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SAGD PERFORMANCE IMPROVEMENT IN RESERVOIRS WITH HIGH SOLUTION GAS-OIL RATIO

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Paper addresses the issue of Steam Assisted Gravity Drainage (SAGD) performance in the reservoirs with various solution gas-oil ratios (GOR). Results of extensive reservoir simulation study show that during the steam injection gas comes out of solution and accumulates at the edge of the steam chamber. In cases of high methane content in the bitumen the effect of gas layer development ahead of the steam front becomes detrimental and reduces the efficiency of conventional SAGD performance. It was suggested that by adjusting injected fluid composition it is possible to mitigate negative impact of the reduced heat transfer from water steam to bitumen.

Keywords: *steam assisted gravity drainage, SAGD, bitumen recovery, thermal recovery, steam and solvent co-injection*

INTRODUCTION

Heavy oil and bitumen (HOB) resources are vast and diverse in terms of modes of occurrence as well as reservoir fluid and rock properties. Often HOB might have similar macro-characteristics like viscosity or gravity, but composition differs significantly due to the complex history of hydrocarbon generation, migration, accumulation and subsequent degradation [1]. Particularly, HOB can have different content of solution gas. Although the variety of solution GOR of HOB has been recognized for a long time but this property is not always considered during the recovery method selection and planning.

Steam Assisted Gravity Drainage (SAGD) technology was proposed in 70s in Canada by Roger Butler [2]. In SAGD two horizontal wells (steam injector and producer) are drilled one above another with vertical well separation ranging from 4 to 10 meters. Since then SAGD underwent extensive piloting and in the recent years has become fully commercial technology and very often referred to as industrial standard for bitumen recovery. The concept of classical SAGD and its main features were broadly discussed under various perspectives and could be found elsewhere (Butler et al. (1994), Albahlani (2008) and others).

The number of SAGD operations globally grows rapidly and companies tend to apply this proven technology in new reservoirs using best practises and experience gained from the earlier successful applications. However, recent studies indicated that certain reservoir properties can limit SAGD applicability. Among those properties is solution GOR.

GAS-OIL RATIO EFFECT ON SAGD PERFORMANCE

In order to investigate solution gas-oil ratio's impact on SAGD performance, thermal numerical simulation model was built for generic properties of Athabasca oil sands, Canada. Some reservoir properties are presented in Table 1.

Table 1

Reservoir properties

Parameter	Units	Value
Depth to top	m	210
Reservoir thickness	m	25
Absolute permeability (horizontal)	Darcy	5
Absolute permeability (vertical)	Darcy	1.25
Porosity	%	35
Initial reservoir pressure	MPa	2,0
Initial reservoir temperature	°C	10
Initial oil saturation	%	80

In severely biodegraded Athabasca bitumens methane often dominates the composition of solution gas. Due to this fact, for the purpose of the current study we assumed solution gas to be represented by methane only. The primary fluid model consisted of three components, namely: water, dead oil and methane. Secondary composition included hexane for the purpose that will be explained later on.

In total five bitumen models were build with various methane mole fractions and correspondingly five different solution GOR values. Bitumen properties are presented in Table 2. In all cases density of bitumen was higher than that of water.

Table 2

Bitumen properties

Property	Units	Case				
		1	2	3	4	5
Solution GOR	m^3/m^3	3.5	4.3	5.3	6.9	8.6
Molar fraction of methane in oil phase at initial reservoir conditions	frac.	0.082	0.100	0.120	0.150	0.180
Density	kg/m^3	1008.4	1007.3	1006.0	1004.0	1001.9
API Gravity	deg	8.82	8.97	9.16	9.44	9.73
Viscosity at:	mPa·s					
10 °C		$4.2 \cdot 10^6$	$3.9 \cdot 10^6$	$3.7 \cdot 10^6$	3.2·106	$2.9 \cdot 10^6$
60 °C		8807.9	8301.8	7773.5	7043,5	6381.9
110 °C		254.6	242.2	229.1	210.8	193.9
160 °C		29.3	28.1	26.8	24.9	23.2
210 °C		7.4	7.1	6.8	6.4	6.0
260 °C		2.9	2.9	2.8	2.6	2.5

Sound thermal reservoir simulation requires using substantially refined reservoir grid in order to achieve acceptable precision in temperature, pressure and saturation distribution calculation. At the same time, advanced recovery methods' simulation is a very time and computational resource consuming task. As a trade-off between precision and computational time an element of symmetry was built for one SAGD wellpair. The size of the element is 25x45x500 m with the grid block size 1x500x1 m. SAGD wells' length is 500 m each with vertical separation of 5 m. Element contains 155880 m^3 of original oil in place (OOIP).

