WELL COMPLETION PROCESS & PROCEDURE

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WELL COMPLETION PROCESS & PROCEDURE

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CERTIFICATE

This is to certify that the work contained in this thesis titled "WELL COMPLETION PROCESS & PROCEDURE" has been carried out by Promel Jain, Shalabh Sharma under my/our supervision and has not been submitted elsewhere for a degree.

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CHAPTER I INTRODUCTION Well completion is a set of operations meant to ease production from a well. Based on the definition, this means that well completion is not only one of the most important aspects of a well, but also it constitutes the connection between the borehole and the pay zone, the pay zone treatment (if any), equipment, and etc. of the same well. Completion therefore, can be defined as the interval that goes from well locating to well abandonment. Completion furthermore makes possible well operations using a logical and inexpensive way. As a result, it should not be "off the rack," but "tailor made" 20. Figure 1.1 shows an appropriate illustration of a completed well. To decide on the type of completion, some specific basis of conduct and expectation must be meant20: o Completion and maintenance vs. profits; evidently the larger the field with excellence oil production at fast flowrate, the greater the expenses. o Money-saving vs. possible risks; a risk taken should always consider predictable spending and chances of erroneous hazards. o Supposed change in production of the field vs. supposed change in production of the specified well; the selected type of completion must be met from the beginning of production or must allow a trouble-free adjustment for a future workover. 1.1 TYPES OF WELL COMPLETIONS There are three categories of well completions18: 1.1.1 Casing completions The casing completion is the most used (90% of the time) of the three types. There are five types of casing completions. 1.1.1.1 Conventional perforated casing completions It is a completion technique in which a casing string is run from the surface to the producing zone, followed by its cementing in place. This technique involves the perforation of the casing string. Oil is produced through the casing string. 1.1.1.2 Permanent well completions In this completion, the tubing and wellhead are placed permanently. All other activities (completion or corrective operations) are executed with a small diameter tool through the tubing. 1.1.1.3 Multiple-zone completions It is a completion used when there is more than one producing zone. The technique permits a synchronized production of two or more producing zones. This technique is complex and pricey due to the downhole equipment and tools used to complete the job. 1.1.1.4 Sand-exclusion completions It is a complicated completion used when a well is drilled in unconsolidated sand. Sand-exclusion completion is usually used during completion time or sometimes during the life of a well. The risk is that sand production can wear down the equipment, wellbore and flowlines, thus it can ruin your investment. 1.1.1.5 Water- and gas-exclusion completions Water-and gas-exclusion completions are used when free gas conservation and lesser water productions are needed. Thus to achieve it, appropriate zones inside the producing zone are chosen. 1.1.2 Open-Hole completions Open-hole completions are wells completed with the oil tubing string placed above the productive zone, or in which the productive zone is left open without protection. This technique is merely employed in steady rock formations. It is used since it allows the zone of interest to be tested while drilling, there is no formation damaged from drilling mud or cement, the production is greater than other completions, and it is cheaper. Figure 1.1 shows an illustration of open-hole completion. Table 1. 1 Comparisons of Various Well Completion Types18 Well

ACKNOWLEDGEMENTS

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TABLE OF CONTENTS

ABSTRACT

This project is on the well completion processes and procedures which focuses on nearly all important aspects of completion phase. The objective of this project is to study the planning and phases of well completion.well completion is not only one of the most important aspects of a well, but also it constitutes the connection between the borehole and the pay zone, the pay zone treatment (if any), equipment, and etc. of the same well.

The process of well completion design includes the reasoning and functions that must be performed to specify the components required to complete the well.this process encompasses production engineering, as well as operational consideration

Designing a safe and effective completion without considering how to install it is impossible. Safety is paramount, and safe installation activities may require additional equipment and more time.

LIST OF TABLES & FIGURES

LIST OF ABBREVIATIONS

Symbol	Definition
A	Cross-sectional Area
B_o	Oil formation volume factor
B_g	Gas formation volume factor
C_t	Total reservoir compressibility
D	Tubing inner diameter
f_F	Fanning friction factor
g	Gravitational acceleration
g_c	Unit conversion factor
h	Reservoir thickness
J	Productivity index
K	Permeability
kr	Relative permeability
L	Tubing length
N_p	Cumulative produced oil

ΔN_p	Cumulative produced change
P	Pressure
P_e	Pressure drainage
P_{node}	Pressure of the chosen nodal point
P_R	Reservoir pressure
$\overline{P}_R$	Average reservoir pressure
P_{sep}	Separator pressure
P_{wf}	Well flowing pressure
ΔP	Pressure drop
P_{WFS}	Pressure through perforations
q	Production rate
rd	Reservoir drainage radius
re	Drainage radius
Rs	Solution gas-oil ratio
rw	Well bore radius

Conversion of Units Factors

Quantity	U.S. Field unit	To SI unit	To U.S. Field unit	SI unit
Length (L)	feet (ft)	0.3084	3.2808	meter (m)
Area (A)	sq. ft (ft^2)	$9.29 \cdot 10^2$	10.764	meter^2 (m^2)
	acre	4.0469 · 10^3	$2.471 \cdot 10^4$	meter^2 (m^2)
	sq. mile	2.59	0.386	$(km)^2$
Volume (V)	gallon (gal)	0.003785	264.172	meter^3(m^3)
Mass (M)	ounce (oz)	28.3495	0.03527	gram (g)
	pound (lb)	0.4536	2.205	kilogram (kg)
	lbm	0.0311	32.17	Slug
Pressure (P)	lb/in^2 (psi)	6.8948	0.145	kPa (1000 Pa)
	psi	0.0680	14.696	Atm
	psi/ft	22.62	0.0442	kPa/m
	inch Hg	$3.3864 \cdot 10^3$	$0.2953 \cdot 10^3$	Pa
Temperature (t)	F	0.5556(F+32)	1.8C+32	°C
	Rankine (8R)	0.5556	1.8	Kelvin (K)
Viscosity (m)	cp	0.001	1,000	Pa-s
	lb/ft-sec	1.4882	0.672	kg/(m-sec) or (Pa-s)
	lbf-s/ft^2	479	0.0021	dyne-s/cm^2 (poise)
Density (P)	lbm/ft^3	16.02	0.0624	kg/m3
Permeability (k)	md	0.9862	1.0133	mD ($=10^{-15}m^2$)
	md (= 10^{-3}darcy)	$9.8692 \cdot 10^{-16}$	$1.0133 \cdot 10^{15}$	m^2

CHAPTER I

INTRODUCTION

Well completion is a set of operations meant to ease production from a well. Based on the definition, this means that well completion is not only one of the most important aspects of a well, but also it constitutes the connection between the borehole and the pay zone, the pay zone treatment (if any), equipment, and etc. of the same well. Completion therefore, can be defined as the interval that goes from well locating to well abandonment. Completion furthermore makes possible well operations using a logical and inexpensive way. As a result, it should not be "off the rack," but "tailor made" [20]. Figure 1.1 shows an appropriate illustration of a completed well.

To decide on the type of completion, some specific basis of conduct and expectation must be meant:

- Completion and maintenance vs. profits; evidently the larger the field with excellence oil production at fast flowrate, the greater the expenses.
- Money-saving vs. possible risks; a risk taken should always consider predictable spending and chances of erroneous hazards.
- Supposed change in production of the field vs. supposed change in production of the specified well; the selected type of completion must be met from the beginning of production or must allow a trouble-free adjustment for a future workover.

1.1 TYPES OF WELL COMPLETIONS

There are three categories of well completions[18]:

1.1.1 Casing completions

The casing completion is the most used (90% of the time) of the three types. There are five types of casing completions.

1.1.1.1 Conventional perforated casing completions

It is a completion technique in which a casing string is run from the surface to the producing zone, followed by its cementing in place. This technique involves the perforation of the casing string. Oil is produced through the casing string.

1.1.1.2 Permanent well completions

In this completion, the tubing and wellhead are placed permanently. All other activities (completion or corrective operations) are executed with a small diameter tool through the tubing.

1.1.1.3 Multiple-zone completions

It is a completion used when there is more than one producing zone. The technique permits a synchronized production of two or more producing zones. This technique is complex and pricey due to the downhole equipment and tools used to complete the job.

1.1.1.4 Sand-exclusion completions

It is a complicated completion used when a well is drilled in unconsolidated sand. Sand-exclusion completion is usually used during completion time or sometimes during the life of a well. The risk is that sand production can wear down the equipment, wellbore and flowlines, thus it can ruin your investment.

1.1.1.5 Water- and gas-exclusion completions

Water-and gas-exclusion completions are used when free gas conservation and lesser water productions are needed. Thus to achieve it, appropriate zones inside the producing zone are chosen.

1.1.2 Open-Hole completions

Open-hole completions are wells completed with the oil tubing string placed above the productive zone, or in which the productive zone is left open without protection. This technique is merely employed in steady rock formations. It is used since it allows the zone of interest to be tested while drilling, there is no formation damaged from drilling mud or cement, the production is greater than other completions, and it is cheaper. Figure 1.1 shows an illustration of open-hole completion.

1.1.3 Drainhole completions

Drainhole completions are methods used to complete horizontal wells or slant wells. The main advantage of the technique is to elongate the production zone in order to boost the productivity. Figure 1.2 shows two types of drainhole completions.

Table 1. 1 Comparisons of Various Well Completion Types[18]

Well Completion Types	Advantages	Disadvantages
Casing completions Types □ Conventional perforated casing completions □ Permanent well completions □ Multiple-zone completions □ Sand-exclusion completions □ Water- and gas-exclusion completions	□ Water-bearing rocks from above or below the productive formation are sealed off. □ Better economy	□ Required casing swabbing. □ Tools are tiny and ineffective. □ More complex and pricey.
Open-Hole Completions	□ Speed up the rate of flow from the productive interval. □ More productive than a conventional perforated-casing completion. □ Less expensive □ Less cement contamination	□ Less degree of control over the desired productive interval.
Drainhole completions	□ Increase in productivity	□ Cost more than other completion types.

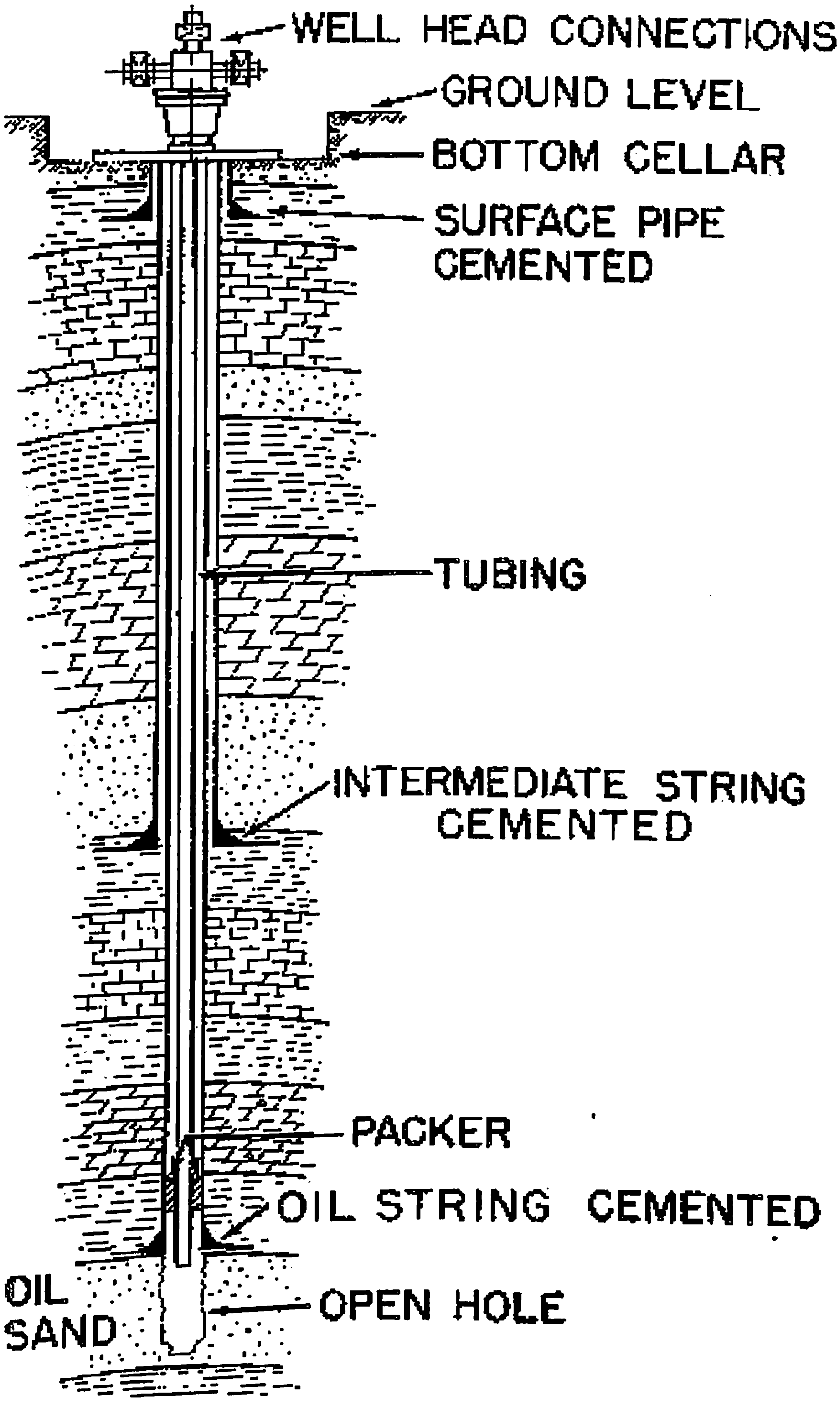


Figure 1.1: Completed well/Open-hole completion[24]

