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Reduced Productivity Impairment for Fracture Stimulated Gas Condensate Wells

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Abstract

Development of a retrograde condensate reservoir requires accurate well productivity predictions for a capital commitment to gas processing facilities. Historically, Fussell[1] identified that liquids condensing in the reservoir will result in a substantial productivity impairment. A single well model, which included a hydraulic fracture as part of the grid system, was developed to perform sensitivities for well test interpretation and to predict long term performance. Interesting results were obtained. The productivity of fractured wells was not impaired to the degree expected. Radial modelling confirmed the results obtained by Fussell. Current simulation technique allows for direct modelling of a hydraulic fracture instead of using an equivalent well bore radius. The distribution of pressure drawdown and condensate dropout around a hydraulic fracture results in limited productivity impairment. The methodology used and the results obtained are described.

Introduction

This work was originally completed to forecast production from wells in a new field, which was being developed in the Deep Basin area of Alberta, Canada. This study was comprised of geological review, PVT characterization, numerous well test sensitivities, as well as simulating the effects of condensate dropout on well productivity. The ultimate objective of this work was to make a nomination for a sour gas plant.

This paper concentrates on the most important technical point which is that the productivity of wells, which are hydraulically fractured, may not be as adversely affected by condensate precipitation as was previously reported. However, in any actual study, there are a significant number of factors which are derived from different disciplines within petroleum engineering, which must be integrated. We have therefore placed our main results within an abbreviated outline of the process used in solving an actual field problem. In the authors' opinion, this is more valuable to practicing engineers.

As much as possible, the material is presented chronologically so as to follow the development of the technical work. Material is presented under the following major headings: Geological Review, PVT Characterization, Model Construction, Well Test Modelling, Effects of Condensate Dropout, and Conclusions. Originally this work was completed for a single well, which was later expanded to include other wells in other pools. Only the work done on the first well analysed is presented and does not apply universally to the area.

Geological Review

The main objective of this phase of the study was to develop a quantitative reservoir description. This included porosity, permeability, water saturation and layering (heterogeneity). Since this was a new play, relatively little information was available on this zone.

The lithology of the sandstone in this well was derived from a core description. Overall, the sand comprises interbedded dark grey-black shaley siltstones and light grey dolomitic sandstones. The shaley siltstones occur in beds that range in thickness from centimetres (inch) to metres (3 to 6 ft.) . The sandstone occurs in beds $^1/_{10}$ of a metre (4 in.) to metres (3 to 6 ft.) thick.

Layering can be a major consideration in the design of a simulation, particularly for secondary recovery. Although permeability variations would likely effect the amount of liquid dropout, the permeability variation in this reservoir was not servere. Due to limited time constraints, this issue was therefore not addressed during the initial study phases and is not discussed in this paper.

A good quality relationship was found by plotting core porosity vs. core permeability from several wells. Tests were also made at overburden (hydrostatic) stresses. The porosity and permeability showed only a slight sensitivity to overburden pressure.

Water saturation was derived from log analysis to be 15%. This is a low value for a tight sandstone and consequently generated a great deal of discussion. This issue could not be resolved quickly. From the point of view of modelling condensate drop-out, the initial water saturation would not effect the overall process. This value was therefore retained and input at a constant value of 15%. The balance was assumed to be gas.

Overall, the reservoir is of low quality. A good quality core porosity vs. core permeability relationship was found. No layering was included in the models.

PVT Characterization

A PVT characterization was required that could be used in a compositional simulator. A general phase behaviour package was utilized for this study. The Peng-Robinson equation of state was used throughout this work.

The original reservoir temperature and pressure was approximately 81˚ C (178˚ F), or 354˚ Kelvin (637˚ Rankine), and 18,875 kPa (2,738 psi) respectively. The critical point of the mixture was calculated to be 231˚ Kelvin (415˚ Rankine) and 5,070 kPa (735 psi), which was well below the original reservoir conditions. Hence, on first look, it appeared that this reservoir was unlikely to exhibit retrograde condensation. There was a relatively low concentration of intermediate hydrocarbon components (C2's are under 5%), however, there is over 10% H_2S. Sour gases are more

TABLE 1: Scoping sensitivity reservoir fluid compositions.

Case	#1	#2	#3	#4
Component	Mole Percent			
H2S	10.9	10.9	10.9	10.9
C1	78.04	78.04	78.04	78.04
C2	5.73	5.73	5.73	5.73
C3	2.11	2.11	2.11	2.11
nC4	1.15	1.15	1.15	1.15
nC5	0.54	0.54	0.54	0.54
nC6	0.29	0.29	0.29	0.29
nC7	1.24			
nC8		1.24		
nC9			1.24	
nC10				1.24

prone to retrograde condensation, which prompted a partial gas-condensate lab study.

Initially, a PVT package was used to get a general “feel” for the problem. For this, a number of simplifications were made to the reservoir fluid composition. First, the iso-pentanes and normal-pentanes, plus all other structural isomers were input as the normal component. Second, a small correction was applied to the re-combination so that the sum of the mole fractions of the reservoir fluid summed exactly to 1.0000. Third, the heavy ends (C7 +) were characterized as a single component.

A total of four sensitivities were run with the C7+ components characterized as: nC7, nC8, nC9 and nC10. The compositions used are outlined in Table 1.

The results of these sensitivities were plotted on a convergence chart[(2)], as shown on Figure 1. This chart is normally used for estimating parameters for flash calculations using equilibrium ratios, how ever, the authors have also found it to be useful in tuning equation of state parameters. The critical points of individual components are shown, as well as the approximate locus of critical points for binary mixtures. Note that the critical pressures and temperatures of C7 (heptane) through C10 (decane) are on the right side of the diagram. Even minor amounts of the heavier ends will shift the phase diagram quite far to the right. The critical point of the mixture remains fairly close to the left hand side, near methane.