During the first three months preheating was simulated in both injector and producer by placing line heaters. After the hydrodynamical connection between the wells had been established, wellpair was put into the normal operating regime which implied maximum bottomhole pressure (BHP) constraint at the injector equal to 2.5 MPa and maximum rate was limited to 220 m^3/day. Producer was set to operate at one degree subcool in order to avoid steam breakthroughs so that results of the simulation would be more sensitive towards the processes that are outside the near-wellbore region. Well constraints were kept the same in all the cases for the purpose of obtaining justifiable comparison. Total operational time was 12 years.

In Figure 1 cumulative oil production (COP) profiles are presented for all GOR cases. One can clearly see that despite lower initial viscosity at higher GOR, COP drops significantly as methane fraction increases. Figure 2 demonstrates corresponding recovery factors.

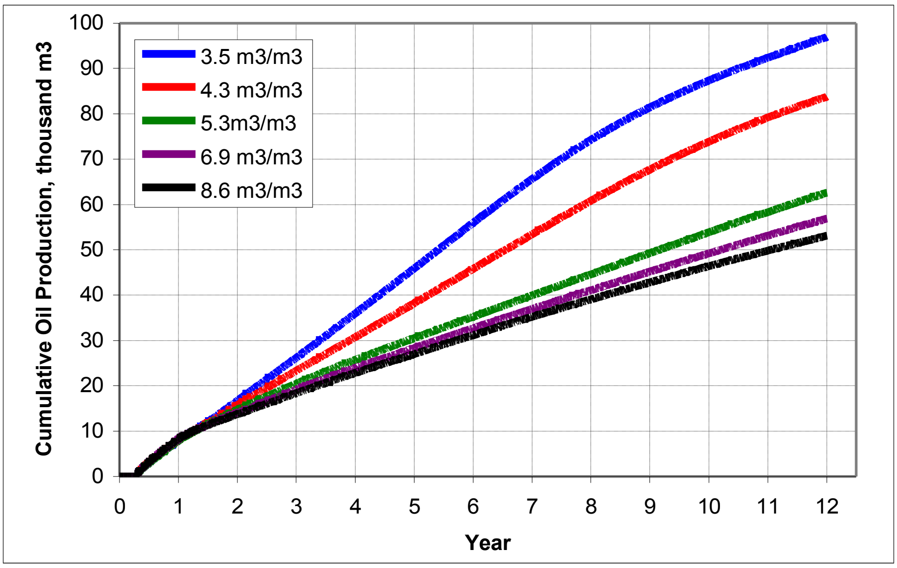

Figure 1. Cumulative oil production profiles for various solution GOR values

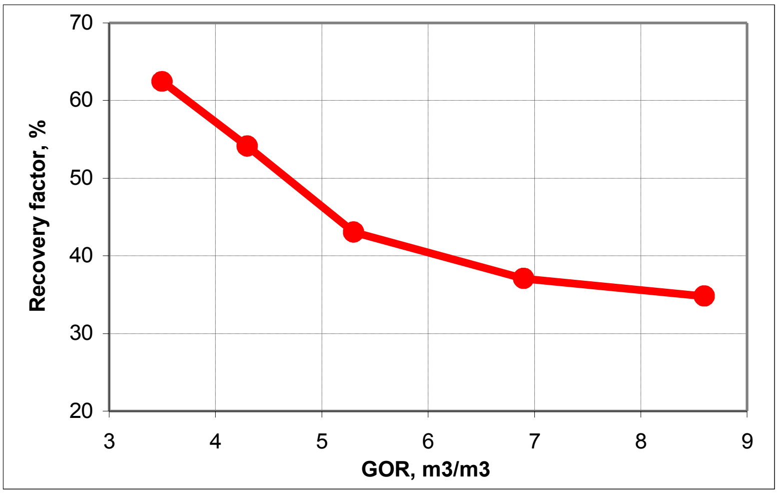

Figure 2. Recovery factor versus solution GOR

One of the main reasons behind reduced recovery factor is methane accumulation at the edge of the steam chamber. Such a gas layer acts as an insulator and deteriorates heat transfer from hot water steam to the cold bitumen. Reduced heat transfer creates poor opportunities for steam chamber to grow deeper into the reservoir and thermal sweep declines. In Figure 3 methane gas saturation distribution after 6 years of steam injection is visualized with corresponding temperature distribution in the Figure 4 for the cases of GOR 3.5 and 8.6 m^3/m^3.

