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A/S NORSKE SHELL E&P

TANANGER

PRODUCTION TEST PROGRAMME

WELL 31/2-3

RIG: BORGNY DOLPHIN

UND — ARKIVET
Nr.:

Preliminary copy;16.5.80

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INDEX

APPENDICES

OBJECTIVES AND GENERAL TEST OUTLINE

1. Objectives

a) To obtain accurate date on reservoir fluids,pressures, fluid compositions and trace elements in the indicated water, oil and gas bearing legs to aid in determination of reserves.

b) To assess the significance and producibility of the indicated micaceous oil bearing reservoir section from c.1571 - 1585 m.

c) To investigate the producibility of the micaceous gas sands.

d) To investigate the inflow performance and sand control effectiveness of a gravel packed completion for the clean gas sands.

2. General Test Outline

a) A highly porous, clean, water bearing sand will be tested in the interval 1600.5 - 1605.0 m. A Halliburton DST string will be used for this test, which is designed primarily just to recover good formation water samples owing to the lack of success in achieving such samples during the open hole RFT programme. Accordingly, after perforating, the DST string will be run and the packer set. After opening the tool, the well will be flowed until it kills itself, whereupon the test will be concluded and the test string retrieved. The zone will then be abandoned by squeeze cementing through a retainer.

b) The oil bearing reservoir section will be tested in the interval 1577.5 - 1582.5 m in highly micaceous sands. Following packer setting, the production string will be installed and the well flow tested as follows, after perforation:-

i) Flow well clean then produce well for 12 hours slowly to avoid coning, while taking bottom hole and surface samples. Close well in and install pressure and temperature bombs.

ii) Produce well for 36 hrs at low stabilized rate, approximately twice rate in (i), then close in for 36 hrs pressure build up survey.

iii) Pull bombs then bean up well slowly to maximum obtainable sand free rate.

iv) Close well in and proceed to kill and abandon the oil zone.

c) The micaceous gas sands will be tested in the interval 1520 - 1535 m. Following packer setting, the production string will be installed and the well flow tested as follows after perforation and depending on sand production:-

i) Flow well clean then bean up slowly to high rate, i.e. approximately 60 MMscf/d. Flow well at this rate for 4 hours. Close in well.

ii) Install pressure/temperature bombs for initial static pressure. Pull bombs then rerun same.

iii) Flow well at same high rate, c. 60 MMscfd, for 24 hrs then close in for 24 hrs pressure build up. Pull,then rerun bombs.

iv) Flow well at c. 10,20 and 40 MMscfd for evaluation of rate dependent parameters and to permit detailed sampling. Close in well. Pull bombs.

v) Bean well up to maximum obtainable rate and flow at this rate at c. 4 hrs.

vi) Close in well.

On completion of the flow testing,the production string will be pulled and the zone abandoned.

d) The clean gas sands will be tested in the interval 1435 - 1460 m BDF in loosely consolidated, highly porous and permeable massive sands. Accordingly, a wire wrapped inner liner will be gravel packed across the perforated interval prior to performing the actual flow testing. Following the gravel packing, the production string will be installed and the well flow tested as follows:-

i) Flow the well clean then bean up slowly to high rate, i.e. approximately 60 MMscf/d. Flow well at this rate for 4 hours. Close in well.

ii) Install pressure/temperature bombs for initial static pressure. Pull bombs then rerun same.

iii) Flow well at same high rate, c. 60 MMscfd, for 24 hrs then close in for 24 hrs pressure build up. Pull,then rerun bombs.

iv) Flow well at c. 10,20 and 40 MM scfd for evaluation of rate dependent parameters and to permit detailed sampling. Close in well. Pull bombs.

v) Bean well up to maximum obtainable rate and flow at this rate for c. 4 hrs.

vi) Close in well.

On completion of the flow testing, the production string will be pulled and the well abandoned.

PREPARATION OF TUBING

1. Offload and rack tubing, separating each layer with at least three evenly spaced wooden strips.

2. Number and measure each joint. WSPE and Production Test Supervisor to make separate tubing tallies.

3. Remove pin and box protectors, inspect threads for damage, clean with solvent, and if possible, with steam.

4. Brush each joint to remove scale and loose solids; if any joint has excessive scale it should be rejected.

5. Drift each joint with appropriate 42" long tubing drift. All drifts should be fitted with a fishing neck.

6. Reclean pins and boxes and replace protectors. (N.B. Protectors should also be clean and only lightly doped).

7. Check that there are a reasonable number of pup joints for spacing.

8. Inform shore of any further tubing requirements.

9. Return any unsatisfactory joints.

PREPARATION OF TUBING SUB-ASSEMBLIES/GP EQUIPMENT

1. Physically check all tubing and GP accessories and inspect and clean threads with solvent.

2. Ensure that spares of each item are available on the rig.

3. Function test all eqipment (sliding sleeves, nipples, etc.)

4. Make up tubing sub-assemblies.

5. Run wireline drift through each sub-assembly paying particular attention to polished sections as these can easily be squeezed in make up. N.B. Separate drift runs should be made down to and through No-Go nipples.

6. Carry out API pressure test on each tubing sub-assembly to 5,000 psi (to be witnessed by WSPE, TP and Production Test Supervisor).

7. Accurately measure each tubing sub-assembly and GP equipment item and note the positions of all accessories.

8. Replace protectors on each end of the tubing sub-assemblies and GP items.

9. Examine sub-assemblies for tong damage. If excessive, a new sub-assembly should be made up as above.

10. TP and WSPE to carry out final dimensions check.

PREPARATION

(8½" open hole plugged back and 9-5/8" casing plugged to c.1700 m).

1. Pull 18-3/4" BOP stack and inspect marine riser.Test the BOP stack on test stump with the following configuration:

a)	Shaffer Bag Type	SWP 5000 psi	test 2000 psi
b)	Shaffer Bag Type	SWP 5000 psi	Test 2000 psi
c)	Blind/Shear Rams	SWP 10000 psi	Test 1000 psi
d)	3½" Pipe Rams	SWP 10000 psi	Test 5000 psi
e)	5" Pipe Rams	SWP 10000 psi	Test 5000 psi
f)	5" Pipe Rams	SWP 10000 psi	Test 5000 psi

   Function test stack on spider beams prior to re-running. Run and land BOP stack and marine riser. Pressure test stack as above. Run and set wellhead wearbushing.

2. RIH with 8½" bit (no nozzles) on 5" DP/6-1/4" DC's with 9-5/8" scraper just above the bit. Scrape interval 1350 - 1610 m, then RIH to 1700 m. (PBTD).

3. With bit at bottom, circulate well to seawater using a 50 bbl pill of seawater viscosified to 150 secs MF with 4-5 ppb CMC EHV as a spacer ahead of the clean seawater. Continue circulating seawater as fast as possible until the solids level has reached an irreduciable minimum as measured by the BS&W test. Repeat hi-vis pills as necessary. N.B. Rotate and reciprocate pipe intermittently to assist in hole cleaning.

4. Circulate well to filtered (2-micron) 1.21 SG (525 psi/1000 ft) inhibited CaCl2 brine. Dump seawater returns until return fluid weight reaches 1.10 SG (475 psi/1000 ft). Ensure filtering continues throughout to maintain minimum solids concentration in the CaCl2 brine.

5. Spot 50 bbls of viscosified (150 MF) CaCl2 brine on bottom - to viscosify, add HEC at 4.0-4.5 ppb into brine while stirring vigorously and maintaining a brine PH of 6.0, obtained by addition of J286. Thereafter, while continuously stirring the brine, the PH should be increased to 8.5 - 9.0 with caustic soda (check with pilot test first).

6. POH with 8½" bit and 9-5/8" scraper.

7. Make up fluted hanger, slick joint, SSTT (blank off injection and control line ports) and 4½", 19.2 lbs/ft, C75, PH6 tubing riser, including riser valve. Run in and land fluted hanger on wearbushing. Space out so that top of riser is +/- 3 metres above rig floor. Pull out and stand 4½" riser back in derrick, SSTT to be laid down on walkway.

NOTES

A. During the whole course of these production tests and the attended preparation/gravel packing, it is essential that the wellbore and fluids be kept as clean as possible. To this end, a brine filtration system is being employed, filtering out particles as small as 2 microns. It is therefore necessary that the surface equipment mud tank and all related equipment (shale shakers, desanders and desilters, Thule mud cleaner and degasser) be spotlessly clean prior to first circulating brine into the hole from the Dowell tanks. In addition, the use of pipe dope must be minimized throughout all the necessary trips and pipe make-up, as this dope can be particulary harmful to a gravel pack. Brine should also be circulated down the kill and choke lines.

B. Since the surface equipment mud tank will be part of the brine circulation system, it must be blocked off from the other mud tanks. The other mud tanks are to be kept as full as possible of drilling mud for use in an emergency as kill mud (weight 1.28 S.G.).

C. $CaCl_2$, both as brine and powder, can cause unpleasant skin irritation and even blistering if allowed to remain in contact with the skin. It is therefore important that personnel involved in work where they may be exposed to the brine or powder should be protected as follows:-

i) Rubber gloves (gauntlet type to cover wrists).

ii) Waterproof slicker suits with hoods.

iii) Rubber boots (leather boots are shrivelled by the brine).

iv) Full face masks for use when mixing powdered $CaCl_2$.

v) Barrier cream (e.g. "Vaseline") for use on exposed skin, particulary face,neck and wrists, to prevent direct skin contact with the brine.

Additionally, whenever brine/powder is inadvertently splashed onto clothing then the affected clothes should be changed and washed forthwith. <u>Never</u> allow brine to dry on the skin or clothes. If brine is splashed into eye,wash the eye at once with copious amounts of fresh water.

D. If in the course of the test the well has to be squeeze killed because of deteriorating weather, a 20 bbl pill of viscous brine should be pumped to the perforations ahead of the clear brine to prevent losses. The viscous brine should be made up as follows: add HEC at 4.0-4.5 ppb into brine while stirring vigorously and maintaining a brine pH of 6.0, obtained by addition of Dowell's J286. Thereafter, while continuously stirring the brine, the pH should be increased to 8.5-9.0 with caustic soda (check with pilot test first).

PERFORATING - WATER ZONE

(Depth reference: ISF/SONIC run 3 of 5/5/80)

1. Rig up Schlumberger and run gauge ring/junk basket to PBTD at c. 1700 m. POH.

2. RIH and perforate interval 1600.5 - 1605.0 m with 2-1/8" Hyperdome Scallop guns at 4 shots/foot, 0 deg phasing. Observe well then POH and check gun, noting any misfires.
N.B. No lubricator/shooting nipple required.

3. Refer to Appendix (1) for safety procedures when handling explosives.

INSTALLATION OF DST STRING - WATER ZONE

1. Run the DST string as shown in Appendix 3 (ib) using 1775 psi (= 1250 m) water cushion (fresh water) and the following pressure/temperature gauges:

   a) In "bundle" carrier:

      1 x RT7 temperature gauge, 0-200 degs F,36 hour clock.

      2 x RPG3 pressure gauges, 0-3000 psi with 2 x 36 hour clocks.

   b) In blanked off BT cases:

      1 x Temperature recorder, 0-200 degs F, 36 hour clock.

      2 x BT pressure gauges, 0-5000 psi with 2 x 36 hour clocks.

   N.B.

   i) As is not possible to pressure test the tubing internally, the string will be Gator Hawk tested to 5000 psi during running.

   ii) Ensure RTTS circulating valve is in locked open position while RIH so fluid can bypass the packer.

   iii) Adjust length of 3½",10.2 lbs/ft, C75, VAM tubing so that with tubing riser, RTTS packer will be set at 1582.5 m, to leave the packer tailpipe some 7 m above the top of perforations at 1600.5 m.

2. Make up tubing riser with fluted hanger, EZ-tree, lubricator valve and flow head. Install Chiksan lines to flow and kill sides of flow head and pressure test same to 3000 psi.

3. Set fluted hanger into wellhead wearbushing. Pick up 2½ - 3 m, turning pipe to the right (1½ turns required at packer). Lower string and note loss of weight of drill collars (c.28000 lbs) as RTTS sets and slip joints commence closing. Continue lowering string until fluted hanger lands in wellhead wearbushing again. Close middle 5" pipe rams round 5" slick joint.

4. Disconnect elevators, install 40' x 2½" strops and support tubing riser with same from heave compensated travelling block.

5. Rig up wireline (no lubricator needed). RIH with blind box and note depth of air-water cushion interface.

TEST PROGRAMME - WATER ZONE

1. Pressure up on annulus to open APR-N tester valve (c. 1000 psi required).

2. Leave tester valve open for extended flow period, which will be determined by the well performance.

   i) If there is no flow to surface, keep the well open for two hours after "bubble bucket" indicates no further fluid entry. Rig up wireline lubricator and BOP and pressure test same to 3000 psi. RIH with blind box and note the new depth of the air-water cushion interface.POH. Close APR-M sampler valve by pressuring up annulus to 2000 psi (this will also open the APR-M circulation ports, allowing the APR-N valve to close). Reverse out fluid from test string through burners, taking samples of formation fluid in 5 litre plastic containers and/or 45 gallon drums. Condition brine.

   ii) If the well does flow to surface, accurately measure water cushion volume produced back till well dies. If well flows and hydrocarbon indications are present in the well effluent, switch flow through the separator and produce well clean, until a constant GLR and BS&W is obtained. Maintain pressure of 1500 psi over WHP on ball valves of the Flopetrol EZ tree.

      a) At the earliest moment, test for H_2S.

      b) Monitor back pressure on burners.

      c) Check at the choke manifold for sand production (See Appendix 5a).

      d) Record gas analysis via Geoservices gas chromatograph.

      Produce well at maximum safe (i.e. sand free) stabilized rate for a minimum of 2 hours after clean-up,depending on flow rate, taking samples as per Appendix 7. Close APR-M sampler valve by pressuring up annulus to 2000 psi (this will also open the APR-M circulation ports, allowing the APR-N tester valve to close). Reverse out fluid from test string through burners. Condition brine. Allow final build up period of twice the surface flowing period before unseating the packer.

   N.B. When brine returns to surface during reversing, direct flow to mud pits via gas buster/degasser and condition as necessary.

3. Open middle pipe rams and unseat packer, picking up 4-5 metres to get fluted hanger out of wellhead. Turn pipe to the right to open RTTS circulating valve to equalize across packer. Observe annulus for brine losses; if everything satisfactory, rig down flowhead and POH with test string, keeping annulus full and observing for swabbing.

