INVESTIGATING THE FACTORS INFLUENCING THE FLOW BEHAVIOR AND PERFORMANCE OF CONDENSATE GAS RESERVOIRS

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Abstract - Gas condensate reservoirs have become more and more important since late 30s because of explorations and deep drilling. Development and efficient production of these tanks require engineering and operational procedures, which makes these reservoirsdifferent from oil and gas reservoirs.By comparing dry gas and gas condensate reservoirs, very important parameters can be found that have an impact on the performance of gas condensate reservoirs.Precision of engineering calculations for gas-condensate systems (e.g. wells verification, estimation of recoverable gas, wellhead equipment, etc.) necessitates a deep understanding of the phase behavior of this system as well as the relationship between gas and condensates.When the pressure drops below the dew point pressure, reduction of the productivity of the well is crucial in the development of gas condensate fields.Reduction of the pressure to below the dew point makes condensate go out of gas phase and create a saturation of condensates near the well leading to reduced production and productivity of the reservoirs.Predicting the performance of gas condensate reservoirs requires modeling of two-phase relative permeability near the wellbore and this permeability itself is a function of the change in capillary number.Better mobility of fluid because of high capillary number is the most important phenomenon that can be seen in the zone around the wellhead in condensate gas reservoirs while, non-Darcy flow which mainly occurs due to high speeds in reservoirs tend to reduce fluid mobility.

Keywords - Condensate Gas Reservoirs, Fluid, Dew Point, Factor Productivity

I. INTRODUCTION

The Flow Behavior of Gas Condensate Reservoirs
According to the definition, condensate gas reservoirs are hydrocarbon reservoirs the temperature of which is higher than the critical temperature and lower than the two-phase maximum temperature of the system. The most common feature of these reservoirs is reverse condensation that occurs at constant-temperature paths inside the reservoir.[Rajeev, 2003] bubble curve represents a 100 percent liquid system and dew curve represents 100 percent gas system.The two-phase zone is enclosed between the two figures and its behavior varies with temperature and pressure.Figure 1 -2 shows that the reverse condensation phenomenon occurs when reservoir temperature is between the critical temperature and the maximum two-phase temperature. If the initial reservoir conditionsis shown as B1, the line B1-B shows a decrease in pressure of the reservoir at constant temperature during production.Because the initial pressure of reservoir is bigger than dew point pressure of the system, gas mixture is initially single-phase gas and when the pressure is reduced to the point B2,the liquid begins to form through passing the dew point inside the reservoir.Production of liquid continues until it reaches its maximum degree at point B3. After passing B3, the liquid has a tendency to change to gas phase and we have a 100 percent gas system until we disconnect the curve again. Because most of the heavy hydrocarbon components change to liquid through reverse condensation process and are integrated in reservoir, fluid composition of reservoir becomes progressively richer and molecular weight of the compound left in the reservoir increases. Therefore, two-phase shellof these reservoirs will be inclined to the lower right over time. In addition, critical point inclines to the right towards achieving the maximum temperature. Figure 1 depicts biphasic curve for a gas condensate reservoir. The left graph is the initial graph of two-phase gas system and the other graphs are for the days 0.87, 7, 60 and 180.

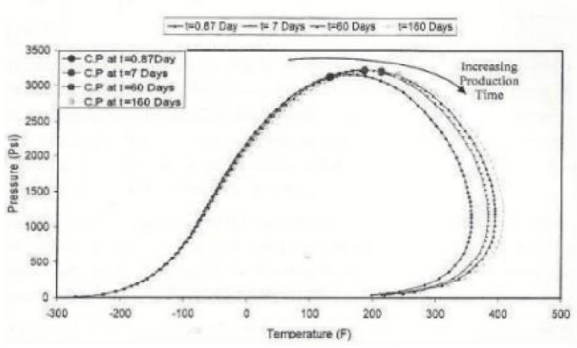

Figure 1: Biphasic Curve for a Gas Condensate Reservoir (Tabatabaei, 2006)