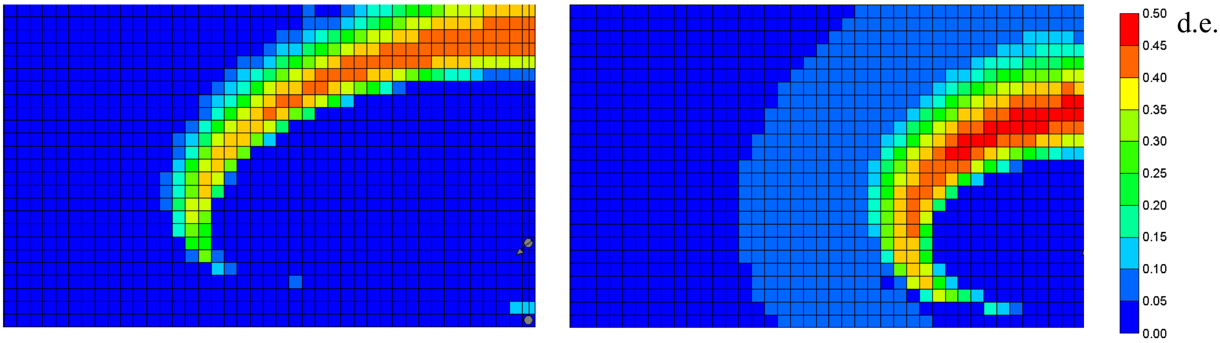

Figure 3. Methane gas saturation distribution after 6 years of steam injection.
Left figure – GOR 3.5 m^3/m^3, right figure GOR 8.6 m^3/m^3

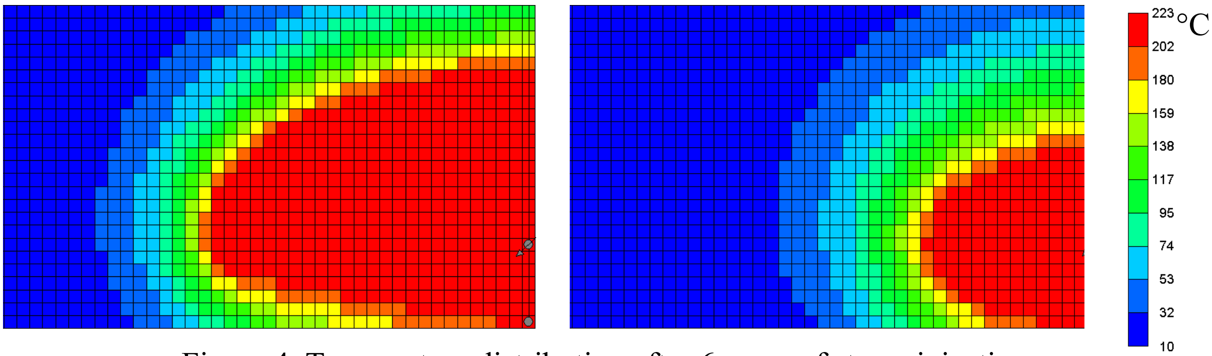

Figure 4. Temperature distribution after 6 years of steam injection.
Left figure – GOR 3.5 m^3/m^3, right figure GOR 8.6 m^3/m^3

Yuan et al. suggested that sudden change in fluid specific volume due to the condensation at the boundary of the steam chamber rapidly lowers the pressure locally so that dynamic suction occurs [3]. Such a dynamic vacuum draws gases towards the chamber's edge. In cases where the dynamic vacuum dominates diffusion, the gas exsolved from the bitumen would likely to stay ahead of the steam front and provide resistance to further propagation. If pressure and temperature conditions of injection were close to the critical point of water then condensation would not cause that dramatic change of specific volume. However critical point conditions (22.06 MPa and 374.15 °C) could not be achived in reality for overwhelming majority of bitumen deposits.

FLUID COMPOSITION MODIFICATION

One of the ways to mitigate a negative impact of exsolved gas on oil rates is to introduce the physical process that would facilitate steam chamber propagation and at the same time be insensitive to the gas layer ahead of the steam front. Such a process should reduce bitumen viscosity and accelerate bitumen withdrawal from the reservoir so that the chamber can grow sideways. If bitumen upgrading in situ is not considered there are essentially only two ways to reduce viscosity: heating and dilution. As it was demonstrated pure heating in reservoirs with high GOR leads to the gas blanket issues. The second option which is dilution could be achieved by hydrocarbon solvent injection into the reservoir.

