Completions & Workovers

Module Summary

Students will learn what is involved in a well completion, how a completion is performed and the identification and purpose of some of the equipment and tools used in the well completion or workover.

The drilling of a well takes many months of planning, preparation and a sizable quantity of cash. The purpose of drilling the well is to access oil or gas reserves, which hopefully will be present. If an optimistic indication of reserve potential can be achieved from the drilling and testing operations, casing will be set and cemented in the wellbore by the drilling rig.

The setting of the casing is really the first step in the completion of the well. The completion of the well will enable access to the oil or gas reserves, so that they may be produced to surface.

This module will provide information on how the completion progresses from a cased well to the point of having a well capable of production. The well will require perforating, equipment will be installed inside the casing, the productive formation may require treatment to enable production and the fluids may need assistance in getting up to the surface. After producing for a period of time, a workover may be necessary if the downhole equipment needs repair or servicing or the formation requires additional treatment in order to continue efficient production.
Topic 1: Casing and Tubular Completion Configurations

Goals of this Topic:

In this unit students will be introduced to the equipment installed in a well, the purpose of that equipment and how the well equipment might be set up differently for discrete needs of the well.

Objective 1: Typical Configuration
The student will identify and name the basic components of a well.

Objective 2: Casing Review
The student will identify and name the different basic casing strings of a well.

Objective 3: Tubing and Downhole Equipment
The student will name and identify some basic downhole well equipment and explain the purpose of that downhole well equipment.

Objective 4: Completion Configurations
The student will recognize and identify some of the differences and the reasons for those differences in the set-up of downhole well equipment.

Objective 5: Wellhead
The student will identify and name the basic components of a wellhead and explain the purpose of the wellhead.

Topic 2: Completion Techniques

Goals of this Topic:

This unit will provide information on the techniques and considerations in obtaining a productive well.

Objective 6: Information for Completion
The student will name some of the sources of information which help to identify where in the well hydrocarbon production may be found and explain how that information helps in the assessment of the hydrocarbon location.
Objective 7: Perforating
The student will name and explain the two methods of providing a flow path for the formation fluids from the reservoir into the wellbore.

Objective 8: Well Stimulation
The student will explain the purpose and types of well stimulation and how both acidizing and hydraulic fracturing improve well productivity.

Objective 9: Hydrostatic Pressure
The student will explain what hydrostatic pressure is and how it influences the production from a well and explain the term swabbing and when this procedure is used.

Objective 10: Multiple Zone Completions
The student will explain what is meant by the terms segregated and commingled production, will explain a multi-zone completion and will list advantages and disadvantages of such completions.

Objective 11: Well Evaluation
The student will list the reasons why a well might be tested and some of the different types of tests.

Objective 12: The Completion Program
The student will describe the purpose and basic content of a completion program.

Topic 3: Artificial Lift

Goals of this Topic:
In this unit the students are presented with artificial lift and a brief explanation of the three key methods of providing this lift in a well.

Objective 13: Artificial Lift
The student will explain the term artificial lift, why it may be needed in a well and describe the three main forms.

Objective 14: Pumpjack Unit
The student will explain the basic operation of a pumpjack and a bottomhole pump.
Objective 15: Pumps
The student will explain the basic operation of the electric submersible pump and the progressive cavity pump.

Objective 16: Gas Lift System
The student will explain the basic operation of a gas lift system.

Topic 4: Workovers and Service Rigs

Goals of this Topic:

In this unit the student will be presented with information on the types of jobs which would be considered a workover, the different service rigs which might be used to perform the work and how these jobs are classified by oil companies on the "books."

Objective 17: Well Workovers
The student will define a workover and identify what type of work on a well would be constituted as a workover and define remedial cementing and list the reasons it may be required.

Objective 18: Workover / Service Rigs
The student will describe a service rig and list the main types and their particular functions.

Objective 19: Well Abandonment
The student will explain what is meant by the terms abandonment and active and suspended wells.

Objective 20: Capital versus Expense Workovers
The student will determine if a workover cost is classified as a capital cost or an operating expense.

Recap of Important Points
Topic 1: Casing and Tubular Completion Configurations

Objective 1: The student will identify and name the basic components of a well.

TYPICAL CONFIGURATION

The casing, tubing and other downhole equipment will vary from well to well. They will vary depending on the depth of the well, the type of fluids being produced, the number of productive formations being produced and numerous other choices available in designing the well completion.

Figure 1 presents a simplified cross-sectional view of a fairly common well completion and its basic components. (The information labeled on this diagram will be covered in more detail throughout the notes.)
Objective 2: The student will identify and name the different basic casing strings of a well.

CASING REVIEW

The first step in the sequence of completing a well is the setting of the casing. As covered in the Module on Drilling, the setting of the casing is normally an operation handled by the drilling rig. The casing is set in position and cement is pumped down the well, out and around the casing, into the annular region between the casing and the wellbore. The procedure for cementing the casing in place is known as primary cementing. The cement serves two key purposes: it holds the casing in place and it prevents contamination resulting from formation fluids flowing from one formation to another.

If a well is assessed as a dry hole the well will be abandoned. However, on a well with some potential of hydrocarbons (oil or gas) the drilling rig is used to case the well down to the deepest potential zone. The casing strings are set as the drilling progresses. The shallowest casing string is the surface casing and all subsequent casing strings are smaller in diameter and are placed into the well inside the last casing string. The casing strings in a well, in the order of installation, could include: surface casing, intermediate casing, production casing and a liner casing string. At a minimum a cased well will include surface casing and production casing.

Once the final casing string is set the drilling rig is normally released and moved off the well site. A service rig is then moved onto the well site for the final completion of the well. The service rig's primary role at this stage of the completion is to install tubing and other downhole equipment. The drilling rig is capable of handling the operations performed by the service rig; however the hourly costs for a service rig can be significantly less than for a drilling rig (more discussion on different types of service rigs will be found in Objective 18, Workover/Service Rigs). The conventional service rig bears a resemblance to the drilling rig; however it is more portable, and typically mounted on the back of a truck. The service rig is primarily designed for the job of running tubing and other tubing related equipment; although some light drilling can be accomplished with proper equipment on a service rig.
Objective 3: The student will name and identify some basic downhole well equipment and explain the purpose of that downhole well equipment.