TABLE 2

Component	Mole Percent
C1	78.02
H_2S	10.90
C2	5.78
C3	3.26
nC6	0.83
nC10	1.24

The liquid drop out curve from the partial gas-condensate lab analysis is shown in Figure 2. A prediction utilizing the PVT package is also shown. The calculated amount of liquid drop out is different by almost a factor of two. Although this is a large error in relative terms, the overall amount of liquid drop out is relatively small.

In order to reduce simulation times the original ten component system was simplified to six components. These are shown in Table 2. The phase diagram for this system matches the original ten component system very closely as depicted in Figure 3. This characterization was used initially for the compositional modelling.

Further tuning was done on the equation of state parameters. One way to split the characterization is to group the molecules by general chemistry and geometry. Paraffms (P), Napthenes (N), and the Aromatics (A) can be split to improve characterization. This distribution was applied to the C7+ fraction. Tuning was also done using a regression option, on the critical temperature, pressure and volume as well as acentric factor of the C7+ components. Following this more sophisticated tuning was done by allowing regression on the binary interaction coefficients between H_2S and the C7 +. The improvement was not as great. Most of the liquid volume predicted for constant volume depletion are accurate to within plus or minus 20%, an acceptable result.

Only the initial six component system was used. Although the final PNA interaction tuned model was considerably better (par-

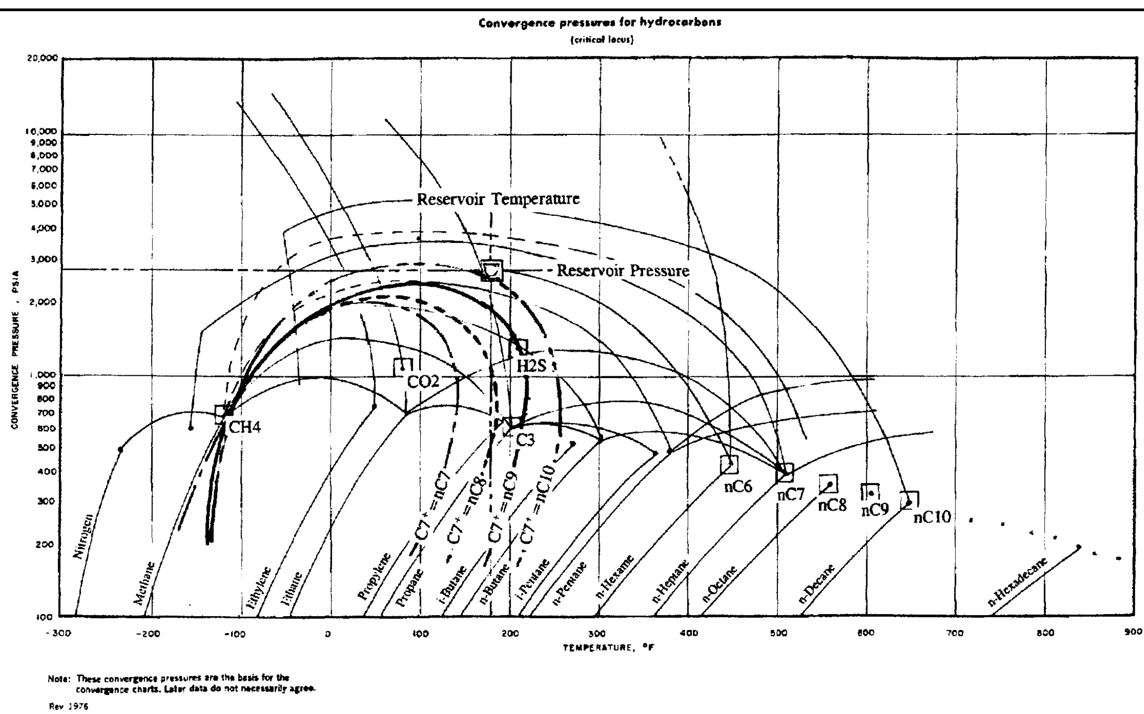


FIGURE 1: Scoping analysis – convergence chart.

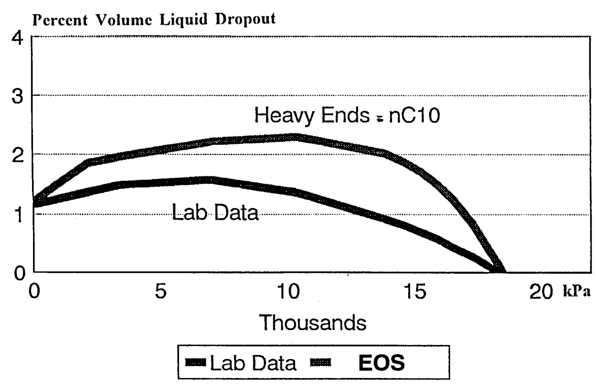


FIGURE 2: CVD lab results and EOS liquid dropout prediction.

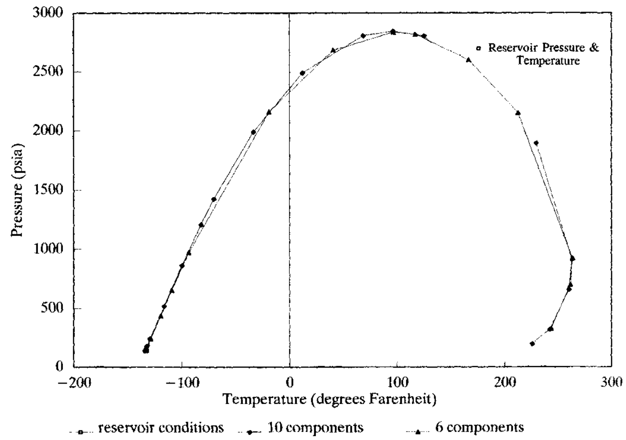


FIGURE 3: Phase diagram six vs. ten components.

ticularly in relative rather than absolute terms), the results indicated that liquid precipitation would not be a problem at 2.5% of pore volume. Re-running the model was therefore not justified.

