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Simulation Model of Faregh 5A5 Gas-Condensate Well Test

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Abstract

Gas condensate reservoirs exhibit a unique phase behavior as the reservoir pressure decreases. The condensate will drop out around wellbore, which ultimately restricting the flow of gas and reducing well productivity. Therefore, well deliverability and condensate blockage, if not properly treated at the beginning of gas field life, could lead to a breach of long term contracts with the buyers, due to shortage of gas supply. Libyan Faregh field, well 5A5, has faced huge pressure drop during the initial test indicating of some challenges associated with this well deliverability. The objective of our study is to assess and evaluate 5A5 well deliverability using well test analysis with the integration of simulation models and then project its future performance. The study utilized integration of all the available and measured reservoir technical data around well 5A5, including formation properties, phase behavior, dynamic flow models and SCAL data, and DST well test history. Eclipse E100 and E300 were used to simulate gas-condensate well deliverability during the test period. The main outcome of this study revealed that 5A5 well is limited by confined area, as there is no enough volume of gas to support the severe pressure loss during the test analysis. The impact of condensate blockage is of second order considering the average reservoir measured permeability is not so bad (~15 md) which allows for both gas and condensate flow without excessive damage around the wellbore. Furthermore, the study revealed that the expected life of 5A5 well is short (within 5 years) with plateau period of two years if produced at 7.0 MMscf/day. If the well is replaced by a horizontal well, the improvement in overall gas recovery is negligible, but it can extend the plateau period by an extra half year.

Keywords: Gas condensate; well deliverability; simulation models.

1. Introduction

Gas-condensate reservoirs represent an important source of hydrocarbon reserves and have long been recognized as a reservoir type possessing the most complicated flow and complex thermodynamic behaviors. The associated condensate production has an added economic value and it makes the recovery of condensate a key consideration in the development of gas-condensate reservoirs.

The gas-condensate reservoir is typically in single gas phase at the initial reservoir conditions, and as the reservoir pressure decreases below the dewpoint, liquid condenses from gas and forms a "ring" or "bank" around the producing wells in the near-well region. Normally this liquid will not flow until the accumulated condensate saturation exceeds the critical condensate saturation due to the IFT forces and capillary pressure effects in the porous medium. This causes a loss in gas well productivity. Therefore, such reservoirs must be evaluated very well during development stage.

In the world of reservoir engineering, well testing is one of the most applicable tools for estimating reservoir parameters and evaluating well performance. In addition to well testing, the integration of simulation models are the appropriate means to assess and quantify the gas-condensate well deliverability.

It has been shown that an equivalent single-layer

reservoir model is not as accurate when describing a well completed in a layered reservoir. Usually, the single-layer model will be optimistic [2]. Evaluating and simulating a multilayer reservoir system often requires a geological analysis ,core analysis data, well logging data, characterization of natural fractures and faults (if applicable), and well test history.
Our study was focused on simulating the Modified Isochronal test conducted on 5A5 well of Faregh field. The field is located in the Sirte basin and characterized by faulted area. The well was drilled and tested on November 2009. The study utilized integration of all the available and measured reservoir technical data around well 5A5, including formation properties, well-logging data, fluid properties, SCA data, and DST well test history. Then using Eclipse E100 and E300 to simulate gas-condensate well deliverability during the test period.
Our main objective is to assess and evaluate Faregh well 5A5 deliverability and project its future performance. The main steps to achieve our objective are highlighted below:

- Construction of 3D Radial and Cartesian models, with the proper characterization of Well 5A5 rock properties as well as the phase behavior modeling.
- Identify the proper dynamic flow to simulate the Modified Isochronal Test sequences by assigning the appropriate gas-condensate relative permeability curves.
- Study the sensitivity impact of different parameters such as, permeability, porosity, critical condensate saturation, etc. on the overall history match of the test.
- Obtain the best and optimum match to the test and define the boundary conditions of such test.
- Predict the future life and performance of well 5A5.
- Identify other options of improving 5A5 well productivity and prolonging its life.

