CHAPTER FIVE

*****

AN OVERVIEW OF OIL EXPLORATION, DRILLING AND PRODUCTION

INTRODUCTION

An overview of oil exploration, drilling and production may seem a little out of place in one's autobiography, as I intimated in the Preface and even attempted to justify therein. However, feeling my effort was a little puny; I have decided to enlarge on it before getting into the details of the overview.

This overview could, in fact, be a little misleading in that it covers only those facets of the business Schlumberger was directly or indirectly involved in. It is far from a comprehensive description. The oil business is composed of an extremely complex group of operations involving many major disciplines of science, engineering and business. My objective is to present a view of that portion in which I was most closely associated so as to make my personal history more meaningful and understandable to the uninitiated. Even in these closely associated areas, my knowledge is rather superficial, at best, having been gained through association with reputable people working in those disciplines for the various oil exploration and producing companies as well as through reading and involvement with personnel of certain drilling companies. Such knowledge is also dated in that I left the business some 23 years ago and numerous changes have most certainly occurred. Even so, the principles involved are still the same and the descriptions in general should be reasonably accurate. Thus, I believe I can lay a background, which will be readable and which will make my experiences as described in chapters 9 through 16 more meaningful. I might add that I found my association with people of the geologic, geophysical, petroleum engineering and drilling professions extremely rewarding, in an intellectual sense, as I had opportunities to discuss their problems and how our services might be of benefit to them. It is through such circumstances that most of my limited understanding has been developed.

EXPLORATION PRINCIPLES/TERMS

THE EARTH'S CRUST

Geophysical and geological studies indicate the earth's crust surrounds a molten core and essentially floats thereon. It is composed of so called tectonic plates, which form the continents, as well as the bottoms of the various oceans and seas. Their movement relative to one another produces certain degrees of stress throughout the earth's crust, which in turn results in earthquakes and volcanic activity. Earthquakes of consequence usually occur along major fault lines where the earth's crust has been fractured or cracked because of the various stresses, which constantly build up until they are relieved. However, numerous fractures or faults of lesser magnitude have also occurred and continue to occur throughout the crust from forces not necessarily related to plate disturbance and with little or no seismic activity of consequence. These faults play a major role in the oil business and will thus be described in more detail later.

COMPOSITION OF THE EARTH'S CRUST

The earth's crust is made up of three principle rock types, i.e. igneous, metamorphic and sedimentary. It is primarily the latter rock type that is involved in the oil business although we occasionally had experience with the others as well. Conversely, hard rock mining or mining for valuable metals, typically involves igneous and metamorphic rock with some sedimentary rocks coming into the picture. If I remember my geology correctly, one can further subdivide the sedimentary rocks into clastics, precipitates and evaporites. Clastics are sediments whose components or individual grains are transported by mechanical means, i.e. water, air or maybe gravity, from a site of origin to the depositional site whereas the other two are derived from dissolved minerals which are either precipitated through pH and salinity changes or left by complete evaporation of the water which originally contained them. All types are encountered in oil and gas exploration and introduce differing problems when drilling, evaluating or completing a well. I'll try to be a little more specific in the following descriptions.

SEDIMENTARY ROCK PARAMETERS

In describing sedimentary rocks various terms and adjectives are used to denote mineral content, variation in grain size, the empty or fluid filled space within the rock and the rock's ability to allow fluid flow through its matrix. Mineral content can be extremely variable but common adjectives are shaley, anhydritic, calcareous, etc. They simply mean that a percentage of the rock matrix is made up of such minerals through original deposition or later cementing of the individual grains. This can be extremely important in determining just how a rock will react to drilling and completion fluids. The variation in grain size found in sandstone is described by the term "sorting" such that poorly sorted sandstones would have many grain sizes within their matrixes while well sorted sandstones would have grains of relatively constant size. Empty or fluid filled space is referred to as porosity and basically describes the percent of volume, which is capable of storing fluid, hopefully oil and gas. The ability of a rock to conduct the flow of fluid within its matrix is termed permeability, which is very important in determining how well a given formation will be able to produce fluids. The percent of void space containing water is described as the water saturation whether a rock contains hydrocarbons or not. The remaining void space is usually filled with oil or gas. If so, we can then describe water saturation in a mathematical sense as being described by the following equation;

$$1)\ S_w = 1 - S_h$$

Where S_w signifies water saturation and S_h denotes hydrocarbon saturation. Without getting too mathematical, such void space, referred to as porosity, contains one or more of the three fluids, i.e. water and maybe some combination of the other two. While a well is being drilled, a geologist examines the drill cuttings, which have been pumped to the surface, through a microscope for traces of oil or gas. He also observes the effects of various chemical agents on the cuttings to establish their composition. Similarly, the mud or drilling fluid is analyzed for traces of oil or gas. I'll leave this particular topic for now and discuss it in more detail later when we get to Schlumberger services.

In describing sedimentary rocks different terms and adjectives are used to denote mineral content, variation in grain size, the empty or fluid filled space within the rock and the rock's ability to allow fluid flow through its matrix.

CLASTIC ROCKS

The so-called clastic rocks (composed of fragments of older rocks) can be roughly classified into three categories according to grain size. These are most commonly known as conglomerates, sandstones and shales. Additionally, these classes are further subdivided into various classes of differing descriptions.

CONGLOMERATE

A conglomerate is made up of poorly sorted rocks and pebbles indicating a high-energy depositional environment meaning the currents carrying such rocks had to be swift to accomplish the task. Grain size is obviously large. Porosity is variable but generally on the high side as is permeability. Their occurrence is rather common and they constitute the matrix rock of some oil reservoirs even though I am unfamiliar with such cases.

SANDSTONES

Sandstone contains smaller grain sizes than the conglomerates do, which indicates the individual particles were deposited by slower or lower energy currents. They may vary from "well sorted" to "poorly sorted" which means grain size will be relatively constant to highly variable as mentioned earlier. This sorting impacts both porosity (amount of void space) and permeability (ability to allow fluid flow). Consequently, it is a critical parameter, which is described by the well site geologist. Mineral content, separate from the individual grains, also impacts both porosity and permeability. It may be laid down in original deposition or added later through circulation of ground water. Thus, it too, is very important. Sandstones typically contain the oil and/or gas in a well, when they are found in favorable circumstances, and are referred to as reservoirs. In general, the higher the porosity and permeability of a formation, the better the reservoir will be in terms of oil or gas production.

SHALES

Shales are deposited in low energy environments and contain very small particle sizes. Such particles float with little or no current and are typically deposited in quiet waters, often deep and far away from the mouth of a river emptying into a lake or sea. They can contain many microorganisms living in the associated waters. Such organisms become an integral part of marine shales, which are considered the source of most oil and gas. Supposedly the oil or gas moves into surrounding permeable beds, e.g. sandstones, limestones and dolomites, as the shales are subjected to heat and pressure. Through gravitational means (they being lighter than water) oil and gas will move along a permeable bed or layer of rock, displacing the so called connate water, until stopped by some impermeable (no permeability) obstruction. This is termed a trap and allows the hydrocarbons to collect in varying quantities.

PRECIPITATE ROCKS

Precipitates or rocks formed of such material are laid down when materials such as calcium and magnesium, which are typically dissolved in seawater, reach saturation levels and the water can hold no more. The dissolved mineral is then precipitated and falls to the bottom as a solid. As it collects, a sedimentary bed is formed. At times such beds form around reefs or the calcareous (bony) remains of living organisms, which then make up part of the rock. Important precipitate rocks in the oil business are limestones and dolomites, which can contain oil and gas. Other associated common precipitate rocks, which can create evaluation, drilling and production problems, are anhydrite and salt. Less common precipitates may also be present creating diverse problems. Carbonates, as limestone and dolomite are frequently referred to, develop porosity and permeability as they are fractured (cracked) and worked on by water percolating through them. Thus they also become oil and gas reservoirs under favorable conditions. Earlier mentioned reefs are important carbonate reservoirs because they typically have high porosity and permeability but unfortunately, are of limited areal extent.

EVAPORITES

Many different mineral deposits are formed through evaporation of seawater under proper conditions and can be economically important. Such deposits aren't related to the oil and gas business, per se, but a variety of big companies may seek to find and produce them. They may be encountered as oil and gas wells are drilled and thus Schlumberger engineers became conversant with them. Mining companies would call a local office, at times, to help evaluate suspected deposits in shallow drill holes but they were only a small fraction of Schlumberger's business. Typical minerals often encountered were, phosphates, potash, trona and coal, although others might occur occasionally.

Coal, though not an evaporite; is another rock we often got involved with when coal companies

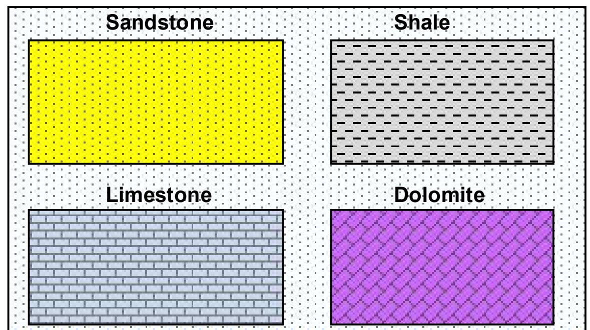

Figure 5-1 Graphic Symbols of Lithology or Rock Type of Common Oil Field Rocks.

tried to define the economic limits of deposits for strip mining. Such deposits resulted from massive coastal swamps, which were buried and eventually compressed to form peat bogs first and ultimately coal, according to geology. Coal may also occur relatively deep in the earth as in some areas of Wyoming, for instance. I have encountered it in massive beds, as deep as 6000 feet, while logging oil wells. Such deposits are too deep, presently, for economic retrieval but may be useful in the future.

EXPLORATION METHODS & TERMS

Hydrocarbon traps, mentioned earlier, provide a mechanism whereby oil and gas can collect as they migrate through permeable beds in the earth's crust. There are a number of different kinds and they are varied in trapping principles and complexity, which makes it virtually impossible for a person of my limited understanding to describe them all. However, I feel confident that few of you would be interested in them anyway. In fact, the same might be said for each trap I do include but that's your tough luck. However, being rather thoughtful in nature I will only attempt to describe a couple of different ones with which I am familiar and which I feel should provide the background I'm interested in developing. Notice, I said with which I am interested not with which you are interested.

MAPPING PRINCIPLES AND SYMBOLS

COMMON TYPES OF MAPS

Drawings of maps and cross-sections are used in visualizing sedimentary beds and common trapping mechanisms. Maps help a person visualize the lateral extent of a given feature while cross sections provide a vertical view. The latter term may be new to some of you and consequently deserves a short description. It is nothing more than the view of a given phenomenon one would get by slicing through it in a specified direction and observing the face of the slice. The vertical cross section is most common in geologic descriptions. It will be used liberally in this chapter. As a consequence, you must, once again, suffer along as I engage in my artistic efforts, at least, if you aren't familiar with this particular concept and still have a little desire to digest the material in this section.

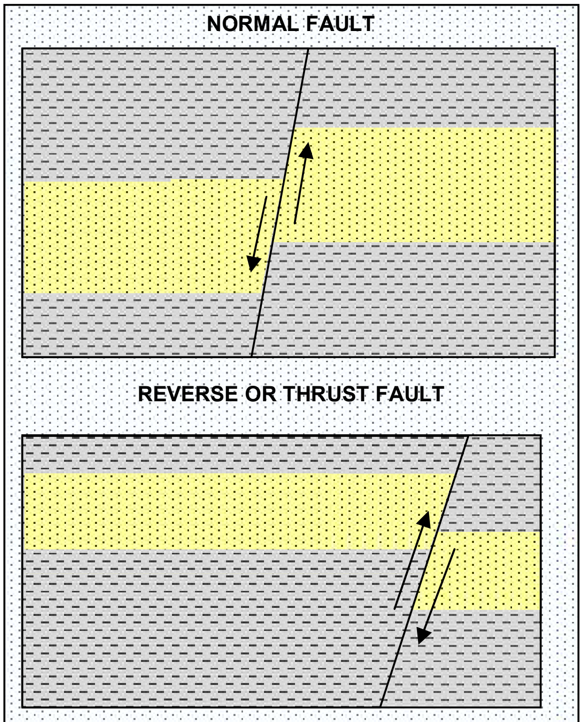

Figure 5-2 Graphic symbols for the normal fault (top) and reverse fault (bottom).

LITHOLOGIC OR ROCK SYMBOLS

I'll begin with some common graphic symbols used to describe various lithologies (rock types) and structures (faults, anticlines, etc.). Consider figure 5-1 which graphically summarizes four common oil field rock types. They should be sufficient to illustrate necessary sedimentary cross sections and associated structure. As you have probably already figured out, such symbols represent a layer of rock as viewed from the side when sliced through vertically. Those of you, who might be familiar with such symbols, forgive the crudeness of mine. After all, I'm limited by my drawing tools and skill as well as my memory of the exact appearance of these symbols. In any case, they'll have to suffice.

TYPES OF FAULTS

Faults occur when layers of rock undergo either compression or tension beyond their elastic capability to give with the force. Thus the rock fails producing a fracture or crack along some weak zone, typically with some movement. Both vertical and lateral movement can be associated with a fault, which, if sufficiently strong, is identified as an earthquake. In describing faults in a cross section, movement is illustrated by arrows showing the relative direction of that movement. Figure 5-2 demonstrates this method of description.

Notice there are two basic types, i.e. a normal fault usually produced by tensional forces and a reverse or thrust fault produced by compressional forces. They typically cut across numerous beds resulting in missing section (a normal fault) or repeated section (a reverse fault). I'll explain that phenomena in more detail later. Both are common but the normal fault occurs more frequently, at least in my experience in the oil field. There might also be a movement component at right angles to the dip or tilt of the fault plane. That is, in figure 5-2, a three dimensional model including this cross section might show movement at right angles to it, i.e. in or out of the page.

ANTICLINES AND SYNCLINES

Compressional forces in the earth's crust produce folds (i.e. anticlines and synclines) in addition to faults. An anticline is an upward bow of sedimentary beds while the syncline is a downward bow. Both are common and are frequently seen in surface rocks in the western states. Thrust faults may accompany folding where lateral forces have been severe. Normal faults also accompany folding but probably occur after compressional forces are removed. Cross section representations of both anticlines and synclines are illustrated in figure 5-3. It should be noted that such warping of the earth's crust might occur over localized areas, which are relatively small in size or, over significantly larger areas up to semi-continental in size. The latter are such massive folds that they include many wrinkles or other lesser anticlines and synclines within their confines and are referred to as geo-synclines or geo-anticlines. For our purpose, however, we'll talk about the more localized anticlines, which become a trapping mechanism for oil and gas as they migrate along permeable beds in search of a resting place.

MAP TYES

Cross sections are a type of map. Though vertical in nature, they still indicate relative depth of the various horizons along a specific bearing and in a specific horizontal position. Of course, as bearing or horizontal location change, so will the cross section. Thus, maps in horizontal or plan view, with some parameter of a given vertical horizon are also essential to describe an oil prospect. They come in all shapes, sizes and types. The most common types utilize contour lines to illustrate a parameter pertinent to a study such as elevation, thickness, pressure, temperature, etc. For the uninitiated, a contour line could be defined as a line connecting points of equal magnitude for a given parameter as described above. A given line connects all consecutive points of equal magnitude without crossing one of a different value. As an example, consider figure 5-5 which is a surface contour map illustrating two hills and a valley. It is a map describing the elevation of the ground in the area of interest. If a person walked around one of the hills while maintaining a constant elevation or height on the hill, he would follow a contour such as 5300' shown on the map. If we wanted to slice through the map of the hills and look at the resulting vertical cross section, we might indicate on the map just where we intend to do that by a straight line and label it A - A' or B - B'. On our map such a cross section A - A' is to be taken and is so indicated. The cross section itself is then illustrated in figure 5-4 for comparison purposes. Compare the relative depths if you care to.

A person can visualize the degree of slope or steepness of the topography on the contour map as well, by noting the spacing between the contours. Closer lines indicate a steeper slope and vice versa. Such a map could also represent variations in formation thickness, in temperature or in pressure depending upon the parameter of interest. Similar remarks could then be made regarding the rate of change in magnitude of those particular parameters. Contour maps and cross sections are drawn by the geologist utilizing control data, i.e. measured units of a given parameter such as elevation or any others, like thickness, temperature, pressure, lithology, etc. He then visualizes a structure or other regime he is mapping which fits the control data. The resultant contour map represents his interpretation of that control data and is constantly updated and refined as additional empirical information is obtained.

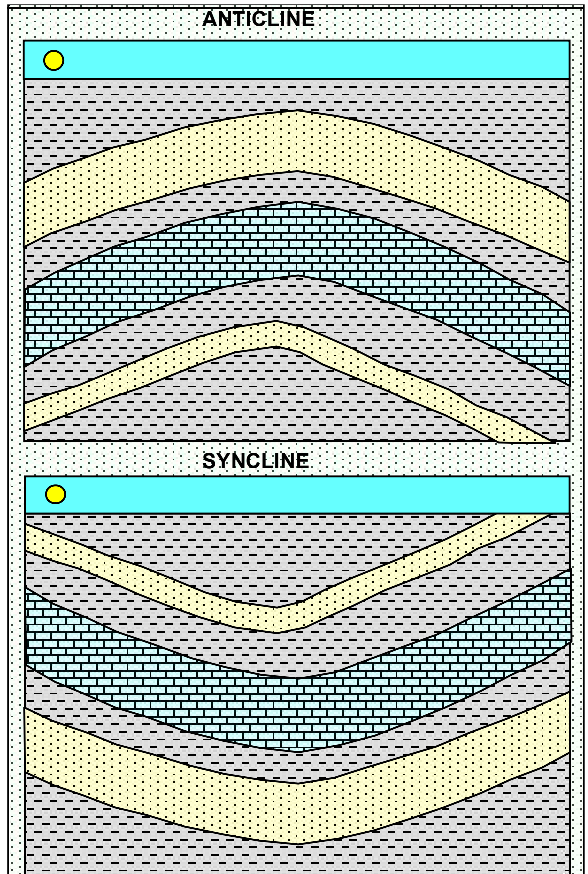

Figure 5-3 Graphic symbols for an anticline (top) and a syncline (bottom).

MAP CONTROL

In the case of oil field maps, the best control data is obtained from wells drilled within the map area. Such wells provide hard data at specific map points and thus validate the map at those points. The resultant map then becomes a vehicle, which guides decision-making such that any additional drilling is done in the more favorable locations. Of course, as continued drilling takes place, map accuracy improves, as does the placement of future wells because of the complementary nature of these two activities, i.e. mapping adjustments and drilling.

SEISMIC DATA

Obviously, in new areas where no nearby wells exist, i.e. a wildcat, any map must be hypothesized through some other means or source of data, usually geophysical. Such data comes from seismic records wherein the depth, attitude and thickness of a given formation can be determined with some degree of accuracy. Seismic data, like geological data, is improved through the drilling of additional wells and thus obtaining more accurate velocity information at various depths in the well bore. Such data may result in the recognition of one or more lithology changes or variations of rock type.

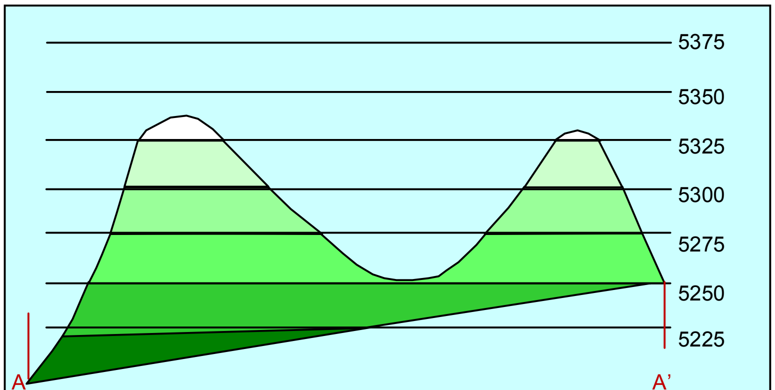

Figure 5-4 Cross section A-A' taken as illustrated from the contour map of figure 5-5 immediately below.

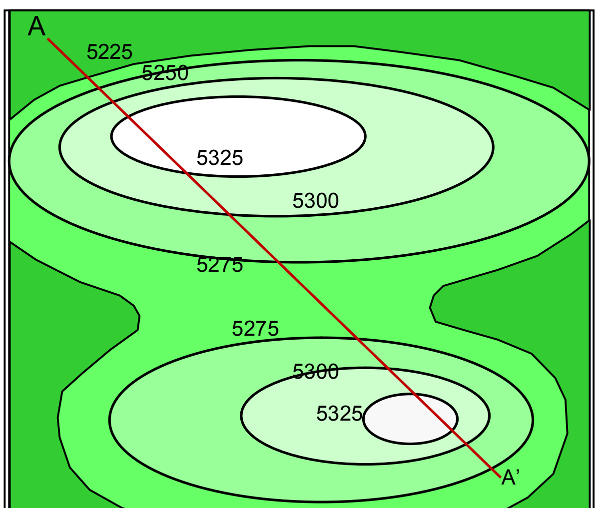

Figure 5-5 Surface contour map with an accompanying cross-section A-A'.

Seismic data is obtained by activating a high-energy sound source in short bursts. The resultant sound waves penetrate deep within the earth with a portion being reflected from the various boundaries of rock layers they encounter. The time required for these reflections to appear back at the sound source is measured as they return from the different horizons or formations found in the earth's crust. Initially, many assumptions have to be made which, of necessity, are upgraded with actual well information when it becomes available. Thus, geologists and geophysicists work together with their maps from different data sources to reach agreement on a probable structural and depositional model that seems most likely to be involved. All of this work is done to improve the chance of success of the next well or, maybe we should say, reduce the risk of failure. Dry holes, of course, are costly and though the data obtained may be valuable, the hole has no other economic value.

EXAMPLES OF TYPICAL TRAPS

As has been previously mentioned, oil and gas appear to originate in shales, which are rich in decaying plant and animal life. These hydrocarbons are squeezed into porous and permeable beds or formations nearby, through temperature and pressure; as such shales are buried deep in the earth's crust. These beds also contain seawater of variable salinity, i.e. differing amounts of dissolved salts, mostly NaCl (Sodium Chloride). Thus, the gas and/or oil entering the porous beds intermingle with the water present to form a three-component fluid.

FLUID MOVEMENT AND ENTRAPMENT

Of the three fluids (gas, oil and water), gas is the lightest or least dense, oil next and water the most dense of all. Consequently, they tend to segregate themselves by virtue of these density differences. Where all are present, water will exist at the bottom, oil in the middle and gas at the top of the trap. Rock formations are seldom if ever horizontal, i.e. they are tilted in some direction. Because of their lesser density, the oil and gas move up slope or up dip, as it is termed, until they are stopped by some trapping mechanism or escape at the surface through the exposed permeable bed or through a fault providing the necessary communication. When hydrocarbons reach the surface, the gases escape into the atmosphere while the oil thickens and becomes a tar source. When movement is prohibited by virtue of a trap, the oil and gas collect next to the element obstructing their movement. The gas ends up on top, the oil next and finally the water, which has been displaced in a manner similar to that shown in figures 5-6 and 5-7.

IRREDUCIBLE WATER

Actually, some water remains in the pore space occupied by the oil and gas due to capillary pressure and is termed the irreducible water saturation. Such water will not flow but remains locked in the rock when the oil or gas is produced. The task of those looking for oil and gas deposits is really one of finding potential traps through geologic and geophysical means. Where oil and gas is found a trapping mechanism lies nearby. However, all such mechanisms don't necessarily trap hydrocarbons and it's not unusual to drill a dry hole where a bona fide trap exists. Both parameters, i.e. the trap and hydrocarbon, must exist if an oil or gas discovery is to be made. In addition, the reservoir discovered must also have reasonable porosity and permeability for commercial production. However, more recent techniques have made it possible to coax production from reservoirs once thought un-producible, especially since I left the business.