Model Construction

The quality of any simulation is only as good as the input data. Much of the input was common to the two models used. In the following summary, the order used in the data file was retained as much as possible:

For modelling a fracture stimulated well, a detailed grid is required. A fine grid and quarter element of symmetry was therefore used. Figure 4 shows the grid used. The grid was set up to represent single section (259 ha or 640 acre) spacing, with an overall grid dimension of 805 m by 805 m (2,641 ft. by 2,641 ft.). Variations of this grid have been used and tested extensively before[3, 4].

Net pay and porosity were input based on log analysis. Since the model is largely conceptual these values were rounded off. Also, since a type model was being used, these parameters were input as constants for the entire simulation grid.

Fracture dimensions for the well were determined from a treatment design prepared by a well service company. Pertinent data is outlined in Table 3. The treatment design does not, of course, necessarily represent the fracture that was placed in the formation. This could be due to lack of cement bond integrity or due to large height growth. What actually happened was therefore uncertain.

TABLE 3

Propped Half Length	210 m	689 ft
Average Conductivity	197 mD*m	646 mD*ft
Propped Width at Well	3.4 mm	0.134 inches
Average Fcd	1.2	1.2
Avg. Propped Width	2.8 mm	0.11 inches

Distance Along Frac		Propped Dimension					
		Width		Height		Conductivity	
m	feet	mm	inches	m	feet	mD*m	mD*ft
53	174	2.8	0.110	20	66	451	1479
105	344	3.5	0.138	24	79	138	453
158	518	2.9	0.114	21	69	123	401
211	692	1.9	0.075	18	59	76	249

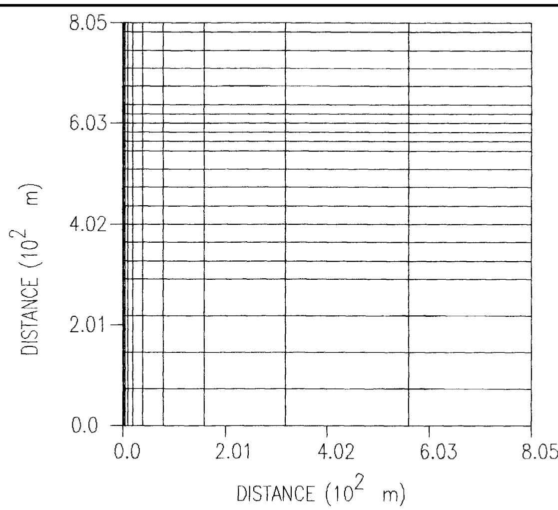


FIGURE 4: Quarter element of symmetry grid.

Detailed analysis was performed on the treatment log. No indication of vertical height growth was seen, however, bottom hole pressure measurements were not available. The interpretation was therefore not conclusive. On this basis, the design parameters were accepted as being at least reasonable indications of fracture dimensions.

In the early stages of development a considerable amount of input data is not well known. The net pay and porosity are relatively well quantified from log and core analysis. Propped fracture properties were derived from a fracture stimulation design program, which does not necessarily represent the fracture placed in the ground. This is very difficult to check by direct observation. Analysis of the treatment log did not indicate severe height growth.

Well Test Modelling

Well test analysis can provide an estimate of formation permeability and hydraulic fracture properties. The majority of pressure data obtained came from the bi-linear flow regime, which does not give unique results. Various combinations of fracture conductivity, fracture length and formation permeability yield similar results. A complete analysis cannot be obtained without pressure data that comes from the pseudo radial or transition to pseudo radial flow regime. Error minimization was used to determine the "best" interpretation. An investigation was made to see if the minimization procedure was sufficiently sensitive to converge to correct formation permeability and fracture proper- ties, even if com-

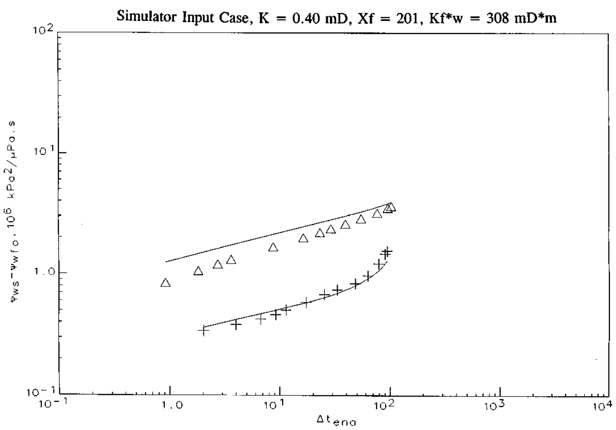


FIGURE 5: Type curve plot (derivative is bottom curve).

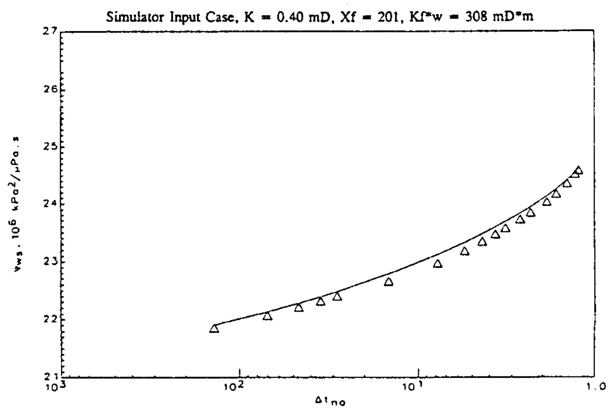


FIGURE 6: Horner plot.

plete conventional analysis (straight line) methods could not be used.

One way to test this was to generate a buildup via simulation with known input and then analyse the test. For this segment a black-oil model was used assuming a dry gas. Hence, condensate dropout and gravity segregation were not accounted for.