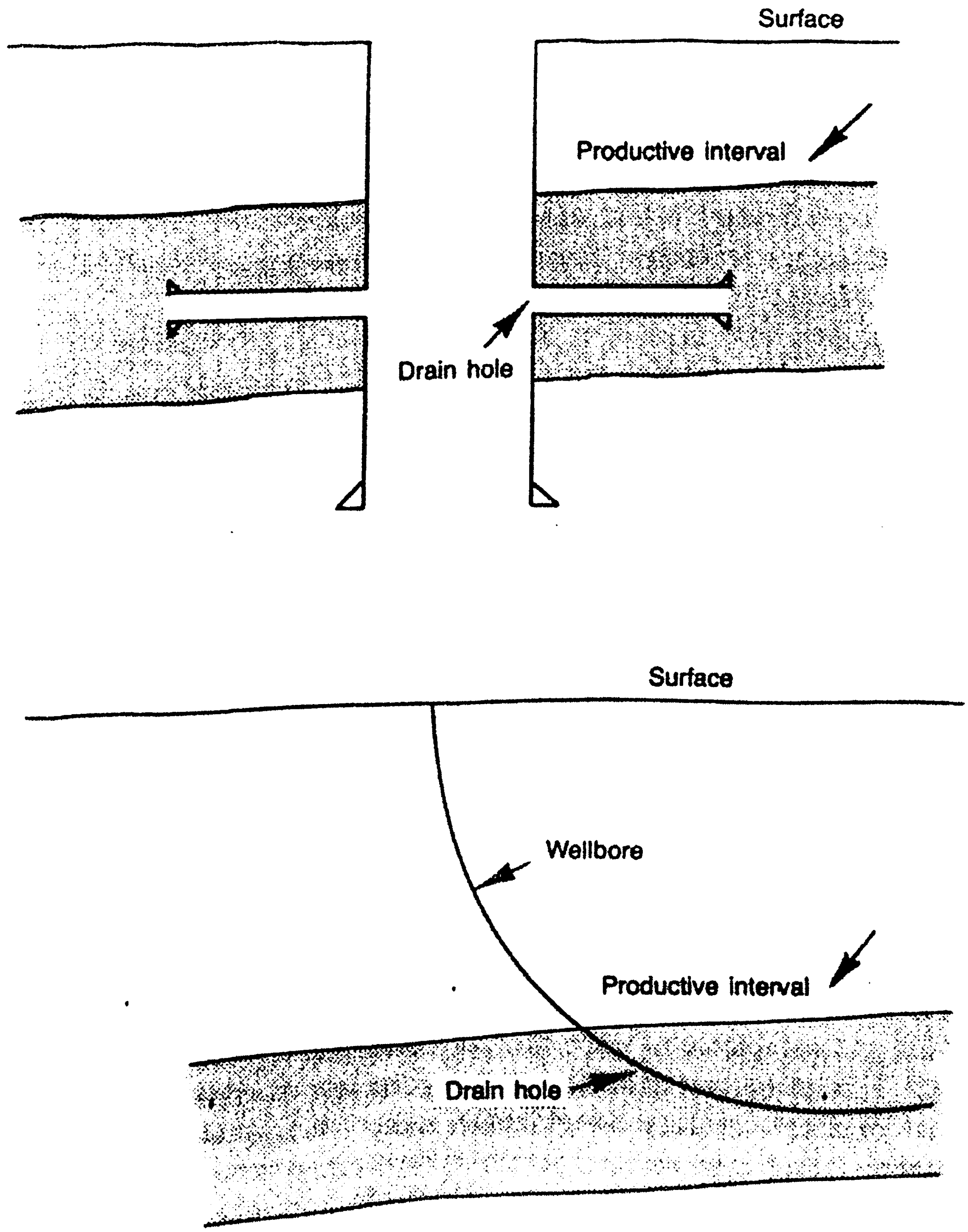


Figure 1.2: Two Types of Drainhole completions[18]

Chapter II

Completion process and procedure

The Design Process

Many operators have their own internal processes for ensuring that designs are fit for purpose. There is a danger that such processes attempt to replace competency, that is, the completion must be fit for purpose so long as we have adhered to the process. Nevertheless, some elements of process are beneficial.

2.1.1 Statement of Requirements

Pulling together the data that will be incorporated into the design. This document can be called the statement of requirements (SoR). The SoR should incorporate reservoir and production data and an expectation of what the completion needs to achieve over the life of the field.

2.1.2 Writing a basis of desgin

This document outlines the main decisions made in the completion design and their justification. The table of contents of this book gives an idea of the considerations required in the basis of design. This document can form the basis of reviews by colleagues (peer review), internal or external specialists and vendors. The basis of design should include the basic . installation steps and design risk assessments.The outline basis of design covers major decisions such as the requirement for sand control, stimulation, tubing size and artificial lift selection. These decisions affect production profiles, well trajectories and numbers and production processing.

2.1.3 Detailed basis

The detailed basis of design fills in the blanks and should include metallurgy, elastomers, tubing stress analysis, and equipment selection and specifications. This document is aimed more at equipment vendors, fellow completion engineers and specialist support. This detailed basis of design document should ideally be completed and reviewed prior to purchasing any equipment (possible exception of long lead items such as wellheads and trees).

2.1.4 completion procedures

Getting these reviewed and agreed by all parties involved in the installation. Again reviews and issuing procedures should precede mobilisation of equipment and personnel.

2.1.5 Post completion report

Post-completion report detailing well status, results and lessons learnt. As a minimum, the document should include a detailed schematic (with serial numbers, equipment specifications, dimensions and depths), a tubing tally, pressure test details and plots, summaries of vendor reports, etc. This document is critical for any engineer planning a later well intervention. It is frightening how hard it is to find detailed information about a well, post construction.

In a nutshell the process of well completion design includes the reasoning and functions that must be performed to specify the components required to complete the well.this process encompasses production engineering, as well as operational consideration as shown in fig 2.1

It depicts the process of completion design. As shown, no determininstic procedure exist for a well completion design. Rather ,key topic such as perforating or tubular selection are considered after the gross objectives and functional requirement of the completion have been identified.

At the outset of the design process, some initial knowledge of the reservoir is known in addition to well bore, fluid , and well test data. Based on an understanding of the reservoir and other parameters, general type of well completion(cased hole,gravel pack, subsea) can be considered.these general type of completion acts as a guide in formulating the final design.identifying relevant types of completions could also aid in formulating functional requirements for the design

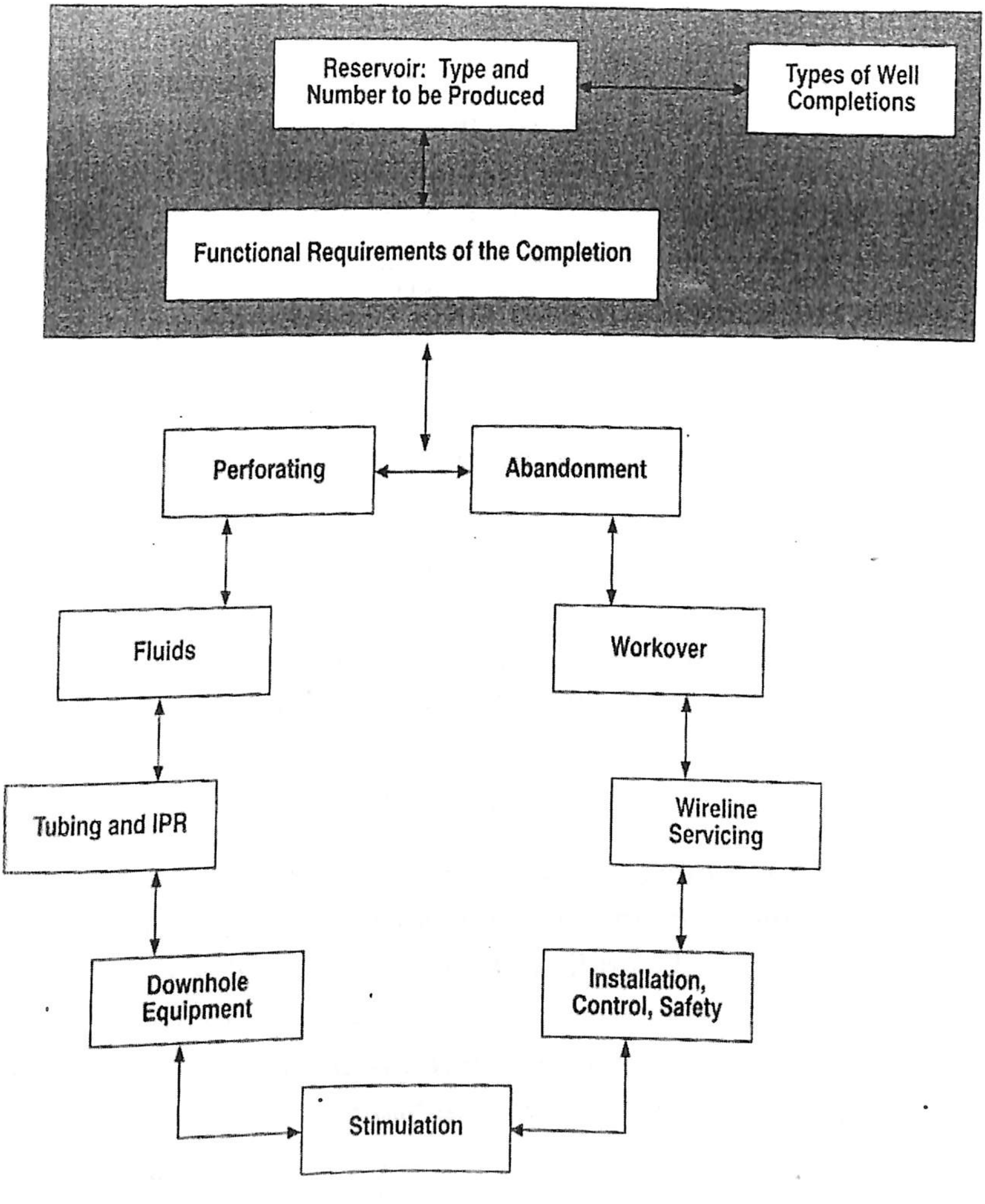


Figure 2.1 Highlights of initial process of well-completion design

2.2 How Installation Affects Completion Design

Designing a safe and effective completion without considering how to install it is impossible. Safety is paramount, and safe installation activities may require additional equipment and more time – for example adequate barriers and pressure testing. A significant proportion of completion costs are associated not with purchasing equipment, but with rig time; this is particularly true of subsea completions. Design modifications that safely and reliably speed up the installation activities should therefore be encouraged. Examples include hydrostatic setting packers (avoid running wireline plugs), single trip completions, enhanced vertical subsea trees (using a single-bore riser), and a combined trip for perforating and gravel packing. Most completion suppliers are aware of high rig costs and market tools (with a premium) specifically aimed at reducing rig time.

2.2.1 Wellbore Clean-Out and Mud Displacement

Drilling always generates debris whilst most completions are debris intolerant. At some stage during well construction, the well will be displaced to a clear, solid- free, thin fluid. Wellbore clean-outs may be required on multiple occasions – for example before and after perforating or before running the lower completion and then again before running the upper completion. The goal of the wellbore clean- out or displacement is to remove and recover the mud, remove all debris from the wellbore (including material stuck to the inside of casing), avoid formation damage, and prepare the well for the installation of all or part of the completion.

Debris is probably the single biggest contributor to non-productive time associated with completion activities. Drilling mud is designed to recover debris (i.e. cuttings) and drilling tools are designed to operate in such debris-intensive environments. Completion fluids are not designed to lift solids. Many completion components (packers, wireline tools, formation isolation valves, etc.) cannot be installed or operated in debris-infested wells. A thorough wellbore clean-out is therefore an essential link between drilling and completion operation Responsibility and knowledge for this critical task are often poorly defined. For example, some drillers do not appreciate the consequences of running completion equipment in a solid-laden environment. Conversely, completion engineers may not be used to drillpipe operations or the properties of muds. Some degree of shared involvement is required albeit with completion operations taking responsibility.

2.2.1.1 Sources of debris

Debris comes from a variety of sources. Solids remaining after well construction activities can include:

→Baryte or calcium carbonate used to weight the mud.

→Cuttings left behind due to poor hole cleaning.

→Cement from drilling out the casing shoe.

→Perforating debris (cement, formation and charge debris). It is an obvious cause of potential problems for cased-hole gravel packs (Javora et al., 2008).

→ Lost circulation material (LCM) used in drilling or completion operations, for example killing the perforations before running a cased-hole gravel pack or smart completion.

→Swarf and segments remaining from milling operations. Figure 2.2 shows segments of packer slips recovered during a well clean-up operation.

→Rust and mill scale from inadequately prepared tubulars.

→Thick, viscous fluids (gunk) can also be left downhole from various drilling- related activities

Figure 2.3 shows pipe dope mixed with drill cuttings. This dope was eventually recovered following the failure to run a completion.

Figure 2.3 Debris from the milling of a packer.

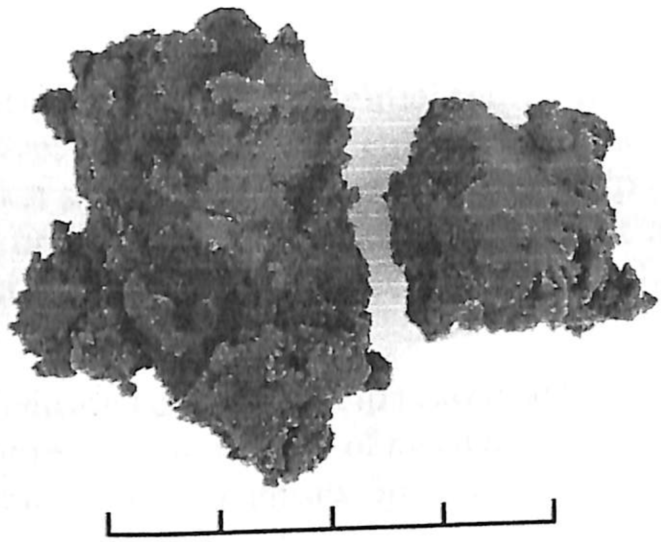


Figure 2.4 Mixture of pipe dope and drill solids

Muds left downhole. Some muds can 'set' when kept at elevated temperatures and long durations or increase in viscosity at low temperatures (particularly synthetic oil–based muds at the mudline in a deepwater well).Viscous pills used for hole cleaning or gels used for loss control.Emulsions or sludges formed from the mixing of oil and water-based fluids.

1) The other common source of debris is junk that inadvertently enters the well: Tools, screws, parts of mats, wooden pallets, gloves and any other dropped objects. Hole covers are there for a good reason and should be used to prevent events like this. Inadequate hole covers such as small plastic wraps can themselves be lost down hole confounding the problem. Items left in the well through down hole tool failure. Examples include roller cone bits, parts of clamps, parts of clean-out assemblies, non-encapsulated shear screws, elastomers from seals and larger elastomer chunks ripped from the blow-out preventer (BOP).

