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A Case History of Sustainable Annulus Pressure in Sour Wells – Prevention, Evaluation and Remediation

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Summary

This paper describes evaluation of the possible causes of Sustainable Annular Pressure (SAP) in a sour gas field in the Middle East. It explains the diagnostic testing undertaken and describes how evidence was used to identify the cause of the SAP. The steps taken to prevent the occurrence of SAP in new wells and to remedy the problem in existing wells are described.

This practical approach, based on critical assessment of many aspects of the whole well condition put the SAP problem under total control, covering the process from well design through the lifecycle of the well. This all-encompassing approach is regarded to be essential for all sour gas wells, but especially for HPHT designs.

Introduction

Varying magnitudes of annular pressure exist in wells in some of the fields of the Middle East. The sources of this pressure vary along with the particular affected casing string in the well. In some high rate wells casing pressure is caused by thermal expansion of annular fluid. However, once a well is flowing at steady state conditions, the pressure from all casing strings should bleed through a needle valve to, and remain at, atmospheric conditions. If the casing pressure builds up when the valve is closed, then the casing exhibits sustainable annular pressure (SAP).

The general policy adopted internationally is that departure approval is automatic as long as the SAP is less than 20% of the minimum internal yield pressure and can be bled down to zero through a 0.5-in. needle valve in less than 24 hours. Outside of these conditions,

diagnostic testing must be implemented, followed by remediation of the source of SAP^{1,2}.

The consequences of SAP may be very severe if not brought under control; well blow-outs have been attributed to SAP³. Our experience in dealing with SAP problems in client wells has allowed the development of a rational approach to quantify the magnitude and source of sustained annular pressure and this has been incorporated into a comprehensive software model the "Well Integrity Toolkit".

This paper describes the experience of SAP in the onshore sour gas wells of one client based in the Middle East. It discusses the extent of their problem, the diagnostic testing implemented and its interpretation, and the recommendations made to prevent SAP arising in new wells and to remedy the SAP in the existing wells.

Experience of SAP in Client Wells

Routine measurement of the pressures in Annulus A (production) and B (intermediate) had been carried out by the client. Figures 1, 2, and 3 represent the magnitude of annulus pressure measured on three representative wells.

The design limit of annulus pressure allowed, according to the client's criteria, was 1300 psi for Annulus A and 500 psi for Annulus B (these figures being slightly below the calculated 20% of maximum allowed annulus surface pressure values which would cause burst of the outer pipe or collapse of the inner pipe in the given annulus). So these three wells were typical of the situation where excessive pressures had been noted in random pressure testing and the decision was taken that wells showing this kind of behaviour would be subjected to comprehensive diagnostic testing.

SAP Diagnostic Testing Approach

It is important that a comprehensive approach is adopted. Focusing too closely on the immediate problem without considering the complete well behaviour and status may result in incorrect conclusions being reached, or less than optimal remediation action. So operators

must address all casing pressure diagnostics and departures on a whole well basis. This means that when any annulus on a well needs a diagnostic test, operators must check the pressure response on all casings at the same time.

Operators must record pressure bleed-down and the rate of pressure buildup of each annulus for the 24-hour period immediately following the bleed-down. Pressure buildup must be recorded graphically or in a table at no greater than 1-hour increments for each casing annulus in the wellbore. If fluid is recovered during bleed-down, operators must record the type and amount. The technical complexity of the SAP mechanism requires the inclusion of the measurement of the gas and liquid flow rates as a part of the SAP risk evaluation. Operators should conduct pressure bleed-down in such a way to minimize the removal of liquid from the annulus.

For subsea wells, where only the production annulus can be monitored, operators must conduct diagnostic testing as indicated, except that results for adjacent annuli will be restricted to monitoring the tubing pressure response.

Records of each diagnostic test must be maintained for each casing annulus with SAP. The diagnostic tests must be repeated regularly whenever the pressure is observed to increase (above the value that triggered the previous test) by more than 100 psi on the conductor or surface casing or 200 psi on the intermediate or production casing. Well operations such as acid stimulation, shifting of sliding sleeves, and replacement of gas lift valves also require the diagnostic tests to be repeated. If, at any time, the casing pressure is observed to exceed 20% of the minimum internal yield pressure of the affected casing (or collapse pressure of the inner pipe), or if the diagnostic test shows that the casing will not bleed to zero pressure through a 0.5-in. needle valve over a 24 hour period, the operator is expected to repair the well using an approved practice.

The Well Integrity Toolkit model can be used to analyze the diagnostic testing data, distinguishing different types of pressure test responses, leading to an understanding of possible SAP causes and indicating the severity of the problem. Pressure testing analysis is successful in identifying wellhead, tubing and production casing leaks, and these leaks can also be remedied by conventional workover operations. However, for outer strings, the interpretation of casing pressure test data and methods of SAP remediation are less advanced.

SAP Diagnostic Test Results. From the various diagnostic testing results several typical response patterns were noted; two SAP bleed-down patterns and three SAP buildup patterns:

- Instant Bleed-Down
- Incomplete Bleed-Down

- Normal Buildup
- S-Shape Buildup
- Incomplete Buildup

The instant bleed down pattern is recognized when the needle valve is opened wide to bleed a small amount of gas and liquid from the casing annulus in a very short time. The casing pressure drops to 0 psi in about 15 seconds and a volume of liquid annular fluid is removed.

The incomplete bleed down case is observed when the casing pressure does not decrease to 0 psi over the duration of the bleed down test (up to 15 minutes).

Normal buildup behavior of casing pressure during diagnostic test is observed when the casing pressure rises quickly after the bleed-down (initial period behaviour) and ultimately stabilizes at a certain level (late-period behaviour). The transition shows a gradual pressure increase. The stabilized casing pressure is determined by the mud weight and gas-source formation pressure; the transition period is controlled by the magnitude of gas migration in the cement and mud column.

S-shape buildup behaviour shows no obvious increase of casing pressure until the first volume of gas reaches the casing head, then the casing pressure increases gradually. Finally, the pressure stabilizes at a certain level to finish one cycle of buildup.

Incomplete buildup is noted after the bleed-down when the casing pressure continually increases. No late-period stabilization is apparent in the testing interval (usually 24 hours). Compared with the normal buildup pattern, the casing pressure increase in the initial period is relatively low.

Fig. 4 (a to e). shows examples of the characteristic diagnostic test results illustrating each of the typical patterns of behaviour. Interpretation of the curve shapes indicates the possible causes of SAP and provides information which is used to identify the optimum remediation approach.

Evidence of Possible Causes of SAP. The most significant cause of SAP in the outer casing strings, outside of the production casing, is gas migration through a poor cement bond. Even after the cement sets, pressure and temperature changes caused by the next drilling phase and completion and production operations contribute to the development of cracks and micro-annuli in the cement sheath. Those channels and cracks provide paths for gas to migrate to and accumulate at the wellhead, causing SAP.

Gas migration can occur at both "primary" and "secondary" stages. The former is related to aspects of

the actual cementing operation, slurry characteristics, displacement mechanics, and hydrostatic pressure. The "Secondary" or "late" gas migration, has little to do with the cementing operation. It is caused by mechanical and thermal stresses which damage the integrity of the cement bond and lead to gas leakage. In some cases the cement shrinkage causes long-term leakage. Our investigation indicated that gas migration in the client wells had occurred at both "primary" and "secondary" phases.

There are two possible configurations in the annulus; cemented to the surface or a mud column above the cement.

In the Middle East client case, all of the annuli were intended to be cemented to the surface. In that case gas migration would be considered as a flow through porous media having some permeability. After bleedoff, the annular pressure increase would be analogous to the pressure bleedoff. The buildup behavior is controlled by the cement properties such as permeability and porosity, as well as by the formation pressure. There may also be a contribution from gas flowing through matrix channels or micro-annuli. Matrix channels exist in the cement itself; micro-annuli can exist as a path between the cement sheath and casing or the cement sheath and formation.

In reality the Middle East client wells had a mud column above the cement. In this case gas flow in the cement is affected both by formation and cement properties and also the rheology of the mud, since the mud properties control the gas flow rate at the interface between the cement and mud column.

Interpretation of the diagnostic test data allowed distinction to be made between the type of annular media present i.e. thin or thick mud and cement with a poor or acceptable cement bond. In this client case the data indicated that in most cases there was a thick mud with a poor cement bond present. The implication was that during primary cementing, gas had invaded the cement and formed channels. Separate evidence of wellhead movement indicated that there were secondary causes of gas migration in the production annulus. The conclusions of the analysis of the data was then used to establish the best means of control of SAP in the affected wells and also to introduce measures to prevent SAP problems in new wells presently being drilled.

Contributory Factors in SAP Control in New Wells

SAP was evident in 47 of the 152 total gas producer wells and was present in some cases on several annuli. Evidence of SAP was noted very early in the lives of some wells, within 2 years and as short as 6 months in

one case, indicative of fairly fundamental problems. The gas leakage from the outer annulus was the main reason for reassessing the Middle East client well redesign, so a thorough review of the gas well design in the field was made. A detailed review of the cement jobs was also carried out for each casing and liner.

Review of the initial drilling operations, reports and other documentation indicated some gaps in the adopted well design and the drilling and cementing practice. Corrective steps were recommended, focusing on involving the Cement Bond Integrity Test for new wells, as a powerful tool to evaluate the cementing job at the critical point and to indicate the necessity for corrective secondary cementing job during the well construction.

Well Design Issues. A thorough review of the gas well design in the field was made. It was based on the approach of "Maximum Load concept", which includes:

- Burst load design
- Collapse load design
- Tension load design
- Buckling and wellhead loads design
- Biaxial analysis
- Triaxial analysis

The conclusions of this detailed review were that the currently used casing design for the gas wells was quite conservative, meeting the load bearing requirements, with the exception of the buckling load requirements, biaxial and triaxial considerations.

