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Production Performance of a Retrograde Gas Reservoir: A Case Study of the Arun Field

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ABSTRACT

The Arun field is one of the world's giant retrograde gas reservoirs. Approximately 10 years after production began, a significant loss in well productivity occurred in some of the wells. The study shows that this productivity loss was due to near wellbore condensate accumulation, and documents its effects on production and pressure transient response.

A radial, single well, compositional model was used to study this effect and confirm that the productivity loss was due to liquid accumulation. The model was also used to predict the future performance of the well. The model matches well production data and the pressure transient response of affected wells.

This work identifies near wellbore condensate accumulation as an extremely important factor to consider when predicting future well performance as some of the productivities are reduced by 50%. The work also details how production data and well test analysis can be used to quantify the effects of near wellbore condensate accumulation on well productivity.

INTRODUCTION

The engineering aspects of gas condensate well performance have been a subject of research and development for many years. Recognizing that classical analytical methods (such as Al-Hussainy, et. al.[1] and Govier[2]) for dry gas wells do not apply for two phase conditions of a gas condensate well, several semi-analytical and numerical methods were developed. Here, our intension is not to present an exhaustive literature review. However, the reader is referred to Chopra[3] for some reference to prior work. In this paper we present the application of compositional modelling to pressure transient response of wells affected by condensate dropout, and to predict future well performance.

The Arun field is one of the world's giant retrograde gas reservoirs. Well test analyses indicated possible liquid accumulation effects. This was confirmed with well productivity plots. A conceptual, single layer compositional model was used to verify that liquid accumulation would cause the same type of behavior observed in the field. Subsequently, a multi layer compositional model was used to model a specific well.

BACKGROUND

The Arun field is located on the northern coast of Aceh Province in North Sumatra, Indonesia (Figure 1). Mobil operates the field, which began production in 1977. The average reservoir pressure and temperature were 7,100 psia and 352°F at a datum elevation of 10,050 ft-ss. The reservoir is a thick limestone formation with a thickness of over 1,000 ft in local areas and covers a productive area of over 23,000 acres. The initial condensate to gas ratio (CGR) was 65 Bbl/MMscf at separator conditions of 1,250 psia and 68°F. The field currently produces 3.4 Bscf/day of separator gas from a total of 78 producers with an average reservoir

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Figure 1 - *Location map*

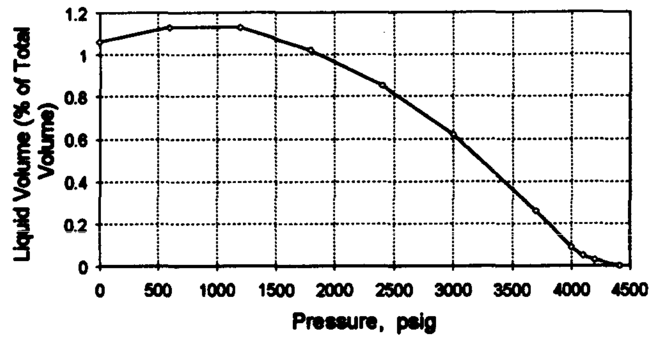

Figure 2 - *Constant composition expansion*

pressure of 2,250 psia.

After initial separation, gas is sent via pipeline to PT Arun, an LNG plant. Unstabilized condensate is also sent to the LNG plant for further separation. A side stream of separator gas is sent to a field NGL plant where extraction of LPG components is removed and sent to the LNG plant. The residue gas supplies field fuel, domestic sales, and injection.

Gas injection was implemented as soon as field production began to accelerate liquid recovery. Currently 25% of the produced gas is injected. The lean gas is injected on the periphery of the reservoir to sweep condensate rich gas towards the producers.

This makes the Arun reservoir a compositionally dynamic system where retrograde condensation, water vaporization, and lean gas injection affect reservoir behavior.

A fluid sample was taken prior to production. Experimental data revealed the dew point pressure to be 4,400 psi. Retrograde behavior was determined as shown in Figure 2. Gas began condensing at the dew point and increased with lower pressure to a maximum liquid dropout filling about 1.1% of the pore volume. Further reduction in pressure caused vaporization of a small portion of the liquid.