4. When APR-M sampler valve reaches rig floor, do not unscrew it from the test string as a high pressure formation fluid sample is trapped in the stand of DC's between it and the APR-N tester valve. Pick up string until the drain valve at the bottom of this stand of DC's comes above the rotary table, then bleed down pressure inside the DC's while collecting all trapped fluid in clean 5 gallon sample bottles. (N.B. Capacity of 90' of 6½" x 2 13/16" DC's is approximately 30 U.S. gallons).

5. Run back down until the APR-M sampler valve is again at rig floor and remove same from string.

   i) If produced fluid in DC's in step (4) was entirely water, bleed off APR-M sampler valve.

   ii) If produced fluid in DC's in step (4) contained hydrocarbons, then PVT transfer fluid sample from APR-M sampler valve.

6. Retrieve and lay down remaining DST tools.

ABANDONMENT OF WATER ZONE

1. Rig up Schlumberger and run gauge ring/junk basket to 1600.0 m. POH. RIH and set Baker Model "K" cement retainer with top at 1595 m. (N.B. Ensure retainer is at least 2 m from a casing collar). POH and rig down Schlumberger.

2. RIH with Baker Model "B" snap-latch stinger sub on 5" DP. Sting into retainer and perform 20 bbl injection test, establishing injection rates versus pressure. Do not exceed 775 psi surface pressure. Pull out of retainer - 10000 lbs overpull required - then pump 150 sx Class "G" cement, slurry weight 15.8 ppg (additives to be advised), using 30 bbls freshwater ahead of the slurry and 30 bbls behind. (Cement volume may be increased depending on injection test.) Displace cement to within 5 bbls of stinger sub then sting into retainer and set down 15000 lbs to re-engage snap-latch. Inject cement at ½ bpm through retainer - cement will hit perforations after pumping a further 6.5 bbls. Shut down pumping for 30 mins when squeeze pressure increases to 250 psi over initial injection pressure (do not exceed BHP of 3530 psi at 1600.5 m) or when half the cement has been pumped out of the DP. Resume pumping at ½ bpm and displace further cement until squeeze pressure reaches 500 psi above initial injection pressure or until further one-sixth of the cement has been pumped out of the DP. Wait a further 30 minutes and then resume pumping at ½ bpm to achieve final squeeze pressure of 800 psi, constant for 30 minutes. Leave minimum 3 bbls cement in DP. Bleed off squeeze pressure, then snap out of retainer (approximately 10000 lbs overpull required). Pick up and reverse out excess cement and circulate hole to clean 1.21 SG brine all round.

3. After WOC for 12 hours, RIH with 8½" bit and scraper and clean out to retainer at 1595 m. Circulate hole clean then POH.

PACKER SETTING - OIL ZONE

(N.B. All depths are referenced to the ISF/SONIC, run 3 of 5/5/80.)

1. Rig up Schlumberger and run gauge ring/junk basket to retainer at 1595 m. Ensure correct gauge ring for 9-5/8", 47 lbs/ft casing is fitted. POH.

2. Set Baker Model "D" production packer,size 194 - 47, without flapper valve with top of packer at 1545 m. Ensure that packer is at least 2 m away from a casing collar. POH. When out of hole with setting tool, check same to ensure packer is satisfactorily set.

   Note: See Appendix 1 for safety precautions whilst handling explosive devices.

3. Rig down Schlumberger.

INSTALLATION OF PRODUCTION STRING - OIL ZONE

1. Run the test string as per Appendix 3 (iia), excluding the 4½" tubing riser at this stage. 3½" VAM tubing should be run to surface with a white painted single installed at the BOP level for spacing purposes.
   N.B. When the first full joint of 3½" VAM tubing has been run through the rotary table, rig up the wireline unit and install plug in the S-1 nipple above the perforated joint. Install x-overs and Lo-torq valve and pressure test plug to 5000 psi/15 minutes, recording pressure and observing for flow from annulus. If test satisfactory, recover plug and continue running tubing.

2. Check depth to Baker Model "D" packer by:

   i) Noting entry of mule shoe into packer.
   ii) Noting pressure increase when first seals enter packer bore while pumping slowly through tubing string.
   iii) Lowering tubing until locator seal assembly stops on top of packer.

3. With seal assembly fully stabbed into packer, close upper (3½") pipe rams around painted single for spacing purposes. Pressure test annulus to 500 psi/15 minutes down kill line.If all OK, bleed off pressure and open pipe rams (N.B. Check 3½" VAM collar positions before closing rams).

4. Pull back +/- 400 m and calculate spacing requirements so that, when fluted hanger lands in the wellhead, the top of the locator seals will be 2.5 - 3.0 m above the top of the packer.

5. Space out 3½" VAM tubing. Install the tubing hanger, slick joint and SSTT. Run 4½", PH6 tubing riser, with the Flopetrol riser ball valve installed at +/- 50 m BDF, spaced out so that the top of the tubing riser is +/- 3 m above rig floor.

6. Flange up flow head and install Chiksan lines to flow and kill sides of flow head. Pressure test same to 5000 psi.

7. Stab into packer and land SSTT. Close middle 5" pipe rams around slick joint and pressure test annulus to 500 psi/15 minutes down the kill line. Bleed off pressure and open rams.

8. Disconnect elevators, install 40' x 2½" strops and support tubing riser with same from heave compensated travelling block. Install wireline lubricator and wireline BOP and test same to 5000 psi/15 minutes.

9. RIH with 2" drift to bottom,noting hold up depth. POH, then RIH with wireline retained test plug and set same in Q nipple. Pressure test tubing and tubing riser to 5000 psi/15 minutes. Bleed off pressure slowly to zero and recover test plug.

10. RIH with B shifting tool and open XA-SSD. POH with B shifting tool. Displace tubing with diesel down to XA-SSD (underdisplace by 5 bbls). RIH with B shifting tool and close XA-SSD. POH with B shifting tool.

11. Close middle 5" rams. Pressure up annulus to 500 psi/15 minutes to check XA-SSD. Bleed pressure down to 100 psi (just to give a gauge reading). Keep the middle 5" pipe rams closed throughout the production testing programme and observe the annulus pressure via the kill line. Do not exceed 500 psi annulus pressure.

PERFORATING - OIL ZONE

(N.B. Depth reference ISF/SONIC run 3 of 5/5/80)

1. Rig up Schlumberger BOP's and short lubricator with control head and pressure test same with dummy inside to 5000 psi with water. Close Schlumberger BOP rams on Schlumberger cable and bleed off lubricator, hence testing rams to 5000 psi. Bleed off pressure.

2. Make dummy/CCL run and record hold up depth at bottom of sump. POH.

3. Install perforating gun and check lubricator. RIH with gun and perforate interval 1577.5 - 1582.5 m with 2-1/8" Hyperdome Scallop gun, 0 deg phasing, 4 spf, with magnetic positioning device.
   Note: by using zero THP while perforating, there will be an effective drawdown into the wellbore of some 300 psi.

4. Record THP with DWT during 15 minutes build-up after perforating.

5. POH with gun. WSPE and Production Test Supervisor to inspect gun and report any misfires/irregularities.

Note: Refer to Appendix 1 for safety procedures when handling explosives.

TEST PROGRAMME - OIL ZONE

(Note: This programme sequence is a guide only. Specific items, e.g. rates and durations of tests periods, lengths of pressure build-ups, etc., may be varied in light of onsite information during the course of the test).

1. Open up and unload well slowly through separator. Gradually bean up until FTHP has fallen to 250 psi maximum below initial closed in pressure with diesel in tubing. However, if flowrate exceeds 100 b/d,bean back to restrict flowrate to 100 b/d maximum. Maintain control pressure of at least 1500 psi greater than FTHP on ball valve of EZ tree.

   It is essential to restrict the flowrate to 100 b/d maximum at this stage to avoid coning water and/or gas into the well. Accordingly the oil flowrate must be strictly monitored. In addition, as soon as formation hydrocarbons are produced to surface:

   a) Monitor for H2S in produced gas.

   b) Establish GOR at earliest opportunity.

   c) Check produced fluids for sand content - see Appendix 5(a).

   d) If gas breakthrough is experienced, commence injection of glycol at the EZ tree to inhibit hydrate formation.

   e) Record gas analysis via Geoservices chromatograph.

2. If stable oil production of c.100 b/d is established with formation fluids at surface, maintain this rate for 12 hours while monitoring closely for evidence of coning (e.g. increase in GOR; increase in water cut, etc.).

3. While flowing well at c.100 b/d, make wireline drift (2") run through tubing to below half-mule shoe. POH then take four bottom hole samples with Flopetrol sample taker. Ensure sample bubble points agree within 50 psi; otherwise, repeat sample runs until compatible samples are obtained. PVT transfer samples on rig.

4. Close in well for c. 18 hours at choke manifold. Make 2.3" drift run to "F" nipple then install Sperry Sun pressure/ temperature bombs - use 2 x Sperry Sun MRPG gauges, sample interval 4 mins. In addition, run 1 x Amerada pressure bomb (3000 psi; 96 hour clock). Calibrate pressure bombs against DWT THP measurement for 1 hour, then make 1 hour gradient stops at 600 m and 300 m above "F" nipple prior to landing bombs.

5. Record static BHP for 2 hours then open up well slowly to a maximum rate of 200 b/d. Increase production rate in 25 b/d increments between 100 and 200 b/d, producing at least one tubing volume at each rate prior to further increasing production in order to check for coning. If 200 b/d can be reached without evidence of coning, maintain this rate stable for 24 hours while taking KSLA, Thornton and separator samples as per Appendix 7.

6. Close well in at choke manifold and carry out 24 hour build-up survey.

7. Pull bombs, making 1 hour gradient stops at 300 m and 600 m above "F" nipple and in lubricator.

8. If no evidence of coning has been exhibited at the 200 b/d rate, proceed to bean the well up in 100 b/d increments to maximum obtainable stable oil rate. Produce for at least two hours at each rate prior to further increasing production in order to check for coning. When water or gas coning is established, conclude the test, closing in well at choke manifold.

ABANDONMENT - OIL ZONE

1. Squeeze tubing contents down to perforations with brine of 1.21 S.G. (525 psi/1000 ft), using a 10 bbl, HEC viscosified brine pill ahead. Observe tubing.
   Note: take care not to fracture formation. Expected fracture gradient is 1.64 S.G. (710 psi/1000 ft), giving a maximum allowable BHP (200 psi safety) of 3473 psi. Maximum allowable surface pressure with 1.21 S.G. brine in the tubing is thus 760 psi.

2. RIH with wireline sand bailer and tag bottom, recording hold up depth and retrieving sand sample, if any.

3. Pick up seals out of packer and reverse circulate and condition well with 1.21 S.G. (525 psi/1000 ft) brine. Observe well dead.

4. Flange down Xmas tree and pull production string. Stand back 4½" tubing riser and lay down 3½" tubing.

5. Rig up Schlumberger. Run gauge ring/junk basket to Model "D" packer at 1545 m. POH. RIH and set Baker Model "K" cement retainer with top at 1540 m.(N.B. Ensure retainer is at least 2 m from a casing collar.)POH and rig down Schlumberger.

6. RIH with Baker Model "B" snap-latch stinger sub on 5" DP. Sting into retainer and perform 20 bbl injection test, establishing injection rates versus pressure. Do not exceed 760 psi surface pressure. Pull out of retainer - 10000 lbs overpull required - then pump 150 sx Class "G" cement, slurry weight 15.8 ppg (additives to be advised), using 30 bbls freshwater ahead of the slurry and 30 bbls behind. (Cement volume may be increased depending on injection test.) Displace cement to within 5 bbls of stinger sub then sting into retainer and set down 15000 lbs to re-engage snap-latch. Inject cement at ½ bpm through retainer - cement will hit perforations after pumping a further 14 bbls. Shut down pumping for 30 mins when squeeze pressure increases to 250 psi over initial injection pressure (do not exceed BHP of 3473 psi at 1576.5 m) or when half the cement has been pumped out of the DP. Resume pumping at ½ bpm and displace further cement until squeeze pressure reaches 500 psi above initial injection pressure or until a further one-sixth of the cement has been pumped out of the DP. Wait a further 30 minutes and then resume pumping at ½ bpm to achieve final squeeze pressure of 800 psi, constant for 30 minutes. Leave minimum 3 bbls cement in DP. Bleed off squeeze pressure, then snap out of retainer (approximately 10000 lbs overpull required). Pick up and reverse out excess cement and circulate hole to clean 1.21 SG brine all round.

7. After WOC for 12 hours, RIH with 8½" bit and scraper and clean out to retainer at 1540 m. Circulate hole clean then POH.

PACKER SETTING - MICACEOUS SAND GAS ZONE

(N.B. All depths are referenced to the ISF/SONIC, run 3 of 5/5/80)

1. Rig up Schlumberger and run gauge ring/junk basket to Model "K" retainer at 1540 m. Ensure correct gauge ring for 9 5/8", 47 lbs/ft casing is fitted. POH.

2. Set Baker Model "D" production packer, size 194 - 47, without flapper valve with top of packer at 1470 m. Ensure that packer is at least 2 m away from a casing collar. POH. When out of hole with setting tool, check same to ensure packer is satisfactorily set.
Note: See Appendix 1 for safety precautious whilst handling explosive devices.

3. Rig down Schlumberger.

INSTALLATION OF PRODUCTION STRING - MICACEOUS SAND GAS ZONE

1. Run the test string as per Appendix 3(iib), excluding the 4½" tubing riser at this stage. 5" VAM tubing should be run to surface with a white painted single installed at the BOP level for spacing purposes.

   N.B. (i) When the first full joint of 5" VAM tubing has been run through the rotary table, rig up the wireline unit and install plug in the S-1 nipple above the perforated joint. Install x-overs and Lo-torq valve and pressure test plug to 5000 psi/15 minutes,recording pressure and observing for flow from annulus. If test satisfactory,recover plug and continue running tubing.

   (ii) As the 5" VAM tubing is range 3,make up stands of two singles and one half joint for ease of handling.

2. Check depth to Baker Model "D" packer by:

   (i) Noting entry of mule shoe into packer.
   (ii) Noting pressure increase when first seals enter packer bore, while pumping slowly through tubing string.
   (iii) Lowering tubing until locator seal assembly stops on top of packer.

3. With seal assembly fully stabbed into packer, close middle (5") pipe rams around painted single for spacing purposes. Pressure test annulus to 500 psi/15 minutes down kill line. If all OK, bleed off pressure and open pipe rams (N.B. Check 5" VAM collar positions before closing rams).

4. Pull back +/- 400 m and calculate spacing requirements so that when fluted hanger lands in the wellhead, the top of the locator seals will be 2.5 - 3.0 m above the top of the packer.

