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Santos

EAST MEREENIE 41
LOWER P3/P4
FRACTURE STIMULATION PROGRAM

ONSHORE

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August 1996

Prepared by:

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CONTENTS

OBJECTIVE

To fracture stimulate the P4 and Lower P3 sands independently and then recomplete East Mereenie 41 as a tandem producer from the two zones.

WELL DATA

Location
Latitude: 24^0 01' 20.858" S
Longitude: 131^0 35' 38.283" E
Line:

Elevation
Ground Level: 764.3 m
Kelly Bushing: 770.5 m

Surface Casing

Size	Weight	Grade	Jnts No	Thread	Length	From M	To M	Remarks
10-3/4"		K55		8RD STC	0.40	667.84	668.24	FLOAT SHOE
10-3/4"	40.5	H40	1	8RD STC	12.10	655.74	667.84	
10-3/4"		K55		8RD STC	0.26	655.48	655.74	FLOAT COLLAR
10-3/4"	40.5	H40	12	8RD STC	144.72	510.76	655.48	
10-3/4"	40.5	K55	44	8RD STC	503.80	6.96	510.76	
10-3/4"	40.5	K55		8RD STC	7.63	-0.67	6.96	LANDING JOINT

Production Casing

Size	Weight	Grade	Jnts No	Thread	Length	From M	To M	Remarks
5-1/2"			1	8RD	0.40	1572.60	1573.00	FLOAT SHOE
5-1/2"	17	L80	1	8RD	11.81	1560.79	1572.60	
5-1/2"			1	8RD	0.28	1560.51	1560.79	FLOAT COLLAR
5-1/2"	17	L80	133	8RD	1561.21	-0.70	1560.51	STICK UP 1.10 m RT

Cementing

Surface 10-3/4"
Class "A" cement
316 sacks, 15.5 ppg

Production 5-1/2"
Class "G" cement with 0.1% HR5 and 0.5% Gas Stop
750 sacks, 15.8 ppg

TD 1573 metres KB

PBTD 1560 metres KB

RESERVOIR	Pacoota P3-230/250
Pressure	12066 kPa (1750 psig) at 1550 m KB (5086 ft) at 63^{0}C (145^{0}F)
	Virgin Pressure
RESERVOIR	Pacoota P4
Pressure	12618 kPa (1830 psig) at 1550 m KB (5086 ft) at 64^{0}C (148^{0}F)
	Virgin Pressure
Santos Cost Code	1EA-C644-775
Contact Personnel	PB Lansom (07) 3228 6541 DC Reeve (07) 3228 6540 SM Liddle (07) 3228 6534 (Mobile): 0419 834 962

WELL HISTORY

East Mereenie 41 was drilled in May/June 1996 to develop the Lower P3 and P4 zones on the Eastern nose of the Mereenie Field. Since perforating the well, East Mereenie 41 has performed well below expectations.

Recent work on the well has suggested a significant problem with the production casing cement quality. **A summary of this work has been provided as an attachment and should be read by all key personnel involved on the well**. It has been decided to proceed with fracture treatments on both zones as this appears the only way to test the cement quality and obtain economic rates from the well. The Lower P3 and P4 will be fracced independently and the well recompleted as a tandem producer.

KILL FLUID CALCULATION SHEET

Reservoir Pressure	=	1830.0 psi at 1550 m KB (5086 ft)
Reservoir Temperature	=	145^0F @ 5086 ft
Fluid Kill Weight	=	$\frac{1830.0 + 25}{5086\ (0.052)}$
	=	6.7
Temperature Correction	=	$\frac{145 + 80}{2}$
	=	113 °F
Density Correction	=	0.003 (113 - 80)
	=	0.098 ppg
	=	6.8 ppg

Use 3% KCL filtered Brine at 80^0F - 8.48 ppg. This is equivalent to 10.82 lbs of KCL per barrel of water. Add 0.2% F75N surfactant when mixing the KCL Brine (8.4 gal F75N per 100 Bbl of KCL).

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1.0 WORKOVER WELL FOR P4 STIMULATION

1.1 Move in EWS rig complete with 2-7/8" frac string (180 joints). Strap all tubing on location.

1.2 Mix approximately 400 bbls of 3% Tech Grade KCL brine filtered to 10 micron and 0.2 % F75N surfactant and 0.25 gal/bbl of BE-5 Biocide.

1.3 Measure and record, then bleed off the production, intermediate and surface casing pressure.

1.4 Circulate 3% KCl down the tubing and bleed off the annulus pressure. Ensure well is dead and continue to monitor tubing head and casing head pressure.

1.5 Install back pressure valve (BPV). Remove existing wellhead. Nipple up BOP's, remove BPV and install two way check valve. Pressure test BOP's to 1500 psi. Remove two way check valve.

1.6 To release packer, apply an upstrain of 3000 lb to 6000 lb and rotate the tubing to the right from eight to ten turns at the tool, until the tool moves up the hole. Continue to rotate to the right several times while moving up the hole to be certain the slips are fully retracted.

1.7 POOH Baker packer and tubing string. Tally and inspect tubing.

1.8 Make up frac BHA. RIH hydraulic fracture treatment string. (See Figure 3). Rabbit tubing and BHA, remove any scale or dirt prior to RIH. Fill tubing with filtered slick water and reverse circulate hole volume prior to setting packer.

1.9 Set AL-2 Lok-Set packer at 1492 m KB (4895 ft KB). Ensure the final joint of 2-7/8" EUE tubing is approximately 2 - 3 ft above the rig floor to allow hook up to Halliburton. Set packer with approximately 10 - 15,000 lbs compression. This should be sufficient to allow for thermal and pressure expansion during the treatment.

1.10 Install mini frac head of Halliburton. (See Figure 4).

2.0 P4 - FRACTURE STIMULATION

2.1 Rig Up

2.1.1 All frac tanks should be well cleaned prior to mixing fluid. Lined tanks should be used for the main frac gel storage.

2.1.2 Flush Halliburton lines. Rig up injection line from frac manifold to the wellhead.

2.1.3 Pressure test all lines against valve on top of wellhead to 9000 psi using slick water to fill lines. Hold for 10 minutes. Bleed off.

Note: The injection line from the frac manifold to the wellhead is to be staked down and anchored to the wellhead at the tubing/casing spool flange.

2.1.4 Rig up and stake down a 2" pressure release line from the casing/tubing annulus side arm valve and run it to a safe position at least 100 ft from the wellhead. This line will be tied into the cement pump truck which will be used to fill up the annulus, bleed off pressure if necessary during the job and reverse out sand in the tubing in the event of tubing failure during the job.

2.1.5 Rig up pump truck to this line, with casing side arm valve closed, pressure test to 2000 psi for five minutes. Bleed off. Open casing side arm valve and fill casing/tubing annulus with KCl water. **During the P4 fracture treatment, the casing/tubing annulus is to be kept full at all times with a minor positive pressure. This is due to the open perforations of the Lower P3.**

2.1.6 Contractor should rig up a pressure transducer to this line, and to the injection line, to continuously monitor at the frac van both annulus and injection wellhead pressures.

2.1.7 At no time should wellhead injection pressures exceed 7500 psi. On site instructions to pump unit operators must include specific details of pumps coming off line in a nominated sequence starting at 7000 psi. Set pop-offs as follows; annulus - 1800 psi injection line - 7500 psi.

2.2 Stress Testing

Note: **THIS WELL HAS A SUSPECT PRODUCTION CASING CEMENT JOB. PARTICULAR CARE IS REQUIRED DURING ALL PUMPING OPERATIONS TO CAREFULLY OBSERVE ANY ANNULUS PRESSURE CHANGES. SHOULD ANNULUS PRESSURE INCREASE DURING ANY PUMPING OPERATION, PUMPING SHOULD CEASE IMMEDIATELY. BRISBANE OFFICE SHOULD BE CONTACTED BEFORE ANY FURTHER WORK CAN PROCEED. PLEASE ENSURE THAT ALL KEY PERSONNEL ARE INFORMED OF THIS CEMENT PROBLEM BEFORE PUMPING OPERATIONS ARE COMMENCED.**

Safety Meeting and equipment checks to be conducted prior to any high pressure pumping.

2.2.1 Rig up Expertest with tandem Schlumberger SLSR-A gauges (10000 psi pressure rating). Run gauges in hole on E-line and land in 2-3/8" XN-Profile (See Figure 3). Rig down Expertest.

2.2.2 Displace surface lines to filtered stress testing fluid. Refer to **Table 1** for fluid specifications.

2.2.3 Start filling hole at 5 BPM.

2.2.4 Breakdown formation before performing 10 Bbls injection/shut-in decline test at 5 BPM to evaluate closure and reservoir pressure. This will be used in assessing the accuracy of the stress profile used in the fracture treatment.

2.2.5 Perform step rate injection test with filtered treated water according to the following schedule:

Note each rate to be held for two minutes.

Injection Rate (bpm)	Volume (bbls)
0.5	1
1.0	2
1.5	3
2.0	4
3.0	5
5.0	6
7.0	10
10.0	20
12.0	24
15.0	30
	114 bbls

Stabilised pressures from each step-rate increment will be plotted vs injection pressure "on the fly" in order to determine "fracture extension pressure". Should extension pressure be calculated prior to pumping the higher rates, then the test will be terminated and the pressure decline monitored to detect closure pressure.

Note: Maximum care must be taken to ensure the minimum amount of fluid is used in stress test evaluations.

2.3 Mini Frac

2.3.1 Mix up 3000 gal fracturing fluid 3% KCl filtered brine containing a base 30 lb/1000 gal X-link Borate HPG gel system with additives. Refer to **Table 2** for fracturing fluid specification. Conduct quality control checks of fracturing fluid rheology prior to pumping.

2.3.2 Displace surface lines to mini frac fluid.

2.3.3 Pump 2000 gal mini frac fluid and filtered slick water displacement volume at 15 BPM, limiting the pump pressure to 7500 psi to initiate frac. Shut down pumps at the discretion of the frac supervisor.

2.3.4 Monitor pressure decline. Confirm fracture closure and calculate fluid leak-off co-efficient and fluid efficiency.

2.3.5 After gel has broken down, rig up Expertest and POOH gauges and retrieve BHP data.

2.3.6 Analyse mini-frac data and redesign main frac treatment based upon results. Review design with the Brisbane office.

2.3.7 Mix chemicals for main frac treatment.

2.4 Main Fracture Treatment

2.4.1 Conduct safety meeting and equipment checks prior to commencement of job.

2.4.2 Conduct quality control checks on fracturing fluid.

2.4.3 Rig up and run in hole tandem Expertest EMR gauges and land in 2-3/8" XN-profile. Install head for main frac. Pressure test lines and set pop-offs.

2.4.4 Pump main fracture treatment as redesigned following mini frac. Maximum treating pressure to be 7500 psi. Set hydraulic pop-off valve for 7500 psi.
A SMALL POSITIVE PRESSURE SHOULD BE HELD ON THE ANNULUS AT ALL TIMES.

Approximate job size based on comparison with East Mereenie 38 is as follows;
Fluid volume = 5000 gal
Pad volume = 1100 gal
Proppant volume = 8500 lbs
Pumping rate = 15 BPM

2.4.5 Commence displacement count after detecting drop in fluid density from densitometer at wellhead below 5 PPG.

Note: The actual displacement volume requires calculation for the final completion configuration. It will be 2 bbls less than total volume from densitometer to top perforation.

Conversions:

2-7/8" 6.5# tubing	=	0.2431 gals/ft
5-1/2" 17# casing	=	0.9764 gals/ft

2.4.6 Shut down pumps. Record pressure bleed off. Wait till gel breaks and pressure to bleed off. Flow back through tubing to bleed off remaining pressure so that WHP equals zero.

2.4.7 Open annulus. Bleed pressure slowly to 0 psi.

2.4.8 Release packer. POOH treatment string. Recover memory gauges.

__Note:__ If early screen out, hold approximately 1,000 psi on Annulus when releasing packer and reverse circulate well clean. Actual pressure required to be calculated prior to reversing out.

3.0 ISOLATE P4 ZONE

3.1 Rig up wireline unit. RIH with blind box and tag proppant depth. If the P4 interval is not covered by proppant, dump proppant down wellbore to satisfactorily cover the P4 interval. RIH with blind box and ensure proppant depth is at approximately 1490 m KB (4889' KB). POOH with wireline.

4.0 RECOMPLETE WELL FOR LOWER P3 STIMULATION

4.1 Make up frac BHA. RIH hydraulic fracture treatment string. (See Figure 6). Fill tubing with filtered slick water prior to setting packer.

4.2 Set AL-2 Lok-Set packer at 1440 m KB (4724 ft KB). Ensure the final joint of 2-7/8" EUE tubing is approximately 2 - 3 ft above the rig floor to allow hook up to Halliburton and Schlumberger. Set packer with approximately 10 - 15,000 lbs compression. This should be sufficient to allow for thermal and pressure expansion during the treatment.

4.3 Close BOP's (pipe and annular). Pressure test annulus to 1500 psi to check BOP's and packer are holding.

4.4 Install mini frac head of Halliburton and Schlumberger. (See attached Figure 4).

5.0 LOWER P3 - FRACTURE STIMULATION

5.1 Rig Up

5.1.1 Flush Halliburton lines. Rig up injection line from frac manifold to the wellhead.

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5.1.2 Pressure test all lines against valve on top of wellhead to 9000 psi using Slick water to fill lines. Hold for 10 minutes. Bleed off.

5.1.3 Rig up pump truck to the 2" pressure release line from the casing/tubing annulus. With the casing side arm valve closed, pressure test to 2000 psi for five minutes. Bleed off. Open casing side arm valve and fill casing/tubing annulus with KCl water. Pressure up the casing/tubing annulus to 1500 psi.

5.1.4 Contractor should rig up a pressure transducer to this line, and to the injection line, to continuously monitor at the frac van both annulus and injection wellhead pressures.

5.1.5 The annulus pressure should not be allowed to exceed 1600 psi if possible, but at all times be held below the safe working pressure of the tubing head spool (2000 psi). Set pop-offs for 1800 psi.

5.1.6 At no time should wellhead injection pressures exceed 7500 psi. On site instructions to pump unit operators must include specific details of pumps coming off line in a nominated sequence starting at 7000 psi. Set pop-offs for 7500 psi.

5.2 Stress Testing

Note: **THIS WELL HAS A SUSPECT PRODUCTION CASING CEMENT JOB. PARTICULAR CARE IS REQUIRED DURING ALL PUMPING OPERATIONS TO CAREFULLY MONITOR ANY SURFACE CASING ANNULUS PRESSURE CHANGES. SHOULD SURFACE CASING ANNULUS PRESSURE INCREASE DURING ANY PUMPING OPERATION, PUMPING SHOULD CEASE IMMEDIATELY. BRISBANE OFFICE SHOULD BE CONTACTED BEFORE ANY FURTHER WORK CAN PROCEED. PLEASE ENSURE THAT ALL KEY PERSONNEL ARE INFORMED OF THIS CEMENT PROBLEM BEFORE PUMPING OPERATIONS ARE COMMENCED.**

Safety Meeting and equipment checks to be conducted prior to any high pressure pumping.

