Chapter 1: Drilling the Pay, Selecting the Interval and the Initial Design

The completion begins when the drill bit first penetrates the pay. Drilling the pay zone is one of the most important parts of the drilling procedure, thus drilling mud that is adequate for drilling the rest of the well may not be acceptable in the pay. Whereas formation damage created by the mud is acceptable in a nonproductive interval, it cannot be tolerated in the pay zone. What is needed is a mud that can control leakoff without creating permanent damage. The mud may require special treatment and occasionally, a change out of the mud to a nondamaging fluid. There are several goals in drilling besides well control that are of interest to the completions engineer.

1. Drill a usable hole - A hole through the pay that will not accept the design size of casing limits the possibilities of the well and may impair the productivity.

2. Minimize formation permeability damage - High drilling mud overbalance pressure, uncontrolled particle size, mud filtrate that swells clays and poor leakoff control may mask the response of a productive formation to a drill stem test (DST) and may lead to bypassing a producing zone.

3. Control washouts - Hole stability problems may cause hole enlargements that make perforation and formation breakdown much more difficult.

From a drillers viewpoint, there are five main functions of a drilling mud:[1] pressure control, bit lubrication, shale stability, fluid loss control and cuttings retrieval. The most important aspects of a drilling mud from a formation damage standpoint are to prevent loss of the drilling mud filtrate and to make sure that the filtrate that is lost will not react with the formation to reduce permeability. Fluid reactivity is usually controlled by using potassium chloride or other salts to stabilize the clay in the formation.[2] Potassium chloride may not always control clay reactions or may require as much as 4% or more salt where smectite clay is present in the larger pore passages. Fluid loss control is accomplished by rapidly sealing off the permeable sections of the formations.[3,4] The mud accomplishes this fluid loss control by creating an almost impermeable mud cake of particles on the surface of the formation where leakoff occurs. The mud cake is produced by simple dehydration; as the liquid penetrates into the formation (the mud filtrite), the solid particles are stranded on the surface of the formation. In a properly formulated mud, there are a wide range of particle sizes that, on dehydration, fit together into a tightly compacted, very low permeability seal. By carefully controlling the size range of particles and minimizing the clay size particles that could invade the pores of the formation, invasion damage from particles can be stopped.[4-7] In some drilling and workover fluids, fine particles and at least parts of the solids in the fluids will be designed to be acid soluble.[8]

The time required to form the mud cake will depend upon the mud characteristics, the permeability and the pressure differential, (Must be toward the formation for well control!) A higher permeability formation will generate a mud cake very rapidly than a low permeability formation since the rate of initial fluid loss (spurt) is higher. After the mud cake is formed, further liquid losses depend on the permeability of the cake. Formation of a cake does not insure that leakoff stops.

In cases where the formation matrix permeability is between approximately 0.5 md and 100 md and the pressure differential toward the formation is small ($\Delta P<100$ psi), the filtrate of even a damaging mud will not likely extend into the formation beyond a depth of a few inches provided that the filter cake is successful in controlling leakoff. To build a successful mud cake, there must be leakoff. If the permeability is very low (e.g., $k<0.05$ md), the filter cake may be only poorly formed and fluid loss could be much higher than expected. This is especially true when the pay is an upper formation in a deep well where a high density mud is used and the formation is exposed to the mud for a long period of time. Fortunately, most very low permeability formations require fracture stimulation, so the zone of damage is easily bypassed. The occurrence of the damage is important, however, since a productive interval might be missed on a test of an unstimulated well. The higher permeability formations pose special problems if the mud cake cannot be formed quickly. Since every trip out of the hole scrapes off much of the protective mud cake, the cake must reform easily to prevent the loss of large volumes of mud filtrate into the formation. Tell-tail identifiers of a permeable formation are deflections on the SP log, bit drag and where the caliper log shows a narrow spot of slightly less than the bit diameter. This sticking point should not be confused with borehole deformation; a plastic flow of the rock in response to bore hole deformation, active faulting, folding, salt domes, etc.[15]

The depth of damage created by the filtrate of the mud is directly related to the amount of driving pressure that the mud exerts on the formation. Even with a high quality mud, damage can be very deep if there is high mud overpressure. When high pressure zones elsewhere in the hole require the use of high pressure on the mud system, lower pressure zones are forced to take fluid by the pressure differential. This situation becomes critical when a zone that may be pay is broken down and fractured with the mud. Several hundred barrels of mud can be lost when the well is fractured. Some wells damaged in this way never produce as expected. The only safe way to prevent this type of fluid loss from occurring is to case through the zones requiring high mud weights before the pay zones are drilled. Improving the filter cake and making the mud filtrate more compatible with the formation is one of the best methods of controlling formation damage. The use of inhibited filtrate prepared with potassium chloride (such as 2% KCl) will often minimize the formation damage in pays with even water sensitive sandstones.