2.2.2 Clean-out string design

Bearing in mind the potential source of debris, mud is the best fluid for recovering solids such as cuttings. The mud should be conditioned (over finer shaker screens) before any clean-out trip to lift as much debris as possible and break any gels. Any known junk that the mud is incapable of lifting (at least as far as a junk basket) should be fished.

A dedicated clean-out trip is invariably required. The design of this trip requires a combination of mechanical tools (some generic, some specialised), hydraulics and chemicals. Specialist companies are now able to provide a range of specific clean-out tools of increasing reliability, robustness and versatility. These can be run in a variety of combinations that best suit the well geometry and clean-out requirements. In most cases, it is now possible to perform a wellbore clean-out and displacement in a single trip, but in some cases multiple trips are still preferred. An example of a clean- out string is shown in Figure 2.4.

The clean-out string is designed to mechanically scrape all the casing down to the depth of the final completion or intervention toolstrings such as perforation guns. Any debris that is dislodged by this mechanical action should be either flushed to the surface or caught in a junk basket. A number of types of mills and scrapers are available. A drill bit is positioned at the base of the string to break up large chunks of debris and ensure access. Mills such as watermelon mills are often used in liner tops. Brushes may be rigid assemblies or sprung loaded. They may use wire, plastic or bristles. Brushes should clean 100% of the casing, allow rotation and have sufficient bypass to allow effective circulation and therefore not push debris down the well. They must also be robust - either a single-piece construction or use pads that are retained. Modern 'lantern' configuration scrapers are non-rotating, that is the outer shroud (the lantern) does not rotate with the drillpipe.

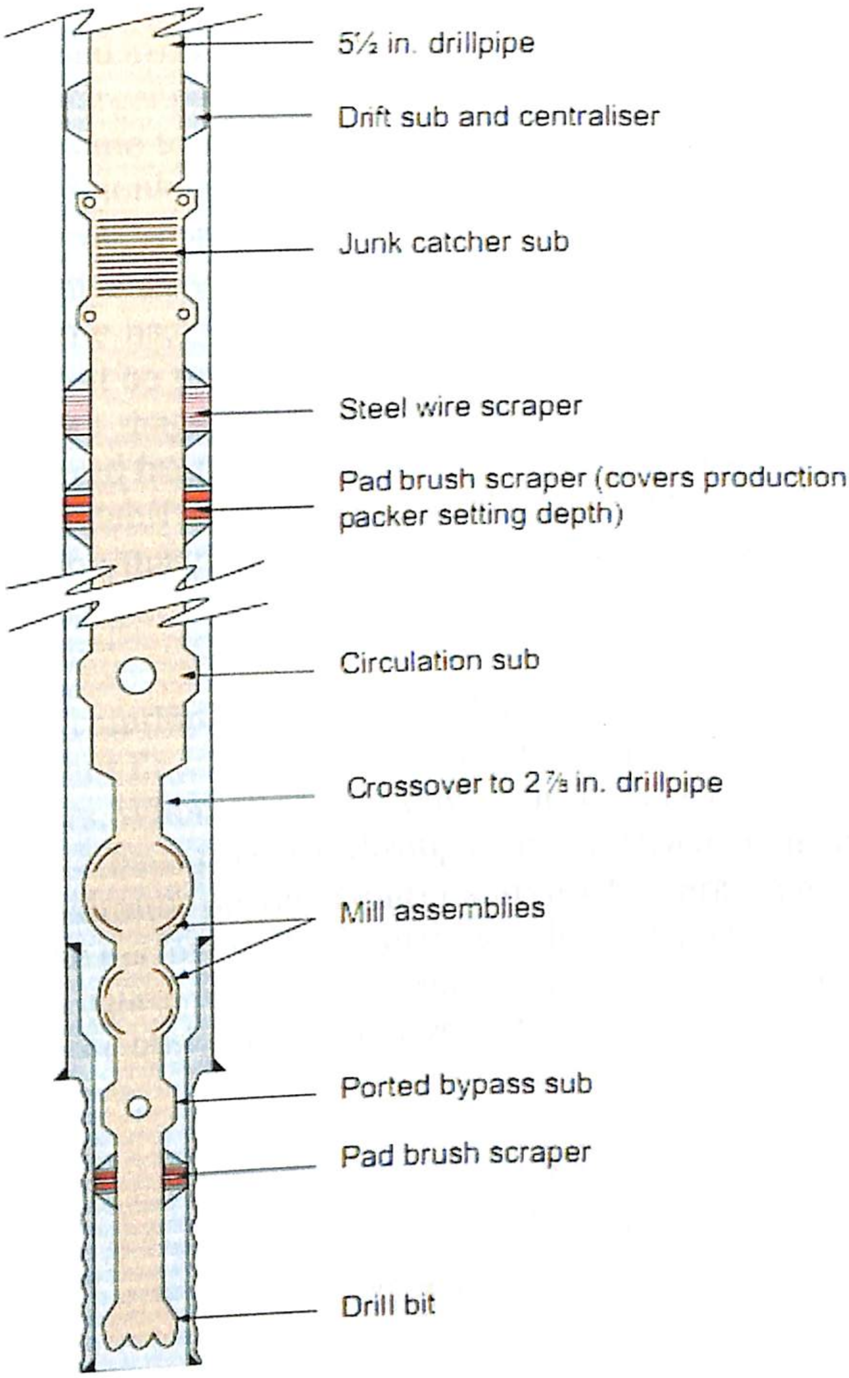


Figure 2.5 Typical casing and liner clean-out string.

Debris that is scraped from the casing may not necessarily be recovered at the surface. It is the larger particles (pieces of cement, cuttings or metal pieces) that can be troublesome to recover and damaging to completion or intervention tools. A junk catcher sub (junk basket) can be used to maximise the probability of recovering debris. The sub incorporates a basket with fluid being forced into this basket by a venturi (sucking), or by a wiper ring and a screened basket. If the basket comes back full (as shown in Figure 2.5), the clean-up string should be rerun. For some metallic debris such as swarf, this can be captured with magnets positioned downstream of a mill. Figure 2.6 shows debris recovered from such a device. Centralisers (above and below) help protect the captured debris from being scraped off the tool. Note that many oilfield metals are non-magnetic (aluminium and some high-chrome steels, for example)

Turbulent flow and rotation are required to flush solids to the surface. Maintaining turbulent flow in the annulus is difficult in wells with liners or large diameter risers. When the clean-out assembly is at the base of a long or narrow liner, the back pressure through these restrictions means that the back pressure or hydraulic power requirements are too large. A hydraulic calculation should be performed to determine velocities, pressures and power requirements, with typical pumping pressures being as high as 3000–4000 psia. Hole cleaning is notoriously difficult between 401 and 601.

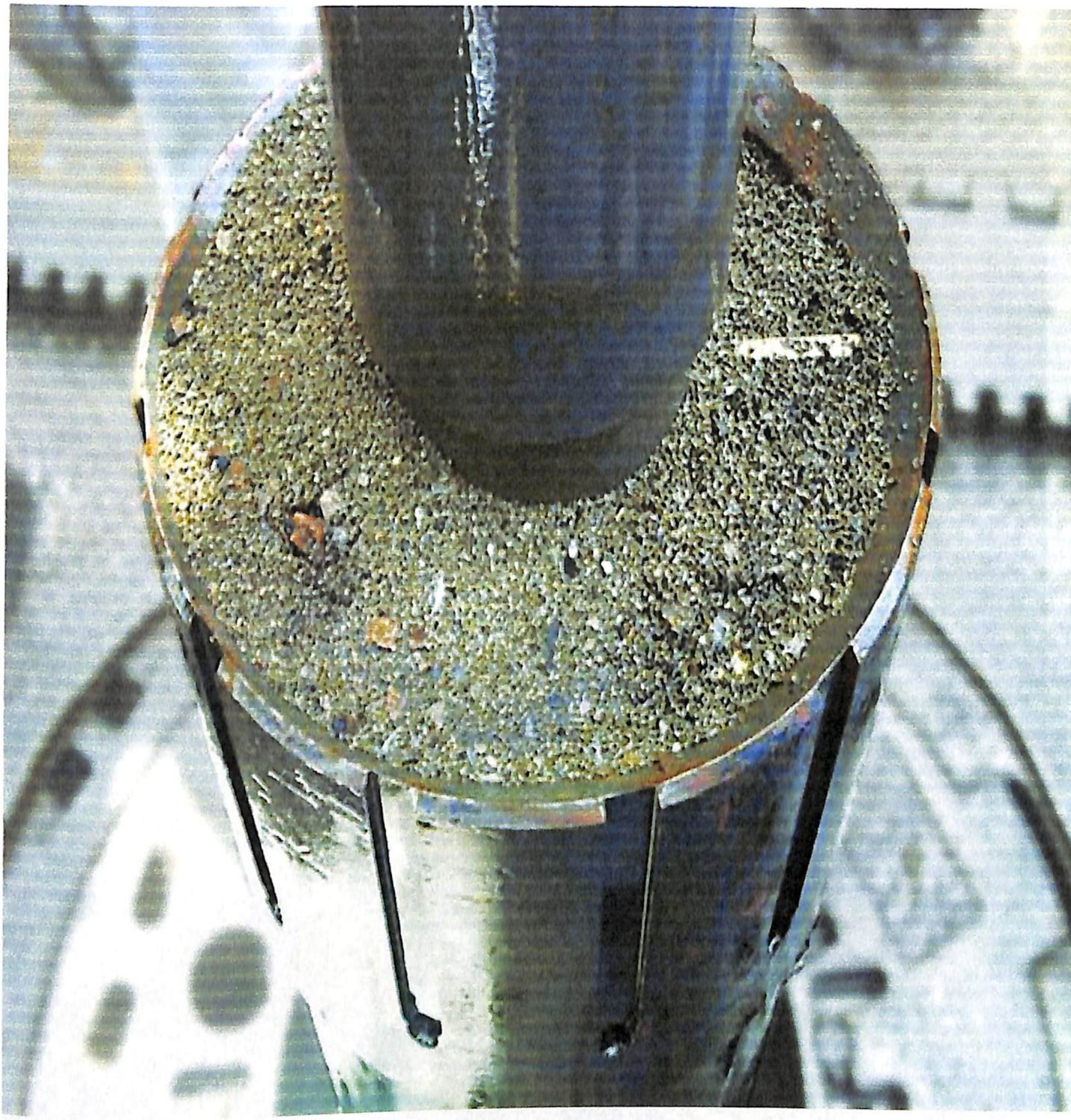


Figure 2.6 Full junk basket assembly (photograph courtesy of Bilco Tools, Inc.).

Figure 2.7 Magnetic debris sub

A circulating sub can be deployed in the string to short-circuit a convoluted circulation route. Such a circulation sub is ideally positioned adjacent to the top of the liner when the string is at the maximum depth. The purpose of the circulating sub is to maintain high circulation velocities above the liner top. This will sweep debris that settles out above the liner top once the liner itself has been cleaned. A similar strategy can be employed in the riser. Modern circulating subs, such as those supplied by the specialised wellbore clean-out vendors, allow the large diameter drillpipe above a liner top to rotate whilst the smaller diameter drillpipe inside the liner does not rotate. The circulating sub is activated by setting weight down on the liner top. This opens circulating ports and declutches the upper string from the lower string thus allowing upper string rotation (for improved hole cleaning). Other types of circulation subs are actuated by dropping a ball into a shearable seat or using a smart actuation method such as dropping a small radio frequency tag that is then detected by downhole electronics. Where turbulent flow cannot be achieved, higher rates are still preferred.

In some cases, a clean-out may be required with the formation open or controlled by LCM. Breaking down this material or fracturing the formation can be disastrous for productivity or cause a well control problem. The equivalent circulating density (ECD) and hence rates are particularly constrained in these circumstances. In such cases, the liner is cleaned out in one trip with the casing, and the riser is more completely cleaned once reservoir isolation has been achieved. However, great care must be taken to ensure that cleanouts above reservoir isolation valves or plugs do not encourage debris to fall on top of the valve or plug.

A well-known area for debris to accumulate is in BOP cavities (especially forsubsea wells). This area Is not effectively cleaned with scrapers. This debris poses a particular hazard for running tubing hangers and associated plugs (both vertical and horizontal trees). Jetting tools are required to clean the wellhead and BOP. They can be incorporated into the clean-out assembly (but require actuation to avoid short-circuiting of fluids during the well clean-out). They can also be short-tripped or used with a dedicated clean-out trip to the wellhead with a junk basket below the jetting assembly to catch debris falling back into the well. The jets should bedirected sideways, up and down (typically at 451). When a jetting tool is used in conjunction with casing/liner clean-out tools, it requires actuation (opening the flow through the jets). The simplest method is to drop a ball or dart in a similar way to circulating subs. If tools are actuated by setting down weight then they should land off in a wear bushing and be designed to avoid damage to seal areas. Tools such as these can sometimes be reset back to deep circulation. Cleaning the BOP/wellhead requires maximising the riser boost flow and functioning the rams (pipe and annular). Functioning the blind/shear ram (with the clean-out assembly above the BOP) simply invites debris to fall down the well. The riser will also require a mechanical scraper or brush and this should be able to cope with doglegs associated with the flex joint as well as various diameter changes. The riser brush shown in Figure 11.6 is designed to cover 100% of the riser, regardless of rotation due to the orientation of the brush pads.

2.2.3 Displacement to completion fluid

Before displacing any chemicals and recovering the mud, the logistics of mud recovery and brine handling require detailed assessment and agreement. The brine can be shipped or trucked in – sometimes requiring dilution on site. Occasionally, brine is made up from solid salts, but solid salts are more expensive than the equivalent brines due to the additional cost of drying. Regardless, the brine will need a dedicated pit or pits and space for clean mud, contaminated fluids, return fluids, spacers and clean brine. This is a logistical challenge as most rigs are not designed with these types of operations in mind (Darring et al., 2005). Many pits have large dead volumes and thus require excess pill volumes. All brine and spacer pits and associated pipework need thorough cleaning to avoid brine contamination. Pit cleaning cannot always be carried out offline. If it becomes necessary to clean out the mud system within the critical path, adequate time must be allocated to it in the completion programme. A heavily used mud system with oil-based mud can take up to 2 days to clean properly. The temptation to save time at this point is false economy. Pits can be cleaned with squeegees and power washers. This requires pit entry, with associated potential confined space and access hazards. Dedicated pit washing tools are available that eliminate this pit entry requirement when used in conjunction with detergents. Effective isolation between pits is required and this is notoriously problematic. The routes for pumping brine down the well and taking mud, contaminated mud and brine returns back from the well should be thought out well in advance. These routes will need cleaning including the shaker area, header box cement/choke/kill lines and pumps.

