Geological Model of the Khabour Reservoir for Studying the Gas Condensate Blockage Effect on Gas Production, Akkas Gas Field, Western Iraq

Husam Sabea¹, Jalal A. Al-Sudani² and Omar Al-Fatlawi³,⁴,*

¹ Midland Oil Company, Iraqi Ministry of Oil, Iraq
² Department of Petroleum Engineering, University of Baghdad, Baghdad, Iraq
³ Department of Petroleum Engineering, University of Baghdad, Baghdad, Iraq
⁴ Curtin University, WA School of Mines, Mineral and Chemical Engineering, 26 Dick Perry Avenue, 6151 Kensington, Australia
* Correspondence: Omar.Al-Fatlawi@coeng.uobaghdad.edu.iq

Abstract

The Khabour reservoir, Ordovician, Lower Paleozoic, Akkas gas field which is considered one of the main sandstone reservoirs in the west of Iraq. Researchers face difficulties in recognizing sandstone reservoirs since they are virtually always tight and heterogeneous. This paper is associated with the geological modeling of a gas-bearing reservoir that containing condensate appears while production when bottom hole pressure declines below the dew point. By defining the lithology and evaluating the petrophysical parameters of this complicated reservoir, a geological model for the reservoir is being built by using CMG BUILDER software (GEM tool) to create a static model. The petrophysical properties of a reservoir were computed using the notion of hydraulic units, and there are a number of basic steps to building a geological model, beginning with the creation of a single well model and then moving on to the distribution of properties. Depending on the variance in petrophysical parameters, the reservoirs were separated into seven zones. The Ordovician Formation (Khabour Formation) is penetrated by well Akk-1, which is included in the single well geological model to focus on studying the impact of gas condensate on gas production. The prediction of gas condensate wells production will strongly depend on oil banking evaluation and modeling. For this reason, well Akk-1 was chosen to build the model. Upper and lower sandstone units characterized as the most important due to containing of gas. The cost and risk to develop these reservoirs under severe conditions of pressure and temperature highlight the need to be able to confidently predict the recovery of gas and liquid drop-outs from Khabour reservoirs so, it is so necessary to predict the cost of this step in another paper

Keywords: Geological model; Builder software; Khabour Reservoir; Akkas gas field

1. Introduction

Reservoir modeling is a crucial phase in the evolution of hydrocarbon methods. Gas reservoirs have already traditionally been regarded as uneconomical because to their low permeability, which is estimated to be less than 0.1mD, necessitating sophisticated drilling methods and stimulation to boost

DOI: 10.46717/igj.55.1C.7Ms-2022-03-26
hydrocarbon production (Al-Fatlawi et al., 2021). In general, the subject of condensate blockage in gas wells has been debated and analyzed, and a variety of solutions have been proposed. Condensate banking phenomena must be studied in order to assess the productivity and behavior of gas field wells (Sabea and Al-Fatlawi, 2021). The Akkas gas field is located in Iraq in the Northwestern part of the Western desert within the administrative boarders of Al-Anbar Governorate (M.O.C, 2012). (Fig.1), the field is positioned immediately south of the Euphrates River and directly East of the Iraqi-Syrian boarders. The Akkas Contract area covers 986 km². The field has a structure of symmetrical anticline fold with northwest to south-east axis (M. O.C, 2012). The dimensions of field are 50 km. length and 18 km. width at the top of the Khabour Formation. The Khabour Formation considers the most important penetrated formation in Akkas field and the west region of Iraq which belongs geologically to the Ordovician age (Aqrawi and Masri, 2020) that contains subsequent units of sand, silt and shale rocks. Five wells were drilled starting in 1992 A.C. well Akk-1, and ending with well Akk-5 in 2003 A.C. showing that Khabour formation contains gas and condensate in upper and lower sandstone units with average rate of gas (8.2) mm SCF/D for the upper unit while the lower unit did not test precisely. So, construct a geological model will lead to concentrate studying condensate banking phenomenon and its effect on productivity index.

Fig. 1. Map demonstrates Akkas field location (M.O.C, 2012)

2. Materials and Methods

2.1. Software Overview

Builder is a program developed by the Computer Modelling Group (CMG) for creating simulation data input (sets of data) for CMG simulators such as IMEX, GEM, and STARS. Generating and integrating grids and grid characteristics, identifying wells, importing well production data, designing or importing fluid models, petrophysical properties, and beginning conditions are all included in the Builder.