Several slight deviations were made in the final rates between the actual field test (not discussed) and the simulation model. These changes were not significant for testing the minimization process, however, the test interpretations shown do not represent the actual well test.

The fracture treatment prediction program indicates a tapered fracture. This was included in the numerical simulation model and would be expected to a significant effect, since the flux into a finite conductivity fracture is concentrated at the ends(5). The analytical solution used in the pressure transient analysis assumes a constant fracture conductivity.

Input parameters were a formation permeability of 0.4 mD, a fracture conductivity of 308 mD*m (1,011 mD*ft), and a fracture length of 201 m (669 ft.)

Buildup type curves were used generated through an option in the pressure transient analysis program and allowed to regress on Xf, Kf*w, and K. The results are shown in Table 4. The results of the above minimization changed depending on the initial guesses of K, Xf and Kf*w.

A buildup was then generated in the pressure transient analysis package using the simulator input parameters and compared against simulator output. Results are shown in Figure 5 through Figure 7. The least squares error was 52.5 kPa (7.6 psi). Although

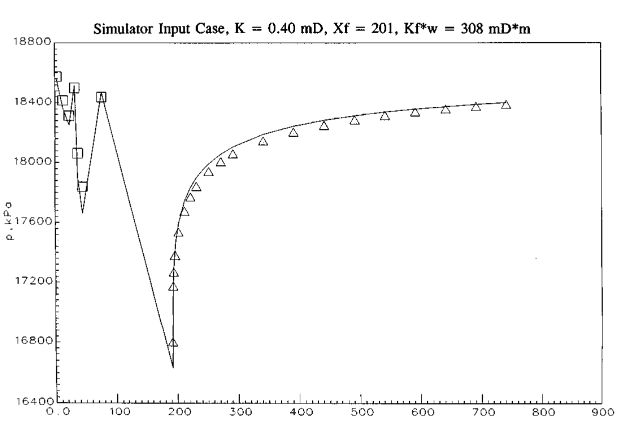


FIGURE 7: Strip chart.

TABLE 4

K	Xf		Kf*w		Error	
mD	m	feet	mD*m	mD*ft	kPa	psi
0.44	149	489	536	1759	13.1	1.9

not as good as the earlier minimization, this is still a relatively low level of error.

The well test did not extend into pseudo radial flow, nor the transition to pseudo radial flow, hence, reliable formation and fracture properties were not expected. In the author's experience such tests will invariably be analysed, to get as much information as possible out of diem. The simulation and well test interpretation were not directly comparable, since a tapered fracture was included in the simulation. No rigorous error analysis was made. Although simulator tolerances were tightened, analytical pressure transient solutions are inverted from Laplace space to real time via numerical inversions and therefore have a numerical error.

From a pragmatic point of view, the tools were compared as they would normally be used.

Modelling the pressure transient analysis gave an indication of a systematic bias in the estimation of formation permeability. With this it was possible to combine the different sources of data to make a better estimate of formation permeability. It should be pointed out that a reasonable order of magnitude estimate of formation permeability was derived..

Although a reliable interpretation of fracture properties could not be made from well test analysis, there was no indication that the information from the fracture treatment prediction were not correct.

Effects of Condensate Dropout

As a wet gas approaches the wellbore, the pressure drops below the dew point causing liquid hydrocarbons to condense in the reservoir. Due to relative permeability effects, the effective permeability to gas is reduced, which decreases well deliverability. This process is shown pictorially in Figure 8 and Figure 9. The major objective of this work was to quantify how severe this effect would be and make an accurate well production forecast.

From a pragmatic point of view, the tools were compared as they would normally be used.

Compositional modelling was ran on a Unix RISC based engineering workstation. The black oil model and the compositional model came from the same vendor, hence, all that was required was to replace the PVT section of the data file with compositional information. The use of a single layer model continued, gravity segregation effects have therefore been ignored.

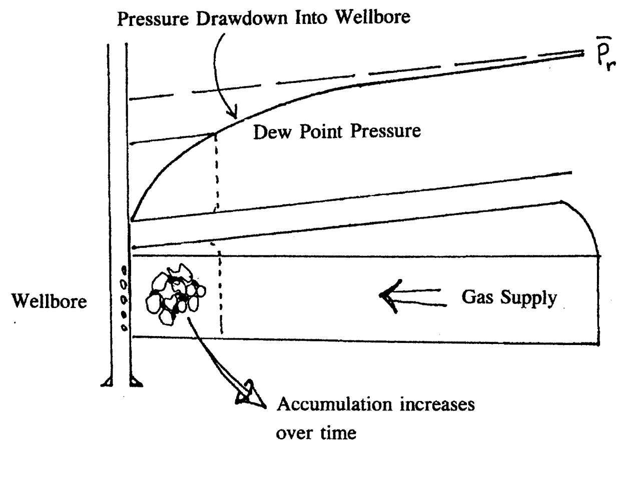


FIGURE 8: Condensate dropout process.

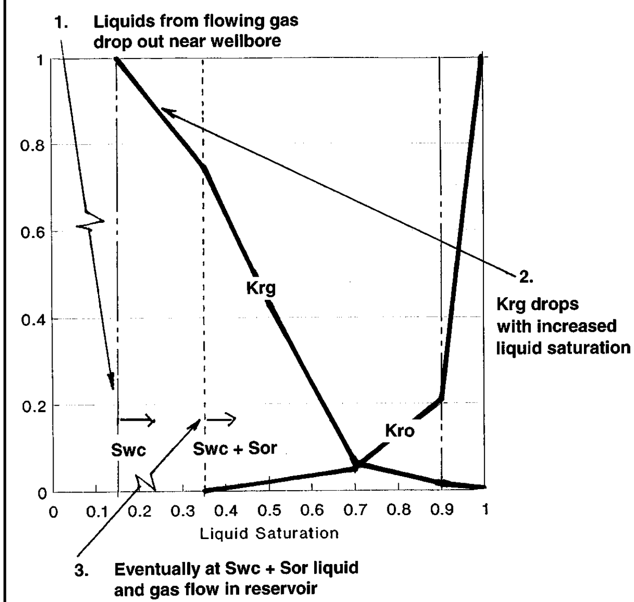


FIGURE 9: Relative permeability dropout.