Filtration is not an alternative to effective pit cleaning and management.The displacement to brine can be a single (direct displacement) or a two-step approach (indirect displacement). In a two-step approach, the mud is first displaced with an intermediate fluid - typically seawater. Dirty seawater returns can be discharged (assuming no environmental issues). Once the intermediate fluid is clean,it is displaced by the completion fluid. Although the intermediate fluid gives an opportunity for additional circulation and chemical deployment, seawater is often sub-hydrostatic and introduces well control concerns depending on the degree of mechanical isolation from the reservoir. Indirect displacement is particularly well suited to cased and (un)perforated deviated wells with synthetic oil-based muds. Oxygen scavengers should be added to the seawater to combat corrosion (Burman et al., 2007a, 2007b).

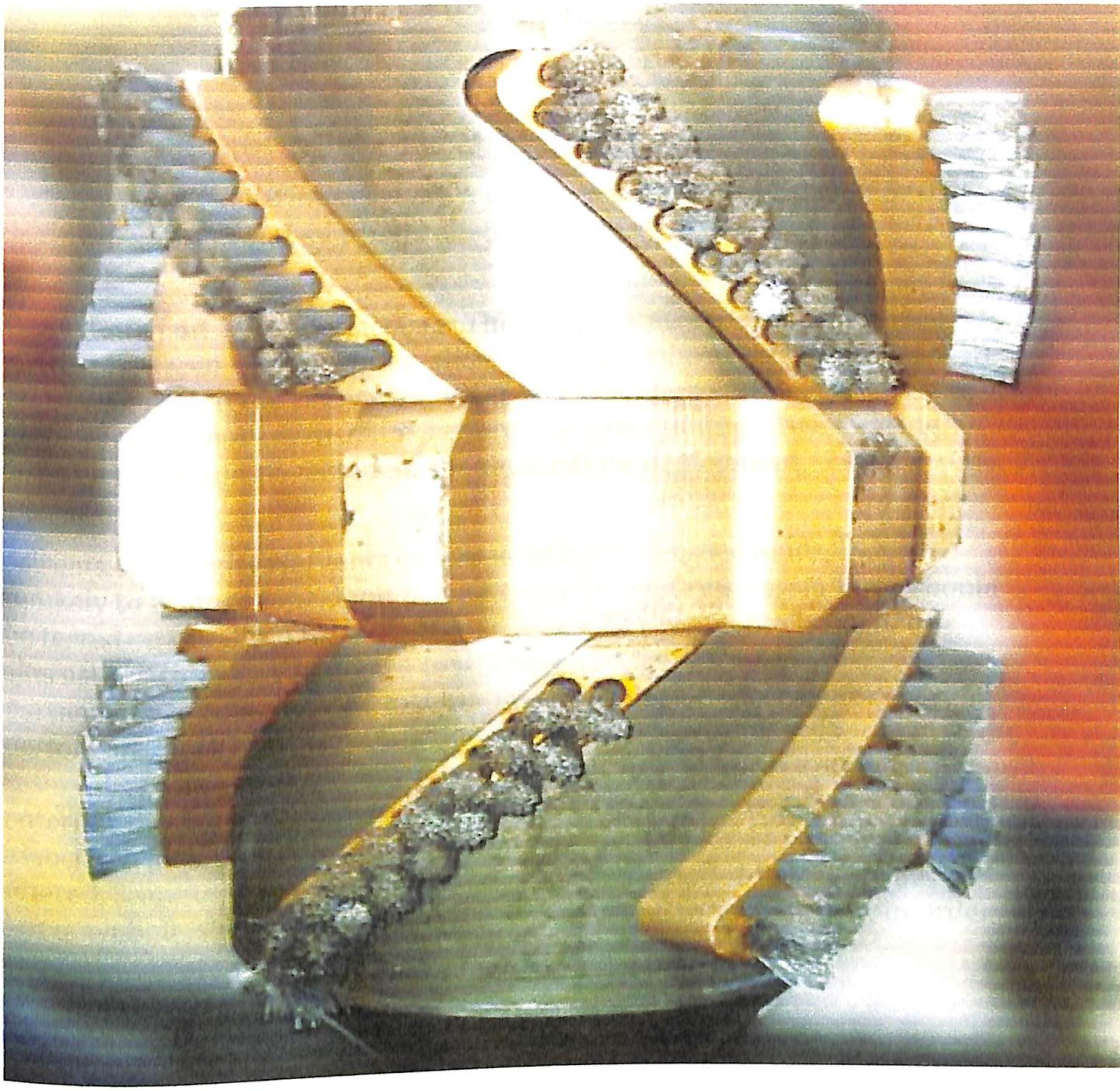


Figure 2.8 Riser brush (photograph courtesy of Bilco Tools, Inc.).

2.2.3.1 Various chemicals can be used to aid in the removal of oil and synthetic oil-based muds:

Detergents and other surfactants. These chemicals reduce the surface tension between oil and water, allow the dispersion of oil within the water phase and return the casing to a water-wet condition – although Saasen et al. (2004) argues that corrosion is reduced by maintaining oil-wet casing. Detergents should be tested on the mud before deployment.

Solvents. Although detergents can disperse most oil-based muds, they are unlikely to remove pipe dope. Solvents may be required – again these should be tested on the dope used for the drillpipe. Environmentally friendly alternatives to xylene and, care is still required in its selection, particularly if this fluid is lost to the formation.Underbalance perforating does not guarantee that the completion fluids will not enter the reservoir; perforating without flowing will likely lead to the completion fluid entering the base of the reservoir. This can lead to clay interactions and associated formation damage or plugging if the water is not clean or filtered. Seawater can lead to sulphate scaling formation damage Seawater left downhole should also be inhibited to prevent souring servoir in order to prevent losses.

2.2.4 Brine selection

The desirable properties for a completion fluid are

→Adequate density (if kill weight is required) to maintain overbalance under conditions of downhole temperature.

→Temperature stability.

→Formation and reservoir fluid compatibility if the fluids could be lost to the reservoir or an influx into the completion occurs. Some calcium- and zinc-based brines can promote asphaltene precipitation for example, whilst others promote emulsions. Compatible with additives such as inhibitors, loss control material and viscosifiers.

→Compatible with the mud – there will likely be a period where the drilling mud and the completion fluid are in direct contact.

→Compatible with any other fluids that might contact the completion fluid such as control line fluids.

→Environmentally acceptable. Many high-density brines (e.g. zinc bromide) are highly toxic. In some locations, their use is severely restricted.

→Low corrosivity – during displacement operations and long-term contact with the casing and tubing

→Compatible with elastomers, coatings and plastics (such as encapsulation)

→Clean and uncontaminated. Brines should be clear and uncoloured (unless they contain inhibitors in which case they may contain a slight colour tinge but will remain clear). Brines are easily contaminated.

During the completion process, the possibility of contact between the completion fluid and incompatible materials (fluids or solids) is very real. In order to prevent problems, these potential contacts must be identified. Most potential completion fluid interactions can be identified from a careful analysis of the comple- tion programme. However, this may not cover all potential fluid incompatibilities. Where there is doubt or different materials are coming into contact for the first time, additional testing may be required. Where incompatible materials are identified, one of the materials can be changed out or procedures revised to ensure that contact does not occur. This process can then be controlled - for example if a different completion fluid is required due to higher than expected reservoir pressures then potential compatibility issues can be quickly identified.

The maximum density of a brine depends on the salts used, brine temperature and to a lesser extent pressure. A guide to the common completion brines is shown in Figure along with approximate maximum densities. The reason that these numbers can only be used as a guide is that the maximum density reduces as the temperature reduces; deepwater brines will have lower maximum densities than similar brines used in a land well in the tropics. Generally, mixtures of brines can achieve higher densities than single-salt brines.

As the density of brine is increased, the chemical activity reduces; this reduces the amount of 'free' water (most of the water molecules being bound to the salt ions). Brines will therefore tend to absorb moisture from the air if stored in open tanks or pits. This will reduce the brine density over time. The lack of free water also affects additives such as viscosifiers that require water to hydrate. Dense brines behave increasingly less like water and more like other organic liquids. H_2S and CO_2 become less soluble in dense brines; conversely calcium carbonate increases in solubility (Bridges, 2000). This means that brines can be contaminated - for example dissolving calcium carbonate weighting material, mud or cement left in pits. Counter-intuitively, precipitates can form if some brines are excessively diluted - zinc bromide, for example, behaves in this manner. They can also react with various elastomers

Dense brines such as zinc bromide are extremely expensive, corrosive and highly toxic. They present increasing compatibility problems (muds, reservoir fluids and additives) and must be tested for compatibility using mix tests under downhole conditions or return permeability tests where fluids could be exposed to the reservoir. Many dense brines present handling difficulties and can attack the elastomers used in the construction of transfer hoses and seals. They can also be difficult to filter due to their high viscosity. Handling these brines is aggravated by the serious consequences of contact with personnel or the environment. An extract from the material safety data sheet (MSDS) for zinc bromide is shown in Figure 2.9.

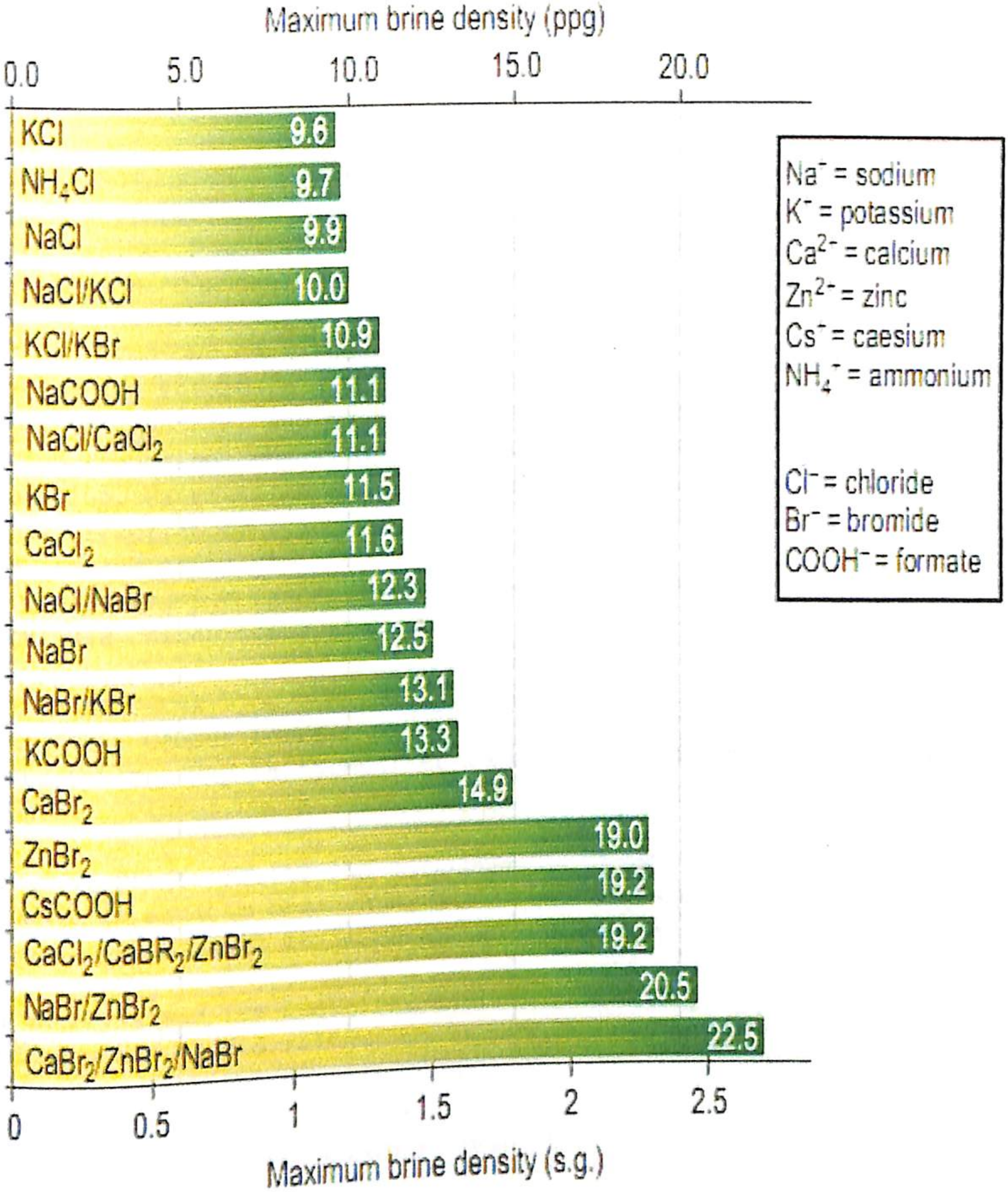


Figure 2.9 Common completion fluid brines with approximate maximum densities

...PERSONAL PROTECTIVE EQUIPMENT
Respiratory Protection: Government approved respirator.
Hand Protection: Compatible chemical-resistant gloves.
Eye Protection: Chemical safety goggles...

...SIGNS AND SYMPTOMS OF EXPOSURE
Inhalation may result in spasm, inflammation and edema of the larynx and bronchi chemical pneumonitis, and pulmonary edema. Symptoms of exposure may include burn sensation, coughing, wheezing, laryngitis, shortness of breath, headache, nausea and vomiting. Material is extremely destructive to tissue of the mucous membrane and upper respiratory tract, eyes, and skin. Ingestion of large doses can cause severe stomach pain, violent vomiting, shock, and collapse. Less than an ounce m cause death. Bromide rashes, especially of the face, and resembling acne and furunculosis, often occur when bromide inhalation or administration is prolonged.