NORMAL AND REVERSE FAULT TRAPS

As described earlier, a trap may also be formed by a normal or reverse fault. If the fault is near the surface, the fault plane (actual fracture) may provide a conduit for the hydrocarbons to escape and thus form an oil seep. However, if deeper in the crust with no access to the surface, the fault may block any escape and allow the oil and gas to collect in a permeable bed as in figure 5-6. Notice the impervious shales up dip from the hydrocarbon sand block any further migration of the oil and gas, securing its collection below the fault plane. A trap could also be caused by a reverse fault in a somewhat similar manner.

ANTICLINE TRAPS

Consider figure 5-7 which is an example of a trap formed by an anticline in which both oil and gas have collected. Notice the gas (red) is at the top of the permeable bed and is blocked by the impervious shale bed above. Being lighter than the oil or water below, it can move no further. Of course, the oil (black) being next in density collects right below it, being blocked by the presence of the gas, while the water (no color, only background of yellow sand) remains at the bottom. Reference is often made to the so-called oil-water contact or the gas-oil contact where the fluid mediums change from one to the other. Such contacts really aren't sharp as shown in the cross section but actually occur over an interval of a few feet depending upon the properties of the fluids and rock in question.

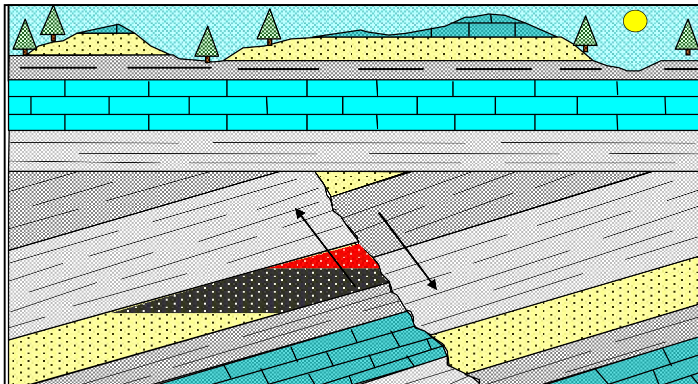

Figure 5-6 A "cross-section" illustrating a hydrocarbon trap produced by normal faulting.

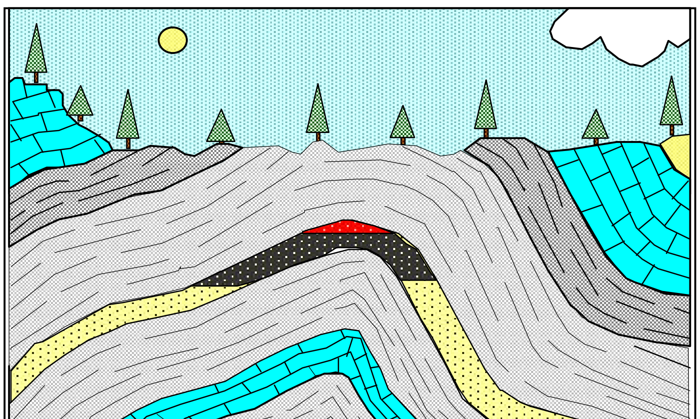

Figure 5-7 A cross-section illustration of a trap containing oil and gas produced by an anticline.

STRATIGRAPHIC TRAPS

Oil and gas traps are also produced through changing stratigraphy or variations in the nature of a sedimentary bed. A formation may change from porous sandstone into a siltstone and finally shale as changes in ocean environmental conditions progress laterally through a given area. Consider figure 5-8, which illustrates such conditions along a monocline, or in laymen's terms, a group of beds tilted in one direction. The monocline provides the means of segregation of the oil, water and gas within the porous medium of sandstone and the changing nature of the sandstone to silt and finally shale provides the necessary trapping mechanism.

Such traps are relatively common because the attitude of sedimentary beds is seldom horizontal and their nature constantly changes with relative position to ancient shorelines. That is, they are nothing more than offshore sand bars which have been deeply buried as later subsidence and deposition occurred. As in the previous illustrations, the red area indicates gas collection while the dark black area simulates that of oil. The light yellow indicates water filled porosity and the darker brown indicates a siltstone, which has no permeability. As a result, the gas and oil are prohibited from moving further up-dip. The trap results from stratigraphic changes rather than structure, hence the name.

TRAPS ASSOCIATED WITH SALT DOMES

Salt domes occur widely throughout the world (notably along the gulf coast of Texas and Louisiana) and are an important mechanism for producing various kinds of traps. They result from deep-seated salt beds being subjected to high pressures, making them of a plastic nature and squeezing them upward in a vertical column shoving the sediments before them. This produces a structural dome in the sediments above allowing overlying porous beds to collect oil and gas much like an anticline. Frequently the upward moving salt pierces some of the overlying beds and the result is termed a piercement type dome. The tops tend to flair outward like a mushroom. Such a situation is depicted in figure 5-9. The top of the salt may be near the surface and actually be mined for the mineral content or lie far deeper such that its presence is only indicated by the distortion of the beds around it. Normal faults typically occur in association with a salt dome, as do various changes in the stratigraphy or, i.e. sediments. As a result, some variation of the traps previously described in figures, 5-6, 5-7 and 5-8 may all be present near a salt dome. In addition the salt itself can become the trapping mechanism as has been illustrated in figure 5-9. In piercing a permeable bed, it blocks further migration of any hydrocarbon present and the oil and/or gas collects, as depicted. The mushrooming top of the salt may hide some such deposits, i.e. deposit A of figure 5-9, and their presence is then masked from normal exploration methods. One enterprising geologist working for a major oil company theorized their presence even though drilling next to the salt had only produced water from that particular horizon. Unable to convince his management of the possible presence of oil beneath the overhang of the salt, he resigned, set up his own company, leased

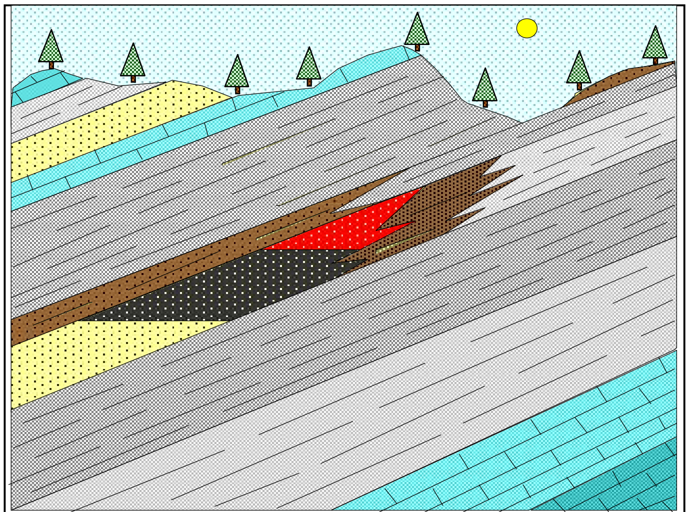

Figure 5-8 A "cross-section" illustrating a stratigraphic oil and gas trap in inclined sediments.

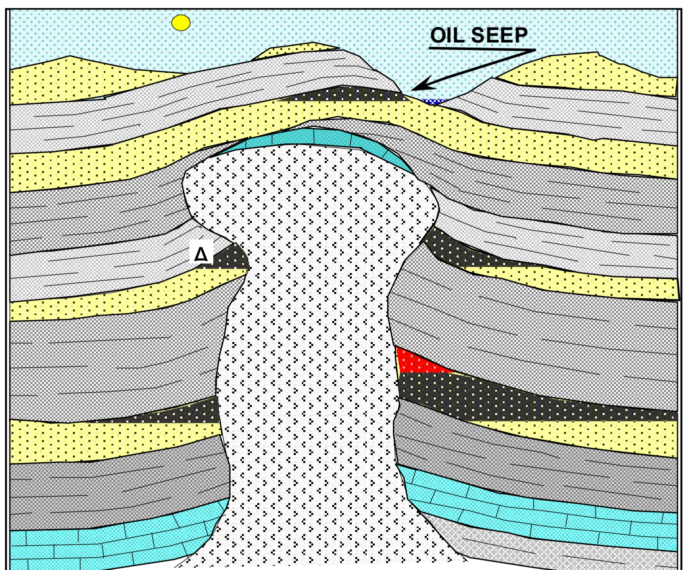

Figure 5-9 An illustration of a piercement type salt dome with multiple associated types of traps.

the mineral rights and set about to become a millionaire. He became known for identifying this particular type of trap. His name was Michael T. Halbouty. His determination was and still is a testament for a person to proceed forward with a belief, when strongly convinced of its value and validity.

ANCIENT REEF TRAPS

One last trap worth describing is the reef, which is composed of skeletons of small and microscopic marine life. Living reefs exist in many areas of the world where water conditions are just right for the marine life making up the reef. They seem to thrive where waters are warm and at relatively shallow depths. Thus they exist along the shorelines of islands and continents with such conditions and are relatively near the equator.

As geologic conditions change through such things as continental drift, subsidence of an island, emergence of shore lines, etc. as well as the changing of various sea conditions, the reef may die. If buried by sediments the skeletons of the reef life make up a type of limestone with unusually high porosity and permeability. Consequently old reefs make wonderful oil reservoirs even though somewhat limited in extent and quite difficult to find. The contour map of figure 5-10 is an isopach map representing reef thickness, which provides a view of their geometry. Notice the reef thickness decreases rapidly as the edge is approached and their general shape in the horizontal plane is somewhat oval. Individual reefs typically lie end to end and form a long chain parallel to the old shoreline, which fostered conditions favorable to the growth of living reefs in that geologic era.

As in living reefs today, openings connecting the sea to the interior lagoon also exist all along the reef. These manifest themselves as a thinning or complete disappearance of the reef at various points along the trend. Once such a trend is discovered the geologist's job becomes one of successfully predicting the direction of its winding nature so as to minimize dry holes. Knowing the geologic nature of a reef, continuing exploration would be cautious in nature with additional drilling being nearby so as to be able to predict the reef's trend more accurately. Oil wells are usually drilled on 40 acre spacing or 16 wells to the square mile. That places them about 1325 feet apart. A typical configuration, as indicated by the black dots, might look like that shown in figure 5-10. This would result from analyzing geologic data

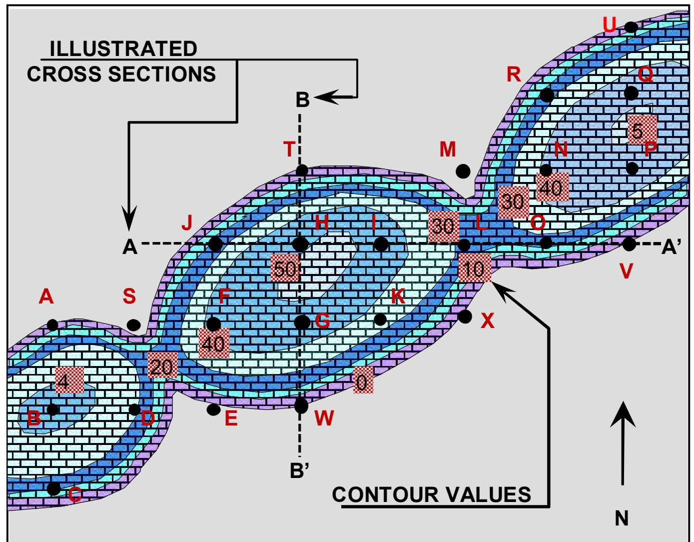

Figure 5-10 An isopach map (formation thickness) of a typical reef trend paralleling an old seacoast.

obtained in each well, updating maps and then staking the next location based on the company's best understanding of the reef's position and trend. The lettering indicates a hypothetical drilling sequence, which we'll discuss later while the dashed lines labeled A-A' and B-B' are directions along which cross sections will be taken. These will also to be discussed in some detail a little later.

As the drilling progresses the geologic picture, as developed by the maps, will usually improve in quality, thus improving the odds of success. Even so, dry holes and/or poor wells are drilled as every effort is made to fully develop the field. As in any business venture, the task is to minimize expenditures while maximizing profit. This means, of course, that a sufficient number of wells must be drilled to properly drain the reservoir but their location must be optimized to limit unnecessary drilling cost. One can appreciate the difficulty of spotting a surface location directly over the thickest part of a reef about 500 to 600 yards wide when it lies some one to two miles above it. The juiciest part or most profitable zone might only be a couple hundred yards wide as it follows the curving nature of an ancient shoreline. It's kind of like

It's kind of like being in a chopper flying at six to ten thousand feet and trying to follow a winding river with an intervening cloud layer blocking your view.

being in a chopper and trying to follow a winding river from 6 to 10 thousand feet with a cloud layer intervening. Even though the river may be visible through an occasional break in the clouds (i.e. a successful well), other breaks simply reveal dry ground (a dry hole) or some plant, animal or geologic deposits associated with rivers (marginal wells). At best it wouldn't be easy and luck as well as skill and a credible imagination must enter in. So it is with the geologist as he tries to visualize this ancient reef through his meager openings to the subsurface called wells. It is interesting but as you can surmise, very difficult in most cases.

DEVELOPING THE REEF DISCOVERY

As indicated earlier, the letters in figure 5-10 designate a hypothetical drilling sequence which I will now guide the reader through and provide at least some logic behind the reasons for staking succeeding locations as shown. Obviously, the sequence could be different, depending upon the interpretation of the data from the wells being drilled.

THE DISCOVERY WELL

Let's assume well A was the original well in the area or a so-called wildcat. The odds of striking the reef are very low and the location may well have been chosen based on the probability of a favorable geologic environment for its formation or maybe even a reason not associated with reef formation, i.e. its appearance was strictly accidental. The play may have been based on other geologic phenomena, which gave the geologist the idea that one of many other possible traps might exist at this location.

The geologist does just that, i.e. flips a coin and decides to drill location E. Bad move, right? There is no reef at all in the well.

The isopach map (a contour map describing the thickness of a given zone or formation) indicates that about 10 feet of reef are present in well A. This particular ten feet might be highly permeable and result in a fair well, i.e. it results in sufficient production to produce a profit or it might have poor enough characteristics to cause the operator to plug the hole. Assuming the former, casing would be set and the company involved might determine the well's potential through testing before deciding on additional locations. In this case, being on the edge of a thick porous and permeable zone the well would perform better than might be anticipated from ten feet of pay. This would tell the operator that the reef thickens in some unknown direction. Using all geologic data at hand and any geophysical data available to maximize the odds of success, an adjacent 40-acre location would be drilled to gather data as well as test the company's initial hypothesis.

THE FIRST OFFSET WELL

I chose the 2nd drilling location, i.e. well B, as shown, although it could also be north, east or west of A. The completed map indicates that all of these choices would have been dry holes and the gambling would have to go on until the location B was, in fact, drilled. At this point available data may not have been definitive enough to provide any real guidance and the operator just got lucky. Anyhow, well B has 40 plus feet of reef porosity as indicated by the map, which would make a lucrative well and explain why well A performed above expectations.

WHICH WAY NOW?

The question now before the geologist might be, "Does the reef thicken even further and if so, in which direction"? The choice of location C, D or to the west of B would again be potluck, so to speak. That is, without some inside knowledge like knowing the cook, you're not sure which dish to choose. Unlike a potluck, you can't take a little of each. Assuming the operator chose C, he came up rather disappointed in that the zone thinned to twenty feet. Such a thickness still makes a fair to good well but it's not what he hoped for. Next location D is selected or again he might go to the west. We'll leave the latter out, however, since it's off the map and thus outside the lease. This choice turns out pretty good with about thirty feet of pay but the prospects of a mother-load are beginning to dim. "What to do next" becomes the question of the day. The prospects of locations to the north or south don't look good. Locations to the east and northeast look like the best bet and it's a coin toss to determine the better of the two without any more information.

A DRY HOLE

The geologist does just that, i.e. flips a coin and decides to drill location E. Bad move, right? There is no reef at all in the well. Can't you just see the geologist feverishly erasing and adjusting his map to try to picture the trend of the reef? Frankly, they would probably move to the west if the land was under lease but someone else has it. Had it already been drilled they would try to negotiate an exchange of data to improve their projections. Because of well B you can bet that all surrounding land is now under lease, if it wasn't already, either by this operator or someone else. Yes sir, land-men by the score will be pestering the neighbors.

IS THERE A TREND?

At this point no trend in reef direction has yet been defined. The geologist knows the characteristics of the reservoir he is chasing but it is being illusive, to say the least. He could recommend location S or even one to the south of D but because of an active imagination and the data from wells A and C, he chooses F. After all, reefs do have openings between major sections, which provide a means of communication between sea and lagoon. He muses, that's why E turned up dry and consequently spurns S for the time being. If his theory is correct, his crudely drawn map shows the reef trending to the northeast and makes F the best shot just across the channel through the reef. Voile, 40 plus feet of pay and he's a hero. Not only is the well the best to date but a real trend is beginning to show. It would also appear that the channel theory is correct. Drawing a straight line through B and F would indicate sites G, H and I all look good. Locations J and K also seem like possibilities and will be drilled to help define the reef width.

BRING ON ANOTHER RIG

At this point the operator may move in a second rig to speed up drilling process with its resultant data acquisition and hopefully overall profit. The next five wells are sunk as indicated and results seem to confirm the hypotheses posed just prior to well F, i.e. that the reef trend is NE-SW. They also provide additional control for a more complete set of contours and the second section of reef begins to take shape.

Knowing that a typical reef thins rapidly as the edge is approached, the geologist draws in the probable twenty, ten and zero foot contours just north of J as well as the 30, 20, 10 and 0 foot contours south of K. Though their exact location is based strictly on conjecture, the resulting picture they portray is quite likely. Likewise, the fifty-foot contour between F, G, H and I is also drawn by conjecture as well as on experience and probability. Even with this added information, the geologist knows the trend direction can change as ancient reef development parallels a probable changing ancient shoreline.

PICKING ADDITIONAL LOCATIONS

Well, it would seem the next most favorable sites would lie at L, M and N if the trend continues as indicated, a valid supposition unless data indicates otherwise. The producing section at L comes in just under 30 feet while M is a complete bust. What a bummer that decision was.

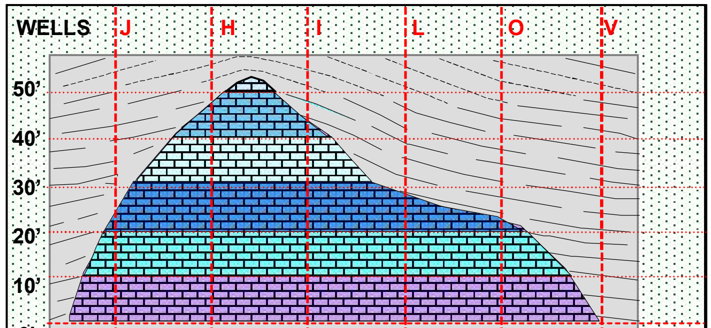

Figure 5-11 Cross-section A-A', colors are as in 5-10

"What happened", puzzles George the geologist? Is the trend swinging to the east or have we come to another reef opening? Location N now becomes more attractive along with O. These are drilled yielding 40 plus feet and 20 feet of pay respectively. This would indicate a continuing trend to the NE so P and Q are drilled with about 42 and 47 feet of productive reef respectively.

SIZING UP THE REEF

George sure would like to have some more sites to the NE but with the lease line just to the east of these last two wells, the operator decides to go back and fill in where reef limits are speculative. R is the best bet and is drilled with reasonable success, i.e. 25 feet of pay. This seems to confirm the second channel theory. S also presents some possibility but when drilled the operator gets burned. Sure enough the thinning at D and the reef's disappearance at E were indicative of a channel as confirmed by S. What next? Should we quit or have we really defined the limits of the reservoir? Will the cost of additional wells be justified by better information? The operator could quit while he's ahead but remember, the reef shape is as visualized by the geologist and edges haven't been confirmed. As indicated, there are some questions still remaining. Thus, he drills locations T and U hoping that the reef width is greater than shown. Being an eternal optimist and not wanting to leave any oil in the ground the operator then turns to locations V and W with similar results. Then as a parting gasp he decides to drill at the site indicated by well X.

Five wells and five dry holes, I guess it's time to quit he muses, once again. Oh well, at least the reef edges are confirmed and nothing was left to speculate about. Knowing the latter wells are near the edge of the reef, the operator might choose to side track the holes towards the reef, a drilling technique we'll consider later. He might produce some oil from them and then use them as injection wells for a later water flood, a production technique to maximize total recovery of hydrocarbons and a subject to be considered under that title.

Well, I hope you, the reader, found this little exercise of mine rather interesting because it's quite real. I well remember working with a geologist who had a similar problem working for Aztec Oil Co. in Farmington, New Mexico while I served as a sales engineer for Schlumberger there. Each new well brought new possibilities

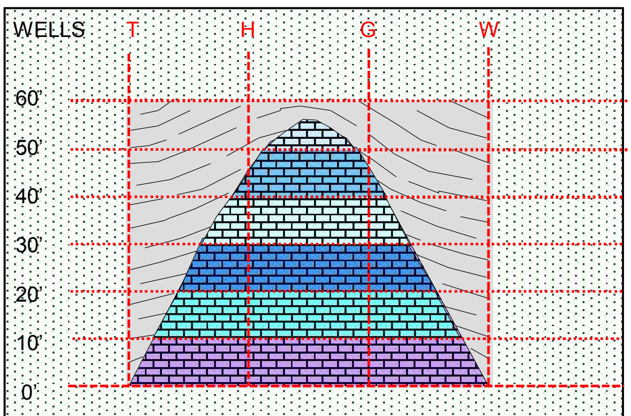

Figure 5-12 Cross-section B-B' taken from figure 5-10 with directly comparative colors.

for succeeding locations, which kept him scouring his data for other possibilities.

LOOKING AT THE CROSS SECTIONS

CROSS SECTION A - A'

Now, let's consider cross section A-A', which is taken through wells J, H, I K, L, and V. This is shown in figure 5-11. Because it's taken from an isopach of a given horizon, only that particular sedimentary member need be portrayed. Figure 5-11 shows the surrounding sediment as being shale, which is rather typical. True thickness of the bed in question is obviously known only at control points within the wells. Between wells, changes in thickness can only be inferred through interpolation, that is, by following contour changes as envisioned by the geologist. However, more accurate values are seldom that important. I have followed the assumed contours in this case. Notice the cross section indicates only a small zone as being over 50 feet in thickness. This conforms to the contour map, which indicates the cross section just barely cuts the 50-foot contour on the north end. Obviously, the cross section must agree with the contour map for a consistent picture, whether one of the elevation or isopach variety.

CROSS SECTION B - B'

Cross section B-B' is illustrated in figure 5-12 and represents a north - south slice through the reef. First you'll notice it is narrower or a shorter section as indicated on the contour map of figure 5-10. Second, the reef thins rapidly to either side and finally the thickest part is something greater than 50 feet, which is also depicted by contour lines in figure 5-10. The same information is present on both maps but the thickness and its rate of change is much more striking, visually speaking, on the cross section.

Well, to me that was an interesting exercise but it may have bored you out of your skull. If so, don't you worry, there will be more just as bad. In fact, I have one more multiple or combination trap example to stimulate your imagination or sedate you to the point of complete disregard for my efforts, depending upon your interest in this particular area of geology.

Remember, I said in the preface that I had decided to have a little fun while writing this story but such fun might not extend to you, the reader. It might well be this complete chapter falls in that category. Of course, you have your agency and rights, to read or not to read. That, of course, is the question.

