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Effect of Solution Gas on 1D Steam Rise in Oil Sands

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Abstract

This paper summarizes evidence of gas effects in several Athabasca SAGD projects and shows that these effects can be easily reproduced with simple 1D column simulations. Solution gas probably has a material impact on SAGD rise, and therefore production rates in general, especially where the operating pressure is significantly below the initial pressure.

Introduction

Following the UTF Phase A SAGD test, it was reported that: "No significant accumulations [of non-condensable gas] were observed in the steam chamber. This was fortunate because such accumulations appear to be harmful because they inhibit steam transport to the front.

"Current simulators incorrectly predict that even small amounts of gas…will accumulate in a steam chamber and substantially impair drainage…more work is required to account for gas transport mechanisms adequately so that reasonable predictions can be made for reservoirs containing greater amounts of gas(1)."

Simulators still do not properly account for known amounts of solution gas in the McMurray formation in the sense that it is not generally possible to produce a reasonable history match of field behaviour if the full amount of solution gas is included(2).

The question of how the gas is being removed from the chamber, and therefore what is missing from the simulators, remains unresolved, and is beyond the scope of this paper. Meanwhile, two important points have been passed over.

The first is that, even at UTF, some insignificant gas accumulations can be found in the data, for example as reported by Ito et al.(3).

The second is that "reservoirs containing greater amounts of gas" than UTF or Dover, include most of the current McMurray SAGD projects. In the case of Foster Creek, at the deep end, saturation pressure is 2,800 kPa and the solution GOR is estimated to be about five times that of Dover.

Since the gas removal mechanism(s) is unknown, it has always been possible that it was strong enough under UTF circumstances to prevent "significant" accumulations, but not strong enough to do this in deeper Athabasca reservoirs. However, the difficult nature of the SAGD gas problem, combined with the apparent success of UTF history matching without it, has understandably encouraged a situation where it has become standard practice to ignore solution gas in SAGD simulations.

Standard practice is also to arbitrarily lower absolute and/or relative permeabilities in order to match field performance. In the case of the UTF project, there was good correspondence between measured core and history match permeabilities using "open" relative permeabilities. This correspondence does not seem to apply to deeper, thicker reservoirs such as Surmont or Foster Creek, particularly with respect to steam rise rates.

Field Evidence

Hangingstone

Ito et al.(3, 4) conducted detailed analyses and history matching of observation well temperature data from the UTF Phase B and Hangingstone Phase I projects. Although the Hangingstone situation is complicated by the high operating pressure of 5 MPa at a depth of 280 m (i.e. 18 kPa/m, which they demonstrated by cold water injection was enough to begin deformation of the sand matrix), it show anomalies in the rise rates at some wells where steam rise would "suddenly stop" for a while and then resume.

In one case (Hangingstone OBA1) the halt occurred in a breccia zone, a high energy environment which should not have any "impermeable" barriers at all. The halt of steam rise was correlated in time with a reduction in chamber pressure (of about 500 kPa), and it resumed again when the pressure was restored. They showed this behaviour could be explained by assuming the presence of "impermeable layers" which persist for a while and then disappear.

There is an alternate explanation, however, which is implied by some of the authors' conclusions with respect to UTF Phase B: "Although…steam…would not penetrate…into the IHS [shaley] region, a large amount of oil can be drained…[T]he oil…is replaced by the incondensable solution gas liberated from bitumen.(3)"

The ability of solution gas to drain oil from zones below steam temperature is well known. What has not been considered is what happens, if anything, to that gas after all the oil has drained. The usual assumption, that the gas just goes away, appears to cause a disconnect when pondering why the steam is observed to stop rising before the top of the permeability is reached. But if the gas doesn't go away, it will occupy a "blanket" at the top of the reservoir, and the steam will stop at the bottom of the blanket.

Surmont

ConocoPhillips(5) presented a review of the Surmont Pilot Scheme performance in which they show data from the temperature observation well OBS 22, located overhead the S2 injector (see Figure 1).

Figure 2 reproduces ConocoPhillips' plot of the apparent steam level in this well. Chamber pressure is also plotted. There is a strong correlation between the pressure and steam levels.

