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New Model to Predict Formation Damage due to Sulfur Deposition in Sour Gas Wells

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Abstract

Elemental sulfur (S_8) is often present in considerable amounts in sour gas reservoirs at the reservoir conditions (pressure and temperature). For the isothermal conditions in the reservoir, the reduction in reservoir pressure below a critical value will cause the elemental sulfur to deposit in the formation. Sulfur deposition can cause severe loss in the pore space available for gas, and in turn it will affect the gas well productivity. Accurate prediction of sulfur deposition in the reservoir will help in better management of sour gas reservoirs with potential sulfur deposition problems.

In this paper a new analytical model was developed to predict the formation damage due to sulfur deposition. This model can be used to study the effect of sulfur deposition on gas relative permeability, reservoir porosity, skin damage and reservoir rock wettability. The main objective of this model is to investigate the effect of radial distance on formation damage. Accurate correlations of different rock and fluid properties were used in this model for improved predictions. Accurate correlations of gas viscosity and gas compressibility were used, as the sulfur solubility is a strong function of gas viscosity and gas density. These correlations were used for the calculation of sulfur solubility at reservoir conditions.

Model predictions showed that sulfur deposition depends on the radial distance from the well bore. The most damage occurred in the 3 ft around the wellbore. As the radial distance increases the effect of sulfur deposition becomes negligible. Unlike previous models, which neglected the effect of pressure on gas properties, accurate correlations were used in the new model. Also, various sulfur solubility correlations were tested using the new model. A reduction of 2000 psi in the reservoir pressure, causes a 40 % loss of reservoir porosity at a radial distance of 3 ft from the wellbore and almost 85 % loss in the gas relative permeability at the same distance.

Introduction

Elemental sulfur is often present in considerable quantities in sour gas at the reservoir pressure and temperature. The gas production decreases the reservoir pressure, and in turn the solubility of sulfur in the sour gas decreases (Kennedy and Wieland 1960).

Elemental sulfur is present as a dissolved species in virtually all deep sour gas reservoirs. Sulfur precipitation is induced by a reduction in the solubility of the sulfur in the gas phase beyond its thermodynamic saturation point as a result of decrease in pressure and temperature. The change in pressure and temperature occur during production operations and can result in sulfur deposition in the reservoir, wellbore and surface facilities (Hands et al. 2002 and Shedid et al. 2006). Deposition of elemental sulfur in the near-wellbore region may significantly reduce the inflow performance of sour gas wells. Deposition of the liquid sulfur in the reservoir may impair both the reservoir porosity and permeability and results in the productivity impairment of the gas well. T he decline in the well productivity from a dry sour gas reservoir (south west Alberta) with a 16 vol. % H_2S was attributed to sulfur deposition in the formation (Mei et al. 2006).

Sulfur in the gas phase reacts to form a hydrogen polysulfide species at high temperatures and pressures. Deposition of elemental sulfur occurs when changes in pressure and temperature helps in the decomposition of polysulfide to elemental sulfur and H_2S (Xiao et al. 2006). Sulfur deposition in the formation, especially, in the vicinity of the wellbore may significantly reduce the inflow performance of sour gas wells. Wells have become completely plugged with sulfur in certain sour gas reservoirs after several months of production. Accurate prediction and effective management of the sulfur deposition are, therefore, crucial to the economic viability of sour gas reservoirs.

Many analytical and numerical models were developed to predict the effect of sulfur deposition on the inflow performance of gas wells. There are some shortcomings in previous models which may not allow for accurate prediction of

sulfur deposition. Some of these models assumed that the gas properties are constant and they are not changing with the reservoir pressure and temperature. Also some of these models rely only on a single sulfur solubility correlation from the literature. In this study, we have developed a model which takes into consideration the change of gas properties with the reservoir conditions (pressure and temperature). Accurate correlations were used to calculate the gas compressibility factor (Z), gas density, and gas viscosity. These correlations were tested with accurate charts that are used for determination of these properties.

Sulfur Deposition and Formation Damage

Deposition of a liquid sulfur phase in the reservoir will not significantly plug the pores in the formation if it was a mobile phase. But if the sulfur was deposited as a solid phase, it will result in plugging the pore space available for gas flow and will reduce the reservoir productivity index to a great extent (Mei et al. 2006).

An early concern of many problems associated with sulfur deposition during production of sour gas wells has been documented. Kuo and Colsmann (1966) developed a mathematical model of a solid phase precipitation in a porous medium and its effect on the fluid flow in porous media. The results of this model showed a rapid buildup of solid sulfur around the well and significant depositions near the wellbore due to the depletion of the reservoir pressure.

As stated by Hyne (1968) in his survey of more than 100 producing sour gas wells in Canada and Europe, there was sulfur deposition at the bottom of the producing wells. Hyne stated that, high bottom hole and wellhead temperatures and low wellhead pressures provide favorable conditions for sulfur deposition in the tubing.

Experimental studies were done using core samples to investigate sulfur deposition in the reservoir rock. Al-Awadhy et al. (1998) conducted a core flow experiment to study the sulfur deposition in carbonate oil reservoirs. They used actual crude oil and a carbonate core sample. The experiment indicated an increase in the differential pressure across the core and decrease in permeability due sulfur deposition under different flow rates. Also they stated that the flow impairment due to sulfur deposition in the vicinity of wellbore is the most severe when sulfur deposits as a solid phase. The deposition of the immobile phase can completely plug the formation.

Shedid and Zekri (2002) in their experimental study of sulfur deposition indicated that the deposition of elemental sulfur in carbonate reservoirs is highly dependent upon the flow rate, initial sulfur concentration and reservoir rock permeability. They showed that low permeability carbonate reservoirs suffer of accelerated and accumulated deposition of elemental sulfur than that of higher permeability, which have minor deposition or do not suffer of this problem.

