

# WELL TEST TRANSIENT ANALYSIS— ANALYSING PRODUCTION IMPROVEMENTS FROM WELL STIMULATIONS

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## Abstract

This paper discusses the case histories of two wells that used well test transient analysis to identify their need for treatment and to evaluate their subsequent treatment.

Toe Toe 7A came on production in 1989 in the McKee field. The initial production from the well was lower than expected. A transient well test indicated an Inflow Performance Index of 1.01 bpd/psi and a permeability thickness of 553.7 mD.ft. This test identified the need for stimulation of this well. A HF/HCl matrix acidisation was used to treat the well. The treatment improved the oil production of the well by 28%. A post treatment well transient test indicated an Inflow Performance Index of 1.91 bpd/psi and a permeability thickness of 1129.9 mD.ft, proving the success of the treatment.

Kaimiro 2 was drilled in 1988. Early production rates were lower than expected. A transient well test indicated a high skin value of 13.88, a permeability thickness of 262.6 mD.ft, and an Inflow Performance Index of 0.129 bpd/psi. This test identified the need for a stimulation treatment. A hydraulic sand fracturing treatment was used to treat the well. Oil production improved by 48%. Post treatment well test transient analysis indicated a skin value of 0.46, a permeability thickness of 146 mD.ft, and an Inflow Performance Index of 0.174 bpd/psi.

Both wells were identified as requiring treatment as a result of the transient analysis. The success of the treatment was accurately determined by the use of the transient tests. Ongoing transient testing is used on all Petrocorp wells to identify the need for stimulation treatments.

## Introduction

In many producing reservoirs, the production from wells may not match expectations. The main reasons for this are formation damage or low permeability. In both cases well stimulation treatments are available to increase the production rates from the well. Two common methods are matrix acidisation and hydraulic sand fracturing. However it is important to correctly identify which treatment to use.

This paper discusses the case histories of the pre and post stimulation transient pressure build up analysis of two wells successfully stimulated by Petrocorp Exploration in onshore Taranaki, New Zealand, including:

- Initial production;
- Selection criteria;
- Stimulation methods; and
- Results.

## Reservoir Stimulation

The radial flow solution to Darcy's Law can be written as Equation 1 and describes the variables that control well productivity.

In most reservoirs all of these variables except the skin factor (s) and the flowing pressure (Pwf) are fixed. The reservoir permeability (k) is normally constant, however in some cases the value kh can vary by increasing or decreasing the reservoir thickness open to drainage. The skin factor (s) is a dimensionless number that refers to the pressure drop in the permeability damaged zone near to the well bore.

Matrix acidisation is used to remove near wellbore damage, typically caused by drilling mud, thereby lowering the skin factor (s) and as a result increasing the production rate. Hydraulic sand fracturing; (1) bypasses the near wellbore skin damage by opening a high permeability fracture

$$q = \frac{kh(P_e - P_{wf})}{\phi_r B \mu \left( \ln \frac{r_e}{r_w} + s \right)}$$

(Equation 1)

Where

- k = Reservoir permeability (mD)
- h = Reservoir thickness (ft)
- Pe = Reservoir pressure (psig)
- Pwf = Flowing well pressure (psig)
- $\phi_r$  = Reservoir shape factor

- B = Formation volume factor (res bbl/STB)
- $\mu$  = Viscosity (cp)
- $r_e$  = Reservoir radius (ft)
- $r_w$  = Well radius (ft)
- s = Skin factor
- q = Flow rate (bopd)

that allows production from the undamaged formation, this appears as a skin reduction, or (2) creates a highly conductive path (for several hundred metres) in an otherwise low permeability reservoir thereby increasing the wellbore contact area of the reservoir (Economides and Nolte, 1989). Due to this effect a fractured well will normally have a skin value of less than zero (i.e., a negative skin). Economic production rates can be obtained from very low permeability formations (less than 1 mD) by the use of hydraulic fracturing.

The values of skin factor (s) and permeability thickness (kh) are required for the design and evaluation of a well stimulation. They can only be found with the use of a pressure transient well test analysis. This involves the use of downhole electronic pressure recorders, that record the bottom hole pressure while the well is flowing and/or after the well is shut in.