The steam zone initially rose about 12 m, reversed course during a steam outage, then resumed rising when steam was restored. Rise was steady at less than 3 cm/day for the next two years, at which time the rise halted in a sandy unit. Then, in the following year,

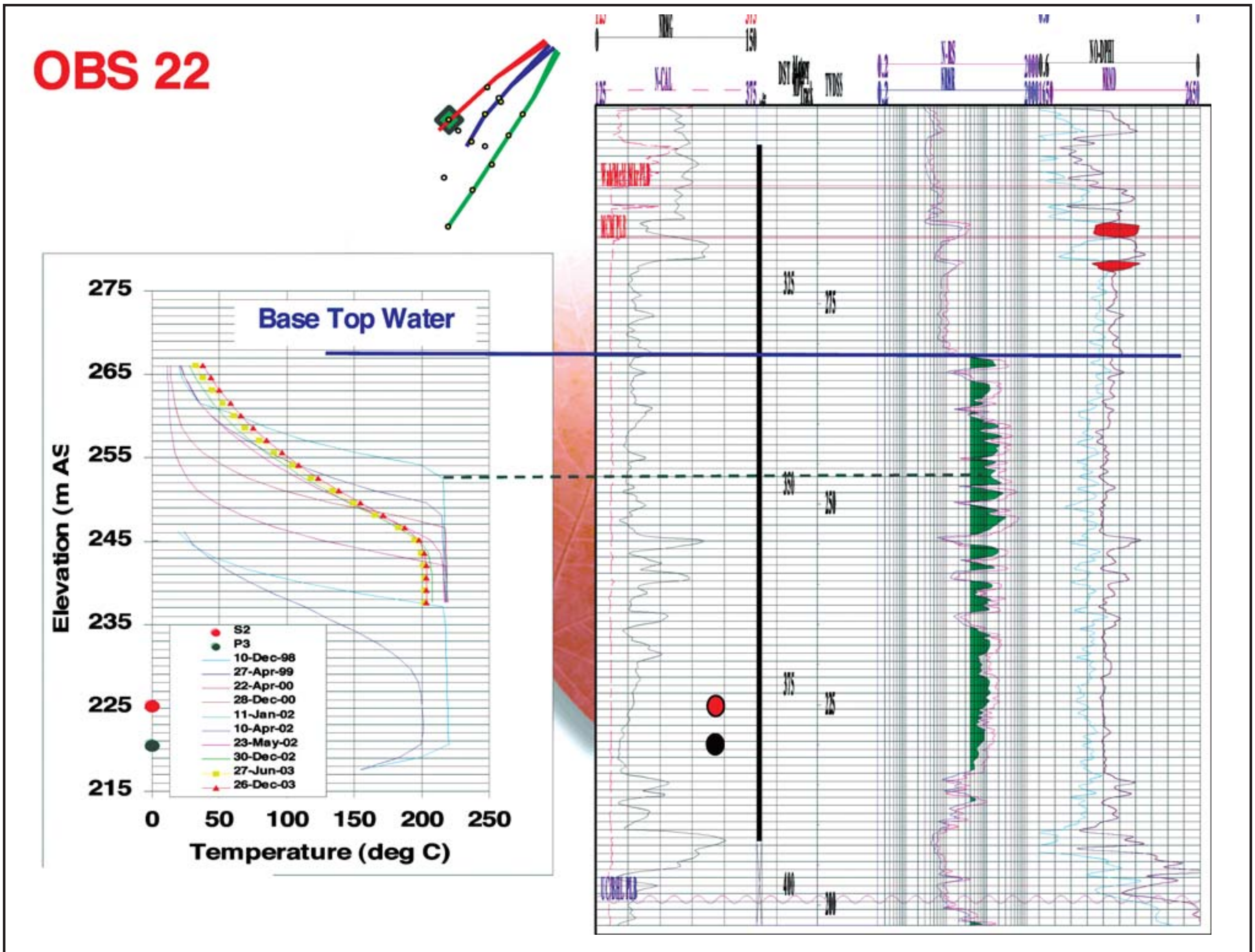

FIGURE 1: Surmont OBS 22 rise data(7).