The client believed that the effects of buckling were reduced by supporting the casing with a full column of cement and that this was achievable through a combination of primary cementing and a follow-up top job. In practice the full column of cement was not achieved during primary cementing and the following top cement job was not effective. This was proved by the evidence of significant movement of the wellhead. Wellhead movement was a problem in several cases; evidence of casing movement and contributory to cement bond deterioration. Considering the extended measured length of wellhead and implying the procedure for "frozen string" it was not a hard task to determine the depth of the free point. Wellhead movement indicates that the casing has been landed with insufficient tension to eliminate any build up of axial stress. An improved casing load calculation was proposed, as a means to control wellhead movement and also to reduce the risk of SAP in new wells. Fig. 5. presents an example of the Stability Force and Wellhead Loads design calculations.

In cases where thermal effects due to large temperature variations result in high axial stress, buckling of an unsupported casing string needs to be considered using a more comprehensive approach.

Cementing Issues. In order to avoid the annular gas leakage problem in the early stage of the life cycle of the well it was recommended to the client to achieve optimum cementing. The main purposes of annular cementing is to:

- provide zonal isolation
- prevent casing buckling
- control external corrosion of casing.

The cement height in the annulus determines which intervals behind the pipe are covered. It was the clients intention to completely fill all annuli, but severe external corrosion of the casing, where the casing passed through corrosive reservoir fluids and highly saline surface aquifers, was evidence of the absence of a complete cement sheath behind the pipe.

A significant number of gas producer wells drilled in the critical part of the field experienced high 'B' annulus pressure, with tens of the wells requiring bleed down of the 9.5/8in /13.3/8in annulus more than once a month. It was noted that some of the injectors also experienced high 'B' annulus pressure.

Gas migration during and after the cementing job and the presence of micro annuli are the principal causes for the poor well integrity of the production casing cementing sheath which allows the migration of hydrocarbons to the surface. These aspects had not been considered at the well design stage to mitigate 'B' annulus pressures in critical wells.

In order to avoid gas migration and the forming of micro annular spaces it is recommended to take into consideration that:

- Gas pockets encountered while drilling should be fully depleted prior to cementing.
- During the cement job, a dynamic hydrostatic head across the gas section where the first high background gas (>2%) is observed should be maintained equivalent to the mud gradient needed to control the background gas whilst drilling that section.
- A 'mud filled' external casing packer should be run just above the zone of suspected high background gas (as part of the production casing string) if applicable.
- The cement should, if operationally possible, be displaced with a fluid of the same density as the density of the mud to be used for the next hole section or the density of the brine to be left in the 'A' annulus after completion of the well to minimise the formation of micro-annuli. The consequence is, however, that the circulating pressure during displacement will increase considerably. Some thermal expansion of the cold mud after bump may be expected.
- Losses should always be cured and gas presence eliminated prior to starting cementing. In the event

that casing has been run and losses cannot be cured or gas presence cannot be avoided, consideration should be given to pulling the casing and an additional wiper trip run to gain control over the hole. Multi-stage cementation collars should be used only if operationally required.

- The design of the cement should be tailored to individual wells taking into account events such as losses and high background gas in the drilling phase. One of the prime objectives of the cementation is to achieve a good bond across the gas bearing intervals.

The Cement Bond Integrity Test. Review of the initial drilling operations, reports and other documentation indicated some gaps in the drilling and cementing practice. Whilst a lot of effort had been given to optimising the cement type, quality and placement techniques, the overall cement job quality was evaluated only by logging. Corrective steps were recommended, focusing on involving the Cement Bond Integrity Test (CBIT) for new wells, as a powerful tool to evaluate the cementing job at the critical point and to indicate the necessity for corrective secondary cementing job during the well construction.

It was strongly recommended to the client to introduce a test procedure which provides a way of evaluating the cement shoe bond strengths in absolute value (ppg). It was considered that any other method of cement bond test was only qualitative and does not convey really useful data on the condition of a completed cement job.

The CBIT approach enables the:

- Quantification of the cement bond integrity,
- Measurement of the proper quality of the cementing operations,
- Evaluation of the performance of cementing service companies,
- Minimization of the risk of leaks around the cement,
- Reduction of the problem of SAP in new wells
- Minimization of operational time and risk exposure to personnel, process, production and equipment.

Fig. 6 illustrates the Cement Shoe Bond Integrity Test. Considering the results of the Cement job design calculations and practical implementation the following conclusions can be reached regarding the Middle East client "Cement Job concept" for casing strings 18 5/8' ; 13 3/8 ; 9 5/8 and Liner 7' :

- In general the aims of the cement practice was acceptable, however a key quality control aspect was missing.
- The surface, intermediate and production casing strings required evaluation of the cement shoe

bond strengths in absolute terms (ppg) in order to optimise well integrity, and in particular prevent SAP.

Gas migration in the "primary" phase is related to aspects of the actual cementing operation, slurry characteristics, displacement mechanics, and hydrostatic pressure. These aspects can be monitored by means of the job quality assessment sheet, such as that illustrated in Fig. 7. "Secondary" or "late" gas migration is not addressed by control of the cementing operation; it is caused by mechanical and thermal stresses which damage the integrity of hydraulic bond or the cement material and lead to gas leakage. The corrective step in terms of these secondary effects was to involve a proper buckling design calculation (as discussed under well design, above).

Recommended SAP Remediation in Existing Wells

Referring to the Middle East client "Well history", several procedures were employed in the past with only limited success in reducing but not eliminating the sustained annulus pressure. Rig-less methods of SAP remediation involve external treatment of the casing annulus using a combination of bleeding off pressure and injecting a sealing/killing fluid either at the wellhead (Bleed-and-Lube) or at depth through flexible tubing inserted into the annulus (CARS). A limited number of case histories report the Bleed-and-Lube method as partially successful. However, it was judged that completion of the job would have required months, or years, of pressure "cycling" application since the volumes injected at each cycle were judged from the diagnostic test results to be extremely small. In some previous cases incomplete reduction in surface casing pressures was achieved when this method was employed. It was concluded that the best approach would be a rig-based method of SAP remediation⁴.

For Rig technology SAP removal, previous perforate to squeeze operations may have failed due to the inability to place sufficient pressure barriers in the affected annulus. There are many difficulties in isolating SAP through perforation or cut to squeeze operations. Although perforations or a cut can access some of the channels, all of the conduits may not be isolated with sufficient volumes of cement. It is highly unlikely that any cement could be placed on the low side of the hole in a highly eccentric situation. The Middle East client experience was that previous perforate-to-squeeze operations had usually failed due to the inability to place sufficient pressure barriers in the affected annulus.

Each well presented its own unique operational difficulties; the general recommendation to the client was intervening as deeply as possible. This allowed for future

remedial work if the present operations did not succeed, as well as maximizing the hydrostatic pressure available to kill any pressure.

Casing shoe integrity and casing burst characteristics are the limiting factors considered when fluid weights and test pressures are chosen during the operation.

To solve all the client wells difficulties, two main approaches to access and alleviate SAP were recommended for the workover program:

- a) Termination of the affected inner casing string as deeply as possible inside the outer casing without extending below the intermediate casing shoe. This kind of termination maximizes the room available for possible future intervention and provides the hydrostatic advantage of the longer fluid column.
- b) Section Milling a 120 ft. foot window and isolating both the lower stub and upper stub with cement plugs. This has to be attempted in cases where the inner casing string cannot be economically or feasibly removed to the necessary minimum depth to address annular pressure.

Some of the client drilling reports indicated the inner casing was cemented in place with cement to surface, or a cement bond log indicated a too shallow top of the cement. In these cases it was therefore necessary to introduce a window milling procedure. The two approaches are described below.

Termination of Inner Casing. Termination of Inner Casing was possible in the cases where the cement sheath was absent behind the pipe. The typical 'cut and pull' or 'termination of inner casing' operation is explained in well schematics that illustrate the following sequence of events. This is the preferred method for the customer wells when the affected casing annulus is not cemented or removal is not otherwise restricted.

Termination of Inner Casing consists of three base operations:

- Cut and Pull Casing
- Casing Cleanout
- Pressure Isolation of Inner Casing Stub and Annulus

Before "*Cut and Pull*" Casing, the mud is circulated out to kill weight fluid. A trip in the hole with the workstring and a mechanical cutter is then made to cut the inner casing in an attempt to circulate kill weight fluid down the casing and into the annulus, if possible. When the deep cut is made, the well is verified to be dead before the cut immediately below the hanger is made. When a successful shallow cut is made, the pumps are rigged down and the workstring has to be pulled out of the hole. The shallow cut releases tension on the hanger allowing it to be removed along with the first 50-ft. of casing down to the shallow cut.

The procedure assumes the spear and grapple set to catch inner casing have to be then tripped into the hole to spear into the inner casing. An attempt to establish circulation is not made until there is casing movement in order to avoid packing mud or sediment in the annulus. Once the pipe is moving, it has to be reciprocated while mud is circulated in the hole. The casing is picked up and pulled out of the hole to recover the casing to the deeper cut.

In the situation where the affected casing can not be cut and pulled, stretch calculations have to be performed to make a cut as deeply as possible. The following step would be to set a spear and grapple for catching. The aim is to spear into the stub and provide casing movement. Mechanical cuts are then made at depths calculated from stretch not to be restricted behind pipe.

Sometimes it is necessary to pilot mill immediately below the casing hanger or from the deepest successful casing cut and recovery. The pilot mill has to contain carbide inserts to increase penetration rates and mill life. The blade design creates small cuttings for ease in removal and is run in conjunction with a shock sub and drill collars to provide weight. The weight on mill and rotating speed are determined by penetration rate, torque, and hole cleaning.