TUBING AND DOWNHOLE EQUIPMENT

Tubing comes in sections known as joints, around 10m (30 feet) in length with threaded ends. The tubing joints are joined together by screwing the tubing into threaded collars. The most common tubing sizes have an outside diameter of 60.3mm (2 3/8") or 73.0 mm (2 7/8"), however more prolific producing wells may require significantly larger diameter tubing. The tubing is installed inside the production casing with the end of the string of tubing near the depth of the productive horizon.

The tubing is installed inside the casing for several reasons:

- Tubing has a smaller cross-sectional area than the casing. The fluids will be easier to produce up the tubing, since the velocity will be increased in the smaller sized pipe.

- Chemicals can be pumped down the annulus between the outside of the tubing and inside of the casing. These chemicals may be needed to treat the producing fluids to reduce corrosion or prevent freezing or scaling in the tubing or casing.

- In order to "kill a well" fluids must be pumped down the well. The kill fluid is pumped down the annulus between the casing and the tubing. A well that has been killed is said to be "dead". A dead well can be brought back to life by removing the kill fluid.

- The tubing can aid in protecting the casing from abrasion, corrosion and excessive pressures.

- The tubing/casing annulus provides a means of monitoring fluid levels in the well and determining the bottomhole pressures.

Some of the other equipment, which might be installed inside the casing, could include:

Packers - A packer is used to isolate the annulus between the casing and the tubing. Production entering the wellbore can enter the bottom of the tubing, but the annulus is isolated from this production. This will protect the annulus if the production is corrosive or if the pressures are too high for the casing. Also dual
or multiple packers can be used so that more than one tubing string can be installed in the well and isolated from one another (see multiple zone completion in the next section).

**Blast Joint** - This is a joint of tubing composed of specially alloyed steel. The blast joint is used where tubing is beside a productive zone with high velocity fluid being produced, which could erode normal tubing.

**Sliding Sleeve** - This is a piece of equipment installed with the tubing which can be opened and closed to provide communication between the tubing and the annulus. This would be of use where a packer is isolating the annulus but there is a short term need to circulate chemicals down the annulus and up the tubing. The sleeve has slots on it, which are aligned with slots on the tubing string when the tool is in the open position. The tool is opened and/or closed by lowering a tool on the end of a wire.

**Nipples** - These are short pieces of pipe with an inside profile in which a removable plug could be set. These nipples can be used to plug off the tubing for some completion process or tools such as pressure recording tools might be hung and left at the bottom of the well during a flow test.
Objective 4: The student will recognize and identify some of the differences and the reasons for those differences in the set-up of downhole well equipment.

COMPLETION CONFIGURATIONS

A sampling of some of the possible wellbore completion configurations are as follows:

1. **Single zone completion**: This is an example of a simple completion with a string of tubing set down to the productive zone.

2. **Tubing and packer completion**: The tubing has been run down to the productive zone and a packer has been included to isolate the annulus from the pressures and fluids in the tubing. The sliding sleeve has been installed so that fluids can be flowed between the tubing and annulus, if the need arises. The sliding sleeve is mechanically opened and closed by a tool lowered into the well on the end of a wireline.

3. **Multiple zone completion**: In this example three separate strings of tubing have been run down to three separate productive zones. Note that for the multiple completions, in order to install more than one tubing string, a larger wellbore would have been drilled and larger casing installed. The packers are used in this installation to isolate the produced fluids. The blast joints protect the lower tubing strings from the abrasive force of the production in the upper zone.

4. **Tubing-less completion**: In a tubing-less or a slim-hole completion, a smaller hole is drilled and a small diameter pipe is installed for casing which is too small to permit tubing to be installed. This type of well is cheaper to develop, however the risks are higher. A well of this type may have to be abandoned if downhole problems occur, such as a plug in the wellbore from debris or a hole in the casing, as it could be difficult to run the necessary repair tools in the small diameter wellbore. Sweet shallow gas wells (less than 1000 m) with no fluids might be well suited for this type of completion.

5. **Pumping well (with sucker rods and a bottomhole pump)**: In this well the oil zone is being pumped. The tubing has been run down to the zone and a bottomhole pump has been installed at the bottom of the tubing. The pump is stroked by solid sucker rods run on the inside of the tubing and attached to the pump. The sucker rods at the surface are connected to a pumpjack unit.

Please see Figure 2 for examples of tubing and completion configurations.
Figure 2

Tubing and Completion Configurations

<table>
<thead>
<tr>
<th>Single Zone With Packer &amp; Sliding Sleeve</th>
<th>Triple Zone With Liner, Blast Joints, Dual and Single Packers</th>
<th>Single Zone Tubing-Less (slim hole completion)</th>
<th>Single Zone Sucker Rods &amp; Bottom Hole Pump</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Zone</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sliding Sleeve</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Packer</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shale</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Objective 5: The student will identify and name the basic components of a wellhead and explain the purpose of the wellhead.

WELLHEAD

After the tubing has been placed inside the casing it is hung at the surface in a tubing hanger. The tubing hanger is a component of the wellhead.

The purpose of the wellhead is to contain the pressures and segregate the annuluses of the various casing and tubing strings at the surface of the well. The top portion of the wellhead is known as the Christmas Tree. The Christmas Tree is made up of several valves, on which several other fittings, gauges and other controls may be attached. With all of the valves and other attachments, the wellhead set up may look quite elaborate, like a Christmas tree.

The components of the wellhead (shown in Figure 3) are described as follows:

Casing Head: is attached to the surface casing, either threaded or welded. This forms the foundation for the rest of the well and the wellhead.