II. REVERSE CONDENSATION IN POROUS ENVIRONMENTS

Liquid forms in condensate gas reservoirs when the pressure of the reservoir decreases to below the dew point. Although the average reservoir pressure is usually higher than the dew point pressure, in most cases because of the pressure near the well mouth, condensate bank occurs mainly near the well. This liquid bank reduces gas production in these reservoirs. Condensate gas reservoirs with very low percentages (poor) of heavy hydrocarbon, too, have a

large bank of condensate near wellbores and many spaces in the holes are given to the liquid phase. The degree of production decrease is directly influenced by liquid and gas phase mobility[Boom et al., 1996]. In general, at the time of the discovery and initial extraction, most condensate gas reservoirs in the world have a pressure more than dew point pressure and are single phased.When production begins, the pressure near the wellbore drops and this wave of pressure drop flows in the reservoir and will reach the border. When bottom-hole flowing pressure falls below the dew point pressure, condensates start to form and accumulate near wellbores and create anzone of highly saturated liquid near wellbores which is called Condensate Bank [Jahanbakhsh, 2005].The liquid does not have mobility capability before it reaches its critical saturation.The accumulated fluid has no role in production because of its very low mobility compared to gas phase and is trapped near the mouth of the well, which reduces gas saturation, increases liquid-phase saturation and dramatically decreases effective gas permeability. Therefore, as mentioned above, the decline in production due to accumulation of fluid bank near wellbores in gas condensate reservoirs is considerable and extremely significant.In order to understand the mechanism of production in gas condensate reservoirs, fluid saturation profiles should be investigated properly.Different researchers have proposed a variety of different saturation profiles for condensate gas reservoirs the bottom-hole pressure of which has dropped under the dew point pressure. Researchers such as O'Dell and Miller [O'Dell et al., 1996] suggested a two-zone diagram for the profiles of fluid saturation near the wellbore.

They considered a single-phase liquid gas that flows into the mouth of the well and upon arrival to azone of lower pressure than the dew point pressure separates into liquid and gas phases. However, other researchers like Fevang and Whitson [Fevang et al., 1996] have introduced a third zone that changes due to the presence of non-removable condensate of fluid composition. Zone 1 is the closest to the mouth of the well where liquid and gas phases move at different speeds and are produced. Zone 2 contains immobile liquid phase andsingle-phase gas flows in the third zone.

In addition to these three zones, other researchers like Gringarten introduced another small zone near wellbores where fluid saturation decreases and relative permeability of gas increases due to high speed of the flow and the increase of capillary number [Gringarten et al., 2000]. This will be investigated in full details later in this section.

Figure 2 shows a schematic of fluid flow to the mouth of the well and its saturation in reservoir during production process. Three various flow zones can be observed in this figure.

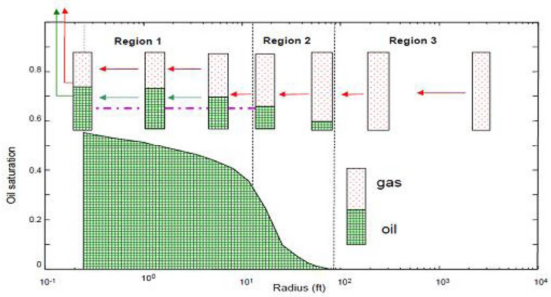

Figure 2: fluid flow to the mouth of the well and its saturation in reservoir during production process

Figure 3 shows the decrease of relative permeability of gas phase due to the formation of saturation of condensate near a well 800 days after the production with a pressure below the dew point pressure. As it can be seen, only with the formation of a little saturation of liquid, relative permeability of gas has fallen sharply. [Sheikhi et al., 2012]