Casing Cleanout assumes a trip in the hole to the inner casing stub with a bit and scraper sized for the outer casing has to be made. The bit and scraper is worked from the casing stub up through the top of the proposed plug location.

It was recommended to the client that whenever possible, a bottom should be set to avoid cement contamination from gas or other fluids migrating through the setting cement. A cast iron bridge plug (CIBP) is the preferred method. It has both slips and sealing elements rated to 5,000 psi differential and up to more than 300°F and could be usually set on the workstring inside the proposed casing stub before milling or pulling operations. The CIBP has then to be pressure tested, resulting in a pressure loss of no more than 10% during a 15-minute time period, which verifies proper setting. When cementing in a water-based mud environment, a diverter sub has to tripped in the hole to the planned top of cement and rotated into the hole throughout the plug interval. The tool has an axial flow pattern for efficient removal of mud cake or trash from the casing.

Pressure Isolation of Inner Casing Stub and Annulus the workstring has to be tripped into the hole down fifty feet inside the inner casing stub. The annulus has to be closed and injection rates are established before the cement is mixed. A spacer has to be pumped ahead of the latex cement. The latex cement is mixed, pumped, and then displaced to balance the cement plug inside and outside of the workstring.

The workstring is then slowly picked up, 30 to 50 ft. per minute, four stands out of the cement plug. The workstring annulus has to be closed and pressure applied to attempt to squeeze a maximum of 2-bbl of cement around the inner-outer casing annulus. A minimum of 20 ft. of cement has to be left in the outer casing. Before the squeeze pressure is released, a final squeeze pressure should be established and recorded.

Either one and one half tubing volumes has then to be reverse circulated, or until no cement is in the returns, without exceeding a pump pressure that could possibly break down any exposed casing shoes. The casing has then to be pressured to the final squeeze pressure determined earlier. The final squeeze pressure has to be held while waiting on the cement to cure for a minimum of twelve hours before the workstring is pulled out of the hole.

Next, a bit and scraper for the outer casing has to be run to the top of the cement plug. If the top of cement is above a minimum depth necessary to place all subsequent isolation plugs, the top of cement is dressed off to that minimum depth. The scraper is worked and a bottoms up has to be circulated before pulling out of the hole with the bit and scraper.

An outer CIBP is then tripped in the hole on a workstring and set after tagging the cement plug and picking up around ten feet. Once the CIBP is set and tested, 100-ft. of cement has then to be spotted on top.

Fig. 8. presents the 'cut and pull' operation illustrating the cement and mechanical isolation of the terminated casing stub.

Section Milling. Section Milling Operation is the second method to alleviate SAP. The primary concern when milling concentric strings of casing is breaching the outer barrier with the mechanical cutters. The requirement is a very difficult when a cut has to be made at a point where the inner casing is eccentric in relation to the outer pipe. Cutters need to be optimized to the outer diameter they are cutting.

For the operation, the Middle East client was recommended to use two cutter sizes on every casing when a window 'cut-out' is made:

- One specifically sized to cut the casing pipe, and
- A larger cutter for the casing collars.

The chances of cutting into the next larger diameter casing are minimized to the length of each collar. It is of significant importance that the cutters have cutting material only on the lower end of the blades, to avoid unnecessary wear on the outer casing string.

The *Section Milling Operation* consists of five base

steps:

- Section Milling
- Preparation for Pressure Isolation of Lower Casing Stub
- Pressure Isolation of Lower Casing Stub
- Preparation for Pressure Isolation of Upper Casing Stub
- Pressure Isolation of Upper Casing Stub

Prior to *Section Milling* a bottom has to be set to avoid cement contamination from gas migrating through the setting cement or if the wellbore fluid and cement have insufficient density difference. The preferred method is to set a CIBP between 100 and 200-ft. deeper than the proposed top of the inner casing stub. The bridge plug is then pressure tested to a nominal pressure, depending on the burst capabilities of the surrounding casing, to verify proper setting. The implementation of the CIBP is not meant to act as a long-term pressure seal when not used in conjunction with a cement plug, it is simply an aid in obtaining a suitable cement job, since long-term degradation could occur to the CIBP rubber elements from constant exposure to the wellbore environment (mainly temperature).

The main concern for the operation design is the risk of contamination of the cement by mixing with the drilling mud which may jeopardize the cement integrity. The bottom has to be set far enough into the stub to allow debris to fall out of the way from any milling operation.

The milling operation has to be conducted in two steps:

- outer casing 'cutout' section milling (to cut a window in the outer tube of the casing immediately below a casing coupling).
- section milling with 'mill-down' blades

When the proposed cutting zone is verified to be clear of obstructions, *outer casing. 'cutout' section milling* operation is started. The pumps have to be idled while slacking off. When the weight indicates a collar near the desired window depth, the assembly is slacked off 2 to 3 ft. below the collar so that the window can be cut out.

To begin milling the "cutout window", the mill has to be rotated while increasing the circulation rate. The tool is rotated several minutes before slacking off and then slacked off in 1/4-in. increments for the first 12 to 18 in. The cutout time varies depending on tool pressure, but adequate time is taken in cutting out the window to ensure a smooth cut-out. Circulation rates for proper tool function depend on the mud weight being used.

When the "cutout window" is complete, the following part of the operation assumes usage of the *section mill with 'mill-down' blades*.

Prior to starting *section milling with 'mill-down' blades*, the window has to be located from the previous window

'cutout' run. Milling has to be stopped at 1 to 2 ft. above the next deeper coupling.

Higher weights and rotary speeds are needed to achieve the best milling results. The string mill and section mill are worked to the upper stub to help prevent cutting buildup at that point, and to assist in hole cleaning. The milling fluid parameters have to be sufficient to clean the hole, and the rate of penetration varies due to hole cleaning and the hardness of cement behind the casing. Upon reaching the next deeper coupling, the section mill bottom hole assembly has to be pulled out of the hole. The mill-down blades are changed out to a set of 'coupling cutout' blades with a larger maximum expansion and the tool is tripped back in the hole to the bottom of the window.

This milling procedure with the two sizes of mill-down blades has to be repeated until a 120-ft. section is completed. The milling assembly has then to be pulled out of the hole in preparation for cementing operations.

Preparation for Pressure Isolation of Lower Casing Stub assumes a trip is made in the hole with a bit and scraper sized for the milled casing, along with an under-reamer dressed with blades for the next larger casing. This trip is used to clean the greater portion of the cement and dehydrated mud from the casing wall. The outer casing is cleaned throughout the milled region, and a minimum of one bottoms up has to be circulated to clean the outer casing before a cement plug is pumped.

The next step in the procedure is addressed to the next larger diameter casing. A Multi-String Cutter (MSC) tool is run in the hole with a bit and scraper sized for the inner casing. This tool is used to polish off the casing throughout the milled area of the casing to increase the bonding characteristics of the cement to casing.

A minimum of one bottoms up has again to be circulated to clean the outer casing before the cement plug is pumped.

Instead of MSC tool run in tandem with a bit and scraper for the casing it is more efficient to run with an under-reamer tool. This is done for several reasons:

- The under-reamer is a better solution to provide sufficient cleaning of the casing walls without the need for the MSC run, and
- Unnecessary wear on the outer casing is minimised.

Pressure Isolation of Lower Casing Stub assumes a trip in the hole with the workstring for spotting a heavy mud to help minimize any cement contamination from the swapping of light and heavy fluids in the wellbore. This plug is spotted to the bottom of the expected cement plug in the inner casing stub. Upon spotting heavy fluid, the workstring is placed at the proposed cement plug bottom. The annulus has to be closed and injection rates

are established before the cement is mixed. The recommendation to the client was to pump a 25-bbl spacer ahead of the latex cement slurry.

Necessary cement volumes are calculated to leave 50 ft. of cement in the inner casing stub and 40 ft. in the stub annulus. The cement plug is displaced and balanced inside and outside the workstring.

When the cement plug has been spotted, the workstring is slowly picked up, four stands at 30 to 50- ft. per minute. The annulus between the workstring and inner casing annulus is closed and pressured in an attempt to squeeze a maximum of 4-bbl of cement into the annular between the intermediate and surface casing. Squeeze pressure is based on burst characteristics of the casing. A final squeeze pressure is established, and then released.

One and a half tubing volumes has then to be reverse circulated or until there is no cement in the returns, without exceeding 80% of the final squeeze pressure.

After the hole is circulated clean, the casing is re-pressured to the final squeeze pressure determined earlier. The final squeeze pressure is held while waiting on the cement to cure for a minimum of 12 hours. The pressure is then released before pulling out of the hole.

Preparation for Pressure Isolation of Upper Casing Stub is starting with a trip in the hole with a bit and scraper for the intermediate casing run in tandem with an MSC tool for surface casing. The MSC tool's arms are locked out; the same tool is used in milling the inner casing, but the blades are changed out to protect the outer casing.

The surface casing is cleaned from the top of the 120-ft. window down to the top of cement. The top of cement has to be tagged for depth control. The MSC tool is worked through the window and a bottoms up is circulated to clean the surface casing before the annulus is isolated around the upper intermediate stub.

Pressure Isolation of Upper Casing Stub assumes an inflatable bridge plug is run in the hole and set 10 ft. above the top of cement for use as an artificial bottom. The reason is to help prevent gas migration and to minimize any mud contamination of the cement slurry. An inflatable bridge plug is needed to pass through the smaller intermediate casing and set in the larger surface casing.

The inflatable bridge plug has to be tested with a resulting pressure loss of no more than 10% during a 15-minute time period to verify proper setting.

In the case of client wells with water-based drilling mud, it was recommended that a diverter sub be tripped in the hole to the planned top of cement at ± 100 ft. above the inflatable bridge plug. The plug interval is cleaned by

washing and rotating into the hole. The casing is then displaced with 8.6-lb/gal water, and the well has to be monitored for flow to serve as an underbalance test.