2.2. Reservoir Description

To model the grid and grid simulation for detailing the reservoir volume and its properties (rock and fluid properties), the GEM simulator was used to update or create the fluid model to build a gaswater or blackoil model by applying correlations. (Ali et al., 1994). The contour map of Akkas field shows the structure as an anticline fold elongates from north-west to south-east almost has a symmetric side. Its
dimensions are about 50 km. long and 18 km. wide at the top of the Khabour Formation (Fig. 2). Based on seismic data (M. O. C, 2012). Major faulting within the Akkas field was clearly defined. A prominent graben striking northwest to southeast defines the eastern boundary of the Akkas field. A well-defined horst structure exists east of this graben just outside of the current contract area (Fig. 3). The Khabour Formation is the Iraq’s oldest Paleozoic formation. Well Akkas-1 is discovered in early Silurian and Late Ordovician sandstone reservoirs (Aqrawi and Masri, 2020; Al-Hadidy, 2007). The top portion of the Khabour Formation (upper Ordovician sandstones) are also gas and condensate reservoirs (Aqrawi and Masri, 2020). The bed thickness and lithology of the formation are varying, including dark gray and black shale, gray and white sandstones, and siltstones. The Khabour formation has been penetrated by several wells, including the Akkas-1, Akkas-2, Akkas-3, Akkas-4 and Akkas-5.

![Fig. 2. Contour map of the top of Khabour formation (M.O.C, 2012)](image)

### 2.3. Units Divisions

The Khabour formation has been subdivided into many units (Al-Hadidy, 2007) (Ahmed and Hamd-Allah) which its lithology can be defined as sandstone interbedded with dark gray and black shale. The term “reservoir flow zones” refers to a group of rocks with comparable geology, physical, and depositional features that influence fluid flow. Depositional, diagenetic, and post-depositional modifications all affect rock characteristics. Statistical investigations, in addition to a geology method, are necessary to prove the existence of these flow zones (Agunwoke et al., 2004). The formation has upper and lower units were subdivided into several layers depending on the lithological properties (porosity) and the ratio of shale (G.R.) and water saturation. Table 1 shows the top of units for Khabour Formation.
Table 1. Tops of Khabour formation units (M.O.C, 2012)

<table>
<thead>
<tr>
<th>Well</th>
<th>surface</th>
<th>MD. (ft.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Akk-1</td>
<td>Khabour K1</td>
<td>7632</td>
</tr>
<tr>
<td>Akk-1</td>
<td>Khabour K2</td>
<td>7687.5</td>
</tr>
<tr>
<td>Akk-1</td>
<td>Khabour K3</td>
<td>7738.34</td>
</tr>
<tr>
<td>Akk-1</td>
<td>Khabour K4</td>
<td>7763.76</td>
</tr>
<tr>
<td>Akk-1</td>
<td>Khabour K5</td>
<td>7738.34</td>
</tr>
<tr>
<td>Akk-1</td>
<td>Khabour K6</td>
<td>7763.76</td>
</tr>
</tbody>
</table>

2.3.1. Unit-1 (Upper sandstone)

Unit-1 is subdivided into six layers as they are. It is overlain by hot shale of the Akkas Formation. The hot shale has been identified in core and characterized by organic materials. This kind of shale is also a prominent maximum flooding surface. These sediments are the best rock quality of the area with average porosities of 7.6 pu and maximum values close to 11.5 pu. The first productive unit with fine to intermediate grains interbedded with shale. It has a secondary porosity representing by fractures and this is shown clearly in loss circulation during drilling operations and this unit was penetrated by all five wells. Total thickness of this reservoir unit has a range between 147.6 m. to 164 m. starting from 7632 ft. RTKB. to 7687.5 ft. RTKB.

2.3.2. Unit-2 (Upper shale)

Unit-2 mainly contains shale influenced by silt and interbedded by consolidated fine-intermediate sand grains.

2.3.3. Unit-3 (Sequence of sand & shale)

For the most part contains shale that involves barite, siltstone and sandstone which is fractured with fine grains. This unit is completely penetrated by wells Akk-1, 2, 3. to a great degree contains fractured shale that only well Akk-1 is partially penetrated it. Total thickness of this reservoir unit has a of 492 ft. which is subdivided into 15 layers.

