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On in situ hydrogen sulfide evolution and catalytic scavenging in steam-based oil sands recovery processes

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A B S T R A C T

In the SAGD (Steam-Assisted Gravity Drainage) process, high temperature saturated-steam is injected into an oil sands reservoir to lower the viscosity of the bitumen hosted within the reservoir. Typical steam temperatures range from 200 to 260 °C. Under these conditions, the bitumen, in presence of steam–condensate, undergoes aquathermolysis yielding H_2S and CO_2. Current SAGD simulation models take into account complex spatial heterogeneity of geology and oil composition and the physics of heat transfer, multiphase flow, gas solubility effects, and viscosity variations with temperature; however, few have taken the chemistry of SAGD into account. Here, we have added aquathermolysis reactions to a simulation model to understand H_2S reactive zones in SAGD. Given the requirement to constrain sulfur emissions from thermal recovery processes, it is necessary to reduce H_2S production to surface. The results demonstrate that injecting small amount of SO_2, along with steam, initiates the Claus reaction in the reservoir which converts H_2S into liquid sulfur. Thus, sulfur emissions are reduced below that of the original operation without SO_2 co-injection. The ability to use in situ Claus reaction-based H_2S scavenging offers an elegant way to reduce sulfur emissions from thermal oil sands recovery processes.

1. Introduction

Alberta, Canada hosts about 170 billion barrels of bitumen reserves in the Athabasca oil sands deposit [1]. Since the bitumen viscosity at reservoir conditions is in the hundreds of thousands to millions of centipoise, without stimulation, even if wells were placed in the oil formation, the oil would not flow from the reservoir into the wellbore due to its extremely low mobility. However, when heated to over 200 °C, the viscosity of the oil can drop by as much as six orders of magnitude becoming mobile under conventional drive mechanisms such as gravity drainage, solution–gas drive, and formation recompaction. Commercially, for Athabasca oil sands deposits, the reservoir is commonly heated by injecting high pressure saturated steam into the formation. Steam delivers its latent heat to native bitumen which in turn raises its temperature which in turn increases its mobility [2]. In SAGD (Steam-Assisted Gravity Drainage), portrayed in cross-section in Fig. 1, steam, injected through the top well, enters a depleted zone called the steam chamber. The steam travels to the edge of the chamber, where it loses its latent heat, thereby heating the formation beyond the edge of the chamber. Under the action of gravity, bitumen then flows to the base of the chamber where the production well is placed [3]. A liquid pool, consisting of steam condensate and mobilized bitumen, sits above the production well and prevents production of injected steam from the injector.

Typical SAGD steam injection pressures range from 1000 kPa up to 5000 kPa depending on the formation and its depth. This implies that the corresponding steam saturation temperature is between about 185 and 265 °C. The key physics of both gravity drainage and steam chamber growth in SAGD are relatively well understood [3,4]. However, the chemistry of the system and interaction of chemistry and physics remain unclear.

Given the temperatures and the co-existence of steam and bitumen, hydrous pyrolysis, also referred to as aquathermolysis [5], occurs yielding products such as hydrogen sulfide and carbon dioxide. Typically, the sulfur content of bitumen in Athabasca oil sands is between 4 and 6 percent by mass [6]. Hydrogen sulfide is a major concern due to its toxicity associated with emissions to the environment and impact on processing the produced oil. Often produced gases, given their methane content, are burned in a steam generator converting hydrogen sulfide to sulfur dioxide. Under current operating regulations, between 70 and 99.8% of the sulfur in the inlet stream to the treatment facility must be recovered before the gases are emitted to the atmosphere [7]. In current

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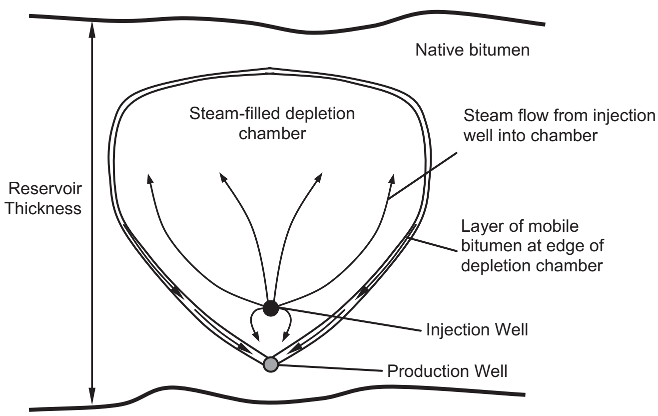

Fig. 1. Cross-sectional view of the SAGD (Steam Assisted Gravity Drainage) steam chamber. The top well is a horizontal injection well whereas the bottom well is a horizontal production well (both wells extend into the page).

practice, the limit on the emissions of sulfur is based on the oil processing plant capacity. For smaller plants with sulfur production rates between 1 and 5 tonnes per day, the sulfur recovery criterion is 70% at the recovery facility [7]. Similarly, for larger plants with sulfur production rates greater than 2000 tonnes/day, the sulfur recovery criterion is 99.8% [7]. If emissions exceed this criterion, a constraint on oil production is imposed. Many SAGD operators are facing hydrogen sulfide production issues and thus it is important to understand how, how much, and where hydrogen sulfide is generated in this process. Kapadia et al. [8] developed kinetic model from experimental data to predict gas volume and composition evolved during steam stimulation of bitumen. This model was further tested and tuned by using sulfur emission data from SAGD operators in Alberta [9].