Sulfur Solubility in Sour Gas:

Brunner and Woll (1988) extensively studied the sulfur solubility in sour gas for different mole fractions of H_2S. The mass fraction of the sulfur phase in solution can be determined using the following equation:

$$m_s = \frac{\rho_s}{\rho_{mix}} \tag{1}$$

$$\rho_{mix} = \rho_g^0 \left(1 - \frac{\rho_s}{\rho_s^L}\right) + \rho_S \tag{2}$$

The correction term $\frac{\rho_s}{\rho_s^L}$ takes into consideration the volume fraction of the dissolved sulfur. Brunner et al. (1988) stated that the main parameters that govern the sulfur solubility in the sour gases are: temperature, pressure and composition of the sour gas. The mole fraction of H_2S in sour gas has the most significant effect on the solubility of sulfur. At pressures above 1500 to 2000 psi the sulfur solubility increases extremely rapidly because sour gas attains liquid like densities as the pressure rises. At higher pressure the rate of solubility increase becomes less. Also, the sulfur solubility increases with the increase of H_2S content in the sour gas. Roof (1971) studied the elemental sulfur solubility in the hydrogen sulfide and carbon disulfide at high temperatures and pressures. He found that the sulfur solubility in the hydrogen sulfide increases with pressure. At low temperatures (above freezing point) the solubility increases with temperature.

All the existing models that can be used to predict the sulfur solubility in the gas are depending on the Chrastll's equation for the solubility of solids in gases. Chrastll derived the following equation to determine the solid solubility in gas:

$$C = d^k exp\left(\frac{a}{T} + B\right) \tag{3}$$

Where; c is the concentration of a solute in a gas in g/l, d is the density of gas in g/l, k is an association number, a = ΔH/R and b = ln (M_A + kM_B), ΔH is the total heat of reaction, M_A is the molecular weight of the solute, M_B is the molecular weight of the solute, and R is the general gas constant.

The deviation from the experimental results performed by Brunner and Woll (1988) was determined by Cézac et al. (2007) model as follows:

$$\Delta S_8(\%) = 100\sqrt{\frac{1}{np,exp}\sum_{i=1}^{np,exp}\left(\frac{y_{s_{8i}}^{exp}-y_{s_{8i}}^{cal}}{y_{s_{8i}}^{exp}}\right)} \quad (4)$$

Where; y^{exp} and y^{cal} are respectively the experimental solubility of sulfur and the solubility estimated using the model; np exp is the number of experimental points available for each solubility.

Cézac et al. (2007) model prediction for sulfur solubility in sour gas deviated from the experimental values obtained by Brunner and Woll (1988) by a percentage of 22.3% in some gas mixtures.

Model Formulations:

The sulfur solubility for a certain reservoir at the reservoir pressure and temperature can be predicted using Chrastil correlation (Brunner and Woll 1988, Bruce 1997, and Chrastll 1982):

$$C_{sulfur} = \rho_g^k \, exp\left(-\frac{A}{T} - B\right) \quad (5)$$

Where C_{sulfur} is the sulfur concentration in the gas phase, g/m^3, ρ_g is the gas density, kg/m^3, T is the gas temperature, ^{o}K. The parameters k, A and B are empirical constants that can be determined from experimental data.

This correlation was tested with the experimental data obtained from Brunner and Woll's (1988) experimental data and it was modified to the following form:

$$C_{sulfur} = \rho_g^4 \, exp\left(-\frac{4666}{T} - 4.57\right) \quad (6)$$

This correlation can be used to predict sulfur deposition for a specific reservoir fluid at the reservoir conditions.

Also, the gas density can be determined from the general gas law at reservoir conditions as follows:

$$\rho_g = \frac{p\gamma_g M_{air}}{ZRT} \quad (7)$$

Where, ρ_g = gas density, lb/ft^3, M_{air} = air molecular weight = 29, lb/lb-mole, γ_g = gas specific gravity, z = gas compressibility factor, R = general gas constant =10.7 psi. ft^3/^{o}R, T = reservoir temperature, ^{o}R, p = reservoir pressure, psia.

After matching the units of equation 3 and 2 we will get the following final equation:

$$C_{sulfur} = \left(\frac{43.43p\gamma_g}{ZT}\right)^4 exp\left(-\frac{4666}{\frac{5}{9}T-\frac{1}{3}} - 4.57\right) \quad (8)$$

Where; T is the reservoir temperature in ^{o}R.

The gas compressibility factor or z factor can be determined at a certain reservoir conditions using Abu-Elkassem correlation by iterations using visual basic program. The error between the z factor from charts and that from the correlation was less than 0.0001. The correlation used for z factor calculation can be written as follows (Tarek Ahmed 2001):

$$Z = 1 + \left(A_1 + \frac{A_2}{T_{pr}} + \frac{A_3}{T_{pr}^3} + \frac{A_4}{T_{pr}^4} + \frac{A_5}{T_{pr}^5}\right)\rho_{pr} + \left(A_6 + \frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right)\rho_{pr}^2 - A_9\left(\frac{A_7}{T_{pr}} + \frac{A_8}{T_{pr}^2}\right)\rho_{pr}^5 + A_{10}\left(1 + A_{11}\rho_{pr}^2\right)\left(\rho_{pr}^2 / Tpr3EXP{-}A11\rho pr2\right) \quad (9)$$

$$\rho_{pr} = 0.27\left(\frac{p_{pr}}{zT_{pr}}\right)$$

$$p_{pr} = \frac{p}{p_c} \;, T_{pr} = \frac{T}{T_c}$$

The values of A_1 to A_{11} are listed in **Table 1**.