MULTIPLE OR COMBINATION TRAPS

Oil and gas fields frequently contain 2 or maybe even more mechanisms for trapping oil or gas in combination thus causing their geometric configuration to vary from a rather simple situation (as described so far) to one quite complex or even extremely so. I don't have time, the room or the know how to provide an example of the latter but I will try to illustrate the principle involved with an anticline, a fault and various changes in stratigraphy. I will also try to generate a structural contour map, an isopach map and a couple of appropriate cross sections to help the reader better understand how the geologist might try to describe the field. Of course he would probably have several other maps in his possession, which would add to his overall knowledge of the problem.

A STRUCTURAL CONTOUR MAP

We'll begin with the structural contour map, which simply describes the vertical position of the surface of a particular bed, usually the upper surface, relative to some datum, as it is called, or permanent reference such as sea level. The map figure 5-13 illustrates the structure in question through contours of the upper surface of a limestone bed, which we'll call the Madison, as a reference.

FAULT MODIFICATION

It has been modified by a normal fault, which not only displaces the right or east side of the structure and formation vertically but also moves it horizontally as indicated by the zone marked "normal fault". This fault zone, colored green, indicates the limestone at that point is missing, being relatively thin compared to the movement of the fault. The scale chosen of 5/8 inch = 1360', indicates the horizontal displacement, width of the fault zone, is approximately 240'. Thus wells such as F and M completely miss this particular bed because of their location and the horizontal movement of the limestone bed to the east (right) 240' at the depth they would normally encounter it. With proper information, they could be successfully sidetracked.

The scale chosen of 5/8 inch = 1360' indicates the horizontal displacement or width of the fault zone is approximately 240'.

For the purpose of the example, I also chose a vertical displacement of 240' or the fault plane is inclined at 45 degrees. This displacement is shown in the map by contours on the right side of the fault, which are 240' deeper than those on the left. Such a choice makes calculations and resultant drawings somewhat easier, a trick grandpa has learned over the years. The moral behind this logic is, "don't make things more complicated than is necessary to demonstrate a point. It just causes more work for you and usually produces more boredom on the part of the intended recipients". The Lord knows, that I have probably reached that limit already.

If we were to follow the face of the fault (fault plane) upward approximately 1110' we find its horizontal position moving 1110' feet to the left or west and the particular horizon at this level is now missing in well J (see figure 5-14), whereas wells F and M encounter this sandstone which I've arbitrarily termed the Navajo sand. Comparing the fault zone in figures 5-13 as well as 5-14 one can see it has moved to the west not quite one well location in a vertical distance of 1110'. This compares to a horizontal well spacing of 1360'.

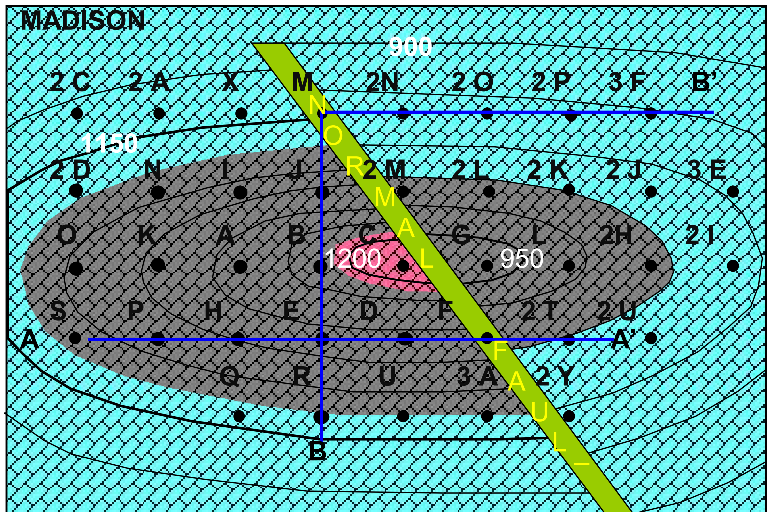

Figure 5-13 A structural contour map and modifying fault, which defines the upper surface of a limestone sedimentary bed and its accumulation of hydrocarbons.

It is through such organized drilling of multiple wells that the presence of a fault, as well as its location and attitude, can be determined. This information is obtained by comparing the depth and thickness of formations in different wells or correlating well logs (records of various kinds). I include this example to give the reader an idea of the complexity of finding and developing an oil or gas field. The example might be typical of an average field with some less complex but many, if not most, much more complex.

A SECOND RESERVOIR

Figure 5-14, an isopach map, illustrates the thickness of a sand trap rather than its structural relief. It is termed a stratigraphic trap because the sand bodies are completely surrounded by impervious shale or changing stratigraphy, and the oil therein cannot escape regardless of structure. Even though the structure of 5-13 may well be present at this depth, it has only a relatively minor effect because the sand body is completely full of oil and dissolved gas, at least west of the fault. The northeastern sand body does contain water and, the resultant oil - water contact is controlled by the structure described, though it may not be obvious.

MORE FAULT MODIFICATION

The reservoir, i.e. sand body, is modified by the fault, however. If a structural contour map of the sand's lower surface, (i.e. the top of the shale upon which it rests) were to be drawn, wells to the east of the fault would indicate the sand to be 240' deeper than those drilled to the west (the fault's vertical displacement) just as they were in figure 5-13. Of course, the sand should have been present in well J but is missing because of its horizontal displacement, which also results from the fault. If the geologist isn't on his toes, he may map the sand disappearance as changing stratigraphy rather than a loss of section due to the fault.

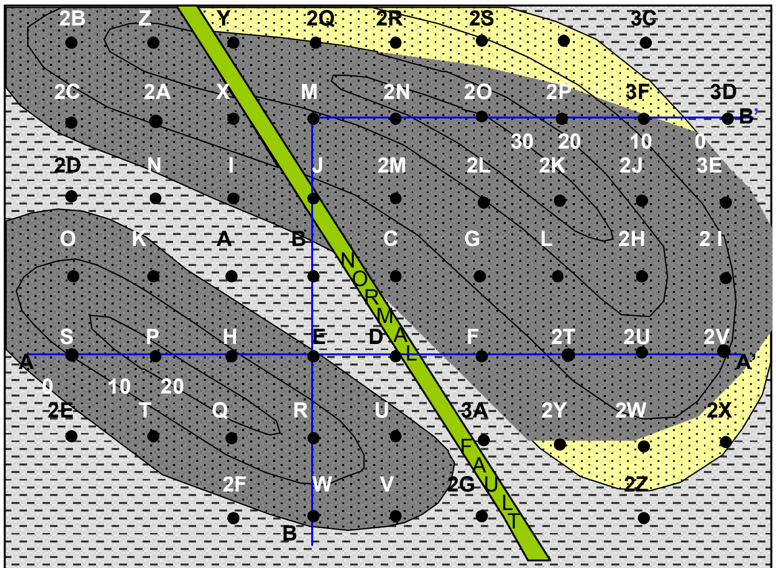

Figure 5-14 Isopach map of a sand reservoir controlled by stratigraphy and the fault of figure 5-13. It also lies about 1080 feet above the limestone of figure 5-13.

The reader will probably notice that fewer wells are shown in the map of 5-13 as compared to that of 5-14. This occurs because the sand reservoir of 5-14 lies 1110' above the limestone and once the limits of the oil deposit are established in the limestone; there is no need to drill deeper in the wells exploiting only the sand reservoir. Such activity would only incur extra drilling cost and would not even produce information of value.

CROSS SECTIONS

To help clarify the picture a little, I have added a couple of vertical cross sections labeled A-A' and B-B' respectively and which were taken as designated in figures 5-13 and 5-14. These are now numbered as figures 5-15 and 5-16. You will notice that B-B' makes a right angle turn but don't worry now, they will be discussed in detail a little later on. Now, let's look a little closer.

To help maintain a reasonable size and scale as well as limit myself to the two cross sections I have settled on, the intervening beds or formations between the two reservoirs are left out, as indicated by the blank space between the sequences of interest. This allows them to fit nicely on the page with an expanded vertical scale, which is desirable for visualizing details of the reservoirs.

The reader will probably notice rather quickly that the vertical scale is expanded to allow necessary bed definition. This, in turn, distorts the apparent fault plane inclination I described as being 45 degrees, making it look almost vertical but don't you worry, as all such aberrations and adjustments are considered in the associated discussion.

THE MADISON

In discussing this particular combination of traps, we'll begin with the Madison limestone horizon of figure 5-13. A normal fault has virtually split the anticline in half with the eastern portion dropping 240'. That is the 930' contour of the right side of the anticline, if it were visible, would lie just across the fault from the 1170' contour (invisible once again) west of the fault, a difference of 240'.

Accumulation of hydrocarbon west of the fault is greater being some 50' thick (including both the oil and gas columns) while accumulation east of the fault is about 25' and has no gas cap. The light blue area represents limestone, which contains water, the dark gray that contains oil and the red that contains gas. Differences of quantity and type of hydrocarbon might be related to the sequence of geologic events, which occurred over geologic time as well as to the efficiency of the trap, i.e. how securely the hydrocarbon is blocked.

A WATER DRIVE

The limestone bed might well extend in every direction many miles but the structure we are interested in is confined to the area pictured. Virtually the whole limestone bed is filled with water except the trap. As such, it is termed a water drive reservoir. The surrounding body of water pushes the oil into the well bore, a concept, which will be discussed in more detail later on.

OIL WATER CONTACTS

The left edge of the area shown in bubbly black, i.e. the oil deposit, is on the line of demarcation between oil and water on the upper surface of the bed. The right end of the contact line in figure 5-15 is on the oil – water contact on the lower surface of the bed, which encloses a somewhat smaller area. This smaller area can be visualized clearly if you refer to the cross section of figure 5-16 and examine the oil accumulation (dark gray) at the 1160' level. If a person were to visualize a circle or ellipse in the horizontal plane, which included the two points defining the oil-water contact at the lower bed boundary, it would encircle a somewhat smaller area than would a similarly circle connecting the two equivalent points, which represent the upper boundary contact.

Wells drilled within the area encircled by the demarcation line of the lower boundary will contain only oil. Wells drilled between the two demarcation lines will have an oil-water contact and those outside the demarcation line of the upper boundary will contain only water. This is evident in figure 5-15 at the 1160' level. Notice wells D & E are within the boundary defined by the lower contact and only encounter oil. Wells H, P & S, however, lie between the two areas and all have oil-water contacts. Similarly, wells 2T and 2U are outside the area defined by the upper bed boundary area on the down thrown side of the fault and contain only water.

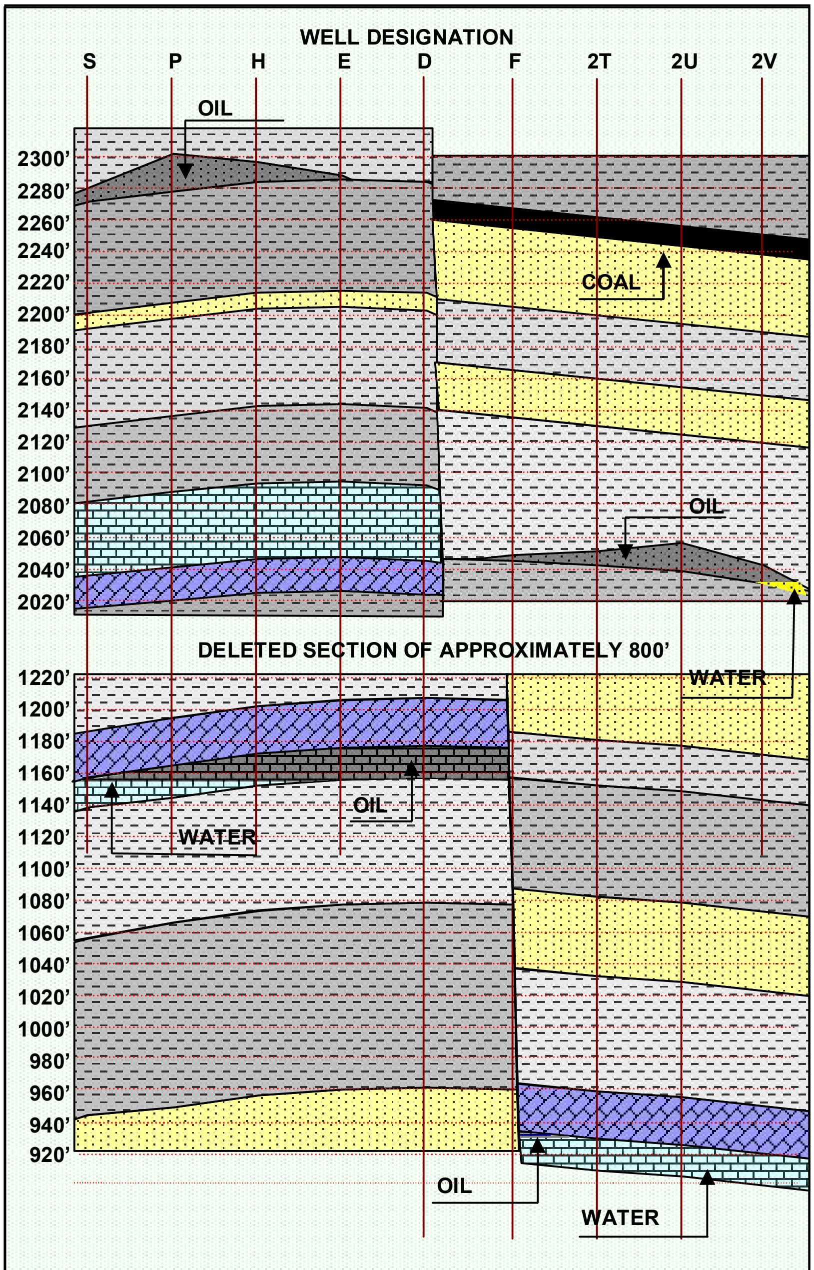

Figure 5-15 An E-W cross-section, AA', taken through the structural and isopach maps of 5-13 and 5-14. Depths are relative to sea level. Vertical scale expanded X 25.

CROSS SECTION DISCUSSION

A cross-section represents a slice through a particular bed or zone of interest and may be taken in any direction or even in multiple directions to provide the geologist with an improved visual image of consistent or even changing conditions within the reservoir. They help him better visualize the dip or tilt of a bed, the nature of its fluid content and the relative position of wells as they penetrate the reservoir. When coupled with the contour maps, they provide a simplified three dimensional picture of the various trapping mechanisms and reservoirs that are involved.

To help the reader more fully appreciate this idea, consider the map of figure 5-13 along with the cross sections of 5-15 and 5-16. If the contour map of figure 5-13 were taken by itself, one might get a false impression of how large the field is at this particular depth. However, when coupled with the cross sections a person can easily see that wells P, H, E and J are all near the edge of the oil bearing rock and will need to be both completed and produced, with a great deal of care. In a similar sense, well B appears to be in the gas cap in figure 5-13 and so it is, but the majority of the producing section is oil as illustrated in figure 5-16. Thus it would be completed as an oil well in a way to minimize gas production and take advantage of the better price of oil while conserving the gas with its associated energy. This improves total oil recovery and thus, the profit from the well. Failure to do so can lead to an expanded gas cap, which will eventually begin to impact adjoining wells and lead to a loss of production in them as well.

A DISJOINTED CROSS SECTION

One might question the value of taking cross section B - B' through wells 2N, 2O, 2P and 3F, at least in the Madison and rightly so. That portion only confirms what is obvious from figure 5-13. It was done to demonstrate the principle that a cross section doesn't have to be straight and to also include well M. In examining the well designated as M in figure 5-16, we can see the Madison limestone is completely missing as it is in well F of figure 5-15. Thus, the same information is expressed in different ways in cross sections and maps. Together they provide a clearer image of the portrayed data.

As a last consideration of the Madison reservoir, consider figure 5-15 and the small amount of oil shown in the Madison to the right of the fault or down thrown side. Both wells F and 2T have missed the target but for different reasons. The structural map of figure 5-13 confirms these failures. That bit of oil accumulation will ultimately be produced in wells G and/or L.

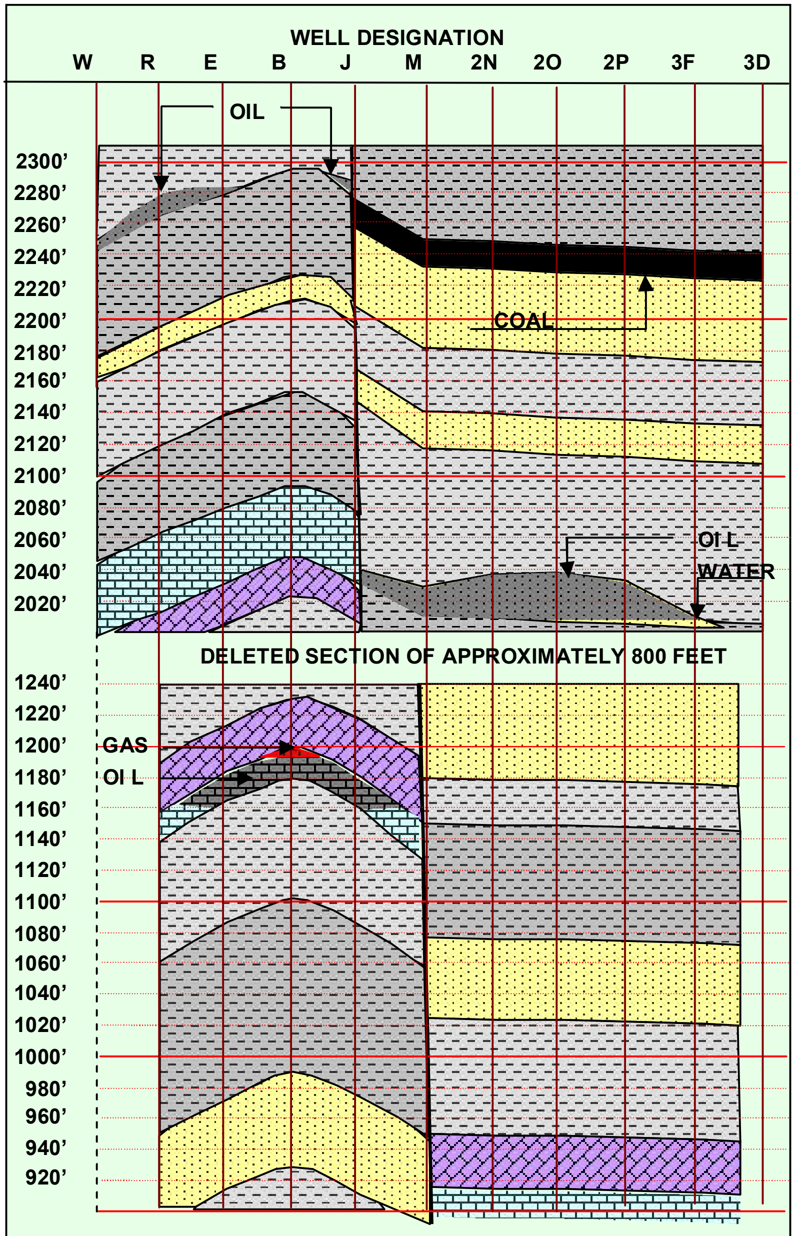

Figure 5-16 Cross-section B-B' taken as illustrated in figures 5-13 & 5-14. Depths are relative to sea level and the vertical scale is expanded to X 25 of the horizontal scale.

Well, that's certainly long-winded and probably even boring to many of you who have struggled this far. Don't fret though because, as mentioned earlier, it's bound to get worse as I launch into a description of the Navajo sand.

THE NAVAJO SANDSTONE

Both cross-sections, i.e. B-B' and A-A' illustrate another characteristic of this particular trap, i.e. the sand body east of the fault (to the right) is impacted by structure whereas that to the west seems independent of it. That is, the sand reservoir west of the fault is completely full of oil (mentioned earlier) while that to the east has an oil water contact. This is also illustrated on the isopach map of figure 5-14 by the blackish yellow and pure yellow colors, which indicate oil and water respectively. Once again, the oil-water interface shown in the Navajo is against the upper bed boundary and in this case is impacted by both structure and sand thickness. Thus, it does not follow the structural contours, as does the contact in the Madison of figure 5-13. Such a complicating factor adds to the challenge of trying to display the contact in cross section but old grandpa will certainly rise to the occasion.

If the contour map shown in figure 5-13 were taken by itself, one might get a false impression of how large the field is at this particular horizon.

CROSS SECTION A - A'

Now, let's look at a few details of the Navajo sandstone and compare the isopach map with the cross-sections. Looking at the cross-section A-A' as indicated in figure 5-14, we see that wells S, P, H, and E all encountered the sand but well D missed it. There is no indication of water being present along this part of the cross-section. Comparing this to the cross-section of figure 5-15 we see a similar story with the sand thickness expressed in the vertical dimension at about 2280'. Again no water is indicated. Now, let's go on to cross-section B-B' and see what story it might have for us.

Note that the sand is missing in well J because of the fault and not due to a facies or sediment change as in well B.

CROSS SECTION B - B'

In a similar manner, we can compare cross-section B-B' in figure 5-14 with figure 5-16. Figure 5-14 indicates that wells W and E strike the Navajo sand near its edge while well R encounters some 15 or 16 feet of oil-bearing formation. As with well D, well B encounters only shale. However, in figure 5-14 the reader might notice the cross-section encounters a small amount of sand just before entering the fault zone with well J located in the middle of it at that particular depth. Note that the sand is missing in well J because of the fault and not due to a facies or sediment change as in well B. Comparing cross-section B-B' of figure 5-16 with the isopach of 5-14 we, once again see the same story. At approximately 2290', there is a small body of sand containing oil right next to the fault on the left or west side. At this depth well J is to the east or right of the fault and doesn't encounter the sand, which has slid to a depth of 2050'. In so doing it has also moved east approximately 240' and the well bore of J passes west of the sand body when it gets to that depth. That black gold is so close and yet so far, as far as the geologist is concerned. Well J is taken on down to the Madison at about 1170' as described earlier where oil is encountered. It is probable, after the geometry is figured out and the Navajo east of the fault better defined, that well J would be side-tracked at 2050' to help drain that sand body. Now isn't that fascinating? Look at all the three dimensional geometry involved as depicted by figures 5-13, 5-14, 5-15 and 5-16.. I believe most any reader can see that visualizing the size, shape and location of the various sedimentary bodies from data obtained in relatively few wells constitutes an intriguing puzzle for the geologist and a little artistry to display the results. Hopefully, such insight will provide a little compassion for grandpa's efforts.

DEEPER HORIZON - SMALLER ELEVATIONS

To help avoid confusion, the reader who has persevered through this example should remember that the elevations referred to in the above are relative to sea level and not to the surface elevation. Thus the Madison located at 1170' is deeper in the hole than is the Navajo at 2280'. Depending upon the surface elevation, the well's depth at these points might be many thousand feet or quite shallow but the Madison in any case would be 1110' deeper in the well than is the Navajo but also 1110' closer to sea level thus justifying the numbers assigned. No, the drawing is not upside down and yes, I really do know up from down regardless of your opinion at this point. Just keep in mind that such examples are clues to the mystery of Grandpa Tom's demented mind, which, you'll remember from the preface, is somewhat twisted from sniffing too much aromatic octane.

A FINAL CROSS SECTION REVIEW

Continuing on with the example; ha! I bet you thought you were done, let's look at the Navajo east of the fault or to its right. Once again we'll compare figures 5-14 with figure 5-15 and also 5-16. In 5-14 the line defining the location of cross-section B-B' turns 90 degrees to the right as it encounters well M. There, it continues on through well 3D and we can see the varying sand thickness described by the contours of figure 5-14. In well M there appears to be about 18' of Navajo sand which then thickens to something over 30' as the cross-section moves through wells 2N and 2O. At that point it begins to thin until it disappears between wells 3F and 3D. Note also that water is encountered as the line passes between the last two wells, which would lead one to believe that well 3F has questionable value as a producer. Moving on to figure 5-16 we see the same circumstances depicted in the vertical plane but we also see the oil water contact is present in wells 2O and 2P as well as in 3F. As suspected, well 3F will produce little or no oil but it may well have value as an injection well, which application I intend to discuss later. Wells 2O and 2P will be good wells but the completions will have to take into consideration the encroaching water.