The skin factor and the permeability thickness are evaluated in the transient test analysis. The value of the permeability (k) is then estimated from the permeability thickness (kh) if the thickness of the formation is known. However it is not possible to determine the exact value of the thickness (h) or the exact value of the permeability (k) directly from the test.

## Toe Toe 7A Matrix Acidisation

### Well History

Toe Toe 7A is located in the Southern area of the McKee oilfield in PML 38086, in onshore Taranaki approximately 30 km east of New Plymouth.

The McKee Formation sandstone reservoir is on average 70 m thick and although superficially it has a homogeneous appearance, it is heterogeneous on a metre scale. This is due to the presence of subtle variations in grain size, thin calcareous cemented beds, small scale healed faults and fractures, and indistinct sedimentary structures. Reservoir quality suffers from significant degradation of primary reservoir properties due to diagenetic processes.

The well was drilled in July/August 1989 using O.D.E rig number 16 and began production on the 25 August 1989. The well took 28 days to drill and was completed with 5-1/2" casing and 2-7/8" tubing. The well was perforated with 2-1/8" through tubing Enerjet guns with 4 shots per foot and zero degree phasing. Two intervals of 12 m each with a 5 m space were perforated in two wireline runs.

### Initial Production

The well initially produced at approximately 130 m<sup>3</sup>/d oil (818 bopd), with a flowing top hole pressure of 25 bar (362 psig). Therefore the well would not flow to the normal production station pressure of 30 bar (435 psig), requiring the well to be flowed into a test separator set at 11 bar (160 psig). However, due to the high quality and thickness of the McKee Formation encountered in the wellbore, this rate, and the lower than normal wellhead pressure, was considered to be unacceptable.

All Petrocorp wells are transient pressure tested after drilling for evidence of formation damage. A flowing/build-up transient survey was carried out in Toe Toe 7A from the 28 August to the 1st September.

The survey consisted of a 24 hour flowing period followed by a 72 hour shut in period. Two 5000 psi Panex electronic memory recorders were used. The gauges were suspended on an Otis "X" lock mandrel and were hung at 2158 m AHBKB (1992.4 m TVSS). The 4324 recorded data points

were processed into pressure and elapsed time format and sampled logarithmically to 80 data points.

The program AUTOMATE by Garrett software was used to interpret the pressure transient build-up. This program is specifically designed for the analysis of transient well testing. The program consists of seven modules designed for the analysis of tests. These include a data manipulation module, a straight line analysis module capable of producing Horner and other plots, a type curve matching section and a section capable of matching calculated reservoir model responses to the actual data.

The Horner method was used to estimate the values of the permeability thickness (kh) and the skin factor (s) (Figure 1). The values were then checked with a type curve match. Figure 2 is a log-log plot of the dimensionless pressure and time data and the corresponding derivative curve from the pre-stimulation flowing/build-up survey. The solid line is the produced type curve match for the given parameters. It can be seen from Figure 2 that a boundary effect may be occurring due to the slight decline in the late time derivative data. However, it is not possible in this test to accurately determine the precise nature of this effect, hence no boundary has been used. The close match to the data justifies this approach. The produced output and input variables are shown in Table 1.

The value of the skin factor was found to be -0.714, with a permeability thickness of 553.7 mD.ft. The Productivity

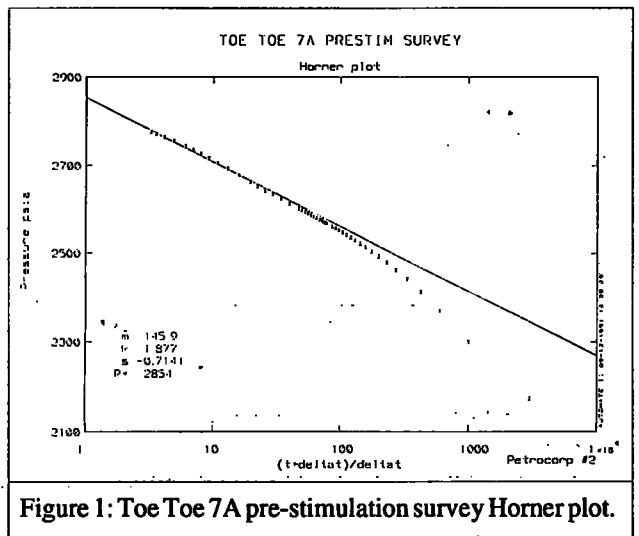


Figure 1: Toe Toe 7A pre-stimulation survey Horner plot.