5. Space out 5" VAM tubing. Install the tubing hanger, slick joint and SSTT. Run 4½", PH6 tubing riser, with the Flopetrol riser ball valve installed +/- 50 m BDF, spaced out so that the top of the tubing riser is +/- 3 m above rig floor.

6. Flange up flow head and install Chiksan lines to flow and kill sides of flow head. Pressure test same to 5000 psi.

7. Stab into packer and land SSTT. Close middle 5" pipe rams around slick joint and pressure test annulus to 500 psi/15 minutes down the kill line. Bleed off pressure and open rams.

8. Disconnect elevators, install 40' x 2½" strops and support tubing riser with same from heave compensated travelling block. Install wireline lubricator and wireline BOP and test same to 5000 psi/15 minutes.

9. RIH with 2" drift to bottom,noting hold up depth. POH,then RIH with wireline retained test plug and set same in Q nipple. Pressure test tubing and tubing riser to 5000 psi/15 minutes. Bleed off pressure slowly to zero and recover test plug.

10. RIH with B shifting tool and open XA-SSD. POH with B shifting tool. Displace tubing with diesel down to XA-SSD (underdisplace by 5 bbls). RIH with B shifting tool and close XA-SSD. POH with B shifting tool.

11. Close middle 5" rams. Pressure up annulus to 500 psi/15 minutes to check XA-SSD. Bleed pressure down to 100 psi (just to give a gauge reading). Keep the middle 5" pipe rams closed throughout the production testing programme and observe the annulus pressure via the kill line. Do not exceed 500 psi annulus pressure.

PERFORATING - MICACEOUS SAND GAS ZONE

(N.B. Depth reference ISF/SONIC run 3 of 5/5/80)

1. Rig up Schlumberger BOP's and short lubricator with control head and pressure test same with dummy inside to 5000 psi with water. Close Schlumberger BOP rams on Schlumberger cable and bleed off lubricator, hence testing rams to 5000 psi. Bleed off pressure.

2. Make dummy/CCL run and record hold up depth at bottom of sump. POH.

3. Install perforating gun and check lubricator. RIH with gun and perforate interval 1520 - 1535 m with 2 1/8" Hyperdome Scallop gun, o deg phasing,4 spf, with magnetic positioning device (1 run with 2 x 7.5 m guns with conducting intercarrier.)
   Note: by using 100 psi THP while perforating, there will be an effective drawdown into the wellbore of some 300 psi.

4. Record THP with DWT during 15 minute build-up after perforating.

5. POH with gun. WSPE and Production Test Supervisor to inspect gun, and report any misfires/irregularities.

Note: Refer to Appendix 1 for safety procedures when handling explosives.

TEST PROGRAMME - MICACEOUS SAND GAS ZONE

(Note: This programme sequence is a guide only. Specific items, e.g. rates and durations of test periods, lengths of pressure build-ups, etc., may be varied in light of onsite information during the course of the test).

1. Ensure separator has been checked and emptied of sand.

2. Open up and unload well using 6" x 3600 psi flowline, gradually increasing flowrate to c. 10 MMscf/d. Maintain a pressure of at least 1500 psi greater than FTHP on ball valve of EZ tree.

3. Inject glycol via chemical injection line at EZ tree and at separator and choke manifold.

4. When gas to surface, switch flow through separator. Gas flowrate should be measured at earliest opportunity. During initial clean up, the flow rate should be restricted to 10 MMscf/d.

   a) Monitor for H2S as soon as possible.

   b) Monitor back pressure on burners.

   c) Check for sand production via Flopetrol "Sandec" probe and Baker sand trap.

5. Flow the well on clean up for 6 hours or until stable flowing conditions have been reached. If condensate slugging occurs, it will be characterized by a fluctuation in FTHP and erratic GLR. (This can only be overcome when the well is beaned up later).

6. Bean the well up as follows:

   a) 20 MMscf/d for 6 hours - to permit Thornton and KSLA sampling trials.

   b) 40 MMscf/d for 2 hours.

   c) 60 MMscf/d for 4 hours.

   If continuous sand production becomes evident, bean back to previous sand free rate and produce at that rate for a further four hours prior to beaning up again.

7. Close in well at Xmas tree and choke manifold.

8. Rig up wireline lubricator and pressure test to 5000 psi/ 15 minutes.

9. Make drift run to "F" nipple.

10. Install Sperry Sun pressure and temperature bombs - use 2 x Sperry Sun MRPG gauges, sample interval 1 min.

    In addition, run 1 x Amerada pressure bomb (3000 psi, 24 hour clock).

11. Calibrate pressure bombs against DWT THP measurement for ½ hour then RIH making ½ hour gradient stops at seabed and at 600 m and 300 m above "F" nipple. Land bombs in "F" nipple. POH.

12. Pull bombs after well has been closed in for 12 hours.

13. Rerun Sperry Sun pressure and temperature bombs - use 2 x Sperry Sun MRPG gauges, sample interval 4 mins.

    In addition, run 1 x Amerada pressure bomb (3000 psi, 96 hour clock).

    Calibrate pressure bombs against DWT THP measurement for 1 hour, then make 1 hour gradient stops at seabed and at 600 m and 300 m above "F" nipple prior to landing bombs. Land bombs in "F" nipple.

14. Record static BHP for 2 hours prior to opening up well, then open well up as follows:

    a) 10 MMscf/d for 2 hours.

    b) 20 MMscf/d for 2 hours.

    c) 40 MMscf/d for 2 hours.

    d) 60 MMscf/d for 24 hours.

    Note: If pressure from step 12 is not fully built up, leave well closed in for 12 hours prior to opening up.

15. Close well in for 24 hour pressure build-up survey.

16. Recover pressure bombs, making 1 hour gradient stops at 300 m and 600 m above "F" nipple, at seabed and in lubricator, while recording DWT THP measurement.

17. Rerun Sperry Sun pressure and temperature bombs - use 2 x Sperry Sun MRPG pressure gauges, sample interval 1 min.

    In addition, run 1 x Amerada pressure bomb (3000 psi, 24 hour clock).

    Calibrate pressure bombs against DWT THP measurement for ½ hour. Land bombs in "F" nipple.

18. Record static BHP for 1 hour prior to opening up well, then open well up as follows (to obtain data for evaluation of rate dependent flow parameters and to permit detailed Thornton and KSLA sampling):

    a) 10 MMscf/d for 4 hours.

    b) 20 MMscf/d for 4-8 hours. (This is the anticipated timing for Thornton and KSLA main sampling).

    c) 40 MMscf/d for 4 hours.

19. Close well in.

20. Recover pressure bombs, making ½ hour at seabed and in lubricator, while recording DWT THP measurement.

21. Open well up and flow as follows:

    a) 75 MMscf/d for 4 hours.

    b) Maximum flowrate for 4 hours.

22. Close well in and conclude the test.

ABANDONMENT - MICACEOUS SAND GAS ZONE

1. Squeeze tubing contents down to perforations with brine of 1.21 S.G. (525 psi/1000 ft),using a 10 bbl, HEC viscosified brine pill ahead. Observe tubing.
   Note: take care not to fracture formation. Expected fracture gradient is 1.64 S.G. (710 psi/1000 ft), giving a maximum allowable BHP (200 psi safety) of 3330 psi. Maximum allowable surface pressure with 1.21 S.G. brine in the tubing is thus 725 psi.

2. RIH with wireline sand bailer and tag bottom,recording hold up depth and retrieving sand sample, if any.

3. Pick up seals out of packer and reverse circulate and condition well with 1.21 S.G.(525 psi/1000 ft) brine. Observe well dead.

4. Flange down Xmas tree and pull production string. Stand back 4½" tubing riser and 5" tubing string.

5. Rig up Schlumberger. Run gauge ring/junk basket to Model "D" packer at 1470 m. POH. RIH and set Baker Model "K" cement retainer with top at 1464.5 m.(N.B. Ensure retainer is at least 2 m from a casing collar.) POH and rig down Schlumberger.

6. RIH with Baker Model "B" snap-latch stinger sub on 5" DP. Sting into retainer and perform 20 bbl injection test, establishing injection rates versus pressure. Do not exceed 725 psi surface pressure. Pull out of retainer - 10000 lbs overpull required - then pump 150 sx Class "G" cement, slurry weight 15.8 ppg (additives to be advised), using 30 bbls freshwater ahead of the slurry and 30 bbls behind.(Cement volume may be increased depending on injection test). Displace cement to within 5 bbls of stinger sub then sting into retainer and set down 15000 lbs to re-engage snap-latch. Inject cement at ½ bpm through retainer - cement will hit perforations after pumping a further 17 bbls. Shut down pumping for 30 mins when squeeze pressure increases to 250 psi over initial injection pressure (do not exceed BHP of 3330 psi at 1515 m) or when half the cement has been pumped out of the DP. Resume pumping at ½ bpm and displace further cement until squeeze pressure reaches 500 psi above initial injection pressure or until a further one-sixth of the cement has been pumped out of the DP. Wait a further 30 minutes and then resume pumping at ½ bpm to achieve final squeeze pressure of 800 psi, constant for 30 minutes. Leave minimum 3 bbls cement in DP. Bleed off squeeze pressure, then snap out of retainer (approximately 10000 lbs overpull required). Pick up and reverse out excess cement and circulate hole to clean 1.21 SG brine all round.

7. After WOC for 12 hours, RIH with 8½" bit and scraper and clean out to retainer at 1464.5 m. Circulate hole clean to filtered (2-micron) 1.21 S.G. brine, spot 300 bbls viscosified brine (4-4.5 ppb HEC) on bottom then POH.
   Note: See "Preparation",Note D for viscosified brine mixing instructions.

PERFORATION AND BACKSURGING - CLEAN SAND GAS ZONE

(Depth reference: ISF/SONIC run 3 of 5/5/80)

1. RIH with 5" DP (open ended) to c.1335 m, with Flopetrol lubricator valve installed at c. 50 m below derrick floor. Close middle 5" rams and land DP on same, spacing out to leave c.3 m stick-up at drill floor.

2. Rig up Schlumberger X-over/circulating nipple, wireline BOP's, short lubricator and control head. Pressure test same with dummy inside to 3000 psi with water against Flopetrol lubricator valve. Close Schlumberger BOP rams on Schlumberger cable and bleed off lubricator, hence testing rams to 3000 psi. Bleed off pressure.

3. Make dummy/CCL run and record hold up depth at bottom of sump. POH.

4. Install perforating gun and check lubricator. RIH with gun and perforate interval 1447.5 - 1460 m with 2-1/8" Hyperdome Scallop gun, 0 deg phasing, 4 spf, with magnetic positioning device (1 run with 2 x 6.25 m guns with conducting intercarrier). Observe well for losses or gas influx and if all satisfactory,POH.

5. Reperforate interval 1447.5 - 1460 m as in (4) above, to give 8 spf. Similary, perforate 1435 - 1447.5 m at 8 spf.
Note: If excessive fluid losses are noted after firing leading to concern over well safety, pump viscosified brine (4-4.5 ppb HEC) through DP to attempt to stop losses. If viscous brine alone will not adequately reduce fluid losses,then powdered calcium carbonate pills will have to be used as advised by Base. Make up of the pills is as follows:
Add to required volume of brine 1.5 ppb HEC, 1 ppb lime and 15 ppb $CaCO_3$ (check with pilot test).

6. Rig down Schlumberger and POH with OEDP.

7. RIH with Halliburton backsurge tool string on 5" DP with 8 bbl chamber - see Appendix 3(ia) for tool string schematic. Fill the drillpipe with brine above the upper PR valve after RIH. Set the packer at 1382.5 m BDF (after tagging the Model "K" retainer) so that the bottom of the drill pipe tailpipe is at 1417.5 m BDF. Close upper annular round DP and install lower kellycock and circulating valve on DP.

   N.B. (i) Run 2 x 5000 psi Ameradas in the tailpipe bundle carrier (24 hour clocks).

   (ii) Backsurge volume is only 0.5 gall/perforation to reduce gas influx.

8. Open the surge tool by pressuring annulus to 500 psi (max. 750 psi) then wait one hour. N.B. Increase pressure in 50 psi increments until surface indications that tool has opened are obtained.

9. Open the upper chamber PR valve by pressuring DP to 750 psi. Unseat the packer, and circulate out the gas influx, down DP, up annulus and through choke. Do not open RTTS circulating valves. Report data on sand/gas/pressures during circulating out gas. Open upper annular and observe well.

10. RIH very slowly with toolstring to first sign of resistance, close upper annular and reverse out any fill above the bridge plug - report height of fill if any. Open upper annular. POH with packer to 1382.5 m BDF (tailpipe shoe at 1417.5 m BDF) and wait for 2 hours - observe for losses. RIH to bottom again and note any fill on bottom. Reverse clean and report fill. POH.

Note

In case losses are observed after the backsurge operation, 250 bbls of 4-4.5 ppb HEC viscosified brine should be available on surface for spotting as and when necessary. $CaCO_3$ pills may also be required (see step 5 above for composition).

GRAVEL PACKING - CLEAN SAND GAS ZONE

1. Pick up gravel pack assembly consisting of the following (from bottom up):

   a) 5½", LTC box up GP bull plug

   b) 5½", Bakerweld tell tale screen (6' long,LTC pin x box)

   c) 5½" x 3.25" GP seal bore receptacle (LTC pin x box)

   d) 5½" Bakerweld screen (4 x 20' joints and 1 x 10' joints,LTC pin x box)

   e) 5½" blank pipe (5 x 20' joints; LTC pin x box)

2. Hang off this section in rotary and then run the following inside the screen and blank pipe:

   a) G22 locator seal assembly, size 80-32, with 6 seal units (2-3/8", Hydril CS box up).

   b) 2-3/8", 4.7 lbs/ft, P105, Hydril CS wash pipe with N80 pup joints as required for correct space out - i.e. to position the G22 locator seal assembly as far as possible in the 5½" x 3.25" GP seal bore receptacle when the entire GP assembly is made up - see drawings in Appendix 3(iii).

3. Hang off the wash pipe on the 5½" blank pipe and then pick up the preassembled Model SC-1 gravel pack packer, Model "S" gravel pack extension with sliding sleeve, 6-5/8" x 5½" crossover sub, Model GP shear-out safety joint,upper indicating coupling, 5½" spacer pup joint and lower indicating coupling. Preassembled and connected also will be the Model "SC" crossover/setting tool (4½" IF box up) with Model S-1 shifting tool, 2-3/8" EUE pup joints, multiple acting indicating collet and 2-3/8" EUE (box) by 2-3/8" Hydril CS (pin) crossover.