Finally, let's move on to cross-section A-A' and examine it in figure 5-14 east of the fault. All the wells from F through 2V encounter oil with the latter one being suspicious even as well 3F above. The contours indicate well F has only about 3' of sand with the thickness increasing to maybe 16' in well 2U before decreasing to 10' in well 2V. Moving on to the cross-section of figure 5-15 we see the same story in a different format. All the wells will produce oil though well F will be marginal because of sand thickness and well 2 V must be completed carefully to control the water nearby.

BROADER GEOLOGIC FEATURES

By this time I feel all my readers must be in pure ecstasy assuming they have followed through the example. Isn't it amazing what a twisted mind can conjure up? Guess what? I'm through with specific oil well exploration examples, although several more just as exciting could be included. Before leaving the exploration area, however, I should probably lay a little more general groundwork regarding geologic provinces or areas favorable to the accumulation of oil and gas. So let's speak of depositional basins and their role in the oil business. They, very simply, constitute the geographic areas of thick sedimentary rock. After all, I'll be tossing those terms around in my field experiences in later chapters.

A depositional basin covers a relatively large area compared to the traps that were discussed earlier. That is, many such traps or oil and gas fields may lie within a given depositional basin. They also vary greatly in size as well as depth and geologic age and thus are almost as varied as the traps within them. They have no respect for state lines or national boundaries, nor even land or sea. Some are actively receiving new sediments at this time while others have been eroding and supplying sediments to the oceans for thousands of years. Thus each supplies its own special problems for the oil companies seeking after that so called "black gold".

DEPOSITIONAL BASINS

The states of Wyoming, Utah and Colorado include a number of basins covering a variety of different problems. Figure 5-17 depicts portions of these states and their associated basins with which I am familiar.

Speaking strictly from geological studies, the Rocky Mountains from Alaska down into Mexico were once covered by oceans as evidenced by the rock types that were formed at that time. This area was termed the Cordillarian Geo-syncline and was later thrust upward by compressive forces resulting from movement of the various tectonic plates. Even after being raised above sea level, vast lakes still existed between the various mountains that were formed resulting in additional lake type deposits. Even now they are subject to the depositional forces of streams and wind. As a result, they have become known as Inter-Montaine Basins, each with their individual source rocks and various types of trapping mechanisms.

Each has had some success as oil and gas producing areas. Some structures would appear to be traps as evidenced by their names but seldom are they as simple as a single name would imply. All the basins have traps of varying sorts but generally have little surface relief. My main purpose in displaying this map at this point is to acquaint the reader with a few more geologic terms. For instance, arches are generally elongated in horizontal view, while uplifts tend to be more equi-dimensional. Both have rounded tops, which may or may not be expressed at the surface. Platforms, on the other hand, are flat topped and are often associated with a mountain range. However, my crude map doesn't necessarily infer those shapes. All are rather large in terms of the area over which they extend. Similarly, all may be deep seated, i.e. expressed only below the surface, or they may also be visible in topographic relief. For instance, the Rawlins and Rock Springs uplifts are very apparent at the surface while the Labarge Platform. Moxa Arch and Wamsutter Arch are hardly apparent at all. I'll probably refer to this particular figure in chapters ten through fourteen because I spent so many years working the Wyoming area and in virtually all the basins indicated.

Having bored the reader stiff by now (my objective in disguise), I have decided a change of pace is in order. Consequently, we'll move on to the drilling of oil wells, a process, which I feel sure, will have all of you on the edge of your seats waiting with great anticipation for the story to unfold. If I can only do justice to the wondrous process and materials involved, you will realize a thrill equal to or greater than that of the exploration phase. Doesn't it just bring goose pimples to your whole body when you think of all the excitement associated with drilling a hole in the ground several thousand feet deep using such exotic materials and equipment as mud, grease, iron and diesel engines with associated goo, smoke and horsepower? Gosh, I can't wait to start.

DRILLING AN OIL WELL

It's obvious to me that it will be difficult to write a section on oil well drilling that can generate a level of interest equal to or even approaching the excitement the reader must have felt regarding oil exploration. After all, who but a most unfeeling, insensitive, unimaginative lout could make his way through that section without experiencing the utmost euphoria resulting from nature's diverse ways of trapping energy for the modern automobile, not to speak of the wiles of the cunning geologist unlocking her ancient secrets. Ah yes, such intrigue will be difficult to duplicate but don't under estimate grandpa Tom's ingenuity. He may well top the untopable, exceed the inexceedable, even write the unwritable, as he unlocks his vast storehouse of memories (well, maybe half vast) regarding his experience on oil rigs. So, prepare yourself for a thrilling, chilling and even filling drilling experience as I consider ways to accomplish the foregoing adjectives. Most assuredly such an effort will tax even grandpa's ingenuity in the realms of engineering, the art of story-telling and of course, providing proper pictorial illustrations.

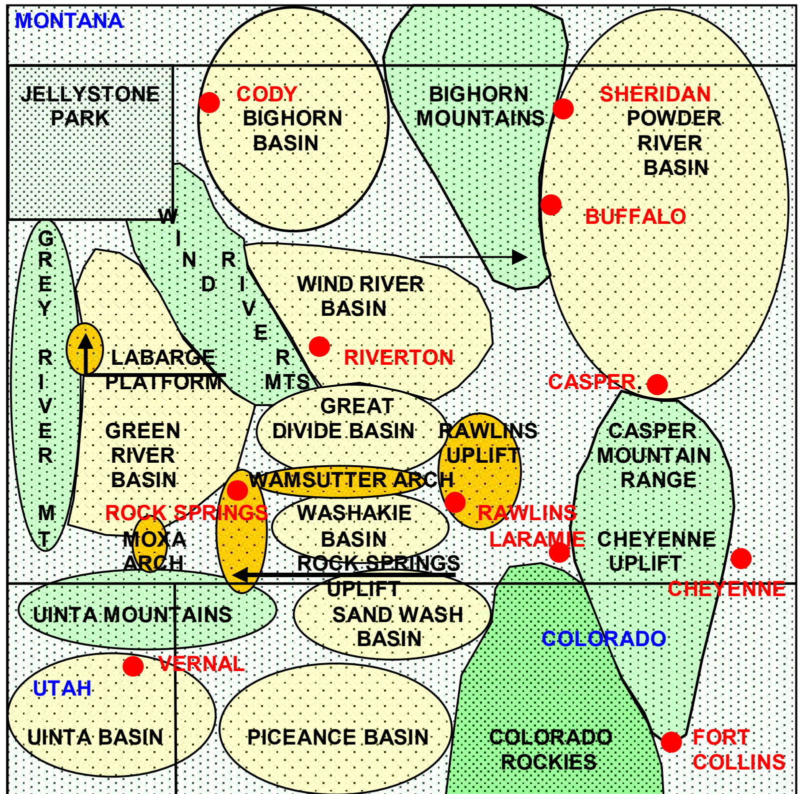

Figure 5-17 Depositional basins and uplifts of Wyoming and nearby areas of Utah and Colorado with pertinent towns.

DRILLING METHODS

We could begin with the earliest wells in the United States drilled around the turn of the 19th century in Pennsylvania to find a substitute for whale oil but not having been there, my memory bank is somewhat depleted of facts relative to that era. We might also begin with the great Spindletop discovery in the gulf coast of Texas, which blew out spewing oil all over the landscape of that great state. It was not only one of the earliest but also one of the oiliest discoveries in the business. Cable tool drilling was used in these cases which relied on mankind's ingenuity to bring under control an out of control well and reap its rewards in an orderly manner. Wells like Spindletop must have caused the driller to stop and quizzically ponder such questions as, "Is there a better way?" or, "Might we not drill in a manner such that we control the action as we penetrate various geologic horizons in good old mother earth?" Such probing questions and concepts resulted in the birth of modern rotary drilling, which constitute something like 99.99% of my experience with drilling rigs.

Yes, I've run into a few cable tool rigs during my time digging very shallow holes in known low pressure areas but such drilling is not only dangerous, if the unexpected happens but also inefficient in most types of geologic strata. I once worked with an old cable tool hand in the Green River basin of Wyoming as well as in the San Juan Basin of New Mexico. We were completing wells for a company called Caulkins Oil, a so-called independent operator. He used to describe some of his wild and woolly experiences in Kentucky as they drilled into gas zone with cable tools. He spoke of how they come blowing in, spewing gas all over location before being controlled. I don't need that experience.

ROTARY DRILLING

Rotary drilling is really the only accepted method in today's oil exploration and even in water well drilling. So-called drilling mud is now used to help control subterranean pressures, transport drill cuttings and cool the drill. In recent years, i.e. the 1980s, "logging while drilling methods" also utilize the mud column to transmit signals to the surface for evaluation. More on that subject will come later. For now, let's immerse ourselves in the drilling rig and all those glorious gadgets which come together in majestic synergy to provide a unique capability for drilling a borehole deep within the earth. Ah yes, a pathway through which the robber barons of the oil industry gleefully grab the liquid gold of ancient traps. Traps in which old mother earth had confidence her ancient riches would certainly be safe. Little did she know that modern technology would result in equipment and methods with which man could analyze and locate such traps but also drill into the secret treasures, which lay in her subterranean depths.

ROTARY DRILLING EQUIPMENT

Probably the best way to describe the rotary

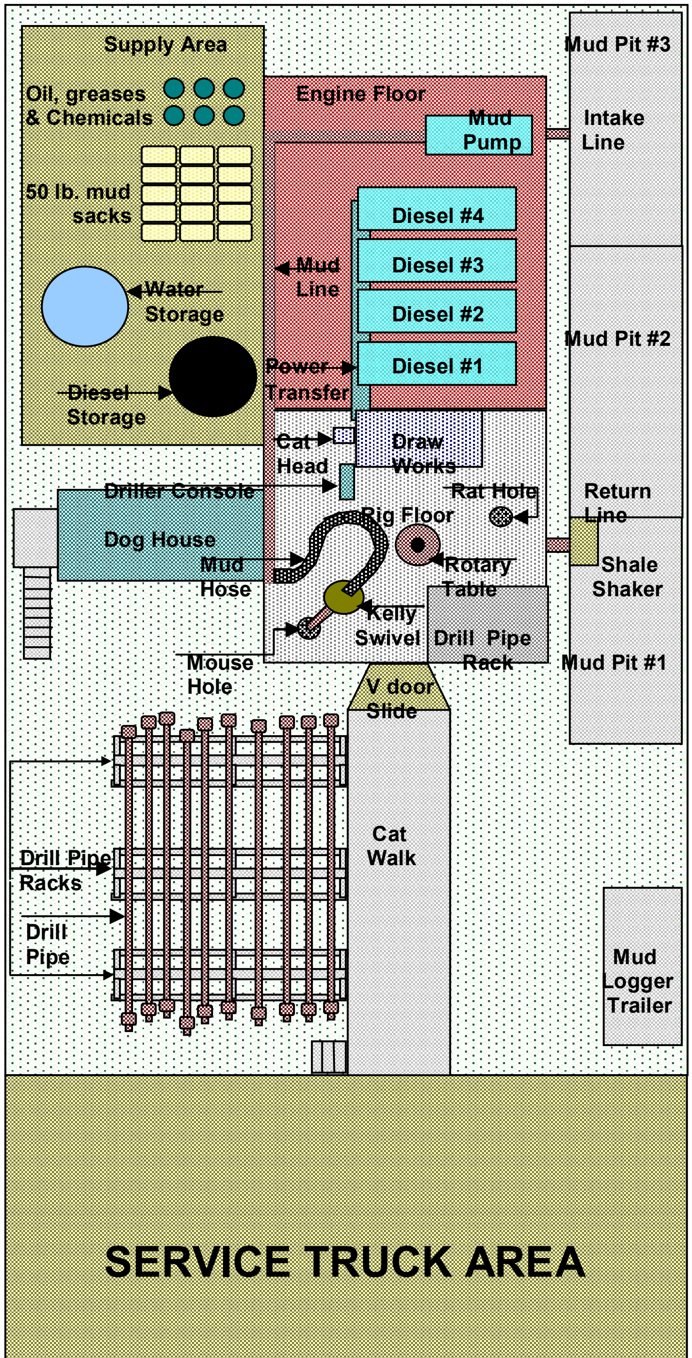

Figure 5-18 A plan view illustration of a typical drilling location on land with rig and supplies.

drilling rig is to begin with a diagram containing the rudimentary elements of said rig and explain their various functions in some type of orderly manner. Actually, it will probably take a couple of diagrams, i.e. a horizontal or plan view and a vertical view similar to a geologic cross-section. We'll make figure 5-18 the plan view and 5-19 the vertical snapshot. Ah yes, the geologic tools for describing a structure of Mother Nature applies to man-made structures as well.

A PLAN VIEW

In figure 5-18 we see the layout of a rather typical drilling location. Typical, that is for land based rigs. Off shore and even barge mounted rigs are a different story. We'll deal them in a little more detail later. Of course, some are simpler than that shown and some much bigger and complex. In general, the deeper a given well is to be drilled, the larger and more complex the location. On any location there will also be a tool pusher's trailer off to one side, which is not shown. It provides his living quarters and a basic office for business associated with the drilling. For discussion purposes, we'll divide the elements shown in figure 5-18 into 5 groups, i.e. the storage area, the engine floor, the mud pits and circulating system, the drilling floor with its associated dog house and finally the slide, catwalk, pipe racks and service truck area, the latter of which includes the mud logger's trailer.

These materials are added to the drilling fluid, frequently referred to as mud. Though it may look like mud, it is a complex drilling fluid. …

STORAGE AREA

The storage area is used for supplies needed to keep the rig running. It will contain items such as grease, oil and diesel fuel for the various engines. Additionally many different types of materials or chemicals may be used for maintenance of the well bore as the borehole progresses through various types of rocks and minerals. These materials are added to the drilling fluid, frequently referred to as mud. Though it may look like mud, it is a complex drilling fluid carefully controlled by the company supplying that so called mud.

DRILLING MUD PROPERTIES

The mud utilizes as weighting material, some form of barite (a heavy mineral), to raise the mud density to a specified value dictated by the formation pressures being penetrated. Mud density can range from 8 to 18 lbs. per gallon.

Water loss must be controlled to maintain stability of the walls of the hole and minimize the effect such water may have on formations of interest as it forces its way into the surrounding rock exposed to the mud column. This will be discussed in greater detail in the next chapter, i.e. Schlumberger Technique but, let me say, mud with a high water loss can create a myriad of problems in the drill hole.

The ph is held within a certain range depending upon the type of rock, which the rig expects to be encounter. Incorrect ph's may cause minerals to be dissolved and result in borehole damage, i.e. sloughing and enlargement.

Likewise the viscosity or thickness of the fluid must be maintained within suitable limits. Too low a viscosity will result in drill cuttings sinking to the bottom of the hole rather than being carried to the surface for analysis and to help maintain a clean mud system. Too high a viscosity makes the mud difficult to pump, raising the pump pressure required to maintain circulation. This can cause the rock to breakdown through fracturing or actually splitting the rock with its consequent lost circulation. More about that problem will come later too but for now I need to get back to mud properties. I'll be talking about such in later chapters and I'd really hate to muddy up my explanation.

Gel strength is yet another parameter that has to be maintained within specified limits. The mud will set up like jello if allowed to stop moving or is not stirred through circulation. A certain level is desirable to help transport drill cuttings but too high a strength will cause circulation problems and make it difficult to lower wire line tools into the well. I should know, having experienced such problems throughout my days in the field.

Usually about 10% of the fluid is diesel oil, which is added to help lubricate the bit. This increases bit life and reduces cost by keeping the temperature down in the bearings of the bit, a very important contribution to minimizing the cost of drilling a well.

Finally the salinity of the mud must be held at a reasonable level to help maintain formation stability. Most formations contain water with dissolved salt therein. Too high a resistivity, i.e. too low salinity, can cause shales to swell as well as create an environment allowing excessive solution of various types of salts from some formations with resultant sloughing. It will also impact the information derived from various well logs, which are sensitive to mud salinity.

I don't expect the average reader to be interested in the many properties just described but they should understand that the drilling fluid used is often a very complex fluid that is very expensive. Mud costs are an appreciable part of the total cost of drilling and in extreme cases, i.e. lost circulation, may bankrupt a small operator.

THE ENGINE FLOOR

The engine floor is really self-explanatory but a few comments may be in order. The reader can see four diesel engines with an accompanying power transfer unit which couples their individual drives to the draw works. Usually all four would be used while hoisting the drill pipe and when drilling but, one might be down for servicing or even repair and the rig processes can continue with the remaining engines. The number and size of the engines depends on the depth for which the rig is designed. Deeper wells require more drill pipe, more hoisting power and thus more and/or larger engines. They also require stronger derricks and other auxiliary equipment associated with the necessary load that is being borne. Truly, they are massive pieces of equipment and may cost an oil company up to several thousand dollars per hour just to be on location. Mud, technical services and other miscellaneous costs must be added to that.

POWER SOURCES

Originally, rotary rigs were powered by steam and the rig floor had a boiler and steam engines of various sizes. Such engines were more powerful than their later diesel cousins and thus such rigs maintained a place in the industry for many years as the deep-hole rigs. Diesel powered rigs were much easier to rig up and down as well as requiring fewer truckloads to move which, of course, lowered drilling costs. Consequently they eventually became the only available type as larger more powerful rigs became available. The mud pump shown on the engine floor is also powered by a diesel engine, independent of the others and somewhat smaller. It is part of the mud circulating system and a description of its purpose will be included in the discussion, which involves the mud system with its attending principles.

MUD PITS AND CIRCULATING SYSTEM

On earlier rotary rigs, the mud pits were, indeed, pits carved out of the landscape to contain the

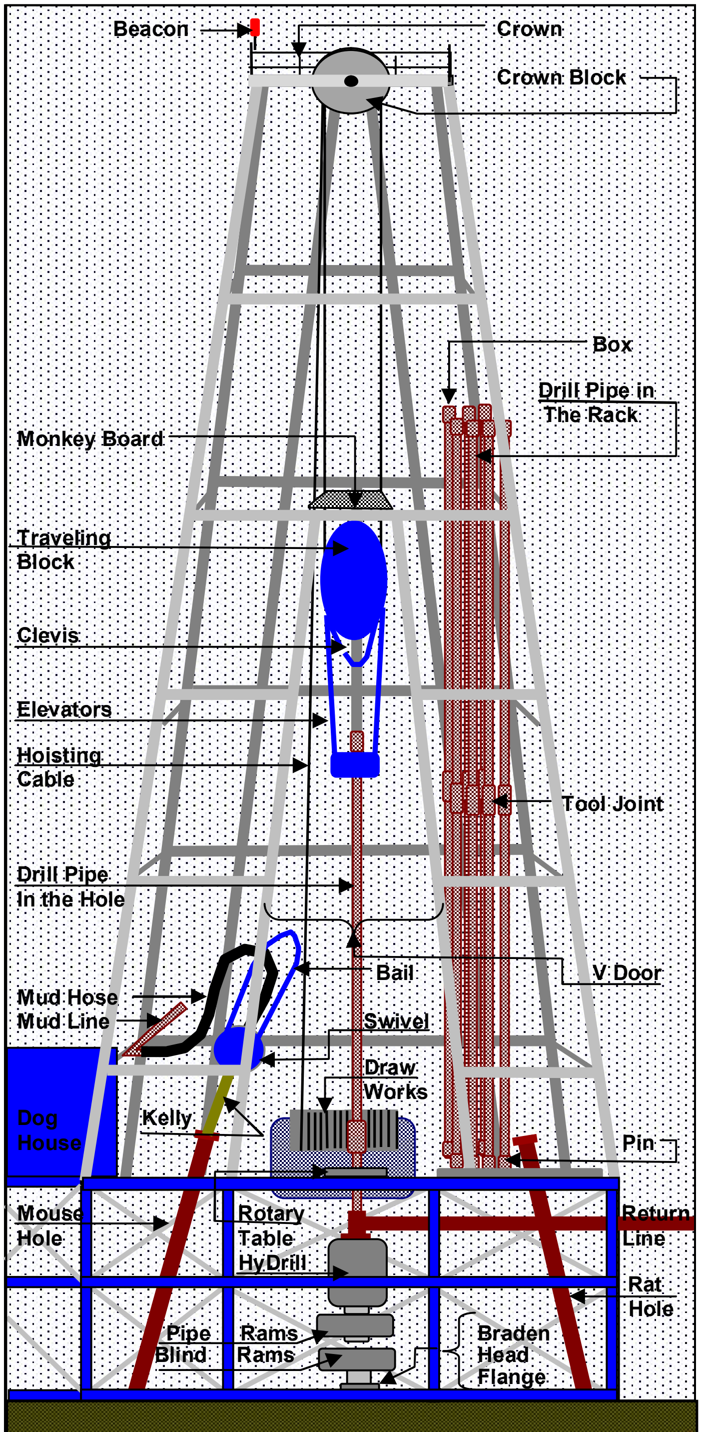

Figure 5-19 A simplified illustration of the vertical configuration of a rotary drilling rig.

necessary mud. Typically, there was a primary pit and a reserve pit, each of which was full of mud. The latter was necessary in case lost circulation was encountered and wasn't part of the active circulating system per se. Normally, as the hole deepened and mud needs increased, mud chemicals and water were added gradually so as to maintain sufficient volume to keep the expanding hole full and provide the necessary excess for normal use. The reserve pit's contents were then kept available for unexpected mud losses resulting, primarily, from lost circulation. Thus, they were held in reserve and given that descriptive name.

In figure 5-19, the reader may notice the mud-pits are rather symmetrical and no reserve pit is indicated. The figure illustrates later rig setups in which metal tanks were used as pits. They are moved with the rig and become part of the setup. There might be sufficient tanks to provide the necessary volume for the unexpected, i.e. as in figure 5-18, or another tank or two might be filled and placed along-side the ones shown without being hooked into the system. A brief description of the mud circulating system follows with more details provided later. It's not really complex but the many elements involved and their importance may surprise you.

CIRCULATING SYSTEM

Clean mud, a bit of an oxymoron, *is* uncontaminated mud and is picked up by the pump from pit #3. This mud has all the impurities picked up in the drill hole cleaned out at this point and consists only of those chemicals, weighting materials, etc. used to provide the characteristics designed into the mud for the particular horizons being penetrated by the bit. It is pumped at a relatively low pressure (maybe 50#) through the mud line to the mud hose, sometimes called the Kelly hose. There it enters the Kelly, which adapts the fixed pipe and line to the rotating drill pipe via the swivel joint. The Kelly consists of a rectangular metal pipe, with appropriate couplings, which is about 35 or maybe 40 feet long. A so-called Kelly bushing fits around the square pipe and can travel its complete length. The bushing engages the rotary table and turns as the table is rotated under the control of the driller. As the hole increases in depth, the Kelly slides through the bushing and down into the hole with the rotating motion provided by the rotary table. When the Kelly is drilled down, so to speak, the driller hoists it back up until the bottom connection is exposed and the mud pump is then shut down. A joint of drill pipe (30+ feet) is then added to the string in the hole and the process is repeated. Thus the Kelly couples the mud system to the drill pipe even as it helps couple the power provided by the diesel engines to the drill string. Thus, it is a kind of interface, which couples the drill string with surface power.

