Abstract

With rapid depletion of conventional petroleum supplies and due to energy security concerns, the world is increasingly turning its attention to unconventional hydrocarbon reservers such as oil shales, gas shales, tight gas sands, coalbed methane, and gas hydrates. Despite the abundant unconventional reservers, the production is still hindered by many obstacles including lack of technology and knowledge of the physics of flow in tight porous media. Flowing the tightly-locked hydrocarbon to the well in such formations, unlike the conventional, requires a large number of inter-connecting pathways for flow. The existing in-situ cracks in rock have to be connected in order for the hydrocarbon to flow into the wellbore. In this paper we go over the basic mechanisms of rock fracture in micro and Macro levels and then study the two parameters whose variations could reduce the effective stress and lead to rock fracturing. We then discuss the effect of inhomogeneity on the fracture load and show that the dominant load for thermal fracturing is the tensile stress. There are three governing equations of stress, heat transfer, and flow which should be solved in a coupled fashion, for which we are using the finite element software packages. Assuming that thermal cracks increase the permeability of rock in the near wellbore zone by 10-10,000 times, we show the impact of rock stimulation by thermal shock on cumulative production of gas from a sample case of a wellbore placed in a tight formation. The improved recovery for the sample case is 16%.

Introduction

Injection of cold fluids into reservoir rock, induces thermal cracks. This has been observed in the injection of cold CO2 into reservoir rock for sequestration purposes and from extensive studies of thermal loading on rock properties (Kim and Kemeny, 2009; Izadi and Elsworth, 2013; Keaney et al., 2004). Successful production of oil and gas from shales with nano-Darcy range permeability calls for understanding of the complex behavior of the rocks. To better design the production, we utilize the finite elements analysis (FEA) of the coupled physics (thermal, flow and stress deformation) behind these behaviors.

Fracture mechanics started with the works of Inglis (Inglis, 1913) and Griffith (Griffith, 1921). They showed the effect of size of a component in the strength of that component. Inglis studied the stresses around a crack and found out that the stress at the crack tip of an elliptical crack is a function of the curvature of the crack tip and the size of the crack. We introduce a method for manipulation of rock strength that makes the rock more susceptible to a ramified pattern of fracture. There are two distinct analysis classes for quantifying the well productivity enhancement: the Finite Elements and Discrete Elements methods, (FEM and DEM). Our simulation tool in this paper is the FEM.

Currently, the popular industry approach to production from tight formations, is massive hydraulic fracturing, to create extensive surface area exposed to flow. Our numerical investigations in this paper indicate that, hydraulic fracturing can be improved by taking advantage of the combined effect of the fracturing fluid temperature and reduced effective stress on flow properties to create a larger surface area and a more ramified pattern of conductive flow pathways.

Unlike pore pressure diffusion, heat diffuses easily in shales. Moreover, rocks in general are very weak in tension, and as a result, thermal reduction of the near wellbore region can lead to significant tensile stresses in the rock, leading to drastic permeability enhancements. Simulation results for production from horizontal gas wells stimulated by thermal shocks for three hours in a zone of two feet radius around the wellbore exhibit a 16% enhancement in recovery. Thermal stimulation of rock in the near wellbore zone could also facilitate the hydraulic fracturing process where the earth stresses are isotropic.

This paper looks into the geomechanical challenges of producing tight formations and highlights a few rock properties which have the most significant role in the success of matrix stimulation of tight formations. During production of hydrocarbon, both components of
a reservoir rock: fluid and rock matrix, undergo pressure and deformation through their compressibilities. This paper highlights the methods of improving the injectivity/productivity of wells placed in tight formations, through inducing thermal shocks in reservoir rock. The efficiency of the thermal shock relies on the large stiffness and the complex structure of shale. The large stiffness and the complexity of shale matrix is not an obstacle to producing tight formations. In fact, the method of thermal shock that we propose in this paper, heavily relies on the large stiffness of reservoir rock. We have shown that the stiffer the rock, the easier the thermal fracture initiation (Enayatpour and Patzek, 2013). There are shale reservoirs with extremely stiff matrix around the world, for example in China (Lau and Yu, 2013), for which thermal shock and creation of thermal strains required for fracturing could work efficiently; hence, thermal shock is the potential candidate to stimulate matrix and enhance recovery in such tight and stiff shale formations. What makes the matrix stimulation process successful, is the grain disintegration process which in turn depends on the complex structure of shale. The numerical simulations in this paper are carried out using Finite Element method. Here we solve the coupled system of equations for flow, stress, and temperature diffusion in rock to study how fast and how far the reservoir heat diffuses. Once we obtain the zone of thermally frozen rock around the wellbore, we can determine the permeability enhancement in this zone which leads to improved recovery. In this paper, we have not investigated the permeability enhancement aspect of the study; rather, we have assumed that, when thermal cracks are created around the wellbore and connected to natural fractures, permeability could increase 10 to 10,000 times with respect to initial permeability of formation. Studying this assumption is the subject of our future research works.