Table 1—THE CONSTANTS VALUES IN ABU-ELKASSEM CORRELATION										
A_1	A_2	A_3	A_4	A_5	A_6	A_7	A_8	A_9	A_{10}	A_{11}
0.3265	-1.07	-0.5339	0.01569	-0.05165	0.5475	-0.7361	0.1844	0.1056	0.6134	0.721

In this case, to get the Z-Factor value, we should assume a value first to calculate ρ_{pr}, which was used to calculate Z then calculate it by iteration. Also p_{pr} and T_{pr} were calculated using the corrected critical pressure (p_{pc}) and temperature (T_{pc}) for H_2S content using the following equations:

$$T'_{pc} = T_{pc} - \varepsilon$$

$$p'_{pc} = \frac{p_{pc} T'_{pc}}{T_{pc} + A(1 - A)\varepsilon}$$

$$\varepsilon = 120[A^{0.9} - A^{1.6}] + 15[A^{0.5} - A^{4.0}] \quad (10)$$

Where A is the volume % of hydrogen sulfide in the sour gas.
Sulfur saturation at reservoir pressure and temperature can be determined from the following equation (Bruce 1997):

$$S_s = \frac{ln\left[\frac{A q^2 B\mu \left(\frac{dc}{dp}\right)t}{4\pi^2 k_a h^2 \emptyset (1 - S_{wi}) r^2} + 1\right]}{A} \quad (11)$$

Where; A is a constant which can be determined for a specific gas and a specific rock using coreflood, q is the gas production rate, B is the gas formation volume factor = $0.0283\frac{zT}{p}$, ft^3/scf, μ = gas viscosity, dc/dp is the change in sulfur solubility with pressure, t = time, k_a = reservoir absolute permeability, h = reservoir thickness, S_{wi} = irreducible water saturation, r = radial distance from the wellbore, ϕ = reservoir porosity.

The sulfur saturation can be related to the gas relative permeability by the following relative permeability function' assuming that the change in effective pore volume is only due to sulfur deposition:

$$k_r = e^{A\left(\frac{\emptyset_i - \emptyset_f}{\emptyset_i}\right)}$$

$$k_r = e^{AS_s} \quad (12)$$

Where: k_r = gas relative permeability = $k_g k_a$, S_s = sulfur saturation as a fraction from the pore volume, A = constant = - 6.22, ϕ_i = initial reservoir porosity, ϕ_f = reservoir porosity after sulfur deposition.

The gas viscosity at the reservoir condition can be determined from the following correlation **(**Lee-Gonzalez-Eakin Method**)** (Tarek Ahmed 2001):

$$\mu_g = 10^{-4} k \, exp\left(x\rho_g^y\right) \quad (13)$$

$$k = \frac{(9.4 + 0.02M)T^{1.5}}{209 + 19M + T}$$

$$x = 3.5 + \frac{986}{T} + 0.01M$$

$$y = 2.4 - 0.2x$$

Where: T = reservoir temperature, ^oR, M= gas molecular weight = $29\gamma_g$, ρ_g= gas density, gm/cc= PM/ (ZRT)
The solubility of sulfur in sour gas can be predicted using different correlations. The first correlation that was derived by Kuo (1971) based on the experimental data done by Roof (1972). This correlation can be applied only for pressure ranges greater than 2000 psi and it can be written as follows:

$$R = -1.005 + 0.839(10^{-3}p) \quad (14)$$

Where sulfur solubility, R, is in pounds of sulfur per cubic foot of solution, and pressure in psi.
Also, the sulfur solubility in sour gas can be predicted using the data after Bruce (1997). This correlation was derived for high pressure ranges (>2900 psi) and for pressure ranges below 2900 psi, and it can be written as follows:

For pressures < 2900 psi $$C_{sulfur} = 4(10^{-10}p^2) + 2(10^{-7}p) - 5(10^{-5}) \quad (15)$$

For pressures > 2900 psi $$C_{sulfur} = -4(10^{-10}p^2) + 4(10^{-6}p) - 0.0043 \quad (16)$$

Where: C_{sulfur} is the sulfur solubility in the sour gas, m^3 sulfur/$10^9 m^3$ gas/kPa, and p is the reservoir pressure, kPa.

Also, sulfur deposition affects the value of skin damage especially in the near-wellbore region. The skin damage due to sulfur deposition can be predicted by Hawkins formula (Economides et al. 1994) as follows:

$$S = \left(\frac{k}{k_s} - 1\right) ln \frac{r}{r_w} \quad (17)$$

Model Assumptions

i. Sulfur deposition will be considered as a second phase with relative permeability of zero.
ii. No sulfur adsorption by the reservoir rock.
iii. Isothermal reservoir conditions.
iv. The flow is radial
v. The reservoir fluid is saturated with elemental sulfur.
vi. The gas relative permeability is related to the sulfur saturation with the previous mentioned correlation.

Model Results and Discussion

We examined **Equation 13** for gas viscosity calculation and compare the results with that calculated from Carr's correlation and the results are shown in **Fig. 1**. The viscosity data in this figure was estimated for a gas with a specific gravity of 0.65 and a temperature of 220°F. The viscosity estimated from Carr's charts takes into account the effect of H_2S on the gas viscosity. The gas viscosity was determined at different reservoirs pressures starting from the initial reservoir pressure and under constant reservoir temperature. The data from the Carr's chart are in good match with that obtained from Lee correlation which means we can use Lee's correlation in our model even in the case of sour gas.

