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PR96-62

SANTOS LIMITED

E. MEREENIE WELL NO. 41
P3-230/250 TSO FRAC TREATMENT

INTERPRETIVE
DATA

Signed
Date
Delegate of: Designated Authority
Minister for Mines & Energy

11 OCTOBER 1996

E. MEREENIE WELL NO. 41
P3-230/250 TSO FRACTURE TREATMENT

Prepared for:
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11 October 1996

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SUMMARY

On 13 September 1996, a tip-screenout (TSO) fracture treatment was performed on Santos' East Mereenie Well No. 41 through lower "P3" sand perforations at 4812-4838 and 4844-4874 ft. Reservoir properties were estimated to be a net pay thickness of 37 ft, a reservoir pressure of 1750 psi (no depletion), and a BHT of 140°F. Because of problems with the primary cement job (discussed herein) only minimal pre-frac flow was obtained from the combined lower P3 and P4 zones. An attempt to remedy this by reperforating was unsuccessful and attempts to circulate between the zones behind the production casing were also unsuccessful. Thus, a remedial cement job could not be performed. With this problem and the inability to establish a steady flow from the well, a pre-frac pressure buildup test could not be conducted to determine formation permeability and skin. A fracture treatment performed in the P4 on 11 September did not communicate around the backside through the lower P3 perforations, indicating that the cement between these two zones was sufficient to withstand the higher pressure during fracturing. The quality of the cement above the lower P3, however, was still unknown.

Prior to the treatment, pre-frac tests were conducted to evaluate closure stress, fluid efficiency, and fracture geometry for final design formulation. The results indicated a closure pressure of 3870 psi and a fluid efficiency of 0.45 from pressure decline analysis. This gave an efficiency during injection, using the Mereenie correlation of decline to injection efficiency, of 0.22. A reasonably good model history match of the minifrac was obtained with (1) boundary stresses of 4900 (upper) to 5050 psi (lower) and a stress of 4500 psi in the shalier region between the two sets of lower P3 perforations, (2) a pay zone modulus of 6.5×10^6 psi and $7.5\text{-}8.5 \times 10^6$ psi in the middle shaly region and boundaries, and (3) a leak-off coefficient of 0.0055 ft/sq.rt. minute. This "calibrated" model was used to design the final treatment.

With the desire to minimize fracture growth above the gas-oil contact, the final treatment design pad stage was limited to 2000 gals with an additional 3900 gals of gel carrying 14,800 lbs of 20/40 Carbo-Lite proppant at 0.5-8 ppg and at a rate of 15 bpm. The model-predicted TSO occurred at the beginning of the 3 ppg stage and net BHTP

went from 900 to 2236 psi with a corresponding average fracture width increase from 0.05 to 0.16 inches. Other fracture dimensions were a propped half-length of 105 ft, a maximum height of 142 ft, an average conductivity of 1242 md-ft, and an average in-situ concentration of 0.8 lbs/sq.ft.

The treatment was pumped reasonably close to design, placing 17,652 lbs of proppant (119% of design) in the fracture with 6560 gals of gel (111% of design) at a maximum concentration of 8 ppg. The TSO did occur as predicted and the actual net BHTP gain was 1130 psi as compared to the design prediction of 1335 psi. This seemed to indicate that the cement above the lower P3 was also adequate to withstand the higher fracturing pressures. To model history match the treatment behavior required (1) a slight increase in the stress of the shaly zone within the pay from 4500 to 4800 psi, (2) an increase in the modulus in this same zone to 8.5×10^6 psi, and (3) a slight increase in the pay zone leak-off from 0.0055 to 0.006 ft/sq.rt minute. These relatively minor changes resulted in a good match with model-predicted dimensions of a propped half-length of 111 ft, a maximum height of 196 ft, an average conductivity of 1050 md-ft, and an average in-situ concentration of 0.7 lbs/sq.ft. Based on these, the treatment came reasonably close to achieving the design goals.

DISCUSSION

Introduction:

This report details the design, execution, and analysis of the tip-screenout (TSO) fracturing treatment performed in Santos' East Mereenie Well No. 41 on 13 September 1996. The treatment was pumped through Pacoota P3-190/230/250 perforations at 4812-4838 and 4844-4874 ft (MD), 4700-4725 and 4732-4760 ft (TVD), as shown in Fig. 1.

When perforated underbalanced with TCP guns, the well performed below expectations, i.e. only 8 bopd. The completion was pulled and indicated that all guns had fired and there was no plugging of the vent sub or perforated joint. A casing drift run was performed and indicated 30 ft of fill above the original PBTD. Bailer runs sampled the fill, which appeared to be unset cement of a putty-like consistency. Samples were sent out for analysis. This seemed to confirmed the original USIT log prior to perforating, which indicated a very poor cement bond. A second USIT log, run after perforating, showed that the bond had worsened and the only area remaining of similar quality was below the P4 perforations. In an attempt to prepare for a remedial cement job, a packer was set between P4 perforations at 4917-4959 ft (MD) and the P3-230/250 perforations and an attempt to circulate between the two was unsuccessful with each zone holding 1500 psi surface pressure for 15 minutes with minimal leak-off. Next an attempt was made to break circulation over a shorter interval between the P3-190 and added squeeze perforations 10 ft above. Again no circulation could be achieved. The result of this work indicated that the quality of the cement was such that it could hold a hydraulic seal under low injection pressures but might still be suspect during a fracture treatment. Assuming the low oil flow rate was due to significant blockage of the perforations with cement, the well was reperforated using TCP guns over both the P4 and lower P3 intervals. While there was an initial strong blow for approximately one hour, the well eventually died off and repeated swab runs were unsuccessful in establishing flow. At this point the only available method for testing the cement and obtaining an economic flow rate was to fracture stimulate the well. The P4 zone, fracture treated on 11 September 1996 did not communicate around the backside through the lower P3 perforations, indicating that the cement between these two zones was sufficient.

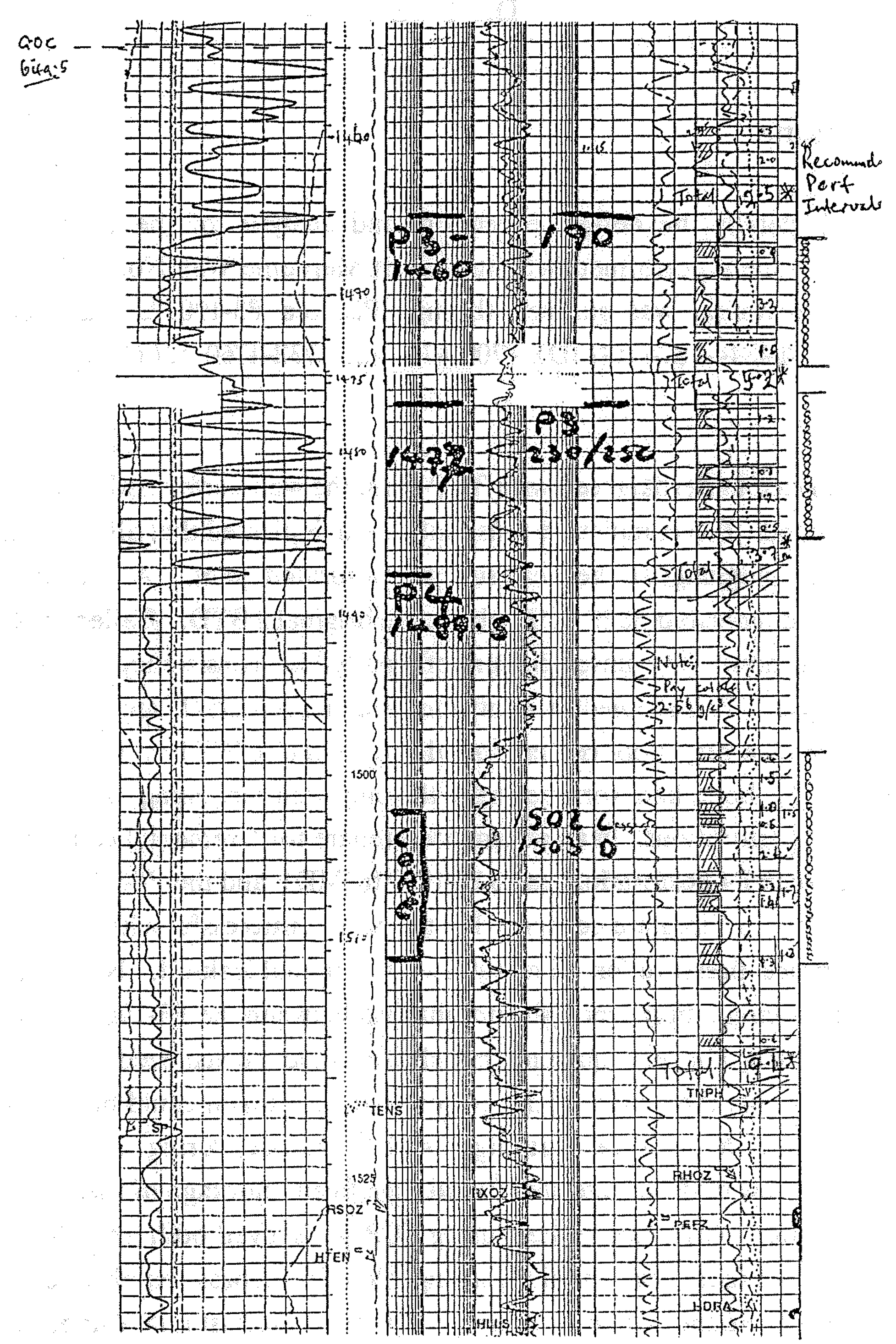

FIG. 1 - Log section thru pay interval and boundaries, E. Mereenie #41 (P3-190/230/250).

This well intersected a total of 37 ft of net pay in the lower P3. Without a pre-frac flow, a pressure buildup test could not be conducted and, thus, permeability was unknown but suspected to be relatively low. Reservoir pressure was thought to be at virgin conditions, i.e. 1750 psi, and the BHT was around 140^{o}F. Wellbore deviation through the pay was 18.5^{o}.

The lower P3 fracture treatment, performed by Halliburton, was preceded with pre-frac injection/decline tests to evaluate closure pressure, fluid efficiency, and fracture geometry for final design formulation. Bottomhole pressure was obtained with electronic memory gauges set in the tailpipe for both the testing and main treatment. The following discusses the details of this testing and treatment.

Pre-Frac Test Analysis:

Pre-frac testing consisted of (1) a 15 bbl slick water pump-in/shut-in (PI/SI) test at 5 bpm, (2) a slick water step-rate test (SRT)/SI at rates of 0.5-15 bpm, and (3) a 2000 gal, 30 ppt borate XL gel (Boragel H3595) minifrac at 15 bpm. The first two tests were designed to evaluate closure pressure and the minifrac was used to determine fluid efficiency and fracture geometry.

Fig. 2 shows a summary of the surface parameters for the sequence of tests and Fig. 3 shows the gauge BHP for the first PI/SI test. After an initial breakdown of about 6800 psi, pressure dropped to 5450 psi prior to shut-down. At shut-down, an ISIP of 4535 psi was measured, as shown in Fig. 4; this giving a very high downhole excess pressure of 915 psi. From the Horner plot of the pressure decline, Fig. 5, the pressure extrapolated to 1999 psi or higher than the expected reservoir pressure and probably due to insufficient decline data to reach the correct psuedo-steady-state straight line. The square-root of SI time plot indicated a possible closure pressure at 4182 psi (Fig. 6) and from the G-function plot closure was picked at 4095 psi - Fig. 7. Both of these values were higher than expected based on other closure measurements in this zone throughout the field, i.e. expected to be closer to 3500 psi.

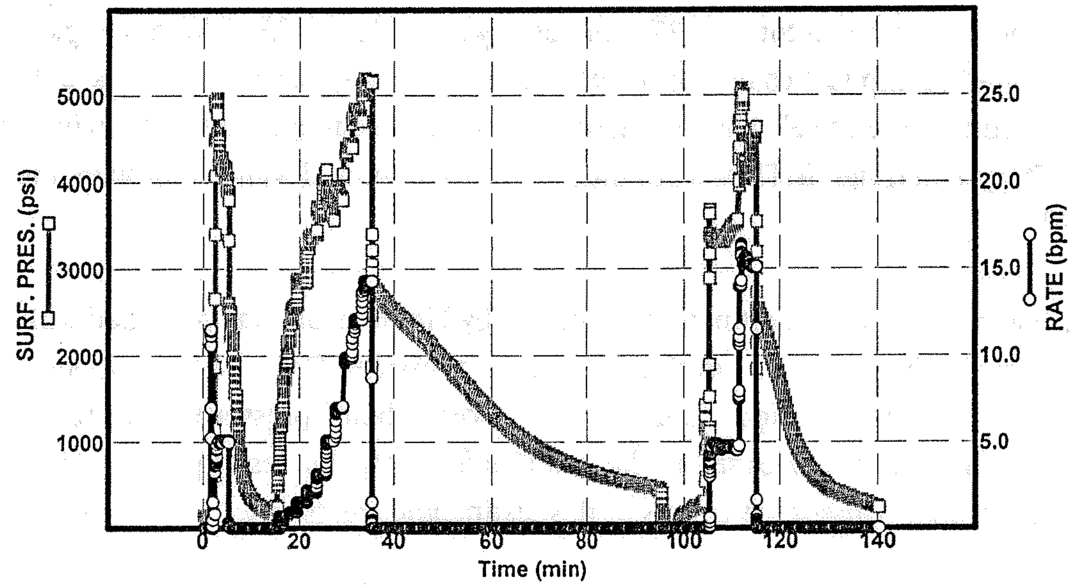

FIG. 2 - Pre-frac injection tests surface P and rate, E. Mereenie #41 (P3-190/230/250).

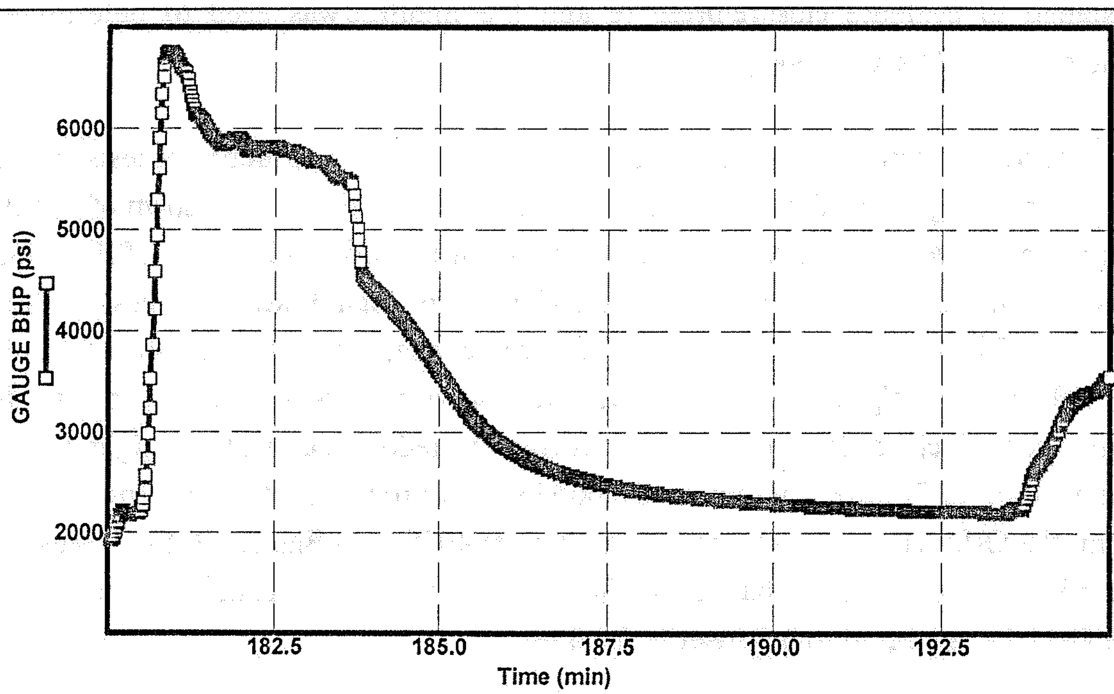

FIG. 3 - Slick water PI/SI test BHP record, E. Mereenie #41 (P3-190/230/250).

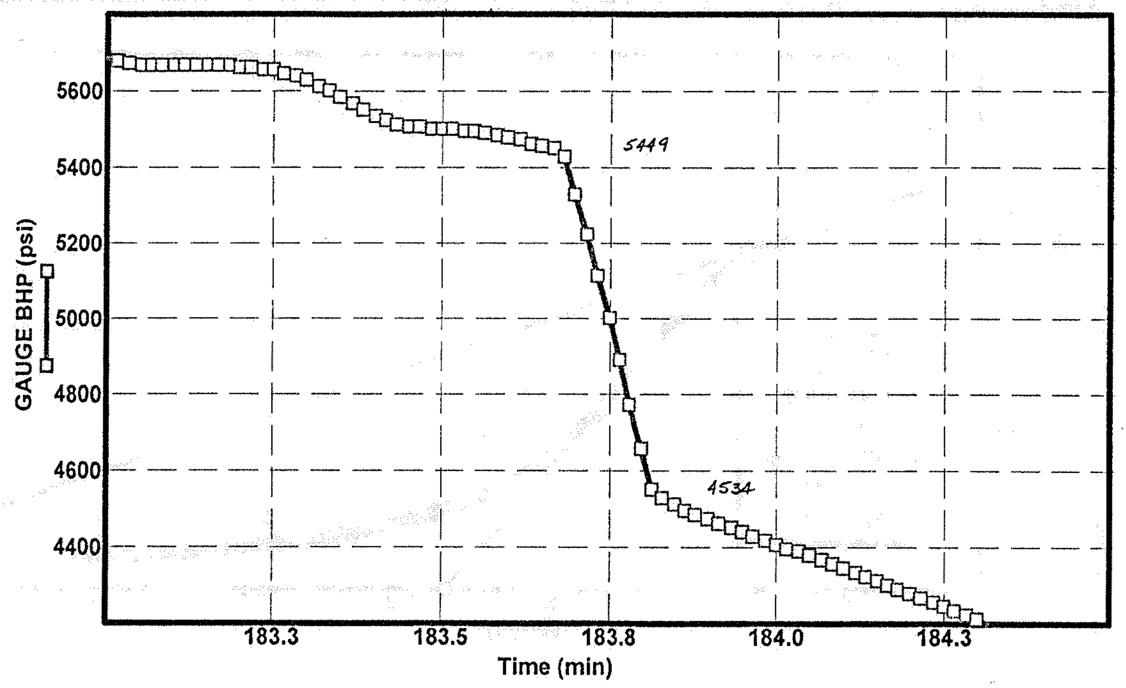

FIG. 4 - Slick water PI/SI test BH ISIP evaluation, E. Mereenie #41 (P3-190/230/250).

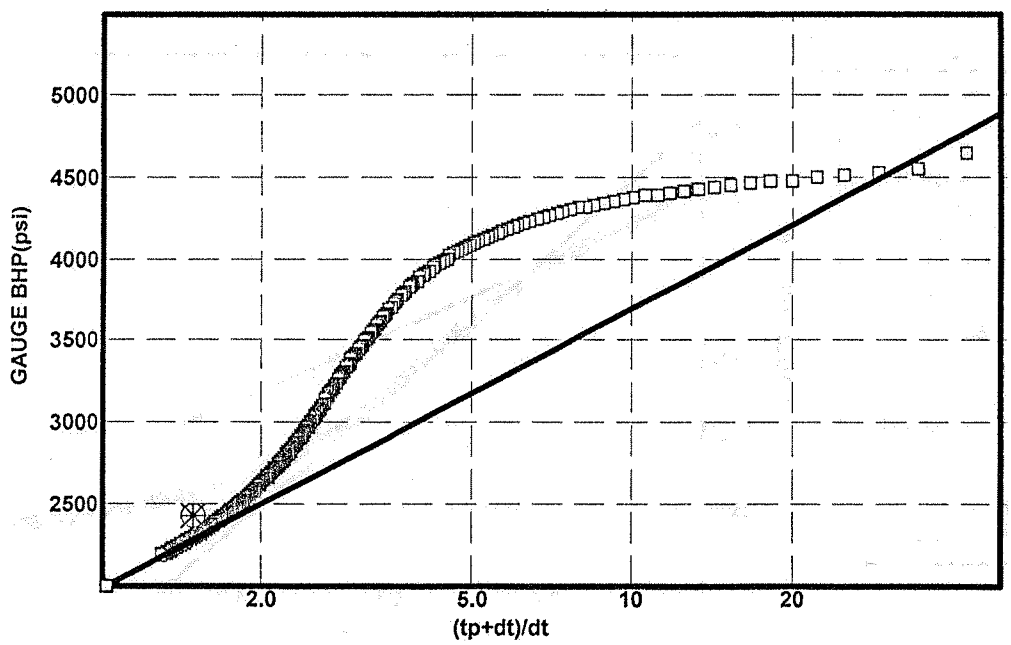

FIG. 5 - Slick water PI/SI test BH Horner plot, E. Mereenie #41 (P3-190/230/250).

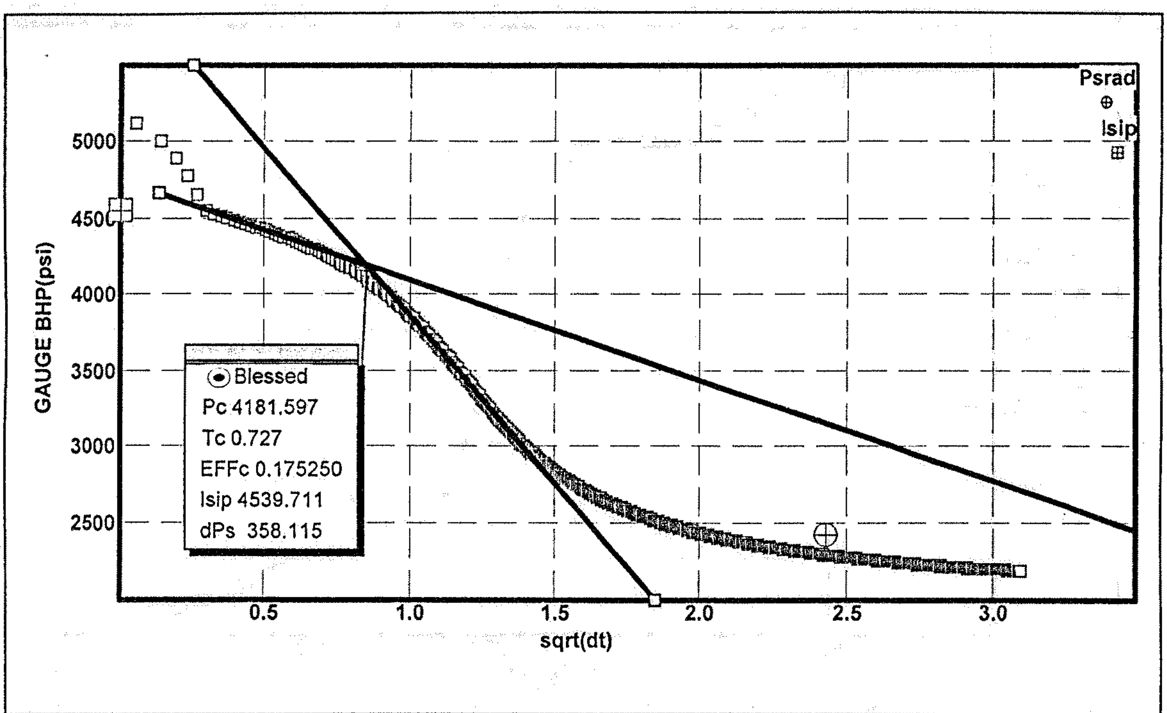

FIG. 6 - Slick water PI/SI test BH sq.rt. SI time plot, E. Mereenie #41 (P3-190/230/250).