2. PVT Analyses and EOS Modeling

The PVT data of recombined sample for well 5A5 (Separator Gas and Separator Condensate Samples) and routine PVT analyses, which it mainly includes CCE, CVD and Separator experiments, were used in this study. The sample has the following reservoir fluid composition, table-(2.1) and table (2.2):

Table 2.1: Fluid composition of 5A5 well

Composition	Mol %
N2	0.77
co2	1.30
C1	81.54
C2	9.46
C3	2.37
iC4	0.52
nC4	0.89
iC5	0.31
nC5	0.38
C6	0.33
C7+	2.14

Table 2.2: Properties of 5A5 well

Parameter	Value	Unit
Initial Pressure (Pi)	5,100	psia
Reservoir Temp	240	^{o}F
Dew Point (Pd)	4,735	psia
Z-factor	0.9462	unitless
Gas FVF	0.0044	ft^3/scf
CGR	38	Stb/MMscf
API	59.2	^{o}API

PVTi Eclipse package [3] was used to simulate the phase behavior of Faregh well 5A5 applying 3P-PR EOS and Lohrenz-Bray-Clark (LBC) [4] viscosity correlation. As the CVD liquid drop-out experiment is the most effective on well deliverability, by properly simulating the liquid drop-out around the well, our tuning was mainly focused on this experiment. The C7+ was broken into four pseudo-fractions using modified Whitson method [5] and then by adjusting the key variables of the heavy pseudo-fractions, we were able to achieve reliable match to the CVD, CCE experiments as well as the flash separation experiment.

3. Formation Evaluation of 5A5 Well

Formation Evaluation is the process of interpreting a combination of measurements taken inside a wellbore to detect and quantify oil and gas reserves in the rock adjacent to the well, using rou-

tine core analyses (RCA) and wire-line logging measurements.
Using formation evaluation to evaluate hydrocarbons in place and provide the reservoir engineers with the formation's geological and physical parameters necessary for the construction of a fluid-flow model of the reservoir.
The geological model around well 5A5 was build using a combination of well logs data and conventional core analyses. Based on the porosity and permeability distribution, sixteen numerical layers were identified with the top formation at 10308 ftss and bottom formation at 10520 ft. The perforated interval is 33 ft distributed across the gas zone interval from depths 10308 to 10363 ft. The GWC was estimated at 10375 ft.

4. Relative Permeability Curves

Calculation of gas condensate well deliverability has been a long-standing difficult subject with no simple solution. When FBHP drops below the dew point, a region of high condensate saturation builds up near the wellbore, resulting in reduced gas effective permeability and lower gas deliverability. Modeling the impact of a condensate blockage depends on the accuracy of the imposed relative permeability, the accuracy of PVT properties, and how the well is being produced.
Fevang and Whitson [6] have shown that the appropriate data for well deliverability predictions in gas condensate reservoirs is Krg as a function of (Krg/Kro,Nc). They have shown that the condensate saturation near the well does not play a significant role as long as the functional relationship between Krg vs. Krg/Kro remains the same. "Since the near-well condensate blockage region controls well deliverability, where the gas/condensate flow is steady-state, the flowing condensate/gas ratio is essentially constant and the PVT condition is considered a constant composition expansion (CCE) region. This condition simplifies the relationship between gas and condensate relative permeabilities, making the ratio between the two (k_{rg}/k_{ro}) as a function of PVT properties"[6].
Fevang and Whitson have shown the relation between K_{rg}/K_{ro} and fluid properties as follows:

$$\frac{k_{rg}}{kro} = \frac{\mu_g}{\mu_o}\left(\frac{1}{V_{ro}} - 1\right) \tag{4.1}$$

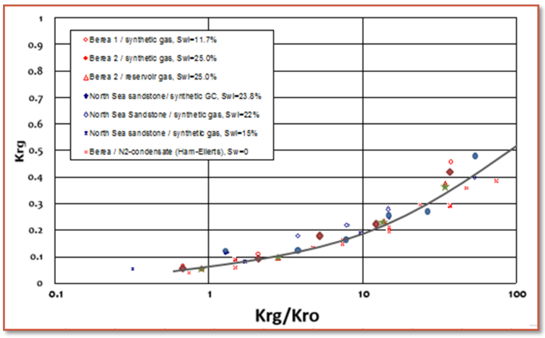

Figure 4.1: Fit of all available krg data using the proposed relative permeability model [7]