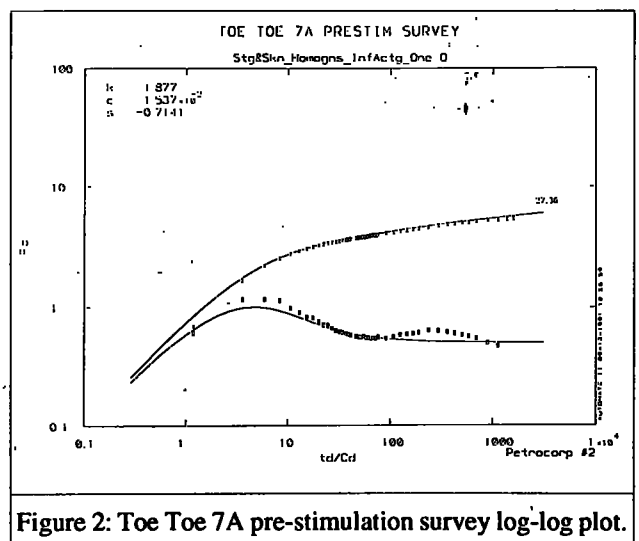


Figure 2: Toe Toe 7A pre-stimulation survey log-log plot.

Index (PI) of this well was found to be 1.01 bpd/psi. The permeability of 1.877 mD (using the log determined formation thickness of 90 m (295 ft) and the PI were both lower than in surrounding wells.

### Selection Criteria

The main factors in selecting Toe Toe 7A for a stimulation treatment were :

- (i) the PI value is 50% lower than the average;
- (ii) the ideal placement of the formation in terms of the gas/oil and water/oil contacts in this area; and
- (iii) the apparent lower than normal permeability of the well.

The determining factors were the low permeability thickness of 553.7 mD.ft (which implies that with a typical permeability of 10 mD only 55.37 ft (16.9 m) of the formation was contributing to the flow), and the need to increase the low flowing top hole pressure.

The McKee formation normally has a permeability in the range of 10 - 30 mD which would usually preclude the use of hydraulic fracturing techniques. There was also the risk of inducing gas flow from the large gas cap in the field. Therefore a matrix acid stimulation was chosen for the stimulation treatment. The selection of this stimulation method is not typical for a well with no apparent skin damage, but was chosen to induce flow from the entire perforated interval.

### Stimulation Methods

To ensure the success of the matrix acidisation, core plug tests were performed to determine the correct acid mixture for the McKee Formation. The selected matrix acidisation consisted of the following features.

Stage	Chemicals	Volume
1	4% NH4Cl spacer	420 USG
2	7.5% HCl	4000 USG
3	1.5% HF/13.5% HCl	12,000 USG
4	4% NH4Cl spacer	420 USG
5	Diesel Displacement	±50 Bbls

Perforation sealing balls were used to ensure diversion of the acid and that perforation breakdown occurred. The well was cleaned up with nitrogen gas lifting through a Nowsco coiled tubing unit. The well was flowed to flare until cleaned up and then produced to the production station as per normal operating procedure.

Throughout the matrix acidisation, pump rates were limited to 1 Bpm and a maximum surface treating pressure of 4800 psig to avoid fracturing the formation.

### Results

The average production rate of the well increased from 130 m<sup>3</sup>/d oil (818 bopd) to 170 m<sup>3</sup>/d oil (1070 bopd), i.e., a 31% improvement. To further quantify the effects of the acid job a flowing/build-up survey was carried out. The survey was planned for a 24 hour flowing period and a 100 hour shut in period.

The build up data was processed and interpreted using Automate. The detailed results are shown in Table 2 and can be seen graphically in Figures 3 and 4. Figure 3 shows the Horner plot for this test. Figure 4 shows the log-log plot of the dimensionless pressure and time data and the corresponding derivative curve.

