

February 14, 2007

Husky's Response to Information Requests of EnCana dated February 7, 2007

1. On Page 2 of its reply evidence Husky states "Extensive piezometer data in Husky's Caribou leases located in the bitumen zone show pressure drops in excess of 50% in places" Please identify the specific wells and piezometer depths where Husky believes the pressure has dropped by more than 50% of virgin pressure.

Husky's Response:

This data can be found in Husky's Response to Board Staff Information Request, Nov. 10, 2006. It is observed that there are two piezometers in the 3-4 well that read 52.15% (496 m, bitumen zone) and 56.04% (491.5 m, gas zone) lower pressures. This is a solid example of the extreme pressure drop that can be observed in the bitumen because of gas production.

2. On page 14 Husky states "The piezometer pressure decline rate data is reasonably matched in Husky's reservoir simulation". In Husky's Jan 19 2007 response to Encana information request 8. Husky states "simulation values have been shifted in time to line up with the first data point of piezometer data" Please provide the model pressure time graph for the 16-7 grid blocks and the pressures for the 16-7 piezometers before the data was "shifted".

Husky's Response:

As stated in our earlier submission of January 8, 2007, the reservoir simulation model is of a generic nature and is representative of the properties of the reservoir. Only a small part of the gas pool is present in the gas zone of the numerical model so that the thermal process can be simulated with a sufficiently fine grid. The simulations were arbitrarily started at 1995-01-01 and thus a time shift was applied to align the simulation with the piezometer data. The attached spreadsheet shows history match with the time shift. The details of the time shift are also provided in the same spreadsheet. Note that the simulated pressure decline rate is similar to that of the actual piezometer data.

Note that this methodology only adjusts the amount of gas withdrawn within a specified time frame from the gas zone to history match the piezometer data. The geological model and its assigned properties, rock and fluid properties have not been altered at all from the initial input in the model. Therefore, the history matching procedure employed is reasonable given the nature of the model and that no unusual features of the model (e.g. shale layers, vertical and horizontal transmissibilities, oil viscosities, relative permeabilities) were adjusted. The pressure decline rate determined in the reservoir simulation model is consistent with the decline rate determined from the piezometer data. Both the trend and absolute value are reasonable matched.

3. Regarding the core data in Table 1 on page 16.

a) If Husky really believes these two core samples with porosities of 34% and 29.8% are representative of shale intervals in Twp 69-4W4 why did it use a porosity of 10% for shale in its model?

Husky's Response:

The simulator considers this shale zone in a conservative manner by assigning it a lower porosity than it actually has. If the shale layer was modeled with larger porosity and permeability, the effect of solution gas depletion on the solution gas content in the reservoir prior to thermal stimulation would be more pronounced.

Husky reiterates that this unit (variously referred to as the Central Basin Mud, Valley Margin muddy sand and C&D muds) needs to be differentiated from the Eastern and Western Regional Shales (refer to Figure 2.1 of Husky's Reply Evidence, 07.01.30). The Central Basin Muds represent a baffle to flow, and are absent over much of Husky's eastern lease.

b) The two core samples listed have vertical permeabilities of 36.49 md and .98 md producing vertical to horizontal permeability (kv/kh) ratios of .069 and .034. What kv/kh ratio did Husky apply to the "shales" in its model.

Husky's Response:

The horizontal permeability of the shale zone in the model is 50 mD which is in the range of what has been measured in the laboratory. The vertical permeability of the shale zone is 16.65 mD which again is in the range of what has been measured in the laboratory. Therefore, the properties assigned to this zone in the simulator are consistent with the laboratory data and captures the behaviour that could be expected from this zone under the conditions investigated in our study. However, the same cannot be said of EnCana simulations which assign zero permeability to this zone.

4. In its January 30, 2007 reply submission, Husky provided a DVD containing input and output datasets for its 2D simulation. The DVD contains input and output datasets of 2D sensitivity runs for HSAGD Well Spacing (WS-34) and CSS Liquid Constraint (STL-35). Please confirm the following:

a. No maximum liquid production constraints were applied to the CSS and HSAGD producers, and