...ROUTE OF EXPOSURE
Skin Contact: Causes burns.
Skin Absorption: May be harmful if absorbed through the skin.
Eye Contact: Causes burns...

...Corrosive. Dangerous for the environment. Causes burns.
Very toxic to aquatic organisms, may cause long-term adverse effects in the aquatic environment...

...This material and its container must be disposed of as hazardous waste. Avoid release to the environment...

Figure 2.10 Extracts from zinc bromide MSDS.

2.2.4.1 Additives

A number of different chemicals may be added to completion brines to reduce adverse effects:

1. Corrosion inhibitors. If fluids are being circulated then corrosion inhibitors can be effective for short-term protection. Inhibitors work by forming a thin film on the metal surface. These films are unstable with long-term exposure (more than a few days at most), particularly at elevated temperatures. For fluids that are left downhole such as packer fluids, corrosion inhibition will not affect long-term corrosion and can exacerbate stress corrosion.Particular care is required with thiocyanate corrosion inhibitors that may be added to tanks or before brine supply to the rig.

2. Oxygen scavengers. Circulating fluids should ideally have oxygen removed. The practicalities of this are difficult in open pits. Generally, oxygen will react with the carbon steel casing and cause a small amount of superficial corrosion. Once the oxygen has been consumed by this reaction, corrosion will stop.

3. completion fluids such as seawater left downhole should be inhibited against souring.

4. Hydrate inhibition. Where completion fluids are left in pressure balance with the formation, for example the end of a stimulation, an influx of gas is likely, especially with thick, permeable reservoirs. Such an influx creates a hydrate risk. Increasing brine salinity provides some natural hydrate inhibition. Where this is insufficient, displacement of the hydrate prone upper part of the completion to a fluid such as glycol may be required (Section 7.5, Chapter 7), but the volume required can present enormous logistical challenges as well as being expensive. Glycol and methanol can be incompatible with some brines.

5. Iron control agents. Iron (typically from corrosion) can affect productivity by precipitating in the reservoir. Iron can also impair polymers and stabilise emulsions (Javora et al., 2006). Iron sequestering agents may be added to prevent these adverse reactions. Iron already in solution will give an obvious red (rusty) stain to the brine but the iron can be removed by adding caustic soda or lime.

2.2.5 Safely Running the Completion

Procedures for preparing and running the completion will vary enormously depending on the location and type of completion. This section does however provide some general guidelines.

2.2.6 Pre-job preparation of tubing and modules

Several activities can be performed before getting to the site of the well. This includes preparation of not only the modules but also the tubing. Tubing preparation (after manufacturing and quality checks at the mill) includes the following:

Clean and inspect each joint (and pup joints). The cleaning is intended to remove internal and external rust, scale deposits and thread compounds. Figure 2.14 shows cleaned pins - note that the internal mill scale is yet to be removed. Mill scale should be removed mechanically (blasted).

Mark the pipes with the joint number. Markings can be by paint or white markers. Stencils reduce confusion between numbers such as 1s and 7s but add time. Indented marks can be more permanent and round indents should cause less corrosion than slip or tong marks (including 'non-marking' tongs). Drift each joint to API or company specification. Special drift requirements should be advised by the completion engineer. Note that the drifts are specified not only by diameter (typically 0.125 in. less than nominal diameter) but also by drift length (the length depends on the tubing size). Drifting tubing is shown in Figure 2.15. Measure all tubing joints using laser (Figure 2.16; note the joint numbers and lengths marked on the coupling and pipe body). As confirmation, some of the joints (typically 10%) can be checked with a tape measure. Laser measurements have taken over from tape measures as the primary method for measuring pipe. It is faster, more accurate and less prone to error – no correcting for the missing.

Figure 2.15 Cleaned tubing pins.

Figure 2.16 Drifting tubing before shipment to the wellsite.

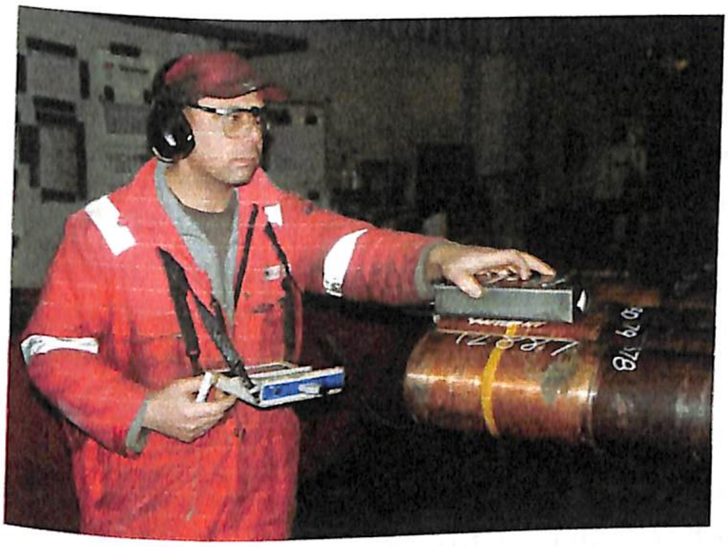


Figure 2.17 Measuring pipe by laser before shipment to the wellsite.

2.2.7 Rig layout and preparation

Completion operations cover intense and diverse activities requiring different skills and equipment to drilling activities. Wellsite preparation for running the comple- tion naturally occurs whilst drilling the reservoir section – another intense period in constructing a well often involving specialist activities such as coring, geosteering or logging. These challenges place demands on logistics, positioning of equipment (particularly offshore), crew levels and the drilling crew (drilling supervisors, rig hands etc.). A pre-completion meeting should be held at the wellsite with the rig team to discuss the completion procedures with attention placed on areas requiring rig crew assistance:

1. Safety should always be the first priority. Most hazards can be identified and, where possible, mitigated up-front. Additional hazards may be noticed before or during operations. Completion-related hazards include high-pressure testing, hazardous chemicals (solvents, brines, H_2S etc.), well control, radioactive sources, explosives and heavy lifts (such as trees). Simultaneous operations (SIMOPS) are a particular concern and may involve interfaces with ongoing production (depending on the location).

2. The procedures should identify the layout for critical pieces of equipment such as filtration units, control line reels, module baskets and well testing spreads. Such layouts should not come as a surprise to the drilling and completion supervisors, but may need to be modified – for example reduced space due to ongoing drilling operations. Pit management is critical and as already discussed requires a careful manipulation of mud demobilisation, brine mobilisation, filtration, chemical pills and pit cleaning.

3. Roles, responsibilities and management of change should be highlighted.

The differences between running a completion and drillpipe or casing are many:

1. Some tubulars such as duplex require additional protection and therefore modification to the rig floor and pipe deck to prevent the pipe landing on metal or being scratched Screens require similar protection.

2. Premium connections may sometimes only be encountered with the completion and require different make-up tongs. However, many modern wells use premium-threaded tubulars for production casing and liners.

3. Control lines are an added complication with most completions, and sheaves, tensioners and reels should be positioned ideally outside of the critical path.

4. Many completions require the use of long modules, along with heavy and awkward loads such as subsea test trees (SSTTs) and trees. The routes for getting this equipment onto or under the rig floor and thence downhole should be worked out well in advance.

In order to provide sufficient space for completion operations, as much drilling- related equipment as possible should be laid down or demobilised including drillpipe and automated pipe handling equipment. The rig crew may be reluctant to do this. Once completion operations commence, the layout of equipment will need to change. An especially challenging point is landing out the upper completion with its attendant tubing make-up, control line running and tree installation alongside potential well testing and through tubing operations such as wireline perforating or stimulation.

2.2.8 Running tubing

Running tubing frequently involves contact with corrosion-resistant alloys and the use of premium connections. A typical sequence for running corrosion-resistant tubing with premium connections is:

1. The pipes are transferred to the catwalk by rolling or by crane – usually a few at a time. Corrosion-resistant alloys should be transferred using plastic-coated wire or nylon slings. Dropped pipe should be rejected.

2. A collar type elevator and hoist is used to transfer the pipe from the catwalk to the derrick. The pin of the tubing is protected – typically with a plastic composite protector. Direct contact of the tubing with the V-door is avoided by using secured wooden or plastic battens. The pipe is prevented from swinging into the rig floor by rope.

3. The tubing string is held at the rig floor using slips (or hydraulic slips – a spider) and hoisted using elevators. Slip (gripping) or collar (holding the tubing by the square-edged tubing collar) type elevators can be used. For bevelled or slim-line connections, slip-type elevators are required. If flush joint tubing is run, a special lifting nubbin should be used.

4. When the new tubing joint is lowered to working height, the pin protector is removed and the pin and previous box are inspected for damage (Figure 2.19)This inspection can be performed by the tubular running crew or by a dedicated tubular inspector. The pin is cleaned (again), and pipe dope specifically approved for the connection is applied sparingly to the pin or box end (or both). Opinions vary regarding the best method to apply pipe dope (brush or applicator) and whether it should be applied to the pin or box; recommendations specificto the connection being run should be sought. The primary purpose of the dope is thread lubrication but some connections are now dope-free API dope is a mixture of grease and metals such as lead and zinc. It is therefore environmentally unfriendly; more environmentally acceptable alternatives are available and widely used. Some of these 'green dopes' have caused galling on high-chrome premium connections. They should be workshop tested before use. Applying dope to the pin has the advantage that excess dope can be wiped from the outside of the connection once made up. Excess dope inside the tubing risks problems with through tubing interventions and has the potential to cause formation damage. Insufficient dope risks high torque to make-up the connection and potential thread galling.

5. The new joint of tubing is lowered onto the string using a stabbing guide (shown in Figure 11.19) to ensure that the connections remain undamaged. A stabbing guide is effectively a double funnel to guide the pin into the coupling. The guide covers the entire face of the coupling and thus prevents the pin from landing on the coupling face. The guide is hinged for removal.

6. The connection is made up initially by hand using a strap or chain wrench(unless the tubing is too large to rotate by hand). The pipe must be vertical to avoid galling the threads. The power tongs can then be brought in to complete the connection and grip the pipe above the connection (Figure 2.20).The tongs have an integral back-up positioned below the coupling. Modules are incorporated into the completion in exactly the same way – ideally the modules will have connections on the pup joints identical to that on the tubing.

7. Excess dope should be wiped from the outside of the connection.

8. The main elevator is then lowered and latched around the tubing. The string can then be slowly lifted allowing the slips to be pulled or released and the string lowered. The running speed depends on clearances and whether surge/swab is a concern.

9. For running the first few (10–20) joints a safety clamp is used around the pipe. Each connection (including variations in weight and grade) has recommended make-up torques. Over-torque is prevented by a dump valve set to the recommended make-up torque. An ideal make-up torque versus turns plot is shown in Figure 2.22. In the event that the joint is incorrectly made up, the joint is broken out and inspected for damage and the make-up process examined. If the threads are undamaged, the connection can be attempted again (up to two or three times). If damaged, the two offending joints are removed and replaced (with the tally adjusted).

Figure 2.20 Preparing to make-up chrome tubing

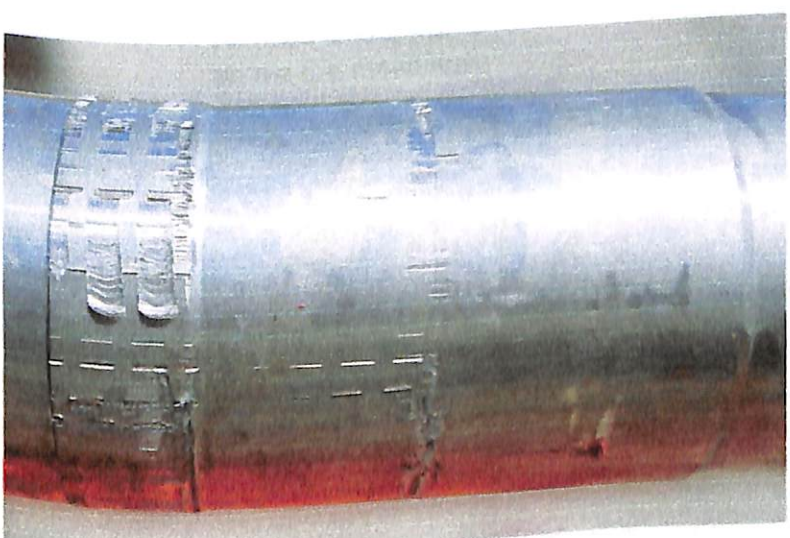


Figure 2.21 Make-up damage to a module component.

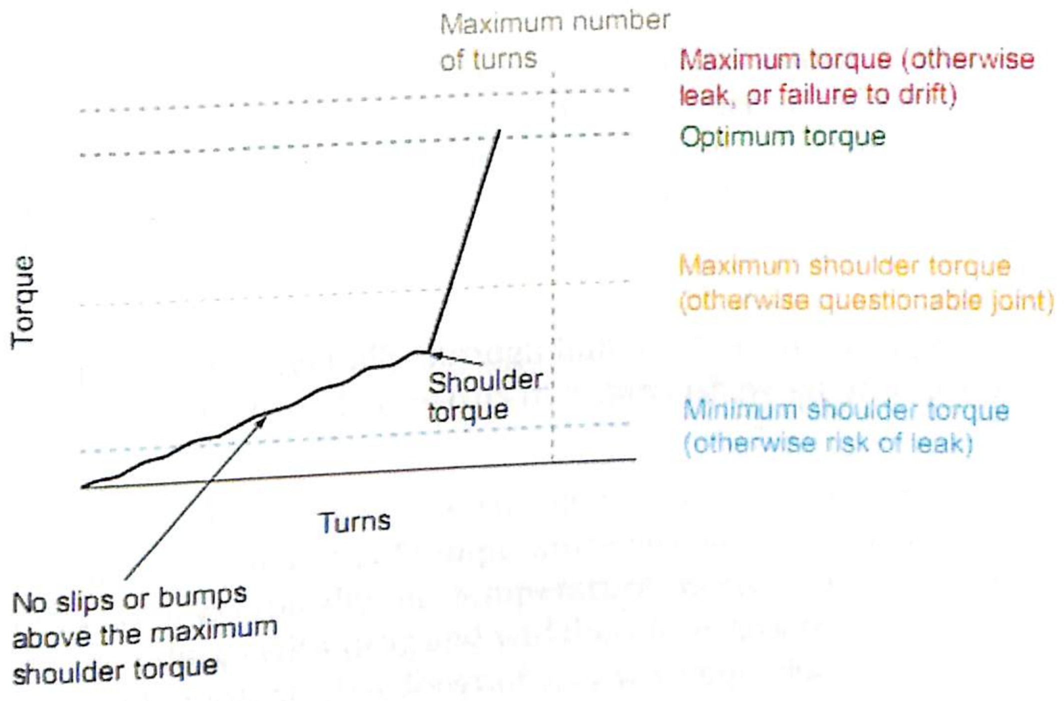


Figure 2.22 Torque-turn graph for a premium connection.