In formations that are sensitive to fluid, the total time that the sensitive zone is exposed to mud may be critical. Once a section of the well that is known to be sensitive is penetrated, operations should continue as quickly as possible until casing can be cemented over the zone. This treatment is usually reserved for sections of caving shale or other unstable formation; however, it may also be used very successfully in drilling pay zones that are water sensitive. If loss of permeability is plotted against accumulative fluid loss from the mud, permeability damage increases very steadily as total fluid loss increases, almost regardless of the type of fluid. This emphasizes the importance of maintaining a high quality mud and lowering the exposure of the formation to fluid loss.

Most of the solids and cuttings from the mud are halted at the formation face and very little penetration occurs unless a poorly designed mud with a large amount of clay or silt sizes particles are used in a formation with large pore throats. The damage from these solids is most apparent in the form of formation face plugging. Movement of the solids into the formation is dependent on the size of the pores, particle size and quantity of the finest solids in the mud. Although some tests have shown several centimeter penetration of fine mud particles into high permeability sandstone,[5] a properly conditioned mud will probably not invade the formation.

If the formation has rubble zones (very poorly sorted grains with sizes that may range from fines to small boulders), very permeable porous sections, fractures or vugs, then severe whole mud penetration may occur and produce lasting formation damage. It is very advantageous to design the mud or completion fluid to bridge off on the face of the formation to prevent the possibility of particle invasion.

When the mud or kill fluid cannot be circulated, the formation has a lost circulation zone that has very high permeability or cannot support the weight of the mud column without fracturing. For these problem cases, special pills of LCM, lost circulation material, are often run to plug off the high perm zones.[9] Where the formation will not support the mud column, a cement sheath is often tried to reinforce the zone. After setting a cement plug, the hole is redrilled. The cement invades fractures and vugs, adding strength and controlling leakoff. One problem with lost circulation material (LCMs) cases is that drillers use a variety of LCMs, such as paper, sawdust, leather, grain, etc., that are very effective in preventing leakoff but cannot be removed if the zone is a pay zone. Any LCM used in a potential pay must be easily removable.
The decision on whether a mud system should be changed before the pay is drilled depends upon the sensitivity of the pay to the mud filtrate. If the formation contains swellable clays such as smectite, a filtrite sensitivity test on core from an offset well will tell

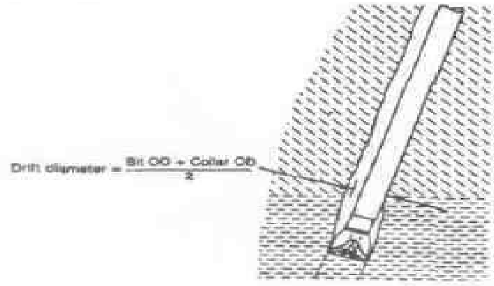
whether the formation is damaged by introduction of the mud filtrate. Where core is not available, a mud with a low damage potential (potassium chloride) should be considered. Smectite clay in the pore throats is usually reactive to fresh fluids, up to 5% or more KCI is sometimes needed to prevent clay problems in formations that have 3 to 8% smectite. In gas zones, the use of most oil-based muds should be avoided unless the mud has been proven to be of a nondamaging nature in the zone of interest. In oil or gas zones that are to be fractured, less emphasis is placed on the mud damage at the wellbore since a fracture will extend beyond the damage.

When natural fractures or vugs are present in the pay, whole mud can be lost. In these situations, it is often necessary to set a casing string above the pay and drill the formation without returns or use a fluid loss control additive capable of sealing fractures at the wellbore. Other methods, such as drilling the well while flowing and diverting the produced fluids, have also been considered but are dangerous in high pressure formations.