A 25-bbl spacer has to be pumped before the latex cement is mixed and pumped to place 100 ft. of cement in the surface casing. Fluid is pumped behind to balance the cement plug inside and outside the workstring. The workstring is again slowly picked up, four stands at 30 to 50-ft. per minute.

One and one-half tubing volumes has to be reverse circulated or until there is no cement in the returns. Pressure is held on the cement while waiting a minimum of 12 hours for the cement to cure.

Fig. 9. presents the sequence of the section milling operations.

Recommendations related to the Workover programme

Certain problems and solutions that could be expected in running the workover program are as follows:

- Initially, some balling of metal cuttings could occur in the mud return flowline. The use of an open-top surface trough, and elimination of unnecessary sharp bends, restrictions, or obstructions in the return lines would minimize any delays due to balled cuttings.
- An HEC-blended system and xanthan gum have to be implemented as an effective way to obtain the necessary rheology to lift heavy cuttings and clean the hole.
- The proper density of workover fluid has to be determined by considering the fracture gradient of the outermost exposed casing shoe and expected applied pressures as the upper available weight limit. When possible, attempts have to be made to stay closer to the pore pressure than fracture gradient to avoid breaking down the formation at the casing shoe.
- Prior to the cementing operation proper hole preparation is imperative and has to be done by rotating a diverter sub into the hole throughout the plug interval and the pumping of properly sized spacers. The diverter tool has to remove mud cake or trash efficiently to increase the bonding characteristics of the cement to casing.
- The cement slurry is treated with a latex additive to help increase both the initial and long-term bonding characteristics with the casing⁵.
- Isolation of windows or casing stubs has to be done by squeezing cement into the annulus and pressurising. The final squeeze pressure is established based upon burst characteristics of casing and the established pressure prior to reversing out the workstring.

- To prove the well integrity, although the casing has to be pressure tested upon completion of remedial operations, it is recommended to include running of a calliper log or equivalent after milling operations to aid in verifying that the outer casing did not sustain excessive damage that could compromise pressure integrity.
- For sour gas service, as handled by the client, the drilling fluid is the primary means of preventing a release of H₂S. To avoid the problem it is necessary to:
 - Maintain sufficient hydrostatic head to prevent H₂S influx from the formation.
 - Keeping H₂S in the mud by converting it to sodium sulfide, provided that the pH is over 10.
 - Removing dissolved H₂S and/or sodium sulfide with a scavenger such as Zinc Carbonate or Ironite sponge.
 - The oil based system is preferred. The water phase of an oil-based drilling fluid has a high pH (greater than 12) due to an excess of lime in the system. This converts the H₂S to calcium sulfide, which is insoluble in the mud. If lime in the mud is allowed to fall to zero, any further intrusions of H₂S would come out of the mud at surface. It is therefore essential that the lime content is monitored, and that an excess lime content of between 6-8 lb/bbl is maintained when H₂S is expected.

encompassing approach is regarded to be essential for all sour gas wells, but especially for HPHT designs.

References

1. Minerals Management Service (MMS), POLICY LETTER 30 CFR 250.517, August 5, 1991.
2. Bourgoyne, A.T. Jr, Scott, S.L., and Regg, J.B.: "Sustained Casing Pressure in Offshore Producing Wells," paper OTC 11029 presented at the 1999 Offshore Technology Conference, Houston, Texas, 3-6 May.
3. Bradner, T., "BP: Pressure Led to Well Blast", Alaska Oil and Gas Reporter. BP ALASKA, Well A-22 ,Final Incident Summary Investigation Close Out Meeting 12/20/02, Date of Incident: August 16, 2002
4. Wojtanowicz, A.K., Nishikawa, S. and Rong X. "Diagnosis And Remediation Of Sustained Casing Pressure In Wells,"; Louisiana State University; Baton Rouge, Louisiana July 31, 2001
5. Halliburton Energy Services: "Latex 2000 Cement Additive," Technical Data Sheet, 1998.

Conclusions

1. SAP was widespread, in approximately 30% of wells in an onshore sour gas field in the Middle East. In some wells several annuli showed SAP with pressures exceeding design values.
2. Detailed diagnostic testing was recommended to identify the cause of the problem and establish the optimum route for remediation of the problem.
3. Elimination of the SAP problem in new wells was achieved by adjusting some aspects of the well design, improving some aspects of the cementing operation and introducing tighter quality control of cementing, including the introduction of the cement shoe bond integrity test.
4. Two methods of remediation of SAP in existing wells were recommended; termination of the inner casing or section milling.
5. This practical approach, based on critical assessment of many aspects of the whole well condition put the SAP problem under total control, covering the process from well design through the lifecycle of the well. This all-

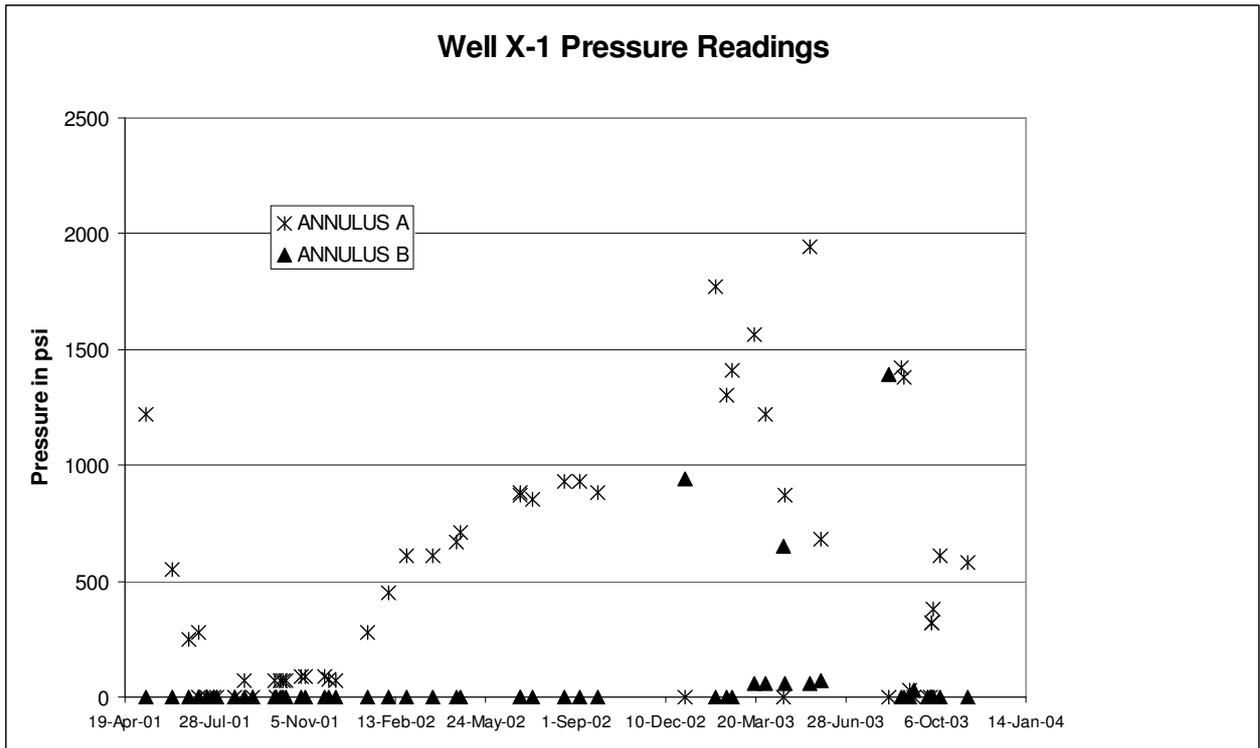


Fig. 1. Routine annulus pressure readings from Well X-1.

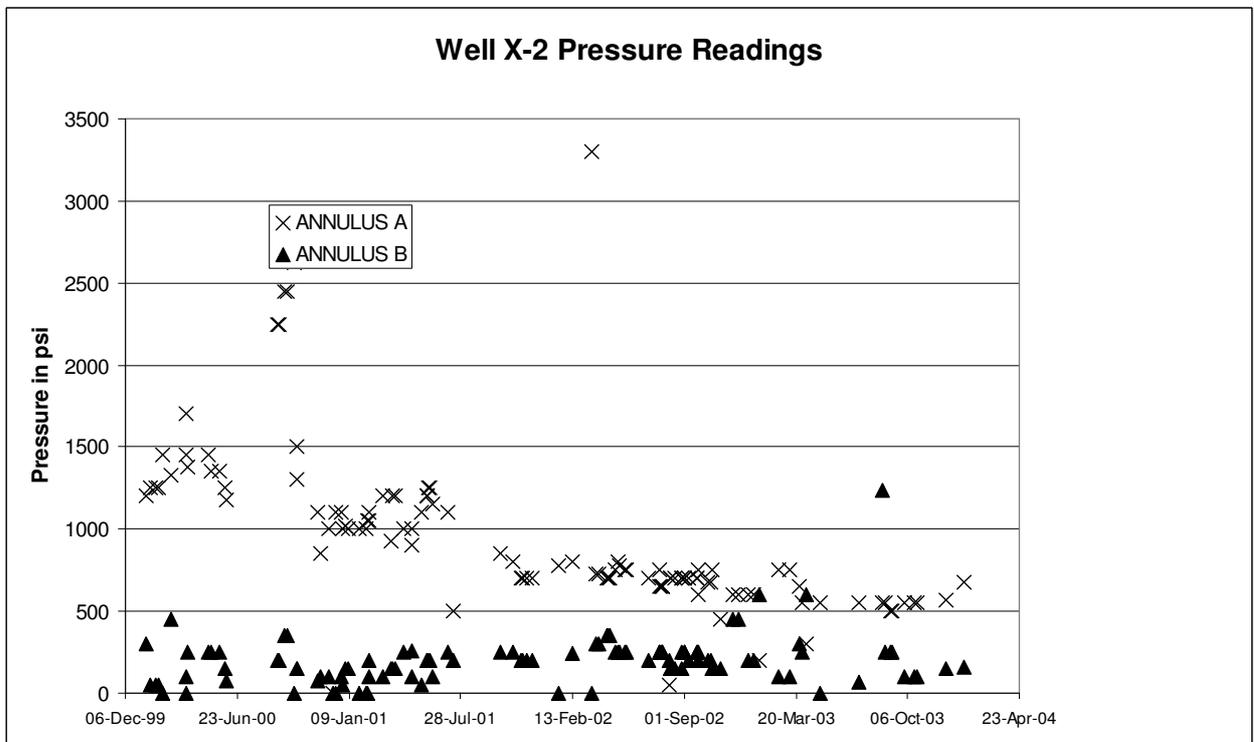


Fig. 2. Routine annulus pressure readings from Well X-2.