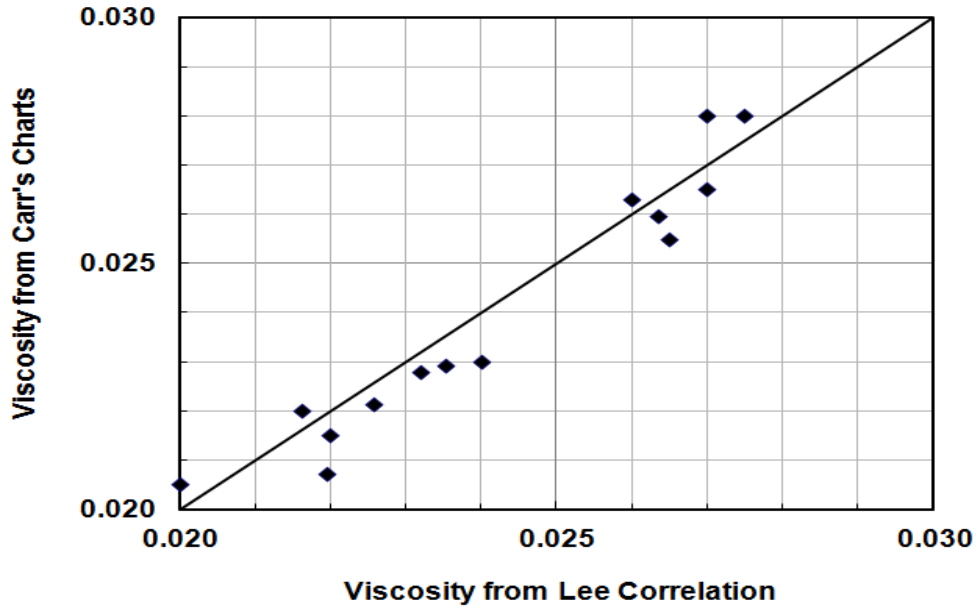

Fig. 1—Comparison between the predicted gas viscosity and that calculated from Carr's Charts.

The sulfur solubility can be predicted by using Bruce data for different pressure ranges, as shown in **Fig. 2**. For pressures less than 2900 psi we can used correlation 15 to determine the sulfur solubility and for pressures greater than 2900 psi, correlation 16 can be used. We used Bruce (1997) data and we were able to find the deflection point at 2900 psi pressure and the correlations 15 and 16 were obtained by adding trend lines to the data. In this case Bruce assumed that the sulfur solubility does not depend on the reservoir temperature or he just studied the solubility under isothermal conditions. In reality the reservoir temperature may change due to gas production, in this case we can use correlation 8 which correlate the sulfur solubility to the reservoir pressure, gas properties, and reservoir temperature.

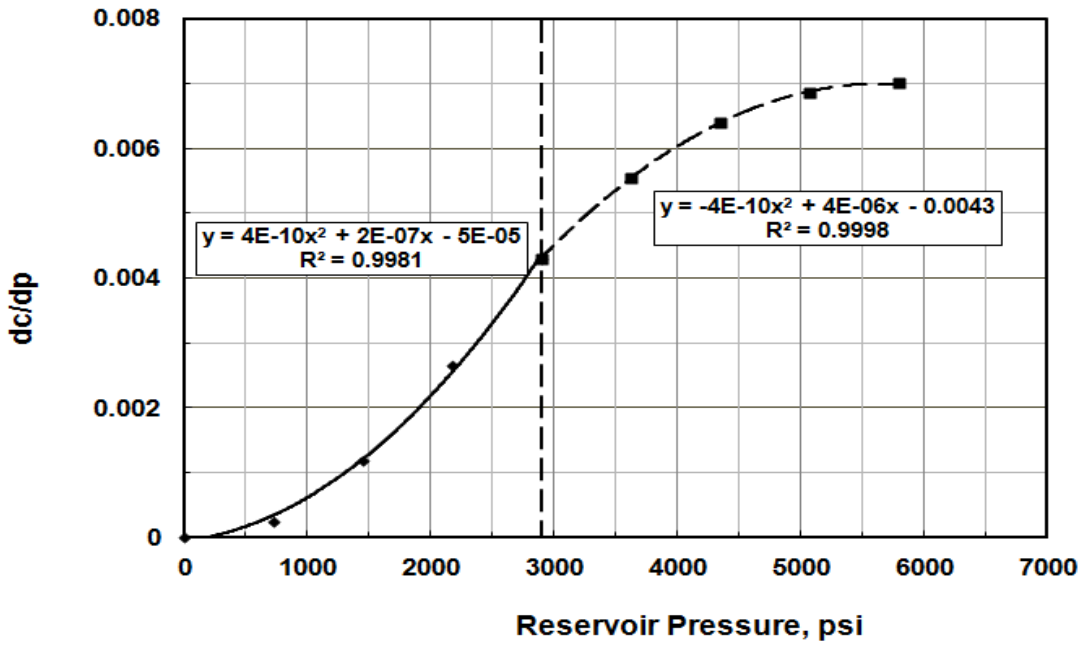

Fig. 2—Change of sulfur solubility with reservoir pressure based on Bruce data (1997).

Sulfur Saturation as Function of Time and Radial Distance from the Wellbore

Table 2 listed the reservoir fluid and rock properties that were used in the model to study the different parameters that affect the reservoir productivity due to sulfur deposition.

The reservoir pressure history should be recorded with time from the transient test analysis. The reservoir super compressibility factor can be determined by iteration from equation 9. The gas viscosity at each pressure should be determined from equation 13 and the gas formation volume factor also can be determined at different reservoir pressures. The change in sulfur solubility with pressure can be determined based on the pressure value using equations 15 and 16. Finally equation 11 can be used to determine the sulfur saturation at a constant radial distance from the wellbore with time. The gas composition that was used in this study is listed in **Table 3**.

Table 2—RESERVOIR FLUID AND ROCK PROPERTIES THAT WERE USED AS INPUT DATA TO THE MODEL	
Initial reservoir pressure, psi	5500
Reservoir permeability, md	5
Gas specific gravity	0.65
Reservoir temperature, ^{o}F	220
Gas viscosity at reservoir initial pressure and temperature, cP	0.0244
Reservoir thickness, ft	80
Reservoir porosity	0.15
Well radius, ft	0.328
Reservoir area, acres	40
Reservoir radius, ft	1490
Total compressibility, psi^{-1}	15×10^{-5}
Critical temperature, ^{o}R	365
Critical pressure, psia	672
Gas flow rate, MMSCFPD	500

Table 3—GAS COMPOSITION USED IN THE MODEL	
Component	**Mole Fraction**
N_2	0.0231
H_2S	0.1610
CO_2	0.0202
C_1	0.7904
C_2	0.0028
C_{3+}	0.0025

