PRIMARY BITUMEN SUBCOMMITTEE REPORT

TO

THE GOVERNMENT-INDUSTRY ADVISORY GROUP (GIAG)

June 26, 2001

Subcommittee Members:

Tom Keelan, P. Eng. (Chair)	Alberta Energy and Utilities Board
Terry Jocksch, (Co-Chair),	Canadian Natural Resources Limited
Ian Langdon, P. Eng.	Alberta Energy Company Ltd.
Linda Buck, P. Geol.	Anderson Exploration Ltd.
Wendy Shier, P. Geol.	BP Canada Energy Resources Company
Richard Wadsworth, P. Eng.	Koch Exploration Canada L.P.
Brent Fairgrieve, P. Geol.[1]	Alberta Energy and Utilities Board

[1] Brent was available to the committee for consultation, but only attended the initial meetings.

1. Introduction

Based on the Subcommittee deliverables, which were initially defined at the April 2 GIAG head table meeting, the primary bitumen subcommittee (the subcommittee) was given the tasks of:

- Reducing the uncertainty associated with gas and bitumen development in Oil Sands Areas, by establishing widely accepted criteria that would be used to evaluate gas production and gas shut-in applications related to primary bitumen recovery issues.

- Expediting the EUB's approval process for gas developments in Oil Sands Areas related to primary bitumen recovery issues, by creating routine and non-routine processes for gas production applications.

The above deliverables were to be completed by July 1, 2000.

1.1 Scope Limitation For July 1, 2000 Deadline

On May 9 2001, in response to the May 3 Facilitator's report by Dave Gould (Canadian Dispute Resolution Corporation), the subcommittee limited its scope to deal with bitumen within the region of influence (ROI) as defined by EUB Interim Directive 99-1 (ID 99-1). ID 99-1 states, "The region of influence is taken to be the extent of the gas pool in the case of gas directly overlying bitumen or the combined extent of the gas pool and water zone in the case of gas overlying water overlying bitumen." The committee's action report recognized that communication through bitumen only (i.e. from an offsetting gas and/or water zone) is a major issue that needs to addressed by GIAG as a longer-term initiative. Regarding this, the subcommittee recommended that ROI subcommittee take on this initiative, with the assistance of at least two additional members with extensive primary bitumen recovery expertise. Failing that, the primary subcommittee may be prepared to reconvene in the fall to consider it.

1.2 Using the "80/20 Rule" as a Guiding Principal

In attempting to deal with the variety of reservoir situations that are encountered in associated gas and primary bitumen reservoirs, the subcommittee realized that practical application criteria could not attempt to address every eventuality. Therefore, the subcommittee agreed that our guiding principle would be to protect most (~80%) of the potentially impacted bitumen. While exceptions may be found where a bitumen resource may not be adequately protected by these criteria, the assumption is that the EUB is prepared to either accept that potential loss of resource as a practical limitation to a reasonable application process, or rely on other processes to deal with them. The most important exceptions to the criteria would be cases where a bitumen leaseholder intervened in the gas production application or submitted a gas shut in request. In either case, it is assumed that the subcommittee criteria would be useful as a starting point for discussion, but site-specific arguments may lead any hearing panel or arbitrator to use other criteria in reaching a decision.

When reviewing the decision tree, please keep in mind this 80/20 rule. The question is; if you can think of exceptions, are they significant enough to change a criteria, especially when top gas

is always assumed to be present? Also, the criteria will not be applicable to specific equity disputes you may be involved in, but only a starting point.

1.3 The Need for Technically Supportable Criteria

The subcommittee recognizes that a recommended criterion must be technically supportable. Applicants have a right to know the basis of any decision the EUB makes. Therefore, while it is important to have industry input and feedback on these decision criteria, it is not sufficient for a joint industry-government committee to agree on application criteria that have no technical basis. Wherever possible, the subcommittee has provided the supporting technical arguments for a criterion, either based on field experience or technical literature. Gathering this technical support is ongoing in some cases, especially where field examples and statistics are being relied upon. The subcommittee expects that other GIAG participants may provide valuable feedback, and it is recommended that if this document is circulated to Industry, it be sent to the CIM Lloydminster Heavy Oil Special Interest Group for technical review.

