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305001

DST PROCEDURE

YOLLA NO 1

SEPTEMBER 1985

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CONTENTS

YOLLA NO 1

DRILLSTEM TESTING
W/ CASING GUNS

INTRODUCTION

The following memorandum outlines the test objectives and test procedures for the testing of the Yolla No 1 Well. All testing will be done in cased hole.

SERVICE COMPANIES

The following service companies will perform the test work:

Downhole Tools	Halliburton
Surface Production Equipment	Otis
Perforating (Casing Guns)	Schlumberger
SRO	Otis

TEST OBJECTIVES

The testing program, as designed, should accomplish the following objectives:

1. Determine the initial reservoir pressure.

2. Determine reservoir parameters of Kh, skin, boundaries and changes in these parameters within the radi us of investigation of the test.

3. Obtain representative water samples, if produced, to determine Rw and composition. Other tests may also be conducted on the sample.

5. Determine well productivity.

TEST INTERVALS

Attachment No 1 specifies the test intervals and packer setting depths. Testing should commence at the lower most interval and proceed to the upper most interval. Upon the completiong of each test a cement retainer will be set and the per forations squeezed.

PROGRAM REVISIONS

Program revisions may occur from time to time during the course of this test. These revisions will be telexed to the rig and will overide any instructions contianed in this program.

In order to accomplish the objectives, the following test is outlined:

1. A minimum initial flow of 10 minutes to remove load fluids colum and obtain storage free build-up data. Ten minutes is required to insure supercharging effect of mud column is relieved.

2. Shut in approximately 60 minutes to determine initial reservoir pressure from analysis of storage free pressure build-up data. Actual shut-in time will be determined by well test engineer based on surface readout data.

3. Second flow will be 6-8 hours at stabilized flow conditions (actual time may be longer depending on the time required to reach a stabilized rate). Fluid samples will be taken during the stabilized test to determine properties. In addition, flow rate and pressure data obtained will be used to determine well productivity. Flow rate will be determined by well site engineer based on reservoir parameters estimated during first flow test.

4. Conduct build-up for 12 hours or until engineer considers build-up to be complete. The build-up will be used to determine reservoir parameters.

5. Flow well for maximum rate determination. Rate should be stabilized. Additional sample collection may be required during this part of test.

6. Shut well in.

TEST EQUIPMENT

In order to accomplish the outlined objectives, the following equipment is required:

1. DST Equipment -- Attachment 3 is a breakdown of the Halliburton/Otis equipment required to run the test. Surface readout gauges using Otis wireline equipment will be used. Downhole shut-in is planned only in the case of a low permeability (K) zones and will be determined based on logging and drilling data.

2. Surface Equipment -- Otis surface equipment will be used. Attachment 4 is a summary of the Otis equipment including the subsea test tree (SSTT) that Otis has onboard for testing.

3. Additional Test Equipment -- Attachment 5 is a breakdown of additional equipment required to insure that the test is successful. Methanol injection may be required to reduce hydrate formation. Also an emulsion breaker and a pump to inject into the wellstream upstream of the separator is required in case problems are encountered during cleanup. Ensure spare equipment is available on critical items.

TEST PROCEDURE

1. After running 9-5/8" seal assembly test BOP Stack.

2. Pressure Test Surface and Subsurface Equipment

NOTE: Where possible, testing of component parts of subsurface downhole equipment should be performed before actual rig up to prevent wasting valuable rig time. It is VERY important that each pressure test be held for at least 10 minutes and that the pressure recording chart on the cement unit or Koomey Unit be used, labelled correctly, dated, and signed.

a. Otis should pressure test their surface tree, subsea test tree and lubricator valve. This should be done while the equipment is laying on the deck. Each valve should be independently tested from below, and each valve should be cycled twice before the pressure test. The tests will be to 5000 psig and will be held for 10 minutes as noted above.

b. The surface test system will include the test equipment for production testing and a well cleanup system. The lines from the rig floor to the rig choke manifold should be tested to 5000 psig. The heater and lines downstream of the heater should be tested to 1000 psig. In addition, the lines to the well cleanup system (pressured tanks or degasser/mud system), to be used during well unloading, should be pressure tested to 1000 psig. All equipment should be tested with drill water.

NOTE: If it is possible to isolate the high pressure coils in the heater, they should be tested to 5000 psig. The separator should be tested to its rated working pressure. If the design of the relief valve allows, the separator should be tested by pressuring up to the relief pressure. Do not pressure up too quickly or in excess of relief valve pressure setting to avoid weakening the rupture disks.

3. Space Out Landing String

NOTE: Prior to starting test, read Attachment 6 for emergency procedures.

a. Before running the DST string, it will be necessary to function test the Otis subsea test tree and lubricator valve and test the space out of the landing string from the wellhead back to rig floor so that that the surface test tree is about 10-12 feet above the rig floor. Coat a slick joint with white paint and allow to dry before RIH.

b. Make a dummy run to test landing string space out as follows:

Run 2 stands of drill collars below fluted hanger, 5" slick joint (painted) and subsea test tree. Run 5" pipe spacing out lubricator valve to about 100 feet below surface tree and 5" drill pipe back to surface. Space out landing string using pipe joints, if required, so that when the fluted hanger sits in the wear bushing, the surface tree will be about 10-12 feet above the rig floor.

NOTE: Run the SSTT and lubricator valve in the hole with valves in the open position.

c. After landing the fluted hanger in the 9-5/8" wear bushing, close appropriate rams on slick joint ot mark white paint for correct space out.

d. Function and pressure test SST and lubricator valves to 3000' psi from below with surface tree open to atmosphere.

e. Open rams.

NOTE: In the case of the tool string being hung off from the wellhead, it will be possible to close the shear rams above the SSTT.

f. Lay down surface tree and pull landing string, lubricator valve and SSTT with valves in open position.

g. Stand landing string back in derrick. Rack drill string separately to ensure that the same stands will be used again for the actual run.

h. When the lubricator valve is on surface, (close valve and install blanking plug if available). Stand in derrick.

i. When the SSTT is at surface, function quick disconnect coupling. Regrease disconnect and reconnect.

j. Note position of ram marks on pipe and ensure measurements check that tree was fully landed.

NOTES: 1. Otis should have pressure tested their lubricator and SSTT prior to making this dummy run.

2. Use Otis test pump on deck.

3. It is VERY improtant that all valves be pressure tested and that each pressure test be for at least 10 minutes. All tests should be witnessed by an Amoco Representative and recorded in a DST Tool Test Log.

4. <u>Dress Cement and Log</u>

a. Drill DV Equipment and dress top of CMT to insure adequate rat hole. Run CSG Scraper and work at Packer Seats. Circulate seawater while on bottom with CSG Scraper and while working CSG Scraper. Circulate until clean. Displace well to perforating Fluid while on bottom with CSG Scraper.

b. If not already completed, run CBL/CCL/GR if + 24 hours since cementing.

5. Perforate Test Interval with 5" Casing Guns. (Wait on day light to perforate).

6. <u>Run Test String</u>

a. Make up test tools and RIH ensuring that string is not rotated. (Place ball in shear out sub when making up same)

b. Ensure that all tools, drill collars, and drill pipe are drifted with an appropriate drift for any wireline work necessary. (Ensure drift has a wireline fishing neck). 2.8" above Otis landing nipple 2.125" below nipple. Wash out all D.C.'s and D.P. to remove Barite which could settle on Tester Valve.

c. The annulus controlled test valve (LPR-N) should be set to function at ± 1500 psi applied annulus pressure. The annulus controlled sampler safety valve (APR-M2) and annulus controlled circulating safety valve (APR-A) should be set to function at ±2000 psi and ±2500 psi respectively above the LPR operating pressure.

d. Run appropriate clocks and gauges in bundle carrier as required. At least 2 gauges should be run below APR-M2 valve. Refer to Attachment 5 for list of gauges which should be available.

e. Set Packer and collapse slip jts to close bypass valves. Pressure test test string to 5000 psi. If no test POH setting packer and retesting every ten stands. After positive test RIH and test next 30 connections with Gator Hawk Tester to isolate leak.

f. Pick up landing string and attach hoses to SSTT and lubricator valve while RIH. Function test each component.

g. Pick up surface tree. Ensure there is plenty of slack in hoses for setting the RTTS packer.

h. Set the packer as follows:

1. Land fluted hanger in wear bushing.

2. Space out so that with the packer set and the fluted hanger landed in the wear bushing, the slip joints will be open 5'.

3. Set slips, rotate to right to give 1/4 turn at the packer (beware of hoses, etc.).

4. Pull slips and land fluted hanger in wear bushing.

i. Pressure test annulus to 500 PSI below LPR-N Operating Pressure for at least 10 minutes.

j. Open upper hydraulic by-pass and spot diesel 5 BBL short of by-pass. (Remove pulsation dampners from cementing unit prior to pumping diesel).

k. Close hydraulic by-pass (open pipe to atmosphere to check bypass).

l. Pressure string to 2000 psi. Open LPR-N and Test String to 4000 psi. Hold at least 10 min. Increase Pump Pressure to 4900 psi plus underbalance pressure to drop ball and seat from shear-out sub.

m. Close LPR-N. Rig up 75 foot slings needed for wireline work. Rig up surface test tree.

6. Pressure Test Surface Equipment

a. Connect surface line from choke manifold to actuator wing valve on surface tree. Connect other wing valve to cement unit.

Note: Choke manifold will be on rig floor

b. Purge lines to burners with water.

c. Close valve at heater and test to 5000 PSI. This will test chicksan connections and hose connections to choke manifold, and surface tree, and connections to test string.

8. Well Test

Note: Flow period should commence in daylight. Only essential personnel should remain on rig floor during DST operations. Prior to test, read safety procedures in Attachment 8.

a. Rig up surface readout gauges on wireline. Install in lubricator and pressure test wireline lubricator to 5000 psig with water. RIH to top of lubricator valve. Won't run with pressure on.

b. Ensure
   1. all tools are correctly set and landed in hole with required cushion.

   2. all surface lines, connections and vessels are tested and all valves are in the correct positions.

   3. the flow from the well is routed via the choke manifold to the well cleanup system and the fluids will be sent to either the mud tanks or clean out tanks, whichever is piped up. This is only during unloading flow.

c. If testing a low K gas zone, RIH with Otis electric line downhole shut-in tool (prong, stem, adapter and surface readout tool). Latch into locksub. Wireline should be slacked off to open tool.

d. Open the well using the LPR-N. Allow well to flow for 10 minutes only.

   During the flow period, the well should be allowed to flow via 1/2" choke, and will be monitored via a bubble bucket for flow. Any fluid returned will be sampled using the cans provided (See Attachment 9 for fluid sampling summary). Pressure will be monitored using a dead weight tester (DWT) every minute. Time of first fluid to surface (cushion) should be noted, as well as time of any other fluids to surface.

e. For oil or high K gas zone, shut well in using surface tree for 60 minute shut-in peroid. For a low K gas zone use Otis electric line downhole shut-in tool to close in for 60 minute shut-in period.

f. For all but low K gas test, open wireline valve and RIH with surface readout gauge. Hang the gauge just below perfo.

g. Open well to flow controlling rate of flow with adjustable choke. Attempt to moderate the flow so that a differential to the wellbore of 1000-1500 psig is maintained. Samples of the fluid returned will be taken every 15 minutes and checked for BS&W content. This is a 6-8 hour stabilized flow period after initial unloading and unstable flow.

Notes:

1. To prevent excess fluid drag on the cable causing severe movement of the gauge up the hole, it is important that:

   a. the choke be opened very gradually at the start of each flow period, i.e. the flow should be increased slowly.

   b. the cable tension be closely monitored and telephone communication be maintained between wireline unit and choke manifold when opening the well to flow.

   c. the well is choked back at the first indication of cable or tool movement (as shown by cable tension decreases or CCL movement).

2. Sufficient methanol should be onboard (5 drums), as well as a high pressure (5000 psig) injection pump to allow injection of methanol directly upstream of the choke manifold should hydrate formation be suspected.

h. Injection of chemicals and sample collection: Emulsion breaker should also be on hand to allow treatment of any crude which forms stable emulsions during flowing. The fluid will be injected upstream of the choke manifold. Once flow is established, catch samples every 30 minutes to one hour, and at obvious fluid changes. An estimation of gas and oil gravity should also be obtained. If the well does not flow, see section 11 (no flow or low flow response of well) below.

It will be necessary to collect uncontaminated oil samples. This can be done by bottom-hole sampling (see section 9) or by not injecting chemicals at good flow conditions prior to shutting the well in. The test engineer and drilling supervisor should evaluate well flowrate, temperatures, pressures, etc. prior to stopping chemical injection. If major problems that will result in losing the test are anticipated, bottom-hole sampling should be considered. It is important that these samples are collected in order to evaluate the crude in the laboratory for future treating requirements.

Oil, gas and water rates should be established every 15 minutes using the test separator. Oil and gas gravity, water salinity and shrinkage factor should also be recorded. Oil and water samples should be taken every hour in the cane provided (Attachment 10). Larger pressured samples of oil and gas will be taken as dictated by the engineer using the vacuum container technique. During sampling, pressure of the separator will be recorded with a dead weight tester.

i. Shut well in at surface tree (at downhole shut-in tool for low K gas zone) after a minimum of 8 hours flowing. Longer flow periods may be required to achieve a stabilized rate.

j. Monitor build-up for 12 hours or until the engineer considers build-up to be complete.

k. After build-up is complete, open well slowly on adjustable choke to flow at maximum production rate. Produce on 2" choke or at separator capacity. Change to fixed choke bean if possible. Pending analysis of engineer on site, bottom hole surface readout gauges may be pulled prior to this test. Flow well at maximum stabilized rate for 2-4 hours. Monitor injection equipment, test equipment, sand production, etc. and ensure that rate does not exceed equipment, safety and reservoir constraints.

l. Shut well in at choke manifold

m. POH with wireline gauges.

<u>Data Gathering - Duration of Test</u>

1. Gather data for flowing well (FWHP, FBHP, temperature) every one minute for first 5 minutes, every 5 minutes for next 25 minutes, every 15 minutes (at least) thereafter.

2. Gather data for shut-in well (BHP, WHP, temperature) once per minute for first 5 minutes, onece per 5 minutes next 25 minutes thereafter.

9. <u>Bottom-hole Samples</u> (if required)

Bottom-hole samples are to be collected as instructed by the test engineer. Bottom-hole samples may be required to obtain non-contaminated fluids (i.e., no emulsion breakers, etc.).

Note: Check to verify that Otis bottom hole sampler is available.

a. RIH with gauge, CCL and tandem bottom-hole samplers to top of lubricator valve. Sufficient sinker bars should be included in the string to hold string in a reduced flowrate.

b. Pressure up tubing to shut-in tubing pressure to equalize pressure across lubricator valve.

c. Open valve and RIH to producing formation.

d. Flow well at a very small rate before taking sample. Three (3) hr clocks in samplers should be set so that well can be flowed at a reduced rate for 2 hrs before samples are taken.

e. Wellhead pressure and temperature, as well as gas, oil and water rates will be recorded throughout the flowing period.

f. Recover the bottom-hole samples.

g. Repeat steps a-f until as necessary.

10. Procedure to Kill Well

a. Displace with mud down test string to Perfs.

b. Pressure up on annulus and shear APR-M2 and/or APR-A valve.

c. Circulate until mud weight in and out are equal.

d. Be sure well is killed before unseating packer.

e. Unseat packer and observe well. Be sure hole is static before POH.

f. POH with test string.

g. If further zones are to be tested, they will be isolated with a packer (EZSV) and cement squeezed before the next zone is perforated.