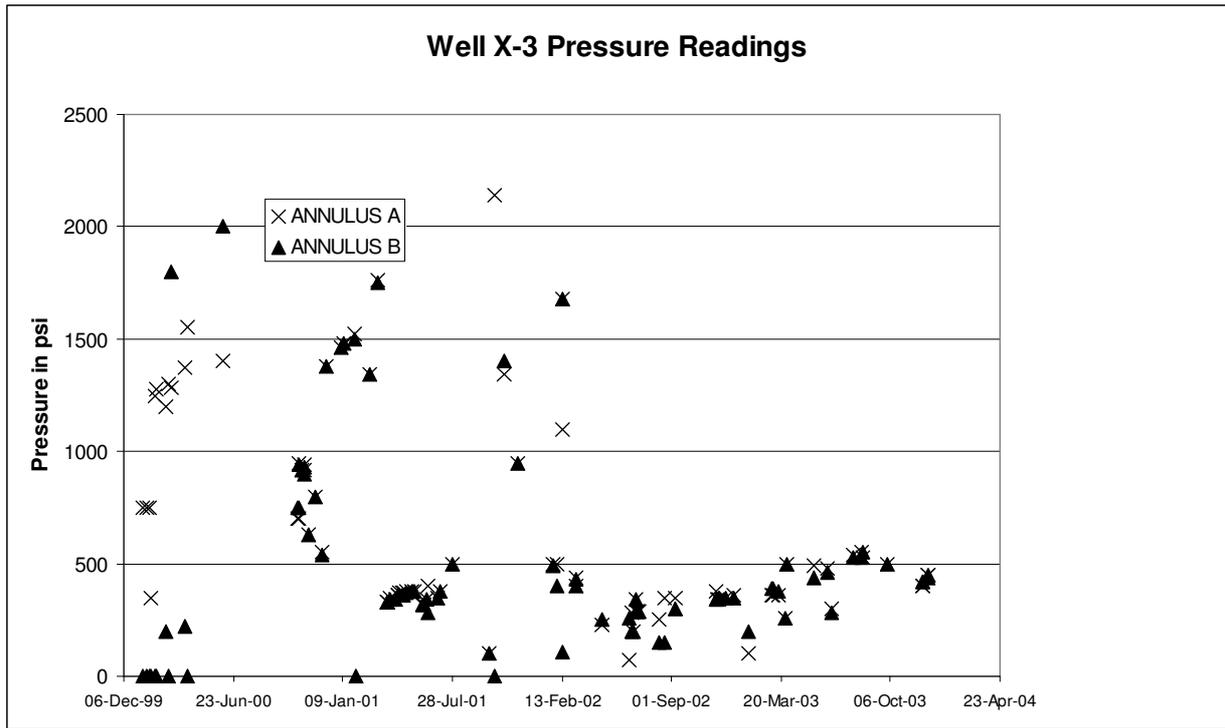


Fig. 3. Routine annulus pressure readings from Well X-3.

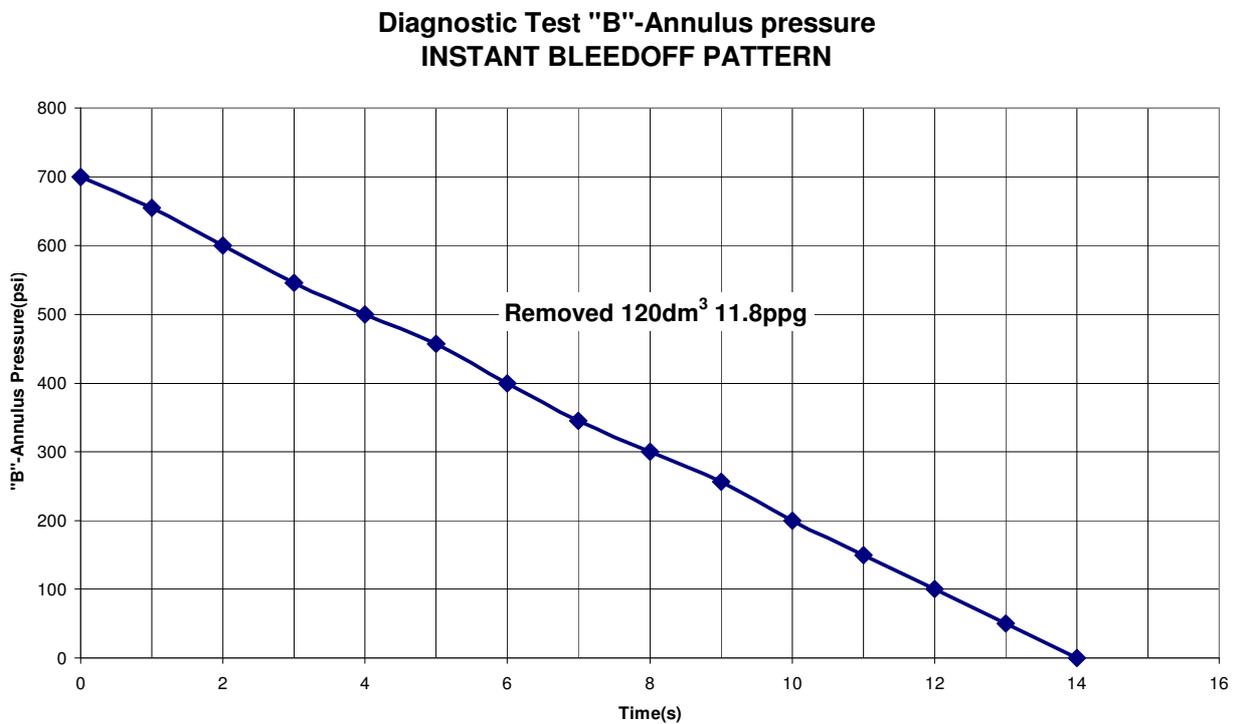


Fig. 4 (a). Example of the diagnostic test results illustrating instant bleedoff behaviour.

**Diagnostic Test "C"-Annulus pressure
INCOMPLETE BLEEDOFF PATTERN**

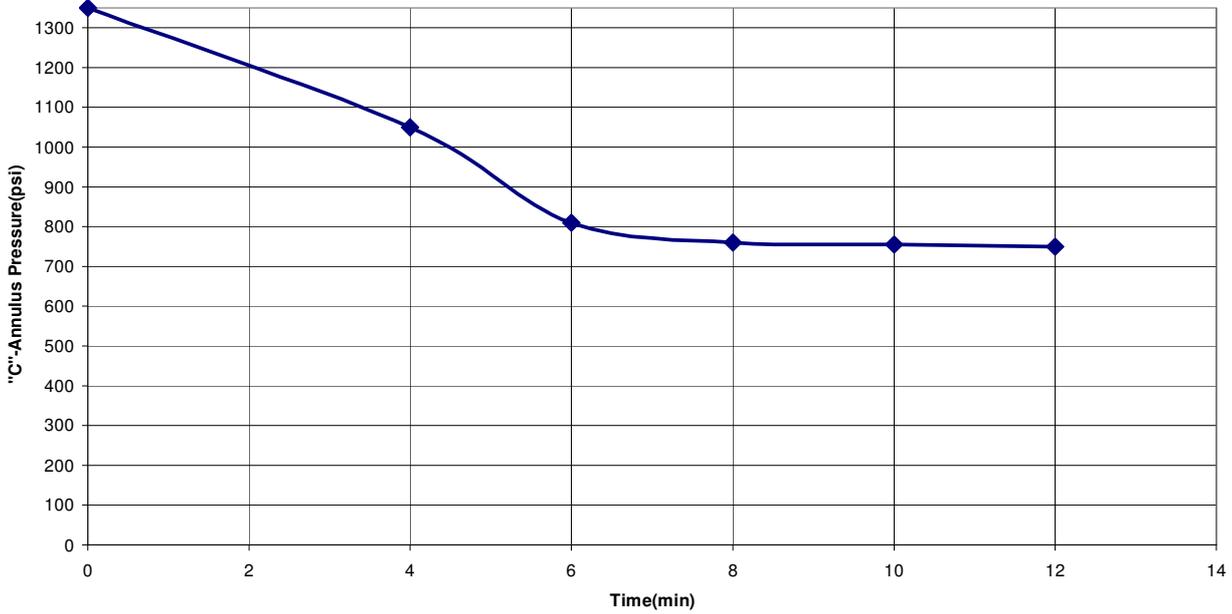


Fig. 4 (b) Example of the diagnostic test results illustrating incomplete bleedoff behaviour.