Date	28 August - 1 September 1989
Oil rate	130 m <sup>3</sup> /day
Formation thickness	295 ft, estimated from the well logs
Permeability	1.877 mD
Formation skin factor	-0.714
Permeability thickness	553.7 mD.ft
Flowing bottom hole pressure	2104 psia
Reservoir pressure at datum	(2100 m TVSS) 2950.4 psia
Performance index	1.01 bpd/psi

Table 1: Toe Toe 7A Pre-Sulation Transient Test.

Date	24 - 30 May 1990
Oil rate	170 m <sup>3</sup> /day
Formation thickness	295 ft
Permeability	3.83 mD
Formation skin factor	-1.13
Permeability thickness	1129.9 mD.ft
Flowing bottom hole pressure	2148 psia
Reservoir pressure at datum	(2100 m TVSS) 2814.3 psia
Performance index	1.908 bpd/psi

Table 2: Toe Toe 7A post-stimulation transient test.

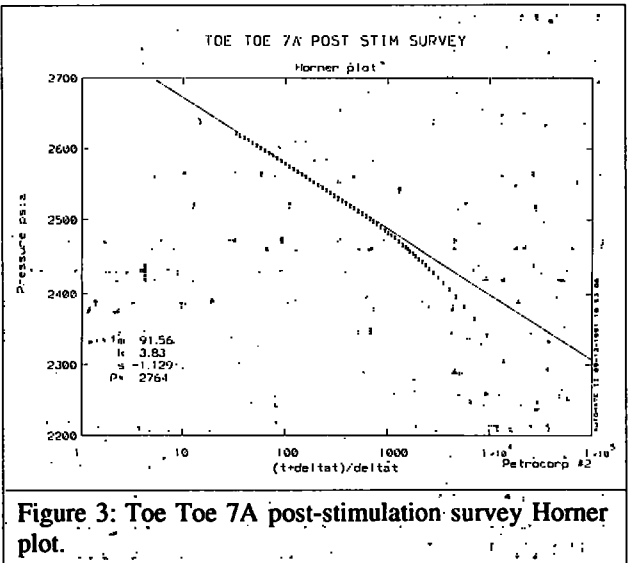


Figure 3: Toe Toe 7A post-stimulation survey Horner plot.

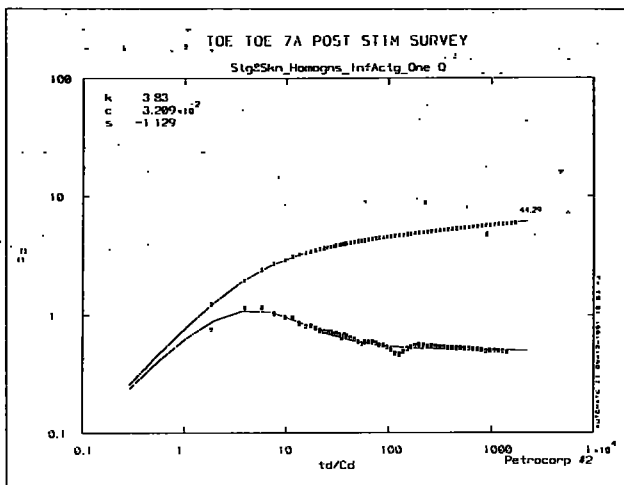


Figure 4: Toe Toe 7A post-stimulation survey log-log plot.

The PI was found to be 1.908 bpd/psi. The permeability thickness (kh) was found to be 1129.9 mD.ft. The permeability (k) was found to be 3.83 mD and the skin factor (s) was -1.13. It was not possible to determine the type of the late time effect.

### Conclusions

The skin factor (s) of Toe Toe 7A was reduced from -0.714 to -1.13, a decrease of 58%. A negative skin factor implies that the near wellbore formation has a higher permeability than the surrounding formation. In this case the increase in the negative skin implies that the matrix acidisation further improved the near wellbore permeability.

The permeability thickness of the well was increased from 553.7 mD.ft to 1129.9 mD.ft (an increase of 104%), indicating that the formation thickness contributing to the flow was increased. Therefore allowing a more efficient drainage of the reservoir.