11. <u>No Flow or Low Flow Response of Well</u>

If once the well is opened to flow, no response is seen and if the Well will not flow to the surface, the following steps will be taken to remedy the situation.

a. Check that all surface valves are open.

b. Determine fluid level in pipe and fluid gradient from surface readout gauge.

c. If (b) above indicates no flow into the wellbore and perforating gun misfires seem not to be a problem consider swabbing if possible. After swabbing, proceed to flow test or evaluate fluid movement.

d. If (b) or (c) above indicates fluid movement, either catch a bottom-hole sample or consider reversing out contents of pipe.

e. If the contents of the pipe was not reversed out, attempt to establish an injection rate to the formation.

NOTE: Caution should be exercised to ensure that formation is not fractured while trying to establish injection rate. Use a fracture gradient of 0.7 psi/ft if no other data is available.

f. If it is decided to acidize the well and an injection rate has been established then the acid Upper Hydraulic By Pass. Acid should be chased with diesel to provide a pressure differential to the wellbore.

g. If the APR has already been closed by reverse circulation or if an injection rate could not be established, POH and collect APR-M2 sample if appropriate. If no attempts have been made yet to establish an injection rate, then close blind rams and attempt to establish injection rate down kill line. Consider note in (e) above for pressure guidelines.

h. If (g) above has been followed and the decision to acidize has been made, rerun test string (with Ameradas having been reloaded and rewound). Before setting packer, displace acid downpipe to packer level. Again, chase acid with spacer and diesel. Set packer.

i. Slowly inject acid to formation. Use information gained in (e) or (g) above.

j. Shut well in for 1/2 hour after displacing acid.

k. Attempt to flow well.

l. If well does not flow, abandon test. If well does flow, test as described in Section 8 starting at cleanup flow.

NOTE: See attachment No 11 for Acid Program.

PROPOSED DST INTERVALS

ATTACHMENT 1

DST NUMBER	PERFORATION INTERVAL	ESTIMATED FORMATION PRESSURE	APPROXIMATE PACKER DEPTH	EZSV SET DEPTH
1	2809-2814 M (9216-9232 ft)	8.67 ppg	2794 m (9164 ft)	2806 m (9204 ft)
	2818-2824.5 M (9245-9267 ft)	8.66 ppg		
Optional:	2987-2993 (9800-9819)	8.60 ppg		
2	1830-1835 M (6004-6020 ft)	8.67 ppg	1815 M (5923 ft)	1827 M (5993 ft)
Optional:	1813-1823 M (5948-5981 ft)	8.67 ppg	1798 M (5897 ft)	1810 M (5937 ft)

NOTES:

1. Perforation Depths Ref: LDL/CNL/GR
2. Formation pressures calculated from RFT results.

PACKER/PERFORATING FLUID FORMULATION

ATTACHMENT 2

PACKER/PERFORATING FLUID:

PROPERTIES

Plastic Viscosity	23
Yield Point	19
Mud Weight	9.6 ppg
API Water loss	7.5 cc
Nitrate	150 ppm

MATERIAL CONCENTRATION

Caustic	1.0 ppb
Gel	10.0 ppb
Dextrid	4.0 ppb
Drispac L	2.0 ppb

DST STRING

ATTACHMENT 3

Lift Sub
Surface Test Tree
x/o Sub
5" DP
Lubricator Valve
5" DP
Centralizer & Sub
SSTT
Slick Joint
Fluted Hanger

DOWNHOLE DST STRING

Surface Tree
XO
DP
XO
Lubricator Valve
XO
DP
XO
SSTT
XO
DP
XO
Otis SRO Nipple
XO
XO
Full Flow Safety Valve
XO
1 STD DC
XO
2 - Slip Jt
XO
1-STD DC OK
XO
HYD By-pass
2 Slip Jt
XO
1 STD DC
XO
APR-A
APR-M2
LPR-N
Jars
Bundle Carrier
HYD By-pass
XO
Safety Joint
RTTS Packer
Tail Pipe
XO
Otis Shear Out Sub
W/L Guide

ATTACHMENT 4

SQUEEZE CEMENT PRODCEDURE

The following is a brief outline for squeeze cementing the open perforations for squeeze cementing the open perforations for each DST interval. Exact slurry formulation to be advised.

1. R/U Schlumberger wireline and RIH with gauge ring/junk basket pooh.

2. RIH with 9-5/8" EZSV Squeeze Packer and set 3 m (10 ft) above top perforation with wireline. Correlate with CCL. Pooh.

3. RIH with cement stinger and star guide assembly. Close hydril and pressure test top of EZSV to 1000 psi. Sting into packer and establish an injection rate. Unsting from EZSV.

4. Mix and pump squeeze cement slurry to within 5 bbls of stinger.

5. Sting into EZSV and displace squeeze cement slurry to perfs and leave 5 BBLS CMT in Drill Pipe.

6. Unsting from EZSV, Pooh 1 Stand, and circulate out remaining cement. Pooh.

7. RIH with a bit/scraper to top of EZSV. Note depth where tagged. Circulate and condition mud. Pooh.

ATTACHMENT 5

ADDITIONAL MATERIALS FOR PRODUCTION TESTING

1. Methanol (5 drums) and injection pump

2. Emulsion breaker (2 drums).

3. Bottom-hole guages: 6 pressure, 2 temperature; clocks: 72 and 144 hour clocks for all above gauges. May need 5000 or 10,000 psi gauges depending on test depth.

4. Sand trap for surface equipment

5. Shrinkage meter (should be attached to separator)

6. Gas gravity meter (Ranarex or equivalent).

7. Two dead weight testers.

8. Two sets of fixed chokes from 1/8" capacity and larger to the maximum size of manifold. At least one set to be ceramic type.

9. Complete set of orifice plates for gas and oil meter package. NOT OF LOCAL MANUFACTURE. API specification plates are required.

10. Acid, mixed or concentrate, to make 5000 gal. of 7 1/2% HCL with all normal additives (inhibitor, emulsion breaker, etc.). Should be made available on call out basis if possible.

ATTACHMENT 6

EMERGENCY SHUTDOWN PROCEDURE

A safety meeting of all key personnel will be held prior to the test. Emergency shut down procedures will be thoroughly discussed and course of action established.

If, during a flow test, it becomes necessary to shut the well in due to an emergency situation, the following procedure should be followed:

a. Pull wireline tools out of hole.

b. Prepare to release SSTT and riser from stack. Close hydraulic actuated wing valve on surface test tree.

c. If required to move rig off well location:

i. Close LPR valve.

ii. Bleed pressure from test string.

iii Close SSTT valves, ensure lubricator valve is open.

iv. Release Hydraulic Release and pick up landing string above blind rams.

v. Close shear rams. Close pipe rams if shear rams cannot be closed.

vi. Release LMRP and move off location.

NOTE: In the event that the well must be shut in downhole with the wireline at depth; the ball valve of the SSTT should be closed by use of the valve assist control line. This ball valve will shear the wireline and close for a positive shut off.

ATTACHMENT 7

PRECAUTIONS TO BE TAKEN WHILE PERFORATING:

1. Before any gun is armed, the supply base, any boats, required authorities and Amoco offices should be notified of impending radio silence.

2. The boat/boats will be required to stand off one mile and to intercept any approaching vessels fitted with radios. Boats are to be instructed not to transmit until called by the rig at the end of radio silence.

3. All hand held radios are to be collected and stored in radio room.

4. Notices are to be posted on all radios outside the radio room and where possible they should be disabled from transmit mode.

5. All welding permits are to be revoked and no welding is to take place during the radio silence period.

6. Radio operator is to switch off as much of his equipment as is practicable, and he is to be made fully aware of the requirements of radio silence and the possible consequences of breaking of radio silence.

7. Radio silence is to be maintained from the time that the gun is armed to the time that the gun is out of the hole and disarmed or has proved to be discharged.

8. The Amoco Drilling Foreman may, at his discretion, allow the use of the radio when the gun is 800' below mud line (at least 1000' of line in hole). The wireline company engineer should be informed of this because he will be required to stop at this depth when POH until he has been assured that radio silence is again in effect.

9. Once all the above has been accomplished, the wireline engineer should be informed that he may proceed to arm the gun. It should be emphasized that the wireline engineer should satisfy himself that the above has been carried out and that the above in no way absolves him from the usual check and procedures demanded by his company.

10. Vent lines on bulk tanks will be kept open during test program.

ATTACHMENT 8

AMOCO WELL TESTING SAFETY PROCEDURES

A. General

1. Nonessential personnel will be put ashore for the duration of the test program.

2. Rams, bag type preventers, kill/choke lines and valves, surface well control equipment will be tested before program commences. All surface well test equipment will be tested to rated working pressure. All downhole well test equipment will be pressure tested to an appropriate pressure for the particular test.

3. Man overboard, fire and abandon ship drills will be held before testing commences. Drills will be repeated between tests if thought desirable (i.e. if test program is lengthy or crew change occurs, etc.).

4. Pretest safety meetings will be held to ensure that all personnel concerned are fully familiar with test safety procedures and are fully aware of their duties and responsibilities.

5. Lifeboats, engines, equipment, and operating gear will be checked out.

6. No smoking, matches or cigarette lighters will be allowed outside living quarters. Anyone found breaking this rule will be dismissed immediately.

7. All doors to living quarters, pump room, engine room, mud pit area, etc., will be kept closed throughout test period.

8. During test periods, all exit doors from quarters will be posted as follows.

   "Well test in progress.
   No exit for off duty personnel or personnel not concerned with well test without permission from installation manager or Amoco representative. No smoking, matches or cigarette lighters permitted beyond this door."

9. Fire mains will be pressured and fire hoses manned and laid to strategic points throughout test periods.

10. All gas pressure bottles will be stored on deck as far away as possible from test lines and burners. They should be positioned for easy dumping.

11. If service personnel change during testing operations, ensure that the relief personnel are fully briefed as to operations, test program, safety procedures, and their specific responsibilities.

ATTACHMENT 8

12. Electrical equipment and installations not required during tests will be disconnected from power supply.

13. Helicopter scheduling will be controlled from rig throughout test program to accord with test requirements.

14. The following people will be informed (before well is opened) of commencement time of each test, and upon completion of each test, when the well is closed in and killed.

15. All hands will be informed via the P.A. system when well is to be opened for test.

16. During test periods, a fire watch will be kept on helicopter refuelling tanks, and they will be made ready for dumping in the unlikely event that this becomes necessary.

17. Gas explosion meters, a hydrogen sulphide detector and breathing apparatus will be checked and made ready. Key personnel will be taught operating procedure for same. Produced fluids will be monitored continuously for hydrogen sulphide -- if this is detected, Amoco representative will be informed immediately.

18. Adequate killing fluid of the correct weight should be available. An emergency kill line will be connected from one wing of the surface control head to the cementing unit. The supply of killing fluid will be connected to the cementing unit.

19. Working areas around the control head of rig floor and around the choke manifold, separator, etc., will be kept clear and there will be unobstructed access to these areas at all times. When work is to be carried out on the control head, a suitable platform will be erected.

20. Testing will only be carried out during hours of darkness if the flow test can be satisfactorily commenced during daylight hours.

B. <u>CREW ORGANIZATION AND DUTIES</u>

1. Contractor's Captain is the appointed "Offshore Installation Mananger" and as such has final responsibility on the rig for rig and crew safety. He must approve safety procedures and can make overriding decisions in cases of doubt or emergency.

ATTACHMENT 8

2. Amoco Drilling Foreman will coordinate and control testing operations, and will work closely with contractor's superintendent to ensure he is kept well informed on test progress and any changes to agreed test program.

3. All service company personnel will report to and be under control of Amoco representative.

4. Rig Floor - Driller and two floormen will be on rig floor at all times. Driller will be responsible for monitoring annulus pressure during test periods. He will report immediately to Amoco representative should he observe any untoward happening.

   One subsea test tree operator will be on rig floor at all times during test period to operate SSTT and subsea lubricator valve.

   One downhole tool operator (if appropriate) will be on rig floor at all times during test period to operate downhole test tool.

5. A cementer will be on standby at cementing unit or on rig floor during test periods.

6. Derrickman and helper will be on duty in pump and mud rooms throughout test periods.

7. Barge control room will be manned at all times during tests.

8. Radio operator or his substitutes will man radio room throughout test periods. Standby boat will maintain constant radio watch and will be contacted by radio operator at regular intervals. Amoco Drilling Foreman will advise boat through radio operator of test start up and shut down, and amy emergency or other instructions.

9. Boat will be at steaming stations throughout tests and will make ready to use dispersant gear if this should be called for.

10. Fire hoses will be manned at strategic points through test periods (see A, General, item 9).

11. Roustabout crew under supervision of crane operator will standby at a designated area throughout test periods. Crew will be equipped with axes, sledgehammers, crow bars, and 36" through 12" pipe wrenches.

12. Welder with cutting gear and helper will standby at appointed area. No hot work will be carried out without approval of toolpusher and Amoco representative.

13. Mechanic and electrician will obtain permission from both Amoco Drilling Foreman and contractor's toolpusher before starting up and stopping equipment.

14. Cranes will not be operated during test periods without permission of Amoco Drilling Foreman,and contractor's toolpusher and will not be allowed to make lifts over pressured equipment.

15. Subsea engineer and assistant driller will be utilized by contractor's pusher for relief work. Amoco Drilling Foreman should be notified when personnel are being released temporarily.

16. The Amoco Drilling Foreman will base himself in the Amoco office, which will be the test control center. Should he wish to leave the office for any reason, he will leave it manned with instructions regarding his whereabouts and length of absence.

C. EMERGENCY WEATHER PROCEDURE WHILE TESTING

1. Due attention will be paid to weather forecasts at all times. Tests will not be started without a favourable forecast.

2. If weather forces suspension of test and sufficient time is available.

    a. Retrieve wireline tools.

    b. Secure well as appropriate for fluid produced.

    c. Close SSTT. Hang off test string and retrieve running string.

    d. Close shear rams. Prepare to unlatch riser.

3. If weather change forces suspension of test and time does not permit retrieval of wireline or killing of well:

    a. Close LPR-N

    b. Close rams on slick joint of SSTT.

    c. Close SSTT.

    d. When it is thought advisable, unlatch from SSTT and pull running string if time permits. Close shear rams if short SSTT is used. Prepare to unlatch riser.

4. If weather forecast changes while tripping test tools and time does not permit pulling tools:

    a. Install hang off tool and land in wellhead.

    b. Retrieve running string.

ATTACHMENT 9

FLUID SAMPLING SUMMARY

1. The following is a summary of samples to be caught during the well test:

   a. Initial flow period -

      i. Any fluid returned will be sampled using one quart tin containers.

   b. Second flow period -

      i. Catch samples to check for BS&W content every 5 minutes.

      ii. Catch samples in one quart tin containers every 30 minutes to one hour and at obvious fluid changes.

      iii Pressured samples will be caught in 500cc oil sample bottles and 20 liter gas sample bottles using vacuum container technique. Number of samples and frequency of sampling will be determined during test.

   c. Maximum flow rate -

      i. Additional sampling may be required during this flow period.

   d. Reversing out to kill well or after no flow/low flow response -

      i. Catch samples of reversed fluid in one quart tin containers.

   e. Tripping out of hole -

      i. Catch sample from between APR-M2 sampler and LPR-N in pressurized container.

   f. If required, bottom-hole samples will be collected following second build-up period.