Figs. 3 and 4 show the relation between sulfur saturation, radial distance from the wellbore, and production time. As the production proceeds the pressure declines around the wellbore and the sulfur solubility in the gas decreased. As a result of that the sulfur saturation increased with time. Maintaining the reservoir pressure constant with the production by secondary recovery methods will keep the sulfur solubility in the gas at a constant value as the well produces and avoid sulfur precipitation around the wellbore. Another important observation from this figure is the relationship between radial distance and sulfur saturation. At small radial distance the sulfur saturation is higher than that at greater radial distance. This is because the volume around the well bore is smaller compared to that away from the wellbore. The sulfur saturation or sulfur precipitation is not a concern at greater radial distance because the flow area is very large compared to that around the wellbore at 1 and 3 ft radial distance. The flow area at 10 ft radial distance is hundred times that at 1 ft radial distance, therefore, the sulfur precipitation can be neglected compared to the total flow area. At 0.7 ft radial distance after 10 years of constant production rate and decline in reservoir pressure, the reservoir will lose 50% of its area available for flow near the wellbore per foot thickness of the reservoir. The most important term affecting the damage caused by sulfur precipitation in the reservoir is the radial distance at which the precipitation will occur.

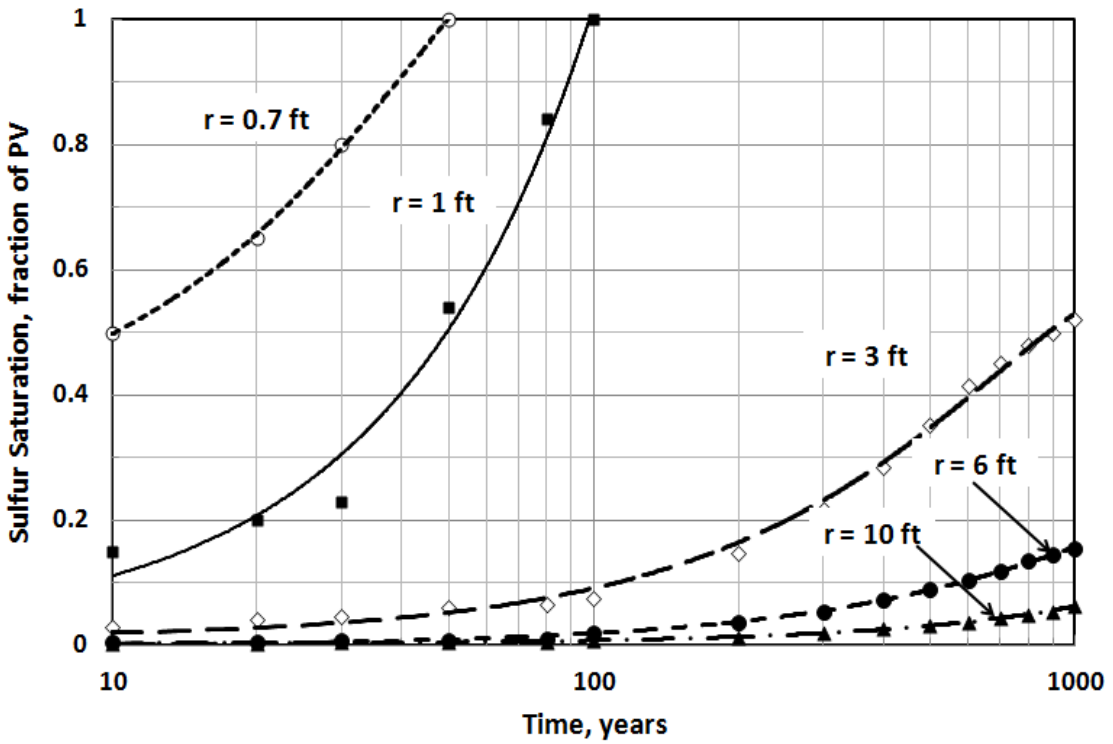

Fig. 3—Effect of production time on sulfur precipitation around the wellbore as function of radial distance.

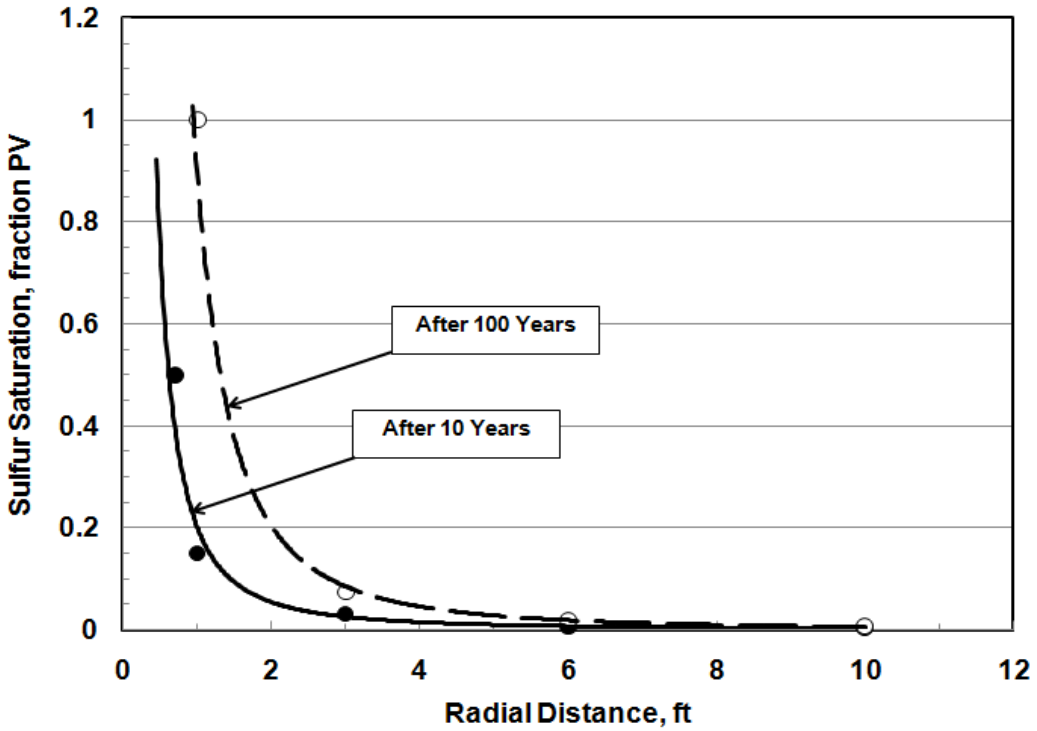

Fig. 4—Effect of radial distance on sulfur precipitation around the wellbore as function of time.

