

Introduction to Underbalanced Drilling

By:

Leading Edge Advantage
Old Stonewood Church
Bankhead Road
Bucksburn, Aberdeen
AB21 9HQ

Telephone 44-1224-716969

Fax 44-1224-712333

Email <mailto:eng@lealtd.com>

Website www.lealtd.com

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1 Introduction

This document is intended to provide an overview of current underbalanced drilling technology and is therefore by no means exhaustive. It should serve as a guide to current technology, explaining how and why underbalanced drilling is carried out.



2 *What is Underbalanced Drilling?*

When the effective circulating downhole pressure of the drilling fluid - which is equal to the hydrostatic pressure of the fluid column, plus pump pressure, plus associated friction pressures - is less than the effective near bore formation pore pressure. (Definition)

Conventionally, wells are drilled overbalanced, which provides the primary well control mechanism. Imposed wellbore pressure arises from three different mechanisms:

1. Hydrostatic pressure of materials in the wellbore due to the density of the fluid used (mud) and the density contribution of any drilled cuttings (passive).
2. Dynamic pressure from fluid movement due to circulating friction of the fluid used and the relative fluid motion caused by surge/swab of the drillpipe (dynamic).
3. Imposed pressure, with occurs due to the pipe being sealed at surface resulting in an area with pressure differential (e.g., a rotating head or stripper element) (confining or active).

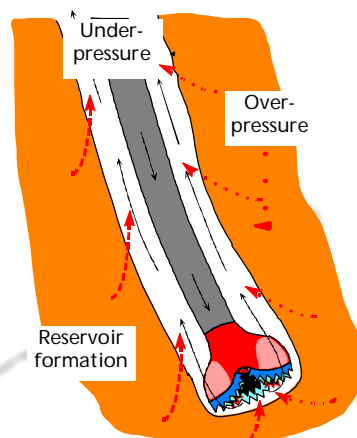
Underbalanced drilling is defined as drilling with the hydrostatic head of the drilling fluid intentionally designed to be lower than the pressure of the formations being drilled. The hydrostatic head of the fluid may naturally be less than the formation pressure or it can be induced. The induced state may be created by adding natural gas, nitrogen or air to the liquid phase of the drilling fluid. Whether the underbalanced status is induced or natural, the result may be an influx of formation fluids which must be circulated from the well and controlled at surface. Underbalanced drilling in practical terms will result in flow from one or more zones into the wellbore (this is more likely, however, to be solely from one zone as cross-flow is likely to result) or where the potential for flow exists.

The lower hydrostatic head avoids the build-up of filter cake on the formation as well as the invasion of mud and drilling solids into the formation. This helps to improve productivity of the reservoir and reduce related drilling problems.



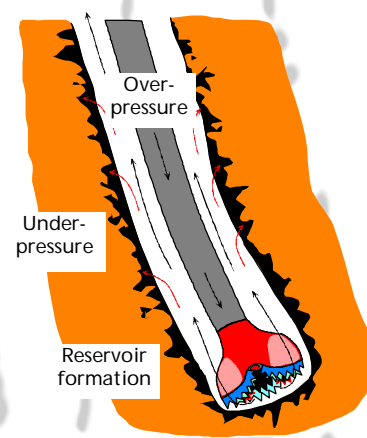
When comparing underbalanced drilling with conventional drilling it soon becomes apparent that an influx of formation fluids must be controlled to avoid well control problems. In underbalanced drilling, the fluids from the well are returned to a closed system at surface to control the well. With the well flowing, the BOP system is kept closed while drilling, whereas in comparison to conventional drilling fluids are returned to an open system with the well open to atmosphere.

Underbalanced Drilling



Drilling Fluid Returns to Closed Circulation system.

Conventional Drilling



Drilling Fluid Returns to Open Circulation system.

3 Objectives of Underbalanced Drilling

The objectives of underbalanced drilling can be broken down into two main categories:

- Maximising hydrocarbon recovery
- Minimising drilling problems

These categories illustrate underbalanced drilling operations are performed.

There are also specific advantages and disadvantages of performing a drilling operation underbalanced. These can be summarised as follows:

Advantages:

- Increased ROP
- Decreased formation damage
- Eliminate risk of differential sticking
- Reduce risk of loss circulation
- Less weight on bit required
- Improved bit life
- Tight hole problems may be reduced
- Reduced cutting size increasing hole cleaning capability

Disadvantages:

- Wellbore stability
- Wellbore consolidation
- Increased drilling costs (depending on system used)
- Compatibility with conventional MWD systems
- Spontaneous counter current imbibition effects
- Gravity drainage in horizontal wells
- Possible near wellbore mechanical damage
- Discontinuous underbalanced conditions
- Generally higher risk with more inherent problems
- String weight is increased due to reduced buoyancy
- Possible excessive borehole erosion
- Possible increased torque and drag

3.1 Maximising Hydrocarbon Recovery

The two main objectives of underbalanced drilling can be subdivided as follows:

Reduced formation damage.

No invasion of solids or mud filtrate into the reservoir formation.

Early production

Well is producing as soon as the reservoir is penetrated with a bit. This could be a disadvantage if hydrocarbon production cannot be handled or stored on site or if the required export lines are not available.

Reduced Stimulation

As there is no filtrate or solids invasion in an underbalanced drilled reservoir, the need for reservoir stimulation is eliminated. It has been noted in wells drilled underbalanced that stimulation with fluids significantly reduces the productivity of the reservoir. An acid wash carried out on an underbalanced drilled well, reduced productivity from 20MMscft/day to 2 MMscft/day. The full benefits of underbalanced drilling were never regained.

Enhanced recovery

Due to the increased productivity of an underbalanced drilled well combined with the ability to drill infill wells in depleted fields, the recovery of bypassed hydrocarbons is possible. This can significantly extend the life of a field. The improved productivity of the wells also leads to a lower drawdown, which can, in turn, reduce water coning.

3.2 Drilling Problems

Differential sticking.

The absence of an overburden on the formation combined with the lack of any filter cake serves to prevent the drillstring from becoming differentially stuck. This is especially useful when drilling with coiled tubing because of the lack of tooljoint connections. This increases the stand-off in the borehole.

No Losses

In general, a reduction of the hydrostatic pressure in the annulus reduces the fluid losses into a reservoir formation. In underbalanced drilling, the hydrostatic pressure is reduced to a level where losses do not occur.

Improved Penetration Rate

The lowering of the overpressure over the formation pressure has a significant effect on penetration rate. The reduction in the so-called chip hold down effect also has a positive impact on bit life. The increased penetration rate combined with the effective cuttings removal from the face of the bit leads to a significant increase in bit life. In underbalanced drilled wells, sections have been drilled with one bit where as in overbalanced drilled wells 3, 4 or even 5 bits were used.

Reduction of ECD in extended reach wells

The drilling of long horizontal or near horizontal sections creates more and more friction pressure in the annulus. This friction pressure acts on the bottom of the well and slowly increases the overpressure over the formation interval. This results in a reduction of ROP and increases the potential for losses. Underbalanced drilling provides an opportunity for a reduction in annular friction losses by allowing the reservoir energy to push fluids out of the hole.

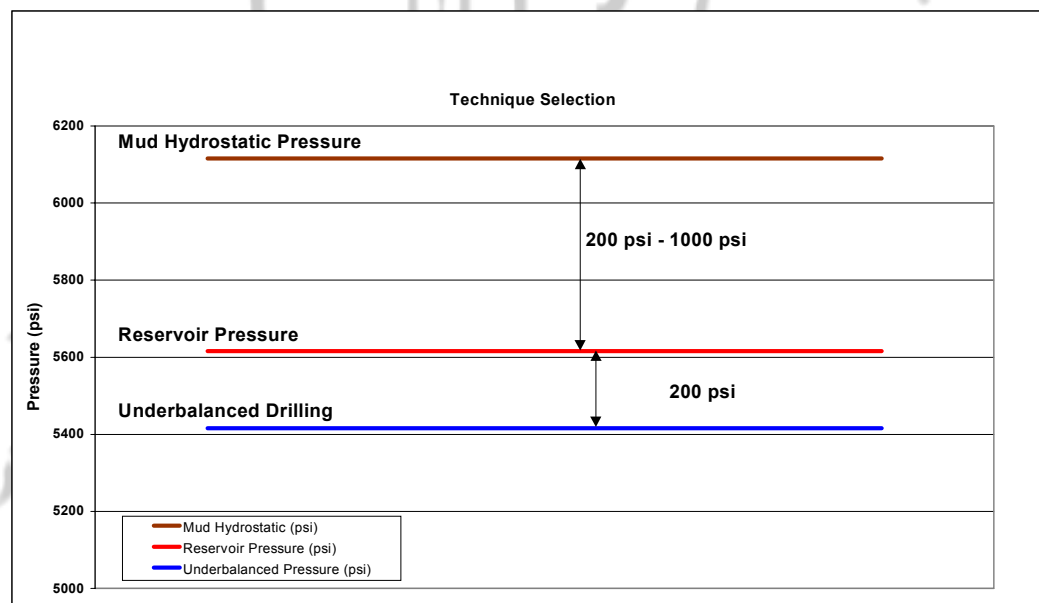
4 Technique Selection of Underbalanced Drilling

A basic four-step process can be applied to determine the options and requirements for a well to be drilled underbalanced:

1. Determine BHP requirements.
2. Identify the drilling fluid options.
3. Establish the well design and perform flow modelling.
4. Select the surface equipment.