ATTACHMENT 10

FLUID SAMPLES

1. Fluid samples should be collected as instructed by the test engineer. The following equipment will be available:

   a. Two 600 cc bottom-hole samplers complete with clocks, transfer pump, mercury and (8) 10,000 psi sample bottles.

   b. (12) - 20 liter gas sample bottles.

   c. (12) - 500 cc oil sample bottles.

   d. (4) - clean 55 gallon drums.

   e. (100) - one quart tin containers c/w screw caps.

   f. Required new piping to obtain sample as described in the Amoco Sampling Handbook.

ATTACHMENT 11

ACIDIZING PROCEDURE

The following acid make-up is to be used if a mud cleanout acid is necessary.

15% MCA ACID - 20 gals/ft of perforation.

ITEM	DESCRIPTION	CONCENTRATION/1000 GALS
1	Drill Water	398 gals
2	20 Be HCL Acid	442 gals
3	HAI 75	20 gals
4	MORFLO 11	30 gals
5	MUSOL	100 gals
6	FE-1A	10 gals
7	FE-2	50 lbs

Diesel After Flush: 3 gals/ft of perforation

ITEM	DESCRIPTION	CONCENTRATION/1000 GALS
1	HYFLO - IV	10 gals

Acidizing Procedure:

1. Open hydraulic by-pass valve.
2. Spot Acid to within 5 bbls of Hydraulic by-pass valve.
3. Close hydraulic by-pass valve.
4. Pressure down annulus to 500 psi below LPR-N operating pressure.
5. Open LPR-N valve.
6. Pump acid and diesel after-flush to formation
7. Displace with diesel
8. Wait ± 30 mins before flow back of diesel and spent acid to burners.
9. Proceed with DST program

Attachment 12.

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HALLIBURTON SERVICES

before the tester opens, the valve is being positioned for opening. This helps prevent premature opening of the tester valve should a bridge or tight spot be encountered on the trip in the hole. At the end of the time interval, which is determined by the amount of applied weight, the tester valve opens rapidly giving a definite indication at the surface by a slight movement of the drill pipe and the weight indicator needle. When weight is removed from the tool, the mandrel returns automatically to the fully extended position, closing the tester valve and opening the by-pass. Weight must be reapplied for the full time interval before the tester valve will open again.

The by-pass valve aids the packer in passing through restrictions caused by filter cake, and by so doing helps prevent pressure build-up below the packer that could cause a breakdown of the formation and the possible loss of circulation. The by-pass valve also helps to prevent the forcing of mud into the formation being tested which could result in not obtaining a successful test. The pressure is equalized above and below the packer at all times until the tester opens.

Ease of maintenance, simplicity of operation and adaptability to formation testing make the Halliburton Hydrospring ® Tester readily acceptable wherever it is run.

This tool is available in 5" OD (illustrated), 3⅞" OD, 3" OD and 1¾" OD.

An indexing-J-type Hydrospring® tester is available, for testing applications requiring reciprocal tool movement to take closed-in pressures. This permits placing setting weight on the packer during the closed-in period when using the Multiple CIP Sampler or LOC by-pass valve.

B.T. (Bourdon Tube) Pressure Recording Device

The Halliburton B.T. Pressure Recording Device is placed in the testing string to record subsurface well pressures throughout the formation testing procedure. The inherent sensitivity of the bourdon tube produces an accurate recording of pressures suitable for calculation and reservoir evaluation.

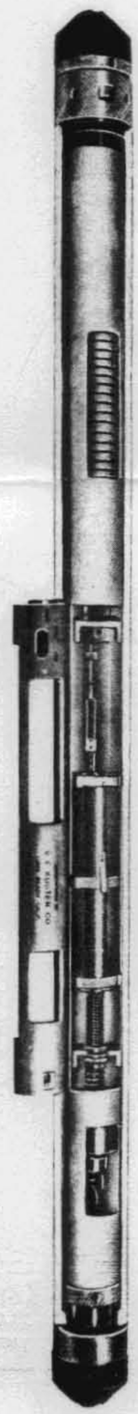
Pressure recordings are made on a black coated metal chart by a marking stylus attached to the end of the bourdon tube. The base line or line of zero pressure is inscribed on the chart after it is inserted in the gauge. Well pressure is transmitted through a rubber diaphragm to fluid contained inside the tube. Pressure increase causes the tube to tend to uncoil, moving the stylus away from the base line on the chart.

The chart travels past the stylus at a constant rate. It is controlled by a spring driven clock especially designed to withstand shock and high temperature. Clocks are supplied in ratings of 3, 12, 24, 48, 72, 96, 120, 144 or higher hours time duration. The clock rating determines the time required for complete travel of the chart. A complete recording of pressure vs. time is made in one passage of the stylus across the face of the chart with no overlapping.

The gauges are supplied in pressure ratings ranging from 1,-500 to 30,000 psi. Accuracy is maintained by individual calibration at regular intervals in special calibrating units. The gauges are submersed in a temperature controlled bath and calibrated by a dead weight tester. Calibration curves are supplied with each gauge.

The B.T. pressure sensing element is constructed of alloys that minimize deviation due to creep and temperature. Each element is tested and calibrated under both temperature and pressure variables. A calibration table is used to convert direct reading of the chart from deflections in thousandths of an inch to psi and a temperature correction factor is applied as required.

For other B.T. Recording Devices see following page.



B. T.
Pressure Recording Device

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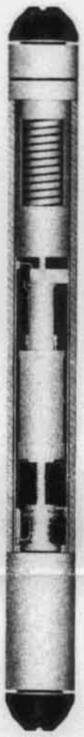
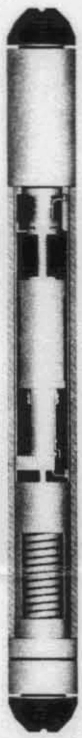
Testing



BT
Pressure Recorder

RT-7 Temperature Recorder
and RPG Pressure Recorder



BT
Temperature Recorder

Chart Reading and Data Report

When the metal chart is removed from the gauge at the completion of the test, the Halliburton Testing Operator may make a field reading of significant pressure points using a steel scale and magnifying glass, and converting readings to pressure by use of the calibration tables or curves, with corrections for well temperature. For extreme accuracy, a Micrometer-type chart reader is required.

The final reading is made in one of the Halliburton Chart Processing Departments, with the use of a Micrometer Optical Chart Reader. With this instrument, the deflection can be measured accurately to the nearest one thousandth of an inch, so that the final reading is consistent with the inherent sensitivity and accuracy of the gauge. A Formation Testing Service Report folder is then prepared which includes an enlarged photographic reproduction of the charts, along with the data pertinent to the test. This folder, together with the original chart, is then sent to the customer for his permanent record of the test results.

Chart Readers

The Halliburton Field Chart Reader was designed to provide an accurate method of reading formation testing charts in the field, laboratory, or office. The Field Chart Reader permits extrapolation of closed-in pressure buildup curves by providing a more accurate way to measure the time increments and the corresponding pressure points. These extrapolations are useful in calculations which help evaluate a test.

Two styles are available: the Field Chart Reader which is equipped with 6X scope and dial indicators that permit reading to the nearest one-thousandth (.001) in.; and, for a greater degree of accuracy, the Micrometer-Type reader which is equipped with 65X scope and direct reading counters.

HALLIBURTON SERVICES

Both Readers are compact and easy to carry. These precision instruments can be operated at wellsite with automobile cigarette lighter extension, or in the office with 115-230 AC current.

Both the Field Chart Reader and Micrometer-Type Reader are adaptable to reading of charts from any subsurface pressure or temperature instrument. Both Readers are available for purchase.

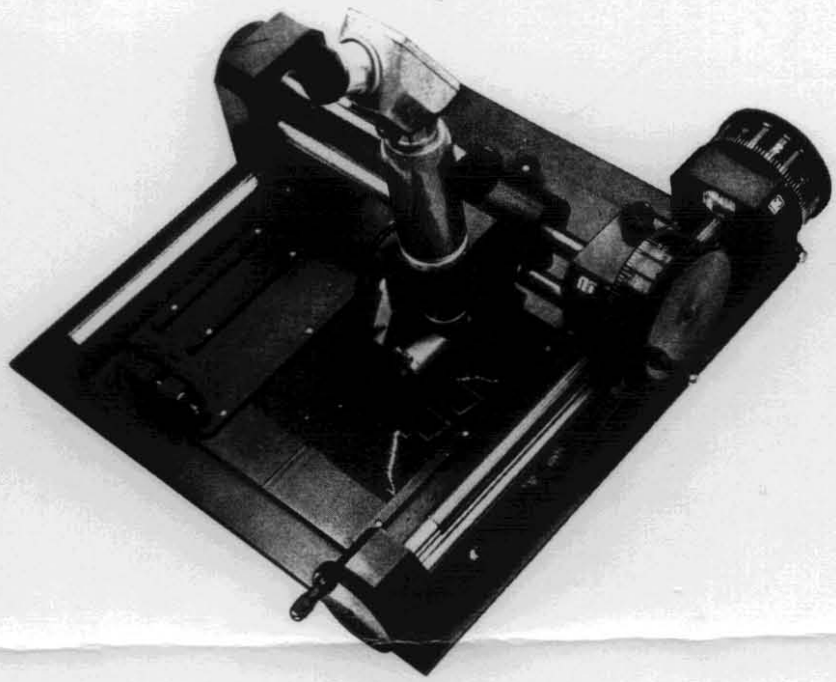
Halliburton Dual Closed-In-Pressure

Many formation tests employ the dual closed-in-pressure technique to provide more extensive and usable bottom hole pressure information.

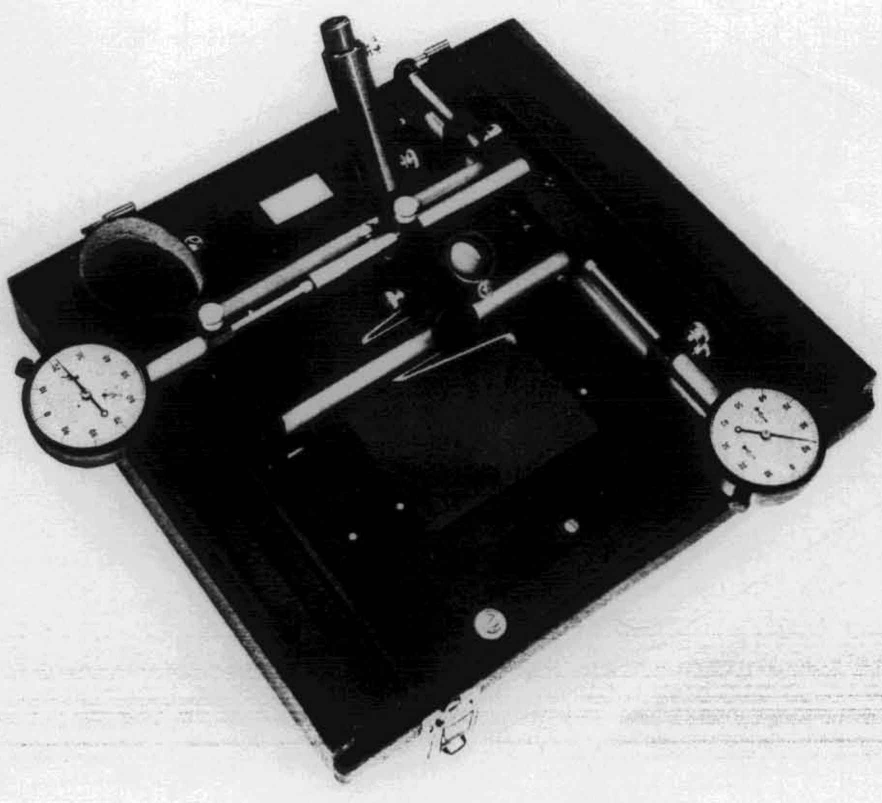
This technique involves the opening of the formation fluid flow into the drill pipe for a desired length of time and then closing the dual closed-in-pressure valve. The dual closed-in-pressure valve is then reopened for a second flow period and reclosed for a final closed-in-pressure buildup

This type of test produces two sets of recorded values. Subsequent comparison of, and calculations from, these values help determine the "damage ratio", production, transmissiblity, actual flow capacity, permeability, potentiometric surface, and other desired characteristics.

When tests are suitable, chart readings in time-versus-pressure increments are supplied.

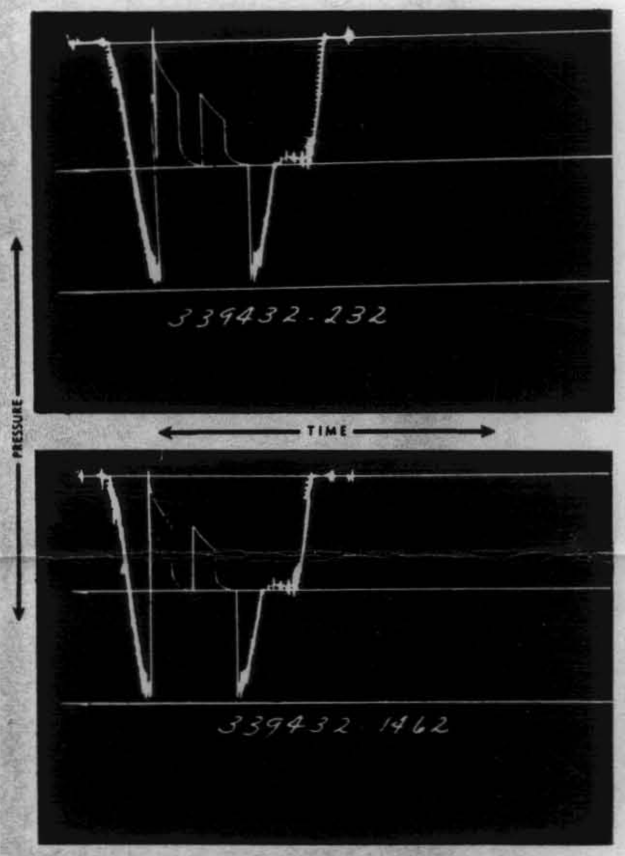


Micrometer-Type Chart Reader



Field Chart Reader

Testing



Each Horizontal Line Equal to 1000 p.s.i.

FLUID SAMPLER DATA

Sampler Pressure 540 P.S.I.G. at Surface
Recovery: Cu. Ft. Gas 0.3
cc. Oil 1040
cc. Water No Water
cc. Mud 50
Tot. Liquid cc. 1090
Gravity 39.2 ° API @ 60° °F.
Gas/Oil Ratio cu. ft./bbl.

	RESISTIVITY	CHLORIDE CONTENT
Recovery Water	@ °F.	ppm
Recovery Mud	@ °F.	
Recovery Mud Filtrate	@ °F.	ppm
Mud Pit Sample	@ °F.	
Mud Pit Sample Filtrate	@ °F.	ppm
Mud Weight 10.5	vis 40 cp	

Date 8-5-66 Ticket Number 339432 S
Kind of Job Open Hole Test Halliburton District
Tester Witness
Drilling Contractor

EQUIPMENT & HOLE DATA

Formation Tested
Elevation 1898 Kelly Bushing Ft.
Net Productive Interval 6 Ft.
All Depths Measured From Kelly Bushing
Total Depth 3336 Ft.
Main Hole/Casing Size 7.875
Drill Collar Length 480 I.D. 2.764
Drill Pipe Length 2820 I.D. 3.82
Packer Depth(s) 3330 Ft.
Depth Tester Valve 3313 Ft.