Where (Vro) is the relative oil volume from a CCE, and (µg/µo) is the ratio of the gas and condensate viscosity of the steady state flowing phases in the near wellbore region.
Using results obtained from 5A5 gas-condensate modeled PVT, CCE and CVD experiments, we were able to calculate the (K_{rg}/K_{ro}) ratio at different pressures. Then, from this relation between (K_{rg}/K_{ro}) ratio versus pressure, we could read the corresponding (K_{rg}/K_{ro}) ratio at different flowing bottom hole pressures. In order to determine K_{rg} corresponding to the (Krg/Kro), the relative permeability data was fitted to match the literature data [7], Figure (4-1), since no gas-condensate measurements are made for Faregh field.
In this study, we have also used Corey's correlation [8], Eqs. (4.2) and (4.3), of relative permeability, in addition to Eq. (4.1) above, for describing low capillary number immiscible behavior of steady-state data measured for Faregh gas condensate cores.

$$k_{rg} = k_{rg}^{max}\left[\frac{S_g - S_{gc}}{1 - S_{wi} - Sgc - S_{cc}}\right]^{ng} \tag{4.2}$$

$$k_{ro} = k_{ro}^{max}\left[\frac{S_o - S_{gc}}{1 - S_{wi} - Sgc - S_{cc}}\right]^{no} \tag{4.3}$$

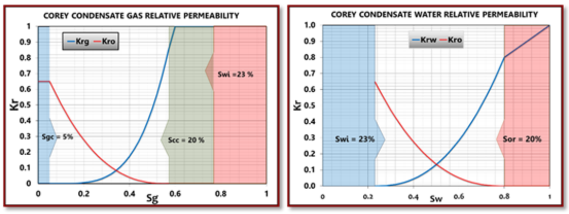

Figure 4.2: shows the final shapes of gas-condensate and water-condensate relative permeabilities

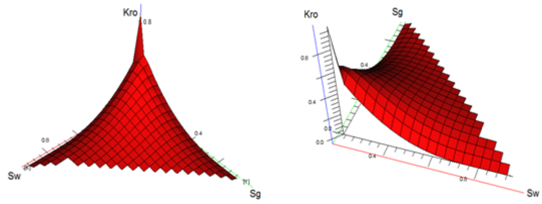

Figure 4.3: 3D-Visualisation of 3-Phase Relative Permeabilities

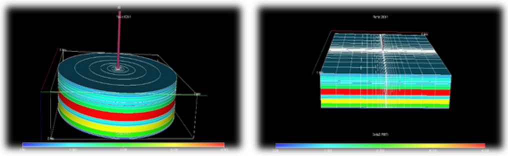

Figure 5.1: The Radial and Cartesian models grid-blocks

K_{rg}	= relative permeability of Gas
K_{rgmax}	= max relative permeability of Gas
n_g	= Corey gas exponent
S_g	= gas saturation
S_o	=condensate saturation
S_{gc}	= critical gas saturation
K_{ro}	= relative permeability of Oil
K_{romax}	= max relative permeability of Oil
n_o	= Corey oil exponent
S_{wi}	= initial/connate water saturation
S_{cc}	= critical condensate saturation

Corey equations were used to back calculate relative permeability from the obtained matched curve with the literature experiments, Figure (4-1) above. The exponents and coefficients of Corey equations were determined by the least-squares method (trial and error iterations) to match the experimental relative permeability data.
Figure (4-2) Saturation dependent relative permeability curves using Corey's equation used for simulation studies.
Finally, the generated curves were all then exported to the Eclipse SCAL program to generate the three phase relative permeability curves, which are needed to simulate the flow in each numerical layer. A typical shape of three-phase relative permeability generated by Eclipse SCAL is shown in Figure (4-3) below.

5. Single Well Simulation Models of 5A5 Well

Radial and Cartesian single well models were constructed using Eclipse100 (modified black-oil model) and Eclipse300 (compositional model)[9]. The radial model consists of (15*1*16) grid-blocks and the radial extent of the model is about 1500 ft.

The cartesian model consists of (29*29*16) grid-blocks and the extent of the model is also around 1500ft. One producing well 5A5 was located in the center of the radial and cartesian models and only penetrated the first six vertical layers (hp= 33 ft)
The radial grids DR, and also the cartesian grids, DX and DY, were designed and distributed logarithmically to be small enough around the wellbore in order to evaluate the effect of condensate blockage as illustrated in Figure (5-1).