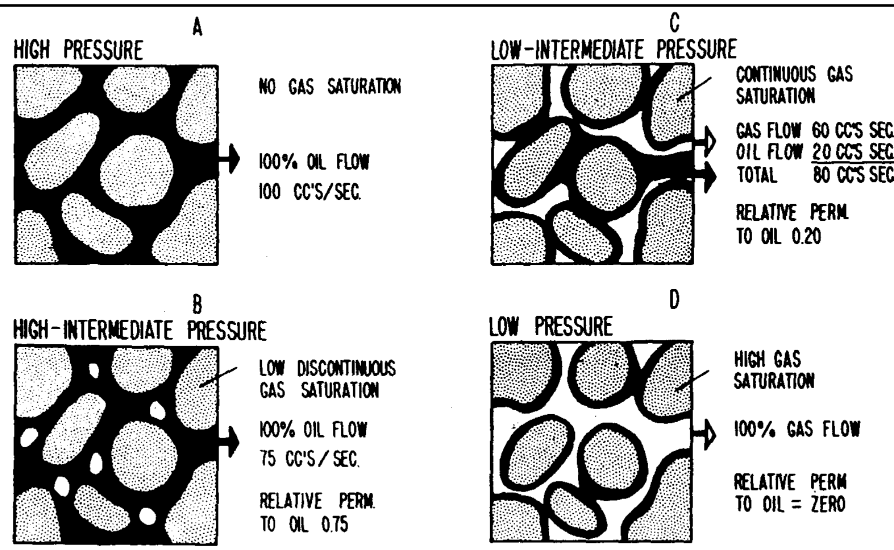
Some thought was given to modelling the effects of condensate dropout on the pressure buildup response. In the end time did not permit this to be analysed. Most of the condensate is known to drop out near the wellbore. For a hydraulically fractured well, formation permeability is determined in late time, ie a long distance away from the well. With limited pressure drop on an initial well test, the formation permeability a long distance from the well, would not have been strongly affected. On the other hand, near frac liquid dropout would probably diminish the apparent effectiveness of the fracture treatment.

Two sources of data were available, core data and well test interpretation. Core data was adjusted from air to liquid permeabilities. Overburden pressure was also accounted for based on lab tests. The preceding modelling of pressure buildups indicated a systematic bias for the pressure transient analysis to over-predict formation permeability. A compromise permeability of 0.4 mD was chosen.

The fundamental reservoir mechanisms in an oil reservoir and a gas condensate reservoir are quite different:

1. For a typical oil reservoir, with a solution gas drive, which is initially at the bubble point, a gas saturation begins to form as the reservoir pressure drops due to withdrawals. This process is shown diagrammatically in Figure 10. As the gas bubble forms the amount of pore space open to flow decreases, making it harder for liquid to move in the reservoir. When the gas bubbles expand to the point where the gas phase becomes continuous between pores, both oil and gas flow simultaneously. Eventually, the oil phase will become discontinuous and stop flowing.
2. The fundamental mechanism in the reservoir is completely different for a gas condensate system. Heavy ends will condense on the surface of the rock as the pressure is reduced, as shown in Figure 11. It was clear that a different reservoir process occurs. It was not clear how condensate would move in the reservoir. In particular, if the dropout would occur as a thin film or as droplets. Further we were not sure if a continuous liquid phase have to occur in order for condensate to move. More research was required on this topic.

Honarpour, Koederitz, and Harvey[6] discuss a number of fac-



—Concept of relative permeability showing that a change in the amount of a fluid present in the pore channels will change the rate at which that fluid flows relative to the rate it would flow if only that fluid were present.

FIGURE 10: Reservoir process – solution gas drive.

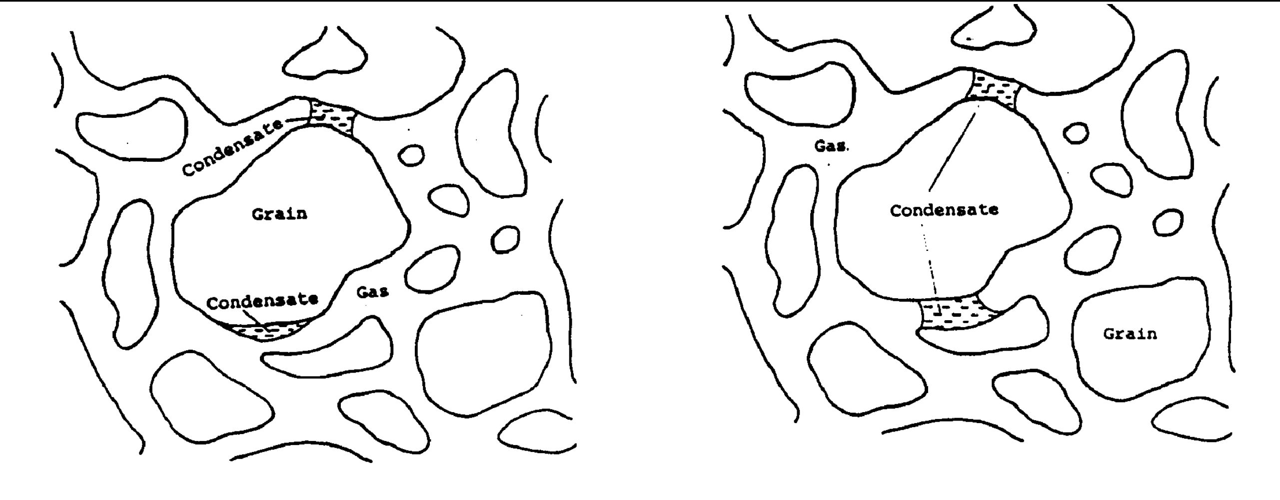


FIGURE 11: Reservoir process liquid condensation.