Cushion TYPE None AMOUNT Ft. Depth Back Pres. Valve Surface Choke 1.0" Bottom Choke 5/8"

Recovered 420 Feet of Gas show from drill pipe above fluid
Recovered 1800 Feet of Clean gassy oil
Recovered Feet of
Recovered Feet of
Recovered Feet of

Remarks Tool opened at 3:12 A.M. for first flow with a strong blow. Closed tool for 30 minutes. Re-opened tool at 4:12 A.M. with a strong blow throughout 30 minute second flow. Closed tool for 30 minutes. Started off bottom at 5:12 A.M.

TEMPERATURE	Gauge No. 232 Depth 3326 Ft.		Gauge No. 1462 Depth 3332 Ft.		Gauge No. Depth Ft.		TIME	
Est. °F.	Hour Clock Blanked Off		Hour Clock Blanked Off		Hour Clock Blanked Off		Tool Opened 3:12 A.M.	
Actual °F.	Pressures		Pressures		Pressures		Tool Closed 5:12 A.M.	
	Field	Office	Field	Office	Field	Office	Reported Minutes	Computed Minutes
Initial Hydrostatic		1832		1844				
First Period Flow Initial		23		63			—	—
First Period Flow Final		413		425			30	30
First Period Closed in		995		1006			30	30
Second Period Flow Initial		422		430			—	—
Second Period Flow Final		632		644			30	30
Second Period Closed in		994		1004			30	30
Third Period Flow Initial							—	—
Third Period Flow Final								
Third Period Closed in								
Final Hydrostatic		1823		1835			—	—

Lease Name SMITH ESTATE
Legal Location 37 - 31S - 67W
Well No. 101
Test No. 8
Tested Interval 3330 - 3336
Field Area WILDCAT
Lease Owner/Company Name NO NAME PRODUCING COMPANY

FORMATION TEST DATA

Interpretation and Calculation

Test interpretation and calculation, an advisory service available on a regular basis from Halliburton Services, supplements the conventional drill stem test. The service consists of translating the actual test information into the theoretical values needed to help guide the well operator's decision to complete, stimulate or abandon the formation. The translation is accomplished through the use of basic equations and formulas of proven authenticity generally accepted in reservoir evaluation practice. These calculations offer the following formation characteristics:

PRODUCTION—B/D In order to calculate the production a decision must be made as to which flow indication will be utilized for each of the flow periods. The first flow, for example, requires the use of fluid weight of fill-up in the test string during this period and often the flow time is too short to be reliable. When the flow period is considered sufficient, the weight of fluid recovered is converted to barrels produced in a given period and then converted to B/D. When calculating the second flow, one of three methods is employed: If the well is a very good producer, a difference of pressure must be used during the early part of the flow period, as the rate will rapidly decline as back pressure increases; if the well produces at a constant rate during second flow, the footage of recovery in the test string can be converted to B/D; or if the well flows and tank gauges are available, this method is used to compile the estimated daily rate of production.

Properly planned flow periods will result in a more accurate test and more accurate interpretation and calculation.

TRANSMISSIBILITY—md ft/cp This represents three factors—permeability, height and viscosity—and is solved in a cluster. This value is then used to solve

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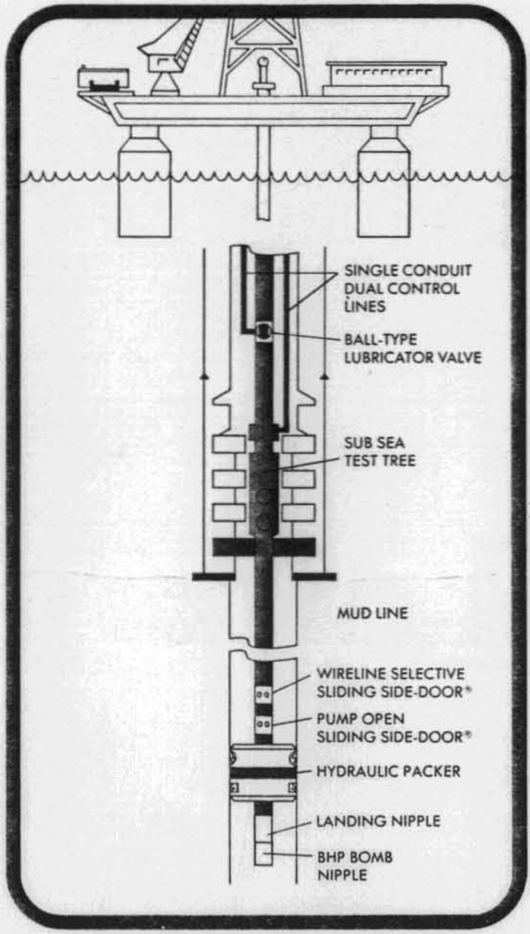
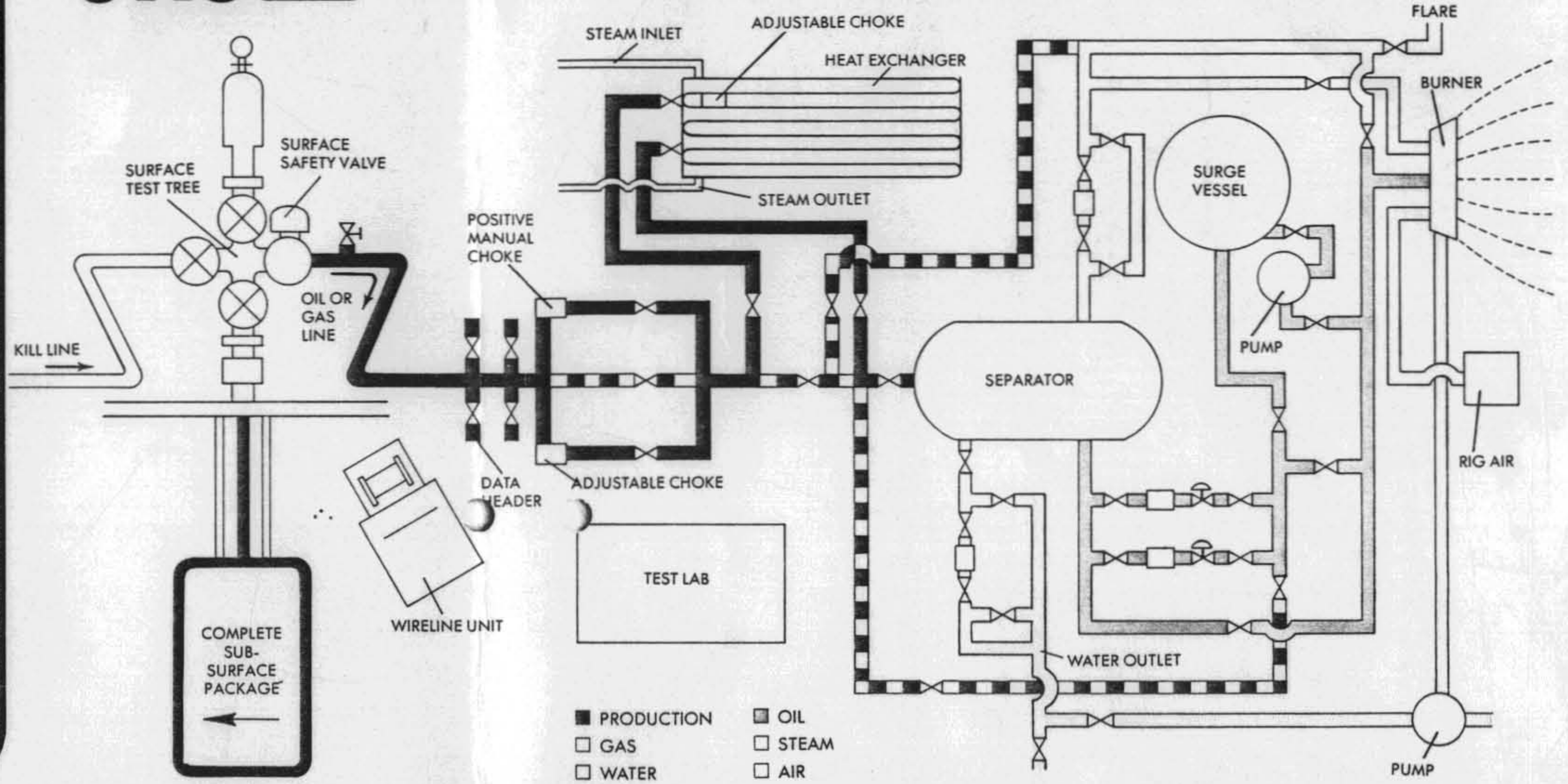


OTIS PRODUCTION TESTING SERVICE EQUIPMENT CAPABILITIES AND FLOW DIAGRAM



SUBSURFACE EQUIPMENT PACKAGE

BHP Bomb Nipple — A Type XN Otis Landing Nipple and Locking Mandrel.

Test Packer — A Type RH Otis Hydraulic Set Retrievable Production Packer with Holddowns.

Pump Open Circulating Tool — A Type PO Otis Sliding Side-Door.

Wireline Operated Circulating Tool — A Type X Otis Sliding Side-Door with nipple profile and Type X Locking Mandrel.

Quick Disconnect Sub Sea Test Tree — A standard Otis Sub Sea Test Tree complete with surface pressure control manifold and control line reel package.

Ball Type Lubricator Valve — A surface controlled, subsurface full opening ball valve complete with control line reel package and control manifold.

SURFACE EQUIPMENT PACKAGE

Surface Test Tree — A 10,000 psi working pressure H_2S Test Tree complete with Master Valve, Type U Otis Safety Valve, Kill Valve, Lubricator Valve with special lubricator section and a chemical injection valve.

Flow Line Choke Manifold — A manifold consisting of two different chokes — one, an adjustable automatic choke; the other a positive choke, with sufficient full opening plug valves and piping to permit by-passing chokes if desirable.

Heat Exchanger — A 6-million BTU/hr., 5,000 psi working pressure Steam Heat Exchanger.

Separator — A 1440 psi W.P. three phase high efficiency separator to separate out oil, gas and water. Separator is designed to handle up to 80 MMCFD or 12,000 BPD.

Surge Tank and Transfer Pump — A 100 Bbl., 25 psi pressure vessel for use in cleaning up the well, taking samples and proving liquid flow meters. Tank comes with a high volume pump for use in transferring fluid to the burner. Pumps are available for moving up to 10,000 Bbls. of fluid per day at 350 psi.

Otis CB-12 Clean Burning Oil Burner — An OTIS/NAO Burner designed to clean burn 12,000 Bbls. of fluid (hydrocarbons) per day at 350 psi. Burner head mounts on a boom that is a minimum of 60 feet in length and can be directionally adjusted up to 60° for best leeward burning.

Wireline Service Unit with Operator — A standard single drum, 20,000 foot reel capacity skid mounted Otis Wireline Unit and Operator are available as part of the Equipment and Service Package.

Portable Laboratory — A compact test lab containing a deadweight tester, bomb calibration bath, centrifuge, hydrometers, gas gravitometer, salinity test kit, vacuum pump and other equipment completes the package.

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OTIS REMOVABLE SUB SEA TEST TREE

An Otis Removable Sub Sea Test Tree lets you conduct standard well productivity evaluation tests without removing the blowout preventer stack! It is a compact, easy to install tool which is designed to be run and retrieved on tubing or drill pipe through the riser pipe of a well being drilled from a floating vessel. It is normally installed in the blowout preventer stack with its point of support in the wellhead at the ocean floor. Three alternate methods of installing the Test Tree are shown by schematic drawings on the opposite page.

You use it in the same manner you would a conventional sub sea production tree that has been installed for testing. It permits the same range of tests and reservoir evaluation operations to be performed. It is not necessary to modify your preventer stack to use an Otis Sub Sea Test Tree! Your Otis Production Testing Specialist can supply you a Test Tree to fit the blowout preventers you are using, regardless of make or model.

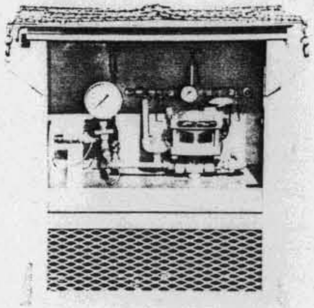
When properly installed, an Otis Sub Sea Test Tree is designed to allow the well to be tested safely. The design principle provides that should it become necessary to temporarily abandon the well, the tree would be used to effect a shut-in and disconnect. The tree's disconnect assembly is released either hydraulically or pneumatically. For further protection, a mechanical override is provided that is designed to permit releasing of the tree mechanically should the hydraulic or pneumatic mechanism become inoperable for any reason.

THESE ARE THE BENEFITS OF DESIGN PRINCIPLE

- You benefit from the safety aspect of having the BOP stack over the hole at all times.
- You save the time required to round trip the preventer stack.
- You save the cost of a diver to break-out the "stack" and hook-up a conventional underwater tree.
- You greatly simplify the job of safely moving the drilling rig off location during test operations should it become necessary.
- You obtain reservoir evaluation data through flow testing and formation draw-down that may save you additional expenses when completing and producing the well.
- Accepted, automatic ball-type safety valves are designed to protect well, personnel and drilling equipment during evaluation tests.

DESIGN PRINCIPLE

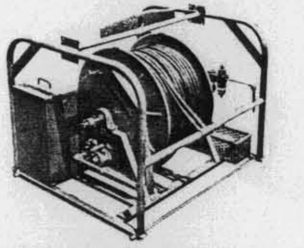
The design and operating principles of the Otis Removable Sub Sea Test Tree are as remarkably uncomplicated in concept as is the installation of the tool. The sub sea portion of the tree consists of two full-opening, normally-closed ball valves, a hydraulic fluid control circuit to operate the valves, and a hydraulic release connection on top (see schematic). A pressure control manifold and reel of flexible, hydraulic pressure control line make up the package.



PRESSURE CONTROL MANIFOLD—A control manifold of this type is used to maintain hydraulic pressure to the Otis Sub Sea Test Tree. It utilizes a ratio-piston hydraulic pump to regulate pressure.

When properly installed in the preventer stack, hydraulic pressure regulated by the manifold unit located on the drilling vessel, acts to maintain the ball valves in an opened position. A flexible nylon hose serves as the conductor of hydraulic pressure from the manifold to the tree. Pay-out and take-up of the flexible hose is automatically controlled by the reel package housing the hose.

Should it become necessary to move off the well, the Test Tree is designed to be released by: (1) bleeding-off control line pressure to permit the safety valves to close, shutting-in the well; (2) pressuring-up on the release line and (3) picking-up on the handling string and removing it. Riser pipe can then be disconnected and retrieved and the vessel moved.

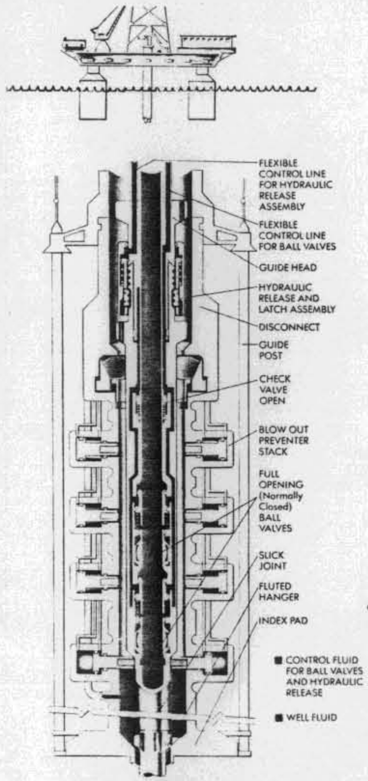


REEL PACKAGE—This reel contains the flexible nylon hose which serves as the carrier of both hydraulic lines. Pay-out and take-up of the hose is automatically controlled with its self contained air driven motor.