5.2.1 Rig up Expertest with tandem Schlumberger SLSR-A gauges (10000 psi pressure rating). Run gauges in hole on E-line and land in 2-3/8" XN-Profile (See Figure 6). Rig down Expertest.

5.2.2 Displace surface lines to filtered stress testing fluid. Refer to **Table 1** for fluid specifications.

5.2.3 Start filling hole at 5 BPM.

5.2.4 Breakdown formation before performing 10 Bbls injection/shut-in decline test at 5 BPM to evaluate closure and reservoir pressure. This will be used in assessing the accuracy of the stress profile used in the fracture treatment.

5.2.5 Perform step rate injection test with filtered treated water according to the following schedule:

Note each rate to be held for two minutes.

Injection Rate (bpm)	Volume (bbls)
0.5	1
1.0	2
1.5	3
2.0	4
3.0	5
5.0	6
7.0	10
10.0	20
12.0	24
15.0	30
	114 bbls

Stabilised pressures from each step-rate increment will be plotted vs injection pressure "on the fly" in order to determine "fracture extension pressure". Should extension pressure be calculated prior to pumping the higher rates, then the test will be terminated and the pressure decline monitored to detect closure pressure.

Note: Maximum care must be taken to ensure the minimum amount of fluid is used in stress test evaluations.

5.3 Mini Frac

5.3.1 Mix up 5000 gal fracturing fluid 3% KCl filtered brine containing a base 30 lb/1000 gal X-link Borate HPG gel system with additives. Refer to**Table 2** for fracturing fluid specification. Conduct quality control checks of fracturing fluid rheology prior to pumping.

5.3.2 Displace surface lines to mini frac fluid.

5.3.3 Pump 4000 gal mini frac fluid and filtered slick water displacement volume at 20 BPM, limiting the pump pressure to 7500 psi to initiate frac. Shut down pumps at the discretion of the frac supervisor.

5.3.4 Monitor pressure decline. Confirm fracture closure and calculate fluid leak off co-efficient and fluid efficiency.

5.3.5 Analyse mini-frac data and redesign main frac treatment based upon results. Review design with the Brisbane office.

5.3.6 Mix chemicals for main frac treatment.

5.4 Main Fracture Treatment

5.4.1 Conduct safety meeting and equipment checks prior to commencement of job.

5.4.2 Conduct quality control checks on fracturing fluid.

5.4.3 Rig up and run in hole tandem Expertest EMR gauge and land in 2-3/8" XN-Profile. Install head for main frac. Pressure test lines and set pop-offs.

5.4.4 Pump main fracture treatment as redesigned following mini frac. Maximum treating pressure to be 7500 psi. Set hydraulic pop-off valve for 7500 psi.

Approximate job size based on comparison with East Mereenie 38 is as follows;
Fluid volume = 10000 gal
Pad volume = 5000 gal
Proppant volume = 14000 lbs
Pumping rate = 15 BPM

5.4.5 Commence displacement count after detecting drop in fluid density from densitometer at wellhead below 5 PPG.

Note: The actual displacement volume requires calculation for the final completion configuration. It will be 2 bbls less than total volume from densitometer to top perforation.

Conversions:

2-7/8" 6.5# tubing	=	0.2431 gals/ft
5-1/2" 17# casing	=	0.9764 gals/ft

5.4.6 Shut down pumps. Record pressure bleed off. Wait till gel breaks and pressure to bleed off. Flow back through tubing to bleed off remaining pressure so that WHP equals zero.

5.4.7 Open annulus. Bleed pressure slowly to 0 psi.

5.4.8 Release packer. POOH treatment string. Recover memory gauges.

Note: If early screen out, hold approximately 1,000 psi on Annulus when releasing packer and reverse circulate well clean. Actual pressure required to be calculated prior to reversing out.

5.4.9 RIH open ended 2-3/8" tubing and tag proppant. Record depth. Reverse circulate out proppant, 1 stand at a time to PBTD using 3% KCL brine. Circulate clean. POOH with 2-3/8" tubing.

6.0 WELL COMPLETION FOR PRODUCTION

6.1 Make up lower BHA including Baker Model DB packer (complete with millout extension), swage, pup joint, 'XN' nipple and wireline re-entry guide (per attached Figure 7).

6.2 Rig up Schlumberger complete with setting kit for Baker Model DB packer. RIH on wireline packer setting kit and above BHA.

6.3 Correlate on depth and set DB packer at approximately 1491 m KB (4891' KB). POOH with wireline. Rig down Schlumberger.

6.4 Make up remainder of BHA on top of packer seal assembly (see attached Figure 7). Both sliding sleeves should be closed. RIH and shoulder DB packer seal assembly. Pull up on tubing string and set seals in neutral position.

6.5 Rig up wireline unit. RIH with 'PX' plug and set in the 'X' profile of the Lower sliding sleeve at approximately 1488 m KB (4883' KB).

6.6 Nipple down BOP Stack.

6.7 Connect high pressure line to Annulus and ensure hole is full.

6.8 Connect high pressure line to tubing and set hydraulic packer by pressuring up to 1500 psi.

6.9 Pressure test Annulus to confirm packer is set.

6.10 RIH with wireline and retrieve "PX" blanking plug.

6.11 Install Wellhead Assembly.

6.12 RIH with wireline and open upper and lower Sliding Sleeves, swab well and flow to clean up.

6.13 Rig Release.

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TABLE 1

TREATED WATER

ADDITIVE	CONC/1000 GALS	QUANTITY	DESCRIPTION
Clayfix II	3.0	45 gals	Clay Control
WG-11	10 lbs	150 lbs	Gelling Agent
HYG-3	1.0 lbs	15 lbs	pH Buffer
BE-5	0.4 gals	6 gals	Bactericide
Cla-Sta XP	5.0 gals	75 gals	Clay Control
Losurf 357	1.0 gals	15 gals	Surfactant

Note: Have K-34 on location to ensure adequate gel hydration, if needed.

TABLE 2

FRACTURING FLUID - BORAGEL H3595

ADDITIVE	CONC/1000 GALS	QUANTITY	DESCRIPTION
Clayfix II	3 gals	60 gals	Clay Control
WG-11	30 lbs	600 lbs	Gelling Agent
HYG-3	1 lbs	20 lbs	pH Buffer
BE-5	0.4 gals	8 gals	Bactericide
Losurf 357	1.0 gals	20 gals	Surfactant
BA50	5.4 lbs	108 lbs	Crosslinking Agent
MO-67	1.0 gals	24 gals	Activator
K-38	4.5 lbs	68 lbs	Crosslinker
SP Breaker	0 - 5 lbs	10 lbs	Breaker
Optiflo III	5 - 2 lbs	60 lbs	Delayed Release Breaker
Cla Sta XP	5.0 gals	20 gals	Clay Control

Note:

1. MO-67 is to be added on the fly.
2. Optiflo III breaker to be added during the mini-frac, the pad and the proppant laden fluid.
3. SP Breaker to be added to the proppant laden fluid.
4. Cla Sta XP to be run in the mini frac x-linked fluid

EAST MEREENIE 41

FRACTURING WORK STRING MATERIALS LIST

FRACTURE WORK STRING

SOURCE	DESCRIPTION
Howco	Halliburton treating head 3" NPT pin
Mereenie	X-Over 2-7/8" EUE pin x 3" NPT box
Mereenie	162 joints 2-7/8" N-80 6.5 lb/ft tubing EUE
Mereenie	2 each 5-1/2" Baker AL-2 45-B Lok-Set packer. 2-7/8" box x pin EUE. Make sure spare is available.
Mereenie	1 pre-perforated joint. 2-7/8" EUE tubing C/W 62 ¾" holes + 60½" holes
Mereenie	1 joint 2-7/8" EUE tubing 6.5 lb/ft
Mereenie	Crossover 2-7/8" EUE box 2-3/8" EUE pin
Mereenie	1 2-3/8" OTIS XN profile 2-3/8" EUE box pin
Mereenie	2 2-3/8" EUE collar
Mereenie	1 joint 2-3/8" 4.7 # EUE tubing
Mereenie	2-3/8" EUE wireline re-entry guide

Note: Ensure all crossovers are minimum 1.99" drift diameter.

EAST MEREENIE 41

PRODUCTION STRING

SOURCE	DESCRIPTION
EM 41	Tubing hanger 2-3/8" EUE top and bottom
EM 41	156 joints 2-3/8" 4.7# J55 EUE tubing
EM 41	1 x 2-3/8" Otis 121XA sliding sleeve
EM 41	1 joint 2-3/8" 4.7# J55 EUE J55 tubing
Mereenie	1 x 5-1/2" Baker FH Hydraulic Retrievable Packer, 2-3/8" EUE box and pin
EM 41	4 x joint 2-3/8" 4.7# J55 EUE J55 tubing
Mereenie	1 x 2-3/8" Baker CMD Sliding Sleeve c/w Otis "X" profile
EM 41	1 x 4' pup joint 2-3/8" 4.7# J55 EUE tubing
Mereenie	1 x Baker DB Packer Size 44-26, 5-1/2" casing, 3-1/2" NU box down
Mereenie	1 x Baker Mill Out Extension
Mereenie	1 x swage 3-1/2" NU box x 2-3/8" EUE pin
EM 41	1 4' pup joint 2-3/8" 4.7# J55 EUE tubing
EM 41	Otis 2-3/8" EUE "XN" Nipple
Mereenie	2-3/8" Wireline Re-entry Guide

M0590018

EAST MEREENIE 41
PROGRAM APPROVAL

Prepared By: .... Date 27/8/96 ....

P B Lansom
Senior Reservoir Engineer

Reviewed By: .... Date 28/8/96 ....

S M Liddle
Staff Petroleum Engineer

Reviewed By: .... Date 28/8/96 ....

D C Reeve
Supervising Chief Petroleum Engineer

Approved By: .... Date 2/9/96 ....

A F Mayers
Manager - Petroleum Engineering & Drilling

M0590019

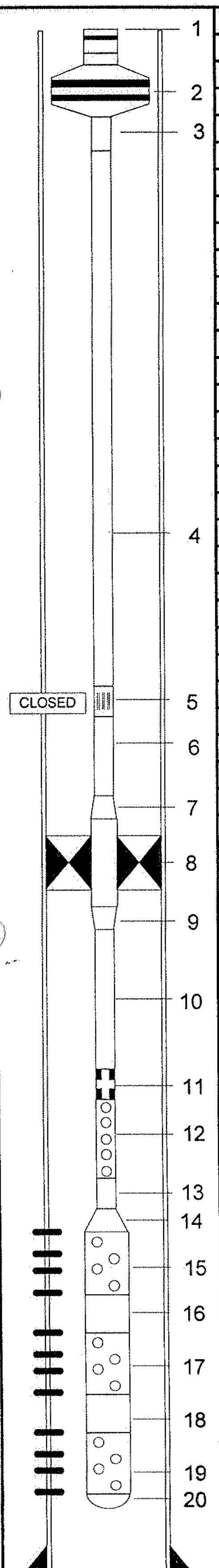
Figure 1

PETROLEUM ENGINEERING DEPARTMENT

DOWNHOLE 2-3/8" TCP SINGLE REPERFORATION

Santos

WELL: **EAST MEREENIE 41** DATE: 04 Aug 96



PBTD - 1,558.8m KB DRILLER

ITEM No.	DESCRIPTION	LENGTH (m)	DEPTH KB (m)	MIN ID (in)
1	KB TO TOP OF TUBINGHEAD SPOOL	4.97		
2	KVAERNER NATIONAL 2-3/8" EUE TUBING HANGER	0.25	4.97	
3	1 PUP JOINT 2-3/8" 4.7# J55 EUE TUBING	2.36	5.22	**1.990**
4	151 JOINTS 2-3/8" 4.7# J55 EUE TUBING	1,430.38	7.58	
5	BAKER 2-3/8" EUE CMD SLIDING SLEEVE (CLOSED)	1.18	1,437.96	**1.875**
6	1 JOINT 2-3/8" 4.7# J55 EUE TUBING	9.48	1,439.14	PIP
7	CROSSOVER 2-3/8" EUE BOX x 2-7/8" PIN	0.22	1,448.62	
8	BAKER 2-7/8" x 5-1/2" AL-2 LOCKSET PACKER 15# - 20#	1.40	1,448.84	
9	CROSSOVER 2-7/8" EUE BOX x 2-3/8" PIN	0.24	1,450.24	
10	1 JOINT 2-3/8" 4.7# J55 EUE TUBING	9.48	1,450.48	
11	OTIS 2-3/8" EUE 11XN LANDING NIPPLE	0.37	1,459.96	**1.791**
12	1 PERFORATED PUP JOINT 2-3/8" 4.7# J55 EUE TUBING	3.05	1,460.33	
13	SCHLUMBERGER 3-3/8" OPEN SYSTEM FIRING HEAD	0.56	1,463.38	**NO-GO**
14	SCHLUMBERGER 3-3/8" SAFETY SPACER	2.56	1,463.94	
15	SCHLUMBERGER 3-3/8" TCP GUN	8.00	1,466.50	
16	SCHLUMBERGER 3-3/8" EMPTY GUN SPACE	2	1,474.50	
17	SCHLUMBERGER 3-3/8" TCP GUN	9	1,476.50	
18	SCHLUMBERGER 3-3/8" EMPTY GUN SPACE	13.00	1,485.50	
19	SCHLUMBERGER 3-3/8" TCP GUN	13.00	1,498.50	
20	SCHLUMBERGER 3-3/8" EMPTY GUN SPACE AND BULL NO	0.20	1,511.50	
	BOTTOM OF PERFORATING GUNS		1,511.70	

PERFORATION INTERVALS

FORMATION	INTERVAL (m KB)	GUN SIZE	GUN TYPE	CHARGES SPF	CHARGES TYPE	CHARGES WT(g)
PACOOTA P3 - 190	1,466.5 - 1,474.5	3.67	TCP	5	RDX	34
PACOOTA P3 - 230/250	1,476.5 - 1,485.5	3.67	TCP	5	RDX	34
PACOOTA P4	1,498.5 - 1,511.5	3.67	TCP	5	RDX	34

REMARKS:	String weight includes 4,000 lb for travelling block assembly
ANNULUS FLUID:	Weathered crude
INDICATED STRING WEIGHT:	22,000 lb
CALCULATED STRING WEIGHT:	22,000 lb
SLACK-OFF WEIGHT:	3,000 lb
TENSION:	