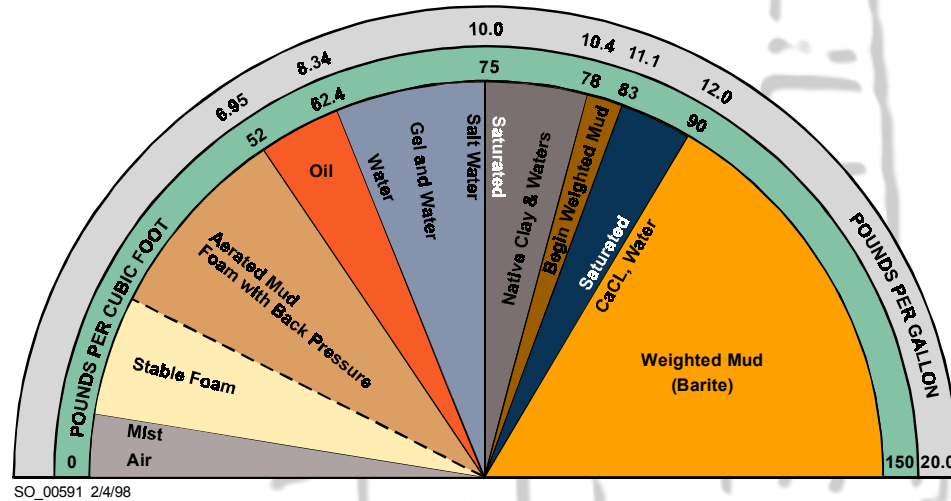
4.1 Bottom hole pressure requirements

In overbalanced drilling a mudweight is selected that provides a hydrostatic pressure of 200 to 1000 psi above the reservoir pressure. In underbalanced drilling we select a fluid that provides a hydrostatic pressure of around 100-200 psi below the initial reservoir pressure. This provides a starting point for the selection of a fluid system. In the feasibility study this was further refined, depending on the expected reservoir inflow, with a drawdown of 200 psi. A closer look at the drilling hydraulics may indicate that 200 psi drawdown is not sufficient and the well will be overbalanced when circulating. In this case, the circulation fluid may have to be further reviewed.



5 Drilling Fluid systems

Correct selection of the fluid system used in underbalanced drilling is the key to the successful outcome of an underbalanced drilling operation. We will therefore have a closer look at the fluid systems used in underbalanced drilling.



5.1 Gaseous & Compressible (two-phase) Fluids

Compressible fluid drilling is, in essence, a drilling technique in which the more common circulating fluids water or mud, are injected with or replaced by highly compressible gases. These gases perform most of the same functions as a drilling fluid, i.e., cool the bit and clean the hole.

Applicability of compressible fluid drilling is limited to a specific set of lithological and pore pressure conditions. It is also where significant savings of rig time and money can be achieved despite the need for additional equipment. Compressible fluid drilling includes: drilling with air, mist, foam stiff/stable and aerated mud.

5.1.1 Gaseous Fluids

These are basically the gas systems. In initial underbalanced drilling operations, air was used to drill. Today air drilling or dusting is still applied in hard rock drilling and in the drilling of water wells. The use of air in hydrocarbon bearing formations is not recommended as the combination of oxygen and natural gas may cause an explosive mixture. There have been a number of reported cases where downhole fires have destroyed drillstring with the obvious potential consequences of the rig burning down if the mixture gets to surface.

To avoid the use of air, nitrogen was introduced. The experience with nitrogen in well servicing operations made it a first choice for underbalanced drilling operations. The use of so-called cryogenic nitrogen or tanks of liquid nitrogen in drilling operations can be restricted. This depends on the logistical issues involved due to the large amount of nitrogen required for a drilling operation. Another option is to use natural gas, which, if available, has sometimes proved a worthy alternative in drilling operations. If a gas reservoir is being drilled underbalanced, a producing well or the export pipeline may well produce sufficient gas at the right pressure to drill. This avoids the introduction of oxygen into the well and, if available, may provide a cheap drilling system.

Characteristics of air-drilling:

- Fast penetration rates.
- Longer bit life.
- Greater footage per bit.
- Good cement jobs.
- Better production.
- Requires minimal water influx.
- Slugging can occur.
- Mud rings can occur in the presence of fluid ingress.
- Relies on annular velocity to remove cuttings from the well.

5.1.2 Mist Drilling

If gas systems are not suitable the addition of a small amount of liquid will initially form a mist system. The fluid added to the gas environment will disperse into fine droplets and form a mist system to drill with. In general this technique needs to be used in areas where some formation water exists which prevents the use of complete 'dry air' drilling.

Characteristics of mist-drilling:

- Similar to air drilling but with addition of liquid
- Relies on annular velocity to remove cuttings from the well
- Reduces formation of mud rings
- High volumes required (30%-40% more than dry air drilling)
- Pressures generally higher than dry air drilling
- Incorrect air/gas-liquid ratio leads to slugging, with attendant pressure increase

5.1.3 Foam drilling

If more liquid and a surfactant is added to the fluid, stable foam is generated. Stable foam used for drilling has a texture not unlike shaving foam. It is a particularly good drilling fluid with a high carrying capacity and a low density. One of the problems encountered with the conventional foam systems is that a stable foam is as it sounds. The foam remains stable even when it returns to the surface and this can cause problems on a rig if the foam cannot be broken down fast enough. In the old foam systems, the amount of defoamer had to be tested carefully so that the foam was broken down before any fluid left the separators. In closed circulation drilling systems stable foam could cause particular problems with carry over. The recently developed stable foam systems are simpler to break and the liquid can also be re-foamed so that less foaming agent is required and a closed circulation system can be used. These systems, in general, rely on either a chemical method, of breaking and making the foam or the utilisation of an increase and decrease of pH, to make and break the foam. The foam quality at surface used for drilling is normally between 80% and 95%.

The same amount, 80% to 95%, is gas with the remainder being liquid. Downhole, due to the hydrostatic pressure of the annular column, this ratio changes as the volume of gas is reduced. An average acceptable bottom-hole foam quality (FQ) is in the region of 50%-60%.

Characteristics of foam-drilling:

- Extra fluid in the system reduces the influence of formation water
- Very high carrying capacity
- Reduced pump rates due to improved cuttings transport
- Stable foam reduces slugging tendencies of the wellbore
- The stable foam can withstand limited circulation stoppages without affecting the cuttings removal or ECD to any significant degree
- Improved surface control and more stable downhole environment
- The breaking down of the foam at surface needs to be addressed at the design stage
- More increased surface equipment required

5.1.4 Gasified Systems

If a foam system is too light for the well, a gasified system can be used. In these systems, liquid is gasified to reduce the density. There are a number of methods that can be used to gasify a liquid system and these methods are discussed within the injection systems section. The use of gas and liquid, as a circulation system in a well, complicates the hydraulics programme. The ratio of gas and liquid must be carefully calculated to ensure that a stable circulation system is used. If too much gas is used, slugging will occur. If not enough gas is used, the required bottom hole pressure will be exceeded and the well will become overbalanced.

Characteristics of gasified-mud systems:

- Extra fluid in the system will almost eliminate the influence of formation fluid unless incompatibilities occur
- The mud properties can easily be identified prior to commencing the operation
- Generally, less gas is required
- Slugging of the gas and fluid must be managed correctly

- Increased surface equipment will be required to store & clean the base fluid
- Velocities, especially at surface, will be lower, reducing wear & erosion both downhole and to the surface equipment.

5.2 Single phase fluids

If possible, the first approach should normally be to use a fluid system with a density low enough to provide an underbalanced condition. If water can be used then this would be the first step to take. If water is too heavy, oil can be considered. However, it must be remembered that a well can be kicked off with a base oil system but, if the reservoir produces crude oil, the circulation system will become crude oil since base oil cannot be separated from the crude. Obviously pumping \$25 per barrel base oil and producing \$15 per barrel crude oil to drill a well underbalanced does not make economic sense. If a crude oil system is selected, the rig must be equipped to ensure that the crude can be degassed before it enters the enclosed pit system. On an offshore rig, a fully enclosed, vented and nitrogen blanketed pit system must be used to ensure that gas is not released from the crude.

The use of additives, such as glass beads has been attempted to lighten a fluid but since the glass beads come out over the shakers in the solids separation system or get crushed and damaged throughout the whole system, new beads need to be continuously added. The addition of glass beads is therefore, an expensive option and not very effective in lightening the fluid.

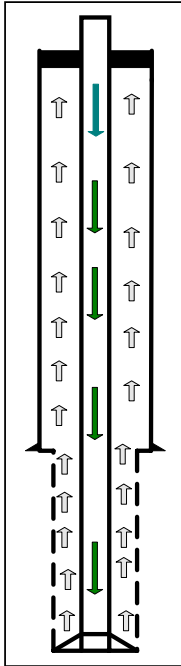
5.3 Gas lift systems

If a fluid needs to be reduced in density, the use of an injection of gas into the fluid flow could be an option. This offers a choice into not only the gas used but also in the way the gas is used in the well.

Normally, natural gas or nitrogen is used as a lift gas, but both CO₂ and O₂ can also be utilised. However, gasses containing oxygen are not recommended for two main reasons. The combination of oxygen and saline fluids with the high bottom hole temperatures can cause severe corrosion to tubulars used in the well and drillstring. Also, if during the drilling process, carbohydrates enter the borehole (expected in an underbalanced environment), then a potentially explosive situation could arise, resulting in a downhole fire.

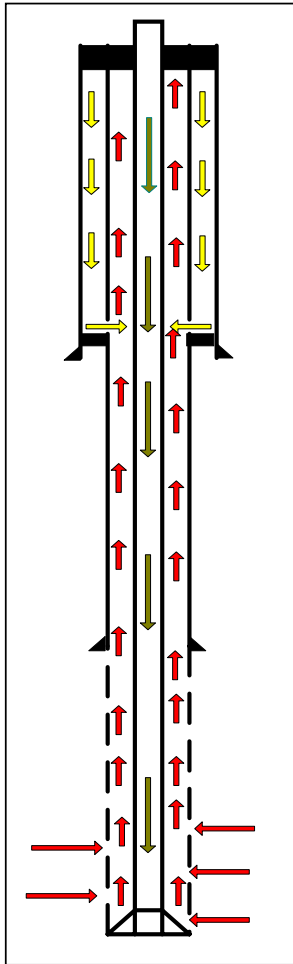
A number of injection methods are available to reduce the hydrostatic pressure and these are discussed overleaf.