2.3.4. Unit-4 (Middle shale)

same as unit-2 in addition to outcrop feldspar and calcite. This unit was completely penetrated by well Akk-1, 2 and 3.

2.3.5. Unit-5 (Lower sandstone)

the second main unit also has the same lithology in unit-1, but this unit was completely penetrated by well Akk-1 and partially by wells Akk-2, 3, while Akk-4 did not penetrate it because the well was drilled horizontally through upper sandstone unit and the drilling was stopped till the lower part of unit-1 in well Akk-5.

2.3.6. Unit-6 Interculation shale, sandstone and silt.

2.3.7. Unit-7 Lower thick shale.

2.4. Gridding

There have been a variety of goals, relevance, and outcomes that have been used to support a study of single well. However, little, if anything, was said regarding its importance in improving output. The act of studying well performance using numerical reservoir simulation equations is known as single well
modeling. It can be used to evaluate strategy of completion, investigate coning behavior, reserves of well, and pseudo-functions of relative permeability for wells in models of full field, as well as analyze well economics and complicated pressure transient data (Ezuka et al., 2004). A radial (cylindrical) gridding model (single model) was used to simulate the Khabour Formation consisting of 50*36*63 with total number of 13,400 cells. Near wellbore region is of great interest. The simulation grids should be performed on very fine grid blocks around the well (Ariadji and Suryanto, 2005). Coarser grid size is accepted because of the fact that the pressure drops are lower considerable in the region far from the wellbore region. Many physical effects control the choosing of gridding size: Relative permeability, Phase distribution and profile of pressure flow. Propagation of condensate liquid saturation building up near the wellbore first and then separates radially away along with the drop of pressure (Bozorgzadeh and Gringarten, 2004), as this reason an increasing in the grid size is as the distance increases away from the wellbore region. Akk-1 is the well centered the radial model because it is the only well that penetrates all the units of the Khabour Formation which is the targeted formation to study the condensate banking in addition to surface shows of condensate that noticed. Fig. 4 shows the top of Khabour formation by using single (radial) model centered by well Akk-1.

![Fig. 3. Cylindrical model centered by well Akk-1 (Khabour formation)](image)

The inner radius of the innermost block (well radius) is at 0.3ft., while the outer radius of the outermost block is at 5000 ft. The grids distribution of the whole model can be summarized in the following (Table 2). The inner radius of the innermost block (well radius) is at 0.3ft., while the outer radius of the outermost block is at 5000 ft. The grids distribution of the whole model can be summarized in Table 2.
Table 2. Grids distribution for well Akk-1, The Khabour Formation

<table>
<thead>
<tr>
<th>r (ft.)</th>
<th>Ø Divisions</th>
<th>Layers (ft.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.0547619, 0.0667573, 0.0813803,</td>
<td>Unit-1 _ 6 layers (Upper sandstone)</td>
<td></td>
</tr>
<tr>
<td>0.0992065, 0.120937, 0.147428, 0.179722, 0.21909, 0.267081, 0.325584, 0.396903, 0.483843, 0.589828, 0.719028, 0.87653, 1.06853, 1.30259, 1.58792, 1.93575, 2.35977, 2.87667, 3.5068, 4.27495, 5.21137, 6.35291, 7.7445, 9.44091, 36° 10°, 11.5089, 14.0299, 17.1031, 20.8495, 25.4166, 30.984, 37.771, 46.0446, 56.1305, 68.4258, 83.4143, 101.686, 123.96, 151.113, 184.214, 224.566, 273.756, 333.722, 406.823, 495.936, 604.57, 736.999, 898.437</td>
<td>Unit-3 _ 15 layers (Sequence of sand &amp; shale)</td>
<td></td>
</tr>
<tr>
<td>2.5. Assign Petrophysical Properties (Rock-Fluid Properties)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The technique of distributing the entire set of continuous log characteristics to the entire reservoir is known as petrophysical modeling (Ahmed and Hamd-Allah, 2021b).