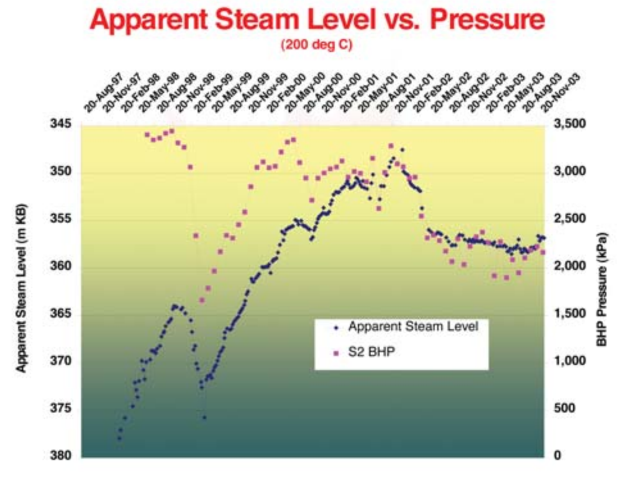

FIGURE 2: Surmont steam levels and pressure vs. time(7).

accompanying a reduction in pressure, the steam zone shrunk by over ten metres.

If it is assumed that there is a blanket of gas on top of the steam, then not only is it possible for the steam to stop in the middle of good pay (as a result of the gas hitting a true barrier somewhere above), but if the pressure is reduced, the blanket should expand and therefore push the convection zone down.

Foster Creek

Figure 3 shows (optical fibre) temperature and chamber pressure data from Foster Creek observation well A1-21-70-4W4, which is approximately 25 m from the E25 pair in the Phase 1 commercial area. Steam appears to be stalled about 4 m below any obvious barrier.

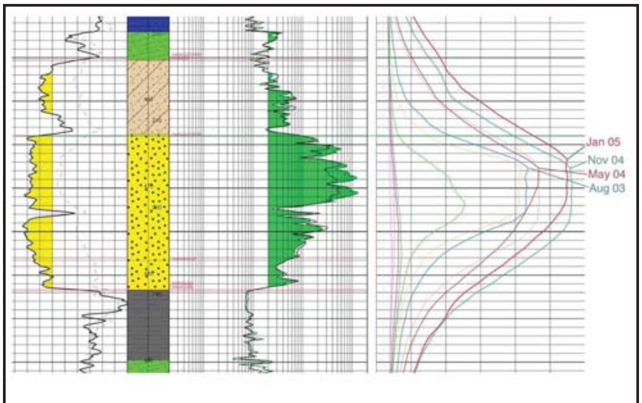

FIGURE 3: Foster Creek A1-21 temperature profiles.

With fibre data, there is some uncertainty about depths. Considerable care was taken to calibrate depths, for example, by alignment of the casing flange where values change from ground to air temperatures. It is believed that depth errors are less than 2 m in this case.

Simulation

Common Parameters

Table 1 summarizes the parameters used. All cases were performed on a vertical, one-dimensional grid 1 m^2 in area and with

TABLE 1: Simulation parameters.

Case ID	Figure(s)	Initial Pressure (kPaa)	Saturation Pressure (kPaa)	Steam Pressure (kPag)	k_v (D)	h (m)
nogas	4, 9	2,100	0	3,100	8	25
athab	4, 5, 7, 8, 9		2,100			
25pct	9, 11		525			
pi	7, 8		2,100	2,100		
utf	9	0	600	3,100	10	10
utf.qgas	9		150			
sin	10	2,800	2,800	2,800 ~ 2,150	8	25
fineup	11, 12	2,100	2,100	3,100	8, 1, 0.1	
fineup.nogas	11					

0.25 m vertical grid spacing. In most cases, the vertical permeability was 8 D and the one-dimensional "reservoir" was 25 m thick above the injection point. Production was taken from the bottom block, immediately below the injection block. No wellbore models were used and constraints refer to grid block pressures.

Heat losses were computed for the top of the column (overburden), but not for the bottom. The intent was to model an element of the chamber above the injector and avoid possible artifacts relating to the interaction of steam trap control and underburden heat losses, which are not to be scaled.

Production control in most cases consisted of a gravity trap, where the production pressure was set 1 kPa higher than the injector. This imposes a 4 kPa/m gradient between the (0.25 m thick) injection and production blocks. This gradient produces countercurrent flow, with liquid falling and gas rising.

Basecase

Figure 4 plots steam rise in an 8 Darcy column, with and without solution gas. The top of steam is defined as the point where the temperature is 2°C less than in the injection block. Also shown for the case with gas, is a "blanket top" defined as the point where the gas saturation exceeds 5% (also equal to S_{gc} in this case).