5.3.1 Drillpipe injection



Compressed gas is injected at the standpipe manifold where it mixes with the drilling fluid. The main advantage of drillstring injection is that no special downhole equipment is required in the well. The use of reliable non-return valves is required to prevent flow up the drillpipe. The gas rates used when drilling with drillpipe injection system are normally lower than with annular gas lift. Low bottom hole pressures can be achieved using this system.

The disadvantages of this system include the need to stop pumping and the bleeding of any remaining trapped pressure in the drillstring every time a connection is made. This results in an increase in bottom hole pressure. It may then be difficult to obtain a stable system and avoid pressure spikes at the reservoir when using drillpipe injection. The use of pulse type MWD tools is only possible up to 20% gas by volume. If higher gas volumes are used, the pulse system deployed on MWD transmission systems will no longer work. Specialist MWD tools such as electro-magnetic may have to be used if high gas injection rates are required. However, these tools do not work very well offshore or if significant amounts of evaporites are drilled. One alternative is to connect the MWD back to surface using an electric cable. This technique has previously been used very successfully with coiled tubing as the drillstring. If drill pipe is to be used, wet connects can be utilised, however, the additional time consumed using this technique can be limiting. A further drawback for drillstring injection is the impregnation of the gas into any down hole rubber seals. Positive displacement motors (PDM's) are especially prone to fail when the rubber components get impregnated with the injection gas and then tripped back to surface. Once a trip is made, the rubber can explode or swell as a result of the expanding gas not being able to disperse out of the stator sufficiently quickly. This effect (explosive decompression) destroys not only the motors but also affects any rubber seals used downhole, resulting in a high turnover of motors. This can be very costly to the drilling operation. Special rubber compounds have been developed and the design of motors is changing to allow for this expansion. The majority of motor suppliers can now



provide PDM's specifically designed for use in this kind of downhole environment. But, if drillpipe injection is an option, the use of all metal turbines should be considered depending on the operational demands. Care must be taken at surface when breaking out the drilling assembly in case there is any high-pressure gas is trapped in the toolstring.

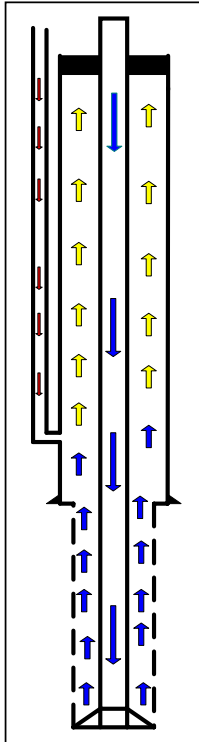
5.3.2 Annular injection

Annular injection through a concentric string is most commonly utilised offshore in the North Sea. This method is worthwhile if a suitable casing or completion tubing scheme is installed in the well. For a new drill well, a liner should be set just above the target formation. The liner is then tied back to surface using a modified tubing hanger to suspend the tie-back string. Gas is injected in the casing liner annulus to facilitate the drawdown required during the drilling operation. The tie back string is then pulled prior to installation of the final completion. The alternative is for an older well to have a completion in place incorporating gas lift mandrel pockets. These can be set-up to provide the correct bottom hole pressures

during the drilling operation.

The drawback with this type of operation is that the hole size and tools required are restricted by the minimum ID of the completion. However, the main advantage of using an annulus to introduce gas into the system, is that gas injection is continued during connections thus creating a more stable bottom hole pressure. As the gas is injected, via the annulus, only a single-phase fluid is pumped down the drillstring. This has the advantage that conventional MWD tools operate in their preferred environment, which can have a positive affect on the operational cost of a project. However, the drawbacks of this system, are that a suitable casing/completion scheme must be available and that the injection point must be low enough to obtain the required underbalanced conditions. There may also be some modifications required to the wellhead for the installation of the tie-back string and the gas injection system.

5.4 Parasite string injection



The use of a small parasite string strapped to the outside of the casing for gas injection is really only used in vertical wells. For safety reasons, two 1" or 2" coiled tubing strings are strapped to the casing string above the reservoir as the casing is run in. Gas is pumped down the parasite string and injected onto the drilling annulus. The installation of a production casing string and the running of the two parasite string makes this a complicated operation. Wellhead adaptation is required to provide surface connections to the parasite strings. This system cannot be used in deviated wells as the parasite string is ripped off with the casing on the low side of the hole. However, the principles of operation and the advantages of the system remain the same as above.

6 Reservoir studies

Prior to an underbalanced drilling operation being undertaken, a significant amount of work needs to be carried out on the reservoir. Not only is an accurate reservoir pressure needed but the damage mechanism of the reservoir must be understood to ensure that the required benefits are indeed possible. Some wells or reservoirs are suitable for underbalanced operations and result in an enhanced recovery. Other formations or fields may not be viable for a variety of other reasons. A summary of those reservoirs that will benefit from underbalanced drilling include:

- Formations that usually suffer major formation damage during drilling or completion operations
- Formations that usually exhibit high trends for differential sticking and lost pipe
- Formations that exhibit regions of high loss circulation or fluid invasion during drilling or completing
- Wells with large macroscopic fractures
- Wells with massive heterogeneous or highly laminated formations that exhibiting differing permeability's, porosities or pore throats throughout
- High production reservoirs with medium-high permeability
- Formations with rock-fluid sensitivities
- Formations with fluid-fluid sensitivities
- Formations generally exhibiting very low ROP's with overbalanced drilling

Reservoirs generally not benefiting from underbalanced drilling include:

- Wells in an area of very low cost conventional drilling
- Extremely low permeability wells
- Poorly consolidated formations
- Wells with a low borehole stability
- Wells with loosely cemented laminar boundaries
- Wells containing multiple zones of different pressures

Coreflush testing will be required to establish compatibility between the proposed drilling fluid and the produced reservoir fluids. This is critical if oil reservoirs are drilled underbalanced. The potential for scale and emulsion forming needs to be reviewed before drilling operations start. The stability and UCS of the zone of interest need to be ascertained to determine if the proposed well path is structurally capable of being drilled with the anticipated formation drawdown.

Expected productivity with the proposed drawdown must be reviewed. The objective of underbalanced drilling is to clean the reservoir and not to produce the well to its maximum capacity. If the reservoir is likely to produce any water this must be taken into account as water influx can have significant effects on the underbalanced process. It is important that expected productivity is analysed with the reservoir engineers, to obtain an accurate indicator as to whether underbalanced drilling would be of benefit.

When the reservoir issues are understood, it is proven that it would be advantageous to drill the well underbalanced, and that the proposed well profile would be also be sufficiently stable, the surface equipment can be selected.

7 Surface Equipment For UBD Operations

The surface equipment for underbalanced drilling can be broken down into four main categories. These are:

- Drilling system
- Gas Generation Equipment
- Well Control Equipment
- Surface Separation Equipment

If the platform process or export equipment is used when drilling underbalanced then this is considered a separate issue and therefore is not included in this document.

7.1 Drilling System

Hole size and reservoir penetration as well as directional trajectory will determine whether coiled tubing or jointed pipe is the optimal drillstring medium. If the hole size required is larger than 6-1/8", jointed pipe may have to be used. For hole sizes of 6-1/8" or smaller coiled tubing can be considered. The size of coiled tubing currently used for drilling operations is between 2" & 2-7/8" OD. This is due to many factors including the flow rate through the coil, pressure drop through the tubing, WOB, profile of the well, maximum pick-up weight, both in hole and the surface equipment and weight of the coiled tubing itself. Occasionally the ideal coiled tubing for an operation may be excluded due to such factors as crane or transport limitations or that the life of the coil may not be feasibly economical.

Generally, coiled tubing has several advantages and disadvantages over jointed pipe systems. For jointed pipe systems, drill string properties and tripping under pressure will need to be considered. The installation of a snubbing system on a platform or rig with a fixed distance between rotary table and wellhead may cause severe problems. Several previous operations on land rigs had to be re-designed to accommodate rig assist snubbing systems.

7.1.1 Coiled Tubing V Jointed Pipe?

Coiled Tubing	Jointed Pipe
No connections made during drilling	Connections require gas injection shut down causing pressure peaks.
Higher pressure containment	Pressure of Rotating Diverters limited to 3000 psi.
Stiff Wireline makes MWD systems simpler in gasified fluids	MWD systems unreliable in gasified systems
No snubbing system required	Pressure deployment requires snubbing unit
Maximum hole size 6"	No hole size limit
Hole cleaning more critical	Hole cleaning can be assisted by rotation
Potential for pipe collapse in high pressure wells	Special drillstring connections required for gas fields
Thru tubing drilling work possible	Thru tubing work requires special rig floor tools on conventional rigs
BOP stack smaller	BOP stackup requires rotating diverter system.
Lower costs	Higher costs as a result of rig.
Limited with drag for outreach	Ability to drill long horizontal sections

7.2 Gas generation Equipment

7.2.1 Natural Gas

If natural gas is used for underbalanced drilling, a natural gas compressor may be required; this would need to be reviewed once the source of the gas is known. Most production platforms have a source of high pressure gas. A flow regulator and a pressure regulator would be required to control the amount of gas injected during the drilling process.