Casing Hanger: is threaded to the top end of the casing. With the casing hanger attached, the casing can be positioned in the well and hung in the casing head (and normally then cemented during the drilling operation). The hanger has seals which will isolate the casing annulus.

Casing Spool: If an intermediate casing string is set in the casing head a casing spool will be bolted onto the top of the casing head. The production casing would then have a casing hanger attached and be hung in the casing spool.

Tubing Head: is bolted onto the top of casing head or casing spool.

Tubing Hanger: is attached to top of tubing. It allows the tubing to be hung in the tubing head and isolates the annulus.

Master Valve: is bolted to the tubing head and is the first valve which can control the production and pressures at the top of the tubing.

Flow Tee: directs flow and attaches to master, stabbing and wing valves.

Wing Valves: are valves off to the side of the wellhead and the production will normally end up flowing through these valves.

Swabbing or Crown Valve: is a valve at the top of well through which tools or instruments may be run.
Cross-Sectional View of Wellhead

- Tubing Pressure
- Crown or Swabbing Valve
- Secondary Valve
- Master Valve
- Tubing Spool
- Casing Head
- Production Casing
- Surface Casing
- Tubing Hanger
- Casing Pressure
- Wing Valve & Choke
Topic 2: Completion Techniques

Objective 6: The student will name some of the sources of information which help to identify where in the well hydrocarbon production may be found and explain how that information helps in the assessment of the hydrocarbon location.

INFORMATION FOR COMPLETION

Critical information is obtained during the drilling operation. It is used to determine which equipment is required and where it should be installed.

1. **Well logs** are run by a logging unit during the drilling operation. The logging instruments are lowered into the well on the end of an electric cable. As the cable and the instruments are pulled out of the well, the measurements from the instruments are recorded and correlated to the depth. There are three basic categories of well logs: electric, acoustic and radioactive. Well logs can be analyzed to assess some of the formation characteristics (porosity, presence of hydrocarbons, permeability, water saturation, shale content, rock type).

2. **Drill Stem Tests (DST)** are run prior to setting the production casing. A DST uses packers on the end of the drill pipe to isolate a potential zone of interest. The hydrostatic pressure is released and an attempt is made to flow the zone. During the test, pressure recorders with the packer assembly record the pressure responses of the interest zone. Flow is monitored at the surface and after the test the types and volumes of fluids trapped in the drill pipe are recorded.

3. **Drill cuttings** are sampled during the drilling operation. Records are kept of drilling speed, drilling mud circulation and "shows" in the drilling mud returns. These records will help in understanding the hardness of the formation, changes in the rock type, potential for permeability and the possibility of productive intervals.

4. **Core** may be cut from the well during the drilling operations. The core provides a sample of the formation rock which can be analyzed and inspected for such things as porosity, permeability, rock type and hydrocarbon shows with in the samples.
Objective 7: The student will name and explain the two methods of providing a flow path for the formation fluids from the reservoir into the wellbore.

PERFORATING

Perforating is the method used to make holes in the casing, through the cement and into the formation. There are three principal types of perforating tools: **through-tubing gun, casing gun** and **end-of-tubing gun**. The through-tubing gun can be run with the tubing in the well, while the tubing must be removed to run the larger diameter casing gun. The end-of-tubing gun is run in on the end of the tubing and the charges can be detonated mechanically by dropping a metal bar down the tubing.

Along the length of the perforating gun explosive charges are mounted. The charges contain either a shaped charge, which forms a jet when ignited, or a bullet. Today the jet is used almost exclusively. The gun carries several of these charges, so that the well is perforated over the productive interval with as many as 12 to 15 shots per metre. The resulting perforation is approximately 1 to 2 cm in diameter (1/2 to 3/4 inch) and passes through the casing and cement and into the formation up to a depth of 30cm (1 foot). Refer to Figure 4.
The perforating procedure begins by running logging tools into the well to correlate to the logs obtained during the drilling operations. A magnetic collar locator log is also typically run which picks up the location of the casing collars. The through-tubing gun or the casing gun is run into the well on an electric cable by the wireline perforating unit. With all of the logging information the perforating tool is placed at the proper depth by the wireline unit. The explosive charges in the tool are discharged by an electric current passing down the electric wireline.

In some instances a well may be completed as an open hole completion. In the open hole completion the well is drilled down to the top of the formation of interest and the production casing is set. The well is then drilled down into the zone of interest. The well now has a fully exposed formation with no cement or casing obstructing the flow of the formation fluids into the wellbore. Refer to Figure 5.
Unlike the open hole completion, most wells are completed with casing and cement over the potential formations, thus communication needs to be established.

There are some advantages and disadvantages for the use of open-hole completion versus perforating a cased hole, which could include the following:

**Advantages of the Open-Hole Completion**

- Eliminates the expense involved with casing and perforating the production interval.
- Formation is fully exposed for a less restrictive flow.
- Damage to the formation from cementing is eliminated.
- Drilling fluids can be changed after the casing is set and prior to penetrating the zone, in order to reduce formation damage from the drilling mud.
- If the need for a cased hole arises, it may still be possible to install a liner.

**Disadvantages of the Open-Hole Completion**

- The open hole section is limited to intervals at the bottom of the hole. Although "open hole" is often the best option for completing a well for the reasons listed in the "Advantages" section above, only the bottom portion of the hole can be used for this purpose. In a well completed "open hole", all uphole prospective zones (those with both porosity and permeability) in the well must be completed "normally" and therefore the above advantages only apply to the deepest prospective zone penetrated by the well bore.
- A good prior understanding of the zone is needed, in order to know where to case the well prior to drilling into the formation.
- If the well is unsuccessful, the abandoned well would have been unnecessarily cased and cemented at a significant cost.
- The open-hole interval will be eliminated in controlling the production of fluids from the various portions of the exposed section (Some intervals may produce gas or water in preference to oil).
- Sloughing of the sides of the hole may force the interval to be cased or lined.
- Stimulation of selective portions of the interval will be considerable more difficult.
Objective 8: The student will explain the purpose and types of well stimulation and how both acidizing and hydraulic fracturing improve well productivity.