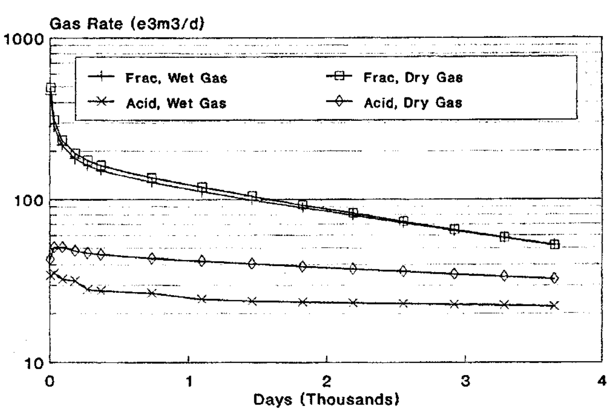


FIGURE 12: Well production forecasts.

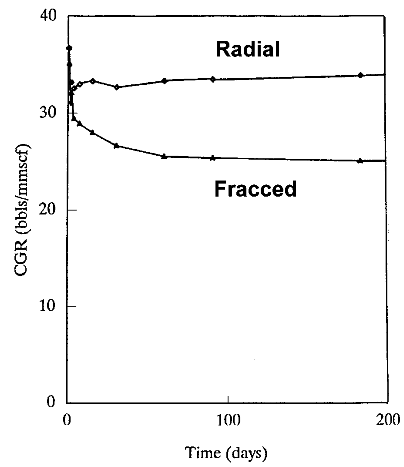


FIGURE 13: Well effluent condensate gas ratio.

tors that effect two phase relative permeability. Their summary presents some debate as to how strongly different factors affect relative permeability. Wettability is accepted as having a strong impact on relative permeability. Saturation history is known to have a definite effect on relative permeability. For interfacial tension, some studies indicate some sensitivity while many show no sensitivity. Viscosity was shown in many studies to have no effect on relative permeability, however, agreement on this was not universal. Many studies indicated that other factors, such as interfacial tension and wettability, that correlated with viscosity, were governing factors. Further research was required on gas condensate permeability curves.

More recent study has been done specifically for gas condensate reservoirs[7-12]. The results can be summarized fairly briefly:

1. Where low interfacial tensions exist, gravity effects become important.
2. At low levels of interfacial tension, the relative permeability relationship does not follow the classic gas-oil curves. Low interfacial tension occurs at temperatures and pressures near the reservoir fluid's critical point. Under these circumstances, the liquid and vapour phases become near miscible. The relative permeability curves will be intermediate between miscible relative permeabililty curves and conventional gas-oil relative permeability curves.
3. At more normal reservoir conditions, in which there is moderate to high interfacial tension, critical condensate saturations are high and the relative permeability relationship is similar to a normal gas-oil system.

Recent gas-condensate relative permeability research supports the drops in permeability predicted by Fussell.

To date, there has not been sufficient time for relative permeability data to be obtained from the producing zone in the area. Data must therefore be generated from experience and or correlations. Subsequently the data was checked to see if it was reasonable.

Bottomhole flowing pressures were estimated using an assumed gathering system pressure at the well and well gradient curves.

The first compositional sensitivity was made with the fracture Condensation was then eliminated by changing the heavy end characterization from C10 to C7. The results are shown in Figure 12. The results were quite surprising; deliverability did not seem to be strongly affected by liquid dropout. Note that by changing the composition slightly, the Z factor will change and the total well productivity will change accordingly. This was not a very large difference. These results appeared to contradict the earlier work done by Fussell. The only apparent difference was the manner in which fractures had been handled. Earlier modelling had used an equivalent wellbore radius to account for the frac.

The grid in the existing model was then converted to a radial model. To allow better comparison, the two models were constructed with the same pore volume, by setting the outside radius equal to 908 in (2,978 ft.). As in the previous section, two sensitivities were run. In the first case, the heavy ends were characterized as nC1O and in the second case as nC7. The results are shown in Figure 12 and confirm the results of Fussell's study.

It should be pointed out that simulators and computers have undergone significant changes during the past 20 years. The cur-

TABLE 5: Variation of well effluent composition with time.

Fractured Well Case

Component	Recovery Percent	m3/ kgmol	0.25	0.5	1.25	2	3.5	7	15	30	60	90	182	365
			Time (days)											
			Composition - Mole Percent											
C1			77.93	78.16	78.56	78.46	78.91	78.76	78.84	78.96	79.05	79.07	79.10	79.12
H2S			10.90	10.88	10.83	10.84	10.82	10.82	10.82	10.82	10.82	10.82	10.81	10.81
C2			5.78	5.78	5.77	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78
C3			3.26	3.25	3.23	3.23	3.22	3.22	3.21	3.21	3.21	3.20	3.20	3.20
nC6			0.83	0.81	0.77	0.78	0.75	0.74	0.73	0.71	0.70	0.70	0.69	0.69
nC10			1.24	1.13	0.84	0.91	0.72	0.68	0.62	0.52	0.44	0.43	0.41	0.40
C3	70	0.084	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
nC6	100	0.114	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
nC10	100	0.164	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
M3/E6M3			208	199	176	181	166	163	158	151	144	143	142	141
bbls/mmscf			36.8	35.2	31.1	32.1	29.5	28.9	28	26.7	25.6	25.4	25.1	24.9