2. Decision Tree Criteria

Figure 1 is a flow chart of the application decision tree generated by the subcommittee. You progress down the tree by answering questions related to the various defined criteria. The criteria are meant to be applied to all wells within the ROI, as defined in ID 99-1. The purpose of the tree is to identify whether an application can be considered routine or non-routine. The subcommittee expects that, once sufficient information is submitted to allow the application to be classified as routine, the application would be approved by the EUB, assuming proper notification has been carried out and there have been no interventions. A non-routine application would not necessarily be denied by the EUB, but further detailed technical work would likely be required to justify approval.

The following is a discussion of each step of the decision tree, the criterion being applied at that step, and the supporting technical arguments that form the basis of the criterion.

Step 1:

If top water is present in association with the bitumen resource in the ROI, the application is routine.

Top water is interpreted to mean that the underlying primary bitumen resource is denser than water (i.e. >1000 kg/m^3 or < 10°API.) The subcommittee believes that bitumen of this density will have too high a viscosity to be economically producible, especially in the presence of top water and top gas. If the EUB agrees with the top water interpretation, a representative bitumen viscosity is not needed.

Subcommittee members are currently reviewing their primary bitumen schemes for examples of wells with top water in direct contact with bitumen, but at this time it is believed that no economic primary wells are producing with top water present.

Further technical support is provided by a general correlation of dead oil viscosity versus temperature and oil gravity for heavy oils and tar sands, given in the Appendix. This correlation was taken from the technical notes accompanying S.M. Farouq Ali's course "Practical Heavy Oil Recovery", October 1999. Although the correlation should be used with caution except as a rough estimate, it shows that 10°API bitumen will have an absolute viscosity above 100 000 (cp) at the typical reservoir temperatures in the Oil Sands Areas, which are below 25°C (77°F).

Step 2:

If dead oil viscosity at reservoir temperature in the ROI is greater than 50 000 mPa·s (cp), the application is routine.

Bitumen with a dead oil viscosity of greater than 50 000 mPa·s is not considered economically recoverable under primary production. Subcommittee members have reviewed their primary bitumen production schemes, and while exceptions to this cutoff have been found, the wells are usually poor producers with questionable economics. Typically, high viscosity bitumen plays have a very large range of viscosities, with values varying by an order of magnitude between wells. Therefore the subcommittee believes that a 50 000 mPa·s cutoff is reasonable for the purpose of the gas production application decision tree. (Some specific well examples and summaries will eventually be provided in the Appendix)

In order to establish that bitumen viscosity is above 50 000 mPa·s, a representative sample of the bitumen needs to be obtained. In addition, due to the many variables that can affect sampling (wellbore diameter, perforation techniques, isolation of bitumen from gas zone, etc), the subcommittee concludes that failure to obtain a sample does not imply that the bitumen is immobile. Therefore, failure to obtain a sample on a test is not considered a criterion for routine approval of gas production. In the absence of a representative bitumen viscosity, this step must be bypassed.

To ensure the bitumen viscosity is representative, the subcommittee believes the following requirements should apply:

- The subcommittee recommends that a sample be obtained from the applied for well, rather than another well in the area. Field experience shows that viscosity can vary significantly from well to well, and even vertically within a well. A sample from the applied-for well will ensure that the data is acceptable to the EUB and, if the results support gas production approval using the decision tree, will ensure a faster turnaround time on application processing. If the bitumen is unleased Crown, prior to drilling the well, operators should contact the Crown and obtain approval to test (or core) the bitumen zone under the condition that the results will be made public (This process is currently being looked at by the data collection subcommittee, which has Crown participation). If the bitumen is leased, operators should contact the bitumen leaseholder for approval to test (or core) the bitumen zone. As per the recommendations of the data collection subcommittee, operators should be encouraged by GIAG to cooperate in testing where trespass is involved.

- In order to ensure the viscosity measurement is of good quality, applicants should ensure the influence of injected chemicals or drilling fluids is minimized and that proper handling, transportation and analysis of the sample occurs. In this regard applicants may wish to refer to a paper by K.A. Miller and B.P. Erno "Use and Misuse of Heavy Oil and Bitumen Viscosity Data", presented at the 46 Annual Technical Meeting of the Petroleum Society of CIM. The checklists provided in Tables 1 to 4 of that paper could be filled out and submitted as part of the application (See Appendix).