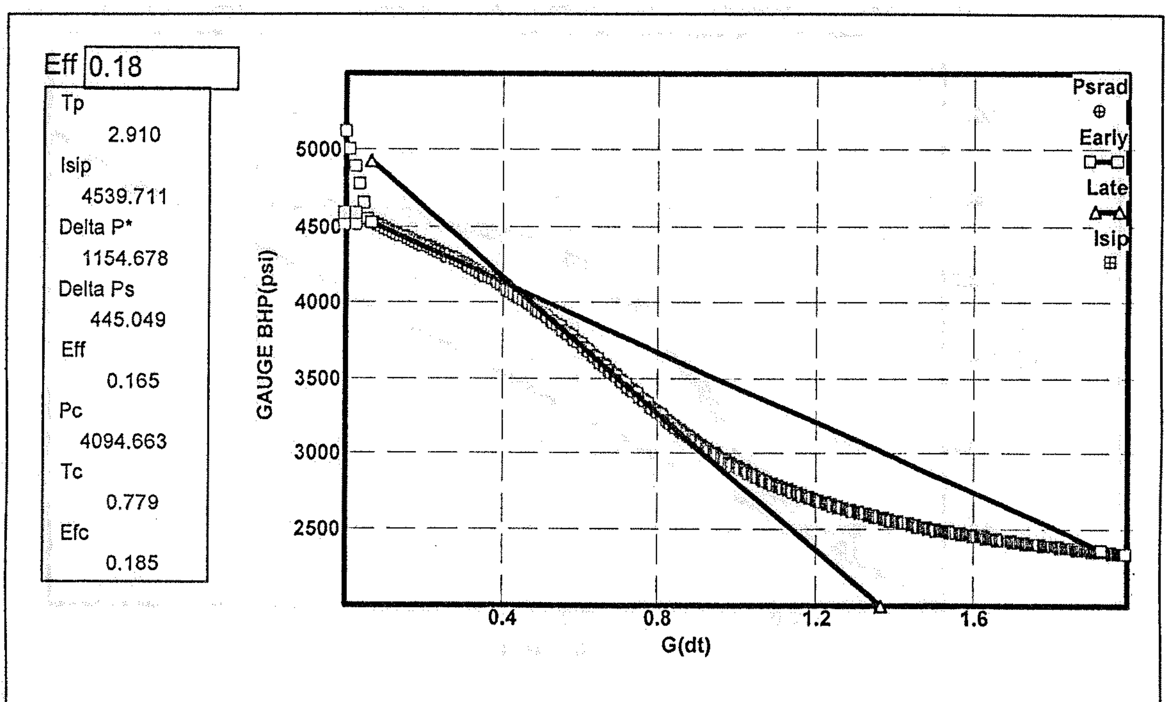

FIG. 7 - Slick water PI/SI test BH G-function plot, E. Mereenie #41 (P3-190/230/250).

Fig. 8 shows the gauge BHP record for the SRT/SI. At the end of injection, BHP was 5617 psi and the ISIP was 4880 psi (Fig. 9), again giving a relatively high downhole excess pressure of 737 psi. From a plot of stabilized BHP versus injection rate, Fig. 10, fracture extension pressure appeared to be at about 5206 psi or much higher than expected for the previous closure pressure picks. In all likelihood, fracture extension pressure was closer to the indicated final ISIP of 4880 psi. The square-root of SI time plot of the pressure decline, Fig. 11, indicated closure at 4330 psi with the G-function plot, Fig. 12, suggesting a closure at 4196 psi. Again both of these were higher than anticipated.

Fig. 13 shows the gauge BHP record for the minifrac. To minimize the effect of the residual wellbore fluid ahead of the crosslinked gel on determining fluid efficiency, the leading edge of the gel was pumped to near bottom at 5 bpm to bullhead the slick water into the fracture. The XL gel was then injected at 15 bpm. At the end of the minifrac, displaced with slick water to the top perforation, the BHTP was 5040 psi (less than the previous two slick water injections) and at shut-down the ISIP was 4722 psi, Fig. 14,

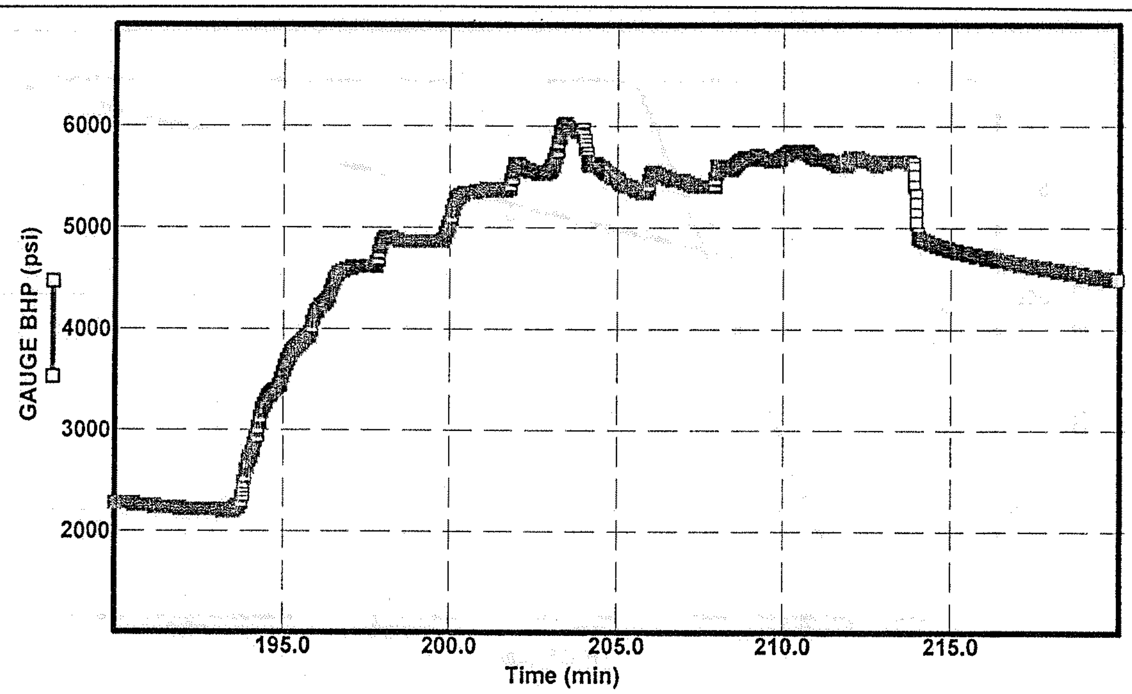

FIG. 8 - Slick water SRT/SI test BHP record, E. Mereenie #41 (P3-190/230/250).

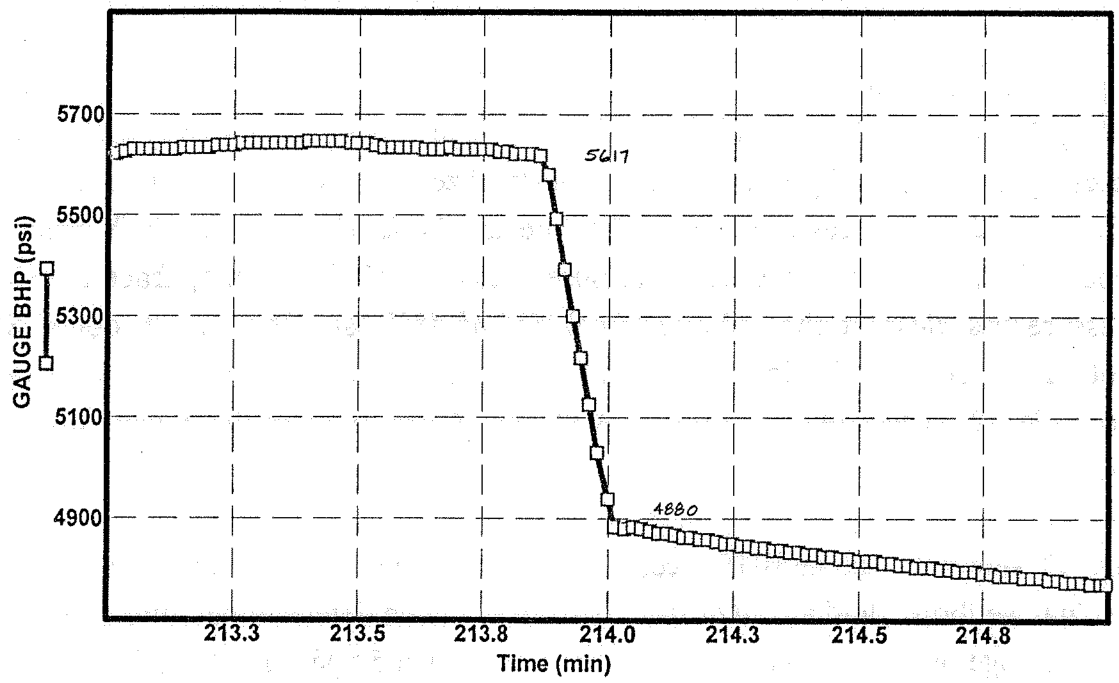

FIG. 9 - Slick water SRT/SI test BH ISIP evaluation, E. Mereenie #41 (P3-190/230/250).

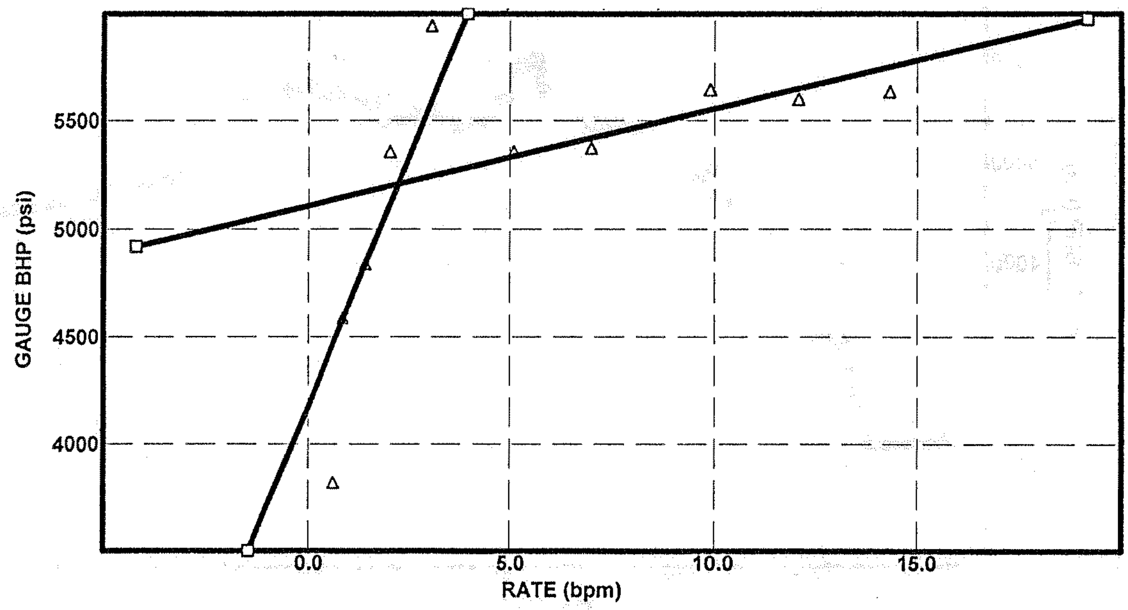

FIG. 10 - Slick water SRT/SI BH frac extension evaluation, E. Mereenie #41 (P3-190/230/250).

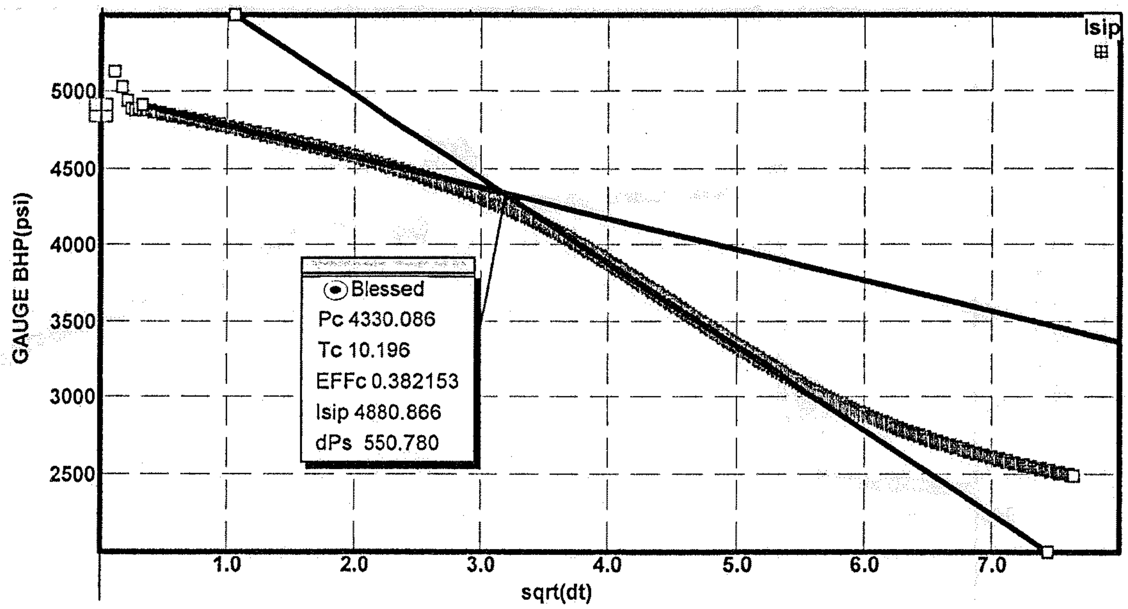

FIG. 11 - Slick water SRT/SI test BH sq.rt. SI time plot, E. Mereenie #41 (P3-190/230/250).

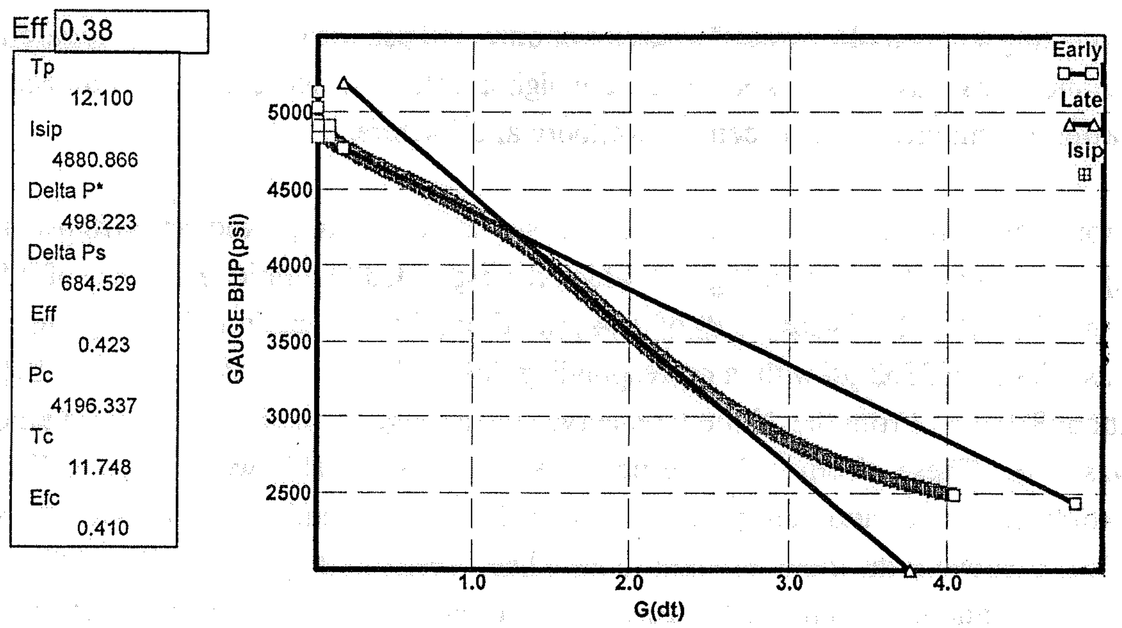

FIG. 12 - Slick water SRT/SI test BH G-function plot, E. Mereenie #41 (P3-190/230/250).

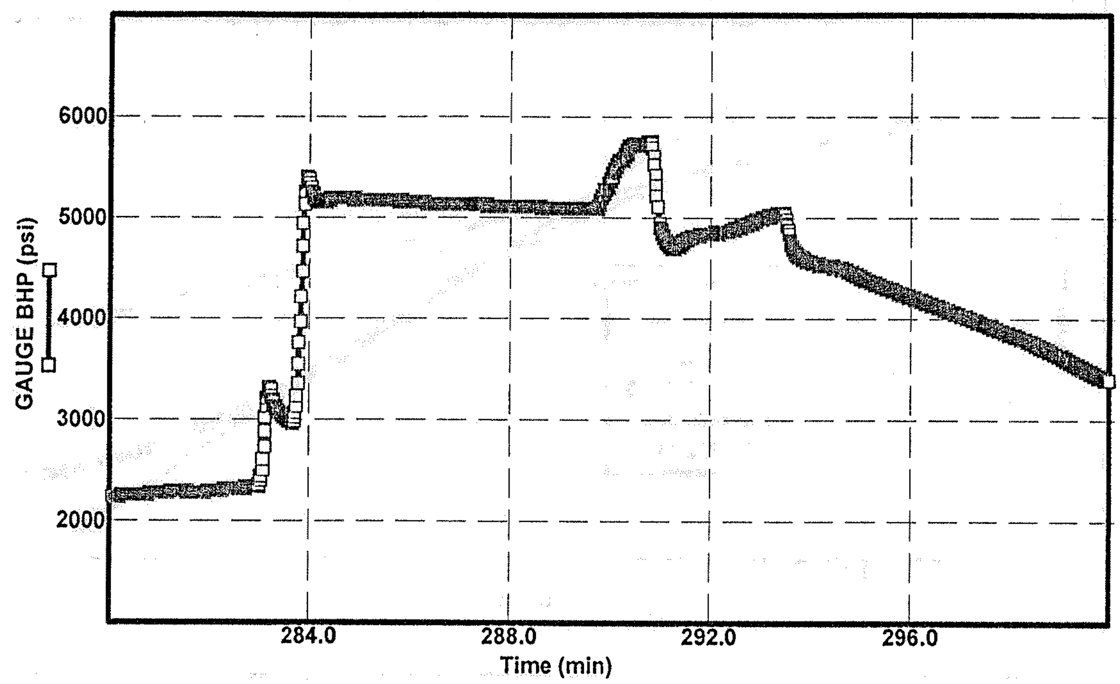

FIG. 13 - Boragel minifrac BHP record, E. Mereenie #41 (P3-190/230/250).

indicating a downhole "excess" pressure of only 318 psi. From this it was apparent that the more viscous crosslinked gel at the higher rate was successful in establishing far better communication between the wellbore and fracture.

From the minifrac pressure decline analysis, closure was picked at 3878 psi on the square-root of SI time plot, Fig. 15, which corresponded to a fluid efficiency of 0.45 and a net BHTP (BHTP-closure P) of 844 psi. From the G-function plot, Fig. 16, closure was picked at 3862 psi with a corresponding fluid efficiency of 0.45 and a net BHTP of about 860 psi. From the Nolte type-curve match, Fig. 17, the indicated fluid efficiency was 0.38. These closure picks, efficiencies, and net BHTP's were more in line with anticipated values and thus given far more weight in subsequent analysis than the results of the first two tests, these thought to have been obstructed by poor wellbore to fracture communication. From the Mereenie correlation of efficiency during injection to that determined from the decline, the injection efficiency was estimated to be 0.22.

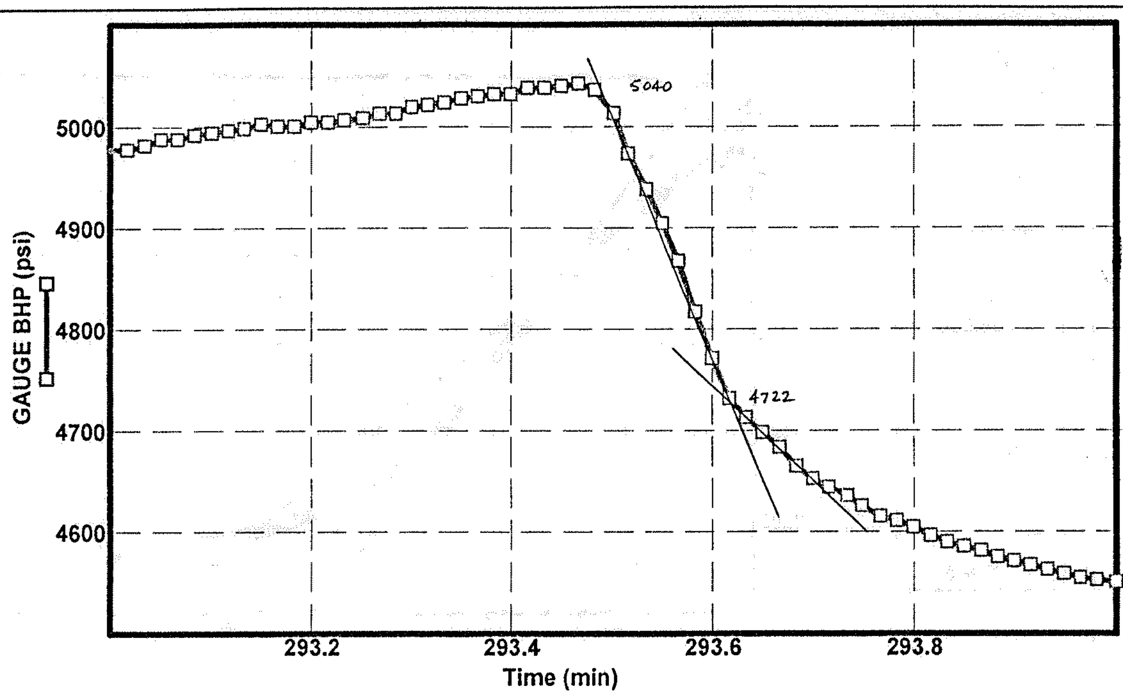

FIG. 14 - Boragel minifrac BH ISIP evaluation,
E. Mereenie #41 (P3-190/230/250).