**Diagnostic Test "C"-Annulus pressure
NORMAL BUILDUP PATTERN**

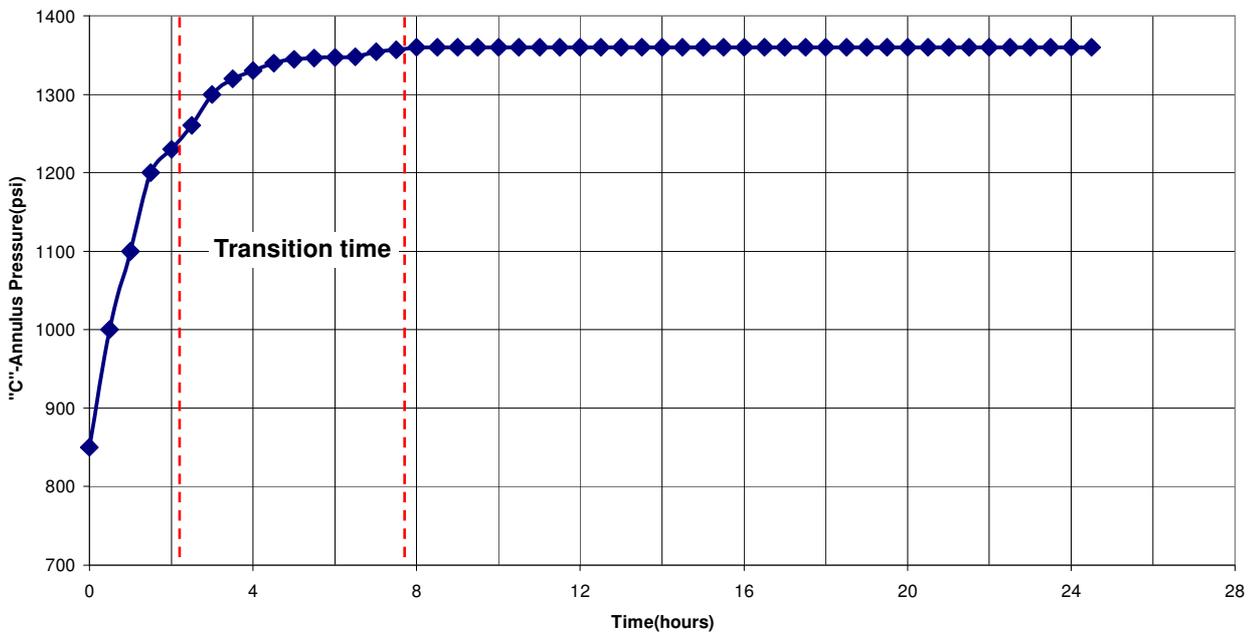


Fig. 4 (c). Example of the diagnostic test results illustrating normal buildup behaviour.

**Diagnostic Test "C"-Annulus pressure
S-SHAPE BUILDUP PATTERN**

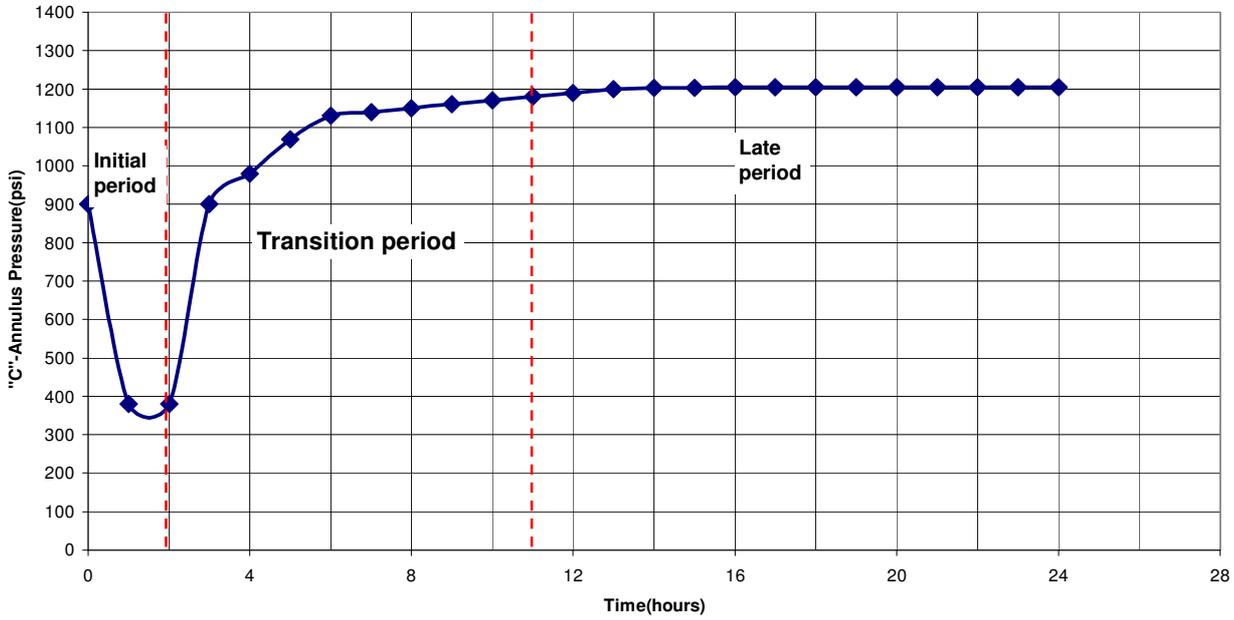


Fig. 4 (d) Example of the diagnostic test results illustrating S-shape buildup behaviour.

**Diagnostic Test "C"-Annulus pressure
INCOMPLETE BUILDUP PATTERN**

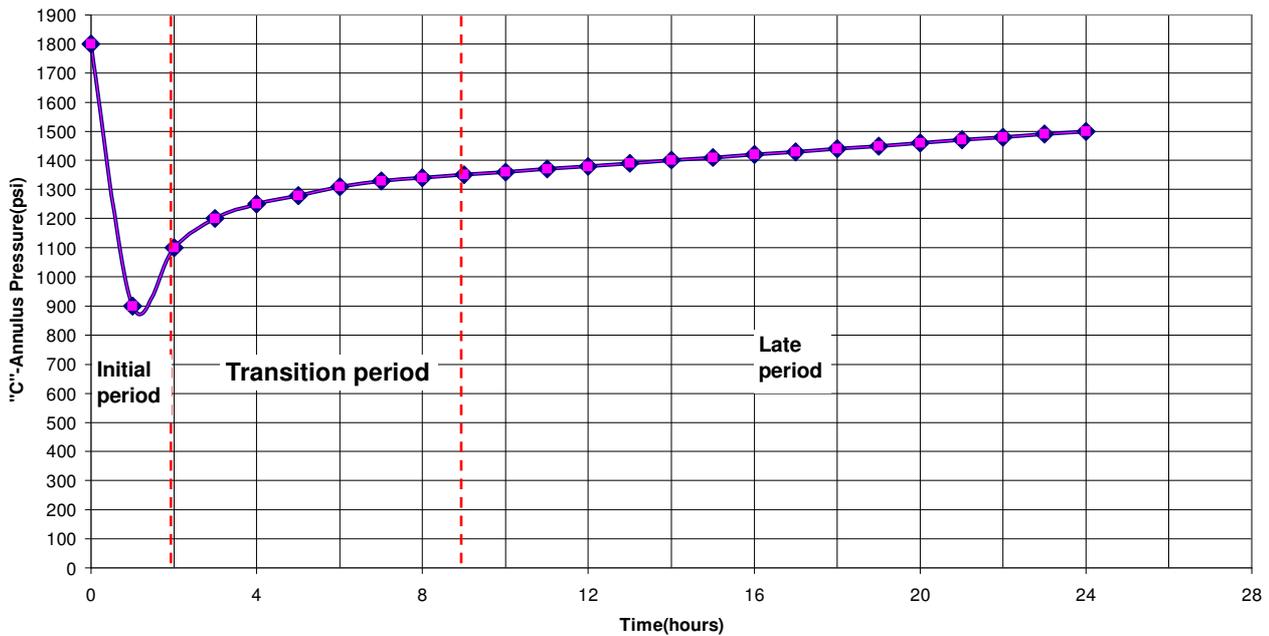


Fig. 4 (e). Example of the diagnostic test results illustrating incomplete buildup behaviour.