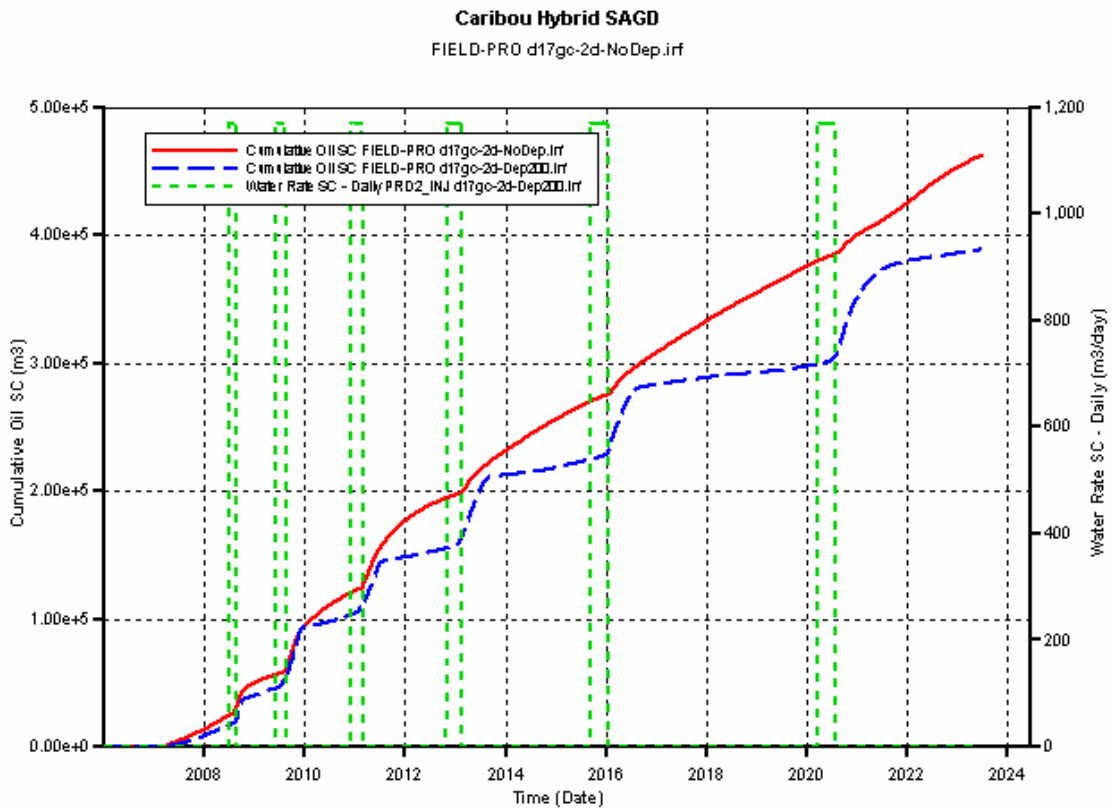
Husky's Response:

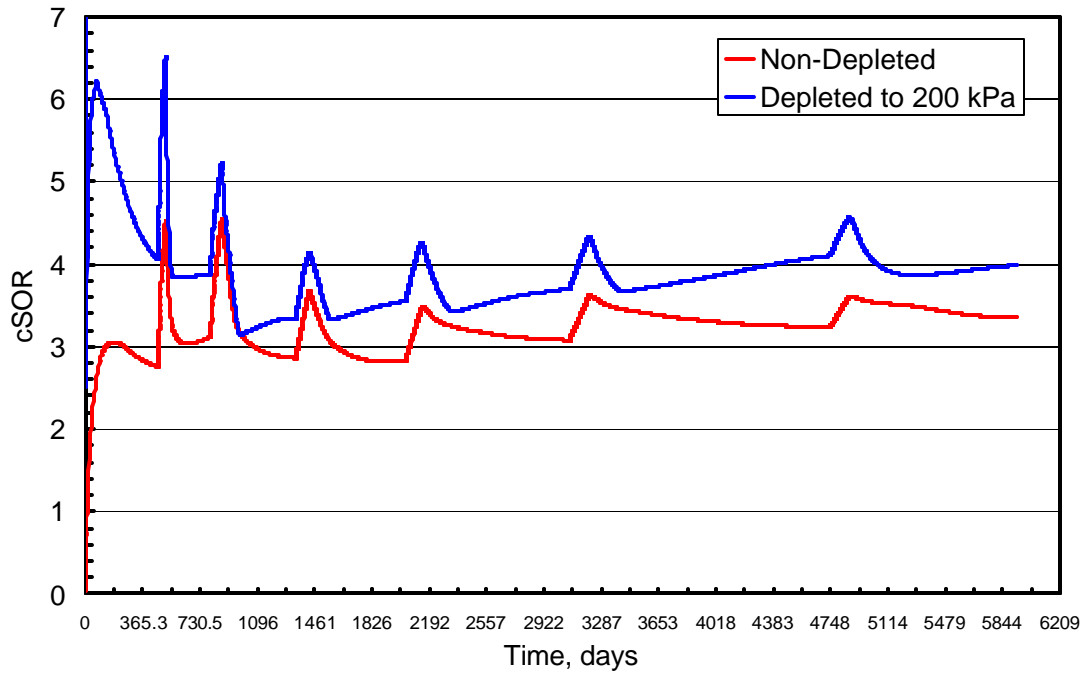
Liquid production constraints were not applied to HWCSS and HSAGD cases. Note that when such is the case, the same trends can still be observed with modified operating strategy. If the total liquid constraint is used and the CSS CDSR (calendar day steam rate) string is chosen incorrectly, then one consequence of the process performance is that the impact of solution gas drive on the process is suppressed. This means that the delta