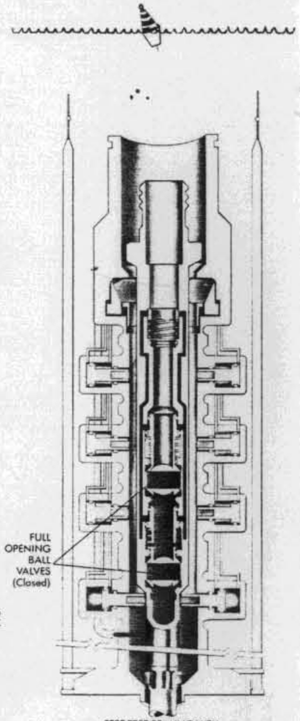
If the hydraulic control lines should part, the latch assembly is designed to be released by picking-up and rotating the handling string approximately six times to the right. Check valves serve to prevent contamination of the hydraulic control fluid following a disconnect.

Re-latching the tree is accomplished by rerunning the riser pipe, the handling string with its guide head and the hydraulic control line, and performing prescribed latch re-engaging procedures.

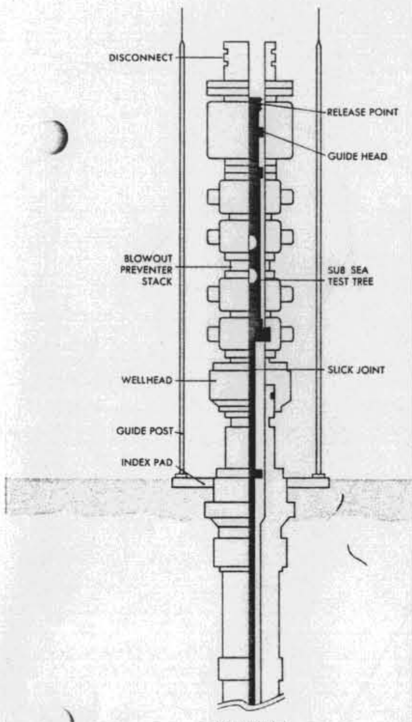
Pressure applied to the hydraulic circuit is designed to open the valves in the tree so that testing or completion work may be resumed.



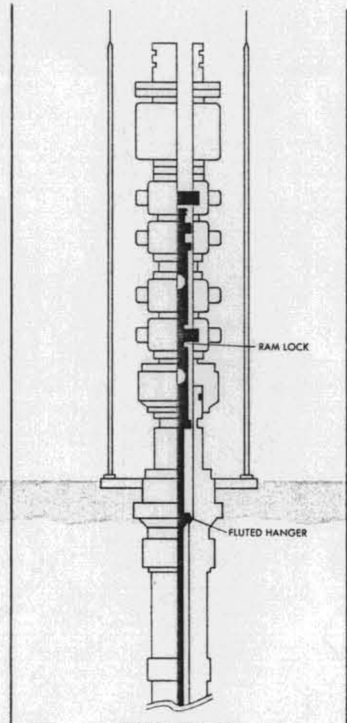
TEST TREE INSTALLED FOR TEST PROCEDURES



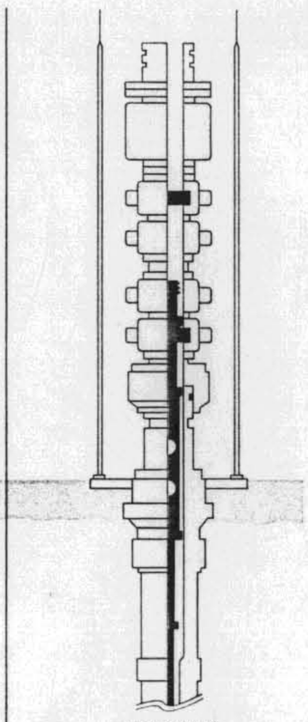
TEST TREE SEALING WELL WITH VESSEL REMOVED



TREE IN STACK HUNG OFF ON RAMS



TREE IN STACK HUNG OFF ON FLUTED HANGER (No slick joint)


TREE BELOW STACK HUNG OFF ON RAMS

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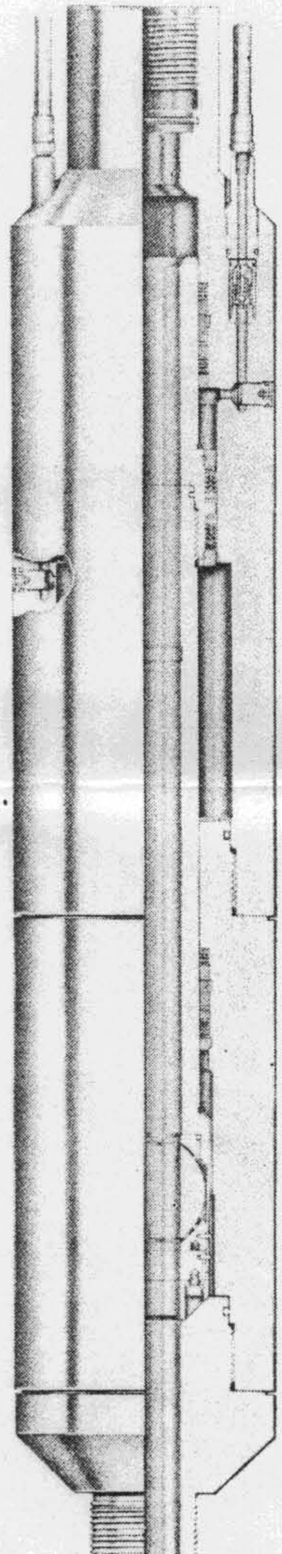

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OTIS BALL-TYPE LUBRICATOR VALVE

The Otis Ball-Type Lubricator Valve is a special version of the ball-type closure used in the Otis Subsea Test Tree. It is controlled by applying hydraulic pressure through control line(s) from the rig floor. The valve serves to eliminate the hazard of installing a wireline lubricator above the surface tree at the rig floor of a constantly moving vessel. The valve is available in three different models. These are: (1) a normally closed model which requires hydraulic pressure to hold it in the open position against spring pressure; (2) a normally open model which requires hydraulic pressure to close it against spring pressure; and (3) a model which is neither normally open nor closed. Dual control lines permit pumping this model to the desired position. A control line reel package facilitates ease of installing control lines.

Thread Connections .... 4½" Otis Acme
Working Pressure - PSI 10,000
Service .... Standard or Sour

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Ful-Flo SAFETY VALVE

The Ful-Flo® Safety Valve may be installed in a test string to automatically close the string should the pipe come apart or be dropped. The safety valve is full opening and pressure balanced. It is normally open, and stays open while tension is applied (as when pipe is suspended below it). The valve closes when tension is released. During a test, the safety valve should always be in tension.

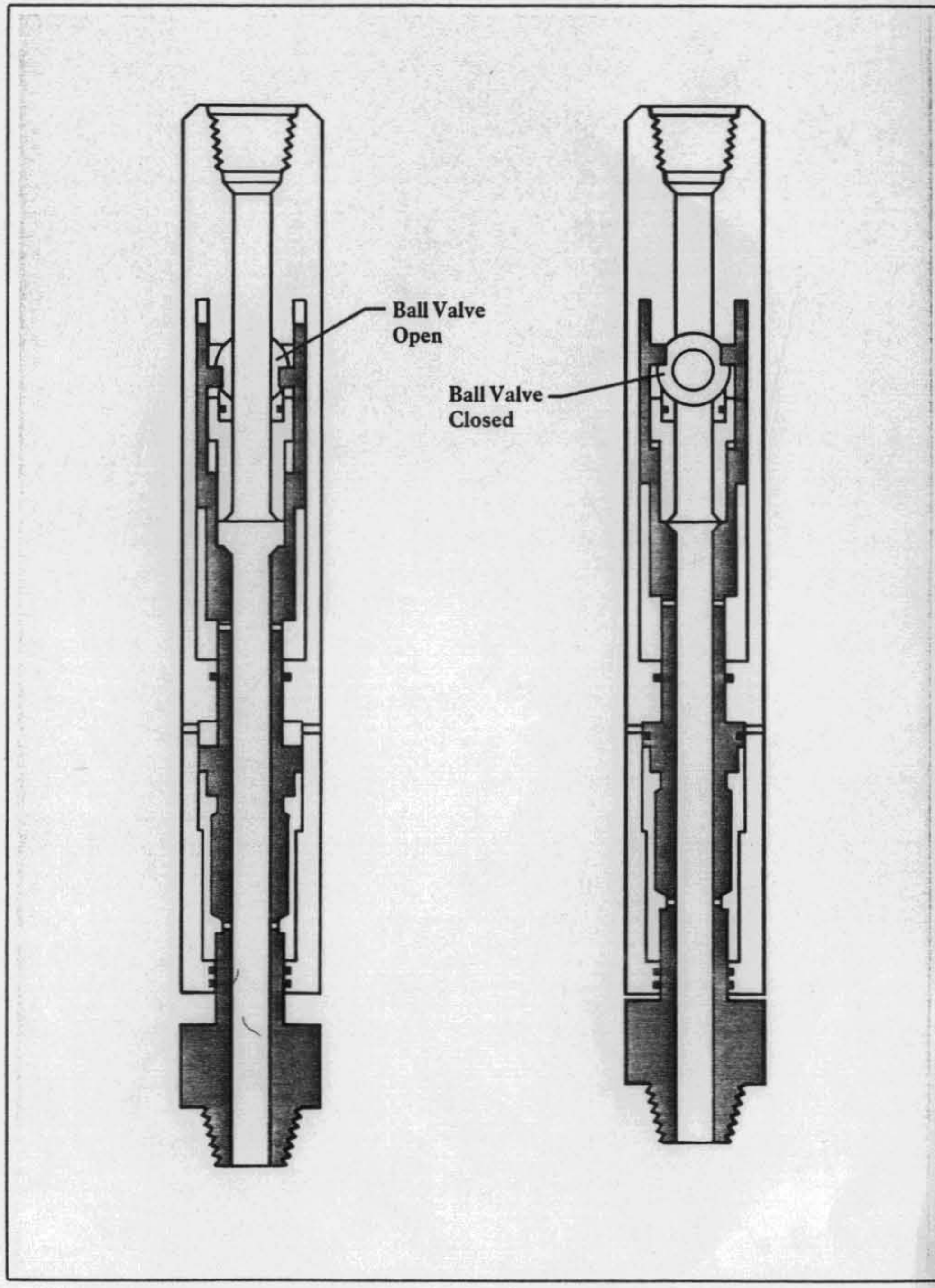
When the valve is run in an off-shore testing string with slip joints, it is installed above the slip joints with one or more stands of drill pipe below it to keep it in tension and hold the valve open.

When the Ful-Flo Safety Valve is run in a string without slip joints, the tool should be placed at a point in the string where there is enough pipe weight below it to set the packer plus 5000 lb additional weight to allow for setting the required weight on the packer and still have 5000 lb tension at the tool to keep the ball valve open.

CAUTION: The Ful-Flo Safety Valve does not **kill** a well when it closes. Should the pipe separate, causing the valve to close, the operator should be prepared to control any pressure encountered at the time the tool is reopened.

Ful-Flo Safety Valve Sizes Available

Tool Size OD, in.	Actual OD, in.	Actual ID, in.	Connections
5	5.00	2.25	3½" IF Tool Joint
4⅝	4.68	2.00	3½" IF Tool Joint
3⅞	3.90	1.80	2⅞" 8 RD EUE TBG.
3	3.03	1.12	2⅜" 8 RD EUE TBG.



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HEX MANDREL SLIP JOINT

Halliburton Hex Mandrel Slip Joints help maintain a constant weight on the packer and other tools while compensating for up and down movement of a floating drilling vessel. These slip joints were designed specifically for the following floating vessel operations:

- Open hole testing
- Hook wall testing
- Pumping operations (squeezing, treating, etc) with compression packers.

When a floating vessel rises, the slip joint is lengthened, thereby increasing its internal volume. At the same time, an internal piston displaces an equal volume of fluid into the pipe; downward movement of the vessel reverses the process.

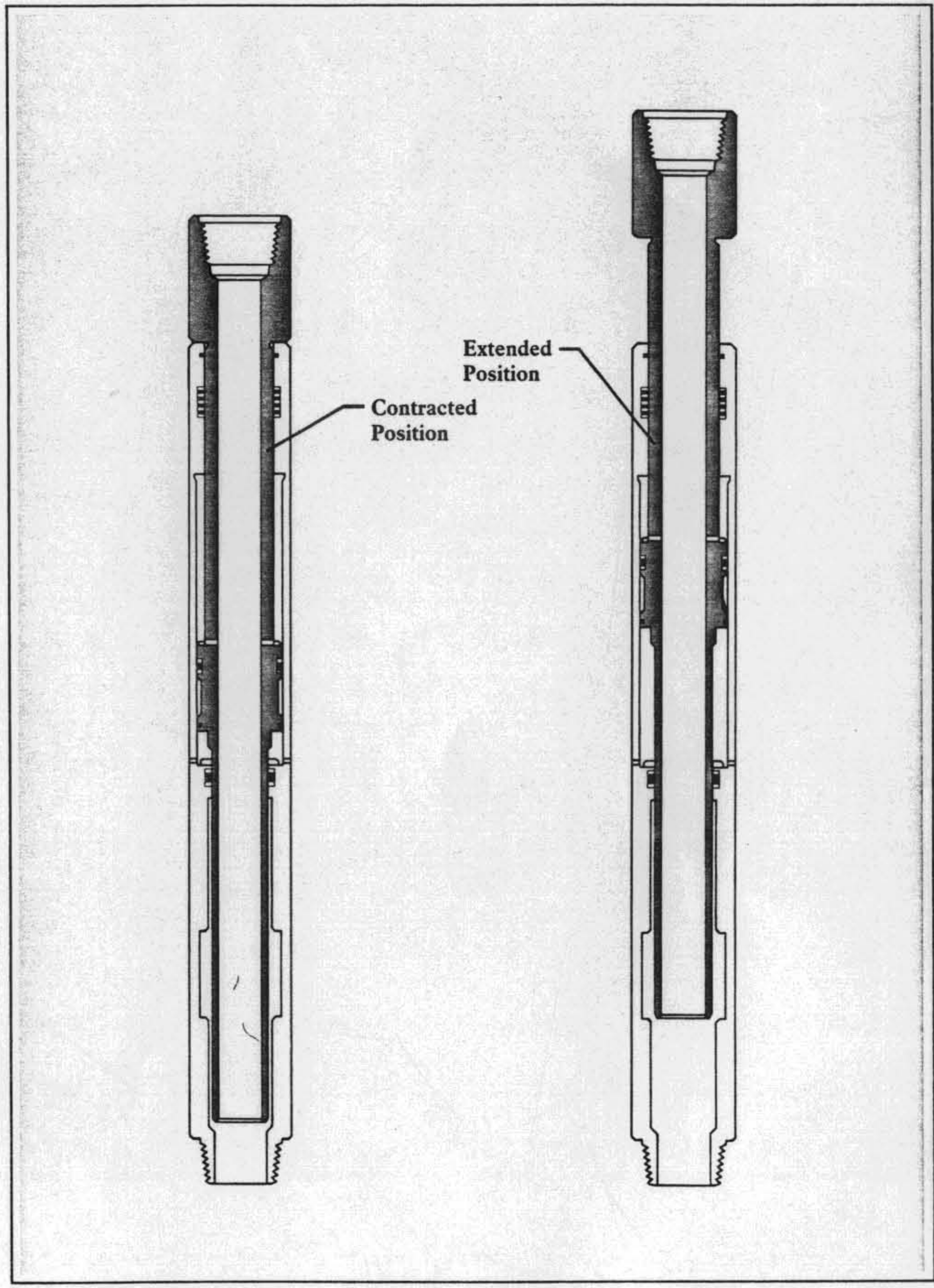
Each slip joint provides five feet of movement, and additional slip joints can be stacked (they must be located together) to provide more travel.

