken for virgin reservoir pressures, new regions of influence being established, and communication not being detected.

To illustrate that the SPG approach of establishing the presence or absence of pressure communication solely on the basis of pressures in an aquifer below a gas pool is inappropriate, Petro-Canada conducted a three-dimensional simulation of communication between a producing and a nonproducing gas pool through an underlying aquifer. Petro-Canada adapted a reservoir-engineering model to a closed system (i.e., aquifer no-flow boundaries) with two gas pools. The purpose of the simulations was to demonstrate a possible mechanism for pressure communication within the same region of influence and between regions of influence.

With regard to the permeability of the water sands in the region between the two gas pools, Petro-Canada presented simulations of two cases:

- same permeability of 1000 mD as the water sands underlying the gas pools, with the gas pools 3000 m apart, and

- a permeability of 100 mD (i.e., 10 times smaller than that of the water sands underlying the gas pools), but for a region between the gas pools of only 120 m (i.e., 25 times narrower than in the preceding case).

Petro-Canada concluded that gas flow between the two pools would start in both cases in the third to fourth year.

Petro-Canada submitted that the pressure behaviour of the gas pool aquifer system must be understood by modelling the transient behaviour of the aquifer because pressure transients move through the aquifer faster than the water flows in the aquifer. Petro-Canada interpreted the model results to indicate that

- when gas production begins, the aquifer pressures deplete radially away from the producing gas pool;

- due to the high compressibility of the shut-in gas pool, pressures in the aquifer below the pool do not drop markedly, but remain close to the original pressure as the transients move past the pool;

- the small pressure drop in the aquifer below the shut-in gas pool and the pressure gradient imposed in the aquifer result in gas flowing out of the shut-in pool, predominantly towards the producing gas pool;

- only when communication of free gas is established between the two gas pools does the pressure in the shut-in gas pool start to drop significantly, even though pressure in the surrounding aquifer has been continually dropping; and

- pressure differentials greater than 1000 kPa can exist between communicating gas pools.

On the basis of its simulation results, Petro-Canada concluded the following:

- A single point pressure taken in a gas pool is inadequate to demonstrate the absence of communication through an aquifer between gas pools. Due to the compressibility of the gas pool, aquifer pressures below a gas pool are likely to be unchanged until gas migration reaches the producing gas pool. Consequently, the pressure data from the wells analyzed in the SPG's submission are likely indicative of pressures taken prior to gas flowing between the offsetting gas pools. Single point pressures cannot demonstrate the absence of communication; they can only be used to demonstrate the presence of communication.

- To demonstrate that communication may be imminent, it would be necessary to install piezometers in the water leg immediately below a shut-in gas pool to reliably monitor the small pressure changes that occur in it prior to communication. Piezometers or static gradients taken in wells drilled only into the aquifer and between communicating gas pools could also be used to indicate pressure transients moving through the aquifer.

- Once communication of free gas is established, drainage between the pools will continue over a longer period, and the final equilibrium pressure may be substantially lower in the shut-in pool. Conversely, the producing pool would gain in pressure after shut-in.

- Monitoring a producing gas field for evidence of communication through p/z-versus-cumulative-production plots would likely result in demonstration of communication long after communication had already been established.

Petro-Canada stated that its model input parameters were representative of the broad range of conditions that were encountered at Surmont. It further stated that the purpose of the model was to show that a gas reservoir on top of an aquifer would mute any pressure transient that had been initiated in that aquifer from offset gas production. Petro-Canada contended that the Wabiskaw-Upper McMurray aquifer provided a mechanism (i.e., conduit) for both pressure transmission and gas migration. However, it acknowledged that its communication model had not been supported by specific Surmont field data.

Petro-Canada supported Gulf's position that the Wabiskaw-Upper McMurray aquifer underlying the gas pools in the Surmont area was weak and that, consequently, little natural repressuring (i.e., pressure rebound) over the area could be expected from it during the life time of a commercial SAGD project. On the basis of analysis of pressure data, Petro-Canada concluded that localized, short-term pressure rebound could occur in shut-in pools, most likely as a result of pressure transmission from adjacent gas pools at relatively higher pressure. The conduit for pressure transmission between the gas pools would be the underlying aquifer.

Petro-Canada noted that for pools with sufficient pressure data, nonlinear p/z-versus-cumulative-production plots were indicative of external pressure influence. Although the SPG recognized nonlinear p/z-versus-cumulative-production plots, Petro-Canada contended that the SPG did not take this into account with regard to its abandonment pressures or reserve calculations. The nonlinear p/z-versus-cumulative-production plots suggested pressure influences from beyond the boundaries of the SPG gas pools that may be in the form of water or gas influx. Additionally, Petro-Canada argued that the Gulf piezometer data from the 8-3 well, which demonstrated response to offset water injection, indicated that pressure communication occurred on a production time scale between regions of influence.

Petro-Canada submitted that the currently available pressure data set was too limited for the extensive analysis required to establish the extent of regions of influence. It commended the EUB for its efforts to pursue current pressure data deficiencies and expressed the need for an appropriate ongoing pressure survey program in the oil sands areas. It suggested that a "shut-in and monitor" program be implemented to collect the necessary data to arrive at a better understanding of pressure transmission and its effect on gas and bitumen production. Petro-Canada submitted that because of the heterogeneous nature of the gas pools and the potential for water influx, simple straight-line p/z-versus-cumulative-production plots were not sufficient to identify the limits of regions of influence.

On the basis of its evidence, Petro-Canada submitted that gas production at Surmont would cause pressure depletion at Chard. It stated that this was due to the presence of regionally interrelated gas and water pools between Surmont and Chard, which transmitted the effect of gas depletion.

5.4.3 Views of the SPG

Definition of Regions of Influence

The SPG submitted that a region of influence is that area within which bitumen resources would be adversely affected by a reduction in pressure due to gas production. The SPG accepted the definition of a region of influence to be the extent of the gas pool in the case of gas directly over bitumen or the combined extent of the gas pool and the water zone in the case of gas overlying water overlying bitumen. The SPG noted that a formation must have lithological and fluid continuity over its extent to transmit pressure. With regard to pressure transmission between regions of influence, the SPG submitted that if effective pressure communication exists between various pools, then, by definition, these pools must be in the same region of influence.

The SPG contended that any potential effect of pressure depletion on bitumen recovery would be confined solely to the bitumen directly underlying a local region of influence.

Mapping of Regions of Influence

The SPG stated that the laterally continuous muddy IHS zone within the upper McMurray provided an effective barrier at Surmont that prohibited effective pressure communication across the Surmont leases other than in a geological time frame. As a result, the regions of influence were small, localized, and compartmentalized, not part of a hydrodynamic flow system. The SPG argued that the localized extent of regions of influence at Surmont was

- supported by observed geological features at Surmont;
- validated by pressure measurements taken from newly drilled wells;
- consistent with pressure trends observed in standing wells; and
- confirmed by recent (i.e., since 1997) well tests run on wells drilled on seismic gas anomalies.

For hydrocarbon history, the SPG used a regional model that covered a large area (i.e., approximately 1535 km^2), describing separate pools encapsulated by nonreservoir rock such that no communication could occur between pools over short periods of production time. The bitumen today represented remnants of a degraded, old oil accumulation. The overlying gas pools were more recent accumulations of bacterial gas.

During pre-Tertiary time, Surmont was located along the crest of a pre-existing high area. Structural effects associated with salt collapse provided regional closure for the oil accumulation within structural stratigraphic traps. The original oil was medium-gravity asphaltic crude. Initially, this crude oil displaced formation water out of the reservoir rocks. At this time, paleo-gas accumulation was localized and restricted to stratigraphic-structural traps. Gas/oil and oil/water contacts were structurally flat, and the hydrocarbon pools within the McMurray reservoirs filled with gas to the spill point. Some of the thin, water-bearing, shaly sands were never charged with hydrocarbons. The hydrocarbons did not flow from the bottom up into the McMurray reservoirs, but rather hydrocarbon charging occurred laterally or from the top down into the McMurray Formation. The SPG submitted that, because of this lateral charge of hydrocarbons during emplacement, one would expect a degree of interbedding of reservoir and nonreservoir rock at the top of the McMurray Formation.

During the Tertiary period, significant erosion occurred that removed the overburden and allowed oxygenated formation waters to invade the McMurray Formation. This was followed by biodegradation of oil within the McMurray reservoirs. This biodegradation resulted in the conversion of the oil to a much more viscous bitumen. The bitumen was rendered immobile, becoming an effective aquitard under natural conditions. During advanced stages of biodegradation, a small mobile formation water component formed within the bitumen column. Original gas was bled off and replaced over geological time by this mobile formation water. Subsequently, the region was tilted, there was differential compaction, and there was salt dissolution—all of which resulted in structurally tilted water/bitumen and bitumen/water contacts.

During the Quaternary period, formation waters within the McMurray Formation became anaerobic due to deposition of a thick overburden. Under the anaerobic (i.e., low-oxygen) conditions, bacteria degraded carbonaceous material and low-rank kerogens within the Cretaceous sediment, which resulted in the local generation and accumulation of bacterial gas. Over geological time, the bacterial gas moved in and replaced the mobile formation water in the old, depleted gas caps. This bacterial gas is currently still accumulating and displacing water in the upper zones of the McMurray Formation.

In summary, the SPG submitted that the present position of the upper water/bitumen contact represents the paleo-gas/oil contact at the time of biodegradation of the oil. The SPG further submitted that throughout the history of the hydrocarbon accumulation in the McMurray Formation, there were a number of significant changes to the rock itself as a result of stratigraphic loading, reduction in pore systems and pore throats, and a change in the hydrocarbon. The basal paleo-oil/water contact is represented today by the basal bitumen/water contact. The upper water zones in the McMurray at Surmont represent naturally depleted gas zones. Locally, when pools were naturally depleted, residual gas was trapped, mainly held by capillary pressures within the pore systems of the gas pools. Local gas was also trapped in areas where there was lensing out (i.e., interfingering) of reservoir and nonreservoir rock. Locally, this residual gas resulted in water being visible on seismic due to residual gas concentrations in the water and in pronounced attenuation on sonic logs in the water zones of the McMurray at Surmont.

The SPG stated that it reviewed all of the available geological, geophysical, hydrological, and reservoir engineering information to develop a categorization of the regions of influence at Surmont that considered the pressure relationship among the gas pools, water pods, and bitumen deposits. Regarding margins of error and tolerances of data used in pooling and mapping the regions of influence, the SPG stated that the magnitude of the accepted tolerance becomes critical in defining regions of influence. If accepted margins of error are low, then regions of influence can be precisely defined; conversely, if accepted margins of error are high, then the definition of separate regions of influence becomes imprecise. The SPG rejected Gulf's margins of error as exceptionally high and stated that such tolerances are not supported by the available data. The SPG contended that the use of large margins of error by Gulf resulted in the erroneous mapping of large regions of influence at Surmont.

The SPG's tolerances for pooling were as follows:

- Potentiometric surface elevations were assumed to be constant within a water pod with a tolerance of ±1 m.

- The margins of error for geological picks ranged from ±0.35 to ±1 m.

- Virgin gas pressures were mapped together as common pools with a ±6 kPa tolerance, based on extrapolation from a real variation in the gas pressure data at Surmont of ±3.6 kPa.

The SPG's main sources of data for mapping regions of influence were the gas anomalies on seismic lines, pressure tests, well logs, and production volumes. The SPG gas pools honour the seismic grid, such that the gas pools match where seismic anomalies indicate that gas is present. The edge of the seismic anomaly indicated proximity to the edge of the gas pool. The SPG submitted that seismic is one of the best tools for finding gas, noting that it is accurate and reliable; therefore, the SPG used seismic extensively in mapping gas pools. The SPG noted that Gulf's gas pool outlines bear little or no relationship to Gulf's interpreted seismic gas anomalies.

The SPG identified and differentiated gas pools on the basis of virgin gas pressures, subject to a reasonable margin of error. The virgin pressures used by the SPG were obtained from pressure tests and AOF data. The SPG did not use DSTs. Fluids and fluid contact elevations were determined from well logs, and gas-over-water pools were mapped with a constant gas/water contact that honoured a reasonable margin of error.

The SPG identified and differentiated individual water pods on the basis of their potentiometric surface elevations. In the SPG's hydrostatic interpretation of the water sands at Surmont, the potentiometric surface within the same water pod had to be constant, hence it must have had equal hydraulic heads, while different water pods may have had different hydraulic heads. As a corollary to this view, the SPG contended that gas pools with different hydraulic heads must have been in different, disconnected water pods. The SPG related the pressure data through its potentiometric surface elevation map, the elevations of the fluid contacts, the types of fluid, and the use of the SPG interpreted isopachs of the original gas cap that existed prior to biodegradation of the oil. In those cases where shale beds were present between the base of the present gas and the top of the present water, the SPG calculated a range of potentiometric surface elevations. The SPG stated that the mapped water zones were naturally depleted gas zones and that water sands visible on seismic were mapped to correspond to the edges of weak seismic gas anomalies. The SPG maintained that the water sands were visible on seismic due to weak residual gas saturations (i.e., approximately 5 per cent). Where water pods were present under gas pools, the water pods were mapped as halos extending uniformly 100 m beyond the seismically defined limits of the gas pool and as being slightly larger than the overlying gas pools. The SPG contended that drilling results substantiated this interpretation.

The SPG determined net gas pay from well logs. To calculate the volumetric gas in place, the SPG did not construct contour maps in the traditional sense. Due to the heterogeneous nature of the McMurray Formation, the SPG first defined the limits of a given gas pool by seismic. Then it averaged the gas pay from those wells that fell within the pool outline and obtained volumetric gas in place using the average pay values multiplied by the area established from seismic. The computed volumetric gas-in-place values were then adjusted to ensure that the values were larger than the material balance values. The SPG acknowledged that some pools, for example, the 00/07-24-083-07W4 (the 7-24 pool), 02/01-14-083-06W4, and 00/08-34-081-07W4 pools, were not mapped large enough to accommodate its material balance derived estimate. Although Petro-Canada contended that the SPG method assumed that each gas pool has vertical sides and a flat top, the SPG disagreed, stating that its method represented the average thickness over a pool having a variable top and thickness.

The SPG argued that its review of the pressure data was more detailed than Gulf's, noting that Gulf acknowledged that

- it did not procure and review copies of field notes regarding pressure tests;
- it used surface pressures to calculate material balance when it should have used sand-face pressures;
- it did not use all of the available pressures to calculate material balance; and
- some 60 pressure readings that it used in its analysis were in error.

The SPG submitted that Gulf's mapping of the gas pools was not consistent with its material balance estimates of gas in place and that if Gulf's hypothesis of water drive was correct, the material balance estimates should have always been greater than the volumetric gas-in-place estimates, which was not the case. The SPG also submitted that Gulf mapped its gas pools with an unrealistic tolerance of variation and that it mapped multiple stratigraphic units into common gas pools.

Pressure Communication Within and Between Regions of Influence

The SPG presented data from some producing regions of influence (as mapped by the SPG) that illustrated that pressures within producing gas zones and within water zones were declining at rates of 44 kPa/year and 17 kPa/year respectively. On the basis of these data, the SPG concluded that the rate of pressure decline in producing gas zones and underlying water zones was slow and was decreasing as production rates decreased. The SPG also presented data from some nonproducing regions of influence (as mapped by the SPG) that showed that no pressure depletion was occurring. The SPG submitted that because of the slow rate of pressure decline, there was time to monitor the steam chamber rise at the Surmont pilot, and as such there was no immediate crises requiring gas wells to be shut in.

With regard to pressure transmission between regions of influence, the SPG submitted that if effective pressure communication existed between various pools, then, by definition, these pools must be in the same region of influence. It further submitted that pressure rebound was and would be observed at the producing well after production shut-in as a result of pressure equilibration across the pool, but not because of pressure transmission from adjacent gas pools. The SPG disagreed with Petro-Canada's contention that pressure rebound in a gas pool could be due to either water influx from the underlying water pod or gas migration through a water pod, as suggested by Petro-Canada's numerical simulations. It submitted that the interpretation offered by Gulf and Petro-Canada with respect to pressure transmission between regions of influence was based on inconclusive data.

The SPG stated that pressure data from the 00/07-08-082-06W4 water pod (the 7-8 water pod) demonstrated that there was no pressure communication between regions of influence and nonproducing regions. The 00/07-08-082-06W4 well was drilled in 1981, ten years prior to any area gas production, with an initial pressure of 1531 kPa absolute (kPaa). A second well at the same location drilled seventeen years later, in 1998, had a gas zone pressure of 1529 kPaa. The SPG contended that no pressure depletion had resulted from eight years of adjacent gas production. The nearest gas pool to these wells was penetrated by the 00/12-31-081-06W4 well, the pressure of which had been drawn down by almost 700 kPa by June 1998. Other wells drilled into the 7-8 water pod also encountered virgin pressure conditions, confirming that pressure communication has not occurred between regions of influence in the heart of the Surmont leases.

The SPG stated that the pressure data from the 7-14 well did not provide any evidence of pressure communication between regions of influence, as interpreted by Gulf and Petro-Canada, but rather that the pressure in the 7-14 well was a record of the pressure history of a much more laterally extensive Chard pool located south of Surmont. Using average pressures, the SPG submitted that the 7-14 well does not belong to the pool, as mapped by Gulf, but rather the well should be mapped with the 00/11-20, 00/11-22, and 00/7-32-79-6W4 wells and the 00/10-7-80-6W4 well. The SPG noted that an initial pressure of 1756 kPaa for the pool containing these wells matched the initial pressure for the 7-14 well within a reasonable margin of error. It also noted that similar log character and pressure history trends of the wells supported its interpretation of the pooling.

In its analysis, the SPG determined from the Gulf piezometer data that the pressure responses within producing gas pools at Surmont were nonuniform. The SPG interpreted this to be a consequence of the complex interbedding of highly variable sands and mudstones within these gas reservoirs. The SPG further noted that most of the McMurray gas pools did not have adequate pressure control to properly assess the pressure gradients across pools.

The SPG noted that the presence of mudstone beds within the water zones was significantly higher than the occurrence of such beds in overlying gas zones. The SPG conducted a log study of 108 gas zones and 120 water zones in the McMurray Formation at Surmont. It found that the water sands and gas sands were not the same quality of reservoir rock and that considerably more mudstone existed within the water zones in comparison to the gas zones. The SPG stated that because it was impossible to resolve thin mudstone interbeds using log analysis, the true mudstone contents in the water zones might be larger, exceeding 39.5 per cent. Therefore, the SPG concluded that mudstone interbeds in the water sands would impede pressure transmission.

The SPG referred to pressure distributions in the 7-24 pool as an example of how reservoir heterogeneity was reflected in pressure distributions and p/z-versus-cumulative-production plots. It stated that pressures in the water sands that occur beneath producing gas pools are not in lateral equilibrium, as suggested by the pressure distribution when the 7-24 gas pool was prematurely shut in. Pressure depletion was greatest in the gas and water zones and least in the bitumen zone. Therefore, the SPG concluded that there was no pressure communication between regions of influence through the bitumen section. The SPG presented calculations of average pool pressures during and after production to show that they had not changed, which the SPG contended was further proof that there was no lateral pressure transmission either. Additionally, the SPG stated that, regarding p/z-versus-cumulative-production plots, pressures at the producing wellbore were not representative of average pressures within a given pool. The SPG noted that a pressure sink existed around the wellbore and, therefore, successive p/z data points gave increasing material balance estimates of in-place gas, as the pressure sink progressively expanded and tapped farther into the reservoir. The SPG concluded that nonlinear p/z-versus-cumulative-production plots for the Surmont gas pools were due to inherent reservoir heterogeneity and not an indication of water influx.

The SPG used a reservoir model only to assess the effect of bitumen characteristics on pressure transmission in bitumen strata and contended that the pressure transmission was restricted to short distances of propagation (i.e., up to 120 m).

In light of the above considerations concerning pressure variation within and between regions of influence, the SPG concluded that Gulf's and Petro-Canada's argument about widespread pressure depletion between regions of influence was difficult to accept and that the regional hydrological regime was, in fact, static rather than dynamic. The SPG further stated that pressure decreases could not be transmitted across the entire Surmont area within the time frame of gas and bitumen production. As a result, the SPG contended that continued production of the Wabiskaw-McMurray gas reserves would not impact on or result in wastage of the bitumen resource potential at Surmont.

Regarding the monitoring program proposed by Gulf and Petro-Canada, the SPG expressed its concern that such a program would be at the SPG's expense, and therefore it was not in favour of such a program.

5.4.4 Views of the Board

Pressure transmission is a fundamental issue because both Gulf and Petro-Canada submitted that the drop in pressure caused by gas production in strata overlying bitumen reservoirs is detrimental to the SAGD process for bitumen extraction. Therefore, the extent, magnitude, rate, time frame, and paths for transmission of pressure decrease are critical elements in establishing the extent of the effects of gas production from Wabiskaw-McMurray gas pools. Within a system where hydrodynamic communication has been established, the transmission of pressure changes depends on fluid and rock properties (i.e., compressibility, viscosity, permeability, and porosity) and their distributions, on the distance from the production wells, and on time. The pressure drop, which is highest at the production well, decreases with distance from the well with a magnitude and rate that depend on the permeability and compressibility of the fluid-saturated porous medium. Higher permeability allows a faster transmission of a pressure change or, conversely, a higher drop in pressure at a given distance. The compressibility of the porous medium has an opposite effect on pressure transmission. In an isotropic and homogeneous porous medium, pressure changes propagate radially from the production well. In an anisotropic and/or heterogeneous medium, pressure changes propagate unequally, faster and farther through high-permeability and low-compressibility media, such as water-saturated sands, than through low-permeability and high-compressibility media, such as shales.

Definition of Regions of Influence

In its *Gas/Bitumen Inquiry Report*, the Board defined a region of influence as the extent of a gas pool directly overlying bitumen or the extent of a water zone in the case of gas overlying water overlying bitumen. In *Interim Directive 99-1*, the Board modified the definition of a region of influence to be the extent of a gas pool directly overlying bitumen or the combined extent of the gas pool and water zone in the case of gas overlying water overlying bitumen. This definition is based on the static distribution of various fluids saturating the pore space. The Board notes that the definition used by Gulf and Petro-Canada in mapping regions of influence was as follows: an area of approximately equal hydraulic heads and high transmissivity separated from another region of influence with differing hydraulic heads by an area of lower transmissivity. The Board believes that this definition represents a step in the right direction of considering all the parameters that pressure transmission depends on, but it is still incomplete given the dynamic, hence time-dependent, nature of the process. The Board believes that theoretically a proper definition of a region of influence should take into account the distributions and properties of gas and water, rock properties (i.e., permeability and compressibility), distance from the producing wells, time, and rates of production or pressure drop at the producing well. Furthermore, the Board believes that if a point is or would be affected by production from a well, then inherently it is within the region of influence of that producing well.

While recognizing the need to use a proper definition of regions of influence, the Board acknowledges the difficulty in applying it because of a lack of data. Collecting data at the resolution needed for a precise delineation of a region of influence is impractical and economically prohibitive. In addition, rates of future gas production cannot be established; at best they can be forecast under various economic scenarios. Although abandonment pressure may constitute a defining (i.e., limiting) parameter, unfortunately it does not provide for the pressure distribution at the time production is abandoned. Therefore, the Board acknowledges that it is difficult, perhaps impossible, to establish the actual size and shape of the regions of influence in the Surmont area with the available data and knowledge about the geometry, heterogeneity, and properties of the Wabiskaw-McMurray gas pools and aquifer and without clear scenarios for gas production and bitumen SAGD development. The Board believes that the minimum size of any region of influence is that provided by the definition in *Interim Directive 99-1*.

Mapping of Regions of Influence

The Board notes that Gulf, Petro-Canada, and the SPG each used a multidisciplinary approach to map the regions of influence and yet the resulting interpretations are significantly different. The Board believes that this is a result of the various tolerances used, the interpretive nature of the data themselves (i.e., well logs, pressures, and seismic), and the variability and reliability of the data sources.

The Board believes that the use of a ±1 m tolerance versus a ±2 m tolerance for gas/water and water/bitumen contacts could significantly affect the delineation of gas and water pools. The Board notes that both Gulf and the SPG used seismic data in the delineation of the gas pools. However, contrary to the SPG's view, the Board believes that due to the limited ability of the seismic to resolve thin gas accumulations, the precise placement of the gas pool edges cannot be determined by seismic alone. With respect to the pressure data, the Board notes the lack of consensus among the hearing participants, even after the technical conference, as to the validity of individual pressure values and the method of interpreting whether or not these values represent virgin conditions. The Board recognizes that there are limited pressure data of questionable quality for many of the wells in the Surmont area and believes that additional pressure data through time (i.e., time series) for individual wells would be required for any definitive pool delineation. As a result, the Board relied more on geological correlation and common gas/water and water/bitumen contacts, since limited confidence can be placed on the existing pressure data to substantiate the pooling interpretations submitted to the hearing. Furthermore, the Board believes that this lack of quality pressure data limits the confidence that can be placed on p/z-versus-cumulative-production plots. As a result, the Board believes that it is unable to validate the volumetric reserve estimates, and ultimately the pool areal extent, by material balance methods.

The Board notes from Gulf's submission that the marine sand gas production could affect the bitumen resource because the zone is commingled with channel sand gas in the wellbore and/or because natural communication exists with channel sand gas due to the effects of channelling. The Board further notes that the SPG did not present evidence regarding the potential effects of marine sand gas production. The Board believes that the close proximity (i.e., typically 0 to 5 m) of the marine sand gas accumulation to channel sand gas accumulation within the wellbore prohibits the effective isolation of these intervals. The Board concludes that due to the potential for natural communication to occur and because artificial communication does exist, marine sand gas production could potentially affect bitumen recovery.

The Board notes that the SPG interpreted the water zones at Surmont to be restricted to the size of the overlying gas pools (i.e., within 100 m), whereas Gulf interpreted the water zones to be more laterally extensive, at times encompassing several gas pools. The Board has reviewed the wells on the Surmont leases and has determined that there are wells more than 100 m beyond some gas pools where water is present. On the basis of this observation, the Board considers a 100 m water halo to be quite conservative. However, the lack of good quality pressure data prohibits the Board from fully assessing the hydraulic head values presented by Gulf and Petro-Canada to verify the limits of their water pool interpretations. Furthermore, in assessing some of the gas pools on the Surmont leases, the Board interprets that some of the SPG gas pools are too small.

Pressure Communication Within and Between Regions of Influence

As stated in Section 5.1, the Board believes that the Wabiskaw-Upper McMurray strata form a continuous aquifer such that pressure transmission and fluid movement would occur at Surmont. The Board notes that the Wabiskaw-Upper McMurray aquifer is quite heterogeneous, as indicated by geological logs and permeability values. This heterogeneity affects the pressure transmission and fluid flow within and between regions of influence.

The Board believes that the numerical simulations presented by Gulf and Petro-Canada regarding pressure transmission in the heterogeneous Wabiskaw-Upper McMurray aquifer are generic and indicative only of the direction of the process, but that they do not cover the full spectrum of possible scenarios. Therefore, the Board believes that these simulations are not precise in terms of time, distance, and rate of pressure transmission and of the predicted drop in pressure at any given point in time and location. Furthermore, the Board also believes that the pressure observations are only qualitatively indicative of pressure transmission across the Wabiskaw-Upper McMurray aquifer, because, unfortunately, their interpretation is difficult and open to debate as a result of

- lack of historical data;
- location of the pressure observations being dictated by the location of the exploration and production wells, not by the need to determine the pressure field; and,
- possible unidentifiable superposition of pressure effects from multiple sources.

While the Board considers the different arguments presented by the hearing participants regarding the interpretation of the piezometer data to have merit, none of them was compelling enough to allow the Board to draw a definitive conclusion regarding the interpretation of these measurements. With respect to the effects of installation procedures on piezometer measurements, the Board believes that no conclusive evidence was presented to permit the assessment of when the first valid piezometer measurement was recorded.