Radial Flow Case

Component	Recovery Percent	m3/ kgmol	0.25	0.5	1.25	2	3.5	7	15	30	60	90	182	365
			Time (days)											
			Composition - Mole Percent											
C1			78.00	78.08	78.36	78.36	78.42	78.38	78.35	78.41	78.34	78.33	78.29	78.21
H2S			10.90	10.89	10.85	10.85	10.84	10.85	10.85	10.85	10.86	10.86	10.86	10.87
C2			5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78	5.78
C3			3.26	3.25	3.24	3.24	3.23	3.24	3.24	3.23	3.24	3.24	3.24	3.25
nC6			0.83	0.82	0.79	0.79	0.78	0.79	0.79	0.79	0.79	0.79	0.80	0.81
nC10			1.24	1.10	0.98	0.98	0.94	0.97	0.99	0.95	0.99	1.00	1.03	1.09
C3	70	0.084	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
nC6	100	0.114	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
nC10	100	0.164	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.005
M3/E6M3			207	197	187	187	184	186	188	184	188	189	191	196
bbls/mmscf			36.7	35.0	33.2	33.2	32.6	33.0	33.3	32.7	33.3	33.5	33.9	34.7

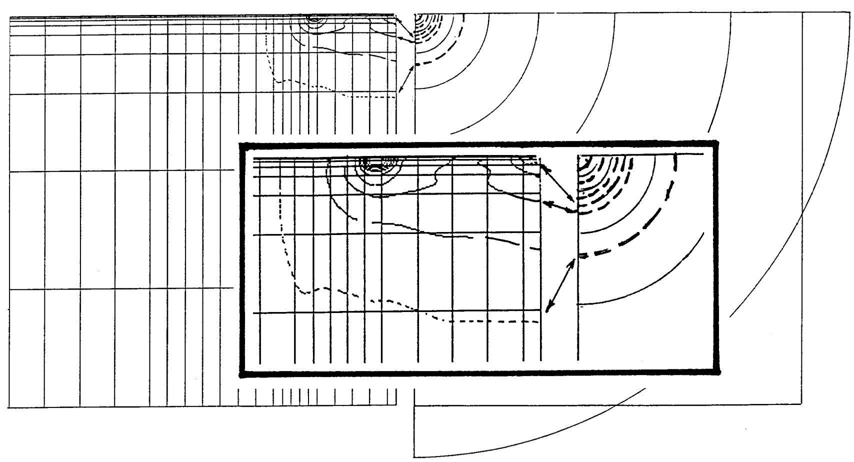


FIGURE 14: Pattern of condensate dropout.

rent results relied on this more advanced technology.

It was also assumed that an un-fractured well would be acidized. Permeability was increased in the immediate wellbore gridblock by a factor of 2 (i.e., 0.8 mD).

The output from the simulator was analysed to determine whether the composition of the well effluent varies with time. These results are shown in Table 5. Note that recovery is a function of the gas plant. This data was graphed as shown in Figure 13. These results were analysed for both radial and hydraulically fractured reservoir systems. Note that in the fractured well case productivity is much higher and the reservoir pressure would be at an overall lower average reservoir pressure than for the radial case.

It is known that well effluent composition changes with the amount of flow time, the degree of layering and the rate of production. The sensitivities with a hydraulic fracture indicate that the well effluent composition changes more rapidly and tends in a different direction than for the radial case. Low rates and earlier samples give more representative compositions of reservoir fluid.

In practical terms, wells must be flowed on cleanup for several days, particularly when energized fracture treatments are used. Therefore, it is inevitable that samples taken will show some deviation from the original reservoir fluid composition.

We suspect that the true initial reservoir conditions could be back calculated, on a trial and error basis, by increasing the proportion of heavier components (PNAs) such that the dew point and original reservoir pressure match. Since the overall liquid content is moderate and since the composition used over estimated the level of dropout, such an effort was not justified. With higher dropout levels, where condensate is a more significant proportion of the revenue stream, such an effort maybe justified.

From the previous two sensitivities, there clearly must be a dif-

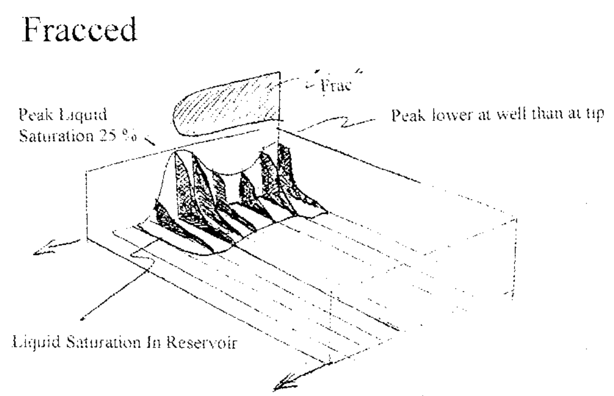


FIGURE 15: Relative permeability correlation.

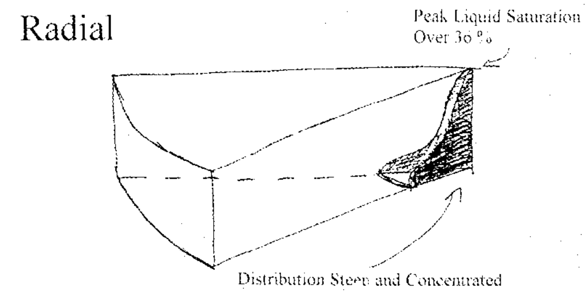


FIGURE 16: Well production forecast – Krg/Kro sensitivity.

ference in the way the gas flows in the reservoir and how much. Intuitively, the radial case would result in a more concentrated flow. A more elliptical flow pattern would be expected from a hydraulic fracture.

The condensate saturations the two cases were contoured and compared as shown in Figure 14. The buildup of condensate is concentrated near the wellbore, as a consequence this Figure is quite hard to read. To show the differences more clearly, this information has been represented in Figures 15 and 16. To make as direct a comparison as possible, the dropout profiles shown in Figure 14 were obtained at approximately the same average reservoir pressure. For the radial case this was at a time of 7,300 days, at which point the average reservoir pressure was 15,340 kPa (2,224 psi). For the fractured case the average reservoir pressure was 15,310 kPa (2,220 psi).