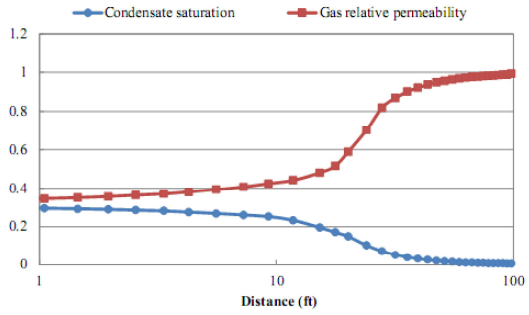

Figure 3: reduced gas-phase permeability due to the formation of liquid bank near the mouth of the well [Sheikhi, 2012]

Condensate saturation in zone 1 is more than the critical saturation 1 (S_{oc}) and therefore both liquid phase and gas are moving.GORin zone 1 is constant, which means the gas phase entering into zone 1 has the same composition as the gas produced in wellhead.In addition to this, the dew point of gas mixture produced in the well is equal to the pressure on the outer border of Zone 1 is [Rajeev, 2003].Zone 1 is the main source of reduction of gas condensate wells. Moreover, due to the formation of a saturation of liquids, gas relative permeability is significantly reduced. Gas relative permeability reduction mainly happens in this zone. The size of zone 1changes and becomes larger over time. In stable conditions, condensate saturation in zone 1 can be calculated through using the distance from the mouth of the well.Because the composition of the fluid in zone 1 is constant, CCE test can be used to determine the saturation of condensates. PVT properties of gas fluid mixture and Debbi of production determine how much liquid is formed in zone 1.

The second zone is an interstitial area. The formation of condensate starts in this zone. The zone is defined as an area of pure condensate accumulation. In this zone, condensate saturation isbelow their critical saturation and only gas is effectively mobile in this zone. It is because the mobility of condensates is zero or something close to it.Because of the lack of mobilityof liquid phase, condensate saturation in zone 2 can be calculated through discharge test at constant volume of CVD with the correction of water saturation.The second zone has the biggest area at the beginning and before the pressure drops below the dew point but its size decreases over time as zone 1grows. In poor condensate gas reservoirs, the size and importance of the second zone is vital.

The third area is the furthest area from the mouth of the well where the pressure is above the initial fluid dew point pressure of reservoir and there is single-phase flow of gas there.

III. PHENOMENA NEARWELLBORES IN GAS CONDENSATE RESERVOIRS

The area close to wellbore has the most important influence on the productivity of gas condensate reservoirs. The analysis has shown that the productivity of these wells heavily depends on condensate saturation distribution in the region close to the wall of the well.Productivity of gas condensate reservoirs is greatly affected by the balance between physical phenomena that occur due to pressure changes during the life of the reservoir.Two physical phenomena that reduce the productivity of the wells are the formation of a liquid bank and the effect of non-Darcy flow. On the other hand, the increase in capillary number leads to the increase in relative permeability and finally increases the productivity.Another parameter increasing the productivity of condensate gas reservoirs is water evaporation near wellbores that occurs in reservoirs with high temperatures. Overall, this is the balance between these parameters which determines the productivity of condensate gas reservoirs.

Fluid flow in gas condensate reservoirs moving towards production wells can be divided into two main parts: the flow near wellbore and the flow in reservoir's bulk.Condensate accumulation near wellbore can reduce gas production. The impact of this phenomenon is bigger in thereservoirs with low permeability and porosity (Tight) as pressure dropsmore sharply in such reservoirs[Ataei, 2004].Some researchers have observed that production has decreased to one fourth due to the creation of condensate bank near wellbores. The productivity of one well in Arun field in Indonesia is reported to decrease to half due to the formation of a bank of condensate after bottom-hole pressure dropped below dew point pressure [Afidick et al., 1994] .In this field, the maximum fluid getting out of fluid reservoir in laboratory tests was only 1%. However, its dramatic effect on the decline of production from well cannot be ignored. Another researcher called Smith reported that the productivity of two gas fields in Oman decreases to one third due to the phenomenon of condensate bank [Smith et al., 2001].