**Rock Fracture**

To improve the wellbore injectivity/productivity, we utilize the physical matrix stimulation as opposed to matrix acidizing; therefore, we have to deal with stresses between rock grains and study the parameters which impact intergranular effective stresses in rock. We then look into the mechanism and effect of rock fracturing due to freezing the reservoir rock in the near wellbore zone. To disintegrate the rock constituents in an effort to increase permeability by opening pathways for flow, we should increase the fluid pressure so as to reduce the effective stress or the grains contact pressure. This is not quite feasible in tight formations; however, we could resort to a novel method of reducing the effective stress through inducing thermal strains by freezing the reservoir rock. In this method, the cold fracturing fluid or a freezing agent in the fluid, reduces the reservoir temperature in the near wellbore zone for certain period of time, for instance 30 minutes to 3 hours depending on rock properties. The contraction of the laterally-confined reservoir rock, results in thermal strains and tensile stresses. These tensile stresses, reduce the effective stress from the minimum horizontal stress to $\tau_0$: the rock tensile strength, as shown in Figure 3. Once the minimum horizontal stress in rock reaches the tensile strength of rock, the rock starts to rupture.

Let's start with a brief introduction to mechanism of rock fracturing in tight formations. The total overburden pressure on rock is taken by matrix and fluid in the pores of the rock. The former is called the effective stress of rock and the latter is called fluid pressure or pore pressure. The effective stress is the contact pressure between grains, in other words, it is the component which is holding the rock grains together. To initiate the rupture in rock, the effective stress has to decline and go from compressive to tensile stress. Once the grains are under tensile stress, they start to get separated.

The fracture in rock is a function of the loading and the rock strength. The rock strength is a function of the compressive load; therefore, any reduction in the effective stress leads to lowering the rock strength and making the rock more prone to rupture. The rock grains are bonded by cementing agents, as a result, cracks in rock could initiate from each single grain (inter-granular rupture) or from the interface of each two grains (interface rupture). Depending on the strength of rock grains and bonds, either of the rupture zones could dominate the fracture of rock. In macro-scale studies, there are two modes for rupturing the rock: shear and tensile. These are shown in Figure 1. It should be noted that, in reality, due to inhomogeneity in rock properties, any loading would result in both modes of failure. Figure 2 exhibits a simple model of a homogenous rock (A), and an inhomogenous rock (B) which are both fixed at ends and then frozen. Due to thermal stresses, both samples tend to exhibit contraction, consequently, due to the presence of fixed boundaries which simulate the rock lateral confinement, thermal strains are developed. Notice that in (B), both shear and tensile stresses are developed; however, the dominant mode is shear. At the moment, we base our studies on tensile failure mode for rock matrix stimulation and take only this component into consideration. Bear in mind that, rock stimulation could potentially benefit even more from shear failure as well, which is not investigated in this paper. In micro-scale; however, the tensile mode is the dominant mode; therefore, we focus on this type of failure. This failure mode occurs when the minimum horizontal stress exceeds the thermal strength of rock as shown in Figure 5. Figure 3 also shows the failure envelope for a tensile fracture in rock (Schultz, 2000).