Because of damage by both incompatible filtrate and the migration of very small particles in the mud, the completion zone in many wells has been drilled with completion fluid. This practice eliminates much of the damage from mud and mud filtrate. The basic problem with the process is in completely cleaning the hole and pipe of residuals from the mud so that the left-over mud and cuttings do not contaminate the completion fluid. Fluid loss from solids free systems may be very high, especially in high permeability formations.

In very sensitive pay zones, the wells are often drilled with mud to the top of the pay and the pay itself is drilled with air, mist or foam to reduce the amount of water in contact with pay. Another method of reducing formation damage is to drill the pay with reverse circulation. This approach has been used in sensitive formations to limit the contamination of the mud by drill cuttings. Regardless of the formation sensitivity, well control must always be the **Number 1** priority.

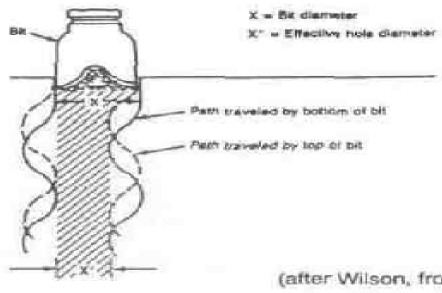
The importance of drilling a usable hole through the pay and its importance on running and cementing pipe cannot be overstated. Failure to get a casing string or a liner to bottom can be very costly in terms of cost of an additional string or liner and the reduction of working space where pumps and other equipment need to be set. Simply drilling a hole with a certain diameter drill bit through a formation does not lead to a hole that will accept a string of pipe of an outside diameter just smaller than the drill bit.[10,13] In most instances where casing cannot be run in a freshly-drilled hole, the problem is that a usable hole has not been drilled, i.e., the drift diameter of the hole is not equal to the bit diameter. This problem is shown schematically in Figures 1.1 and 1.2. Figure 1.1 illustrates problems with hard ledges or changes in formation, while Figure 1.2 shows an extreme case of bit wobble. The spiral hole illustrated in Figure 1.2 was caused by an under-stabilized bit creating a hole too small to run the planned casing. Normally, casing strings are run with 1-1/2 to 2 in. minimum clearance between the hole diameter and the outside diameter of the pipe. In a straight hole, this is adequate clearance, but in a hole with an incorrect BHA (bottomhole assembly of drilling bit, collars, and stabilizers), problems will develop during running of the pipe. Drilling "slick" (drill collars in the BHA without stabilizers) usually leads to a hole with a usable diameter significantly less than the diameter of the drill bit. Estimation of this usable hole or drift diameter is:[12]



(after Woods, from Adams)

Figure 1.1: Abrupt change in hole angle caused by drilling with an unstabilized bit through hard ledges.

$$\text{Drift diameter} = \frac{\text{Bit OD} + \text{Collar OD}}{2} \qquad (1.1)$$

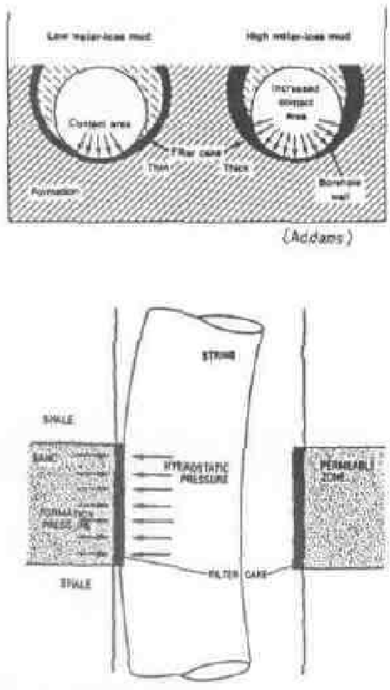


(after Wilson, from Adams)

Figure 1.2: A spiral hole caused by an unstabilized bit.

The formula points out that the usable diameter of the hole may be smaller than the bit. If the hole has been drilled with the intention of running a liner, the problem may be even more pronounced. Liners are usually characterized by close tolerances between the pipe and the hole, thus it is essential that good hole diameter stability be maintained.