6. Well Test Interpretation Model

In our study, we used single phase analogy method for 5A5 well test analysis (DST). Using pseudo pressure transformation in interpreting transient buildup pressure data from the well. We tried to identify an interpretation model that relates the measured pressure change to the induced rate change and is consistent with other information about the well. Our focus was mainly on the interpretation of long 4th buildup period.
The single-phase pseudo pressure technique was first proposed by Al- Hussainy and Ramey (1966) [10] in order to linearize the real gas flow equation. The single-phase method works best for dry gas, therefore, it can be applied on gas condensate wells producing above the dew-point pressure. Once the pressure falls below the dew-point

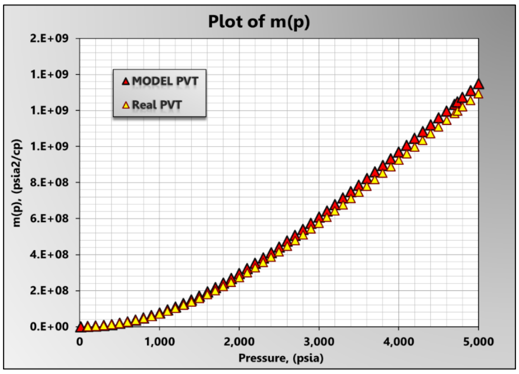

Figure 6.1: Plot of m(p) vs. pressure for lab and modeled PVT data

Table 6.1: Equations used in well test analysis

Pseudo-pressure difference (Δm(P))	$m(P_{ws}) - m(P_{wfo})$
Effective time (Δte)	$\left(\dfrac{t_p \times \Delta t}{t_p + \Delta t}\right)$
Pressure derivative (Log-Log: Δm(P'))	$(\Delta t_e)_i \left(\dfrac{m(P)_{i+1} - m(P)_{i-1}}{(\Delta t_e)_{i+1} - (\Delta t_e)_{i-1}}\right)$

pressure, a condensate bank forms around the wellbore and the single phase method deviates from the liquid-flow solution.
The data required for the method include the usual recorded bottom-hole pressure-time data, rate history prior to shut in, and laboratory CCE data. These CCE data usually include the measured fluid relative volume, gas z-factor and gas viscosity versus pressure.
From lab PVT and EOS based model PVT, we calculated the values of m(p) at all pressure records using Trapezoidal rule, then was plotted ve pressure for both lab PVT and EoS model results. Figure (6-1) shows the results of m(p) plots, and as indicated from this figure, a perfect match between the m(p) obtained from measured PVT and m(p) obtained from the tuned EoS, which confirms the reliability of our tuning.
Having established the m(p) data, then we can construct the plot of m(p) vs Δt and also the plot of derivative curves on log-log diagram, using equations described in Table (6.1) below.
The pseudo-gas potential m(p) calculated by using equation obtained from previous work carried by Monder et al [11], with the below regressed Polynomial Equation (6.1), was adopted in our study. This equation has perfect match to the above plot and will be directly used to convert the measured pressure records to m(p) and can be applied for any other tested Faregh wells as well.

$$m(P) = 6.506 * 10^{-3} * P^3 + 861.1 * P^2$$

$$- 9.279 * 10^3 * P + 1.146 * 10^6 \qquad (6.1)$$

It is important to know which reservoir variables may have a significant effect on the history match and contribute to overall pressure trends and response similar to those measured in the well test. Thus, at the beginning of the history match process, sensitivity analyses were carried out to examine the key parameters that have direct impact on well test pressure history. Such key parameters include the absolute permeability, porosity, transmissibility, relative permeability, critical condensate saturation, mechanical skin and wellbore storage effect.
The history match is a tedious job, especially when we are dealing with complex geological reservoir like Faregh field and complex gas-condensate fluid with dew-point pressure very close to initial pressure. A tremendous number of runs with different adjusting parameters and more detailed analyses were carried out in this study to match the well test data and narrow the discrepancy.
Based on different sensitivity results and after having many trails, finally managed to come-up with the acceptable match to the modified isochronal test conducted on Faregh 5A5 well, as shown in Figures (6-2) and(6-3). The most effecting parameters on history match are permeability, porosity and with less influence is the critical condensate saturation.
The main achieved parameters for our best simulation model are as follows:

- Weighted average effective permeability = 15.5 md (on the basis of Krgmax = 0.9)
- Weighted average Porosity = 12 %
- Relative permeability with Scc = 10 %
- Skin factor = -1

The well test interpretations led us to the following main model outcomes:

- Area around well 5A5 is acted as a bounded closed area (compartment) with limited initial gas in place of around 8.0 Bscf as estimated from Eclipse 3D radial model. This can be explained by the diagnosed continues pressure build-up on the measured and simulated derivative plots.
- The estimated limited GIP volume is mainly contributing to the severe pressure loss during the test analysis, as there is no enough volume of gas to support the pressure.
- The impact of condensate blockage is of second order considering the average reservoir measured permeability is not so bad (~15 md) which allows for both gas and condensate flow without excessive damage around the wellbore.

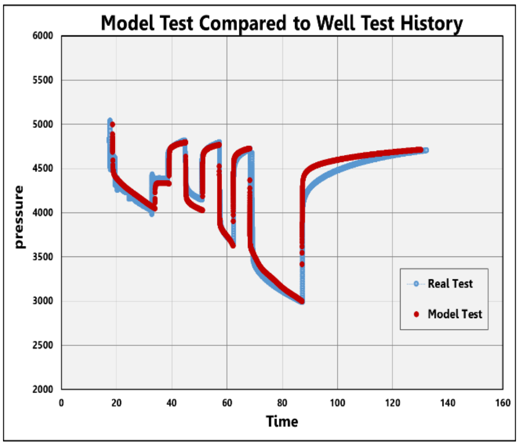

Figure 6.2: Final well test history match

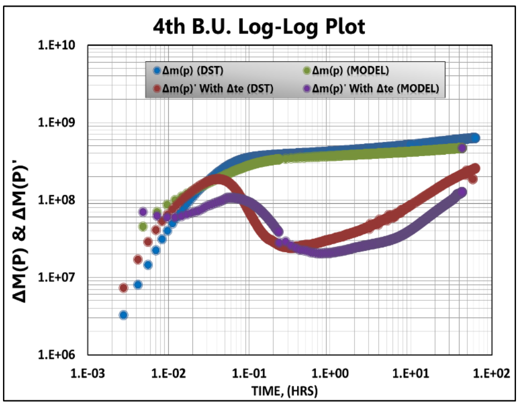

Figure 6.3: BU4 well test interpretation (simulation model vs DST results)

7. Future Prediction Performance of 5A5 Well

Once we have achieved reasonable match to the well 5A5 test data, the simulation model was ready to assess and predict the well life and productivity, also to recommend any other alternatives, if possible, to enhance the gas production from this well. The main issue as indicated from BU-4 interpretation (Figure(6-3)) is the limited available amount of GIP around this well. Future performance predictions of well 5A5 have been conducted through natural depletion.
E300 Radial and Cartesian models were used to simulate the natural depletion for 5A5 vertical well, at its current completion scheme, and project its future performance. The projected gas production profile of well 5A5 is quite short, within

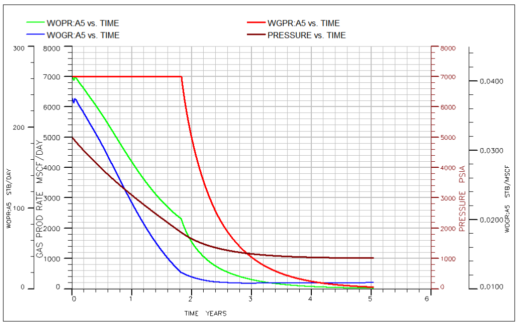

Figure 7.1: Future prediction performance (natural depletion)

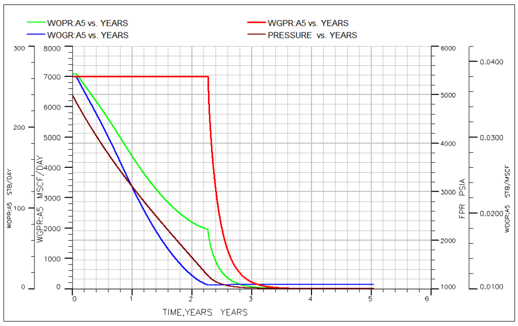

Figure 7.3: Future prediction performance (Horizontal Well)

