LABORATORY SUPPORTED COMPLETIONS ENGINEERING PRACTICES

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INTRODUCTION

The economically successful exploitation of oil and gas resources has become more and more difficult to achieve as the quality of the reservoirs available for exploration have declined. In the last decade much of the activity on-shore in the lower 48 states has concentrated on previously by-passed lower quality reservoirs and in intensive in-field drilling programs in mature fields.

Tertiary recovery projects have been emphasized but typically do not compete with well conceived primary production projects. Under these marginal economic conditions, the implementation of optimum completion practices will often make the difference between economic success and failure. The purpose of this paper is first to relate several well histories to demonstrate some important observations about the influence of completion parameters on well productivity. Secondly, it will demonstrate the role of laboratory studies in optimizing completion practices. Finally, it will emphasize the need to fully understand the necessity of using laboratory tests, and ensuring that the tests employed can provide field implementable answers and not just laboratory data from routine tests.

DISCUSSION

The following example is one of the most dramatic that we have encountered. The well was completed through the productive interval in June, 1983. The 11 ft zone was perforated with 13 shots and the initial production after breakdown was 3.1 mmcfd at 3780 psi. The initial bottom hole static pressure was 16300 psi. The well had an identified casing leak and was allowed to be produced under emergency order at maximum rate (Figure 1) for over 2 years. The first indication of a damaged wellbore was seen in July when the flow rate doubled and the surface flowing pressure increased by 1000 psi for no apparent reason. The Early Flow Response (EFR)[1] production plot of the pressure drop/flow rate (mcf) versus the square root of time (Figure 2) showed that there was an initial decline rate established, then the flow efficiency improved and then slowly reverted to the original decline rate. The well was worked over to repair the casing after this production period and, during the workover, it was killed with mud numerous times. After workover, the well still flowed at the pre-workover rate. After the well had produced 2.3 bcf gas it was treated with HF acid at fracturing rates because of the field history of success from this type of treatment. Note here that this type of treatment is contrary to any recommended use of HF acid. The gas production rate was improved slightly and the

well tested at 1.8 mmcf at 4900 psi surface flowing pressure. The well was then hydraulically fractured and tested 5.0 mmcf at 4000 psi flowing tubing pressure.

The treatment was successful from the standpoint of production improvement. But how does this production rate compare to the true well potential? In most wells this issue is never truly answered because pressure-transient diagnostic procedures generally do not provide unique answers about reservoir properties, especially in fractured wells. Therefore, a clear indication of well potential is not obtained so that a "completion efficiency" score card can be developed. At least 5 wells were actively and competitively draining the same field based on the P/Z curves for the field. In order to successfully compete for the reserves, the well in question needed to produce at a higher rate. Field experience indicated that the performance might be improved by a post-frac treatment with HF acid. However, the probability of improving the production was historically only 2 in 10. By the time the post-frac acid treatment was performed the well had produced 4 bcf and the current flow rate was 1.3 mmcfd at 1850 psi. After treatment the production rate rose to 5.12 mmcfd at 8400 psi even though the average reservoir pressure for the field had declined to 9600 psi. At that point the technical under-performance of the well was obvious, even though the gross production had been an economic success.

In order to try to understand the well history, a production history match was attempted. The well performance was modelled using a conventional 3-D single phase production simulator. Utilizing a radial production model, the production history was modelled using a highly damaged wellbore with a skin of 15 and a permeability of 0.6 md. The shut-in reservoir pressure history required that the drainage area be significantly extended to match the shut-in pressures observed. Even 2 mi^2 underestimated the drainage area. If the data were incorporated into a multi-well model, it would show that an even larger reservoir was being drained.

The fracture treatment resulted in an economically significant increase in production. The modelling results showed that a marginally successful fracture of 250 ft with a fracture permeability of 3.75 darcies, which is only slightly better than crushed sand even though bauxite was used in the treatment, and a fracture face skin damage of +20 would account for the observed production increase. The reason for the successful post-frac acid treatment is probably related to the extremely damaged nature of the post-frac production as was shown by reservoir simulation studies.

These data clearly demonstrate a number of factors relating to the well completion efficiency index:

1. Production from a well represents the results of all activities that have occurred and may spontaneously change with continued production. These types of production rate changes are often observed in core flow studies with damaged core but go unreported because no logical explanation can be used to explain the observed phenomena. Wells with damage are often characterized with unstable flow rates.