between depleted and non-depleted cases is reduced but this is a total consequence of the chosen operating strategy where the delivery of oil to the wellbore by solution gas is suppressed.

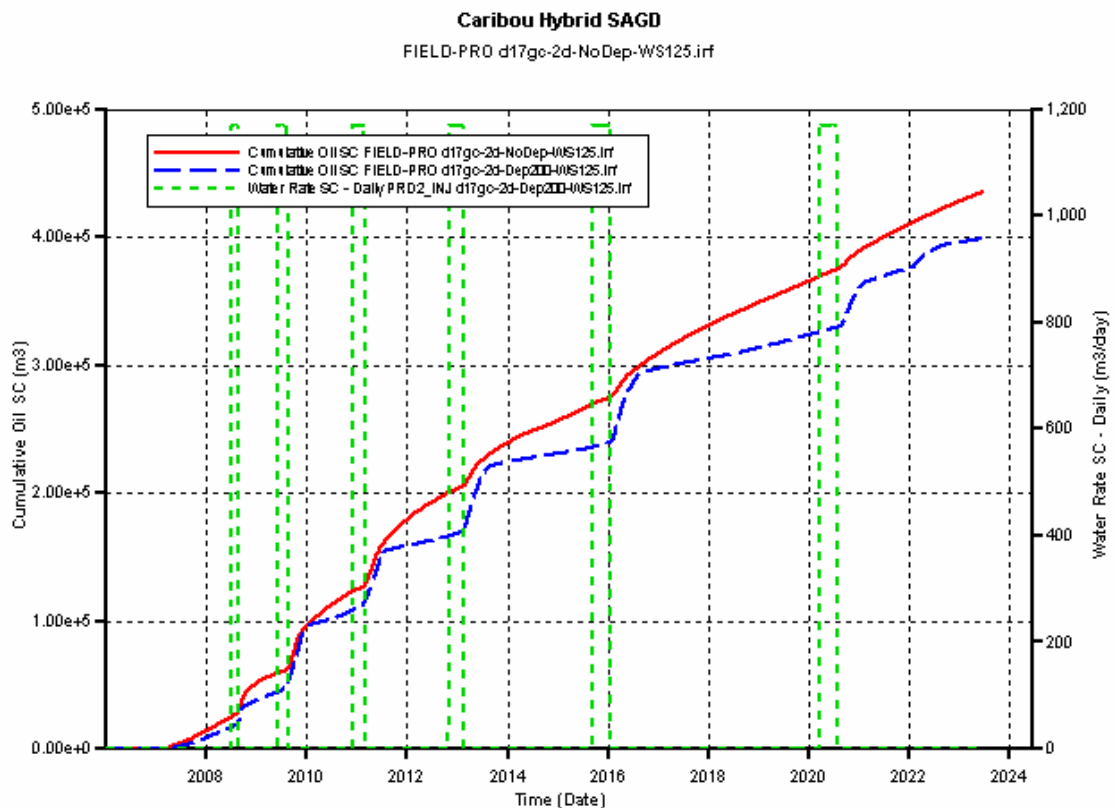
However, in the field, it has been well established that solution gas drive is a major production mechanism for CSS and that viable commercial operating strategies must include oil delivery by this mechanism. Earlier simulation runs, without the liquid constraint, reflect the unconstrained case where the reservoir deliverability is the key constraint on the process. This means that the physics of the process in the reservoir is controlling the oil delivery to the wellbore and the true effect of reduction of solution gas, both its viscosity impact and as a drive mechanism, is reflected when the performances of the processes are compared.

New simulation runs, using a CDSR string based on CNRL's operating strategy with focus on overall process performance improvement, applied in the HSAGD process have shown that even with the liquid constraint the impact of solution gas depletion is evident and therefore that there is a risk to the bitumen resource if the gas production continues until the abandonment pressure. The following Figure displays cumulative oil and field cSOR (in directory NOPI-HSAGD-BASE).

