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Advances in the Prediction and Management of Elemental Sulfur Deposition Associated with Sour Gas Production from Fractured Carbonate Reservoirs

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Abstract

Shell Canada has experienced significant deposition of solid sulfur during the production of dry sour gas from several of its deep carbonate pools located in Southern Alberta. In several cases, wells have become completely plugged with sulfur in the reservoir within several months. Accurate prediction and effective management of the sulfur deposition are crucial to the economic viability of these fields.

A new analytical model has been developed for predicting sulfur deposition associated with sour gas production in naturally fractured reservoirs. Key features of the model include incorporation of reservoir temperature profiles and the concept of critical velocity, which accounts for dynamic effects, resulting in a zone of reduced deposition close to the wellbore.

The model has been used to successfully match and predict sulfur deposition in several sour gas producers. The modeling results have been used as a design basis for downhole sulfur treatments and clean-out operations, the optimization of well completions and off-take rates to minimize the impact of sulfur deposition, and the development of new well designs and operating strategies for sulfur producers.

Introduction

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 decreases in pressure and temperature. These changes occur during production operations and can result in sulfur deposition in the reservoir, wellbore and surface facilities[1].

Shell Canada has experienced significant deposition of solid sulfur during the production of dry, sour (15-30% H_2S) gas from several of its deep (3000-4000 m [10,000-13,000 ft]) carbonate pools (30-40 MPa [4500-5750 psi], 80-100 ^oC [175-215 ^oF]) located in the Foothills of the Canadian Rockies in Southern Alberta, Canada[1]. Despite sulfur content determinations typically not exceeding 2 g/scm [125 lb/MMscf], in several cases, wells flowing at relatively low rates, 150-300 $10^3 m^3/d$ [5-10 MMscf/d], have become completely plugged with sulfur in the reservoir within several months. Accurate prediction and effective management of the sulfur deposition are critical to the economic viability of these fields.

Many investigations relating to sulfur deposition have been reported. Whilst most papers focus on the wellbore and use of sulfur solvents, several papers do discuss techniques for predicting and managing reservoir plugging[1-5]. However, not all of these studies are relevant to solid sulfur deposition associated with sour gas production. Furthermore, some of the key results and conclusions from the relevant papers are not supported by Shell Canada's most recent field experience.

Against this background and building on the approach of the earlier work, new analytical models have been developed for predicting sulfur deposition associated with dry, sour gas production. The basic model is a production system tool for predicting the quantity and location of sulfur deposition in the reservoir, wellbore and at surface (production system model). The other models are more complex and can be used to predict sulfur deposition in naturally fractured reservoirs (fracture model) and non-naturally fractured, or mechanically fractured reservoirs (matrix model). This paper describes the development and key advances of the new analytical fracture model, and assesses the implications of the results for managing sulfur deposition in naturally fractured reservoirs.

New Analytical Fracture Model

Reservoir - Wellbore System. **Fig. 1** represents a simplified view of a reservoir – wellbore system for a well that has been drilled at some angle through a carbonate reservoir, intersecting regular matrix rock as well as one natural fracture. Three distinct gas flow regimes have been defined: (1) Gas flow into the wellbore from the matrix rock (radial matrix flow), (2) Gas flow into the natural fracture from the matrix rock (linear matrix flow), (3) Gas flow into the wellbore from the natural fracture (radial fracture flow).

For naturally fractured reservoirs, gas flow in the significant fractures intercepting the wellbore are of most interest (depicted by flow regime 3 in **Fig. 1**). These fractures have the main influence on well productivity and ultimately determine well life and gas recovery from reservoirs prone to sulfur plugging. Equations have been re-written and developed to describe gas flow into the wellbore from natural fractures. The new fracture model uses these equations as a basis for predicting pressure, temperature, and velocity profiles along the significant natural fractures.

Key Flow Assumptions. Semi-steady state equations have been developed to model compressible, radial flow of gas in natural fractures towards the wellbore. It has been assumed that the flow regime is not influenced by boundary effects (i.e. reservoir dimensions ignored), and that gas flow into the wellbore is distributed evenly between the total number of fractures known, or estimated, to intersect the wellbore. The potential impact of fracture closure with reservoir depletion is considered negligible and has been ignored.

The new fracture model is not yet capable of handling variable production rates or declining reservoir pressures. For long-term forecasting, average rates and pressures are used as a basis for predicting well life and ultimate recovery.

Reservoir Gridding. A gridding is used in the model to sub-divide the reservoir into discrete intervals from the far reservoir to wellbore. Since the pressure and temperature gradients increase towards the wellbore, more definition is required there. The model uses an exponential approach to divide the radial distance in 25 grid blocks from the wellbore (r_w) to the far reservoir (r_e).

Pressure Profile in Natural Fractures. A common approach to the analytical modeling of fractures is to assume that they act like separated, parallel plates. However, this is definitely not the case in natural fractures. The surfaces are neither perfectly smooth nor completely separated. Rough fracture surfaces which contact in many places results in a more tortuous path for the gas flowing between them. Extending this rationale, it also follows that tortuosity increases with decreasing fracture network connectivity. In order to accurately determine the pressure drop associated with (high) rate gas flow through fractures, the impact of tortuosity must be taken into account. A new approach to fracture modeling has been developed which accounts for tortuosity and simplifies the description of the fracture system (required to estimate pressure drop due to gas flow through it) down to just 4 key variables: N, Number of fractures; ε, Fracture aperture; λ, Mean asperity height; A_c, Contact area. The new approach represents a significant simplification and advancement over previous fracture models suitable for gas flow.

Calculation of Pressure Profile. The most commonly accepted equation for flow through fractures is the cubic law, which is based on the analogy of flow between parallel plates:

$$q = -\frac{\varepsilon^3}{12\,\mu}\left(\frac{dp}{dx}\right) \quad \ldots\ldots\ldots\ldots (1)$$

Considerable controversy exists over the validity of the cubic law when applied to natural fractures[6]. The principal arguments against the use of the parallel plate model are that it ignores: (i) roughness or variability of natural fractures; (ii) the waviness or tortuosity of the fracture network; (iii) the existence of surface contact between the fracture surfaces; and (iv) pressure losses resulting from turbulence.

The cubic law (Eq.1) is derived assuming laminar flow. However, non-linear flow may occur as a result of inertial losses arising from entrance and exit losses along fracture boundaries, changes in flow velocity or direction along the flow path due to constrictions or obstructions, and initiation of turbulence due to localized eddy formation. Such inertial losses are generally proportional to the square of the fluid velocity[6]. To account for such losses, Eq. 1 is re-written as:

$$-\frac{dp}{dx} = a_c \upsilon + b_c \upsilon^2 \quad \ldots\ldots\ldots\ldots (2)$$

We can rewrite Eq.2 as,

$$\Delta P^2 = \frac{128\mu \ln\left(\frac{r_1}{r_2}\right)}{\rho_O C_n \pi^2 \varepsilon^4} Q_m + \frac{8 b_D}{\rho_O C_n^2 \pi^4 \varepsilon^5}\left(\frac{1}{r_1} - \frac{1}{r_2}\right) Q_m^2 \quad \ldots\ldots\ldots\ldots (3)$$

Eq.3 has been used as the basis for calculating the pressure profile as a function of flow rate in the fracture model. For more details concerning the derivation of these equations, see Reference 6.

Luis[7] examined the non-linear coefficient, b_D, as a function of surface roughness, S, and proposed the following empirical equation,

$$f_D = (2 * \log(c/S))^{-2} \quad \ldots\ldots\ldots\ldots (4)$$

Where $b_D = f_D / 2$.

This term is the basis for determining the additional pressure loss due to friction caused by the surface roughness, or asperities. Through his experimental work, Luis[7] determined that S generally had values between 0.033 and 0.4. He also determined that c = 3.7 for S < 0.033 and c = 1.9 for S > 0.033.