Effect of Sulfur Precipitation on the Gas Relative Permeability, Wettability, Porosity, and Skin Factor

Sulfur precipitation in the reservoir pores reduces the pore volume available for the gas and diminishes the area of gas flow, and in turn decreased the gas relative permeability. The relative permeability equation, **Eq. 12**, can be used to predict the gas relative permeability from the change in sulfur saturation with time as a result of sulfur precipitation. **Fig. 5** shows the effect of sulfur precipitation on the gas relative permeability with time and as a function of radial distance from the wellbore. Sulfur precipitation decreased the relative permeability of gas with time at all radial distance from the wellbore. The loss in gas relative permeability was severe in the case of small radial distance. In the near-wellbore region at radial distance of 0.7 ft the flow area is very small and the reduction in pressure caused the sulfur deposition and decreased the flow rate of the gas in that region. After 10 years of production the gas relative permeability dropped from 0.82 to 0.35 due to the sulfur precipitation around the wellbore.

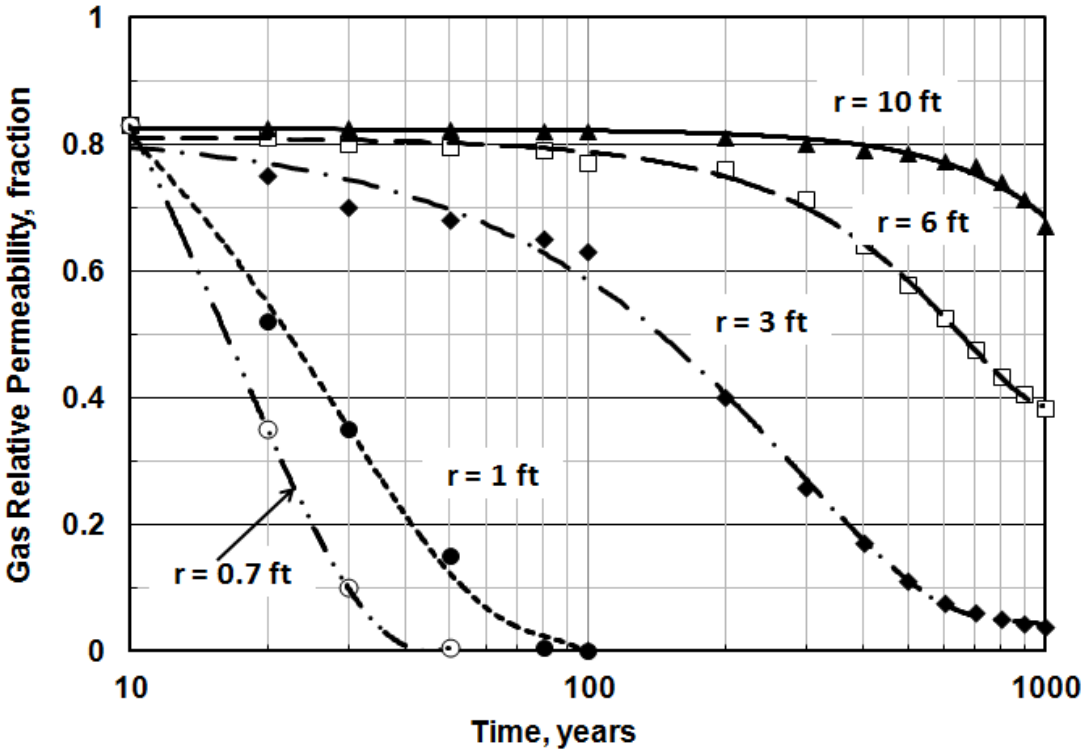

Fig. 5—Effect of sulfur deposition on gas relative permeability.

As discussed earlier, the gas relative permeability affected by sulfur deposition in the reservoir. If we considered sulfur as a second flowing phase and precipitates at different radial distance from the wellbore due to the decrease in reservoir pressure we can construct the relative permeability curves in **Fig. 6**. The relative permeability curves as shown in fig. 5 with the sulfur saturation as a second flowing phase were affected by the radial distance from the wellbore. At 6 ft radial distance from the wellbore the critical sulfur saturation (S_c) was 0.43 and it decreased to 0.11 at radial distance of 3 ft. In both cases gas was the wetting phase but at radial distance of 3 ft the wettability of gas increased to highly gas wet. Increasing the wettability to gas in the near-wellbore region is another mechanism to decrease the gas production in addition to the decrease in the gas relative permeability. From this figure we can conclude that decreasing the radial distance shifted the critical saturation of the non-wetting phase to the left and in the same time increased the reservoir wettability to gas. The critical sulfur saturation was found to be a strong function of the radial position from the wellbore; also we can relate the critical sulfur saturation to the critical velocity at which the gas should flow above to prevent sulfur precipitation. Filling the pores with elemental sulfur changed the degree of wettability of the formation to gas. At greater radial distance the flow area is very large compared to that at small distance from the wellbore and in turn the relative permeability curves and the degree of wettability will not be affected by the sulfur deposition.