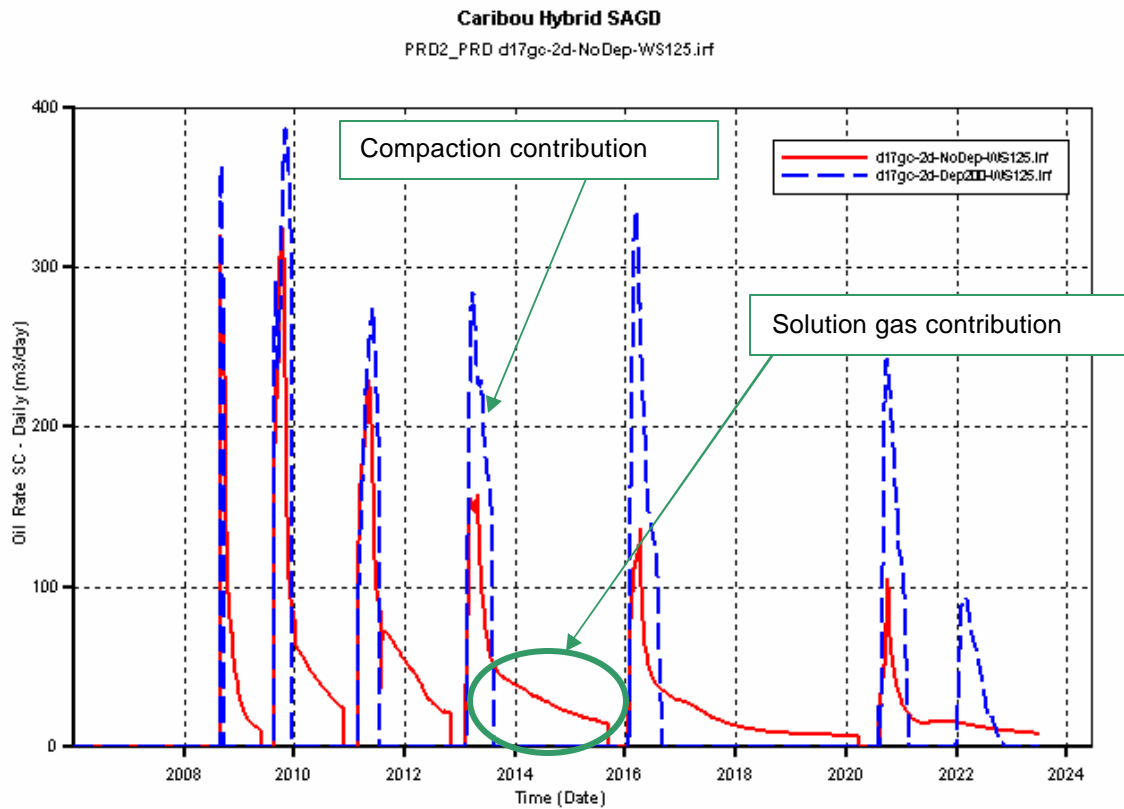




The results make it clear that there is a significant risk of loss of bitumen productivity as a consequence of solution gas depletion. Given the production rate profiles in each cycle, if the production periods of each cycle were extended, the delta between the depleted and nondepleted cases would enlarge. Results shown below indicate that this conclusion is unaltered if the spacing is changed to 125 m (in directory NOP1-HSAGD-WS125). Note that, there are probably other potential optimized well spacing and production schedule combinations that could show greater differences between the two cases. The influence of the production schedule is apparent if one looks at the trends just before the last two steam injection cycles. The depleted case is leveling off as the undepleted case maintains its production rate.



Another key point is that the timing of the CSS cycles must take advantage of the solution gas drive mechanism. This has been demonstrated by practitioners of CSS in the field. The following Figure shows the oil rate for the CSS well in the HSAGD process (from NOP1-HSAGD-WS125). The results show that the solution gas contribution is large but if solution gas has been depleted or the CDSR string is poorly designed (that is, the production interval of each cycle is too short), it will not be taken into account and the delta between the depleted and non-depleted cases will diminish. EnCana's runs of Husky simulations were run with production cycles that were too short and the solution gas drive effects were masked. Industry practice has clearly shown that the solution gas drive mechanism is a significant contributor to oil production from CSS wells.



The operating strategy described in the NOP1 directories is specific for Husky's preferred process HSAGD and cannot be used for HWCSS. It must be borne in mind that the processes are related but it is too simplistic and not accurate to simply model the individual SAGD and CSS processes given the interaction and coupling of the two in the HSAGD process. An operating strategy for HWCSS would be different and has not been explored in detail given time constraints.

b. A maximum steam injection rate constraint of 1500 m³/d was applied to the CSS and HSAGD steam injectors.