The Board has reviewed the hearing participants' interpretations with respect to the pooling of the 7-14 well because it believes that a conclusion regarding pooling is critical to explain the well's observed pressure response. The Board interprets the gas accumulation to exist within marine sand because the gamma ray log indicates an upward coarsening sequence underlain by an extensive correlatable shale. Wells with similar log character were found to the south, whereas the wells to the east exhibit a fining upward gamma ray signature indicative of channel sands. As a result, the Board concurs with the SPG's pooling interpretation of this well, which it correlated geologically with wells to the south. The Board further examined the pressure and production data of the wells in the area and determined that the data did not contradict the geological correlation. As a result, the Board does not believe that the pressure data for this well represent an example of communication between regions of influence.

With regard to the hydrocarbon emplacement models, the Board considers the Gulf and Petro-Canada models to be more representative than the SPG's. The Board believes that extensive water circulation as presented in the models would be required to biodegrade the 890 10^9 bbl (141 10^9 m^3) of oil estimated to be present in the oil sands deposit. However, the Board believes that the geological time frame required for oil biodegradation into bitumen, compared with the time frame of gas and bitumen production, renders this process not applicable to the case of pressure depletion caused by gas production.

As stated in Section 5.1.4, the Board believes that the Wabiskaw-Upper McMurray aquifer is weak and therefore is unable to provide sufficient support for natural pressure rebound across the entire Surmont area. In terms of the initial stages after the shut-in of gas production, the pressure disequilibrium from the initial state of the system would cause pressure rebound in some regions of influence at the expense of others. As time passes, this effect would propagate toward the outer limits of the aquifer, and the system would attempt to return to the equilibrium state dictated by the elevation of the recharge and discharge areas and the permeability distribution between them. However, the Board believes that the time frame for this natural process is much longer (i.e., over geological time) than the time frame envisaged for gas and bitumen production.

The Board believes that the evidence presented with respect to pressure transmission and depletion is highly interpretive but sufficient to establish a trend within regions of influence, although inconclusive between regions of influence. With respect to the SPG's contention that there is time to monitor the steam chamber rise at the Surmont pilot because of the slow rate of pressure decline, the Board notes that substantial volumes of gas have already been produced at Surmont, resulting in a significant reduction in reservoir pressure in some areas. Therefore, the Board believes that continued pressure depletion would increase the risk of bitumen sterilization on the Surmont leases. The Board notes that Gulf and Petro-Canada suggested that a pressure measurement and monitoring program be implemented at Surmont. The Board would be prepared to work with the parties to implement such a program if requested.

The Board notes that both Gulf and the SPG have mapped substantive gas reserves on the Surmont leases. The Board concluded in Section 5.2.1.4 that the occurrence of thick bitumen-saturated sands in direct communication with overlying gas and water zones is extensive and randomly distributed. This supports Gulf's contention that gas production should not be allowed since moving laterally can mean moving from off-channel, nonreservoir strata to part of a channel most prospective for SAGD bitumen development. On this basis, where a gas well does not encounter thick bitumen, the production from that well may be affecting bitumen nearby through lateral continuity. Therefore, the Board concludes that all the Wabiskaw-McMurray gas being produced by wells on the Surmont leases is or has the potential to be associated with the underlying bitumen, either through direct vertical continuity or indirectly through lateral continuity of the gas and water zones.

The Board has reviewed the Wabiskaw-McMurray gas wells requested by Gulf to be shut in within the three-section buffer area surrounding the Surmont leases. The Board believes that the gas being produced from only those wells that are connected to the Surmont leases through gas and/or water pooling is or has the potential to be associated with bitumen on the Surmont leases. In determining the pooling of the wells in the buffer area, the Board used primarily geological correlation of the intervals, elevation of gas/water or water/bitumen contacts (i.e., ± 1 m) and, where available, pressure data.

The Wabiskaw-McMurray gas wells that the Board believes are or have the potential to be producing gas associated with the bitumen on Gulf's Surmont oil sands leases are listed in Appendix 1.

6 EFFECT OF ASSOCIATED GAS PRODUCTION ON SAGD BITUMEN RECOVERY

6.1 Reservoir Model Studies

6.1.1 Views of Gulf

Gulf resubmitted the reservoir modelling work that it had submitted to the Gas/Bitumen Inquiry. Gulf used the Computer Modelling Group's Steam and Additives Reservoir Simulator (STARS) for its modelling work. Gulf's models were three-dimensional representations of a half-symmetry element of a SAGD well pair. The pay zone drainage half-width (i-direction) was 50 m, which represents a distance of 100 m between well pairs. Gulf used two different bitumen pay zone descriptions, with gross bitumen thicknesses (k-direction) of 52.5 m and 28 m. Both pay zones included shale barriers represented by discontinuous low porosity and permeability layers (which included reducing the vertical permeability from 2000 to 200 mD).

The models included a 3 m thick gas cap and two different top water zones with thicknesses of 3 m and 10.5 m. These thief zones were modelled with grid blocks having a lateral extent of 230 m. The thief zones were modelled as "infinite acting" by means of horizontal wells located in the last grid blocks. The gas cap had one well set to produce all fluids at that location at a pressure only 1 kPa above the initial gas cap pressure. The water zone had one production well and one injection well, which provided for water inflow or outflow if the pressure at the wells changed by a few kilopascals. The models had two layers along the SAGD wellbores (j-direction). One layer represented the bulk of the steam chamber and was 650 m long. The other was a "short-circuit" layer 50 m long. Gulf included the short-circuit layer to allow for early breakthrough of the steam chamber into the thief zone at a particular location along the wellbore. The horizontal and vertical permeabilities of the bitumen pay in the short-circuit layer were 1.4 times those of the bulk layer.

Gulf modelled the performance of a SAGD process in the presence of thief zones by applying a mitigating strategy for some cases and a limited mitigating strategy for other cases. The mitigating strategy included reducing the steam injection pressure close to the thief zone pressure prior to steam breakthrough into the thief zone, changing the steam injection pressure as a function of the ratio of produced water rate to steam injection rate and using a noncondensable gas (NCG) blanket to maximize the ratio of horizontal to vertical steam chamber development. The limited mitigating strategy used the same approach, but the strategy was not optimized. The main effect of this was that the steam injection pressure was generally higher than it was with mitigating strategy. Gulf used a combination of factors, including the bitumen production rate, the steam-oil ratio (SOR), the water-oil ratio (WOR), and a 30-year operating limit, to determine when to terminate the model runs.

The results of the model runs that Gulf initially submitted to the Gas/Bitumen Inquiry are summarized in Table 2. Gulf stated that while each simulation run had not been completely optimized in terms of such factors as interwell distances and operating strategies, the trends evident in the simulations were important in looking at the impact of a particular variable rather than the absolute recovery factor associated with a particular case. Gulf contended that the simulation runs were sufficient to clearly indicate the negative impact of reduced reservoir pressure as a result of gas cap production.

Table 2. Gulf model study results initially submitted to Gas/Bitumen Inquiry

Case	Bitumen zone thickness (m)	Thief zone thickness (m) Gas	Water	Gas cap pressure (kPa)	Injection strategy	Recovery (%)	CDOR (m^3/d)	Cum SOR	Operating time (years)
1	52.5	3	10.5	1340	M[1]	34.6	127.7	1.67	7
2	52.5	3	10.5	800	M	29.9	96.2	1.63	8
2a	52.5	3	10.5	800	LM[2]	25.4	130.5	2.51	5
3	52.5	3	10.5	200	M	21.6	79.1	1.80	7
3a	52.5	3	10.5	200	LM	18.1	115.8	2.86	4
4	52.5	3	3	1340	M	78.2	126.0	2.17	16
8	52.5	3	3	800	M	77.2	99.3	2.04	20
6	52.5	3	3	200	M	64.0	54.5	1.98	30
6a	52.5	3	3	200	LM	51.2	81.9	4.00	16
5	28.0	3	3	1340	M	78.8	74.2	2.46	15
7	28.0	3	3	200	M	66.6	31.1	2.73	30
9	28.0	10	0	1338	M	52.1	61.2	1.73	12
10	28.0	10	0	400	M	47.4	37.0	1.68	18

[1] M = mitigating strategy.
[2] LM = limited mitigating strategy.

Gulf submitted the following additional modelling work to the hearing; the results are summarized in Table 3.

- Evaluation of the effect of a higher initial solution gas content (Rsi) at low SAGD pressure (Case 9*): This was a modification of Case 6, which involved increasing Rsi from 1.5 mole per cent to 5.5 mole per cent. The model predicted a significant reduction in SAGD performance over a 4-year period starting at year 2.5. The SAGD performance recovered to a value similar to that with a low Rsi after the main section of the steam chamber communicated with the thief zones.

- Evaluation of the effect of reduced vertical permeability (k_v) of the shale barriers and increased Rsi (Cases 10* and 11): Case 10* was a modification of Case 4, which involved reducing k_v from 200 to 20 mD. Case 11 was a modification of Case 6, which involved reducing k_v from 200 to 20 mD and increasing Rsi from 1.5 to 5.5 mole per cent. The two model runs showed that sections of the steam chamber where the mobility was reduced suffered drastic reductions in performance if the gas cap was produced to abandonment pressure and solution gas effects exacerbated the problem.

- Evaluation of the effect of using lab-measured k-values[8] rather than the history-matched (or intermediate) k-values used in Gulf's initial models and the effect of changes in Rsi (Cases Rebut 10, Rebut 11, and Rebut 14): Rebut 10 was a modification of Case 4, which involved using lab-measured k-values rather than history-matched k-values. Rebut 11 was a

* Cases 9 and 10 that were submitted to the hearing (as distinguished from Cases 9 and 10 initially submitted to the Gas/Bitumen Inquiry) (see Table 2).

[8] k-values determine the amount of solution gas that will dissolve into bitumen at a particular pressure and temperature

Table 3. Gulf model study results submitted to hearing

Case	Description	Bitumen zone thickness (m)	Thief zone thickness (m) Gas	Water	Gas cap pressure (kPa)	Recovery (%)	CDOR (m^3/d)	Cum SOR	Operating time (years)
9*	Rsi = 5.5 mole %	52.5	3	3	200	21.4	54.8	2.06	10[1]
6	Rsi = 1.5 mole %	52.5	3	3	200	25.8	66.0	2.31	10[1]
10*	Rsi = 5.5 mole %; k_v (of shales) = 20 mD	52.5	3	3	1340	37.6	60.4	2.07	16[1]
11	Rsi = 5.5 mole %; k_v (of shales) = 20 mD	52.5	3	3	200	13.8	22.0	2.23	16[1]
4	Rsi = 5.0 mole %; history-matched k-values	52.5	3	3	1340	73.9	136.1	2.22	14[1]
Rebut 10	Rsi = 5.5 mole %; lab k-values	52.3	3	3	1340	73.6	135.6	2.13	14[1]
Rebut 14	Rsi = 0; lab k-values	52.5	3	3	1340	72.0	132.6	2.36	14[1]
6	Rsi = 1.5 mole %; history-matched k-values	52.5	3	3	200	64.0	54.5	1.98	30
9*	Rsi = 5.5 mole %; lab k-values	52.5	3	3	200	21.4	54.8	2.06	10[1]
Rebut 11	Rsi = 0; lab k-values	52.5	3	3	200	64.8	55.2	2.00	30
M2GAS	SPG case, run for 12 years	52.5	6	0	1340	65.2	139.0	2.56	12
M2GAS	SPG case, optimized by Gulf	52.5	6	0	1340	69.7	148.6	1.82	12
M2P13R	SPG repressured case, run for 12 years	52.5	0.2	5.8	1340	60.7	130.6	2.75	12
G52-3-10		52.5	10	3	1340	67.2	130.6	2.50	14
G52-3-10R	Repressured with water	52.5	1	12	1340	22.0	120.0	2.54	5
G28-3-10		28.0	10	3	1340	73.6	76.1	2.54	15
G28-3-10R	Repressured with water	28.0	1	12	1340	14.2	84.5	2.58	2.6

* Cases 9 and 10 that were submitted to the hearing (as distinguished from Cases 9 and 10 initially submitted to the Gas/Bitumen Inquiry) (see Table 2).
[1] Not run to normal termination.

modification of Case 6, which involved using dead oil (no initial solution gas content) rather than an Rsi of 5.5 mole per cent and lab-measured rather than history-matched k-values. Rebut 14 was a modification of Case 4, which involved using dead oil instead of an Rsi of 5.5 mole per cent and lab-measured rather than history-matched k-values. In rebuttal of the SPG's critique that Gulf did not correctly model the evolution of solution gas or the effect of dispersion of NCG, Gulf stated that these sensitivity tests showed that its model results depended very little on the choice of k-values (and that the use of higher k-values as required by the SPG would enhance Gulf's submission, not the SPG's submission). Gulf also maintained that the issue of dispersion of NCG was not important in its Surmont models. Gulf pointed out that the initial solution gas content of the bitumen at Surmont is about three times higher than that at Dover. This, combined with the higher operating pressure of the Dover SAGD pilot, would mean that the volume of NCG in a 200 kPa steam chamber at Surmont would be more than forty times the volume at Dover for equal-size steam chambers.

- Critique of the SPG's modelling work from which the SPG concluded that similar SAGD recovery factors could be obtained at gas cap pressures of 500 kPa and 1340 kPa: Gulf pointed out that the SPG could not obtain similar recovery factors for one of the three cases it ran. For the other two cases, the SPG could only obtain similar recovery factors by continuing the SAGD operation at a gas cap pressure of 500 kPa beyond the economic limit. The calendar-day oil rate (CDOR), SOR, and WOR were all worse at 500 kPa.

- Critique of the SPG's modelling work regarding the repressuring of depleted gas caps with water and additional modelling work by Gulf:

  - Gulf pointed out that at the Gas/Bitumen Inquiry the Alberta Producers Group stated that the impact of the overlying water was more severe than the effect of the overlying gas zone, which demonstrated that the water zone dominated the performance of the SAGD process. With its model runs on repressuring the overlying gas zones with water, the SPG changed its position regarding the effects of overlying water.

  - Gulf submitted that two of the SPG cases had a very thick bitumen pay zone and an original gas cap thickness of only 3 m. The thick bitumen pay zone and thin gas cap, combined with the pre-existing overlying water, minimized the effect of repressuring with water. However, even in these cases, the SPG model runs showed that repressuring with water resulted in worse SORs, WORs, and water balances (ratio of produced water to injected steam).

  - Gulf stated that the SPG ran the case with only gas overlying bitumen (Case M2GAS) incorrectly. When Gulf ran this case correctly, it showed that the comparable case (Case M2P13R), which involved repressuring with water, had much poorer SAGD performance.

  - Gulf stated it was contradictory that most of the time the SPG tried to show lack of harm with low-pressure SAGD, yet concluded it would be beneficial to repressure above the native pressure to 2000 kPa. Gulf submitted that repressuring to 2000 kPa would not be feasible for several reasons: it would add to the stress placed on the overlying Clearwater shales and increase the risk of wellbore failures; it would be difficult to sustain since pressure leak-off to neighbouring regions of influence would be increased; and it would require the high-pressure pumping of massive volumes of water. In addition, repressuring to 2000 kPa with water would be harmful to SAGD performance.

- ♦ Gulf submitted four additional cases (Cases G52-3-10, G52-3-10R, G28-3-10, and G28-3-10R) that compared the performance of SAGD operations conducted in the presence of undepleted gas caps with those conducted in the presence of depleted gas caps that had been repressured with water. These cases showed that SAGD performance was greatly harmed when water was used to repressure a depleted gas cap. Gulf stated that repressuring with water was harmful because the top water has high heat capacity and drains into the steam chamber and it must then be lifted to the surface, separated in the surface facilities, and disposed.

- Critique of the SPG's model runs in which Gulf's discontinuous shale barriers were removed and a 10.5-m continuous IHS layer was added at the top of the bitumen zone: Gulf submitted that although the SPG's model exhibited somewhat improved SAGD performance, it still showed that the steam chamber pressure had to be reduced toward the depleted gas cap pressure (to 300 kPa for a gas cap pressure of 200 kPa). This indicated that the IHS zone modelled by the SPG was not a block to steam rise. Also, the bitumen production rate was still reduced to one-half that at the higher pressure.

- Rebuttal of the SPG's critique regarding the geological description used in Gulf's models:

  - ♦ With respect to the SPG's inference that the Surmont geology should be the same as that at the Dover pilot, the fact that Surmont has massive thief zones while Dover does not suggests there are differences between Surmont and Dover.

  - ♦ The source of the geological description used in Gulf's model was the Alberta Oil Sands Technology and Research Authority (AOSTRA) study, which was done in May 1995, prior to the gas/bitumen conflict.

  - ♦ Even if the SPG was correct and Surmont had a continuous IHS zone at the top of the pay zone, the SPG's own model study showed that the SAGD operating pressure must still be reduced towards the depleted gas cap pressure and the bitumen rate would fall dramatically.

- Rebuttal of the SPG's critique of how Gulf operated its model runs:

  - ♦ Gulf submitted that its runs were optimized and then terminated based on a number of economic factors, including bitumen rate, SOR, WOR, and water balance. Gulf provided all the rates graphically to show that its operations and termination times were reasonable.

  - ♦ The two low-pressure cases that received no gas optimization were run for 30 years, so a gas wind-down at the end of the runs would have made virtually no difference to the results.

Gulf provided a list of factors that, in its view, affect and those that do not affect the simulation trends or conclusions regarding the effect of gas production on SAGD performance. These factors are summarized in Table 4.

In summary, Gulf provided the following arguments regarding the use of reservoir modelling to evaluate the effect of associated gas production on SAGD bitumen recovery:

- Numerical simulation is the best available tool.

- Gulf's numerical model results were consistent with the SAGD performance at Surmont, the piezometer data at one of the observation wells at Surmont, the available steam rise data at Surmont, the steam rise data in the IHS zone at the Dover Phase B pilot, and material balance assessment of bitumen recovery from the IHS zone at the Dover Phase B pilot.

- When possible, history matching is advisable. However, often it is not possible to wait many years for field information. This is the case at Surmont, since waiting for definitive data from the Surmont pilot that shows steam is being lost to the thief zones would result in loss of one of the richest oil sands deposits in Alberta.

- Because the McMurray Formation is very complex, it is not possible to represent the Surmont geology exactly in a reservoir model. However, Gulf used a variety of models and its initial simulations gave a good prediction of the Surmont pilot performance. Hence the geological model used by Gulf gave a practical, average representation of the pilot area.

- All numerical models showed that the SAGD pressure must be reduced to close to the thief zone pressure before breakthrough of the steam chamber into the thief zone.

- Numerical modelling indicated that at a gas cap pressure of 800 kPa, the SAGD bitumen rate is reduced significantly compared to that at the native pressure and the risk factors are increased. However, the recovery factor and SOR show little change. Hence, SAGD performance remains promising at an intermediate thief zone gas pressure.

- Numerical modelling indicated that as gas production continued to abandonment pressure, the SAGD bitumen production rate is greatly reduced, the SOR is generally worse, the recovery factor is greatly reduced, and the risk factors become more onerous.

- The models were run under ideal conditions. Under real life conditions, which include the risk factors mentioned in Table 4, SAGD operations could not continue after breakthrough of the steam chamber into a low-pressure thief zone. Bitumen recovery would be drastically reduced compared to the submitted simulation results.

- Most simulations were done for zones with very thick bitumen pay. As the bitumen pay thickness decreases, the impact of gas cap pressure depletion on SAGD performance is even greater.

Table 4. Gulf list of factors that affect/do not affect simulation trends and conclusions regarding the effect of associated gas production on SAGD performance

Factors that do affect simulation trends and conclusions		
1.	Thief zone pressure	Reducing the thief zone pressure below the native pressure by gas production is very detrimental because it results in a loss of recovery efficiency even under ideal conditions. It also introduces the following risk factors: solution gas collecting in the steam chamber; water influx into depleted gas caps; geomechanical effects; artificial lift; higher residual oil saturation in the steam chamber; increased impact of flow baffles; increased well failures during a 30-year operation; and the inability to apply new process technology for 30 years.
2.	Thickness of overlying water sand	Water sands 3 m or less can be managed if the thief zone pressure is not depleted, whereas water sands 10.5 m thick reduce the recovery factor significantly. Repressuring with water has deleterious effects.
Factors that do not affect simulation trends and conclusions		
1.	Permeability in the thief zone	Since the water and gas phases have low viscosities, the fluids can have significant mobilities even if the absolute permeability is quite low. Vertical permeability has even less influence than horizontal permeability in the water sand because the distance fluids have to flow vertically is only about 10 m.
2.	Permeability in the pay zone	If the permeability is varied over the range of possible values at Surmont, it would have an effect on SAGD performance, but it would not affect the trend regarding the detrimental effects of gas production.
3.	Bitumen viscosity versus temperature curves	Since bitumen is immobile at 10°C, it does not matter whether the viscosity is 2×10^6 mPa·s or a much higher value at 10°C.
4.	Exact termination criteria	More precise determination of when to terminate operations would not affect Gulf's trends or conclusions.
5.	History-matching field performance prior to sensitivity studies	History matching would be beneficial but is not essential. In this case it is not possible to wait for history matching because, if the model predictions are correct, irreparable damage will have occurred. It is very common to do simulation sensitivity studies with new processes without the luxury of being able to history match.
6.	Fourth constant pressure well in thief zone	Having no injection well in the gas cap is expected to have little effect on the reported results because the dominant flow direction should be out of the thief zone and the gas sand should not have counterflow effects.
7.	k-values and dispersion of NCG	Gulf used both intermediate and lab k-values, which do not affect Gulf's trends. Gulf also used initial solution gas saturations from 0 to 5.5 mole per cent, and all the simulations support Gulf's trends and conclusions.
8.	Start-up time	Whether the start-up time is 20 or 60 days has very little impact on the overall SAGD performance for operations that last 7 to 30 years. Also, the accuracy of the start-up phase modelling means nothing with regard to the accuracy of the subsequent SAGD modelling since the two phases are modelled differently.
9.	Geological model	The geological model can vary widely and still support Gulf's trends and conclusions regarding the effect of gas production on SAGD performance. All the models used by Gulf, Petro-Canada, and the SPG show that the steam chamber communicates with the overlying thief zone during early SAGD operations, and prior to this the steam chamber pressure must be reduced to close to the thief zone pressure.

(continued)

Table 4. Gulf list of factors that affect/do not affect simulation trends and conclusions regarding the effect of associated gas production on SAGD performance (continued)

Factors that do not affect simulation trends and conclusions (continued)	
10. Permeability within the flow baffles	The horizontal permeability within the flow baffles does not matter – lateral flow will be dominated by flow within the high-permeability sand surrounding the baffles. The vertical permeability of the flow baffles does affect SAGD performance, but none of the changes discussed at the hearing would change Gulf's trends.
11. Continuous barriers	A continuous flow barrier for 20 well pairs would have to be about 0.7 km by 3 km and have to be at least 5 m thick. There is no evidence that such barriers exist at Surmont.
12. IHS	The presence of IHS at Surmont does not affect Gulf's conclusions regarding the effect of gas production on SAGD.
13. Presence of bottom water	Gulf believes bottom water is manageable. If the bottom water is not very extensive, it could be handled by allowing the water to be produced into the SAGD wells or into separate water production wells until the pressure in the bottom water equals the required SAGD pressure. If the bottom water is extensive, the SAGD production wells would have to be offset high enough above the bottom water to avoid the creation of a heated path between the bottom water and the production wells.

6.1.2 Views of Petro-Canada

Petro-Canada also used STARS for its modelling work. Petro-Canada's models were three-dimensional representations of a half-symmetry element of a SAGD well pair, as were Gulf's models. The pay zone drainage half-width (i-direction) was 50 m. Petro-Canada developed two models based on the properties of two wells it considered to be representative of the geology at the Chard A Bitumen Prospect inside the three-section buffer area surrounding Gulf's Surmont leases. Model 1 had 36 m of bitumen pay, a 4 m top water zone, and a 8.5 m gas cap (z-direction). The vertical permeabilities of the bitumen pay ranged from 500 to 2500 mD. Model 2 had 18 m of bitumen pay, 13.5 m of bitumen zone, a 5 m top water zone, and a 10.5 m gas cap (z-direction). The vertical permeability of the bitumen zone was 100 mD. Regarding the permeability values used in reservoir modelling, Petro-Canada explained that they could not be determined just from core analysis or well test analysis. Since these sources of permeabilities are not normally representative of the grid size used in modelling, there is a need to "upscale" the permeabilities. The vertical permeability of 100 mD used for the bitumen zone was the history-matched value of the IHS layer at the Dover pilot. The top water and gas zones were modelled with grid blocks having a lateral extent of 250 m. These thief zones were modelled as being laterally "unconfined" by including gas and water production sinks at the tops of the gas cap and top water zone, with minimum production pressures set at 5 kPa above the early time pressure. Also, a water injection source was included at the bottom of the water zone with a maximum pressure set at 5 kPa below the early time pressure. The models had two layers along the SAGD wellbores (j-direction). One layer represented the bulk steam chamber and was 700 m long. The other layer was a "breakthrough column" 50 m long. Petro-Canada's reason for including a breakthrough column was as follows: since reservoir quality can change rapidly over distances smaller than the well pattern size, the first time direct communication is established between the steam chamber and the thief zone it will be at one location only, and not uniformly along the length of the well. Petro-Canada set the vertical permeabilities for the breakthrough column in Model 1 equal to the horizontal permeabilities (which resulted in the vertical permeabilities ranging from 1000 to 5000 mD), while the breakthrough column in Model 2 consisted of 31.5 m of bitumen pay.

Petro-Canada optimized the model runs by closely monitoring the response at the injection and production wells and changing the operating conditions of the injection well as necessary. Generally, once the steam chamber started to enter the thief zone, the steam injection pressure quickly fell to values close to the thief zone pressures. Bitumen production was maintained by NCG injection towards the end of the well life. Gas injection was continued until a cash flow analysis determined that continued operation of the well pair was no longer economic.

Petro-Canada ran the two models at three different thief zone pressures (1750, 700, and 200 kPa) and also with the following additional sensitivities:

- use of a thinner bitumen pay by setting the bitumen pay thickness in Model 1 to 15 m (Cases M115hp, M115ip, and M115lp);

- use of bitumen saturated with solution gas by using live bitumen in Model 1(Cases M1lihp, M1liip, and M1lilp);

- use of a higher quality reservoir by increasing the permeability in Model 1 (Cases M1hqhp, M1hqip, and M1hqlp); and

- use of a higher quality reservoir and bitumen with solution gas by increasing the permeability and using live bitumen in Model 1 (Cases M1hlhp, M1hlip, and M1hllp).

Petro-Canada also evaluated the effect of repressuring a depleted gas cap with water injection by running Models 1 and 2 after the gas cap was repressured from an abandonment pressure of 200 kPa to 700 and 1750 kPa (Cases M1rphp, M1rpip, M2rphp, and M2rpip). Petro-Canada used an annual average WOR of greater than 15 to determine when to shut in the SAGD well pair.

The results of Petro-Canada's model runs are summarized in Table 5. Petro-Canada made the following conclusions from its modelling work:

- For SAGD operations with the gas cap at abandonment pressure, the sustained bitumen rate and the recovery factor are significantly reduced compared to SAGD performance at the original pressure.

- For SAGD operations with the gas cap between the original pressure and abandonment pressure, as the pressure is reduced, the trend is lower sustained bitumen rates and lower recovery factor.

- The cumulative SOR is quite similar at all three thief zone pressures considered.

- Even for the higher-quality thick bitumen pay, bitumen rates and the recovery factor are reduced at gas cap abandonment pressure. Hence gas cap depletion is detrimental to SAGD recovery even in the most optimistic case.