7.2.2 Cryogenic Nitrogen

The use of tanked nitrogen could be considered on onshore locations where a large truck could be used for its supply. Cryogenic nitrogen in 2000 gallon transport tanks provides high quality nitrogen and utilises equipment that is generally less expensive. Liquid nitrogen is passed through the nitrogen converter, where the fluid is pumped under pressure prior to being converted to gas. The gas is then injected into the string. Generally, the requirement is for the nitrogen converter and a work tank with additional tanks being provided as

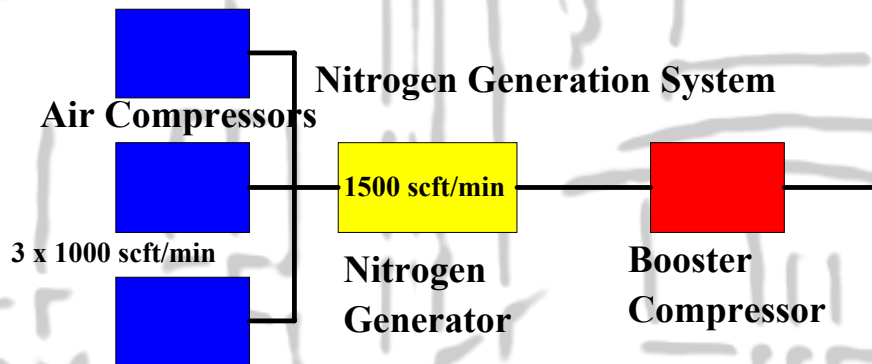
necessary. For operations in excess of 48 hrs, the requirement for liquid nitrogen could be quite large, and this can result in logistical difficulties.

The use of cryogenic nitrogen offshore is sometimes not recommended, this would depend on the application. Pumping 1500 scft/min of nitrogen for a 24hr drilling period requires 15 tanks of 2000 gal each. Moving this on and off an offshore platform is a significant task and therefore could present some serious safety implications. If drilling is ongoing at this rate for several days, then two dedicated supply boats would be required to maintain supply.

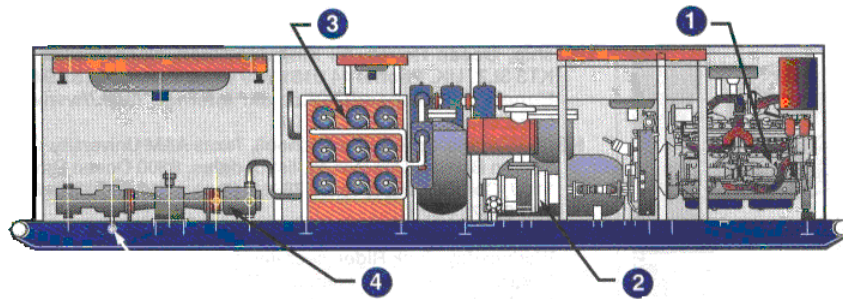
In order to move away from tank transport for large nitrogen dependant drilling operations, the use of nitrogen generators is often recommended offshore.

7.2.3 Nitrogen Generation

A nitrogen generator is no more than a filtering system that filters nitrogen out of the atmosphere. A nitrogen generator uses small membranes to filter the air. Oxygen enriched air is vented to the atmosphere and nitrogen is boosted to the required injection pressure.



A nitrogen generator is 50% efficient. In real terms, if 1500 scft/min of nitrogen is required, then 3000 scft/min of air needs to be pumped into the generator. A fill nitrogen system for 1500 scft/min would comprise of three or four large air compressors, a nitrogen generator and a booster compressor. This equipment will take up significant deck space on an offshore rig or platform. Improved systems are now entering the market and a nitrogen generation package in a 40ft ISO container is now available from several service suppliers.



Another issue associated with nitrogen generation is the purity of the nitrogen itself. Depending on the amount of nitrogen required, the purity will vary. At 95% purity, 5% oxygen will be delivered. Although this is not enough oxygen to reach explosion levels, it is sufficient oxygen to cause significant corrosion problems. The corrosion is further worsened when salt brine systems are used at elevated temperatures.

7.3 Well Control equipment

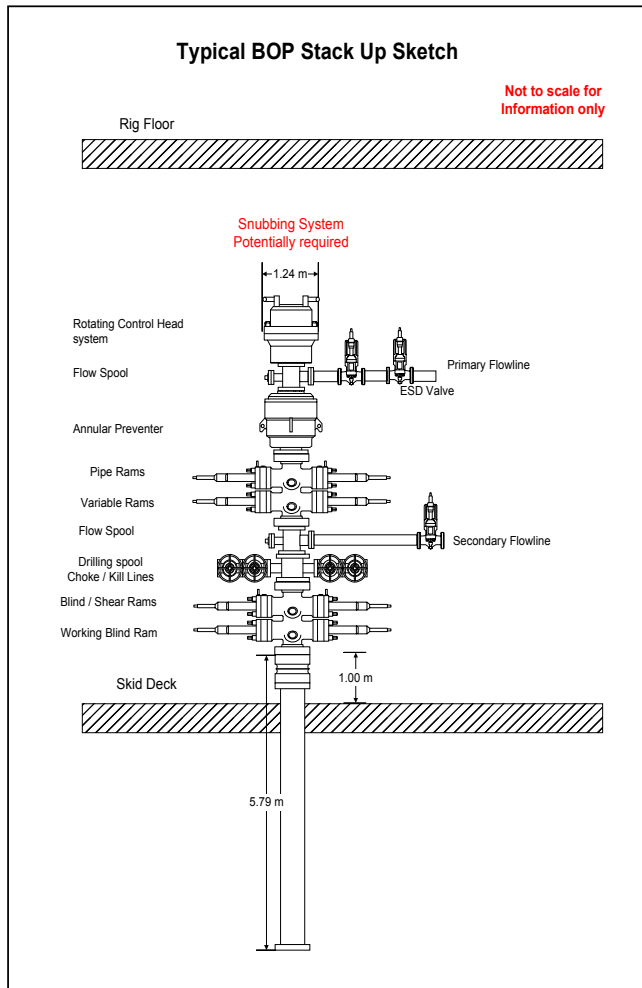
7.3.1 Jointed Pipe systems

The conventional BOP stack used for drilling is not compromised during

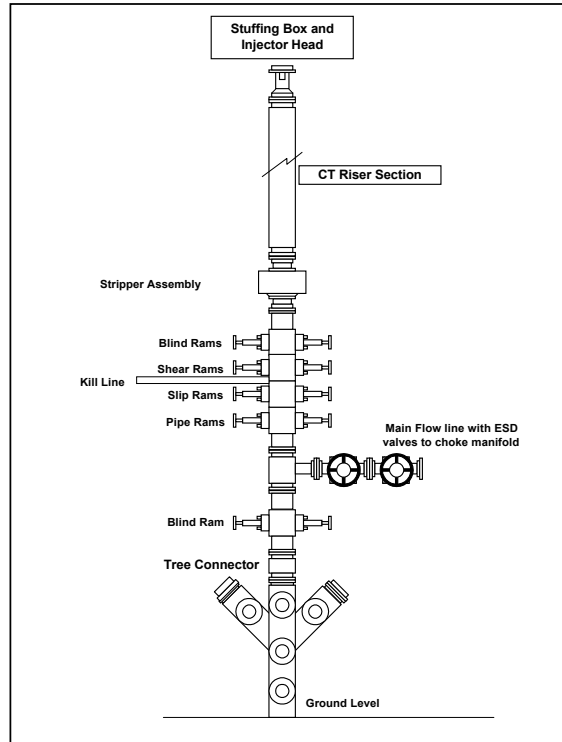
underbalanced drilling operations.

The conventional BOP stack is not used for routine operations and will not be used to control the well except in case of emergency.

A rotating control head system and primary flowline with ESD valves is installed on top of the conventional BOP. If required, a single blind ram, operated by a special kooomey unit is installed under the BOP stack to allow the drilling BHA to be run under pressure.



7.3.2 Coiled Tubing Systems



Well control is much simpler when drilling with reeled systems. A lubricator can be used to stage in the main components of the BHA or if a suitable downhole safety valve can be used then a surface lubricator is not required. The injector head can then be placed directly on top of the wellhead system.

The reeled systems can then be tripped much faster and the rig up is therefore much simpler. However, one consideration relating to reeled systems is the cutting strength of the shear rams. Verification is required in order to ascertain that the shear rams will cut the tubing and any wireline or control line systems inside the coil. For a stand-alone operation on a completed well an example stack up is shown above.

7.4 Snubbing system

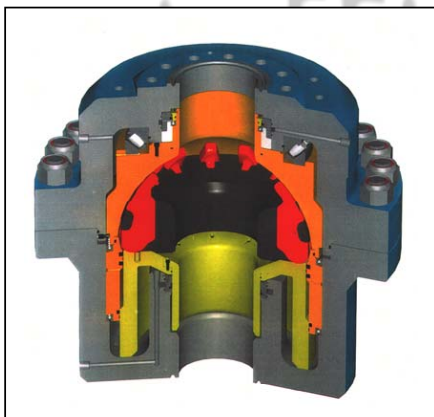
If tripping is to be conducted underbalanced, a snubbing system will be installed on top of the rotating control head system. The current systems used



offshore are called rig assist snubbing systems. A jack with a 10ft stroke is used to push pipe into the hole or to trip pipe out of the hole. Once the weight of the string exceeds the upward force of the well, the snubbing system is switched to standby and the pipe is tripped in the hole using the draw works. The ability to install a snubbing system below the rig floor allows the rig floor to be used in the conventional drilling way.

The snubbing system is a so called rig assist unit. This unit needs the rig draw works to pull and run pipe. It is designed to deal only with pipe light situations.