THE IMPACT OF FLUID VELOCITY AND SURFACE TENSION FORCES

The area near wellbores can be distinguished from other areas by high-pressure gradient and the increase in the speed of fluids. However, the speed of the bulk is much smaller than the speed in the area near the mouth of the well. In conditions when temperature and pressure is higher than initial fluid reservoir, the reservoir shows behavior close to the critical behavior and characteristics of the gas and liquid phases are very close together. This means surface tension is small between the two phases. In such circumstances, the relative permeability of phases does not merely depend on the saturation. Rather, other propertiesof fluids also have great impacts on the relative permeability of the two phases.

In most reservoirs with two-phase flows, capillary force controls distribution of fluids in holes. In condensate gas reservoirs close to critical conditions, capillary force is very small due to small surface tension between the two phases. In addition, viscous force is very strong because of high velocity of fluid production near wellbores. Therefore, viscous force controls the flow. Hence, macroscopic flow properties such as remaining saturation and relative permeability are a function of the ratio of viscous forces to capillary forces shown by capillary number. Nc stands for capillary number and is defined as the ratio of viscous to capillary forces:

$$N_c = \frac{(\text{flow rate}).(\text{viscosity})}{\text{IFT}}$$

Productionfrom a well is mainly a function of the relative permeability of gas and liquid phases, which, in turn, is a function of the interaction between capillary, inertial, and gravitational forces in cavity dimensions.In porous environments, at high speeds, the gas permeability is affected by two factors which make it a function of the fluid velocity. The first factor that increases the relative permeability of the gas at high speeds is Positive Coupling that has been observed in numerous laboratory tests.The second factor is the effect of inertia (non-Darcy flow), which reduces gas permeability at high speeds. This is also called Negative Effect of Inertia and is mainly observed in reservoirs with single-phase gas flow [Mott et al., 2000].

These two phenomena act oppositely. While positive coupling phenomenon increases the permeability of gas-phase, negative effect of inertia reduces permeability of gas phase at high speeds. In majority of condensate gas reservoirs, it has been seen that the

effect of positive coupling is bigger than negative effect of inertia, and the winner of the competition is coupling. At high speeds, ultimately, the increase in permeability of the gas phase is seen. Therefore, the overall effect of these two phenomena is the increase in the relative permeability of gas phase andproductivity of well.

The Effect of Positive Coupling

In 1949, through a study by Brownell and colleagues [Brownell et al., 1949] it was found out that relative permeability depends on the forces which trap phases, which can be called capillary number. In recent years it has also been verified for condensate gas reservoirs and its effect on relative permeability of these reservoirs has been proven [Pope et al., 1998]. It is largely accepted that when surface tension is small, relative permeability of gas phase and condensates is greatly affected by velocity of fluids, their saturation, and surface tension. The research carried out by Henderson has shown that the relative permeability increases if surface tension decreases. They also have shown an increase in fluid velocity within the core results in the increase of gas phase relative permeability.

Boom and his colleagues suggested that capillary number should be used instead of using surface tension as adaptive parameter in relative permeability curves [Boot et al., 1996].In their studies, they have observed that relative permeability of gas phase improves because of the high velocity near the wellbore and condensate bank decreases.There are many empirical equations to simulate the relative permeability resulting from the phenomenon of coupling near wellbores that are influenced by the capillary number.All these empirical relationships have two special features: firstly, relative permeability is obtained by interpolation between the relative permeability of the base (when the capillary force controls the flow) and relative permeability fusion (when viscous forces control the flow). Secondly, capillary number is used as an interpolation parameter. The model presented by Fevang [Fevang et al., 1997] is based on this principle.In this model, gas-phase relative permeability is shown by the following equation:

$$k_{rg} = f\, k_{rgb} + (1\text{-}f)\, k_{rgm}$$

Where,

K_{rgb} is the base relative permeability of gas-phase and k_{eg} is gas relative permeability also in fusion conditions. F parameter is calculated by the following equation:

$$f = 1 - \frac{1}{(\alpha N_c)^n + 1}$$

Where,

α and n are experimental parameters and the values of f is variable between 1 (low capillary number) and 0 (high capillary number). Mott and colleagues have suggested α = 3000 and n = -0.6 [Mott et al., 2000].