WELL STIMULATION

Well stimulation treatment may be required if the well will not produce after perforating or if the flow performance requires improvement. During drilling and possibly the completion process, the formation may be subjected to damage by the drilling and completion fluids or the permeability of the formation rock may be poor. The stimulation attempts to remove, break past or create improved flow paths in the formation. The two primary stimulation techniques are acidizing and fracturing (frac).

In acidizing, acid is pumped into the formation to dissolve the rock or any damaging material, which might be restricting the permeability. The two principal types of acid, used in well treatments, are hydrochloric (HCl) which is used to dissolve calcium carbonates (CaCO₃: limestone & dolomites) and hydrofluoric (HF) acid which dissolves silica (sand stone), clays and muds. A blend of HCl and HF is known as mud acid, since it is well suited for cleaning out mud damage which might have resulted from the drilling mud.

In the hydraulic fracture treatment, fluids are pumped into the well at rates and pressures that create fractures in the formation (one or more cracks are formed in the formation rock). The frac fluids are pumped into the well and into the formation at rates faster than the fluid can leak off into the formation. This is continued until the pressures build up such that the formation rock fractures. After the pressure is released, the fracture will close back providing little or no benefit. In order to keep the fractures open a proppant, such as specially selected sand, is pumped into the fracture with the frac fluids. When the pressure is released in the fractures, the propping agent is trapped when the fracture tries to close resulting in permeable flow paths from the wellbore deep into the formation. The desired characteristics of a proppant would be:

- small and light enough so that the frac fluid can carry it into the structure.
- uniform in size and able to pack to provide a high degree of permeability.
- hard enough so that it is not crushed by the closing pressure of the fracture.

Sand is usually the material of choice because of its cost and ability to meet the desired needs of a good proppant. It comes from special quarries, which have sand with the roundness and strength essential for proppants. The sand is carried into the frac in a viscous fluid called a gel. Shortly after the gel/sand mixture is injected, a chemical reaction occurs and the gel reverts to water. The water is produced from the well and the sand is left behind in the frac. Some other
materials used as proppants include ceramics and in the early days of the oil industry, even crushed walnut shells.

Acid-fracturing is a process where the formation is fractured with acid. The surface of the fracture is etched by the acid, improving the productivity of the formation rock. This is especially useful in carbonate formations (dolomite or limestone) with a non-uniform composition.
**Objective 9:** The student will explain what hydrostatic pressure is and how it influences the production from a well and explain the term swabbing and when this procedure used.

**HYDROSTATIC PRESSURE**

A principle that must be understood by completions specialists is hydrostatic pressure. Hydrostatic pressure is the pressure exerted by a column of fluid. For a column of water the hydrostatic pressure is 9.8 kPa per metre of depth. A well 1000m deep and filled with water will have a hydrostatic pressure, at bottom, of 9800 kPa or 9.8 MPa (1,420 pounds per square inch, psi). Please see Figure 6.

As was covered in drilling, drilling mud is weighted so that its hydrostatic pressure will be greater than any formation pressures encountered to prevent a blowout (uncontrollable production). During the completion process hydrostatics are used to control the well. If the reservoir pressure is greater than the hydrostatic pressure of the column of fluid in the well bore, fluids will flow from the formation to the surface of the well unassisted.

---

*Figure 6*
A well is said to be "killed" or "dead", if a fluid column can be established in the wellbore which exerts a hydrostatic pressure greater than the formation pressure and thus prevents the well from flowing.

After a well is completed the hydrostatic pressure may have to be relieved before the well will flow. This is accomplished through an operation known as swabbing. Swabbing is usually performed with a wireline unit and a tool with swabbing cups. As the tool is lowered in the well, down into the fluid column, the swabbing cups fold up. When the tool is pulled out of the well, the swabbing cups fold down, so that the fluid is trapped above the tool and the fluid can be pulled to the surface and removed. After a few trips in the well with the swabbing tool, the fluid column is reduced and the well may start to produce.

The fluids used during a completion or workover (for killing the well, as a frac fluid etc.) are known as load fluids. Load fluids are recovered from the well before production is reported for the well. This is particularly important if oil was used as a load fluid. The load oil is recovered before production is reported and royalties are only paid on new production.
Objective 10: The student will explain what is meant by the terms segregated and commingled production, will explain a multi-zone completion and will list advantages and disadvantages of such completions.

MULTIPLE ZONE COMPLETIONS

In many instances more than one prospective formation will be encountered in a well. The decision to produce more than one formation, in a well at the same time, requires some special considerations in terms of the completion procedures and the ongoing operation. Some of the considerations for a well with two or more completed zone could include:

1. Equipment

For most multi-zone completions the production from each zone must be segregated (isolated) until it has been measured at surface. Segregation will prevent contamination of one zone by another, pressurization of a low pressure zone by a higher pressure zone and it will allow the measurement of the production from each zone.

In order to achieve segregation each zone must have a separate and isolated flow path to the surface (Figure 7), which could involve more than one tubing string, one or more packers and a special wellhead to accommodate the tubing strings. In some cases it may be possible to flow production from one zone up the tubing-casing annulus or to run two or more tubing strings by installing them co-centrically (one inside the other) and flowing production up a tubing-tubing annulus.
2. Planning

A multiple zone completion may need to be planned from the drilling stage. The wellbore would be drilled with a larger bit and larger diameter casing would be installed, to allow for the installation of more than one tubing string. This adds to the drilling costs of the well, as it takes more time to drill a larger hole. The larger casing and other drilling materials (drilling mud, cement) are also more costly.