Of the paraffin samples collected, one began to soften at 124°F, was near molten at 145°F and molten at 155°F. The other two samples had higher melting points as measured by the drop melting point method[5] of 165°F and 161°F, which was higher than the reservoir temperature of 140 - 150°F. Note, however, that this temperature is an estimate based on adjusted temperatures from the open hole logs. We have recently seen a number of incidents where temperatures recorded later during build up tests showed a significantly higher temperature: up to 30°F higher than predicted from the open hole logs.

Measured paraffin and asphaltene levels in the oil samples ranged from 1 - 4% each and did not particularly suggest a problem. A 5% by weight sample of the lowest melting paraffin sample was melted and mixed into the oil at 180°F. On cooling, the oil congealed at 130°F. The ASTM and API definition of a paraffin is any material soluble in n-hexane whereas asphaltenes are insoluble. The collected paraffin samples were not readily soluble. Furthermore, paraffins melt on heating and asphaltenes do not. This issue will be discussed in more detail later.

Carbon disulfide is the best known solvent for organic deposits originating from crude oil. When 10 ml of CS_2 was added to 2 gms of the sample, it completely dissolved in 5 minutes at room temperature. The second best solvent, xylene, only dissolved about 3/4 of the sample in 30 mls. A proprietary paraffin and asphaltene solvent soak treatment was performed on the well that had been acidized with no production improvement. However, after the treatment it was learned that the solvent treatment was incompatible with significant volumes of water and an emulsion was swabbed back. The aqueous phase was determined to be spent acid (Table 1) even though the acid treatment was performed 2 months before.

The fact that the paraffins collected were not soluble in diesel suggested that paraffins could be the source of the problem with cold diesel-based fracturing treatments. There is an even more important downside to gelled oil fracturing treatments which we believe to be the reason that oil based treatments do not out perform water based treatments to the degree that they theoretically should.

To evaluate the regained fracture and matrix permeability following a gelled oil treatment, 2 types of fracturing treatment simulations were performed. In the first, gelled oil containing breaker was pumped past a 1" diameter core to measure fluid loss at 1000 psi differential pressure. The core was then shut-in for 12 hours to allow the gel to break and the returned oil permeability was determined to be 57% (Figure 7). The second test measured fracture conductivity using a modified linear flow cell and employing the procedure and equipment outlined by Penny[2]. After a 90 minute dynamic fluid leak off period, the closure stress was raised to 1000 psi and the temperature was raised to 140°F. The gel was allowed to break for 12 hours. The oil clean up was initiated while the closure stress was slowly raised to 3000 psi to represent the early producing condition of the well. The conductivity was 277 md-ft for 1 lb/ft^2 which was 10% of the expected conductivity of a non-damaged proppant pack with a similar type reservoir rock.

These data suggested that a number of factors were responsible for the observed well performance:

1. Gelled oil fracture treatments showed marginal technical performance because of limited conductivity in the fracture and because of matrix permeability damage [see discussion below].

2. Paraffin deposition occurred from cooling which magnified the problem.

3. Water based treatments suffer from the same paraffin deposition problems plus the lower permeability observed for water in a water-wet oil reservoir.

The well which was acidized and treated with paraffin solvent was then fractured with a 70% nitrogen foam using heated water. This well, which had significantly less quality reservoir than other wells in the field, made the second best well in the field.

A very important point raised earlier is the measurement of asphaltenes and paraffins and the predictive value of these measurements in identifying potential oil production problems.

It has been our experience that paraffin and asphaltenes are routinely measured in the laboratory to identify problem oils. However, there are three significant problems with this test which are not generally acknowledged. First, extreme care must be exercised in collecting the oil sample since materials such as sand on the sampling valve will be analyzed as asphaltenes. If water is present, the process of separating water may remove much of the asphaltene and problem paraffin material. The third problem is the basic premise that paraffin type materials, which tend to cause serious problems, are soluble in heptane at room temperature.

Excerpt from UOP Procedure[6]:

Oil sample: add 250 ml heptane for 1 gm sample, collect insolubles and dry sample. Report weight as asphaltenes.

"Gunk" sample: add 250 ml heptane for 0.1 gm sample, collect insolubles and dry sample. Report weight as asphaltenes.

Especially with "gunk" samples, some high melting point paraffinic waxes are almost insoluble in heptane at room temperature and hence get reported as asphaltenes.

In the second step of the procedure the heptane soluble materials are treated with bentonite or diatomateous earth to remove "resins". These materials are the components of crude oil which solubilize asphaltene miscelles. They, themselves, may or may not contribute to petroleum deposits in both the tubulars and the near wellbore area. The heptane is then evaporated and dissolved in a reduced heptane volume. If color persists, the adsorption step

is repeated. At that point problem paraffins are surely removed. The point here is that high melting, limited solubility paraffins are not measured and thus any assessment of the paraffin content by standard procedures will generally only measure the non-problem paraffinic components of crude oil.