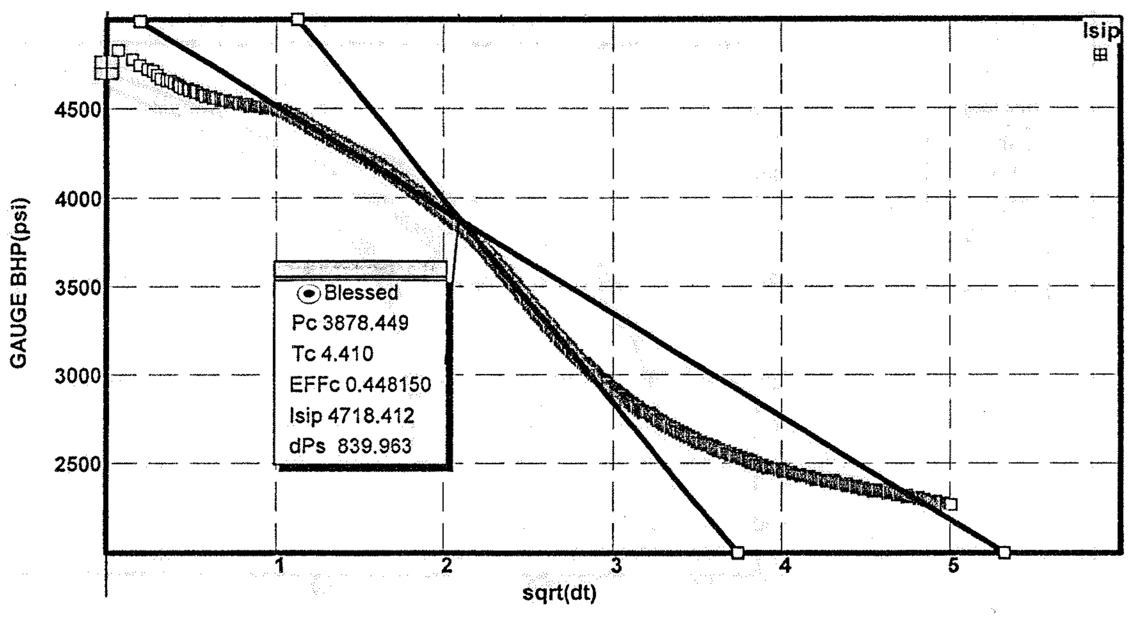

FIG. 15 - Boragel minifrac BH sq.rt. SI time plot,
E. Mereenie #41 (P3-190/230/250).

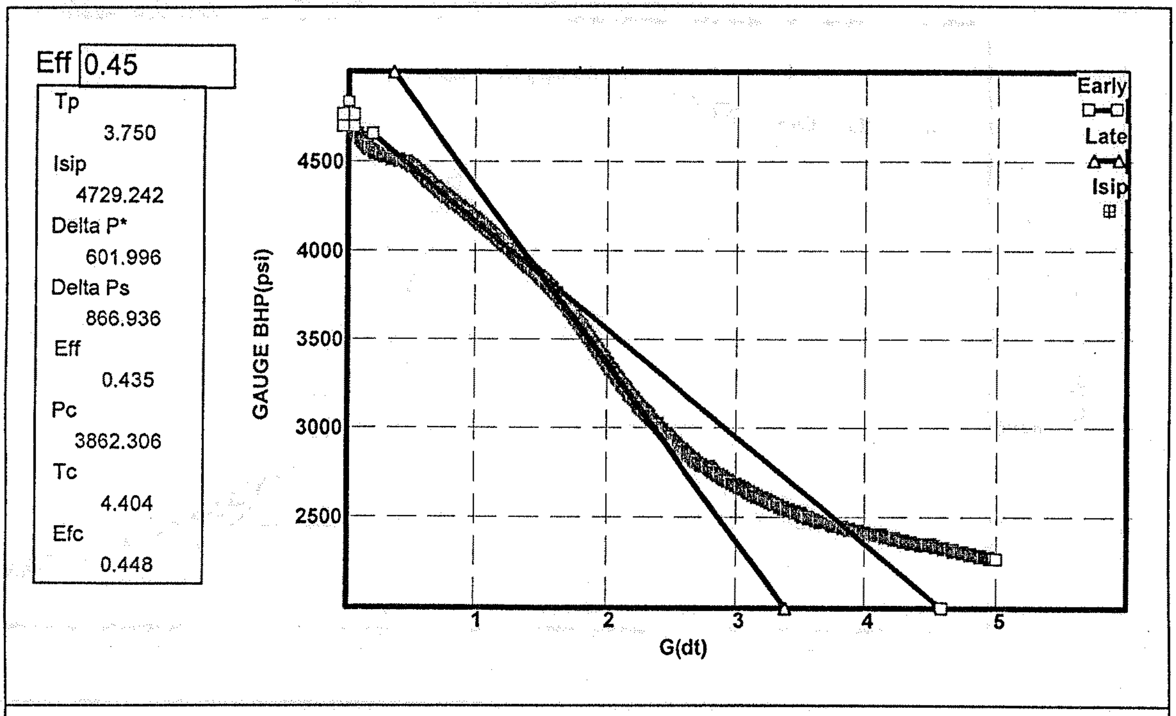

FIG. 16 - Boragel minifrac BH G-function plot, E. Mereenie #41 (P3-190/230/250).

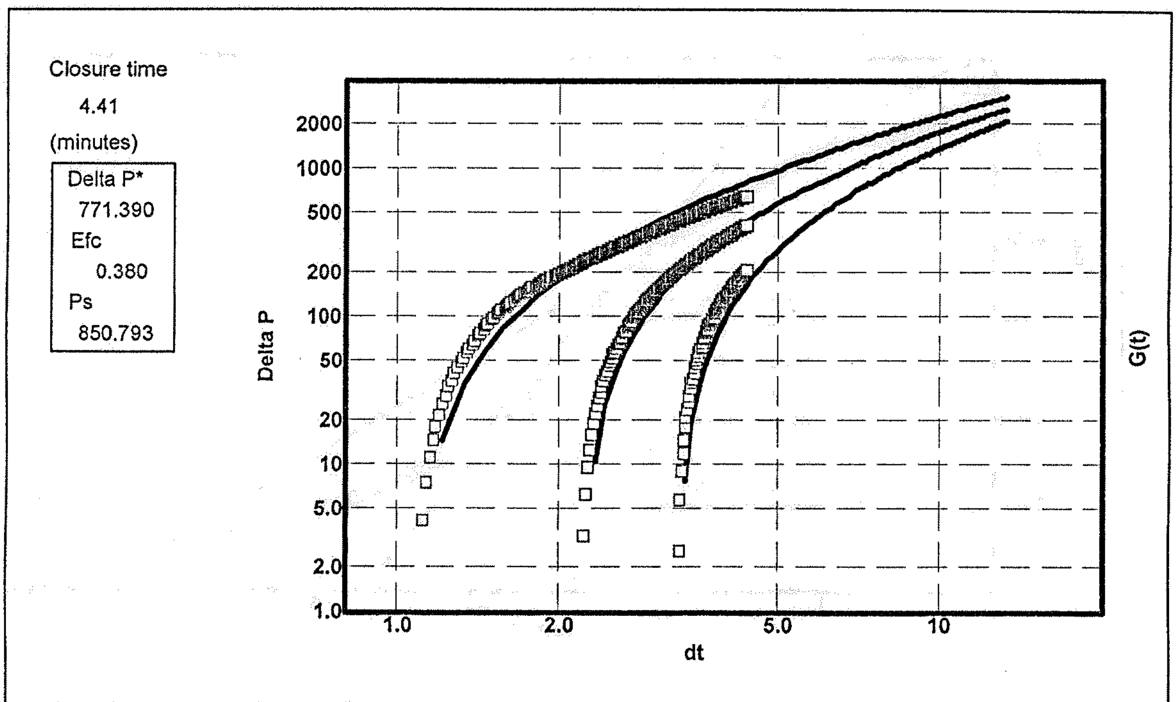

FIG. 17 - Boragel minifrac BH Nolte type-curve match, E. Mereenie #41 (P3-190/230/250).

To further the minifrac analysis and generate a "calibrated" model for final design evaluation, the minifrac injection profile was history matched. Net BHTP's were calculated with a closure pressure of 3870 psi and a downhole excess pressure of 318 psi. As shown in Fig. 18, the early-time pressures could not be matched, this being when the slick water was being injected at 5 bpm and probably a result of much higher excess pressure downhole during this period. Thus, the history match concentrated on only the period when crosslinked gel was being injected at the elevated rate. To match this portion and the resultant fluid efficiency at the end of injection of 0.22 required (1) boundary stresses of 4900 (upper) to 5050 (lower) psi and a stress of 4500 psi in the shalier interval between the P3-190 and 230/250, (2) a pay zone modulus of $6.5x10^6$ and $7.5\text{-}8.5x10^6$ psi in the middle shaly region and boundaries, and (3) a leak-off coefficient of 0.0055 ft/sq.rt. minute in the pay. The model-predicted fracture dimensions were a created half-length of 95 ft and a maximum height at the wellbore of 123 ft as shown in Fig. 19. The top of the indicated fracture was at 4660 ft (TVD) or near the estimated gas-oil contact at 4661 ft. The I/O for this simulation is included in Appendix Table A-1.

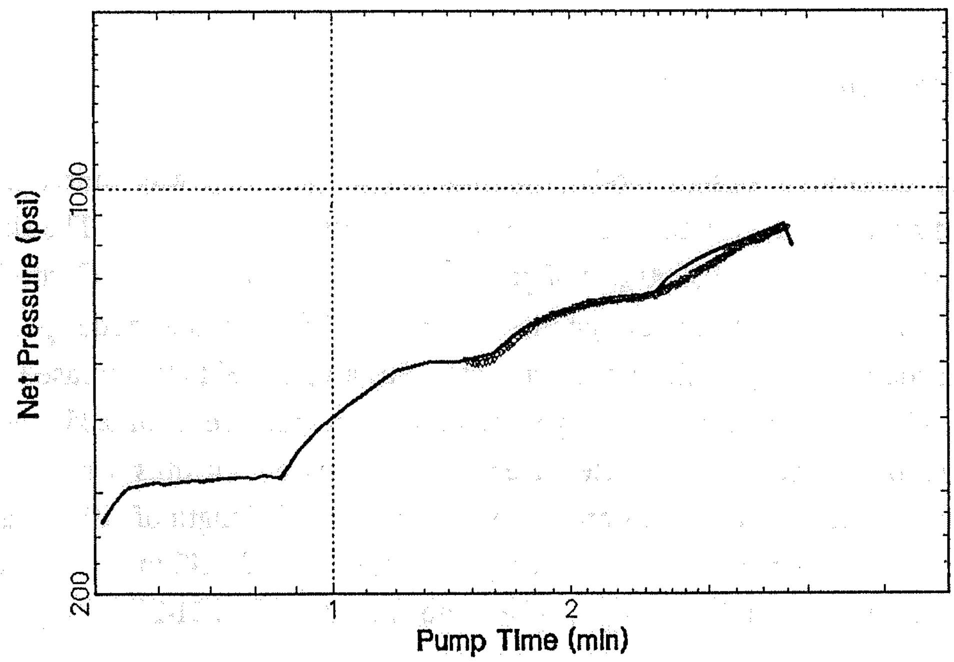

FIG. 18 - Boragel minifrac net BHTP model history match, E. Mereenie #41 (P3-190/230/250).

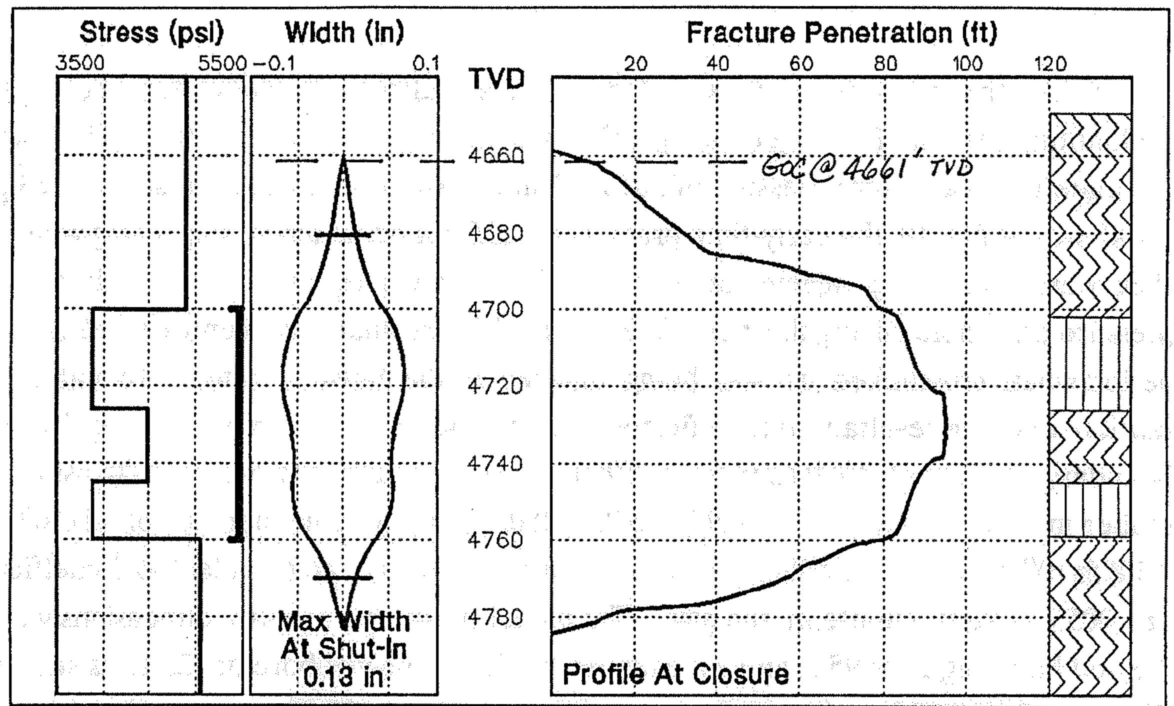

FIG. 19 - Boragel minifrac history match predicted frac geometry, E. Mereenie #41 (P3-190/230/250).

Final Treatment Design:

Using the "calibrated" design model, the final design pad stage was limited to 2000 gals to minimize upward growth above the gas-oil contact (Table 1). The slurry stages consisted of an additional 3900 gals of gel carrying 14,800 lbs of 20/40 Carbo-Lite at 0.5-8 ppg. With this pad and the design injection rate of 15 bpm, the model-predicted TSO started at the beginning of the 3 ppg stage (Fig. 20) and net BHTP increased from 900 to 2236 psi with a corresponding average fracture width increase from 0.05 to 0.16 inches. At the wellbore, the final predicted average and maximum widths were 0.20 and 0.39 inches. Other modeled dimensions were a propped half-length of 105 ft, a maximum height at the wellbore of 142 ft, an average conductivity of 1242 md-ft, and an average in-situ concentration of 0.8 lbs/sq.ft. These are shown in Figs. 21-23 with the model I/O included in Appendix Table A-2.

TABLE 1 - Final treatment design schedule, E. Mereenie #41 (P3-190/230/250).

Fluid Type	Slur. Vol. (gal)	Fluid Vol. (gal)	Prop Conc. (ppg)	Prop Amt. (lbs)	Avg. Q (bpm)	Pump t (min)
Boragel H3595	2000	2000	0.00	0	15.00	3.17
Boragel H3595	613	600	0.50	300	15.00	0.97
Boragel H3595	522	500	1.00	500	15.00	0.83
Boragel H3595	435	400	2.00	800	15.00	0.69
Boragel H3595	453	400	3.00	1200	15.00	0.72
Boragel H3595	470	400	4.00	1600	15.00	0.75
Boragel H3595	488	400	5.00	2000	15.00	0.77
Boragel H3595	506	400	6.00	2400	15.00	0.80
Boragel H3595	523	400	7.00	2800	15.00	0.83
Boragel H3595	541	400	8.00	3200	15.00	0.86
	6551	5900		14800		13.83

Note: Proppant 20/40 Carbo-Lite.

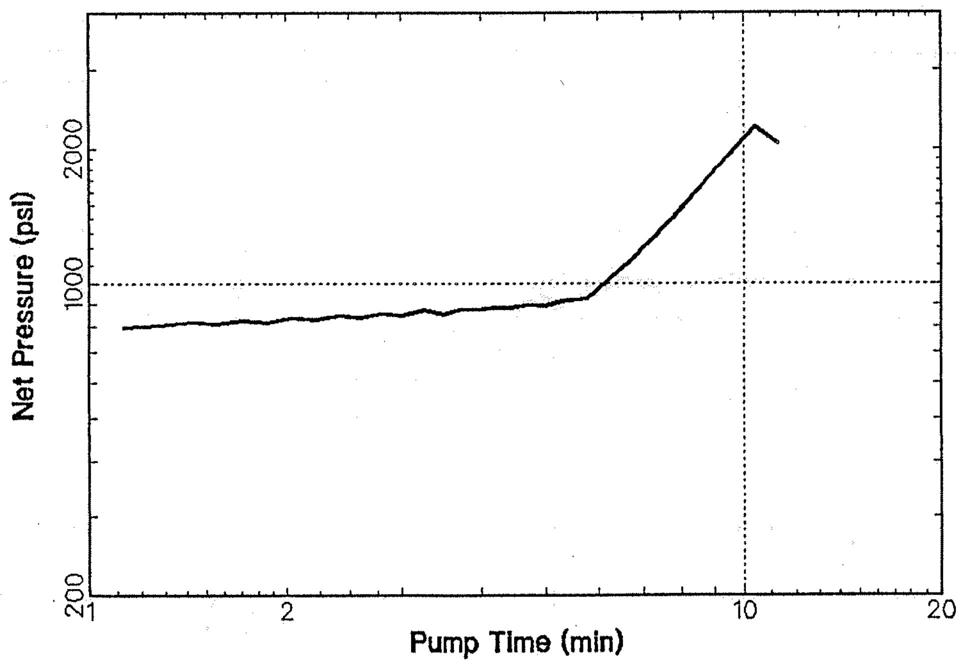

FIG. 20 - Final treatment design predicted net BHTP, E. Mereenie #41 (P3-190/230/250).

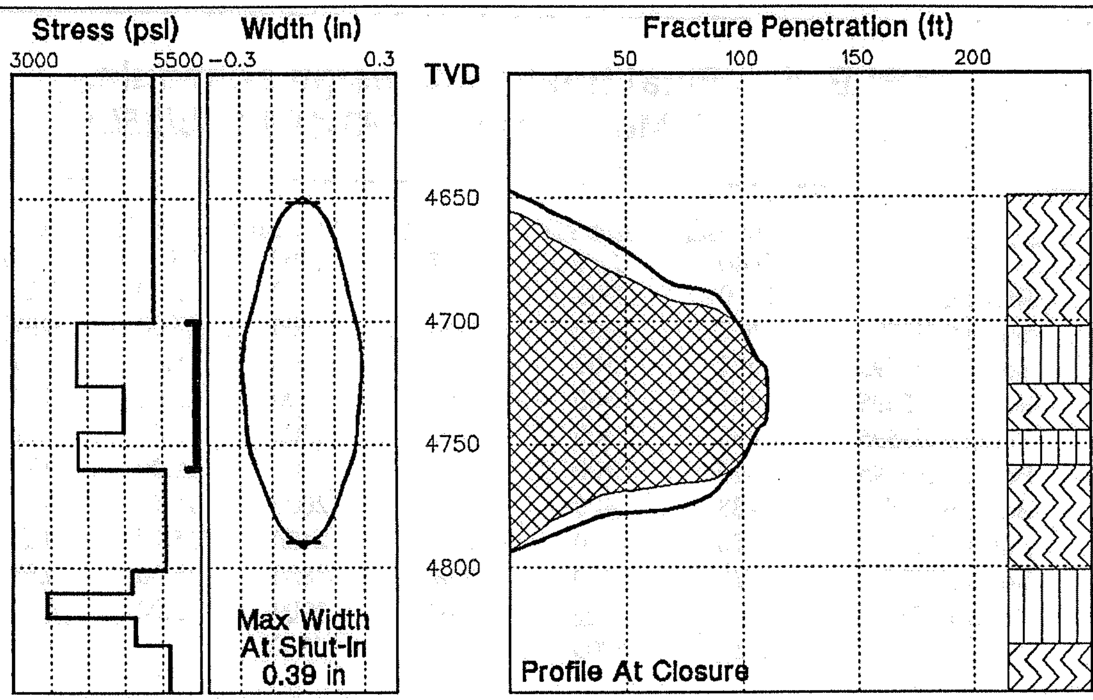

FIG. 21 - Final treatment design predicted frac geometry, E. Mereenie #41 (P3-190/230/250).

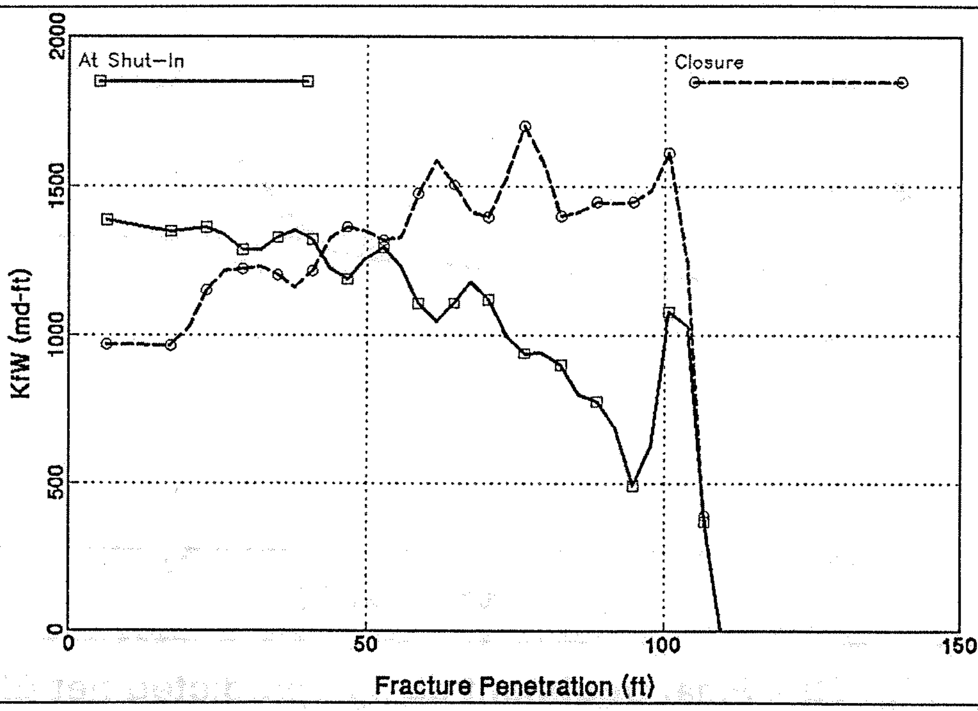

FIG. 22 - Final treatment design predicted conductivity, E. Mereenie #41 (P3-190/230/250).