The type of drilling mud may also make a difference in getting pipe to the bottom. Differential sticking is caused by a pressure differential into a permeable zone that holds the pipe (or logging tool) against the wall and buries the lower side of the pipe in the mud cake.[14] Sticking is increased by thick mud cakes because of increased contact area, Figure 1.3. An efficient mud forms a thin, slick mud cake with very low permeability. A thin mudcake keeps the pipe from becoming deeply embedded, resulting in less torque and drag.[14] The goal is a high colloidal clay-to-silt (or cuttings) ratio that produces a slick, thin cake.



(Addams)

Basic concept of differential pressure sticking shows pipe is stuck in the filter cake of permeable zones.

Figure 1.3: Differential sticking caused by *thick, spongy* mudcake. The pipe is held against the mudcake by pressure differential.

Diagnostics of stuck casing are often made after examining the drilling record and trying different types of pipe movement and circulation. A simple, stuck pipe diagnostic routine is shown schematically in Figure 1.4.[14]

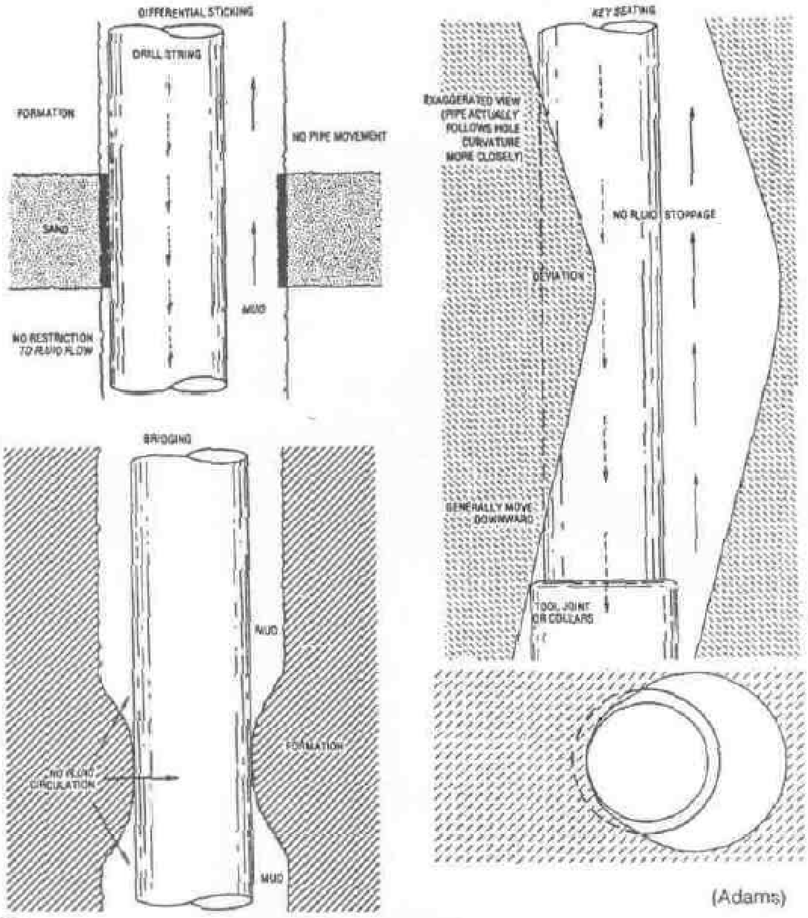


Figure 1.4: Top Left: Differential sticking-pipe held on wall by inward driving pressure. Pipe cannot move, but circulation is possible.
Lower Left: Bridging from formation debris, cuttings or formation movement. Pipe movement usually not possible. No circulation.
Right: A key seat through a dog leg. Pipe can be rotated and either pushed down or pulled up until a collar is reached. Circulation is possible.

Calculating the true vertical depth, TVD, from the measured vertical depth, MD, can be accomplished for consistent deviated wells from simple trigonometry or from tables. When wells use long turn radii, other corrections may be needed.

During drilling of wildcats or field development wells in sparsely drilled areas, mud density is handled as a function of well control, with pore pressures estimated from other data. In this type of environment, high mud overbalance conditions may occur, especially in deep formations. Although fracturing is the most obvious effect of high mud weights, excess formation permeability damage may also
occur. In a study of factors influencing stimulation rates, Paccaloni, et al.,[16] reports that in formations greater than 100 md, 90% of DST's were dry or doubtful when an overbalance of over 1100 psi was used during drilling. Excessive mud overbalances should be avoided in pay zones.