As deliverability became more critical to meet LNG contracts, deliverability estimates became more important. To improve these estimates an intensive pressure transient well testing program began in 1989, at which time the reservoir pressure had fallen below the initial dew point. By 1993 all wells were tested at least once.

A typical Arun well test response is shown in Figure 3. The test consisted of three one-hour flow periods followed by a build up period. A typical log-log derivative curve of the build up period is shown in Figure 4. The curve exhibits two different stabilization regions which represent zones of

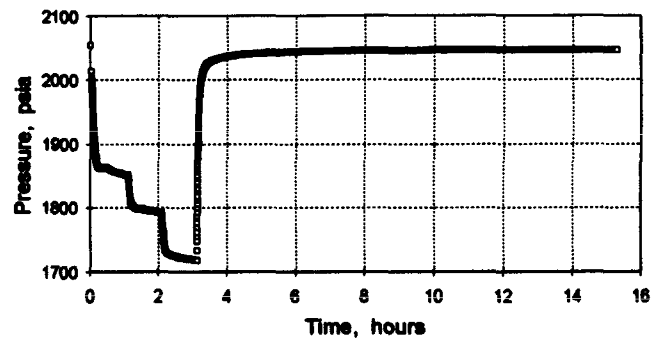

Figure 3 - *Typical Arun pressure transient response*

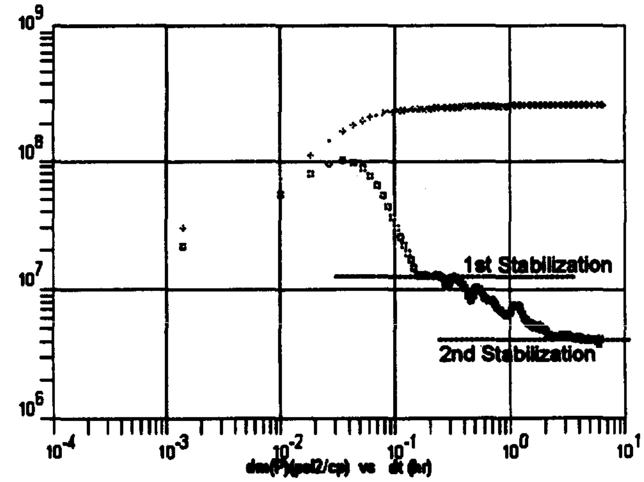

Figure 4 - *Typical log-log derivative plot*

different effective gas permeability-thickness products ($k_{eg}h$). In this case, $k_{eg}h$ in the inner zone is lower than that of the outer zone.

The most common explanations for this type of behavior are spherical flow or multi layer effects. With the reservoir pressure below the dew point, another possibility was the effects of liquid accumulation around the well bore.

Liquid accumulation occurs because producing a well creates a relatively large pressure drop in the vicinity of the well. Gas migrating to the well originates away from the well where the pressure is higher. This gas is in vapor liquid equilibrium at the higher pressure. As the gas migrates to the well, pressure decreases and a small fraction of the gas condenses close to the well. This condensate is below the critical liquid saturation (S_{lc}) and does not flow. As more gas is produced, the small amount of gas which condenses begins to accumulate until the critical liquid saturation is reached. Condensate then flows into the well as a liquid phase.

The bank of condensate which accumulates around the well bore can be envisioned conceptually as shown in Figure 5. Initially a small bank forms and is entirely below the critical saturation. Later, the area immediately around the well reaches the critical saturation followed by a transition zone of decreasing liquid saturation. Eventually, when the reservoir pressure reaches the point of maximum liquid dropout, the transition zone terminates at the maximum liquid saturation ($S_{l\,max}$) in the reservoir.