The parameter C_n is defined as the number of fractures per unit width and represents the equivalent fracture density,

$$C_n = N / W_f \quad \text{.......} \quad (5)$$

It is noted that W_f also implicitly includes a tortuosity factor, since flow path length will generally be greater than the integration limits of sample length. The value of N can be related to the flow field width and equivalent fracture width by,

$$N = C_a W_f / \varepsilon \quad \text{.......} \quad (6)$$

C_a is the ratio of the flow area to the total fracture area, and can be written as,

$$C_a = (1 – A_c) \quad \text{.......} \quad (7)$$

This term is used to determine the additional pressure loss due to reduction in non-contact area. A_c is generally defined as a fraction, which is greater than zero (surfaces which never contact) and less than one (surfaces which touch everywhere and therefore offer no residual flow area).

Linking Eq. 5–7, we get the simplified relationship for C_n,

$$C_n = (1-A_c) / \varepsilon \quad \text{.......} \quad (8)$$

Temperature Profile in Natural Fractures. It is well known from field evidence that considerable temperature drops can be experienced near the wellbore in naturally fractured reservoirs. Since temperature has a significant impact on sulfur solubility and the potential for sulfur deposition, it is important to be able to realistically predict the temperature profile. To achieve this in the natural fracture model, the temperature drop is calculated using terms for the change in kinetic energy and Joule-Thomson expansion.

Calculation of Temperature Profile. Due to compressibility, development of a simplified temperature model for high rate gas flow must include terms for kinetic energy and density changes[8]. Given the low density of a gas, potential energy effects are negligible. The thermodynamic energy balance reduces to the following form:

$$-\left[d\overline{H} + d\overline{KE}\right] + d\overline{q} = 0 \quad \text{.......} \quad (9)$$

For gas flowing in natural fractures close to the wellbore, high local velocity and Joule-Thomson cooling effects can contribute to temperature changes. This means that both the kinetic energy and enthalpy terms are important[9]. The effect of unsteady state conduction is comparatively minor and can be ignored. Assuming an adiabatic process and forming the terms, Eq.9 becomes:

$$d\overline{H} = C_p \mathrm{dT} + \left[\mathrm{v} - \mathrm{T}\left(\frac{\partial \mathrm{v}}{\partial \mathrm{T}}\right)_{\mathrm{P}} \right] \mathrm{dP} = -\mathrm{d}\overline{KE} = -\frac{\Delta\left(v^2\right)}{2\phi^2 g_c} \quad \text{.......} \quad (10)$$

Eq.10 has been used as the basis for calculating the temperature profile as a function of the pressure and local velocity profiles in the fracture model. For more details concerning the derivation of these equations, see References 8 and 9.

Sulfur Deposition. In order to calculate sulfur deposition in the reservoir, the model requires sulfur solubility data. The primary factors affecting sulfur solubility are pressure, temperature and H_2S concentration (**Fig. 2**). Other factors affect sulfur solubility, but their impact is secondary. The new fracture model uses only the primary factors affecting solubility as a basis for predicting sulfur deposition. Sulfur solubility is the subject of many prior publications and no further discussion is undertaken here.

Following a comprehensive review and comparison of the available sulfur solubility data (**Table 1, Fig. 3**), the sulfur solubility database developed by Alberta Sulfur Research Ltd. was selected as the optimum sulfur solubility data source for the conditions of this study and use in the new fracture model.

For a given gas composition, the model uses the database values to determine the difference in sulfur solubility between two conditions of pressure and temperature at discrete locations within the fracture. This difference is then multiplied by the gas flow rate to predict the sulfur precipitation between those two locations. In cases where the sulfur content, s, of the reservoir fluid has been determined, the model only allows sulfur to precipitate if the sour gas is saturated with elemental sulfur at those conditions.

Once sulfur particles have formed, they will either deposit as elemental sulfur, or be transported by the local energy of the gas. At the field conditions considered for this study, sulfur deposits as a solid[1]. When sulfur deposits within the fracture, the space available for gas flow is reduced. This results in a reduction in local fracture aperture and effective gas permeability and leads to increased pressure (and temperature) gradients.

Dynamic Effects. As mentioned above, once sulfur particles have been formed, they will either deposit as elemental sulfur or be transported due to dynamic effects. Based on an understanding that kinetic energy is one of the key factors controlling deposition environment[10-12], the concept of critical, or transport velocity[11,12] has been developed. The critical velocity is used by the new model as a 'lumped' parameter to account for dynamic effects when predicting sulfur deposition in the natural fractures.

The model requires specification of a critical velocity, υ_c. If the predicted local gas velocity, υ, is lower than the critical velocity, precipitated sulfur is allowed to deposit, otherwise, it is transported towards the wellbore. The location at which this transition occurs is termed the critical radius, r_c. The fracture model checks the local gas velocity against the user defined critical velocity in all grid blocks and at each time step. This approach ensures that the predicted sulfur deposition profile accounts for the transportation impact of dynamic effects. The result of the dynamic effects is a zone of reduced deposition within the fracture relatively close to the wellbore where the local velocities are the highest.

Calculation of Velocity Profile. As described above, the first term in Eq.3 represents laminar flow and the second term represents turbulent flow. Close to the wellbore local velocity is relatively high and the first term can be ignored. Re-organizing, the average local fluid velocity in the fracture between any 2 points, r_1 and r_2, can be estimated using the following equation:

$$v = \sqrt{\frac{\Delta P^2 \rho_o C_n^2 \pi^4 \varepsilon^5}{8A\rho^2 b_D (\frac{1}{r_1} - \frac{1}{r_2})}} \quad \text{................................} \quad (11)$$

Eq.11 has been used as the basis for calculating the local velocity profile in natural fractures relatively close to the wellbore.

Downhole Treatments. The model is capable of handling the impact of downhole treatments designed to remove sulfur deposition and/or regain productivity previously impaired by sulfur deposition within the reservoir. If after a certain time period sulfur deposition has accumulated to the point where gas flow is significantly restricted, a treatment is automatically carried-out by the model. Previously deposited sulfur is then removed from the formation. The end result of the treatment is a zone of reduced deposition within the fracture, which extends from the wellbore as far as the treatment is able to penetrate.

Treatment Design. The model will schedule a downhole sulfur treatment when the sulfur plugging at any distance from the wellbore has built to 95% of the original available fracture space. When a downhole treatment is conducted, the sulfur deposited in the natural fractures is removed from the wellbore, r_w, back to the given r_t, with given efficiency, e.

Program Steps.

1. Define the reservoir parameters, gas properties, and production data (**Table 2**).
2. For the given gas flow rate, calculate radial pressure and temperature profiles from the far reservoir to wellbore.
3. Link the pressure and temperature predictions with sulfur solubility data, sulfur content and gas flow rate, to estimate a daily sulfur deposition profile from far reservoir to wellbore.
4. Modify the daily sulfur deposition profile to account for dynamic effects.
5. Update the available space within the fracture to account for volume reductions due to sulfur deposition or increases due to sulfur removal by treatments.
6. Re-calculate all key parameters at the end of each time step (1 day) and for each grid block (pressure, temperature, sulfur saturation, available space and related terms such as fracture dimensions/roughness/tortuosity).
7. Repeat steps 2 through 6, for as long as gas flow remains possible (i.e. until pressure drop becomes too large and flow not sustainable).
8. When gas flow rate is totally restricted by sulfur plugging within the reservoir, stop the program and generate an output file containing the key parameters (pressure, temperature, sulfur saturation, available space, number/frequency of treatments, well life & gas recovery).

Model Calibration. Following basic data entry, the fracture model requires calibration. This is a relatively complex multi-level process, which requires at least one representative well with plenty of reliable subsurface data. In the absence of existing field data (i.e. for a 'green field' development), the default assumptions in the model, or parameters from an analogue field should be used.