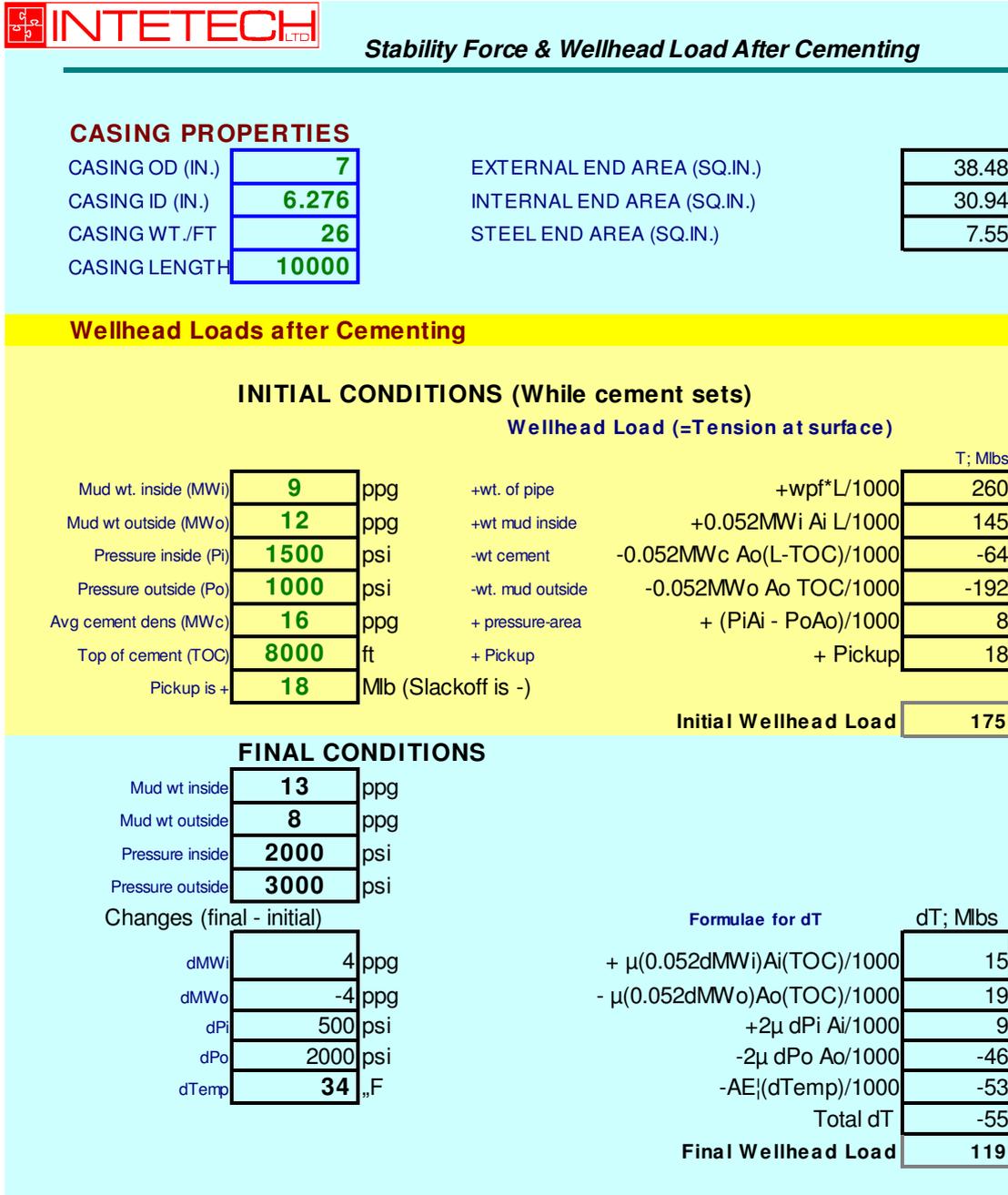


Fig. 5. Example of the Stability Force and Wellhead Loads design calculations

Buckling of Casing after Cementing

INITIAL CONDITIONS (While cement sets)

		Initial Effective tension at TOC		Teff;Mlbs	
Mud wt. inside (MWi)	9	ppg	+pipe below TOC	+wpcf(L-TOC)/1000	52
Mud wt outside (MWO)	12	ppg	+wt mud inside	+0.052MWi Ai(L-TOC)/1000	29
Pressure inside (Pi)	1500	psi	-wt cement	-0.052MWc Ao(L-TOC)/1000	-64
Pressure outside (Po)	1000	psi	+Pickup	+Pickup	18
Avg. cement dens (MWc)	16	ppg			
Top of cement (TOC)	8000	ft			
Pickup	18	Mlb (Slackoff is -)			
				Initial Teff at TOC	35

FINAL CONDITIONS

Mud wt inside	13	ppg			
Mud wt outside	8	ppg			
Pressure inside	2000	psi			
Pressure outside	3000	psi			
Changes (final - initial)					
dMWi	4	ppg			
dMWO	-4	ppg			
dPi	500	psi			
dPo	2000	psi			
dTemp	34	,,F			
If Teff < 0, assume casing is buckled.					

		Formula for dTeff	dTeff;Mlbs	
		-(1-μ)(0.052dMWi)Ai(TOC)/1000	-36	
		+(1-μ)(0.052dMWO)Ao(TOC)/1000	-45	
		-(1-2μ)dPi Ai/1000	-6	
		+(1-2μ)dPo Ao/1000	31	
		-AE _i (dTemp)/1000	-53	
			Total dTeff	-109
			Final Teff at TOC	-74
			Buckled?	Yes

TEMPERATURE CALCULATIONS

(For drilling strings)

Static Temperatures			
Surface (Ts)	60	,,F	
Bottom hole (Tb)	355	,,F	
TVD next hole section	14000	ft	
			y = TOC/ TVD
			0.57
			k = 0.4+0.306y+0.029y ² -0.125y ³
			0.561
			Init. avg temp: Ts + (Tb-Ts)/ 2
			144
			Final avg temp; ,,F: Ts+(Tb-Ts)k
			225
			Must be entered above; ,,F: dTemp
			81

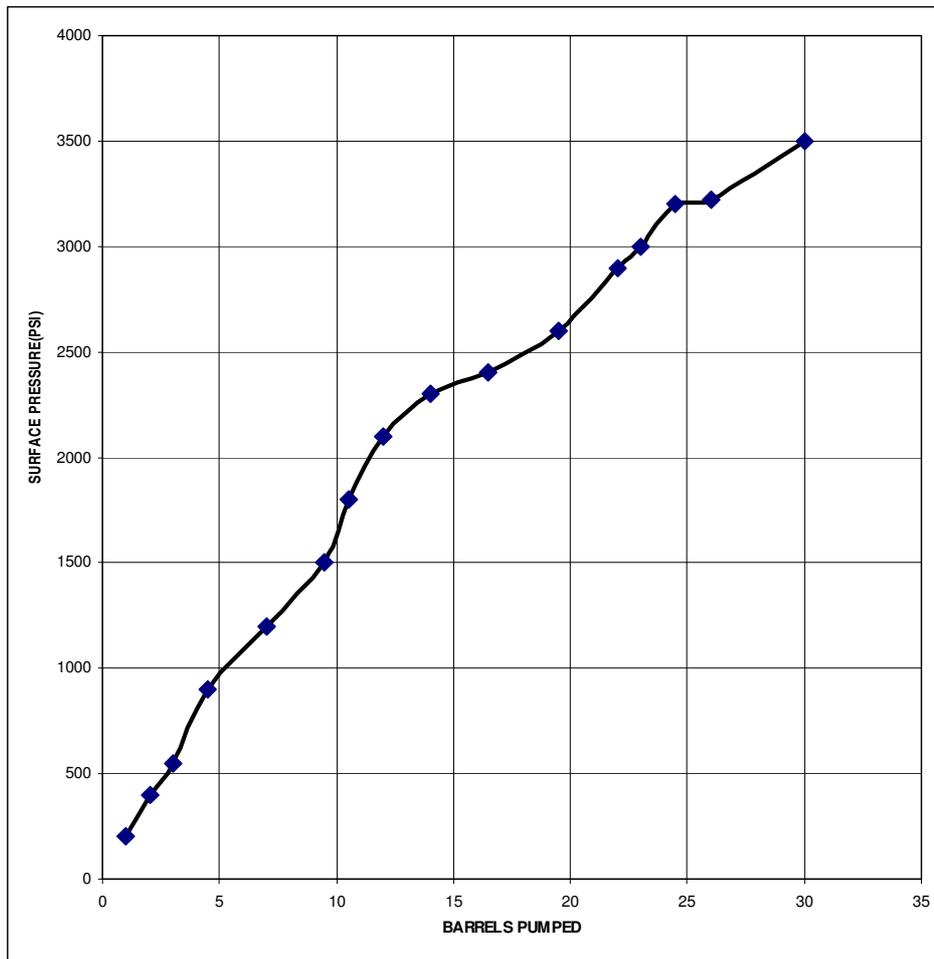
(For completion strings)

Surface Injection (Tsi)	32	,,F	
At perforations (Tp)	123	,,F	
TVD Perforations	9000	ft	
			y = TOC/ TVD
			0.89
			For big jobs f = 3 Little jobs f = 2
			3
			Final avg temp; ,,F: Tsi+(Tp-Tsi)y/ f
			59
			Must be entered above; ,,F: dTemp
			-85

E = 30,000,000 psi; Poisson's ratio μ = 0.3; Coefficient of thermal expansion α = 6.9E-6 / ,,F

Fig. 5. cont: Example of the Stability Force and Wellhead Loads design calculations.

Cement Shoe Bond Integrity Test			<i>WELL:</i>
			<i>RIG:</i>
<i>TESTED BELOW:</i>		<i>DATE:</i> 5-Feb-05	
<i>CASING SHOE DEPTH:</i>	Ft.MD	Ft.TVD	<i>VIS</i>
<i>HOLE DEPTH:</i>	Ft.MD	Ft.TVD	<i>P.V.</i>
<i>MUD WEIGHT:</i>	ppg		<i>Y.P.</i>
<i>FLUID PUMPED/RETURNED:</i>	BBL	BBL	<i>GELS</i>
<i>RATHOLE DEPTH:</i>			