**Shale properties and structure.** Shale is composed of clay, silt and water. The complex structure of clay (Figure 4) is due to the presence of plates of silica and aluminum. Our objective of illustrating the structure of shale is to emphasize the inability of effective stress reduction as a result of pore pressure increase in tight formations. The excessive capillary pressure due to small pore throat size, makes the rate of pore pressure diffusion extremely small; therefore, fracturing by fluid pressure will not be successful. Although the hydraulic fracturing in homogenous rock creates a bi-wing fracture, in reality rock is not homogenous; hence, the fractures open along weak planes forming a main bi-wing with multiple extensions along weak planes. In reservoir rocks with not as many weak planes, thermal shocks can create such weak planes through freezing the rock leading to rock contraction in a confined medium. This opens up more voids which could then be pressured by fracturing fluid resulting in propagation of fractures. The pattern of fractures and the effect of such thermal fractures in increasing the permeability of rock is not the subject of this paper; rather, how fast and how far the temperature could diffuse in rock, are the focus of this paper. This preliminary numerical investigation has the potential to pave the road for field scale operations of thermal shock in oil and gas shales in near future.
Figure 4 shows the geometry of a horizontal well bore and the complex structure of shale.

Method of Thermal Fracturing

Phase I: Effectiveness of freezing the rock. One way to induce volumetric rock stimulation in rock, is through pore pressure increase. Increasing pore pressure is an efficient way to break the matrix bonds by introducing tensile stress in matrix and reducing the effective stress. This method works the best for permeable rocks such as sand stone, however for impermeable rocks such as shale, the elevated pore pressure can not be readily diffused into the rock pores; therefore, it is not easy to break the impermeable rock by pore pressure increase. What is done in hydraulic fracturing is applying pressure as an external tensile load, not an internal compressive pore pressure leading to tensile stress in matrix. The inability to induce tensile stress by pore pressure increase in tight formations, leads us to other possibilities such as freezing the rock. The thermal process of freezing the body of rock where it is confined by surrounding rock, makes the rock undergo tension as it shrinks. This macro-scale process of rock shrinkage, leads to volumetric rock stimulation and permeability enhancement in rock. The extent of tensile stress away from wellbore is a function of the following parameters;

- The temperature reduction in wellbore
- Mechanical properties of rock: E and ν
- Thermal properties of rock and fluid such as specific heat C, thermal expansion α, and thermal conductivity K
- Permeability of rock k
- Presence of natural fractures and their types including joints, veins, and dikes

Natural fractures are normally filled with minerals. Joints are empty fractures with no mineralization. Veins, however, are open fractures with partial mineralization such as calcite or hematite and dikes are filled with igneous rocks or magma. Whether or not the fractures are filled with minerals, affects both fluid flow and heat transfer in fractured rock.

The rocks might be thought of as solids containing voids which hinder the heat transfer, but the thermal conductivity of shales in our numerical simulations of the coupled heat transfer and effective stress reduction show the opposite. Notice that the permeability used here is expressed in terms of velocity units. We have used the permeability so we could utilize the finite element code ABAQUS for this simulation. This software uses hydraulic conductivity instead of permeability. The permeability from the above hydraulic conductivity can be obtained assuming viscosity \( \mu = 1 \, cp \) and density \( \rho = 1000 \frac{kg}{m^3} \) for water as \( k=1 \, nD. \)

Figure 5 shows the geometry of the model used to demonstrate the effectiveness of thermal fracturing in rocks. The parameters used for this simulation are shown in Table 2. In this model a core size rock sample is simulated under reservoir conditions of 1000 psi pressure and 373.15°K temperature. The core is confined circumferentially around the outer diameter only on top and bottom to both allow for simulation and let the central hollow space which is acting as wellbore, deform radially. In the first step of simulation, the initial conditions are activated and in the second step, the constant temperature of 273.15°K is applied to the mid-section of the interior cylinder. This generates the heat flux from the core toward the low temperature mid-section of the central core. Since the rock is confined externally similar to rock confinement in reservoir, it will not be able to deform freely under this heat transfer process; hence, thermal stresses are developed in rock leading to tensile cracks.