2.2.9 Space-outs

The completion will always be spaced out to position equipment at the correct depth. Some positions can be more critical than others; for example a safety valve can normally be positioned within a tolerance of several joints, whilst tubing conveyed perforating guns may require positioning within an accuracy of a foot or less. Using dead-reckoning (reliance on the accuracy of the tally) is subject to various errors:

1. The absolute accuracy of the position is rarely important; it is the relative position that is significant (with respect to the liner or reservoir completion top, reservoir depths, seal bores, etc.). The relative position depends on the accuracy of the tubing tally and the accuracy of the previous casing or drillpipe measurement.

2. Tallies can be inaccurate – typically through human error; for example a joint is rejected but not recorded, or errors in a spreadsheet go unnoticed.

3. Tubing, drillpipe, casing and wireline stretch when run in the hole. Stretch comes from a combination of temperature increase, self-weight, ballooning and buoyancy; typically the temperature increase is the most important. Stretch reduces with drag and will therefore vary between completion fluids and muds. Stretch does not vary with pipe thickness or diameter so in the absence of drag it does not vary between tubing and casing. Stretch is non-linear (doubling the length of pipe, typically quadruples the stretch). Stretch in excess of 20 ft is

possible with a deep well, but and production facilities are put in place and connected. In many cases, ensuring that the well can flow before moving the rig can avoid embarrassment (and considerable expense) later. A clean-up flow is also an opportunity to gather data such as the completion skin. Such data can be used to improve future completion performance For a platform well, where facilities are already available, it is routine to simply route the new well to the test separator. This allows solids to be recovered and data recorded.

For subsea wells, a dedicated well test spread should be mobilised. This involves logistical and environmental challenges (Burman et al., 2007a, 2007b). If coiled tubing is required to remove solids (such as proppant), the logistical challenges increase. Isolating the well during production operations may require a subsea test tree (SSTT) and this is essential for a horizontal tree. The SSTT sits and seals inside the BOP and requires the running of umbilicals.If the purpose of the flow is to clean up the well, specific, realistic acceptance criteria should be in place along with the means of measuring these.

2.2.10 Procedures list

There are two methods of using procedures for completion operations:

1. Write a detailed procedure that includes all the information required for the completion operations.

2. Write a summary procedure with a list of references of more detailed procedures for various routine operations (e.g. tree installation or perforating rig-up).

The former is generally used where there are a small number of diverse wells and the latter for large numbers of similar wells - especially land wells.The purpose of the procedures is to tell the completion installation team how to install the completion in a safe, unambiguous way and to capture lessons learnt.It does not imply that whoever is installing the completion lacks competence to decide the best method for constructing the completion - written procedures allow all parties to assess and review the operations. The procedure author should expect (and welcome) the procedures to be challenged.

All procedures should include:

→ Basic well data – water depth, location, pressures, temperatures, H_2S content, etc.

→Expected well status at the start of the completion, including a well schematic showing actual or expected casing, cement and reservoir positions.

→Safety aims and aspirations with the main assessed hazards highlighted specifically.

→Roles and responsibilities. A useful method of documenting responsibilities is through an RACI chart (responsible, accountable, consult, inform). An example is shown in Table 2.26 Contact information for office-based, rig-based and vendor personnel –including out-of-office hours contacts.

→ A procedure for managing change.

→ Documentation control – a distribution list and a method of ensuring that only the up-to-date procedures are used. The distribution list is usually extensive.

→An overview of the completion design and objectives – for example rate, skin, sand-free and lifetime.Company specific training or competency requirements such as offshore survival,permit to work or H_2S procedures.

→An outline programme with planned times.

→Detailed step-by-step instructions for the installation of the completion, including preparation work and activities that can be performed offline (concurrent with rig activities). Contingent operations and how these will be assessed.

→Start-up and well testing procedures including criteria for acceptable termination.Well handover procedure including documentation requirements and associated pro-forma sheets (in appendices).

Such a list can make a single procedure cumbersome. It is possible to split the procedures into separate controlled documents (reservoir completion and upper completion for example). Reducing the volume of the main procedures (and therefore the probability that they are read beforehand) can be achieved by placing supporting information in appendices:

Basic reservoir and fluid data, including composition.

→ Well location map (especially if a land well).

→ Liner and casing tallies.

→Deviation survey or directional plan - including a plot.

→Tubing detail including handling procedures, make-up torques and acceptance criteria.

	Senior Management	In-Country Resident Management	Asset Manager	Completion Designer	Emergency Response Team	Drilling Manager	Drilling Superintendent	Completions Superintendent	Drilling Wellsite Supervisors	Completions Wellsite Supervisors	Third Party Vendors	Logistics	HSE	Procurement	Production
Project scope, objectives and expectations		C	A/R	C		R	R						I		I
Changes to original project scope			A/R	C		R	R	R							
Organisational structure			A/R	C		C	C	C	I	I	I	I	I		I
Work process flow						A/R	C	C	I	I					
Personnel selection and assignment			A	R		C		C							
Project planning and coordination						A	R	R	C	C	C	C			
Completion design			C	A/R				C		C					
Completion equipment selection and cost estimation			A	R		C		C		C				C	
Completion implementation			A	C		C	C	R	C	R	C				
Logistics				A		C	I	R	I	I				R	
Completion surveillance, scorecard analysis and performance improvements				A		C	C	R	I	I					
Well control				C	I	A	R	C	C	I					C
Completion safety performance				A		C	C	C	R	R					C
Financial cost reconciliation				A		C	C	R	I					C	
Total project AFE and budget			A	R		C	C	R	C					I	

R = responsible: individual or groups who perform the activity
A = accountable: individual who is ultimately accountable for ensuring that the work gets done
including yes/no and veto
C = consulted: individual(s) who need to be consulted before a final decision is made
I = informed: individual(s) who need to be informed after a decision has been made

Table 2.1 Typical RACI chart for completion operations

→Load out lists (equipment and people), with associated checklists (Ajayi et al. ,2008). For critical items, spares or back-ups should be listed and carried.

→Volumes and capacities (tubing, annulus and open hole).

→Equipment specific preparation and handling, for example termination of control lines into a downhole safety valve.

→Module make-up schematics.

→Chemical hazard data sheets.

→Weather operating guidelines and disconnect procedures.

→BOP drawings and configurations.

→Rig layout drawings - identifying the expected location of critical pieces of equipment.

→Process and instrumentation drawings (P&IDs) for well testing (if applicable).

→Facility details, for example well bay drawings and flowline connections.

→Pro-forma sheets such as handover certificates.

→Valve status sheets (for example subsea trees, test trees and reservoir isolation valves). These sheets allow the status of downhole valves to be recorded at the rig for quick reference. Laminating these sheets makes them practical for the wellsite.

The completion programme must be reviewed before publication. Many companies have formal procedures for controlling this process. Regardless, the review must include the following features:

1. Timely. This is difficult – too early and some details may not be covered or vendor personnel can be swapped out before operations. Too late and there is insufficient time for changes to be implemented.

2. Correct audience. A representative from all vendors and service companies as well as those from the rig must attend. The programme author, completion designer and completion supervisors (if they differ) should attend as well as those tasked with logistics. Rig involvement is particularly critical as the rig crew and their supervisors understand the capabilities and nuances of the rig (pit layouts for example) and have worked extensively with logistics, weather limitations, subsurface challenges, etc. during the drilling operations. Engineers can also be invited who are not directly involved in the specific operations, but who have previous experience of similar operations. Sometimes this is treated as a separate, less detailed session before programme writing (peer review or peer assist).

3. Understand limitations. It is expected that the detailed operation of a piece of equipment is understood by the vendor or service company – this knowledge will likely exceed that of the programme author. The programme may therefore be attempting to do something that either equipment or personnel are not capable of.

4. Addresses the interfaces. How does the equipment, people or process from one company connect or interface with another.

5. Open. Attendees should be encouraged to highlight concerns and lessons they have learnt from other operations – in a non-confrontational manner.

Operation	Duration			Cumulative
	P10 (h)	P50 (h)	P90 (h)	P50 (days)
Liner clean-out				
Pit cleaning and preparation of brine	12	24	36	1
Run liner clean-out assembly	12	18	24	1.75
Displace well to seawater	3	4	5	1.92
Pump clean-out pills and circulate until well is cleaned	9.6	12.8	19.2	2.45
Turn well over to kill weight fluid	3	4	5	2.62
Pull out of hole (POOH) with clean-out string	8	10	12	3.03
Total for liner clean-out	47.6	72.8	98	3.03
Tubing conveyed perforating				
Carry out BOP test	12	15	20	3.66
Rig up well test equipment	0	2	2	3.74
Make up and run guns	18	24	36	4.74
Carry out correlation run	6	8	10	5.07
Set and test packer, displace tubing to base oil	8	10	18	5.49
Fire guns. Perforate intervals A and B	1	2	24	5.57
Flow well for initial clean-up	2	4	8	5.74
Kill well	8	12	36	6.24
Pull drill string	8	10	12	6.66
Perforation burr polish mill run	14	18	36	7.41
Pull wear bushing	0.5	1	2	7.45
Total for tubing conveyed perforating	77.5	106	204	4.42
Running the completion				
Prepare rig for completion running, rig up equipment, reels etc.	6	10	30	7.87
Pick up tailpipe, nipple and lower packer	0.5	1	1.5	7.91
Connect SSD line. Function test	1.5	2	6	7.99
Run 3 1/2 in. tubing and blast joints to next SSD	5	8	12	8.32
Pick up 7 in. x 3 1/2 in. packer	0.5	1	3	8.37
Connect SSD line. Function test	3	4	8	8.53
Run 3 1/2 in. tubing to crossover. Run crossover	3	4	8	8.70
Run blast joints over interval C	4	6	10	8.95
Run 4 1/2 in. and crossover	2	3	5	9.07
Make up 9 5/8 in. packer and sleeve	0.5	1	3	9.12
Connect SSD line. Function test	4	5	10	9.32
Run 5 1/2 in. tubing to DHSV	30	35	48	10.78
Install DHSV and ported nipple Connect and test control lines	2	3	4	10.91

Operation	Duration			Cumulative
	P10 (h)	P50 (h)	P90 (h)	P50 (days)
Run upper section of 5 1/2 in. tubing up to tubing hanger	2	3	4	11.03
Depth correlation electricline run	6	8	12	11.37
Space out and install hanger	1.5	2.5	4	11.47
Terminate control and SSD function lines	6	8	10	11.80
Land tubing hanger	0.5	1	1.5	11.85
Test hanger seals	2	3	12	11.97
Rig up slickline	3	4	6	12.14
Circulate well to base oil in tubing to create underbalance	3	5	10	12.35
Run 2.75 in. standing valve	2	3	8	12.47
Low pressure test (tubing and DHSV)	2	3	96	12.60
Set packers, test tubing string	0.5	0.5	1	12.62
Integrity test DHSV	0.5	1	1.5	12.66
Pull standing valve	2	4	8	12.82
Set plug in hanger (or DHSV?)	1.5	2	6	12.91
Recover landing string	0.5	1	1.5	12.95
Nipple down BOP	5	6	12	13.20
Install wellhead and terminate all lines	6	8	12	13.53
Install and test tree	2	4	8	13.70
Total for running the completion	108	150	362	13.70
Overall total	233.1	328.8	664	21.15

An example of an outline installation procedure with predicted timings is shown in Table 2.2

2.2.11 Handover and Post Completion Reporting

Once completion operations are finished, the well is handed over to operations for production/injection. This handover must include transferring knowledge about the completion to the production engineers who will operate the well. Elliot (2006) mentions several wells with integrity problems attributed to inadequate information transfer between completion and production engineers. Information must also be recorded for engineers coming back to the well for interventions – often in many years time (and after several office moves and asset transfers). The information transferred must include:

1. The status of all wellhead and tree valves. It is useful to add in the number of turns required to fully or fully close each valve.

2. The status of downhole valves, including the control line fluid and the volumes required to operate hydraulic valves.

3. Whether any plugs have been installed and where they are positioned.

4. The reservoir intervals and depths completed across.

5. The fluids and pressures in the annuli and tubing at handover point.

6. The annulus operating procedures including maximum allowable annular surface pressures (MAASPs) and whether any of the annuli are open to formations. Specific attention should be paid to annulus monitoring and bleed down (due to thermal fluid expansion) during the first few days and weeks of production.

7. Any material left downhole that could interfere with production operations;examples include methanol, surfactants, muds and solids such as proppants.

8. Bean-up guidelines – how fast should wells be opened up.

9. Any fish or other problems that could impinge on interventions.

10. Monitoring requirements, for example sand production.

Much of this information can be recorded in a completion drawing. Many of these drawings look good, but have minimal information attached. Depths and dimensions of all equipment are critical as is the date and source of modifications to the drawings.A detailed well file (paper or electronic) should also include a sequence of events, detailed tally, module drawings (including part numbers), pressure test records anddeviation survey, along with daily and service engineer reports.

Chapter III

Case study

3.1 MOTIVATION FOR THE PRESENT STUDY

In general, a completion design must be capable to resolve the following problems successfully[20]:

➔ preserve borehole wall stability, if required

➔ guarantee selective fluid production from specific formation, if required

➔ reduce confine in the flow path

➔ guarantee well safety

➔ permit well flow control

➔ permit well operations with minimum workover

- ➔ facilitate workover, if required

Conventional well completion employs in general a single inside-diameter (ID) tubing string.Sometimes a smaller or larger ID tubing string section(s) is used due to workover and borehole constraint necessities.

We note that as the oil flows vertically upward, the flowing pressure decreases as a function of depth. This reduction in flowing pressure causes more and more dissolved gases to come out. Consequently, the flow stream, especially free gas, expands in volume per unit mass flowrate.