Coiled Tubing Drilling

In addition to jointed pipe drilling, coiled tubing (see Chapter 18 for Coiled Tubing Equipment and Techniques) can also be used for drilling and milling in some applications. Coiled tubing offers several advantages and a few current disadvantages that should be explored for their potential in completions and workovers. One of the best uses of coiled tubing drilling may be in combination with underbalanced drilling "where the well is allowed to flow during the drilling operation."

The simplest coiled tubing drilling bottomhole assembly (BHA) includes a bit, mud motor, stabilizers or collars, the connector and the coil. The abilities of coiled tubing for drilling include a continuously fed fluid transfer mechanism (the coil) with no tool joints. This one feature allows the smooth external wall that can be sealed very easily at the surface. Fluids returning from downhole up the annular area are vented under pressure to surface separation equipment and small kicks and gases can be handled easily.

In many of the first examples of coiled tubing milling and drilling, the mud motors which provide turning ability at bit often stalled or stopped turning because of excess loads placed on the bits from either the string or the bottomhole assembly. This reoccurring motor stalling problem resulted in very slow penetration. Motor stalls typically occur when downward forces (weight and force) at the bit are greater than the ability of the motor to turn the bit. There are a number of reasons for motor stalls.

1. Too aggressive a bit or mill design will require excessive power to turn. Less aggressive (smaller teeth) milled and bits are easier to turn, although they may drill some materials slightly slower.

2. Coiled tubing milling and drilling typically uses smaller motors with less torque. The smaller motor design utilizes very small clearances and small loaders and stators in the mud motors.

3. In deviated wells, trying to apply force on coiled tubing from the surface may result in first sinusoidal and then helical buckling. When buckling occurs, regardless of its location in the wellbore, the stored energy will try to work its way either up or down and add an extra force against the bit the surface unit.

4. The injector feed control at the surface is often a major source of the problem. The injector is a source of all upward and downward force exclusive of drill collars and other weight. Ideally, the feed of the coiled tubing through the injector should be no faster than the penetration through the bit or mill. If too much tubing runs through the injector at any time, the total force on the bit increases and a motor stall may occur. For best results, very slow speed or micro movement of the injector head should be possible in any unit used for coiled tubing drilling.

Under-balanced Drilling

Traditionally the main goal of any drilling operation was to keep control of the well. This resulted in a positive pressure from the wellbore outward into the formation stopping the inward flow of all reservoir fluids. Underbalanced drilling with a pressure contained system allows the formation fluids to flow into the wellbore and prevents invasion of the drilling fluids into the formation. Although this method is more difficult to handle with its increasing amount of fluid recovery, it does provide the very best method of damage-free drilling. The elements of an underbalanced drilling system include a contained, safe, surface system that can separate solids, liquids and gases. This type of a separator system generally uses solid separation equipment and a horizontal separator to separate liquids and gases. Other important aspects of underbalanced drilling include adequate hydraulics of the fluid circulation system to allow bit lubrication, cooling and hole cleaning, plus sufficient pressure in the wellbore to prevent full-scale hole unloading. Typically, underbalanced drilling attempts to maintain from 1/2-2 lb per gal under the pore pressure. Depending on the permeability of the formation and the type of fluids flowing, the pressure might have to be adjusted to keep the solid separation facilities within their reasonable operating limits.

Slimholes

Slimhole drilling has become a popular concept in recent years. Although smaller diameter holes are theoretically cheaper to drill because less formation is actually removed, they are not always a cheaper hole to drill. Cost of drilling involves not only the time to cut through a part of the formation, but also involves the use of existing (paid for) versus new and smaller equipment, and several other factors including pressure control and the cost of the completion. Many times it has been found that drilling a smaller hole actually costs more than drilling a traditional hole where costs of normal sized equipments was very cheap in comparison to special ordered newer and smaller equipment.