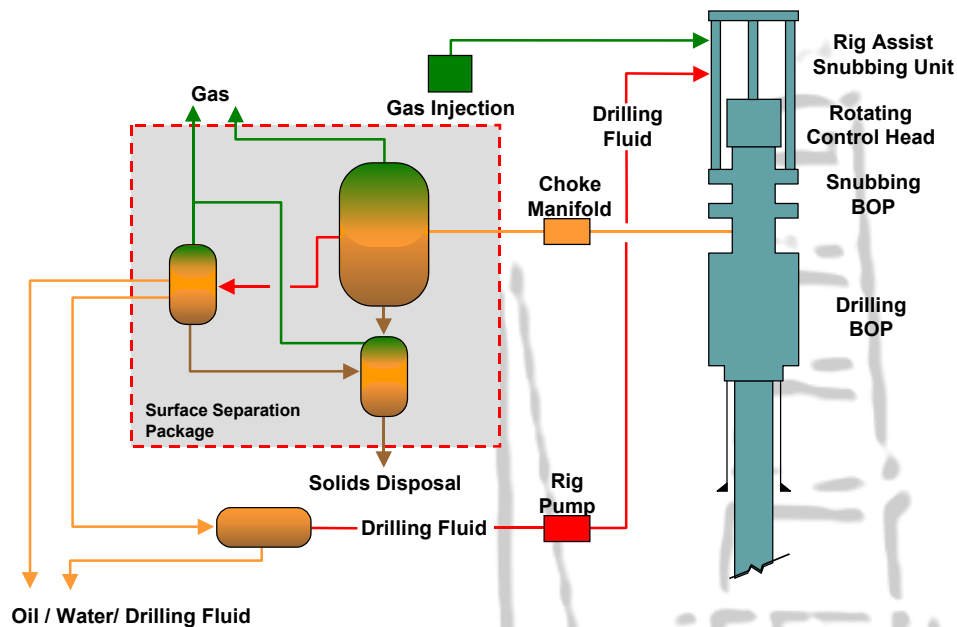
7.5 Rotating Control Head System



The rotating control head system will need to be sized and selected on the basis of the expected surface pressures. A well with a reservoir pressure of 1000psi does not need a 5000psi rotating control head system. A number of companies offer rotating control head systems for underbalanced drilling.

The ESD system on an underbalanced drilling operation closes in the well at the main flowline and shuts down fluid pumps and gas lift systems. The ESD system can be remotely operated from a number of locations on the rig when drilling underbalanced.

7.6 Separation Equipment



The separation system has to be tailored to the expected reservoir fluids. A separator for a dry gas field is significantly different from a separator required for a heavy oil field. The separation system must be designed to handle the expected influx and it must be able to separate the drilling fluid from the return well flow in order that this can be pumped down the well once again.

A number of approaches in separation technology have emerged recently, these include:

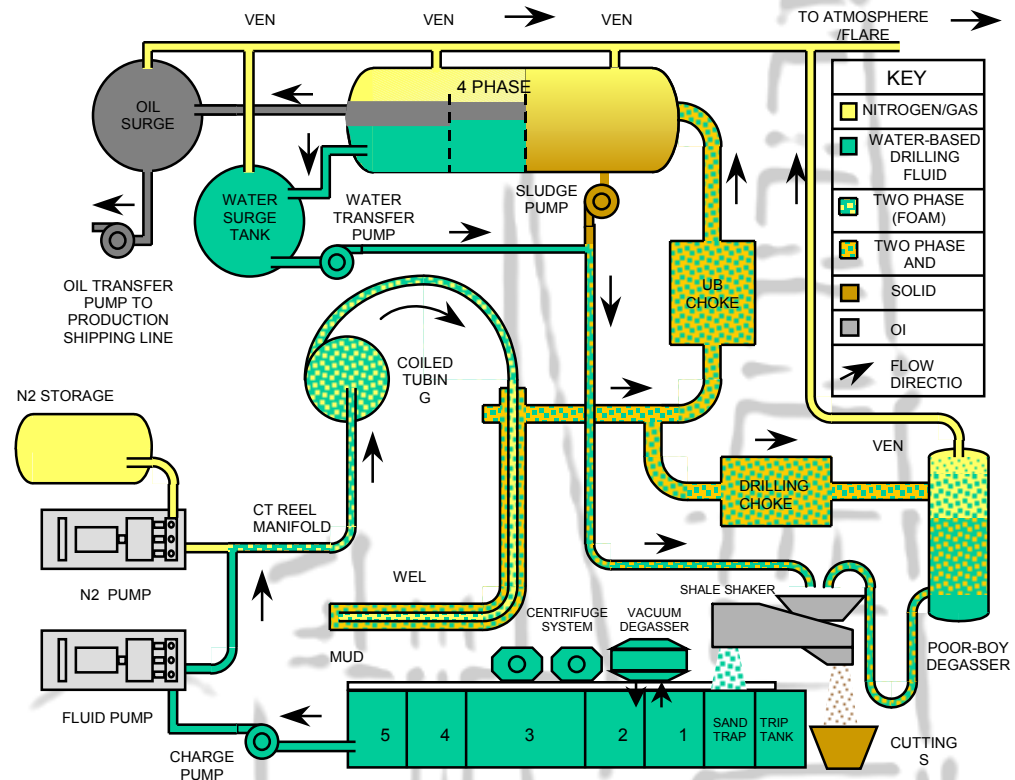
- To first separate the gas and then deal with fluids and cuttings
- To separate solids minimising erosion and next deal with the gas

The approach taken is largely dependent on the expected reservoir fluids. It must be recognised that separation technology for underbalanced drilling may represent as many as 5 or 6 phases.

- Drilling Fluid
- Cuttings
- Gas
- Oil
- Condensate

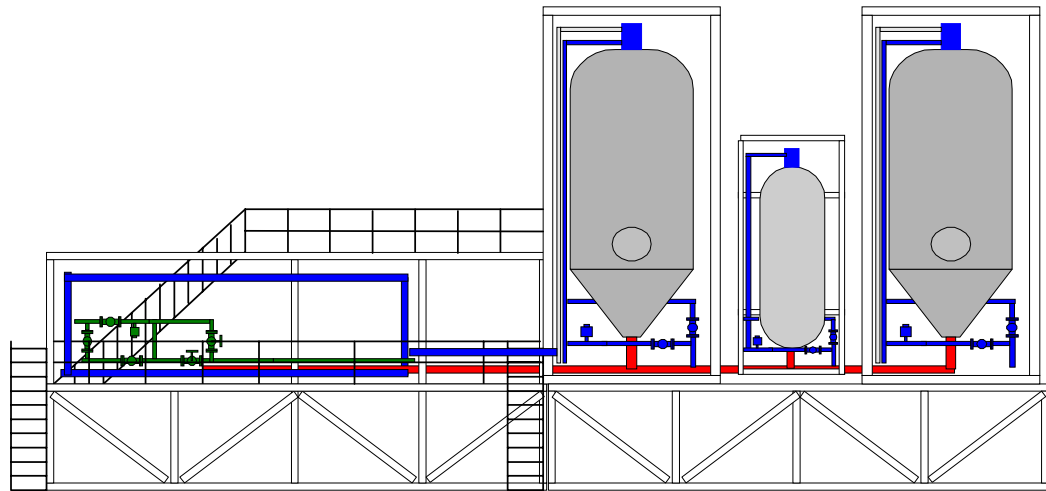
- Nitrogen

An example of a 4-phase separation system is shown below:



Careful design of the surface separation system is required once the reservoir fluids are known. Dry gas is much simpler to separate than a heavy crude or a gas condensate reservoir. However, the separation system must be tailored to reservoir and surface requirements. This requires a high degree of flexibility and the use of a modular system helps to maintain such flexibility.

The use of a modular system for offshore operations is often recommended, because lifting capacity of platform and rig cranes is regularly limited to 15 or 20 Tons. To reduce the total footprint of a separation package, vertical separators are generally used offshore as opposed to the horizontal separators used in onshore operations.



Example of a Modular Vertical Tank Separator System

7.6.1 Data acquisition

The data acquisition used on the separation system should provide as much information as possible. This allows the maximum amount of information to be obtained from the reservoir while drilling. It will also allow for a degree of well testing during drilling. However, the safety aspect of data acquisition should not be overlooked as well control is directly related to the pressures and flowrates seen at surface.

7.6.2 Erosion monitoring

Erosion monitoring and prediction of erosion on pipe work is essential for safe operations. The use of NDT technology has been found to be insufficient in erosion monitoring. An automated system using erosion probes is currently deployed and this allows accurate prediction of erosion rates in surface pipe work.

The flow velocity limits applied by the industry to control erosion are defined in the API recommended practice RP14. One drawback, however, of these guidelines is that the amount of solids in production operations is significantly lower than in underbalanced drilling operations. The use of erosion probes has also now allowed prediction of hole cleaning and borehole collapse. As more

data becomes available, the behaviour of solids in UBD wells is better understood and managed. Erosion in surface pipe work is still a problem in high rate wells and it is a significant cost of the operation. In general, target 'T's should be used wherever necessary and these should include a method of quickly releasing them for inspection and change-out purposes.

7.7 The circulation Process

Fluids from the reservoir flow up the wellbore to the surface. The rotating diverter system ensures that the well remains closed. The fluid exits the well through the main flow-line; into a well test choke manifold where the chokes are normally open. Varying the lift gas rate or the liquid rate controls the well. From the choke manifold, the flow enters the first stage separator where gas is taken off and the solids are extracted from the fluid flow through a vortex system. The overflow of the first stage separator enters the second stage separator where the fluid is further degassed and any remaining solids are taken out. Drilling fluid is send back to the mud pits. Produced oil is sent to a stock tank or to the production train. The drilling fluid is then pumped back down to the well to start the cycle again.

It is currently normal practice to have a first and second stage separator offshore. This is mainly to ensure that drilling fluid is degassed before it is send back to the pit system inside the rig. If a gas condensate field is drilled, a third vessel is often required to ensure that condensate is separated. Further advances in separation technology are ongoing to ensure that surface separation packages are smaller and become more automated.

8 *Completing underbalanced drilled wells*

The majority of wells previously drilled Underbalanced could not be completed underbalanced. The wells were displaced to an overbalanced kill fluid prior to running the liner or completion. Depending on the completion fluid type, some formation would take place. The damage is not as severe for completion brine as with drilling mud due to the removal of the drilled cuttings and fines. However, reductions in productivity of 20 to 50% have been encountered in underbalanced drilled wells killed for the installation of the completion.

If the purpose of underbalanced drilling is for reservoir improvement, it is important that the reservoir is never exposed to overbalanced pressure with a non-reservoir fluid. If the well has been drilled underbalanced for drilling problems, and productivity improvement is not impaired, then the well can be killed and a conventional completion approach can be taken.