2.5.1. Coring

About 80-100% of khabour and Akkas formations (2132 ft.) was covered in coring to be about (909.8) ft. in well Akk-1 (R.F.D.D, 2007). Many core analyses were made for samples in well Akk-1 to involve upper and lower sandstone units in addition to upper and lower shale units. The rock types are used to enter GEM rock sorts and rock fluid characteristics with its related information which are:

- Rock type properties: the wetting phase which is water wet type.
- Porosity
- Permeability
- Water saturation
- Net thickness

2.5.2. Effective porosity & permeability

The reservoir heterogeneities, as well as the porosity and permeability distributions, have an impact on the hydrocarbon recovery factor of any reservoir (Al-Beyati and Abdula, 2021). The characterization of shale-gas reservoirs and the prediction of shale-gas production behavior rely heavily on nanoscale porosity and permeability (Pang et al., 2017). Petrophysical properties such as, porosity, permeability, resistivity and water saturation are necessary for the assessment of reservoirs (Al-Garbawi and Al-Shahwan, 2019). Reservoir and Fields Development Directorate (R.F.D.D., R.F.D.D, 2007) established integrated reservoir joint study for the Akkas field with North Oil Company (N.O.C) in 2007 A.C. which was aiming to evaluating Khabour properties such as porosity and permeability (Figs. 4, 5, 6). This study was adopted as a source for the distribution of these petrophysics.
Fig. 4. Upper Sandstone unit, Khabour Formation, Well Akk-1

Fig. 5. Lower sandstone unit, Khabour Formation, Well Akk-1

Fig. 6. Upper, middle & lower sandstone unit- Khabour formation / well Akk-1
The figures above show a consistency between (K core & $\varnothing$ core) as the trend line detects the relationship shape for sandstone lithology of Khabour formation. From this relationship, a relationship was derived to calculate k values.

$$\log K = (0.1 \times \varnothing) - 2 \quad (1)$$

Where:
- $K$ = Permeability
- $\varnothing$ = Porosity

Effective porosity was estimated depending on the following logs: CNL, RHOB, DT either combined together or two logs whenever that could be depending on the well condition - and compare it with $\varnothing$ core as much as possible (Fig. 7). A plot between $\varnothing$ core & $\varnothing$ log was done in well Akkas-1 and the following relationship was obtained:

$$PHIE = -2.9 + (1.7 \times PHIC) \quad (2)$$

Where:
- $PHIE$ = Effective porosity
- $PHIC$ = Core porosity

**Fig. 7.** Log porosity vs. core porosity for Upper sandstone unit-Khabour Formation, well Akk-1

- **Upper sandstone unit**: The results of core analyses for this unit show low permeability ranges (0.02-0.31) mD with average value of 0.068 mD. While porosity has intermediate values ranges (1.7-11.5) % with average value of (7.6) %.

- **Intermediate sandstone unit**: One way or another, this unit looks like upper unit but with little difference. Its permeability ranges (0.01-0.07) mD with average value (0.026) mD and average value of porosity reaches (4) %

- **Lower sandstone unit**: In comparison with upper sandstone unit, the results of core analyses for this unit reveal low values for permeability but better than the upper one ranges (0.02-2.8) mD with average value of (1.14) mD The same routine for porosity that has average value of (7.6) % better than in upper productive unit.
2.6. Shale Volume

Standard gamma ray log (SGR), or the three elements contribution uranium (U), potassium (K), and thorium (Th) is frequently used for shale content indicator. The shale volume is overestimated by the linear IGR shaliness indicator model (David et al., 2015). Based on Gamma Ray readings, minimum and maximum values were detected to extract shale volume for each unit in Khabour formation. CGR log was used to determine V.Sh. and the minimum values were about (10-15) GPI and maximum values were about (100-120) GPI. An equation is utilized in this calculation due to the flexibility of dealing with shaly sand formations. Dresser equation is used for this goal (Atlass, 1982) (Table 3) (Figs. 8 and 9).

\[ V_{sh} = 0.33 \times (2 \times IGR - 1) \]  \hspace{1cm} (3)

\[ IGR = (GR - GRcl) / (GR_{sh} - GRcl) \]  \hspace{1cm} (4)

Where:

IGR = Gamma Ray Index
GRcl = Clean Gamma Ray
GR = Shale Gamma Ray

### Table 3. Shale volume distribution of the Khabour Formation

<table>
<thead>
<tr>
<th>Formation Unit</th>
<th>Depth (ft.)</th>
<th>Avg. V\text{Sh} %</th>
</tr>
</thead>
<tbody>
<tr>
<td>RU-1</td>
<td>7632-7687.5</td>
<td>21.2</td>
</tr>
<tr>
<td>RU-2</td>
<td>7687.5-7738.34</td>
<td>52</td>
</tr>
<tr>
<td>RU-3</td>
<td>7738.34-7763.76</td>
<td>46.7</td>
</tr>
<tr>
<td>RU-4</td>
<td>7763.76-7738.34</td>
<td>62.1</td>
</tr>
<tr>
<td>RU-5</td>
<td>7738.34-7763.76</td>
<td>45.3</td>
</tr>
</tbody>
</table>

![Fig. 8. Shale volume of upper sandstone unit, the Khabour Formation](image)
2.7. Water Saturation

The necessity of mature source rocks being close to several low permeability gas reservoirs is highlighted in current thinking on the formation of "basin centered" gas. The efficiency of the system is determined by the quality of the gas charge, which is mostly determined by source rock properties (oil vs. gas prone) as well as the temporal sequence of hydrocarbon migration and reservoir unroofing (Spain et al., 2013). The improvement of an appropriate model primarily based totally on essential physics is grudgingly had to deal with the needs of existing and future assessment of petroleum reserves and additionally to conquer the the limitations of nowdays empirical models. Capacitance-Resistance Modeling (CRM) method has been developed for analytical model to estimate water saturation. The mechanism of rock saturation behavior to electric current was simulated by this philosophy throughout a capacitor coupled to a resistor that determines the overall behavior of an electric system (Al-Sudani et al., 2020). A differential mathematical law of the first order was used for this system. The analytical model has no adjustable parameters which gives the advantage, such as existing in Archie’s or shaly electrochemical or empirical models. The mathematical form of this system can be written in quadratic-exponent Form (Table 4).

$$S_w = \left[ -\left(\frac{b^2}{e^{-（b）^2（1-\phi^m）}}\right) \cdot \ln\left\{1 - \left(\frac{X F_n R_w}{R_t}\right)\right\}\right]^{0.5}$$  \hspace{1cm} (5)

$$X = \left[1 - e^{-\left(\frac{1}{2^m}\right)^m}\right]$$  \hspace{1cm} (6)

$$F_n = \frac{1}{\phi e^{-（b）^m(1-\phi^m)}}$$  \hspace{1cm} (7)

$$b = \frac{1}{1+1.582\left(\frac{R_o}{R_t}\right)\left[V_{sh}（1-\phi）\right]}$$  \hspace{1cm} (8)

Where:

- $b$ = Shale factor
- $F_n$ = The new form of Formation Resistivity Factor
- $m$ = Formation Resistivity Factor

![Shale Volume of lower Sandstone Unit/ Khabour formation](image-url)
\( \phi = \) Effective porosity  
\( R_w = \) Water saturation  
\( R_t = \) True resistivity  
\( R_{sh} = \) Shale resistivity  
\( V_{sh} = \) Shale volume

**Table 4** Average S.W. of all five units, the Khabour Formation

<table>
<thead>
<tr>
<th>Formation Unit</th>
<th>Avg. SW %</th>
</tr>
</thead>
<tbody>
<tr>
<td>RU-1</td>
<td>66.27</td>
</tr>
<tr>
<td>RU-2</td>
<td>78.87</td>
</tr>
<tr>
<td>RU-3</td>
<td>90.67</td>
</tr>
<tr>
<td>RU-4</td>
<td>92.18</td>
</tr>
<tr>
<td>RU-5</td>
<td>68.91</td>
</tr>
</tbody>
</table>

### 2.8. Relative Permeability

In the literature, laboratory experiments usually present a package of measurements which relative permeability is one of them. Oftentimes, so as to estimate the values of relative permeability, employing of empirical correlations and calculations are used due to the cost involved and difficulties in measuring these values (Kantzaz et al., 2012). Because testing relative permeability values is difficult and expensive, empirical correlations and computations are frequently used to determine the values. In most cases, when no core data is obtainable, this is done, besides if tests of running laboratory permeability are not workable (Behrenbruch et al., 2018). The widely using of Corey relations (Corey, 1954) are essentially an equations extension for normalized drainage effective permeability established by (Burdine, 1953). The equations provided here have been adjusted for relative permeability estimates from the original Burdine equations.