Whilst the calibration process is non-unique, the key steps are generally: (i) Use of measured bottomhole pressure and temperature data in conjunction with downhole flow information to estimate the most likely combination of fracture parameters (number, aperture, roughness, contact area); (ii) Use of the initial pro-active treatment frequency to determine the critical (or transport) velocity; (iii) Use of increasing pro-active treatment frequency together with ultimate well life and recovery to confirm the likely treatment parameters (effective distance and efficiency), or, in the case of wells which produce far beyond predicted life, to estimate the degree of sulfur saturation at initial reservoir conditions.

Where possible, attempts should be made to measure the sulfur content of the sour gas by obtaining and analyzing a bottom hole sample. Whilst debate continues over the ability to obtain a representative sample, reservoir fluid sampling generally provides insight into the degree of sulfur saturation and can help with model calibration.

Results.

Pressure, Temperature, and Velocity Profiles. Examples of the predicted flowing pressure, temperature, and velocity profiles along the natural fracture for the reservoir and production conditions of a case study well are presented in

Figs. 4, 5 and 6 respectively. These figures also illustrate the sensitivity of these profiles to the initial fracture aperture.

Dynamic Sulfur Deposition Profile. The new model links pressure and temperature profiles with sulfur solubility data and, using the velocity profile to account for dynamic effects, generates a daily sulfur deposition profile along the natural fracture. With each day of production, more sulfur is deposited on the profile from the previous day. Eventually, at a distance just beyond the critical (or transport) radius, the volume of sulfur in the fracture equals the available space and the 'sulfur plugging line' is reached (dotted line '1' in **Fig. 7**). Gas flow becomes severely restricted and the model automatically schedules a downhole sulfur treatment. The treatment removes sulfur from the fracture according to the specified treatment parameters, resulting in a modified sulfur deposition profile below the 'sulfur plugging line' (dashed line '2' in **Fig. 7**). As production resumes, more sulfur is deposited on the modified profile until the 'sulfur plugging line' is again reached (long-dashed line '3' in **Fig. 7**). Following further periods of sulfur deposition (production) and removal (treatments), the modified profile eventually reaches the 'sulfur plugging line' just beyond the effective treatment distance, r_t, and the well is termed 'plugged' (solid line '4' in **Fig. 7**). After this, only enhanced treatments penetrating further into the fracture would be effective at removing the sulfur from the plugged well and restoring production.

The modeling process results in 3 specific zones of sulfur deposition within the natural fracture: (1) A zone of reduced deposition, where dynamic effects result in transportation of sulfur rather than deposition; (2) A zone of reversible sulfur deposition, which can be removed by downhole treatments; (3) A zone of permanent plugging, which is further from the wellbore and can not be reached by conventional treatment techniques. The relative location and potential size of these zones, as calculated by the model for the conditions of the case study wells, are shown in **Fig. 7**.

Sulfur Plugging Overview. The new modeling work indicates that when sour gas saturated with elemental sulfur is produced through the system described in **Fig. 1**, sulfur will deposit in the matrix rock and the natural fractures, as shown by the shaded region in **Fig. 8**. Whilst the matrix plugging is close to the wellbore [0-2m] and the faces of the natural fractures [<1m], plugging in the natural fractures might only start to occur some distance from the wellbore [1-2m], peaking further back [3-10m], and extending relatively deep into the formation [15-30m] (**Figs. 7 and 8**). This result has not been predicted by previous models or suggested in any earlier publications.

Summary of Key Results. For the reservoir conditions of the case study fields, the calibrated fracture model has been used to investigate the producing life, gas recovery and treatment requirements as a function of production rate, reservoir pressure, degree of fracturing and treatment technique. An overview of the key modeling results for the Shell Canada case study wells is presented in **Table 3**.

Comparison with Field Data. After the appropriate level of calibration using one key well from each region, the predictions made by the new fracture model were found to agree well with the field data for other wells (flowing bottomhole pressure, temperature, treatment frequency, well life and ultimate recovery). Some examples of the agreement between predicted and actual well lives and recoveries are given in **Table 3**.

Production Rate. Low production rates generally result in longer well life and higher gas recovery. However, very low rates (e.g. below 100 $10^3m^3/d$ [3 MMscf/d] for the case study wells) can also mean a requirement for more downhole sulfur treatments and higher associated operating costs.

It is also sensible to avoid very high rates (e.g. above 500 $10^3m^3/d$ [17 MMscf/d] for the case study wells). Field experience suggests that for any given set of reservoir / wellbore conditions, there is a maximum rate above which 'uncontrollable deposition' occurs and well performance drops rapidly due to sulfur plugging in the reservoir. A likely explanation for this 'maximum' rate is that the high associated pressure gradient drives a significant volume of sulfur precipitation, even at distances further back than usual. Increased turbulence and delayed deposition effects result in the large quantities of sulfur being transported closer to the wellbore where the available space for deposition is much less. The impact of this can be rapid plugging and deterioration of inflow performance. This phenomenon has been observed many times in the field and is discussed by Hyne[13].

For a given reservoir / wellbore / operational scenario, there will be an optimum production rate at which wells should be produced. The new fracture model can be used to help determine this rate.

The impact of production rate on well life, gas recovery and treatment requirements for the case study well can be seen in **Tables 3 and 4** and **Fig. 9**

The modeling results indicate that doubling the production rate can result in one third less recovery.

Degree of Fracturing. In general, well productivity and ultimate recovery in sulfur plugging reservoirs improves with degree of natural fracturing.

The modeling results indicate that wells with just a few, large fractures will exhibit 4-5 times well life and recoveries compared to wells with medium or many, small fractures (**Table 3**). On this basis, horizontal wells are recommended over vertical or deviated wells when the probability of encountering fractures is significantly increased.

Reservoir Pressure. The lower the reservoir pressure, the lower the sulfur carrying capacity of the sour gas and the lower the amount of deposition per unit volume of gas produced.

The modeling results suggest that for any given new well in a sour gas reservoir (which is saturated with elemental sulfur at initial conditions), a 40% reduction in reservoir pressure could result in 2-3 times the well life and recovery (**Table 3, Fig. 9**).

Sulfur Saturation. It is logical that if a reservoir is under-saturated with sulfur at initial conditions, deposition will not necessarily occur with early production, but will occur later as the reservoir depletes. Generally, under-saturated reservoirs will take longer to plug than saturated ones.

The modeling results indicate that a 50% sulfur saturation level at initial conditions can extend well life and recovery 3 times compared to the fully saturated case (**Table 3**).

Downhole Treatments. Provided that production is stopped before the sulfur deposition in the natural fracture completely blocks the flow path, field experience shows that solvent treatments can effectively remove the deposition and restore production performance. However, once the fracture has been allowed to bridge with sulfur, it appears that the solvent is unable to pass the obstruction and effectively clean the fracture. At this point, acid is often required to remove some rock and re-establish a flow path for the gas. Ultimately however, so much sulfur has deposited, that even repeat acid fracture treatments become progressively less effective and eventually stop working – a phenomenon observed several times by Shell Canada in the case study wells.

The modeling results indicate that the further the sulfur treatment is able to penetrate and the more efficient it is, the longer the sulfur plugging gas well will ultimately last (**Table 3**). Specific modeling results suggest that one very large fracture treatment, which is able to widen significantly the fracture aperture (1000 microns) for a significant distance back into the reservoir (10 m [30 ft]) could result in as much as a 10 fold improvement in well life and gas recovery.

Pressure Build-Up Analysis. Based on early well test analysis, the transmissivity match can be written as[14]

$$k_{welltest} * h = k * \varepsilon \qquad (12)$$

Using Eq.12, the average hydraulic aperture in a case study well with a 3 fracture cluster-set was determined to be approximately 300 microns. After significant history matching and calibration work using the new fracture model, the most likely fracture width for 3 fractures was determined to be in the range of 200–300 microns. This represents an excellent match.