A number of completion methods are available for underbalanced drilled wells:

- Liner and perforation
- Slotted liner
- Sandscreens
- Barefoot

All of the above options can be deployed in underbalanced drilled wells. The use of cemented liners in an underbalanced drilled well is not recommended if the gains in reservoir productivity are to be maintained. Irrespective of the liner type run, the installation process for the completion is exactly the same. It is assumed that a packer type completion is installed. The production packer and tailpipe are normally run and set on drill pipe with an isolation plug installed in the tailpipe. If the well is maintained underbalanced, well pressure will normally require the production packer and tailpipe to be snubbed into the well against well pressure. The use of pressure-operated equipment in underbalanced drilled wells is not recommended. A mechanically set production packer should be used.

8.1 Snubbing

With well pressure acting upwards on the completion, the weight of the assembly will be less than the upward force. This means that a snubbing system is required to get the packer assembly in the hole. In an underbalanced drilling system the well can be allowed to flow via the surface separation package. This is an advantage over conventional snubbing operations as the surface pressure of a flowing well is normally lower than shut in pressure.

At no time during the snubbing operations should the conventional well control BOP stack be compromised. Special snubbing BOP's and a rotating diverter must be used in addition to the conventional drilling BOP's.

8.2 Installation of a Solid Liner

Using solid pipe for the liner is no different than snubbing in drillpipe or tubing. The shoe track of the liner must be equipped with non return valves to prevent flow up the inside of the pipe. The liner is normally run with a liner packer and the liner can be snubbed into the live well. Once on bottom, the liner hanger and packer are set and the reservoir is now sealed. If zonal isolation is required, ECP's must be run at pre-determined intervals. Once the liner is set, the pipe must be perforated to obtain flow. This can be achieved using the normal procedures but it should be remembered that any fluid used must maintain the underbalanced status.

8.3 Installation of a perforated liner or sandscreen(s)

The main disadvantage of running a slotted liner or sandscreens in an underbalanced drilled well is that isolation is not possible across the slotted section of the liner or screen with the BOP's.

The use of plugged slots that dissolve once the liner is installed downhole is not deemed safe for offshore operations. The pressure integrity of each slot would have to be tested prior to running each joint and this is not feasible.

The use of special blanking pipe in sandscreen also adds further complications to the installation procedures. Running a slotted pipe or screen into a live well cannot be done safely, even if all the holes are plugged the potential for a leak is too great. The only way to install a slotted liner in a live well is by using the well as a long lubricator and by isolating the reservoir downhole.

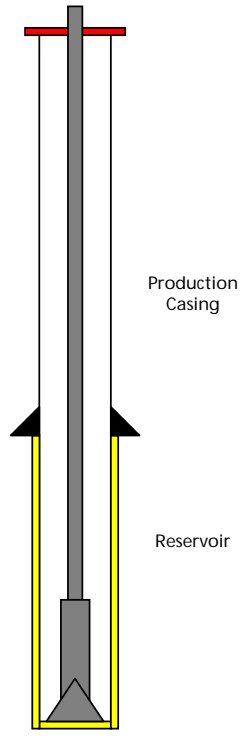
There are very few mechanical methods of downhole isolation available for the running of a slotted liner. The Baker “Underbalanced Liner Bridge Plug (ULBP) system” is one of the few systems currently on the market. This system allows a retrievable plug to be set in the last casing. This isolation plug is released by a retrieving tool which is attached the bottom of the slotted liner. This retrieving tool unseats the isolation plug and then swallows the isolation plug or packer. The swallowing action of the retrieval tool ensures that the plug and retrieving tool are rigid and can be run to TD without hanging up in the open hole. Both the packer and retrieval tool are specifically designed to be released by the liner.

If necessary, the well can be lubricated to kill fluid on top of the plug and displaced via the slotted liner when the drill string is sealed by the rotating diverter.

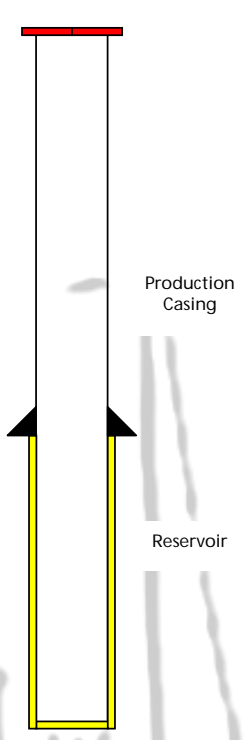
The complete procedure for running of a slotted liner and the completion in an underbalanced drilled well is outlined in the following 12 diagrams.



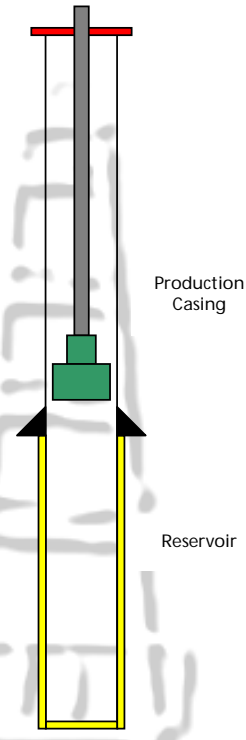
Step 1
Drilling
Completed



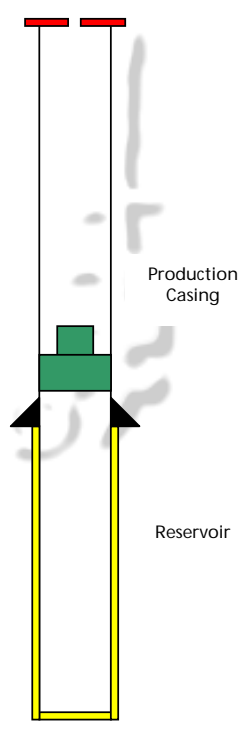
Step 2
Out of the
Hole



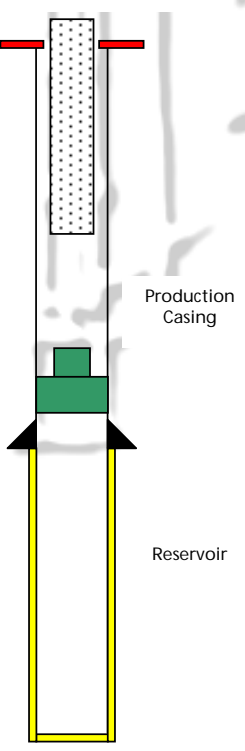
Step 3
Run Underbalanced
Liner Bridge Plug



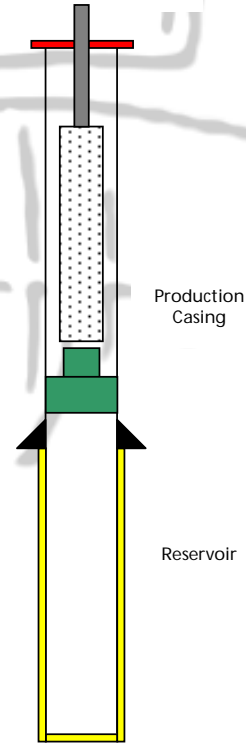
Step 4
Underbalanced Liner
Bridge Plug Set



Step 5
Run Slotted Liner

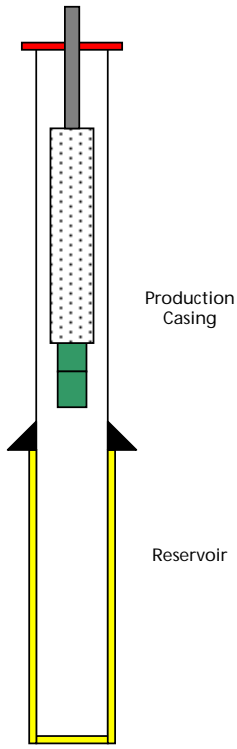


Step 6
Trip in with
Slotted Liner

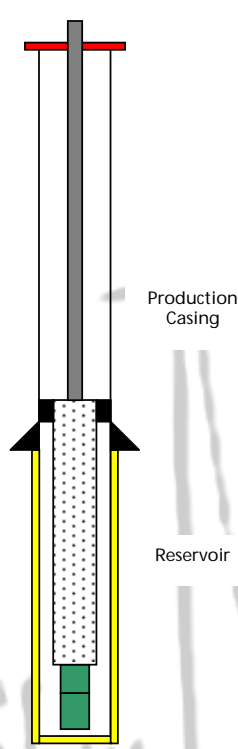




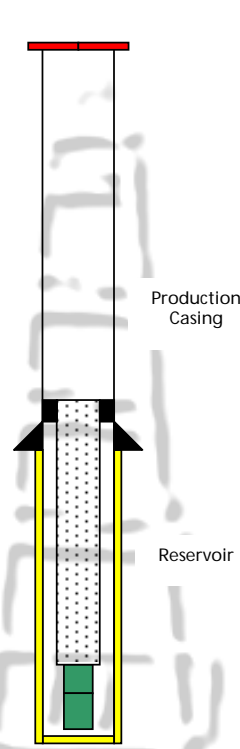
Step 7
Stab into Bridge
Plug & Unset



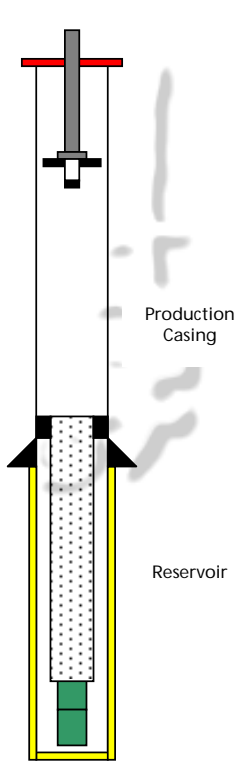
Step 8
Run Liner
to Depth



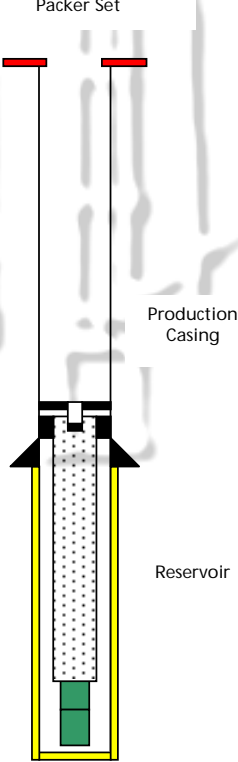
Step 9
Pull Running
String



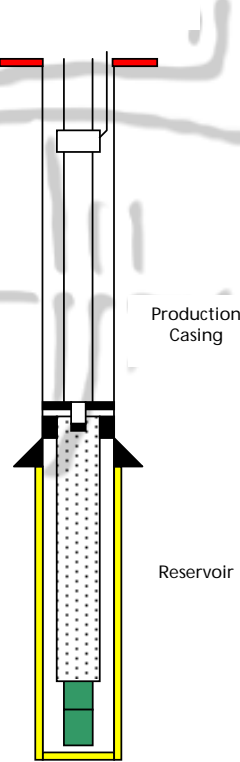
Step 10
Run Packer



Step 11
Production
Packer Set



Step 12
Run Completion



8.4 Completion Running

The main problem with running the completion in a live well is the installation of the SSSV control line. Once the control line is connected, the BOP's no longer seal around the pipe. Once again, therefore the simplest method is to isolate the reservoir prior to running the completion.