In planning the completion, after the well has been cased it is preferred to complete the lower zone first. By working on the lower zone first, each zone can be isolated from the next higher zone with a packer or retrievable bridge plug. This method allows tubing to be removed for perforating, isolation of the zone for stimulation and creates no concerns with production moving into the wellbore or completion fluids moving into a previously completed zone. This practice of moving up the hole to the next zone is also typically used where a zone is completed and the production drained, before completing the next zone.
There are several pros and cons regarding multi-zone completions and some of those are:

CONS

- higher costs to drill the well
- extra completion costs
- more complex downhole configuration
- more complex surface equipment to measure and handle production
- increased risk and potential for problems
- AER will require annual testing to prove segregation

PROS

- optimize time to recover reserves
- may be cheaper than drilling several wells

With the added cost, consideration and the potential for problems, the lower zone is often produced until the reserves are depleted and abandoned before the next zone is completed or a second well is drilled for the uphole zone.

In some instances multiple zones may be produced without segregation of the production in the wellbore. The mixing of production in the wellbore is known as commingling production. Before production may be commingled, approval must be granted by the Alberta Energy Regulator (AER) under the following restrictions:

- pressures in the zones must be comparable (such that one zone will not flow into the other);

- fluids in the zones must be compatible (if one zone did flow into the other damage or contamination could occur if the fluids were not compatible - for example a sour gas flowing into a gas zone containing sweet gas) and

- the rights of all parties must be conserved (if the separate zones had different working interest owners, royalty owners or lessors with commingled production you would not be able to measure the production and allocate the revenues).
Objective 11: The student will list the reasons why a well might be tested and some of the different types of tests.

WELL EVALUATION

In order to evaluate the well after it has been completed, a flow test is performed. If the necessary equipment and flowlines are available the well may be tied-into existing production facilities. If the necessary facilities are not available, temporary testing equipment will be set up on the well site. During the production test, measurements may be taken of the volumes and pressures (surface and bottom hole) all recorded against time. From the tests some of the things which might be assessed are:

- **productivity / deliverability** (the rate at which the well might be capable of producing),
- **evaluation of formation damage** (will a stimulation treatment be needed?),
- **equipment requirements & sizing** (what type of equipment will be needed and what capacities will it have to handle?), and
- **evaluation of reserves** (type and quantity).

Some of the different types of tests are:

- **IP test**: initial production test, the well is flowed at the anticipated production conditions.
- **Single rate test**: the well is produced and a set production rate is maintained for an extended period of time.
- **AOFP**: absolute open flow potential (gas well test) - the well is flowed at various rates for set periods of time. The results from the analysis of the AOFP test indicates the maximum rate the well could flow at if it were not restricted by any hydrostatic pressure. This information also provides the productivity of the well for various surface pressures.
- **Injection test**: fluids are pumped into the well. This type of test is usually used on wells to be used as injection wells for some form of enhanced recovery scheme (EOR, waterflood etc).
Objective 12: The student will describe the purpose and basic content of a completion program.

THE COMPLETION PROGRAM

The completion program is a step-by-step procedure for the actual well completion. The program is prepared by a completion specialist within the company and is used to estimate and budget costs for the planned work, and obtain approvals from partners (if necessary). The completions supervisor will use the program to arrange for the necessary equipment and services. The detail of a program may vary and some steps may be left up to the experience of the completions supervisor, but the overall scope and critical steps for the completion will be provided. The following is a sample of the steps that may be encountered in the completion of a new well.

1. Move on service rig (MOSR) and set-up.

2. Remove wellhead cover and install the tubing spool.

3. Run in tubing into the well and tag and establish the plugged back total depth (PBTD - maximum depth the well can be penetrated).

4. Circulate out hole and circulate fluids out with completion fluid. (The completion fluid will be selected by the completion specialist and could be fresh water, a salt-water solution or possibly oil or some other type of fluid. The fluid will be selected according to the needs for hydrostatic pressures and/or the compatibility with the formation so as not to damage the formation.)

5. Land bottom of tubing at 1208 mKB and set tubing in tubing hanger.

(During the drilling the kelly bushing is used as reference point from which depths are measured, ie metres KB. Before the drilling rig is moved the distance from the wellhead casing flange to the kelly bushing is measured so that after the rig is moved KB measurements can now be adjusted from the depth below the casing flange. If measurements are referred to as mCF, they are the depth below the casing flange.)

6. Install wellhead and move off service rig (MOSR).

7. Move on electric wireline unit, set up lubricator to run in logging tools (The lubricator goes onto the top of the wellhead and allows the tools to be lowered into the well even if the well is pressured up which may be the case after the well has been perforated.)
8. Run in hole with logging tools CCL-GR (casing collar locator and gamma ray tool) and log from total depth to tubing bottom, correlate to open hole logs, pull out of hole.

9. Remove lubricator and install through-tubing gun with and CCL- GR to perforate from 1212 mKB to 1223 mKB. Run in, log, correlate logs and set gun at proper depth. Perforate well.

10. Pull out of hole and rig out electric wireline unit.

11. Move on flow testing equipment and rig up.

12. Move on braided wireline unit and swab well to flare pit until flow is established.

13. Run in bottomhole pressure records and set in tubing at 1200 mKB.

Topic 3: Artificial Lift

Objective 13: The student will explain the term artificial lift, why it may be needed in a well and describe the three main forms.

ARTIFICIAL LIFT

With sufficient reservoir pressure, oil wells will flow oil to the surface unassisted. In time, however, the driving energy in the reservoir will drop, such that in time the column of oil in the wellbore will "kill" the well so that it will no longer flow. As the reservoir pressure drops and production declines, artificial lift may be installed to assist in maintaining an optimum production level.

There are three main forms of artificial lift:

1. pumpjack unit operating a bottomhole rod pump,
2. electric submersible pump and
3. gas lift system.

In some instances, gas wells may also require some form of lift. If a gas well is producing fluids that are not produced to the surface with the gas, these fluids will build-up and accumulate in the wellbore until they overcome the reservoir pressure.
Objective 14: The student will explain the basic operation of a pumpjack and a bottomhole pump.