- In the absence of a bitumen sample from the applied-for well, the subcommittee believes that a bitumen sample from another well, while less likely to be representative, may be acceptable if the applicant can show that the sample comes from an analogous bitumen zone. Some recommended criteria required to show the zone is analogous are:

  - The sample must come from a well within a 5-mile radius of the applied-for well. Although this is somewhat arbitrary, the subcommittee believes that a further distance will reduce the likelihood that the well encounters the similar bitumen to that of the applied-for well.

  - The structural elevation of the sampled well must be similar to the applied-for well.

  - The same depositional environment must be shown to exist in both wells.

  - The fluid distribution (i.e. contacts and saturations) must be similar in both wells.

  Applicants should expect that an application with a bitumen sample from a non-application well will take longer to process, even if it is ultimately considered routine.

Step 3:

If net bitumen pay in the ROI is less than 3.0 metres using a 50% minimum bitumen saturation cutoff, then the application is routine.

This criterion is currently being used by the EUB to determine if a gas production application is routine. The subcommittee believes it is a reasonable lower limit because it was determined in consultation with bitumen and gas producers and has been widely accepted by Industry. Although primary bitumen can be produced from thinner pay, the presence of gas would make economic bitumen recovery unlikely.

Step 4:

If the net bitumen pay in the ROI is 10 metres or greater using a 50% minimum bitumen saturation cutoff, then the application is non-routine.

The subcommittee believes that a bitumen resource not eliminated by steps 1 to 3, that is 10 m or more in thickness could potentially be developed, even in the presence of top gas and bottom water. This implies that even vertical or horizontal wells with sand production (i.e. wormhole

development) could potentially be perforated to minimize water and gas coning. The significance of the bitumen resource warrants its protection, unless the application provides more detailed, site-specific arguments to the contrary. Therefore, an application to produce gas above a bitumen resource that is under 50 000 mPa·s viscosity and 10 m thick or more, should be considered non-routine for primary bitumen recovery impact, and may be denied. If step 2 was bypassed because no representative viscosity was provided, the application may be returned at step 4 as incomplete (if non-routine), given the thickness of the pay and the lack of information on the mobility of the bitumen.

Step 5:

If there is an associated bottom water zone, and the bitumen pay within the ROI is less than 6 m thick, the application is routine.

The subcommittee believes that a minimum standoff distance of 5 m is necessary to ensure the primary bitumen well does not water out due to coning of the bottom water zone. This applies to even low-viscosity bitumen. To account for the top gas that is assumed to be present, an additional metre is required to allow placement of the perforations below the gas zone, resulting in a minimum 6 m thickness requirement. Wells in a ROI that contains net bitumen pay from 6 m to 10 m thick, may still be considered routine in step 6 below, but a representative viscosity must be provided.

One field example of minimum standoff distance is heavy oil production in Suffield (μ_o=400 mPa·s at reservoir conditions). In Suffield a standoff distance of 5 to 6 meters was required or water coning caused a significant reduction in recovery. A correlation based on wells in the Suffield area was previously generated, and will be placed in the Appendix when is it is available. This implies that even relatively low-viscosity bitumen would need at least that standoff distance to ensure wells do not water out. Further primary recovery schemes are being reviewed and specific information will be provided in the Appendix when it is finalized.

Step 6:

If net bitumen pay divided by dead oil viscosity at reservoir temperature is less than 0.0005 metres/mPa·s (m/cp), then the application is routine.

If an application was not yet determined to be routine or non-routine using steps 1 through 5, then step 6 is required as the final step of the decision tree. The basis for the criteria of $h/\mu_o \leq 0.0005$ is discussed below. Using this criterion, the following are some examples of applications for gas production, with top gas assumed:

- Net bitumen pay in the ROI is just below 10 m but with a viscosity greater than 20 000 mPa·s; classified as routine.

- Net bitumen pay in the ROI is 3 m, but with a viscosity less than 6 000 mPa·s; classified as non-routine.

- Wells with or without bottom water that have net bitumen pay of 6 m, with a viscosity greater than 12 000 mPa·s; classified as routine. (Wells with bottom water that have a net pay below 6 m would be considered routine by step 5.)