- The reduction in SAGD performance at gas cap abandonment and intermediate pressures is larger for thinner pay zones. Hence, as the gas cap pressure is reduced, the bitumen pay thickness cutoff for development is increased and continued gas production places more oil sands resource at risk.

- For live bitumen, SAGD recovery at gas cap abandonment pressure is unrealistic even for thick bitumen pay, which represents a significant risk from continued gas production.

- Repressuring a depleted thief zone with water increases the amount of extra produced water and results in lower recovery and increased SOR compared to a native reservoir.

In support of its conclusions on modelling, Petro-Canada provided the following arguments:

- Its models reasonably matched the measured steam rise rate through the IHS at the Dover pilot (based on information submitted to the public part of the hearing), which validates the models' predictions.

Table 5. Petro-Canada model study results

Case	Description	Bitumen thickness (m) Pay	Bitumen thickness (m) Zone	Thief zone thickness (m) Gas	Thief zone thickness (m) Water	Gas cap pressure (kPa)	Recovery (%)	CDOR (m^3/d)	Cum SOR	Operating time (years)
M1hp	Model 1 base cases	36		8.5	4	1750	85.0	104.0	1.63	17
M1ip		36		8.5	4	700	80.0	117.0	1.69	14
M1lp		36		8.5	4	200	78.0	68.0	1.69	24
M2hp	Model 2 base cases	18	13.5	10.5	5	1750	76.0	74.0	1.89	18
M2ip		18	13.5	10.5	5	700	64.0	74.0	1.96	15
M2lp		18	13.5	10.5	5	200	60.0	47.0	1.97	22
M115hp	Model 1 with thin bitumen pay	15		8.5	4	1750	83.0	48.0	2.76	15
M115ip		15		8.5	4	700	73.0	48.0	2.91	13
M115lp		15		8.5	4	200	29.0	31.0	2.62	8
M1lihp	Model 1 with live bitumen	36		8.5	4	1750	84.0	72.0	1.78	24
M1liip		36		8.5	4	700	80.0	90.0	1.62	18
M1lilp		36		8.5	4	200	13.0	91.0	1.79	3
M1hqhp	Model 1 with high reservoir	36		8.5	4	1750	89.0	121.0	1.46	15
M1hqip	quality	36		8.5	4	700	84.0	171.0	1.52	10
M1hqlp		36		8.5	4	200	79.0	103.0	1.53	16
M1hlhp	Model 1 with high reservoir	36		8.5	4	1750	87.0	148.0	1.76	12
M1hlip	quality and live bitumen	36		8.5	4	700	83.0	154.0	1.59	11
M1hllp		36		8.5	4	200	81.0	97.0	1.65	17
M1rphp	Model 1 repressured with water	36		0.5	12	1750	40.0	207.0	2.46	4
M1rpip		36		2.1	10.4	700	79.0	123.0	1.97	13
M2rphp	Model 2 repressured with water	18	13.5	0.7	14.8	1750	63.0	137	2.24	8
M2rpip		18	13.5	2.6	12.9	700	60.0	95	2.50	11

- Its models indicated that it is not necessarily the thickness or vertical permeability of the IHS zone separating the thief zones from the bitumen that will jeopardize a commercial-scale SAGD project, but the strong possibility of the absence or thinning of such a zone that creates the greatest risk. The first contact of the steam chamber or pressure transient with the low pressure thief zone will limit the growth and effectiveness of a steam chamber.

Petro-Canada submitted that it had used a conservative approach in its modelling work because it disregarded the following risk factors associated with lowered thief zone pressures:

- The residual oil saturation may increase as SAGD operating pressure is reduced. Petro-Canada estimated that the residual oil saturation is twice as high at the end of SAGD operations for a gas cap pressure of 200 kPa instead of 1750 kPa.

- Exsolving solution gas at lower pressures will effectively reduce the sustained bitumen production rate.

- Water that encroaches into the thief zone during pressure depletion will enter the steam chamber during SAGD operations and constitutes a major risk for development.

- Variability in reservoir quality introduces the possibility of laterally discontinuous, thinner competent shales that will act as baffles to flow. If the production rate is already low due to gas production, lowering the rate even further can result in shut-in of the well pair.

Petro-Canada also provided a critique of the SPG's modelling work and a rebuttal of the SPG's critique of Gulf's modelling work:

- With respect to the SPG's conclusion that a lower-pressure SAGD operation requires more time to produce the same recovery as a high-pressure operation, Petro-Canada submitted that the ultimate recovery should be determined at the end of the well life. The SPG did not apply an economic test of the predicted SAGD forecast, but including such a test can lead to the conclusion that operating the steam chamber at a low pressure will reduce the ultimate recovery. This was the case for the Chard A Bitumen Prospect.

- Petro-Canada submitted that its analysis of the Dover pilot data presented in the SPG's submission demonstrated that steam chamber pressures need to match the thief zone pressures even in the presence of an IHS layer.

- Petro-Canada submitted that use of k-values different from experimental methane/bitumen values was not "sufficiently fatal to put Gulf's entire work into question," as contended by the SPG. Petro-Canada stated that two extreme approaches could be taken to account for the exsolution of gas during the SAGD process: use of dead bitumen (with no solution gas) and use of live bitumen (with all the gas remaining in solution until the bitumen is contacted by the steam chamber). Petro-Canada used both approaches in its modelling work and pointed out that Gulf used a third approach, where solution gas effects were included but the amount of exsolved gas was reduced with respect to the methane/bitumen system. This approach led to results that fell within the range of results obtained by the two extreme approaches. Since the two extreme approaches led to the same conclusion, an intermediate approach could not constitute a fatal flaw in simulation methodology.

- With respect to the SPG's statement that Gulf did not correctly model the performance of NCG in a steam chamber, Petro-Canada submitted that a constant dispersion coefficient, such as implemented in the STARS model, can properly capture dispersion mechanisms inside the steam chamber. Petro-Canada also submitted that the buildup of NCG close to the advancing steam condensation front was corroborated by a recent numerical investigation.[9]

6.1.3 Views of the SPG

To simplify debate, the SPG decided to use Gulf's model rather than construct its own. Using Gulf's model, the SPG ran the following cases:

- A set of runs (Cases M1P5, M2P5, and M3P5) with the pressure in the overlying zone set at 500 kPa.

- One run (Case M2GAS) to investigate the impact on SAGD performance of an overlying zone that consisted of only gas.

- A set of runs (Cases M1P20R, M1P13R, and M2P13R) with the top gas zone repressured with water. This was done by raising the gas-water contact. Material balance calculations showed that a minimum gas zone thickness of 0.2 m was required if the reservoir was repressured from 200 to 2000 kPa by water injection. To represent this, the gas zone thickness was reduced from 3 to 0.2 m for the cases in which the pressure in the gas zone was raised from 200 kPa to the original gas zone pressure of 1340 kPa and an overpressured case of 2000 kPa. The water zone thickness was increased by 2.8 m to fill the reservoir space previously occupied by the displaced gas. The water saturation of the flooded zone was set at 90 per cent and the residual bitumen and gas saturations were each set at 5 per cent.

- A set of runs (Cases IHSP2, IHSP13, IHSP13R, and IHSP20R) with a modified geological description, which involved removing the discontinuous shale layers in Gulf's model and adding a 10.5 m continuous IHS layer at the top of the bitumen zone. The IHS layer had a vertical permeability of 100 mD, which was estimated from the heat rise rate and the overall well performance of the Dover Phase B wells. Two of the runs also involved repressuring by water injection.

The SPG did not use any fixed criteria to determine when to terminate the model runs. They were run to a point that the SPG considered reasonable, taking into account the instantaneous bitumen production rate, SOR, and WOR. The results of the SPG's model runs are summarized in Table 6. The SPG drew the following conclusions from its model runs:

- For SAGD well pairs in communication with overlying zones, similar recovery factors could be obtained for overlying zones at 500 and 1340 kPa. However, a lower-pressure operation

[9] Zhao L., *et al.*, 1999, *Numerical Investigation of Steam and Gas Distributions in the SAGD Process*, CSPG and Petroleum Society of CIM Joint Convention.

would require more time to produce the same recovery as a higher-pressure operation. The SPG also acknowledged there would be a "penalty" of increased SOR and decreased CDOR.

- The economic parameters of SAGD were restored to levels consistent with a native reservoir when water was injected to raise the pressure of a depleted gas pool.

- The economic parameters could be improved over those of a native reservoir when the pressure in the gas zone was raised above the native pressures.

- The model was less sensitive to the pressure of the overlying zone when an IHS layer was included in the reservoir description. However, the SPG acknowledged that the model predicted breakthrough of steam in the bulk layer to the overlying zone. The SPG stated that it did not "endorse" the approach it used to represent the IHS layer. According to the SPG, the IHS is very complex. The representation used in the SPG's model runs was simplified and used to test the sensitivity to a low-permeability layer at the top of the bitumen zone. The SPG believed the modelling results would not be indicative of what will happen in the field at Surmont.

The SPG provided the following critiques of the modelling work done by Gulf and Petro-Canada. With respect to Gulf's modelling work:

- Gulf made a significant departure from the geological model used to date in the simulation of the performance of SAGD in the McMurray Formation. The current history-matched simulation model tuned to the performance of the Dover pilot uses a continuous IHS layer to model the interbedded facies. Gulf used discontinuous shales to model the interbedded facies. Also, the shales used by Gulf were concentrated in the lower half of the reservoir, which does not seem to be supported by well logs. The configuration of shales used by Gulf increased the apparent influence of the pressure of the overlying zone on SAGD recovery.

- The permeability values used in Gulf's model were overstated, and the model exaggerated the potential effects of depleted overlying gas pools on SAGD recovery.

- Gulf's model predicted that steam would rise more quickly through the discontinuous shales in the model than through clean sand, which was directionally opposite to what had been observed in the field.

- Gulf's model did not match the publicly available data for the Surmont pilot:

    - ♦ The cumulative bitumen production was approximately one-half that predicted by the model.

    - ♦ The model did not match the pressure data from one of the piezometers.

- Modelling the overlying zones as being unconfined exaggerated the flow of water into the SAGD steam chamber.

Table 6. SPG model study results

Case	Description	Bitumen zone thickness (m)	Overlying zone thickness (m) Gas	Overlying zone thickness (m) Water	Gas zone pressure (kPa)	Recovery (%)	CDOR (m^3/d)	Cum SOR	Operating time (years)
M1P5	Gas zone pressure set at 500 kPa	52.5	3	10.5	500	28.6	73.4	2.44	10
M2P5		52.5	3	3	500	78.9	81.0	2.18	25
M3P5		28.0	3	3	500	79.1	46.3	2.59	24
M2GAS	No top water	52.5	6	0	1340	78.6	125.6	2.52	16
M1P20R	Repressuring with water	52.5	0.2	13.3	2000	36.2	156.8	1.66	6
M1P13R		52.5	0.2	13.3	1340	34.2	126.1	1.75	7
M2P13R		52.5	0.2	5.8	1340	77.1	124.3	2.53	16
IHSP13	Use of simplified IHS layer rather than	52.5	3	3	1340	85.3	137.4	2.04	16
IHSP2	discontinuous shale layers	52.5	3	3	200	80.7	68.7	1.82	30
IHSP20R	Use of simplified IHS layer rather than	52.5	0.2	5.8	2000	86.9	150.1	2.26	15
IHSP13R	discontinuous shale layers and repressuring with water	52.5	0.2	5.8	1340	83.1	133.8	1.57	16

- Gulf did not model the evolution of solution gas correctly, since the k-values it used did not correspond to any of the gases normally present in the reservoir. Also, Gulf did not correctly model the performance of NCG in a steam chamber; the dispersion of NCG in the steam chamber was not incorporated into its simulations. This resulted in NCG building up where steam was condensing, which tended to insulate the bitumen from the steam. The Dover pilot showed that a high NCG concentration had very little impact on the performance of SAGD. These errors were sufficiently fatal to put Gulf's entire work into question.

- Gulf terminated its runs at arbitrary points. Also, the low-pressure cases were not optimized with gas injection to the extent that the high-pressure cases were.

With respect to Petro-Canada's modelling work:

- The simulations were not relevant to the Gulf application, since they applied to the Chard A Bitumen Prospect.

- The geological description used in Model 1 was not consistent with the well control in the Chard A Bitumen Prospect in that it did not have an IHS sequence. This resulted in the model overstating the sensitivity of the SAGD process to the overlying gas and water zones. Also, the vertical permeabilities used in the models were exaggerated because an IHS layer was not included and/or because a short circuit layer was included.

- Petro-Canada introduced large volumes of NCG into the model that used live bitumen, and the physics of dispersion was not modelled correctly.

- Different economic limits for terminating the model runs were used: 10 m^3/d at high pressure and 19 m^3/d at low pressure.

- With two exceptions, the simulations showed very similar bitumen recoveries. The exceptions were the simulations run with live bitumen and those run with noncommercial bitumen pay of 15 m.

In addition to its critiques, the SPG also provided the following arguments regarding the modelling work done by Gulf and Petro-Canada:

- The Gulf and Petro-Canada models were designed to demonstrate that communication will occur between the bitumen and the overlying gas and water zones because they included a short-circuit layer or a breakthrough column.

- Gulf's model relied on a geological interpretation for Surmont premised on a geological interpretation made for Gulf by AOSTRA in 1995. Gulf refused to disclose that geological interpretation. Its interpretation necessarily ignored a great deal of current well, core, and published data.

- Gulf's model predictions did not match the steam rise data, particularly at the Dover pilot. Since it had no history match, it had no predictive power. Models that are not history matched need to be viewed with scepticism.

6.1.4 Comparison of Hearing Participants' Views

The hearing participants provided an assessment of the ability of the reservoir models to simulate the physical processes involved in the effect of gas production on SAGD recovery and on how well the models were applied. The assessments are summarized in Table 7.

6.1.5 Views of the Board

Although there was a significant amount of debate about the reservoir modelling work submitted to the hearing, as pointed out by Gulf, all the models (including the SPG's model runs with a "simplified" IHS layer) predicted that the steam chamber will communicate with the overlying zones and prior to this the pressure of the steam chamber would have to be reduced to close to the pressure of the overlying zones. This is not unexpected, since in all the models the vertical permeabilities of the grid blocks were high enough to allow flow in the vertical direction. This representation of the reservoir at Surmont is consistent with the Board's views regarding vertical continuity discussed in Section 5.3.

Regarding the SPG's statement that IHS is very complex and that its model runs used a simplified IHS zone (represented by layers in the model having a vertical permeability of 100 mD), the Board notes that the SPG's submission showed that the model used to history match the Dover Phase B pilot used a similar simplified IHS. The SPG's approach of submitting model runs to the hearing but then not endorsing its own runs with the simplified IHS layer was not helpful to the Board.

The use of a short-circuit layer or breakthrough column in the models is consistent with the Board's view in Section 5.2.1.4 that it believes the chimney hypothesis advanced by Petro-Canada has considerable merit. Regarding the SPG's argument that the Gulf and Petro-Canada models were designed to demonstrate that communication will occur between the bitumen and the overlying gas and water zones because they included a short-circuit layer or breakthrough column, the Board notes that the SPG's submission showed that the model used to history match the Dover Phase B pilot also used a short-circuit layer.

Considering the results of the sensitivity runs conducted by Gulf and Petro-Canada, the Board is not prepared to accept the SPG's statement that Gulf did not properly model the evolution of solution gas and the performance of NCG in a steam chamber and that this put Gulf's entire modelling work into question. The Board notes that the SPG did not submit any sensitivity runs to support its statement.

The Board is not convinced by the SPG's submission that similar SAGD recovery factors could be obtained for overlying zones at 500 and 1340 kPa simply by operating for a longer time at the lower pressure. As pointed out by Gulf, the SPG could not obtain similar recovery factors for one of its three cases (recovery factor of 28.6 per cent at 500 kPa compared to 34.6 per cent at 1340 kPa). Although similar recovery factors were obtained for the other two cases, the SPG acknowledged there would be a penalty of decreased CDOR and increased SOR at the lower pressure. This could require the low-pressure SAGD cases to be operated beyond the economic

Table 7. Comparison of hearing participants' views on reservoir modelling

Issue		Views of the SPG	Views of Gulf	Views of Petro-Canada
A	Ability to simulate physical processes			
A.1	Growth of steam chamber and bitumen drainage	Simulation of this aspect is well understood.	Gulf agreed that simulation of this aspect is well understood.	Thermal simulators are well-established, comprehensive, and reliable tools for the evaluation and prediction of thermal recovery processes.
A.2	Diffusion of NCG through a steam chamber	This aspect is not well understood. No allowance was made for this process. As a result, the models predicted a buildup of NCG at the edge of the steam chamber, which resulted in cooling and a reduction in the predicted bitumen production rate. In contrast, temperature observation wells showed a gradual NCG concentration gradient in the steam chamber, and SAGD operations at the Dover Phase B and Surmont pilots have not shown reduced bitumen productivity with the injection of NCG.	The SPG overstated the importance of gas diffusion. The models predict the same trends with regard to the effects of gas production on SAGD whether there is gas diffusion or not. The models did predict a gradual change in the concentration of NCG in the steam chamber. When NCG was injected at the end of SAGD operations, Gulf's model did not predict a severe drop in performance, which agreed with the Dover Phase B pilot. A recent paper by the Alberta Research Council[1] submitted to the hearing showed that models correctly predicted the trends seen in physical model studies of the SAGP (steam and gas push) process.	Diffusion is normally neglected when studying steam injection processes. This is because artificial diffusion is introduced by the use of a numerical grid that consists of discrete blocks and because the diffusion induced by flow is of secondary importance in processes where the carrier (steam) volume collapses at the edges of the steam chamber. The validity of this approach was substantiated in a recent paper by the Alberta Research Council[1] that was submitted to the hearing. Also, there are many variables of secondary importance, and what is being looked at are the differences between a model at high and low pressures. These factors tend to minimize the impact as the effects arise in both cases and generally cancel each other out.
A.3	Solubility of NCG in the condensed water in the steam chamber	This aspect was not accounted for, resulting in the models overpredicting the amount of NCG available to accumulate at the edge of the steam chamber by as much as 30 per cent.	Not accounting for this aspect would not affect the simulation trends, which show that gas production is harmful to SAGD. Even if 100 per cent of the NCG dissolved in water (i.e., the system acted like a dead oil system), the models showed that gas production was harmful to SAGD performance.	

[1] Zhao, L., *et al.*, 1999, Numerical Investigation of Steam and Gas Distributions in the SAGD Process, CSPG and Petroleum Society of CIM Joint Convention.

(continued)

Table 7. Comparison of hearing participants' views on reservoir modelling (continued)

Issue		Views of the SPG	Views of Gulf	Views of Petro-Canada
B	Application of models to Surmont and Chard			
B.1	Technical features			
B.1.i	Use of UHTR keyword to control the amount of heat added during start-up of a SAGD well pair	The UHTR keyword was improperly used by not adjusting for the length of the gridblocks. This resulted in too high initial heating rates in the short-circuit layer and too rapid communication between well pairs.	Early communication is possible in a commercial SAGD operation. More important, the heater is used only during start-up, so if the model predicted communication too early, it would have almost no impact on long-term SAGD performance.	The use of a preferential heating profile along the horizontal wells properly reflects the well-known field observation that the first communication between the injector and producer is established at one location along the well pair. However, this is of secondary importance, since it occurs in both the low- and high-pressure cases and cancels out when the difference in performance is considered.
B.1.ii	Thermal boundary condition in Petro-Canada's model with an impermeable barrier	The model used an incorrect thermal boundary condition, which resulted in an acceleration of the steam rise rate as the steam chamber approached the barrier.	This issue relates only to Petro-Canada's model.	Petro-Canada agreed there was an error in its model. However, the conclusion that the presence of a thief zone significantly increases the steam rise rate compared to the case where there is no thief zone is still correct. This is because the rise rate acceleration in the presence of a thief zone is significantly greater than the small acceleration observed in the model without a thief zone but with the error.
B.1.iii	Modelling of constant-pressure boundary condition in thief zones	Both gas and water were allowed to flow out of the model, but only water was allowed to flow in. Influx of gas cannot be ignored because the mobility of gas is over 30 times that of water.	No sensitivity runs were reported to test whether this is important. Water inflow is required because overlying water can drain into the steam chamber. Since the pressure in the steam chamber is expected to be at or slightly above the gas zone pressure, the flow of gas is expected to be outward.	Investigation of its input files showed that in all the Petro-Canada runs, the steam chamber was operated at a pressure higher than the pressure of the gas cap, which makes a gas injection well redundant.
B.1.iv	Bitumen viscosity versus temperature curve	Gulf's curve had a sharp bend at 20°C, and this contributed to stability problems.	Gulf tested the effect of smoothing the curve, and it had virtually no effect on the stability of the model or SAGD performance.	

(continued)

Table 7. Comparison of hearing participants' views on reservoir modelling (continued)

Issue		Views of the SPG	Views of Gulf	Views of Petro-Canada
B.2	Reservoir characterizations			
B.2.i	Geology	The geology of a formation has a larger effect on SAGD performance than any other factor. Gulf's geological characterization did not correspond to the core data for Surmont, since it did not account for the presence of mudstone interbeds. This resulted in Gulf's model predictions not matching the Surmont pilot data. Petro-Canada's modelling of Chard suffers from a similar contradiction between the geological characterization and the field evidence.	All the models, even the IHS model submitted by the SPG, showed gas production harmed SAGD performance. Since the model grid is at a much different scale than that of the core data, the geological description used in the model cannot correspond closely to individual core data. Gulf's case 1 model gave a good prediction of the Surmont pilot performance. Although the choice of the specific geological description used in a model will affect the absolute predicted SAGD performance, it will not affect the comparative trends at high and low pressures at a fixed geological description.	The two models used by Petro-Canada contain the relevant geologic description of Chard. Parts of the models were grounded using Dover field data. Other parts were based on using all the information available. The difference in reservoir characterization by Petro-Canada and the SPG does not lead to a flawed numerical analysis; it leads to different reservoir simulation models.
B.2.ii	Permeability of overlying zone	The permeability of the overlying zone used in Gulf's model was higher than that derived from pressure transient analysis.	The permeability values used in the Gulf models were within the range of values obtained from pressure analysis. The permeability can be lowered considerably without affecting the simulation trends.	
B.2.iii	Use of unconfined overlying zone	The unconfined nature of the overlying zone used in the Gulf and Petro-Canada models exaggerated the amount of water available to flow into a steam chamber (by a factor of 2 in Gulf's model).	Water influx through the top water sand occurs from all directions when breakthrough begins. Water influx occurs from a much larger area than that shown by the SPG. Even if the SPG were correct, it would not change the simulation trends.	Use of an unconfined overlying zone was based on Petro-Canada's geologic description of the observed large aquifers.

(continued)

Table 7. Comparison of hearing participants' views on reservoir modelling (continued)

Issue		Views of the SPG	Views of Gulf	Views of Petro-Canada
B.2.iv	k-values	The k-values used by Gulf resulted in supersaturation of the bitumen at the top of the steam chamber. Petro-Canada used a reasonable method to extrapolate lab data to SAGD temperatures and pressures.	Gulf's sensitivity runs showed that the choice of k-values did not impact the simulation trends. Gulf did use lab k-values, and these showed the harm done by gas production was worse. The SPG's claim that Gulf's k-values resulted in supersaturation of the bitumen was not supported by any evidence. Even if the SPG were correct, the simulation results would not change.	
B.2.v	Production of free gas	Limiting the production of free gas exaggerated the amount of NCG that can build up in the steam chamber.	There was no constraint on free gas production in Gulf's model; the constraint was on the steam rate as a method of modelling steam trap control.	Same view as Gulf.

limit in order to achieve recovery factors similar to those for the high-pressure cases. Although the SPG did not use a cash-flow analysis to determine when to terminate its model runs, Petro-Canada did and its modelling work predicted lower SAGD recovery factors at lower gas cap pressures.

Having regard for the above, the Board believes that, subject to its views on the feasibility of repressuring discussed in Section 8.4, reservoir modelling reasonably demonstrates that producing associated gas in the Surmont area would likely have a detrimental effect on SAGD performance and that the detrimental effect increases with decreasing gas cap pressure. The magnitude of the detrimental effect could be significant and it depends on several factors, including the specific reservoir situation, the operating strategy, the abandonment pressure of the gas pools, and the economic circumstances. The Board also believes that the model predictions may underestimate the effect of associated gas production on SAGD bitumen recovery, since the models do not account for all the risk factors raised by Gulf and Petro-Canada.

The Board recognizes that there are uncertainties with using reservoir modelling to evaluate the effect of associated gas production on SAGD recovery. While having a model that has been history matched to field data would provide more confidence in the evaluation, there are limited field data available from the Surmont pilot. Although additional field data are continuing to be obtained from the Surmont pilot, the Board believes that it is not acceptable to wait for this additional field data before deciding on Gulf's request, because waiting would involve a significant risk to bitumen recovery.

6.2 Field Experience

6.2.1 Views of Gulf

Gulf stated that there was no indication from the Surmont pilot data that the steam chambers had communicated with the overlying thief zone. In mid-February 1999, Gulf started to reduce the pressure in one of the SAGD well pairs in order to get early low-pressure data. The data provided by Gulf for the Surmont pilot were for the period September 1, 1997, to July 6, 1999. However, Gulf stated that it had not completed its interpretation of the data obtained since February 1999.

Gulf stated that the Kearl Lake pilot provided a field demonstration that an upper thief zone at low pressure has a large negative effect on the performance of SAGD-type processes unless the thief zone pressure is increased. The Kearl Lake pilot was operated for more than ten years by Husky Oil Operations Ltd. in the Athabasca McMurray Formation. The pilot used fracturing to achieve initial steam injectivity, and it was considered a steam drive process between central vertical steam injection wells and surrounding vertical production wells. However, Gulf submitted that in its mature phase the process became a steam override process through an overlying lean bitumen sand and the main recovery mechanism became gravity drainage from the steam chamber to the base of the vertical production wells. Although the wells in the pilot were vertical wells and the geometry of the steam chamber was different, Gulf submitted that the main recovery mechanism was quite similar to that for the SAGD process with horizontal wells.

Gulf submitted that the performance of the Kearl Lake pilot was complicated by the presence of an overlying lean bitumen sand, which limited the steam zone pressure and caused poor performance for many years. The lean bitumen sand was approximately 5 m thick and contained at least 30 per cent bitumen saturation. There was no gas cap. Once a confinement process was implemented, the bitumen recovery performance was approximately doubled within a few months and it remained high for more than 1.7 years, until the pilot was shut in because of low bitumen prices. Gulf argued that the Kearl Lake pilot showed that excellent recovery can be obtained with SAGD in a reservoir with HS similar to that at Surmont. Gulf also argued that the pilot performance confirmed the results from reservoir modelling, i.e., that production of associated gas adversely affects SAGD performance.

The confinement process used at the Kearl Lake pilot involved continuous injection of natural gas, which resulted in an increase in the steam zone pressure from about 700 kPa to about 1200 kPa. Gulf argued that continuous gas injection was required to maintain the pressure at 1200 kPa and that it was not possible to repressure beyond 1200 kPa due to constant pressure leak-off. Gulf stated that confinement by gas injection would not be feasible at Surmont because of the presence of gas caps in communication with the water sands and because the thickness and water saturation of the water sands at Surmont were higher that those of the lean bitumen sand at Kearl Lake.

Gulf pointed out that the lean bitumen sand at Kearl Lake favoured partial plugging effects because it was only 5 m thick and it contained a significant bitumen saturation. However, until the confinement process was implemented, there was considerable outflow from the steam chamber into the thief zone and the recovery performance was low. Gulf contended that partial plugging effects could not be relied upon to provide economic recovery performance in the presence of low-pressure thief zones.