4. Connect the 2-3/8" washpipe to the 2-3/8" Hydril CS pin protruding from the lower indicating coupling. Then connect the outer blank pipe to the lower indicating coupling.

   Notes

   A. At this point it may be worthwhile to recheck all dimensions to ensure that indeed the size 80-32, G22 locator seal assembly is correctly spaced out in the GP seal bore receptacle above the tell-tale screen.

   B. Check the weight of the entire GP assembly after make-up.

5. RIH with the entire GP assembly, using 18 x 6½" DC's and 5" DP as running string.

N.B.

i) All DP and DC's must be rabbitted to ensure they are clear.

ii) Running speed - 60 seconds per stand.

iii) Set slips slowly and avoid jarring the assembly.

iv) Do not use excessive DP dope - dope pins only and wipe off excess dope squeezed out of the connection.

6. Complete RIH with gravel pack assembly and set down gently on Model "K" retainer at 1464.5 m - c. 10000 lbs wt. should be adequate; control with heave compensator. Space out DP to place top at +/- 3 m above derrick floor. After spacing out and again tagging Model "K" retainer at 1464.5 m, install circulating valve on top of DP. Hook up Dowell lines and pressure test same to 5000 psi. Circulate DP volume + 20% and then drop 1-½" kirksite packer ball (allow 5 mins/300 m for ball to fall).

7. When packer ball is estimated to have landed (25 + 15 = 40 mins after dropping ball) pressure up on DP slowly with brine in 500 psi increments, holding each increment for 1 minute. The SC-1, GP packer will set at approximately 1500 psi. Continue pressuring up to shear ball seat and blow ball out at approximately 2500 psi.

8. Pull 15000 lbs over whole string weight to check packer set (use heave compensator). With DP circulating valve open and upper annular closed, pressurise annulus to 500 psi down kill line to check packer element sealing. Open upper annular.

9. Using heave compensator, slack down to 5000 lbs upward pull at packer. Rotate DP 10-12 turns to the right at the packer to back out with the crossover tool. When crossover tool comes free, set back down on packer with 30 000 lbs weight to ensure location of squeeze position,where the left hand running thread of the setting tool locates on the top of the packer. Mark the pipe - this mark will be referred to as mark (1) for the squeeze position. Establish injection rates and pressures - max surface pressure 675 psi with 1.21 S.G. brine in the hole,corresponding to a bottom hole pressure of 3145 psi,200 psi below 1.64 S.G. estimated fracture gradient.

10. Pick up approximately 1 - 1.5 m at the packer and set back down with indicator collet on lower indicating coupling, using sufficient weight (10000 lbs) to ensure definite location of the coupling. Mark the pipe - this mark will be referred to as mark (2) for circulating through the lower tell tale screen.

11. Pick up approximately 5-6 m at the packer and set back down with indicator collet on upper indicating coupling using sufficient weight (10000 lbs) to ensure definite location of the coupling. Mark the pipe - this mark will be referred to as mark (3) for reverse circulating above the packer.

12. Slack off weight and push indicator collet through upper and lower indicating couplings - approximately 15000 to 20000 lbs will be required. When mark (1) has been definitely located, pick back up and locate mark (2). Set 10000 lbs weight on indicating coupling/indicator collet to ensure definite location of the circulating position.

    At this point, the string is in position to commence gravel packing. It is essential that marks (1),(2) and (3) are unambiguous and hence they should be painted on the DP, 1 m above the rotary table, at mid heave with a simultaneous reading of the derrick floor tide indicator recorded in the driller's note book. When relocating marks (2) and (3), it must be remembered that the indicator collet has to be pulled up past the particular indicator collar to meet it going down. All lines must be arranged so that all operations can be performed via the Dowell manifold without shut downs for repositioning. Sufficient chiksan must be available to the DP circulating valve to accommodate the necessary pipe manipulations.

13. Establish circulation through lower tell tale screen,increasing pump rates up to maximum surface pressure of 675 psi. Monitor returns closely for losses and plot surface pressures versus pump rates. Estimate friction losses in surface pipe and in DP.

14. Mix breaker and gravel into previously gelled fluid - see Appendix 3(iv) for fluid formulations and specifications.

15. Pump "water pack" fluids as follows:

    a) 15 bbls "water pack" pre-pad (10.1 ppg = 525 psi/ 1000 ft).

    b) 16.95 bbls "water pack" slurry containing 10 lbs/gallon of fluid of Baker "Low Fines", 12-20 mesh gravel. The slurry density is 13.1 ppg = 681 psi/1000 ft.

    c) 5 bbls "water pack" after pad (10.1 ppg = 525 psi/ 1000 ft).

    These slurries will lead to an imbalance between the heavy drillpipe and light annulus of 150 psi while the fluids are in the drillpipe. Therefore, during the first 38.7 bbls of displacement with brine until the 15 bbl "water pack" pre-pad arrives at the crossover tool, a maximum surface pressure of 525 psi may be used.

16. Displace "water pack" with brine at maximum allowable rate (max surface pressure 525 psi) until pre-pad reaches crossover tool - approximately after 38.7 bbls of brine.
    Reduce pump rate to give maximum surface pressure of 200 psi.
    After pumping a further 24.4 bbls, the gravel slurry should cover the tell-tale screen and a pressure increase should be noted at surface - do not exceed 675 psi.

17. Slack off work string down to mark (1), the squeezing position, and squeeze slurry out into the formation with a steady pump rate and surface pressure below 675 psi. When final screen-out occurs, reduce pump rate to maintain surface pressure below 675 psi as long as possible but ultimately let pump pressure increase to 775 psi for the final squeeze. However, if no screen out is obtained, overdisplace with 10 bbls of completion fluid to clear the packer. Mix and prepare additional "water pack" pad and slurry volumes (50% of original job size) and repack. N.B. As tell-tale screen out has occurred, the "water pack" fluids will have to be displaced to the crossover tool with the drill pipe positioned at mark (3) the reverse circulation position, to allow direct circulation into the DP x 9-5/8" casing annulus. The string will then have to be lowered to mark (1), the squeezing position, for the repack.

18. After achieving satisfactory screen out, allow the pressure to bleed off. Close the annular preventer and pressurise the annulus to 500 psi. Pick up to mark (3), the reverse circulation position, and reverse out excess gravel/fines from above the packer.

19. Open the annular preventer, then POH with SC crossover/setting tool, washpipe etc.

INSTALLATION OF PRODUCTION STRING - CLEAN SAND GAS ZONE

1. Run the test string as per Appendix 3(iic), excluding the 4½" tubing riser at this stage. 5" VAM tubing should be run to surface with a white painted single installed at the BOP level for spacing purposes.
   N.B. When the first full joint of the 5" VAM tubing has been run through the rotary table, rig up the wireline unit and install plug in the S-1 nipple above the perforated joint. Install x-overs and Lo-torq valve and pressure test plug to 5000 psi/15 minutes,recording pressure and observing for flow from annulus. If test satisfactory, recover plug and continue running tubing.

2. Check depth to Baker SC-1 packer by:

   i) Noting entry of mule shoe into packer.

   ii) Noting pressure increase when first seals enter packer bore while pumping slowly through tubing string.

   iii) Lowering tubing until locator seal assembly stops on top of packer.

3. With seal assembly fully stabbed into packer, close middle (5") pipe rams around painted single for spacing purposes. Pressure test annulus to 500 psi/15 minutes down kill line. If all OK,bleed off pressure and open pipe rams (N.B. Check 5" VAM collar positions before closing rams).

4. Pull back +/- 400 m and calculate spacing requirements so that when fluted hanger lands in the wellhead, the top of the locator seals will be 2.5 - 3.0 m above the top of the packer.

5. Space out 5" VAM tubing. Install the tubing hanger, slick joint and SSTT. Run 4½", PH6 tubing riser, with the Flopetrol riser ball valve installed at +/- 50 m BDF, spaced out so that the top of the tubing riser is +/- 3 m above rig floor.

6. Flange up flow head and install Chiksan lines to flow and kill sides of flow head. Pressure test same to 5000 psi.

7. Stab into packer and land SSTT. Close middle 5" pipe rams around slick joint and pressure test annulus to 500 psi/15 minutes down kill line. Bleed off pressure and open rams.

8. Disconnect elevators, install 40' x 2½" strops and support tubing riser with same from heave compensated travelling block. Install wireline lubricator and wireline BOP and test same to 5000 psi/15 minutes.

9. RIH with 2" drift to tubing shoe. POH then RIH with wireline retained test plug and set same in Q nipple. Pressure test tubing and tubing riser to 5000 psi/15 minutes. Bleed off pressure slowly to zero and recover test plug.

10. RIH with B shifting tool and open XA-SSD. POH with B shifting tool. Displace tubing with diesel down to XA-SSD (underdisplace by 5 bbls). RIH with B shifting tool and close XA-SSD. POH with B shifting tool.

11. Close middle 5" pipe rams. Pressure up annulus to 500 psi/ 15 minutes to check XA-SSD.Bleed pressure down to 100 psi (just to give a gauge reading).Keep the middle 5" pipe rams closed throughout the production testing programme and observe the annulus pressure via the kill line. Do not exceed 500 psi annulus pressure.

12. RIH with wireline sandbailer and tag bottom inside gravel pack. Record hold-up depth and retrieve sample of sand (if any).

TEST PROGRAMME - CLEAN SAND GAS ZONE

(Note: This programme sequence is a guide only. Specific items, e.g. rates and durations of test periods, lengths of pressure build-ups, etc., may be varied in light of onsite information during the course of the test).

1. Ensure separator has been checked and emptied of sand.

2. Open up and unload well using 6" x 3600 psi flowline, gradually increasing flowrate to c. 10 MMscf/d. Maintain a pressure of at least 1500 psi greater than FTHP on ball valve of EZ tree.

3. Inject glycol via chemical injection line at EZ tree and at separator and choke manifold.

4. When gas to surface, switch flow through separator. Gas flowrate should be measured at earliest opportunity. During initial clean up, the flow rate should be restricted to 10 MMscf/d.

   a) Monitor for H_2S as soon as possible.

   b) Monitor back pressure on burners.

   c) Check for sand production via Flopetrol "Sandec" probe and Baker sand trap.

5. Flow the well on clean up for 6 hours or until stable flowing conditions have been reached. If condensate slugging occurs, it will be characterized by a fluctuation in FTHP and erratic GLR. (This can only be overcome when the well is beaned up later).

6. Bean the well up as follows:

   a) 20 MMscf/d for 6 hours - to permit Thornton and KSLA sampling trials.

   b) 40 MMscf/d for 2 hours.

   c) 60 MMscf/d for 4 hours.

   If continuous sand production becomes evident, bean back to previous sand free rate and produce at that rate for a further four hours prior to beaning up again.

7. Close in well at Xmas tree and choke manifold.

8. Rig up wireline lubricator and pressure test to 5000 psi/15 minutes.

9. Make drift run to "F" nipple.

10. Install Sperry Sun pressure and temperature bombs - use 2 x Sperry Sun MRPG gauges, sample interval 1 min.

    In addition, run 1 x Amerada pressure bomb (3000 psi, 24 hour clock).

11. Calibrate pressure bombs against DWT THP measurement for ½ hour then RIH making ½ hour gradient stops at seabed and at 600 m and 300 m above "F" nipple. Land bombs in "F" nipple. POH.

12. Pull bombs after well has been closed in for 12 hours.

13. Rerun Sperry Sun pressure and temperature bombs - use 2 x Sperry Sun MRPG gauges, sample interval 4 mins.

    In addition, run 1 x Amerada pressure bomb (3000 psi/96 hour clock).

    Calibrate pressure bombs against DWT THP measurement for 1 hour, then make 1 hour gradient stops at seabed and at 600 m and 300 m above "F" nipple prior to landing bombs. Land bombs in "F" nipple.

14. Record static BHP for 2 hours prior to opening up well,then open well up as follows:

    a) 10 MMscf/d for 2 hours.

    b) 20 MMscf/d for 2 hours.

    c) 40 MMscf/d for 2 hours.

    d) 60 MMscf/d for 24 hours.

    Note: If pressure from step 12 is not fully built up, leave well closed in for 12 hours prior to opening up.

15. Close well in for 24 hour pressure build-up survey.

16. Recover pressure bombs,making 1 hour gradient stops at 300 m and 600 m above "F" nipple, at seabed and in lubricator,while recording DWT THP measurement.

17. Rerun Sperry Sun pressure and temperature bombs - use 2 x Sperry Sun MRPG pressure gauges, sample interval 1 min.

    In addition, run 1 x Amerada pressure bombs (3000 psi,24 hour clock).

    Calibrate pressure bombs against DWT THP measurement for ½ hour. Land bombs in "F" nipple.

18. Record static BHP for 1 hour prior to opening up well, then open well up as follows (to obtain data for evaluation of rate dependent flow parameters and to permit detailed Thornton and KSLA sampling):

    a) 10 MMscf/d for 4 hours.

    b) 20 MMscf/d for 4-8 hours.(This is the anticipated timing for Thornton and KSLA main sampling).

    c) 40 MMscf/d for 4 hours.

19. Close well in.

20. Recover pressure bombs, making ½ hour stops at seabed and in lubricator, while recording DWT THP measurement.

21. Open well up and flow as follows:

    a) 75 MMscf/d for 4 hours.

    b) Maximum flowrate for 4 hours.

22. Close well in and conclude the test.

ABANDONMENT - CLEAN SAND GAS ZONE

1. Squeeze tubing contents down to perforations with brine of 1.21 SG (525 psi/1000 ft), using a 10 bbl, HEC viscosified brine pill ahead. Observe tubing.

   Note: take care not to fracture formation. Expected fracture gradient is 1.64 SG (710 psi/1000 ft), giving a maximum allowable BHP (200 psi safety) of 3145 psi. Maximum allowable surface pressure with 1.21 S.G. brine in the tubing is thus 675 psi.

2. RIH with wireline sand bailer and tag bottom again inside gravel pack. Record hold up depth and retrieve sand sample (if any).

3. Pick up seals out of packer and reverse circulate and condition well with 1.21 SG brine. Observe well dead.

4. Flange down Xmas tree and pull production string, laying down the 4½" tubing riser and the 5" tubing.

5. RIH with Baker Model "A" retrieving tool on 5" DP/6 1/4" DC's with fishing jars. Circulate above top of packer then set down onto packer with 15000 lbs to engage anchor latch in left hand square thread at the top of the packer.

6. Pick up on the DP string to release the SC-1 packer. 15000 lbs upstrain is required to free the packer, but overpull will be required to recover the GP assembly complete. However, the GP shear-out safety joint will shear at 60000 lbs upstrain. If the shear joint shears, the blank pipe and screen remaining in the hole will be recovered after step (7) with a spear.