Benefits of using slip joints include:

- Slip joints are balanced internally to help keep the internal pressure of the pipe constant as the floating vessel moves up and down.
- A constant weight is kept on downhole tools.
- Design of the slip joints allow torque to be transmitted to tools below.
- When used below testing tools, slip joints can provide free travel for tool operation.
- Slip joints may be used below Ful-Flo Hydrospring® testers as extension joints.

Hex Mandrel Slip Joints Available

Pipe Size OD, in.	Tool Size OD, in.	Tool Size ID, in.	Connections
5	5.00	2.25	3½" IF Tool Joint
4⅝	4.62	2.00	3½" IF Tool Joint
3⅞	3.90	1.80	2⅞" 8 RD EUE TBG.
3	3.06	1.12	2⅜" 8 RD EUE TBG.



Ful-Flo HYDRAULIC BYPASS

The Ful-Flo® Hydraulic Bypass combats the problem of hydrostatic pressure buildup that can occur below the APR-N Tester Valve before its initial opening. This buildup can prevent full entrance of a packer mandrel into the squeeze packer or production packer.

Stinging into a permanent packer or a squeeze packer can cause compression of fluid between the tester valve and the formation, squeeze packer valve, or blank casing below the packer. This compression can cause a pressure increase. Conventional packer bypasses run below the tester valve do not completely solve the problem because the bypasses close before tool movement ceases. With its hydraulic delay system and face seal, the Ful-Flo Hydraulic Bypass closes at the end of tool movement, helping to eliminate a pressure buildup.

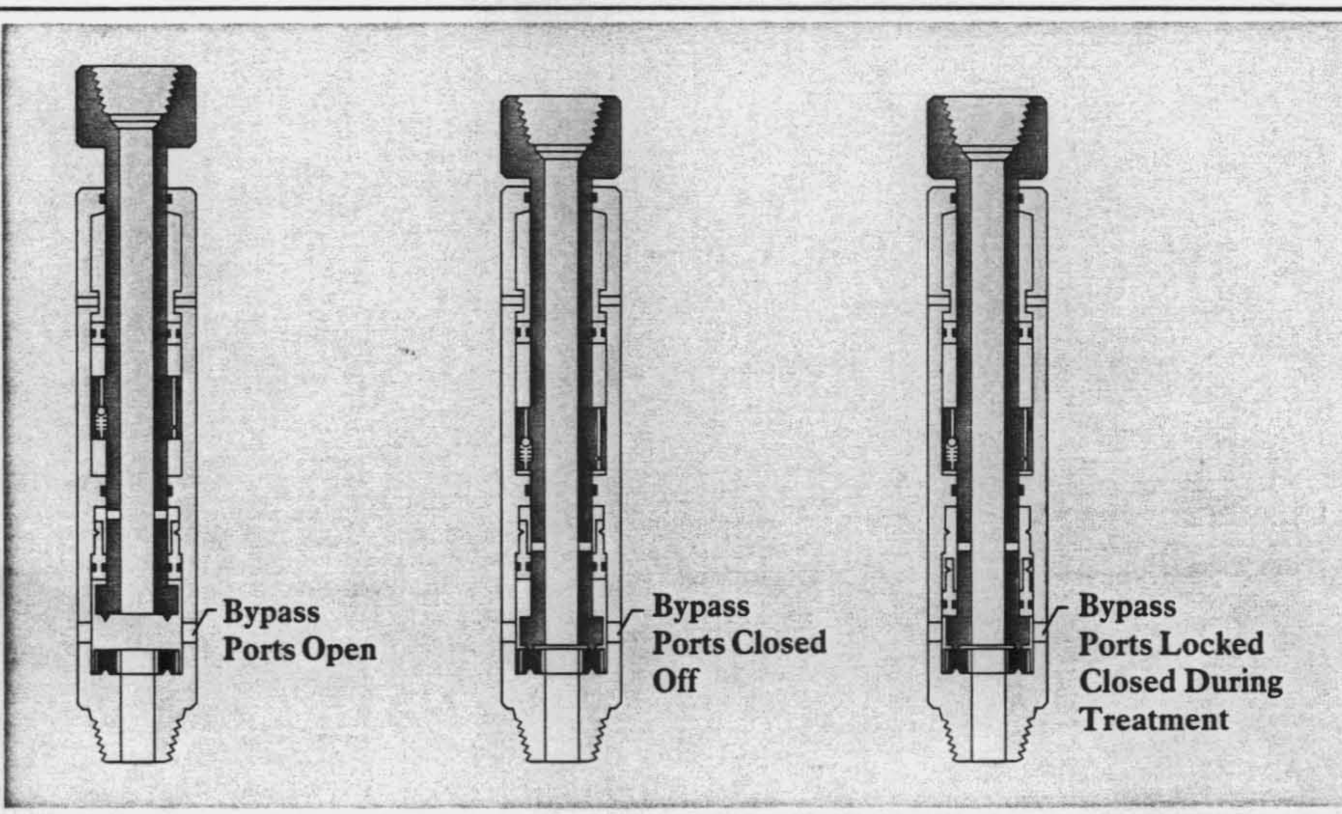
A built-in "lock closed" system keeps the tool closed for treatments through the test string, but allows reopening by picking the tool up.

Ful-Flo Hydraulic Bypass Sizes Available

Tool Size OD, in.	Actual OD, in.	Actual ID, in.	Connections
4⅝	4.68	2.25	3½" IF Tool Joint
3⅞	3.90	1.80	2⅞" 8-RD EUE TBG.
3	3.03	1.25	2⅜" 8-RD EUE TBG.

Table of maximum time needed to close the hydraulic bypass with a given weight on the tool.

WEIGHT ON THE TOOL (lb)						
1000	5000	10000	15000	20000	30000	40000
13 min	6 min	4 min	4 min	3 min	3 min	2 min



305039

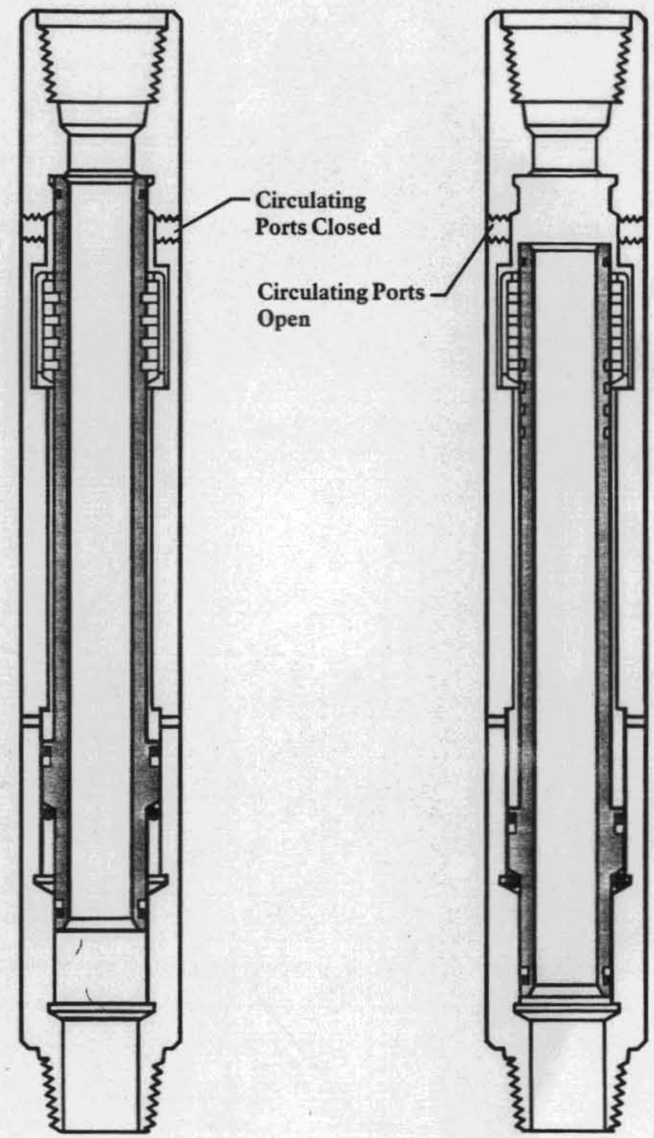
APR-A CIRCULATING VALVE

Halliburton's APR*-A Circulating Valve provides the means to perform the reversing process. The valve is operated by annular pressure (the combination of pump and hydrostatic pressures) and opens at a predetermined pressure. Considerations for determining the operating pressure are:

- Operating pressures of the other annulus pressure responsive (APR) tools---Since reversing out is the last step taken before tripping out, the APR-A is the last tool operated; consequently, the operating pressure of the APR-A must be greater than for the other APR tools.
- Maximum pressure on the casing---the upper limit of the APR-A operating pressure should be less than the maximum annulus pressure allowed.

APR-A Circulating Valve Sizes Available

Tool Size OD, in.	Actual OD, in.	Actual ID, in.	Connections
5	5.06	2.25	3½" IF Tool Joint
4⅝	4.68	2.00	3½" IF or 3⅞" 6-Stub Acme Special
3⅞	3.92	1.80	2⅞" 8 RD EUE TBG.
3	3.06	1.00	2⅜" 8RD EUE TBG.



305040

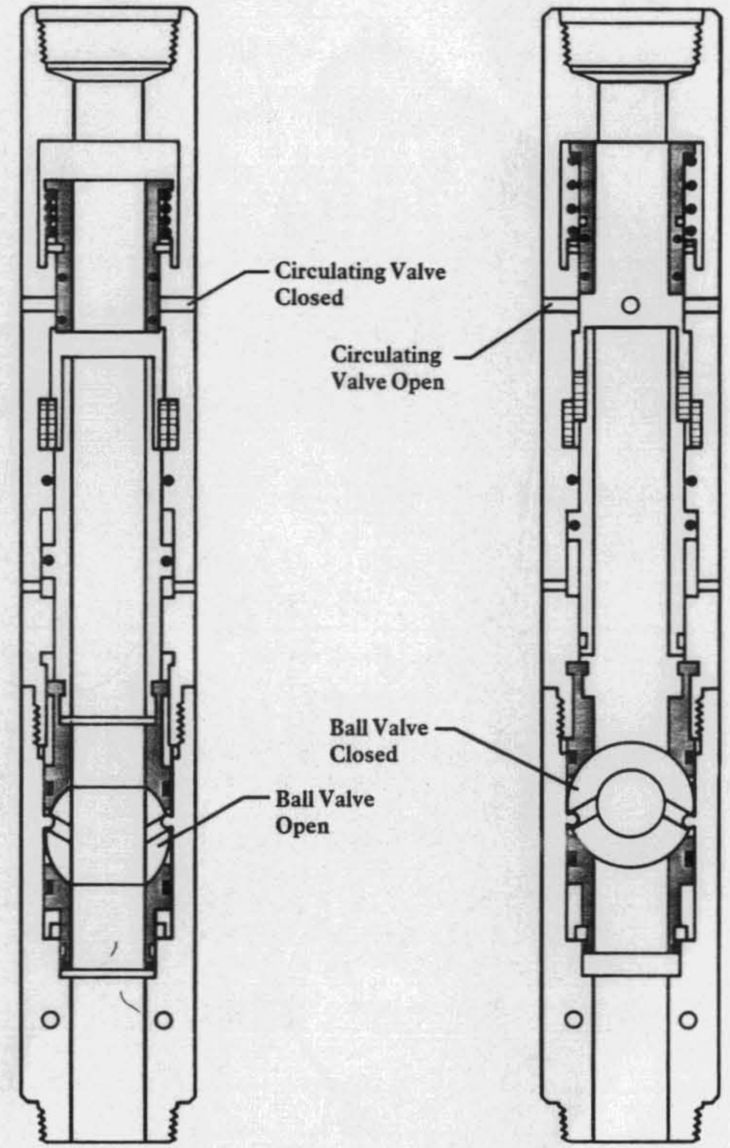
APR-M2 CIRCULATING SAFETY VALVE

The APR®-M2 Circulating Safety Valve combines a safety valve and reversing valve into one tool while still maintaining the full opening feature of other APR tools. The APR-M2 Circulating Safety Valve, which is annulus pressure operated, gives a safety closed-in condition and reverse circulation without pipe manipulation.

As in the APR-A Circulating Valve, the operating pressure of the APR-M2 Circulating Safety Valve is preset by the operator, based on well conditions. This operating pressure is a combination of the hydrostatic and pump pressure on the annulus and is set higher than the calculated operating pressure of the APR-N Tester Valve so that the tester valve can be operated without operating the circulating safety valve. When the final closed-in period is desired, additional annulus pressure is applied to close the ball valve in the APR-M2 Circulating Safety Valve, beginning the final closed-in period. Immediately after the ball valve closes, the circulating valve automatically opens to allow reversing out of recovery during the final closed-in pressure period.

APR-M2 Sizes Available

Tool Size OD, in.	Actual OD, in.	Actual ID, in.	Connections
5	5.03	2.25	3½" IF Tool Joint
4⅝	4.68	2.00	3½" IF Tool Joint
3⅞	3.90	1.81	2⅞" 8-RD EUE TBG.
3	3.06	1.00	2⅜" 8-RD EUE TBG.



305041

RTTS. A Multiple Purpose Retrievable Packer Used Throughout The World For All Basic Service Jobs Normally Associated With Retrievable Squeeze Tools.

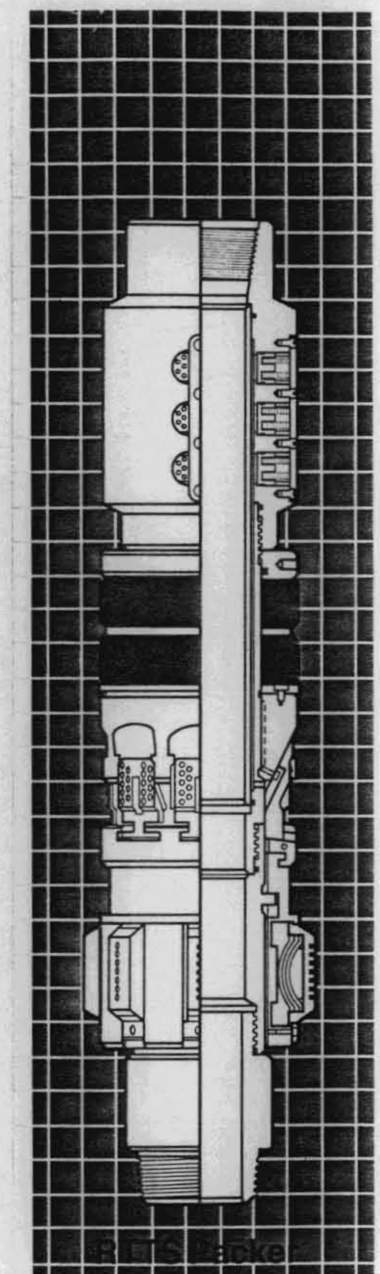
Thousands of wells successfully tested, treated or squeezed offer tribute to the versatility and dependability of the RTTS Retrievable Packer. High performance under many different well conditions has earned the RTTS Retrievable Packer a reputation respected by oilmen around the world.