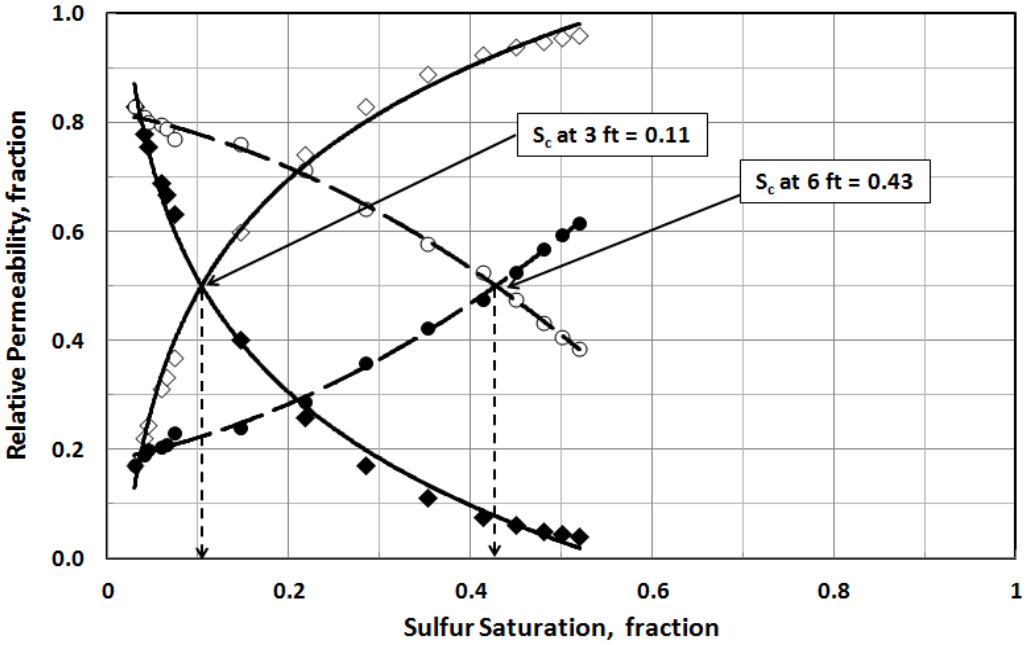

Fig. 6—Effect of sulfur deposition on the reservoir wettability.

The same scenario was observed in the reservoir porosity, **Fig. 7** shows the loss in reservoir porosity with time due to sulfur deposition in the reservoir. The reservoir porosity after sulfur precipitation can be determined as follows:

$$Loss\ in\ porosity = \frac{\emptyset_i - \emptyset_f}{\emptyset_i} \tag{18}$$

$$\emptyset_f = \emptyset_i - \emptyset_i S_{sulfur} \tag{19}$$

Where; S_{sulfur} is the sulfur saturation at time t.

Sulfur deposition in the reservoir caused severe loss in reservoir porosity, and the loss in reservoir porosity will be followed by loss in its effective permeability and loss in the pore volume available for the gas to flow and finally will decrease the gas production rate. The same scenario was repeated, as the effect of radial position from the wellbore was the same as in the case of relative permeability and sulfur saturation. The highest reduction in reservoir porosity was at smaller radial distance. The pressure decline rate is the most important factor that affects the sulfur deposition and in turn, the loss in reservoir porosity. If the reservoir pressure declined by 2000 psi, this will cause 40 % loss in the reservoir porosity at 3 ft radial distance, whereas the same amount of loss in porosity will happen at 0.7 ft radial distance with a pressure decline of 800 psi. Blocking the near-wellbore region with sulfur will decrease the reservoir effective porosity, permeability, and flow rate, therefore, removing the deposited sulfur or preventing its precipitation will help increase the gas production rate.

The effective permeability of the gas will go down as the sulfur saturation increases, the decrease in gas effective permeability will result in decreased in the reservoir absolute permeability. The decrease in reservoir absolute permeability will increase the skin due to damage, **Eq. 17**, caused by sulfur precipitation. **Fig. 8** shows the skin due to damage caused by sulfur precipitation as function of time (pressure decline) and radial position from the wellbore (0.7, 1, 3, 6, and 10 ft). The damaged permeability was the lowest in the near-wellbore region at radial distances of 0.7 and 1 ft because the flow area will be smaller and the pore volume per ft will be smaller. The higher the skin damage the lower the gas production rate, the skin damage is function of the radial distance at radial distance of 0.7 ft after 30 years of production the skin was 10, while as it was 1 at radial position of 3 ft from the wellbore.

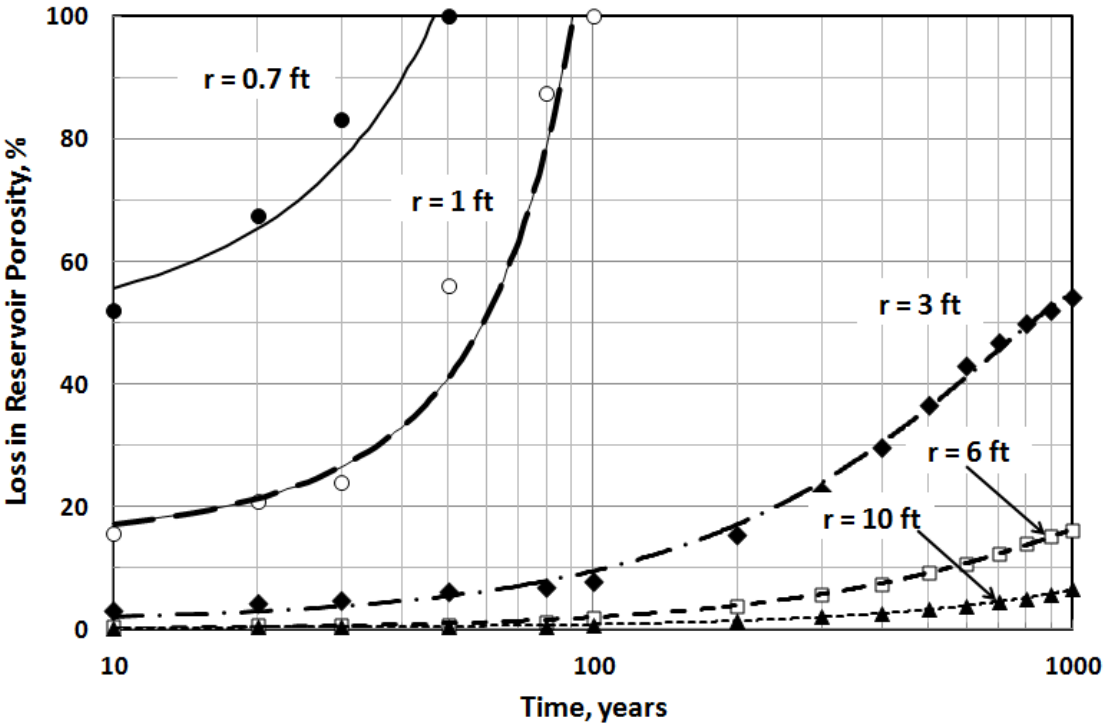

Fig. 7—Effect of sulfur deposition on the reservoir porosity.