The rise rate without gas is about 40 cm/day. When solution gas is included, rise is sharply reduced from the outset and declines to less than 2 cm/day. Steam halts about 5 m below the top of the pay, and then reverses slightly.

Figures 5 and 6 are temperature, saturation and pressure profiles in the column at 100 day intervals from the previous case. The gas and oil phase saturations are nearly the mirror image of each other because water saturations do not anywhere rise much above the initial, critical value.

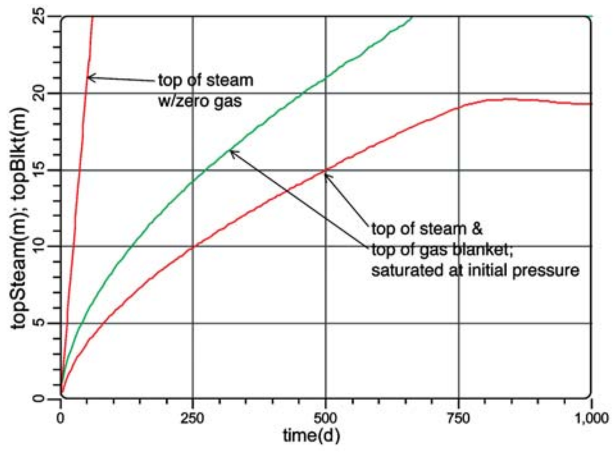

FIGURE 4: Simulated steam rise with and without gas (k_v = 8 D).

The usual countercurrent zone, where steam is exchanged for bitumen and condensate, is at the left (bottom) of Figure 5. The saturations break at the same point the temperature profiles do (i.e. at the top of the steam zone). The temperature break indicates the change from convection heat transfer, in the countercurrent steam zone, to conduction heat transfer over a short interval.

There is essentially no methane below the steam front in any phase and none is produced in these simulations. Therefore, all of the gas that was formerly in any of the oil that has drained so far,

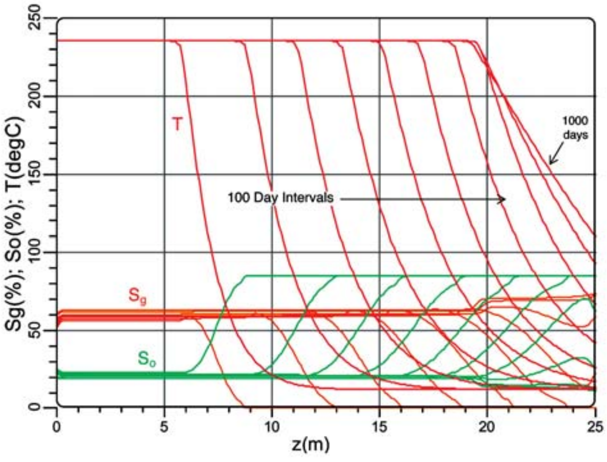

FIGURE 5: Temperature and saturation profiles.

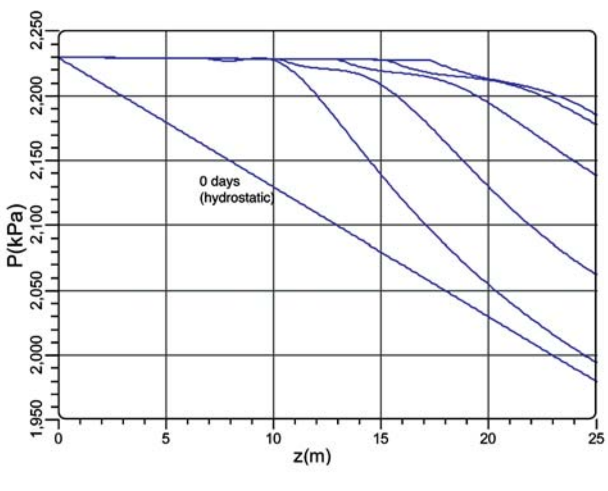

FIGURE 6: Pressure profiles, 0 – 600 days.