M0590020

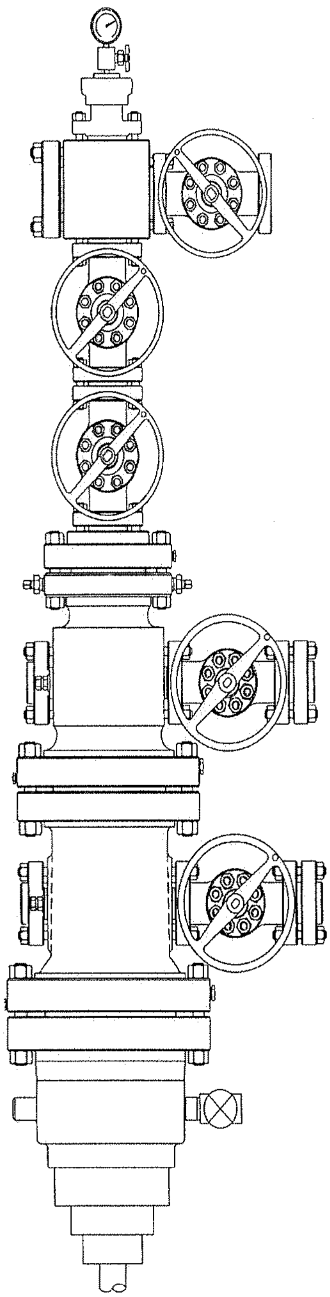
NOT TO SCALE	WELLSITE SUPERVISOR		I. FENDLEY
PROPOSED:	INSTALLATION	DATE:	04 Aug 96
RE-COMPLETION: YES	DRAFTED:	DATE:	
COMPLETION:	REVISED:	DATE:	
CHECKED BY	BRIS:	BRIS:	

Figure 2

PETROLEUM ENGINEERING DEPARTMENT
SINGLE WELLHEAD AS INSTALLED

Santos

WELL: **EAST MEREENIE # 41** **DATE:** **9 Aug 96**



DESCRIPTION			
TREE CAP	MAKE/TYPE		Kvaerner National
	SIZE/RATING		2-1/16" 3000#
	LIFT THREAD		2-3/8" EUE 8RD
	FITTINGS		1-1/2" Reducer AG Valve Gauge
FLOW CROSS	MAKE		
	SIZE		2-1/16" x 2-1/16" x 2-1/16"
	RATING		500 MTL Class EE
	OUTLET	FITTINGS	
	WING VALVE	MAKE	Kvaerner National
		TYPE	BHEL
		SIZE	2-1/16"
		RATING	5000 psi
		TRIM	N-1
UPPER MASTER VALVE	MAKE		Kvaerner National
	TYPE		BHEL
	SIZE		2-1/16"
	RATING		5000 psi
	TRIM		N-1
LOWER MASTER VALVE	MAKE		Kvaerner National
	TYPE		BHEL
	SIZE		2-1/16"
	RATING		5000 psi
	TRIM		N-1
ADAPTOR FLANGE	MAKE/TYPE		Kvaerner National
	SIZE/RATING		7-1/16" 3000 x 2-1/16" 5000
TUBING SPOOL	MAKE/TYPE		Kvaerner National DP70
	SIZE/RATING		11" 3000 x 7-1/16" 3000
	OUTLET 1	VALVE	2-1/16" 3000 Gate Valve c/w
		FITTINGS	2" NPT Companion Flange
	OUTLET 2	FITTINGS	1-1/2" VR Plug
*CASING SPOOL	MAKE/TYPE		Kvaerner National KSB
	SIZE/RATING		13-5/8" 3000 x 11" 3000
	OUTLET 1	VALVE	2-1/16" x 3000# Gate Valve
		FITTINGS	1-1/2" VR Plug
	OUTLET 2		Companion Flange tapped to 1/2" NPT
CASING BOWL	MAKE/TYPE		Kvaerner National NSB
	SIZE/RATING		13-5/8" 3000 x 13-3/8" 8RD
	OUTLET 1	VALVE	2" Ball Valve
	OUTLET 2	FITTINGS	2" Bull Plug
SURF CSG	SIZE/WT/GR/THD/DEPTH		10-3/4" 40.5# H40 / K55 8 Rd 721m
*INT CSG	SIZE/WT/GR/THD/DEPTH		N/A
PROD CSG	SIZE/WT/GR/THD/DEPTH		5-1/2" 17# L80 8 Rd 1,667m
TUBING	SIZE/WT/GR/THD/JTS		2-3/8" 4.7# J55 EUE 156 jts
TUBING HANGER	MAKE/TYPE		Kvaerner National
	LIFT THD./BPV PREP.		2-3/8" EUE / CIW BPV PREP.
REMARKS	STRING WT.	INDICATED	22,000 lb
		CALCULATED	22,000 lb
		SLACKOFF WT.	22,000 lb
		OTHER	

* Intermediate casing installed?
NO

AUTHOR: I. Fendley	DRAFTED: I. Fendley	DATE DRAWN: 9 Aug 96

M0590021

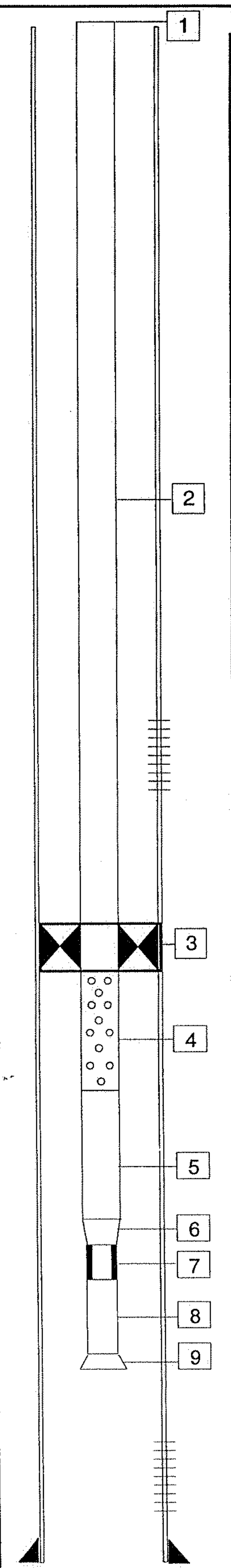
Figure 3

PETROLEUM ENGINEERING DEPARTMENT

Santos

P4 - FRACTURE STIMULATION TREATING STRING

WELL: EAST MEREENIE # 41 **DATE:** 27/8/96



PBTD - 1558.8 m KB

ITEM No.	DESCRIPTION	LENGTH (m)	DEPTH KB (m)	MIN. ID. (in)
1	K.B. to top of 2-7/8" EUE tubing	1.83	0.00	
2	154 Jts. 2-7/8" 6.5# N80 EUE Tubing	1490.00	1.83	2.347
3	5-1/2" x 2-7/8" Baker AL-2 Lockset packer	1.38	1491.83	2.347
4	1 joint 2-7/8" 6.5# N80 EUE Perforated Tubing	9.65	1493.21	2.347
5	1 8' pup joint 2-7/8" 6.5# N80 EUE Tubing	2.44	1502.86	2.347
6	2-7/8" x 2-3/8" cross-over	0.32	1505.30	1.901
7	2-3/8" Otis XN nipple	0.38	1505.62	1.791
8	1 4' pup joint 2-3/8" J55 4.7# EUE Tubing	1.22	1506.00	1.901
9	2-3/8" EUE Re-entry guide	0.31	1507.22	1.901
			1507.53	

PERFORATION INTERVALS:

FORMATION	INTERVAL (M - KB)	GUN: SIZE	GUN: TYPE	CHARGES: SPF	CHARGES: TYPE	CHARGES: WT(g)
PACOOTA P3-190	1466.5 - 1474.5 M	3 2/3	TCP	5	RDX	34
PACOOTA P3-230/250	1476.5 - 1485.5 M	3 2/3	TCP	5	RDX	34
PACOOTA P4	1498.5 - 1511.5 M	3 2/3	TCP	5	RDX	34

REMARKS:

ANNULUS FLUID:

INDICATED STRING WEIGHT:

CALCULATED STRING WEIGHT:

SLACK-OFF WEIGHT:

TENSION:

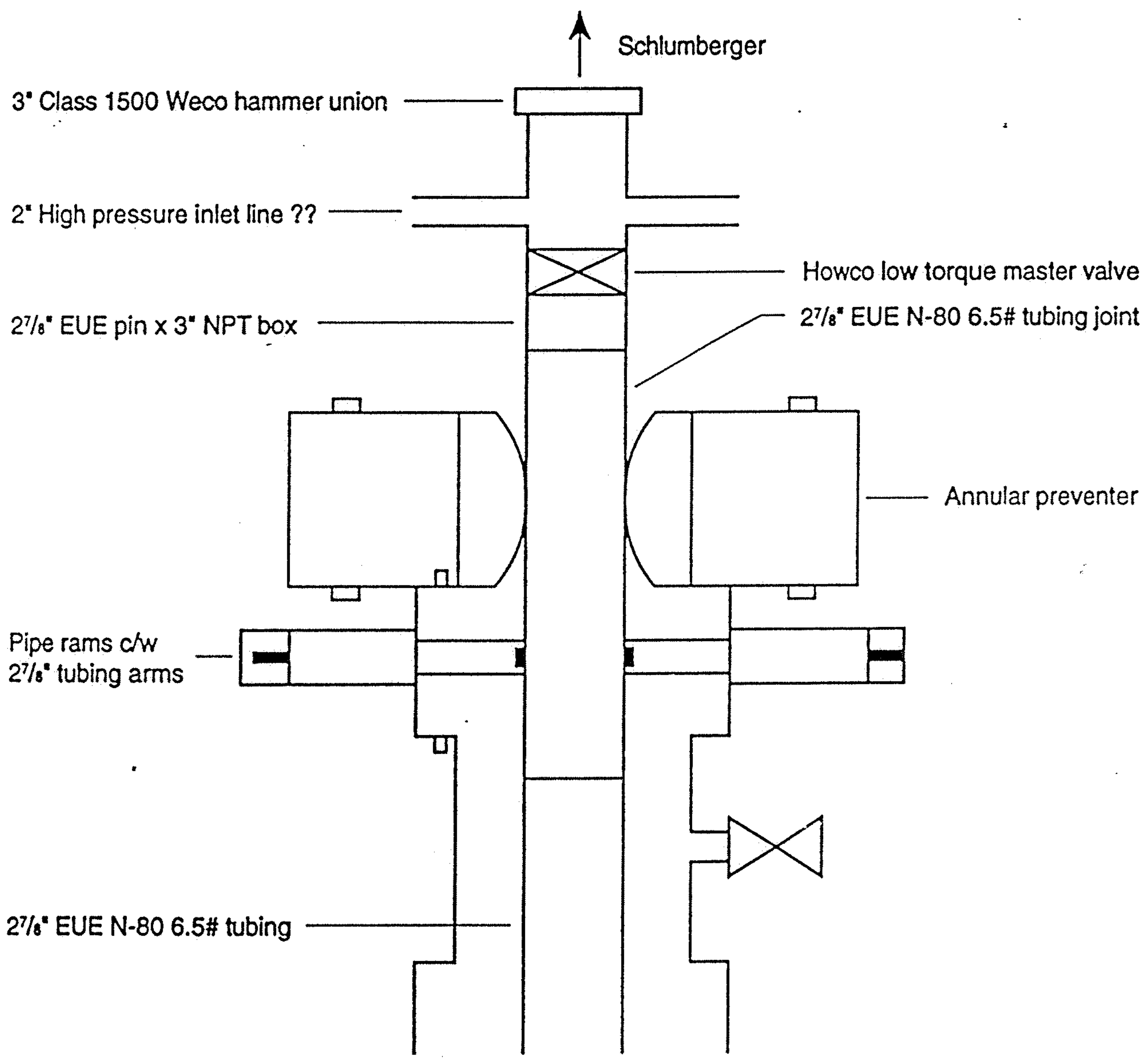
NOT TO SCALE		WELLSITE SUPERVISOR	I. Fendley
PROPOSED:	YES	DATE OF INSTALLATION	
RE-COMPLETION:		DRAFTED: P. Lansom	DATE: 27/8/96
COMPLETION:		REVISED:	DATE:
OTHER:			

M0590022

Santos PETROLEUM ENGINEERING DEPARTMENT & DRILLING GROUP Figure 4

SURFACE WELLHEAD MANIFOLD FOR FRACTURE STIMULATION

WELL: EAST MEREENIE # DATE OF INSTALLATION: SEP 96



M0590023

NOTE - DRAWING IS NOT TO SCALE

AUTHOR: A. Papinczak DRAFTED: T. Luscombe DATE DRAWN: 25/8/94

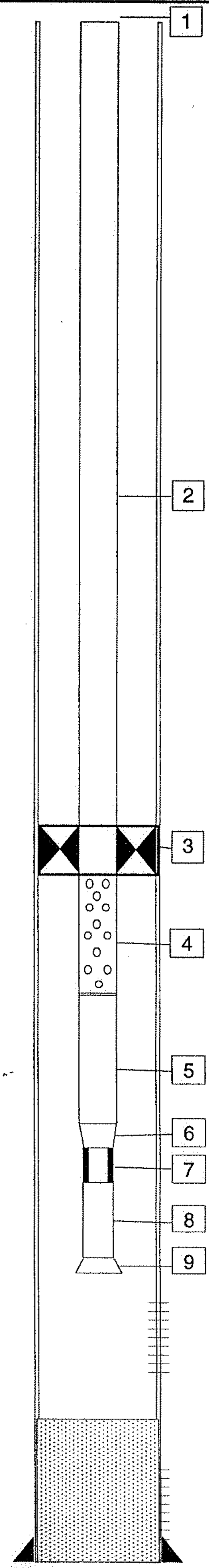
Figure 6

PETROLEUM ENGINEERING DEPARTMENT

Santos

UPPER P3 - FRACTURE STIMULATION TREATING STRING

WELL: EAST MEREENIE # 41 **DATE:** 27/8/96



PBTD - 1558.8 m KB
DRILLER

ITEM No.	DESCRIPTION	LENGTH (m)	DEPTH KB (m)	MIN. ID. (in)
1	K.B. to top of 2-7/8" EUE tubing	1.83	0.00	
2	149 Jts. 2-7/8" 6.5# N80 EUE Tubing	1437.85	1.83	2.347
3	5-1/2" x 2-7/8" Baker AL-2 Lockset packer	1.38	1439.68	2.347
4	1 joint 2-7/8" 6.5# N80 EUE Perforated Tubing	9.65	1441.06	2.347
5	1 8' pup joint 2-7/8" 6.5# N80 EUE Tubing	2.44	1450.71	2.347
6	2-7/8" x 2-3/8" cross-over	0.32	1453.15	1.901
7	2-3/8" Otis XN nipple	0.38	1453.47	1.791
8	1 4' pup joint 2-3/8" J55 4.7# EUE Tubing	1.22	1453.85	1.901
9	2-3/8" EUE Re-entry guide	0.31	1455.07	1.901
			1455.38	