Well test analysis for wells prone to sulfur plugging are notoriously difficult to interpret. This was also true for the case study well, where conventional analysis of three pressure build-up surveys had yielded little in the way of results. However, when the sulfur deposition zone predicted by the new fracture model was used as the basis for designing a composite radial approach[15] to the analysis, a good match was achieved and reasonable reservoir parameters were calculated (**Fig. 10**).

Conclusions

1. A new analytical model has been developed for predicting sulfur deposition associated with sour gas production in naturally fractured reservoirs. The new model has been used to successfully match and predict sulfur deposition in several of Shell Canada's sour gas producers. The modeling results have been used as a design basis for downhole sulfur treatments and clean-out operations, the optimization of well completions and off-take rates to minimize the impact of sulfur deposition, and the development of new well designs and operating strategies for sulfur producers.
2. Sulfur plugging in the matrix rock has been shown to occur relatively close to the wellbore [0-2m] and the faces of the natural fractures [<1m], whilst plugging in the natural fractures might only start to occur some distance from the wellbore [1-2m], peaking further back [3-10m], and extending relatively deep into the formation [15-30m]. This is a new result, which has not been reported in any earlier publications.
3. In agreement with earlier modeling work and field experience, the new modeling results indicate that lower production rates offer the potential for longer well life and higher ultimate recoveries.
4. The new modeling indicates that low production rates result in plugging which is closer to the wellbore. Whilst this plugging is generally more treatable, it occurs more frequently and results in higher associated operating costs. Conversely, high production rates result in plugging which, although less frequent, is further from the wellbore and generally harder to treat.
5. The new model suggests that well productivity and ultimate recovery in sulfur plugging reservoirs generally improve with degree of natural fracturing. On this basis, horizontal wells are recommended over vertical or deviated wells when the probability of encountering fractures in the reservoir is significantly increased.

Nomenclature

A = flow area, m^2
A_c = contact area, m^2
a_c = linear flow coefficient, Pa.s/m
b_c = non-linear flow coefficient, $Pa.s^2/m^2$
b_D = dimensionless non-linear flow coefficient ($b_D = f_D/2$)
c = coefficient dependent on the range of S and b_D
C_a = ratio of the flow area to the total fracture area
C_n = number of fractures per unit width
C_p = constant pressure specific heat capacity, Btu/lb.°F
dp/dx = pressure gradient
e = treatment efficiency, ratio
f_D = dimensionless friction factor
g = gravitational acceleration constant, 32.2 ft/sec^2
g_c = conversion factor, 32.2 $ft.lb/sec^2.lbf$
h = net formation thickness, m
H = enthalpy, Btu

$\overline{H}$ = specific enthalpy, Btu/lb
JC = Joule-Thomson constant
k = fracture permeability, md
$\overline{KE}$ = specific kinetic energy, Btu/lb
$k_{welltest}$ = permeability from well test analysis, md
N = number of fractures
P = pressure, Pa
q = flow rate per unit width of fracture, m^2/s
$\underline{q}$ = heat flow per unit mass of material, Btu/lb
Q = gas flow rate, $10^3 m^3/d$
Q_m = mass flow rate, kg/s
r = radial distance for fracture, m
r_1, r_2 = radial distances between which pressure drop occurs, m
r_c = critical radial distance, m
r_e = drainage radius, m
$(r_p)_{begin}$ = radial distance where deposition starts, m
$(r_p)_{end}$ = radial distance where deposition ends, m
r_t = treatment distance, m
r_w = wellbore radius, m
s = sulfur content, g/scm
S = surface roughness index, $(S=\lambda/2\varepsilon)$
t = time, hours
T = temperature, °F
v = specific volume, m^3/kg
W_f = flow path width $(W_f = 2\pi r)$, m
Δ = difference operator (initial - current conditions)
ε = fracture aperture, m
λ = mean asperity height, m
ϕ = formation porosity, fraction
ρ = gas density, kg/m^3
ρ_0 = proportionality constant between density and pressure, s^2/m^2
μ = absolute gas viscosity, kg/m/s
ν = average local velocity, m/s
ν_c = critical (transport) velocity, m/s

Subscripts
i = initial conditions

SI Metric Conversion Factors

ft × 3.048 E–01 = m
ft^3 × 2.8317 E–02 = m^3
psi × 6.8948 E+00 = kPa
lb × 0.4536 E+00 = kg
md × 9.8692 E–04 = μm^2
Btu × 1.0551 E+03 = J
(°F-32) / 1.8 = °C

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13. Hyne, J.B.: "Controlling Sulfur Deposition in Sour Gas Wells", paper *World Oil* (Aug. 1983) 35.
14. Wei, L., *et al*.: "Discriminating Fracture Patterns in Fractured Reservoirs by Pressure Transient Tests", paper SPE 49233 presented at the 1998 SPE Annual Technical Conference held in New Orleans, Louisiana, U.S.A., Sept. 27-30.
15. Earlougher, R.C.: "Advances in Well Test Analysis", SPE Monograph Vol. 5 of the Henry L. Doherty Series, 1977.

TABLE 1 – SULFUR SOLUBILITY IN SOUR GAS : AVAILABLE DATA AND REFERENCES

Authors	Temperature (°F)/(°C)	Pressure (psi)/(MPa)	Fluid Composition	Reference
Kennedy & Wieland	150, 200, 250 (65.6, 93.3, 121)	1000 - 6000 (7-41.4)	Pure CH_4, CO_2 and H_2S; binary mixtures to 73% H_2S, tertiary mixtures to 57% H_2S (min. H_2S = 25%)	Kennedy HT and Weiland DR "Equilibrim in the Methane-Carbon Dioxide-Hydrogen Sulfide-Sulfur System". Pet. Trans. AIME, 219, 166-169 (1960)
Smith et al	114 - 248 (45.6-120)	Saturation pressure	Pure liquid H_2S	Smith JJ, Jensen D and Meyer B. "Liquid Hydrogen Sulfide in Contact with Sulfur" J. Chem. Eng. Data, 15, 144 - 146 (1970)
Roof	110 - 230 (43.3-110)	1000 - 4500 (7-31)	Pure H_2S	Roof JG "Solubility of Sulfur in Hydrogen Sulfide and Carbon Disulfide at Elevated Temperature and Pressure" SPE J., 11, 272 - 276 (1971)
Swift et al	250 - 400 (121-204)	5000 - 20000 (34.5-138)	Pure H_2S	Swift SC, Manning FC and Thompson RE "Sulfur Bearing Capacity of Hydrogen Sulfide Gas" SPE J., 16, 57 - 64 (1976)
Brunner & Woll	212 - 320 (100-160)	1450 - 8700 (10-60)	Pure H_2S Mixtures with H_2S, CO_2, CH_4, N_2 with H_2S conc. of 1, 6, 7, 20 mol %	Brunner E and Woll W "Solubility of Sulfur in Hydrogen Sulfide and Sour Gas" SPE J., 10, 377 - 384 (1980)
Alberta Sulphur Research Ltd.	140 - 300 (60-150)	1000 - 8000 (7-55)	Sour gas mixtures containing 40, 60, 80, 90% H_2S	Davis PM, Lau CSC and Hyne JB "Data on the Solubility of Sulfur in Sour Gases" ASRL QQ Vol. XXIX, Nos. 2, 3 & 4 (1992-93)
Alberta Sulphur Research Ltd.	Computerized data base for Sulfur Solubility in Sour Gas 140 - 300 (60-150)	1000 - 8000 (7-55)	Sour gas mixtures containing H_2S, CO_2 and CH_4 with H_2S conc. of 1 - 100 mol %	Released for distribution by ASRL February 1988
Brunner et al	257 - 414 (125-212)	870 - 22480 (6-155)	Seven sour gas mixtures containing H_2S, CO_2, CH_4, N_2 and C_2 - C_6 alkanes with H2S conc. of 9, 35, 42, 84 mol %	Brunner E, Place MC and Woll W "Sulfur Solubility in Sour Gas" J. Pet. Tech., Dec, 1587 - 1592 (1988) (SPE 14264)
Tomcej et al	Equation of State Model			Tomcej RA, Kalra H (DB Robinson & Assoc) and Hunter BE (Canterra Energy) "Prediction of Sulfur Solubility in Sour Gas Mixtures" 39th Ann. Tech. Mtg. of Pet. Soc. of CIM Calgary, Alberta, June 12 - 16 (1988)
Guo et al	194 and 230 (90 and 110)	1600-7250 (11-50)	Pure H_2S, CO_2, CH_4 Mixtures w/ 44 and 95% H_2S Originally presented at the 6th Int.Conf. On FPECPD, Cortina, Italy, Jly.19-24, 1992	Min-Xin Gu, Qun Li, Shan-Yan Zhou, Wei-Dong Chen and Tian-Min Guo "Experimental and Modeling Studies on the Phase Behavior of High H_2S-Content Natural Gas Mixtures" Fluid Phase Equilibria, 82, 173-182 (1993)
Migdisov, A.A. et al	122-554 (50-290)	up to 2900 (20)	Pure H_2S	Migdisov, A.A., Suleimenov, O.M. and Alekhin, Yu,V. "Experimental Study of Polysulfane Stability in Hydrogen Sulfide" Geochimica et Cosmochimica Acta., V.62, No. 15 pp. 2627-2635 (1998)
Heidemann et al	Equation of State Model		Originally presented at The 47th Canadian Chemical Engineering Conference, Edmonton, AB Oct.5-8, 1997. (Symposium in Honor of the 20th Anniversary of the P-R EOS)	Karan, K, Heidemann, R.A., and Behie, L.A. "Sulfur Solubility in Sour Gas: Predictions with an Equation of State Model", Ind. Eng. Chem. Res. 37, 1679-1684 (1998)
Heidemann et al	Equation of State Model			Heidemann, R.A., Phoenix, A.V., Karan, K., and Behie, L.A. (The University of Calgary) "A Chemical Equilibrium Equation of State Model for Elemental Sulfur and Sulfur-Containing Fluids". Ind. Eng. Chem. Res. 40, 2160-2167 (2001)