Pressure control during drilling or workovers in small wellbores is often very difficult. An example, shown in Chapter 15 on workover fluids and control, shows that the volume of a 1 bbl kick in a small diameter (3-3/4 in. hole) versus a large diameter hole (9-1/2 in.) may result in several hundred psi difference just from the volume of the hole filled by the 1 bbl kick. When drilling or working over holes with small diameters, accurate trip tanks and a functional alarm system must be used to minimize danger from kicks.

Initial Completion Design

Selecting the Pay Zone

Selecting the pay and deciding where to place the wellbore are two of the most important pieces of engineering that most occur in the completion process. Many rocks from shales to fractured granites contain hydrocarbons, but, not every rock type or reservoir can qualify as a pay zone. Selection of the pay breaks down into several basic considerations:

1. Prospect development economics,
2. porosity and permeability requirements,
3. hydrocarbon type and saturation requirements,
4. recoverable hydrocarbon volumes (by primary, secondary and tertiary methods),
5. pressure support,
6. reservoir stability,
7. recognition of compartmentalization,
8. availability of technology to cost effectively produce the reserves,
9. ability to plug and abandon the reservoir,
10. environmental and other risks.

The economics of a project depend simply on whether enough money can be made from sale of the productive hydrocarbons in a limited amount of time to offset the total costs of the project. The associated cost of the project may include a variety of finding, development, production and abandonment costs. Among these costs are: prospect leasing, field development, field operation, royalties, interests on the money used, profit, risks, plug and abandonment costs and contingency funds for all matters problems such as blowouts and cleanup operations. Substantial deposits of crude oil and gas are known in many parts of the world, but cannot be currently produced because the production rates cannot offset the cost of development and operation. Every year many of these (outer limit) deposits are being brought on-line as producing reservoirs as technology is being developed or the cost of development drops through other factors. Even the cost of Deepwater developments, for example, which can be in the hundreds of millions or even billions of dollars can be economic if risk can be reduced and if the production rate from the wells is high. Every project from the shallowest stripper well at 2 bpd to the 100 mmscf/d or 30,000 bpd oil wells must be judged by some risks versus cost recovery and profit factor.

Porosity and permeability are the reservoir storage and pathway of flowing fluids. Porosity is the void space between the grains in which fluids can be stored. Permeability is a measurement of the ability of fluids to flow through the formation. Rock such as shales and chalk, for example, may have extremely high porosities approaching 30-40 percent, but the porosity is not linked together, thus the permeability is very low. On the other hand, naturally fractured formations may have extremely high permeabilities approaching tens of darcies in some cases, but have very low porosity, often only 4-6 percent. The amount of porosity and permeability necessary for a project depends on the production rate needs, although, operations such as hydraulic fracturing can increase the production rate of a well by a factor of 2 to 10 or more. Fracturing alone may not make the project economic. The economics of a project are such that every factor must be weighed in turn in the economic justification and critical factors, such as hydrocarbon storage and the permeable pathway, must be available before even a huge reservoir with billions of barrels of oil can be made productive. In reservoir selection, often times a porosity or permeability cutoff is used for pay versus nonpay identification. Recognition of this level from porosity logs and flow tests are often critical in establishing minimum pay requirements.

Hydrocarbon type and saturation determine the amount of hydrocarbons that may occupy the pore space of a reservoir. Many factors such as moveable versus irreducible saturations and changing factors such as relative permeability can make the saturation and permeability values "moving targets." There are no set minimum values for hydrocarbon saturation, however, the best parts of the reservoir will usually have the higher values of hydrocarbon saturation. Saturation of water may also be a key in pay identification. Extremely high saturations of water may indicate hydrocarbon depletion or movement of an aquifer into the pay.

The recoverable hydrocarbon volumes are usually calculated form the measured values of porosity and saturation. Oil in place quantities do not indicate that all of that oil can be recovered. The porosity of a formation varies from very large pores to very small pores and the oil in very small pores often will not flow from the small capillaries even under very high depletion pressures. How much oil will flow from a rock is dependent on the size of the pore spaces, the oil saturation and type and the amount of energy available to push the oil towards the wellbore. Recoverable hydrocarbon estimates may vary many percentage points from what reality shows later on. The differences many times are in how well the pressure supports the drive mechanism in producing the fluids.