Now, let's get back to the mud system. Clean mud, that is uncontaminated, has entered the Kelly and thus into the drill pipe where it moves down hole until it reaches the rock bit. This is the device that actually cuts the rock (surprise, huh?) and varies in design with borehole conditions. The bit contains jets, which allow the mud to be pumped out into the hole. There it must move upward in the direction of decreasing pressure to the surface. In so doing, it carries with it the cuttings produced by the bit. At the surface it leaves the hole via the return line and enters pit #1 through the shale shaker. (See figure 5-18). As one might suspect, this device removes the drill cuttings from the mud as it enters the first surface tank. There, drill-cutting samples are typically taken at 10' intervals to check the lithology being drilled as well as to look for evidence of oil and gas. Similarly, a so-called gas sniffer monitors the mud returns for evidence of dissolved gas. Such quantified evidence is labeled a gas kick on the mud log, is of variable amplitude and acts as a flag for further investigation. You'll hear more about that particular subject later.

PURIFYING THE MUD

The shaker, of course has no effect on such things as dissolved gases and minerals or the extraneous fluids such as formation water and oil. The mud is pumped from tank one to tank two and then to three. It is also constantly stirred with hydraulically driven stirrers to eliminate gas from solution and produce homogeneity within the mud. Mud engineers check the properties of the mud on at least a daily basis to be sure its chemical makeup meets required design specifications. Additional chemicals are added as needed to maintain such specs. The contaminated mud of pit one is thus purified or adjusted in properties to meet these requirements as it moves through pit two to number three. Upon arrival there it should have regained properties necessary to complete another round. At the intake line it is picked up once again by the mud pump and another trip begins. Down the drill pipe it goes and out the bit nozzles to pick up another load of cuttings with their associated contaminants.

THE HEART AND SOUL OF THE MUD SYSTEM

Ahhh, what beauty, what harmony and even ecstasy engages one's soul as the pulsating rhythm of the pumps move that magical fluid of such precisely engineered properties through the system to its various extremities and the bit cuts deep within our mother earth. It brings solace to that great lady whose domain is being violated by man's mechanical genius while offering comfort to the driller who simply applies the power of this barbaric machinery in carrying out his job. It is indeed, a fluid approaching that of the golden elixir so sought after by many medieval alchemists. For if one applies it properly and in the right proportions to those compounds lying deep below the surface, it is instrumental in opening a pathway to the crude stores of mother earth, which yield gold in the hands of the wildcatter. Yes, such is the reward given to man for his faith and unyielding effort in pursuing his dream of riches.

I added that last paragraph to try to re-ignite the interest of the women folk as well as those men folk who seem less mechanically inclined. My heart weeps for the latter group, realizing that they may never know the joy of mechanical things with their associated thing-a-ma-bobs. Such do-dads operating in synchronism with the sound of pulsating engines and the mechanical movement of levers, pistons and cables do, indeed, provide unlimited joy, even ecstasy, to the normal youthful male heart.

I suspect, although no one has really said, that the first drilling crews came from the family farm and utilized those names they were most familiar with.

THE DRILLING FLOOR AND DOGHOUSE

As you look at figure 5-18 to survey the drilling floor, you should realize all those names pertaining to the animal kingdom are for real. That is, they haven't been added to increase my juvenile readership. I suspect, although no one has really said, that the first drilling crews came from the family farm and utilized the names of those creatures they were most familiar with as they tried to define the new machinery they were expected to operate. Whatever the reason, these names are a common part of oil field vernacular and are coupled with associated diction applied as adjectives to enhance the description of various activities and problems.

THE DOG HOUSE

Let's begin with the Dog House, a place of respite from wind, rain, storm and sleet or whatever old Mother Nature chooses to cook up. It's there where one can warm his hands as he warms his innards with a cup of coffee and shoots the breeze for a moment or two. It's also a place for records such as bit replacement, mud additives placed in the circulation system and the drill-time log. Where did it get its name? I'm not sure but I suspect the farm hands spoken of earlier began using it because of the protection it offered from the elements.

THE DRILL TIME LOG

The latter is a drilling record of formation penetration rate versus well depth and can be correlated to other near-by wells to get an idea of where the drill bit is in the geologic section. A horizontal mark is made for each foot of section penetrated with a somewhat longer mark made at the ten-foot interval. Obviously the marks will be close together in relatively soft formations and further apart in harder ones. In general, shales drill somewhat quicker than sandstones. Limestone or dolomite intervals drill slower yet. Of course, as the bit grows dull or drops a cone, drill time is slowed and can mask the formation type being cut. Figure 5-18 shows the doghouse location in plan-view and 5-19 shows the edge of the same in vertical cross-section. The doghouse is at drilling floor level, which necessitates the steps and platform for entry.

The reader should notice that there is an area full of gear and with an assortment of names just under the drilling floor in what's called quite naturally "the basement". We'll discuss the items contained therein a little later. For now, however, let's return to the doghouse level and take a tour around the drilling floor.

THE DRILLER'S CONTROL PANEL

As a person steps outside the doghouse door onto the drilling floor he will see a control panel on his left next to the draw works. This is the driller's console from which he controls virtually all of the functions of the rig. Primarily he operates the draw works and other devices associated with raising or lowering the drill pipe, breaking the tool joints as pipe is added or deleted from the drill string and engaging the rotary table while making hole, as it is termed. There would also be mud pump controls to control circulation and nearby would be hydraulic controls to activate the BOP's which you surely noticed in the basement of the rig.

THE DRAW WORKS

Just to the left of the driller's console is the draw works, which spools and un-spools the hoisting cable while raising or lowering the elevators. It is powered by the 4 diesel engines described earlier via the power transfer unit. It has a transmission to vary cable speed and hoisting power. On newer rigs such a transmission is automatic. Older ones require a typical clutch and gearshift. The spool of cable is in the vicinity of 1000 feet long providing sufficient cable to raise or lower the blocks via eight drilling lines connecting the traveling and crown blocks. The number of lines, hence mechanical advantage, is dictated by the weight, which must be raised. Thus, rigs capable of deeper holes utilize more lines as well as bigger engines to help raise the longer and heavier drill string.

THE MOUSE HOLE

Just to the right of the doghouse door is the so-called mouse hole in which the Kelly is placed when not in use. The hole is about 40 feet deep providing sufficient room for the 35 foot Kelly pipe to rest. The Kelly, you will notice is connected to the mud line via the Kelly hose, which is really somewhat longer than illustrated. I had quite a time just drawing one as long as I did, so don't make any comments about it not being to scale. In fact, don't make any comments at all regarding said drawing because I doubt seriously they would be complementary.

THE ROTARY TABLE

Straight ahead of the doghouse door is the rotary table, which is also driven by the diesel engines when they are engaged from the driller's console. It is coupled to the Kelly via the Kelly Bushing as described earlier. When coming out of the hole or going back in, the drill pipe is hung in the rotary table with slips that grab the pipe and which actually increase their bite as weight is added. This allows the driller to raise and lower the blocks as necessary while picking up a stand from the rack or placing one therein. Each time a stand is run in or brought out the floor hands (roughnecks) must temporarily remove the slips and then replace them as connections are made and broken. Though often muddy, greasy and generally untidy, the effort of these roughnecks combined with that of the derrick hand and driller is a marvel to behold when carried out with unity and precision. The speed with which such a crew trips the hole is, indeed, quite amazing. Their activity is every bit as precise in meeting the requirements of their operation as are the various machineries of the rig.

> **Though somewhat dirty and cumbersome, the effort of these rough necks combined with that of the derrick hand and driller is a marvel to behold when carried out with unity and precision.**

THE RAT HOLE

Just beyond the rotary table is the rat hole, which is sufficiently deep to contain one joint of pipe. Such a storage area becomes necessary as single joints are added to the drill string when making-hole, that is, when drilling. Excuse the oil field slang, though you may be sure there is often some much worse than this to abuse the ears. It (the rat hole) is also useful to place special tools in as they are being prepared to run in the hole. Think of it as a convenient storage area for temporary placement of useful down-hole gear, which to be used by driller or service personnel. It is not a long term storage place to store all kinds of things, which one collects or rat-holes for future need.

DRILL PIPE RACK

To the right of the rat hole is the drill pipe rack, which, at floor level, is nothing more than a wooden platform on which the stands of drill pipe are placed. The wood not only protects the floor but also prevents the bottom end of the stand from slipping as the top is leaned toward the elevators. Up at monkey board level, the derrick hand's station, there is a system of iron slots that hold the top of each stand in its appropriate place. The monkey board can be seen near the top of the derrick in figure 5-19 but the steel slots are not illustrated.

THE BASEMENT

WELL CONTROL EQUIPMENT

That pretty well covers things on the upper level of the floor but remember, there's still a basement to consider. Looking at figure 5-19, the reader can see a considerable amount of equipment below the floor. This basement area is typically 10 to 12 feet high on the average rig but on deeper holes such a basement may well be between 20 and 30 feet in height. The distance depends on the amount and size of the well control equipment required for the job. In figure 5-19, I've shown the equipment used on the average rig which consists of a HyDrill blow out preventer and two regular BOP's, one with blank rams and one with pipe rams designed to fit the particular drill pipe used on this rig. All play important roles in providing drilling safety. The HyDrill backs up the two ram types, having the ability to close around any size drill pipe, as well as completely cover the hole.

CASING OR BRADEN HEAD FLANGE

At the base of the BOP stack, as it is termed, lies the Braden head flange. This is a kind of collar, which is both threaded and welded to the top of the surface casing after the latter is cemented in place. It allows other plumbing hardware to be fastened to it via flange bolts and is so designed that a seal fits within which is rated at several thousand pounds of pressure. It is usually placed at ground level but may vary a few inches above or below. Sometimes measurements are referenced to it instead of ground level. Thus, one will see on a typical well log heading the phrase, "KB 12 ' above GL or above BHF meaning, of course, the Kelly Bushing of the rig that drilled the well was 12 feet above the permanent reference which is taken as either ground level or Kelly Bushing.

THE RETURN LINE

Above the BOP stack is the return line from which the drilling mud exits the well and drops through the shale shaker into the mud pit to be cleaned and purified as described earlier. This line is threaded into an adapter through which it is flanged to the HyDrill as illustrated. Should an extension of the BOP above the floor be necessary for safety considerations, this particular flanged adapter must be replaced with one, which is threaded to allow such an extension. We'll talk more about that in certain logging and perforating operations, which I engaged in over the years. They may add more enlightment for the reader if he's truly interested.

This is a kind of collar, which is both threaded and welded to the top of the surface casing after it is cemented in place.

THE SUBSTRUCTURE

The blue frame represents the substructure upon which the drilling floor rests and is designed to hold the weight of all the heavy iron that rests thereon. It, in turn, rests on the ground as indicated by the muddy green strip.

MAKING HOLE

Before leaving figure 5-19, let's move back up into the derrick and discuss some things, which were only mentioned previously. They are clearer in this figure and maybe I can make their purpose and use more evident.

First, let's look at the Kelly. Note the Bail as well as the Clevis on the traveling blocks. When the Kelly is being used, the Bail snaps into the Clevis as the Elevators are held to one side. The Kelly is then pulled out of the mouse hole and the bottom end or so-called pin is threaded into the box on the topside of the drill string. Once engaged, the string is hoisted up a few inches, releasing the slips, which are then moved to one side. The drill string can then be lowered into the hole with the mud pump running which allows mud to be circulated from the pit to the Kelly to the drill string to the bit at the bottom of the hole where it exits the pipe. It then rises up the hole carrying drill cuttings and other impurities to the surface and finally exits the BOP stack via the return line where it drops into the pit labeled #1 in figure 5-18 and is then cleaned up for another round.

ADJUSTING THE BIT WEIGHT

Before the bit strikes the bottom of the hole, the driller would have the floor hands drop the Kelly bushings into the Rotary table providing the necessary coupling between rotary and Kelly for drilling. Once that is done, he would engage both the rotary and mud pumps. With the drill string spinning and mud pumps running the bit would be lowered until just the proper amount of drill pipe weight is resting on it to provide optimum cutting of the formations. Too little weight results in slow drilling while too much results in a crooked hole with its associated problems. Most holes are kept as near the vertical as possible such that the surface location of the well can be considered the geographical point at which the hole penetrates the objective formation. Directional shots are taken at intervals specified in the contract to verify the borehole inclination is within the limits required. In fact, I have a little personal experience to relate relative to the way directional shots were being taken on some po-boy drilling rigs in the Rock Springs, Wyoming area in the late sixties.

RACKING THE DRILL PIPE

Notice that the drill pipe is partially out of the hole in figure 5-19. That is something like seven doubles of roughly 65' are standing in the rack and another one is being run in or pulled out. The point is that this particular rig is capable of only pulling two joints of pipe at a time thus limiting its depth and speed capabilities. Such a rig can drill to around 7000' maximum. Deeper holes must be drilled by one pulling triples or almost 100' per stand. For a ten thousand foot hole the drill pipe rack would have to be capable of holding about 100 stands or the rack when full would measure 10 by 10 stands each 100' long. As well depth increases, obviously more floor space is necessary to handle the drill pipe, "When all is on the bank", as a driller would say. Holes in the 15,000-foot plus range usually stack pipe on both sides of the V - Door or the derrick opening which leads to the catwalk. Such pipe increases in size as well to provide the necessary tensile strength in the top end of the string. Deeper holes thus require more hoisting power, stronger derricks and substructures, bigger draw works, bigger traveling and crown blocks, etc. All this means more size and weight with its associated cost of moving and erecting. This is pointed out to help the reader appreciate that ultra deep holes in the twenty thousand foot plus range require large locations to contain the rig proper as well as the large amount of supplies and services necessary for support of the operation. I have some photos I intend to include a little later which provide glimpses of the mechanical workings of large offshore rigs and a good-sized land rig as well as the immense amount of supporting equipment required. Together they should help provide the desired perspective or, should I say, the perspective I want to provide to whomever is dedicated sufficiently to read this far in this book; regardless of the source of such dedication, that is, curiosity or real interest.

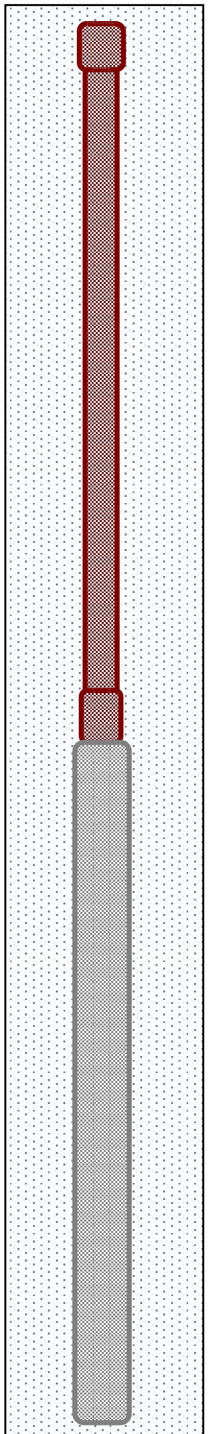

Figure 5-20 A drill collar and drill pipe.

A TYPICAL RIG CREW

If the rig were pulling pipe or going back in the hole for that matter, there would be a derrick hand on the monkey board secured with a safety line. Obviously, a misstep could be fatal for him. Similarly, there would be two floor hands and the driller on the floor. They typically work 8 to 12 hour shifts as the rig runs around the clock. Such a shift is spoken of as the morning tour or evening tour and though pronounced more like tower, I suspect the term was originally tour. Sometimes, particularly on bigger rigs, a fifth hand is added as a motorman or just an all around service hand. He services what has to be serviced and frees the others for drilling. On smaller rigs, such a person is a luxury due to the competitive drilling market.

CONDITIONING THE MUD

When making hole (drilling) the driller may decide to stop temporarily to condition the mud and/or the hole. Gas in the mud is continuously monitored and should he observe a gas kick, so to speak, the driller might decide to condition the mud. Failure to do so could be dangerous. If insufficient hydrostatic pressure exists in the borehole (resulting from insufficient mud weight) gas may bleed into the hole from one or more formations penetrated. Such gas further lightens the mud column and if allowed to persist, a blowout may occur with its many hazards and the difficulty of bringing it under control. Thus, stopping to circulate gas cut mud out, while adding the necessary weighting material and chemicals, is more than just the proverbial, **"a word to the wise is sufficient".** It is a safety procedure all responsible drilling companies employ.

In a similar manner, as hole is drilled, the walls may take time to stabilize. That is, the penetration of rock exposes the new walls to the mud column, which react to the intrusion in differing ways. Shales may swell and attempt to close off the bore-hole; resulting in sticking the drill string. Other rock may go into solution contaminating the mud until the two are stabilized. Some zones adsorb more than a normal amount of drilling fluid and slow or prevent proper circulation even up to the point of lost circulation. The latter term simply means that less mud returns from the hole via the return line than the mud pump is pumping in. Obviously this can't be tolerated for long. Whatever the problem, it must be corrected before proceeding deeper. Thus, the terms conditioning mud or conditioning hole are commonly found on the driller's log, which is simply a record of the crews' activities during their particular tour of duty. Such a log also contains a record of the time and depth at which a joint of pipe is added to the down-hole string. In short it is a summary of all activities of the drilling rig.

THE DRILL STRING

In most cases, the drill string is composed of one given size drill pipe to simplify the operation. Typically this is 4½ inches in diameter but smaller pipe is used for slim holes and the use of 5½ is rather common on deeper holes. The pipe chosen is based on available clearance in up hole casing strings and tensile strength requirements based on drill-hole depth. To support 15,000 feet plus of pipe and provide the necessary pulling strength 5½ inch pipe is usually necessary. Lesser depth holes can be handled with the more common 4½-inch pipe. In some cases the two sizes are mixed with the smaller pipe at the bottom, thus gaining the necessary tensile strength while accommodating smaller casing and hole sizes found in deeper horizons.

The traveling block has a heavy duty spring inside which is sufficiently strong to lift the Kelly or a stand of pipe clear once the threads are completely free.

On the bottom end of any drill string are several stands of drill collars, which are larger in diameter than is the drill pipe and also much thicker walled. Their purpose is to add weight to the bottom of the string and create a tendency for it to hang straight, thus allowing a straighter hole to be drilled. One could compare the drill collars to a plumb bob on the bottom of a chalk string, which is used to pull the string straight before snapping a vertical line. Oddly enough, the rigid drill pipe is more flexible than it would seem and can bend considerably when in strings of several thousand feet. The extra weight of the drill collars help keep the string straight. Figure 5-20 illustrates the appearance of a drill collar hooked to a joint of drill pipe. Notice, no tool joints are apparent as is the case of the drill pipe. The pin and box are cut into the collar and become an integral part of it during manufacture whereas tool joints are added to the drill pipe afterwards. The collar has a larger diameter as well, all of which contributes to its weight. Dashed lines indicate the internal diameter of a drill collar. Now, let's move to the last area of figure 5-19.

THE CATWALK AND SERVICE AREA

The catwalk is the area where various types of equipment are placed and prepared for use in the drill hole. Such equipment may consist of special drilling tools, simple drill pipe, casing used at various depths or various equipments used by any of several service companies. It is the gateway to the rig floor.

CAT-LINE USE

Let's consider first the drill pipe of which a sufficient amount is stored on the adjoining pipe racks to drill to the anticipated total depth. As additional pipe is needed, it is rolled on to the catwalk where a roughneck hooks the cat line around it just below the box on the rig end. The cat line is a thick rope (2"or so) with a chain on the end, which is pulled to the catwalk. The chain is hooked around the pipe. The driller or maybe another floor hand will then wrap the cat line around the cathead sufficiently tight to begin spooling in the cat line, which hoists the joint of pipe into the derrick through the V door. There it is placed in the rat hole until the driller is ready for its use. Notice, the V door is the opening connecting the slide to the rig floor and is shown in both figures 5-18 and 5-19. It has sufficient height to allow a joint of drill pipe or other long tools to be picked up from the cat walk or laid down thereon in the course of working on the well. Its shape obviously produced the name unlike many items on the rig.

The pipe racks are self-explanatory holding all different types of pipe to be used on the rig, most commonly drill pipe, drill collars and casing of various sizes. On a deep hole such racks would be on either side of the catwalk providing easy access to them for drill pipe, etc.

MUD LOGGER'S TRAILER

A mud logger's trailer is found on, virtually all, modern drilling locations. It provides a place for the well site geologist to examine drill cuttings, which are usually collected for every 10 feet of hole drilled or even more frequently in zones of special interest. It also has sensors placed in the mouth of the return line to check for shows of oil and gas in the mud exiting the drill hole. The signal generated by these sensors is continuously recorded on a chart or graph, indicating gas content versus borehole depth. A so-called kick is frequently obtained in the top of water bearing sands as well as those bearing oil and/or gas. Likewise, large kicks are obtained as a seam of coal is penetrated. Such information alerts the geologist to pay special attention in examining samples in that area in case other tell tale signs of hydrocarbon are present. If sufficiently large and persistent, they can also signal the possibility of a mud control problem and thus alert the driller to condition the same. The trailer also serves as an office for business activities where the various service activities are carried out. It also usually has sleeping facilities in which the mud logger and the geologist can get a little well deserved rest.

TRIPPING THE HOLE

Let's consider the activities that take place when a driller decides to come out of the hole. Such a situation may result from the need to change a bit, run a drill stem test, cut a core, run logs or a number of other activities.

PREPARING TO COME OUT OF THE HOLE

The driller would probably condition the hole for a couple of hours to be sure both hole and mud are stabilized before pulling the pipe. After shutting down the rotary table, he would then raise the Kelly via the blocks until it disengaged the rotary table at which point the floor hands would pull the Kelly bushings and insert the slips to hold the drill pipe once the Kelly is disconnected. The mud pump would be shut down and the connection between the Kelly and drill pipe would be broken. This requires a lot of force because the tool joints are big and the connections made up tight. Thus, each rig has a set of pipe tongs, which are nothing but big wrenches with chains connected from their opposite ends to a power source in the draw works. The driller applies power to the tongs to break the connection loose once they are in place. The bottom tongs are then disengaged and the rotary table is typically engaged to spin the pipe string loose down hole. Sometimes a crew is required to chain out instead, a practice I will explain later. The traveling block has a heavy duty spring inside which is sufficiently strong to lift the Kelly or a stand of pipe clear once the threads are completely free. With that done the floor hands push the bottom of the Kelly over to the mouse hole and once lined up the driller slowly lowers the square shaft of the Kelly into the hole. The Clevis is then released from the Bail and the blocks swing back to the center of the derrick.

Depending upon requirements, a Totco hole deviation-measuring device may be dropped into the drill string and pumped down prior to coming out of the hole. Time is allowed for the device to make a deviation measurement at the bottom of the hole and then the Kelly is placed in the mouse hole and the trip begins.

The situation would then look much like that of figure 5-19 except the tool joint on the down hole string of pipe would be about two feet above the rig floor and there would be no pipe in the rack. Now it's time to get the crew in place for pulling the pipe. The derrick-hand stands on the elevator collar (that portion which closes around the drill pipe), snaps his safety line around the elevators and away he goes up into the derrick like a stand of pipe. The driller is an expert with the draw works. Even though the blocks move rapidly, he shuts the elevator down exactly opposite the monkey board where the derrick hand steps off. There he unsnaps his safety line and secures it to a derrick member and signals the driller that he is clear. He is now ready to handle the various situations that might face him in the course of the next operation. One can appreciate that one small slip could be deadly.