PERFORATION INTERVALS:

FORMATION	INTERVAL (M - KB)	GUN: SIZE	GUN: TYPE	CHARGES: SPF	CHARGES: TYPE	CHARGES: WT(g)
PACOOTA P3-190	1466.5 - 1474.5 M	3 2/3	TCP	5	RDX	34
PACOOTA P3-230/250	1476.5 - 1485.5 M	3 2/3	TCP	5	RDX	34
PACOOTA P4	1498.5 - 1511.5 M	3 2/3	TCP	5	RDX	34

REMARKS:
ANNULUS FLUID:
INDICATED STRING WEIGHT:
CALCULATED STRING WEIGHT:
SLACK-OFF WEIGHT:
TENSION:

NOT TO SCALE		WELLSITE SUPERVISOR	I. Fendley
PROPOSED:	YES	DATE OF INSTALLATION	
RE-COMPLETION:		DRAFTED: P. Lansom	DATE: 27/8/96
COMPLETION:		REVISED:	DATE:
OTHER:			

M0590024

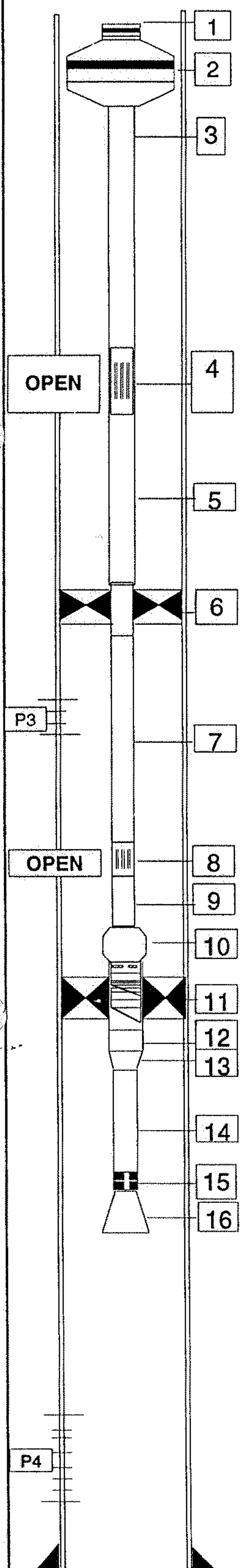
Figure 7

Santos PETROLEUM ENGINEERING DEPARTMENT

ACN 007 550 923

DOWNHOLE 2-3/8" TANDEM COMPLETION

WELL: EAST MEREENIE 41 **DATE:** 27/8/96



ITEM No.	DESCRIPTION	LENGTH (M)	DEPTH (M)	MIN ID (in)
1	K.B. TO TOP OF TUBINGHEAD SPOOL	4.98		
2	KVAERNER NATIONAL 2-3/8" EUE TUBING HANGER	0.35	4.98	
3	148 X JOINTS 2-3/8" 4.7# J55 EUE TUBING	1432.00	5.33	
4	1 X 2-3/8" EUE OTIS SLIDING SLEEVE (DOWN TO OPEN)	0.88	1437.33	
5	1 X JOINT 2-3/8" 4.7# J55 EUE TUBING	9.65	1438.21	
6	1 X 2-3/8" X 5-1/2" BAKER FH PKR 15# TO 20# EUE	1.80	**1447.86**	
7	4 X JOINT 2-3/8" 4.7# J55 EUE TUBING	38.60	1449.66	
8	1 X BAKER 2-3/8" EUE CMD SLIDING SLEEVE WITH 'X' PROFILE	0.88	1488.26	
9	1 X 4' PUP JOINT 2-3/8" 4.7# J55 EUE	1.22	1489.14	
10	2-3/8" BAKER G22 LOCATOR SEAL ASSEMBLY SIZE 44-26 2-3/8" EUE BOX X 1/2 MULESHOE, W/- 2 'V-RYTE' SEAL UNITS	0.49	1490.36	
11	5-1/2" BAKER DB PACKER SIZE 44-26 F/- 13-17 # CASING , 90 DURO PACKING ELEMENT, 3-1/2" NU BOX DOWN	1.19	**1490.85**	
12	BAKER MILL OUT EXTENSION 3-1/2" NU PIN X PIN	1.65	1492.04	
13	SWAGE 3-1/2" NU BOX X 2-3/8" EUE PIN	0.54	1493.69	
14	1 4' PUP JOINT TUBING 2-3/8" 4.7# J55 EUE	1.22	1494.23	
15	1 X OTIS 2-3/8" EUE 11XN LANDING NIPPLE	0.39	1495.45	
16	1 X 2-3/8" WIRELINE RE-ENTRY GUIDE	0.18	1495.84	
	BOTTOM OF ASSEMBLY		1496.02	

PERFORATION INTERVALS:

FORMATION	INTERVAL (M / KB)	GUN: SIZE	TYPE	CHARGES: SPF	TYPE	WT(g)
PACOOTA P3-190	1466.5 - 1474.5 M	3 2/3	TCP	5	RDX	34
PACOOTA P3-230/250	1476.5 - 1485.5 M	3 2/3	TCP	5	RDX	34
PACOOTA P4	1498.5 - 1511.5 M	3 2/3	TCP	5	RDX	34

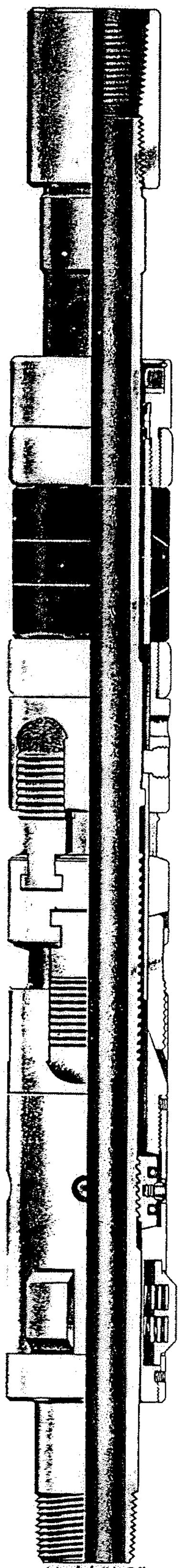
REMARKS:
ANNULUS FLUID:
INDICATED STRING WEIGHT:
CALCULATED STRING WEIGHT:
SLACK-OFF / TENSION:

NOT TO SCALE	WELLSITE SUPERVISOR	I FENDLEY
PROPOSED: YES	DATE OF INSTALLATION	
RE-COMPLETION:	DRAFTED: PETER LANSOM	DATE: 27/8/96
COMPLETION:	REVISED:	DATE:
OTHER:	CHECKED (JX):	DATE:
	CHECKED (BRIS):	DATE:

P.B.T.D. 1558.8 M KB DRILLER

M0590025

M0590026



Model "A-3" Lok-Set Retrievable Casing Packer

MODEL "A-3"™ LOK-SET® RETRIEVABLE CASING PACKER

Product No. 646-30

The "Lok-Set" combines features of both permanent and retrievable packers in one general purpose packer for production, injection, zone isolation and remedial operations.

MODEL "AL-2"™ LARGE-BORE LOK-SET RETRIEVABLE CASING PACKER

Product No. 646-28

The "AL-2 Lok-Set" is similar to the "A-3" and is recommended when a larger-than-normal bore through the packer is required.

FEATURES/BENEFITS

- "Lok-Set" holds pressure from above and below without requiring any set-down weight, tubing tension or hydraulic hold downs to maintain its pack-off.
- May be used to isolate bad casing and can serve as a tubing anchor when tension is applied as in pumping wells. In water-flood applications where seasonal temperature changes in injection water can cause problems for conventional packers, the "Lok-Set" permits the tubing to be set in a neutral condition.
- Opposed, non-transferring, dovetail slips prevent movement of the packer in either direction due to pressure differentials, while allowing the landing of the tubing in tension compression or neutral.
- Right-hand tubing rotation controls setting and releasing.
- Releaseable lock ring provides a no-return, ratchet takeup for holding compression of packing elements after pack-off. The lock can be released only by right-hand rotation of the mandrel. Left and right-hand multiple threads on the mandrel engage the segmented lock ring and permit movement of the mandrel in one direction only, relative to the lock ring. Movement in the opposite direction is possible only by rotating to the right.
- Ratchet takeups of 1/8-inch in the packer threads assure a complete pack-off.

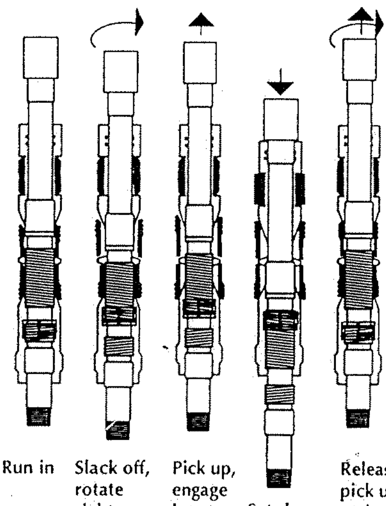
ACCESSORIES

On-Off Sealing Connector (Prod. No. 684-15)
Downhole Shut-off Valve (Prod. No. 684-10)

TO SET THE PACKER: Slacking off during right-hand rotation of the tubing causes the mandrel to move downward to free the slips and initiate setting. An initial 6,000 lb (2669 daN) set-down weight sets the upper slips and begins compression of the packing element. Then, 10,000 (4448 daN) to 12,000 lb (5338 daN) of upstrain engages the lower slips. Setting down 6,000 lb (2669 daN) to 10,000 lb (4448 daN) moves the mandrel through the lock ring to complete and lock-in the pack-off. If sufficient set-down weight is not available, left-hand rotation or spudding can be used to attain required pack-off force.

TO RELEASE THE PACKER: Apply an upstrain of 3,000 lb (1334 daN) to 6,000 lb (2669 daN) and rotate the tubing to the right from eight to ten turns at the tool, until the tool moves up the hole. Continue to rotate to the right several times while moving up the hole to be certain the slips are fully retracted.

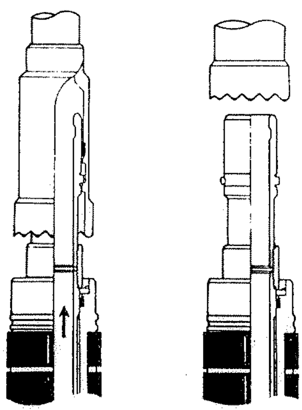
ORDERING EXAMPLE:
PRODUCT NO. *646-30*
SIZE: 47B4; THREAD & WT UP: 2-7/8 O.D. 6.4 lb/ft E.U. Box, yes (Baker equivalent acceptable?); THREAD & WT DOWN: 2-7/8 O.D. 6.4 lb/ft E.U. Pin, yes (Baker equivalent acceptable?) PACKING ELEMENT: 90-70-90 Nitrile; MATERIAL: Standard (Low Alloy Steel 36Rc Standard); COATING: PA-400 internal (internal/external), yes (Baker equivalent acceptable?); QTY: 5



MODEL "FL-22"™ ON-OFF SEALING CONNECTOR

Product No. 684-15

Use of an On-Off Sealing Connector above a Lok-Set Packer is a very effective and popular combination. This hook-up permits retrieval of the tubing string with the formation blanked-off at the packer by setting a BFC Blanking Plug in the On-Off tools standard seating nipple profile. The On-Off tool also facilitates circulation of well fluids above the packer. Due to right-hand operation of the Lok-Set Packer, the "FL-22" Model (Left-hand off) On-Off tool is recommended.



MODEL "D" RETAINER PRODUCTION PACKER SPECIFICATION GUIDE

Casing O.D. In. / mm	Casing Weight[C] Lb/ft	I.D. Range in Which Packer May Be Run: Min In. / mm	I.D. Range in Which Packer May Be Run: Max In. / mm	Packer[A] Size[D]	Packer Max O.D. In. / mm	Packer Diameter of Sealing Bore In. / mm	Seal Assembly[B] Size	Min Bore Thru Seals[E] In.	Min Bore Thru Seals[E] mm
4-1/2[F] 114,30	17.7-20.0	3.600 91,44	3.696 93,88	19-25	3.475 88,27	2.500 63,50	20-25	1.865	47,37
	15.1-17.1	3.697 93,90	3.826 97,18	21-25	3.562 90,47				
	11.6-15.1	3.781 96,04	4.000 101,60	22-19	3.593 91,26	1.968 49,99	21-19	1.312	33,32
							20/40-19	.984	24,99
	9.5-13.5	3.920 99,57	4.090 103,89	23-26[G]	3.750 95,25	2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
	9.5-11.6	4.000 101,60	4.124 104,75	24-19	3.812 96,82	1.968 49,99	21-19	1.312	33,32
							20/40-19	.984	24,99
5 127,00	15-21	4.125 104,78	4.436 112,67	32-26[G]	3.968 100,79	2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
				32-25		2.500 63,50	20-25	1.865	47,37
				32-19		1.968 49,99	21-19	1.312	33,32
							20/40-19	.984	24,99
	11.5-13	4.437 112,70	4.670 118,62	34-26[G]	4.250 107,95	2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
				34-25		2.500 63,50	20-25	1.865	47,37
5-1/2 139,70	23-26			34-19		1.968 49,99	21-19	1.312	33,32
							20/40-19	.984	24,99
	20-23	4.625 117,48	4.811 122,20	42-26	4.328 109,93	2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
				42-19		1.968 49,99	21-19	1.312	33,32
							20/40-19	.984	24,99
	13-17	4.812 122,22	5.044 128,12	44-26	4.500 114,30	2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
				44-19		1.968 49,99	21-19	1.312	33,32
							20/40-19	.984	24,99
6 152,40	14-23	5.140 130,56	5.552 141,02	64-30	4.937 125,40	3.000 76,20	42/62-30	2.375	60,33
							40/80-30	1.970	50,04
6-5/8 168,28	24-32	5.540 140,72	5.921 150,39	81-32	5.350 135,89	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
	17-32	5.675 144,14	6.135 155,83	82-32	5.468 138,89		60/80-32	2.406	61,11
							61/81-32	1.990	50,55
				82-26		2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
	17-20	6.049 153,64	6.366 161,70	84-32	5.687 144,45	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
				84-26		2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
7 177,80	38-49.5	5.540 140,71	5.921 150,39	81-32	5.350 135,89	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
	32-44	5.675 144,15	6.135 155,83	82-32	5.468 138,89		60/80-32	2.406	61,11
							61/81-32	1.990	50,55
				82-26		2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
	23-32	8.049 153,64	6.366 161,70	84-32	5.687 144,45	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
				84-26		2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
	20-29	6.184 157,07	6.456 163,98	86-32	5.875 149,22	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
	17-20	6.456 163,98	6.765 171,83	88-32	6.187 157,15		60/80-32	2.406	61,11
							61/81-32	1.990	50,55
				88-26		2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45