PUMPJACK UNIT

The pumpjack unit bobbing up and down on the horizon is a familiar site to many in oil producing areas (Figure 8). The pumpjack unit is attached to rods, known as sucker rods, which are run on the inside of the tubing and are connected to a pump at the bottom of the tubing. The up and down motion of the pumpjack provides the stroking action necessary to operate the bottomhole pump.

The conventional pumpjack is composed of an electric or gas driven motor connected to a gear box. The gear box rotates a crank which is attached to one end of the pitman rod and counter-balance weights. The counter-balance weights offset the weight of the fluid and sucker rods on the upstroke, since on the upstroke the weight of all of the sucker rods and the fluids above the bottom-hole pump are being lifted by the pumpjack. The other end of the pitman rod is linked to the walking beam. The walking beam pivots up and down and has the horse's head attached at the opposite end as the pitman rod. From the horse's head a cable connects down to the polish rod. The polish rod passes down into the wellhead through a stuffing box. The polish rod is allowed to stroke up and down through the stuffing box, where a packing material fits around the polish rod and holds back the pressure from any fluids in the wellhead. The polish rod is threaded into the top sucker rod and the sucker rods are threaded together to provide a string of rods, through the tubing down to the bottomhole pump. The bottomhole pump has chambers with a valving assembly, which passes the oil from below the pump up into the tubing and to the surface (Figure 9).
On the upstroke, the valve on the travelling barrel is seated. The valve on the stationary barrel has been forced out of its seat (lifted) due to flow of fluid from the well bore into the pump.

On the downstroke, the valve on the stationary barrel is forced into its seat (preventing fluid flow back into the reservoir). The valve on the travelling barrel is lifted by fluid moving past it into the tubing.
Objective 15: The student will explain the basic operation of the electric submersible pump and the progressive cavity pump.

PUMPS

Electric Submersible Pump

The electric submersible pump (ESP) is used in applications where higher volumes of fluid must be pumped. The electric submersible pump is run on the end of the tubing with an electric cable down the outside of the tubing. A shaft from an electric motor in the submersible unit is joined to a high speed centrifugal pump which forces the fluid pass the impeller blades of the pump into the tubing and up to the surface.

Progressive Cavity Pump

The progressive cavity pump is used in applications where the oil is viscous. This pump works on much the same principle as an auger bit, a grain auger or a meat grinder. It is basically a screw conveyor where the viscous oil is pushed through the pump and to the surface.
Objective 16: The student will explain the basic operation of a gas lift system.

GAS LIFT SYSTEM

Artificial lift can also be accomplished through a system known as a gas lift system. If a field has a large supply of gas and the number of wells and the amount of fluids to be lifted can justify the costs involved a gas lift system might be installed. For an oil well with a packer installed, gas lift involves pressurizing the annulus with gas. At selected intervals gas lift valves are installed on the tubing string. The gas lift valves allow the gas to flow into the tubing with the oil. Between the gas attempting to rise to the surface and the lighter oil column caused by the gas mixed in the oil, the oil is produced to the surface. At the surface the oil and gas are collected into a gathering pipeline system. The gas is then separated from the oil, collected, compressed and transported back to the wells. The gas is then injected into the annulus of the oil wells. In some cases, where a large gas cap exists in the reservoir, the gas pressure in the annulus is supplied by perforating the casing in the gas cap zone. In this scenario the returned gas would be injected into the gas cap rather than being delivered back to each individual well.

Gas lift systems are expensive to set up initially, due to the equipment and pipeline systems involved. Once set up, gas lift systems are effective and competitive with other artificial lift systems if the operating conditions and volumes warrant the system.
**Topic 4: Workovers and Service Rigs**

**Objective 17:** The student will define a workover and identify what type of work on a well would be constituted as a workover and define remedial cementing and list the reasons it may be required.

**WELL WORKOVERS**

After a well has been completed and has been on production for a period of time, problems may occur which require some form of work in the wellbore. Any work on the wellbore which changes the flowing characteristics of the well or repairs a problem within the wellbore can be classified as a workover. Some of the work and treatments which may be performed on a well are:

- re-perforation job,
- complete the well in a different zone,
- stimulation treatments (acid, frac),
- remedial cementing,
- chemical treatments to remove various types of deposits (dewaxing, asphaltenes (tar like oil compound), scale, sand, sulphur or hydrates (freezing off))
- repair leaking tubing or casing
- parted or broken sucker rods
- repair to a bottomhole pump

Remedial cementing or secondary cementing is a workover to place additional cement in the wellbore and/or behind the casing. Several reasons why remedial cementing may be required are:

- to plug a hole in the casing which is leaking fluids,
- eliminate channels behind the casing (poor primary cement job),
- to plug off existing perforations in a well,
- to plug off an interval producing water or gas,
• to abandon a depleted zone in a well or

• to abandon the well itself.

To assess the existing cement behind the casing a logging tool known as the Cement Bond Log (CBL) may be run in the well. This tool uses sound waves to detect the cement and the degree that the cement is bonded to the borehole and the casing.

For the remedial cement job, where the cement is to be placed behind the casing or in perforations, the cement will be pumped down the tubing and squeezed into the repair point. If the remedial cement is to be placed in a longer interval behind the casing, the well may be perforated above and below the area to be cemented and the cement will be circulated from the lower perforations and out through the upper perforations. After the cement has set the service rig may run in the hole with a casing scraper and small drill bit to clean out any residual cement in the casing.

For the abandonment of a zone or interval of the wellbore the wellbore may be filled with cement from the bottom of the well up to the necessary plug-back point. An alternative may involve setting a mechanical plug in the casing with cement pumped down the tubing on to the top of the plug. A dump bailer used by a wireline unit may also be used to place the cement. The dump bailer is a tubular container which is filled with the cement slurry, run into the well by the wireline unit and it is opened to dump the cement.
Objective 18: The student will describe a service rig and list the main types and their particular functions.