PULLING THE PIPE STANDS

The blocks are quickly dropped and stopped just above the drill string. One of the floor hands grabs the elevator collar and closes it around the tool joint or box of the exposed drill pipe as the driller slowly drops the blocks another foot. As he then hoists the drill string the floor hands pull the slips and stand them on the rotary table just inches from the hole. The string is quickly hoisted to the top of the derrick at a speed the uninitiated might consider reckless. At least that is the case once the string down hole is light enough to allow such speed. However, the driller brings the traveling block to a stop, just inches below the crown. The slips are quickly kicked into place around the drill string and the driller slacks off until the slips hold the complete weight of the string. The pipe tongs are put in place once again, the connection broken and then spun loose with the rotary. The stand is snapped up about 6 inches by the elevator spring, clearing the box. Next, the floor hands push the bottom of the stand to the proper place on the pipe racking board while the driller slowly lowers the blocks. With the bottom end in place, the derrick hand unlatches the elevator collar and pulls the top of the stand over to the rack such that the stand is vertical. Quickly the driller drops the blocks and once again stops them inches from the top of the drill string still in the hole. The floor hand engages the elevator collar around the box on the string in synchronism with the driller's careful lowering of the blocks another foot and the process is repeated. Again the floor hands pull the slips as the pipe is raised and the driller quickly hoists the pipe.

It really is surprising just how fast a good crew can pull a stand of pipe. Ten thousand feet of pipe may take 3 hours under typical conditions including tying off the drill collars, which number about 12 or 15. However, I should add at this point that hoisting speed may be limited to minimize the swabbing effect down hole. Rapid upward movement lightens the hydrostatic pressure at zones below the pipe and may suck gas or oil into the borehole, which lightens the fluid column even more. If not properly controlled such a situation could lead to a blowout or total loss of well control with its associated complications and cost. Similarly, too fast a decent can build up pressure ahead of the bit and actually fracture the formation.

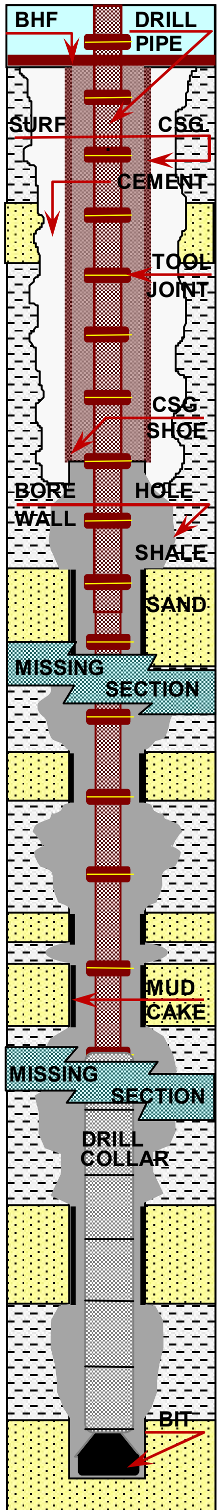

Figure 5-21 A typical profile of a borehole.

HANDLING THE DRILL COLLARS

As was shown earlier, the drill collars are absolutely smooth and very heavy. They require special handling as they are brought out of the hole. When the first collar appears, the floor hands place a special collar clamp around it, which is tightened with wrenches such that it can't slip with the full weight of the drill collars pulling down. The clamp then rests against special slips used on the collars. When the last stand of drill pipe is taken off the top of the collars a drill collar adapter is screwed into the protruding collar and tightened with the tongs. The adapter looks much like the top of a joint of drill pipe having an enlarged top, which rests in the elevator collar. The drill collar clamp is removed and a stand of collars is pulled up into the derrick. The drill collar clamp is then reinstalled on the next stand and the slips placed back in the rotary. The stand of collars is then broken loose from the string down hole and swung carefully over near the pipe rack but not on it (they won't fit). The top or adapter is then securely tied off to the derrick superstructure to prevent any possibility of movement. Should a stand of collars get loose, they could damage the derrick because of their weight. The driller then continues to pull each stand of collars in a similar manner until the bit appears. At that point, the driller will examine the bit to see if it needs changing and, if so, it is broken off with the tongs and a special bit receptacle, which fits in the rotary. At that time the Totco will also be pulled and checked for deviation if one was run. The floor is then hosed down and the derrick hand brought down via the elevators for a little rest and relaxation before participating in whatever rig requirement might happen to come up next.

RUNNING IN THE HOLE

When going back in the hole the procedure is obviously reversed as a new bit is placed on the lowest collar and each stand is lowered carefully in the hole. Getting the collars safely in the hole is rather slow but from that point on the speed picks up. As the driller raises the blocks rapidly upward after being released from the down-hole string and slips, the derrick hand already has the top of the next stand pulled over in front of him. The floor hands quickly apply thread dope (grease) to the box standing in the rotary table and put the tongs in place. As the elevators come within range of the derrick hand, he grabs the collar, which is open and snaps it around the top of the stand, hardly waiting for the blocks to stop. The floor hands push against the bottom of the stand to prevent it from swinging as the blocks pick it up. Its weight slowly swings the bottom end into place over the string down hole.

The pin or threaded joint on the bottom of the hanging stand is tapered with the diameter being reduced at the end to allow ease of entry into the box or joint it will engage. The box internal threads are tapered in the opposite direction, obviously, to allow the two ends to join properly. The pin on the lower end of the stand is edged into the box and the floor hands quickly move a chain already wrapped around the box up on to the hanging stand. The driller applies tension to the chain from the draw works and as it pulls around the hanging stand, it spins the pipe into the box. The tapered nature of the tool joint requires only a few turns of the hanging stand to completely make it up. Tongs are then put in place and the tool joint is securely tightened. As the driller picks up on the blocks, the floor hands pull the slips so the new stand can be lowered. The driller drops the stand rather rapidly and the operation proceeds quickly in a repetitious manner.

However, too fast an entry back into the hole can create a piston effect pushing the mud ahead at tremendous pressure. In so doing, the pressure may actually fracture the rock and create a zone of lost circulation with its attendant problems. Thus, as previously indicated, the drillers operating mode is frequently controlled by a higher authority and he moves the blocks going in or out of the hole at speeds within a specified limit.

Coming out of the hole with the drill pipe is usually referred to as pulling the pipe while going back in the hole is termed heading for bottom. The two combined activities are considered a round trip.

Once on bottom, a new joint of pipe is added if necessary and the Kelly is engaged. The driller applies a specified weight to the bit as he engages the rotary table and mud pumps. Drilling is underway. Bit weight is carefully controlled to provide maximum penetration while maintaining proper hole deviation or staying within the specified limits. If the borehole deviation becomes excessive, steps must be taken to straighten it out, usually with less weight on the bit and its associated slower penetration.

THE DRILL HOLE

It would seem worthwhile to examine a typical drill string and review its makeup. Although many variations may occur in different holes, most are rather standard because nothing out of the ordinary is experienced. The most common configuration of a drill string, which is situated in a borehole, is illustrated figure 5-21. Because of the vertical space available, the reader will notice two breaks in that particular dimension which simply mean large vertical sections were left out at those points to minimize chances for mistakes and facilitate the drawing.

SURFACE CASING

Let's begin with the surface casing. Notice the Braden head flange is flush with the ground surface, which is usually the case. After the surface casing has been cemented in place, it is cut off flush with the ground and the flange is welded in place. The flange provides a sealing mechanism with hardware mounted above and thus helps contain the pressure within the pipe. Just as important, of course, is the cement job around the pipe. Failure to have a good cement job is inviting catastrophe should the well kick and threaten to blow out. The BOP's of the rig may be working fine and all fittings secure but if gas can escape around the surface pipe, all that is for nothing. Not only can it escape to the surface with its consequent danger of ignition but it also can charge shallow water sands with flammable gas.

CONSEQUENCES OF POOR SURFACE STRINGS

I remember such a case occurring near Baggs, Wyoming in the late 60's. Baggs is a little ranching community near the Colorado border on the north east side of the Sand Wash Basin (see figure 5-17). Even though the area was noted for high-pressure gas sands, proper precautions were not taken and the hole began to unload. The BOP's were used to shut the well in and contain it until sufficient mud could be mixed to kill it or bring it under control.

As I remember the incident, the gas didn't leak to the surface around the rig but instead took the path of least resistance into a water-sand behind the surface casing, which it pressured up to a level equal to that of the gas reservoir. Soon the housewives of area ranchers found gas coming from their faucets and other plumbing as they prepared dinner or flushed the commode, etc. It wasn't only scary but down-right dangerous. Additionally, the charged sand was close enough to the surface such that gas began to break through the overburden into places like ponds and streams. Soon there were little fountains all over the area. Had the gas collected in a low spot and later ignited, cattle most surely would have been killed and maybe people. Fortunately, that didn't happen and people were safely evacuated until the situation was safe. It cost the drilling company an arm and a leg. I'm confident their attention to properly cementing the surface casing was raised to a new level after that experience.

Soon the housewives of area ranchers found gas coming from their faucets and other plumbing as they prepared dinner, flushed the commode, etc.

BLOW OUT PREVENTERS

Before we leave the surface, let's talk about BOP's whose use I have tossed around rather indiscriminately. In the drawing of figure 5-19 the reader will notice 3 different blowout preventers stacked one on top of the other. The driller normally operates all their hydraulic controls from his console on the rig floor. The bottom set is labeled blind rams. Its function is to close in the hole should the pipe be on the bank when the well begins to kick. Those labeled pipe rams are designed to close around the pipe should it be in the hole when such occurs. They are designed to fit a particular size pipe and must be changed as pipe size changes. A kick while in the hole is the best situation if it has to occur because the crew can not only contain the well but they can also mix heavier mud up to pump in and control the gas inflow. The top BOP is called a HyDrill after the company who makes them and is an all-purpose unit. The glands or rubber-packing element can close off a borehole void of drill pipe or close around pipe of any size with a tight seal. In fact they can even close around a wire line such as a Schlumberger logging cable, which is typically 9/16" in diameter. In this situation it serves as a backup to both the pipe and blind rams. A HyDrill is found on most rigs drilling in areas of any significant pressure risk.

BACK TO THE DRILL HOLE

Assuming typical surface casing, i.e. 10 ¾", a 12 ¼" surface hole would have been drilled. Once the surface casing is in place and the BOP's installed, drilling will begin on the rest of the hole. Ten and three quarter pipe will allow up to a 9 7/8" bit size below it, a rather common oil field size. In a known area, mud properties are already well documented and preparing the mud is rather standard procedure. Even so, its properties must be checked on a regular basis for assurance and to prepare for or control the unexpected.

DRILL HOLE CHARACTERISTICS

As hole is made, we find that shales tend to wash out or the drill hole becomes enlarged while cutting through them. Sands, on the other hand tend to remain in gauge and take fluid until the mud seals off their permeability. (The reader may remember that the permeability of a rock is a measure of its ability to allow fluid flow through it.) To maintain control of pressures

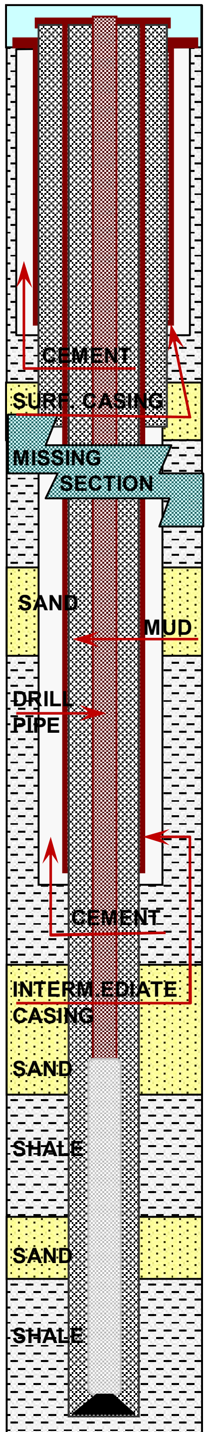

Figure 5-22 Well with an intermediate casing string.

encountered, the hydrostatic pressure exerted by the mud is always about 200 lbs. more than formation pressure. Obviously, this will create a fluid flow into the rock unless something is done to prevent it. The mud cake shown in figure 5-21 is the mechanism for that control. As the reader moves his eyes down near the bottom of the hole he will notice the cake is somewhat thinner, indicating it is in the process of building up sufficiently to completely shut off any fluid flow.

The profile of the well bore is essentially what is seen when a caliper log is run on the well. In general, well diameter is something less than bit size in sands due to mud cake and something greater than bit size in shales because of swelling and subsequent sloughing in those areas.

INTERMEDIATE CASING STRINGS

In some areas, such as Baggs Wyoming, the formation pressure gradient (pressure increase per foot of depth) is known to suddenly increase at a specified depth. If the mud is weighted too heavy after reaching that depth, lost circulation will occur in the upper zones and if kept too light, the well will blow out as the deeper high pressure zones are cut.

To forestall this situation an intermediate string of casing is run when the well reaches the critical depth. This situation is depicted in figure 5-22 where a string of intermediate casing has been run at some unspecified depth. The sand just up the hole from the casing shoe of the intermediate string would be a relative low-pressure zone requiring standard mud weight. The pressure gradient takes a sharp increase in the shale beneath the sand. Knowing this, the drilling company runs the protective casing, which seals off the low-pressure zone and allows them to bring the mud weight up to the specified level. When the bit penetrates the high pressure sand the hydrostatic column of the mud is now sufficient to prevent appreciable gas entry into the hole. Unlike the surface casing, the reader should note that cement is only pumped part way up the outside of the intermediate string, sufficiently high to provide the seal but nothing extra as waste. This practice also provides the option of pulling much of this particular string should the well be a duster (dry hole). Although such practice can be costly, it is far cheaper than fighting a blow out or lost circulation.

DIRECTIONAL DRILLING

I have indicated that a straight hole is the desired profile of a hole, at least when possible. Unplanned borehole deviation creates mapping errors because the actual location of where the bit cuts the mapped horizon is different than that assumed. Also crooked holes can create problems in drilling a well, logging it as well as running casing. Consequently, in general, it is an undesirable attribute. However, there are situations where the hole is deviated intentionally and the amount of deviation as well as its direction are not only planned but controlled as well. This can be done with a great deal of precision as the operation proceeds.

SIDE TRACKING A WELL

Consider well F as illustrated on the maps of figures 5-13 and 5-14. If it were to be directed a little to the north east just a little above the Navajo sand, it would cut a thicker sand interval and when drilled on down to the Madison the well would exit the fault zone on the north east side and be high enough structurally to produce oil from that horizon as well. Such a well is definitely a candidate for sidetracking, so to speak, because of the potential reward. A cement plug would be set a couple hundred feet above the Navajo. When properly cured, a borehole deviation device called a whip stock would be run in and so oriented that it would kick the bit to the northeast as it was encountered. As the bit passed through the sand, the hole deviation would be corrected to the vertical and drilled down to the Madison, a deeper objective of the operator in this particular example. This would keep the TD target in the optimum producing area for that structurally controlled horizon while improving the production characteristics in the Navajo sand.

OFF SHORE FIELDS

Off shore fields are the provinces of sophisticated directional drilling. Once a field is discovered and its limits defined, plans must be made to drill a sufficient number of wells to properly deplete the reservoir as well as for installing production facilities. A platform for the well heads and offshore storage facilities must be built, which is very expensive, especially when the field lies in 600 or more feet of water. Thus one platform with directional wells drilled from a central point to the desired subsurface location is the most economical approach. Figures 5-23 and 5-24 depict such a situation for a 16 well field. Figure 5-24 is a hypothetical cross section taken in the orientation shown in the horizontal plane in figure 5-23 as X - X'. It provides a better idea of the horizontal versus vertical distances the wells must traverse in reaching its destination at TD (total depth). In figure 5-23, the 12 wells comprising the platform's perimeter, are shown in red as they traverse the horizontal distance necessary to reach their target. The 4 inner wells of the 16 well-group are shown in dark magenta as they move horizontally to their destination. The cross section X - X' is shown in blue to differentiate it from the well bores.

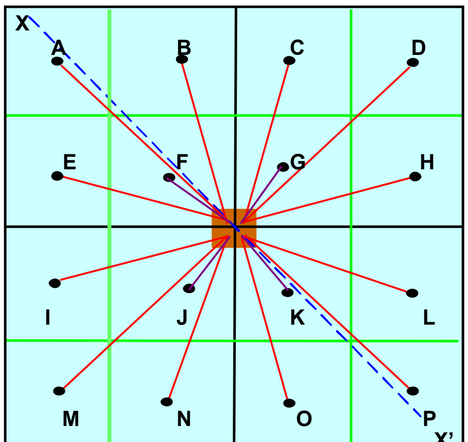

Figure 5-23 Map of proposed drilling configuration in an offshore oil or gas field.

OFF SHORE EXAMPLES

The producing area covered by the platform might typically be 4 square miles with each well expected to drain 160 acres of the reservoir. This would be rather normal for an offshore oil field where reservoir permeability is high and the number of wells must be minimized to keep investment as low as possible. In fact, the 16 well-platform is rather common in the Gulf of Mexico. I am aware of at least one 64 well platform. When completed, one can imagine the maze of casing strings leaving the platform in varying directions and their associated wellheads. What a plumber's nightmare. Also, Shell has one platform in over 1000 feet of water. I don't remember the number of wells it serviced but two different rigs were drilling from it. I suspect the number of wells was 48 to 64. The cost is in the billions of dollars, because they must be designed to withstand hurricanes as well as any other possible disturbances. Gas fields in the gulf are often spaced at 640 acres or one well is designed to drain one square mile. This is possible because of the low viscosity of gas and the very high permeability of the sands in the off shore environment.

CONTINUOUS -CONTROL OF DIRECTIONAL DRILLING

Although I spent some-time on offshore rigs, it was only a minor part of my experience. As a result, my knowledge of directional drilling is quite limited. I have been around rigs in the process of side tracking the hole to get around a problem, move up dip for a better well, etc. but I haven't really been involved with directional crews offshore. Having read the trade journals, however, I do know such equipment was very sophisticated and was under the direction of an engineer who oversaw its operation. The position of the bottom of the hole is always known and the drilling company has the capability of changing drilling direction almost at will. Consequently, the drilling is guided along a pre-planned route to the target position in the reservoir much like you and I follow a road map.

RUNNING CASING

Earlier in this section, I talked about surface casing and intermediate casing strings but said nothing about running it in the hole or even cementing it in place, for that matter. This seems an appropriate place to take up these matters in simplified form.

The borehole is thoroughly conditioned before attempting to run casing. The operator wants to be sure the casing string goes to bottom cleanly without experiencing obstructions. Any problems slow the operation down at the very best and can result in the need to pull the casing back out of the hole. Obviously, this is a no-no and every effort is made to prevent such an occurrence. From such a perspective, one can easily understand the wisdom of such conditioning prior to running casing as well as special effort to handle any unusual problems that might occur.

CEMENTING THE SURFACE STRING

In drilling a typical oil or gas well, state laws require the setting of a surface casing string to protect fresh ground waters from their more salty cousins lying deeper in the hole and to also protect them from contamination by oil, gas or any other marketable substance should such be encountered. The amount of casing will vary by state and even by areas within a state. Typical lengths run from 100' up to as much as 2000 feet with 4 to 5 hundred being the average. Such a string is easily handled by the rig and is cemented in place with a full column of cement as indicated by returns from the annulus around the casing. As mentioned earlier, a good cement job is imperative if the well encounters high-pressure zones and is difficult to control. There may be no second chances.

A cementing company is called out to pump the cement once the casing is in place. The casing would be held off bottom a foot or two by the rig elevators, while the cementing company does their work, so as to allow free movement of the cement down and around the casing shoe and back up the annulus. Typically, after the surface string has been cemented in place, some 10 to 15 feet may be sticking up in the air. It is then cut off at ground level and the flange (Braden head) is welded in place, which allows installation of pressure control equipment as mentioned earlier and then, drilling resumes.

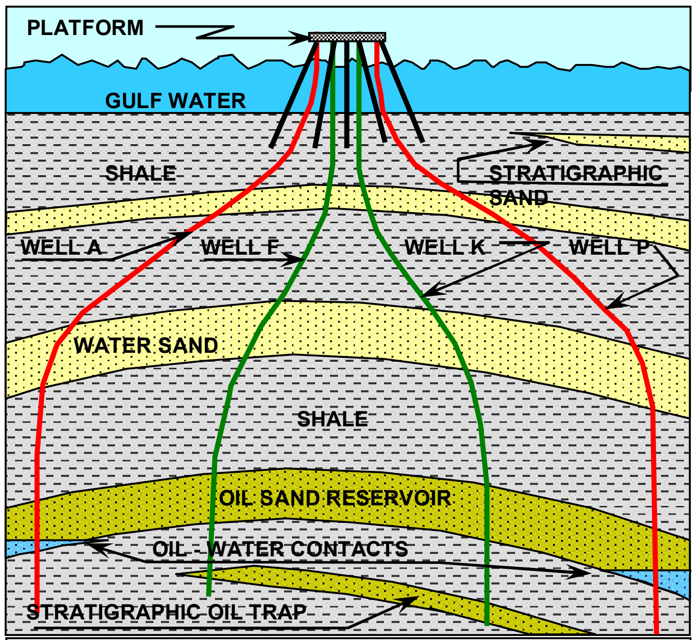

Figure 5-24 A cross-section of a typical offshore oil field illustrating common trapping mechanisms.

OTHER TYPES OF CASING STRINGS

Unless unusual drilling problems are encountered, no additional casing will be set unless the operator is fortunate enough to strike pay dirt, which requires production casing. If this occurs, typically it will be seven inch or five and a half inch casing, depending on borehole size. The larger 7" casing requires a borehole of 9 7/8" while 5 ½" will run in an 8 ¾" or even a 7 7/8" hole. A 6 1/8" bit will permit only 4 ½" casing as a maximum. It should be noted that collars coupling the casing joints together add about ¾" to the string diameter. I mention all this to help the reader understand that the planning of casing strings and consequent borehole sizes is done well in advance. If not, TD may be reached with a borehole size too small for the desired casing and restrict down-hole hardware choice, which in turn, complicates production problems.

CASING CREWS

Making up a production string as it is run in the hole is not the work of the rig crew. The work entails special knowledge as well as equipment, resulting in a casing crew being ordered out just prior to the cementing company. The casing has already been unloaded and placed on the drill pipe racks earlier, where it has also been tallied or added up in the order it will be run in the hole. This will allow the operator to keep track of the casing shoe depth at any given time. The rig crew along with the casing crew provides the manpower necessary to connect casing joints in the proper order.

CONFIGURING THE STRING

As the operation begins, the bottom joint or first one to be run in the hole is fitted with a casing or guide shoe to help negotiate the casing past ledges as it is run in the hole. One joint up or about 30 feet higher, a float collar is installed. This device is basically a valve that can be opened and closed with special devices pumped down the string. The top of each joint has a collar in place, such that a new joint is always screwed into the one looking up from the hole. Joints of casing with a thread protector in place on the lower end are picked up one at a time with the cat line, placed in the elevators and raised into place to be screwed into the string with casing power tongs.

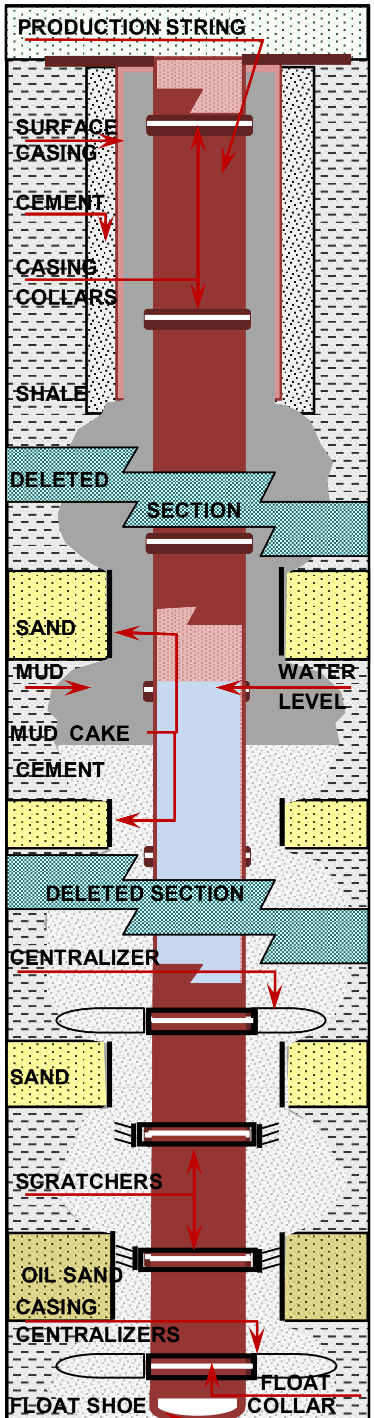

Figure 5-25 A typical casing string with its associated hardware in simplified form.