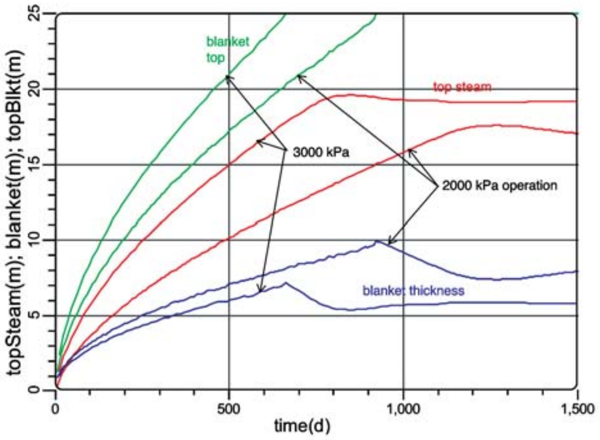

FIGURE 7: Effect of operating vs. saturation pressure.

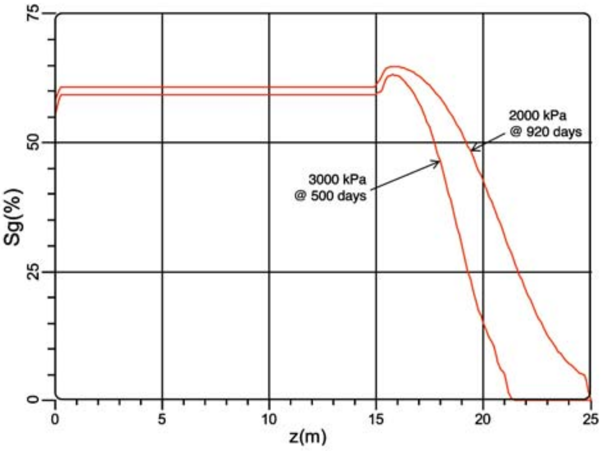

FIGURE 8: Gas saturation profiles vs. operating pressure.

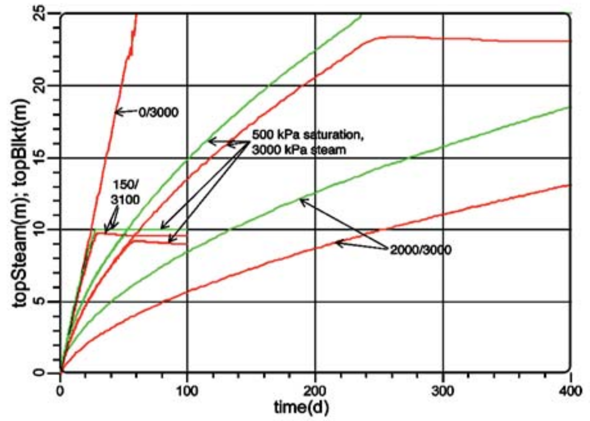

FIGURE 9: Effect of saturation pressure and thickness.

give or take solution exchanges, must be contained between the top of the steam and the blanket top.

Steam cannot rise through accumulated methane; it essentially follows along as the gas blanket rises.

The blanket is a sort of inverted, dynamic transition zone where the collected gas moves upward as oil drains. Oil drains as a function of local temperature, which is in turn determined by the velocity of rise and the local distance above the steam front.

For a given amount of accumulated gas, a certain blanket thickness and saturation profile is required to contain it. If the blanket is thick, the temperature at the top will be lower, and so it will rise more slowly. Rise is therefore controlled by the blanket thickness.

Rise rates decay with time because gas accumulates as fresh oil is stripped, and the blanket must get thicker.

Effect of Operating Pressure

In the previous case, steam pressure was about 50% above the initial/saturation pressure of 2 MPa. Figure 7 shows the effect of operating instead at the initial pressure. The time required to rise a given distance is about double. Blanket thickness (blue lines) is about 25 – 35% greater for the lower pressure case. By 1,500 days, at the end of depletion, the blanket thicknesses are approaching the expected ratio of 3:2.

Figure 8 compares the gas blankets at 500 days and 930 days, being the time required for 15 m of steam rise in the 3 and 2 MPa runs, respectively. It can be seen that the slower moving 2 MPa blanket holds much more gas at the top (right) than the 3 MPa blanket. This reflects the fact that the transient conductive temperature profile ahead of the steam expands when the front is slowed down. Higher temperatures result in more rapid drainage from higher above the steam. This is why the blanket thickness does not increase in exact proportion to the volume of gas present.

What about UTF?

Figure 9 compares rise rates for 5 cases, all using 3 MPa steam but with varying amounts of solution gas. From right to left in Figure 9, initial solution pressures of 2,000, 500, 150 and 0 kPa were used (see Table 1).