WORKOVER / SERVICE RIGS

There are different types of workover / service rigs available depending on the type of work required. The most common is the conventional service rig. The following is a brief description of the rigs and the basic duties they can perform:

Conventional Service Rig: looks very much like a small drilling rig. Unlike the drilling rig, the conventional service rig is usually a truck mounted mobile unit with a derrick, which can be folded down for transporting. The rigs will include drawworks for hoisting, a power swivel or possibly a rotary table and kelly for rotating pipe, blowout preventors and pipe handling equipment such as pipe racks, slips and tongs. Pumps and tanks may also be included in order to provide a system for circulating fluids in the well. The conventional service rig performs basic workover jobs usually involved with the tubing such as:

- heavy pulling jobs such as pulling tubing or sucker rods;
- light remedial drilling or packers / bridge plugs installed with or by tubing;
- small acid or cementing jobs, spotted through tubing, and well clean outs involving cutting or scraping tools mounted on tubing.

For well work to be conducted with a conventional service rig, the well must be "dead."

Coiled Tubing Units (CTU): are usually trucks or trailers mounted with a large reel containing a continuous coil of thin-walled, small diameter tubing (OD 20 to 38 mm, 3/4 to 1.5") which will fit inside the existing tubing of most wells. The units come with a blow-out preventor and injector head. The coiled tubing is fed to the injector head, which will push the continuous tubing string down into the well. The work which can be performed by the CTU can be done without removing the tubing and includes:

- light jobs such as spotting chemicals or cement downhole, light drilling (with downhole motor tool) and setting downhole equipment (such as tubing plugs or sliding sleeves).

Some units have electric wireline inserted through the tubing coil, which makes them attractive for logging deviated or horizontal wells. Coiled tubing units can work on "live" wells (pressure at surface).
Snubbing Units: also known as hydraulic workover rigs, are special rigs designed primarily to handle tubing in "live" wells. Snubbing units are self-contained and portable. They are set-up on top of the wellhead and can push, pull or rotate the tubing. A hydraulic cylinder allows the rig to handle one joint of tubing from the well at a time. Once the joint of tubing has been raised into the cylinder it can be isolated from the well and removed. The work duties include:

- most of the same jobs functions as a conventional service rig and
- pushing tubing in the hole (conventional service rigs can only pull).

Snubbing units are designed specially to handle work on "live" wells.

Wireline Units: are typically mounted on the back of a truck with a wire on a reel. The reel is connected to a measuring device (depth measurements) and a weight indicator. The wire is run into the well through a lubricator mounted on the top of the wellhead, which allows the wire to be run in or out of the well with pressure at surface ("live" well). There are three types of wireline units: slickline, braided wireline or electric wireline. The duties of these units are as follows:

Slickline: has solid single strand of wire and is used for:

- light pulling jobs of downhole equipment or setting equipment such as bridge plugs, tubing plugs or sliding sleeves and
- running mechanical instruments for measuring pressure or temperature.

Braided wireline: has a strong line of braided wire and is used mainly for swabbing operations or fishing jobs for tools or equipment stuck in tubing.

Electric wireline: has a braided wire with an electric cable inside and

- can performs same work a "slickline" plus.
- it can run electric logging tools and perforating tools discharged by an electric impulse.
Objective 19: The student will explain what is meant by the terms abandonment and active and suspended wells.

WELL ABANDONMENT

Well abandonments are performed once a well is no longer viable or problems have occurred in the well, which cannot be alleviated. The procedures for the abandonment of a well are as follows:

- recover downhole equipment, tubing and production casing, if possible;
- recover the wellhead equipment;
- fill wellbore with non-corrosive fluid;
- block off and isolate all productive intervals with bridge plug and cement;
- place a cement plug in the top section of the well;
- cut off casing 2m below surface level;
- weld a steel plate to the casing with a marker above ground;
- restore the surface to original conditions.

It is also possible to abandon a zone or portion of a well without abandoning the total wellbore. This is done when a lower zone is no longer producing enough oil or gas to be economically viable and another potential zone exists higher up in the well. To abandon the zone, the perforations might be cemented off and a bridge plug will be set above the abandoned zone. After this the well is available for a completion in the upper zone of the well.

The AER requires the operator of a well to apply and obtain permission before a zone or well is abandoned. For a well abandonment the AER will also issue a Reclamation Certificate, once they have inspected the location and if the surface conditions have been returned to their natural state, including the growth of seeded grass.

A suspended well is any well which has had production suspended. The AER classifies a well as inactive if it has never been completed, produced or if production has been suspend for a year or longer. For an inactive well the AER requires that the well be conditioned to preserve the wellbore and the wellbore
equipment. This can be accomplished by removing the tubing and setting a removable bridge plug in the well or setting a plug in the tubing, if a packer is installed. With the plug(s) in place, the wellbore is filled with a non-corrosive inhibit fluid to provide further security to the well.
Objective 20: The student will determine if a workover cost is classified as a capital cost or an operating expense.

CAPITAL VS EXPENSE WORKOVERS

The costs of performing workovers must be classified between a capital cost and an expense, for both taxation as well as corporate asset bookings purposes.

For taxation purposes, in general, the costs of the initial completion of a productive zone will be capitalized for income tax. Any subsequent work on the well will be considered by the government as expense work.

For corporate asset records, each company will have guidelines as to how they will classify work between capital and expense. In general, work acceptable for capital under the taxation rules, will be capitalized. Beyond this, if the work is conducted to access reserves considered undeveloped or will increase booked reserves the costs may be capitalized. This leaves work on zones to improve existing production, for repairs or for maintenance as an operating expense.

Tangible equipment (equipment which can be removed if desired) which has a significant cost, such as the replacement of the majority of a tubing string or the installation of other new equipment (packer, bottomhole pump and sucker rods etc.) is usually capitalized for both tax and corporate purposes.
Completions and Workovers - Recap of Important Points

**Topic 1: Casing and Tubular Completion Configurations**

The surface casing is the first string of pipe run into the well. It is the shallowest string of pipe and has the largest diameter. Each subsequent string of pipe is inserted inside the previous string. Each string of pipe run into the well is given a name for easy reference.