Figure 4 shows the effect of increasing capillary number on gas-phase relative permeability in numerous tests:

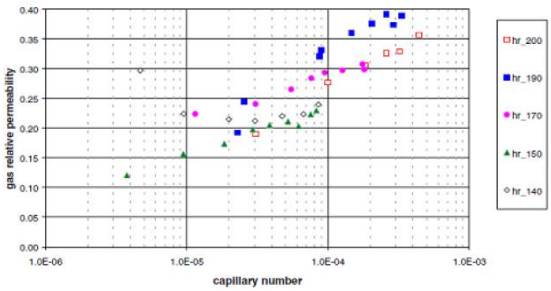

Figure 4: the effect of increasing capillary number on gas-phase relative permeability [Mott, 2000]

The same empirical relationship is used in GEM software, as relative permeability is the result of interpolation between base relative permeability and fusion relative permeability.

In GEM software, interpolation between base relative permeability and fusion relative permeability through a standard parameter is used and the standard parameter is a function of the capillary number. This method is based on determining two parameters for each phase. In this method, the capillary number for both liquid and gas phase is obtained by potential gradient. For liquid phase, gas phase is considered as the shifting phase and its capillary number is calculated by the following equation:

$$N_{cc} = \frac{K \nabla \phi_g}{\sigma}$$

For gas phase, condensate ids the shifting phase and its capillary number is calculated by the following equation:

$$N_{cg} = \frac{K \nabla \phi_c}{\sigma}$$

For aqueous phase, capillary number is considered equal to that ofgas phase.

For gas, condensate or aqueous phases, if the capillary number is less than the base capillary number, relative permeability is considered equal to base relative permeability. Base relative permeability is entered in CMG's application data file in tables coded * SWT and *SGT.

The Negative Effect of Inertia

Pressure drop of fluid flow in porous environments with low to medium speeds is proportional to fluid velocity. Mathematical form of the relationship expressed by Darcy's law and is shown as follows:

$$\frac{dp}{dx} = \frac{u\mu}{k}$$

Where, μ is fluid viscosity, K is permeability of rock and u is fluid velocity which is shown by the following equation:

$$u = \frac{Q}{2\pi rh}$$

At higher Debbi, in addition to viscous forces, inertia force is great too. Forchheimer suggested the equation below to calculate pressure drop at high Debbi:

$$\frac{dp}{dx} = \frac{u\mu}{k} + \beta\rho u^2$$

In this equation, the first part on the right represents Darcy flow and the second part represents the non-Darcy flow. In this equation, β is the inertia factor forsingle-phase gas system.At low speeds, non-Darcy flow is negligible and can be removed from the equation.Forchheimer's relationship can be used for additional pressure drop due to non-Darcy flow. Using reasonable assumptions, quasi pressure drop caused by non-Darcy flow can be shown like this:

$$\Delta m(p)_{nD} = 3.161 \times 10^{-12} \frac{\beta T \gamma_g Q^2}{\mu_g h_p^2 r_w} = FQ^2$$

Where,

- ✓ $\Delta m(p)_{nD}$: Quasi non-Darcy flow pressure drop($\frac{psi^2}{cp}$)
- ✓ β: Inertia factor of single-phase gas(ft^{-1})
- ✓ T: temperature of reservoir (R)
- ✓ γ_g : gas gravity
- ✓ Q: Volumetric flow rate of gas (MSCF)
- ✓ μ_g: Gas viscosity(cp)
- ✓ h_p: well height (ft)
- ✓ r_w: well mouth radius(ft)
- ✓ F: non-Darci flow factor ($psi^2/cp/(MSCF)^2$)