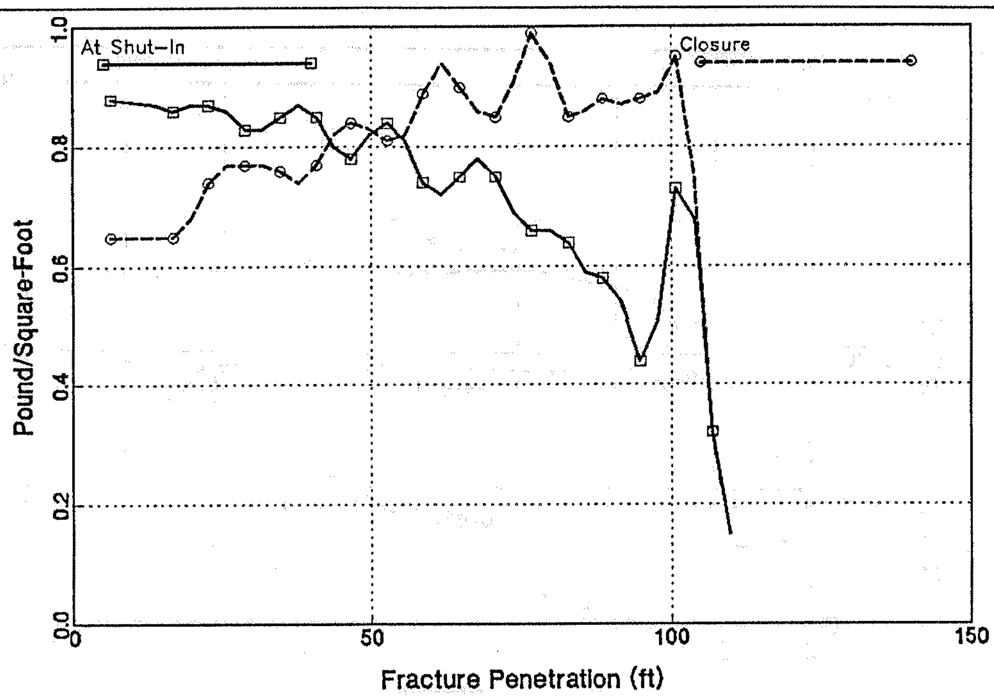

FIG. 23 - Final treatment design predicted in-situ conc., E. Mereenie #41 (P3-190/230/250).

Treatment Execution:

Samples of the gel were tested on-site prior to the treatment and found to possess the proper characteristics with respect to base gel viscosity, pH, and crosslink. To minimize the effect of the bullheaded residual wellbore fluid ahead of the pad, the pad was pumped to the bottom of the tubing at 5 bpm. The rate was then increased to 15 bpm for the remainder of the treatment. The treatment was pumped without any mechanical or blending mishaps and there was no indication of problems with the cement integrity. Fig. 24 shows the surface treating parameters, with Table 2 showing the surface schedule from Halliburton's computer printout. This indicated a total of 21,241 lbs of proppant pumped with 7883 gals of gel and flush. Based on the amount of proppant loaded (21,000 lbs) and accounting for approximately 1500 lbs left at the surface due to spillage and that remaining in the blender bin, the actual amount of proppant pumped in the well was 19,500 lbs, indicating the wellhead densiometer to be reading 8.93% high.

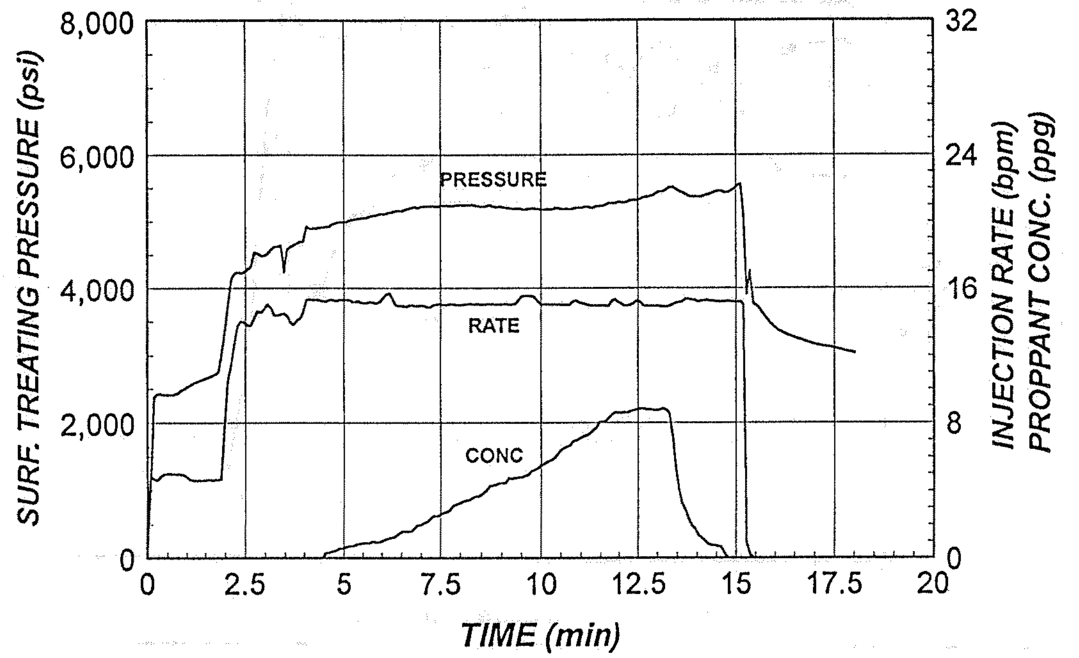

FIG. 24 - Treatment summary of surface parameters, E. Mereenie #41 (P3-190/230/250).

Also, based on tank dips, a total of 7728 gals of fluid was pumped, indicating that the flowmeter was reading 2.01% high. Making these corrections, the surface schedule in Table 3 was derived. This was then used to determine the downhole treatment schedule shown in Table 4. From this, a total of 17,652 lbs of proppant (119.3% of design) was placed in the fracture with 6562 gals of gel (111.2% of design). This resulted in an actual average slurry concentration of 3.83 ppg as compared to the design of 3.79 ppg. When compared to the design proppant schedule, Fig. 25, the actual schedule was somewhat less aggressive than the design, however, considerably more 8 ppg slurry was pumped. Overall this was a very good treatment.

TABLE 2 - Halco computed surface pump schedule, E. Mereenie #41 (P3-190/230/250).

Fluid Type	Slur. Vol. (gal)	Fluid Vol. (gal)	Prop Conc. (ppg)	Prop Amt. (lbs)	Avg. Q (bpm)	Pump t (min)
Boragel H3595 (Fill Hole)	115	115	0.00	0	-	0.30
Boragel H3595	388	388	0.00	0	4.86	1.90
Boragel H3595	138	138	0.00	0	9.86	0.33
Boragel H3595	290	290	0.00	0	13.81	0.50
Boragel H3595	257	257	0.00	0	14.68	0.42
Boragel H3595	499	499	0.00	0	14.26	0.83
Boragel H3595	310	310	0.00	0	15.27	0.48
Boragel H3595	630	615	0.56	347	15.25	0.98
Boragel H3595	480	460	0.97	446	15.24	0.75
Boragel H3595	442	415	1.50	621	15.03	0.70
Boragel H3595	428	389	2.30	895	14.91	0.68
Boragel H3595	463	406	3.16	1285	15.03	0.73
Boragel H3595	483	410	4.07	1669	15.00	0.77
Boragel H3595	493	407	4.81	1958	15.31	0.77
Boragel H3595	516	410	5.85	2399	15.04	0.82
Boragel H3595	422	322	7.05	2271	15.07	0.67
Boragel H3595	474	349	8.19	2853	15.05	0.75
Boragel H3595	786	568	8.73	4956	14.97	1.25
Flush	575	507	3.04	1541	15.21	0.90
Flush	628	628	0.00	0	15.21	0.98
	8817	7883		21241		15.51

Note: (1) Proppant 20/40 Carbo-Lite.
(2) Based on tank dips 7728 gal total fluid pumped. Flowmeter reading 2.01% high. Corr. factor = 0.9803.
(3) Based on prop loaded (21,000 lbs) minus prop remaining at surface (1500 lbs), pumped 19,500 lbs. Wellhead densiometer reading 8.93% high. Corr. factor = 0.918.

TABLE 3 - "Corrected" surface pump schedule, E. Mereenie #41 (P3-190/230/250).

Fluid Type	Slur. Vol. (gal)	Fluid Vol. (gal)	Prop Conc. (ppg)	Prop Amt. (lbs)	Avg. Q (bpm)	Pump t (min)
Boragel H3595 (Fill Hole)	113	113	0.00	0	-	0.30
Boragel H3595	380	380	0.00	0	4.76	1.90
Boragel H3595	135	135	0.00	0	9.74	0.33
Boragel H3595	284	284	0.00	0	13.52	0.50
Boragel H3595	252	252	0.00	0	14.29	0.42
Boragel H3595	489	489	0.00	0	14.03	0.83
Boragel H3595	304	304	0.00	0	15.08	0.48
Boragel H3595	617	603	0.53	319	14.99	0.98
Boragel H3595	469	451	0.91	409	14.89	0.75
Boragel H3595	432	407	1.40	570	14.69	0.70
Boragel H3595	417	381	2.16	822	14.60	0.68
Boragel H3595	450	398	2.96	1180	14.68	0.73
Boragel H3595	469	402	3.81	1532	14.50	0.77
Boragel H3595	478	399	4.50	1797	14.78	0.77
Boragel H3595	499	402	5.48	2202	14.49	0.82
Boragel H3595	408	316	6.60	2085	14.50	0.67
Boragel H3595	457	342	7.66	2619	14.51	0.75
Boragel H3595	757	557	8.17	4550	14.42	1.25
Flush	559	497	2.85	1415	14.79	0.90
Flush	616	616	0.00	0	14.97	0.98
	8585	7728		19500		15.51

Note: Proppant 20/40 Carbo-Lite.

TABLE 4 - Treatment downhole pump schedule, E. Mereenie #41 (P3-190/230/250).

Fluid Type	Slur. Vol. (gal)	Fluid Vol. (gal)	Prop Conc. (ppg)	Prop Amt. (lbs)	Avg. Q (bpm)	Pump t (min)
WB Fluid	380	380	0.00	0	4.76	1.90
WB Fluid	135	135	0.00	0	9.74	0.33
WB Fluid	284	284	0.00	0	13.52	0.50
WB Fluid	335	335	0.00	0	14.23	0.56
Boragel H3595	406	406	0.00	0	14.03	0.69
Boragel H3595	1390	1390	0.00	0	14.98	2.21
Boragel H3595	161	161	0.00	0	14.69	0.26
Boragel H3595	617	603	0.53	319	14.64	1.00
Boragel H3595	469	451	0.91	409	14.67	0.76
Boragel H3595	432	407	1.40	570	14.52	0.71
Boragel H3595	417	381	2.16	822	14.72	0.67
Boragel H3595	150	133	2.96	393	14.78	0.24
Boragel H3595	300	265	2.96	787	14.49	0.49
Boragel H3595	469	402	3.81	1532	14.50	0.77
Boragel H3595	478	399	4.50	1797	14.51	0.78
Boragel H3595	499	402	5.48	2202	14.44	0.82
Boragel H3595	408	316	6.60	2085	14.45	0.67
Boragel H3595	457	342	7.66	2619	14.79	0.74
Boragel H3595	541	504	8.17	4117	14.95	1.09
	8472	7696		17652		15.19

Note: (1) Proppant 20/40 Carbo-Lite.
(2) Placed 119.3% of design prop amount in fracture with 111.2% of design gel volume. Avg. slurry conc. = 3.83 ppg (design - 3.79 ppg).

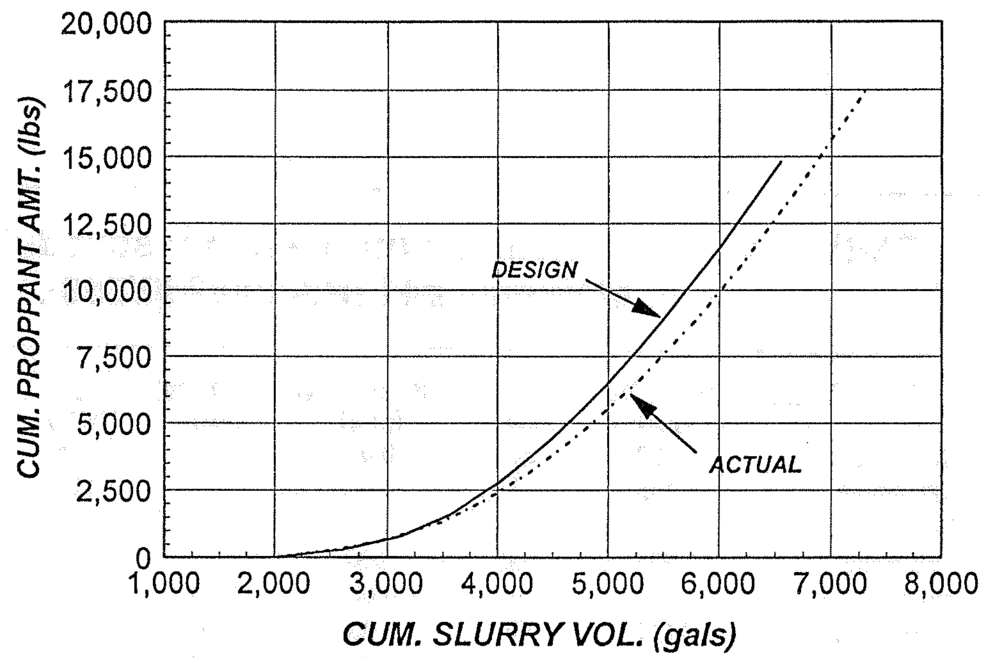

FIG. 25 - Comparison of actual to design prop schedule, E. Mereenie #41 (P3-190/230/250).

Post-Frac Evaluation:

Fig. 26 shows the gauge BHTP record plotted with the corresponding rate and downhole proppant concentration. From this it seemed that the TSO started somewhere around 10 minutes, with a pressure gain of 1130 psi as compared to the design prediction of 1335 psi. To history match this behavior, net BHTP was calculated using the closure pressure of 3870 psi and the downhole "excess" pressure of 318 psi from the minifrac. Fig. 27 shows the match, this requiring (1) an increase in the stress of the shalier interval between the P3-190 and 230/250 from 4500 to 4800 psi, (2) a slight increase in the modulus of this same interval from 7.5 to 8.5x10^6 psi, and (3) a slight increase in the pay zone leak-off coefficient from 0.0055 to 0.006 ft/sq.rt. minute. These relatively minor changes resulted in a good match with model-predicted dimensions of a propped half-length of 111 ft (design - 105 ft), a maximum height of 196 ft (design - 142 ft), an average conductivity of 1050 md-ft (design - 1242 md-ft), and an average in-situ concentration of

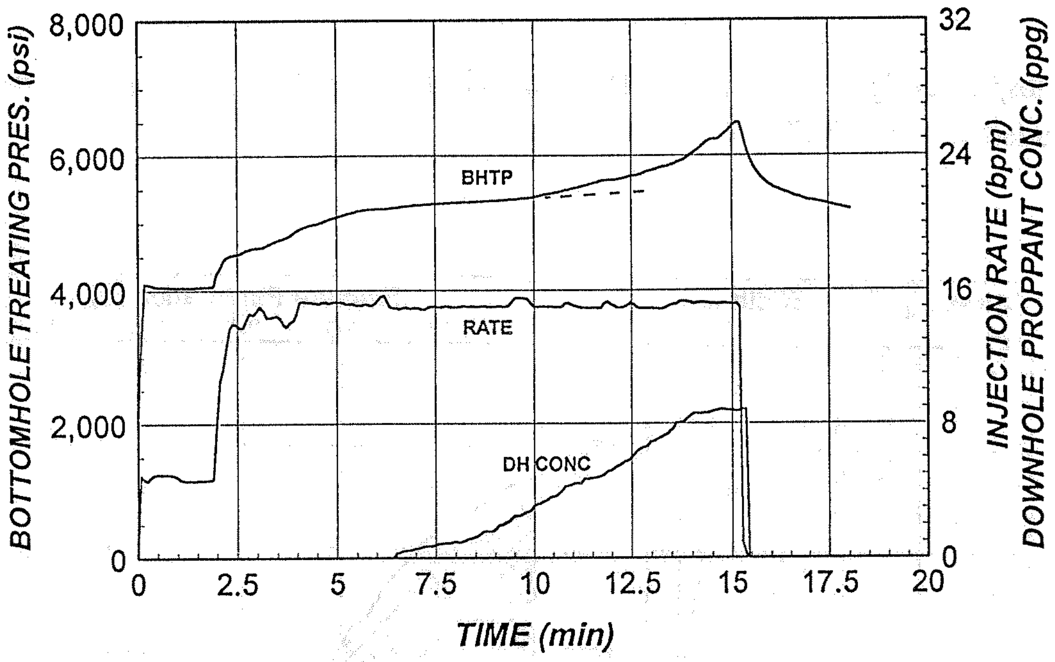

FIG. 26 - Treatment summary of bottomhole parameters, E. Mereenie #41 (P3-190/230/250).

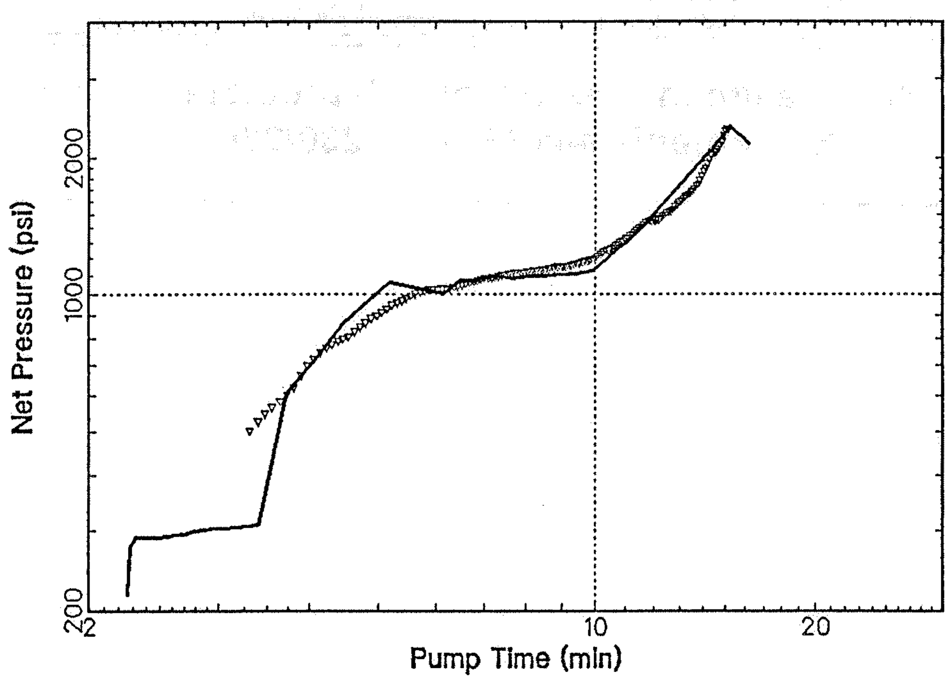

FIG. 27 - Treatment net BHTP model history match, E. Mereenie #41 (P3-190/230/250).

0.7 lbs/sf (design - 0.8 lbs/sf). These are shown in Figs. 28-30, with the model I/O included in Appendix Table A-3.

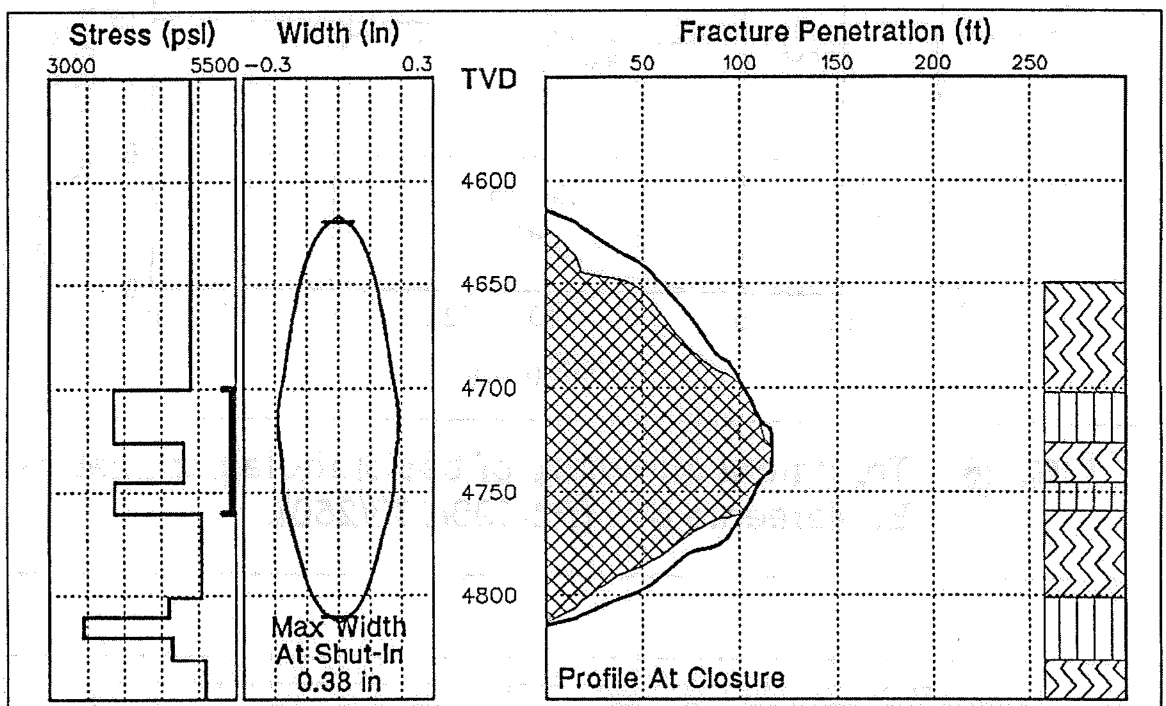

FIG. 28 - Treatment history match predicted frac geometry, E. Mereenie #41 (P3-190/230/250).