A key feature of SAGD is that the edge of the chamber is at high temperature and contains relatively large volumes of steam, steam condensate, and oil. These are the main ingredients for aquathermolysis. Thus, the system operates not only as an oil recovery technology but also as an in situ aquathermolysis reactor whose temperature and pressure range from 185 to 265 °C and 1000 to 5000 kPa, respectively. Hence, carbon oxides and hydrogen sulfide and fuel gases such as hydrogen and methane are generated because of steam and bitumen chemical reactions (aquathermolysis) [5,10–14]. Additionally, oil sands mineral analysis have demonstrated the presence of heavy metals like vanadium,

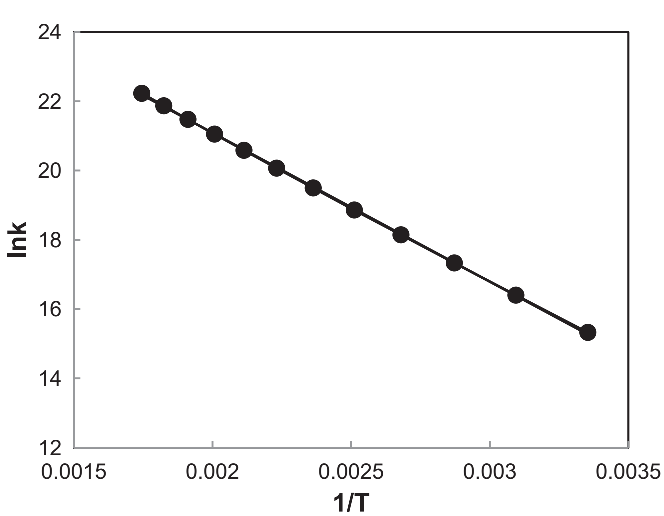

Fig. 2. Arrhenius plot for the Claus reaction.

Table 1
Input data used in two-dimensional SAGD reservoir simulation model.

Parameter	Value		
Grid blocks	177 (horizontal) × 60 (vertical)		
Average porosity	0.25		
Average horizontal permeability, mD	2424		
Average vertical permeability, mD	485		
Average oil saturation	0.64		
Average water saturation	0.36		
Original oil in place, m^3	1.1349×10^5		
Initial reservoir temperature, °C	10		
Initial reservoir pressure, kPa	2600		
Rock heat capacity, J/m^3 °C (also used for overburden and understrata)	2.600×10^6		
Rock thermal conductivity, J/m day °C (also used for overburden and understrata)	6.600×10^5		
Water phase thermal conductivity, J/m day °C	5.350×10^4		
Oil phase thermal conductivity, J/m day °C	1.150×10^4		
Gas phase thermal conductivity, J/m day °C	5.000×10^3		
Water–oil relative permeability curve [34]	S_W	k_{rw}	k_{row}
	0.1500	0.0000	0.9920
	0.2000	0.0002	0.9790
	0.2500	0.0016	0.9500
	0.3000	0.0055	0.7200
	0.3500	0.0130	0.6000
	0.4000	0.0254	0.4700
	0.4500	0.0440	0.3500
	0.5000	0.0698	0.2400
	0.5500	0.1040	0.1650
	0.6000	0.1480	0.1100
	0.6500	0.2040	0.0700
	0.7000	0.2710	0.0400
	0.7500	0.3520	0.0150
	0.8000	0.4470	0.0000
	0.8500	0.5590	0.0000
	0.9000	0.6870	0.0000
	0.9500	0.8340	0.0000
	1.0000	1.0000	0.0000
Gas–liquid relative permeability curve [34]	S_L	k_{rg}	k_{rog}
	0.1500	1.0000	0.0000
	0.2000	0.9500	0.0002
	0.2500	0.8400	0.0016
	0.3000	0.7200	0.0055
	0.3500	0.6000	0.0130
	0.4000	0.4700	0.0254
	0.4500	0.3500	0.0440
	0.5000	0.2400	0.0698
	0.5500	0.1650	0.1040
	0.6000	0.0930	0.1480
	0.6500	0.0750	0.2040
	0.7000	0.0450	0.2710
	0.7500	0.0270	0.3520
	0.8000	0.0200	0.4470
	0.8500	0.0100	0.5590
	0.9000	0.0050	0.6870
	0.9500	0.0000	0.8340
	1.0000	0.0000	0.9920

nickel, iron, titanium, etc, as a part of its mineral content [15–17]. This signifies that if sulfur dioxide is injected into SAGD steam chamber then there is a strong likelihood of occurrence of low temperature Claus reaction in which sulfur dioxide reacts with hydrogen sulfide to produce steam and liquid sulfur [18,19].

The research conducted in this study endeavors to test the possibility of using the Claus reaction to scavenge hydrogen sulfide within and at the edge of the steam chamber.

2. Methods and materials

2.1. Aquathermolysis reaction system and hydrogen sulfide scavenger

Kapadia et al. [9] included a comprehensive aquathermolysis reaction model in a thermal reservoir simulation model of SAGD to