As each joint is added, the string is lowered into the well until TD is reached. It is then raised up a couple of feet and held in place with the elevators during the rest of the operation, which includes cementing. This allows the cement to pass out of the pipe and back up the annulus before pumping stops.

LOWERING THE STRING

The casing string is floated into the hole by virtue of the float collar and a back up valve in the guide shoe. They keep mud from entering the bottom of the casing causing it to have a degree of buoyancy. Hence the name float collar. A typical casing string is usually somewhat heavier than the drilling string, which the rig normally handles. Providing a degree of buoyancy during the operation has a couple of beneficial results. Sufficient water is then added to cause the casing to drop at a reasonable speed but still prevent the formation from being fractured as the casing descends like a piston. The reduced weight minimizes the load on the draw work's brakes as work proceeds.

SPECIAL HARDWARE

Joints to be placed in critical zones (production zones) are usually fitted with both centralizers and scratchers. These are welded in place on specified joints before the casing is run, while still on the pipe rack. The centralizers center the pipe in the drill hole and allow the cement to encircle it evenly to assure a good cement job at those depths. The scratchers are designed to remove mud cake from potential production zones so the cement will properly adhere to the sandstone or other type reservoir rock. When the casing has reached the proper depth, it is moved up and down several times so the scratchers can do their job. This is vital to maintain a good seal between casing and formation.

PUMPING THE CEMENT

With the casing in place the cementing operation begins. First, sufficient treated water is placed in the casing before the cement pumping starts to clean the hole ahead as the cement exits the shoe and moves up around the casing. This helps assure a good cement job. I should mention that the valves I spoke of in the float collar and guide shoe are opened with pump pressure, which allows the fluid to exit the pipe. When the last of the cement enters the string, a plug, designed to lock in place in the float collar, is pumped down with water behind it. When the plug is bumped (locked in place), the pumping stops but pressure is usually maintained on the string to assure no cement can back up into the casing before it sets.

Figure 5-25 depicts what such a string might look like. The reader might take time to examine it and note the positions of various items discussed so far. Note particularly, the casing centralizers and scratchers are placed near the pay zone to eliminate the mud cake and position the casing so optimum cementing can take place. Also, one can observe that the float collar is positioned one joint up and the casing or float shoe is placed on the bottom of the casing string. A real astute observer will note additionally that the cement for the production string has not filled the hole completely outside the pipe. This is typical practice to minimize cement costs and allow later recovery of a portion of the casing string, which might be used elsewhere. The only zone requiring isolation around the production string is the pay zone. All such zones must be isolated to prevent water entry from nearby water sands. Sufficient cement is used to assure this is accomplished but the top is usually far below the surface casing. Once cementing operations are complete, a survey of some type will be run to determine the exact position of the cement top.

OTHER DRILLING FLUIDS

Although fresh mud or mud with little salt is the norm for the industry, many other drilling fluids are encountered to meet special subsurface conditions. For example, a saturated salt mud is used in provinces where salt sections are cut during drilling. These are usually encountered older geologic formations wherein such beds have been laid down.

SALT MUDS

A good example is the Williston Basin, an area covering North Dakota and parts of eastern Montana and South Dakota. When such is the case, salt is added to the mud in sufficient quantity to saturate it and prevent further solution of salt as the beds are penetrated. This prevents drill-hole enlargement in the salt zones with its associated borehole instability. The shallower formations are drilled in a conventional manner with fresh mud, which is cheaper, easier to handle and compatible with these formations. Once the Madison or upper Mississippian is encountered, an intermediate casing string is run to protect the shallower beds and the mud is converted to a salt base. Drilling to TD is then accomplished with the latter fluid. Its use is of no particular consequence except in formation evaluation. A special breed of well logs is run, which is adaptable to salt mud. This will be discussed in some detail under Schlumberger Open Hole Measurements, as provided in chapter 7.

GAS DRILLING

The use of other, less common drilling fluids also occurs for more specialized conditions. In the San Juan Basin of northern New Mexico, for instance, many wells are drilled with gas. This has the advantage of being faster and cheaper and works well once shallower water bearing horizons are cased off. Large gas fields are close by, which provide a ready supply of the necessary fluid. Deeper formations contain no flowing water, which could produce a sticky mud when mixed with the dust created by drilling. Thus the possibility of the drill pipe becoming stuck is removed. Once the intermediate string is set the circulation system is converted. Dry gas is then pumped down the drill pipe as drilling proceeds. As it exits the bit, the gas provides the necessary cooling and lifts the smaller cuttings produced to the surface in the form of dust. As the gas exits the return line, it is ignited and burns with a constant flare as drilling is carried out. When a gas horizon is cut, drilling can be shut down and the potential of that zone measured. Drilling is then resumed until TD is reached. The faster penetration rate of 2 to 3 times provides an economy not realized with regular mud. Drill cuttings are of no value and are consequently ignored, but then the geologic section is well known and their examination is of little value. The well is mudded up once TD is reached. This allows the casing to be run more

The use of other, less common drilling fluids, also occurs for more specialized conditions. In the San Juan Basin of northern New Mexico, for instance, many wells are drilled with gas.

easily and to be properly cemented in place. After that, a normal completion for the area can be carried out with the operator's choice of gun-type, shot density and spacing as well as fracturing technique. Some utilize so-called ball sealers while others practice a technique called limited entry. These will also be discussed more in chapter eight.

AIR DRILLING

Air drilling is used occasionally in other parts of the south western US where no ground-water is encountered and no ready gas supply is nearby. The air, a form of gas, is provided by a group of large air compressors. The cost is higher because of the compressors required but principles are the same as for regular gas drilling. A real danger can lurk down hole, however, in the form of a natural gas horizon. If such is encountered and not handled properly, a down-hole explosion can occur, which results in a fishing job (retrieving the damaged bit, pipe, etc.) with its attendant cost. Thus, it is only used where absolutely necessary. Unfortunately, where no water bearing formations occur, lost circulation will often occur if regular mud is used. The operator consequently finds himself between a rock and a hard place, so to speak.

FOAMING AT THE MOUTH (OF THE WELL)

Yet another drilling fluid sometimes used in the desert southwest is foam. In some areas the sands bleed sufficient water to create mud from the dust of air drilling but once again, are of such low pressure that even the weight of conventional water will result in lost circulation. The weight as measured in lbs. per gallon is just too high, being between 8 and 9. The approach is then to add a surfactant (soap) to create foam, which is lighter than water but will still bring the drill cuttings back to the surface. Proper control of the fluid is somewhat difficult and it is only used where conventional mud won't do the trick.

It is the driller's bane as well as that of anyone called out to perform services on such a well.

THAT OLD BLACK MAGIC

I guess I would be negligent if I failed to mention the most delightful drilling fluid of all, i.e. "black magic". This fluid utilizes an oil base with all its nasty insinuations. It is sticky, gooey, dirty and hard to work with. Its only redeeming grace is that it will not damage formations that are super water sensitive and better wells can be obtained on completion. It is the driller's bane as well as that of anyone called out to perform services on such a well. Proper cleanup of equipment is next to impossible and you can be sure that any pay received is well deserved when the job is complete. It must have been invented by Satan himself who surely is the source of the song we used to hear, i.e. "That Old Black Magic".

COMPLETION AND PRODUCTION PRACTICES

With our imaginary well drilled with some type of fluid and properly cased, it would seem we are now ready to discuss completion and production practices. So, as an old man with a white beard once said to me as I sat up late one Christmas Eve, "On Donner, on Dancer, on Cupid and Vixen. To the top of the derrick, to the top of the pipe; let's get on with the show and forget all the hype". Such logic applies here, I do believe so, without further ado I will spout the little I know.

By now the reader should be pleased to find out that this is the last of these oil field basic topics we will consider in this introductory chapter. I'm about as knowledgeable in this complex area as the others I've chosen to violate and so my comments should be every bit as uninteresting and invalid. But, just you wait until I get to Schlumberger Technique, which is oh so Magnifique. I think that last adjective I used is French for magnificent but some of you language experts would know better and can set me straight. In that particular area, Schlumberger Technique, I do claim reasonable credentials, having gained the same over some thirty years in the business.

To the uninitiated, the job may seem complete once oil is discovered and casing is run. Well, it's more like having grabbed a tiger by the tail and wondering; "what do I do now"? Yes siree, there's plenty more to understand and take proper action on to maximize the recovery of that so-called "Black Gold". If you don't handle it right, that tiger (the investor, higher management or the like) may just up and snap at you, taking a piece of your hind quarters to the board for closer examination. So let's begin by reviewing a few basic principles as well as some potential completion and reservoir problems before getting into any details.

RESERVOIR DAMAGE

The reader may remember from the basic geology covered, (ha-ha! rather unlikely), that oil and gas reservoirs are nothing more than subsurface rocks that happen to contain oil and or gas in there innards (porosity, that is). As such they are composed of sand with varying amounts of shale therein, limestone derived from calcium carbonate ($CaCO_3$) in solution by precipitation as well as from them little critters that have been living around the coral reefs, or possibly even dolomite ($CaMgCO_3$) which has been derived through the percolation of nature's ground waters. In any case, like people, they come with their own variety of problems including sensitivity to those elements in nature, which act upon them.

HEY, ROCKS HAVE FEELINGS TOO

Sandstones usually come with a little shale mixed in (dirt), again kind of like people. When

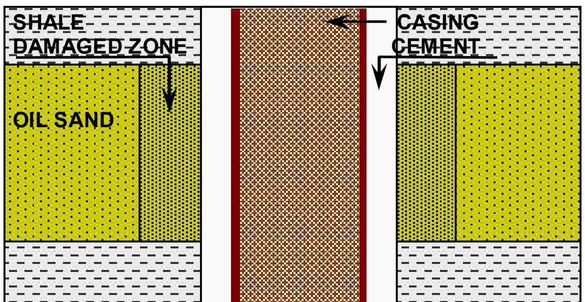

Figure 5-26 A sandstone-reservoir with formation damage near the well bore.

some insensitive foreigner (like drilling mud) touches the dirt (no one likes their dirty laundry exposed), it swells up clear out of proportion and

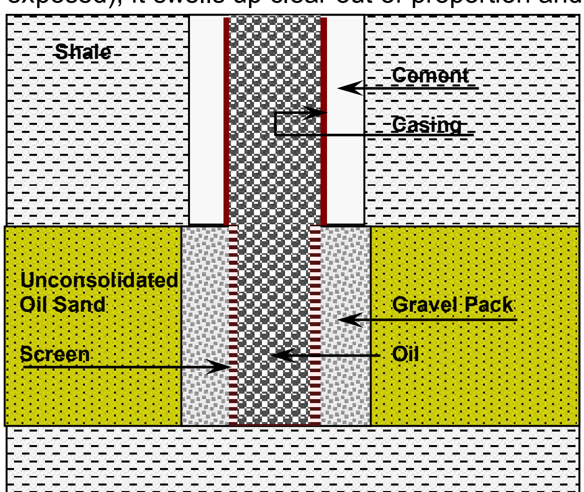

Figure 5-27 An unconsolidated sand reservoir with a screen and gravel pack.

blocks the lines of communication (permeability) such that the reservoir can't produce the hydrocarbon, as it should. Well, something has to be done to bypass that puffed up ego or soothe it so the value of the reservoir can be realized, similar to dealing with people. In completing such a reservoir, the damaged particles may be dissolved with mud acid and cleaned out to some degree via the suction produced by a swabbing operation or maybe just over ridden and plain blown by or bypassed with perforations and fracturing. See figure 5-26 as an illustration of such a damaged reservoir.

NO INNER STRENGTH

Sometimes sandstones have no inner strength, nothing to bind their soul together, so to speak, and simply fall apart when produced. They can't stand the loss of their treasure and simply flow with it into the well if unrestrained. Ah yes, they have much to offer mankind but when some slick operator begins to deprive them of their earthly treasure, they simply crumble, having been sustained by the black gold within their pores and without inner strength of their own. Some caring soul (the producer) must help hold them together with screens, gravel packs and the like or they will simply follow the flow of the crowd and end up useless in the bottom of the pit (well). With all they have to give, they are unable to do so of their own free will because they haven't experienced the rigors of being buried in the depths of worldly stress and developing that basic internal framework so necessary to self-existence. In any case figure 5-27 depicts such an unfortunate situation, which is quite common in the gulf coast area.

CARBONATE ROCKS

In most cases limestones and dolomites form reservoirs because of secondary alteration. When laid down, the necessary porosity and permeability doesn't exist unless reefs are involved. Thus, they must be buried and subjected to various forms of tectonic stress before such characteristics are developed. As tectonic forces fracture the carbonates, ground waters begin to percolate within them and dissolve the adjacent rock forming both porosity and permeability. Keep in mind, porosity is void space within the rock and constitutes the ability of the rock to store fluid while permeability is comparable to a pipeline and constitutes the ability of the rock to conduct fluid flow. It is the latter that frequently gets blocked off through damage to the rock by invading well bore fluids and impairs the reservoir's production characteristics. The porosity of limestones is primarily of the vugular type or void space created by solution of adjacent rock and can be contrasted with so called inter-granular porosity or that void space created by stacking grains or little spheres in a jar or other container.

YA NEED TO CLEAN UP YOUR ACT

All rock tends to be damaged to some extent by the invasion of well bore fluids. As they move into the reservoir, solids in suspension are carried along and deposited within the rock, which then blocks the channels available for hydrocarbon flow into the well. It is this damage that must be cleaned out or bypassed if the well is to reach its natural productivity. Natural permeability can also be low, in and of itself, which provides poor productivity without associated damage. Thus, stimulation techniques of various kinds are used to improve or enhance both damaged and natural reservoir permeability. These come under headings of washing, acidizing and fracturing services offered by various service companies.

RESERVOIR RADIAL FLOW

A well is little more than a pipeline with its appropriate valves connecting a large subterranean tank to the surface. Admittedly, said tank is full of dirt and various other rock particles which don't help. The end or section of the pipe thrust into the tank (reservoir) must be kept clear of foreign matter, which can plug it. This is more complicated than it would seem because the flow into the well is naturally restricted by the geometry of the system. Consider figure 5-28 to better understand the situation. As the fluid moves towards the intake pipe, it must move through a smaller and smaller cross section of formation, which is analogous to a sponge with small holes throughout. Both the decreasing cross section and the small holes restrict the fluid movement within that rock. Any debris in the sponge further decreases its ability to conduct fluid. The combination of decreasing diameter, sponge effect and debris can be disastrous for production.

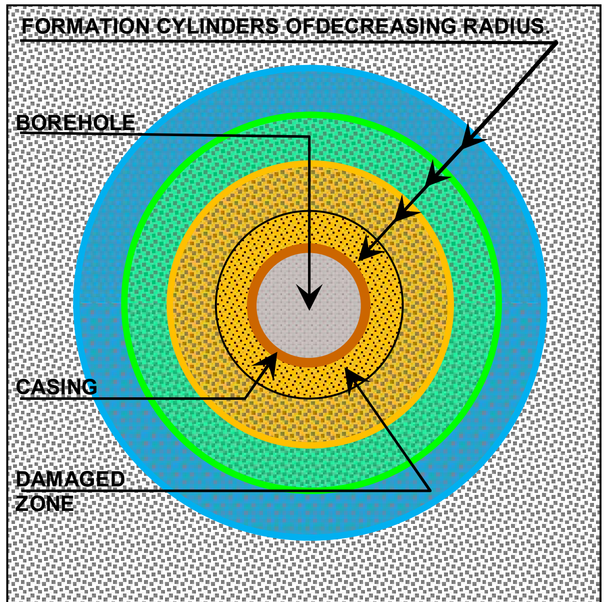

Figure 5-28 A plan-view of the geometry of radial flow in a hydrocarbon reservoir.

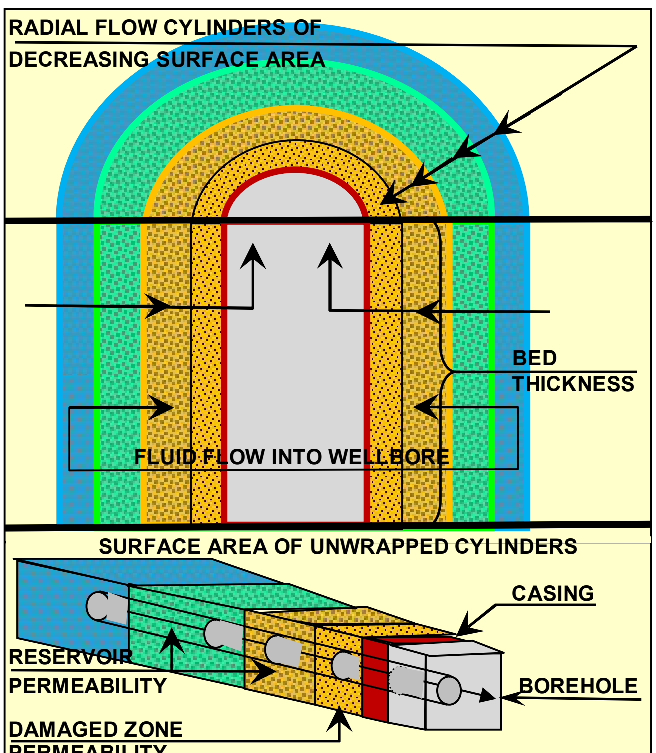

Figure 5-29 A shrinking cross-section illustration of fluid approaching the casing.

A DIFFERENT PERSPECTIVE

The declining cross section is better illustrated in figure 5-29. In the top portion of the figure the reader will notice a series of concentric cylinders of equal height but decreasing diameter through which the fluids move from the formation to the casing. The plan view of these cylinders is also shown in figure 5-28. The surface area of these same cylinders is then reproduced in rectangular form in the bottom part of figure 5-29, which better illustrates the shrinking size of the path or cross section through which the hydrocarbon must flow, as it approaches the well. Such rectangular forms would be obtained if one un-wrapped a tin can and laid it out flat on a table.

A damaged zone then clearly acts as an extra choke: being small and of low permeability.

The stippled zones are meant to represent the actual formation material whose permeability, like the sponge, further inhibits fluid flow. The more densely stippled zone between the orange sheet and casing represents the damaged zone whose permeability will be less than that of the native rock by virtue of damage inflicted on it by the invading well bore fluid and likened to a sponge with smaller holes. Such damage occurs in clays already in the rock, which swell as the water from the well bore comes in contact with it. Likewise additional damage occurs from mud solids, which are deposited, as fine particles, in the pore space of the rock.

A CONVERGING ANALOGY

Now let's liken the travels of a molecule of hydrocarbon from the far reaches of the reservoir towards the casing to those of Blackfoot Pete from Babb, Montana who finds himself en-route to St. Paul, Minnesota. As he traverses the wide-open spaces of the Big Sky country, he owns the road and his speed is only limited by the twisting nature of the road (permeability). As he approaches St. Paul, how-some-ever, things begin to change. Others seem to be going his way, which wouldn't be so bad, except they get in his way. He soon learns that he has to get in line and take his turn. Things go better if he has arrived on four or six lane freeways (better permeability) before traffic gets too thick but heaven forbid if there be a driving rainstorm or winter blizzard (damaged zone). If that be the case, movement slows to a crawl and it seems like eons before old Blackfoot Pete manages to arrive in down town St. Paul (the well bore). Even good road design and proper implementation is not a match for inclement weather and so it is with a damaged zone and well designed stimulation methods. They help move the fluid but seldom completely overcome a damaged formation.

From my little analogy, the geometry involved in my example and the low permeability exhibited by the damaged zone, even a fine arts or social services student should have no trouble understanding the serious nature of formation damage and why drilling and completion engineers go to such extremes to minimize it. I can hear those of my posterity involved in such disciplines murmuring just now; "Well, it's obvious grandpa Tom was about as artistic as a guru of back alley graffiti and his comments seem to offer very little more in the way of redeeming social values". Oh well enjoy your selves because you have a long way to go. Consider this bit just a warm up for later effort.

To me figures 5-28 and 5-29 are mighty purty pictures, indeed, and my cup runneth over with the personal pleasure I find in the drawing tools of my technological marvel called a computer. Though my pleasure may stem from a low appreciation for the arts rather than from the ability to create such work, it makes no difference for pleasure is pleasure regardless of its source. Ah yes, beauty is, indeed, in the eye of the beholder. Well, on to more important things pertaining to well completions and their production mechanisms.

RESERVOIR FLUIDS AND ENERGY

Reservoir fluids are composed of three types, i.e. water, oil and gas, previously discussed. All are often found in a given reservoir in differing amounts. Water invariably occupied the rock interstices (porosity) before any hydrocarbon arrived. As it was displaced by the oil or gas arrival, a small percentage refused to budge. Such was bound to its rocky abode by molecular forces, giving it an inalienable right to remain. These stubborn little fellows became known as irreducible water molecules or connate water. They occupy space but will never cause production problems in terms of a water-cut because, "they ain't gonna move". Thus, their new neighbors, oil and/or gas molecules, learn to live peaceably with them side by side.

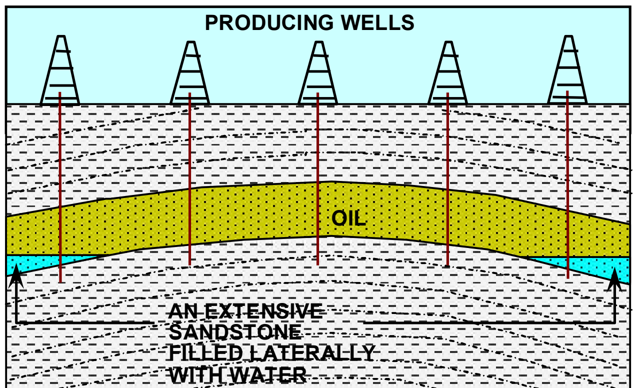

Figure 5-30 A simplified illustration depicting a water drive hydrocarbon reservoir.

A WATER DRIVE

This isn't the case, however, for so called free water, which exists down dip. Remember, some of these guys used to live there before the hydrocarbons moved in and displaced them through gravity segregation. They can't wait to get back and are constantly pushing or providing pressure to move the hydrocarbon out once an exit is provided. Such force is called a water drive and is a most compelling type of reservoir energy. Pressure drops off very little as the hydrocarbon is moved because the oil or gas is immediately replaced by the incoming water. The water bearing area is of much greater size than that of the hydrocarbon making complete depletion of the field but a drop in the bucket, so to speak. It's like a neighborhood with good resale values, i.e. vacancies don't last and a few people exiting the area is of no consequence. Housing demand is greater than the supply.

GAS CAP RESERVOIRS

Whether a gas cap exists in a given reservoir depends upon both reservoir pressure and the type of hydrocarbons, which have collected therein. The oil operator can't change what Mother Nature deals him. If a gas cap exists, the best he can do is to prevent it from growing. He can't undo Mother Nature's handiwork. Thus, the wise operator will strive to maintain reservoir pressure near its virgin level to keep as much gas in solution as possible and for as long as possible. Keeping the lighter hydrocarbons in solution lowers the crude viscosity and improves its producibility as indicated previously. Actually, reservoir pressure will drop off slowly in spite of all the operator can do. You might say a reservoir is much like a person. As it matures, "I mean gets older baby", its energy decreases and activity slows. Its inner workings start to stiffen while its contribution to society invariably drops off. It requires a lot more remedial work in terms of stimulation or just plain cleaning up. I can personally attest to such changes. Sooner or later one accepts the inevitable, which is, "The poor devil has contributed all he ever had or can, so let his blessed soul rest in peace."