Casing O.D. In. / mm	Casing Weight[C] Lb/ft	I.D. Range in Which Packer May Be Run: Min In. / mm	I.D. Range in Which Packer May Be Run: Max In. / mm	Packer[A] Size[D]	Packer Max O.D. In. / mm	Packer Diameter of Sealing Bore In. / mm	Seal Assembly[B] Size	Min Bore Thru Seals[E] In.	Min Bore Thru Seals[E] mm
7-5/8 193,68	45.3-52.8	6.184 157,07	6.456 163,98	86-32	5.875 149,22	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
	33.7-39	6.456 163,98	6.765 171,83	88-32	6.187 157,15	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
				88-26		2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
	24-33.7	6.706 170,33	7.025 178,44	92-32	6.375 161,93	3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
				92-26		2.688 68,28	40/80-26	1.968	49,99
							41/81-26	1.750	44,45
8-5/8 219,08	36-49	7.500 190,50	7.825 198,76	126-38	7.125 180,98	3.875/98,43	120-38	2.468	62,69
				126-40		4.000/101,60	80-40	2.985	75,82
	24-36	7.812 198,42	8.150 207,01	128-38	7.600 190,50	3.875/98,43	120-38	2.468	62,69
				128-40		4.000/101,60	80-40	2.985	75,82
9-5/8 244,48	36-53.5	8.438 214,33	9.001 228,63	194-47	8.125 206,38	4.750 120,65	192-47	3.875	98,43
							190-47	3.000	76,20
							191-47	2.500	63,50
				194-40		4.000	80-40	2.985	75,82
				194-32		3.250 82,55	60/80-32	2.406	61,11
							61/81-32	1.990	50,55
10-3/4[H][J] 273,05	60.7-81	9.250 234,95	9.660 245,36	212-47	9.000 228,60	4.750 120,65	190-47 191-47 or 192-47	3.000 2.500 3.875	76,20 63,50 98,43
				212-32		3.250 82,55	80-32 or 81-32	2.406 1.990	61,11 50,55
	32.75-60.7	9.660 245,36	10.192 258,88	214-47	9.437 239,70	4.750 120,65	190-47 191-47 or 192-47	3.000 2.500 3.875	76,20 63,50 98,43
				214-32		3.250 82.55	80-32 or 81-32	2.406 1.990	61,11 50,55
11-3/4[H][J] 298,45	38-60	10.772 273,61	11.150 283,21	220-47	10.437 265,10	4.750 120.65	190-47 191-47 or 192-47	3.000 2.500 3.875	76,20 63,50 98,43
				220-32		3.250 82.55	80-32 or 81-32	2.406 1.990	61,11 50,55
13-3/8[H][J] 339,73	68-102	11.889 301,98	12.464 316,59	230-60	11.562 293,67	6.000 152,40	190-60	4.875	123,83
				230-47		4.750 120,65	190-47 191-47 or 192-47	3.000 2.500 3.875	76,20 63,50 98,43
				230-32		3.250 82,55	80-32 or 81-32	2.406 1.990	61,11 50,55
	48-72	12.175 309,25	12.715 322,96	240-60	12.000 304,80	6.000 152,40	190-60	4.875	123,83
				240-47		4.750 120,65	190-47 191-47 or 192-47	3.000 2.500 3.875	76,20 63,50 98,43
				240-32		3.250 82,55	80-32 or 81-32	2.406 1.990	61,11 50,55

(A) For information on packer or accessory sizes not found in this specification guide, refer to Baker Technical Manual or contact your Baker Representative.
(B) Tubing seal assemblies, tubing seal and spacer nipples.
(C) Includes some drill pipe and line pipe weights.
(D) When proposed for use in other than the casing weight range shown, contact your Baker Representative.
(E) Minimum bore applicable to standard Models "G", "E" and "K" Seal Assemblies only. Not applicable to Models "L", "M", and "N" Seal Assemblies with K-RYTE and R-RYTE Seals which may have reduced ID's.
(F) In 4-1/2" OD 11.6 lb/ft and heavier casing, the size 20 Wireline Pressure Setting Assembly is too large and the size 10 WLPSA must be used. In 4-1/2" 9.5 and 10.5 lb/ft casing, either the size 10 or 20 WLPSA may be used.
(G) Furnished as Prod. 415-05 and 415-13 only. These sizes have steel bodies.
(H) Packers for Sizes 10-3/4" and larger casing should be run and set on a hydraulic setting tool. Products 413-70, 413-71, 413-72, 415-70, 415-72, 415-74 or 437-12.
(J) Packers for these sizes of casing are also available with other size seal bores on special order.

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MODEL "A-3" LOK-SET RETRIEVABLE CASING PACKER PROD. NO. 646-30 SPECIFICATION GUIDE

Casing OD In. mm	Weight[B] Lb/ft	ID Range In Which Packer May Be Run Min In. mm	ID Range Max In. mm	Packer Size	Nom ID In. mm	Max Gage Ring OD In. mm	Standard Thread Specification[A] (Box Up x Pin Down) In. mm
4 101,60	9.5—12.9	3.340 94,83	3.548 90,12	41A2	1.500 38,10	3.244 82,40	2-3/8 OD EU 8RD 60,33
4-1/2 144,30	21.6—23.6						
4 101,60	9.5	3.548 82,40	3.640 92,46	41A4		3.423 112,35	
4-1/2 114,30	18.8 13.5—17.7	3.696 93,79	3.920 99,57	41B		3.578 90,88	
	11.6—13.5	3.910 99,31	4.000 101,6	43A2	1.978 50,24	3.786 96,16	2-3/8 OD EU 8 RD x NU 10 RD 60,33
	9.5—10.5	4.001 101,6	4.090 103,9	43A4			
5 127,00	15—18	4.250 108,0	4.408 112,0	43B		4.140 105,16	
	11.5—15	4.408 112,0	4.560 115,8	43C		4.265 108,33	
5-1/2 139,70	26 20—23	4.635 117,5	4.778 121,4	45A2		4.515 114,68	2-3/8 OD EU 8 RD 60,33
	15.5—20	4.778 121,4	4.950 125,7	45A4		4.656 118,26	
	13—15.5	4.950 125,7	5.190 131,9	45B		4.796 121,82	
6 152,40	26 20—23	5.191 131,9	5.390 136,9	45C		5.078 128,98	
	15—18	5.391 136,9	5.560 141,2	45D		5.171 131,34	
6-5/8 168,28	34	5.561 141,2	5.609 142,5	45E		5.421 137,69	
	24—32	5.610 142,5	5.921 150,4	45F		5.499 139,67	
	24	5.830 148,1	5.937 150,8	47A2	2.441 62,00	5.671 144,04	2-7/8 OD EU 8 RD 73,03
	17—24	5.922 150,4	6.135 155,8	45G	1.978 50,24	5.796 147,22	2-3/8 OD EU 8 RD 60,33
	17—20	5.938 150,8		47A4	2.441 62,00	5.827 148,01	2-7/8 OD EU 8 RD 73,03
7 177,80	38	5.830 148,1	5.937 150,8	47A2		5.671 144,04	
	32—35	5.938 150,8	6.135 155,8	47A4		5,827 148,01	
	26—29	6.136 155,9	6.276 159,4	47B2		5.983 151,97	
	23—26	6.276 159,4	6.366 161,7	47B4		6.093 154,76	
	17—20	6.456 164,0	6.578 167,1	47C2		6.281 159,54	
7-5/8 193,68	33.7—39	6.579 167,1	6.797 172,6	47C4		6.468 164,29	
	24—29.7	6.798 172,7	7.025 178,4	47D2		6.687 169,85	
	20—24	7.025 178,4	7.125 181,0	47D4		6.827 173,41	

MODEL "A-3" LOK-SET RETRIEVABLE CASING PACKER PROD. NO. 646-30 (Cont'd) SPECIFICATION GUIDE

Casing OD In. mm	Weight[B] Lb/ft	ID Range In Which Packer May Be Run Min In. mm	ID Range Max In. mm	Packer Size	Nom ID In. mm	Max Gage Ring OD In. mm	Standard Thread Specification[A] (Box Up x Pin Down) In. mm
8-5/8 219,08	44—49	7.511 190,8	7.687 195,2	49A2	3.500 88,90	7.327 186,11	4 OD NU 8 RD 101,60
	32—40	7.688 195,3	7.921 201,2	49A4		7.546 191,67	
	20—28	7.922 201,2	8.191 208,1	49B		7.796 198,02	
9-5/8 244,48	47—53.5	8.343 211,9	8.681 220,5	51A2		8.234 209,14	
	40—47	8.681 220,5	8.835 224,4	51A4		8.452 214,68	
	29.3—36	8.836 224,4	9.063 230,2	51B		8.608 218,64	

MODEL "AL-2" LARGE BORE LOK-SET RETRIEVABLE CASING PACKER PROD. NO. 646-28 SPECIFICATION GUIDE

Casing OD In. mm	Weight[B] Lb/ft	Packer Size	ID Range In Which Packer May Be Run Min In. mm	ID Range Max In. mm	Packer Size	Nom ID In. mm	Max Gage Ring OD In. mm	Max. Diameter of Compressed Drag Block In. mm	Thread Spec. (Box Up x Pin Down) In. mm
5-1/2 139,70	20—23	45A2 x 2-3/8	4.625 117,47	4.778 121,36	45A2	2.375 60,33	4.515 115,9	4.592 116,64	2-7/8 OD EU 8 RD 73,03
	15.5—17	45A4 x 2-3/8	4.778 121,36	4.892 124,26	45A4		4.656 118,26	4.750 120,65	
	13—15.5	45B x 2-3/8	4.950 125,73	5.190 131,82	45B		4.796 121,82	4.902 124,51	
6 152,40	26								
7 177,80	26—29	47B2 x 3.00	6.136 155,85	6.276 159,41	47B2	3.00 76,20	5.983 151,97	5.959 151,36	3-1/2 OD EU 8 RD 88,90
	23—26	47B4 x 3.00	6.276 159,41	6.366 161,77	47B4		6.093 154,76		
	17—20	47C2 x 3.00	6.456 163,98	6.578 167,08	47C2		6.281 159,54		
7-5/8 193,68	33.7—39	47C4 x 3.00	6.579 167,10	6.797 172,64	47C4		6.468 164,29	6.520 165,61	
	24—29.7	47D2 x 3.00	6.798 172,66	7.025 178,43	47D2		6.687 169,85		
	20—24	47D4 x 3.00	7.025 178,43	7.125 180,97	47D4		6.827 173,41		

(A) Threads shown below are "standard" for the respective packer sizes. Other threads are available on request. Please specify threads when ordering.

(B) When selecting a packer for a casing weight common to two weight ranges (same OD), choose the packer size shown for the lighter of the two weight ranges. Example: For 7" 26 lb/ft casing use packer size 47B4. Under certain circumstances the other packer size may be run, such as when running in mixed casing strings.

Repair Kits, including such items as packing elements, seal rings, etc. are available for redressing Baker retrievable packers. Contact your Baker Representative. Use only Baker repair parts.

BAKER OIL TOOLS
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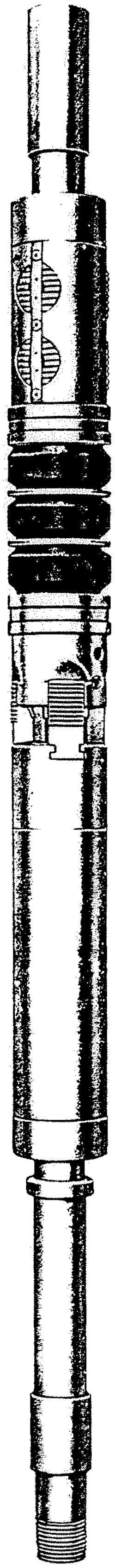
RETRIEVABLE PACKER SYSTEMS


Model "FH" Hydrostatic Single String Packer

MODEL "FH"™ HYDROSTATIC SINGLE STRING PACKER
Product No. 781-08

This packer brings to single string retrievable packers the same rugged construction and dependable hydrostatic setting that have proven outstandingly successful with the Model "A-5" Hydrostatic Dual Packer.

The "FH" can be run in single-packer installations, as the lower packer in multiple-string hookups using hydrostatic or hydraulic duals, or in tandem in single string selective zone or multiple-zone production wells. In addition to applications where displacing and setting after the well is flanged up are desirable, the hydrostatic single is ideal for deviated or crooked holes where conditions are not suitable for mechanically set packers.

MODEL "FHL"™ HYDROSTATIC SINGLE STRING PACKER
Product No. 781-20

The Model "FHL" Hydrostatic Packer is a large bore version of the "FH" Packer. Features, advantages, and operational procedures are basically the same as those described for the "FH".

MODEL "FHS"™ SELECTIVE HYDROSTATIC SINGLE STRING PACKER
Product No. 781-10

MODEL "FHSL"™ SELECTIVE HYDROSTATIC SINGLE STRING PACKER
Product No. 781-25

The Model "FHS" Selective Set Double-Grip Hydrostatic Single String Packer is a modified Model "FH" Hydrostatic Single String Packer equipped with a Selective Set Subassembly to allow (1) the tubing string to be tested prior to setting, and (2) selective setting and individual testing of any number of packers run in combination.

The Model "FHSL" Selective Set Double-Grip Large Bore Hydrostatic Single String Packer (size 47 x 2.75 and size 47 x 2.81) is a large bore version of the "FHS" Packer. Contact your Baker Representative for more information on this model.

FEATURES/BENEFITS
- Flanged up completion/no tubing manipulation required.
- Hydrostatic/hydraulic setting.
- Pack-off is mechanically locked in.
- Standard hydraulic hold downs.
- Simple upstrain shear-release or optional rotational-release.
- Multiple packing element system.

OPERATION: The Model "FH" Hydrostatic Packer is actuated by pressuring the tubing, and this is generally done in one of three ways:

(1) Dropping a ball to seat in a Baker Hydro-Trip Pressure Sub or Shear-out Ballseat Sub (Prod. No. 799-28 or 469-21) located below the packer.

(2) Use of a Baker Differential Displacing Valve (Prod. No. 759-17) provided operations will not require pressuring the tubing before the displacing valve is to be opened.

(3) Landing a BFC Blanking Plug in a BFC Seating Nipple or Sliding Sleeve below the packer (Prod. Nos. 801-50, 801-55 and 810-04). In most cases, the plug can be run, the packer set, and the plug retrieved all in one trip.