Gulf stated that the Kearl Lake pilot provides an example of thief zone behaviour that is an analogy to Surmont. It argued that steam was injected above the fracture pressure only during the initial operation of the pilot. However, Gulf acknowledged that it is not known what would have happened at the pilot if the reservoir had not been fractured. Gulf stated that initially there was an imbalance between the steam injection rate and the water production rate at the pilot. However, once the thief zone was confined by gas injection, there was a very good water balance.

6.2.2 Views of the SPG

The SPG acknowledged that gravity drainage probably occurred at the Kearl Lake pilot once steam override was established by fracturing. However, the SPG stated that the operation at the Kearl Lake pilot was not an appropriate analogy for the performance of a SAGD operation at Surmont before or after the steam contacts the overlying water sand. At the Kearl Lake pilot, steam and water were initially injected at such pressures that the reservoir was massively fractured, which effectively created a direct flow path to the overlying water zone and short-circuited the effective barrier caused by the IHS. Also, the Kearl Lake pilot was not operated according to present-day SAGD operating practices, which require a reasonable balance between the injected steam and the produced water.

The SPG stated that since the geological setting at Kearl Lake is very similar to that at Surmont, repressuring with natural gas should presumably also be possible at Surmont.

6.2.3 Views of the Board

The Board recognizes that the Surmont pilot has not yet provided field evidence of the effect of associated gas production on SAGD recovery, since the data submitted to the hearing indicate that the steam chambers have not yet communicated with the overlying gas and water zones. Also, at the time of the hearing there was very limited experience with the one SAGD well pair that had had its pressure reduced.

The Board agrees with Gulf that the Kearl Lake pilot provides a field example of the negative effect that a low-pressure thief zone can have on a gravity-dominated steam injection process. However, since a SAGD operation at Surmont would not be totally analogous to the Kearl Lake pilot, the Board believes that the results from Kearl Lake cannot be directly applied to Surmont. Because of the differences between Kearl Lake and Surmont (i.e., the presence or absence of gas caps and the thickness and water saturations of the overlying zones), the Board does not believe it can conclude that it would be possible to repressure Surmont with natural gas just because it was possible at Kearl Lake.

Because of the limited amount of applicable field experience, the Board believes that reservoir modelling is the best tool available at this time to evaluate the effect of associated gas production on SAGD bitumen recovery at Surmont.

7 GEOMECHANICAL EFFECTS

7.1 Views of Gulf

Gulf submitted that a commercial SAGD operation would involve a substantial number of horizontal wells that would pass through the Clearwater Formation overlying the Upper McMurray. Gulf contended that the immediate overburden at Surmont, specifically the Clearwater Formation B zone, contained prevalent weak clay shales under undisturbed in situ conditions. Gulf stated that significant strength degradation of these weak clay shales would occur due to gas pool depressurization and/or subsequent repressurization, resulting in potential wellbore integrity risks for SAGD operations at Surmont.

Gulf submitted that these clay shales had been weakened in the geologic past by various diagenetic and deformational processes, including tectonism, rebound, and glacial loading/unloading that led to substantial changes in geotechnical properties. The instability of the weak clay shales is due to internal discontinuities, such as slickensides and other pre-existing shear surfaces, fissures, and weak bedding planes. Gulf stated that the slickensides and other weak discontinuities would remain sealed as long as the weak clay shale remained in its natural state. However, Gulf stated that during gas pool depressurization, the natural stress state would be altered such that fissures and other discontinuities within the weak clay shales would open up. Water would then infiltrate these openings and the faces of the clay fissures would then swell significantly, reducing the strength of the weak clay shale material.

Gulf used the Fast Lagrangian Analysis of Continua (FLAC) computer program to perform simulated analyses to show, in two dimensions, the possible responses of weak clay shale zones within the Clearwater Formation to gas pool depressurization and repressurization. The FLAC simulations were presented by Gulf to show that under SAGD conditions there is the potential for significant horizontal displacement within the Clearwater Formation B zone weak clay shales and that this horizontal movement is greater when there is consolidation of the overburden due to gas pool depressurization prior to SAGD operating conditions being applied.

Gulf conducted simulations with an initial gas pool pressure set at 1700 kPaa and with the following two separate approaches to depressurization of the gas pool:

- instantaneous depressurization of the gas pool above the bitumen zone to 500 kPaa (i.e., the assumed gas pool abandonment pressure); and

- gradual gas pool depressurization at a rate of 100 kPa per year over 12 years.

Gulf did not have site-specific geotechnical strength test data from Surmont for use in its simulation study, but rather used data from the Clearwater shales exposed at mine sites in Fort McMurray and published values for other Cretaceous shales in the province (i.e., Lea Park and Bearspaw Formations). Gulf acknowledged that the computer simulation study could be used only for directional predictions about the geomechanical behaviour of the overburden at Surmont.

The results of Gulf's computer simulation study are shown in Table 8. Under conditions of no consolidation and no weak layer, the computed horizontal displacements were similar to conditions with no consolidation and the occurrence of a weak layer. When Gulf introduced SAGD into the simulations, the computed horizontal displacement increased significantly with instantaneous gas pool pressure depressurization. Additionally, under conditions of consolidation and no weak layer, the simulations showed more complex deformation patterns after a period of six years with SAGD operations, indicating that consolidation-induced settlements differ when there is the added thermal expansion loading due to the SAGD process. Gulf also submitted that the horizontal displacements would be manifested primarily at the edges of the gas pools. Therefore, considering the placement of these wells, the risk to wellbore integrity, would be more of a concern for the horizontal SAGD wells than for vertical gas wells. Gulf concluded that to maintain wellbore integrity, the simulations under conditions of depressurization of the gas pool demonstrated that it is necessary to maintain the properties of the Clearwater Formation B zone weak clay shales intact prior to application of the SAGD process.

Regarding repressurization, Gulf stated that consolidation-induced deformation of the weak clay shales could not be recovered by repressurization, and any subsequent repressurization efforts would cause further weakening of horizons previously deformed by depressurization within the overburden.

Gulf submitted that there was sufficient sealing capability within the overburden above the gas pools to enable the fluid pressures within the gas pools, the Clearwater Formation, and the McMurray Formation to be maintained at their distinct and separate values. Gulf further submitted that SAGD operations would employ continuous low-pressure steam injection into the McMurray bitumen reservoir well below the fracture pressure of the reservoir rock. Gulf stated that the clays within the clay shales would expand and seal fissures, joints, and fractures when the clays were heated with steam. The pressure of the steam within the steam chamber would mobilize bitumen, which would be forced into any small mobile water saturation areas that might

Table 8. Gulf FLAC computer simulation study results

Run no.	Simulation conditions	Displacement (mm) Vertical	Horizontal	Observations
1	No weak layer [1] No overburden consolidation Gas pool depressurization rate not specified	3.9[2]	1.3[2]	Gas pool consolidation results from depressurization
2	Weak layer No overburden consolidation Gas pool depressurization rate not specified	4[2]	2[2]	No significant impact of weak layer on movements
3	No weak layer Overburden consolidation Instantaneous gas pool pressure decline	82[3]	25[3]	Horizontal displacements manifested at edges of gas pool 400 kPaa shear stress developed within underlying McMurray Formation
4	Weak layer Overburden consolidation Instantaneous gas pool pressure decline	n/a 101[3]	20[4] 35[3]	300 to 400 kPaa shear stress developed above and below the gas pool
5	Weak layer Overburden consolidation Gas pool pressure decline at 100 kPa/year	68[3]	18[3]	Less horizontal strain than with instantaneous gas pool pressure decline after six years Shear stress at twelve years increased to 450 kPaa within the Middle McMurray
6	No weak layer No overburden consolidation Instantaneous gas pool pressure decline SAGD thermal conditions at 200°C Thermal expansion of oil sand[5] Steam chamber developed instantaneously after six years of consolidation	113[3]	n/a	Instantaneous pore pressure distribution within steam chamber Vertical displacements are maximum directly over the steam chamber Horizontal displacements are maximum adjacent to the steam chamber
7	No weak layer Overburden consolidation Instantaneous gas pool pressure decline SAGD thermal conditions at 200°C Thermal expansion of oil sand Steam chamber developed instantaneously after six years of consolidation	n/a	50[3]	Complex deformation pattern for "consolidation" case compared with the "no-consolidation" case Changes in deformation pattern following consolidation reflect the effective stress redistribution occurring due to consolidation-induced settlement and subsequent loading due to thermal stresses
8	Weak layer Overburden consolidation Instantaneous gas pool pressure decline SAGD thermal conditions at 200°C Thermal expansion of oil sand Steam chamber developed instantaneously after six years of consolidation	n/a	90[3]	Displacement pattern extremely complex Significant alteration to horizontal displacement profile Thermally induced deformations result in large, concentrated deformation within the weak layer Need to maintain intact properties of Clearwater Formation B zone weak clay shales to prevent excessive shear strains from occurring within the overburden

[1] Weak layer—consists of presheared, slickensided clay shale materials with the angle of internal friction at 8°.
[2] Measurements after unspecified period.
[3] Measurements after simulated time of six years.
[4] Measurements after simulated time of one year.
[5] Coefficient of thermal expansion of oil sand assumed to be 1.0 x 10^{-5}/°C.

exist. Such areas would become sealed by the hot bitumen, which would subsequently harden and plug the seepage path. Therefore, Gulf concluded that the sealing capability of the Clearwater Formation B zone clay shales would not be compromised by SAGD operations.

7.2 Views of the SPG

The SPG submitted the following:

- The gas pools may be lowered to abandonment pressure without adversely affecting the geomechanical parameters of the reservoir.
- The gas pools were originally underpressured, and the in situ pressure was not significantly contributing to the support of the overburden.
- If repressurization were required, it could be done safely by working within the limits of the fracture gradient of the gas pools reservoir rock.
- The gas-bearing units comprise overconsolidated, interbedded fine sand, silt, and mudstone and are underpressured. Removal of gas from these units would result in less than 0.2 per cent compaction of the gas-bearing sands and is not likely to produce any more significant volume loss than that associated with the normal rearrangement of the sand packing within the gas reservoir strata during consolidation.
- Resultant stresses associated with gas pool depressurization are minor and would not cause any significant degree of compaction of the sand reservoirs or any significant deformation of the overburden.

The SPG contended that the risks identified by Gulf were very minor. The key issue was the existence of slickensided areas within the Clearwater Formation B zone weak clay shales. The SPG argued that Gulf presented no evidence to show that such slickensides existed at a depth of 300 m (i.e., the depth of the gas pools) at Surmont.

The SPG submitted that compaction over the centre of the gas pools would be in the order of a few millimetres. Geomechanical effects, if any, would be much greater during SAGD operations than during gas pool depressurization, as was shown in Gulf's no consolidation of overburden case. Geomechanical effects would not be exacerbated by depressuring gas pools down to 400 or 500 kPaa. With the shear strength of slickensided surfaces at a residual angle of internal friction of 8° or less, depressurization could cause the development of small shear stresses, which should not create any problems with SAGD wellbore integrity. Any sheared surfaces resulting from the overcompaction associated with glaciation would likely be partially healed and possess some residual bonding shear strength, which would resist sliding at depth. The SPG maintained that premature failure within these weak shales was, therefore, unlikely.

The SPG submitted that depressurization of the Surmont gas reservoirs from virgin pressures to abandonment should not have any effect on the sealing mechanisms of the gas reservoirs. The SPG's model of the upper McMurray showed that it contained muds and shales, with discontinuous sands that contained gas and water. The SPG further submitted that currently there was sufficient sealing of the Clearwater and McMurray reservoirs to maintain the pressures within the gas pools at very different distinct values. The SPG pointed out that Gulf, in its submission at the Gas Bitumen Inquiry and again at the hearing, stated that the geomechanical effects would not impact vertical gas wellbores or seal integrity.

7.3 Views of the Board

The Board reviewed Gulf's computer simulation study and notes Gulf's acknowledgement that the simulations may not accurately predict potential geomechanical problems associated with gas pool depressurization and any associated overburden consolidation. The Board also notes that the materials geotechnical strength data used in the simulations were not from Surmont, but from mine sites at Fort McMurray and other locations in the province. The test data were for Cretaceous Bearspaw bentonitic clay shales and surface-exposed, weathered Clearwater Formation clay shales, which were subjected to glaciotectonic activity and contain slickensides. The Board believes that these materials have different geological histories and geotechnical strength parameters from the weak clay shales at Surmont. Therefore, the data used in the simulations would not be representative of the strength parameters of materials at Surmont, which could be stronger than those used, resulting in lower displacements than were computed.

Slickensided Clearwater Formation clay shales at the mine sites in Fort McMurray could be the result of glaciotectonic activity on shallow clay shales. However, Gulf did not submit compelling evidence at the hearing to confirm the existence of slickensided surfaces at a depth of 300 m at Surmont. Also, Gulf did not provide permeability test data on materials from Surmont to justify the values used in the simulations. Similarly, Gulf provided no test data from Surmont to confirm the coefficient of thermal (i.e., linear) expansion value used. Heated bitumen being deformable would choose the path of least resistance. Therefore, a three-dimensional study (rather than a two-dimensional study) may better represent deformational patterns under SAGD conditions and would most likely show SAGD-induced displacements primarily in two directions in the horizontal plane within the bitumen zone.

The Board accepts that gas pool depressurization could induce a small amount of consolidation within the gas-bearing sands and overburden materials at Surmont. However, the Board concurs with the SPG that virgin gas pressures within the gas pools at Surmont are significantly below the fracture pressure of the reservoir rock. Therefore, the gas does not significantly contribute to overburden support, and the gas pools may be lowered to abandonment pressure without significantly affecting the geomechanical parameters of the reservoir rock or the overburden materials. Also, consolidation and horizontal deformation of Clearwater Formation B zone weak clay shales depend on their ability to expel fluid (i.e., water) from within their pore space so that they can be compressed. These materials, being clay shale aquitards, would allow dissipation of fluid at an extremely slow rate. The resultant consolidation impact would, therefore, occur over only a geological time frame. Furthermore, because the gas pools were initially underpressured, the Board believes that any subsequent repressurization of the gas pools up to virgin pressure levels could be achieved safely and without any adverse effect on the geomechanical parameters of the reservoir rock or the overburden materials.

The Board accepts that the Clearwater Formation B zone weak clay shales exist as a depositional feature above the McMurray Formation at Surmont. The Board believes that any impact of heat from the steam chamber to the weak clay shales is related to the distance between the clay shales and the upper level of the steam chamber, as well as the ability of the intervening materials to transmit heat. On the basis of the information submitted to the hearing, the Board determined that the weak clay shale zone is between 11 and 21 m (with an average distance of 15 m) above the top of the bitumen zone. The intervening materials are primarily water sands and water-saturated clay shales, which are very poor conductors of heat. On the basis of the poor heat conductivity and the average distance above the steam chamber to the weak clay shales of 15 m, the Board believes that there would not likely be any impact on the clay shales by heat from SAGD operations. Therefore, the Board is not convinced that gas pool depressurization and/or repressurization and any subsequent SAGD operations would have a significant impact on wellbore integrity at Surmont.

The Board concurs with the views of Gulf and the SPG that gas pool depressurization and/or repressurization with any subsequent SAGD operations would likely not lead to a reduction in the sealing capability of the overburden.

8 FEASIBILITY OF ARTIFICIAL REPRESSURING

8.1 Views of Gulf

Gulf argued that repressuring with any fluid, including methane, would not be feasible. Gulf contended that the Upper McMurray is an open system, not a collection of isolated gas caps. Therefore, the interpool communication that exists at Surmont would not allow the repressuring of a single pool without the leak-off of pressure to low-pressure areas. This means that a significant portion of the Surmont leases would have to be fully repressured to allow commercial development at or close to native pressure conditions. Gulf further contended that gas zones would need to be depleted to abandonment pressure before repressuring took place, which would cause the following problems:

- Depressuring would cause weakening of overlying shales, which combined with subsequent SAGD operations would increase the risk of widespread wellbore failures.
- The weakening of the shales during depressuring would not be reversible, and repressuring would further weaken the shales and increase the risk of wellbore failures.
- Water influx into the gas cap during pressure depletion would cause two detrimental impacts: it would further weaken the overlying shales and increase the risk of subsequent wellbore failure; and it would negatively impact SAGD performance.
- Depressuring would cause significant further delays to commercial bitumen development.

In addition to the above general concerns with repressuring, Gulf submitted the following specific concerns with regard to repressuring with nitrogen and water:

- If less than pure nitrogen were to be used, the oxygen contained in the nitrogen/oxygen mixture would cause serious corrosion problems in the wellbore and surface facilities.

- Pure nitrogen is more costly from both a capital and operating perspective than a 95 per cent nitrogen/oxygen mixture. The cost of the nitrogen generation plant would be about 70 per cent higher than estimated by the SPG if pure nitrogen were to be used. Additionally, the SPG's cost estimate did not take into consideration other key factors, such as the cost of lease sites, pipelines, and injection wells. For a 25 000 bbl/d (3975 m^3/d) SAGD project, repressuring with nitrogen would reduce the net present value from $120 million to $16 million and reduce the rate of return from 18 to 12 per cent, making the project uneconomic.

- There would be a significant increase in operating costs if nitrogen were to be used for repressuring. The nitrogen would be produced when the steam chamber reached the thief zone, causing contamination of the produced and/or lift gas. This would result in either additional make-up gas being required for flaring the contaminated gas or additional fuel being required for steam generation.

- Any remaining gas in the gas cap, which would ordinarily be recovered after SAGD operations, would be contaminated with nitrogen.

- Repressuring with water would increase the amount of water in the thief zone, which would be harmful to SAGD performance, as demonstrated by reservoir simulations.

- The increased top water would increase the water/oil ratio at steam breakthrough to the thief zone and would create additional water-handling and disposal costs.

- The volume of water required from local sources, when added to the requirements for SAGD steam generation, would present a formidable environmental challenge.

- Water obtained from local sources is not always compatible with the Upper McMurray.

Gulf submitted that if the risks associated with repressuring were added to the many technical challenges already facing the Athabasca in situ bitumen developers, the odds against proceeding with a commercial bitumen project would become overwhelming. Gulf stated that it was not the magnitude of any one individual factor, but the accumulation of many factors, that eliminated repressuring from being an effective solution. These technical challenges would add financial risks that would preclude aggressive development of the Surmont bitumen resource.

8.2 Views of Petro-Canada

Petro-Canada submitted that repressuring was not a currently demonstrated or practical solution and, therefore, the best solution was to leave the existing gas in place to maintain reservoir pressure. Petro-Canada contended that, based on reservoir simulations, water influx into the steam chamber as a result of repressuring with water would adversely affect SAGD performance. Petro-Canada also argued that repressuring with methane made no sense. It stated that the cost of replacing the original methane by purchasing and reinjecting methane was economically unsound and illogical and did not meet the EUB's test that implementation must be practical. Petro-Canada further submitted that for repressuring purposes, pure nitrogen was too expensive;

membrane-generated nitrogen, flue gas, and carbon dioxide were too corrosive; and air was too explosive and corrosive.

8.3 Views of the SPG

The SPG submitted that it did not believe that repressuring depleted gas pools at Surmont would be necessary, since IHS is an effective barrier to steam rise. However, if Gulf believed that a specific pool was at significant risk with regard to the potential for steam leak-off through the IHS, repressuring from abandonment conditions could be considered as an alternative to purchasing the gas. The SPG said that repressuring of reservoirs was a common oilfield practice that could be applied to Surmont if Gulf so chose. The SPG argued that repressuring should, therefore, be seen as an insurance policy.

The SPG submitted that it was not able to test the effect of repressuring on Surmont SAGD since Gulf owned the P&NG rights overlying its SAGD pilot. The SPG contended that by virtue of the water volumes Gulf was currently disposing of at Surmont and its ongoing SAGD pilot, Gulf could test whether or not repressuring an overlying gas pool had any impact on SAGD at Surmont. It pointed out that Gulf had chosen not to conduct such a test.

The SPG submitted that natural cross-flow of water through wells from the Grand Rapids and Clearwater aquifers would likely be the most cost-effective option. The major issue surrounding this repressuring method would be the volume of water required and time needed to place the water. However, faster repressuring could be accomplished by pumping water to maintain a constant injection rate. The SPG maintained that no insurmountable water compatibility problems were anticipated with the reservoir fluid or the formation clays, as asserted by Gulf.

The SPG submitted that repressuring depleted gas pools by nitrogen injection was a viable technical solution. It stated that the cost of injecting the nitrogen with on-site generators would be about $0.68/mcf ($24.29/10^3 m^3) using 95 per cent pure nitrogen. This was based on one nitrogen generation/injection unit capable of supplying the required volume for four years and the utilization of a recylindered existing compressor. The SPG contended that the use of 95 per cent pure nitrogen would not be a problem, as asserted by Gulf, since any leak-off from the steam chamber would occur late in the life of a SAGD project and the cross-flow would be at relatively low rates. Therefore, the degree and duration of the corrosion and fuel gas contamination would be much less than calculated by Gulf, especially given the large volumes of lift and fuel gas that would be needed for a commercial scheme.

The SPG submitted that repressuring with methane did not risk capital, nor did it represent a technical risk. On the basis of Petro-Canada's estimate that a 20 000 bbl/d (3180 m^3/d) SAGD bitumen project would require 35 million cubic feet per day (mmcf/d) (980 10^3 m^3/d) of fuel gas, the SPG submitted that such a project would use 320 bcf (8960 10^6 m^3) of fuel gas over a 25-year life span. Therefore, given that the gas pool overlying Gulf's Surmont SAGD pilot had produced about 2 bcf (56 10^6 m^3) of gas prior to being shut in, the SPG contended that less than 1 per cent of the fuel gas requirements for a SAGD project would be needed to repressure the gas pool to virgin conditions. Using the same ratio, 26 trillion cubic feet (tcf) (728 10^9 m^3) of fuel gas would be needed to produce Gulf's estimate of 15 10^9 bbl (2385 10^6 m^3) of SAGD bitumen at Surmont. Therefore, based on the SPG's upper-end estimate of 180 bcf (5040 10^6 m^3) of remaining recoverable gas reserves at Surmont, less than 1 per cent of Gulf's Surmont SAGD fuel gas requirements would be needed for pressure maintenance of all the Wabiskaw-McMurray gas pools. The SPG further contended that Gulf would not have to invest up-front capital for pressure maintenance, since it could slip stream its SAGD fuel gas supply.

The SPG also considered repressuring with carbon dioxide or air, but it submitted that it would not presently recommend either for repressuring depleted gas pools.

8.4 Views of the Board

The Board believes that there is little risk that depressuring and subsequent repressuring of a gas zone would increase the risk of wellbore failures. As stated in Section 7.3, the Board believes that any depressuring and subsequent repressuring of gas zones would not likely induce any significant geomechanical effects on wellbore integrity at Surmont. The Board further believes that there is little risk that water influx into the gas zone during depressuring would negatively impact SAGD performance. As stated in Section 5.1.4, the Board believes that the Wabiskaw-Upper McMurray aquifer is weak and, therefore, unable to provide sufficient support for natural pressure rebound (i.e., water influx) in the Surmont area.

The Board notes that the SPG presented two different gases, nitrogen and methane, as being viable options for repressuring a depleted gas zone. Given the uncertainty regarding the lateral extent of the gas and top water zones, as discussed in Section 5.4.4, and the potential for leak-off of pressure to low-pressure areas, the Board is not convinced that repressuring with gas, or any other fluid, is viable. Even if it were technically feasible, the Board believes that the amount of lead time needed to repressure a potentially large area (i.e., region of influence) could have a significant negative impact on the economics of a SAGD project. Therefore, the Board is not prepared to rely on repressuring of depleted gas zones until it has been proven that its implementation is both feasible and practical. If the Board were confident that the gas zones could be operated similarly to gas storage schemes—that is, that the reservoir pressure could be reduced and then replenished to a satisfactory level in a practical manner—the Board would be more prepared to accept the proposition that repressuring is viable "insurance" against resource sterilization.

The Board notes that the modelling work submitted to the hearing showed a large variation in the predicted effect that repressuring a depleted gas zone by water injection would have on SAGD recovery. Gulf's and Petro-Canada's modelling work predicted that there would be a negative effect on SAGD recovery relative to the recovery for a native reservoir, with the decrease in recovery ranging from 6 to 59 percentiles, depending on the specific reservoir situation. On the other hand, the SPG's modelling work predicted that similar recoveries could be obtained when a depleted gas zone was repressured to its native pressure and that somewhat improved recovery could be obtained when the depleted gas zone was repressured above its native pressure. As pointed out by Gulf, the Alberta Producers Group stated at the Gas/Bitumen Inquiry that the impact of the overlying water zone is more severe than the effect of the overlying gas zone, which demonstrates that the water zone dominates the performance of the SAGD process. The Board is sceptical about the SPG now submitting to the hearing that increasing the amount of water in the overlying zone would not have a negative impact on SAGD recovery. Furthermore, the Board notes that both Gulf and the SPG acknowledged that the volume of water required for repressuring is a significant issue. The Board believes that this issue is further complicated by the uncertainty of the lateral extent of the gas and top water zones, especially with regard to repressuring a depleted gas zone above its native pressure, as suggested by the SPG. The Board also notes that the issue of water compatibility is an additional risk of repressuring with water. On the basis of these considerations, the Board is not convinced that repressuring depleted gas zones with water is a viable option.

9 FEASIBILITY OF ARTIFICIAL LIFT

9.1 Views of Gulf

Gulf stated that conventional gas lift would be the preferred option for high-pressure SAGD operations, that is, at steam chamber pressures exceeding 1500 kPaa. However, it pointed out that once a SAGD operator was faced with decreasing pressure below which conventional gas lift could be used, the lift systems and wellbore completions would become increasingly unproven, risky, and costly. Gulf reported that of the alternatives available for lower-pressure conditions, it would prefer to use a modified form of gas lift if possible. However, Gulf pointed out that for modified gas lift to be economic at lower pressures, the volume of lift gas must not exceed the fuel requirements of the steam plant. Gulf added that for artificial lift to remain technically feasible as the pressure was lowered further, the pressure at the heel of a horizontal SAGD production well would have to be sufficiently high for fluid to be able to flow to the lift system. Therefore, it stated, at very low thief zone pressures, such as 200 kPaa—contended by Gulf to be the gas abandonment pressure in the Surmont area—there was no current or foreseeable artificial lift system capable of producing a Surmont SAGD well because of the hydraulics and pressure drops involved.

Gulf referred to thief zone pressures in excess of 1000 kPaa as being desirable because that would allow the steam chamber to be operated at 1050 kPaa. Therefore, the pressure drop anticipated by Gulf would result in an adequate pressure of 620 kPaa at the point where the lift system would be installed. If the thief zone pressure were reduced significantly below 1000 kPaa, Gulf submitted that it would attempt to use lift systems such as electrical submersible pumps or "ELift." Gulf stated that it is currently testing ELift at high-pressure conditions before testing can begin at lower pressures. Gulf suggested that ELift with a bottomhole pump would work at 300 kPaa at the heel of the well and 550 kPaa in the thief zone. However, if the thief zone pressure were reduced to 500 kPaa, the resulting pressure of 120 kPaa at the lift system intake would mean that the steam saturation temperature would be about 104°C, making the viscosity of the bitumen a challenge to any pump manufacturer.

Gulf noted that the SPG had suggested that 400 kPaa would be required at the heel of the well to facilitate lifting operations and, therefore, the pressure in the thief zone could not be allowed to drop below 650 kPaa. Gulf further noted that this pressure was well above any potential gas zone abandonment pressure suggested by the SPG.

Gulf stated that it was encouraged that several types of artificial lift may prove to be applicable to SAGD commercial operations. Twin-screw multiphase pumps, downhole electrical motors, and two-stage Elift appear interesting, but all would require further testing before it could be known if they would work at the conditions anticipated if the thief zones were depressured below 1000 kPaa. Gulf further stated that while it was investigating means of artificial lift at steam chamber pressures greater than 600 kPaa, it was not prepared to pursue artificial lift at lower pressures because the hydraulics involved made artificial lift technically impossible.

