

A General Theory of Gas Production in SAGD Operations

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ABSTRACT

The small GOR commonly measured in SAGD projects has not previously been adequately explained, and various phenomena such as “microfingering” have been proposed to account for its presence.

It is shown that the production of gases can be entirely explained by gases dissolved in the produced fluids at the temperature and pressure conditions of the SAGD steam chamber. Although methane is produced in part via bitumen, there is a significant contribution from methane dissolved in water as well. Other gases, such as carbon dioxide and hydrogen sulphide, are primarily produced by virtue of their solubility in water at the pertaining temperature and pressure.

This result is a consequence of the asymptotic Henry's Law behaviour of gases in water as the critical point of water is approached. This asymptotic behaviour is shown to govern at temperatures well below the critical point, and within the temperature range of SAGD steam zones. The theoretical foundation of this work permits the estimation of gas-water equilibrium constants for the major produced gases of importance in SAGD, and thus an ultimate understanding of gas effects in the steam zone.

INTRODUCTION

The production of hydrogen sulphide and carbon dioxide together with other minor gases in thermal recovery processes such as Steam Assisted Gravity Drainage (SAGD) is a common observation. The process that gives rise to these gases is a high temperature hydrolysis of aliphatic sulphur linkages in the bitumen, dubbed “aquathermolysis” by Hyne *et. al.*^{1,2,3} Typically, the amount of hydrogen sulphide produced per tonne of bitumen varies between 6 and 75 litres. Considerably more carbon dioxide is produced, usually in the range 900-10,000 litres per tonne. However, Hyne and co-workers have not dealt with the question of whether steam or steam condensate effects these reactions, and their experiments permit no conclusions in this regard.

In some of our own experiments, the procedure of Hyne *et. al.* was changed in that a stainless steel reaction vessel was used. In order to avoid loss of hydrogen sulphide to the steel, it was necessary to suppress the hydrogen sulphide in the gas phase. The experiment was arranged such that the reaction vessel was completely filled to eliminate a headspace, and an overpressure of 50,000 kPa was applied by means of helium gas. Thus, while Hyne’s experiments at 240⁰C were conducted at the steam saturation pressure of approximately 3500 kPa, in our case a gas phase was effectively prevented from forming. Our results were within the range reported by Hyne, suggesting strongly that the steam condensate rather than steam itself is the reagent in the aquathermolysis.

The question thus arises about the location within the steam zone where this reaction occurs. Elementary considerations of chemical kinetics would suggest that the steam front and the fluid drainage zone are the only regions of the SAGD steam chamber where the reaction is possible, these being the only regions where both steam condensate and bitumen are present in high saturations. The region ahead of the steam front is too cold to permit the reaction to proceed, and the region behind the steam front, while containing residual bitumen, must represent a region that has already been exhausted as far as hydrogen sulphide and carbon dioxide production is concerned.

Since SAGD is normally operated such that no free gas is permitted to enter the production well, the above considerations permit an estimation of the amount of produced gas that is due to dissolution of gases in the produced fluids, as demonstrated below. This gas will escape the produced fluids at the lower pressures that exist in the wellbore and the surface facilities.

GAS SOLUBILITY

The modified Henry's Law constant⁴ is given by

$$k_H = \frac{y_2 P \phi_2}{\gamma_2 x_2} \exp \left[\int_{p^s}^p \frac{v dP}{RT} \right] \dots(1)$$

where the ratio before the exponent is evaluated on the steam saturation curve. The exponent is known as the Poynting factor and accounts for the effect of pressure on the reference fugacity.

For the case of a SAGD steam zone (but not for the zone ahead of the steam front, or for a cooling steam zone under re-pressurization with gas) it may be assumed that the pressure is the saturation pressure of steam. Thus the integral in equation 1 vanishes and the exponent becomes unity.

For this condition, Japas and Levelt Sengers⁵ have shown that the function $T \ln(k_H/f^s)$ varies linearly with water density, and thus the Henry's Law constant is much reduced at higher steam temperature. This behavior is derived thermodynamically for the critical point of the solvent, but has been shown to govern the behavior of gases in water above 150°C or so. For small, non-polar molecules, including methane and the noble gases, Harvey and Levelt Sengers⁶ have shown that the use of the equation

$$T \ln \frac{k_H}{f^s} = A + B(\rho^s - \rho_c) + CT\rho^s \exp \left[\frac{273.15 - T}{\tau} \right]$$

is valid between the triple point and the critical point of water. Both hydrogen sulphide⁷ and carbon dioxide⁸ show similar limiting behaviour as the critical point is approached, although in the latter case there is a small deviation from the limiting situation in the SAGD temperature range.

This permits the calculation of Henry's Law constants and K-values as a function of water temperature, as shown in Tables

1 and 2. It is generally true for all gases that the solubility of the gas goes through a minimum, and then increases to the critical point. The minimum solubility (maximum Henry's Law constant) is near 100°C for most gases, but lies in the range 160-180 degrees for the acid gases hydrogen sulphide and carbon dioxide. The K-values for all gases approach unity at the critical point, as shown in Figure 1 for a number of gases.