Where more than one Model "FH" Packer is to be run, only one of these plugging devices needs to be used below the lowermost packer. This arrangement will result in simultaneous setting of all the "FH" Packers when the tubing is pressured. If simultaneous setting is not desirable, shear values can be altered so the packers will set in sequence, the bottom first and the top last.

TO SET PACKER WHERE HYDROSTATIC PRESSURE IS GREATER THAN 1,500 PSI (10,34 MPa)

Run the packer to setting depth, flange up the well and displace the tubing. Using one of the methods mentioned above, plug the tubing and increase tubing pressure to approximately 1,000 psi (6,89 MPa) over annulus pressure at the packer. The shear screws will shear, exposing the setting mechanism to the hydrostatic pressure in the well. This pressure completely sets and packs-off the packer.

The Body Lock Ring mechanically locks in the set so that a drop in hydrostatic pressure can have no effect on the packer. After the packer is set, the tubing is opened by pressuring to force the tripping ball through the pressure sub or displacing valve or by retrieving the BFC plug.

TO SET PACKER WHERE HYDROSTATIC PRESSURE IS LESS THAN 1,500 PSI (10,34 MPa): The packer is dressed with additional shear screws to increase the actuating pressure to 2,000 psi (13,78 MPa); and the Hydro-Trip Pressure Sub or Shear-out Ballseat Sub is dressed to require 3,500 psi (24,12 MPa) differential to blow the ball through after the packer is set.

USING A DIFFERENTIAL DISPLACING VALVE: This valve offers distinct advantages where it is desirable to displace the tubing after the well is flanged up and the tubing sealed off in a packer below the "FH". The valve is opened and the tubing displaced, then one ball is dropped to set the packer and close the valve.

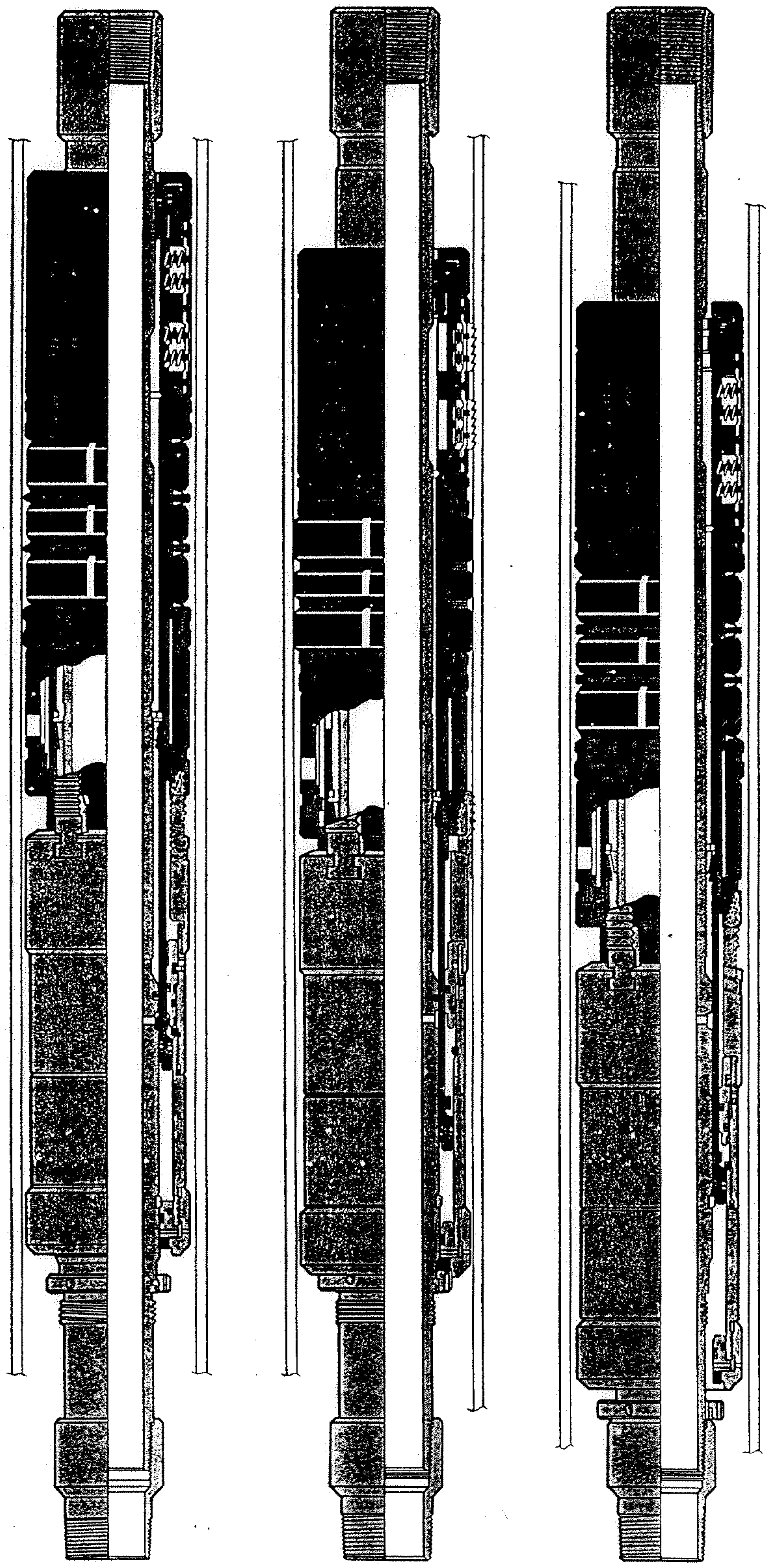
TO RELEASE THE PACKER: The standard Model "FH" Packer is equipped with a 30,000 lb (3344 daN) Shear Ring for a straight upstrain release. Other values of Shear Rings available are shown in the table below.

An alternate rotational-release is available on special order, which permits the packer to be released by taking an upstrain and rotating to the right. The rotational release has a 50,000 lb (22240 daN) [40,000 lb (17792 daN) on Size 43] straight upstrain shear-out safety release.

ORDERING EXAMPLE:
PRODUCT NO. *781-08*
SIZE: 47B2; THREAD & WT UP: 2-7/8 O.D. 6.4 lb/ft New Vam Box, N/A (Baker equivalent acceptable?)
THREAD & WT DOWN: 2-7/8 O.D. 6.4 lb/ft New Vam Pin, N/A (Baker equivalent acceptable?)
PACKING ELEMENT: 90-70-90 Nitrile
SHEAR RATING: 30,000 lbs.
MATERIAL: 41XX 22Rc (BMS-A099) Flow wetted (Low Alloy Steel 36Rc Standard); COATING: None (internal/external), N/A (Baker equivalent acceptable?); QTY: 5

SHEAR RING AVAILABILITY GUIDE

PACKER SIZE	SHEAR RATING Lb x 1,000 *daN*			
	20 *8896*	30 *13344*	40 *17792*	50 *22240*
43	X	X	X	
45	X	X	X	X
47	X	X	X	X
49	X	X	X	X
51	X	X	X	X



Running Position | Set Position | Retrieving Position

Model "FH" Hydrostatic Single String Packer Operation

M0590030

RETRIEVABLE PACKER SYSTEMS

BAKER OIL TOOLS
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SPECIFICATION GUIDE

Casing				Packer			
OD	Weight[A]	ID Range in Which Packer May be Run Min	ID Range in Which Packer May be Run Max	Size	Nom ID	Max Gage Ring OD	Standard Thread Specifications[B] Box Up & Pin Down
In. *mm*	Lb/ft	In. *mm*	In. *mm*		In. *mm*	In. *mm*	In. *mm*
4-1/2 *114,30*	9.5—13.5	3.910 *99,31*	4.090 *103,89*	43A		3.786 *95,16*	
5 *127,00*	15—18	4.250 *107,95*	4.408 *111,96*	43B		4.140 *105,16*	
	11.5-15 26	4.408 *111,96*	4.560 *115,82*	43C		4.255 *108,33*	
5-1/2 *139,70*	20—23	4.625 *117,48*	4.778 *121,36*	45A2		4.515 *114,68*	
	15.5—20	4.778 *121,36*	4.950 *125,73*	45A4	1.978 *50,24*	4.656 *118,26*	2-3 8 OD EU 8RD *60,33*
	13—15.5 26	4.950 *125,73*	5.190 *131,83*	45B		4.796 *121,82*	
6 *152,40*	20—23	5.191 *131,85*	5.390 *136,91*	45C		5.078 *128,98*	
	15—18	5.391 *136,93*	5.560 *141,22*	45D		5.171 *131,34*	
6-5/8 *168,28*	34	5.561 *141,25*	5.609 *142,47*	45E2		5.421 *137,69*	
	28—32	5.610 *142,49*	5.791 *147,09*	45E4		5.499 *139,67*	
 7 *177,80*	24—28 38	5.791 *147,09*	5.921 *150,39*	46A4	2.416 *61,37*	5.603 *142,32*	2-7 8 OD EU 8 RD *73,03*
6-5/8 *168.28*	24	5.830 *148,08*	5.937 *150,80*	47A2		5.671 *144,04*	
	17—20	5.938 *150,83*	6.135 *155,83*	47A4		5.827 *148,01*	
7 *177,80*	38	5.830 *148,08*	5.937 *150,80*	47A2	2.416 *61,37*	5.671 *144,04*	2-7 8 OD EU 8RD *73,03*
	32—35	5.938 *150,83*	6.135 *155,83*	47A4		5.827 *148.01*	
	26—29	6.136 *155,85*	6.276 *159,41*	47B2	or	5.983 *151,97*	or
	20—26	6.276 *159,41*	6.456 *163,98*	47B4		6.093 *154,76*	
	17—20	6.456 *163,98*	6.578 *167,08*	47C2		6.281 *159,54*	
7-5/8 *193,68*	33.7—39	6.579 *167,11*	6.797 *172,64*	47C4	2.000 *50,80*	6.468 *164,29*	2-3 8 OD EU 8RD *60,33*
	24—29.7	6.798 *172,67*	7.025 *178,44*	47D2		6.687 *169,85*	
	20—24	7.025 *178,44*	7.125 *180,98*	47D4		6.827 *173,41*	
8-5/8 *219,08*	44—49	7.511 *190,78*	7.687 *195,25*	49A2	3.000 *76,20* or	7.327 *186,11*	3-1/2 OD EU 8RD *88,90* or
	32—40	7.688 *195,28*	7.921 *201,19*	49A4		7.546 *191,67*	
	20—28	7.922 *201,22*	8.191 *208,05*	49B	2.416 *61,37*	7.796 *198,02*	2-7/8 OD EU 8RD *73,03* or
9-5/8 *244,48*	47—53.5	8.343 *211,91*	8.681 *220,50*	51A2	or	8.233 *209,12*	
	40—47	8.681 *220,50*	8.835 *224,41*	51A4	2.000 *50,80*	8.452 *214,68*	2-3 8 OD EU 8RD *60,33*
	29.3—36	8.836 *224,43*	9.063 *230,20*	51B		8.608 *218,64*	

MODEL "FH" HYDROSTATIC SINGLE STRING PACKER Prod. No. 781-08

[A] When selecting a packer for a casing weight common to two weight ranges (same OD), choose the packer size shown for the lighter of the two weight ranges. Example: For 7" 20 lb/ft. casing use packer size 47C2. Under certain circumstances the other packer size may be run, such as when running in mixed casing strings.

[B] Threads shown below are "standard" for the respective packer mandrel sizes. Other threads are available on request. Please specify threads when ordering.

Repair kits, including such items as packing elements, seal rings, etc., are available for redressing Baker retrievable packers. Contract your Baker Representative. Use only Baker repair parts.

SPECIFICATION GUIDE

Casing				Packer			
OD	Weight[A]	ID Range in Which Packer May be Run Min	ID Range in Which Packer May be Run Max	Size	Nom ID	Max Gage Ring OD	Standard Thread Specifications[B] Box Up & Pin Down
In. *mm*	Lb/ft	In. *mm*	In. *mm*		In. *mm*	In. *mm*	In. *mm*
6-5/8 *168,28*	24	5.830 *148,08*	5.921 *150,39*	47A2		5.671 *144,04*	
	20	5.989 *152,12*	6.094 *154,79*	47A4		5.827 *148,01*	
	17	6.135 *155,83*	6.276 *159,41*	47B2		5.983 *151,97*	
7 *177,80*	38	5,830 *148,08*	5.921 *150,39*	47A2		5.671 *144,04*	
	32-35	5.989 *152,12*	6.094 *154,79*	47A4		5.827 *148,01*	
	26-29	6.135 *155,83*	6.276 *159,41*	47B2	3.000 *76,20*	5.983 *151,97*	3-1/2 OD EU 8RD *88,90*
	20-26	6.276 *159,41*	6.456 *163,98*	47B4		6.093 *154,76*	
	17-20	6.456 *163,98*	6.578 *167,08*	47C2		6.281 *159,54*	
7-5/8 *193,68*	33.7-39	6.579 *167,11*	6.765 *171,83*	47C4		6.468 *164,29*	
	24-29.7	6.766 *171,86*	7.025 *178,44*	47D2		6.687 *169,85*	
	20-24	7.025 *178,44*	7.125 *180,98*	47D4		6.827 *173,41*	
9-5/8 *244,48*	47-53.5	8.343 *211,91*	8.681 *220,50*	51A2x 4-3/4	4.750 *120,65*	8.233 *209,12*	5-1/2 OD Long Casing *139,70*
				51A2			
	40-47	8.681 *220,50*	8.835 *224,41*	51A4	4.000 *101,60*	8.452 *214,68*	4-1/2 OD Long Casing *114,30*
	29.3-36	8.836 *224,43*	9.063 *230,20*	51B		8.608 *218,64*	

MODEL "FHL" HYDROSTATIC SINGLE STRING PACKER Prod. No. 781-20

M0590031

[A] When selecting a packer for a casing weight common to two weight ranges (same OD), choose the packer size shown for the lighter of the two weight ranges. Example: For 7" 20 lb/ft. casing use packer size 47C2. Under certain circumstances the other packer size may be run, such as when running in mixed casing strings.

[B] Threads shown below are "standard" for the respective packer mandrel sizes. Other threads are available on request. Please specify threads when ordering.

Repair kits, including such items as packing elements, seal rings, etc., are available for redressing Baker retrievable packers. Contact your Baker Representative. Use only Baker repair parts.