Regarding incremental costs of artificial lift suggested by the Alberta Producers Group at the Gas/Bitumen Inquiry, Gulf conceded that the calculated incremental cost of 30 cents/bbl ($1.89/m^3$) would not by itself be sufficient to make an otherwise economic SAGD project uneconomic. However, Gulf maintained that as steam chamber pressures were reduced, SAGD would nonetheless be uneconomic because of a combination of factors, such as reduced resource recovery and increased capital and operating costs.

Gulf stated that if the thief zone pressure were allowed to decline, artificial lift systems would be less likely to succeed, putting the entire SAGD project at risk. It maintained that basing the success of a commercial SAGD project on the hope that some new artificial lift technology would be developed was not an acceptable approach. Gulf referred to the *Gas/Bitumen Inquiry Report* and agreed that it would be unwise to depend on future technology to produce bitumen below depressured gas zones.

9.2 Views of Petro-Canada

Petro-Canada stated that it had been demonstrated that conventional gas lift could produce SAGD fluids at a steam chamber pressure of 1750 kPaa. Petro-Canada added that other forms of artificial lift could be successfully applied at pressure conditions where the bottomhole pressure exceeded 1200 kPaa (i.e., 1400 kPaa in the steam chamber and 1350 kPaa in the thief zone). It contended that SAGD performance would be better at higher pressures because fluid inflow would be higher, resulting in fewer operating problems, and production equipment would be more reliable because it would not have to run at the lower limit of its operating range.

Petro-Canada stated that as the bottomhole pressure approaches the range of 700 to 1200 kPaa, artificial lift becomes more challenging. For example, Petro-Canada reported that reciprocating rod pumps could produce fluids at a steam chamber pressure of 900 kPaa (or a bottomhole pressure of 700 kPaa), but that steam flashing would severely impair rod pump performance. Petro-Canada further stated that as the bottomhole pressure approaches the range of 400 to 700 kPaa, artificial lift would be possible but difficult. For example, high-temperature electrical submersible pumps theoretically could be used at steam chamber pressures of 600 to 700 kPaa. Petro-Canada also reported that progressive cavity pumps, plunger lift, and hydraulic jet pumps would be unsuitable for providing the lift needed at these low-pressure conditions.

Petro-Canada contended that it would be technically impossible to lift SAGD fluids at bottomhole pressures of less than 400 kPaa. It stated that the SPG had also presented evidence supporting the view that 400 kPaa is the minimum flowing bottomhole pressure achievable in a horizontal SAGD well. Petro-Canada further stated that this pressure equated to 600 kPaa in the steam chamber and 550 kPaa in the thief zone and therefore a gas zone pressure of 550 kPaa would be the lowest pressure at which artificial lift would be technically feasible. Petro-Canada referred to gas zone abandonment pressures of 150 kPaa as being likely. In support of this, it cited an application for approval to produce gas by Rio Alto—a member of the SPG—as compelling evidence that the likely abandonment pressure in the area would be as low as 150 to 200 kPaa. Petro-Canada also pointed out that the gas zone pressures were already in the range of

700 kPaa in the area of its Chard A Bitumen Prospect, which is within 150 kPaa of the lowest thief zone pressure at which artificial lift would be technically feasible.

Petro-Canada submitted that it should not be expected to base serious investment decisions on the presumption that technological advancements would provide a production method that would be unaffected by gas zone pressure reduction. Petro-Canada further submitted that the province should not be requested to assume that advancements in technology would enable conservation of the bitumen resources to occur under depressured gas and water zones.

9.3 Views of the SPG

The SPG questioned the need to maintain the pressure in a SAGD steam chamber to within 50 kPaa of the zones above the bitumen. Referring to evidence from the Kearl Lake pilot, the SPG stated that it should be feasible to conduct SAGD operations at steam chamber pressures 200 to 300 kPaa higher than the pressure in the overlying gas and water zones. Hence, the SPG argued, there was more choice and discretion in the hands of a SAGD operator than had been suggested by Gulf and Petro-Canada.

The SPG agreed that gas lift was the preferred method for lifting SAGD fluids where the bottomhole pressure was sufficient and that gas lift would work successfully and economically down to bottomhole pressures of 800 to 1000 kPaa. The SPG stated that it was in general agreement with Petro-Canada regarding the performance envelopes for the various types of artificial lift systems available for pressures below that range. The SPG also stated that the type of artificial lift selected would be determined on the basis of economic optimization studies. It agreed with Gulf and Petro-Canada that there is no existing artificial lift technology that would work at a steam chamber pressure of 200 kPaa and at a depth of 330 m. However, it pointed out that the limit of current technology was a steam chamber pressure of 400 to 500 kPaa and that this was more likely the pressure range for gas zone abandonment than the 200 kPaa gas zone abandonment pressure cited by Gulf and Petro-Canada.

The SPG further stated that Rio Alto's application for approval to produce gas should not be taken as an indication of gas zone abandonment pressure for Surmont, because the area of Rio Alto's application was not typical of the geology and reservoir conditions at Surmont. The SPG suggested that 300 kPaa would be the minimum pump intake pressure using current technology. It showed how this pressure could be achieved using multilateral technology, allowing a steam chamber pressure of 400 kPaa to be used. The SPG stated that the incremental costs to be incurred with the drilling of a sump were in the order of $100 000 to $200 000. The SPG also stated that the steam chamber pressure limit would be about 500 kPaa if a sump were not used. The SPG agreed that operating difficulties and gas lift volumes would increase dramatically at lower operating pressures; however, it suggested that there were several lift system modifications that could be put in place. Additional gas compression was one example, although it acknowledged that it would cause operating and capital costs to increase. Other examples it provided included high-volume rod pumps, and high-temperature electrical submersible pumps, which the SPG described as the hearing participants' preferred option for dealing with low pressures. The SPG also referred to the new pumping concepts, such as ELift and twin screw multiphase pumps, which it said might resolve some of the technical challenges. The ability to handle vapours was one such critical issue that ELift, might be capable of dealing with.

9.4 Views of the Board

The Board notes that there was agreement among all of the parties that the preferred artificial lift system for producing SAGD fluids would be conventional gas lift wherever it could be applied. The Board further notes general agreement by the parties that conventional gas lift must be replaced by alternative artificial lift systems if the steam chamber pressure is maintained below 1000 kPaa and that most of these systems have yet to be proven in SAGD operations. The Board accepts that artificial lift becomes increasingly difficult as the steam chamber pressure is decreased below 800 kPaa until at some point it is not likely to be technically feasible to lift the fluids at all. The Board also notes that before the pressure range in which artificial lift would not be technically feasible is reached, costs will have increased. However, the Board believes that these increased costs are not likely to be the main reason that a SAGD project would become uneconomic. Rather, the Board believes that if a SAGD project were to become uneconomic at reduced steam chamber pressures, it would be primarily because of the significant reductions in total resource that can be produced and the rate at which the resource can be produced.

The Board notes that Gulf and Petro-Canada estimated the gas zone abandonment pressure in the Surmont area to be 200 kPaa and the SPG estimated it to be in the range of 400 to 500 kPaa. The Board further notes that Gulf and Petro-Canada submitted that the minimum steam chamber pressure required for artificial lift to be technically feasible would be 600 kPaa, while the SPG submitted that it would be 400 kPaa with a sump and 500 kPaa without a sump. On the basis of the above, the Board concludes that the minimum steam chamber pressure required for artificial lift to be technically feasible would be in the range of 400 to 600 kPaa. The Board further concludes that even if the gas zone abandonment pressure were 500 kPaa, as suggested by the SPG, there would be a significant risk that artificial lift would not be feasible. Furthermore, since the Board believes that IHS would slow but not stop steam rise, thereby potentially allowing contact with overlying depressured gas or water zones within the time frame of a SAGD project, the Board does not agree with the SPG that there is the option for a SAGD operator to hold steam chamber pressures considerably higher than the pressure of overlying gas or water zones. Therefore, the Board believes that the more costly and less proven types of artificial lift would likely be required if the Board were to allow the overlying gas and water zones to be depressured. The Board concludes that the less gas zone depressuring that occurs the better, as minimizing such depressuring would better ensure successful SAGD operations in terms of resource recovery and minimize the costs and technical difficulty of lifting SAGD fluids.

10 PRODUCTION OF ASSOCIATED GAS BY SAGD WELLS

10.1 Views of Gulf

Gulf acknowledged the potential for associated gas to be produced by SAGD wells once the steam chamber communicated with the overlying gas and water zones, because of the gas dissolving in water and the water subsequently being produced by the SAGD wells. However, Gulf stated that at the anticipated operating conditions of a SAGD project, the amount of solution gas from the bitumen zone that would be carried with the steam into the thief zone would exceed the amount of associated gas that would be carried away by water. Therefore, Gulf stated that there is an unresolved issue as to whether a portion of the gas cap would belong to the bitumen owner. While Gulf had earlier referred to its application as a request to defer gas production, it acknowledged that if, in fact, there were a net loss of associated gas from the overlying zones, the result would not be a deferral but rather a loss incurred by the gas owner.

10.2 Views of the SPG

The SPG argued that both Gulf's and Petro-Canada's SAGD models predicted that steam would enter the overlying gas zone and commingle with and displace the gas, resulting in associated gas being produced as part of the SAGD process. Hence, Gulf would thereby produce gas owned by the SPG, and in such a circumstance it is clearly unreasonable and inequitable for the Board to order the shut-in of that gas production, because to do so would constitute taking gas from the SPG and giving it to Gulf without compensation to the SPG. The SPG concluded that if the IHS at Surmont would not block the rise of steam, then the only reasonable solution would be for Gulf to purchase the overlying gas.

10.3 Views of the Board

The Board acknowledges that the SAGD process could result in loss of associated gas into the bitumen zone and that there could be a loss of evolved solution gas from the bitumen zone into the overlying gas zone. However, because there was very little evidence submitted to the hearing on this issue, the Board is not in a position to draw any conclusions at this time. The Board believes that this issue should be dealt with in the context of future SAGD applications, and any future applicants will be expected to fully address this issue.

11 ECONOMICS

11.1 Resource Conservation

11.1.1 Views of Gulf

Gulf provided an economic analysis of a 25 000 bbl/d (3975 m^3/d) bitumen project in a zone with thick oil and thin water that showed that resource income (i.e., total revenue less capital and operating costs) would be about $275 million when discounted at 10 per cent.

Gulf also provided a hypothetical assessment of a project in its primary commercial bitumen target area showing that, without any mitigating strategy, a decline in reservoir pressure to 200 kPa would be expected to reduce the recovery by about 27 per cent of the in-place bitumen. This analysis, provided for illustrative purposes because of the technical impossibility of lifting the bitumen to the surface, showed that for a 20 000 bbl/d (3180 m^3/d) project there would be a loss of bitumen with a net present value of almost $140 million in after-tax net revenues.

Gulf suggested that if the minimum reservoir pressure were limited to 800 kPa, mitigating strategy might ameliorate the effect of the pressure decline to some extent and still allow for an economically viable project. However, Gulf further stated that this would need to be confirmed through a pilot project.

Gulf repeatedly asserted that there would be the potential for multiple SAGD projects on the Surmont leases. Gulf stated that the Surmont leases contain the best bitumen deposits in the Athabasca region and could easily support 15 to 20 bitumen development modules of a nominal capacity of 20 000 bbl/d (3180 m^3/d), for an ultimate potential production rate of 400 000 bbl/d (63 600 m^3/d). Gulf's immediate plan would be to develop the Surmont leases to 100 000 bbl/d (15 900 m^3/d) by 2007. Gulf submitted that the bitumen resources on its Surmont leases would support a 100 000 bbl/d (15 900 m^3/d) project for 140 to 200 years or a 200 000 bbl/d (31 800 m^3/d) project for 70 to 100 years.

By comparison with the upside potential for bitumen production on the Surmont leases, Gulf estimated that a long-term deferral of gas production would cost in the order of $140 million in terms of net social benefits based on gas production of 106 bcf (2968 10^6 m^3).

11.1.2 Views of Petro-Canada

Petro-Canada's economic analysis compared the value of gas reserves to bitumen resources at its Chard A Bitumen Prospect. Petro-Canada described the conservation trade-off as being the choice between at least 250 10^6 bbl (39 750 10^3 m^3) of bitumen versus, at most, 20 bcf (560 10^6 m^3) of gas. Sensitivity analyses of the value of the gas reserves included an evaluation based on twice the base-case estimate of original gas in place, while the bitumen evaluation assumed a facility producing 30 000 bbl/d (4770 m^3/d). The highest estimate of resource income accruing from gas production was some $31 million (discounted at 10 per cent), while the forecasts of resource income from bitumen production were generally in the range of $400 million to $500 million when discounted at 10 per cent.

11.1.3 Views of the SPG

The SPG argued that any potential impacts that gas cap depletion might have on SAGD performance should not be a matter for the public interest, since variations in SAGD operating pressure would affect the lengths of time needed for bitumen recovery, not the ultimate recovery itself. Therefore, there would be no loss of resource to the rock matrix and hence no waste.

The SPG questioned whether the production rates forecast by Gulf were realistic in view of the potential for interference with steam migration from the IHS. In view of these potential difficulties, the SPG was sceptical about Gulf's robust economic analysis of Surmont's bitumen potential.

The SPG argued that even if the perceived problem with gas production were as great as Gulf alleged, the protection of the entirety of the bitumen deposits within Gulf's Surmont leases would be unreasonable and excessive. It would force the shut-in of all the gas to protect a resource that has no current economic value, as it would not be produced for 100 to 200 years, if at all.

The SPG stated that there were many other areas where bitumen could be recovered by a SAGD process without at the same time being in conflict with gas production. Therefore, in the SPG's view, Gulf and Petro-Canada ought to purchase the gas reserves outright or move to another location where gas production would not be an issue.

The SPG's economic analysis was limited to an assessment of the financial implications of an order to shut in Surmont gas reserves to the gas producers, the regional economy, and the government. Assuming 180 bcf (5040 10^6m^3) of remaining recoverable gas reserves at Surmont, the SPG submitted that the current market value of the gas was in the order of $180 million to $200 million. The future stream of discounted after-tax cash flows from continued gas production would be about $93 million, Alberta's royalties and taxes would be about $75 million, and federal taxes would be $47 million. On the other hand, an order to cease gas production would result in a cost of $11 million to abandon the associated facilities.

The SPG argued that when there had been conflicts in the past between conventional oil and gas producers, the Board had considered the investments made by gas producers in the broader context of the Board's general conservation objectives, notwithstanding its mandate for the prudent conservation of energy resources.

11.1.4 Views of the Board

The Board does not accept the SPG's argument that the potential for resource sterilization should not be a matter for the public interest. It appears to the Board that if it followed the SPG's recommendation, the Board could ignore many situations where resources could be effectively sterilized under any reasonably foreseeable economic conditions. This would not be in keeping with the Board's mandate.

The Board acknowledges that it could take in the order of 100 to 200 years to produce the bitumen resources on Gulf's Surmont leases. However, as stated in the *Gas/Bitumen Inquiry Report*, the Board does not believe it is reasonable and prudent to "force" bitumen development by requiring leaseholders to demonstrate, along with performance requirements, commitments to bitumen projects within a given time frame. Conceivably, this might cause ill-timed investment in bitumen projects and, in any event, such a requirement would imply that the public interest is driven by specific operators' plans for bitumen projects. The Board believes that its conservation role must consider a broader set of issues than the immediate plans of any one company or industry sector.

As noted in Section 8.4, if the Board were reasonably convinced that reservoir pressure could be restored to virgin conditions at some point in the future, it could take the view that depleting the gas pools now would not be an irreversible burden to impose on future bitumen producers. Therefore, the Board could leave it to future investors to come up with the equivalent of $200 million in gas (or some other medium) to repressure the pools if repressuring were considered to be a low-risk option. This would not be an unfair burden to impose on a future generation. It would not be much more expensive for them to incur the cost of repressuring than it would be for these costs to be incurred today by shutting in gas production indefinitely. However, this alternative is largely academic, since the Board is not convinced that repressuring with gas, or any other medium, is viable. In view of the technical uncertainties—such as the lead-time that would be required to repressure the gas pools—the Board is not willing to impose such a risk on future generations.

11.2 Commercial Resolution/Compensation

11.2.1 Views of Gulf

Gulf stated that its decision on whether to proceed with bitumen development would be based on the economics of a single module of 25 000 bbl/d (3975 m^3/d), rather than an assessment of the full potential of the Surmont leases. Therefore, the investment necessary to acquire the gas reserves would be considered a start-up cost of the first module and, hence, would kill the economic viability of the project. Therefore, such an investment in gas reserves would not be justified.

Gulf also stated that had it owned all of the Surmont gas reserves in the first place and had it developed these reserves to their current stage, it would shut in gas production of its own volition, in recognition of the much higher value of the bitumen resource.

Gulf maintained that the current proceeding was not the proper forum to consider the issue of compensation and that this would more properly be the subject of some future initiative.

11.2.2 Views of Petro-Canada

Petro-Canada supported Gulf's view that the first bitumen module would have to be sufficiently lucrative to finance the purchase of the gas reserves, should such a purchase be necessary. Petro-Canada further maintained that since the first module would undoubtedly be too small to warrant such expenditure, there would be no development of the bitumen resource.

Petro-Canada contended that a commercial arrangement is impossible in view of the fact that the SPG does not recognize a conservation issue. In Petro-Canada's view, it is essential to resolve the conservation issue prior to attempting to negotiate for an outright purchase of the SPG's gas reserves, since the fair value of the reserves cannot be established in the absence of a resolution of the conservation issue. Petro-Canada stated that the commodity value of gas in the market would not reflect the value of the Surmont gas reserves if those reserves were to be shut in by a Board order.

11.2.3 Views of the SPG

The SPG maintained that if the value and benefit of the Surmont oil sands development was sufficiently great to warrant the cost of shutting in the gas requested by Gulf, it should follow that those who expected to reap the benefits should absorb the costs. Therefore, in the SPG's view, if the public interest was to be enhanced by the development of bitumen projects at Surmont, then the public should also equitably bear the burden of those costs.

11.2.4 Views of the Board

Although accurate estimates of the volume and value of gas reserves at issue were not exhaustively considered in this proceeding, the Board notes that the SPG's estimate of the current market value of the Surmont gas reserves was approximately $200 million. Furthermore, the Board rejects Petro-Canada's contention that the value of these reserves should be based on the circumstance of their being shut in by a Board order.

The Board also notes Gulf's assertions that the Surmont leases have much more potential than a single bitumen module of 25 000 bbl/d (3975 m^3/d). It stands to reason, therefore, that shutting in the gas reserves would constitute a significant benefit to considerably more than merely one 25 000 bbl/d (3975 m^3/d) bitumen module. It follows, then, that an economic analysis of acquiring the gas reserves should have been based on something more than merely one 25 000 bbl/d (3975 m^3/d) bitumen module. It seems paradoxical to the Board that Gulf would argue that potential bitumen production of upwards of 300 000 bbl/d (47 700 m^3/d) should be a matter of the broad public interest, but then apparently dismiss this potential in its own economic analysis by limiting the economic analysis to a comparison of the value of gas reserves to only one bitumen module. It appears to the Board that Gulf's reluctance to acquire the gas reserves as an investment in even its initial plans for 100 000 bbl/d (15 900 m^3/d) of bitumen production more likely stems from a concern about the risk associated with the application of SAGD on the Surmont leases.

The Board acknowledges the risk associated with the commercial application of relatively unproven technology and is mindful of the SPG's view that shutting in gas production could be an overreaction. However, even with the number of variables involved in the economic analyses, the Board accepts that the potential value of bitumen reserves exceeds the value of remaining gas reserves in the Surmont area by an order of magnitude. The Board is persuaded that it would be irresponsible to accept the possibility of sterilizing a vast bitumen reserve by allowing continued gas production.

The Board acknowledges that an order for the immediate shut-in of Surmont gas reserves would result in a significant impact on the SPG that could lead to some complementary action. The Board notes that Section 91 of the Oil and Gas Conservation Act provides that the Lieutenant Governor in Council may direct the Board to proceed to prepare a scheme to compensate persons who are injured or suffer a loss by reason of any orders made pursuant to the Act.

12 REGIONAL ISSUES

12.1 Views of the Anzac Metis Local No. 334

The Anzac Metis expressed concerns about the encroachment of oil and gas activity on their traditional way of life. There was a sense that animal populations had declined over the past twenty years, since the emergence of industrial activity in the Surmont area. This had a profound impact on traditional pursuits of trapping and hunting.

The Anzac Metis felt that their interests had largely been ignored and that oil and gas operators had generally been oblivious to the Metis' concerns. Although their preference would be for no further industrial activity, the Anzac Metis noted that Gulf, at least, seemed to be more responsive to the Metis' interests and appeared more willing to consult with them. Therefore, they had more confidence that their future interests would be better preserved if Gulf were managing the region's industrial development rather than the current gas producers.

12.2 Views of the Chipewyan Prairie Dene First Nation and Fort McMurray No. 468 First Nation

The First Nations listed a number of pervasive problems with gas producers in the Surmont area:

- Gas producers had made little effort to discuss with First Nations people the possibility that gas developments might conflict with the First Nations' traditional activities.
- There appeared to be a lack of concern or sensitivity for such traditional ties to the land.
- Any communication between gas producers and First Nations representatives had typically been at the initiative of the latter.

The First Nations stated that they would like to access opportunities for long-term jobs that would provide some potential for acquiring more valuable skills, but their experience with the gas producers in the Surmont area suggested to them that they were relegated to performing manual labour, such as brush clearing, which provided only temporary income and limited opportunity to acquire new skills. They said that gas producers in the Surmont area had not implemented any measures to provide training to First Nations people for more technically demanding positions. The First Nations felt that there was a need for more consultation leading to a statement of principles that would promote a better working relationship between industry and the First Nations people.

On the other hand, the First Nations praised Gulf and Petro-Canada for the initiative they took to involve First Nations people in planning for bitumen developments in the Surmont area. They pointed out that Gulf and Petro-Canada had discussed traditional land-use studies with elders and trappers and had been active in local schools, encouraging children to complete their education. Furthermore, Gulf and Petro-Canada had actively supported business initiatives undertaken by the First Nations.

The First Nations expressed the view that, judging from their past experience with gas producers in the region, there would be more opportunity to forge a base for economic development if companies like Gulf and Petro-Canada were allowed to proceed with bitumen development. Therefore, the First Nations stated that they were averse to jeopardizing such development by continued production of gas.

12.3 Views of the SPG

Several of the companies in the SPG registered concern that they had been cast in such a negative light by the Metis and First Nations peoples. Their view was that they had been more of a positive influence in the region and that there had been more gas-related job opportunities for First Nations people than was acknowledged.

12.4 Views of the Board

The Board notes that the Metis and First Nations interveners stated that they have been very dissatisfied with the manner and extent to which the gas producers have consulted with them to address their concerns. The Board believes that even if the gas producers are justified in believing that they have been more of a positive influence in the region than was acknowledged, it is clear that their efforts fell far short of the Metis' and First Nations' expectations.

The Board expects that operators will consult with all stakeholders in a meaningful way throughout the life of a project, that they will explain the project to them, obtain their input about it, answer their questions, and address their concerns. On the basis of the evidence, the Board believes that this has not occurred. However, having regard for the positive views expressed by the First Nations interveners about Gulf's and Petro-Canada's approach, the Board is optimistic that the interveners' needs will be addressed appropriately. Notwithstanding, with respect to concerns about impacts and opportunities from future development, the Board intends to follow up on this matter to determine if ongoing regional initiatives may be of assistance.

Dated at Calgary, Alberta, on March 30, 2000.

ALBERTA ENERGY AND UTILITIES BOARD

F. J. Mink, P.Eng.[10]
Board Member

J. D. Dilay, P.Eng.
Board Member

W. J. Schnitzler, P.Eng.
Acting Board Member

[10] Effective September 3, 1999, Mr. Mink no longer participated in this decision.