Extensive laboratory and simulation studies on pure solvent injection (for example VAPEX [4]) suggest that due to the slow process of molecular diffusion it is a great challenge to achieve commercially viable oil rates in reservoirs with oil viscosity beyond million mPa·s. So neither steam alone nor pure solvent are the means for efficient bitumen recovery in cases of high GOR.

Solvent and steam co-injection is among rapidly emerging branches of SAGD inprovements nowadays. During the last fifteen years a number of solvent-based technologies were proposed and tested, for example Expanding-Solvent SAGD (ES-SAGD)[5], Solvent Aided Process (SAP) [6], etc. Although the efficiency of such hybrid methods is widely recognized, there was little research done to evaluate and analyze solvent additive's benefit in reservoirs with high GOR.

In order to investigate solvent co-injection's impact on SAGD performance in reservoirs with various solution GOR values a sensitivity study was designed. Solvent for co-injection was chosen to be n-hexane with fraction step equal to 2% mole. Injection strategy in all cases implied co-injection from the very beginning of SAGD operation. Well operation constraints were kept the same as in pure SAGD simulation runs to make simulations comparable. Table 3 summarizes sensitivity study and Fig. 5 visualizes recovery factor change (in absolute %) as a function of solvent mole fraction and solution GOR. Pure SAGD recovery factors were taken as a basis for comparison.

Table 3

Sensitivity study's summary. Recovery factor change
in solvent co-injection cases as compared to the pure SAGD

Mole fraction GOR, m³/m³	0.02	0.04	0.06	0.08	0.10
3.5	-0.26	0.43	1.02	1.73	2.52
4.3	0.97	2.10	2.94	3.69	4.38
5.3	4.10	6.91	8.38	9.62	9.62
6.9	5.55	8.61	10.98	12.17	13.22
8.6	5.05	8.57	10.78	12.25	13.28

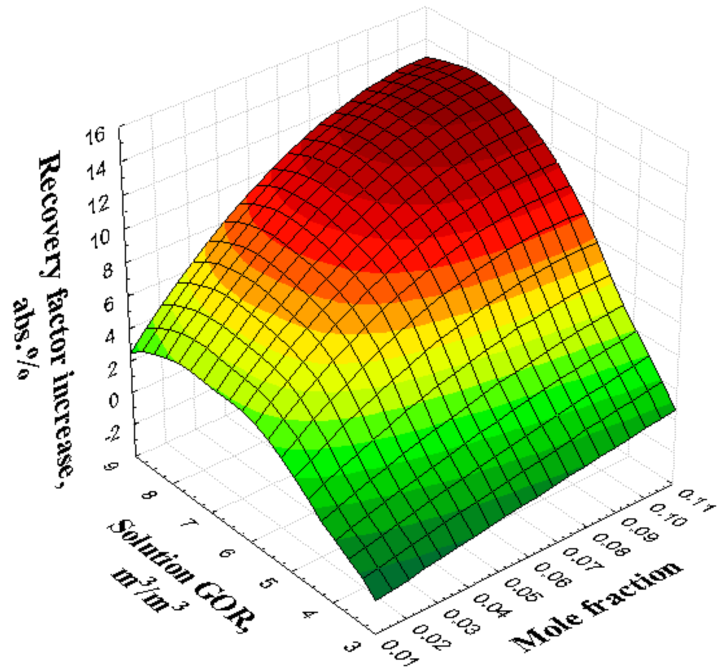

Figure 5. Recovery factor change as a function of solution GOR
and solvent's mole fraction in the injected stream

One can clearly see that in reservoirs with higher GOR co-injection of solvent gains larger increase in recovery factor. Thick gas blanket does not prevent solvent transport to the edge of the steam chamber but deteriorates heat transfer. That is why the effect of bitumen dilution by light hydrocarbon plays more profound role in cases with high GOR. In case of low GOR gas blanket is not an issue and partial replacement of water steam by solvent may have minor or even slightly negative effect as overall latent heat of the injected fluid is lower than that of pure water steam.

CONCLUSIONS

Extensive numerical study identified that during steam injection in SAGD operation solution gas exsolves from the bitumen and accumulates at the edge of the steam chamber;

It was shown that such a gas blanket has a detrimental impact on heat transfer from water steam to bitumen and hence it reduces an overall SAGD performance;

One of the possible ways to mitigate negative impact of reduced heat transfer could be an injection composition modification by addition of light hydrocarbon solvents;

Results of sensitivity study suggest that recovery factor increase due to the solvent additive is higher in high solution GOR reservoirs, because bitumen dilution plays more important role when resistance to the heat transfer from the gas blanket is strong;

Solvent and steam co-injection could be very promising alternative to classical SAGD technology in reservoirs with high solution GOR.

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