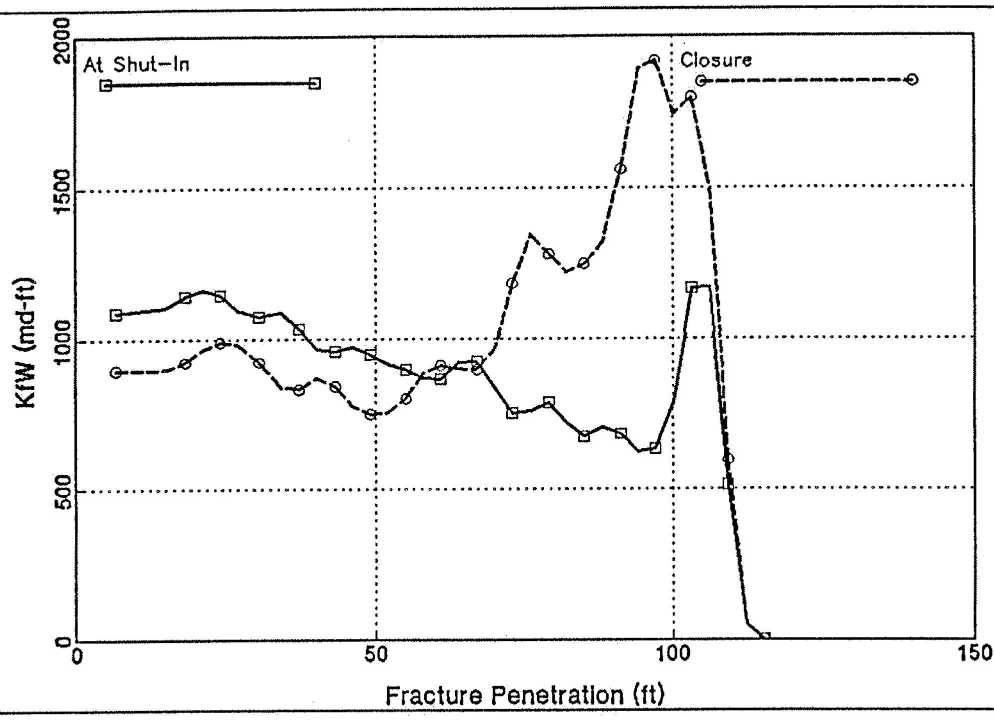

FIG. 29 - Treatment history match predicted conductivity, E. Mereenie #41 (P3-190/230/250).

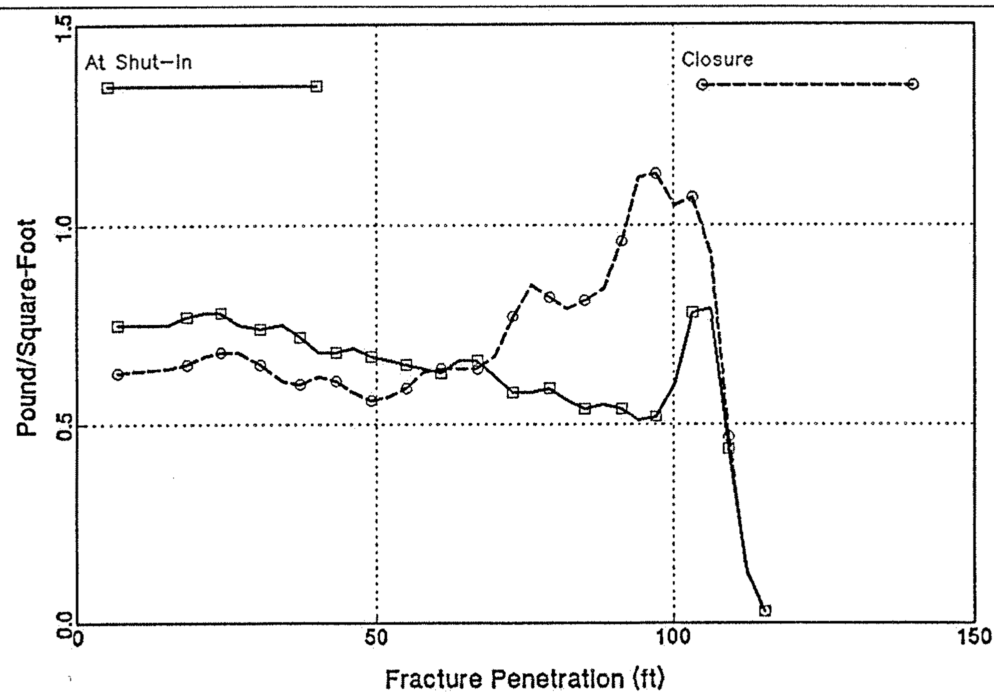

FIG. 30 - Treatment history match predicted in-situ conc., E. Mereenie #41 (P3-190/230/250).

CONCLUSIONS / RECOMMENDATIONS

From pre-frac test analysis, closure pressure was 3870 psi (0.82 psi/ft), fluid efficiency from pressure decline analysis was 0.45, and net BHTP was on the order of 850 psi with the XL gel at 15 bpm. Using the Mereenie correlation of fluid efficiency from pressure decline to injection efficiency, the efficiency was reduced to 0.22 for final design formulation. Downhole "excess" pressure during the minifrac was only 318 psi, indicating good wellbore to fracture communication.

A reasonably good model history match of the minifrac net BHTP's was obtained with (1) boundary stresses of 4900 (upper) to 5050 psi (lower) and a stress of 4500 psi in the shalier interval between the P3-190 and 230/250, (2) a pay zone modulus of 6.5×10^6 psi and $7.5\text{-}8.5 \times 10^6$ psi in the middle shaly region and boundaries, and (3) a pay zone leak-off coefficient of 0.0055 ft/sq.rt. minute.

The treatment design, based on the calibrated minifrac model, was pumped reasonably close to design without any mishaps due to pumps, blending, or the cement integrity. A total of 17,650 lbs of proppant (119.3% of design) was placed in the fracture with 6560 gals of gel (111.2% of design) at an average slurry concentration of 3.83 ppg (design - 3.79 ppg). Overall this was a very good treatment.

From the treatment BHP record it was apparent that the TSO did occur, with a pressure gain of 1130 psi as compared to the design prediction of 1335 psi. To match this required (1) increasing the stress and modulus in the middle shaly region to 4800 psi and 8.5×10^6 psi, respectively, and (2) increasing the pay zone leak-off coefficient to 0.006 ft/sq.rt. minute. With these changes the indicated created propped half-length was 111 ft (design - 105 ft), the maximum height was 196 ft (design - 142 ft), the average conductivity was 1050 md-ft (design - 1242 md-ft), and the average in-situ concentration was 0.7 lbs/sf (design - 0.8 lbs/sf). Based on these, the treatment came relatively close to achieving design goals.

APPENDIX A

Fracture Model Simulations

TABLE A-1

```
Frac Summary * SANTOS - E. MEREENIE #41 (LP3) MINIFRAC HISTORY MATCH
              Filename: EM41P3MF.FRK ;  Sep 12, 96

                            Design Data
-------------------------------------------------------------------
FLUID LOSS  Top     Bottom   Thick      Loss Coef.         Spurt
LAYERS:     (ft)     (ft)     (ft)   (ft/sqrt(min)) (Gal/100 ft^2)
            4649.0  4702.0    53.0      0.00010           0.00
            4702.0  4726.0    24.0      0.00550           0.50
            4726.0  4745.0    19.0      0.00010           0.00
            4745.0  4759.0    14.0      0.00550           0.50
            4759.0  4801.0    42.0      0.00010           0.00
            4801.0  4831.0    30.0      0.00500           0.20
            4831.0  4900.0    69.0      0.00010           0.00
 FORMATION:    Modulus (e6_psi) ....................     6.82
               Perforated Height (ft) ..............     60.0
               Permeability (md)  ..................    1.000
 TEMPERATURE: Bottom Hole (deg_F) ..................      145
 PRESSURE:     Reservoir Pressure (psi) ............   1830.0
               Closure Pressure (psi) ..............   3860.0
 DEPTH:        Well Depth (ft) .....................   4700.0
-------------------------------------------------------------------
FORMATION LAYER DATA - Multi-Layer Height Growth
-----Depth(ft)------   -Stress (psi)-- Gradient Modulus Toughness
  Top    Botm   Thick    Top     Botm   (psi/ft) (e6_psi) (psi/in)
4500.0 4700.0  200.0  4900.0  4900.0   0.000    8.00    3000.0
4700.0 4726.0   26.0  3860.0  3860.0   0.000    6.50    3000.0
4726.0 4745.0   19.0  4500.0  4500.0   0.000    7.50    3000.0
4745.0 4760.0   15.0  3870.0  3870.0   0.000    6.50    3000.0
4760.0 4801.0   41.0  5050.0  5050.0   0.000    8.50    3000.0
4801.0 4810.0    9.0  4600.0  4600.0   0.000    8.25    3000.0
4810.0 4820.0   10.0  3450.0  3450.0   0.000    8.00    3000.0
4820.0 4831.0   11.0  4650.0  4650.0   0.000    8.25    3000.0
4831.0                5100.0           0.000    8.50    3000.0
 Fluid Pressure Gradient (psi/ft) ..................    0.450
 Perforations - Top   (ft) .........................     4700
              - Bot   (ft) .........................     4760
 Initial Fracture Top (ft) .........................     4700
         Fracture Bottom (ft) ......................     4760
-------------------------------------------------------------------
 3-D SIMULATOR      Step Size (ft) ....................    1.5
 PROGRAM CONTROL    Time Step (min) ...................    0.9
```

```
                       Calculated Results
                       from 3-D Simulator
                 STIMPLAN (TM) , NSI , Tulsa,OK
     Licensed To: ARCO Exploration & Production Technology
-------------------------------------------------------------
1/2 LENGTH:  'Hydraulic' length (ft) ...........     95.2
             Propped length (ft) ...............      0.0
PRESSURE:    Max Net Pressure (psi) ............    867.8
TIME:        Max Exposure to Form. Temp. (min)        1.0
             Time to Close (min) ...............      3.4
RATE:        Fluid Loss Rate during pad (_BPM) ..    0.00
EFFICIENCY:  at end of pumping schedule .........    0.20
PROPPANT:    Average In Situ Conc. (#/sq ft) ....     0.0
             Average Conductivity (md-ft) .......       0
HEIGHT:      Max Fracture Height (ft) ...........   122.8
WIDTH:       Avg width at end of pumping (in) ...    0.04
```

StimPlan 2.61 (TM). NSI Technologies, Tulsa, OK
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WELL ID:
SANTOS - E. MEREENIE #41 (LP3) MINIFRAC HISTORY MATCH

DEPTH:	Well Depth (ft)	4700
PRESSURE:	Reservoir Pressure (psi)	1830
	Closure Pressure (psi)	3860
TEMPERATURE:	Bottom Hole Temperature (deg_F)	145

** Pumping Schedule **

Sl Vol (MGal)	Fl Vol (MGal)	Conc (_PPG_) Start	Conc (_PPG_) End	Rate (_BPM)	Fluid Type	Prop Type	Cum Prop (MLbs)	Pump Time (min)
0.22	0.22	0.0	0.0	10.50	3	1	0.0	0.5
0.23	0.23	0.0	0.0	16.64	3	1	0.0	0.3
0.35	0.35	0.0	0.0	15.30	4	1	0.0	0.5
0.65	0.65	0.0	0.0	15.30	1	1	0.0	1.0
0.85	0.85	0.0	0.0	15.30	2	1	0.0	1.3

Total Slurry ...	2.3	Total Fluid ...	2.3
Total Proppant ...	0.0	Avg. Conc	0.0
Total Pump Time	3.7 min	Pad %	100.0

Proppant ID No. 1 20- 40 Un-Defined

Specific Gravity					2.65
'Damage Factor'					0.70
Proppant Stress (Mpsi)	0	2	4	8	16
KfW @ 2 #/sq ft (md-ft)	4800	3850	2750	990	50

Fluid ID No. 3 10#_SLICK_WATER

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	2	2	2	2	2	2
non-Newtonian n'	0.90	0.90	0.90	0.90	0.90	0.90
K(lb·sec/ft^2)x1000	0.07	0.07	0.07	0.07	0.07	0.07

Fluid ID No. 4 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	50	50	25	10	5	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb·sec/ft^2)x1000	24.74	22.33	10.60	4.03	0.17	0.05

Fluid ID No. 1 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	150	100	75	75	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb·sec/ft^2)x1000	74.22	44.65	31.81	30.22	0.34	0.05

Fluid ID No. 2 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	325	325	275	200	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb·sec/ft^2)x1000	160.82	145.12	116.65	80.59	0.34	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (LP3) MINIFRAC HISTORY MATCH

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
0.1	11.8	179	10.50	0.0	0.1	0.14	8.2	60	0.01
0.2	13.3	183	10.50	0.0	0.1	0.16	8.4	60	0.01
0.2	14.8	208	10.50	0.0	0.1	0.16	9.0	61	0.01
0.2	16.3	221	10.50	0.0	0.1	0.15	10.1	61	0.01
0.2	17.8	227	10.50	0.0	0.1	0.13	10.4	61	0.01
0.3	19.3	237	10.50	0.0	0.1	0.12	10.2	62	0.01
0.3	20.8	244	10.50	0.0	0.1	0.12	10.1	62	0.01
0.3	22.3	245	10.50	0.0	0.1	0.11	9.8	62	0.01
0.3	23.8	247	10.50	0.0	0.2	0.10	10.0	62	0.01
0.4	25.3	251	10.50	0.0	0.2	0.10	9.4	63	0.01
0.4	26.8	255	10.50	0.0	0.2	0.10	9.7	63	0.01
0.4	28.3	259	10.50	0.0	0.2	0.10	9.8	63	0.01
0.5	29.8	263	10.50	0.0	0.2	0.10	9.5	63	0.01
0.5	31.5	266	10.50	0.0	0.2	0.10	7.8	63	0.01
0.5	33.0	289	16.64	0.0	0.2	0.10	13.8	64	0.01
0.5	34.5	299	16.64	0.0	0.3	0.11	11.4	64	0.01
0.6	36.0	305	16.64	0.0	0.3	0.11	12.0	64	0.01
0.6	37.5	307	16.64	0.0	0.3	0.12	12.8	64	0.01
0.6	39.0	309	16.64	0.0	0.3	0.12	13.2	64	0.01
0.6	40.5	311	16.64	0.0	0.3	0.12	14.6	64	0.01
0.6	42.0	309	16.64	0.0	0.3	0.12	13.4	64	0.01
0.6	43.5	311	16.64	0.0	0.3	0.12	13.8	64	0.01
0.6	45.0	312	16.64	0.0	0.3	0.12	14.1	64	0.01
0.7	46.5	314	16.64	0.0	0.3	0.13	14.6	64	0.01
0.7	48.0	313	16.64	0.0	0.3	0.13	14.3	64	0.01
0.7	49.5	314	16.64	0.0	0.4	0.13	14.2	64	0.01
0.7	51.0	317	16.64	0.0	0.4	0.13	14.8	65	0.01
0.8	52.5	318	16.64	0.0	0.4	0.13	14.6	65	0.01
0.8	54.0	318	16.64	0.0	0.4	0.13	14.5	65	0.01
0.8	55.5	317	16.64	0.0	0.4	0.13	14.7	65	0.01
0.8	57.0	321	16.64	0.0	0.4	0.13	14.5	65	0.01
0.9	58.5	317	15.30	0.0	0.5	0.12	14.3	65	0.01
0.9	60.0	355	15.30	0.0	0.5	0.12	13.8	65	0.01
1.0	61.5	389	15.30	0.0	0.5	0.12	13.1	66	0.01
1.1	63.0	428	15.30	0.0	0.6	0.13	12.3	67	0.01
1.2	64.6	484	15.30	0.0	0.7	0.14	11.8	71	0.02
1.3	66.1	502	15.30	0.0	0.8	0.15	11.7	73	0.02
1.5	67.6	502	15.30	0.0	0.9	0.15	13.5	74	0.02
1.6	69.1	520	15.30	0.0	0.9	0.14	14.2	75	0.02
1.7	70.6	555	15.30	0.0	1.0	0.14	12.4	77	0.02
1.8	72.1	577	15.30	0.0	1.0	0.15	11.4	79	0.02
1.8	73.6	594	15.30	0.0	1.1	0.15	11.4	81	0.02
1.9	75.1	607	15.30	0.0	1.1	0.16	11.0	82	0.03
2.0	76.6	615	15.30	0.0	1.2	0.16	10.9	82	0.03
2.0	78.1	624	15.30	0.0	1.2	0.17	10.8	83	0.03
2.1	79.6	631	15.30	0.0	1.3	0.17	11.4	84	0.03
2.3	81.1	637	15.30	0.0	1.4	0.17	12.4	84	0.03

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (LP3) MINIFRAC HISTORY MATCH

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
2.4	82.6	640	15.30	0.0	1.4	0.17	12.8	85	0.03
2.5	84.1	649	15.30	0.0	1.5	0.17	12.8	85	0.03
2.6	85.6	664	15.30	0.0	1.6	0.17	12.8	86	0.03
2.7	87.1	694	15.30	0.0	1.6	0.17	12.2	88	0.03
2.8	88.6	720	15.30	0.0	1.7	0.17	11.9	90	0.03
2.9	90.1	749	15.30	0.0	1.8	0.18	11.8	95	0.03
3.1	91.6	777	15.30	0.0	1.9	0.18	11.4	101	0.03
3.3	93.1	809	15.30	0.0	2.0	0.19	11.0	107	0.04
3.7	95.2	868	15.30	0.0	2.3	0.20	10.4	123	0.04
3.8	95.2	798	0.00	0.0	2.3	0.18	11.0	123	0.04
3.9	95.2	729	0.00	0.0	2.3	0.17	9.0	123	0.03
4.1	95.2	660	0.00	0.0	2.3	0.15	8.7	123	0.03
4.2	95.2	590	0.00	0.0	2.3	0.13	8.4	123	0.02
4.2	95.2	555	0.00	0.0	2.3	0.12	8.2	123	0.02
4.3	95.2	521	0.00	0.0	2.3	0.11	8.1	123	0.02
4.4	95.2	486	0.00	0.0	2.3	0.10	8.0	123	0.02
4.4	95.2	451	0.00	0.0	2.3	0.09	7.9	123	0.02
4.5	95.2	417	0.00	0.0	2.3	0.08	7.8	123	0.01
4.6	95.2	382	0.00	0.0	2.3	0.07	7.7	123	0.01
4.6	95.2	347	0.00	0.0	2.3	0.06	7.6	123	0.01
4.7	95.2	312	0.00	0.0	2.3	0.05	7.5	123	0.01
4.8	95.2	278	0.00	0.0	2.3	0.04	7.4	123	0.01
4.8	95.2	243	0.00	0.0	2.3	0.03	7.3	123	0.01
4.9	95.2	208	0.00	0.0	2.3	0.02	7.2	123	0.00
5.0	95.2	174	0.00	0.0	2.3	0.01	7.2	123	0.00
5.1	95.2	139	0.00	0.0	2.3	0.00	7.1	123	0.00

GEOMETRY SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) MINIFRAC HISTORY MATCH

Dstnce (ft)	Press (psi)	W-Avg (in)	Q (_BPM)	Sh-Rate (1/sec)	------Hght (ft)------- Total	Up	Dn	Prop	Bank Fraction	Prop (PSF)
5	861	0.07	7.7	501	123	40	23	104	0.00	0.00
11	848	0.06	6.8	499	118	37	21	98	0.00	0.00
13	845	0.06	6.7	506	117	36	20	97	0.00	0.00
14	841	0.06	6.5	513	115	36	20	95	0.00	0.00
16	835	0.06	6.4	521	113	35	19	93	0.00	0.00
17	827	0.06	6.2	533	112	33	18	91	0.00	0.00
19	819	0.06	6.1	547	110	32	18	90	0.00	0.00
20	811	0.06	6.0	563	108	30	18	88	0.00	0.00
22	802	0.06	5.8	581	107	29	18	87	0.00	0.00
23	793	0.06	5.7	601	105	27	18	85	0.00	0.00
25	787	0.06	5.6	605	104	26	18	84	0.00	0.00
26	782	0.06	5.5	613	102	25	18	83	0.00	0.00
28	776	0.05	5.4	617	101	24	17	82	0.00	0.00
29	770	0.05	5.3	622	100	22	17	81	0.00	0.00
31	763	0.05	5.2	628	98	21	17	80	0.00	0.00
32	756	0.05	5.0	633	97	20	17	79	0.00	0.00
34	750	0.05	4.9	638	95	18	17	78	0.00	0.00
35	743	0.05	4.8	642	94	17	17	76	0.00	0.00
37	736	0.05	4.7	648	92	16	17	75	0.00	0.00
38	729	0.05	4.6	657	91	15	16	74	0.00	0.00
40	721	0.05	4.4	671	91	15	16	74	0.00	0.00
41	714	0.05	4.3	686	90	14	16	74	0.00	0.00
43	706	0.05	4.2	701	89	14	15	73	0.00	0.00
44	697	0.05	4.1	717	88	14	15	73	0.00	0.00
46	688	0.05	4.0	734	88	14	14	73	0.00	0.00
47	678	0.05	3.8	753	87	13	14	72	0.00	0.00
49	669	0.04	3.7	774	86	13	13	72	0.00	0.00
50	659	0.04	3.6	798	85	13	13	71	0.00	0.00
52	648	0.04	3.5	825	84	12	12	71	0.00	0.00
53	637	0.04	3.4	854	84	12	11	71	0.00	0.00
55	625	0.04	3.3	884	83	12	11	70	0.00	0.00
56	612	0.04	3.1	912	82	11	10	70	0.00	0.00
58	599	0.04	3.0	945	81	11	9	69	0.00	0.00
59	585	0.04	2.9	983	79	11	9	68	0.00	0.00
61	570	0.04	2.8	993	76	9	6	67	0.00	0.00
62	555	0.03	2.7	1059	75	9	6	66	0.00	0.00
64	538	0.03	2.6	1136	75	9	6	66	0.00	0.00
65	519	0.03	2.4	1223	74	9	5	66	0.00	0.00
67	500	0.03	2.3	1270	73	8	4	65	0.00	0.00
68	483	0.03	2.2	1283	72	8	4	64	0.00	0.00
70	466	0.03	2.1	1295	70	7	3	64	0.00	0.00
71	448	0.03	2.0	1310	69	7	2	63	0.00	0.00
73	429	0.03	1.9	1325	68	7	1	62	0.00	0.00
74	412	0.03	1.7	1358	67	6	1	62	0.00	0.00
76	390	0.02	1.6	1485	66	6	1	62	0.00	0.00
77	361	0.02	1.5	1718	62	2	0	61	0.00	0.00
79	343	0.02	1.4	1731	60	0	0	60	0.00	0.00
80	324	0.02	1.2	2046	60	0	0	60	0.00	0.00
82	343	0.02	1.0	1879	59	0	0	59	0.00	0.00
83	339	0.02	0.8	1729	56	0	0	56	0.00	0.00
85	335	0.01	0.5	2105	53	0	0	53	0.00	0.00
86	311	0.01	0.2	4209	39	0	0	39	0.00	0.00
88	275	0.00	0.2	8662	27	0	0	27	0.00	0.00
89	240	0.00	0.1	9999	26	0	0	26	0.00	0.00
91	214	0.00	0.1	9999	20	0	0	20	0.00	0.00
92	198	0.00	0.1	9999	17	0	0	17	0.00	0.00
94	215	0.00	0.0	9063	17	0	0	17	0.00	0.00