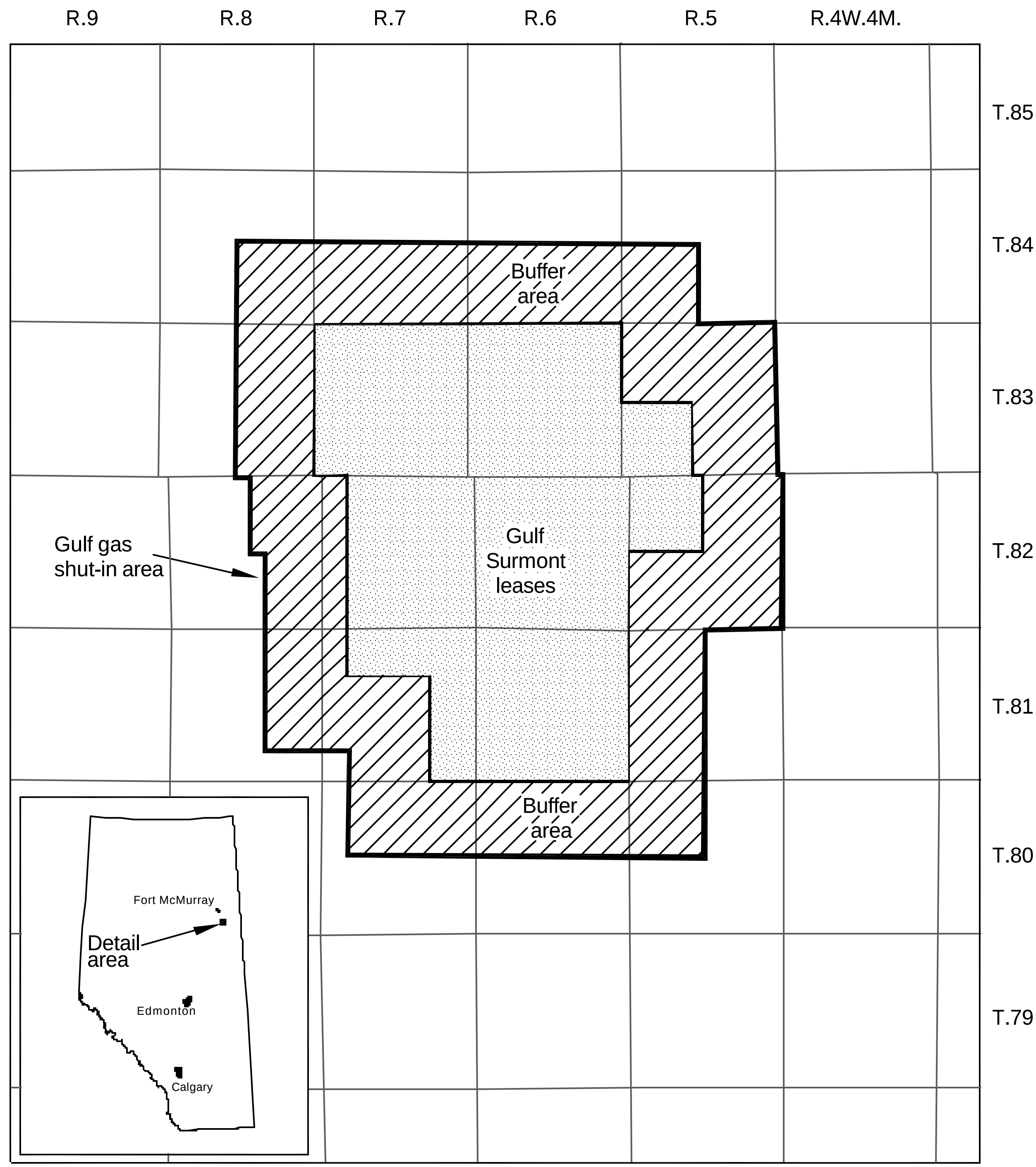


Figure 1. Gulf Surmont leases and gas shut-in area
Proceeding No. 960952
Gulf Canada Resources Limited

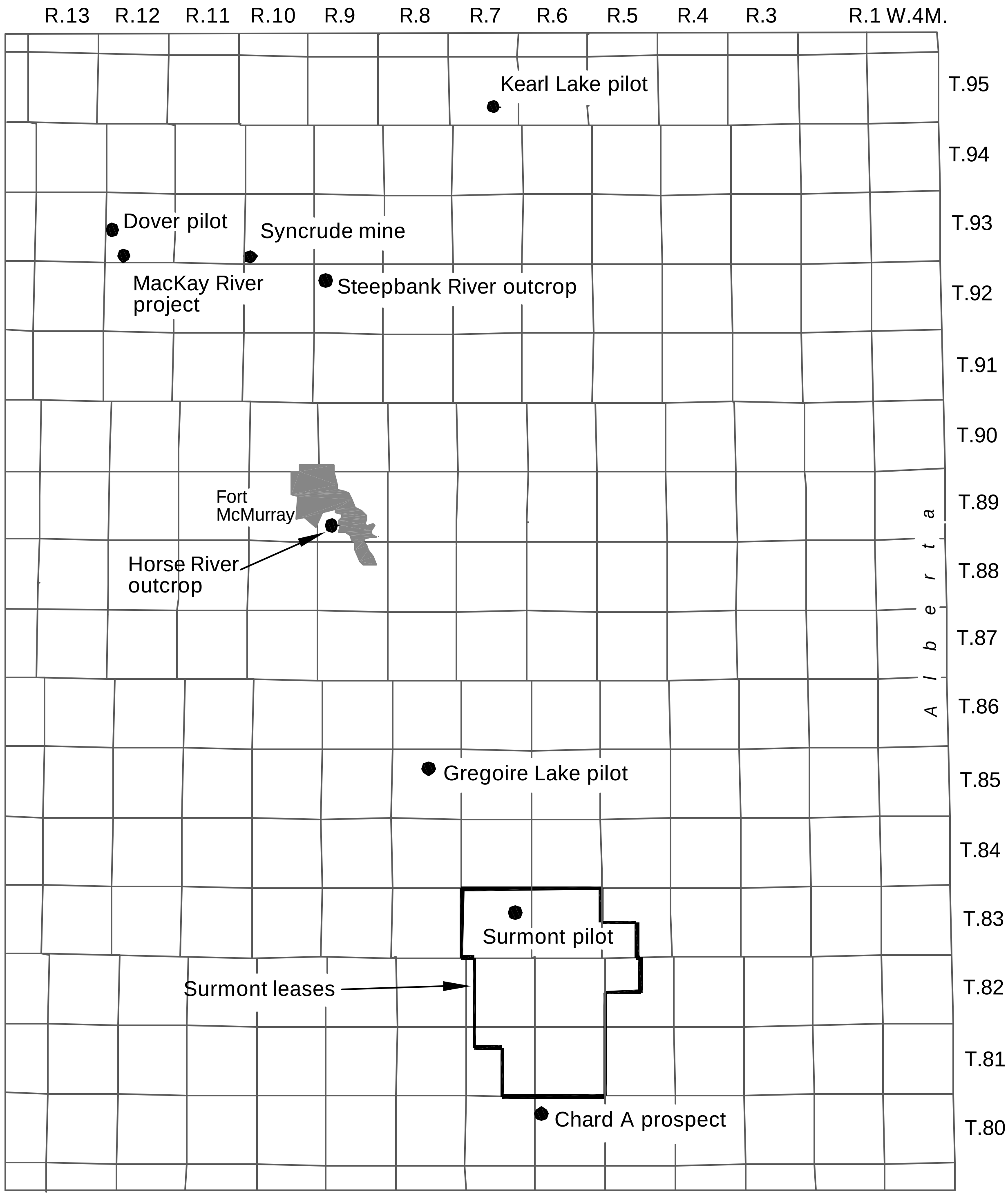
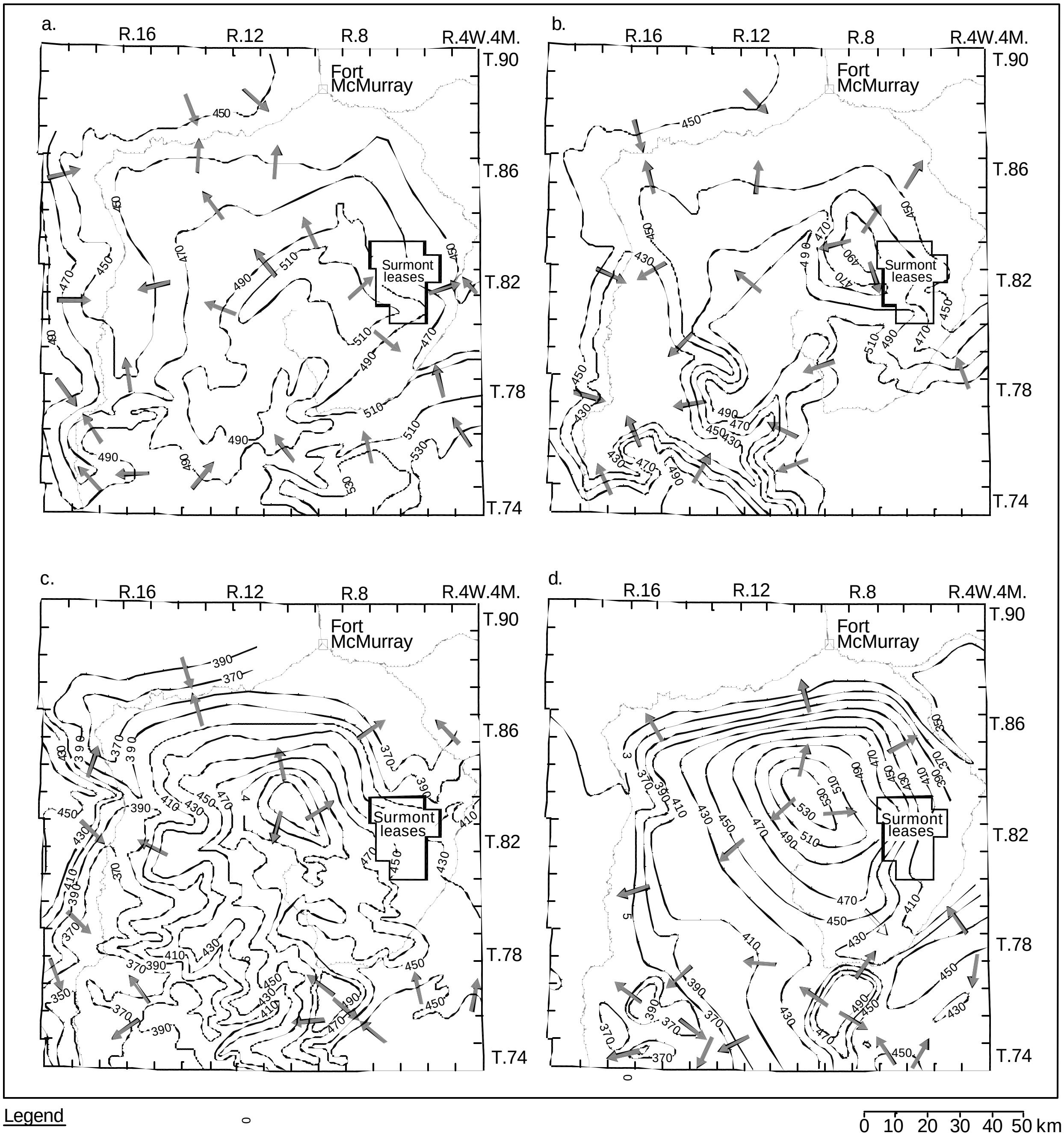


Figure 2. Gulf Surmont leases and other areas discussed at the hearing

Proceeding No. 960952

Gulf Canada Resources Limited



Legend

Groundwater flow direction

450 Hydraulic head (m)

Figure 3. Hydraulic head distribution in the Athabasca area aquifers: a) Grand Rapids, b) Clearwater, c) Wabiskaw-Upper McMurray, and d) Basal McMurray-Devonian (based on Exhibit No. 93)

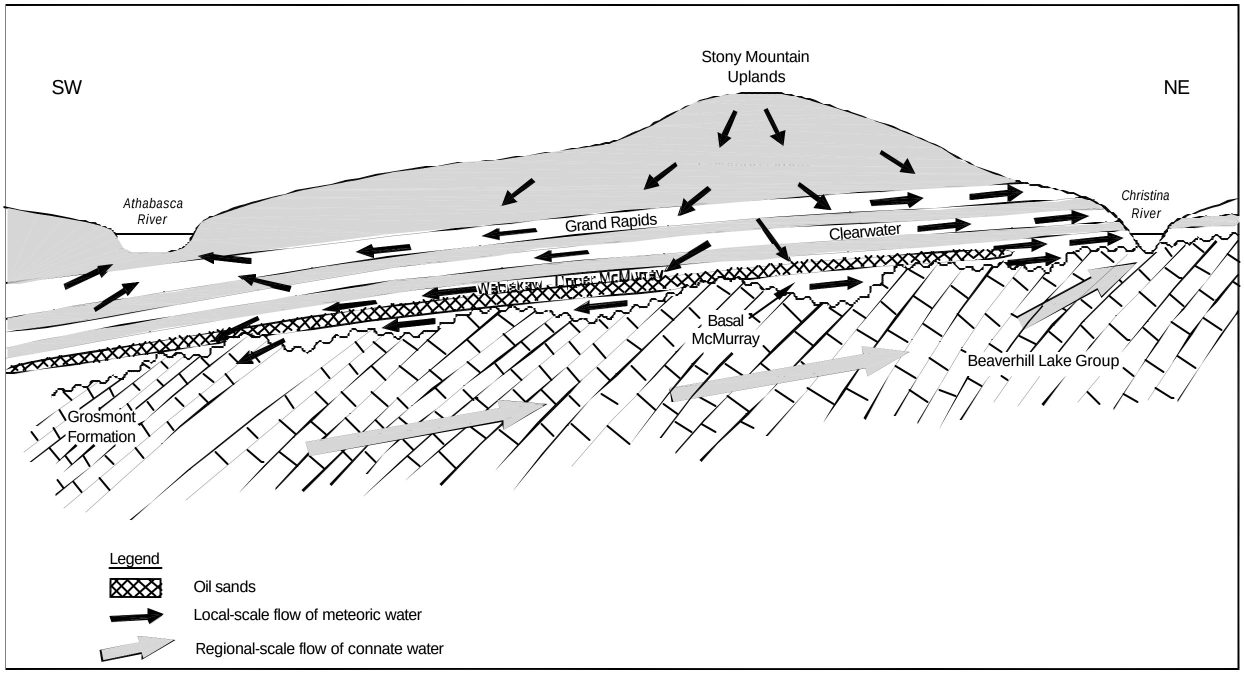


Figure 4. Diagrammatic representation of the flow of formation water in the Athabasca area aquifers along a dip cross-section

Proceeding No. 960952
Gulf Canada Resources Limited

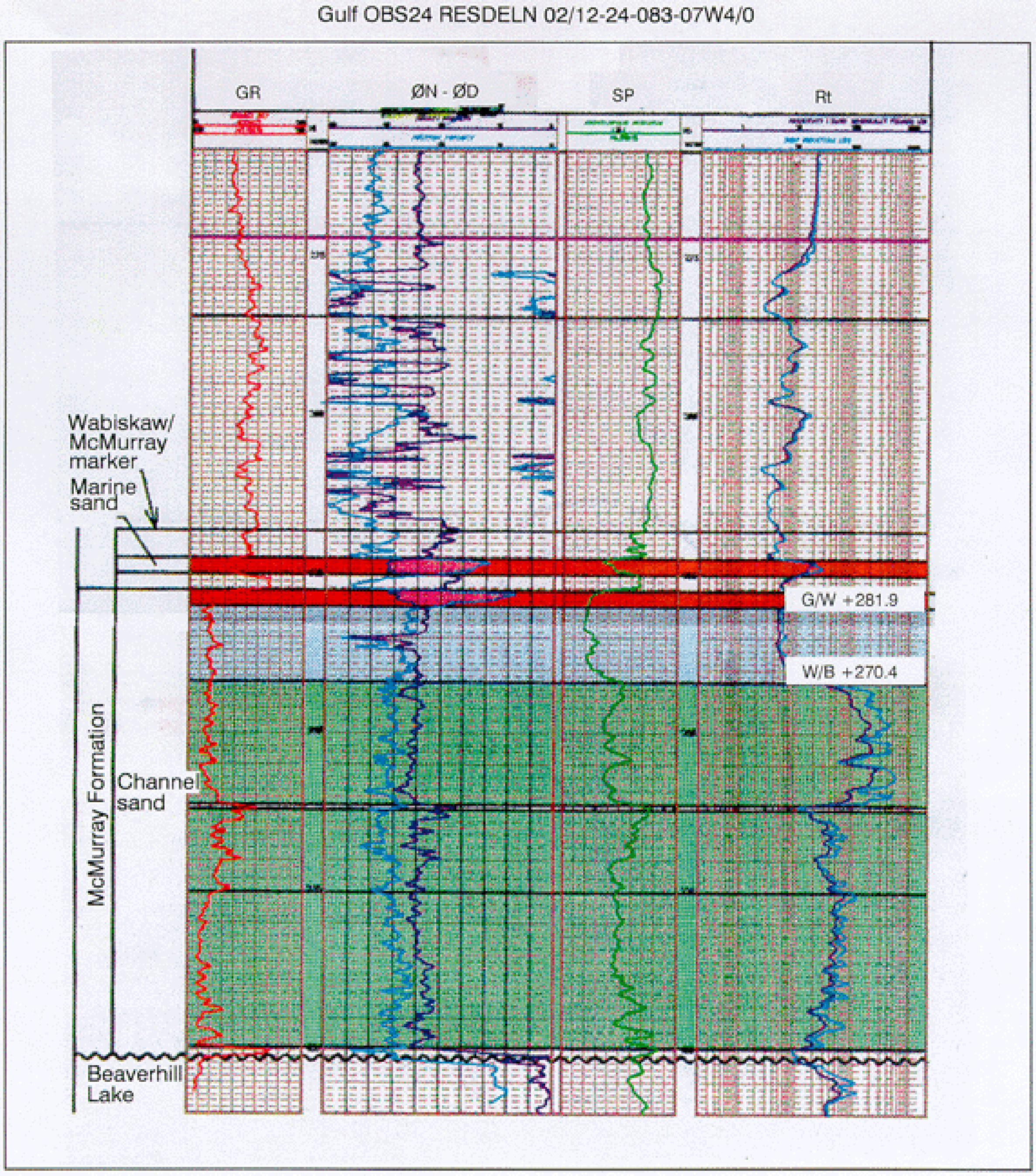


Figure 5. Gulf type well - Surmont SAGD pilot (based on Exhibit No. 4)
Proceeding No. 960952
Gulf Canada Resources Limited

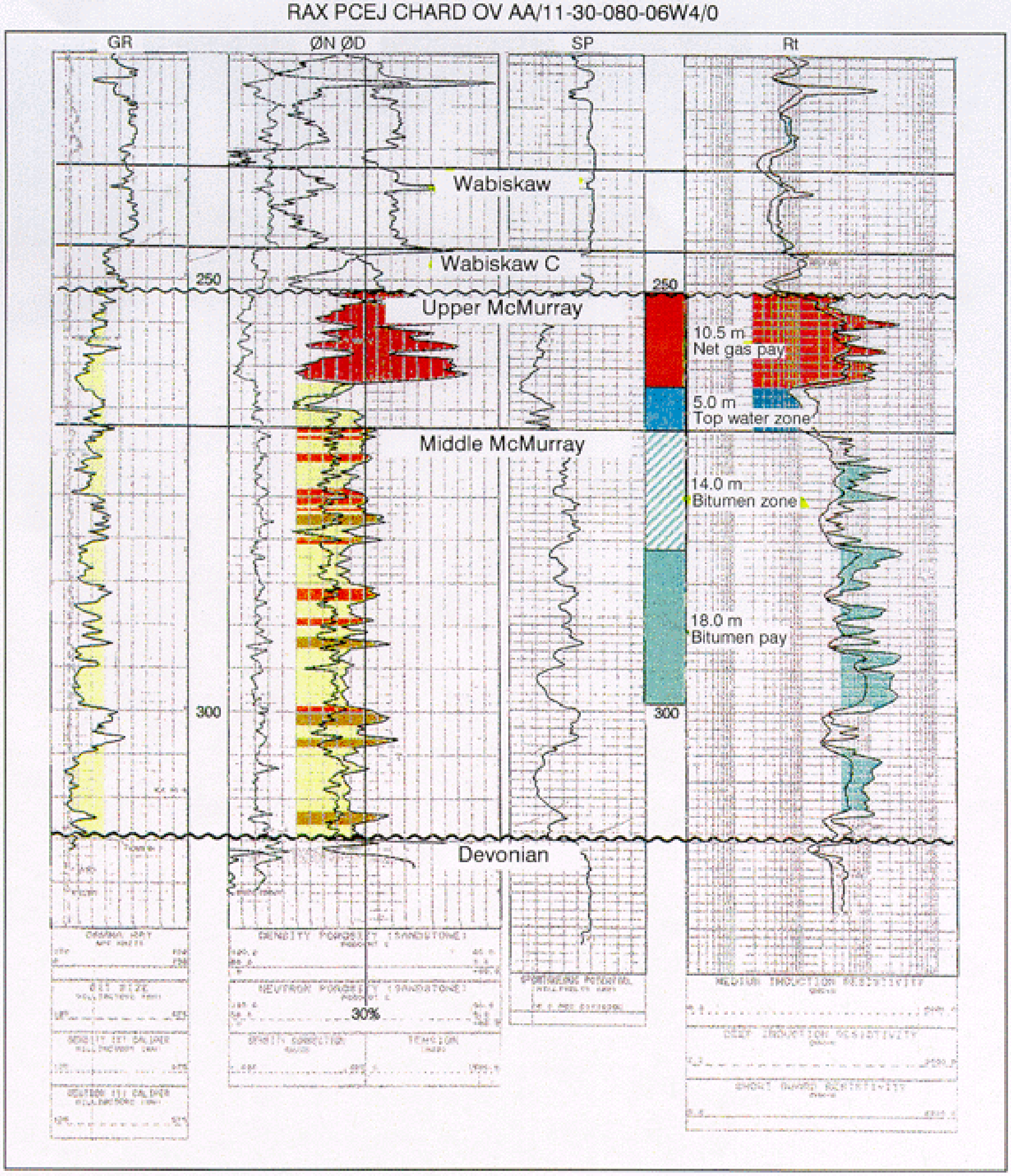


Figure 6. Petro-Canada type well - Chard A Bitumen Prospect (based on Exhibit No. 96)
Proceeding No. 960952
Gulf Canada Resources Limited

Appendix 1

Wabiskaw-McMurray Gas Wells to Be Shut In

Appendix 1. Wabiskaw-McMurray Gas Wells to Be Shut In

	Licensee	Unique Well ID
1	Paramount	00/05-31-080-05W4/0
2	Rio Alto	00/11-19-080-06W4/0
3	Paramount	00/13-24-080-06W4/0
4	Paramount	00/13-24-080-06W4/2
5	Paramount	00/13-25-080-06W4/0
6	Rio Alto	00/15-26-080-06W4/0
7	Rio Alto	00/07-29-080-06W4/0
8	Rio Alto	00/11-30-080-06W4/0
9	Rio Alto	00/07-35-080-06W4/0
10	Paramount	00/07-36-080-06W4/0
11	Quintana	00/09-24-080-07W4/0
12	Quintana	00/02-36-080-07W4/0
13	Paramount	00/08-05-081-05W4/0
14	Paramount	00/12-08-081-05W4/0
15	Rio Alto	00/06-09-081-05W4/0
16	Paramount	00/11-17-081-05W4/0
17	Paramount	00/03-18-081-05W4/0
18	Paramount	00/11-19-081-05W4/0
19	Paramount	00/03-30-081-05W4/0
20	Paramount	00/08-01-081-06W4/0
21	Paramount	00/15-02-081-06W4/0
22	Paramount	00/11-03-081-06W4/0
23	Paramount	00/07-04-081-06W4/0
24	Paramount	00/07-05-081-06W4/0
25	Paramount	00/09-08-081-06W4/0
26	Paramount	00/11-12-081-06W4/0
27	Paramount	00/07-13-081-06W4/0
28	Paramount	00/07-14-081-06W4/0
29	Paramount	00/07-15-081-06W4/0
30	Paramount	00/06-17-081-06W4/0
31	Quintana	00/08-19-081-06W4/0
32	Paramount	00/14-20-081-06W4/0
33	Paramount	00/03-21-081-06W4/0

	Licensee	Unique Well ID
34	Paramount	00/11-22-081-06W4/0
35	Paramount	00/07-23-081-06W4/0
36	Paramount	00/02-26-081-06W4/0
37	Paramount	00/12-27-081-06W4/0
38	Northstar	00/12-31-081-06W4/0
39	Paramount	00/03-32-081-06W4/0
40	Paramount	00/08-33-081-06W4/0
41	Paramount	00/11-34-081-06W4/0
42	Northstar	00/07-35-081-06W4/0
43	Paramount	00/09-36-081-06W4/0
44	Quintana	00/07-02-081-07W4/0
45	Quintana	00/12-13-081-07W4/0
46	Quintana	00/14-15-081-07W4/0
47	Quintana	00/10-16-081-07W4/0
48	Quintana	00/11-20-081-07W4/0
49	Northstar	00/12-21-081-07W4/0
50	Northstar	00/11-22-081-07W4/0
51	Quintana	00/10-23-081-07W4/0
52	Northstar	00/07-27-081-07W4/0
53	Northstar	00/06-29-081-07W4/0
54	Northstar	00/06-30-081-07W4/0
55	Northstar	00/06-30-081-07W4/2
56	Quintana	00/11-32-081-07W4/2
57	Northstar	00/08-34-081-07W4/0
58	Northstar	00/05-35-081-07W4/0
59	Rio Alto	00/08-15-082-05W4/0
60	Paramount	00/02-16-082-05W4/0
61	Paramount	00/10-16-082-05W4/0
62	Paramount	00/15-17-082-05W4/0
63	Paramount	00/02-19-082-05W4/0
64	Rio Alto	00/14-20-082-05W4/0
65	Rio Alto	00/06-21-082-05W4/0
66	Rio Alto	00/14-22-082-05W4/0

(continued)

Appendix 1. Wabiskaw-McMurray Gas Wells to Be Shut In

	Licensee	Unique Well ID
67	Rio Alto	00/03-23-082-05W4/0
68	Rio Alto	00/07-24-082-05W4/0
69	Paramount	00/06-31-082-05W4/0
70	Paramount	00/03-05-082-06W4/0
71	Paramount	02/07-08-082-06W4/0
72	Paramount	00/05-12-082-06W4/0
73	Paramount	00/14-16-082-06W4/0
74	Northstar	00/10-19-082-06W4/0
75	Paramount	00/06-20-082-06W4/0
76	Paramount	00/04-22-082-06W4/0
77	Paramount	00/02-24-082-06W4/0
78	Paramount	00/15-26-082-06W4/0
79	Paramount	00/06-28-082-06W4/0
80	Paramount	00/06-34-082-06W4/0
81	Paramount	00/07-36-082-06W4/0
82	Northstar	00/11-01-082-07W4/0
83	Northstar	00/08-03-082-07W4/0
84	Northstar	00/05-05-082-07W4/0
85	Northstar	00/08-07-082-07W4/0
86	Northstar	00/07-08-082-07W4/0
87	Northstar	00/06-09-082-07W4/0
88	Northstar	00/07-10-082-07W4/0
89	Northstar	00/07-12-082-07W4/0
90	Northstar	00/09-13-082-07W4/0
91	Northstar	00/05-14-082-07W4/0
92	Northstar	00/06-17-082-07W4/0
93	Northstar	00/06-19-082-07W4/0
94	Northstar	00/07-20-082-07W4/0
95	Northstar	00/05-26-082-07W4/0
96	Northstar	00/06-29-082-07W4/0
97	Northstar	00/07-30-082-07W4/0
98	Northstar	00/06-32-082-07W4/0
99	Northstar	00/06-34-082-07W4/0
100	Northstar	00/11-36-082-07W4/0

	Licensee	Unique Well ID
101	Northstar	00/15-01-082-08W4/0
102	Northstar	00/07-02-082-08W4/0
103	Northstar	00/08-12-082-08W4/0
104	Northstar	00/07-25-082-08W4/0
105	Northstar	00/16-36-082-08W4/0
106	Paramount	00/11-04-083-05W4/0
107	Paramount	00/10-05-083-05W4/0
108	Paramount	02/10-06-083-05W4/0
109	Paramount	00/12-08-083-05W4/0
110	Paramount	00/08-02-083-06W4/0
111	Northstar	00/12-04-083-06W4/0
112	Northstar	00/12-07-083-06W4/0
113	Paramount	00/01-10-083-06W4/0
114	Paramount	00/02-11-083-06W4/0
115	Paramount	00/11-12-083-06W4/0
116	Paramount	00/12-13-083-06W4/0
117	Paramount	02/01-14-083-06W4/0
118	Northstar	00/15-19-083-06W4/0
119	Paramount	00/08-27-083-06W4/0
120	Northstar	02/02-30-083-06W4/0
121	Northstar	00/07-32-083-06W4/2
122	Paramount	00/06-33-083-06W4/0
123	Paramount	00/16-34-083-06W4/0
124	Paramount	00/15-36-083-06W4/0
125	Northstar	00/08-02-083-07W4/0
126	Northstar	00/07-03-083-07W4/0
127	Northstar	00/08-06-083-07W4/0
128	Northstar	00/09-09-083-07W4/0
129	Northstar	AA/09-13-083-07W4/0
130	Northstar	02/07-16-083-07W4/0
131	Northstar	02/07-19-083-07W4/0
132	Northstar	00/05-20-083-07W4/0
133	Northstar	00/07-21-083-07W4/0
134	Gulf	00/07-24-083-07W4/0

(continued)

Appendix 1. Wabiskaw-McMurray Gas Wells to Be Shut In

	Licensee	Unique Well ID
135	Gulf	00/08-26-083-07W4/0
136	Northstar	00/06-29-083-07W4/0
137	Northstar	00/07-31-083-07W4/0
138	Northstar	00/02-33-083-07W4/0
139	Northstar	02/10-36-083-07W4/0
140	Northstar	00/06-01-083-08W4/0
141	Rio Alto	00/05-07-084-05W4/0
142	Rio Alto	00/02-01-084-06W4/0
143	Rio Alto	00/10-01-084-06W4/0
144	Paramount	00/15-02-084-06W4/0
145	Paramount	00/06-06-084-06W4/0
146	Paramount	00/06-01-084-07W4/0

(continued)

Appendix 2

Buffer Area Wabiskaw-McMurray Gas Wells Not Being Shut In

Appendix 2. Buffer Area Wabiskaw-McMurray Gas Wells Not Being Shut In

	Licensee	Unique Well ID
1	Paramount	00/12-29-080-05W4/0
2	Paramount	00/11-30-080-05W4/0
3	Rio Alto	00/06-20-080-06W4/0
4	Rio Alto	00/06-22-080-06W4/0
5	Rio Alto	00/07-23-080-06W4/0
6	Rio Alto	00/10-27-080-06W4/0
7	Rio Alto	00/11-28-080-06W4/0
8	Rio Alto	00/11-28-080-06W4/2
9	Rio Alto	00/11-34-080-06W4/0
10	Quintana	00/03-34-080-07W4/0
11	Quintana	00/04-35-080-07W4/0
12	Paramount	00/10-04-081-05W4/0
13	Quintana	00/14-03-081-07W4/0
14	Quintana	00/08-07-081-07W4/0
15	Quintana	00/06-17-081-07W4/0
16	Paramount	00/15-07-082-05W4/0
17	Paramount	00/02-18-082-05W4/0
18	Northstar	00/11-35-082-08W4/0
19	Paramount	00/05-07-084-06W4/0
20	Northstar	00/05-09-084-07W4/0
21	Paramount	00/06-12-084-07W4/0
22	Paramount	00/03-13-084-07W4/0

Appendix 3

Wells Not Completed in the Wabiskaw-McMurray

Appendix 3. Wells Not Completed in the Wabiskaw-McMurray

	Licensee	Unique Well ID
1	Rio Alto	00/07-32-080-06W4/0
2	Paramount	02/15-02-081-06W4/0
3	Paramount	00/11-09-081-06W4/0
4	Gulf	00/11-18-081-06W4/0
5	Paramount	00/11-27-081-06W4/0
6	Paramount	02/11-34-081-06W4/0
7	Paramount	00/08-10-082-06W4/0
8	Paramount	00/11-04-083-05W4/2
9	Gulf	00/11-20-083-06W4/0
10	Paramount	00/02-24-083-06W4/0
11	Northstar	00/10-26-083-07W4/0
12	Northstar	00/07-29-083-07W4/0
13	Northstar	00/06-30-083-07W4/0
14	Northstar	00/06-01-083-08W4/2
15	Northstar	00/05-08-084-07W4/0

Appendix 4

Gas/Bitumen Production Review, Memorandum of Decision

Alberta
ENERGY

Office of the Deputy Minister

Petroleum Plaza North Tower
9945 - 108 Street
Edmonton, Alberta
Canada T5K 2G6

Telephone 403/427-8032
Fax 403/427-7737

February 14, 1997

Ms. Céline Bélanger
Chair, Alberta Energy and Utilities Board
640 - 5 Avenue SW
Calgary, Alberta, T2P 3G4

Dear Ms. Bélanger:

RE: Gas/Bitumen Inquiry - EUB

We understand that a number of participants at the recent EUB meeting on the Gas/Bitumen Inquiry suggested that land tenure issues be considered in the Inquiry. I believe we have arrived at an appropriate approach to this question through subsequent discussions between the Department and Board members and staff regarding the EUB's responsibility for conservation issues and the Department's for tenure.