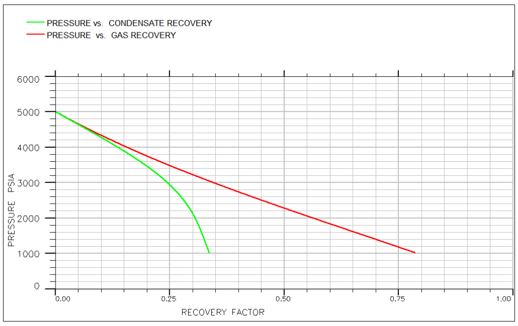

Figure 7.2: Prediction of recovery (natural depletion)

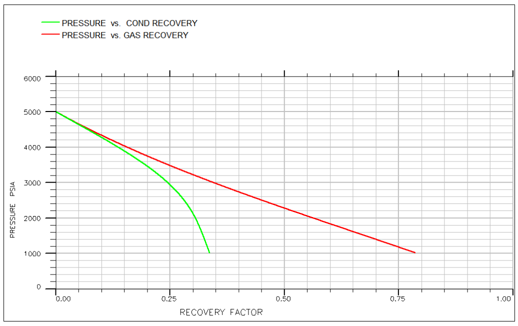

Figure 7.4: Prediction of recovery (Horizontal Well)

5 years, with a plateau period of two years then followed by sharp hyperbolic decline. These are associated with sharp decline in pressure as there is not enough gas available around the well to support the pressure (Figure (7-1)). Also, sharp decline in condensate production, partially due to the losses of condensate inside the reservoir. The ultimate gas recovery at abandonment pressure of 1000 psia is around 78% and for condensate is about 34% (Figure (7-2))

To examine other alternatives of improving the well performance and prolonging its life, a horizontal well scenario was carried out. This scenario is assuming to replace 5A5 vertical well with horizontal well that will penetrate the best vertical layer with drain length of about 1000 ft. Other assumptions kept the same as above scenario.

The plateau period of horizontal well, as indicated by simulation model results, will increase to 2.5 years because of optimization of pressure drop around the wellbore (i.e. horizontal well will enhance gas productivity). However, the well life will remain short, within 5 years, with sharper decline of gas rate after the plateau period (Figure (7-3)). The simulation model results also have indicated no change on ultimate gas recovery (78%) but slight change on condensate recovery (35%), as presented in Figure (7-4).

8. Conclusion

1. Faregh field is characterized by faulted area with very complex geological nature. Pool 5A is producing lean gas-condensate from Nubian sandstone formation at depths of ~11,000 ftss.

2. Huge pressure drops are recorded during the test of well 5A5 (~1800 psi) at high tested rate of 23 MMscf/d (choke size of 64/64). This is mainly attributed to the limited drained volume available for this well. Condensate blockage also has contributed to the pressure drop as secondary factor.

3. Simulation well models have confirmed that 5A5 area is confined (compartment area) with limited gas in place. This can be explained by

the diagnosed continues pressure build-up on the measured and simulated derivative plots of BU4.

4. Simulation model results have indicated that the most impacting parameters on well test history match are permeability, porosity and with less influence is the critical condensate saturation.

5. The expected life of 5A5 well is short (~5 years) due to the limited confined gas volume. If it is produced at 7.0 MMscf/d, the expected plateau period is two years followed by sharp decline of gas production.

6. Horizontal well can only improve the gas production plateau period by an extra half year over vertical well predictions.

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Nomenclature

IFT	= Interfacial Tension Forces
SCA	= Special Core Analysis
DST	= Drill Stem Test
CCE	= Constant Composition Expansion
CVD	= Constant Volume Depletion
EoS	= Equation of State
GWC	= Gas Water Contact
FBHP	= Flowing Bottom Hole Pressure
K_{rg}	= Relative Permeability of Gas
K_{ro}	= Relative Permeability of Oil
μ_g	= Gas Viscosity
μ_o	= Oil Viscosity
Vro	= Relative Oil Volume
Sg	= Gas Saturation
Sgc	= Critical Gas Saturation
Sw	= Water Saturation
Scc	= Critical Condensate Saturation
ϕ	= Porosity
K	= Absolute Permeability
BU	= Build Up
GIP	= Gas Initial in Place
m(p)	= Pseudo-Gas Potential

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