The robustness of this technic can be seen in Figure 6(b) in which the stress distribution in rock after 2000 seconds is shown. The compressive stresses in software are represented with negative sign and tensile stresses are positive. It can be seen that a large zone around the wellbore has fallen into tensile stress mode which is more susceptible to tensile cracks. One more thing that should be noted is that, in order for elements of rock to fall into tensile mode they don’t have to be frozen all the way from 373.15 to 273.15°K. In fact there are tensile zones in which the temperature has dropped only 25°K from initial hot reservoir condition.

Figure 7 shows the deformation(a) due to heat flux(b) in a chunk of core. The deformation plot shows the shrinkage of sample toward the freezing zone and exhibits the highest potential for tensile cracks and permeability enhancement around this zone. Next, we will look at the simulation results in reservoir scale to get an insight on temporal and space distribution of temperature and stresses in reservoir condition. For this analysis, the shale formation of very low permeability of 1 nano Darcy is modeled.

In our numerical simulation we solve the coupled system of Equation (1) and (2) in the near well bore zone.

- Stress-Deformation:
  \[ \nabla \cdot \sigma = 0 \]  
  \[ \text{Equation (1)} \]

- Temperature Diffusion:
  \[ \rho C_p \frac{\partial T}{\partial t} + \rho C_{\text{pp}}. \nabla T = \nabla \cdot (k \nabla T) + Q \]  
  \[ \text{Equation (2)} \]
Phase II: Obtaining the freezing zone. The problem of the creation of tensile stress in rock by freezing the rock is a coupled thermal-hydromechanical problem. The solution of heat transfer in shale using finite element analysis shows that if the reservoir temperature of 100 degrees centigrade could be dropped to and maintained at 0 degrees for 3 hours, the temperature reduction zone could go up to 1 foot from the wellbore walls as shown in Figure 9a for the lowest possible thermal conductivity. For higher thermal conductivities, this zone could go up to 10 feet (Figure 9b). As the formation rock is radially confined, the reduction of temperature causes tension in rock which could develop thermal fractures. The results are promising as the transfer of heat could be carried out in impermeable rocks without much involvement of pore pressure. Figure 8 describes the 3D finite element model used to study the heat transfer to a horizontal well. The wellbore radius is 6 inches and the length of well is 1000 feet. In order to eliminate the effect of boundaries, the well is placed at the center of a 200 by 200 ft² square as shown in Figure 8b. The same parameters of Table 2 are used for this analysis.

Similar analysis was performed for 24 hours of heat transfer and not much change is seen beyond the 3-hour analysis. The results of temperature and stress distribution along the x axis from the wellbore wall, for 3 and 24 hours of analysis are shown in Figure 11. It should be noted that to attain the stress level to initiate fracture, the maximum displacement required is 0.012 in (Figure 10) which is readily available.

The temporal and space extents of heat transfer are studied through previous simulations. This technic would not be efficient enough if the extent of stimulation of rock be limited to a short distance around the wellbore. The question that arises here is that if the thermal cracks propagate to a certain distance away from the wellbore, could we inject the same chemicals that induced the temperature reduction and repeat the freezing process. If it is possible then we are able to create openings or more technically saying, the zones or pockets of susceptible and readily available to fracture propagation. This is a big achievement in the process of rock fracturing. Notice that, this technic has to be used prior to hydraulic fracturing to weaken the rock bonds and set up the pathways for fracturing fluid around the wellbore. Once the pathways are created, they can not be healed; therefore, even if the cracks get closed under in-situ stresses, the later stages of fluid injection could open up these cracks and place the proppants in the fractures.

Results

We studied the effect of thermal cracks induced by thermal shocks on the recovery of gas from a fractured horizontal well. The creation and extension of thermal cracks is studied and formulated in our previous work. (Enayatpour and Patzek, 2013)

Figure 12 shows the geometry of reservoir and finite elements discretization of the three domains used to simulate the gas flow. To add the flow component to the above coupled problems of stress-heat transfer, we first solved the stress-heat transfer problem and obtained the zone of thermal crack extensions around the wellbore. It should be noted that permeability changes are nonlinear in pressure, but we assume at this stage of analysis that permeability remains constant during analysis and increases only at the end of each analysis and start of new analysis. In other words, each flow analysis takes place in a domain of enhanced permeability. For flow problems in a wellbore with radial enhancement of permeability, Equation (3) should be solved.

\[ \nabla^2 p = \frac{\mu c \phi}{k} \frac{\partial p}{\partial t} \]

Equation (3) is the pore pressure diffusivity equation. The derivation of Equation (3) is shown in Appendix A.