The production casing is usually run from surface to below the deepest potential zone. A liner may be used in place of production casing in certain applications. The main advantage of a liner is lower cost. The setting of production casing or liner is normally an operation performed by the drilling rig. The tubing is the smallest string of pipe in most producing wells. It is inserted into the well by a service rig and is used to provide better well control. Tubing can be easily replaced when it becomes worn out.

The procedure for cementing the production casing in place is known as primary cementing. The cement serves to hold the casing in place and to prevent fluids from one zone flowing into a different zone and thereby contaminating the fluids in the second zone.

A typical tubing or casing joint is 10 meters in length. The term “annulus” refers to the region between two concentric strings of pipe, for example, the region between the tubing and the production casing.

A packer can be used to isolate the annulus between the casing and tubing. A sliding sleeve allows access to the region between the tubing and casing above the packer.

The wellhead is the permanent hook up at ground level that is used to control a producing well.

**Topic 2: Completion Techniques**

We use the time between when the drilling rig leaves and the service rig arrives to plan the completion. We start this process by reviewing the information gleaned during the drilling process. This information comes primarily from the drill cuttings, any core data, the open hole well logs and any drill stem test we may have run while the drilling rig was on location.

A well is perforated to allow the hydrocarbons to enter the wellbore from the formation. Any one of three types of perforating guns may be: through tubing gun, casing gun and end of tubing gun. Prior to perforating, the quality of the
primary cement job is checked and the fluid in the well is converted to completion fluid (clean and non-damaging to the formation).

Load oil (oil borrowed from another well) is often used as a completion fluid for a potential oil well. The first oil produced from the new well is deemed to be the load oil which is then returned to the well from which it was borrowed.

With an open hole completion, we do not normally use a perforating gun. Although the open hole completion has many advantages, it has many disadvantages as well, including the fact that the open hole section is limited to intervals at the bottom of the hole.

Near wellbore damage may have been caused during either the drilling or the completion operation. The degree of damage can be determined by performing a flow test on the well. The damaged region can be repaired or bypassed by stimulating the well (acidizing or hydraulic fracturing).

Hydrochloric acid (HCl) and / or hydrofluoric acid (HF) are often used in acidizing operations.

When fracturing, it is common practice to insert a proppant into the open frac to keep it from healing. The ideal proppant has uniform particle size, is difficult to crush and is small and light. Sand is a commonly used proppant.

Acid is sometimes pumped into the open frac in a process known as acid fracturing. The acid etches the rock to open new flow paths in the reservoir.

Hydrostatic pressure is the pressure exerted by a column of fluid. During the completion process, hydrostatics are used to control the well. A live well is a flowing well. A live well can be killed by injecting a heavy fluid into the well such that the hydrostatic pressure of the injected fluid is greater than the pressure of the reservoir. A dead well can be brought back to life by removing the heavy fluid from the wellbore.

From the data obtained during a well test, we will be able to determine the size of the reservoir if it is very small. The converse, however, is not true. We will not have enough data from a short term well test to determine just how big a large reservoir might be.

In many instances, more than one prospective formation will be encountered in a well. The choices at this time are:

• to produce one zone at a time,
• to drill an additional well for each additional prospective formation, or
• complete the well as a multizone well.
A multizone completion is often used when there is more than one potential zone in order to reduce capital costs. For most multizone completions, the production from each zone must be segregated until it has been measured at surface. Segregation is often accomplished by using multiple tubing strings in the well.

A flow test is performed after the well has been completed. This allows us to determine the well’s deliverability and the degree of formation damage, if any. If the reservoir pressure declines noticeably during the test, we will have learned the reservoir is very small, probably not worth tying in to production facilities.

The well is completed following a step-by-step program designed by a completions specialist.

**Topic 3: Artificial Lift**

With sufficient reservoir pressure, oil wells will flow oil to the surface unassisted. When the reservoir pressure declines to the point where the oil will no longer flow to surface, we may have to install artificial lift.

The most common type of artificial lift in Alberta is the bottom hole pump. The pump is powered through the up and down motion of the pumpjack (located at surface) and the rod string, which connects the two.

The polish rod is the uppermost rod in the rod string. It is attached to the horse’s head (part of the pumpjack) and passes into the wellhead through a stuffing box.

The electric submersible pump is used in applications where higher volumes of fluid must be pumped. It is located at the bottom of the tubing string. Power reaches this pump via an electric cable that runs down the outside of the tubing.

When the oil being pumped is very viscous, a progressive cavity pump is used.

If there is a large supply of gas, a gas lift system might be used to lift oil to surface. Gas lift works by gasifying the oil in the wellbore and thereby reducing its density.

**Topic 4: Workovers and Service Rigs**

Any work on the wellbore which changes the flowing characteristics of the well or repairs a problem within the wellbore can be classified as a workover.

A service rig can be used for most workovers on existing wells but cannot be used to drill a deep well from surface to TD. For well work to be conducted with a conventional service rig, the well must be dead. Thus, a flowing well may have to be killed before we can perform a workover. A snubbing unit may be used to perform a workover on a live well.
A remedial cement job is a workover to place additional cement in the wellbore and / or behind the production casing. This may be required when the cement top is not high enough, when there is poor bond between the production casing and the wall of the hole we have drilled or when we want to plug the bottom of the hole (ie. a partial or complete abandonment of the well).

Well abandonments are performed once a well is no longer capable of economic production of oil or gas. They may also be performed if problems have occurred in a well and these problems cannot be fixed. It is possible to abandon a zone or the lower portion of a well without abandoning the entire wellbore. The AER requires the operator of a well to apply and obtain permission before a zone or well is abandoned.

After a well has been abandoned, the AER will inspect the site and once they are satisfied the site has been properly reclaimed, the AER will issue a Reclamation Certificate.

A suspended well is any well which has had production suspended but which remains capable of production.