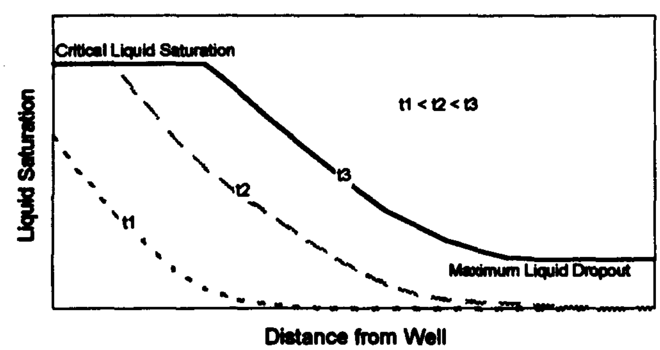

Figure 5 - *Typical condensate accumulation as a function of time*

In May 1990 some experimental work was performed to estimate the critical liquid saturation and the gas relative permeability (k_{rg}). Figure 6 shows the results obtained for a core sample from the Arun field. The critical liquid saturation was 51% while the gas relative permeability at the critical liquid saturation was 0.18. Notice that for the Arun fluid system the small amount of liquid dropout in the reservoir of 1.1% affects the gas relative permeability very little. Even when the maximum liquid drop out is reached the gas relative permeability is 0.99. The flow of fluids in the reservoir is affected very little with condensate dropout. However, the liquid accumulation around the well severely restricts the flow of gas in the near well region.

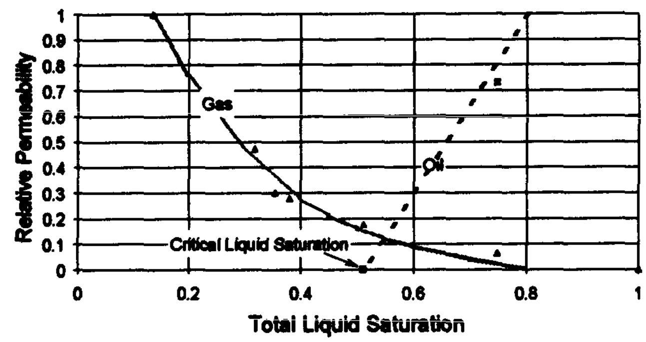

Figure 6 - *Experimental relative permeability data*

In order to prove liquid accumulation was affecting the well tests, Productivity Index (PI) plots were generated. PI is defined as the total well stream (TWS) rate divided by the drawdown pressure. Psuedo-pressures (m(P)) are used in calculating PI. Flowing bottom hole pressures (P_{wf}) were estimated from measured flowing well head pressures with compositional tubing hydraulics. Interpolation of static bottom hole pressures was used to estimate the reservoir pressure (P_r). The PI plot for an Arun well is shown in Figure 7.

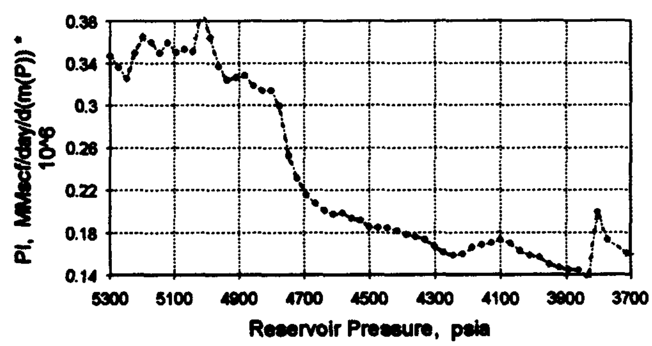

Figure 7 - *PI of a typical Arun well as a function of reservoir pressure*

A significant drop in well productivity occurred when the flowing bottom hole pressure went below the dew point. This was considered strong evidence that the well tests were affected by liquid accumulation. Spherical flow and multi layer effects are not affected by the dew point, so no change in productivity should occur. Only liquid accumulation can account for both the well test effects and the significant loss of productivity below the dew point.

SINGLE WELL MODEL

To confirm that a well undergoing liquid accumulation would behave in the same manner observed in Arun wells, a single well, compositional, 2-dimensional (r-z coordinate system) simulation model was used. The effects of liquid water vaporizing into the vapor phase because of the high reservoir temperature is included in the model (Bette' and Heinemann[4]).

The model consisted of a single 765-ft layer of homogeneous properties with 11 radial cells of varying widths. The inner cell radius was 10 ft with subsequent cells getting larger. Figure 8 illustrates the cell dimensions along with the reservoir properties. The well was completed over the entire interval to eliminate partial penetration effects.