7. POH with Model "A" retrieving tool and lay down recovered GP equipment.

8. RIH with 150 m, 2 7/8" tubing stinger on 5" DP. Wash down to Model "K" retainer at 1464.5 m, circulating with mud. Continue circulating with mud until the whole hole is displaced back to uniform, conditioned mud of weight 1.28 SG.

9. With tubing stinger shoe at 1464.5 m, mix and pump 175 sx Class "G" cement, slurry weight 15.8 ppg (additives to be advised), using 10 bbls mixwater spacer ahead and 1 bbl behind. Displace same with 73 bbls mud. POH slowly to place tubing stinger shoe at 1275 m then reverse clean. POH.

10. After WOC for 12 hours, RIH and tag plug with 8½" bit, using 20000 lbs weight. (Note: if top of plug is below 1405 m, a second plug will have to be spotted, as advised).

11. Pressure test plug to 2000 psi/15 mins.

12. POH with 8½" bit and commence well abandonment programme (to be advised separately).

APPENDIX 1

SAFETY PROCEDURE FOR HANDLING EXPLOSIVES AND FLOWING WELL

SAFETY DURING LOADING AND FIRING

Before the gun armed all transmitters, cranes, welding machines, radar etc. must be switched off and remain switched off until the gun is fired. After firing, transmission can be resumed until the gun has been pulled to about 100 m below the seabed, but must then cease until the gun has been laid down and checked.

Portable transmitters should be placed in one room to prevent accidental transmission.

Helicopters should not be permitted to land on the platform during perforating operations, or to approach closer than 150 m. Supply and standby boats must also stand off from the rig at this time.

Work involving explosives

Work involving the use of explosives should be carried out only by specialist personnel and should never be done during an electrical storm.

During any job involving the use of explosives, the number of personnel employed should be kept to a minimum. All other persons should be excluded from the danger area (e.g. walkway and derrick floor) throughout the operation.

Warning signs should be placed on access routes to the danger area to prevent access by unauthorised persons.

The Platform Manager (Captain) is to inspect equipment and check safety procedures.

Two hours before each perforating run the Petroleum Engineer will telex Base (Urgent) with an estimate of when the radio beacon, VHF transmitter, etc.,will be closed down and for how long. Actual times will be advised by the Radio Operator.

This is particularly important if a helicopter flight is scheduled for the rig concerned.

The first perforating must be carried out in daylight but later runs may be carried out at night. However, if in the course of the production test a well is killed due to unforeseen circumstances, the first of any subsequent perforations must also be carried out in daylight.

A constant check must be made to ensure that no voltage is measured between the casing and rig at surface. In the event that voltage is measured, all sources of electrical energy must be switched off (N.B. This may preclude perforating at night).

Flowing the well

Opening up a well to bleed off, or initial start up of a separator, must be carried out in daylight; production testing may then continue into the night.

Blowing off operations may be carried out under the following conditions:

a) Weather suitable for rescue operations.

b) Wind force sufficient to carry gases away from the platform.

c) Shipping and aircraft warned to stand clear during blowing off.

d) Standby boat advised that this operation is to take place and the action and precations necessary to this operation.

WELL STATUS 31/2-2

1. All depths are given with respect to the derrick floor which is 25 m above mean sea level, and 359 m above seabed. For current status diagram refer to Appendix 2(ii).

2. The well was drilled vertically to a TD at m and completed with 7" - 29 lb/ft - N80 - BTC liner with shoe at m.

3. The 12-1/4" and 8½" hole sections were drilled using a gypsum-lignosulphonate mud system.

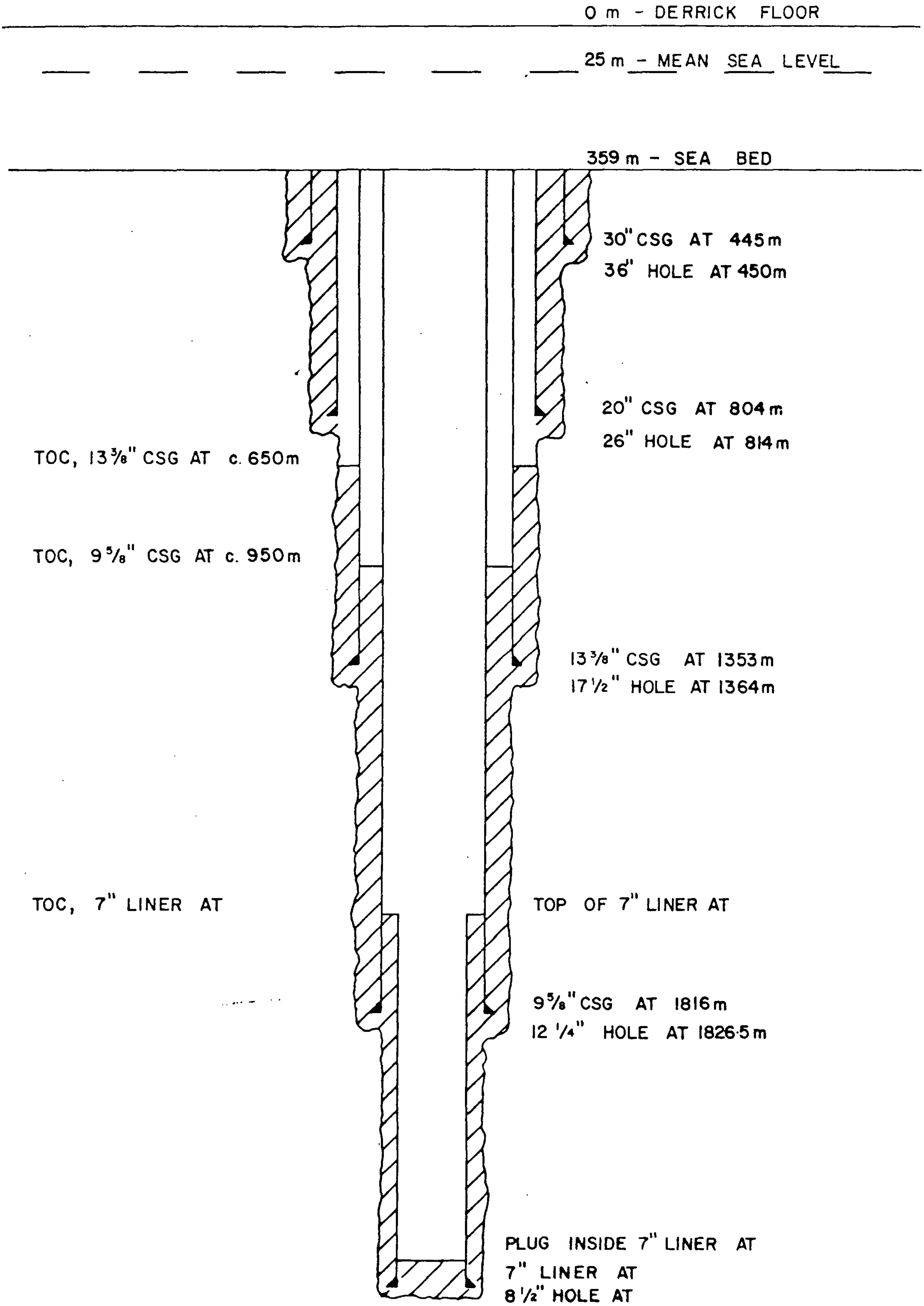
4. Casing and Tubing Data

Size	Weight	Grade	Coupling	Depth (mBDF)	Collapse Strength	Internal Yield	Capacity BBL/FT
30"	310	X-52	Vetco ATD-RB	445 m			-
20"	133	K-55	BTC	804 m	1500	3060	-
13-3/8"	72	N-80	BTC	1353 m	2670	5380	-
9-5/8"	47	N-80	VAM/BTC	1244/ 1816 m	4750	6870	0.0732
7"	29	N-80	BTC	-	7020	8160	0.0371
				Make up			
3½"	10.2	C-75	VAM	3600ft/lbs	11360	10480	0.0083
3½"	9.3	C-75	Hydril CS	3000ft/lbs	10040	9520	0.0087
4½"	19.2	C-75	Hydril PH6	7500ft/lbs	12960	12540	0.0126
5½"	15.5	J-55	LTC	2170ft/lbs	4040	4810	0.0238
2-7/8"	6.5	C-75	Hydril CS	2100ft/lbs	10470	9910	0.0058
5"	15.0	L-80	VAM	6500ft/lbs	7250	8290	0.0188
2-3/8"	4.7	P-105	Hydril CS	1500ft/lbs	15460	14700	0.00387

Note: No safety factors included in the pressure ratings

Appendix 2 (ii)

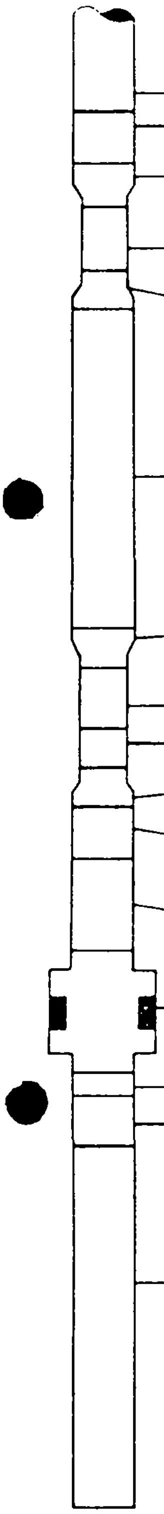
WELL STATUS DIAGRAM, 31/2-3



NORSKE SHELL, E & P, TANANGER

Appendix 3 (1a)

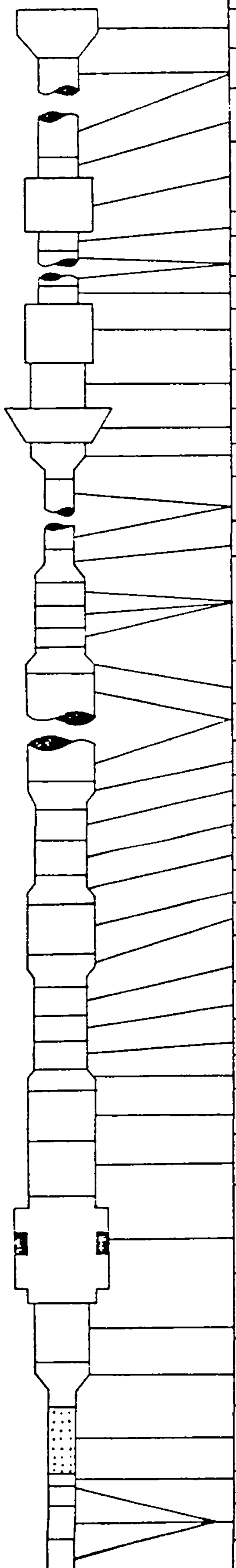
CLEAN SAND GAS ZONE BACKSURGE TOOL STRING (HALLIBURTON)



ITEM DESCRIPTION	MIN. I.D	MAX. O.D
DP. 5", 19.5 LBS/FT, 4 1/2" IF (B) x (P)	3 687"	6 375"
RTTS CIRCULATING VALVE, 4 1/2" IF (B) x (P)	3 000"	6 120"
X-OVER, 4 1/2" IF (B) x 3 1/2" IF (P)	2 347"	6 375"
PR DISC VALVE, 3 1/2" IF (B) x (P)	1 870"	4 620"
X-OVER, 3 1/2" IF (B) x 4 1/2" IF (P)	2 347"	6 375"
8 BBL AIR CHAMBER, c 140m, 5", 19 5 LBS/FT, DP, 4 1/2" IF (B) x (P)	3 687"	6 375"
X-OVER, 4 1/2" IF (B) x 3 1/2" IF (P)	2 347"	6 375"
PR DISC VALVE, 3 1/2" IF (B) x (P)	1 870"	4 620"
BIG JOHN JARS, 3 1/2" IF (B) x (P)	2.370"	4 630"
X-OVER, 3 1/2" IF (B) x 4 1/2" IF (P)	2 347"	6 375"
RTTS CIRCULATING VALVE, 4 1/2" IF (B) x (P)	3 000"	6 120"
RTTS SAFETY JOINT, 4 1/2" IF (B) x (P)	3 120"	6 120"
RTTS PACKER, 4 1/2" IF (B) x 4 1/2" DP (P)	3 440"	8 150"
X-OVER, 4 1/2" DP (B) x 4 1/2" IF (P)	3 687"	6 370"
"FUL-FLO" RUNNING CASE (BUNDLE CARRIER), 4 1/2" IF (B) x (P)	2. 250"	6 375"
35m, 5", 19.5 LBS/FT, DP, 4 1/2" IF (B) x (P) AS TAILPIPE, OPEN-ENDED	3 687"	6 375"