In the case of the completion the production packer with a plug installed in the tailpipe is snubbed into the live well and the production packer is set on drill pipe. The packer assembly would be lubricated into the well by utilising the snubbing well control system.

Once the production packer is set, the drillpipe can be used to pump completion fluid to provide an additional barrier that can be monitored if required. The completion is now run conventionally. The isolation plug in the tailpipe will be retrieved during the well commissioning. Once again, before pulling this plug the fluid should have been displaced out of the completion string. This can be achieved with coiled tubing or with a sliding sleeve. Once the completion has been installed, the well is ready for production. No clean up or stimulation is required in the case of underbalanced drilled wells.

8.5 Workover of an Underbalanced Drilled well

The workover procedure is a reversal of the completion running, i.e. a suspension plug is installed in the production packer tailpipe and the well is lubricated to kill fluid. After retrieving the completion, the packer picking assembly is run to the packer depth and the well is returned to an underbalanced condition prior to retrieving the packer. This ensures that formation damaging kill fluid does not come into contact with the reservoir at any time.

8.6 Underbalanced drilled Multi-Lateral Wells

The setting of the production packer with a mechanical plug allows the lower leg in a multilateral well to be isolated and remain underbalanced whilst the second leg is drilled. After running the liner in the second leg, the completion can be run and a second packer can be installed and stabbed into the lower packer. If leg isolation is required, a flow sleeve can be installed at the junction to allow selected stimulation or production as required. Re-entry into both legs is also possible utilising a selective system. However, more detail as to the exact requirements from a multilateral system will need to be reviewed.

Drilling a multilateral well underbalanced with the main bore producing can be done but the drawdown on the reservoir will be small. A further setback will be that cleaning up of the lateral is difficult if the main bore is a good producer. Getting sufficient flow through the lateral to lift fluids can be a challenge.

8.6.1 Advantages & Limitations for live well deployment

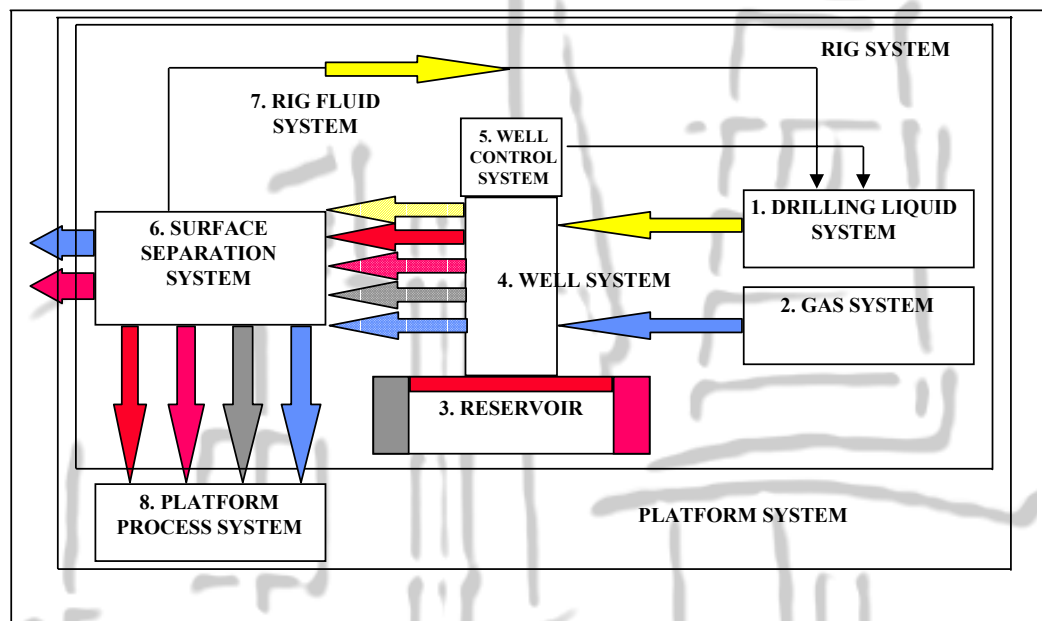
The list below illustrates the advantages and disadvantages for staying with underbalanced drilling and utilising a mechanical injection system (snubbing) to install downhole barriers. This allows both the slotted liner and the completion to be run without the need to be in an overbalanced mode with kill fluid in contact with the formation.

<i>PROS</i>	<i>CONS</i>
1. Reduced formation damage	1. Additional equipment and interfaces required for snubbing
2. Reduced risk of surface leaks	2. Additional single barriers
3. Possible to run irregular OD completion assemblies	
4. Provides downhole barriers for both the completion and the slotted liner	

9 Health Safety and Environmental Issues

Because underbalanced drilling involves working on a live well, a Hazard Operational analysis is required for the full process. To this end a flow chart has been created that shows all the elements in the underbalanced drilling process. Using the diagram, each element can be analysed for input and output and the diagram has also been used to good effect to ensure that all items of an underbalanced drilling system are reviewed during the HAZOP. It also allows procedures and documentation to be reviewed for all parts of the underbalanced drilling system.

HSE System Elements



9.1 Environmental Aspects

The underbalanced drilling system is a fully enclosed system. When combined with a cuttings injection system and an enclosed mud pit system, a sour reservoir can be safely drilled safely using an underbalanced drilling system. The pressures and flowrates are kept as low as possible. It is not the intention to drill a reservoir and produce it to its maximum capacity. A well test can be carried

out during drilling underbalanced to provide some productivity information. The hydrocarbons produced during the UBD process can be routed to the platform process plant, export or flared. There is work currently being undertaken to reduce flaring and recover the hydrocarbons for export. In a prolific well a significant amount of gas can be flared during the drilling process. Recovering this gas provides an environmental benefit and an economic benefit. Oil and condensate recovered are normally exported via a stock tank into the process train.

9.2 Safety Aspects

Beside the full HAZOP a significant amount of crew training is required for underbalanced drilling. A drilling crew has been instructed during its entire career that if a well kicks it must be shut in and killed. During underbalanced drilling the single item to be avoided is to kill the well. This may undo all the benefits of underbalanced drilling. Working on a live well is not a normal operation for a drilling crew and good training is required to ensure that accidents are avoided.

The underbalanced drilling process is more complex when compared to conventional drilling operations. Gas injection, surface separation as well as snubbing maybe required on a well. If the hydrocarbons produced are then pumped into the process train, it is clear that drilling is no longer a stand-alone operation.

The reservoir is the driving force in the UBD process. The driller must understand the process and all the interaction required between the reservoir, the liquid pump rate, the gas injection and the separation and process system to safely drill the well. When tripping operations start, the well must remain under control. Snubbing pipe in and out of the hole is not a routine operation and a specialised snubbing crew is normally brought on to snub the pipe in and out of the hole.

The extra equipment also brings a number of extra crew to the rig. So besides a more complex operation a number of service hands are on the rig that now need to start working with the drilling crew. Yet the drilling crew will move

back to conventional drilling once the well is completed. The drilling crew will need to be trained in this change of operating.

If a number of wells are to be drilled underbalanced in a field, it maybe an option to consider batch drilling of the reservoir sections. This saves mobilisation and it also sets a routine with the drilling crew. It must be stated that few accidents occur during underbalanced drilling, this is mainly believed to the high emphasis on safety during live well operations.

9.3 Step by Step Approach

It is considered prudent if a number of wells are to be drilled underbalanced with a new crew to apply a step by step approach to underbalanced drilling. The first well is drilled underbalanced but killed on trips. The second well is drilled underbalanced and tripped underbalanced but the well is killed for completions. The third well is drilled and completed underbalanced. This allows all crew and service providers to train and prepare the equipment.

10 Limitations

There are not only advantages to underbalanced drilling. Before embarking on an underbalanced drilling program, the limitations of the process must be reviewed. There are technical limitations as well as safety and economic limitations to the underbalanced drilling process.

Conditions that can adversely affect any underbalanced operation:

- Insufficient formation strength to withstand mechanical stress without collapse.
- Spontaneous imbibition due to incompatibility between the base fluid used in the underbalanced drilling fluid and the rock or reservoir fluid. Use of a non-wetting fluid can prevent or reduce this situation.
- Deep, high pressure, highly permeable wells presently represent a technical boundary due to well control & safety issues.
- Non-continuous underbalanced conditions.
- Excessive formation water.
- High producing zones close to the beginning of the well trajectory will adversely affect the underbalanced conditions along the borehole.
- Wells that require hydrostatic fluid or pressure to kill the well during certain drilling or completion operations.
- Slimhole or drilling conditions that result in a small annulus create high back-pressures due to frictional forces.
- Wells that contain targets that contain significant pressure or lithology variations throughout.