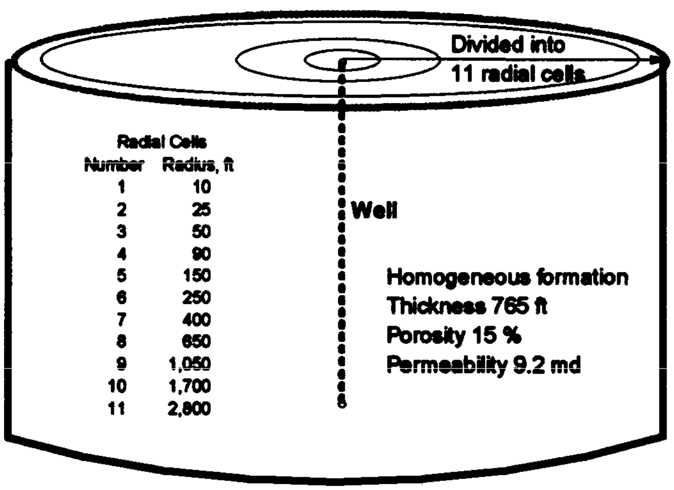

Figure 8 - *Single layer model*

Initial work with this model indicated that the experimentally derived relative permeability curves were not representative of the reservoir and the fluid phases. Therefore, to account for the interfacial properties of the accumulated liquid near the wellbore, the gas relative permeability curve was modified slightly as shown in Figure 9. The experimentally defined critical liquid saturation was honored and the gas relative permeability at the critical liquid saturation was increased to 0.435. This forced the gas curve to be a straight line.

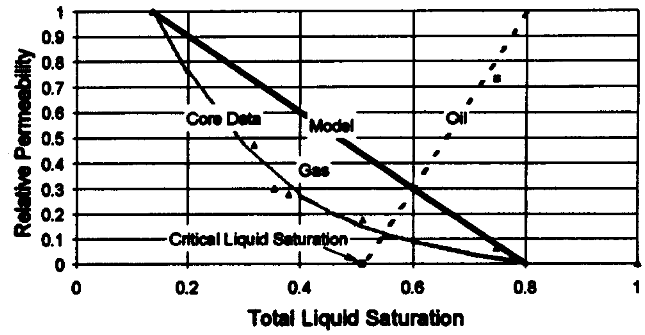

Figure 9 - *Model gas relative permeability curve*

The applicability of this model for generating well test data was confirmed by generating a pressure transient test while the reservoir pressure in the model was at 5,250 psi. Care was taken to ensure that the flowing bottom hole pressure remained above the dew point pressure throughout the test. The pressure response was analyzed using a well test analysis software. Excellent agreement was obtained between the parameters from the analysis versus those used in the simulation model. A comparison of the results is shown in Figure 10. This confirmed the applicability of the simulator to model pressure transient behavior. Notice that the derivative curve in Figure 10 does not exhibit the hump during the early time as shown by the field test (Figure 4). The hump represents wellbore storage effect, which was not simulated in the model.

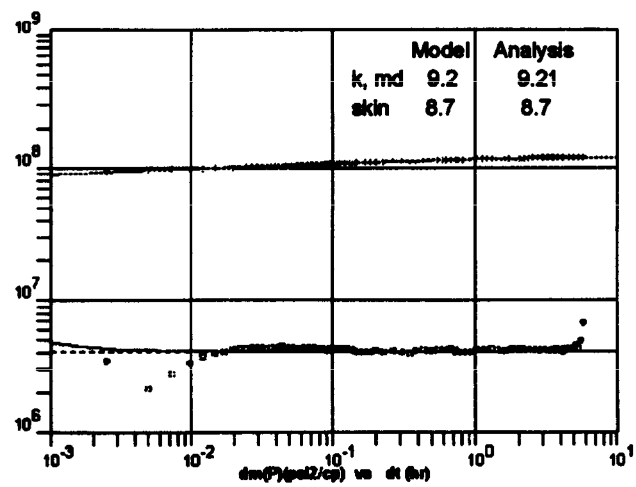

Figure 10 - *Test from single layer model, prior to condensate accumulation*

Using the model, a second well test was generated after a 3-month shut in period at a reservoir pressure of 3,660 psi, well below the dew point pressure. The generated pressure profile was analyzed analytically. The results are shown in Figure 11. The derivative curve exhibits the same character as that observed from our field tests (Figure 4). Stabilized regions developed depicting two regions of different $k_{eg}h$.