M0590032

PERMANENT PACKER SYSTEMS

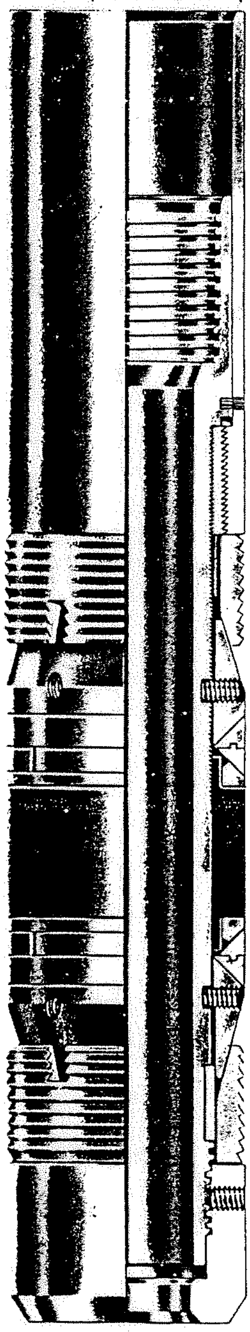
BAKER OIL TOOLS

A Baker Hughes company

MODEL "D"™ AND "DB"™ RETAINER PRODUCTION PACKER

Baker's Model "D" and "DB" Retainer Production Packers are the most widely used, most versatile, high performance permanent production packers available. They are frequently used as a permanent squeeze or testing packer or as a permanent or temporary bridge plug.

The Model "DB" Packer is distinguished from the Model "D" by the "DB's" threaded (Box or Pin) bottom guide. This "DB" Guide can be specified for acceptance of a Millout Extension, a Seal-Bore Extension, or virtually any component desired. Model "D" Packers and their guides can also be ordered separately by those interested in maximum inventory flexibility. Ordering examples and additional information concerning product numbers for packers without guides, material options, guide commodity numbers, o-rings, back-up rings and set screws may be found in Appendix A. Millout extensions, seal bore extensions and their crossovers should be ordered separately. See pages 30-31 and Appendix B for additional information regarding these components.



Model "D" Retainer Production Packer with Blank Guide

This guide serves only as a bottom sub and does not accommodate tailpipe. Product No. 415-13

FEATURES/BENEFITS

- Proven reliability.
- Slim line design.
- Solid construction that makes possible a significant savings in rig time by providing a 50% faster run-in (compared to former permanent packers) without fear of impact damage or premature setting.
- Two opposed sets of full-circle, full-strength slips.
- A packing element that resists swab-off but packs-off securely when the packer is set.
- Unique Interlocked Expandable Metal Back-Up Rings that contact the casing creating a positive packing element extrusion barrier.

PACKER SETTING:

Electric Line (p. 33)
Tubing (p. 34)
—Setting procedures and equipment are the same for both Model "D" and "DB".

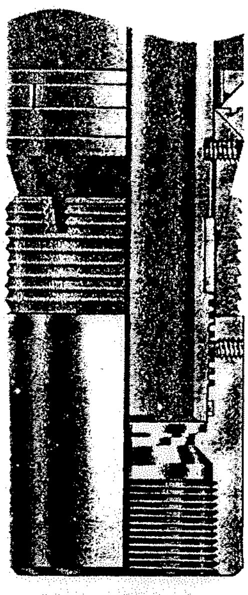
PACKER REMOVAL:

Milling Tools (p. 54-55)

PACKER ACCESSORIES:

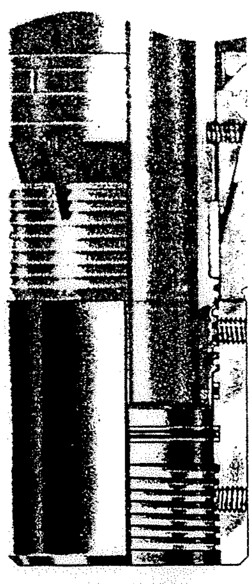
Tubing Seal Assemblies (p. 36-40)
Seal Bore Extensions (p. 30) and Appendix B
Millout Extensions (p. 30-31) and Appendix B
Packer Plugs (p. 52-53)
Expansion Joints (p. 48-49)
Parallel Flow Systems (p. 50-51)
Tubing Seal Receptacles (p. 44-46)

See Appendix A for additional product numbers and ordering information.



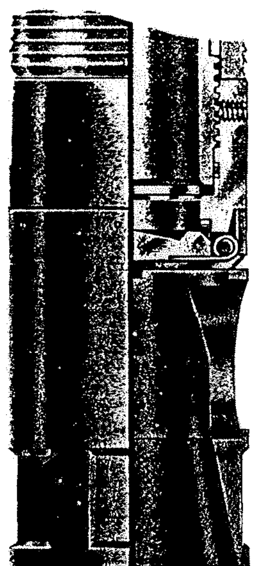
Model "DB" Retainer Production Packer with "B" Guide For Millout Extension

Product No. 415-05 (Nitrile)
Product No. 415-25 (Aflas)



Model "DB" Retainer Production Packer with "B" Guide For Seal Bore Extension

Product No. 415-05 (Nitrile)
Product No. 415-25 (Aflas)



Model "D" Retainer Production Packer with Flapper Valve Guide

This guide serves as a back pressure valve and does not accommodate tailpipe. Product No. 415-01

Aflas™ Trademark of Asahi Glass Company.

PERMANENT PACKER SYSTEMS

DOWN HOLE SEALING SYSTEMS

PACKER TO TUBING SEAL SYSTEM SELECTION

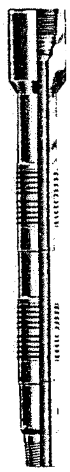
A variety of sealing accessories are available for use with Retainer Production Packers. Each is designed to meet the specific requirements of certain completion techniques. To select the proper packer-to-tubing seal system for any well completion, careful consideration must be given to present and future well conditions. Factors which must be considered are:

- Seal movement
- Maximum pressure differential
- Maximum and minimum temperaures
- Well Fluids (H_2S, CO_2, or other corrosives and inhibitors)

These enviromental considerations will determine the best combination of packer seal accessory type (locator, anchor or other), accessory material (metals), and seal stack (elastomers) for use in each case.

The **Locator Tubing Seal Assembly** is the simplest packer seal system. It is run in the well on the production tubing string until its no-go shoulder "locates" on the top of the packer. This positions one or two seal stacks in the packer's sealbore and establishes a seal between the packer and the tubing. The number of seal stacks in the packer's bore is determined by the type of packer being used. Packers with enlarged upper or alternate seal bores use seal nipples with one seal stack. Packers which do not have alternate seal bores will accept seal assemblies with two or more seal stacks.

When a Locator Tubing Seal Assembly is landed on a packer the tubing is normally set in compression to compensate for any contraction of the tubing during treating operations. It is not always possible or desirable to slack off sufficient weight, particularly in deep deviated wells, to compensate for contraction. In such a case, additional length must be added to the packer's sealbore using sealbore extensions and to the locator tubing seal assembly using a combination of spacer tubes along and additional seal units.



MODEL "G"™ LOCATOR TUBING SEAL ASSEMBLY

Basic assembly includes two seal stacks. Any number of seal units can be added for increased length. Designed for use in Models "D", "F-1", "N", "SB-3", "SC-2P" and "Retrieva-D" seal bore packers. Although not commonly used in this way, they are also compatible with the lower seal bore in most sizes of "DA", "FA", "SAB-3" and "Retrieva-DA" Packers. Production tubes, tailpipe or other accessories with OD's compatible with packer bore can be attached to the bottom of this seal assembly.

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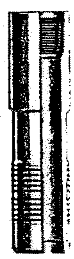

MODEL "K"™ LOCATOR TUBING SEAL NIPPLE

Used for sealing in the upper bore of Model "DA", "FA", "SAB-3" "SABL-3" and "Retrieva-DA" Packers. One seal stack is used on this seal nipple so no upward movement can be tolerated, therefore, sufficient set-down weight must be available to prevent movement. Supplied with blank or half mule shoe bottom sub which will not accomodate tail pipe or production tubes.

MODEL "N"™ LOCATOR TUBING SEAL NIPPLE

Similar to the "K" Locator tubing seal nipple but designed for use in extremely hostile environments in Model "DA", "FA" "SAB-3" "SABL-3" and "HEA" Packers. The "N" features metal-to-metal internal connections and is used with R-RYTE, Seal-RYTE, K-RYTE, K-HEET and A-HEET seal stacks.

Refer to Appendix C for ordering examples and product numbers.

MODEL "G" LOCATOR TUBING SEAL ASSEMBLY WITH SPACER TUBE

This extended Model "G" Locator Tubing Seal Assembly is furnished with 6 seal stacks. Designed for installations requiring tubing movement, this seal assembly should only be used with packers with seal bore extensions or with retrievable packer bore receptacles. Like all locator tubing seal assemblies, it should be landed with sufficient set-down weight to prevent seal movement. When used in a properly designed system, this seal assembly will give long service life even if movement occurs.

MODELS "L"™ and "LM"™ LOCATOR TUBING SEAL ASSEMBLY WITH SPACER TUBE

Similar to the "G" Locator tubing seal assembly with spacer tube but designed for use in extremely hostile environments in Models "D", "F-1", "HE", "SB-3" and "SC-2P" seal bore packers. Normally furnished with 3 seal stacks and 3 debris barriers. The "L" features metal-to-metal internal connections and is used with V-RYTE, R-RYTE, Seal-RYTE, K-RYTE, K-HEET and A-HEET seal stacks. The "LM" also features a compression energized metal-to-metal packer to tubing seal.

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PERMANENT PACKER SYSTEMS

ELECTRIC WIRELINE PACKER SETTING

MODEL "E-4" WIRELINE PRESSURE SETTING ASSEMBLY
Product No. 437-02

This tool is used for setting Baker Models "D", "DA", "F", "F-1", "FA-1", "FA", "HE" and "HEA" Retainer Production Packers. "Retrieva-D", "Retrieva-DA", "Lok-Set" and "SC-2P" Retrievable Seal Bore Packers are also set using this tool. Also required is the Model "B" Wireline Adapter Kits, the equipment and skilled services of a licensed wireline perforating and/or logging service company are also required.

OPERATION:

The proper size wireline adapter kit is installed in the packer. The packer and adapter kit are then connected to the pressure setting assembly. These are run to setting depth on the electric wireline.

A small charge of electrical current, transmitted through the electric wireline, ignites the power charge in the setting assembly, gradually building up gas pressure. This pressure provides the controlled force necessary to set the packer. When the prescribed setting force has been applied to the packer, the release stud in the wireline adapter kit parts thus freeing the setting equipment from the packer, allowing it to then be retrieved. The proper release stud is shipped with each packer at export. The "E-4" wireline pressure setting assembly is recommended for use at temperatures below 400°F.

MODEL "L" HI-TEMP WIRELINE PRESSURE SETTING ASSEMBLY
Product No. 437-12

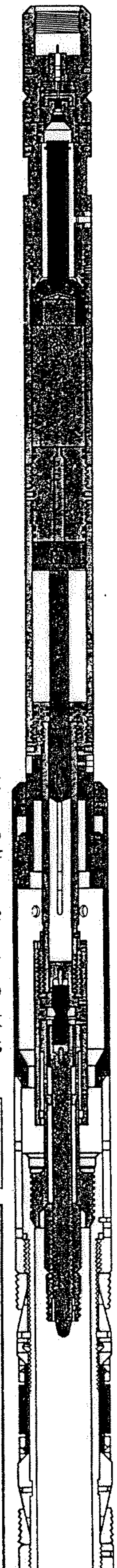
The Hi-Temp Setting Tool is designed to perform the same function as the Model "E-4" Wireline Pressure Setting Assembly in wells which are greater than 400°F. To accommodate some of the packers being made for high temperatures, this setting tool can apply up to 90,000 lbs. force. It also has a metering device which can slow the setting action, from almost instantaneous to over one hour. The tool is made in two versions, a two stage and a three stage. The three stage version is for applications where there is not enough hydrostatic pressure to operate the two stage tool. The primary power source for both versions is hydrostatic pressure acting against atmospheric pressure. An igniter and a small power charge are used to shear off the end of a plug and open a port to the well fluid which provides the controlled force to set the packer and part the release stud. The igniter and charge are rated to operate to a maximum temperature of 600°F.

The same Model "B" Wireline Adapter Kits used with the Model "E-4" are used with the Model "L" Pressure Setting Assembly. The OD of the Model "L" is 3.625 inches and it can be used to run and set packers in 4 1/2" OD and larger casing.

Use of the Baker Slow-Set Power Charge, Product No. 437-66, is recommended when setting permanent or retrievable packers using 10 or 20 size Model "E-4" Wireline Pressure Setting Assemblies.

MODEL "H" WIRELINE FEELER AND JUNK CATCHER
Product No. 439-01

This tool is run into the well on electric line prior to running the packer to assure that the well bore is large enough to permit subsequent passage of the packer. The tool also serves to clean the well of debris that might foul the packer and cause premature setting. It is also suggested that in well conditions involving high downhole temperatures, that the firing head of the setting assembly be run on top of the Junk Catcher to assure that the setting assembly will not prematurely detonate on the subsequent packer run.



Product No. 437-02
Model "E-4" Wireline Pressure Setting Assembly
For setting Baker Models "D", "DA", "F", "FA", "F-1", "FA-1", "HE" or "HEA" Retainer Production Packers and Models "Retrieva-D", "Retrieva-DA" Lok-Set and "SC-2P" Retrievable Seal Bore Packers.

Product No. 438-09
Model "B" Wireline Adapter Kit
Used with Models "E-4" & "L" Wireline Pressure Setting Assembly and Model "J" Hydraulic Setting Assemblies.

Product No. 437-12
Model "L" Hi-Temp Wireline Pressure Setting Assembly
For setting Baker Models "D", "DA", "F", "FA", "F-1" or "FA-1" "HE" or "HEA" Retainer Production Packers and Models "Retrieva -D", "Retrieva-DA", Lok-Set and "SC-2P" Retrievable Seal Bore Packers

EAST MEREENIE 41 WORKOVER HISTORY

The workover recently completed at East Mereenie 41 has highlighted a significant problem with the production casing cement quality. This letter details the results of this workover and the current forward plan for this well.

In summary, the results of this workover suggest that the primary cement job of the 5-1/2" production casing has only partially set and a significant amount of cement has slumped into the wellbore following the initial perforation job. Bottom hole samples of the cement show a putty/plasticine-like consistency which appears capable of holding pressure against a squeeze cement job or circulation job but is slumping into the wellbore following perforation. This problem obviously impacts greatly on the well's potential for fracture stimulation and is impeding the well's pre-frac production which is negligible.

Santos see little opportunity to remedy the poor cement. Fracture stimulation appears to be the only method which will test the quality of the cement job and obtain economic flow rates from the well. Obviously, the risks associated with fraccing, on both an economic and mechanical basis, have increased significantly due to the poor cement job. For the time being, swabbing work and gas lift will be maintained on this well to try and optimise production prior to any fracture treatment.