10.1 Technical Limitations

10.1.1 Wellbore stability

Wellbore stability is one of the main limitations of underbalanced drilling. Borehole collapse as a result of rock stresses is one issue to be considered. The other issue is chemical stability, which is seen in shale and claystone formations. Both these issues can have serious implications in underbalanced drilling. Defining maximum drawdown and reviewing chemical compatibility with the proposed drilling fluids is a key issue in the feasibility of underbalanced drilling.

No borehole collapse due to rock mechanics and drawdown has been reported in underbalanced drilled wells.

A well drilled in Spain in 1996 encountered significant hole problems and was side-tracked three times and finally produced through the drillstring as a result of borehole collapse. No further investigations into the causes have been published but it is one of the published examples of well bore stability problems.

10.1.2 Water inflow

Water inflow in a depleted reservoir can cause severe problems in an underbalanced drilled well. If the flow rate is high enough the well will be killed as a result of the water influx. Gas lifting a well that produces water at a high rate is almost impossible. Care must be taken that the water leg in a depleted reservoir is not penetrated when drilling underbalanced.

10.1.3 Directional Drilling equipment

Directional Drilling equipment can have limitations on underbalanced drilling. Hydraulic operated tools can not be used in UBD wells and if a gasified system is used the MWD pulse systems may not work. Certain motors and other directional equipment may be prone to failure as a result of the rubber components becoming impregnated with the gas used. Explosive decompression of rubber components is a consideration to be made when selecting equipment.

The higher Torque and Drag seen in UBD wells (as much as 20%) may also prevent certain trajectories from being drilled underbalanced. The higher torque is caused by the reduced buoyancy combined with the lack of filter cake on the borehole wall. This is a factor that may be of concern in ERD wells.

10.1.4 Unsuitable Reservoir

The reservoir may not be suitable for underbalanced drilling. A highly porous, high permeable reservoir can provide too much inflow at low drawdown. It is important that the perceived benefits of underbalanced drilling are kept in mind when planning for underbalanced operations.

10.2 Safety and Environment

The HSE issues of an underbalanced drilling operation may prove to be too complicated to allow underbalanced drilling to proceed. If a safe system cannot be designed and implemented, underbalanced drilling should be re-considered. A serious accident in underbalanced drilling operations can cause a severe setback in this technology. It can be done safely providing that all issues are addressed.

10.2.1 Surface equipment

The placement of the surface equipment may prove to be impossible on some offshore locations. There can be problems with rigfloor height and with deck space or deck loading. Both the wellhead equipment and the surface separation equipment must be carefully designed to fit the platform or rig.

10.2.2 Training

The entire platform/ rig crew must be trained in underbalanced techniques. Once the crew understands what is to be achieved, operations will run smoother and with fewer problems and accidents. The documentation and policies and procedures should not be forgotten when considering training.

10.2.3 Personnel

The number of crew required for underbalanced drilling is still considered large. 15 to 20 extra crew members are required for full underbalanced drilling and completing. This number must be brought down for safety reasons. Significant work is being undertaken in automation of underbalanced systems to reduce the crew size.

10.3 Economics

The business driver behind the technology must never be forgotten. If the benefits cannot be achieved then the project must be reviewed. Improvements seen from underbalanced drilling are:

- Twice the Penetration rate.
- Triple the Production rate.

11 Case histories

Underbalanced drilling in Europe started with the technology from Canada in 1995. Initially onshore but migrating offshore with the first well drilled underbalanced offshore by Shell in Lowestoft in June 1997.

Year	Country	Operator	Details
1995	Germany	BEB	Ulsen
		RWE-DEA	Breitbrunn gas storage
	Australia	WAPET	
1996	Denmark	Maersk	Coiled Tubing
	Netherlands	NAM	Coiled Tubing
	UK	Pentex	Oil field onshore
1997	UK	Shell	First Offshore Well
	Mexico	Pemex	Offshore well GOM
	Indonesia	Mobil	Arun gas field (depleted)
	Spain	SESA	
	Algeria	Sonarco	
	Oman	PDO	
	Argentina	YPF	
1998	UK	Shell	Offshore Barque & Clipper
	UK	Edinburgh Oil & Gas	Coiled tubing gas storage onshore
	Indonesia	Kufpec	Oseil
	Indonesia	Gulf	
	Italy	Agip/SPI	Sicily
1999	UK	Shell	Galleon & Barque
	Sharjah	BP Amoco	

All the above listed underbalanced drilled wells had to be drilled underbalanced, either because of productivity or for reservoir depletion.

12 Advantages of Underbalanced drilling

The advantages of underbalanced drilling have been clearly seen during the wells drilled and completed underbalanced. Early wells were killed for trips and this clearly showed the benefits of underbalanced drilled wells. One well was drilled and completed underbalanced and was then stimulated with an acid wash and this once again proved a reduced productivity.

12.1 Drilling Technical Advantages

No mud losses are encountered during underbalanced drilling.

Simple waterbased fluid systems have been used. If torque and drag are an issue, then an oilbased mud system can also be used. Gas solubility in oil needs to be considered when using oilbased mud systems

Penetration rates increase by 2 to 5 fold when drilling underbalanced. This is still a function of formation and bit selection. The amount of drawdown has a direct impact on the rate of penetration.

Bit life is increased. Because the well is drilled faster and the removal of cutting from the bit face is more efficient (Chip Hold down effect)

No differential stuck pipe occurs when drilling underbalanced. There is no wall cake and no over pressure to push the pipe against the wall of the wellbore. It does not mean that no stuck pipe occurs when drilling underbalanced. Key seating and junk as well as hole collapse can still cause stuck pipe even in underbalanced drilled wells.

Inefficient hole cleaning as a result of the multiphase flow can also cause stuck pipe in underbalanced drilled wells.

12.2 Reservoir Technical Advantages

Reduced formation

Reduced formation damage in lower permeability reservoirs leads to an average increase in productivity of 3 times the production seen in overbalanced drilled wells. Although the factor of 3 is now been accepted as an average productivity improvement, significantly larger improvements have been seen on some wells. Once again reservoir studies and knowledge of the damage mechanism will quickly indicate the potential improvements.

Reduced stimulation requirements.

The one well that was drilled underbalanced and then acid washed proved conclusively that acid stimulation does not increase productivity. A well drilled and completed underbalanced will out perform a stimulated well. Saving the costs of hydraulic fracture stimulation often offset the price of underbalanced drilling.

Improved formation evaluation is provided by the ability to test the well while drilling and to steer the well into the most productive zones of the reservoir. Intersection of fractures is possible as a large fracture is recognised by an increase in productivity from the well.

Early Production

Production will start as soon as the reservoir is penetrated. For new field developments this may require the production train to be ready once the first well penetrates the reservoir.

13 Costs

The costs of underbalanced drilling vary greatly with the reservoir encountered and the sophistication required on the surface separation and data acquisition system. The reservoir fluids dictate the required separation equipment and the reservoir pressure dictate the pressure control equipment requirements as well as the gas lift requirements.

The location and the number of wells to be drilled will to a degree dictate mobilisation costs. A detailed feasibility study on a multi-well development will be required while a simple quick look study can be performed on a low pressure land well in Europe.

Comparing a number of operations in Europe, Canada and the middle East we can now provide a ball park figure of 10% of the well cost is the additional cost required for underbalanced drilling. If your well is expensive because of the complex reservoir geometry, it is likely that the underbalanced drilling equipment will also have to be suited to the complex drilling systems required. If a simple vertical well is required in a homogeneous reservoir then the well costs as well as the UBD costs can be low.

If a multi-well development can be drilled successfully underbalanced the reduction in well count could be as high as 25% as a result of the increased productivity. This benefit outweighs the obstacles and cost of underbalanced drilling significantly.

14 Future

The future of underbalanced drilling will see a significant increase in automation and a resulting reduction in crew required.

The use of underbalanced drilling in HPHT reservoirs to avoid or at least increase the narrow pore pressure / fracture pressure window.

The use of underbalanced drilling from floating rigs and with subsea developments. There are currently systems and methods on the drawing board but investment of 2 to 3 million dollars will be required to develop a working system for underbalanced drilling from floating rigs.

Multiphase flow modelling in the annulus and prediction of hole cleaning and cuttings transport will further improve UBD operations.

The use of downhole safety systems will eventually eliminate snubbing systems for UBD wells.

The data acquisition at surface and downhole will improve allowing more and more wells to be drilled underbalanced more effectively.

Better understanding of reservoir damage mechanisms and their associated recovery factors and production profiles will lead to a more selective approach to underbalanced drilling for reservoirs with a real need.

This document provides a flavour of the potential, the drawbacks and the advantages of underbalanced drilling. It is not intended to provide a comprehensive answer to all underbalanced drilling questions. It hope fully provides a guideline and some basic understanding of the technology required for underbalanced drilling.

15 Further Information on Underbalanced Drilling

- Gas research Institute. Underbalanced Drilling Manual. Published by Gas research Institute Chicago Illinois.GRI-97/0236
- Proceedings from 1st International Underbalanced drilling Conference & exhibition held in The Hague, Holland 1995
- Proceedings from 3rd International Underbalanced drilling Conference & exhibition held in The Hague, Holland 1997
- Maurer Engineering Inc. Underbalanced Drilling and Completion Manual. DEA 101 phase 1. October 1996

16 Suppliers of Underbalanced Drilling Equipment

Deutag Northland
Williams
Shaffer
Weatherford
Schlumberger
Halliburton
Alpine

17 Abbreviations

BOP	Blow out Preventors
MMscft/day	Million standard cubic foot per day
ROP	Rate of penetration
BHP	Bottom hole pressure
MWD	Measurement While Drilling
PDM	Positive Displacement Motor
ESD	Emergency Shutdown
BHA	Bottom Hole Assembly
NDT	Non Destructive Testing
UBD	Underbalanced Drilling
HAZOP	Hazard Analysis Operations
ERD	Extended Reach Drilling
HSE	Health Safety and Environment