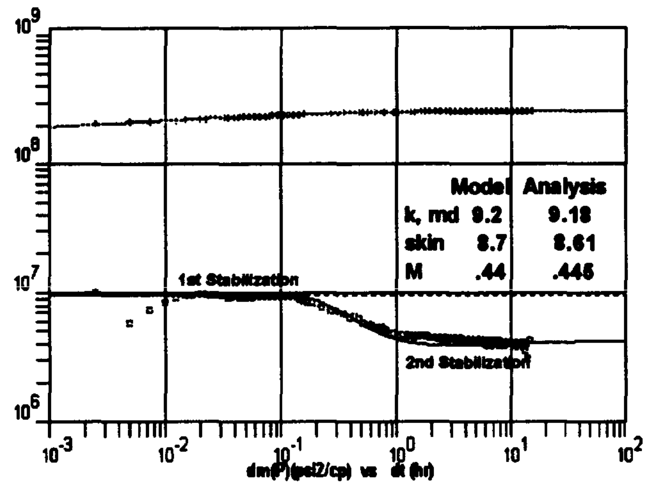

Figure 11 - *Test from single layer model, after condensate accumulation*

An analytical radial composite model was used to interpret this test. The interpretation results are very close to the values used in the simulation model. The ratio (M) of the inner k to the outer k is .445 which is very close to the relative gas permeability at the critical liquid saturation used in the model.

It is important to note that gas relative permeability at critical liquid (k_{rg} at S_{lc}) saturation can be determined from the two stabilized regions of the derivative curve for the Arun fluid system. This is the most important factor in determining well productivity loss. This is so for the Arun system where k_{rg} away from the well is essentially unaffected by liquid dropout. However, other fluid systems which have higher maximum liquid dropout can impact k_{rg} away from the well. In these systems, the ratio of inner k and outer k represents the ratio (M) of k_{rg} at S_{lc} and k_{rg} at $S_{l\,max}$. If M is available from core data, the effect of condensate accumulation can be estimated from the inflow equation for the radial composite model :

$$P_r^2 - P_{wf}^2 = \frac{1422\, Q\mu ZT\, (M\,(\ln(r_e/r_i)-3/4) + \ln(r_i/r_w)+S_o+DQ)}{k_i h} \quad \text{.............. (1)}$$

The analytical solution to the radial composite model is superimposed on the results of the simulation in Figure 11. Both stabilized regions of the derivative curve matched with the transition period between these regions matched fairly well. However, in some of the field tests, the transition zone did not match very well. This is a result of the simplified assumptions used in the radial composite model.

Figure 12 illustrates gas relative permeability as a function of distance from the well from the simulation model and that assumed in the radial composite model. The analytical model, which consists of only two regions, does not account for the transition from the inner zone with S_{lc} to the outer zone with connate water saturation (S_{wc}) or $S_{l\,max}$. Thus, the analytically determined derivative curve reaches the second stabilized region sooner than the simulation model.

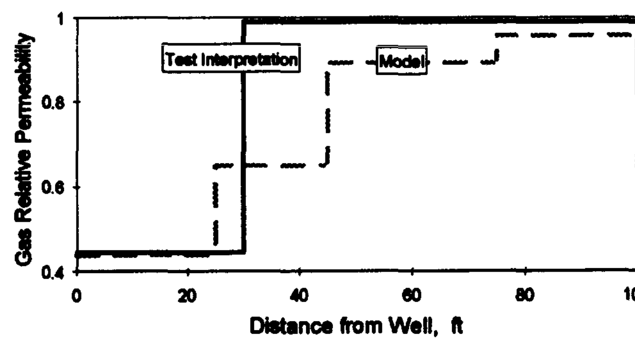

Figure 12 - *k_{rg} as a function of distance from the well*

Satisfied that liquid accumulation can cause the characteristic behavior seen on Arun well tests, well productivity was generated as a function of reservoir pressure. Figure 13 illustrates the results of the simulation model. When the well pressure passed through the dew point productivity was quickly and severely affected by liquid accumulation. PI