If the capacity of the flow string does not increase as the fluid moves up, more and more flow restriction is experienced, causing higher flowing pressure gradient. This will cause an increase in flowing bottomhole pressure (FBHP), which will decrease the reservoir pressure abandonment, and hence the oil production rate.

Therefore, the motivation of the present study is to investigate the effect of different increasing tubing ID as the fluid moves up the string.

3.2 STATEMENT OF THE PROBLEM

This study is important for the following reasons:

- ➔ Production Optimization
- ➔ Accelerated Recovery
- ➔ Better economy performance

To calculate the units used are field units.

3.3 APPROACH TO THE PROBLEM

To examine the effectiveness of the proposed tubing well completion, the following objectives are set for this study:

- Conduct a focused review of literature on IPR and TPR construction methods
- Collect pertinent reservoir, well, fluid, and production data
- Determine stabilized flowrates for different tubing sizes.

3.4 LITERATURE REVIEW

3.4.1 INFLOW PERFORMANCE RELATIONSHIP (IPR)

An inflow performance relationship (IPR) is a graphical method used in production engineering to estimate the relationship between the flowrate and the bottomhole flowing pressure. IPR is a most common way in production engineering to estimate reservoir deliverability.It is generally used to estimate various operating conditions such as determining the optimum production scheme and designing production equipment of a particular well. It is a Cartesian plot (IPR plot) of various bottomhole flowing pressure test data versus the flowrate test data of a particular well.

The IPR graph (inflow performance relationship) curve or an IPR curve is shown in Figure 3.1. The magnitude of the slope of the IPR is called the "productivity index" (PI or J)

$Q=J(Ps-Pwf)$

Where

J = productivity index, STB/D/psi

q = flowrate, STB/D

p_s = pressure at the external boundary of the drainage area, psia

p_{wf} = bottomhole pressure, psia

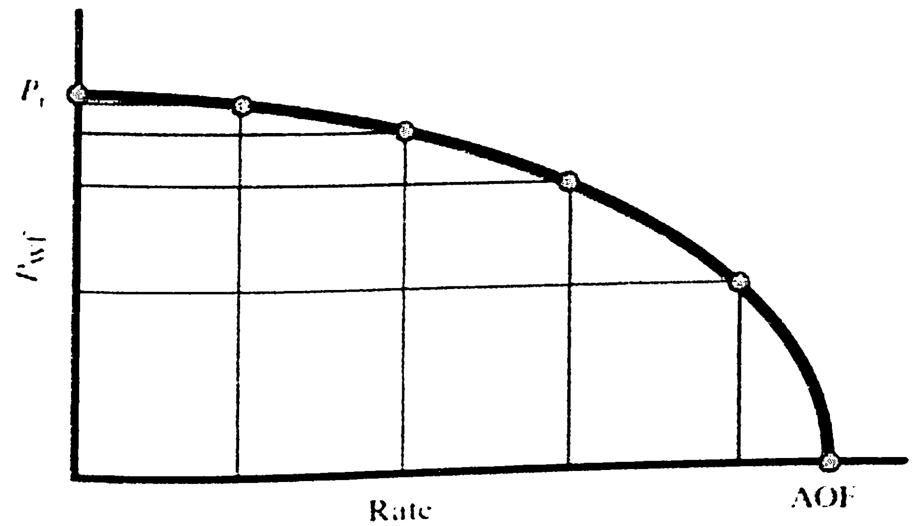


Figure 2.3 Inflow Performance Relationship Curve

Reservoir inflow models used to construct the well IPR curves have either a theoretical basis or an empirical basis. These models are generally verified during test points in the field application.

3.4.2 Vogel's Method

In 1968 Vogel, with the help of a computer model, constructed IPRs for a number of suppositional saturated oil reservoirs which were under a wide range of conditions. This method not only helps to regularize IPR but also generates IPR without any physical units. The following equation is used to generate IPRs curves for different reservoir pressure conditions:

$$\frac{Q_o}{(Q_o)_{max}} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2$$

Where

Q_o = oil rate at P_{wf}, bbl/day

$(Q_o)_{max}$ = maximum oil flow rate when wellbore pressure is zero, bbl/day

P_{wf} = bottomhole pressure, psig

P_r = reservoir pressure, psig

3.4.3 TUBING PERFORMANCE RELATIONSHIP (TPR)

Tubing performance relationship (TPR) is the relationship between bottomhole pressure and the flowrate. TPR is used to observe the connection between the total tubing pressure drop and a surface flowing pressure value as a function of flowrate, GOR (GLR), tubing ID, density, surface pressure, and average temperature.A well deliverability is mostly dependent of the pressure drop required to raise a fluid through the production tubing at a certain flowrate. The tubing pressure drop is the sum of the surface pressure, the hydrostatic pressure of the fluid, and the frictional pressure loss due to the flow.It can be calculated using Gilbert curves.Gilbert's approach to the vertical two phase flow problem was empirical:based on measured values of tubing -flow pressure losses,families of curves were derived that can be used for extrapolation and interpolation purposes.

3.4.4 EFFECT OF TUBING SIZE

Tubing size generally has an essential function in well production. Wells with larger tubing sizes have less pressure drops due to friction and lesser gas velocities than wells with smaller tubing sizes which have high pressure drops due to friction, but have higher gas velocities. Nodal analyses for oil and gas wells usually reveal that certain large size tubing (ID), well flowrate decreases. The indispensable notion of tubing design will be to install an adequate tubing diameter to allow less friction and have a high velocity.

3.5 ASSUMPTIONS AND CONSIDERATIONS

The present study is conducted with the following assumptions and considerations.

1. Well is vertical.

2. Reservoir drive is depletion type, i.e. oil and gas are produced by expansion in volume caused by reservoir pressure depletion.

3. static pressure at 5000 ft is 1850 psig

4. well depth is 5200 ft

5. depth of 7-in casing is 5050 ft

6. Wellbore skin is considered via the IPR equation, but is put equal to zero in this study.

7. We consider only naturally flowing oil well. However, the methodology can be extended to wells on artificial lift methods.

8. The design calculations for various sizes of tubing considered in this study do not include mechanical performance (e.g. tensile collapse, burst, and torsion failure). It is implicitly assumed that the selected tubing sizes satisfy the various mechanical performance requirements.

9. GLR is 0.4 mcf/bbl

10. 2-3/8 inch casing set at 5000 ft

3.6 INPUT DATA (Case Studies)

Well depth:5200 ft

7 inch casing:5050 ft

static pressure at 5000 ft :1850 psig

GLR :0.4 mcf/bbl

2-3/8 inch tubing set at:5000 ft

Pwf=1387 psig

no casing –tubing packer

the well is flowing at 250 bbls/day with CHP of 1245 psig,but the tubing is corroded and must be pulled and replaced.In addition to 2-3/8 inch ,1.9 inch and 3.5 inch tubing strings are available.maximum flow rate with minimum THP of 170 psig is desired.

3.7 RESULTS AND DISCUSSIONS

The Pwf values are determined by using the flow rate and the PI,and the equivalent depth of Pwf is taken from the pressure –distribution curveds,subtracting the tubing length (5000)from this figure gives the equivalent depth of THP , and reference of the distribution curves in theTHP values shown in the column.

3.7.1 SCENARIO 1:

1.9 inch tubing

q, bbl/day	p_{wf}, psi	Equiv. Depth of p_{wf}, ft	Equiv. Depth of THP, ft	THP, psi
1.9-in. tubing:				
50	1760	10,400	5400	740
100	1660	11,200	6200	780
200	1480	10,500	5500	650
400	1100	8,000	3000	360
600	740	5,300	300	30

Table 3.1 scenario 1 for 1.9 inch tube

3.7.2 SCENARIO 2:

q, bbl/day	p_{wf}, psi	Equiv. Depth of p_{wf}, ft	Equiv. Depth of THP, ft	THP, psi
2⅜-in. tubing:				
50	1760	8,900	3900	600
100	1660	9,500	4500	660
200	1480	9,600	4600	580
400	1100	7,500	2500	310
600	740	5,300	300	30

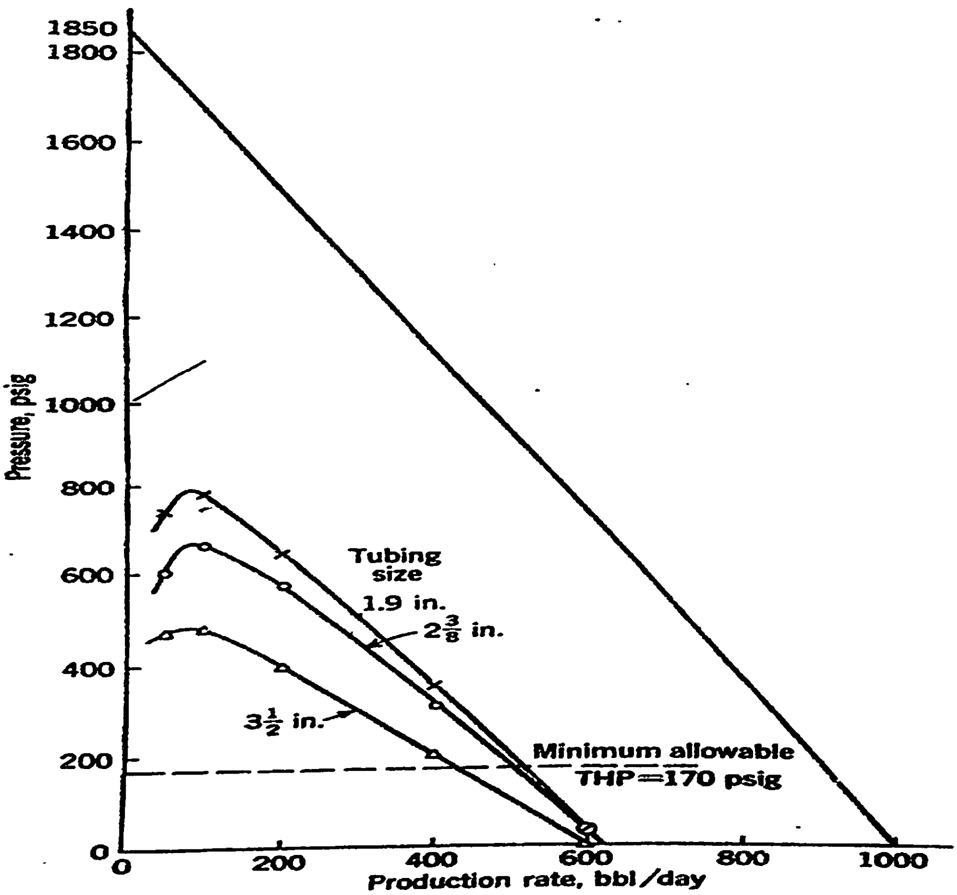
Table 3.2 scenario 2 for 2-3/8 inch tube

3.7.3 SCENARIO 3:

q, bbl/day	p_{wf}, psi	Equiv. Depth of p_{wf}, ft	Equiv. Depth of THP, ft	THP, psi
3½-in. tubing:				
50	1760	7,100	2100	470
100	1660	7,600	2600	480
200	1480	7,600	2600	400
400	1100	6,500	1500	200
600	740	5,000	0	0

Table 3.3 scenario 3 for 3.5 inch tube

Figure 3.2 Plotting of IPR and THP's for given tubing sizes.



3.8 RESULT AND CONCLUSION:

Values of q and theTHP , plotted in figure shows the flow rate against a THP of 170 psig as:

3.5 inch tubing- 430bbls/day

2-3/8 inch tubing- 500 bbls/day

1.9 inch tubing- 515 bbls/day

However , the curve for 2-3/8 inch tubing is nearly as good as that for 1.9 inch tubing , and 2-3/8 inch tubing is more convenient in a well because it has greater strength and the larger diameter allows a greater selection of tools to be run into the hole.thus in practice in a case like this, 2-3/8 inch tubing would probably be rerun into the hole.