Figure 13 shows the improvement in total production as a result of thermal stimulation around the wellbore. It can be observed that the creation of hydraulic fracture increases the productivity profusely and volumetric rock stimulation around the wellbore within 4 feet radius improves the recovery by an additional 16%. Figure 14 shows the impact of the permeability of the stimulated zone in recovery improvement.

Conclusions

- FEM is used successfully to estimate the cooling-down zone around the wellbore. Prediction of the induced fracture pattern is not considered in this paper and is the subject of future works.

- The results exhibit an improvement in total production as a result of thermal stimulation around the wellbore. It can be observed from Figure 13 that the creation of hydraulic fracture increases the productivity profusely; moreover, the volumetric rock stimulation around the wellbore within 4 feet radius improves the recovery by an additional 16%.

- The FEM is a robust method to predict the zone of temperature diffusion into reservoir rock, however, to obtain the pattern of fracture propagation in rock, the DEM is required.

- This method can be used effectively for both horizontal and vertical wells placed in tight formations.

Acknowledgment

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References


Appendix A

Gas diffusivity equation. The gas flow in porous media can be studied using Darcy’s law incorporated into the conservation of mass equation. A quick overview of the assumptions and the equations used in the following simulation of gas in a vertical well is given here.

We are assuming that the flow is under isothermal condition and the thermal freezing was employed to freeze the rock and make the mechanical changes in the rock properties. The fluid compressibility is assumed to remain constant. Since the process is isothermal, the density in the equation of state is a function of pressure only and can be calculated using Equation (4)

$$\rho(p) = \frac{M_w}{Z(p)RT}p$$ ......................................................... (4)

$Z$ is the gas compressibility factor and is equal to 1.0 for ideal gasses. For real gasses, $Z$ can be obtained from the generalized compressibility factor diagram (Sandler, 2006). Assuming the gas to be Methane, critical temperature and pressure are obtained from the Table of liquid-vapor critical temperature and pressure for selected substances (Yunus A. Cengel, 2002) as 109.9°K and 45.79 atm. For the range of temperature and pressure of the reservoir, the compressibility factor can be obtained from the plot and approximated as:

$$Z(p) = -3.427 \times 10^{-24}p^3 + 5.38 \times 10^{-16}p^2 - 1.448 \times 10^{-8}p + 1.0055$$ ......................................................... (5)

Pressure in Equation (5) is in Pa. Viscosity of the fluid is constant and rock is incompressible; therefore, the porosity does not change with pressure. Using the material balance equation for a single phase flow in porous media we get:

$$\frac{\partial (\rho\phi)}{\partial t} = -\nabla \cdot (\rho u)$$ ......................................................... (6)

in Equation (6) $u$ is the Darcy velocity or superficial velocity and equals:

$$u = \frac{q}{A} = \frac{k}{\mu} \nabla \Phi$$ ......................................................... (7)

$\Phi$ is the potential and equals $p+\rho gh$. Ignoring gravity, the potential is equal to the pressure $p$.

If Darcy’s transport law from Equation (7) is plugged into the material balance Equation (6) and gravity is neglected, we can arrive at the equation of pressure diffusivity in porous media:

$$\frac{\partial (\rho\phi)}{\partial t} = \nabla \cdot \left( \frac{k}{\mu} \nabla p \right)$$ ......................................................... (8)

expanding Equation (8) we get:

$$\phi \frac{\partial (\rho\phi)}{\partial t} + \rho \frac{\partial (\phi)}{\partial t} = \frac{k}{\mu} [\rho \nabla^2 p + \nabla p \cdot \nabla p]$$ ......................................................... (9)

in porous media the total compressibility $c_t$ is the sum of the compressibility of the fluid and the formation.