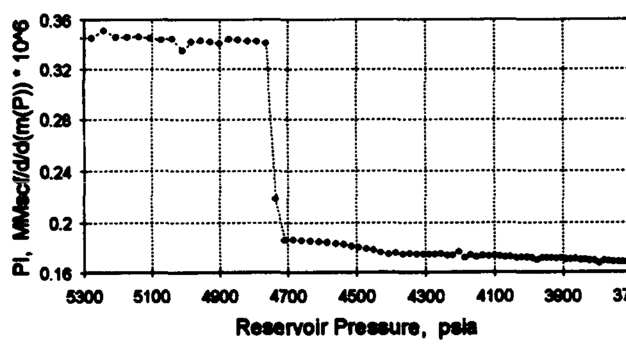

Figure 13 - *PI of the single layer model*

dropped from 0.341 to 0.186, a reduction of about 45%, as soon as condensate accumulated in just the first cell. The first cell was filled up to S_{lc} within a short time due to its relatively small volume compared to the gas throughput. Productivity continues to decline, reaching a 50% reduction, as liquid accumulates but at a much lower rate.

To further investigate this rapid decline in PI, the single layer model was run with the first cell refined to five 1-ft cells. The result is shown in Figure 14. PI drastically drops when the first 1-ft cell was filled to S_{lc}. At the time, condensate had not started accumulating beyond the 1-ft radius. The declining liquid saturation prior to the rapid accumulation of condensate is due to the water vaporizing into the vapor phase.

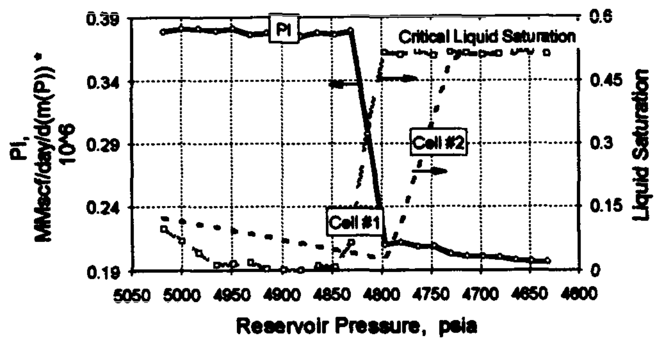

Figure 14 - *Effect of condensate accumulation 1-ft around the wellbore*

This example illustrates a very small zone with liquid saturation at S_{lc} significantly affects well PI. For a high rate, high CGR well, this small zone is filled to S_{lc} as soon as the flowing bottom hole pressure falls below the dew point.

The model with the original radial cells was also used to investigate if the accumulated condensate revaporizes when the well is shut in for a long period. The model simulated a 2-year shut in period after the reservoir pressure was well below the dew point with the following results:

	Liquid Saturation		
Year	Cell #1	Cell #6	Cell #11
0	.512	.15	.142
1	.512	.15	.142
2	.512	.15	.142

The results indicate that liquid saturation in each cell remains constant during the 2-year shut in period. There are several explanations for this but the primary reason is that there is very little gas migration at the shut in well . The gas immediately surrounding the well reaches vapor liquid equilibrium with the condensate at the higher shut in pressure but does not change significantly with time. Shutting in the well does not improve the well productivity (Fussel[5]).

To investigate if liquid will revaporize at lower reservoir pressure, this model was depleted to a reservoir pressure of 500 psia. Figure 15 shows liquid saturation in the first three inner cells as a function of reservoir pressure and the effect it has on PI. The reduction in oil saturation due to revaporization occurred in cell #3 long before cells #2 and #1. PI was not significantly improved until the oil saturation in cell #1 was reduced. Again, this confirms that condensate accumulation immediately around the wellbore significantly affects well productivity.