NORSKE SHELL E & P, TANANGER

DST STRING FOR 9⅝" CASING TESTS



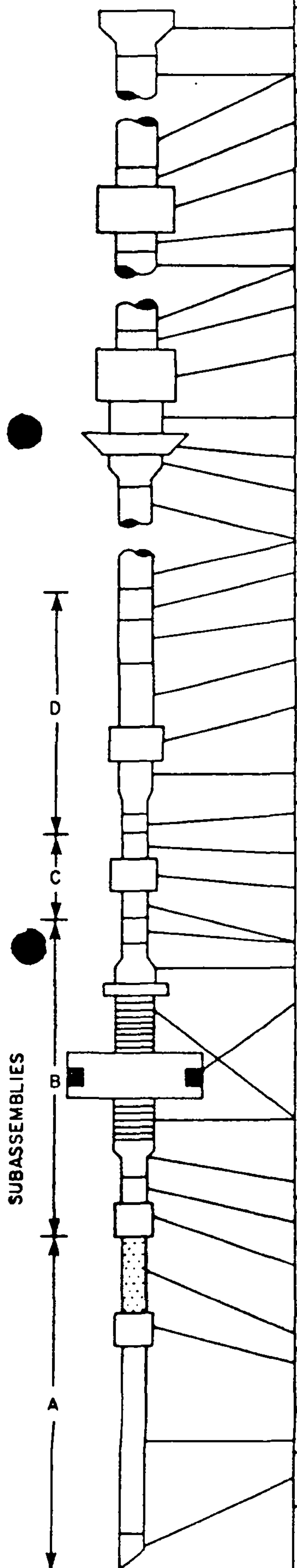
ITEM DESCRIPTION	Min. I.D.	Max O.D.
X-OVER, 6½" ACME (B) x 4½", PH6 (P), C75	3.515"	
TUBING, 4½", 19.2", PH6, C75	3.515"	5.313"
X-OVER, 4½", PH6 (B) x 4½", ACME (P), C75	3.515"	5.313"
FLOPETROL LUBRICATOR VALVE; H2S SERVICE; 10000 PSI W.P.; 4½" ACME (B) x (B)	3.000"	10.750"
X-OVER; 4½" ACME (P) x 4½", PH6, (P); C75	3.515"	5.313"
TUBING, 4½", 19.2", PH6, C75	3.515"	5.313"
X-OVER, 4½", PH6 (B) x 4½", ACME (P); C75	3.515"	5.313"
FLOPETROL EZ TREE; H2S SERVICE; 10000 PSI WP, 4½" ACME (B) x (B)	3.000"	10.750"
SLICK JOINT, 4½" ACME (P) x (P), C75	3.000"	5.000"
FLUTED HANGER; 4½" ACME (B) x (B); C75	3.000"	
X-OVER; 4½", ACME (P) x 3½" VAM (P); C75	2.797"	5.000"
TUBING; 3½", 10.2 LBS/FT, VAM, C75	2.797"	3.917"
X-OVER, 3½", VAM (B) x 3½" IF (P)	2.000"	3.917"
SLIP JOINTS (3); 5' STROKE; 3½" IF (B) X (P); (HALLIBURTON)	2.000"	5.000"
X-OVER; 3½" IF (B) x 4½" IF (P); (HALLIBURTON)	2.250"	6.500"
DRILL COLLARS; (270' = 3 STANDS); 4½" IF(B)x(P)	2.813"	6.500"
X-OVER; 4½" IF (B) x 3½" IF (P), (HALLIBURTON)	2.250"	6.500"
APR-A CIRCULATING VALVE; 3½" IF(B)x(P);(HALLIB)	2.250"	5.000"
APR-M SAMPLER; 3½" IF (B) x (P); (HALLIBURTON)	2.000"	4.628"
X-OVER; 3½" IF (B) x 4½" IF (P); (HALLIBURTON)	2.250"	6.500"
DRILL COLLARS (90' = 1 STAND); 4½" IF (B) x (P)	2.813"	6.500"
X-OVER; 4½" IF (B) x 3½" IF (P); (HALLIBURTON)	2.250"	6.500"
DRAIN SUB; 3½" IF (B x (P); (HALLIBURTON)	2.250"	5.000"
APR-N TESTER; 3½" IF (B) x (P); (HALLIBURTON)	2.250"	5.000"
"BIG JOHN" JARS; 3½" IF(B)x(P); (HALLIBURTON)	2.370"	4.630"
X-OVER; 3½" IF(B) x 4½" IF(P); (HALLIBURTON)	2.250"	6.500"
RTTS CIRCULATING VALVE; 4½" IF(B)x(P); (HALLIB)	3.000"	6.120"
RTTS SAFETY JOINT; 4½" IF(B)x(P); (HALLIBURTON)	3.120"	6.120"
RTTS PACKER; 4½" IF(B) x (P); (HALLIBURTON)	2.440"	8.150"
"FUL-FLO" RUNNING CASE (BUNDLE CARRIER) 4½" IF (B) x (P); (HALLIBURTON)	2.250"	
X-OVER; 4½" IF (B) x 2-7/8" EUE(P); (HALLIBUR.)		
PERFORATED TUBING; 2-7/8" EUE (B)x(P);(HALLIB.)	2.347"	3.668"
X-OVER; 2-7/8" EUE(B) x 2-7/8" DP(P); (HALLIB.)		
BLANKED OFF BT CASES; 2-7/8" DP(B) x (P);(HALL.)		3.870"

NORSKE SHELL, E&P, TANANGER

Appendix 3 (iia)

OIL ZONE

9 5/8" CASING BY 3 1/2" TUBING PRODUCTION TEST STRING

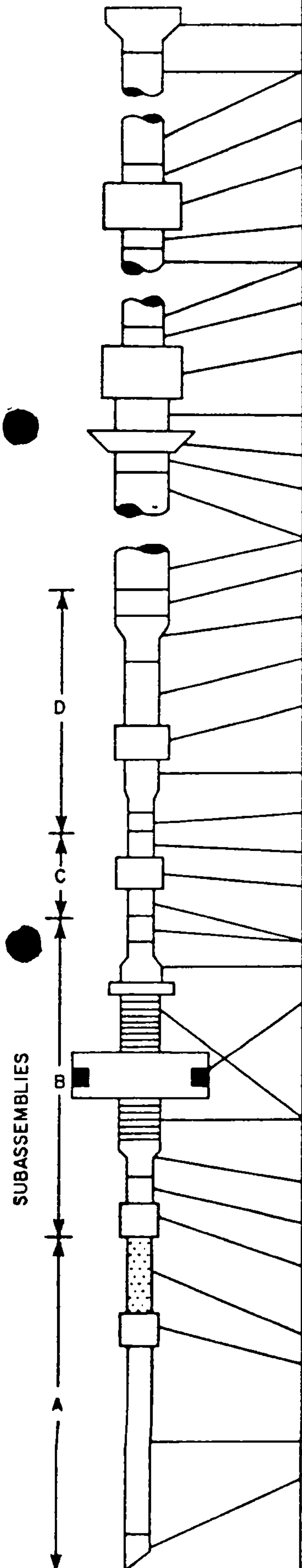


ITEM DESCRIPTION	MIN. I.D	MAX. O.D
X-OVER, 6 1/2" ACME (B) x 4 1/2" PH6 (P), C 75	3.515"	
TUBING; 4 1/2", 19 2 LBS/FT, PH6, C 75	3.515"	5.313"
X OVER; 4 1/2" PH6 (B) x 4 1/2", ACME (P); C 75	3.515"	5 313"
FLOPETROL LUBRICATOR VALVE; H2S SERVICE; 10000 PSI W.P; 4 1/2" ACME (B) x (B)	3.000"	10.750"
X-OVER; 4 1/2", ACME (P) x 4 1/2", PH 6 (P); C75	3.515"	5.313"
TUBING; 4 1/2", 19.2 LBS/FT, PH6, C75	3.515"	5.313"
X-OVER; 4 1/2", PH6 (B) x 4 1/2" ACME (P); C 75	3 515"	5 313"
FLOPETROL EZ TREE; H2S SERVICE; 10000 PSI W.P.; 4 1/2" ACME (B) x (B).	3 000"	10.750
SLICK JOINT; 4 1/2", ACME (P) x (P); C 75	3.000"	5.000"
FLUTED TUBING HANGER; 4 1/2", ACME (B) x (B); C 75	3.000"	
X-OVER, 4 1/2", ACME (P) x 3 1/2" VAM (P); C75	2.922"	4.500"
TUBING, 3 1/2", 10.2 LBS/FT, VAM, C 75	2 922"	3.917"
PUP JOINT (5'), 3 1/2", 10.2 LBS/FT, VAM, C 75	2.922"	3.917"
X-OVER; 3 1/2" VAM (B) x 3 1/2", CS (P); C 75	2 867"	3.917"
TUBING JOINT; 3 1/2", 9.3 LBS/FT, CS; C 75	2 867"	3.905"
3 1/2" OTIS "Q" NIPPLE; NO-GO 2.625"; SEAL BORE 2.750"; 3 1/2", CS (B) x (P); C 75	2.625"	
X-OVER; 3 1/2", CS (B) x 2 7/8", CS (P); C75	2.347"	3.905"
PUP JOINT (5'); 2 7/8", 6.5 LBS/FT, CS, L80	2 347"	3 220"
PUP JOINT (10'), 2 7/8", 6.5 LBS/FT, CS, L 80	2 347"	3 220"
2 7/8", OTIS "XA-SSD"; 2.313" SEAL BORE; 2 7/8", CS (B) x (P); C 75	2.313"	
PUP JOINTS (10'); 2 7/8", 6.5 LBS/FT, CS, L80	2.347"	3.220"
X-OVER; 2 7/8", CS (B) x 3 1/2", CS (P), C 75	2 347"	3.905"
BAKER MODEL "D" PACKER; SIZE 194 - 47 4.750" SEAL BORE.	4 750"	8. 125"
BAKER G-22 LOCATOR SEAL ASSEMBLY; 20' LONG; SIZE 190-47; 3 1/2", CS (B) x 3 1/2" EU (P)	3.000"	4.750"
X-OVER; 3 1/2", EU (B) x 2 7/8", CS (P); C 75	2.347"	4.500"
PUP JOINT (10'); 2 7/8", 6.5 LBS/FT, CS, L 80	2.347"	3.220"
2 7/8", OTIS "S-1" NIPPLE; SEAL BORE 2.313"; 2 7/8", CS (B) x (P), C 75	2.313"	
10' PERFORATED JOINT; 2 7/8", CS (B) x (P); P105	2.347"	3.220"
2 7/8" BAKER "F" NIPPLE; NO-GO 2.250"; 2 7/8" CS (B) x (P); C75	2.250"	3 250"
TUBING JOINT; 2 7/8", 6.5 LBS/FT, CS, P105	2 347"	3 220"
HALF MULE SHOE; 2 7/8", CS (B); P105	2.347"	3.400"
N.B. ALL DIMENSIONS TO BE CHECKED PRIOR TO RUNNING		

NORSKE SHELL, E&P, TANANGER

Appendix 3 (iib)

MICACEOUS SAND GAS ZONE
9 5/8" CASING BY 5" TUBING PRODUCTION TEST STRING

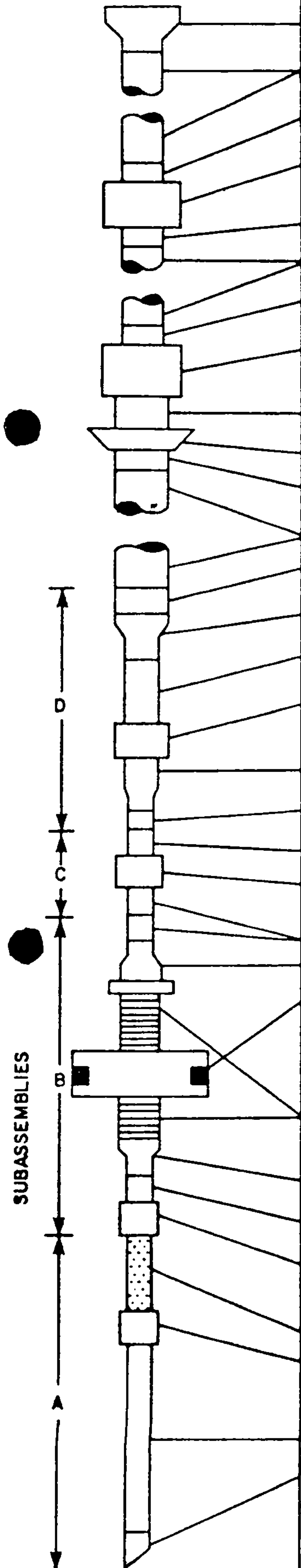


ITEM DESCRIPTION	MIN. I.D	MAX. O.D
X-OVER, 6 1/2" ACME (B) x 4 1/2" PH6 (P), C75	3.515"	
TUBING; 4 1/2", 19.2 LBS/FT, PH6, C 75	3.515"	5.313"
X OVER; 4 1/2" PH6 (B) x 4 1/2", ACME (P); C 75	3.515"	5.313"
FLOPETROL LUBRICATOR VALVE; H2S SERVICE; 10000 PSI W.P; 4 1/2" ACME (B) x (B)	3.000"	10.750"
X-OVER; 4 1/2", ACME (P) x 4 1/2", PH 6 (P); C75	3.515"	5.313"
TUBING; 4 1/2", 19.2 LBS/FT, PH6, C75	3.515"	5.313"
X-OVER; 4 1/2" PH6 (B) x 4 1/2" ACME (P); C 75	3.515"	5.313"
FLOPETROL EZ TREE; H2S SERVICE; 10000 PSI W.P.; 4 1/2" ACME (B) x (B).	3.000"	10.750
SLICK JOINT; 4 1/2", ACME (P) x (P); C 75	3.000"	5.000"
FLUTED TUBING HANGER; 4 1/2", ACME (B) x (B); C75	3.000"	
X-OVER; 4 1/2", ACME (P) x 5", VAM (P); C75	3.000"	5.000"
TUBING; 5", 15 LBS/FT, VAM, L 80	4.283"	5.563"
PUP JOINT (5'); 5", 15 LBS/FT, VAM, L80	4.283"	5.563"
X-OVER; 5", VAM (B) x 3 1/2", CS (P); C75	2.867"	5.563"
TUBING JOINT; 3 1/2", 9.3 LBS/FT, CS; C75	2.867"	3.905"
3 1/2" OTIS "Q" NIPPLE; NO-GO 2.625"; SEAL BORE 2.750"; 3 1/2", CS (B) x (P); C 75	2.625"	
X-OVER; 3 1/2", CS (B) x 2 7/8", CS (P); C 75	2.347"	3.905"
PUP JOINT (5'); 2 7/8", 6.5 LBS/FT, CS, L 80	2.347"	3.220"
PUP JOINT (10'); 2 7/8", 6.5 LBS/FT, CS, L 80	2.347"	3.220"
2 7/8", OTIS "XA-SSD"; 2.313" SEAL BORE; 2 7/8", CS (B) x (P); C 75	2.313"	
PUP JOINTS (10'); 2 7/8", 6.5 LBS/FT, CS, L80	2.347"	3.220"
X-OVER; 2 7/8", CS (B) x 3 1/2", CS (P), C75	2.347"	3.905"
BAKER MODEL "D" PACKER, SIZE 194-47 4.750" SEAL BORE.	4.750"	8.125"
BAKER G-22 LOCATOR SEAL ASSEMBLY; 20' LONG; SIZE 190-47; 3 1/2", CS (B) x 3 1/2" EU (P)	3.000"	4.750"
X-OVER; 3 1/2", EU (B) x 2 7/8", CS (P); C 75	2.347"	4.500"
PUP JOINT (10'); 2 7/8", 6.5 LBS/FT, CS, L 80	2.347"	3.220"
2 7/8", OTIS "S-1" NIPPLE; SEAL BORE 2.313"; 2 7/8", CS (B) x (P), C 75	2.313"	
10' PERFORATED JOINT; 2 7/8", CS (B) x (P); P105	2.347"	3.220"
2 7/8" BAKER "F" NIPPLE; NO-GO 2.250"; 2 7/8" CS (B) x (P); C75	2.250"	3.250"
TUBING JOINT; 2 7/8", 6.5 LBS/FT, CS, P105	2.347"	3.220"
HALF MULE SHOE; 2 7/8", CS (B); P105	2.347"	3.400"
N.B. ALL DIMENSIONS TO BE CHECKED PRIOR TO RUNNING.		