FLUID SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) MINIFRAC HISTORY MATCH

Stage No	Gone	Fluid ID	Prop ID	Pos (ft)	Concentration In	Now	Desgn	Fl Vol (MGal)	Ex Tim (min)	Temp (deg_F)	Visc (cp)	Fall Frac
1	1	3	1	95	0.0	0.0	0.0	0.1	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.1	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.1	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.1	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.1	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.1	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.1	0.0	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.1	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
1	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.2	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.3	0.1	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.4	0.2	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.4	0.2	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.4	0.2	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.4	0.2	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.4	0.2	145	1	0.00
2	1	3	1	95	0.0	0.0	0.0	0.4	0.2	145	1	0.00
3	1	4	1	95	0.0	0.0	0.0	0.5	0.2	145	3	0.00
3	1	4	1	95	0.0	0.0	0.0	0.5	0.3	145	3	0.00
3	1	4	1	95	0.0	0.0	0.0	0.5	0.4	145	4	0.00
3	1	4	1	95	0.0	0.0	0.0	0.6	0.4	145	3	0.00
3	1	4	1	95	0.0	0.0	0.0	0.7	0.4	145	3	0.00
3	1	4	1	95	0.0	0.0	0.0	0.8	0.4	145	3	0.00
3	1	4	1	95	0.0	0.0	0.0	0.8	0.3	145	3	0.00
4	1	1	1	95	0.0	0.0	0.0	0.9	0.5	145	6	0.00
4	1	1	1	95	0.0	0.0	0.0	0.9	0.5	145	6	0.00
4	1	1	1	95	0.0	0.0	0.0	1.0	0.5	145	6	0.00
4	1	1	1	95	0.0	0.0	0.0	1.0	0.6	145	6	0.00
4	1	1	1	95	0.0	0.0	0.0	1.1	0.5	145	6	0.00
4	1	1	1	95	0.0	0.0	0.0	1.1	0.5	145	6	0.00
4	1	1	1	95	0.0	0.0	0.0	1.2	0.6	145	7	0.00
4	1	1	1	95	0.0	0.0	0.0	1.2	0.6	145	8	0.00
4	1	1	1	95	0.0	0.0	0.0	1.3	0.7	145	8	0.00
4	1	1	1	95	0.0	0.0	0.0	1.4	0.7	145	10	0.00
4	1	1	1	95	0.0	0.0	0.0	1.4	1.0	145	8	0.00
5	0	2	1	86	0.0	0.0	0.0	1.5	0.8	145	35	0.00
5	0	2	1	82	0.0	0.0	0.0	1.6	0.7	145	38	0.00
5	0	2	1	78	0.0	0.0	0.1	1.6	0.5	145	39	0.00
5	0	2	1	71	0.0	0.0	0.1	1.7	0.5	145	46	0.00
5	0	2	1	62	0.0	0.0	0.2	1.8	0.3	145	54	0.00
5	0	2	1	50	0.0	0.0	0.2	1.9	0.0	145	65	0.00
5	0	2	1	34	0.0	0.0	0.3	2.0	0.0	145	73	0.00
5	0	2	1	13	0.0	0.0	0.3	2.3	0.0	83	80	0.00

TABLE A-2

Frac Summary * SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN
Filename: EM41P3FD.FRK ; Sep 12, 96

Design Data

FLUID LOSS LAYERS: Top (ft)	Bottom (ft)	Thick (ft)	Loss Coef. (ft/sqrt(min))	Spurt (Gal/100 ft^2)
4649.0	4702.0	53.0	0.00010	0.00
4702.0	4726.0	24.0	0.00550	0.50
4726.0	4745.0	19.0	0.00010	0.00
4745.0	4759.0	14.0	0.00550	0.50
4759.0	4801.0	42.0	0.00010	0.00
4801.0	4831.0	30.0	0.00500	0.20
4831.0	4900.0	69.0	0.00010	0.00

FORMATION:	Modulus (e6_psi)	6.82
	Perforated Height (ft)	60.0
	Permeability (md)	1.000
TEMPERATURE:	Bottom Hole (deg_F)	145
PRESSURE:	Reservoir Pressure (psi)	1830.0
	Closure Pressure (psi)	3860.0
DEPTH:	Well Depth (ft)	4700.0

FORMATION LAYER DATA - Multi-Layer Height Growth

Depth(ft) Top	Depth(ft) Botm	Thick	Stress (psi) Top	Stress (psi) Botm	Gradient (psi/ft)	Modulus (e6_psi)	Toughness (psi/in)
4500.0	4700.0	200.0	4900.0	4900.0	0.000	8.00	3000.0
4700.0	4726.0	26.0	3860.0	3860.0	0.000	6.50	3000.0
4726.0	4745.0	19.0	4500.0	4500.0	0.000	7.50	3000.0
4745.0	4760.0	15.0	3870.0	3870.0	0.000	6.50	3000.0
4760.0	4801.0	41.0	5050.0	5050.0	0.000	8.50	3000.0
4801.0	4810.0	9.0	4600.0	4600.0	0.000	8.25	3000.0
4810.0	4820.0	10.0	3450.0	3450.0	0.000	8.00	3000.0
4820.0	4831.0	11.0	4650.0	4650.0	0.000	8.25	3000.0
4831.0			5100.0		0.000	8.50	3000.0

Fluid Pressure Gradient (psi/ft)	0.450
Perforations - Top (ft)	4700
- Bot (ft)	4760
Initial Fracture Top (ft)	4700
Fracture Bottom (ft)	4760

3-D SIMULATOR	Step Size (ft)	3.0
PROGRAM CONTROL	Time Step (min)	1.8

Calculated Results

from 3-D Simulator
STIMPLAN (TM) , NSI , Tulsa,OK
Licensed To: ARCO Exploration & Production Technology

1/2 LENGTH:	'Hydraulic' length (ft)	111.3
	Propped length (ft)	105.3
PRESSURE:	Max Net Pressure (psi)	2235.8
TIME:	Max Exposure to Form. Temp. (min)	5.4
	Time to Close (min)	7.8
RATE:	Fluid Loss Rate during pad (_BPM) ..	11.36
EFFICIENCY:	at end of pumping schedule	0.38
PROPPANT:	Average In Situ Conc. (#/sq ft)	0.8
	Average Conductivity (md-ft)	1242
HEIGHT:	Max Fracture Height (ft)	142.2
WIDTH:	Avg width at end of pumping (in) ...	0.16

StimPlan 2.61 (TM). NSI Technologies, Tulsa, OK
Licensed To: ARCO Exploration & Production Technology

WELL ID:		
SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN		
DEPTH:	Well Depth (ft)	4700
PRESSURE:	Reservoir Pressure (psi)	1830
	Closure Pressure (psi)	3860
TEMPERATURE:	Bottom Hole Temperature (deg_F)	145

** Pumping Schedule **

Sl Vol (MGal)	Fl Vol (MGal)	Conc (_PPG_) Start	Conc (_PPG_) End	Rate (_BPM)	Fluid Type	Prop Type	Cum Prop (MLbs)	Pump Time (min)
2.00	2.00	0.0	0.0	15.00	2	1	0.0	3.2
0.61	0.60	0.5	0.5	15.00	2	1	0.3	1.0
0.52	0.50	1.0	1.0	15.00	2	1	0.8	0.8
0.44	0.40	2.0	2.0	15.00	2	1	1.6	0.7
0.45	0.40	3.0	3.0	15.00	2	1	2.8	0.7
0.47	0.40	4.0	4.0	15.00	2	1	4.4	0.7
0.49	0.40	5.0	5.0	15.00	2	1	6.4	0.8
0.51	0.40	6.0	6.0	15.00	2	1	8.8	0.8
0.52	0.40	7.0	7.0	15.00	2	1	11.6	0.8
0.54	0.40	8.0	8.0	15.00	2	1	14.8	0.9

Total Slurry ...	6.5	Total Fluid ...	5.9
Total Proppant ...	14.8	Avg. Conc	2.5
Total Pump Time	10.4 min	Pad %	30.5

Proppant ID No. 1 20- 40 CARBO-LITE

Specific Gravity					2.72
'Damage Factor'					0.60
Proppant Stress (Mpsi)	0	2	4	8	16
KfW @ 2 #/sq ft (md-ft)	10500	9200	7600	3200	500

Fluid ID No. 2 30#_BORAGEL

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
Specific Gravity					1.04	
vis (cp @ 170 1/sec) .	325	325	275	200	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb·sec/ft^2)x1000	160.82	145.12	116.65	80.59	0.34	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
0.1	15.3	618	15.00	0.0	0.1	0.29	10.6	62	0.02
0.3	18.3	628	15.00	0.0	0.2	0.32	9.7	62	0.03
0.3	21.3	737	15.00	0.0	0.2	0.33	9.6	62	0.03
0.3	24.3	794	15.00	0.0	0.2	0.32	11.4	62	0.03
0.4	27.3	830	15.00	0.0	0.2	0.31	12.6	63	0.03
0.4	30.3	857	15.00	0.0	0.3	0.29	13.2	67	0.03
0.5	33.3	859	15.00	0.0	0.3	0.27	13.5	73	0.03
0.6	36.3	832	15.00	0.0	0.3	0.26	12.0	80	0.03
0.7	39.3	827	15.00	0.0	0.4	0.25	11.5	87	0.03
0.8	42.3	814	15.00	0.0	0.5	0.26	10.9	93	0.03
1.0	45.3	806	15.00	0.0	0.6	0.26	10.8	100	0.03
1.1	48.3	794	15.00	0.0	0.7	0.27	10.6	105	0.03
1.3	51.3	805	15.00	0.0	0.8	0.27	10.8	107	0.03
1.4	54.3	819	15.00	0.0	0.9	0.27	10.9	110	0.03
1.6	57.3	812	15.00	0.0	1.0	0.27	10.9	110	0.04
1.7	60.3	824	15.00	0.0	1.1	0.27	10.9	111	0.04
1.9	63.3	817	15.00	0.0	1.2	0.27	11.2	111	0.04
2.0	66.3	837	15.00	0.0	1.3	0.26	11.1	114	0.04
2.2	69.3	829	15.00	0.0	1.4	0.26	11.2	114	0.04
2.4	72.3	846	15.00	0.0	1.5	0.26	11.4	118	0.04
2.6	75.3	840	15.00	0.0	1.6	0.26	11.1	118	0.04
2.8	78.3	856	15.00	0.0	1.8	0.26	11.4	121	0.04
3.0	81.3	849	15.00	0.0	1.9	0.26	11.2	121	0.05
3.2	84.3	872	15.00	0.0	2.0	0.26	11.4	126	0.05
3.5	87.3	854	15.00	0.5	2.2	0.26	11.2	126	0.05
3.7	90.3	875	15.00	0.5	2.3	0.25	11.5	128	0.05
3.9	93.3	875	15.00	0.5	2.5	0.25	11.3	129	0.05
4.2	96.3	881	15.00	0.5	2.6	0.25	11.4	131	0.05
4.4	99.3	883	15.00	1.0	2.8	0.25	11.3	132	0.05
4.7	102.3	894	15.00	1.0	3.0	0.25	11.5	135	0.05
5.0	105.3	892	15.00	1.0	3.2	0.25	11.4	135	0.05
Bridge Stage 0 at 5 min, at 89.6 (ft), Avg Dia/W 0.03/0.03 in									
5.3	108.3	910	15.00	2.0	3.3	0.25	11.4	142	0.05
Bridge Stage 0 at 5 min, at 99.6 (ft), Avg Dia/W 0.03/0.02 in									
5.8	111.3	925	15.00	2.0	3.6	0.25	10.6	142	0.06
Bridge Stage 0 at 6 min, at 94.1 (ft), Avg Dia/W 0.03/0.03 in									
Screen Out in Stage 2 at Time = 5.8 min at 103.8 (ft)									
6.7	111.3	1121	15.00	3.0	4.2	0.28	8.4	142	0.08
Bridge Stage 0 at 7 min, at 101.2 (ft), Avg Dia/W 0.03/0.04 in									
7.6	111.3	1361	15.00	4.0	4.8	0.31	7.4	142	0.10
8.6	111.3	1633	15.00	5.0	5.4	0.33	6.7	142	0.12
9.5	111.3	1926	15.00	6.0	6.0	0.36	6.2	142	0.14
10.4	111.3	2236	15.00	7.0	6.6	0.38	5.8	142	0.16
11.3	111.3	2057	0.00	0.0	6.6	0.35	5.6	142	0.15
12.1	111.3	1878	0.00	0.0	6.6	0.32	5.2	142	0.14
13.1	111.3	1699	0.00	0.0	6.6	0.29	5.0	142	0.13
14.1	111.3	1520	0.00	0.0	6.6	0.26	4.8	142	0.11

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
14.6	111.3	1431	0.00	0.0	6.6	0.25	4.6	142	0.11
15.1	111.3	1341	0.00	0.0	6.6	0.23	4.5	142	0.10
15.6	111.3	1252	0.00	0.0	6.6	0.22	4.4	142	0.10
16.1	111.3	1163	0.00	0.0	6.6	0.20	4.4	142	0.09
16.6	111.3	1073	0.00	0.0	6.6	0.19	4.3	142	0.09
17.1	111.3	984	0.00	0.0	6.6	0.18	4.2	142	0.08
17.5	111.3	894	0.00	0.0	6.6	0.17	4.2	142	0.08
17.9	111.3	805	0.00	0.0	6.6	0.16	4.1	142	0.07
18.2	111.3	715	0.00	0.0	6.6	0.15	4.1	142	0.07

GEOMETRY SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN

Dstnce (ft)	Press (psi)	W-Avg (in)	Q (_BPM)	Sh-Rate (1/sec)	------Hght (ft)------- Total	Up	Dn	Prop	Bank Fraction	Prop (PSF)
6	2234	0.20	7.4	43	142	51	32	126	0.00	0.89
14	2230	0.20	6.3	40	135	46	28	119	0.00	0.86
17	2228	0.20	6.1	39	133	45	27	116	0.00	0.86
20	2227	0.20	5.8	39	130	44	26	114	0.00	0.87
23	2225	0.20	5.6	38	128	43	25	111	0.00	0.87
26	2224	0.20	5.3	38	126	41	24	108	0.00	0.87
29	2222	0.20	5.1	37	123	40	23	105	0.00	0.82
32	2220	0.19	4.8	37	121	39	22	102	0.00	0.83
35	2219	0.19	4.6	37	118	37	21	98	0.00	0.86
38	2217	0.19	4.4	36	115	36	20	95	0.00	0.87
41	2215	0.19	4.1	36	113	34	18	92	0.00	0.87
44	2214	0.19	3.9	35	111	32	18	90	0.00	0.79
47	2212	0.19	3.7	34	109	31	18	89	0.00	0.75
50	2210	0.18	3.5	33	107	29	18	87	0.00	0.84
53	2209	0.18	3.3	32	105	27	18	85	0.00	0.84
56	2207	0.18	3.0	32	103	25	18	84	0.00	0.83
59	2205	0.18	2.8	31	100	23	17	82	0.00	0.72
62	2203	0.18	2.6	30	98	21	17	80	0.00	0.71
65	2202	0.17	2.4	29	95	18	17	78	0.00	0.73
68	2200	0.17	2.2	29	92	16	17	75	0.00	0.82
71	2198	0.17	2.0	27	91	15	16	74	0.00	0.76
74	2196	0.17	1.9	26	90	14	15	74	0.00	0.67
77	2195	0.17	1.7	24	88	14	15	73	0.00	0.66
80	2193	0.16	1.5	22	87	13	14	72	0.00	0.65
83	2191	0.16	1.3	20	85	13	13	72	0.00	0.68
86	2190	0.16	1.1	18	84	12	12	71	0.00	0.56
89	2188	0.15	0.9	17	80	11	9	69	0.00	0.58
92	2186	0.15	0.7	16	75	9	6	66	0.00	0.61
95	2184	0.13	0.6	18	62	2	0	61	0.00	0.36
98	2180	0.13	0.4	14	60	0	0	60	0.00	0.45
101	2170	0.12	0.3	12	54	0	0	54	0.15	0.77
104	2162	0.08	0.1	16	37	0	0	37	1.00	0.93
107	343	0.01	0.1	3539	25	0	0	25	1.00	0.10
110	208	0.02	0.1	1321	24	0	0	24	1.00	0.18

FLUID SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN

Stage No	Gone	Fluid ID	Prop ID	Pos (ft)	Concentration In	Now	Desgn	Fl Vol (MGal)	Ex Tim (min)	Temp (deg_F)	Visc (cp)	Fall Frac
1	1	2	1	111	0.0	0.0	0.0	0.1	0.3	145	18	0.00
1	1	2	1	111	0.0	0.0	0.0	0.2	0.3	145	24	0.00
1	1	2	1	111	0.0	0.0	0.0	0.2	0.3	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.2	0.4	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.2	0.3	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.3	0.4	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.3	0.4	145	27	0.00
1	1	2	1	111	0.0	0.0	0.0	0.3	0.4	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.4	0.6	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.5	0.6	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.6	0.7	145	26	0.00
1	1	2	1	111	0.0	0.0	0.0	0.7	0.6	145	27	0.00
1	1	2	1	111	0.0	0.0	0.0	0.8	0.8	145	27	0.00
1	1	2	1	111	0.0	0.0	0.0	0.9	0.9	145	27	0.00
1	1	2	1	111	0.0	0.0	0.0	1.0	0.9	145	28	0.00
1	1	2	1	111	0.0	0.0	0.0	1.1	0.9	145	28	0.00
1	1	2	1	111	0.0	0.0	0.0	1.2	1.0	145	29	0.00
1	1	2	1	111	0.0	0.0	0.0	1.3	1.0	145	27	0.00
1	1	2	1	111	0.0	0.0	0.0	1.4	1.3	145	28	0.00
1	1	2	1	111	0.0	0.0	0.0	1.5	1.4	145	28	0.00
1	1	2	1	111	0.0	0.0	0.0	1.6	1.4	145	29	0.00
1	1	2	1	111	0.0	0.0	0.0	1.8	1.4	145	30	0.00
1	1	2	1	111	0.0	0.0	0.0	1.9	1.5	145	29	0.00
1	1	2	1	111	0.0	0.0	0.0	2.0	1.5	145	34	0.00
2	1	2	1	111	0.5	45.3	0.0	2.0	1.9	145	34	0.00
2	1	2	1	111	0.5	45.3	0.0	2.2	1.5	145	43	0.00
2	1	2	1	105	0.5	45.3	0.0	2.3	2.9	145	247	0.00
2	1	2	1	105	0.5	45.3	0.0	2.5	3.5	145	400	0.00
2	1	2	1	104	0.5	45.3	0.0	2.6	5.4	145	616	0.00
3	0	2	1	102	1.0	39.4	0.4	2.6	5.1	145	741	0.00
3	0	2	1	101	1.0	18.6	0.6	2.8	4.8	145	741	0.00
3	0	2	1	99	1.0	8.4	1.0	2.9	4.4	145	695	0.00
3	0	2	1	95	1.0	5.2	1.4	3.1	4.4	145	603	0.00
4	0	2	1	93	2.0	9.8	1.7	3.1	4.4	145	628	0.00
4	0	2	1	91	2.0	8.0	2.0	3.3	3.7	145	621	0.00
4	0	2	1	86	2.0	6.0	2.5	3.5	3.7	145	581	0.00
5	0	2	1	82	3.0	8.8	2.8	3.6	3.7	145	547	0.00
5	0	2	1	76	3.0	6.9	3.4	3.9	2.8	145	490	0.00
6	0	2	1	68	4.0	8.6	3.8	4.1	1.9	145	448	0.00
6	0	2	1	62	4.0	6.8	4.6	4.3	1.9	145	430	0.00
7	0	2	1	53	5.0	8.2	4.9	4.6	0.9	145	413	0.00
7	0	2	1	46	5.0	6.9	5.7	4.7	0.9	145	399	0.00
8	0	2	1	37	6.0	8.2	5.9	5.0	0.0	145	388	0.00
8	0	2	1	30	6.0	7.2	6.6	5.1	0.0	145	381	0.00
9	0	2	1	22	7.0	8.4	6.7	5.5	0.0	91	369	0.00
9	0	2	1	15	7.0	7.6	7.4	5.5	0.0	80	360	0.00
10	0	2	1	7	8.0	8.6	7.4	5.9	0.0	75	344	0.00

PROPPANT SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
6.2	1387	0.88
13.8	1358	0.87
16.8	1348	0.86
19.8	1357	0.87
22.8	1362	0.87
25.8	1337	0.86
28.8	1289	0.83
31.8	1288	0.83
34.8	1329	0.85
37.8	1354	0.87
40.8	1321	0.85
43.8	1224	0.80
46.8	1188	0.78
49.8	1254	0.82
52.8	1295	0.84
55.8	1231	0.81
58.8	1106	0.74
61.8	1047	0.72
64.8	1108	0.75
67.8	1178	0.78
70.8	1119	0.75
73.8	997	0.69
76.8	940	0.66
79.8	940	0.66
82.8	900	0.64
85.8	801	0.59
88.8	778	0.58
91.8	689	0.54
94.8	494	0.44
97.8	627	0.51
100.8	1079	0.73
103.8	1032	0.68
106.8	372	0.32
109.8	0	0.15

Average Conductivity (md-ft) 1092

PROPPANT SUMMARY * At Fracture Closure
SANTOS - E. MEREENIE #41 (LP3) FINAL TSO FRAC DESIGN

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
6.2	969	0.65
13.8	967	0.65
16.8	966	0.65
19.8	1025	0.68
22.8	1149	0.74
25.8	1215	0.77
28.8	1222	0.77
31.8	1230	0.77
34.8	1203	0.76
37.8	1159	0.74
40.8	1214	0.77
43.8	1325	0.82
46.8	1364	0.84
49.8	1350	0.83
52.8	1317	0.81
55.8	1326	0.82
58.8	1474	0.89
61.8	1585	0.94
64.8	1504	0.90
67.8	1414	0.86
70.8	1396	0.85
73.8	1533	0.91
76.8	1702	0.99
79.8	1587	0.94
82.8	1401	0.85
85.8	1412	0.86
88.8	1448	0.88
91.8	1444	0.87
94.8	1447	0.88
97.8	1483	0.89
100.8	1613	0.95
103.8	1241	0.75
106.8	392	0.32
109.8	0	0.15