<i>Cement Shoe Bond Strength:</i>	psi
<i>EQUIVALENT MUD WT:</i>	ppg

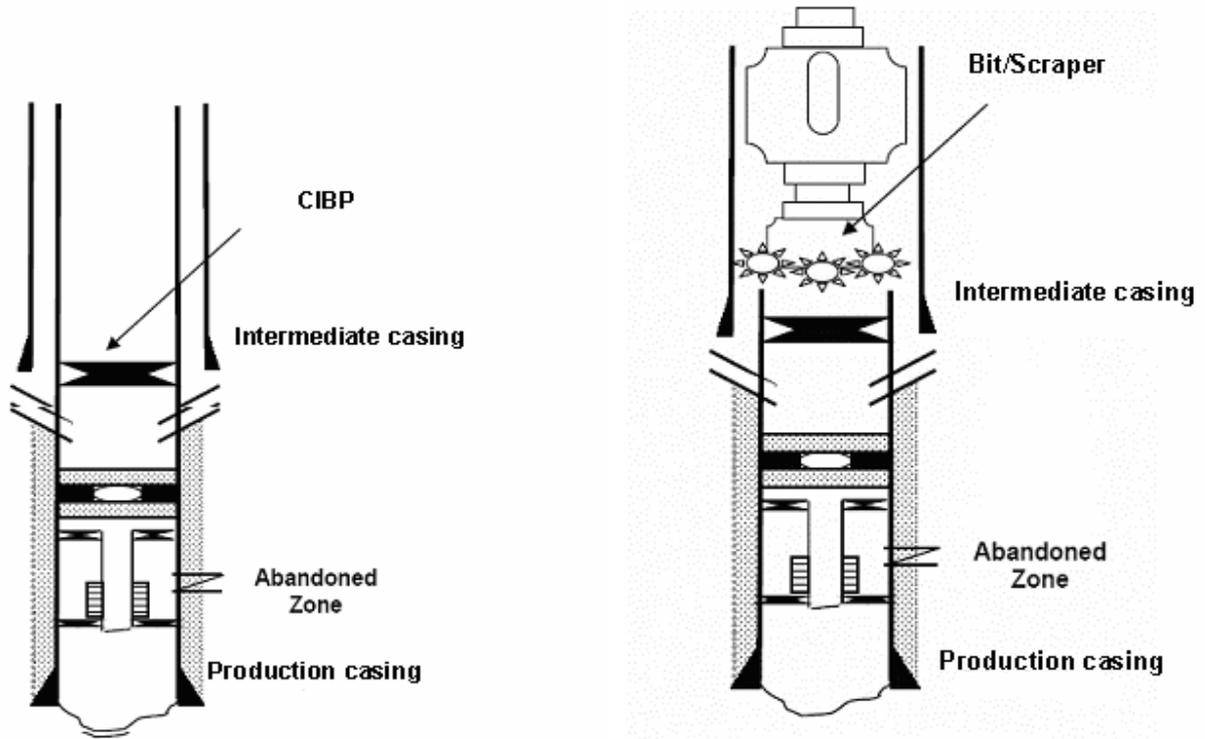
REMARKS:

SUPERVISED BY:

Fig. 6. Cement Shoe Bond Integrity Test.

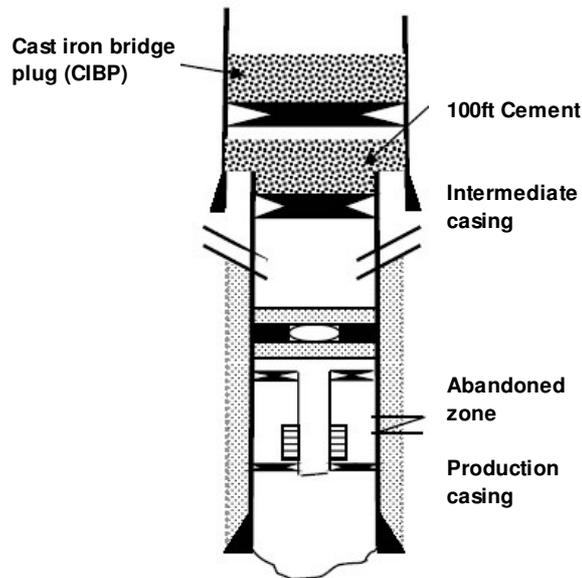
JOB QUALITY ASSESSMENT SHEET				
Date:	Operator (O):			
Well No:	Drilling Supervisor (DS)			
Rig:	Manager (M):			
Type of Job:	Drilling Engineer (DE):			
PREPARATION	Points Available	Pass/Fail	Verification of fulfilment	Score
Job Proposal	8		M/DE	
Job Programme	4		M/DE	
Mobilisation	2		O/DS	
Installation, Testing, Calibration	2		O/DS	
Toolbox Meeting	2		O/DS	
Minimum Score Required	18	Total Score for PREPARATION		
EXECUTION				
Slurry Density (*)	24		O/DS	
Volume Pumped (*)	24		O/DS	
Pumping Rate (*)	4		O/DS	
Real Time Recording	2		O/DS	
No Lot Time	2		O/DS	
Minimum Score Required	52	Total Score for EXECUTION		
COMPLETION				
Waiting on Cement	2		M/DE	
Job Report	4		M/DE	
Minimum Score Required	4	Total Score for COMPLETION		
HEALTH, SAFETY, ENVIRONMENT				
No Lost Time Injury	12		O/DS	
No Non Lost Time Injury	4		O/DS	
No Spills/Disposal of Water	4		O/DS	
Minimum Score Required	16	Total Score for HSE		
Maximum Score Possible	100	Total Combined Score		
Quality Adjustment Factor = $1 + \frac{[(P-18) + (E-52) + (C-4) + (S-16)]}{100}$				
Where: P = actual score for preparation E = actual score for execution C = actual score for completion S = actual score for HSE (*) key criteria all requiring 'pass' to avoid remedial work penalty				
Quality Adjustment Factor	=			
Objective Achieved	Yes	No		
If the cement job fails to achieve the objective agreed in the job programme (for whatever reason), Contractor shall be paid on 80% of the incentive payment due.				
Remedial Work Required	Yes	No		
If remedial work is required and the key criteria for execution (ie slurry density and volume pumped) are not rated as 'pass', Contractor shall undertake such remedial work free of charge.				
Remarks:				
Agreed by Contractor Representatives		Agreed by Company Representatives		
Signed		Signed		
	Operator		Drilling Supervisor	
Signed	Manager	Signed	Drilling Engineer	

Fig. 7. A cement job quality assessment sheet



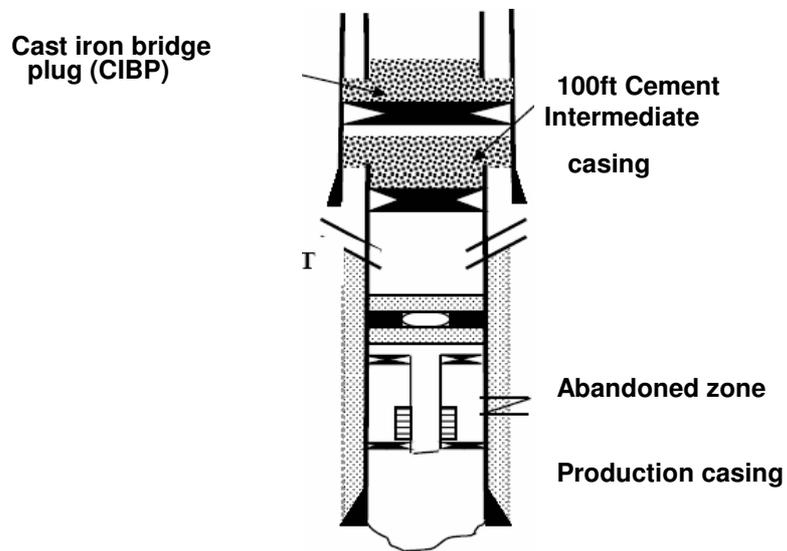
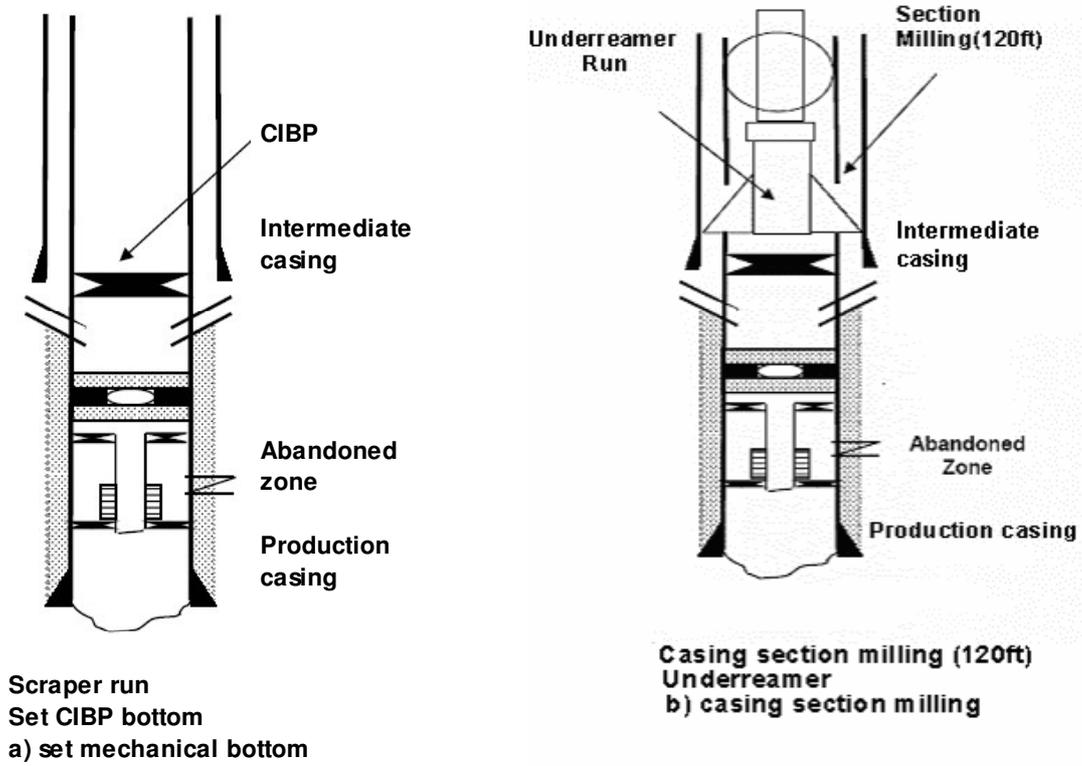
Scraper run
Set CIBP bottom
a) set mechanical bottom

Cut/Pull casing section
Pilot Milling; Scraper run
b) Pull out casing section



c) Cement placement(Spot & Squeeze)

Fig. 8. The 'cut and pull' operation illustrating the cement and mechanical isolation of the terminated casing stub.



c) Cement placement(Spot & Squeeze)

Fig. 9. The 'section milling' operation