The equation can be written in another form that is more common in books and articles:

$$m(\bar{p}) - m(p_{wf}) = \frac{1422\,TQ}{kh}\left[\ln\frac{r_e}{r_w} - \frac{3}{4} + s\right] + FQ^2$$

$$= \frac{1422\,TQ}{kh}\left[\ln\frac{r_e}{r_w} - \frac{3}{4} + s + DQ\right]$$

Here, DQ is Debbi-dependent shell factor. Total shell factor is the sum of Debbi-dependent shell factor and mechanical shell factor:

$$D = \frac{Fkh}{1422\,T}$$

$S_t = S_m + DQ$

Single-phase inertia resistance coefficient, β, is a function of rock properties. In some cases, the factor is also named turbulent flow, which is not a right name because in most cases, fluid flow in porous environment is mostly a quiet type. As mentioned above, the inertial resistance coefficient phase, β, is a function of rock properties and can be calculated by Geerstma equation [Geerstma, 1974]. In this equation, k is absolute permeability in mm Darcy and β is in ft-1.

$$\beta = \frac{48511}{k^{0.5}\phi^{5.5}}$$

When two phases flow within reservoir, Single-phase inertia resistance coefficientcannot properly calculate the pressure loss caused by non-Darcy flow. One of the main problems associated with the impact of non-Darcy flow in gas condensate reservoirs is the lack of accurate simulation and estimate of the two-phase inertia coefficient. Most empirical equationspresented in articles are for water and hydrocarbon system in which water is immobile phase. The method proposed by Geerstma in two-phase flow, uses effective permeability instead of absolute permeability and effective porosity instead of porosity. This relationship can be seen as follows:

$$\beta = \frac{48511}{k_g^{0.5}\phi^{5.5}(1 - swi)^{5.5}}$$

Henderson and his colleagues investigated negative effect of inertia and the effect of positive coupling. They concluded higher speed strengthens the effect of positive coupling more than negative effect of inertia. They repeated their tests for different cores with various lithology in constant conditions. Five categories of relative permeability were used to obtain empirical relationship in the presence of moving condensate. The results were as follows:

Gas inertia factor increases as saturation of condensate and surface tension increase. They also observed that the inertia ratio suggested by Geerstma covers up to 68% of their estimates of two-phase inertia factor in laboratory conditions [Henderson et al., 2000].

Simultaneous Modeling of the Effect of Positive Coupling and Negative Effect of Inertia

Many numerical simulators model the phenomena of high capillary number and the effects of inertia separately and then mix these two phenomena to provide a model for effective permeability. The effect of inertia (non-Darcy flow) is shown by a factor multiplied by permeability. This factor is shown as FND and is calculated as follows:

$$F_{ND} = \frac{1}{1+\frac{\beta k \rho u}{\mu}}$$

Knowing this coefficient, effective permeability of gas can be obtained through the following equation:

$$K_{g,\,eff} = k.\ F_{ND}.\ K_{rg}\,(S_g,\ N_c)$$

In this equation, F_{ND} models the effect of inertia as a function of non-Darcy flow and k_{rg} modelsthe effect of multi- phase flows as a function of saturation and capillary number.
K_{rg} modeling based on these two phenomena is depicted in Figure 5. [Mott et al., 2000]. The thicker curve represents relative permeability of gas at the base mode at low speeds and low capillary number. The dotted curve represents relative permeability of gas phase at high speeds and high capillary number that includes both the effects of inertia and high capillary number. In low saturations, condensate of non-Darcy flow control relative permeability while in high saturations, condensate of capillary number influences relative permeability and controls it. The other graph is for the relative permeability of gas with considering capillary number regardless of non-Darcy flow or effect of inertia. In such conditions, gas-phase relative permeability in all parts is more than the base mode.