TABLE 2 – KEY MODELING INPUTS

Gas Properties	PVT Data (PVT file) H_2S Concentration (%) Sulfur Content, s (g/scm)
Reservoir Parameters	Number of Fractures, N Fracture Aperture, ε (microns) Mean Asperity Height, λ (% of ε) Mean Contact Area, A_c (%) Pressure, P (MPa) Temperature, T (^{o}C) Drainage Radius, r_e (m) Wellbore Radius, r_w (m) Critical Velocity, v_c (m/s)
Production Data	Gas Flow Rate, Q ($10^3 m^3$/d)
Treatment Parameters	Distance, r_t (m) Efficiency, e (%)
Note: Inputs via statistical distributions are possible for N, ε, λ, and A_c	

TABLE 3 – KEY MODELING RESULTS FOR SHELL CANADA CASE STUDY WELLS

Shell Canada Sulfur Modeling Results			Key Parameters					Predictions				Field Data	
Field	Degree of Fracturing	Scenario	Q ($10^3 m^3/d$)	P (Mpa)	N	ε (microns)	r_t (m)	First Treatment Required (days)	No. of Treatments Required	Producing Life (yrs)	Ultimate Recovery ($10^6 m^3$)	Producing Life (yrs)	Actual Recovery (Dec 01) ($10^6 m^3$)
A	Few Big Fractures	High Rate	600	36	3	300	5 [2]	70	6	1	210		
		Medium Rate	300	36	3	300	5 [2]	115	18	3	320	3 [4,5]	385 [10,11]
		Low Rate	150	36	3	300	5 [2]	230	120	8	420		
		40% Depletion	300	20	3	300	5 [2]	600	6	7	740		
		Enhanced Treatments	300	36	3	300	10 [3]	115	12	8	840		
		50% Saturation	300	36	3	300	5 [2]	1440	12	8	930		
	Medium Fracturing	Low Rate	100	36	30	60	0.5 [2]	130	18	2	90		
	Many Small Fractures	Low Rate	100	36	120	30	0.25 [2]	110	20	2	60		
	No Fractures [1]	Vertical Well	65	33	N/A	N/A	6 [3]	315	5	4	100	2 [6]	210 [12]
		Horizontal Well	100	33	N/A	N/A	0.15 [2]	135	9	2	90		
B	Medium Fracturing	Saturated	275	36->25	30	60	0.5 [2]	100	11	2	230	4 [7,8]	385 [12]
		50% Saturation	275	36->25	30	60	0.5 [2]	1005	6	7	710		
	No Fractures [1]	50% Saturation	275	36->25	N/A	N/A	0.15 [2]	1250	5	8	790	7 [7,8]	310 [12]
C	Medium Fracturing	Saturated	200	40->20	35	60	0.5 [2]	210	30	8	580	6 [7,8]	420 [12]
		50% Saturation	200	40->20	35	60	0.5 [2]	1625	15	19	1370		
D	Few Big Fractures	Basic Treatments	170	32->16	2	250	2 [2]	200	60	10	610	11 [9]	680 [12]
	No Fractures [1]	Vertical Well	170	32->16	N/A	N/A	6 [3]	270	55	20	1300	18 [9]	1075 [12]

[Notes]
1. These results have been generated by the new matrix model, which is mentioned but not discussed in this paper.
2. Sulfur solvent or acid wash/soak.
3. Acid fracture treatment.
4. Following a series of successful downhole sulfur treatments, this well eventually became irreversibly plugged with elemental sulfur.
5. This well has subsequently been sidetracked to within 50m of the first wellbore and is currently on production without evidence of reservoir impairment.
6. This well was shut-in for operational reasons after the 2nd acid fracture treatment.
7. These wells are still in production and have not yet displayed symptoms of long-term damage resulting from sulfur plugging in the reservoir.
8. Although not supported by the sulfur content determinations, a degree of under-saturation is the most likely explanation for the lack of sulfur plugging observed in these wells.
9. These wells are still in production, although signs of possible long-term damage resulting from sulfur plugging in the reservoir have been observed more recently in the field.
10. Since this well became irreversibly plugged with elemental sulfur, this figure represents the final recovery from this well.
11. As a result of reservoir depletion through production, it is anticipated that the incremental recovery from the sidetrack will be 1-2 times that from the original well.
12. Since these wells are still in production, the eventual recovery from these wells will be higher than the current figures.

TABLE 4 – IMPACT OF PRODUCTION RATE ON DOWNHOLE TREATMENT REQUIREMENTS

Production Rate ($10^3 m^3/d$)	Cycle	Treatment Required After (days)	Cumulative Production Time (days)	Cumulative Production ($10^6 m^3$)
300	1	113	113	34
	2	107	220	66
	3	103	323	97
	4	82	405	122
	:	:	:	:
	9	38	669	201
	:	:	:	:
	20	36	1050 [1]	315 [2]
775	1	31	31	24
	2	28	59	46
	3	25	84	65
	:	:	:	:
	7	12	210 [1]	155 [2]

Key Reservoir Parameters

P=36Mpa, T=90°C, N=3, e=300microns, I=20%, A_c=20%, H_2S=15%

[Notes]

1. Reservoir irreversibly plugged with elemental sulfur.
2. Predicted recovery from this well with the specified rate.

Fig. 1 – Simplified reservoir - wellbore system.