NORSKE SHELL, E&P, TANANGER

Appendix 3 (iic)

CLEAN SAND GAS ZONE
9 5/8" CASING BY 5" TUBING PRODUCTION TEST STRING



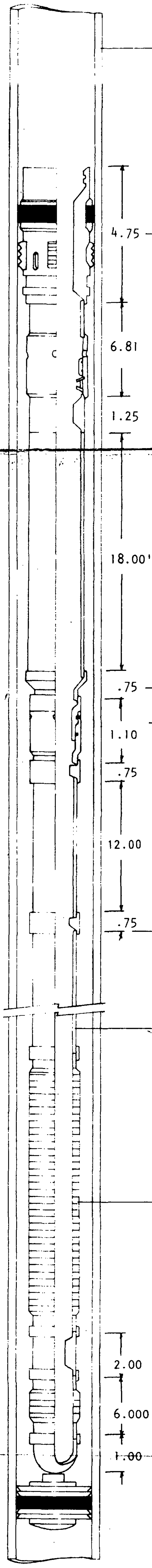
ITEM DESCRIPTION	MIN. I.D	MAX. O.D
X-OVER, 6 1/2" ACME (B) x 4 1/2" PH6 (P); C75	3.515"	
TUBING; 4 1/2", 19.2 LBS/FT, PH6, C 75	3.515"	5.313"
X OVER; 4 1/2" PH6 (B) x 4 1/2", ACME (P); C 75	3.515"	5.313"
FLOPETROL LUBRICATOR VALVE; H2S SERVICE; 10000 PSI W.P; 4 1/2" ACME (B) x (B)	3.000"	10.750"
X-OVER; 4 1/2", ACME (P) x 4 1/2", PH 6 (P); C75	3.515"	5.313"
TUBING; 4 1/2", 19.2 LBS/FT, PH6, C75	3.515"	5.313"
X-OVER; 4 1/2" PH6 (B) x 4 1/2" ACME (P); C 75	3.515"	5.313"
FLOPETROL EZ TREE; H2S SERVICE; 10000 PSI W.P.; 4 1/2" ACME (B) x (B).	3.000"	10.750
SLICK JOINT; 4 1/2", ACME (P) x (P); C75	3.000"	5.000"
FLUTED TUBING HANGER; 4 1/2", ACME (B) x (B); C75	3.000"	
X-OVER; 4 1/2", ACME (P) x 5", VAM (P); C75	3.000"	5.000"
TUBING; 5", 15 LBS/FT, VAM, L 80	4.283"	5.563"
PUP JOINT (5'); 5", 15 LBS/FT, VAM, L80	4.283"	5.563"
X-OVER; 5", VAM (B) x 3 1/2", CS (P); C75	2.867"	5.563"
TUBING JOINT; 3 1/2", 9.3 LBS/FT, CS; C75	2.867"	3.905"
3 1/2" OTIS "Q" NIPPLE; NO-GO 2.625"; SEAL BORE 2.750"; 3 1/2", CS (B) x (P); C 75	2.625"	
X-OVER; 3 1/2", CS (B) x 2 7/8", CS (P); C75	2.347"	3.905"
PUP JOINT (5'); 2 7/8", 6.5 LBS/FT, CS, L80	2.347"	3.220"
PUP JOINT (10'); 2 7/8", 6.5 LBS/FT, CS, L80	2.347"	3.220"
2 7/8", OTIS "XA-SSD"; 2.313" SEAL BORE; 2 7/8", CS (B) x (P); C75	2.313"	
PUP JOINTS (10'); 2 7/8", 6.5 LBS/FT, CS, L80	2.347"	3.220"
X-OVER; 2 7/8", CS (B) x 3 1/2", CS (P), C75	2.347"	3.905"
BAKER SC-1 GP PACKER; SIZE 96A 4-47; 4.750" SEAL BORE.	4.750"	8.440"
BAKER G-22 LOCATOR SEAL ASSEMBLY; 20' LONG; SIZE 190-47; 3 1/2", CS (B) x 3 1/2" EU (P)	3.000"	4.750"
X-OVER; 3 1/2", EU (B) x 2 7/8", CS (P); C 75	2.347"	4.500"
PUP JOINT (10'); 2 7/8", 6.5 LBS/FT, CS, L 80	2.347"	3.220"
2 7/8", OTIS "S-1" NIPPLE; SEAL BORE 2.313"; 2 7/8", CS (B) x (P), C 75	2.313"	
10' PERFORATED JOINT; 2 7/8", CS (B) x (P); P105	2.347"	3.220"
2 7/8" BAKER "F" NIPPLE; NO-GO 2.250"; 2 7/8" CS (B) x (P); C75	2.250"	3.250"
TUBING JOINT; 2 7/8", 6.5 LBS/FT, CS, P105	2.347"	3.220"
HALF MULE SHOE; 2 7/8", CS (B); P105	2.347"	3.400"
N.B. ALL DIMENSIONS TO BE CHECKED PRIOR TO RUNNING.		

BAKER GP EQUIPMENT SCHEMATICS

Drawing No	Title
213/989	Running in/setting/squeezing
213/990	Circulating
213/991	Reverse Circulation
213/988	Completion

BAKER PACKERS

ILLUSTRATIVE DRAWING OF SPECIAL TOOLS AND METHODS



MAX. O.D.	MIN. I.D.		
			9⅝", 47 LBS/FT CASING
8.44	4.75	4.75	96 A4 47 "SC-1" PACKER
		6.81	
		1.25	
7.000	4.75	18.00'	GRAVEL PACK EXTENSION
7.390	4.670	.75	6⅝" x 5½" X-OVER
6.060	4.890	1.10	5½" SHEAR-OUT SAFETY JOINT, 60,000 LBS
6.050	4.000	.75	4.00 x 5½" BOX X BOX INDICATING COLLAR
5.500	4.950	12.00	PUP JOINT, 5½" 8RD PIN X PIN
6.050	4.00	.75	4.00 x 5½" BOX X BOX INDICATING COLLAR
6.050	4.950		5½" BLANK PIPE 90FT
6.090	4.950		5½" x .012 GAUGE SCREEN
6.050	3.250	2.00	3.25 x 5½" SEAL BORE
6.090	4.950	6.000	5½" x .012 GAUGE TELL-TALE SCREEN
6.050		1.00	5½" BULL PLUG

NAME 9-5/8" CASING x 5-1/2" SCREEN GRAVEL PACK FOR LOW BOTTOM HOLE PRESSURE COMPLETION PARTS DIMENSIONED A.S. NORSKE SHELL

DWG. NO. 213 988

DRAWN G.F.RIDEOUT

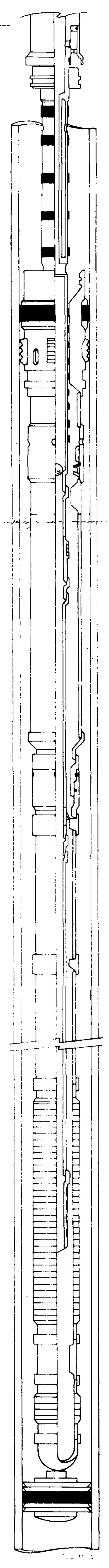
APPROVED C.MASSEY

DATE 28-1-80

REVISION DATES:

BAKER PACKERS

ILLUSTRATIVE DRAWING OF SPECIAL TOOLS AND METHODS



NAME 9-5/8" CASING x 5-1/2" SCREEN GRAVEL PACK FOR LOW BOTTOM HOLE PRESSURE REVERSING POSITION AS NORSKE SHELL

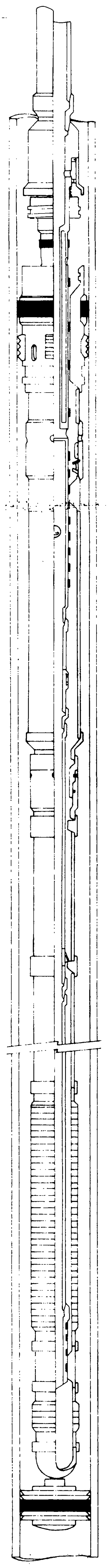
DWG. NO. 213 99

DRAWN G.F.RIDEOUT
APPROVED C.MASSEY
DATE 28-1-80

REVISION DATES:

BAKER PACKERS

ILLUSTRATIVE DRAWING
OF SPECIAL
TOOLS AND METHODS



NAME 9-5/8" CASING x 5-1/2" SCREEN GRAVEL PACK
FOR LOW BOTTOM HOLE PRESSURE
CIRCULATING POSITION
A.S. NORSKE SHELL

DWG. NO. 21-3
990

DRAWN G. F. RIDEOUT
APPROVED C MASSEY
DATE 28-1-80

BAKER PACKERS

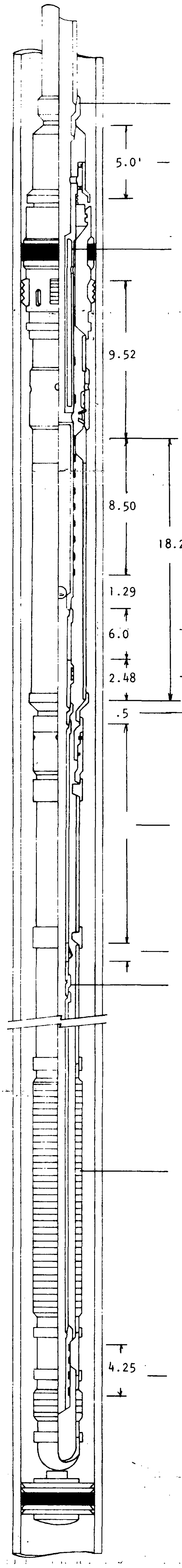
ILLUSTRATIVE DRAWING OF SPECIAL TOOLS AND METHODS

NAME 9-5/8" CASING x 5-1/2" SCREEN GRAVEL PACK FOR LOW BOTTOM HOLE PRESSURE PARTS RETRIEVED DIMENSIONED A.S. NORSKE SHELL

DWG. NO. 213 989

DRAWN G. F. RIDEOUT
APPROVED C. MASSEY
DATE 28-1-80

REVISION DATES:



MAX. O.D.	MIN. I.D.	
6.125	2.441	ROTARY SUB, 4½" IF BOX X 2⅞" EU 8RD PIN
8.125	2.000	MODEL 'B-1' SETTING TOOL 2⅞" EU 8RD BOX UP
6.87		190-47 GRAVEL PACK CROSSOVER TOOL 2⅞" EU 8RD PIN DOWN
3.688	1.870	
3.688	2.441	TUBING NIPPLE 2⅞ EU 8RD BOX X PIN
5.070	2.375	190-47 SHIFTING TOOL 2⅞" EU 8RD BOX X PIN
3.688	1.995	X-OVER 2⅞" EU 8RD BOX X 2⅜" EU 8RD PIN
3.063	1.995	PUP JOINTS, 2⅜" EU 8RD BOX X PIN
		4.00 INDICATING COLLET 2⅜" EU 8RD BOX X PIN
3.063	1.945	X-OVER 2⅜" EU 8RD SPECIAL CLEARANCE X 2⅜" HYDRIL C.S. PIN
2.700	1.945	WASH PIPE AND PUP JOINTS 2⅜" HYDRIL C.S. BOX X PIN
3.687	1.995	SIZE 81-32 G-22 LOCATOR 2⅜" HYDRIL C.S. BOX X ½ MULE SHOE

GRAVEL PACK FLUID FORMULATIONS/SPECIFICATIONS - CLEAN SAND GAS ZONE

"Pre-Pad" gelled fluid: 15 BBL, density 10.1 ppg

15 BBL - 10.1 ppg CaCl2 solution
51 lb - J164, gelled agent
Caustic soda as required to adjust pH to 8.5 - 9.0
19.5 lb - J286, breaker
2.5 gal - A200, inhibitor
(0.5 gal - D47, antifoam agent if required)

"Water Pack" slurry: 16.95 BBL, density 13.1 ppg

4.08 BBL - 10.1 ppg CaCl2 solution	= 11.67 BBL of	
7.59 BBL - Fresh water	9.0 ppg CaCl2 solution	

39 lb - J164, gelling agent
Caustic soda as required to adjust pH to 8.5 - 9.0
15.1 lb - J286, breaker
2.0 gal - A200, inhibitor
(0.4 gal - D47, antifoam agent if required)
4900 lb - 12-20 mesh gravel (10 ppg)

"Post Pad" gelled fluid: 5 BBL, density 10.1 ppg

5 BBL - 10.1 ppg CaCl2 solution
17 lb - J164, gelling agent
Caustic soda as required to adjust pH to 8.5 - 9.0
6.5 lb - J286, breaker
0.8 gal - A200, inhibitor
(0.2 gal - D47, antifoam agent if required)

Note

1. All fluids to be filtered to 2 microns prior to mixing.
2. The use of D47 is recommended to ensure that all air is removed from the slurry.
3. Extra caustic soda may be required to adjust the pH of the fluid when mixing the gel.