The 500 kPa or 25% saturated case might approximately represent a reservoir that was in fact fully saturated, but where some mysterious mechanism removes ¾ of the gas as it is liberated. In this case, the average rise rate to 20 m is about 11 cm/d; the instantaneous rate at the same height is about 7 cm/d. These compare with the 0 gas rate of about 40 cm/d for the same k_v.

Two cases were run with a 10 m thick reservoir. This is intended to represent the mostly-massive bottom unit of the UTF Phase A pattern(1, 2). These cases had saturation pressures of 600 and 150 kPaa, respectively. The initial pressure at UTF was about 600 kPa.

Note in the 10 m cases, the degree of rise impairment, compared to the dead oil case, is proportionately less than for the 25 m thick cases. This is because there is less gas to accumulate over the shorter rise distance.

The 10 m/150 kPa case might represent the Phase A reservoir assuming that 75% of the gas was being removed in other dimensions by the unknown mechanism. Certainly, Phase A could not be matched with solution gas without invoking such removal(2). Under these assumptions, the rise impairment compared to dead oil becomes less than normal uncertainties in permeability and depth measurements.

Phase A was normally operated at about 2,400 kPa, compared to 3,000 used here. This would not make as much difference as in the preceding figure though because 2,400 kPa was still several times the saturation pressure, whereas the Figure 8 cases were saturated at 2 MPa. In addition, the Phase A reservoir had finite permeability above 10 m which was known to drain oil, and could therefore absorb gas from below(6). Finally, the assumption here of 75% removal was completely abitrary. The percentage removed under UTF conditions may be greater than elsewhere because of the lower initial GOR.

Figure 9 shows that if 75% removal is assumed in both cases:

- A UTF analogue will hardly be affected by gas (e.g. less than 15%) and can be matched using core perms and no gas at all; and
- A commercially-thick reservoir operated near initial pressure will experience rise impairment of up to 10 times or more due to gas (i.e. 100 × the UTF effect!). If modelled without gas, $k_v * k_{ro}$ will need to be reduced by a similar amount, but by different amounts for different pressures, thicknesses, etc.

The ability to match UTF Phase A performance without any gas in the model, but using the full core permeabilities, was apparently due to the limited thickness of the unit in question and the

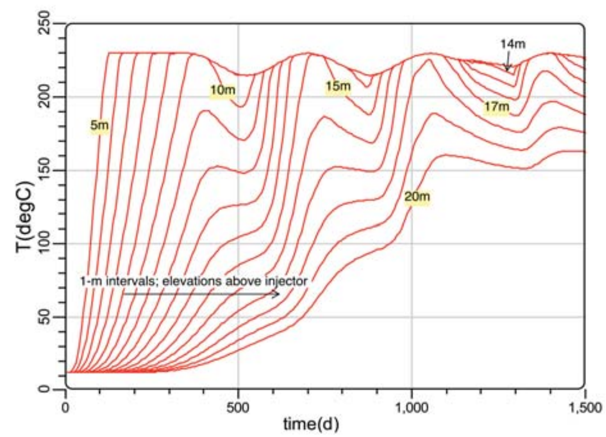

FIGURE 10: Temperature vs. time at 1 m depth intervals with time-oscillating steam pressure.

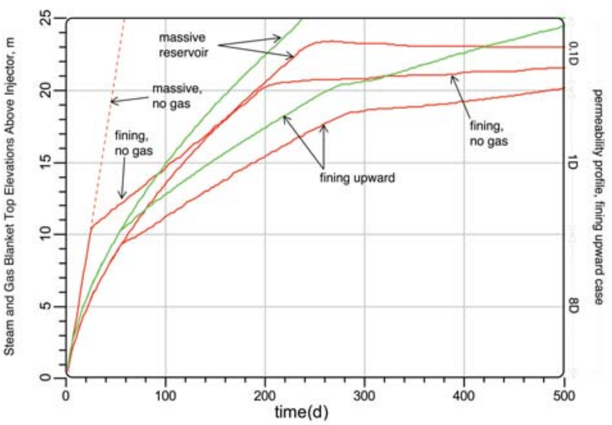

FIGURE 11: Comparison of rise in massive vs. fining-upward reservoirs.