The Performance Index (PI) of the well increased from 1.01 bpd/psi to 1.901 bpd/psi (an increase in well productivity of 88%).

The production of the well increased from 130 m<sup>3</sup>/d (818 bopd) to 170 m<sup>3</sup>/d (1070 bopd), an increase of 31%.

## Kaimiro 2

Kaimiro 2 was drilled in September/October 1988 in PML 38091 between Inglewood and New Plymouth in onshore Taranaki. The well was logged and cased for a cased hole Drill Stem Test, and perforated with 12 spf 5" HSD guns. The well produced oil to the surface at rates varying from 69 to 109 bopd under nitrogen gas lifting of 300 scf/min. The average rate was 79 bopd and the gas/oil ratio was not accurately determined due to the gas lifting. The well was then completed with 2-7/8" production tubing and suspended for further testing.

After a five month shut-in the well was reopened for an interim production test. Initial production rates averaged approximately 20 Bopd. In an attempt to clean up the well, an injectivity test using condensate with a surfactant and clay stabiliser was carried out to remove any emulsion blockage and wash the perforations. However it appeared that the formation had fractured prior to the condensate reaching the formation. All the fluid was pumped above the

fracture gradient. Therefore the perforations were not cleaned as planned due to the high formation damage.

The well was then reperfored over the existing interval and additionally perforated over a new interval. The well was then produced under gas lift to clean up. An average rate of 120 bopd, under natural flow, was obtained.

A flowing/build-up survey was then carried out to evaluate the extent of the formation damage and to determine the formation parameters. This test consisted of a 48 hour build up period after the well was shut-in down hole with the use of a wireline set plug.

The test indicated a high skin value of 13.88 and a permeability thickness of 262.6 mD.ft. The results of this test are shown in Table 3 and Figures 5 and 6. The Inflow performance was calculated as 0.129 bpd/psi. Figure 5 shows the Horner plot for the pre-stimulation flowing build-up. The straight line is matched against the late time pressure data giving the values of the skin factor (s) and the permeability (k) calculated from the formation thickness (h). Figure 6 shows the log-log plot of the dimensionless time and pressure data and the corresponding derivative curve for the flowing/build-up test. The good match of the produced lines to the plotted data points indicate the accuracy of the skin value.

### Stimulation Methods

Due to the high skin factor a stimulation was deemed necessary to reduce the skin factor of the well and to improve the productivity of the well.

Detailed core plug analysis indicated that the formation was not compatible or was non-responsive to hydrochloric

Date	4 - 6 April 1989
Oil rate	19 m <sup>3</sup> /day
Formation thickness	measured from logs.
Formation skin factor	13.88
Permeability thickness	262.6 mD.ft
Performance index	0.129 bpd/psi

Table 3: Kaimiro 2 pre-fracture stimulation transient test.

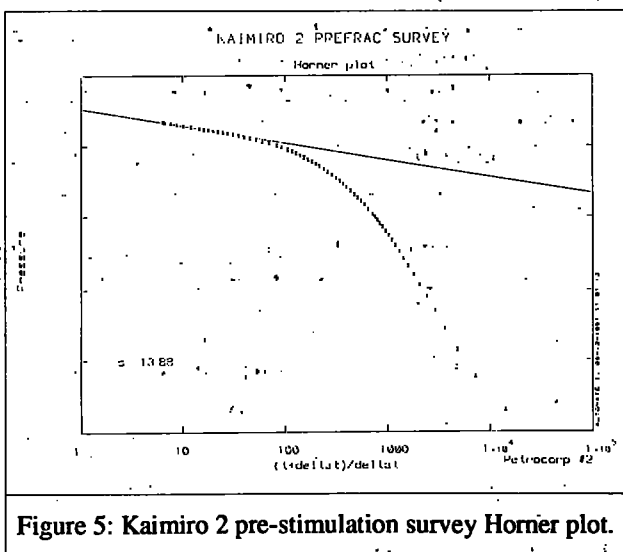


Figure 5: Kaimiro 2 pre-stimulation survey Horner plot.

(HCl) or hydrofluoric (HF) acid. Therefore a matrix acidisation which is most commonly used to remove large skin damage was not considered possible. Therefore a small hydraulic sand fracture was chosen as the best stimulation method to remove the skin damage in this well.