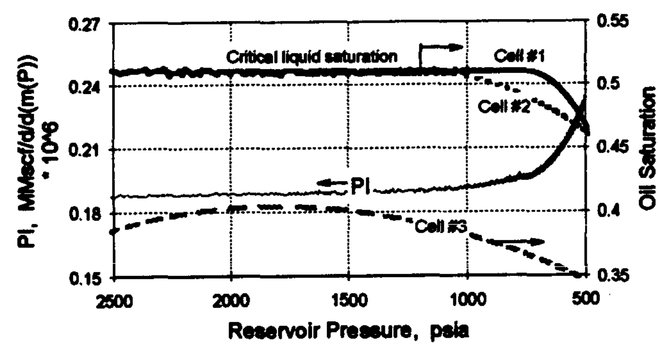

Figure 15 - *Effect of liquid revaporization on PI*

MULTI LAYER MODEL

To investigate the effect of multiple layers on both liquid accumulation and well test response, a six layer model was constructed. The radial dimensions are identical with the single layer model. Figure 16 illustrates the thickness of each layer along with the reservoir properties assumed. These properties were obtained from a detailed geologic description in the region of an individual Arun well. In general, porosity and permeability decrease from top to bottom. The same relative permeability curves as in the single layer model was used for all layers.

The model showed that the rate of condensate accumulation differed from layer to layer. The amount of liquid accumulation is influenced by the gas throughput. Consequently, layers with higher permeability accumulated condensate and developed the inner zone of reduced k_{eg} faster than the low permeability layers. Figure 17 shows this

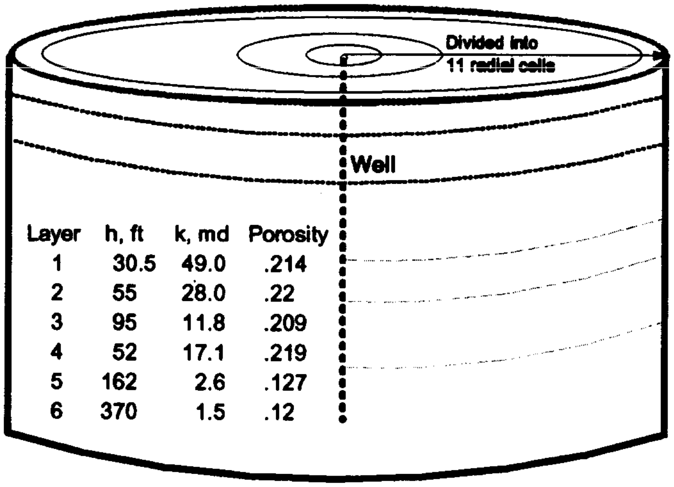

Figure 16 - *Six-layer model*

clearly. The proportion of condensate accumulation in each layer is almost identical to the proportion of kh. The higher kh layers accumulated condensate slightly lower than their kh proportion as these layers were more severely affected by condensate accumulation. Consequently, the proportion of gas throughput in these higher kh layers was curtailed. Thus, liquid accumulation has a normalizing affect on layered systems affecting high kh layers more than low kh layers.

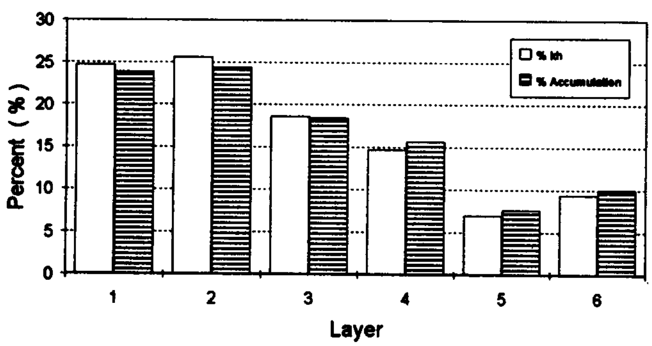

Figure 17 - *Condensate accumulation in different layers*

A well test was generated at a reservoir pressure of 3,660 psi. The calculated derivative curve is shown in Figure 18 superimposed on the derivative curve generated from field data. An excellent match to the two stabilized regions was obtained. Even though six layers were used in this model, the generated transition between stabilized regions and the radius of the zone with S_{lc} did not match the actual data. This is due to the limitation of using a finite number of cells.