APPLICATION

For each gas i in the SAGD chamber, if the solubility of the gas in bitumen is small, the total in the water and gas phases is given by

$$M_T = M_G y_i + M_W x_i$$

where $M_{T,W,G}$ refer to the moles in the total, water phase and gas phase respectively. The terms y and x are the mole fraction in the gas and water phase. Then it is easily shown that the mass ratio of any gas in the aqueous phase is given by

$$Q = \frac{S_w \rho_w}{S_w \rho_w + K(1 - S_{BR} - S_W) \rho_s}$$

Since the densities and K-values are constant at any given temperature, specification of saturations will give the mass distribution between the gas and water phases of any solute gas *vis-a-vis* the water draining to the production well. The distributions are given in Table 3, and the results therein permit the following calculation:

Case 1:

Consider a bitumen saturation of 0.5 in the drainage zone, where the total of steam and non-condensable gas saturations is taken at 0.02 or less. An hydrogen sulphide production of 25 L/tonne bitumen, and a carbon dioxide production of 2000

L/tonne are assumed (these are values measured in the author's own experiments, and are within the range measured by Hyne *et. al.*). Further, if one uses extrapolated methane solubilities as reported by Svrcek and Mehrotra⁹ for Athabasca bitumen, one would expect perhaps 2600 L of methane to be liberated on steaming, with a further 400 L liberated per tonne of bitumen in the facilities.

A prediction for gas production would then be 400L (methane produced in bitumen) + 0.623 x 2600 L (methane produced in water) + 0.9 x 2000L (carbon dioxide produced in water) + 0.96 x 25 L (hydrogen sulphide produced in water) = 3833 Liters. Thus gas would be produced at a GOR of about 4, with a 47% carbon dioxide content and close to 6000 ppm hydrogen sulphide content.

An inspection of the data in references 1-3 will show that hydrogen sulphide and carbon dioxide data will vary within a factor of about 3 for hydrogen sulphide and 5 for carbon dioxide for Athabasca bitumen. It has been observed that core samples from the same well, only a few metres apart, will give very different values, an observation in accord with our own. Thus one should expect some degree of variation in the composition of produced gases. The use of an average hydrogen sulphide generation value of 48 L/tonne, taken from Hyne's data, gives a hydrogen sulphide content of the order of 12000 ppm.

Case 2:

An initial gas saturation of 1 m³/m³ of methane in bitumen, with 35 L/tonne hydrogen sulphide and 2000 L/tonne of carbon dioxide, in a region of total gas saturation 0.05, water saturation 0.5 at 220⁰C is assumed. Proceeding as above yields a GOR of 2.6, with 60% carbon dioxide and 12,250 ppm hydrogen sulphide. The calculation results are thus not highly sensitive to a change in assumptions, in that in all cases the GOR is between 2 and 5, with a produced gas in the region of 50% carbon dioxide.

Obviously the eventual hydrogen sulphide concentration in the produced gas is strongly dependent on the amount of hydrogen sulphide the oil is capable of producing. A hydrogen sulphide concentration of up to 20,000 ppm does not seem unreasonable for short time intervals in Athabasca, and hydrogen sulphide evolution can be considerably higher in oils other than Athabasca bitumen. Therefore safety precautions in SAGD operations should not be ignored.

DISCUSSION

It is apparent that a reasonable approximation of gas production in SAGD operations, in terms of gas composition, GOR and hydrogen sulphide content, can be arrived at by a synthesis of recently published Henry's Law data for gases in saturated steam, as well as the data for aquathermolysis published by Hyne *et.al.*¹⁻³. It is therefore not necessary to postulate phenomena such as microfingering in order to explain the observed GOR in an Athabasca area SAGD project.

The recently developed theory of gas solubilities in saturated steam as the critical point of water is approached has obvious utility in numerical modelling of SAGD production projects, because the K-values for the gases are readily obtainable from the Henry's Law constants. The K-values for the gases in bitumen have been published by Svrcek and Mehrotra⁹. The power laws of these authors are in widespread use, although the extrapolation from experimental temperature data to SAGD conditions is a long one. Thus all required partitioning coefficients are available or are amenable to estimation. A detailed simulation of gas production using the new K-values is now being attempted.

The theory furthermore makes accessible the solution to problems that arise in the case of breakthrough of the steam zone to overlying gas caps, the accumulation of gases in the steam zone, or the injection of non-condensable gases into the steam zone.

It is noteworthy that the theoretical prediction is for virtually all hydrogen sulphide to be in the water phase, and to be produced in that manner. In a further paper¹⁰ we have presented experimental verification of this prediction. During the testing and verification of a new method for measurement of hydrogen sulphide in the field, a situation was encountered where bitumen was produced with essentially no concurrent water production. This condition held throughout a test, for a period in excess of one hour. As predicted theoretically, during this hour there was virtually no hydrogen sulphide production from the well pair under test. Methane production, as measured by a dry test meter, continued during this period but declined rapidly as the water cut diminished.

The above result is also consistent with the idea that at least some methane is produced via the bitumen. Bitumens of

different origin, such as Cold Lake and Peace River bitumen, are known to dissolve gases more readily than Athabasca bitumen, and this phenomenon is, very probably, in part responsible for GOR's greater than 10, which have been observed. Of course, the effects of steam pressure cannot be ignored, as higher pressures render all gases dramatically more soluble in water.

CONCLUSIONS

1. It is possible to predict the gas production from an Athabasca SAGD project solely by considering the solubility of produced gases in the steam condensate, and to a lesser extent in bitumen.
2. Acid gases produced during aquathermolysis are produced only via the produced water, and are predicted to be almost completely produced.

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SYMBOLS

k_H = Henry's Law constant

x = mole fraction of solute in liquid phase

y = mole fraction of solute in gas phase

P = pressure

P^* = pressure of saturated steam at temperature T

R = gas constant

S_w = water saturation

S_{BR} = residual bitumen saturation

γ = activity coefficient

ϕ = fugacity coefficient

v = partial molar volume of gas at infinite dilution

T = absolute temperature, K

f^s = fugacity of water at steam saturation

ρ^s = density of water at steam saturation

ρ_s = density of gas phase (steam and gas)

ρ_w = density of water

ρ_c = density of water at the critical point

τ = a decay constant taken as 50 Kelvin