Total compressibility, $c_t = c_{\text{fluid}} + c_{\text{formation}}$ ......................................................... (10)

fluid compressibility may include all the three phases of oil, gas and water, hence;

$$c_{\text{fluid}} = c_oS_o + c_gS_g + c_wS_w$$ ......................................................... (11)

we assume gas flow in an incompressible rock; therefore, the total compressibility in our formulation is:

$$c_t = c_gS_g$$ ......................................................... (12)

Rock or pore space compressibility is defined as

$$c_{\text{formation}} = \frac{1}{(\phi V_b)} \frac{d(\phi V_b)}{dp} = \frac{1}{(V_p)} \frac{d(V_p)}{dp}$$ ......................................................... (13)

in Equation (13), $V_b$, is the bulk volume, $V_p$ is the volume of the pore spaces and $p$ is the pore pressure.

fluid compressibility is defined as

$$c_{\text{fluid}} = \frac{1}{\rho} \frac{dp}{dp}$$ ......................................................... (14)

since the density varies with pressure, let’s re-write the Equation (9) to bring the variation of density with pressure and the effect of compressibility into the diffusivity equation:

$$\phi \frac{\partial p}{\partial t} + \nabla \phi \left[ \frac{1}{(\phi V_b)} \frac{d(\phi V_b)}{dp} \right] \frac{\partial p}{\partial t} = \frac{k}{\mu} \left[ \rho \nabla^2 p + \left( \frac{dp}{dp} \right) \nabla p \right]$$ ......................................................... (15)
now, let’s use Equation (15) and replace the terms from Equations (13) and (14) and cancel out the density from both sides of the equation to bring the fluid and formation compressibilities to the left hand side of the equation.

$$\phi c_{\text{fluid}} \frac{\partial p}{\partial t} + \phi c_{\text{formation}} \frac{\partial p}{\partial t} = \frac{k}{\mu} \left[ \nabla^2 p + c_{\text{fluid}} \nabla p \cdot \nabla p \right] \quad \text{(16)}$$

The two terms in the left hand side of the Equation (16) can now be added and the total compressibility appears in the equation. Further simplification of Equation (16) results in:

$$\phi c_t \mu \frac{\partial p}{\partial t} = \nabla^2 p + c_{\text{fluid}} (\nabla p \cdot \nabla p) \quad \text{(17)}$$

For analytical solutions of diffusivity equation, the term on the right hand side which includes the product of two pressure gradient will be neglected; however, this assumption is valid only for the zones far away from the wellbore where the pressure gradient is small. Neglecting the product results in:

$$\nabla^2 p = \frac{\mu c_t \phi}{k} \frac{\partial p}{\partial t} \quad \text{(18)}$$

Equation (18) is the pore pressure diffusivity equation and the reciprocal of the coefficient on the right hand side is called the diffusivity coefficient, denoted by $\alpha$ and it’s a function of pressure.

$$\alpha(p) = \frac{k}{\mu c_t \phi} \quad \text{(19)}$$
Fig. 1—Modes of rupturing a rock

Fig. 2—The effect of rock inhomogeneity on thermal fracturing.

Fig. 3—The failure envelope for a tensile fracture in rock.
Fig. 4—Geometry of a horizontal well bore and the complex structure of shale

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Table 2—Input for numerical analysis
Fig. 5—Description of the model

Fig. 6—Temperature(a) in °K and stress distribution(b) in psi in the core after 2000 seconds.
Fig. 7—The vector plots of (a) the total deformation and (b) heat flux.
Fig. 8—Finite element model description for heat transfer analysis
The near well bore zone undergoes excessive tensile stresses, leading to tensile fractures, due to freezing.

(a) Temperature distribution around the wellbore after 3 hours
(b) Stress distribution around the wellbore after 3 hours

Fig. 9—Temperature and Stress distribution around the wellbore after 3 hours

Fig. 10—Displacement vectors of wellbore wall in X direction
Fig. 11—Variation of Temperature in X direction with radial distance from the center of the wellbore

In 3 hours, 2 feet and in 24 hours, 6 feet away from the well bore show drastic temperature reductions resulting in tensile fractures.
Fig. 12—Geometry of reservoir and finite elements discretization of the three domains used to simulate the gas flow.
Fig. 13—Improvement in total production as a result of thermal stimulation around the wellbore
Fig. 14—Improvement in total production as a result of thermal stimulation around the wellbore for various levels of permeability enhancement.