A comparison of the well productivity profiles generated with

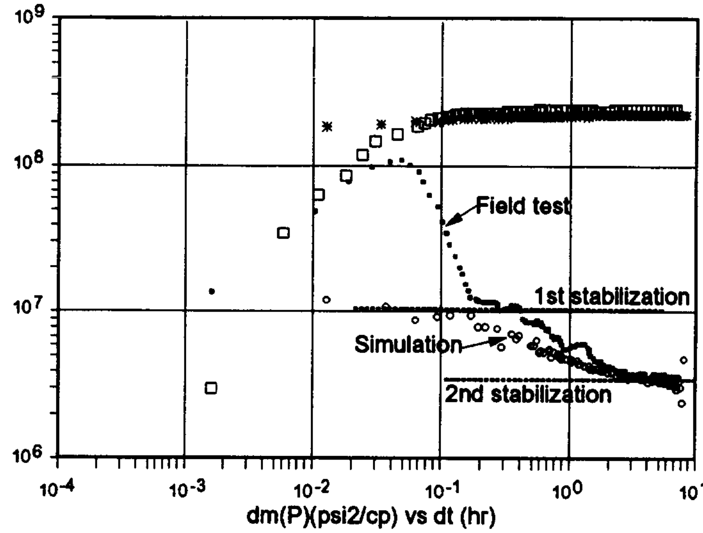

Figure 18 - *Actual vs 6-layer model tests*

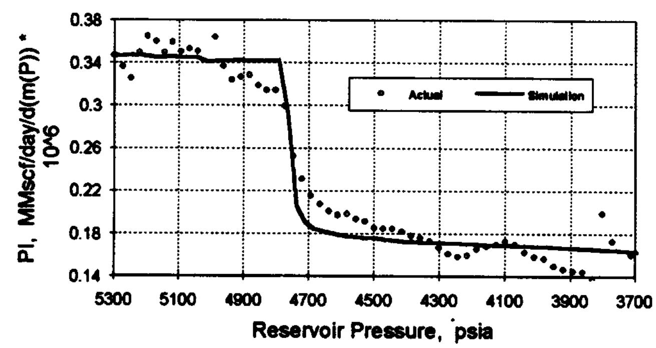

Figure 19 - *PI of the 6-layer model vs. the actual Arun well*

the model to that generated from field data is shown if Figure 19. An excellent match was obtained.

FUTURE WORK

With these results, we are confident that the model used in this study represents the actual Arun well. Some future work to be done based on his study include :

- Effect of lean gas injection breakthrough on condensate revaporization

- Methods of removing the zone of condensate accumulation immediately around the wellbore to improve productivity by injecting miscible fluids

- Effect of condensate accumulation on a much leaner gas reservoirs

CONCLUSIONS

Liquid accumulation has occurred in the Arun reservoir. This was identified through well test interpretation and PI plots. This conclusion was verified with compositional simulation. Other conclusions from this study are :

- Even with a fairly lean gas, liquid accumulation reduced individual well productivities by about 50%

- The most dominant factor which determines productivity loss is k_{rg} at S_{lc}

- For the Arun fluid system, k_{rg} at S_{lc} can be determined from well test analysis. S_{lc} cannot be determined.

- The most critical region affecting productivity is immediately around the wellbore.

- The amount of accumulation is controlled predominantly by gas throughput. Consequently, zones of higher kh contain the most liquid accumulation.

- The accumulated liquid does not re-vaporize if the well is shut in for an extended period.

- A radial composite model can be used to analyze well tests. k_{rg} of the inner and outer regions can be determined but the transition region cannot be modelled.

- Condensate revaporization begins in zones away from the well. Productivity does not significantly improve until revaporization begins immediately around the wellbore.

NOMENCLATURES

CGR = Condensate to Gas Ratio
D = non-Darcy coefficient, day/Mscf
h = formation thickness
k = permeability
k_{eg} = effective gas permeability
k_i = k_{eg} at S_{lc}
k_{rg} = relative gas permeability
LNG = Liquified Natural Gas
LPG = Liquified Petroleum Gas
M = $k_{inner\ zone}/k_{outer\ zone}$
m(P) = gas pseudo pressure
NGL = Natural Gas Liquid
PI = Productivity Index
P_r = average reservoir pressure, psia
P_{wf} = flowing bottom hole pressure, psia
Q = flow rate, Mscf/day
r_e = drainage radius, ft
r_i = radius of inner zone, ft
r_w = wellbore radius, ft
S_{lc} = critical liquid saturation
$S_{l\,max}$ = maximum liquid dropout
S_o = Skin factor at Q=0
S_{wc} = connate water saturation
Z = compressibility factor
μ = viscosity, cp

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