The Department would like to accept the EUB's offer to collect comments on tenure-related concerns that industry may wish to raise at the Inquiry. It is understood that the EUB will simply gather information, summarize it, and forward it to the Department without any recommendations.

In parallel with the EUB's investigations, the Department will be proceeding with its own review of tenure policies that relate to gas/bitumen production. Tenure-related information received from the EUB will be addressed by the Department as part of this review.

The Department would like to support the EUB's Inquiry in two ways. We are prepared to have staff at the Inquiry who are qualified to provide clarification of current policies and historical records, should such information be requested by the Board. The Department has also carried out some preliminary, narrowly-focused research on the possible impact of gas production on the recovery of associated bitumen zones for a limited number of cases. We will release our report on this work when it has been finalized in the coming weeks. Department staff who prepared the study will also be available to the Inquiry to address any questions there may be about their work.

The Department contact for the gas/bitumen issue is David Coombs (422-9430) who is also the Project Leader for the Department's review of tenure-related issues.

Rick Hyndman

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

GAS/BITUMEN PRODUCTION REVIEW **Memorandum of Decision**
TERMS OF REFERENCE **Proceedings No. 960952 and 960953**

1 INTRODUCTION

1.1 Submissions

The Alberta Energy and Utilities Board (Board) received submissions from Gulf Canada Resources Limited (Proceeding No. 960952) and Norcen Energy Resources Limited (Proceeding No. 960953) requesting that the drilling for and/or production of associated gas on specific oil sands leases be prevented. Gulf also requested that a general review of the impact of associated gas production on bitumen recovery on its oil sands leases be conducted. Concern was that pressure depletion of the gas cap in association with the oil sands zone will adversely affect bitumen recovery operations.

The Board subsequently requested and received submissions from the gas owners affected by the applications providing their views on the issue. Upon review of the information the Board denied the immediate requests by Gulf and Norcen to restrict production on the leases in question. However, recognizing the broad implications of the issue on existing and future operations, the Board issued General Bulletin GB 96-15 advising that it would convene a general meeting of all interested parties to discuss the scope of a general review. Subsequent to the meeting, Norcen withdrew its request to cease drilling and production pending the results of further drilling on its leases. The Board will re-consider the Gulf application upon completion of the general inquiry.

1.2 Meeting

The issue was considered at a public meeting on 21 January 1997 at the Board's office by F. J. Mink, Presiding Member, J. D. Dilay, Board Member, and W. J. Schnitzler, Acting Board Member.

A list of the meeting participants is provided below.

THOSE WHO APPEARED AT THE MEETING

Principals (Abbreviations used in Report)	Representatives
Gulf Canada Resources Limited (Gulf)	F. R. Foran, Q.C. N. Dilts M. Krause
Northstar Energy Corporation (Northstar) NAL Resources NAL Energy Inc. Canadian Forest Oil Ltd. UMC Resources Canada Ltd. Paramount Resources Ltd. Wascana Energy Inc. Giant Grosmont Petroleum Ltd.	K. F. Miller
Giant Grosmont Petroleums Ltd.	R. Watson
Wascana Energy Inc.	P. Sidey
Paramount Resources Ltd.	R. Duncan
Norcen Energy Resources Limited	B. Dozzi S. Sills M. Jennings B. Kurtz
Campbell River Engineering Ltd. Elk Point Gas Ltd.	D. Campbell
Petro-Canada	G. Sinclair
Mobil Oil Canada	D. Searle K. Dembicki N. Amoozegar
Canadian Occidental Petroleum Ltd.	J. Wansleeben
Talisman Energy Inc.	J. Harding
Tarragon Oil and Gas Limited	R. Rosine

THOSE WHO APPEARED AT THE MEETING (cont'd)

Principals (Abbreviations used in Report)	Representatives
Minerals Tenure Branch of the Alberta Department of Energy (ADOE)	D. Coombs
Rio Alto Exploration Ltd.	R. Cones
Ranger Oil Limited	D. Drall
Alberta Energy and Utilities Board Staff	G. Dilay K. Sadler T. Byrnes

2 MATTERS RAISED

The matters raised at the meeting fall into the following general categories:

- the identification of interested parties,
- the issues to be considered, and
- the process and timing.

3 IDENTIFICATION OF INTERESTED PARTIES

Some 105 individuals from 58 companies registered for the exploratory meeting.

At the meeting, the representatives identified the following parties that should take an interest in and participate in an inquiry of the matters before the Board.

- Alberta Department of Energy,
- the holders of oil sands leases,
- the holders of natural gas leases overlying and owners of facilities in the vicinity of oil sands leases,
- Nova Gas Transmission Ltd. (NGTL),
- Elk Point Gas Ltd., and
- gas distribution utilities.

The Board accepts the list of interested parties as put forward as those having a particular interest in the subject and will direct correspondence of the proceeding to them. The Board will include mineral rights holders and owners of other facilities operating in oil sands areas. The Board intends to issue a general notice of the inquiry purpose and scheduling in order to allow for the broad participation of all segments of the industry.

4 THE ISSUES

4.1 The participants at the meeting submitted the following issues for consideration at the proposed Board inquiry:

- the efficiency of and advancements in bitumen recovery technologies,
- the effect of depletion of gas caps in association with oil sands zones on bitumen recovery,
- the recovery of resources, on an energy basis, of gas caps and the affected oil sands under various options of recovery,
- evaluation of the economic benefits of both natural gas and bitumen production under various options of recovery,
- policies and procedures to maximize the production of hydrocarbons where oil sands have overlying gas caps or water sands in communication with gas caps,
- policies and procedures for future leases of hydrocarbon lands where oil sands have overlying gas caps or water sands in conjunction with gas caps,
- identification and assessment of the possible impacts of in situ oil sands projects on associated gas development,
- identification and assessment of possible mitigative measures for potential in situ oil sands projects using currently available technology that could avoid detrimental effects,
- discussion of gas and bitumen production priority in the event that concurrent production is not desirable, and
- if gas or bitumen production is prevented, how the appropriate resource holder will be compensated and by whom.

4.2 The Board has reviewed the issues put forward and believes that the following list should form the basis for the proposed inquiry:

(a) Extent of Affected Reserves

- Methodology used to establish the presence of "associated" gas.
- Tabulation of the amount of recoverable reserves, on an energy basis, of associated gas caps and the potentially affected oil sands.

(b) Impact on Recovery

- Identification of factors and evaluation of the possible effect of depletion of associated gas caps on bitumen recovery if mitigative measures are not used.

- Identification of potential mitigative measures and discussion of relative effects if mitigative measures are used to optimize resource recovery.

- Study of the possible effect of bitumen recovery on associated gas caps, whether or not the gas is produced.

- Evaluation of the efficiency and advancements in primary and thermal bitumen recovery technologies that could impact the resource recovery.

(c) Economic Impact

A cost/benefit evaluation showing the optimum depletion strategy for recovering the resources. Such studies should include:

- a production and price forecast of the gas and oil sands reserves,

- an assessment of the likely timing of resource recoveries,

- an evaluation of the possible loss of revenue, gas contract obligations, and capital investment,

- an evaluation of the possible impact on gas distribution companies whose gas supplies are mostly from the affected fields. This should include discussion on the issue of security of supply, alternative supplies, and cost of accessing them, as well as the size of possible stranded investment, and

- an assessment of the impact on NGTL's facilities servicing the affected gas producing areas as a result of a shut-in order.

(d) Policy Considerations

- If co-development is not possible, an identification of the priority of development and reasons for the preference.

- Views on resource conservation policies and procedures to maximize the recovery of hydrocarbons where oil sands have overlying gas caps or water sands in communication with gas caps.

- An identification of possible regulatory changes that could provide for optimum co-development of hydrocarbon resources.

(e) Guidelines

- Rules and procedures to be used for specific development applications in terms of contacting oil sands or P & NG leaseholders and providing opportunities for objection.

(f) Lease Tenure and Related Issues

Discussion of land tenure and related matters are issues outside the jurisdiction of the Board. The Board understands that the Department of Energy will be conducting its own review of current leasing policies and procedures in parallel with this inquiry (see attached letter). The Board recognizes the interest by parties submitting evidence to this proceeding to discuss all implications of the subject before the Board. If the parties see some merit in tabling information on these issues, the Board will summarize this information and related findings from the inquiry and forward it to the government for consideration in context of the conclusions by the Board.

4.3 The Process and Timing

On the basis of the suggested process from the participants and the nature of the issues raised at the 21 January 1997 meeting, the Board is prepared to proceed with the general inquiry of gas/bitumen development. The participants requested that the Terms of Reference be finalized and that the proceeding get underway as soon as practical. The Terms of Reference for the inquiry are laid out under section 4.2 of this report and the Board will adopt the following timetable to receive submissions and to consider the evidence.

Filing of coincident initial submissions	25 April 1997
Filing of responses to initial submissions	9 May 1997
Commencement of inquiry	27 May 1997

With respect to interim procedures for oil sands or gas applications for projects and/or facilities, the Board proposes to consider these under its normal rules and procedures. That is, in the absence of valid objections, the Board will continue to issue approvals for wells, facilities, etc., in the oil sands areas. Parties should recognize that affected facilities are subject to normal regulatory risks that may result from the finding of the inquiry. Where objections have been filed related to the Terms of Reference for this inquiry, the Board will hold these applications in abeyance pending the outcome of the inquiry. The Board also takes this opportunity to remind operators that it is their responsibility to monitor developments which may be of interest to them.

On the matter of costs related to the preparation of submissions and for the retention of experts in specific fields, the Board's view is that each party filing a submission will be responsible for all associated costs. This includes costs for the preparation or review of submissions as well as those for appearing at the inquiry.

5 CONCLUSION

The Board is prepared to proceed with a general inquiry into the issue of gas/bitumen development and invites interested parties to submit information on any or all of the items noted in the Terms of Reference. The inquiry will commence on 27 May 1997 at the Board's office in Calgary, Alberta. The Terms of Reference will be as set out under section 4.2 of this report. A Notice of Inquiry will be published in Alberta newspapers and distributed broadly.

DATED at Calgary, Alberta, on 19 February 1997.

ALBERTA ENERGY AND UTILITIES BOARD

F. J. Mink, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Board Member

W. J. Schnitzler, P.Eng.*
Acting Board Member

---

* Mr. Schnitzler was not available but agrees with the contents of the report.

Alberta
ENERGY

Office of the Deputy Minister

Petroleum Plaza North Tower
9945 - 108 Street
Edmonton, Alberta
Canada T5K 2G6

Telephone 403/427-8032
Fax 403/427-7737

February 14, 1997

Ms. Céline Bélanger
Chair, Alberta Energy and Utilities Board
640 - 5 Avenue SW
Calgary, Alberta, T2P 3G4

Dear Ms. Bélanger:

RE: Gas/Bitumen Inquiry - EUB

We understand that a number of participants at the recent EUB meeting on the Gas/Bitumen Inquiry suggested that land tenure issues be considered in the Inquiry. I believe we have arrived at an appropriate approach to this question through subsequent discussions between the Department and Board members and staff regarding the EUB's responsibility for conservation issues and the Department's for tenure.

The Department would like to accept the EUB's offer to collect comments on tenure-related concerns that industry may wish to raise at the Inquiry. It is understood that the EUB will simply gather information, summarize it, and forward it to the Department without any recommendations.

In parallel with the EUB's investigations, the Department will be proceeding with its own review of tenure policies that relate to gas/bitumen production. Tenure-related information received from the EUB will be addressed by the Department as part of this review.

The Department would like to support the EUB's Inquiry in two ways. We are prepared to have staff at the Inquiry who are qualified to provide clarification of current policies and historical records, should such information be requested by the Board. The Department has also carried out some preliminary, narrowly-focused research on the possible impact of gas production on the recovery of associated bitumen zones for a limited number of cases. We will release our report on this work when it has been finalized in the coming weeks. Department staff who prepared the study will also be available to the Inquiry to address any questions there may be about their work.

The Department contact for the gas/bitumen issue is David Coombs (422-9430) who is also the Project Leader for the Department's review of tenure-related issues.

Rick Hyndman

Appendix 5

Gas/Bitumen Inquiry Report, Executive Summary

EXECUTIVE SUMMARY

In late 1996, the Alberta Energy and Utilities Board (EUB) received submissions from several companies holding oil sands leases outlining their concerns regarding the potential adverse effects on the eventual recovery of bitumen if associated gas was produced in advance of the bitumen. Some oil sands leaseholders requested that all current and future associated gas production from affected oil sands deposits be curtailed. Given the broad implications of such a decision, the Board held a general inquiry on the issue to solicit the views of all segments of the industry.

Gulf Canada Resources Limited (Gulf) submitted a study showing the potential effects of associated gas production on the Steam Assisted Gravity Drainage (SAGD) bitumen project proposed for its Surmont leases. Other oil sands leaseholders raised similar concerns for other oil sands areas. The concerns focused on the effect of gas cap pressure depletion on bitumen recovery. It was contended that such pressure depletion could compromise the recovery efficiency of the SAGD process to such an extent that some bitumen projects might not be viable.

The Alberta Producers Group (APG), representing a group of gas producers, countered that there are ample opportunities for thermal bitumen projects in areas where associated gas production would not be an issue and therefore the activities of gas producers need not be constrained. Furthermore, the APG contended that if bitumen producers believe their projects may be at risk, they could purchase the petroleum and natural gas (P&NG) rights. The APG also contended that there could be adverse effects on gas recovery from SAGD operations. Specifically, the APG was concerned with contamination, pressure depletion, water influx, and geomechanical effects.

Although the effect of associated gas production on primary bitumen recovery had been raised as an issue prior to the inquiry, there was very little discussion of this issue at the inquiry.

The Board notes that there are currently little or no field data available on the effect of associated gas production on SAGD performance. The evidence submitted at the inquiry to evaluate this effect was based on reservoir modelling by extrapolating the experience at the Underground Test Facility. All four of the Athabasca-McMurray models presented at the inquiry predicted that associated gas production would have a detrimental effect on SAGD performance. Notwithstanding the models' limitations to accurately predict the extent of the effects — which would depend on the specific reservoir situation, economic circumstances, and operating strategy — the Board concluded that in some instances the effect on bitumen recovery could be significant.

In order to chart a prudent course for the future development of the gas and bitumen resources in the oil sands areas, the Board concluded that:

- although limited field data are available, sufficient evidence exists to suggest that associated gas production could have a detrimental effect on some bitumen resources, to the extent that significant volumes might never be recoverable;

- while it is possible that thermal bitumen processes could have a detrimental effect on associated gas recovery, such effects would likely be relatively minor;

- Alberta's current and prospective gas reserves and deliverability position would not be materially affected by discouraging some associated gas production in the oil sands areas in favour of conserving the bitumen resources; and

- an evaluation of the appropriate timing of producing gas associated with bitumen should be consistent with the Board's approach to evaluating the production of gas associated with conventional oil.

For these reasons, the Board has decided that some regulatory involvement is warranted, at least until such time as additional information becomes available to clarify the effect of associated gas production on bitumen recovery or alternative technology and/or economic circumstances reduce the risk of bitumen sterilization.

In determining a policy for gas and bitumen production, the Board must consider two distinct cases: currently producing gas wells and facilities developed in advance of this report and investments to be made in the future. In the first instance, the Board will generally allow associated gas production to continue from investments made up to 1 July 1998, unless the Board receives a complaint from an oil sands leaseholder and the subsequent investigation shows continued production from existing gas wells would not be in the long-term public interest. In the second instance, for any development of associated gas in the oil sands areas after 1 July 1998, the Board will require proponents to apply for a "concurrent production" approval. Such applications will be expected to include sufficient evidence to evaluate the scope of impact and provide a discussion of the efforts made by the affected parties to resolve the outstanding issues.

To summarize, the Board will:

- allow associated gas production in the oil sands areas from wells drilled and completed by 1 July 1998, subject to the resolution of any concerns raised by oil sands leaseholders or the Board on its own initiative;

- require concurrent production approval for the production of all associated gas in the oil sands areas from wells drilled after 1 July 1998;

- require, effective 1 July 1998, all new wells in the oil sands areas to be drilled to the base of the oil sands zone;

- develop a notification process, in consultation with the affected parties, to advise leaseholders of prospective developments;

- support modifications to the existing lease tenure system in the oil sands areas to reduce resource development conflicts; and

- investigate the means of conducting further research on the effects of concurrent gas and bitumen production.

Appendix 6

Gulfs List of 183 Wells Requested to Be Shut In

Attachment S-1

Wells Requested to be
Shut-in as at
October 5, 1998

00/12-29-080-05W4/0
00/11-30-080-05W4/0
00/05-31-080-05W4/0
00/11-19-080-06W4/0
00/06-20-080-06W4/0
00/06-22-080-06W4/0
00/07-23-080-06W4/0
00/13-24-080-06W4/0
00/13-24-080-06W4/2
00/13-25-080-06W4/0
00/15-26-080-06W4/0
00/10-27-080-06W4/0
00/11-28-080-06W4/0
00/11-28-080-06W4/2
00/07-29-080-06W4/0
00/11-30-080-06W4/0
00/07-32-080-06W4/0
00/11-34-080-06W4/0
00/07-35-080-06W4/0

00/07-36-080-06W4/0
00/09-24-080-07W4/0
00/03-34-080-07W4/0
00/04-35-080-07W4/0
00/02-36-080-07W4/0
00/10-04-081-05W4/0
00/08-05-081-05W4/0
00/12-08-081-05W4/0
00/06-09-081-05W4/0
00/11-17-081-05W4/0
00/03-18-081-05W4/0
00/11-19-081-05W4/0
00/03-30-081-05W4/0
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00/02-33-083-07W4/0
02/10-36-083-07W4/0
00/06-01-083-08W4/0
00/06-01-083-08W4/2 (exclude Clearwater)
00/05-07-084-05W4/0
00/02-01-084-06W4/0
00/10-01-084-06W4/0
00/15-02-084-06W4/0

00/06-06-084-06W4/0

00/06-01-084-07W4/0

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00/06-12-084-07W4/0

00/03-13-084-07W4/0

Appendix 7
EUB Letter Regarding Pre-hearing Meeting

EUB Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

9 November 1998

To: Interested Parties (see attached list)

PRE-HEARING MEETING
PROCEEDING NO. 960952
SURMONT AREA
GULF CANADA RESOURCES LIMITED

The Alberta Energy and Utilities Board (the Board) has considered the positions put forward by parties at the 5 November 1998 pre-hearing meeting respecting Proceeding No. 960952 wherein Gulf Canada Resources Limited (Gulf) has requested the shut-in of gas in the Surmont Area. The positions pertained to:

- the schedule for the filing of submissions;
- the commencement of the hearing;
- the release of confidential information for Gulf's Steam Assisted Gravity Drainage (SAGD) experimental scheme in the Surmont area;
- the additional information on previous reservoir modelling work done by Gulf; and
- the pressure data for gas wells in the Surmont area.

Regarding the schedule for the filing of submissions and hearing commencement, the Board believes that the following schedule would provide all parties with a reasonable opportunity to prepare and file thorough submissions.

Filing of intervener submissions	8 March 1999
Gulf's response to intervener submissions	5 April 1999
Hearing commencement	20 April 1999

The Board will issue a Notice of Hearing in due course.

Regarding the release of confidential information for Gulf's SAGD experimental scheme, the additional information on previous reservoir modelling work done by Gulf, and the pressure data for gas wells in the Surmont area, as stated at the pre-hearing meeting, the Board is not prepared to require the release of commercially privileged information. However, the Board strongly encourages the parties to share information that might assist the Board and all of the parties to the proceeding.

If you have any questions regarding the above, please contact Ken Schuldhaus (297-3572) or Gary Dilay (297-3561) of the Board's Reservoir Development Group.

Yours truly,

J. D. Dilay, P. Eng.
Board Member

Attachment

Interested Parties

Robert Watson
Giant Grosmont Petroleums Ltd.
1400 700 9 Avenue SW
Calgary AB T2P 3V4

A. L. McLarty
Milner Fenerty
3000 237 4 Avenue SW
Calgary AB T2P 4X7

George Yip
NAL Resources
2400 605 5 Avenue SW
Calgary AB T2P 3H5

Murray Weatherhead
Northstar Energy Corporation
3000 400 3 Street SW
Calgary AB T2P 4H2

Detlef Lehmann
Paramount Resources Ltd.
4000 350 7 Avenue SW
Calgary AB T2P 3W5

Ab Fink
Petro-Canada Oil and Gas
150 6 Avenue SW
Calgary AB T2P 3E3

Ian Towers
Rio Alto Exploration Ltd.
2500 205 5 Avenue SW
Calgary AB T2P 2V7

Bryan Jackson
Wascana Energy Inc.
2900 240 4 Avenue SW
Calgary AB T2P 5C1

Bruce Lounds
Gulf Canada Resources Limited
2000 400 3 Avenue SW
Calgary AB T2P 5A6

Frank R. Foran
Howard Mackie
1000 400 3 Avenue SW
Calgary AB T2P 4H2

Paul Case
Renaissance Energy Ltd.
3000 425 1 Street SW
Calgary AB T2P 3L8

Appendix 8

EUB Letter Confirming Authority to Hear Gulf's Request

EUB Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

4 March 1999

VIA FAX

A.L. McLarty
Fraser Milner
Barristers & Solicitors
Calgary, Alberta
Fax: 268-3100

F. R. Foran
Howard Mackie
Barristers & Solicitors
Calgary, Alberta
Fax: 232-9727

S. R. Miller
Petro-Canada Oil and Gas
Legal Department
Calgary, Alberta
Fax: 296-4910

Dear Sirs:

Re: Application No. 960952 (Application)
Gulf Canada Resources Limited

The Board has received and considered the Surmont Producers Group (SPG) Motion for Dismissal (Motion) and Reply Argument (Reply) dated 4 February 1999 and 2 March 1999 respectively. Responses were received from Gulf Canada Resources Limited (Gulf), Petro-Canada Oil and Gas (Petro-Canada) and Amoco Canada Petroleum Limited (Amoco) dated 25 February 1999.

The Board has also received and considered the SPG letter dated 26 February 1999 requesting a deferral of the 8 March 1999 filing date for intervener submissions and if necessary the 20 April 1999 hearing commencement date to facilitate the incorporation and consideration by the SPG of pressure data for the purposes of its evidence. Responses to this request were received from Gulf and Petro-Canada dated 3 March 1999. The Board has accordingly asked me to advise of its decision as follows.

Request for Deferral of Submission/Hearing Date

Respecting the request for a deferral of the submission and/or hearing date for the Application, the Board notes that the 19 January 1999 request by Board staff for additional pressure data was made as part of the Board's normal objective of collecting field data. While the information may eventually relate to the issues before the Board in the Application, the Board is not in a position to pre-judge the merits or relevancy of collection of that data at this time.

Accordingly, the Board concluded that it will proceed with the submission and hearing dates as proposed and rule upon new evidence submitted outside of the prescribed dates in accordance with its normal practice. While the Board is prepared to hear arguments and receive additional evidence on its merits in the course of completing the record for this Application, it does not intend to delay the hearing.

Motion for Dismissal of the Application

With respect to the Motion, the Board considered the following issues.

a) Notice

The history behind the Application is lengthy and involved and the Board does not see a need to repeat the facts as set out in the submissions in its decision on this Motion. The Board accepts the SPG statement (Reply, p. 14) that "there has never been any doubt as to the nature of Gulf's arguments or as to the nature of Gulf's requests made to the Board". Also, the Board notes that most, if not all, of the members of the SPG participated in the public inquiry (Inquiry) which resulted in the Board's 25 March 1998 report entitled Gas/Bitumen Production in the Oil Sands Areas (Inquiry Report) and in the industry committee formed to address the issues arising from the Inquiry. Accordingly, the Board is satisfied that the SPG has had notice of the facts and substance relating to the Application to the same extent that any interested party has had notice, including the Board itself.

The issue more specifically raised by the SPG, however, is whether the SPG has been notified or been aware of the authority that the Board might purport to exercise with respect to the Application, and therefore has been precluded from determining the specifics of what would be relevant in terms of a response (Reply, p. 14).

The Board recognizes that the issues raised by the Application are novel and are not specifically contemplated by the Board's enabling statutes or regulations. However, for the reasons outlined in the following section, the Board continues to believe that it has the requisite authority and jurisdiction to hear and adjudicate upon the Application. At the Inquiry, the Board heard argument relating to the Board's jurisdiction, generally, to determine issues arising from the conflict between gas and bitumen development, and in particular those matters regarding orderly and efficient development and conservation of the respective resources (gas/bitumen issues). As noted by Gulf, the Board outlined its jurisdiction pertaining to the gas/bitumen issues in a general way at pages 4 and 5 of the Inquiry Report. It is apparent from Gulf's submission that Gulf was encouraged by the Board's findings in the Inquiry Report to re-submit the Application to the Board.

Until now, the Board has not seen a need to outline the specifics of the authority it purports to exercise in relation to the Application for two reasons; (1) as stated, the Application is a novel application and the Board views its role in resolution of the gas/bitumen issues as an evolving one not yet clearly developed or defined, and (2) because the Board has not yet heard the Application, it feels it is premature to rule upon what authority it may choose to exercise in any attempt to mitigate or remedy the issues raised. On the face of the Application, the Board believes that it has the jurisdiction to adjudicate upon the dispute. However, the Board must first give parties a chance to be heard pursuant to section 29 of the *Energy Resources Conservation Act* (ERCA) before it can decide what, if any, relief the Board may grant.