East Mereenie 41 was completed on 28 June 1996. A USIT log was run prior to perforating the well and this indicated extremely poor cement over the entire cemented interval. Sections which were particularly poor included the interval between the P3-120/130 and the P3-230/250 as well as above the P1 units. At the time of assessing the USIT log it was decided to proceed with perforating as many Mereenie wells appear to have poor cement bonds on logs but are satisfactory in providing a seal for the various reservoir units as well as holding fracture treatments. The well was then perforated underbalanced with tubing conveyed perforating guns (TCP) over the P3-230/250 and P4 sands. The well came on-line at a rate of 8 BOPD and maintained this rate up until the time of the workover.

Based on the good log quality of the perforated zones, it was surprising that the production rate was so poor. It was decided to pull the completion and confirm that all the TCP guns had fired and that no mechanical problems were affecting the well deliverability. This workover commenced on the 30 July 1996. The completion was pulled and this indicated that all guns had fired and there was no apparent plugging of the vent sub or perforated joint. A casing drift run was performed and indicated that the well had 30 feet of fill above the original PBTD. In the initial completion, the well was circulated to clean filtered brine to PBTD so the fill must have entered the wellbore following the perforation. Wireline bailer runs were conducted to obtain samples of the fill. These samples indicated that the fill was unset cement. Samples of this green cement have been sent to Halliburton and Amdel for chemical analysis. This result confirmed the original USIT log which indicated a very poor cement bond. The bailed samples showed the cement to be of a putty-like consistency.

At this point it was decided to conduct another USIT log to: (a) confirm the original log, (b) investigate any change in the cement quality post perforation and (c) identify areas requiring remedial cementing. The results of this second USIT log again confirmed an extremely poor cement job. This log also indicated that the cement quality had worsened following perforation with the only area remaining of similar quality was below the P4 perforations. Following this result, it was decided to attempt to prepare for a remedial cement job to isolate the various reservoir units for sealing purposes as well as for subsequent fracture treatments.

In an initial attempt to test circulation, a tubing string was run in the hole and the packer set between the P3-230/250 and P4 perforations. Attempts to circulate between the two zones failed. This circulation was attempted in both directions but no injectivity could be achieved. In fact, each zone held 1500 psi surface pressure for a period of 15 minutes with minimal leak-off. The next step was to attempt to break circulation over a shorter interval above the P3-230/250. On the USIT logs, the zone between the P3-120/130 and the P3-230/250 appears to have little to no cement bond and therefore represented a good candidate for a circulation squeeze. Squeeze gun perforations were performed at the top of the P3-230/250 perforation interval and 10 feet above and a packer set between these intervals. Again no circulation could be achieved across this interval which appeared to have no cement bond on the USIT log. Given the putty like nature of the cement, it is quite likely that this type of cement could hold significant pressure and not allow any circulation. Surface injection pressures were limited to 2500 psi due to the capacity of the rig pump. The result of this work indicated that either the cement had now set behind pipe or that the quality of the cement was such that it could hold a hydraulic seal under low injection pressures but would be highly suspect during a fracture treatment. Assuming that the existing perforations were significantly blocked with cement, it was decided to reperforate the well to improve the well's pre-frac deliverability.

The well was reperforated using TCP over both intervals. The charges used for this job were increased to a 37 gm charge to help achieve greater penetration and assist the well's deliverability. Following perforation, the well had a strong blow for approximately one hour before suddenly dying. The fluid level in the wellbore rose by 1000 feet during this time period. Since this initial period, there has been no apparent fluid influx into the wellbore. Gas lift and swabbing have both been attempted to stimulate flow. This result suggests that the perforations did intersect good quality reservoir but the cement appears to have slumped into the perforations yet again. The well is currently being swabbed each day in an attempt to stimulate flow.

The results of all this work suggest a very poor quality primary cement job which has severely affected the viability of the well. The cement used for the primary cement job of the 5-1/2" production casing in East Mereenie 41 was a new blend developed by Halliburton in an attempt to improve the bond quality in the upper gas zones which have suffered poor bond in recent Mereenie wells. There is evidence that a number of problems occurred during the cement job. Due to the small blender tub at Mereenie, the additives to the cement had to be blended in the mixwater rather than dry blended with the cement. This resulted in the mixwater having a high viscosity which caused problems in maintaining correct cement weight. The requested cement weight was 15.6 ppg but the job appears to have been pumped at densities varying between 14.0 and 15.2 ppg. It should be noted that surface samples gathered from the mix did set hard at surface after 17 hours.

Santos can see little chance of improving the cement quality in East Mereenie 41. Since circulation/injectivity cannot be achieved through the "cement", there is no chance of any remedial cementing. The only available method for testing the cement bond and obtaining an economic flow rate is to fracture stimulate each zone. Obviously the risks of such a job are high, both in terms of an economic situation as well as physically performing the treatments.

WELL NAME:- EM41 - Actual Directional Results

MEASURED DEPTH Metres	HOLE ANGLE DEGREES	AZIMUTH			AZIMUTH DEG N=0, E=90 S=180, W=270	DISPLACEMENT NORTH/SOUTH Metres	DISPLACEMENT EAST/WEST Metres	TVD Metres	DOGLEG SEVERITY deg/30m	VERTICAL SECTION Metres
0.0	0.00	N	0	E	0.0	0	0	0.0	0.00	0.0
33.4	0.25	N	15	W	345.0	0	0.0	33.4	0.00	0.0
62.5	0.30	N	36	W	324.0	0	-0.1	62.5	0.12	0.1
89.6	0.50	N	54	W	306.0	0	-0.2	89.6	0.00	0.3
118.3	0.50	N	38	W	322.0	0	-0.4	118.3	0.15	0.6
146.4	0.40	N	45	W	315.0	1	-0.5	146.4	0.12	0.8
174.6	0.30	N	60	W	300.0	1	-0.7	174.6	0.00	1.0
202.8	0.50	N	72	W	288.0	1	-0.8	202.8	0.23	1.1
230.8	0.60	N	88	W	272.0	1	-1.1	230.8	0.20	1.4
258.6	0.90	N	85	W	275.0	1	-1.5	258.6	0.33	1.7
288.9	1.00	N	72	W	288.0	1	-2.0	288.9	0.23	2.2
315.8	1.00	N	66	W	294.0	1	-2.4	315.8	0.12	2.6
344.7	1.40	N	60	W	300.0	1	-2.9	344.7	0.43	3.2
373.5	1.20	N	49	W	311.0	2	-3.5	373.5	0.33	3.9
402.4	1.00	N	20	W	340.0	2	-3.8	402.4	0.61	4.4
431.3	0.80	N	2	E	2.0	2	-3.8	431.3	0.41	4.4
460.2	0.70	N	15	E	15.0	3	-3.7	460.2	0.20	4.5
489.1	0.90	N	26	E	26.0	3	-3.6	489.1	0.26	4.6
518.0	1.30	N	40	E	40.0	3	-3.3	518.0	0.50	4.7
546.9	1.60	N	48	E	48.0	4	-2.8	546.8	0.37	4.8
575.8	2.20	N	47	E	47.0	5	-2.1	575.7	0.62	5.0
604.7	2.80	N	44	E	44.0	5	-1.2	604.6	0.64	5.6
633.5	3.40	N	42	E	42.0	7	-0.1	633.4	0.63	6.6
662.4	4.00	N	39	E	39.0	8	1.1	662.2	0.65	8.1
699.6	4.90	N	36	E	36.0	10	2.9	699.3	0.75	10.7
728.4	5.80	N	35	E	35.0	12	4.4	728.0	0.94	13.3
757.6	6.90	N	34	E	34.0	15	6.3	757.0	1.14	16.4
786.5	8.10	N	32	E	32.0	18	8.3	785.6	1.28	20.1
815.4	9.70	N	30	E	30.0	22	10.6	814.1	1.69	24.6
844.2	11.00	N	27.5	E	27.5	27	13.1	842.5	1.43	29.7
873.1	13.00	N	27.5	E	27.5	32	15.9	870.8	2.08	35.7
911.7	15.50	N	27	E	27.0	40	20.2	908.1	1.95	45.2
950.1	18.80	N	24.5	E	24.5	51	25.2	944.9	2.64	56.6
1001.6	20.20	N	25	E	25.0	66	32.3	993.4	0.82	73.7
1040.1	20.00	N	23.5	E	23.5	78	37.8	1029.6	0.43	87.0
1078.6	20.00	N	22.5	E	22.5	90	42.9	1065.7	0.27	100.1
1117.1	19.70	N	22.5	E	22.5	103	47.9	1102.0	0.23	113.2
1155.6	19.70	N	21	E	21.0	115	52.7	1138.2	0.39	126.1
1184.5	19.30	N	19.5	E	19.5	124	56.1	1165.4	0.67	135.8
1220.4	19.30	N	18.5	E	18.5	135	59.9	1199.3	0.28	147.6
1258.9	19.90	N	18.5	E	18.5	147	64.0	1235.6	0.47	160.4
1287.7	19.80	N	17	E	17.0	156	67.0	1262.7	0.54	170.2
1326.2	19.20	N	16.5	E	16.5	169	70.7	1299.0	0.49	182.9
1364.7	18.70	N	16	E	16.0	181	74.2	1335.4	0.41	195.4
1403.2	17.60	N	17	E	17.0	192	77.6	1372.0	0.89	207.3
1437.2	16.80	N	18	E	18.0	202	80.6	1404.4	0.75	217.3
1480.2	16.50	N	19	E	19.0	214	84.6	1445.7	0.29	229.6
1566.2	16.90	N	20	E	20.0	237	92.8	1528.0	0.17	254.3
1573.2	16.90	N	20	E	20.0	239	93.5	1534.7	0.00	256.4

PERFORATION RECOMMENDATION APPROVAL

Well	:	East Mereenie 41	
Depth Reference Log	:	Platform Express (copy attached)	
Dated	:	15 June 1996	
Recommended Perforation Interval	:	<u>Formation</u>	<u>Interval</u>
		Pacoota P3-190	1466.5-1474.5 mKB
		Pacoota P3-230/250	1476.5-1485.5 mKB
		Pacoota P4	1498.5-1511.5 mKB
Evaluation	:	KB: 771 m	
		GL: 764 m	
		DF: 770.6 m	

Justification:

The primary target of East Mereenie 41 was the Pacoota P3-190/230/250 and P4 units. This well intersected a total of 11.4 m (37') of net pay in the Lower P3 and 9.4 m (31') of net pay in the P4.

It is intended to perforate the Lower P3 and P4 units and flow test the zones. Following a 3-4 week flow period, each zone will be fracture stimulated independently and the well will be recompleted as a tandem producer from the Lower P3 and P4.

EAST MEREENIE 41
PERFORATION RECOMMENDATION APPROVAL

Prepared By: .... Date: 26/6/96
P B Lansom
Senior Petroleum Engineer

Approved By: .... Date: 26/6/96
T O'Sullivan
Team Leader - Exploration & Development
EQ/NT

.... Date: 26/6/96
'D C Reeve
Supv Chief Petroleum Engineer

.... Date: 27/06/96.
A Jeffery
Manager Exploration & Development
EQ/NT

Andrew Mayers .... Date: 27/6/96.
A F Mayers
Manager Petroleum Engineering & Drilling
QNTBU

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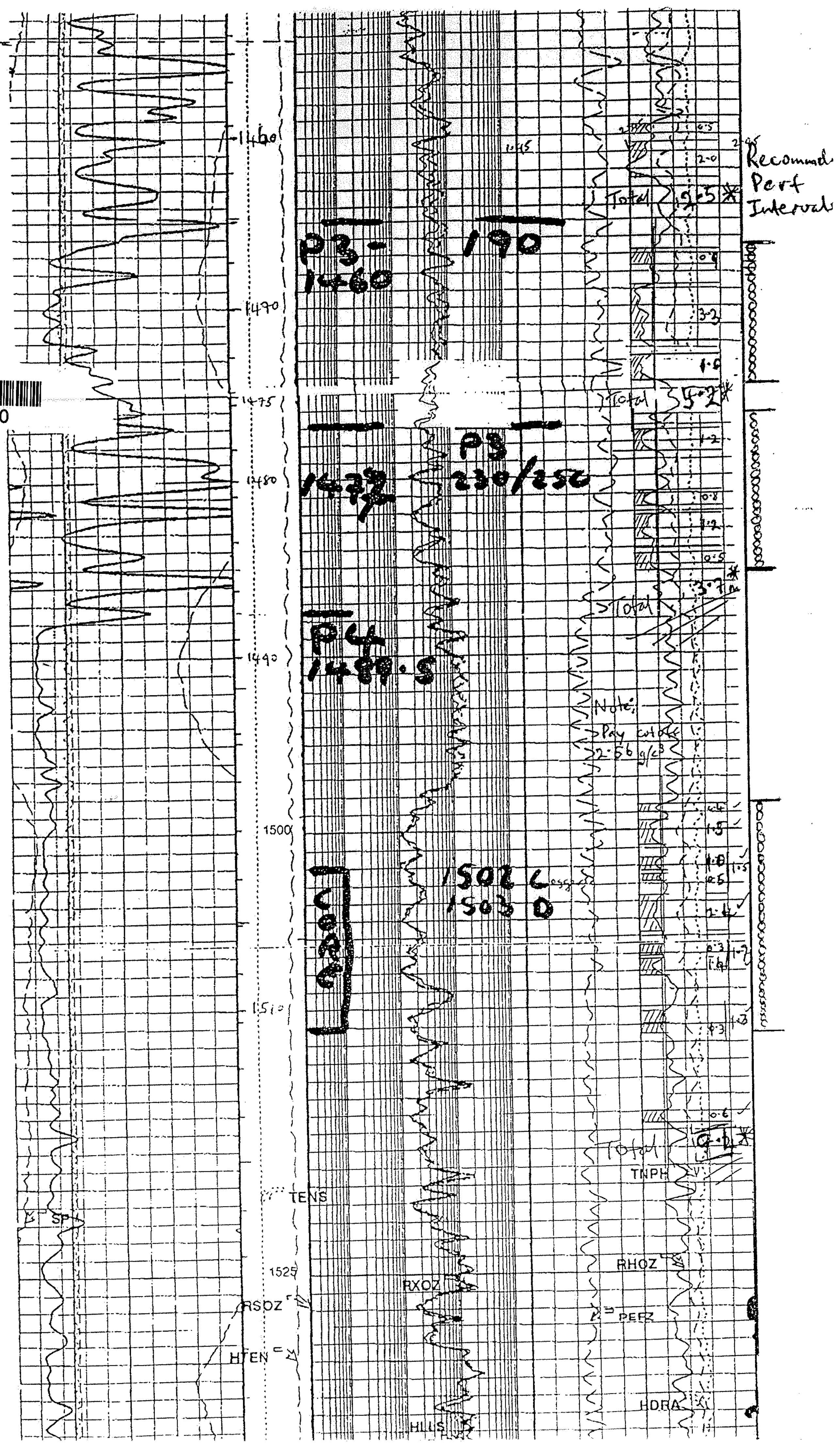

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