The assumption underlying the h/μ_o criteria is that, for less than 10 m of bitumen pay, sand production would result in fracture (wormhole) communication between the perforated interval in the well and the top gas and any bottom water. This would cause severe coning of the gas and water, and result in uneconomic bitumen recovery. Based on this assumption, a well completed in bitumen pay less than 10 m thick with top gas/bottom water, would need to be economic under Darcy flow (no sand production). With no sand production, coning is assumed to be much less severe.

The Appendix contains a paper by R. Butler and C.T. Yee presented at the Petroleum Society's Canadian International Petroleum Conference 2000, in Calgary. Figure 1 in Butler's paper is a plot of pseudo steady-state flow for horizontal and vertical bitumen wells under primary production (no geomechanical effects). For the given reservoir parameters, the plot gives the log of oil production rate versus live oil viscosity. Using an economic cutoff of 10 m^3/day, Butler concluded that horizontal primary bitumen wells would need an oil viscosity below 10 000 mPa·s (at reservoir conditions) to be economic, and vertical wells would need a viscosity below 100 mPa·s. Based on Butler's paper, the subcommittee concluded that vertical bitumen wells could not be produced economically without sand production, for a net pay below 10 m. Therefore, in the presence of top gas/ bottom water, it is assumed that vertical wells would not be used to develop primary bitumen below 10m net pay.

The Appendix also contains the subcommittee's variation on Butler's plot for horizontal wells only, using what it considers to be more typical reservoir parameters and plotted for a variety of reservoir net pays. The family of curves were generated for 1000-metre horizontal wells, with 1.5 Darcy permeability, a pressure drawdown at the wellbore of 2000 kPa, a wellbore radius of 0.10 m, a drainage area of 10 ha (equivalent to 100-metre interwell spacing), and for net pays ranging from 1m to 11m. Using Butler's 10 m^3/d economic rate cutoff (which is assumed to be reasonable for horizontal wells), the maximum economic viscosity for 3 metres of net pay would be 9000 mPa·s (at reservoir conditions). However, using a rough approximation that dead oil has about a 30% higher viscosity than live oil, the equivalent dead oil viscosity limit is about 12 000 mPa·s, giving an h/μ_o of 0.00025. For 10 metres of net pay the reservoir oil viscosity limit is 20 000 mPa·s, corresponding to a dead oil viscosity of about 26 000 mPa·s. This gives an h/μ_o of 0.00038. However, due to the presence of top gas and coning that would result even without sand production, the subcommittee believes that these economic viscosity cutoffs should be lower, resulting in a higher cutoff for h/μ_o. Therefore the subcommittee chose a cutoff of 0.0005, corresponding to a maximum dead oil viscosity of 20 000 mPa·s for 10 m of net pay, and 6 000 mPa·s for 3 m of net pay.

Applications reaching step 6 in the decision tree will require a representative bitumen viscosity in accordance with the guidelines discussed under step 2. If no representative bitumen viscosity is provided by the applicant, the application is non-routine and may be returned as incomplete.

Note that under step 6, a 3 m net pay bitumen zone in the ROI could be protected despite the presence of top gas. However, with a dead-oil viscosity below 6000 mPa·s the subcommittee believes that the optimum depletion strategy may be to produce the gas through coning at the bitumen perforations. Therefore, the non-routine application may have to address the optimum depletion strategy for the bitumen resource, and any equity issues, much the same as for a conventional concurrent production application.