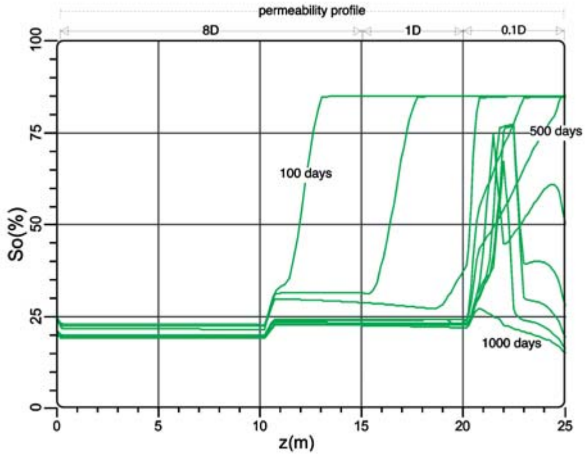

FIGURE 12: Oil saturations vs. elevation at 100 day intervals, fining-upward reservoir.

4:1 ratio between operating and saturation pressure. In combination with the removal of much of the gas by other means, these parameters combined to limit gas effects to negligible amounts for engineering purposes.

Variable Chamber Pressure

Figure 10 shows simulated thermocouple traces at 1 m intervals where the pressure was held constant at 2,800 kPa for 350 days, and then varied sinusoidally thereafter between 2,800 and 2,100 kPa with subsequent periods of 350 days. The reservoir initial and saturation pressure were also 2,800 kPa. For this case only, the producer was controlled by allowing a small amount (<1% injected steam) of free gas production.

In this presentation, which compares to Figure 5 in Reference (4), the steam zone and its varying pressure/temperature are indicated by the converged lines forming the top of the plot. By the first pressure reduction cycle, steam has risen to 10 m, and drops about 1 m during the cycle. By the third cycle, the steam level starts at just under 18 m but drops to less than 14 m. It is also notable that by the third cycle, the pressure did not track the steam controller function; that is, the pressure stayed above the sine function constraint even though the steam was off.

These increasing effects of pressure variation reflect the increasing amount of gas in the blanket as the steam rises, but the blanket expansion seems to be more than can be explained by simple methane expansion exceeding the pressure ratio. There is an amplifying effect of water vapour on the volume of the gas. When the blanket expands, the bottom of it expands into rock at steam temperature. Water vapour contributes significantly to the blanket volume in this zone, until it has time to cool.

Fining-Upward Sequences

Figure 11 shows results using a column having 8 D k_v in the bottom 10 m 1 D in the next 10 m, and 0.1 D in the top 5 m. Porosities were also reduced in these zones (see Table 1). This case was run with and without gas using 500 kPa initial saturation pressure and 3 MPa steam. The equivalent cases using a massive (25 m × 8 D) reservoir are shown for comparison.

In the case of the massive reservoir, the presence of gas reduced the average rise rate by about four times and the final rise rate by about twice that.

For the low permeability units in the fining-upward reservoir, the comparison is quite different. In the 1 D zone, the rise rate for the dead oil case is about 6.5 cm/d vs. about 4.2 cm/d for the gassy case.

In the 0.1 D zone, the rise rate without gas goes below 1 cm/d. With gas, the steam rise is affected shortly after the blanket enters the top zone; that is, while the steam is still more than 2 m below the interface. By the time the steam enters the top zone proper, its rise starts to more or less parallel the case without gas.

However, the top of the gas blanket rises through this zone at a respectable 2 cm/d. This provides the conditions for drainage from the top zone, given continued warming by conduction from the steam zone 5 m or so below.

When vertical permeability is restricted, drainage of oil through a static gas blanket is much easier than against rising steam. The details of drainage in the fining/gassy case are shown in Figure 12. This gives oil saturation profiles at 100 day intervals.

In Figure 12, the area between successive profiles is proportional to the incremental oil recovery during that time. By inspection, it can be seen that oil drainage is reasonable in the 300 – 500 day period (i.e. when the blanket is penetrating the top zone), and essentially complete by 1,000 days. Notably, the main restriction on drainage appears to be penetration of the higher permeability zone below. The steam flux there holds the oil up for more than a year. This demonstrates that drainage from a static gas blanket is more rapid in a 0.1 D zone than is possible, due to countercurrent steam rise in a 1 D zone.

The lesson taken from this brief investigation is that SAGD simulations that do not include solution gas at all, are in danger of seriously underestimating the drainage potential of less permeable units which cap otherwise good quality pay.