RTTS Performance Features

- **Full Opening**
  Design of the packer mandrel bore allows large volumes of fluid to be pumped through the tool. Tubing type guns and other wireline tools can be run through the packer to work below it.
- **Retrievable - Resettable In The Hole**
  Engineered to be set and reset in the hole as many times as is necessary by simple tubing manipulation. Uncomplicated operational features facilitate retrieving the packer when the job is done.
- **Tungsten Carbide Slips**
  Actuated by pressure through the tubing, these slips are designed to provide greater holding power and improved wear resistance in high strength casing.
- **Optional Built-In Circulating Valve**
  Mechanically operated circulating valve locks into open or closed position during squeezing or treating operations, opens easily when required to allow circulation above the packer.

Name The Operation...Test, Treat Or Squeeze...

Halliburton's RTTS Retrievable Packer has the capacity to perform efficiently and economically under almost every type of well condition.



RTTS Packer

RTTS PACKER

SIZE (in.)	CASING WT. RANGE (lb)	TOOL OD (in.)	MIN. ID (in.)	LENGTH (in.)	TOP THREAD CONNECTION*	BOTTOM THREAD CONNECTION
2⅜	4.6	1.81	.60	34.34	1.050 in. OD 10RD EUE (FEMALE)	1.050 in. OD EUE (MALE)
2⅞	6.4	2.22	.75	22.44	1⅞ in. OD 10RD (FEMALE)	1.315 in. 10RD (MALE)
2⅞	7.9-8.7	2.10	.60	34.34	1.050 in. OD 10RD EUE (FEMALE)	1.050 in. 10RD (MALE)
3½	5.7	2.93	.62	31.28	1⅞ in. 12UNS (FEMALE)	1.315 in. 10RD EUE (MALE)
3½	9.2-10.2	2.70	.62	31.28	1⅞ in. 12UNS (FEMALE)	1.315 in. 10RD EUE (MALE)
3½	13.3	2.50	.62	31.28	1⅞ in. 12UNS (FEMALE)	1.315 in. OD 10RD (MALE)
4	9.5-11.6	3.18	1.12	50.74	2-11/16 in. 10UNS (FEMALE)	2⅜ in. 8RD EUE (MALE)
4	12.5-15.7	3.06	.865	47.90	2-11/16 in. 10UNS (FEMALE)	1⅞ in. 8RD DRILL PIPE (MALE)
4½	9.5	3.89	1.80	49.92	3-1/32 in. 10UNS (FEMALE)	2⅜ in. 8RD EUE (MALE)
4½	11.6-13.5	3.75	1.80	49.92	3-1/32 in. 8RD (FEMALE)	2⅜ in. 8RD EUE (MALE)
4½	15.1-18.1	3.53	1.51	47.01	2-11/16 in. 10UNS (FEMALE)	2⅜ in. 10RD NU (MALE)
5	11.5-13	4.25	1.80	46.17	3-1/32 in. 10UNS (FEMALE)	2⅜ in. 8RD EUE (MALE)
5	15-18	4.06	1.80	46.17	3-1/32 in. 10UNS (FEMALE)	2⅜ in. 8RD EUE (MALE)
5	21	3.89	1.80	49.92	3-1/32 in. 10UNS (FEMALE)	2⅜ in. 8RD EUE (MALE)
5	23	3.78	1.80	49.92	3-1/32 in. 10UNS (FEMALE)	2⅜ in. 8RD EUE (MALE)
5½	13-20	4.55	1.90	46.38	3½ in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
5½	20-23	4.40	1.80	46.17	3-1/32 in. 10UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
5½	23-26	4.25	1.80	46.17	3-1/32 in. 10UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
6	15-23	5.06	1.90	46.38	3½ in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
6⅝	17-20	5.65	2.40	52.10	4-5/16 in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
6⅝	24-32	5.43	1.90	46.38	3½ in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
*7	17-29	5.75	2.40	52.10	4-5/16 in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
*7	32-38	5.65	2.40	52.10	4-5/16 in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
*7	49.5	5.25	2.00	46.38	3½ in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
*7⅝	20-26.4	65.0	2.40	52.10	4-5/16 in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
*7⅝	29.7-39	6.35	2.40	52.10	4-5/16 in. 8UNS (FEMALE)	2⅞ in. 8RD EUE (MALE)
*8⅝	24-44	7.37	3.00	76.92	4½ in. API IF T.J. (FEMALE)	4½ in. API IF T.J. (MALE)
*8⅝	49	7.21	3.00	76.92	4½ in. API IF T.J. (FEMALE)	4½ in. API IF T.J. (MALE)
*9⅝	29.3-53.5	8.25	3.75	77.71	4½ in. API IF T.J. (FEMALE)	4½ in. API IF T.J. (MALE)
*9⅝	40-61.1	7.95	3.00	76.92	4½ in. API IF T.J. (FEMALE)	4½ in. API IF T.J. (MALE)
*9⅝	58.4-71.8	7.80	3.00	76.92	4½ in. API IF T.J. (FEMALE)	4½ in. API IF T.J. (MALE)

*7 in. and larger sizes are also available with CAS top connection.

LPR-N

Simplicity, Safety, Versatility -- all the advantages of a full opening APR testing tool and then some.

305042

Another in Halliburton's growing line of full opening testing tools is the Low Pressure Responsive (LPR™-N) tester valve.

Simplicity: Like the APR tools, the LPR™-N tester valve operates by responding to changes in pressure in the casing-to-drill pipe annulus and requires no pipe manipulation at any time during the test. This makes the tool especially useful for operations from floating rigs where up-and-down movement makes pipe manipulation difficult and in directional or deviated wells where there is excessive hole drag.

To open the tool, simply increase annulus pressure on the tool to a prescribed level above hydrostatic. Bleeding annulus pressure closes the tool. Having multiple closed-in periods during the same test is one of the great advantages of this feature.

The LPR-N tool can be used in the same string with any of the APR tools, which allows all perforating, testing, treating, and retesting to be performed in the same trip.

Safety: Since no pipe manipulation is necessary to operate the LPR-N tester valve, tests can be conducted with the blowout preventer rams closed.

As another safety feature in the tool, the LPR-N tester valve automatically closes when the annulus pressure is released.

The closing force of the LPR-N tester valve is faster and greater than other tester valves, so it will overcome obstructions to closing and minimize fluid cutting of the valve ball.

Versatility: By operating at lower pressures than other pressure controlled tester valves, the LPR-N tester valve allows testing of wells with limited casing burst pressures and increases the flexibility of designing tests in conjunction with companion pressure operated tools.

The LPR-N tester valve can be run without a bypass below it because fluid pressure can be allowed to build up or bleed off below the LPR-N tester valve without affecting the pressure required to open the tool. In fact, internal pressure has little or no effect on the tool's operating efficiency. To protect the formation, however, a bypass valve should be run when using production packers or drillable squeeze packers. Other valves below the LPR-N tester valve can be closed, such as in a surge test, so long as the pressure differential between the high pressure in the annulus and the low pressure inside the string doesn't exceed the pressure limitations of the tools or drill pipe.

Fluid temperature also has little effect upon the LPR-N tester valve. Pumping cold fluid through the LPR-N tester valve will not prevent the tool from closing. Adjustments in annulus pressure may be required as the tool is heated or cooled.

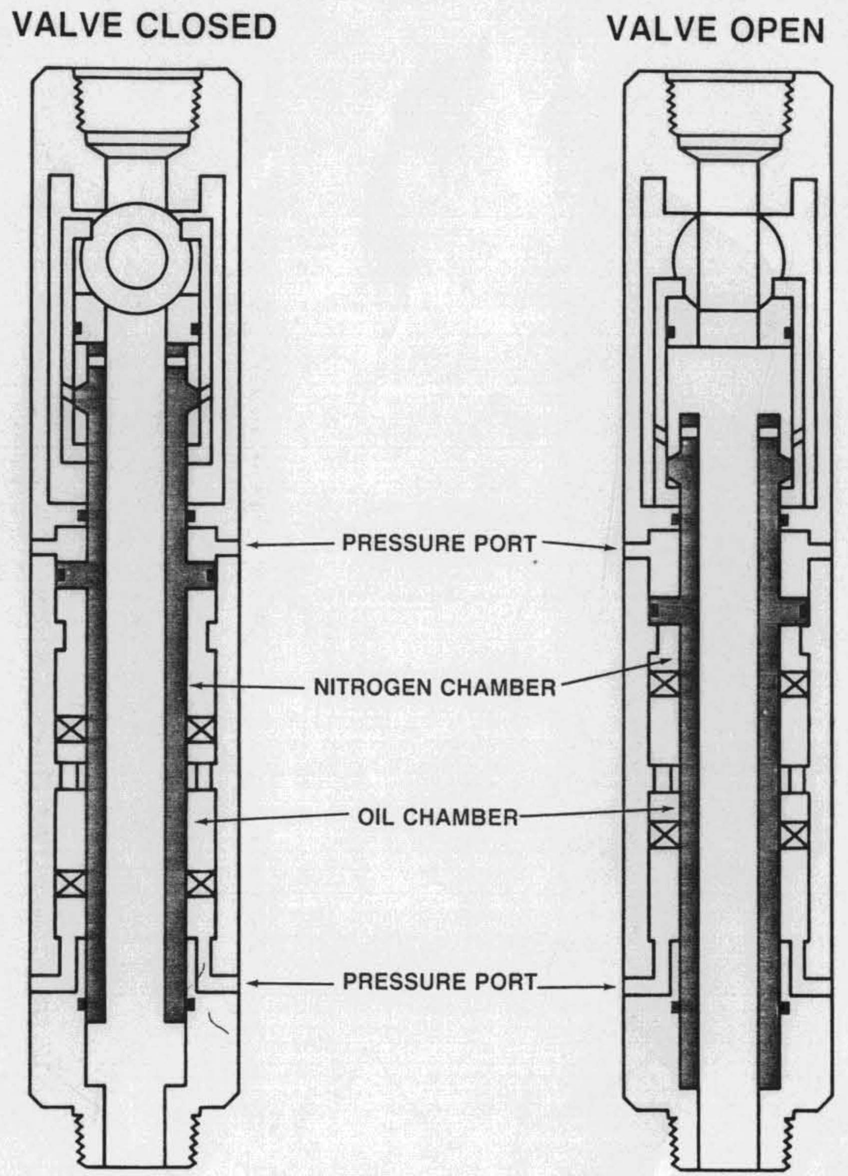
In some cases, the tool's unique isolation valve design makes reverse circulation through the LPR-N tester valve possible by holding backpressure on the work string.

Of course, the full opening feature of the LPR-N tester valve adds to the versatility of the tool just as it does for the APR tools. The larger flow passage of the tool minimizes the choking effect of fluids passing through it. And it allows other tools and equipment to be run through the tool without removing the string from the hole. The well can be perforated with the LPR-N tester valve in the hole using through-tubing guns or tubing conveyed guns run below the packer and fired with drop bars or tubing pressure.

With all these advantages in a downhole testing tool, why search any further? Just use the LPR-N tester valve along with Halliburton's other fine full opening, annulus pressure responsive tools -- then get ready for more LPR tools to follow. See your Halliburton Services representative for more details.

TOOL SIZE	OD IN.	ID IN.	CONNECTION
5"	5.03	2.25	*3½" IF
4⅝"	4.68	2.00	*3½" IF
3⅞"	3.80	1.80	2⅞" 8RD
3"	3.06	1.12	2⅜" 8RD

*Also available with 3⅞ in. 6 STUB Acme Tool Joint

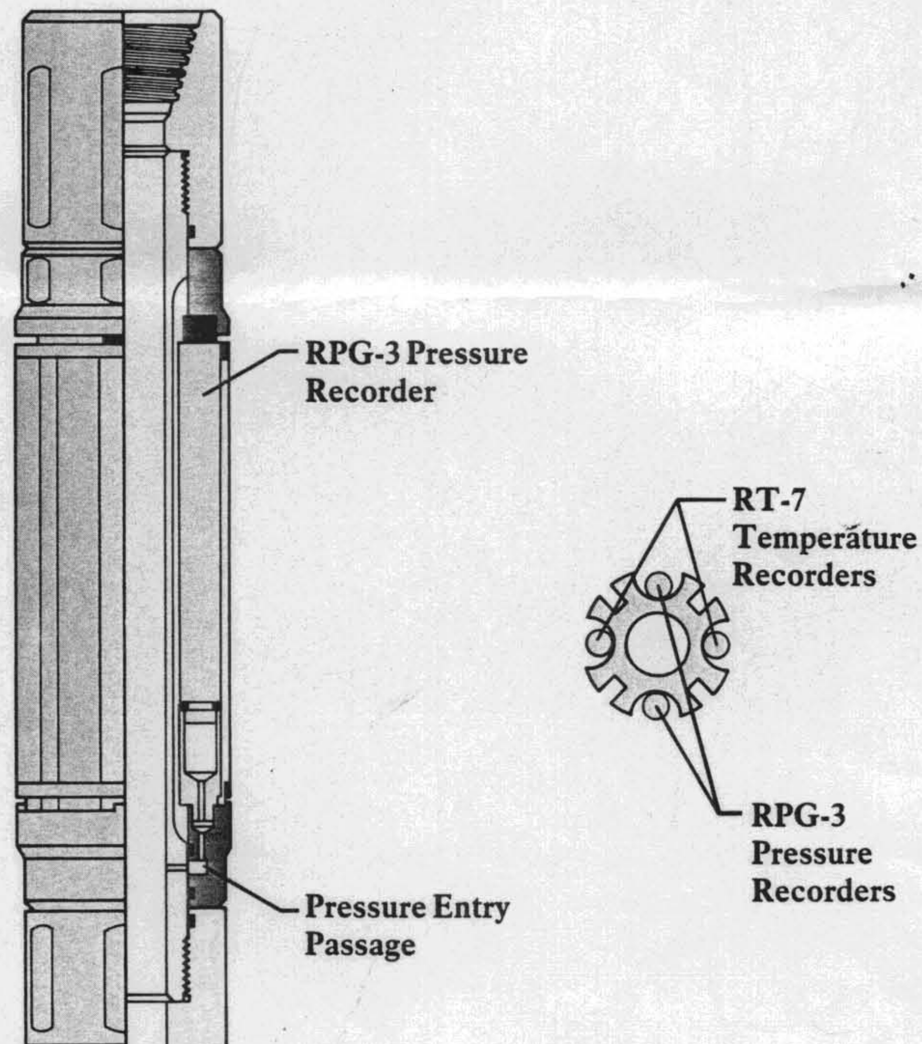


BUNDLE CARRIER

The Ful-Flo® Bundle Carrier provides a means of carrying two pressure gauges and two temperature recorders into a well for a test while maintaining a large bore through the tool to allow for passage of wireline equipment and full flow of fluids or gas. The bundle carrier is designed so that it can be run above or below the packer. If run below the packer, as many as four RPG-3 pressure recorders can be run.