Average Conductivity (md-ft) 1242

TABLE A-3

Frac Summary * SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION
Filename: EM41P3PF.FRK ; Oct 3, 96

Design Data

FLUID LOSS LAYERS:	Top (ft)	Bottom (ft)	Thick (ft)	Loss Coef. (ft/sqrt(min))	Spurt (Gal/100 ft^2)
	4649.0	4702.0	53.0	0.00010	0.00
	4702.0	4726.0	24.0	0.00600	0.50
	4726.0	4745.0	19.0	0.00010	0.00
	4745.0	4759.0	14.0	0.00600	0.50
	4759.0	4801.0	42.0	0.00010	0.00
	4801.0	4831.0	30.0	0.00500	0.20
	4831.0	4900.0	69.0	0.00010	0.00

FORMATION:	Modulus (e6_psi)	7.13
	Perforated Height (ft)	60.0
	Permeability (md)	1.000
TEMPERATURE:	Bottom Hole (deg_F)	145
PRESSURE:	Reservoir Pressure (psi)	1830.0
	Closure Pressure (psi)	3860.0
DEPTH:	Well Depth (ft)	4700.0

FORMATION LAYER DATA - Multi-Layer Height Growth

-----Depth(ft)------ Top	Botm	Thick	-Stress (psi)-- Top	Botm	Gradient (psi/ft)	Modulus (e6_psi)	Toughness (psi«in)
4500.0	4700.0	200.0	4900.0	4900.0	0.000	8.00	3000.0
4700.0	4726.0	26.0	3860.0	3860.0	0.000	6.50	3000.0
4726.0	4745.0	19.0	4800.0	4800.0	0.000	8.50	3000.0
4745.0	4760.0	15.0	3870.0	3870.0	0.000	6.50	3000.0
4760.0	4801.0	41.0	5050.0	5050.0	0.000	8.50	3000.0
4801.0	4810.0	9.0	4600.0	4600.0	0.000	8.25	3000.0
4810.0	4820.0	10.0	3450.0	3450.0	0.000	8.00	3000.0
4820.0	4831.0	11.0	4650.0	4650.0	0.000	8.25	3000.0
4831.0			5100.0		0.000	8.50	3000.0

Fluid Pressure Gradient (psi/ft)	0.450
Perforations - Top (ft)	4700
- Bot (ft)	4760
Initial Fracture Top (ft)	4700
Fracture Bottom (ft)	4760

3-D SIMULATOR	Step Size (ft)	3.0
PROGRAM CONTROL	Time Step (min)	1.8

Calculated Results
from 3-D Simulator
STIMPLAN (TM) , NSI , Tulsa,OK
Licensed To: Internal Use - NSI Technologies

1/2 LENGTH:	'Hydraulic' length (ft)	116.7
	Propped length (ft)	110.7
PRESSURE:	Max Net Pressure (psi)	2342.7
TIME:	Max Exposure to Form. Temp. (min)	5.5
	Time to Close (min)	9.1
RATE:	Fluid Loss Rate during pad (_BPM) ..	11.75
EFFICIENCY:	at end of pumping schedule	0.34
PROPPANT:	Average In Situ Conc. (#/sq ft)	0.7
	Average Conductivity (md-ft)	1050
HEIGHT:	Max Fracture Height (ft)	196.4
WIDTH:	Avg width at end of pumping (in) ...	0.14

StimPlan 2.60 (TM). NSI Technologies, Tulsa, OK
Licensed To: Internal Use - NSI Technologies

WELL ID:
SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION

DEPTH:	Well Depth (ft)	4700
PRESSURE:	Reservoir Pressure (psi)	1830
	Closure Pressure (psi)	3860
TEMPERATURE:	Bottom Hole Temperature (deg_F)	145

** Pumping Schedule **

Sl Vol (MGal)	Fl Vol (MGal)	Conc (_PPG_) Start	End	Rate (_BPM)	Fluid Type	Prop Type	Cum Prop (MLbs)	Pump Time (min)
0.52	0.52	0.0	0.0	5.50	3	1	0.0	2.3
0.28	0.28	0.0	0.0	13.52	3	1	0.0	0.5
0.34	0.34	0.0	0.0	14.23	3	1	0.0	0.6
0.41	0.41	0.0	0.0	14.03	1	1	0.0	0.7
1.39	1.39	0.0	0.0	14.98	2	1	0.0	2.2
0.16	0.16	0.0	0.0	14.69	2	1	0.0	0.3
0.61	0.60	0.5	0.5	14.64	2	1	0.3	1.0
0.47	0.45	0.9	0.9	14.67	2	1	0.7	0.8
0.44	0.41	1.4	1.4	14.52	2	1	1.3	0.7
0.42	0.38	2.2	2.2	14.72	2	1	2.1	0.7
0.15	0.13	3.0	3.0	14.78	2	1	2.5	0.2
0.31	0.27	3.0	3.0	14.49	2	1	3.3	0.5
0.47	0.40	3.8	3.8	14.50	2	1	4.9	0.8
0.48	0.40	4.5	4.5	14.51	2	1	6.7	0.8
0.50	0.40	5.5	5.5	14.44	2	1	8.9	0.8
0.41	0.32	6.6	6.6	14.45	2	1	11.0	0.7
0.46	0.34	7.7	7.7	14.79	2	1	13.6	0.7
0.68	0.50	8.2	8.2	14.95	2	1	17.7	1.1

Total Slurry ...	8.5	Total Fluid ...	7.7
Total Proppant ...	17.7	Avg. Conc	2.3
Total Pump Time	15.3 min	Pad %	36.5

Proppant ID No. 1 — 20- 40 CARBO-LITE

Specific Gravity 2.72
'Damage Factor' 0.60

Proppant Stress (Mpsi)	0	2	4	8	16
KfW @ 2 #/sq ft (md-ft)	10500	9200	7600	3200	500

Fluid ID No. 3 — WB_FLUID

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	1	1	1	1	1	1
non-Newtonian n'	1.00	1.00	1.00	1.00	1.00	1.00
K(lb*sec/ft^2)x1000	0.02	0.02	0.02	0.02	0.02	0.02

Fluid ID No. 1 — 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	225	175	150	75	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb*sec/ft^2)x1000	111.34	78.14	63.63	30.22	0.34	0.05

Fluid ID No. 2 — 30#_BORAGEL

Specific Gravity 1.04

	@Welbor	@FormTmp	@1Hr	@2Hr	@4Hr	@8Hr
vis (cp @ 170 1/sec) .	600	600	475	200	10	2
non-Newtonian n'	0.38	0.40	0.41	0.42	0.90	0.95
K(lb*sec/ft^2)x1000	296.90	267.92	201.48	80.59	0.34	0.05

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
0.7	16.5	170	5.50	0.0	0.2	0.06	5.0	60	0.01
1.1	19.5	175	5.50	0.0	0.3	0.06	5.1	61	0.01
1.3	22.5	194	5.50	0.0	0.3	0.06	5.3	61	0.01
1.6	25.5	202	5.50	0.0	0.4	0.05	5.4	61	0.01
1.9	28.5	210	5.50	0.0	0.4	0.04	5.5	61	0.01
2.3	32.7	217	5.50	0.0	0.5	0.04	5.7	61	0.01
2.3	35.7	276	13.52	0.0	0.5	0.05	8.5	62	0.01
2.3	38.7	290	13.52	0.0	0.6	0.05	10.5	63	0.01
2.4	41.7	291	13.52	0.0	0.6	0.06	11.7	63	0.01
2.4	44.7	290	13.52	0.0	0.6	0.06	12.1	63	0.01
2.5	47.7	291	13.52	0.0	0.6	0.06	12.2	63	0.01
2.6	50.7	292	13.52	0.0	0.7	0.06	12.3	63	0.01
2.6	53.7	294	13.52	0.0	0.7	0.07	12.1	63	0.01
2.7	56.7	295	13.52	0.0	0.8	0.07	12.4	63	0.01
2.8	59.7	300	14.23	0.0	0.8	0.07	12.8	63	0.01
2.9	62.7	301	14.23	0.0	0.9	0.07	13.0	63	0.01
3.0	65.7	304	14.23	0.0	0.9	0.07	13.2	63	0.01
3.1	68.7	304	14.23	0.0	1.0	0.07	13.2	63	0.01
3.2	71.7	306	14.23	0.0	1.0	0.07	13.2	63	0.01
3.3	74.7	308	14.23	0.0	1.1	0.07	13.3	63	0.01
3.4	77.7	310	14.03	0.0	1.2	0.07	13.1	63	0.01
3.7	80.7	607	14.03	0.0	1.4	0.09	11.2	71	0.02
4.5	83.7	858	14.03	0.0	1.8	0.14	9.8	98	0.03
5.2	86.7	1059	14.98	0.0	2.3	0.20	8.7	147	0.04
6.1	89.7	1001	14.98	0.0	2.9	0.23	9.8	162	0.04
6.5	92.7	1071	14.98	0.0	3.1	0.23	11.8	167	0.04
6.8	95.7	1072	14.64	0.5	3.3	0.23	9.9	172	0.04
7.3	98.7	1099	14.64	0.5	3.6	0.24	10.4	179	0.05
7.7	101.7	1080	14.64	0.5	3.8	0.24	10.2	183	0.05
8.1	104.7	1094	14.67	0.9	4.1	0.24	11.5	187	0.05
8.5	107.7	1096	14.67	0.9	4.3	0.24	11.0	190	0.05
9.0	110.7	1104	14.52	1.4	4.6	0.24	11.3	193	0.05
9.4	113.7	1109	14.72	2.2	4.9	0.24	11.4	196	0.05
Bridge Stage 0 at 9 min, at 101.6 (ft), Avg Dia/W 0.03/0.02 in									
9.9	116.7	1124	14.72	2.2	5.2	0.24	11.5	196	0.05
Bridge Stage 0 at 10 min, at 104.4 (ft), Avg Dia/W 0.03/0.02 in									
Screen Out in Stage 7 at Time = 9.9 min at 112 (ft)									
11.0	116.7	1292	14.49	3.0	5.8	0.25	8.7	196	0.07
Bridge Stage 0 at 11 min, at 101.3 (ft), Avg Dia/W 0.03/0.04 in									
Screen Out in Stage 7 at Time = 11.0 min at 109 (ft)									
12.1	116.7	1510	14.50	3.8	6.5	0.28	7.7	196	0.08
Bridge Stage 0 at 12 min, at 107.2 (ft), Avg Dia/W 0.03/0.04 in									
Screen Out in Stage 7 at Time = 12.1 min at 106 (ft)									
13.1	116.7	1763	14.44	5.5	7.2	0.30	7.1	196	0.10
14.2	116.7	2036	14.45	6.6	7.8	0.32	6.6	196	0.12
15.3	116.7	2343	14.95	8.2	8.5	0.34	6.1	196	0.14
16.2	116.7	2155	0.00	0.0	8.5	0.31	5.9	196	0.13

Time History * NSI STIMPLAN 3-D Fracture Simulation
SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION

Time (min)	Pen (ft)	Pres (psi)	Rate (_BPM)	Prop (_PPG_)	Sl Vol (MGal)	Eff-ciency	Loss (_BPM)	Hght (ft)	W-Avg (in)
17.2	116.7	1968	0.00	0.0	8.5	0.29	5.6	196	0.12
18.3	116.7	1780	0.00	0.0	8.5	0.26	5.4	196	0.11
19.4	116.7	1593	0.00	0.0	8.5	0.24	5.2	196	0.10
20.0	116.7	1499	0.00	0.0	8.5	0.22	5.0	196	0.10
20.7	116.7	1406	0.00	0.0	8.5	0.21	4.9	196	0.09
21.4	116.7	1312	0.00	0.0	8.5	0.20	4.8	196	0.09
22.1	116.7	1218	0.00	0.0	8.5	0.19	4.7	196	0.09
22.9	116.7	1125	0.00	0.0	8.5	0.18	4.6	196	0.08
23.6	116.7	1031	0.00	0.0	8.5	0.17	4.5	196	0.08
24.4	116.7	937	0.00	0.0	8.5	0.16	4.4	196	0.08

GEOMETRY SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION

Dstnce (ft)	Press (psi)	W-Avg (in)	Q (_BPM)	Sh-Rate (1/sec)	------Hght (ft)------- Total	Up	Dn	Prop	Bank Fraction	Prop (PSF)
7	2339	0.16	7.4	54	196	83	53	166	0.00	0.74
15	2330	0.16	6.3	46	190	79	50	160	0.00	0.75
18	2327	0.16	6.0	45	187	78	50	158	0.00	0.78
21	2324	0.16	5.8	43	184	76	48	156	0.00	0.78
24	2321	0.16	5.5	42	181	74	47	153	0.00	0.79
27	2319	0.16	5.3	41	178	72	46	151	0.00	0.75
31	2315	0.16	5.0	39	174	70	45	148	0.00	0.71
34	2312	0.16	4.7	37	171	68	43	145	0.00	0.78
37	2309	0.16	4.5	36	168	66	42	143	0.00	0.71
40	2307	0.16	4.2	34	165	64	41	141	0.00	0.67
43	2304	0.16	4.0	33	163	63	40	139	0.00	0.67
46	2302	0.16	3.8	31	162	62	39	137	0.00	0.70
49	2299	0.16	3.6	31	158	60	38	133	0.00	0.67
52	2297	0.16	3.3	30	153	57	36	129	0.00	0.65
55	2295	0.16	3.1	29	150	55	35	125	0.00	0.65
58	2292	0.16	2.9	28	145	53	33	120	0.00	0.64
61	2290	0.16	2.7	28	138	48	30	113	0.00	0.61
64	2287	0.15	2.5	28	133	46	28	108	0.00	0.68
67	2284	0.15	2.3	27	128	43	25	103	0.00	0.68
70	2282	0.15	2.1	27	122	40	23	97	0.00	0.62
73	2279	0.14	1.9	28	116	36	20	91	0.00	0.57
76	2276	0.14	1.8	27	111	33	18	87	0.00	0.56
79	2273	0.14	1.6	27	107	29	18	83	0.00	0.64
82	2270	0.13	1.4	27	103	25	18	80	0.00	0.54
85	2267	0.13	1.3	27	98	20	17	76	0.00	0.52
88	2264	0.12	1.1	27	92	15	16	71	0.00	0.57
91	2260	0.12	0.9	24	89	14	15	70	0.00	0.56
94	2257	0.12	0.8	21	85	13	12	69	0.00	0.48
97	2253	0.12	0.6	18	81	11	10	67	0.00	0.53
100	2245	0.12	0.5	19	62	2	0	61	0.01	0.53
103	2228	0.11	0.3	15	60	0	0	60	0.24	0.79
106	2216	0.09	0.2	15	50	0	0	50	0.89	1.03
109	1193	0.03	0.1	68	33	0	0	33	0.96	0.30
112	739	0.01	0.0	704	22	0	0	22	0.88	0.12
115	235	0.00	0.0	4856	21	0	0	21	0.00	0.00

FLUID SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION

Stage No	Gone	Fluid ID	Prop ID	Pos (ft)	Concentration In	Now	Desgn	Fl Vol (MGal)	Ex Tim (min)	Temp (deg_F)	Visc (cp)	Fall Frac
1	1	3	1	117	0.0	0.0	0.0	0.2	0.3	145	1	0.00
1	1	3	1	117	0.0	0.0	0.0	0.3	0.3	145	1	0.00
1	1	3	1	117	0.0	0.0	0.0	0.3	0.3	145	1	0.00
1	1	3	1	117	0.0	0.0	0.0	0.4	0.3	145	1	0.00
1	1	3	1	117	0.0	0.0	0.0	0.4	0.2	145	1	0.00
1	1	3	1	117	0.0	0.0	0.0	0.5	0.0	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.5	0.1	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.5	0.1	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.6	0.1	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.6	0.1	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.6	0.1	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.6	0.1	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.7	0.2	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.7	0.2	145	1	0.00
2	1	3	1	117	0.0	0.0	0.0	0.8	0.2	145	1	0.00
3	1	3	1	117	0.0	0.0	0.0	0.8	0.2	145	1	0.00
3	1	3	1	117	0.0	0.0	0.0	0.9	0.2	145	1	0.00
3	1	3	1	117	0.0	0.0	0.0	0.9	0.2	145	1	0.00
3	1	3	1	117	0.0	0.0	0.0	1.0	0.2	145	1	0.00
3	1	3	1	117	0.0	0.0	0.0	1.0	0.3	145	1	0.00
3	1	3	1	117	0.0	0.0	0.0	1.1	0.7	145	1	0.00
4	1	1	1	117	0.0	0.0	0.0	1.2	0.5	145	21	0.00
4	1	1	1	117	0.0	0.0	0.0	1.4	0.7	145	18	0.00
4	1	1	1	117	0.0	0.0	0.0	1.5	1.6	145	13	0.00
5	1	2	1	117	0.0	0.0	0.0	1.8	1.8	145	52	0.00
5	1	2	1	117	0.0	0.0	0.0	2.3	1.8	145	63	0.00
5	1	2	1	117	0.0	0.0	0.0	2.9	2.1	145	64	0.00
5	1	2	1	117	0.0	0.0	0.0	2.9	2.2	145	65	0.00
6	1	2	1	117	0.0	0.0	0.0	3.1	2.6	145	59	0.00
7	1	2	1	117	0.5	45.3	0.0	3.1	2.6	145	48	0.00
7	1	2	1	113	0.5	45.3	0.0	3.3	2.2	145	89	0.00
7	1	2	1	112	0.5	45.3	0.0	3.5	2.5	145	272	0.00
7	1	2	1	109	0.5	45.3	0.0	3.6	3.6	145	503	0.00
7	1	2	1	107	0.5	45.3	0.0	3.7	3.2	145	550	0.00
8	1	2	1	108	0.9	45.3	0.0	3.8	5.3	145	1041	0.00
8	0	2	1	105	0.9	37.0	0.4	4.1	5.5	145	1208	0.00
8	0	2	1	102	0.9	8.4	0.9	4.2	5.5	145	1111	0.00
9	0	2	1	99	1.4	10.4	1.2	4.3	5.1	145	1050	0.00
9	0	2	1	95	1.4	6.5	1.7	4.6	5.1	145	1015	0.00
10	0	2	1	92	2.2	10.0	1.9	4.6	5.1	145	904	0.00
10	0	2	1	89	2.2	7.6	2.3	4.8	4.3	145	867	0.00
10	0	2	1	84	2.2	5.7	3.0	4.9	4.3	145	846	0.00
11	0	2	1	80	3.0	7.8	3.1	5.1	3.2	145	845	0.00
12	0	2	1	78	3.0	7.6	3.2	5.1	3.2	145	842	0.00
12	0	2	1	74	3.0	6.3	3.8	5.3	3.2	145	834	0.00
13	0	2	1	66	3.8	7.8	4.0	5.7	2.2	145	835	0.00
13	0	2	1	60	3.8	6.2	4.9	5.7	2.2	145	829	0.00
14	0	2	1	54	4.5	7.3	5.0	6.1	1.1	145	809	0.00
15	0	2	1	48	5.5	9.1	5.0	6.2	1.1	145	783	0.00
15	0	2	1	42	5.5	7.7	5.9	6.5	0.0	145	752	0.00
16	0	2	1	34	6.6	9.4	5.8	6.7	0.0	145	706	0.00
16	0	2	1	29	6.6	8.1	6.6	6.8	0.0	145	678	0.00
17	0	2	1	22	7.7	9.6	6.6	7.2	0.0	94	637	0.00

PROPPANT SUMMARY * At End of Pumping Schedule
SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
6.7	1089	0.75
15.0	1108	0.75
18.0	1142	0.77
21.0	1163	0.78
24.0	1148	0.78
27.0	1094	0.75
30.6	1075	0.74
34.2	1089	0.75
37.2	1035	0.72
40.2	965	0.68
43.2	959	0.68
46.2	972	0.69
49.2	948	0.67
52.2	913	0.66
55.2	898	0.65
58.2	870	0.64
61.2	865	0.63
64.2	920	0.66
67.2	925	0.66
70.2	838	0.62
73.2	753	0.58
76.2	760	0.58
79.2	787	0.59
82.2	721	0.56
85.2	674	0.54
88.2	707	0.55
91.2	684	0.54
94.2	623	0.51
97.2	633	0.52
100.2	790	0.60
103.2	1167	0.78
106.2	1170	0.79
109.2	514	0.44
112.2	51	0.13
115.2	0	0.03

Average Conductivity (md-ft) 904

PROPPANT SUMMARY * At Fracture Closure
SANTOS - E. MEREENIE #41 (LP3) POST-FRAC EVALUATION

Lb/Sq-Ft Lost to Embedment 0.200

Distance (ft)	KfW (md-ft)	Prop Concentration(Total lb/sq foot) Prop ID--> 1
6.7	896	0.63
15.0	899	0.64
18.0	923	0.65
21.0	967	0.67
24.0	990	0.68
27.0	983	0.68
30.6	923	0.65
34.2	839	0.61
37.2	833	0.60
40.2	870	0.62
43.2	843	0.61
46.2	777	0.58
49.2	751	0.56
52.2	755	0.57
55.2	803	0.59
58.2	884	0.63
61.2	909	0.64
64.2	899	0.64
67.2	898	0.64
70.2	967	0.67
73.2	1185	0.77
76.2	1343	0.85
79.2	1281	0.82
82.2	1221	0.79
85.2	1248	0.81
88.2	1320	0.84
91.2	1561	0.96
94.2	1894	1.12
97.2	1922	1.13
100.2	1746	1.05
103.2	1799	1.07
106.2	1497	0.93
109.2	597	0.47
112.2	53	0.13
115.2	0	0.03

Average Conductivity (md-ft) 1050

APPENDIX B

Service Co. Treatment Job Log

TABLE B-1

Customer:	Santos Ltd	Date:	13-Sep-1996
Well Desc:	EAST MEREENIE 41	Ticket #:	EM41UF1
Formation:	PACOOTA P3	Job Type:	FRACTURE TREATMENT