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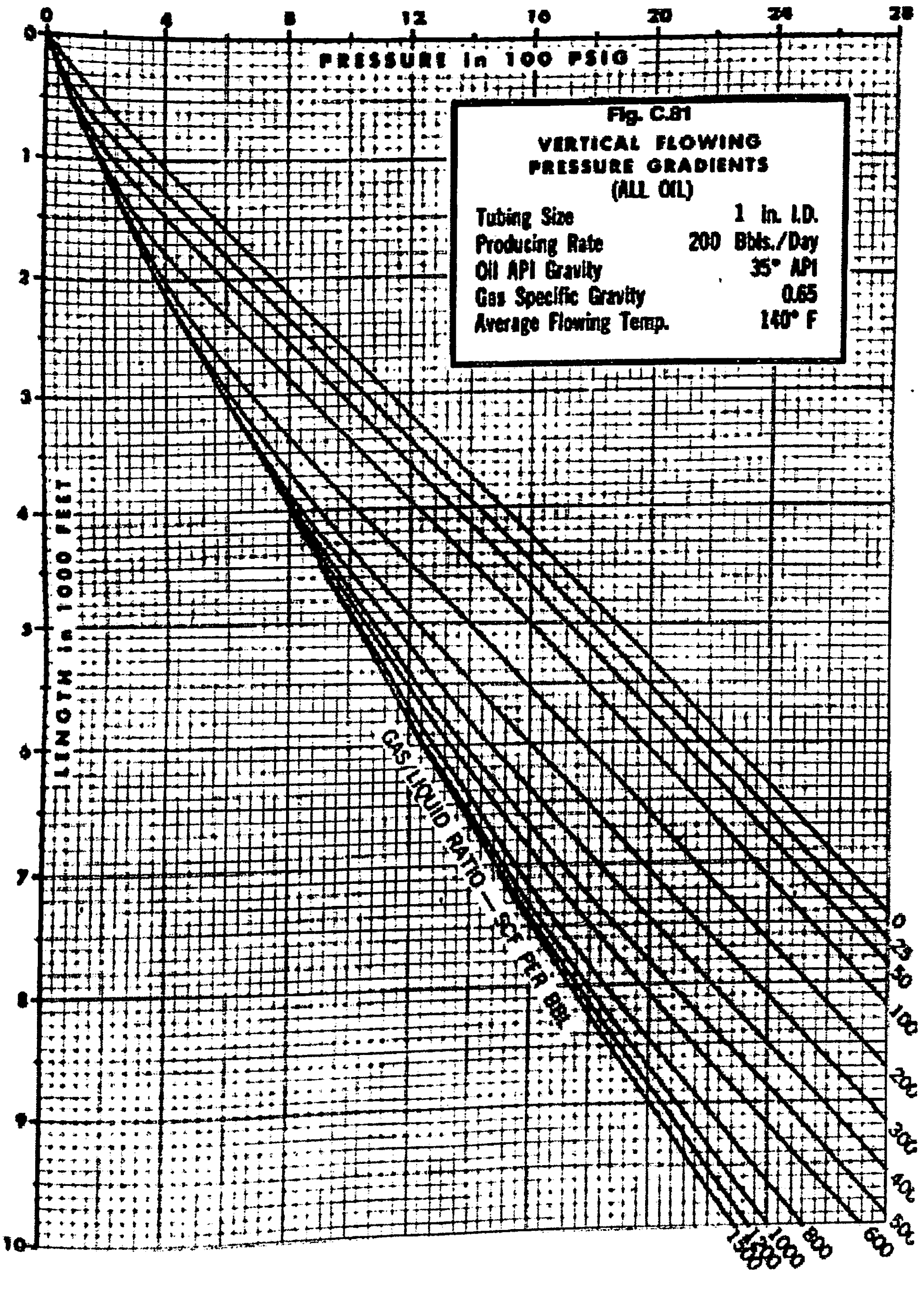
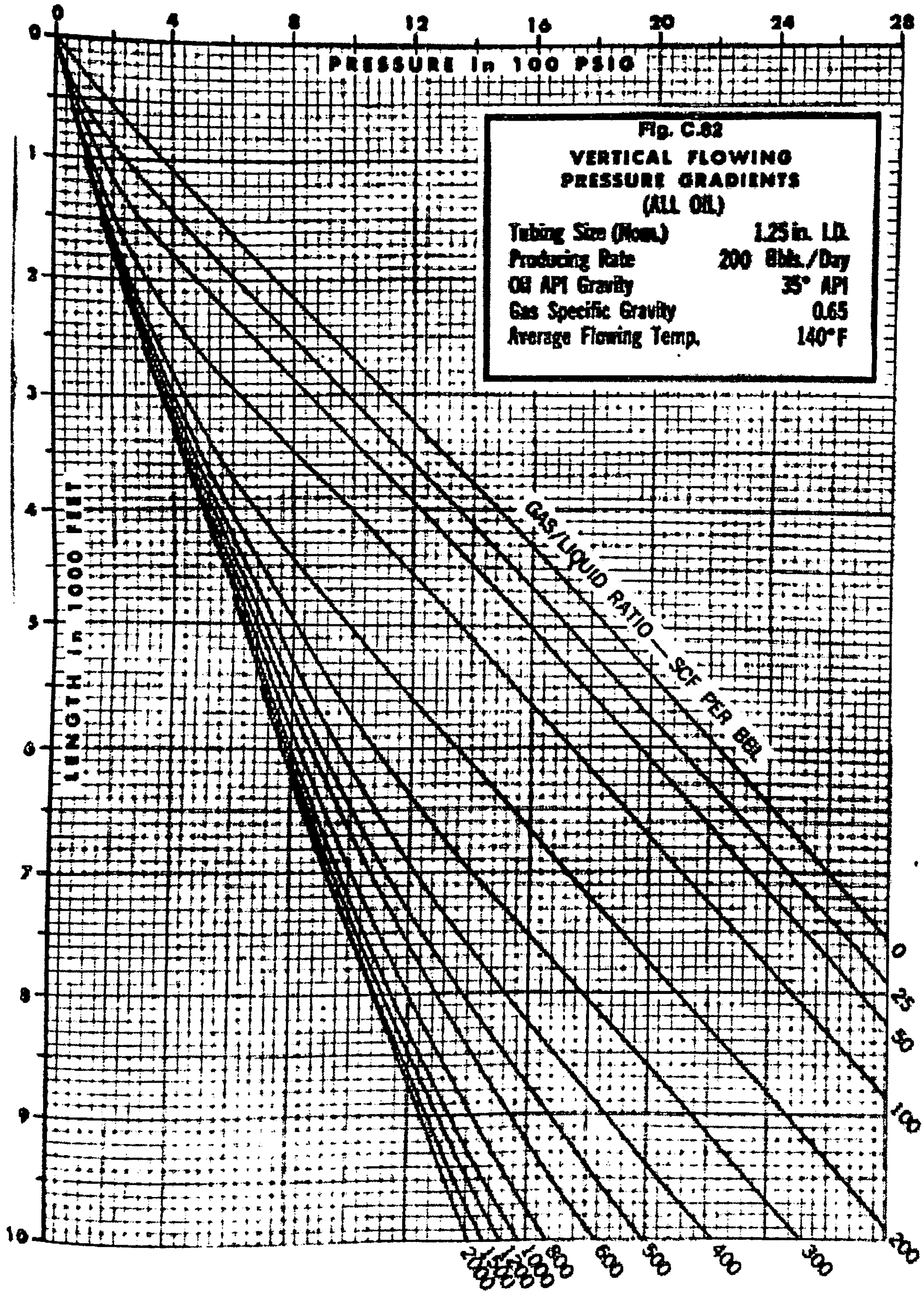
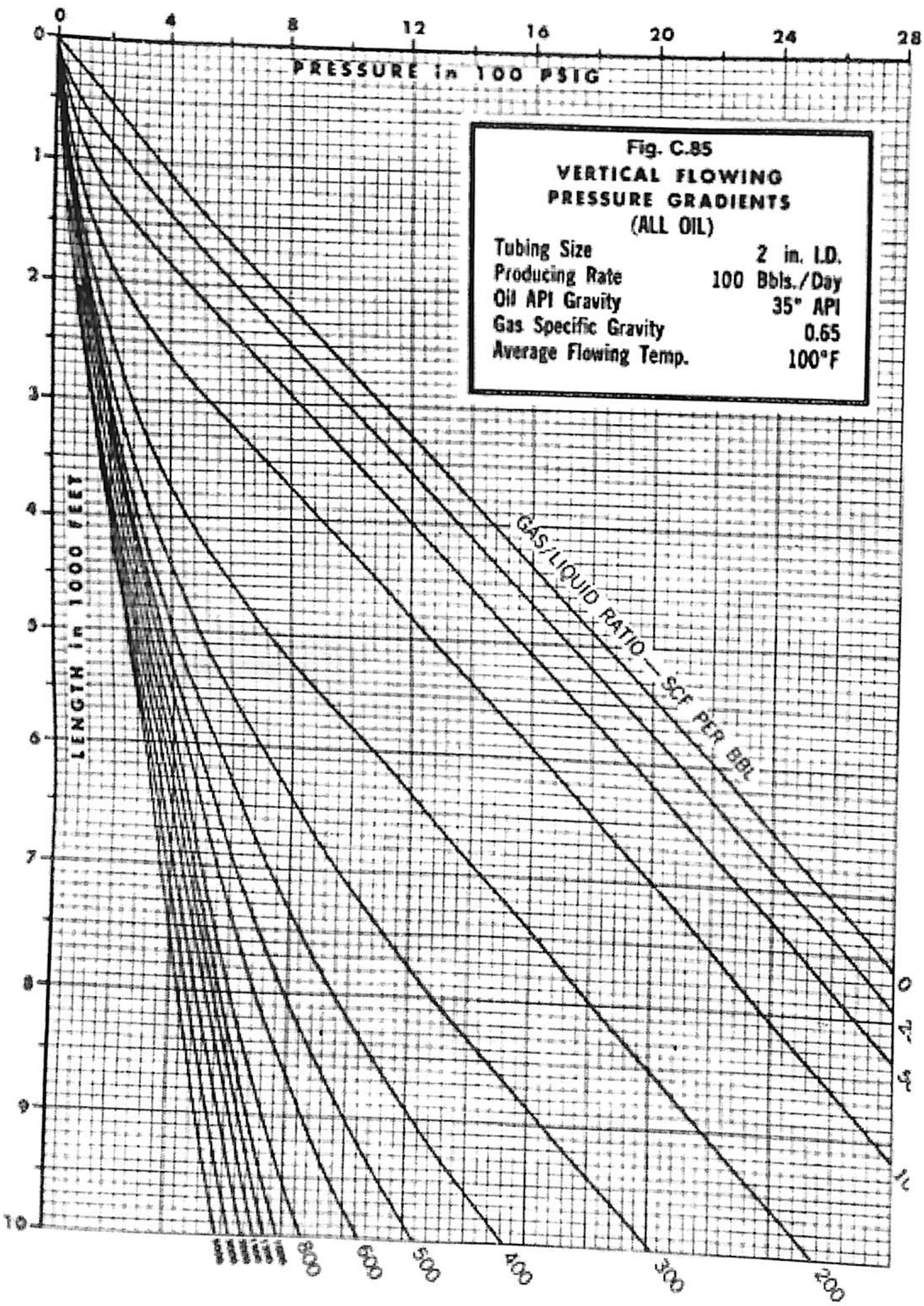
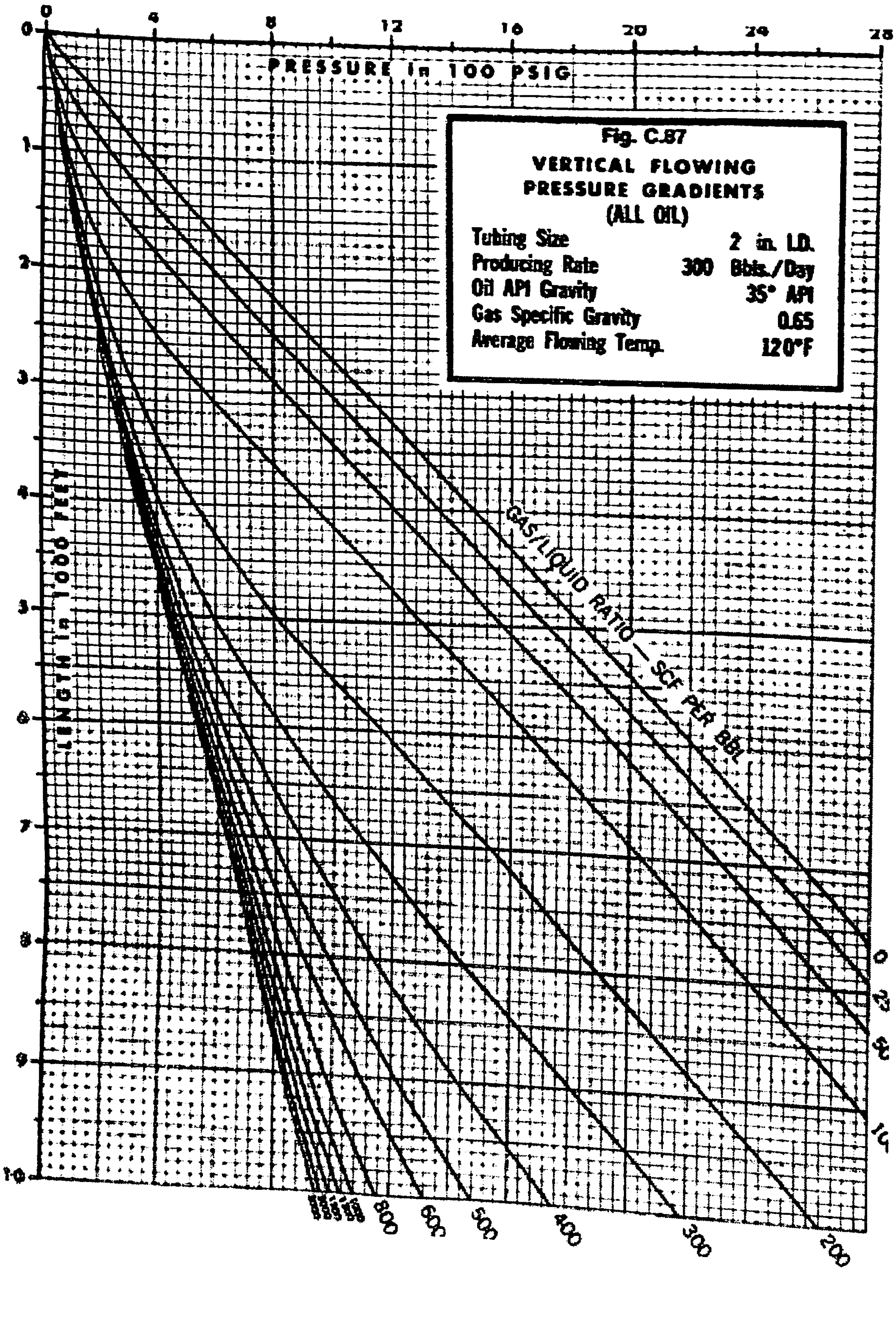
APPENDIX- Gilbert Curves.




PRESSURE in 100 PSIG
0
4
8
12
16
20
24
28
LENGTH in 1000 FEET
Fig. C.82
VERTICAL FLOWING
PRESSURE GRADIENTS
(ALL OIL)
Tubing Size (Nom.) 1.25 in. I.D.
Producing Rate 200 Bbls./Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 140°F
GAS/LIQUID RATIO — SCF PER BBL
0
25
50
100
200
300
400
500
600
800



PRESSURE in 100 PSIG
0
4
8
12
16
20
24
28
LENGTH in 1000 FEET
1
2
3
4
5
6
7
8
9
10
Fig. C.85
VERTICAL FLOWING PRESSURE GRADIENTS
(ALL OIL)
Tubing Size 2 in. I.D.
Producing Rate 100 Bbls./Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 100°F
GAS/LIQUID RATIO — SCF PER BBL
800
600
500
400
300
200



PRESSURE in 100 PSIG
0
4
8
12
16
20
24
28
LENGTH in 1000 FEET
0
1
2
3
4
5
6
7
8
9
10
Fig. C.87
VERTICAL FLOWING
PRESSURE GRADIENTS
(ALL OIL)
Tubing Size 2 in. I.D.
Producing Rate 300 Bbls./Day
Oil API Gravity 35° API
Gas Specific Gravity 0.65
Average Flowing Temp. 120°F
GAS/LIQUID RATIO — SCF PER BBL
0
25
50
800
600
500
400
300
200