CONCLUSIONS

The case studies presented in this paper were selected to demonstrate the necessity of multiple disciplinary studies of the well completion process to maximize well productivity. Laboratory testing is an integral part of improved completion technology if, and only if, the tests performed are specifically designed to provide laboratory answers and not performed just as routine tests to provide laboratory data.

REFERENCES

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3. Cheung, S.K.: "Effect of Acids on Gravels and Proppants," paper SPE 13842 presented at the 1985 California Regional Meeting, Bakersfield, CA, March 27-29.

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5. ___.___: "Drop Melting Point of Petroleum Wax Including Petroleum," *Annual Book of ASTM Standards,* **23**, 86 (1981).

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Table 1
Water Analysis of Fluid Swabbed back after a Paraffin Solvent Treatment

Ca	16,796 ppm
Fe	10,752 ppm
Mg	3,176 ppm
Al	85 ppm
Si	20 ppm
Na	37,184 ppm
K	548 ppm
Chlorides	98,207 ppm

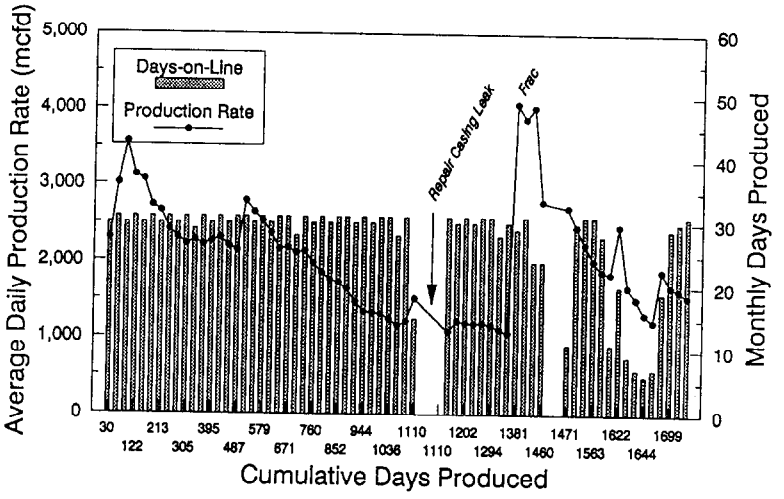

Figure 1 - Production rate and days-on-line for Example Well #1

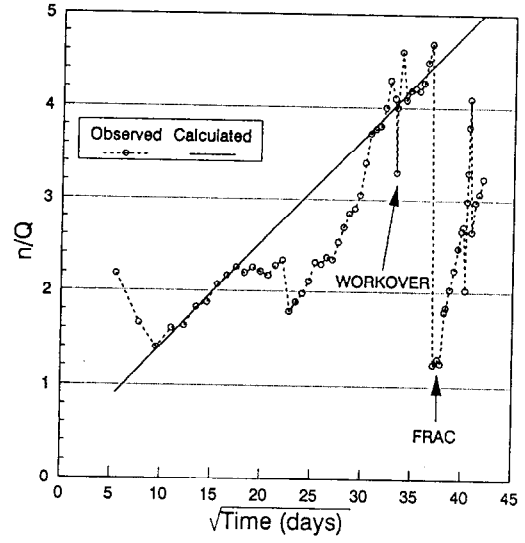

Figure 2 - Early Flow Response Analysis for Example Well #1. The data shows that the well produced in linear flow before frac except for the period of enhanced production

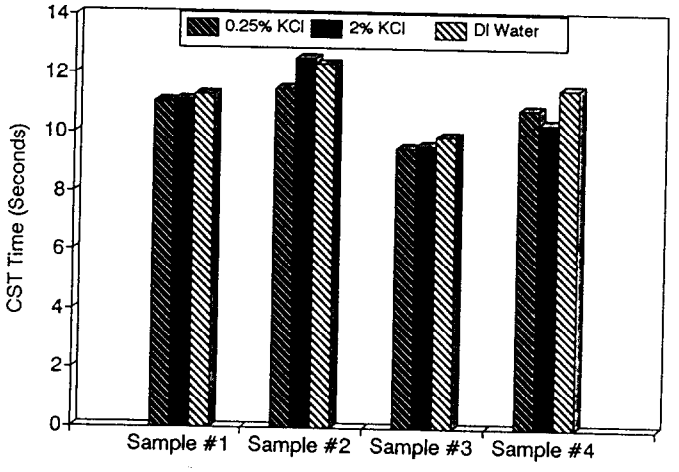

Figure 3 - Effect of brine composition on permeability with core from Example Well #2