DATA LISTING

==== Stage Total 812.65 (gal) ====

09:20:00 Stage #2 FILL HOLE

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:20:03	113	520	3.32	2	1	8.32	0.00	0.0
09:20:08	33	520	11.30	37	1	8.33	0.00	0.0
09:20:13	-15	520	11.19	77	3	8.33	0.00	0.1
09:20:18	-14	522	10.62	115	16	8.32	0.00	0.3
09:20:23	907	558	4.90	140	38	8.31	0.00	0.3
09:20:28	2373	622	4.68	157	63	8.34	0.02	0.5
09:20:33	2417	626	4.60	173	86	8.39	0.09	1.2
09:20:38	2419	625	4.81	190	106	8.42	0.14	3.2
09:20:43	2409	622	4.98	207	125	8.42	0.14	5.9
09:20:48	2406	621	5.00	224	144	8.38	0.09	8.0
09:20:53	2404	619	5.00	242	162	8.39	0.09	9.8
09:20:58	2415	615	4.98	259	181	8.38	0.08	11.2
09:21:03	2432	614	4.96	277	198	8.39	0.10	12.9
09:21:08	2466	609	4.96	294	216	8.39	0.10	14.6
09:21:13	2494	605	4.93	312	233	8.38	0.08	16.2
09:21:18	2524	603	4.83	329	250	8.37	0.06	17.4
09:21:23	2549	599	4.67	345	268	8.35	0.03	18.3
09:21:28	2576	595	4.61	361	285	8.35	0.03	18.7
09:21:33	2598	590	4.60	377	302	8.38	0.08	19.6
09:21:38	2615	586	4.60	394	319	8.41	0.12	21.2
09:21:43	2633	583	4.60	410	336	8.39	0.10	22.9
09:21:48	2648	578	4.61	426	353	8.38	0.09	24.5
09:21:53	2668	573	4.63	442	370	8.39	0.09	25.9
09:21:58	2692	567	4.61	458	387	8.40	0.10	27.5
09:22:03	2717	561	4.64	474	404	8.39	0.10	29.1
09:22:08	2740	556	4.64	491	420	8.41	0.12	30.8

==== Stage Total 493.76 (gal) ====

09:22:09 Stage #3 Start Pad

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:22:12	2968	552	4.68	503	434	8.43	0.16	32.8
09:22:17	3301	553	7.60	529	451	8.44	0.18	37.3
09:22:22	3729	556	10.52	560	467	8.42	0.14	42.0
09:22:27	4137	563	11.39	598	485	8.44	0.17	47.5
09:22:32	4212	564	12.60	641	513	8.45	0.19	54.6
09:22:37	4239	561	13.71	687	544	8.44	0.17	62.8
09:22:42	4224	555	14.02	736	577	8.44	0.18	71.6
09:22:47	4240	543	13.96	785	613	8.41	0.13	78.2

Customer:	Santos Ltd		Date:	13-Sep-1996	
Well Desc:	EAST MEREENIE 41		Ticket #:	EM41UF1	
Formation:	PACOOTA P3		Job Type:	FRACTURE TREATMENT	

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:22:52	4274	538	13.77	834	651	8.45	0.19	85.4
09:22:57	4322	514	13.75	882	688	8.46	0.20	95.1
09:23:02	4533	516	14.20	931	725	8.41	0.13	101.8
09:23:07	4521	492	14.61	981	763	8.41	0.12	107.4
09:23:12	4492	480	14.53	1032	802	8.43	0.17	115.0
09:23:17	4484	492	14.72	1084	842	8.45	0.18	123.8
09:23:22	4511	441	15.04	1136	892	8.47	0.22	134.5
09:23:27	4578	458	14.83	1188	940	8.46	0.21	145.4
09:23:32	4618	454	14.37	1239	986	8.47	0.22	156.3
09:23:37	4616	451	14.35	1289	1029	8.44	0.18	166.2
09:23:42	4638	453	14.43	1340	1071	8.45	0.19	175.8
09:23:47	4242	458	14.47	1390	1113	8.45	0.19	185.4
09:23:52	4573	496	14.34	1441	1155	8.48	0.24	195.9
09:23:57	4617	533	13.96	1490	1196	8.48	0.24	207.7
09:24:02	4640	516	13.80	1538	1238	8.49	0.26	219.5
09:24:07	4667	485	14.08	1587	1279	8.49	0.26	231.9
09:24:12	4693	482	14.17	1637	1321	8.50	0.28	245.2
09:24:17	4962	486	14.59	1687	1362	8.45	0.20	255.9
09:24:22	4924	459	15.28	1740	1403	8.47	0.23	267.2
09:24:27	4892	473	15.33	1793	1444	8.50	0.27	280.9
09:24:32	4895	474	15.30	1847	1485	8.50	0.28	295.5
09:24:37	4897	470	15.32	1900	1526	8.49	0.26	309.5
09:24:42	4904	461	15.27	1954	1568	8.51	0.28	323.1

==== Stage Total 1503.02 (gal) ====

09:24:46 Stage #4 Start Sand

09:24:46	4904	456	15.24	1997	1601	8.54	0.34	336.4
09:24:51	4918	450	15.19	2050	1644	8.51	0.29	351.3
09:24:56	4926	444	15.30	2103	1689	8.54	0.33	367.9
09:25:01	4956	483	15.32	2157	1732	8.58	0.40	388.0
09:25:06	4978	520	15.23	2210	1774	8.61	0.44	410.5
09:25:11	4987	520	15.29	2264	1816	8.67	0.55	436.9
09:25:16	4989	502	15.32	2317	1858	8.67	0.55	466.0
09:25:21	4987	511	15.30	2371	1900	8.73	0.65	498.2
09:25:26	5010	503	15.28	2425	1942	8.77	0.71	533.4
09:25:31	5022	501	15.19	2478	1984	8.77	0.71	570.0
09:25:36	5032	498	15.17	2531	2026	8.80	0.77	607.7
09:25:41	5042	498	15.23	2584	2068	8.84	0.84	649.2

==== Stage Total 629.93 (gal) ====

09:25:45 Stage #5 Increase Sand

09:25:45	5047	490	15.15	2627	2102	8.85	0.86	683.5

Customer:	Santos Ltd	Date:	13-Sep-1996
Well Desc:	EAST MEREENIE 41	Ticket #:	EM41UF1
Formation:	PACOOTA P3	Job Type:	FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:25:50	5055	484	15.10	2680	2144	8.87	0.88	727.3
09:25:55	5056	479	15.11	2732	2187	8.87	0.89	772.4
09:26:00	5075	485	15.16	2785	2229	8.88	0.90	818.6
09:26:05	5086	468	15.15	2839	2272	8.92	0.98	865.7
09:26:10	5094	461	15.09	2891	2314	8.89	0.92	913.8
09:26:15	5109	458	15.16	2944	2356	8.92	0.96	962.6
09:26:20	5110	452	15.39	2998	2398	8.95	1.02	1013.6
09:26:25	5119	455	15.62	3052	2439	9.00	1.11	1069.2
09:26:30	5134	507	15.67	3107	2481	9.03	1.16	1129.1

==== Stage Total 480.27 (gal) ====

09:26:30 Stage #6 Increase Sand

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:26:34	5137	510	15.40	3150	2514	9.05	1.20	1177.7
09:26:39	5155	508	15.01	3203	2556	9.10	1.28	1240.1
09:26:44	5161	505	14.94	3256	2598	9.17	1.41	1307.4
09:26:49	5158	505	14.94	3308	2639	9.26	1.57	1382.2
09:26:54	5177	499	14.88	3360	2681	9.27	1.59	1459.5
09:26:59	5194	465	14.93	3412	2722	9.27	1.59	1536.8
09:27:04	5209	482	14.99	3465	2764	9.27	1.59	1614.8
09:27:09	5219	483	14.92	3517	2805	9.37	1.77	1697.0

==== Stage Total 430.96 (gal) ====

1750.4

09:27:12 Stage #7 Increase Sand 3549

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:27:13	5205	482	14.91	3559	2838	9.46	1.94	1768.2
09:27:18	5217	482	14.96	3611	2880	9.47	1.96	1861.7
09:27:23	5224	474	14.93	3663	2921	9.54	2.08	1959.5
09:27:28	5224	470	14.84	3715	2962	9.59	2.19	2061.6
09:27:33	5233	470	14.87	3767	3003	9.68	2.35	2169.8
09:27:38	5230	463	14.98	3820	3044	9.76	2.51	2284.4
09:27:43	5222	459	15.03	3872	3085	9.75	2.49	2402.4
09:27:48	5236	468	15.03	3925	3126	9.79	2.56	2522.4
09:27:53	5237	513	14.98	3977	3166	9.85	2.68	2645.6

==== Stage Total 439.40 (gal) ====

09:27:53 Stage #8 Increase Sand

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:27:57	5238	519	14.98	4019	3199	9.87	2.72	2746.6
09:28:02	5238	518	15.03	4072	3238	9.91	2.81	2876.8
09:28:07	5232	512	15.03	4124	3277	10.03	3.05	3013.5

Customer:	Santos Ltd		Date:	13-Sep-1996	
Well Desc:	EAST MEREENIE 41		Ticket #:	EM41UF1	
Formation:	PACOOTA P3		Job Type:	FRACTURE TREATMENT	

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:28:12	5242	514	14.98	4177	3317	10.09	3.18	3158.4
09:28:17	5251	510	14.98	4229	3356	10.12	3.23	3305.6
09:28:22	5243	505	14.98	4282	3395	10.17	3.34	3457.2
09:28:27	5241	504	15.04	4334	3435	10.21	3.41	3611.9
09:28:32	5251	500	15.05	4387	3474	10.23	3.47	3769.8
09:28:37	5247	496	15.01	4440	3514	10.28	3.58	3930.9

==== Stage Total 462.20 (gal) ====

09:28:37 Stage #9 Increase Sand

09:28:41	5237	493	15.03	4482	3545	10.31	3.64	4061.6
09:28:46	5233	490	15.03	4534	3584	10.33	3.68	4227.7
09:28:51	5226	485	15.02	4587	3623	10.39	3.81	4395.7
09:28:56	5233	482	15.03	4639	3661	10.48	4.00	4571.7
09:29:01	5246	480	15.04	4692	3698	10.59	4.25	4755.0
09:29:06	5226	478	15.03	4745	3735	10.61	4.29	4944.7
09:29:11	5214	475	15.02	4797	3771	10.63	4.34	5135.0
09:29:16	5223	471	15.01	4850	3808	10.67	4.43	5328.3
09:29:21	5213	466	15.03	4902	3846	10.68	4.44	5521.5

==== Stage Total 473.18 (gal) ====

4923 5600

09:29:23 Stage #10 Increase Sand

09:29:25	5207	465	15.05	4944	3876	10.68	4.46	5678.4
09:29:30	5204	502	15.01	4997	3914	10.81	4.73	5878.0
09:29:35	5193	527	15.01	5049	3951	10.79	4.70	6083.1
09:29:40	5193	534	15.09	5102	3988	10.81	4.75	6289.0
09:29:45	5197	533	15.32	5155	4026	10.82	4.78	6497.5
09:29:50	5186	528	15.52	5209	4063	10.84	4.81	6711.3
09:29:55	5179	524	15.52	5264	4100	10.87	4.88	6929.9
09:30:00	5192	521	15.53	5318	4138	10.90	4.95	7149.5
09:30:05	5195	518	15.52	5372	4175	10.98	5.14	7374.9

==== Stage Total 503.13 (gal) ====

09:30:09 Stage #11 Increase Sand

09:30:09	5197	519	15.47	5416	4205	11.00	5.20	7557.9
09:30:14	5193	516	15.23	5469	4242	11.05	5.32	7787.9
09:30:19	5177	510	15.03	5522	4279	11.11	5.47	8017.9
09:30:24	5181	508	15.01	5575	4316	11.15	5.54	8250.7
09:30:29	5187	507	15.02	5627	4353	11.21	5.70	8489.1

Customer:	Santos Ltd	Date:	13-Sep-1996
Well Desc:	EAST MEREENIE 41	Ticket #:	EM41UF1
Formation:	PACOOTA P3	Job Type:	FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:30:34	5179	502	15.02	5680	4389	11.24	5.77	8729.5
09:30:39	5189	499	15.01	5732	4425	11.29	5.90	8973.6
09:30:44	5201	498	15.01	5785	4461	11.38	6.12	9222.8
09:30:49	5191	495	15.01	5837	4497	11.48	6.38	9481.1
09:30:54	5185	494	14.99	5890	4533	11.53	6.51	9744.4

==== Stage Total 505.60 (gal) ====

09:30:58 Stage #12 Increase Sand

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:30:58	5194	491	14.99	5932	4562	11.56	6.60	9957.3
09:31:03	5185	490	15.01	5984	4597	11.59	6.67	10227.3
09:31:08	5192	487	15.19	6038	4633	11.68	6.92	10505.3
09:31:13	5205	485	15.25	6091	4669	11.69	6.95	10788.5
09:31:18	5203	481	15.12	6144	4705	11.74	7.08	11071.8
09:31:23	5206	478	15.07	6197	4741	11.77	7.16	11358.0
09:31:28	5219	478	15.01	6249	4776	11.80	7.25	11646.0
09:31:33	5210	477	14.97	6302	4812	11.84	7.35	11934.9
09:31:38	5204	473	14.95	6354	4847	11.90	7.53	12228.3
09:31:43	5223	472	14.94	6406	4882	11.96	7.68	12525.2
09:31:48	5233	472	14.93	6459	4917	12.08	8.02	12830.2
09:31:53	5231	478	14.95	6511	4952	12.09	8.06	13141.0
09:31:58	5246	519	14.94	6563	4987	12.10	8.08	13452.6
09:32:03	5270	518	14.91	6615	5021	12.16	8.27	13766.5
09:32:08	5270	515	15.21	6668	5056	12.22	8.44	14089.0
09:32:13	5275	512	15.32	6722	5091	12.26	8.58	14420.4
09:32:18	5290	511	15.17	6775	5125	12.26	8.58	14752.0
09:32:23	5289	510	15.09	6828	5160	12.26	8.56	15080.8
09:32:28	5281	507	14.95	6881	5194	12.27	8.61	15407.9
09:32:33	5294	504	14.95	6933	5229	12.27	8.58	15733.7
09:32:38	5321	505	14.98	6985	5263	12.30	8.69	16061.4
09:32:43	5326	504	15.10	7038	5298	12.31	8.73	16392.3
09:32:48	5320	501	15.25	7091	5332	12.33	8.76	16729.2
09:32:53	5338	500	15.17	7144	5367	12.35	8.82	17067.3
09:32:58	5361	501	14.97	7197	5401	12.34	8.82	17401.8
09:33:03	5368	497	14.92	7249	5436	12.33	8.77	17732.4
09:33:08	5376	494	14.92	7302	5471	12.32	8.76	18062.3
09:33:13	5393	496	14.91	7354	5505	12.32	8.74	18391.5
09:33:18	5422	496	14.91	7406	5544	12.32	8.73	18721.9
09:33:23	5446	494	14.91	7458	5591	12.32	8.75	19051.1
09:33:28	5455	492	14.90	7510	5640	12.34	8.82	19380.8
09:33:33	5477	491	14.87	7562	5691	12.32	8.74	19710.2
09:33:38	5507	490	14.91	7614	5742	12.26	8.57	20036.7
09:33:43	5514	490	15.01	7667	5792	11.76	7.14	20342.0

==== Stage Total 1766.43 (gal) ====

Customer: Santos Ltd
Well Desc: EAST MEREENIE 41
Formation: PACOOTA P3

Date: 13-Sep-1996
Ticket #: EM41UF1
Job Type: FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:33:46 Stage #13 Start Flush								
09:33:47	5490	519	15.11	7709	5832	11.11	5.38	20551.1
09:33:52	5461	536	15.14	7762	5880	10.57	4.11	20760.1
09:33:57	5438	534	15.18	7815	5928	10.17	3.28	20929.8
09:34:02	5411	521	15.34	7869	5975	9.95	2.81	21072.3
09:34:07	5381	521	15.33	7922	6021	9.70	2.33	21192.4
09:34:12	5368	522	15.31	7976	6068	9.49	1.93	21295.6
09:34:17	5374	523	15.29	8029	6115	9.38	1.73	21386.2
09:34:22	5370	524	15.18	8083	6161	9.17	1.35	21457.8
09:34:27	5371	524	15.25	8136	6206	9.09	1.21	21521.1
09:34:32	5394	522	15.26	8189	6251	8.99	1.03	21577.7
09:34:37	5405	547	15.26	8243	6294	8.88	0.84	21624.0
09:34:42	5420	510	15.25	8296	6335	8.84	0.78	21664.9
09:34:47	5444	512	15.19	8349	6376	8.82	0.74	21703.7
09:34:52	5457	511	15.20	8403	6416	8.80	0.70	21740.9
09:34:57	5457	525	15.18	8456	6456	8.79	0.68	21776.4
09:35:02	5435	485	15.20	8509	6497	8.68	0.50	21804.5
09:35:07	5435	484	15.23	8562	6538	8.68	0.51	21830.7
09:35:12	5461	514	15.19	8615	6580	8.69	0.52	21857.1
09:35:17	5499	471	15.16	8668	6624	8.67	0.49	21883.4
09:35:22	5543	489	15.15	8722	6668	8.66	0.47	21908.6
09:35:27	5564	492	15.20	8775	6713	8.65	0.45	21932.1
==== Stage Total 1129.13 (gal) ====								
09:35:32 Stage #14 Stop Pumping								
09:35:31	5141	488	14.99	8817	6748	8.62	0.40	21947.6
09:35:36	3904	439	0.94	8834	6790	8.57	0.33	21955.0
09:35:41	4257	438	0.27	8836	6802	8.54	0.27	21955.4
09:35:46	3764	439	0.00	8836	6809	8.48	0.18	21955.5
09:35:51	3742	436	0.00	8836	6816	8.44	0.12	21955.5
09:35:56	3690	430	0.00	8836	6821	8.43	0.09	21955.5
09:36:01	3616	426	0.00	8836	6826	8.45	0.12	21955.5
09:36:06	3551	423	0.00	8836	6830	8.47	0.17	21955.5
09:36:11	3490	420	0.00	8836	6834	8.47	0.16	21955.5
09:36:16	3439	417	0.00	8836	6838	8.44	0.11	21955.5
09:36:21	3398	415	0.00	8836	6840	8.47	0.16	21955.5
09:36:26	3364	413	0.00	8836	6843	8.44	0.11	21955.5
09:36:31	3338	412	0.00	8836	6845	8.42	0.08	21955.5
09:36:36	3316	411	0.00	8836	6847	8.40	0.04	21955.5
09:36:41	3296	410	0.00	8836	6849	8.41	0.06	21955.5
09:36:46	3278	409	0.00	8836	6851	8.45	0.13	21955.5
09:36:51	3260	408	0.00	8836	6852	8.47	0.15	21955.5
09:36:56	3242	407	0.00	8836	6854	8.42	0.08	21955.5

Customer:	Santos Ltd	Date:	13-Sep-1996
Well Desc:	EAST MEREENIE 41	Ticket #:	EM41UF1
Formation:	PACOOTA P3	Job Type:	FRACTURE TREATMENT

TIME	Tubing Pr (psi)	Annulus Pr (psi)	Slurry Rt (bpm)	Slry Vol (gal)	Clean Vol (gal)	Slurry Den (lb/gal)	Sand Conc (lb/gal)	Sand Vol (lb)
09:37:01	3225	406	0.00	8836	6855	8.41	0.07	21955.5
09:37:06	3208	405	0.00	8836	6856	8.39	0.03	21955.5
09:37:11	3191	405	0.00	8836	6858	8.39	0.04	21955.5
09:37:16	3175	404	0.00	8836	6859	8.39	0.03	21955.5
09:37:21	3159	403	0.00	8836	6859	8.38	0.01	21955.5
09:37:26	3148	403	0.00	8836	6860	8.37	0.00	21955.5
09:37:31	3141	403	0.00	8836	6860	8.40	0.04	21955.5
09:37:36	3134	402	0.00	8836	6860	8.44	0.11	21955.5
09:37:41	3124	402	0.00	8836	6860	8.43	0.09	21955.5
09:37:46	3113	402	0.00	8836	6860	8.45	0.13	21955.5
09:37:51	3102	402	0.00	8836	6860	8.42	0.08	21955.5
09:37:56	3091	402	0.00	8836	6860	8.42	0.08	21955.5
09:38:01	3079	401	0.00	8836	6860	8.40	0.04	21955.5
09:38:06	3068	401	0.00	8836	6860	8.39	0.03	21955.5
09:38:11	3056	401	0.00	8836	6860	8.38	0.01	21955.5
09:38:16	3045	401	0.00	8836	6860	8.40	0.05	21955.5
09:38:21	3033	401	0.00	8836	6860	8.40	0.05	21955.5
09:38:26	3021	401	0.00	8836	6860	8.38	0.02	21955.5
09:38:31	3010	401	0.00	8836	6860	8.38	0.01	21955.5
09:38:36	2999	401	0.00	8836	6860	8.34	0.00	21955.5
09:38:41	2988	401	0.00	8836	6860	8.38	0.02	21955.5
09:38:46	2977	401	0.00	8836	6860	8.37	0.00	21955.5
09:38:51	2966	401	0.00	8836	6860	8.36	0.00	21955.5
09:38:56	2955	401	0.00	8836	6860	8.35	0.00	21955.5
09:39:01	2944	401	0.00	8836	6860	8.38	0.01	21955.5
09:39:06	2929	401	0.00	8836	6860	8.38	0.02	21955.5
09:39:11	2914	401	0.00	8836	6860	8.39	0.03	21955.5
09:39:16	2904	401	0.00	8836	6860	8.40	0.05	21955.5
09:39:21	2888	32	0.00	8836	6860	8.40	0.05	21955.5
09:39:26	2867	5	0.00	8836	6860	8.42	0.08	21955.5
09:39:31	2857	2	0.00	8836	6860	8.41	0.07	21955.5
09:39:36	2854	1	0.00	8836	6860	8.41	0.07	21955.5
09:39:41	2848	0	0.00	8836	6860	8.41	0.06	21955.5
09:39:46	2840	0	0.00	8836	6860	8.41	0.06	21955.5
09:39:51	2832	0	0.00	8836	6860	8.42	0.08	21955.5
09:39:56	2823	0	0.00	8836	6860	8.42	0.07	21955.5
09:40:01	2814	0	0.00	8836	6860	8.44	0.12	21955.5
09:40:06	2805	-0	0.00	8836	6860	8.43	0.10	21955.5
09:40:11	2795	-1	0.00	8836	6860	8.44	0.11	21955.5
09:40:16	2785	-1	0.00	8836	6860	8.41	0.06	21955.5
09:40:21	2775	-1	0.00	8836	6860	8.44	0.11	21955.5
09:40:26	2764	-1	0.00	8836	6860	8.42	0.09	21955.5
09:40:31	2754	-1	0.00	8836	6860	8.41	0.06	21955.5
09:40:36	2744	-1	0.00	8836	6860	8.43	0.09	21955.5
09:40:41	2733	-1	0.00	8836	6860	8.44	0.11	21955.5
09:40:46	2723	-0	0.00	8836	6860	8.43	0.10	21955.5
09:40:51	2712	-0	0.00	8836	6860	8.44	0.11	21955.5
09:40:56	2701	0	0.00	8836	6860	8.45	0.12	21955.5
09:41:01	2690	0	0.00	8836	6860	8.44	0.11	21955.5
09:41:06	2680	0	0.00	8836	6860	8.46	0.14	21955.5