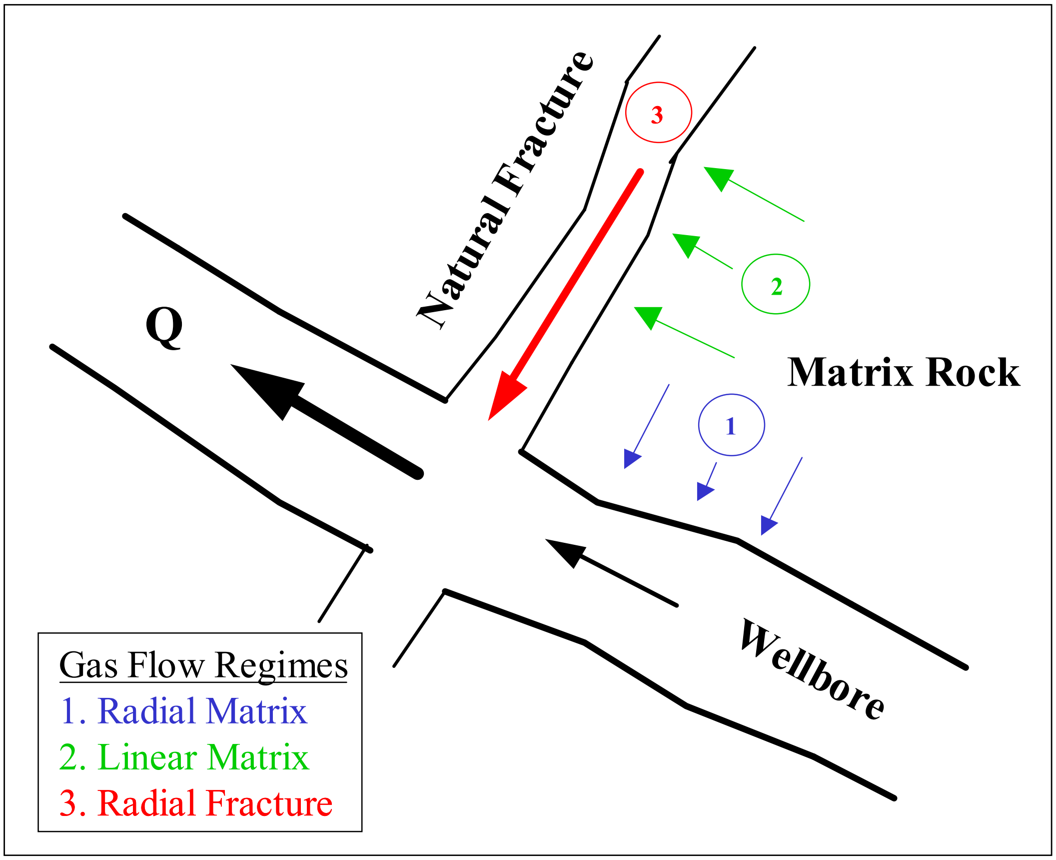


Fig. 2 – Factors affecting sulfur solubility in lean sour gas.

$$[S_8]_{SOL} = f\ (P)\ (T)\ [H_2S] \quad \begin{matrix}[CO_2]\\ [CH_4]\\ [C_2+]\\ (H_2O/Cl^-)\end{matrix}$$

PRIMARY SECONDARY

Fig. 3 - Comparison of sulfur solubility data.

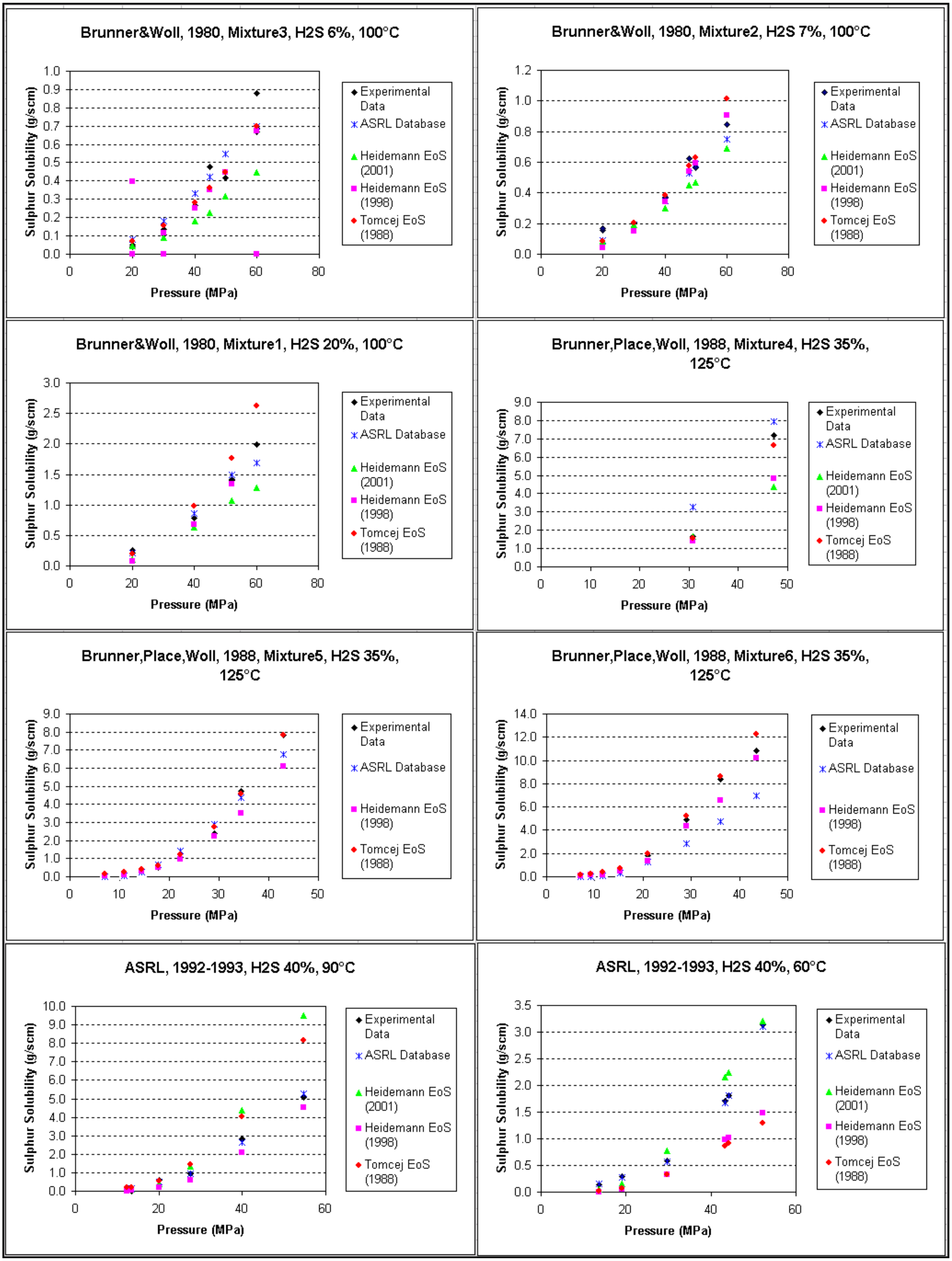
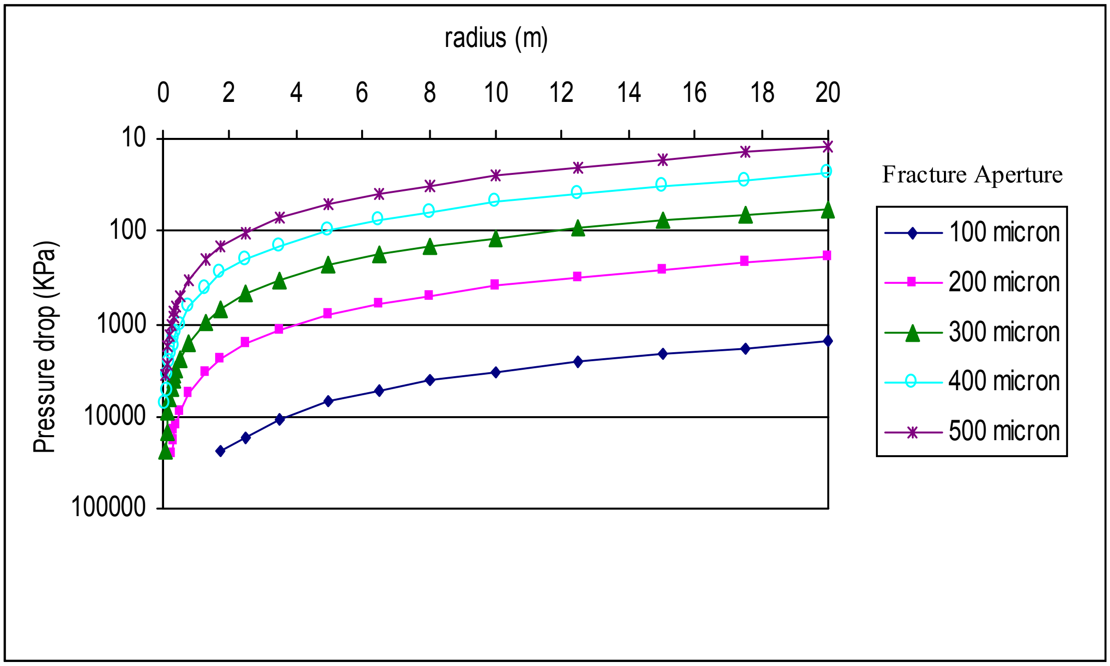