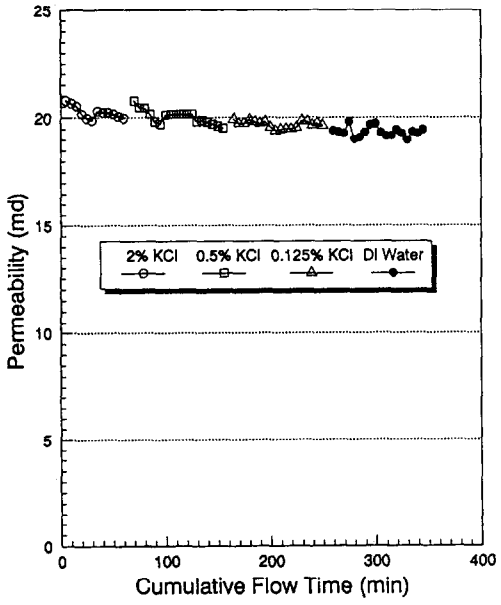

Figure 4 - Effect of brine composition on permeability with core from Example Well #2

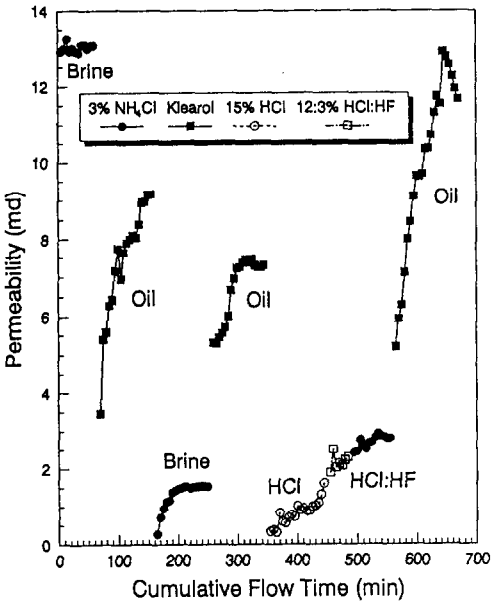

Figure 5 - Effect of 15% HCl and 12:3% HCl:HF on the oil and brine permeability of core from Example Well #2

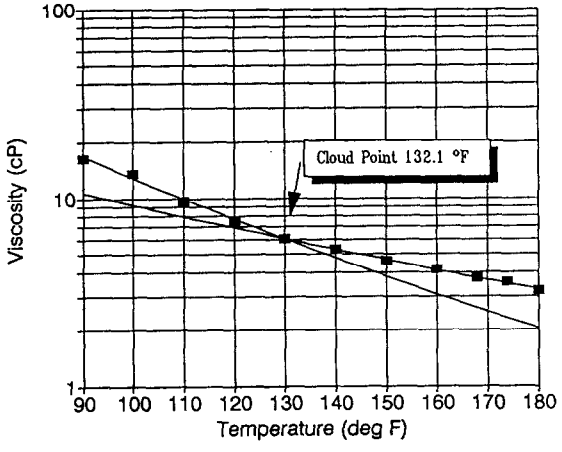

Figure 6 - Capillary viscosity of oil sample collected from Example Well #2 showing a 132.1°F cloud point

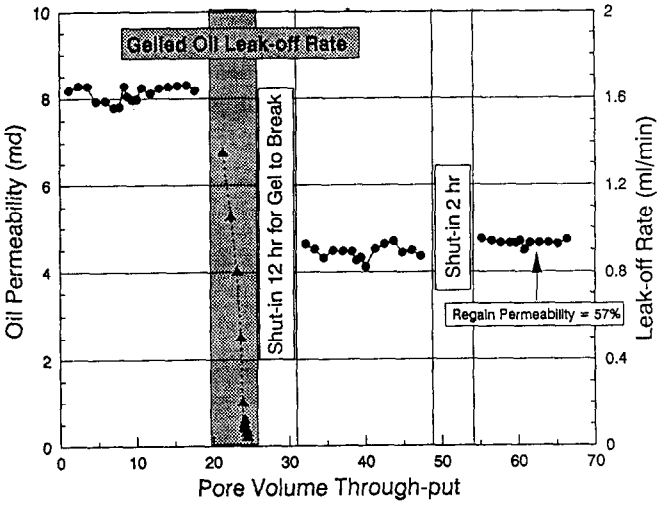

Figure 7 - Effect of gelled oil fracturing fluid on the oil regain permeability