Ful-Flo Bundle Carrier Size Available

Tool Size OD, in.	Tool Size ID, in.	Connections
5⅜	2³⁄₁₆	3½″ IF Tool Joint



305044

T-4051

TESTING TECHNICAL DATA

HALLIBURTON SERVICES

HALLIBURTON SAFETY JOINTS

Two types of safety joints for use in instances where downhole tools have become stuck due to hole sloughing, cavings or similar conditions are available now from Halliburton. They are the already established "VR" Safety Joint used above the top packer and the new Anchor Pipe Safety Joint used between the packer and the anchor pipe. When used in combination, these two safety joints make it possible to retrieve more of a stuck testing tool assembly than was possible before.

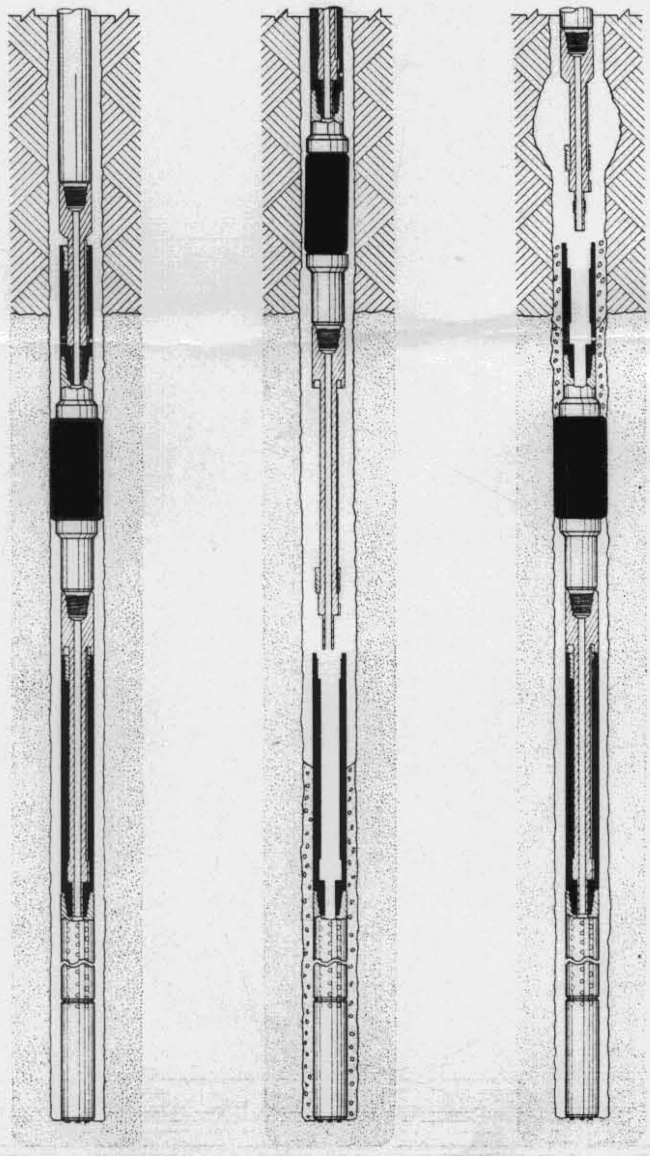
An exhaustive study of stuck pipe problems arising from testing indicates that the overwhelming majority of these problems originate below the bottom packer, due to sloughing and caving, rather than opposite or above the packer. This led to the development of Halliburton's Anchor Pipe Safety Joint.

The Anchor Pipe Safety Joint utilizes a left-hand back-off thread. The thread is designed so that it may not be actuated inadvertently while the string is in either tension or compression. The joint releases only when string weight has been neutralized at the location of the joint and by right-hand rotation of the string; in turn, this backs out the threaded nut at the top of the case, permitting separation of the two safety joint components.

The Anchor Pipe Safety Joint may be adapted to any multi-packer operation where the possibility of sand bridging exists, such as testing in casing with straddle packer or where sand-laden fluids used for stimulation are placed in perforations between packers.

An additional advantage afforded by a successful use of the Anchor Pipe Safety Joint is the elimination of the time-consuming washing-over of the packer or packers above.

SCHEMATIC OPERATIONAL DIAGRAMS
RELEASING SAFETY JOINTS



TYPICAL TESTING STRING WITH SAFETY JOINTS — ANCHOR PIPE STUCK ANCHOR PIPE SAFETY JOINT BACKED OFF — PACKER STUCK VR SAFETY JOINT BACKED OFF

The "VR" Safety Joint utilizes a left-hand back-off thread, the male and female parts are locked together by a spline and lug arrangement to prevent the thread being unscrewed by ordinary manipulation of the drill pipe during test. However, if it becomes necessary to back off the "VR" Safety Joint, a combination of right-hand rotation and vertical movement of the drill pipe allows the thread to be unscrewed easily. Since right-hand rotation is used, the possibility of backing off a tool joint is eliminated. This tool also has a built in by-pass which acts as an auxiliary to the by-pass in the Halliburton Hydro-Spring tester.

Halliburton warrants that the products and materials sold to the customer are free from defects of workmanship and material, but the liability of Halliburton for breach of such warranty or any express or implied warranty of fitness or for damages of any kind resulting from the negligence of Halliburton shall be limited to the replacement of or the allowance of credit for such materials sold.

HALLIBURTON SERVICES
Duncan, Oklahoma 73536
A Halliburton Company

305046

Attachment 13.

OR-0311

Schlumberger

LDL-CNL-GR YOLLA #1 1/200

CSU Field Log

5 cm

COMPANY:	AMOCO AUSTRALIA PETROLEUM CO.
WELL:	YOLLA #1
FIELD:	WILDCAT
RIG .:	R F BAUER
STATE:	TASMANIA
NATION:	AUSTRALIA
LOCATION:	BASS STRAIT - OFFSHORE TASMANIA.
LATITUDE:	039 50 18.96 S
LONGITUDE:	145 48 21.2 E

OTHER SERVICES-
ISF-BHC-MSFL
HDT-GR
VSP-GR
RFT-HP-GR
STL-GR

PERMANENT DATUM: MSL
ELEV. OF PERM. DATUM: 0.0 M
LOG MEASURED FROM: KB
11.0 M ABOVE PERM. DATUM
DRLG. MEASURED FROM: KB

ELEVATIONS-
KB: 11.0 M
DF: 10.4 M
GL: -79.6 M

PROGRAM TAPE NO: 28.2
SERVICE ORDER NO: RFB 850801

DATE: 23 AUG 85
RUN NO: 2

DEPTH-DRILLER:	3347.0 M		
DEPTH-LOGGER:	3351.0 M		
BTM. LOG INTERVAL:	3350.0 M		
TOP LOG INTERVAL:	1755.0 M		
CASING-DRILLER:	399.0 M	1752.0 M	0.0 M
CASING-LOGGER:	0.0 M	1755.0 M	0.0 M
CASING:	20	13 3/8	
WEIGHT:	129.000 LB/F	72.0000 LB/F	0.0 LB/F
BIT SIZE:	26	17 1/2	12 1/4
DEPTH:	399.0 M	1759.0 M	3347.0 M

TYPE FLUID IN HOLE:	FRESH WATER/AQUAGEL/POLYMER
DENSITY:	9.80 LB/G
VISCOSITY:	44.0 S
PH:	11.0
FLUID LOSS:	9.0 C3
SOURCE OF SAMPLE:	FLOWLINE
RM:	1.070 OHMM AT 23.0 DEGC
RMF:	.838 OHMM AT 16.0 DEGC
RMC:	1.370 OHMM AT 16.0 DEGC
SOURCE RMF/RMC:	PRESS /PRESS
RM AT BHT:	.311 OHMM AT 132. DEGC
RMF AT BHT:	.205 OHMM AT 132. DEGC
RMC AT BHT:	.336 OHMM AT 132. DEGC
TIME CIRC. STOPPED:	22:30 21/08
TIME LOGGER ON BTM.:	16:30 22/08
MAX. REC. TEMP:	132.0 DEGC
LOGGING UNIT NO:	65
LOGGING UNIT LOC:	SEA
RECORDED BY:	O.BOUBE R.WINSLOE
WITNESSED BY:	G.M. KJELLGREN

REMARKS:

ALL CURVES RECORDED WITH ZERO FILTERING.
CNT ECCENTRALIZED WITH BOW-SPRING.
3% OF BARITE IN MUD.
COMPATIBLE LIMESTONE SCALE FOR DENSITY AND NEUTRON,
HOLE CORRECTION SET ON BIT-SIZE (CLIENT REQUEST).
THIS LOG TRANSMITTED FROM THE RIG TO SYDNEY.
EPT AND NGT RUN IN COMBINATION.
THERMOMETERS READING : 132,131,132 DEGC.

EQUIPMENT NUMBERS-

TCM-AB 16	TCC-A 296	NGD-A 829	NGC-C 836
CNC-HA 360	CNB-AB 3021	NSC-D 1735	DRS-C 2952
PDH-L 997	PGD-G 987	GSR-J 6152	

ALL INTERPRETATIONS ARE OPINIONS BASED ON INFERENCES FROM ELECTRICAL OR OTHER MEASUREMENTS AND WE CANNOT, AND DO NOT GUARANTEE THE ACCURACY OR CORRECTNESS OF ANY INTERPRETATIONS, AND WE SHALL NOT, EXCEPT IN THE CASE OF GROSS OR WILLFUL NEGLIGENCE ON OUR PART, BE LIABLE OR RESPONSIBLE FOR ANY LOSS, COSTS, DAMAGES OR EXPENSES INCURRED OR SUSTAINED BY ANYONE RESULTING FROM ANY INTERPRETATION MADE BY ANY OF OUR OFFICERS, AGENTS OR EMPLOYEES. THESE INTERPRETATIONS ARE ALSO SUBJECT TO OUR GENERAL TERMS AND CONDITIONS AS SET OUT IN OUR CURRENT PRICE SCHEDULE.

CP 28.2 FILE 103 23-AUG-85 00:01

CHANGED PARAMETERS

NAME	VALUE	UNIT	DEPTH (M)	NAME	VALUE	UNIT	DEPTH (M)
SPLI	1		2099.0				

CP 28.2 FILE 102 23-AUG-85 01:03
DATA ACQUIRED NA

BS (IN)	10.000	20.000
CALI(IN)	10.000	20.000
SGR (GAPI)	0.0	150.00
DRHO(G/C3)	-.2500	.25000
PEF	0.0	10.000
NPHI	.45000	-.1500
RHOB(G/C3)	1.9500	2.9500

SENSOR MEASURE POINT TO TOOL ZERO

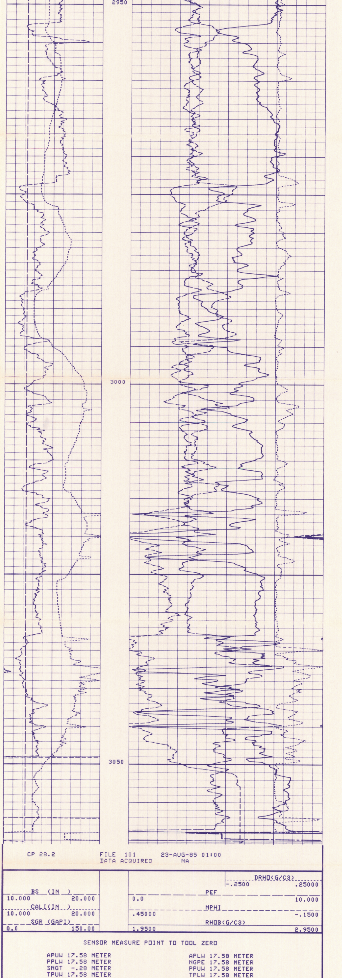
APUW	17.58	METER	APLW	17.58	METER
PPLW	17.58	METER	NGPE	17.58	METER
SNGT	-.28	METER	PPUW	17.58	METER
TPUW	17.58	METER	TPLW	17.58	METER
W2NG	17.58	METER	W1NG	17.58	METER
W4NG	17.58	METER	W3NG	17.58	METER
FCNL	7.24	METER	W5NG	17.58	METER
SCNL	-.28	METER	NCNL	7.24	METER
LL	.79	METER	LITH	.79	METER
LU	.79	METER	LS	.79	METER
SS2	.64	METER	SS1	.64	METER
TENS	-.28	METER	CALI	.81	METER
FVD	9.02	METER	SGR	17.58	METER
NVD	9.02	METER	FVU	9.02	METER
PSDO	9.02	METER	NVU	9.02	METER
NRAT	7.24	METER	PSUP	9.02	METER

PARAMETERS

NAME	VALUE	UNIT	NAME	VALUE	UNIT
SHT	55.0000	DEGF	TD	3351.00	M
CBAR	1.00000		PMUD	0.0	%
TPPT	2.50000	NS/M	NFO	KALM	
ATPT	75.0000	DB/M	TPMT	-2.50000	NS/M
CAPT	-.500000		ATMT	-75.0000	DB/M
TPM	9.10000	NS/M	PC	90.0000	DEG
HC	BS		PSNR	2.27300	
FD	1.00000	G/C3	MATR	LIME	
WMUD	9.80000	LB/G	MDEN	2.71000	G/C3
DHC	BS		BFM	LIQU	
BS	12.2500	IN	BHS	OPEN	
PP	OFF		DO	0.0	M

BS (IN)	10.000	20.000
CALI(IN)	10.000	20.000
SGR (GAPI)	0.0	150.00
DRHO(G/C3)	-.2500	.25000
PEF	0.0	10.000
NPHI	.45000	-.1500
RHOB(G/C3)	1.9500	2.9500

CP 28.2 FILE 101 23-AUG-85 01:01
DATA ACQUIRED NA



CP 28.2 FILE 101 23-AUG-85 01:00
DATA ACQUIRED NA

BS (IN)	10.000	20.000
CALI(IN)	10.000	20.000
SGR (GAPI)	0.0	150.00
DRHO(G/C3)	-.2500	.25000
PEF	0.0	10.000
NPHI	.45000	-.1500
RHOB(G/C3)	1.9500	2.9500

SENSOR MEASURE POINT TO TOOL ZERO

APUW	17.58	METER	APLW	17.58	METER
PPLW	17.58	METER	NGPE	17.58	METER
SNGT	-.28	METER	PPUW	17.58	METER
TPUW	17.58	METER	TPLW	17.58	METER
W2NG	17.58	METER	W1NG	17.58	METER
W4NG	17.58	METER	W3NG	17.58	METER
FCNL	7.24	METER	W5NG	17.58	METER
SCNL	-.28	METER	NCNL	7.24	METER
LL	.79	METER	LITH	.79	METER
LU	.79	METER	LS	.79	METER
SS2	.64	METER	SS1	.64	METER
TENS	-.28	METER	CALI	.81	METER
FVD	9.02	METER	SGR	17.58	METER
NVD	9.02	METER	FVU	9.02	METER
PSDO	9.02	METER	NVU	9.02	METER
NRAT	7.24	METER	PSUP	9.02	METER

PARAMETERS

NAME	VALUE	UNIT	NAME	VALUE	UNIT
SHT	55.0000	DEGF	TD	3351.00	M
CBAR	1.00000		PMUD	0.0	%
TPPT	2.50000	NS/M	NFO	KALM	
ATPT	75.0000	DB/M	TPMT	-2.50000	NS/M
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

5 cm