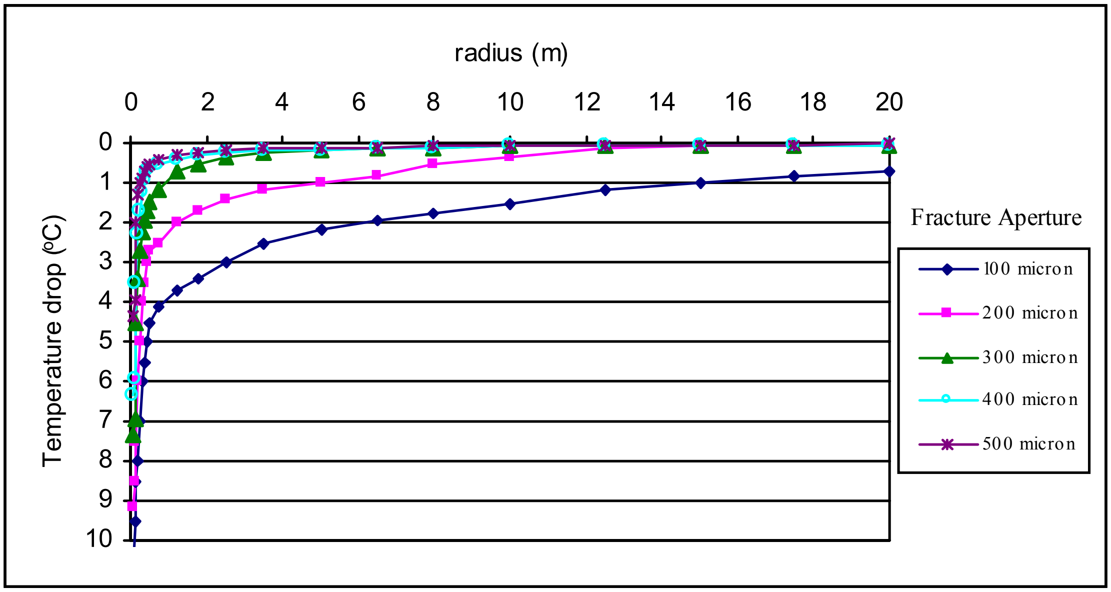
Fig. 4 – Example of the predicted pressure profile along a natural fracture.



Key Reservoir Parameters: P=36Mpa, T=90ºC, λ=0.2, A_c=0.2, N=1,

Production Parameters: 500 $10^3 m^3$/d for 4 weeks, H_2S =15%

Fig. 5 – Example of the predicted temperature profile along a natural fracture.



Key Reservoir Parameters: P=36Mpa, T=90ºC, λ=0.2, A_c=0.2, N=1,

Production Parameters: 500 $10^3 m^3$/d for 4 weeks, H_2S =15%

Fig. 6 – Example of the predicted local velocity profile along a natural fracture.

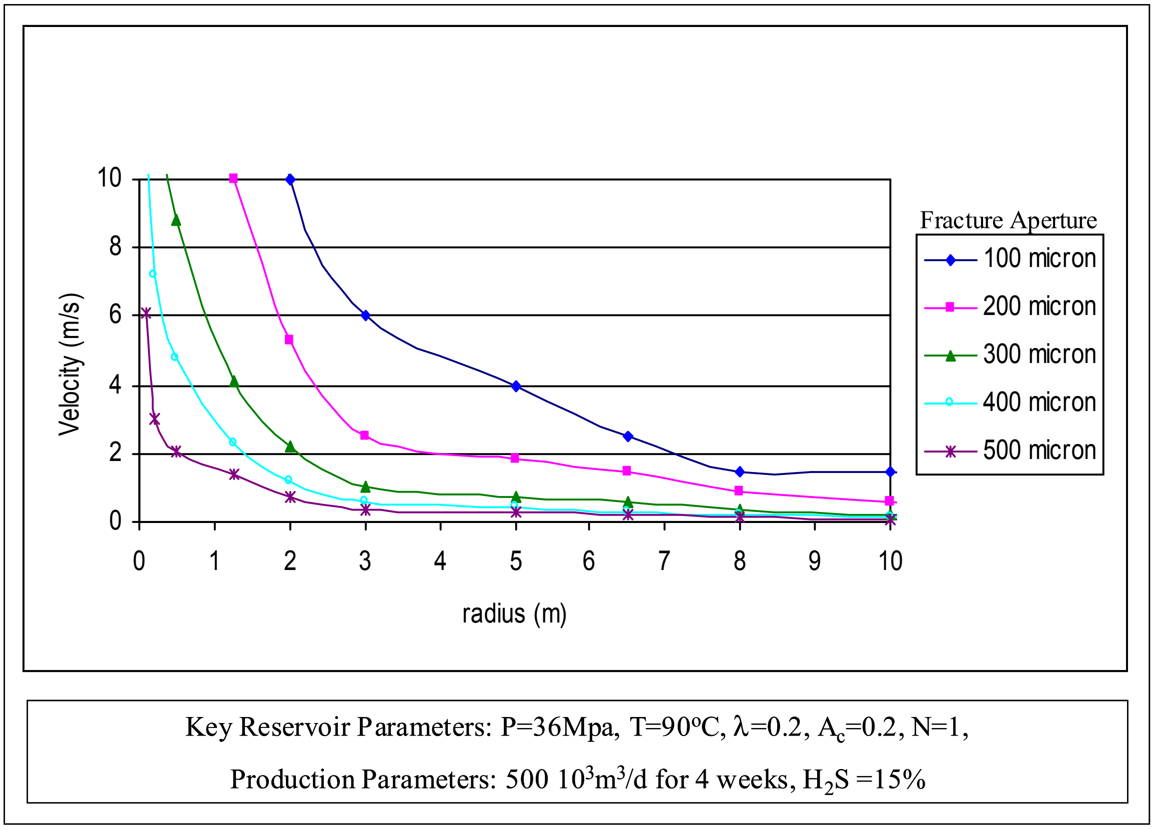


Fig. 7 – Schematic of a dynamic sulfur deposition profile along a natural fracture.