Water Evaporation near Wellbores

The phenomenon of evaporation of gas occurs around the opening of production and injection wells. Dry gas production evaporates water near wellboresand this wave gradually flows in reservoir. The gas moving towards well mouth is initially saturated with water. However, due to high pressure gradient and sudden pressure drop, near wellbores the gas absorbs the water near well mouth.
some modeling exists associated with the evaporation of water in porous environments in articles and the literature. Morin and Montel [Morin and Montel, 1995] have obtained the effect of water salinity on the amount of water absorbed by the gas through salinity-dependent solubility tables. Some researchers have considered this phenomenon in balancing materials [Humpreys, 1991].
Dodson and Standing, 1944, reported the results of their tests in PVT cell. Their experiments were conducted in pressure range of 500 to 5000 Psi pressure and temperature range of 100 to 250 degrees Fahrenheit, while salinity of water was equal to 25000 ppm.The most important finding of their experiments was that mole percent of the aqueous phase in gas phase increases as the temperaturegoes up and it decreases as pressure and salinity increase. Researchers conducted a research on an injection well in Arun field in Indonesia and found out water has dramatically decreased in some parts of the core whereas some other parts have gone completely dry[Bette and Heinemann, 1989]. Mole fraction of water in gas phase C_{wg} is a function of pressure, temperature and salinity of water. As temperature increases, Cwg rate increases and as pressure and salinity of water increases, this amount goes down. Figure 2-7 shows the results of the research done by Morin and Montel [Morin and Montel, 1995].

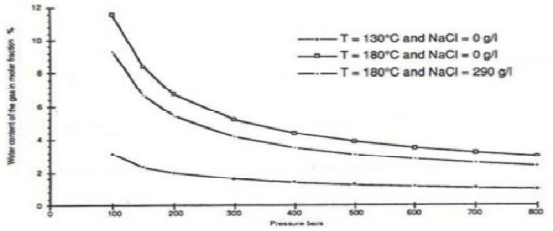

Figure 5: The influence of various factors on the solubility of water in gas phase [Morin and Montel, 1995]

Zuluaga et. al, 2001, too, conducted some studies in porous environment and concluded that increasing Debbi increases the phenomenon of water evaporation and water salinity decreases it.
It should be noted that their tests have been carried out under laboratory temperature and pressure. The mechanisms of water evaporation near production and injection wellbores are completely different, and this paper has just focused on the impact of this phenomenon on production wells.

Water Evaporation in Production Wells

In gas production wells, gas in reservoir is initially saturated in water, and is in thermodynamic equilibrium with it. As soon as production starts, the pressure near wellbores drops and this increases the solubility of water in the gas phase of reservoir [Morin and Montel, 1995; Kamath and Laroche, 2000]. Water evaporation begins from around the well and as the wave of pressure drop flows in reservoir, the wave of the decrease in water saturation and evaporation moves toward the bulk of reservoir. The decrease in water saturation near wellbores or in other words saturation of gas phase increases the productivity of well. Water evaporation creates a new profile of fluid saturation near wellbores. The mixed stimulator GEM can study the effect of this phenomenon on the productivity of well by predicting and simulating these new profiles. For this purpose, the user must enter water in the equation of state and continue the simulation.It is clearly seen that the inertia ratio (non-Darcy flow coefficient), β, and relative permeability are functions of water saturation. Any change in water saturation results in

changes in these parameters. These two parameters have a great impact on the productivity of wells. That is why the effect of water evaporation nearwellbores should be carefully examined in gas reservoirs and gas condensate reservoirs.

CONCLUSION AND SUGGESTIONS

- Evaporation of water occurs in the reservoirs of gas and gas condensate at high temperatures as a function of pressure and temperature. Increasing temperature and decreasing pressure accelerate this phenomenon.
- Porosity and permeability reduction leads to more pressure loss and thereby increases the evaporation of water.
- Reduction of water saturation leads to reduction of inertia ratio. Reduction of inertia ratio will reduce pressure drop and increase productivity.
- Evaporation of water in condensate gas reservoirs near the mouth of the well increases relative permeability of gas phase, increases gas phase saturation and improves productivity factor of well.
- When both positive coupling and water evaporation enter simulations simultaneously, they greatly affect fluid saturation and relative permeability.
- The phenomenon of evaporation of water near the wells in rich condensate gas reservoirs is the same as poor reservoirs except that the deviation from the benchmark happens at a greater distance from the mouth of the well.
- • The effect of evaporation of water near the wells in rich reservoirs is bigger than in poor condensate gas reservoirs.

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