Husky's Response:

Yes, this is correct.

5. Husky also provided a memory disc entitled "January 30, 2007 Husky Submission to Cold Lake Hearings Application Nos. 1394112, 1409180 and 1481725". The memory disc contains input and output datasets for 2D (SIM-75 and SIM-75) and 3D (SIM-34 and SIM-35) model runs. Please confirm the following:

a. The 3D model runs did not run to completion and terminated in 2010-10-13

Husky's Response:

This is correct. It can be seen that trends observed in 2D runs are duplicated in 3D runs for as long as they ran. The well conditions are such that the reservoir controls delivery of fluids and it is clear that solution gas depletion from the bitumen resource lowers the process performance. The results show, in accordance with the 2D results, that directionally there is a significant risk that bitumen resource will be harmed with solution gas depletion.

b. The CSS 2D run had a different maximum liquid production rate constraint for the depletion and the no depletion cases. The maximum liquid production rate constraint for the HWCSS well in the no depletion case was 750 m³/d and 1500 m³/d for the depletion case.

Husky's Response:

See our response to Board Staff IR dated Feb. 7, 2007 for a comparison of HWCSS cases with the same liquid constraint.

6. Husky indicates in Section 6, pages 23-24 of its Reply Submission of January 30, 2007, that "limited optimization" of its model confirms "harmful effects." EnCana has rerun Husky's current HWCSS 2D models (with a modified operating strategy) using the

same maximum liquid constraint of 750 m³/d for depletion and no depletion cases. No other changes were made in the models. Results indicate that a similar bitumen recovery factor of 40.4% of OBIP is achieved for both cases indicating no adverse impact of gas production on HWCSS (see attached Table 1 below). This pair of cases also provides a better optimization in terms of oil recovery factor and cumulative SOR when compared to the Husky's current HWCSS 2D model results shown in Figure 6.1 of January 30, 2007 Reply Submission of Husky. Also, EnCana has rerun Husky's HSAGD 2D models using the same well schedule for the HSAGD CSS wells as in the HWCSS model wells and no other changes were made to the models. Results of the EnCana's runs of Husky HSAGD (see attached Table 1 below) show that no depletion and the depletion cases achieved similar bitumen recovery factors of approximately 45% OBIP. These results indicate no adverse impact of gas production of bitumen recovery factors. Furthermore, EnCana's runs provide a better optimization with a higher bitumen recovery factor and lower CSOR of 6.2 and 6.03 respectively for the depletion and the no depletion cases when compared to those presented in Figure 6.1 for HSAGD in the Husky's reply submission of January 30, 2007.

In light of the above could Husky please:

- a. Indicate which factors in the model it was trying to optimize.

Husky's Response:

The optimization runs were a sequence of runs aimed at improving the cumulative steam to oil ratio and recovery factor from the reservoir. It has been recognized that timing of the CSS contribution to the HSAGD and HWCSS processes is important so that the solution gas drive mechanism actually provides a contribution to the process. If the production period of the cycles is too short, the oil production response could be simply that due to the combination of the well constraints and recompaction. As known by CSS practiced in the field, it is essential that solution gas drive is a contributor to production.

One way to demonstrate that there is no impact between the depleted and nondepleted cases is to simply shorten the production periods until the solution gas contribution is negated.

However, this is not how CSS is practiced in the field. Earlier simulation runs that were done without the total liquid constraint reflect the unconstrained case where the reservoir deliverability is the key constraint on the process. This means that the reservoir production mechanisms are controlling oil production and that the true effect of reduction of solution gas, both its viscosity impact and as a drive mechanism, is reflected when the performances of the processes are compared.

With the liquid constraint in place and a poorly designed operating strategy, the reservoir deliverability no longer controls but now the well constraint does. Given alternate operating strategies, including ones similar to how CNRL practices CSS in the same reservoir in the field, the risk to the resource from solution gas removal is still demonstrated by the earlier runs and the ones presented here. Even a small delta between

the depleted and nondepleted performance results demonstrates that solution gas depletion from the bitumen resource is having impact and that the risk of harming the bitumen exists.

Another key point to bear in mind is that it is not sufficient to compare results at the end of the simulation. Given time value of money, the intermediate rates, recovery, thermal efficiency, etc. must also be examined to determine process performance.

b. Provide a justification for using different maximum rate constraints in the no depletion and depletion CSS runs.

Husky's Response:

This was an oversight and consequence of running too many simulation runs at the same time. The wrong files were copied from the run archive.