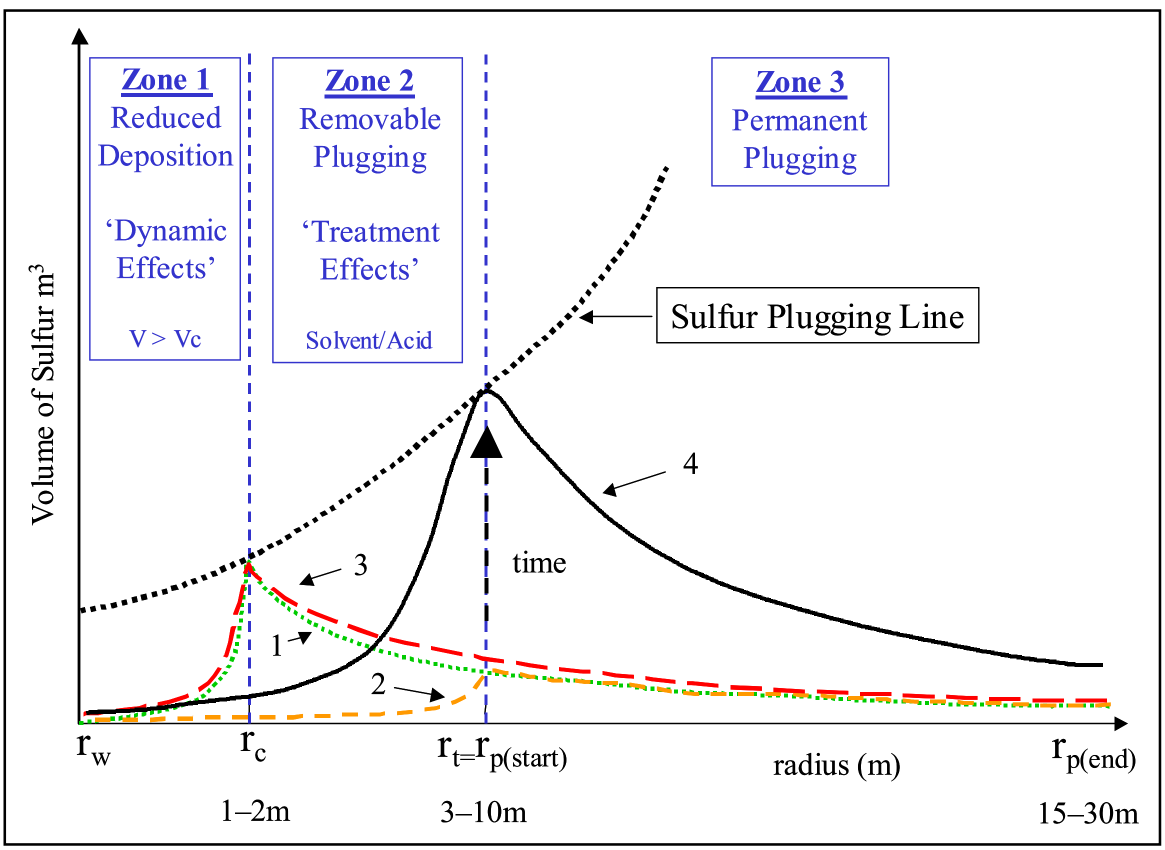


Fig. 8 - Reservoir sulfur plugging overview.

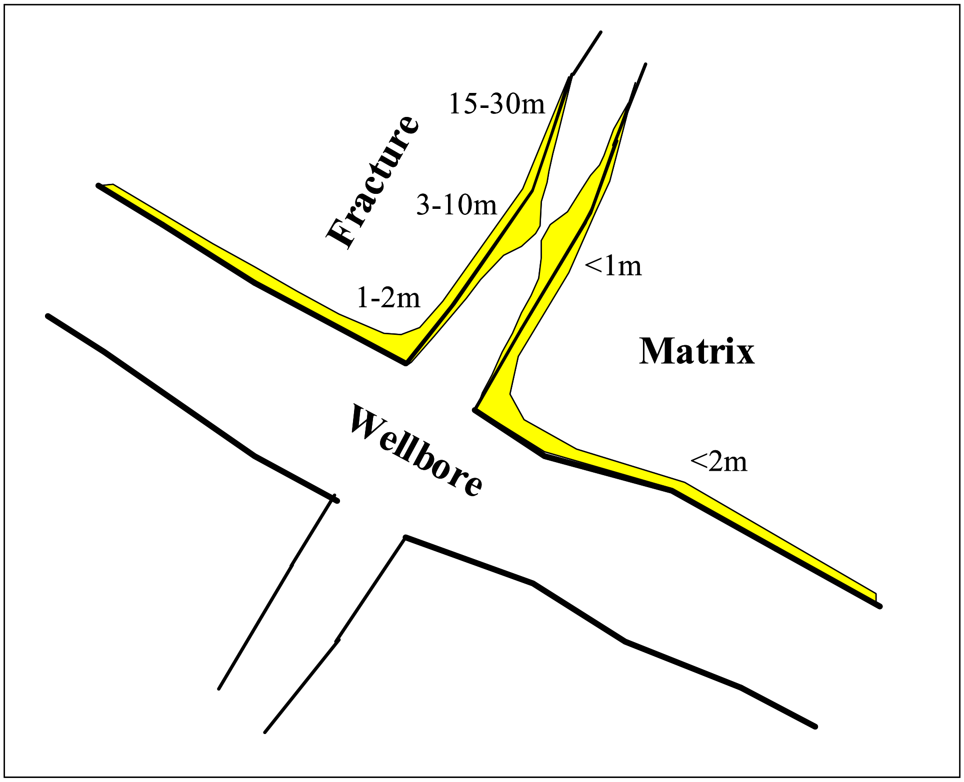
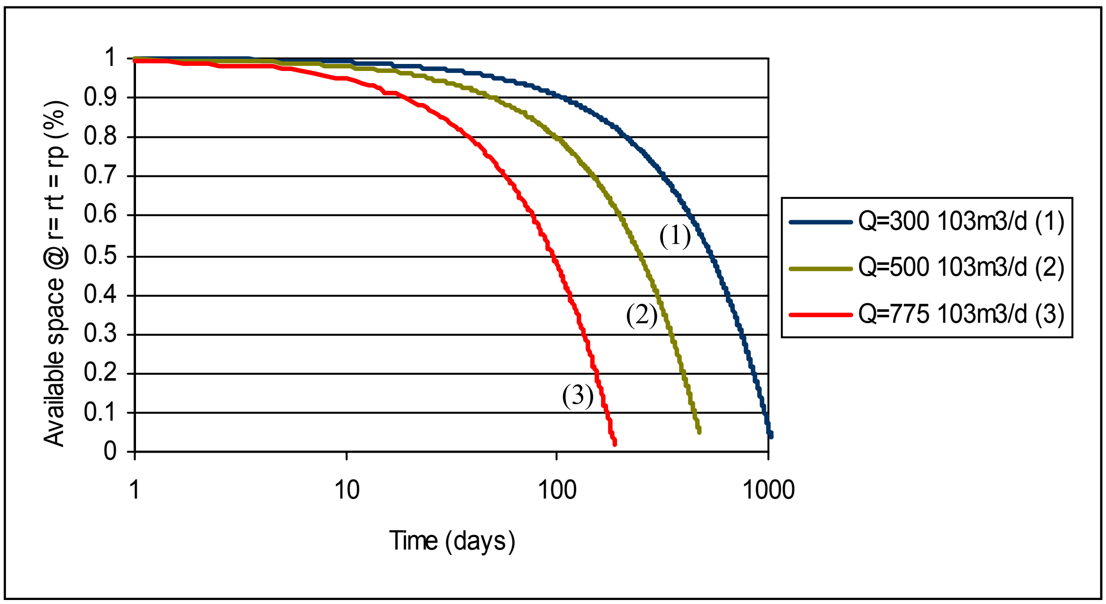


Fig. 9 - Impact of production rate and reservoir pressure on well life, ultimate recovery and downhole treatment requirements.



Rate ($10^3 m^3/d$)	Pres (MPa)	Recovery ($10^6 m^3$)	Number of treatments
300	**36**	**315**	**20**
500	**36**	**240**	**13**
500	20	505	10
775	**36**	**155**	**7**

Key Reservoir Parameters: T=90°C, λ=0.2, A_c=0.2, N=1, H_2S =15%

Fig. 10 - Pressure build-up analysis match using the sulfur deposition zones predicted by the new fracture model.