\[
k_{rw} = (S_w^* \ast)^{4\left(2 + 3 \lambda / \lambda \right)}
\]

\[
k_{rn} = k_r^0\left(\frac{S_m - S_w}{1 - S_{iw}}\right)^2 \left(1 - (S_w^*)^{\frac{2 + \lambda}{2}}\right)
\]

\[
S_w^* = \frac{S_w - S_{iw}}{1 - S_{iw}}
\]

\[
k_r^0 = 1.31 - 2.62S_{lw} - 1.1(S_{lw})^2
\]

Where:

- \( k_{IW} = \) Relative permeability of wetting phase  
- \( k_{rn} = \) Relative permeability of non-wetting phase  
- \( k_r^0 = \) Relative permeability of non-wetting phase at irreducible wetting phase saturation  
- \( S_w^* = \) Normalized wetting phase saturation  
- \( \lambda = \) Pore size distribution index  
- \( S_m = 1 - S_{or} \) (1-residual non-wetting phase saturation)  
- \( S_{lw} = \) Water saturation  
- \( S_{iw} = \) Initial water saturation

The non-wetting phase equation is where the solutions and equations of Burdine provided here differ the most. The additional Kro term is included due to the fact that the solution of non-wetting phase must be at saturation of irreducible wetting phase. The Sm term, introduced by Corey to indicate the moment where the non-wetting phase first begins to flow, is the other modification. The point of critical saturation is what it’s called. This demonstrates that there is no link during the non-wetting phase curve’s
early stages. Pores minimum number are connected at critical saturation, this is the point at which flow is possible and the initial relative permeability value can be determined. The Sm term defines the saturation where the flow is first conceivable in order to achieve real relative permeability values.

2.8.1. Determining pore size distribution index

In computing relative permeability, (pore size distribution index) ($\lambda$) value shown in equations above is critical. The real number shows the sample/pore reservoir's size uniformity. A low number (i.e. 2) indicates a rock with a large variety of pore sizes, while a high number stands for much more uniform pore size distribution (Burdine, 1953). The Wyllie and Corey (Brooks and Corey, 1966) equations are adequate for approximation, although capillary pressure data can be used to derive it empirically to provide a more exact estimate of the pore size distribution index ($\lambda$). Brooks and Corey (Brooks and Corey, 1966) developed a formula that connects normalized wetting phase saturation to capillary pressure:

$$
\log P_c = \log P_e - \frac{1}{\lambda} \log S_w^* \quad (13)
$$

Where:

- $P_c$ = Capillary pressure
- $P_e$ = Minimum threshold pressure
- $S_w^*$ = Normalized water saturation

$P_e$ is the intercept of a straight line with a slope of $-1/\lambda$ should appear from a plot of log-log between capillary pressure vs. normalized water saturation. The value derived using eq.13 may really be supported up with hard data, making the using the Wyllie or Corey relationships instead of this way of determining from experimental data is preferred (Corey, 1954).

**Fig. 10.** Determining pore size distribution index

Slope of the graph is $-1/\lambda = -1.25$, Therefore, $\lambda = 0.606$.

Calculating Relative Permeability Kro.

Recall eq. (12) where $Kro = 0.73578$, $Sm = 0.847 = 1-Srg$.

Relative Perm Values Calculation to obtain the relative permeability of the two phases at varying water saturations, use equations 9 and 10 again (Figs. 10, 11, 12).
2.8.2 Three-phase relative permeability (Stone’s second model) (Stone, 1973)

To calculate three-phase relative permeability data for two-phase data, Stone’s model is utilized to obtain the three-phase relative permeability in Fig. 13 (Fayers and Matthews, 1984). Stone’s concept is better suited to water-based systems. The following normalized formulation was developed by Stone.

\[
K_{ro} = k_{ocw} \left[ \left( \frac{k_{ow}}{k_{ocw}} + k_{rw} \right) \left( \frac{k_{og}}{k_{ocw}} + k_{rg} \right) - (k_{rw} + k_{rg}) \right]
\]  

(14)
Fig. 13. Stone’s second model for two phase relative permeability

2.9. Net Thickness

The findings of cut-off criteria on petrophysical data could be used to evaluate Net to Gross zones (Ahmed and Hamd-Allah, 2021a, Turner et al., 2013). The value of cut off (porosity, permeability, and water saturation cut off) is used to determine the net thickness for Khabour formation. The permeability cutoff was set to 0.01 % as it is known in gas reservoirs literature (Asquith and Gibson, 1982). The porosity cut off is set to be 3 % that is produced from porosity-permeability plot. Water saturation cut off was 60 % (Fig. 14).