Discussion

Fingers

Butler has reported experiments in which gas was added to the steam used in physical models, some of which had transparent windows(7). He noted that gas at the top of the steam penetrated the oil by "fingering" and suggested this took the gas out of the way of the steam so that it would not affect rise, in accordance with the common assumption by numerical modellers.

There does not seem to be any basic disagreement between the objective results from Butler's physical models, and the conclusions of the present paper. If there does arise, in field scale, spacially separate columns of rising gas and falling oil:

- They are not the same as viscous fingers from displacement, but more in the nature of a Rayleigh instability;
- They would be well accounted for in a simulator by using relative permeabilites closer to straight-line, if smaller than grid block scale. If larger, the simulator will predict them (or not); and
- On the basis of results not reported here, the effect of straight-line k_r's on the 1 D rise rate is second-order relative to the other parameters explored here.

Comments on Top Thief Zones

When an extensive mobile gas or water zone exists at the top of the zone and there are no barriers, it will become possible to start venting the gas blanket to the thief zone as soon as the top of the blanket reaches it. Such venting would occur under the smallest of pressure gradients, and would presumably result in greatly accelerated steam rise as the blanket vanished upwards.

More importantly, the pressure differential between the steam and thief zones will likely affect the oil too. If there is 10 m of pay between the top of the steam and the thief zone, a differential of 100 kPa is all that is needed to begin moving the oil upward. As the mobility of the oil at the top of the pay is warmed by conduction from below, the whole oil column between the steam and the thief zone will begin to accelerate upward(8).

Economic Effects of Solution Gas

The temptation to present oil production and steam-oil ratios has been resisted here due to their limited relevance in the real, 3D world. Even in the case of oil drainage, oil that reports to the bottom of the steam chamber may not necessarily arrive at the production liner for some considerable time.

Slow rise has a definite economic effect, because it controls the initial ramp up of production (among other factors), which is important to the project return. Therefore, one would like to have as little gas in the oil as possible at the start.

It might be considered useful to have non-condensable gas in the reservoir at later times, e.g., for final blowdown purposes. Economic value will be maximized by removing as much solution gas as possible prior to SAGD, and then injecting waste gas later on. At current conditions, the value of the gas recovered is more than ten times compression costs.

Thermal Conductivity vs. Saturation

The simulations reported here assume constant thermal conductivity. In reality, conductivity will be reduced somewhat by increased gas saturation. Interestingly, Ito et al.(4) reported evidence of reduced thermal conductivity immediately above the steam zone. This would reduce the rise rate somewhat, but is a small correction relative to the unsolved problem of predicting how much gas will be present.

Conclusions

1. Small amounts of gas accumulation, i.e., fractional relative to initial solution quantities, control the rise rate of steam in oil sands. Rise may be more than 10 times slower compared to a case with dead oil and the same vertical permeability.
2. Rise rate with gas present is controlled by the thickness of the gas blanket above the steam. The mass in this volume is controlled by the initial solution GOR and the height or perhaps the volume swept, and by the unknown mechanism which appears to remove most of the liberated gas. The volume, and hence, thickness of the trapped mass is a function of the operating pressure and will expand and contract with pressure variations.
3. Under UTF Phase A conditions of low initial GOR (low initial pressure), an assumed removal rate of 75%, high relative operating pressure (approximately four times the initial pressure) and limited thickness of massive sand, gas is found to affect the average rise rate by only about 15%.
4. Most commercial reservoirs will experience much larger gas effects; up to 90% or more reduction in the observed steam rise rate. History matching without gas thus requires arbitrary permeability adjustments.
5. Steam rising under a gas blanket will stop when the top of the blanket encounters a vertical permeability barrier. Observation well data will show the rise to halt in the middle of the permeable zone.
6. Whether rising or trapped, the volume of the gas blanket will expand and contract with the chamber pressure. If expanding, it can push the steam back down or cause it to temporarily halt, while the blanket top continues to rise. Under increasing pressures, anomalously high rise rates will be observed as the blanket contracts.
7. There is a critical need for research into the missing gas removal mechanism(s). Without this, the predictive capability of SAGD simulation seems to be in doubt.
8. In the meantime, history matching by the addition of arbitrary amounts of gas (i.e. various degrees of undersaturation and/or additive to steam) may prove more satisfactory than arbitrary permeability adjustments.

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