The pressures in the reservoir dictate how much fluid will ultimately be recovered. Many different types of pressure supports are available. The typical pressure support mechanisms include bottom and edgewater drives, gas cap drives, volumetric depletion and other pressure sources such as reservoir compaction and other factors. Each of these pressure support mechanisms has advantages and disadvantages to deciding recovery in a reservoir. Among the most effective types of reservoir pressure support are the bottom and edgewater drives. These systems may maintain pressure at initial values clear to the end of the project. The problems with them is they may produce large amounts of water along with the oil. Volumetric depletion is usually found in a sealed reservoir and then the reservoir may deplete without producing any water. The recovery, however, from this types of reservoir is extremely low, since reservoir energy bleeds off very quickly. Pressure support can be added, in some cases, by the use of water floods, gas repressurization or other types of pressure maintenance such as tertiary floods. When factors such as bottomwater or edge-water drive are recognized early, the location of the wellbores can be selected to take advantage of flow paths of the drive fluids and recoveries can be enhanced.
Reservoir stability is an issue which may effect the initial completion or repairs or recompletions throughout the life of the reservoir. Many geologically young formations lack sufficient strength for formation coherency during all phases of production. Recognition of this stability issue is usually easy because of rapid drilling rates, sand strength issues in the wellbore or other factors. The decision on adding a stabilizing completion is usually made after consideration from initial flow tests and other factors. The most common methods of completion in low stability reservoirs are frac packs and gravel packs. Other types of

completions may include resign consolidation or production rate restriction to avoid sanding.

Recognition of compartmentalization is probably one of the most important factors in the initial design of well completions for a project. Compartmentalization is the division of a reservoir into partial or fully pressure isolated compartments by faults, permeability or porosity pinchouts, folding, shale streaks, barriers or other factors. When compartmentalization is recognized, the location and type of wellbores can be selected to efficiently drain the compartments and to take advantage of fluid flow patterns within the reservoir. Many of the failures of even large fields can be traced to a failure to recognize compartmentalization during the early development steps in the reservoir.

The availability of technology to produce the reserves is an area which keeps the oil industry active in research and development. Technology such as water flooding, hydraulic fracturing, artificial lift, cold flow of heavy oils, coal degassification and many other projects have increased the worlds recoverable hydrocarbons and continue to be a critical part of meeting the worlds energy needs. When the reservoir flow patterns and other factors are understood, technology can often be developed within a moderate time frame to meet needs in specialized reservoirs.

The ability to produce hydrocarbons should never outstrip the ability to control the flow or the ability to plug an abandoned reservoir. Plug and abandonment intentions must take into account that the reservoir should be left in as good a condition as possible for potential tertiary operations that may recover even more fluids. Plug and abandonment costs can be a significant amount of the project cost. Offshore plug and abandonment of fields may reach over 100 million dollars. There are many associated risks, both political and environmental in developing and producing a hydrocarbon depositry. These risks must be taken into account during the economic justification for the reservoir and should offer as good a solution as is possible to the legitimate concerns posed in any situation.

Once the values are known, selection of the pay can begin. The selection process uses a number of pieces of information gathered by electronics and other factors.

The objectives in this chapter will be to establish ground rules about what general completion mechanisms have the best fit to the reservoir potential.

Completion design is a function of reservoir characteristics. The problem is that reservoir data, particularly the design sensitive data such as permeability, porosity, saturations, pressure, barriers and longevity, are only fully available after most of the wells in the field have been drilled, completed and tested. In many cases, after initial drilling and completion, reservoir barriers are finally recognized and extreme redrilling or stimulations are needed to process the reservoir. The key to a good initial completion is to collect and assess the data at the earliest possible time, to allow the best early choice of completion.

Successful completions recognize the flow characteristics of the reservoir. There are a number of completion possibilities; each with a limited "fit" to the reservoir properties. The following is a general listing of the completion types with a few of the reservoir variables. The numbers for most variables are typical but only general estimates.