Fig. 14. Sw, cut off determination for upper sandstone unit, the Khabour formation

2.10. Rock Compressibility

The results and experimental approaches for a basic laboratory evaluation of compaction of reservoir rock and its effect on porosity and permeability are provided. The impact of rock compressibility on reservoir behavior as fluid pressure drops is a significant topic that has received scant attention. The total pressure on any plane passing through a reservoir is the sum of grain-to-grain rock pressure owing to overburden and the pressure of the interstitial fluid on the plane (McLatchie et al., 1958). The compressibility of Khabour sandstone rocks due to laboratory experiment is \((5.5 * 10^{-6})\) (1/psi) (R.F.D.D, 2007).
2.11. Initial Conditions

Three important conditions are considered to be used in this model which are: Initial pressure, datum depth and G.W.C. The values of P.I. is (3700) psi, and the datum level is about (2120) m B.S.L. While the G.W.C. for Khabour formation that estimated from pressure gradient is about (2200) m B.S.L.

2.12. Results of Pressure History Matching

The process of modifying reservoir model parameters until the simulated data generated by the model matches the actual data of the field is known as history matching. Models of numerical simulation characterizing reservoir behavior call for trustworthy estimates for different reservoir parameters that cannot be computed straightforwardly. Currently, these estimations are obtained using a trial-and-error approach, regression analysis of linear and nonlinear (Slater and Durrer, 1971).

Akkas field, Khabour Formation – Upper Sandstone unit history match was constructed depending on well tests. The well Akk-1 was tested for Khabour formation which involved (485) minutes of productive time (draw down) with a rate of (7.79) mmSCF and (240) minutes of shut-in (build up) time. The perforated (tested) intervals from (7648.9-7678.4) ft., (7708-7740.8) ft. that belong to upper sandstone unit were tested where the BHP was about (3000) psi. The model was run with the same perforation intervals, BHP, draw down, and build up periods as the actual test. As shown in Fig. 6, the best history matching was reached by multiplying the permeability of Upper Sandstone unit by a factor of eighty and assuming the skin factor equals to (+1). In addition to the sensitivity method that applied with the base case (real permeability value) (Fig.15).

![Permeability sensitivity](image)

**Fig. 15.** History match plot for BHP

Taking into consideration some points are noticed with the well test which are:
- The rapid and high depletion that happened reaching to (1250) psi during (475) minutes.
- The estimated skin factor was about (+15) while the value used in the model was (+1).
3. Conclusions

In order to study the condensate blockage or banking near wellbore, single well model was adopted to focus more on this region (near wellbore) and for this reason radial (cylindrical) model used with fine gridding near wellbore. Radial model is used as a benchmark model to compare it to an equivalent Cartesian grid model in term of productivity.

Steep or gentle dip of anticline fold elongates from north-west to south-east with a symmetric side is appeared clearly in contour map of Khabour formation which represents the main pay zone of the field. Low permeability (0.068) mD and (1.14) mD for upper and lower sandstone units respectively leads to separate the heavy components of produced gas to accumulate near wellbore which results low relative permeability. For this reason, single well model was chosen to focus on studying this phenomenon with fine grids near wellbore region.

Acknowledgements

The authors are very grateful to the reviewers, Editor in Chief Prof. Dr. Salih M. Awadh, the Secretary of Journal Mr. Samir R. Hijab, and the Technical Editors for their great efforts and valuable comments.

References

Behrenbruch, P., Hoang, T. G., Do Huu, M. T., Bui, K. D. & Kennaird, T., 2018. The importance of optimal choice of relative permeability relationships in reservoir simulation. SPE asia pacific oil and gas conference and exhibition.
M.O.C 2012. Midland oil company.