It was believed that a small fracture treatment would increase production by reducing the restriction to flow, due to the near wellbore formation damage identified in the transient test, through the introduction of a highly permeable short fracture extending from the wellbore to undamaged formation.

As there was no identified water/oil or gas/oil contacts, there was considered to be low risk in carrying out a fracture treatment.

### Method

The stimulation consisted of two steps. The first was a perforation wash/breakdown acid stimulation. This consisted of 2940 gallons of breakdown acid pumped in two stages of 2 Bpm and 15 Bpm using 1.1 SG perforation ball sealers to ensure diversion of acid. This would ensure that the perforations were open and capable of taking the injected fracture fluid. The acid mixture consisted mainly of 10% Acetic acid due to the high clay content of the sand identified in the core plug analysis testing. The acid was then displaced with 2935 gallons of fluid.

The sand fracture consisted of 3570 gallons of cross linked pad, followed by six stages of 2015 gallons of pad with the sand content increasing from 1 lb/gal to 6 lb/gal of 20/40 sand. The pad was displaced with 1050 gallons of brine. However due to equipment failure the 6 lb/gal stage was not pumped. The predicted fluid leak off rate was established from the core plug tests, however the actual fluid leak off rate was much slower than predicted. This caused the fracture to remain open for longer than planned. The fracture was forced closed by bleeding off the well head pressure after two hours. The well was cleaned up with the use of gaslift.

### Production

The well was produced under natural flow for a further 31 days after the fracture stimulation. At the end of this production period a flowing/build-up survey was conducted. The average production rate after the fracture treatment was 178 bopd (an increase of 48%).

From the transient analysis, the formation skin factor was found to be 0.46 (a reduction of 97%) and the permeability thickness was found to be 146.2 mD.ft (a reduction of 44%). The decrease in the permeability thickness may be due to the reduction in the thickness of the flowing formation which occurred when the fracture did not close as expected due to a longer than predicted leak off time. The longer than predicted leak off time allowed the proppant to settle in the fracture therefore not propping the upper part of the fracture open as planned. The Inflow performance index was found to be 0.174 bpd/psi (an increase of 35%).

From the shape of the transient build-up curve there is no noticeable fracture flow effects. A semi-log straight line develops at the end of the wellbore storage section in the post fracture treatment analysis (Figure 7). This is indicative of radial flow in the formation. This implies that any fracture flow effects are hidden by the wellbore storage section of the build up. This indicates a short fracture length as was

planned. Therefore the post fracture treatment analysis has been analysed using the radial flow model and not a fracture flow model.

The full results of this transient test are shown in Figures 7 and 8 and Table 4. Figure 7 shows the Horner plot for the post-stimulation flowing/build-up transient test. The straight line matched to the late time data indicates the radial flow section of the build-up. Figure 8 shows the log-log plot of

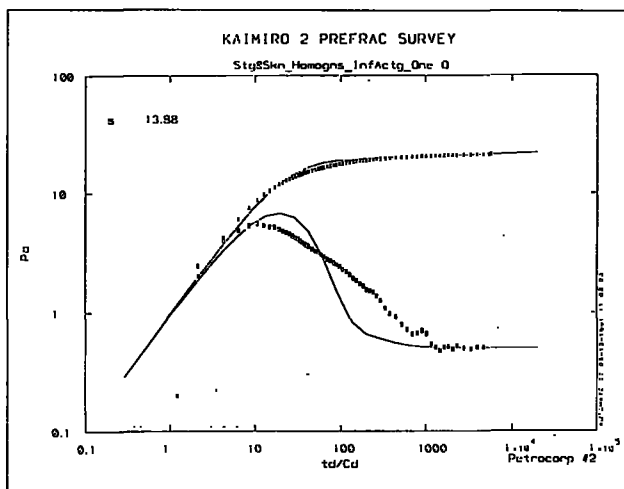


Figure 6: Kaimiro 2 pre-stimulation survey log-log plot.