Vertical well open hole natural completion	High permeability ($K_h \geqslant 10$ md for oil, $\geqslant 1$ md for gas) stable formation (no movement or spalling) no bottom or edge water drives, low K_v($K_v < 0.5\ K_H$ (or deviated wells not considered possible no fracture planned/possible, no limits on surface reservoir access laminations not “frequent”

Vertical well cased hole natural completions	High permeability ($K_h \geqslant 10$ md for oil, $\geqslant 1$ md for gas) possibility of spalling (no sand movement) bottom or edge water control needed, low K_v ($K_v < 0.5\ K_H$) (or deviated wells not considered/possible) no fracture planned/possible no limits on surface/reservoir access laminations not "frequent".
Vertical well open hole frac planned	No limits on permeability, stable formation (no movement or spalling), no bottom or edge water drive control, needs low K_v ($K_v < 0.1\ K_H$) (or deviated wells not considered/possible), no limits on surface/reservoir access, multiple frac not planned, laminations not frequent in zones not fractured, bottom/edge water not penetrated by frac.
Vertical well cased hole frac or frac planned	No limits on permeability, 180^o perforating and screenless pack frac for sand control, 120^o, 90^o, or 60^o phased perfs for other fracs, low K_v ($K_v < 0.1\ K_H$) (or deviated wells not considered/possible), no limits on surface/reservoir access, multiple fracs planned (all heavily laminated zones fractured), bottom/edge water not penetrated by frac.
Vertical well open hole gravel pack	High permeability ($K_h \geqslant 10$ md for oil, $\geqslant 1$ md for gas), laminations not "frequent" (h < 2 ft), no bottom or edge water drive, control needed, low K_v ($K_v < 0.5\ K_H$) (or deviated wells not considered/possible), no limits on surface/reservoir access, very high production rates possible, gravel packs only where sand control needed.
Vertical well cased hole gravel pack	High permeability ($K_h \geqslant 10$ md for oil, $K_h \geqslant 1$ md for gas), laminations not "frequent" (h <2 ft), limited bottom or edge water control needed, low K_v ($K_v < 0.5\ K_H$) or deviated wells not considered/possible), no limits on surface/reservoir access, gravel packs only where sand control needed.
Deviated path approach vertical well in play	Surface/reservoir access limited, deviated wellbore in pay not practical/possible, laminated zones, zones with barriers.
Multi-lateral well vertical or horizontal	Surface/reservoir access limited, thick layered pay zones, multiple well types needed, compartmentalized reservoirs, wellbore placed mostly for water control, wellbore placement for sweep/drainage, very limited need for reentry (unless mechanical system used), no pressure isolation needed.
Horizontal well open hole	$K_v >> 0.5\ K_H$ or plan to frac, no inter bed barriers, no sealing lamination unless plan to frac, stable formation (no movement or spalling or plan to gravel pack), good bottom water control possible, surface/reservoir access restricted.
Horizontal well liner	$K_v >> 0.5\ K_H$ (unless plan to frac), no interbed barriers, no sealing laminations, (unless plan to frac), some spalling control, no sand control problems, no multiple fracs planned (unless isolation packers set), limited bottom water drive control, production logs/isolation not needed.
Horizontal well cased	$K_v >> 0.5\ K_H$ (unless plan to frac), no interbed barriers, no sealing laminations (unless plan to frac), no vugs or natural fractures (severe cement damage, unless plan to frac.

Special considerations:

1. Steeply tilting pay: examine hydrocarbon and water fluid flow path to wellbore including effects of K_y and K_H. Also investigate fracture growth and path. May choose uphill horizontal wellbore to go after "attic" or up-dip reserves that are above vertical well contact.

2. High permeability "streaks": The size and permeability contrast to the reservoir location with respect to oil/water contact can significantly affect production or water break through. Orientation of the well path or decision to frac may be affected.

3. Salt or techtonic forces: Salt "flow" may produce extreme loads on casing. The normal approach requires concentric dual casing strings with annular spaces cemented. Techtonic forces, and some horizontal collapse forces may create point loads on the casing which are better handled by extremely heavy wall casing strings.

4. Sweep/Floods: Well placement to process a reservoir uses the permeability pathways for best advantage. Wellbore location, orientation and deviation may be influenced.

5. Fluid Requirements: Heavy oil, scaling, organic precipitation, chronic emulsions, bubble and dew points and other special requirements may make completion compromises or redesigns necessary.

6. Multiple Zones: multiple zones completions and independent completions may be required by pressure, fluid or royalty owners.

7. The initial design is the starting place for the completion, however, it should never be construed to be unchangeable. Flexibility is required for any completion to take advantage of information that can be obtained from drilling or other sources.

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