PROVISIONS FOR LOST CIRCULATION/BRINE LOSSES

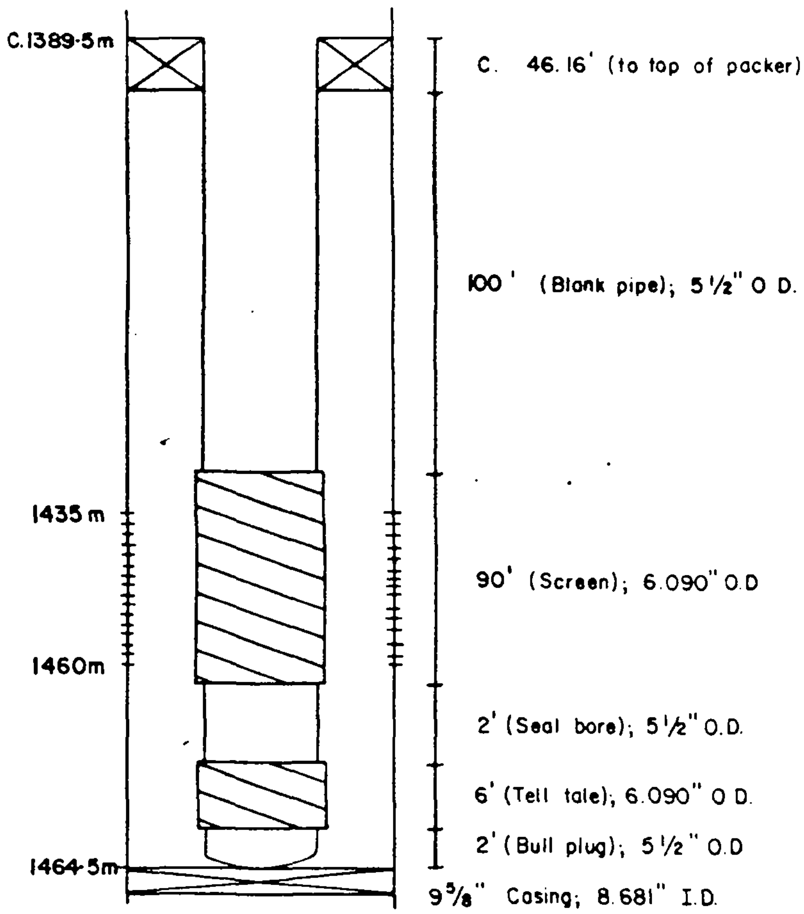
a) If low losses are expected when the well is perforated then the $CaCl_2$ brine may be slightly gelled using 1 lb J-164 (HEC) per bbl of brine. This would give a Marsh funnel viscosity of approx 50 at 80 degs F, 45 at 100 degs F and 38 at 150 degs F. Greater quantities of J-164 (HEC) can be used to give better fluid loss control but this could cause problems if the brine were required to be refiltered.

b) If high losses are expected when the well is perforated then slugs of $CaCl_2$ brine gelled with J-164 (HEC) and containing $CaCO_3$ can be spotted across the perforations until the losses stop.

If $CaCO_3$ is used as a fluid loss additive then this can be cleaned up before the gravel pack by matrix acidizing with a mixture of Hydrochloric Acid and U66 (ethylene glycol monobutyl ether) which combines the normal characteristics of HCl with the U66 which reduces surface tension and thus aids the clean up. This is particulary important in gas wells.

GP VOLUMES- CLEAN SAND GAS ZONE

(N.B. ALL CALCULATIONS TO BE RECHECKED ON SITE).



GRAVEL TO FILL:

104' of 5 1/2" x 8.681"	=	25.59 cu. ft.
96' of 6.090" x 8.681"	=	20.04 cu ft
TOTAL	=	45.63 cu ft

Use 45.63/0.93 = 49 sx gravel, (4900 lbs)

DP/DC volume to packer = 75.6 bbls

Annular volume around screen = 9.4 bbls

Therefore brine volume for tell-tale screen out = 85 - (5 + 16.95) bbls
= 63.05 bbls

MEASUREMENTS REQUIRED

A. During flow periods

The following data should be recorded during flowing periods every 15 mins, or whenever a change occurs:

WHP; WHT; choke size; flowline pressure
Separator pressure; separator temperature
Flowrate (liquid) and GOR
Sand concentration (see Appendix 5)
Annulus pressure (via kill line)

In addition, all produced fluids should be measured for density. Gas should be analysed via the mud logging gas chromatograph, with H2S measured with Draeger tubes. Produced water should be measured for salinity.

B. During BHP surveys

During all BHP surveys the following deadweight THP measurements are required:

a) Every 5 minutes during initial lubricator calibration stop.

b) Every 15 minutes during flow period.

c) After closing in for build up, every 5 minutes for the first hour, thereafter every ½ hour.

d) Every 5 minutes during the gradient stops at 300 m and 600 m above "F" nipple and at seabed.

e) Every 5 minutes during the final lubricator calibration stop.

SAND DETECTION DURING OIL TEST

Materials Required

1. Acetone, toluene and paraffin
2. 10 x 63 sieves
3. 1 gallon cans
4. Electrically driven centrifuge and 50 centrifuge tubes
5. Watch glasses
6. Glass funnel

Procedure

a) Collect one imperial gallon crude oil from choke manifold as fast as possible into a clean container.

b) Shake the sample vigorously and slowly pour the contents over the sieve.

c) Wash the residue on top of the sieve with paraffin, toluene and acetone in that order and allow acetone to evaporate.

d) With the fine brush transfer the residue from the top of the sieve into a graduated conical centrifuge tube, wash the glass funnel and brush with toluene so that particles are flushed into the tube. (It is unsafe to centrifuge with acetone).

e) Centrifuge for about 3 minutes and determine the volume in cubic centimeters of solids collected at the bottom of the tube. The tube should be clearly marked with sample number, date, zone on test, production rate, concentration of sand, well number.

f) Estimated sand concentration in lbs/1000 lbs: Sand content = 102 x No. of cc volume of solids centrifuged out. (For more accuracy, multiples of imp. gallons could be processed and the concentration divided appropriately).

g) To establish whether the sediment is partially wax, pour off excess toluene and add acetone, shake and pour off sediment free acetone. Drain sediment onto a watch glass, allow it to dry and heat to above 100 degs C. Observe for melting. This can also be verified under a microscope.

h) Carefully store the samples and send ashore for analysis.

i) If wax is found to be a large percentage in item (d) the screen contents can be flushed with water so that the wax will lie above the sand and can be easily distinguished.

SAND DETECTION DURING GAS TESTS

Strict monitoring of the flowstream for sand will be performed using:

i) The Flopetrol "SANDEC" sand detection probe installed in the flowline.

ii) A Baker Sand Trap installed in the flowline (if available).

SAND CONCENTRATION - CRITERIA

The maximum allowable sustained concentration is 50 lbs/1000 bbls for all tests, including maximum rate tests. If the concentration exceeds this, the well should be beaned back and a further sample taken after 1½ tubing volumes. In the case of a maximum rate test, the test can be terminated once sustained sand production has been established. N.B. Some sand always occurs after a bean change.

In general:

< 25 lbs/1000 bbls	-	continue with programme.
25 - 50 lbs/1000 bbls	-	maintain the rate steady.
> 50 lbs/1000 bbls	-	bean back rate by half and repeat beaning back until concentration declines.

It is expected that, during clean up, bursts of high sand concentration may be detected. These should not cause undue concern if they are not sustained.

APPENDIX 6 (i)

FIELD DATA

WATER ZONE (for test) 1600.5 - 1605.0 m BDF

Expected reservoir pressure	2318 psi at 1603.5 m BDF(actual)
Water gradient	0.443 psi/ft
Expected maximum CITHP	0 psi
Packer fluid	1.21 S.G. brine
Expected formation breakdown gradient	1.64 S.G.
Log derived water salinity	70000 ppm NaCl

OIL ZONE (for test) 1577.5 - 1582.5 m BDF

Expected GOR	300 - 400 scf/bbl
Expected reservoir pressure	2282 psig at 1577.5 m BDF(interpolated)
Oil gradient	0.902 SG
Expected maximum CITHP	260 psig
Expected bubble point at ambient temperature	NYK
Bubble point at reservoir temperature	2050 psig
Packer fluid	1.21 SG Brine
Expected formation breakdown gradient	1.64 SG
Viscosity at reservoir conditions	NYK
Formation volume factor (Co)	NYK
Total compressibility (CT)	NYK
Average porosity	NYK
Oil saturation	NYK

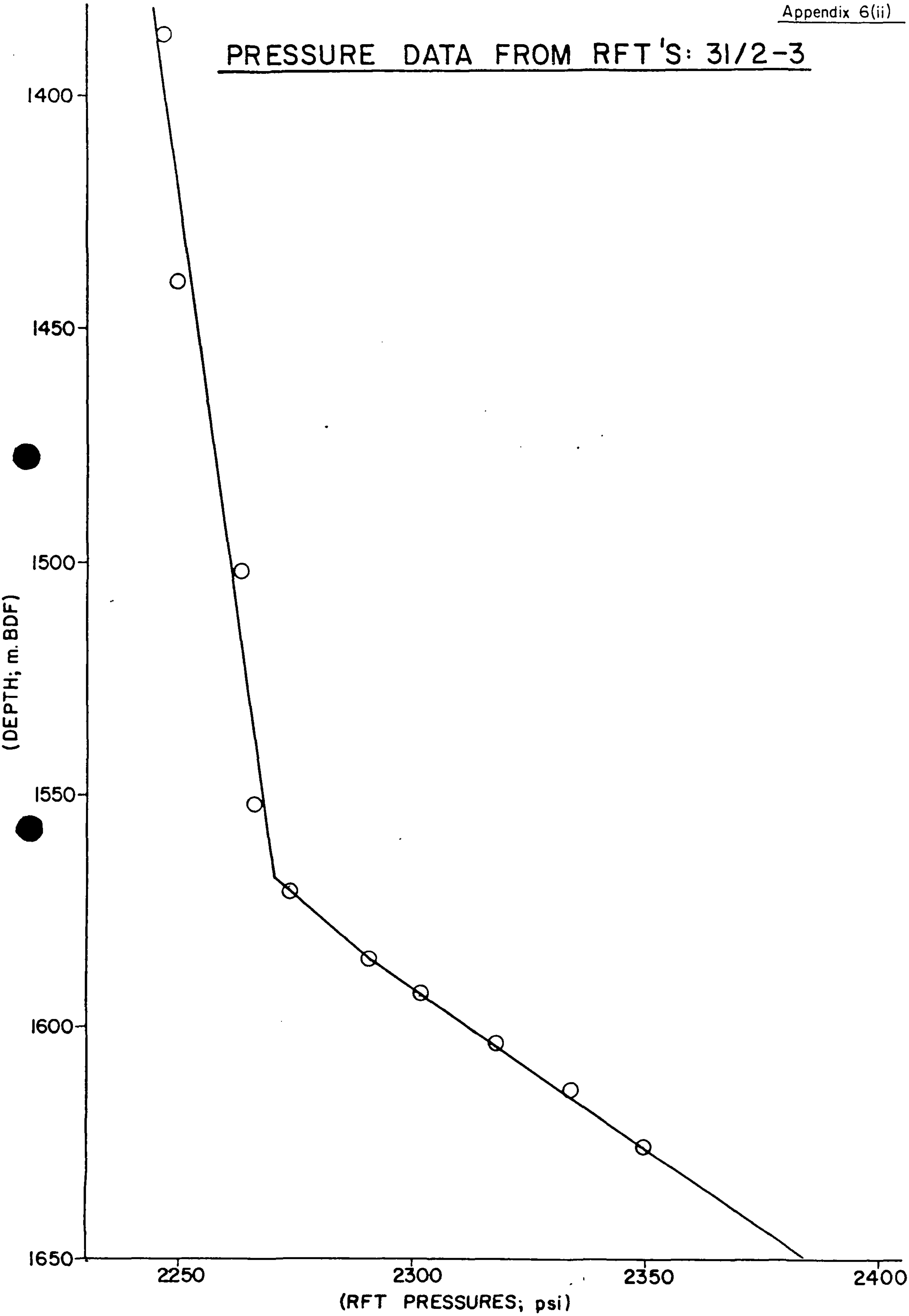
(NYK = not yet known)

GAS ZONE (for test); (i) 1520 - 1535 m BDF, (ii) 1435 - 1460 m BDF

Expected CGR	4 bbls/MM scf
Expected reservoir pressure	(i) 2264 psi at 1520 m BDF(interpolated) (ii) 2250 psi at 1440 m BDF(interpolated)
Gas density (air = 1.0)	0.6 (0.06 psi/ft)
Expected maximum CITHP	1900 psig
Dew point	2200 psig
Packer fluid	1.21 SG Brine
Expected formation breakdown gradient	1.64
Viscosity at reservoir conditions	0.018 cp
Gas expansion factor (E)	172 vol/vol
Deviation factor (Z, at reservoir conditions)	0.8
Average porosity	(i) NYK (ii) 33%
Average gas saturation	(ii)NYK (ii) 95%

N.B. All data herein approximate only

PRESSURE DATA FROM RFT'S: 31/2-3



APPENDIX 7

SAMPLING REQUIREMENTS

a) The Thornton probe manifold will be included in the production test flowline to permit detailed onsite flow stream analyses. In addition KSLA will perform trace element analyses on produced fluids.

b)i) Bottom hole samples are included in the oil zone test programme. If constant separator conditions are achieved, take 4 sets of separator recombination samples.

b)ii) No bottom hole samples are required for the gas tests. 4 sets of separator recombination samples should be taken when a constant CGR has been obtained.

c) 10 x 45 gallon drums of stabilized crude oil (oil test) and stabilized condensate (gas tests) should be collected if possible.

d) For the water zone DST, formation fluid samples will be recovered in the DST string. In addition, while reversing out the test string contents, take as many samples as possible to help establish formation water parameters. Should this supposed water zone flow hydrocarbons to surface, samples as per b)i) and c) above should also be taken.

PROCEDURE FOR RECOMBINATION SAMPLES

A. Gas Sample

1. The bottles should be properly evacuated with a vacuum pump.
2. The Shell Petroleum Engineer ensures that bottles are filled up slowly and are at separator pressure prior to being closed.
3. Check container and valves for leaks.
4. Mark bottles with sample number.
5. Fill in surface PVT sampling forms.

B. Oil/Condensate

1. Oil/condensate sample container should be filled with mercury.
2. Displace slowly 500 cc mercury from 600 cc container with oil/condensate from separator.
3. The Shell Petroleum Engineer ensures that bottles are at separator pressure prior to being closed.
4. Draw off 50 cc of mercury to create gas cap.
5. Check containers and valves for leaks.
6. Mark bottles with sample number.
7. Fill in surface PVT sampling forms.

Sample Bottle Working Pressure

Capacity	W.P.
5 litres	2,800 psi
0.6 (0.7) litres	10,000 psi

WELL TEST ARRANGEMENT ON DRILLFLOOR

(BORGNY DOLPHIN)

1) FLOPETROL WELL HD + AUT WINGVALUE
2) KILL LINE COMPLETE WITH B.P.V.
3) SWIVEL
4) MASTERGATE, HAND-OPERATED.
5) 3"/1502 CHICKSAN LOOPS.
6) LUBRICATOR VALVE AND E.Z. TREE CONTROL PANEL
7) GLYCOL INJECTION PUMP.
8) WIRELINE BOP + STUFFINGBOX
9) "SANDEC" SAND DETECTOR / MONITOR
10) SAND PROBE + HOUSING
11) BAKER KNOCK-OUT SANDFILTER + BY PASS + DRAIN
12) SANDPROBE HOUSING
13) THORNTON MANIFOLD
14) THORNTON MINI-LAB
15) DATA HEADER
16) THP/CHP RECORDER
17) DEAD WEIGHT TESTER
18) CHOKE MANIFOLD
19) 6"/3600 FIXED FLOWLINE
20) SHUT DOWN LINE TO W.V. OPERATIONAL FROM 3 LOCATION