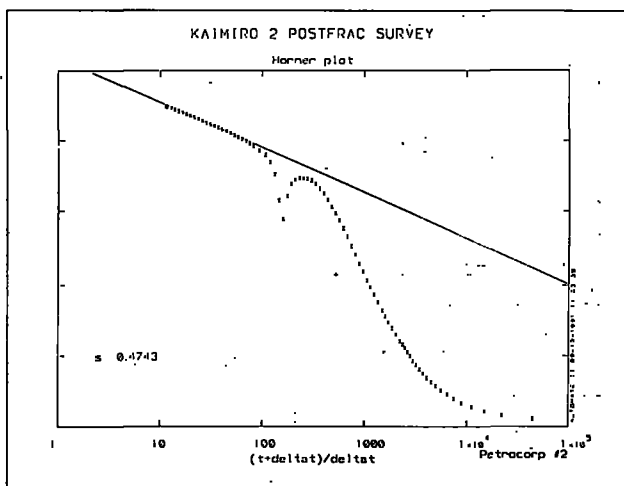


Figure 7: Kaimiro 2 post-stimulation survey Horner plot.

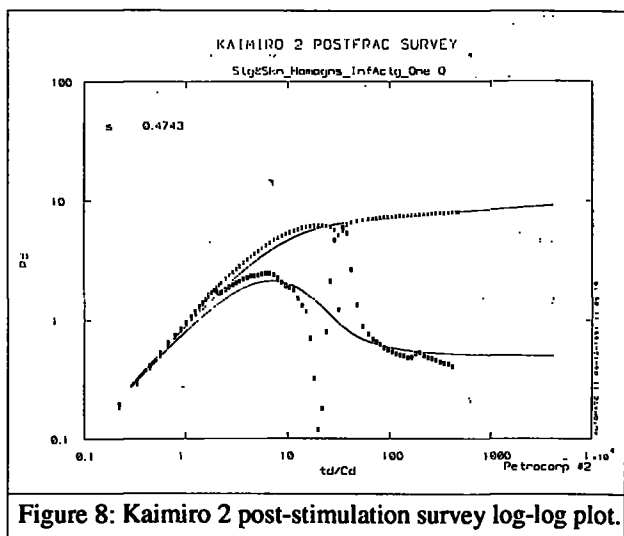


Figure 8: Kaimiro 2 post-stimulation survey log-log plot.

<b>Date</b>	11 - 14 June 1989
<b>Oil rate</b>	28.3 m <sup>3</sup> /day
<b>Formation skin factor</b>	0.46
<b>Permeability thickness</b>	146.3 mD.ft
<b>Performance index</b>	0.174 bpd/psi
<b>Fracture length</b>	Can not be determined due to wellbore storage effects.

Table 4: Kaimiro 2 post-fracture stimulation transient test.

the dimensionless pressure and time data and the corresponding derivative type curve.

### Conclusions

The hydraulic sand fracture decreased the skin factor from 13.88 to 0.46 (a reduction of 97%). Therefore a small fracture was successfully propped open bypassing the formation damage close to the wellbore.

The permeability thickness was reduced from 262.6 mD.ft to 146.3 mD.ft ( a reduction of 44%). This is most likely due to the reduced flowing formation thickness from the effects of late fracture closure.

The PI of the well increased from 0.129 bpd/psi to 0.174 bpd/psi (an increase of 35%).

The production rate of the well increased from 120 bopd to 178 bopd (an increase of 48%).

### Overall Conclusions

Toe Toe 7A was treated with a matrix acidisation. However with no apparent skin and a permeability of 1.9 mD, a hydraulic fracture treatment may have been chosen instead of a matrix acidisation. The transient well testing carried out in previous wells and in this well aided in the correct choice of the stimulation method and proved that the matrix acidisation was the best treatment method for Toe Toe 7A.

Kaimiro 2 had a pre-stimulation skin of 13.9, and a good permeability thickness. This well may have been suitable for a matrix acidisation, however due to the core testing and the well transient testing, a hydraulic fracture was successfully chosen as the best treatment method.

The use of Pressure Transient Analysis is required before and after stimulations are carried out. These tests allow the stimulation to be accurately designed and allow quality control of the stimulation.

Further treatments in a given field can be optimised using the information obtained from the initial transient tests.

### References

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