The dropout profile on the fractured case appears, at first glance, to be quite surprising. However, it is known from pressure transient theory that flux into a finite conductivity frac is not uniform[5]. Condensate saturations reflect the flux pattern into the fracture. The contours on the radial case are more concentrated, only every second contour was shown on this plot to make it more legible. In the radial case, the maximum dropout was 36.6% immediately adjacent to the well. For the well with a hydraulic fracture the maximum dropout was 25.4% in and adjacent to the end of the frac. In the radial flow case, the liquid buildup level was higher but does not involve as much total fluid. The flow is more concentrated and the dropout has more effect. With the hydraulically fractured case, the drawdown is not as concentrated. Liquid buildup levels are not as high, but involve more total condensate.

Multiple Krg/Kro relationships were obtained from various reservoirs[14] as shown in Figure 17. This graph shows:

1. The assumed relative permeability data is off trend at high liquid saturations. In the retrograde gas system modelled, the reservoir never reached these high liquid saturations. Note that the gas-oil relative permeability data is concentrated on the right hand side of the graph. Gas condensate data would be concentrated on the left hand side of the chart, which is off the scale. This suggests that more reliable data may be obtained by specifically testing core for gas-condensate systems.
2. Overall, the curve used falls on an extreme of the expected range.

The gas-oil relative permeability was changed at low liquid saturations as shown in Figure 17. This changes the relative permeability data from the minimum of the expected envelope to the mid range (average). The Krg/Kro ratio decreases from 21 to nine.

The affects on the predicted well performance are shown in

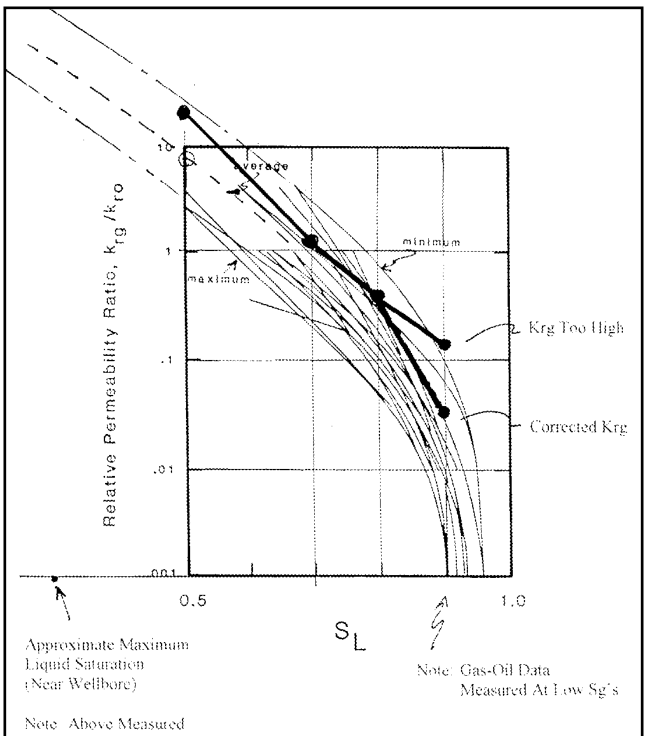


FIGURE 17: Relative permeability ranges from Arps.

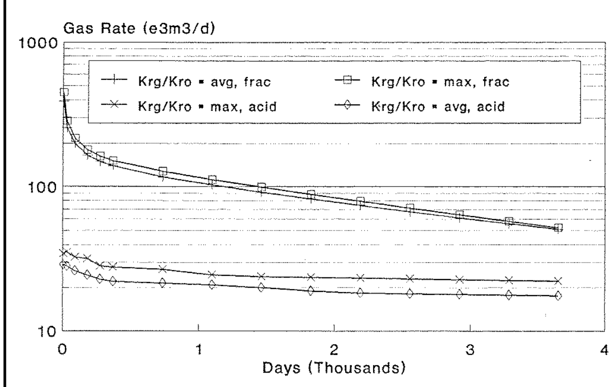


FIGURE 18: Results of relative permeability sensitivity.

Figure 18. As would be expected, the radial case is more affected. Gas production is reduced by about 25%. For the case with a hydraulic fracture, the reduction in productivity is about 14%.

The Krg/Kro ratio was changed by a factor of two, yet the change in production was between 14 and 25%. Hence, changes in Krg/Kro are attenuated. Half the normal variation in relative permeability has been traversed, yet the difference between the fractured versus a non-fractured well remains similar.

The case described applies to a fluid system that has a low overall level of condensate dropout. More work would have to be carried out to extrapolate this work to higher levels of condensate dropout. Since this was a field study this issue was not addressed.

The production forecasts shown on the graphs are on a logarithmic scale. The productivity of an acidizcd well was about one tenth the productivity of a fractured well. Productivity improvement was achieved partly due to the frac and partly due to lower relative permeability effects. For systems with low overall condensate dropout, the drawdown around a hydraulic fracture would be less severe and result in a larger volume which would have to be filled to cause relative permeability impairment. Proper fracture treatments were therefore very important.

Conclusions

1. Assuming radial flow into a wellbore, there will be a significant productivity impairment by condensate drop out in the immediate wellbore area. The results are similar to those predicted previously by Fussell.
2. A hydraulic fracture treatment reduces the amount of drawdown in the well and results in a less concentrated condensate precipitation. Significant impairment does not occur during the first ten years of production for the subject well.
3. Modelling the effects of a hydraulic fracture require that the fracture be included in the grid. This study demonstrates and relied upon, the increased power available with more modern simulation techniques.
4. A successful hydraulic fracture treatment is more important when retrograde condensation can be expected.
5. Compositional modelling of buildups for hydraulically fractured wells could lead to some interesting trends in pressure transient interpretation of retrograde condensate reservoirs.
6. Also, this work should be extended to a broader range of (higher) liquid dropout levels. Since this was a field study time did not permit this to be examined.

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J.W.G. Myer photograph and biography unavailable.