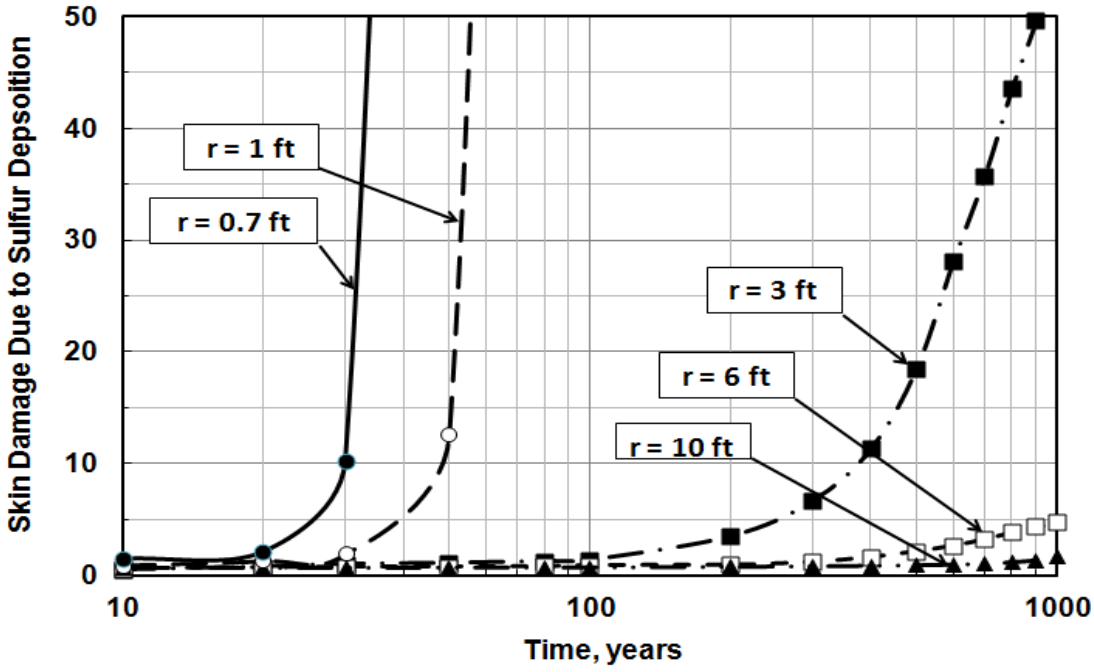

Fig. 8—Effect of sulfur deposition on the skin damage.

Conclusions

In this study sulfur precipitation in sour gas wells was investigated in terms of its effect on formation damage. The effect of sulfur deposition on gas relative permeability, reservoir porosity, wettability, and skin damage were studied. The following are the conclusions that were drawn from this study:

1. Sulfur precipitation occurs in sour gas wells due to the decline in the reservoir pressure.
2. Sulfur deposition is not a concern at higher radial distance from the wellbore.
3. The precipitation of sulfur in the near-wellbore region decreased the gas relative permeability and gas production rate.
4. The reservoir wettability was affected by sulfur precipitation in the near-wellbore region.
5. Sulfur deposition increased the skin damage due to the decrease in reservoir permeability in the near-wellbore region.

Nomenclatures

a	=	constant depends on the heat of reaction
A	=	relative permeability constant
b	=	constant depends on sulfur and gas molecular weights
B	=	gas formation volume factor
C	=	sulfur concentration in solution
C_{sulfur}	=	sulfur concentration in the gas phase
d	=	gas density
dC/dp	=	change in sulfur solubility with pressure
h	=	reservoir thickness
k	=	association number
K_a	=	reservoir absolute permeability
K_g	=	gas effective permeability
K_r	=	gas relative permeability
K_s	=	damaged permeability due to sulfur deposition
M_A	=	sulfur molecular weight
M_{air}	=	air molecular weight
M_B	=	gas molecular weight
m_s	=	mass fraction of sulfur phase in solution
$n_{p,exp}$	=	no. of experimental points available for each solubility
p	=	reservoir pressure
P_{pc}	=	pseudo critical pressure
P_{pc}'	=	pseudo critical pressure corrected for H_2S content
P_{pr}	=	pseudo reduced pressure
q	=	gas production rate
R	=	general gas constant
r	=	radial distance around the wellbore
S	=	skin damage due to sulfur deposition
S_c	=	critical sulfur saturation, fraction
S_s	=	sulfur saturation as a fraction of the pore volume
S_{wi}	=	irreducible water saturation
T	=	reservoir temperature
t	=	time
T_{pc}	=	pseudo critical temperature
T_{pc}'	=	pseudo critical temperature corrected for H_2S content
T_{pr}	=	pseudo reduced temperature
y^{cal}	=	predicted sulfur solubility
y^{exp}	=	experimental sulfur solubility
Z	=	gas compressibility factor
ΔH	=	total heat of reaction
$\Delta S_8\%$	=	difference between measured and predicted sulfur solubility
ϕ	=	reservoir porosity
ϕ_i	=	initial reservoir density
γ_g	=	gas specific gravity
μ	=	gas viscosity

ρ_g^o = original gas density
ρ_{mix} = sulfur/gas mixture density
ρ_{pr} = pseudo reduced gas density
ρ_s = sulfur phase density
ρ_s^L = Liquid sulfur density

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