The Board does not believe that the SPG will be disadvantaged or prejudiced in any way in relation to any other party because of Gulf's omission to state a particular statutory provision upon which its Application is based, recognizing Gulf's argument that the deficiency was remedied by its 25 February 1999 submission on this Motion. In any event, whether Gulf had included its 25 February comments in its original application may be of little consequence given the Board's powers pursuant to section 10(3)(f) of the *Alberta Energy and Utilities Board Act* (AEUB Act), which provides:

> 10(3) Without restricting subsection (1), the Board may do all or any of the following:
>
> (f) where it appears to the Board to be just and proper, grant partial, further or other relief in addition to, or in substitution for, that applied for as fully and in all respects as if the application or matter had been for that partial, further or other relief.

It may be that the SPG, Gulf, Petro-Canada or any other interested party will want to advance argument at the hearing on a number of alternative grounds of relief, as all potential grounds are available to the Board in its deliberations. In that regard, the Board does not believe that the Application should be defeated on the grounds that the SPG has received no or insufficient notice of the authority that the Board might purport to exercise in relation to the Application. In any event, the Board believes that the Motion is premature for the reasons stated.

To assist parties further in preparation for the hearing, however, and without pre-judging the course of action in any way, the Board believes it may be helpful to parties to outline what alternatives are available to it in dealing with the Application.

b) Jurisdiction

The Board has consistently held that it has the requisite jurisdiction to hear the issues raised by the Inquiry and by the Application.

The Board agrees with the SPG that the purposes provisions are not power-conferring, but are one of the interpretive aids to interpreting the substantive provisions of the statute (Reply, p. 7). On the other hand, the Board believes that the expansive language of the purposes provisions referred to indicate the intention of the Legislature to provide the Board with extensive authority to regulate and adjudicate upon matters of conservation and orderly and efficient development of energy resources such as those raised in the Application. In particular, the Board relies on subsections 2(c) and (e) of the ERCA, subsection 4(c) of the *Oil and Gas Conservation Act* (OGCA) and subsections 3(a) and (b) of the *Oil Sands Conservation Act* (OSCA) for the purposes of this Application. In addition, the Board interprets section 5 of the OSCA and section 86 of the OGCA as giving it the exclusive jurisdiction to examine, inquire into, hear and determine all matters and questions arising under the OSCA and the OGCA. Also, section 8(1) of the AEUB Act provides:

> 8(1) All matters that may be dealt with by the ERCB or the PUB under any enactment or as otherwise provided by the law shall be dealt with by the Board and are within the exclusive jurisdiction of the Board.

With respect to substantive authority, the Board believes that there are two potential alternatives which may be available to the Board in respect of the relief which Gulf requests in its Application. Each of these will be discussed in turn.

i) Section 42 of the ERCA

Pursuant to section 42 of the ERCA, the Board may "review, rescind, change, alter or vary an order or direction made by it, or may rehear an application before deciding it". The Board interprets section 42 as providing it with the authority to review the well licences referenced in the Application on the basis that new information (e.g. SAGD technology) has come to the attention of the Board which convinces the Board that a review is necessary. This section gives the Board the requisite authority to at least hear the Application, and maybe ultimately to rescind, change, alter or vary the well licences (or grant other relief in the Board's discretion) depending upon what information is presented at the hearing.

Pursuant to section 10(2) of the AEUB Act, the Board notes that "[i]n any case where the ERCB, the PUB or the Board may act in response to an application, complaint, direction, referral or request, the Board may act on its own initiative or motion". Accordingly, whether or not the Application disclosed in the first instance a desire that the Board exercise its authority under section 42, the Board may decide on its own initiative to conduct the review.

ii) Section 21 of the ERCA

Section 21 of the ERCA provides:

> 21 The Board, with the approval of the Lieutenant Governor in Council, may take any action any may make any orders and directions that the Board considers necessary to effect the purposes of this Act and that are not otherwise specifically authorized by this Act.

Section 7 of the OGCA and section 6 of the OSCA grant the same authority to the Board in respect of the purposes of those Acts.

The Board believes that the remedy Gulf seeks in the Application may be granted pursuant to section 21 (or section 7 or 6 of the OGCA and OSCA, respectively) if the Board determines that such an order or direction is necessary to effect the purposes of the ERCA, as referenced above. Such a determination, however, cannot be made at this stage without having heard all of the evidence and submissions of the parties.

The Board disagrees with the SPG's assertion that, even with the approval of the Lieutenant Governor in Council, the Board does not have jurisdiction to order the shut-in of gas production (Reply, p. 16). First, even though the legislation contains provisions which specifically authorize the Board to require concurrent production or cancel or suspend well licences, the Board interprets section 21 as extending the Board's authority, with the approval of the Lieutenant Governor in Council, to cover instances such as the present case where no specific provision speaks to the relief sought. Further, the Board does not believe that the repeal of sections 29(2) and 26(1)(f) of the OGCA in 1983 can be interpreted as a legislative intent that those powers be taken away from the Board absolutely. The Board agrees with Petro-Canada (submission, pp. 21-23) that the intent of repealing the referenced sections from the OGCA and simultaneously promulgating the OSCA was to gather all of the substantive provisions respecting oil sands into one piece of legislation, and the Hansard excerpts supplied by Petro-Canada at tabs 17 and 18 of its submission supports this interpretation. Furthermore, the Board retained a regulation-making power pursuant to section 21(1)(u) of the OSCA to make regulations with the following purpose:

> (u) generally to conserve oil sands and crude bitumen and to prevent the waste or improvident disposition or oil sands, crude bitumen, derivatives or crude bitumen, declared oil sands or oil sands products.

The Board accepts the above regulation-making power as giving it the flexibility to adapt to a changing environment and technological advances which raise issues of conservation that the Board is asked or decides to address.

Secondly, the SPG states that the legislation may not be interpreted to permit the confiscation of property rights, and in any event that specific power is expressly conferred on the Minister of Energy pursuant to section 8 of the *Mines and Mineral Act*. The Board rejects this argument on two counts. First, the Board does not believe that the effect of an order to shut in gas wells for conservation purposes properly made by the Board is a confiscation of property rights. The Board accepts the arguments of Gulf and Petro-Canada that mineral leases pursuant to which a lessee has the right to take minerals are made subject to any Board regulations, orders or directives, as amended from time to time.

Furthermore, it is pursuant to section 11(1) of the OGCA that a person must obtain a well licence from the Board before commencing to drill or produce a well. That section provides:

> **11(1)** No person shall commence to drill a well or undertake any operations preparatory or incidental to the drilling of a well or continue any drilling operations, any producing operations or any injecting operations unless
>
> (a) a licence has been issued and is in full force and effect, and
>
> (b) the person is the licensee.

Contrary to the SPG's assertion that a well licence gives a licensee a statutory right to produce (submission, pp. 9 and 13), the Board believes that section 11(1) does not confer such a right, but merely prohibits any production from occurring unless and until a licence is obtained from the Board. Pursuant to section 14 of the OGCA, the Board may grant a licence subject to any conditions, restrictions and stipulations that the Board may specify, and section 2.1 of the ERCA obliges the Board to consider the public interest in that determination. As stated above, that licence may also be subject to review at any time under section 42 of the ERCA. Therefore, the Board disagrees that the effect of a shut in order as requested would be a confiscation of property rights as the gas producers' right to take pursuant to their leases is subject to the Board's authority as noted.

c) Regulations

Following the Inquiry, the Board saw the need to publish regulations to give parties some certainty with respect to what framework or requirements the Board would establish to administer and regulate the gas/bitumen issues. Accordingly, the Board worked with industry and the government through the gas/bitumen committee to draft new regulations and requirements. These events are set out in the submissions and will not be repeated here. What has since transpired is that the proposed regulations were filed on 1 March 1999 (attached) and all parties interested in the gas/bitumen issues were notified of these new regulations on 4 March 1999 by letter from the Board. The Board believes that it has the authority to make these regulations pursuant to section 10 of the OGCA and section 21 of the OSCA. Although the Board acknowledges that Gulf could not have filed its application made on 12 November 1996 pursuant to these regulations, the Board notes that the regulations are now filed and that the Board will have regard for the regulations in any future applications which may come before the Board.

d) Conclusions

The Board therefore confirms its position that it has the statutory authority to hear the Application and to take whatever action within the Board's jurisdiction as outlined above it deems necessary.

Yours truly,

Tania Donnelly

Tania H. Donnelly
Counsel

encl.
cc: interested parties
(see attached list)

Interested Parties

D. Stuart
Marathon Canada Limited
1000, 444 - 7 Avenue SW
Calgary AB T2P 0L4

R. McIlwrick
Murphy Oil Company Ltd.
Box 2721, Station M
Calgary AB T2P 3Y3

M. Montemurro
PanCanadian Resources
P.O. Box 2850
Calgary AB T2P 2S5

R. Lane
Mobil Oil Canada Limited
330 - 5 Avenue SW
Calgary AB T2P 0L4

A. Gal
New Cache Petroleums Ltd.
Sun Life Plaza II
400, 140 - 4 Avenue SW
Calgary AB T2P 3N3

F. Morrissey
Numac Energy Inc.
Cadillac-Fairview Bldg.
321 - 6 Avenue SW
Calgary AB T2P 3H3

B. Fialka
Ranger Oil Limited
1600, 321 - 6 Avenue SW
Calgary AB T2P 3H3

P. Case
Renaissance Energy Ltd.
3000, 425 - 1 Street SW
Calgary AB T2P 3L8

B. Purdy
Senoma Energy Corp.
2200, 400 - 3 Avenue SW
Calgary AB T2P 4H2

K. Yeung
Suncor Energy Inc.
112 - 4 Avenue SW
Calgary AB T2P 2V5

W. Shepheard
Unit Energy Canada Inc.
c/o Strategic Energy Resource Corp.
500, 717 - 7 Avenue SW
Calgary AB T2P 0Z3

V. Edwards
Wascana Energy Inc.
635 - 8 Avenue SW
Calgary AB T2P 3Z1

K. Lawrence
Shell Canada Limited
400 - 4 Avenue SW
Calgary AB T2P 0J4

N. Brandelli
Union Pacific Resource Inc.
Box 2595, Station M
Calgary AB T2P 4V4

S. Howell
Unocal Canada Limited
1100, 530 - 8 Avenue SW
Calgary AB T2P 3S8

O. DeVries
Canadian Association of Petroleum Producers
2100, 350 - 7 Avenue SW
Calgary AB T2P 3N9

R. Vogel
Small Explorers and Producers Association
1060, 717 - 7 Avenue SW
Calgary AB T2P 0Z3

D. Coombs
Alberta Department of Energy
2nd Floor. North Petroleum Plaza
9945 - 108 Street
Edmonton AB T5K 2G6

K. West
Crestar Energy Inc.
Box 888
Calgary AB T2P 4M8

G. McTavish
Genesis Exploration Ltd.
350. 321 - 6 Avenue SW
Calgary AB T2P 3H3

W. Ogrodnick
Husky Oil Operations Ltd.
707 - 8 Avenue SW
Calgary AB T2P 1H5

B. Harschnitz
Imperial Oil Resources Limited
P.O. Box 2480. Station M
Calgary AB T2P 3M9

D. Jacques
Indian Oil and Gas Canada
100. 9911 Chula Blvd.
Tsuu Tina (Sarcee) AB T2W 6H6

K. Ogino
Japan Canada Oil Sands Limited
2100. 101 - 6 Avenue SW
Calgary AB T2P 3P4

D. Livesey
Koch Exploration Canada Ltd.
1400. 111 - 5 Avenue SW
Calgary AB T2P 3Y6

R. Eresman
AEC East
3900, 421 - 7 Avenue SW
Calgary AB T2P 4K9

B. Dau
Anderson Exploration Ltd.
1600. 324 - 8 Avenue SW
Calgary AB T2P 2Z5

A. Ruus
Baytex Energy Ltd.
2200. 205 - 5 Avenue SW
Calgary AB T2P 2V7

D. Warkentine
Camberley Energy Ltd.
700. 635 - 8 Avenue SW
Calgary AB T2P 3M3

D. McCallum
Chevron Canada Resources
500 - 5 Avenue SW
Calgary AB T2P 0L7

R. Sendall
Amoco Canada Petroleum Company Ltd.
P.O. Box 200. Station M
Calgary AB T2P 2H8

J. Kay
Cabre Exploration Ltd.
P.O. Box 630. Station M
Calgary AB T2P 2J3

J. Bereson
Canadian Natural Resources Limited
2000, 425 - 1 Street SW
Calgary AB T2P 3L8

R. Jonston
Coparex Canada Ltd.
2nd Floor. 615 - 3 Avenue SW
Calgary AB T2P 0G6

ALBERTA REGULATION 47/99
FILED ON March 1 19 99

THE PROVINCE OF ALBERTA

OIL AND GAS CONSERVATION ACT

ALBERTA ENERGY AND UTILITIES BOARD

Regulation to Amend the Oil and Gas Conservation Regulations

The Alberta Energy and Utilities Board, pursuant to section 10 of the *Oil and Gas Conservation Act* makes the Oil and Gas Conservation Amendment Regulation set out in the Appendix.

Made at the City of Calgary, in the Province of Alberta, this 24th day of February 1999.

ALBERTA ENERGY AND UTILITIES BOARD

P. Prince

P. Prince, Ph.D.
Board Member

APPENDIX

Oil and Gas Conservation Act

OIL AND GAS CONSERVATION
AMENDMENT REGULATION

1 The *Oil and Gas Conservation Regulations* (AR 151/71) are amended by this Regulation.

2 Section 1.020(2) is amended by adding the following after item 11:

11.1. "oil sands strata" means the geological intervals defined in the Board's Oil Sands Area Orders OSA 1, 2 and 3, as amended from time to time;

3 The following is added after section 3.010:

3.011 No person shall produce gas from a well completed in the oil sands strata prior to obtaining an approval from the Board in accordance with section 3 of the *Oil Sands Conservation Regulation* (AR 76/88), unless the Board has exempted the well from the application of this section.

4 The following is added after section 6.190:

Drilling in the Oil Sands Strata

6.200 Any well drilled in the oil sands strata must be drilled deep enough to be able to log over the base of the oil sands deposit containing the zone to be produced, unless the licensee has obtained an exemption from the Board.

2/90222/74/10727

ALBERTA REGULATION 48/99
FILED ON March 1 19 99

THE PROVINCE OF ALBERTA

OIL SANDS CONSERVATION ACT

ALBERTA ENERGY AND UTILITIES BOARD

Regulation to Amend the Oil Sands Conservation Regulation

The Alberta Energy and Utilities Board, pursuant to section 21 of the *Oil Sands Conservation Act* makes the Oil Sands Conservation Amendment Regulation set out in the Appendix.

Made at the City of Calgary, in the Province of Alberta, this 24th day of February 1999.

ALBERTA ENERGY AND UTILITIES BOARD

P. Prince. Ph.D.
Board Member

APPENDIX

Oil Sands Conservation Act

OIL SANDS CONSERVATION AMENDMENT REGULATION

1 The *Oil Sands Conservation Regulation* (AR 76/88) is amended by this Regulation.

2 Section 1(2) is amended

(a) by adding the following after clause (u):

(u.1) "oil sands strata" means the geological intervals defined in the Board's Oil Sands Area Orders OSA 1, 2 and 3, as amended from time to time;

(b) by adding the following after clause (z):

(z.1) "solution gas" means gas that is dissolved in crude oil or crude bitumen under reservoir conditions and evolves as a result of pressure and temperature changes;

3 Section 3 is amended by adding the following after subsection (2):

(3) No person shall produce gas from a well completed in the oil sands strata prior to obtaining an approval from the Board, unless the Board has exempted the well from the application of this subsection.

(4) An application to produce gas in accordance with subsection (3) must be made by the well licensee and include the documentation required by the Board.

(5) Where it appears to the Board that the ultimate recovery of crude bitumen in the oil sands strata may be affected by gas production, the Board may, on its own initiative or on application by an affected party, make any order or directive it considers necessary to effect the conservation of the crude bitumen in any particular case.

1/90222/71/10728

(6) Subsections (3), (4) and (5) do not apply to the production of solution gas.

Appendix 9

Those Who Appeared at the Hearing

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Gulf Canada Resources Limited (Gulf)	
F. R. Foran R. W. Block	R. Chalaturnyk, Ph.D., P.Eng., Consultant, Assistant Professor, Department of Civil & Environmental Engineering, University of Alberta G. Demke, of Demke Mangement Ltd. P. Esslinger, P.Geol., of Rakhit Petroleum Consulting Ltd. K. Kisman, Ph.D., P.Eng., of Rangewest Resources Ltd. B. Lounds, P.Eng. D. Manner C. Mothersele R. Penny, P.Eng. F. Raffin, P.Geol. D. Theriault, P.Eng. H. Thimm, Ph.D., P.Eng., of H. F. Thimm & Associates Ltd. D. Thomas E. Zaghloul, Ph.D., P.Geol.
Petro-Canada Oil and Gas (Petro-Canada) S. R. Miller W. T. Corbett A. Broughton	D. Barnes, of Baker Atlas GeoScience Consulting Ltd. D. Barson, Ph.D., P.Geol., of Rakhit Petroleum Consulting Ltd. G. Duncan, P.Eng. J. Fong. P.Eng. J. Knight, Ph.D., P.Geol. D. Lee, P.Geol. C. Palmgren, Ph.D., P.Eng., Consultant G. Sinclair, P. Eng.
Anzac Metis Local No. 334 P. E. Kennedy A. C. Rice	L. Lavallee J. Malcolm J. Mulawka L. Mulawka

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Chipewyan Prairie Dene First Nation D. Roth	J. Janvier W. Janvier R. Kent A. Paul H. Thiessen
Fort McMurray No. 468 First Nation M. Cheecham	M. Cheecham
Durando Resources Corporation G. Stabb	
PanCanadian Petroleum Limited P. A. McCunn-Miller	
Surmont Producers Group (the SPG includes Canadian Forest Oil & Gas Ltd., Giant Grosmont Petroleums Ltd., NAL Resources Ltd., Northstar Energy Corporation, Ocean Energy Resources Canada Ltd., Paramount Resources Ltd., and Rio Alto Exploration Ltd.) A. L. McLarty T. L. Campbell	K. Adegbesan, Ph.D., P.Eng., of KADE Technologies Inc. J. Besse, P.Eng., of Northstar Energy Corporation . G. Birrell, of Northstar Energy Corporation . W. Haessel, Ph.D., of Calgary Energy Consultants Ltd. C. Kramchynski, of Rio Alto Exploration Ltd. J. Pearce, P.Eng., of Northstar Energy Corporation . B. Pearson, P.Eng., of Adams Pearson Associates Inc. P. Putnam, Ph.D., P.Geol., of Petrel Robertson Ltd. R. Watson, P.Geol., of Giant Grosmont Petroleums Ltd. M. Weatherhead, P.Eng., of Northstar Energy Corporation . D. Work, P.Geol., of Paramount Resources Ltd.
Anderson Exploration Ltd. K. Krynowsky	

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Renaissance Energy Ltd. P. Case	
Alberta Department of Resource Development M. Huk	
Alberta Energy and Utilities Board staff S. Bachu, Ph.D., P.Eng. M. E. Connelly, P.Geol. G. W. Dilay, P.Eng. T. H. Donnelly D. B. Fairgrieve, P.Geol. F. J. Hein, Ph.D., P.Geol. K. M. Johnston D. A. Larder K. F. Schuldhaus, P.Eng.	

Appendix 10

EUB Order to Produce Documents

EUB Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

8 July 1999

TO: Order Addressees **(HAND DELIVERED)**
Interested Parties **(VIA FAX)**
(see attached lists)

Re: Proceeding No. 960952
Gulf Canada Resources Limited
Order to Produce Documents

Enclosed is an Order to Produce Documents (Order) issued by the Alberta Energy and Utilities Board (Board) today in the above proceeding (Proceeding). Attached to the Order is the form of Declaration and Undertaking not to Disclose (Undertaking) that parties privy to the documents ordered to be produced must sign to maintain their recipient and participant status in the in camera portion of the Proceeding to be held.

The procedures the Board will follow in respect of the documents to be produced is set out in the Order. Further clarification of procedure will be dealt with in the context of the Proceeding itself.

In consideration of the submissions of interested parties relating to the draft Order, the Board has asked me to provide further explanation for certain portions of the Order as follows:

(1) Under the heading "Documents Ordered to be Produced", the Board decided:

a. Because it is unclear whether the core photos available as part of the Dover SAGD information constitutes a representative cross-section of all of the wells, the Board requires that Recipients be given access to all cores upon request, unless it can be otherwise shown that the available photos are a representative sample.

b. Although the Board recognizes that gas composition data may be useful regarding the potential for contamination of gas caps, the Board believes that the information is not pivitol to its decision in the Proceeding. Accordingly, the Board will not order gas composition analyses to be produced.

c. The Board recognizes gas lift volumes and gas production data to be directly relevant to the Proceeding in the context of the effect of solution gas on SAGD performance and therefore requires that data be produced.

(2) Under the heading "Document Recipients and Conditions of Production", the Board decided to allow inclusion of the three additional representatives from the Surmont Producers Group (SPG) as requested. The Board believes that the

principles of fairness dictate that, because of the direct and adverse effect which may result to these parties specifically if Gulf's request is granted, these parties are entitled to know the case against them and be given a reasonable opportunity to provide evidence or make arguments rebutting that case, notwithstanding they are part of the SPG. Further, the Board believes that the terms of the Order and Undertaking will be strictly complied with by all Recipients.

) Although the Board has not named specifically the individuals who it expects will be Recipients, in order to allow parties a reasonable amount of flexibility in that regard, inclusion of Board staff, company representatives and counsel other than those named below will require leave of the Board:

a. *Board staff*: Ken Schuldhaus, Gary Dilay, Marnie Connelly, Brent Fairgrieve, Kevin Johnston, Fran Hein, Stephan Bachu, Tania Donnelly and Doug Larder;

b. *Gulf*: Dave Theriault, Ken Kisman, Essam Zaghloul, Frank Raffin, Randy Penny, Frank Foran and Randall Block;

c. *Petro-Canada*: James Fong, Derek Lee, Mark Chan, Bill Corbett and Scott Miller; and

d. *SPG*: Peter Putnam, John Pearce, Greg Birrell, Jim Besse, Dave Work, Ian Towers, Bob Watson, Tara Campbell and Al McLarty

) Under paragraph 3(e) of the Order, parties will note that the word "transcripts" has been added to ensure parties understand that any transcripts they receive from the in camera portions of the hearing shall be returned to the Board with all copies of the produced documents and working material at the end of the Proceeding or when the Board directs.

the Order reads, the Board expects that the documents referred to in the Order will be ›duced on Monday, 12 July 1999 once the Undertakings have been signed by all the cipients. Signing of Undertakings will take place in the Proceeding itself on Monday ›rning.

:ase direct questions or concerns regarding any of the above to me at (403) 297-4110.

›urs truly,

Tania Donnelly

nia H. Donnelly
unsel

:l.

and use being solely for the purposes of the Proceeding. Those persons, collectively referred to as the "Recipients", are:

(i) 9 members of Board staff;
(ii) 5 representatives and 2 counsel for Gulf;
(iii) 3 representatives and 2 counsel for Petro-Canada Oil and Gas;
(iv) 7 representatives and 2 counsel for the Surmont Producers Group; and
(v) representatives of Amicus Reporting Group who participate in the in camera sessions of the Proceeding.

(b) One (1) copy of the Dover SAGD information and the Gulf information shall be provided for the collective access and use by each of groups (ii), (iii) and (iv) enumerated above and three (3) copies shall be provided to Board staff for the Board's use. No additional copies, in any form, shall be made or permitted to be made by the Recipients or by anyone.

(c) No use whatsoever shall be made of the Dover SAGD information or the Gulf information by the Recipients or their employers, principals, clients or others that they represent, except for the purposes of providing evidence (direct and cross-examination) and argument at the Proceeding.

(d) The produced copies of the Dover SAGD information and the Gulf information shall be returned to the Board at the close of the Proceeding or earlier as directed by the Board and, with the sole exception of one copy forming a confidential part of the record, which copy shall remain confidential, the remaining materials shall be destroyed by the Board and such destruction shall be confirmed by the Board.

(e) All working, preparation, briefing and review notes, or calculations and transcripts, in any form or medium, and all copies thereof, as well as any and all formal submissions to the Board, related to the Dover SAGD information and the Gulf information shall also be delivered to the Board at the close of the Proceeding or earlier as directed by the Board. However, where the requirement to deliver up all working, preparation, briefing and review notes or calculations in any form or medium may serve to destroy solicitor client privilege, the party claiming such privilege shall provide a statutory declaration that all such review notes, or calculations, in any form or medium and all copies thereof have been destroyed by it and its counsel.

(f) The Recipients shall strictly safeguard and retain in strict confidence their respective copy of the Dover SAGD information and the Gulf information, as well as the working material described in paragraph 3(e), which safeguarding shall consist of ensuring that only the Recipients shall have access to and use of the said copy and working material. When the copy and working material are not being immediately used by the said persons, the copy and working material shall be kept under lock.

Hearing Procedures re: Production

4. The Board shall consider the Dover SAGD information and the Gulf information at the Proceeding, in camera, with only the Recipients and the court reporter in attendance. The transcript of the Proceeding regarding the Dover SAGD information and the Gulf information shall be segregated from the other evidence and argument taken at the Proceeding and only the Recipients shall have access to and use of the said transcript under the same conditions set forth in paragraph 3(a) to (f). Where counsel wish to make detailed references to the Dover SAGD information and Gulf information in final argument, they shall first advise the Board of their intention to do so whereupon the Board shall order that portion of the argument to be held in camera following the procedures outlined herein.

Court Reporter

5. The court reporter shall deliver to the Board all his/her short-hand or other notes, in written, electronic or any other form, taken at the Proceeding as well as all copies of the transcript related to the Dover SAGD information and Gulf information not distributed to the Recipients, on the day of or the next day following the taking of any such evidence or at other times as directed by the Board. No use whatsoever of the said information or notes or transcripts related to it, shall be made by the court reporter, his/her employer or any one else except for the purposes of the Proceeding.

MADE at the City of Calgary, in the Province of Alberta, this 8 day of July, 1999.

ALBERTA ENERGY AND UTILITIES BOARD

Per: ______________________

Frank Mink
Presiding Member

ALBERTA ENERGY AND UTILITIES BOARD

DECLARATION AND UNDERTAKING NOT TO DISCLOSE

IN THE MATTER OF THE *ALBERTA ENERGY AND UTILITIES BOARD ACT*, S.A. 1995, Chapter A-19;

AND IN THE MATTER OF THE *ENERGY RESOURCES CONSERVATION ACT*, R.S.A. 1980, Chapter E-11, as amended;

AND IN THE MATTER OF Proceeding No. 960952 (Proceeding) respecting an application by Gulf Canada Resources Limited for an order of the Alberta Energy and Utilities Board that natural gas production from the Wabiskaw-McMurray formation in the Surmont area be shut in and otherwise precluded until the recovery of bitumen is complete.

I hereby declare that I have read the Order to Produce Documents (Order) dated 8 July 1999 made by the Alberta Energy and Utilities Board in the Proceeding and understand that the Order may be filed with the Alberta Court of Queen's Bench. I understand that any breach of the terms of the Order could be the subject of contempt proceedings in the Alberta Court of Queen's Bench. In keeping with the Order:

1. I will maintain the confidentiality of the Dover SAGD information or Gulf information and related evidence, transcripts and written submissions that I receive or review during the course of the Proceeding in compliance with paragraph 3(b), (c) and (f) of the Order;

2. I will not copy or reproduce any information, notes, evidence, transcripts or written submissions dealing with the evidence taken and submissions made in the in camera portion of the Proceeding;

3. At the close of the Proceeding or earlier as directed by the Board, I will return to the Board all of the information described in paragraphs 1 and 2 above and in compliance with paragraph 3(d) and (e) of the Order.

MADE at the City of Calgary, in the Province of Alberta, this ____ day of July 1999.

Signature:______________________________

Print Name:______________________________

Firm/Company:______________________________