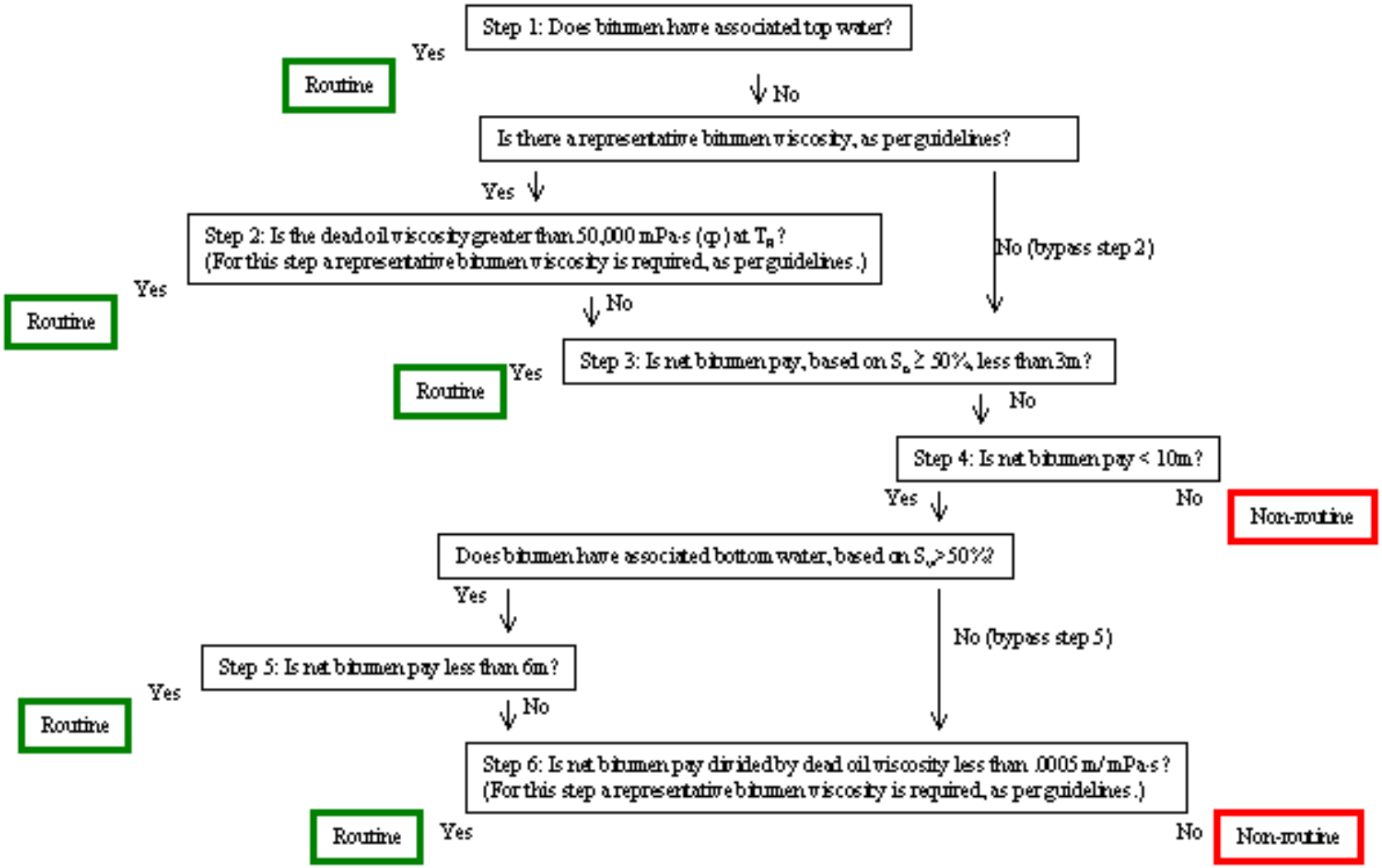
3. Future Work

The subcommittee expects that the decision tree will need further refinements as feedback is obtained, and as primary schemes are reviewed for exceptions to the criteria. Should GIAG require more detailed technical work, it may be useful to use a consultant, provided that the scope is well defined. The major obstacle encountered by the subcommittee was not lack of enthusiasm or cooperation, but lack of time. Time commitments are expected to continue to be a problem for any future work of the subcommittee.

Section 1.1 discusses the need for the scope of the decision tree to be expanded to include bitumen impacted by gas production from a gas zone that does not directly overlie the bitumen.

Figure 1 Gas Production Application Decision Tree For Primary Bitumen

(June 2001)



This decision tree is limited to the region of influence as defined in ID 99-1 (ROI is extent of top gas and water zones). Criteria have yet to be established for pressure depletion through the bitumen zone from offsetting gas and water zones. Once an application can be classified as routine for primary bitumen, it would be approved, in the absence of thermal bitumen potential or an intervention. An application classified as non-routine will require further detailed technical work to justify approval.

Horizontal Well Productivity

Assumes k=1.5 darcy; Delta P=2000kPa; A=10 ha; L=1000m; Rw=.1m; net pay as per legend