SOLUTION GAS DRIVE

Some reservoirs have no water in them except irreducible water. They are usually of limited extent, i.e. a small but snobbish subdivision in which the free water (original owners), that must have been present at one time, surely sold out to the highest bidder as property (porosity) disappeared and the associated values rose with the ensuing demand of the incoming moneyed class of hydrocarbon barons. It isn't long until an all black neighborhood results, which in this case, represents a moneyed class rather than an ethnic group.

CLASS DISTINCTION

Even so, the hydrocarbons aren't quite as a homogenous group as one would think. Within their community are many different types or weights of hydrocarbon, each with differing specific gravity. They tend to separate, as quickly as social pressure will allow, that is the pressure at which they move from the liquid state into the gaseous state. Making this conversion allows them to segregate or rise to the top where the most elite reside. This results in a gas-cap astride the oil accumulation below.

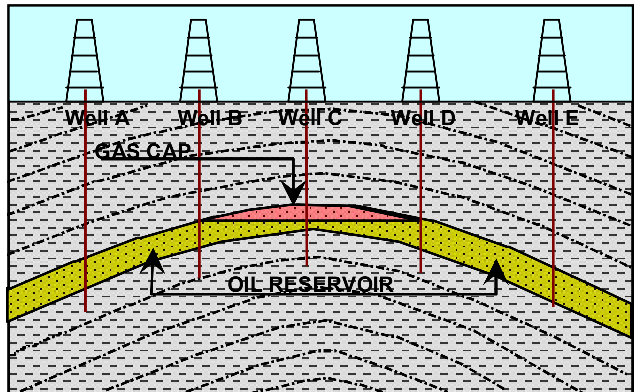

Figure 5-31 A Simplified illustration of an anticline oil reservoir trap with a gas cap.

One can say what he will about this particular class or classes of hydrocarbon but, regardless, they provide the drive to move the hydrocarbon.

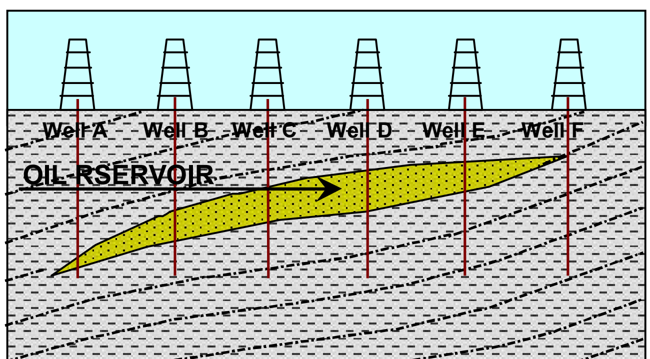

Figure 5-32 A Simplified Illustration of a Solution Gas Drive Reservoir.

Not only does their expanding nature provide the pressure to move those with less motivation but they also change the nature of the hydrocarbon liquids making them lighter and easier to move. Also, as heavier molecules move out, the gas expands to fill the space left void and tends to maintain reservoir pressure. Even so, the gas by itself can't maintain reservoir pressure at the level a water drive can and consequently such a drive or source of pressure decreases and becomes less efficient. As hydrocarbon is withdrawn, the dropping pressure leaves much oil trapped in the pore spaces with no motivation to move. The loss of their lighter friends has made their nature despondent and thick or viscous, a difficult nature to move, with little energy left. Let's face it, that particular class of liquid hydrocarbon just ain't got what it takes. Without their bubbly friends and their lighter natures, those guys just don't have what it takes to make it through the pores of life. They must change their nature to compensate for the loss.

HYDROCARBON COMPOSITION

With hydrocarbons having such a wide range of specific gravities, one might expect almost an infinite number of differing hydrocarbon accumulations derived from the different numbers and volumes involved. This is the case, of course, and operators find themselves with thick viscous crudes, lighter crudes with considerable gas, wet gas with considerable amounts of the lighter fluids, even up to dry gas from which no liquids drop out during production. Likewise their lives are further complicated by other impurities such as carbon dioxide, sulfur dioxide, etc. Crudes are known as sweet (low acid content) or sour (high acid content). The most common acidic contaminant is sulfur, which drops the price of the oil because of handling problems. Where SO_2, Sulfur Dioxide, is present safety is a problem, which requires special handling and safety procedures in drilling, completing and producing the crude oil. Even so, such fields can be highly profitable and are not ignored. Both hydrocarbon and sulfur are marketable. Wells in this category are prevalent in the USA from Wyoming to the state of Mississippi and maybe beyond. The sulfur and oil combined compensate for the extra cost.

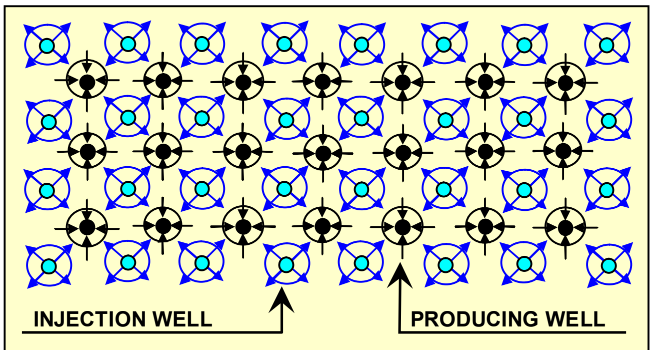

Figure 5-33 A simplified Illustration of a 5 Spot Water Flood Configuration. Each Producing Well's Flow is determined by water from 4 Injection Wells, Thus a 5 Spot Configuration.

A SUMMARY OF RESERVOIR TYPES

In summary, let me repeat that water drive reservoirs are the most efficient and thus the most desirable just as big fields are better than their smaller cousins. Unfortunately, the oil operator has to take what he gets and figure out how best to handle it. His is the problem of exploiting the discovery in such a way as to maximize production with the minimum possible investment. Not much different than any other business, except for the problems involved. Each business has its own types of problems.

In water drive fields (Figure 5-30); primary recovery constitutes about 70% of the original oil in place whereas recovery drops to 20% or less in certain solution gas-drive fields (Figure 5-32). That's a lot of missing oil and an operator will necessarily make great efforts to raise those percentages through secondary recovery methods. Just think, if an operator found a hundred million barrel field (not particularly big) with solution gas drive, he gets only 20 million barrels and leaves 80 in the ground without appropriate action. If he waits until the reservoir pressure drops too much, his ultimate recovery drops as well. Consequently, operators strive to define field limits as quickly as possible and usually institute pressure maintenance and even secondary recovery operations soon thereafter. If properly instituted, such efforts pay off handsomely in good hard, cold cash or that particular entity, which drives American ingenuity and the economy.

SECONDARY RECOVERY METHODS

GAS REINJECTION

If the field has a gas cap, the operator will probably re-inject the produced gas to help maintain reservoir pressure. With or without a gas cap he will begin plans for a water flood, assuming the field is not of the water drive variety. This will help maintain pressure and physically push the oil towards producing wells. Keeping the pressure up is important because the gas remains in solution, which lowers the oil viscosity (thickness) and allows it to flow or produce more easily resulting in better recovery. It also provides lift within the well by making the fluid column lighter.

Figures 5-30, 5-31 and 5-32 depict the three major types of drives I am familiar with. Of course, these drives may exist in combination as well, such as a gas cap on a water drive reservoir or a solution gas drive reservoir. In the latter case, a gas cap will develop if nothing is done to maintain reservoir pressure. Note that diagrams aren't always on the discussion page. Don't let that bother you. They will be nearby.

In the market place oil is more lucrative than is gas and every effort is used to maximize its recovery while utilizing the gas as an aid in such effort. A certain amount of gas is always produced as it breaks out of solution at surface pressure. Such gas used to be flared because of the expense of handling and its relatively small value. Today's laws prevent that and it is now accumulated and sold or used to enhance production through injection back into the field. For example, well C in figure 3-31 might be used to inject the gas back into the gas cap, thus handling the gas produced in wells A, B, and E in addition to helping maintain reservoir pressure. Though it might have originally been a producing well, it later becomes an injection well. This, of course, minimizes the necessary costs involved and enhances profits.

WATER FLOODS

Water floods are now as common in the industry as the exploration for new fields. In solution gas drive reservoirs, with or without a gas cap, they are begun early in the life of a field to maintain pressure and increase ultimate recovery. Water is injected into the reservoir in appropriately placed wells and the resulting oil produced from others. The well configuration may vary depending upon field properties. Early injection would probably be carried out on the structurally low end of the field near the edges such as well A in figure 5-32. Later, additional injection wells would be added in configurations, which would provide the greatest enhanced production. A very common water flood configuration is a so called five spot, which is depicted in figure 5-33. Such a configuration would probably take place in the later stages of a flood. The reader can easily visualize just how the water front moving out from the several injection wells would work together to force or push the oil towards the lower pressure production wells. Obviously, the blue circles around each injection well symbolize the outward moving waterfront while the black circles around the producing wells symbolize a wave of oil being pushed towards a producing well. In principle, the effect is similar to a water-drive reservoir and, I understand, recoveries will approach that desired value of 70%.

I don't intend to get very deep into secondary recovery systems because my involvement and knowledge of those processes is limited. My only intent here is to give my posterity a brief overview of the complicated processes utilized to make their trips possible, as they drive the highways with little understanding or interest in where the fuel they use is coming from. Of course, the determining factor in the secondary recovery process is profit. Yet, it is amazing, even to me, the number of methods that have been derived to improve the recovery from a field. Of course, each has to be economical to survive. Isn't it interesting how complicated many things are, which we take for granted?

EXOTIC FLOODS

Before leaving the subject of floods, let me mention a few of the more exotic ones, which are being used to recover known reserves that don't seem to want to move. Where water won't do the job, various solvents have been injected to dissolve the thicker crudes still in place and thus carry them to the production wells. Though such solvents are expensive, as compared to water, apparently this approach has proven economical because of the quantity of crude locked up in the pore spaces of those reservoirs. However, the solvents are separated out upon production and re-used again and again.

Another tactic used in reservoirs of thick, almost solid crudes (tar) has been steam floods and fire floods which make the hydrocarbon liquid and movable by virtue of the absorbed heat. As I understand it, in a fire flood the tar sand is actually ignited by feeding oxygen down injection wells. The heat from the advancing fire in the formation liquefies the tar ahead of it and allows it to flow into producing wells. In steam floods super heated steam is injected to liquefy the hydrocarbon. However, in this method steam is injected for a period of time and then shut down. The injection well then reverts to a production well and sucks the liquid out. As the liquid flow drops off, steam is injected once again and the process is repeated. Consequently such an operation became known as the "Huff and Puff Method".

THE PUMPING WELL

It would seem appropriate to mention the pumping of oil before leaving the subject of reservoir energy. When pumps appear, the reservoir has insufficient energy to produce on its own. Flowing wells are like artesian water wells and, should they occur, they only last until the reservoir pressure drops below that which is required to maintain continued flow. That's not a long time and eventually all oil wells go on the pump. That's where the pump jacks so common along various highways come in. The well itself has sufficient pressure to lift the top of the oil to some level within the well. The pump jack in it's up and down motion must take it from there to the surface. This isn't the most interesting subject, even in my biased opinion, so I doubt if any reader, having gotten this far, will be disturbed if I call it quits. Suffice it to say that there are several kinds of pumps of which the pump jack, I mentioned, is the most common and they all get the job done. When lifting costs exceed the revenue made from the well, it is shut down. That explains many of the stationary pump jacks along our highways, which seem to be gathering rust. The wells simply aren't paying their way any longer and will remain idle until economic circumstances improve.

THE WELL COMPLETION

I've talked a lot about the exploitation of various reservoirs up to now without mentioning completions. Obviously, these constitute an essential step before any oil or gas can come out of the ground. This is an area in which I have considerable experience from a wire line standpoint and have also learned a great deal in my association with various completion engineers over the years. Thus, it's one I might get a little windy about and create the impression that I'm more of an expert than I am. Bear with old grandpa, however, and see if you can find the line between reality and my vivid imagination, as I try to describe such operations from my experience. Keep in mind they come from associations as well as wire-line work.

The last time we talked about the well, per se, was back about page 211 where we had just run a string of casing complete with centralizers, scratchers and other goodies to ensure a good cement job. The reader may have wondered then, just how any oil was going to flow, after we had just stuffed the steel casing down the hole and pumped a bunch of cement around it. Later we talked about formation damage, which might have puzzled you. How in the world could such little damage compare with getting the oil through the cement and steel we just placed in the path of its flow? Well, the answer lies in the proximity of the latter to the borehole and our ability to get our hands on them, so to speak. Yep, if we could pull that damaged formation out of the hole for a moment and give it a good and sound scrubbing, it wouldn't be much of a problem either. In reality, that's what oil companies try to do with the various treating methods they employ down-hole in the completion of a well.

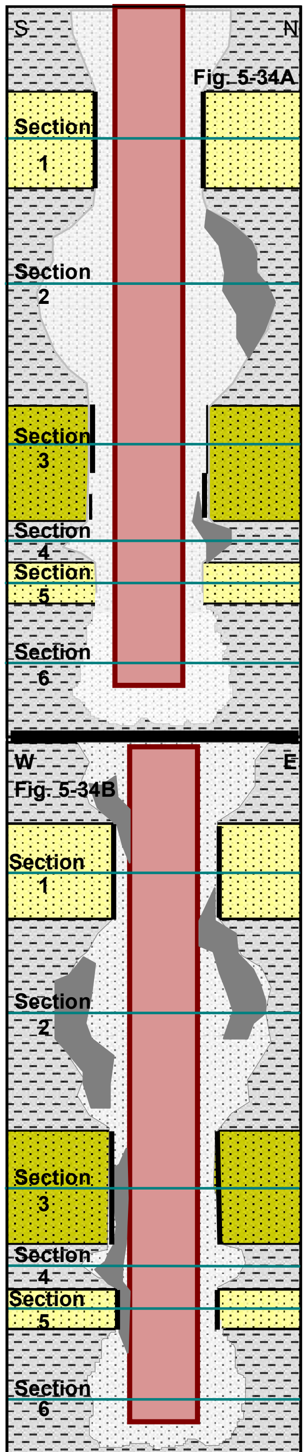

Figure 5-34 A casing illustration of a poor cement job.

A QUALITY CEMENT JOB

You may remember that a good cement job was necessary to isolate the oil or gas zone from other porous and permeable zones. If we didn't, one of two things would happen: the surrounding zones would either produce their fluid, usually water, and over power the hydrocarbon zone or the hydrocarbon zone would contaminate up-hole sands, creating problems in surrounding wells of various kinds. Assuming the former were the case, the water from nearby zones would enter the casing and build a hydrostatic column, which would essentially shut off any significant hydrocarbon production. Yes, the cement job must be reliable and do its part of the job, i.e. zone isolation. Figure 5-34 illustrates a case in which the cement job isn't quite up to snuff and needs some help. This isn't unusual, by the way. Obtaining a good cement job can be extremely difficult even though techniques improved many fold in recent years.

VISUALIZING THE CEMENT JOB

In figure 5-34 two vertical cross sections of the casing, drill hole and cement are illustrated, i.e.

section A (the top half of 5-34) taken in a N-S direction and section B (the bottom half) taken in an E-W direction. Likewise 6 horizontal sections labeled 1-6 are taken through the cased-hole and surrounding formations and are so indicated on both cross sections A and B. They are shown in the drawing of figure 5-35. All of this is done to help the reader better appreciate the nature of a poor cement job. The cement moving up the outside of the pipe, as pumping progresses, may not push all the mud ahead of it and consequently leave mud channels of various sizes and shapes as well as in varying positions. These are three dimensional in nature, positioning themselves in an almost infinite number of ways around and along-side the pipe. Thus, they will not show up completely on a given cross section but the horizontal slices along with the cross sections will help the reader picture their tortuous paths in the bore-hole annulus.

The significance of the mud channels is the communication they provide along the drill hole between the various formations. In the example shown, the oil sand lies between two water sands. Failure to completely isolate the three will allow fluids from all to be produced with the negative results mentioned a little earlier. This has been a very real problem for the operator.

EVALUATING A CEMENT JOB

Well, the reader might ask, how does the oil operator know he has a good cement job and what recourse does he have if it isn't? That's a good question, of course, and the answer varies with the chronology of the oil business. When I first got involved, oil operators ran temperature logs within about 18 hours after the plug was bumped or cementing finished. Cement gives off heat as it sets and this thermal shift could be seen inside the casing.

The log was run from about a thousand feet above the expected top to total depth. When the top was reached going down the cased-hole, the engineer could see a sharp shift to the right (increasing temperature) as the temperature tool passed the cement top. This is described more completely in chapter 8 under Schlumberger cased-hole services. As a result the top was accurately located. Unfortunately, such a device didn't register the presence of channels and the operator had to feel his way in their resolution.

Many operators would shoot holes in the casing above and below the zone of interest and pump cement out through them. This was termed a cement block squeeze because it was done under rather high pressure, squeezing the cement into any void space available on either side of the sand. Usually it was effective in isolating the oil-bearing zone. They would then complete the well by shooting holes through the casing and cement opposite the zone to be

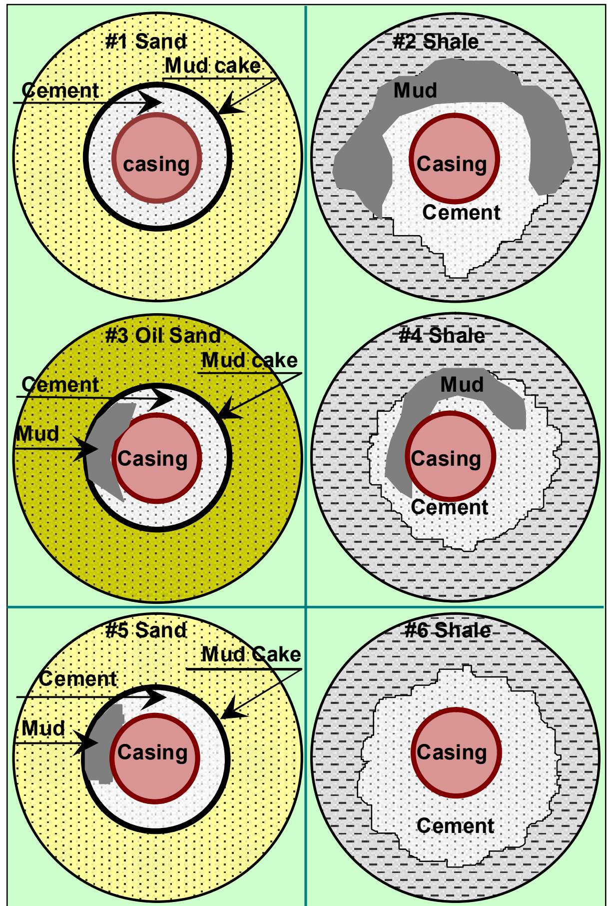

Figure 5-35 Horizontal Slices, 1 through 6, taken as Shown in Figure 5-34 Through Casing, Drill-hole and Adjacent Formation.

produced and if all went well, water free production followed as the well cleaned up.

Obviously, something better was needed to give the operator a clearer idea of the quality of his cement job. Along about 1963 or so, this became a reality with the advent of a device known as the cement bond tool or CBL. It was an offshoot of the sonic log, both of which will be described in detail later.

THE PERFORATING OPERATION

Now, take a minute and turn your attention to figure 5-36, which simply illustrates how the oil is eventually able to enter the well once the preliminary cement work has been completed. Notice the holes that extend through the casing and cement into the formation. Such holes were produced through so called perforating services. In the early days they were actually accomplished by casing piercing bullets. These were powerful guns and could penetrate the casing, cement and a ways into the formation, if the latter wasn't too hard, that is.

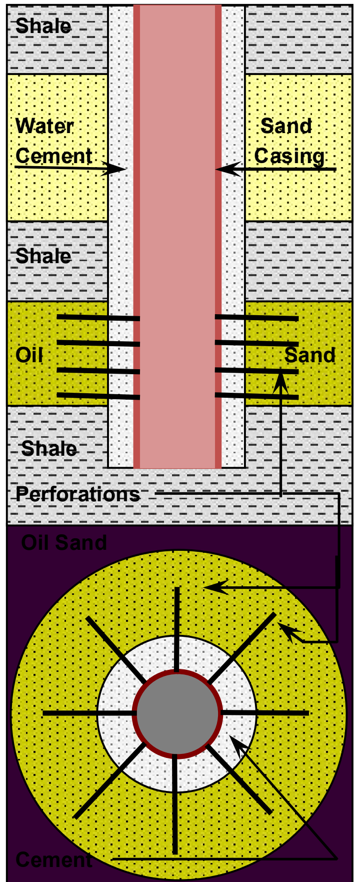

Figure 5-36 A diagram Illustrating perforated casing, which allows oil entry into the well.

Many problems were associated with these guns, however, and they gave way to so called shape charge guns, which were an offshoot of the armor piercing bazookas of World War 2. These latter guns were adapted to many different types of completion modes and still exist today in many different forms to fit the requirements set for the variety of ways in which an operator chooses to complete a given well. We'll discuss this type of gun in much more detail as well, a little later on. However, before leaving the general well completion, as in figure 5-36, the reader should notice that the perforations were in all directions and at different levels in the sand. The vertical spacing is designated as the shots per foot of a perforating tool while the radial spacing is described in degrees as the phasing.

We spoke of formation damage back on page 214 which I have conveniently left out to illustrate both cement jobs and the actual perforation of the casing. It would be nice if the oil operator could just pretend it wasn't there as well but unfortunately it exists to some degree in almost every well. If not too severe, perforations may penetrate beyond it and effectively bypass such damage but that's not usually the case. Thus, different approaches are taken to minimize its effect. To better understand such approaches, let's take a closer look at the major hardware involved in a typical producing well. It may surprise you just what is involved to wrest the hydrocarbon from old mother earth's innards. This is illustrated in figure 5-37, which is a poor man's effort to depict the foregoing situation.

As the oil moves into the casing and up the tubing, the lighter hydrocarbon components as well as the natural gas coming out of solution as bubbles, provide the necessary lift to reach the surface.

A TYPICAL WELL HEAD

In figure 5-37 I have illustrated a typical well head, usually referred to as a Christmas tree and also tubing which has been placed inside the casing and seated in a packer just above the producing zone. In my typically boring way, I'll now try to describe the purpose of each of these most fascinating little thing-a-ma-jigs so that you, my posterity, can fully appreciate their importance in your tender lives. Yes, you really should realize that without these gadgets, your car wouldn't run and you'd be forever walking between home, school and work. You see, they control the flow of those most crucial fluids, oil and gas, which power all those monsters tied up by gridlock on the various highways and byways of your frustrating lives. Surely you want to know how it all came about and why you are now sitting there, in traffic, listening to some DJ or Talk Show host while the steam issues from your ears. Then again, maybe you're lucky enough to be really moving down some interstate dodging the 18 wheelers as they close in on you like a herd of charging rhinos breathing fire from their "nostril-like" exhausts and just daring you to make an unwise move. Just think, without these gadgets, I plan to explain, you would be confined to some peaceful home in the country without such exciting opportunities, such as controlling your frustrations within the law. That is, not allowing your actions to follow your thoughts in some form of road rage or another manifestation of your boiling imagination. So, let's move on to the gadgets of a producing well.

A STARTING PLACE

Let's begin at the bottom of figure 5-37 and work our way to the top. After all, that's an exercise all need to experience in life. That means the tubing and packer come first on our list and later, as we rise to the top like a bubble of gas, we'll learn what it is that controls the destiny of those poor slobs trying to make their way up the tubing of life to contribute to the good of society.

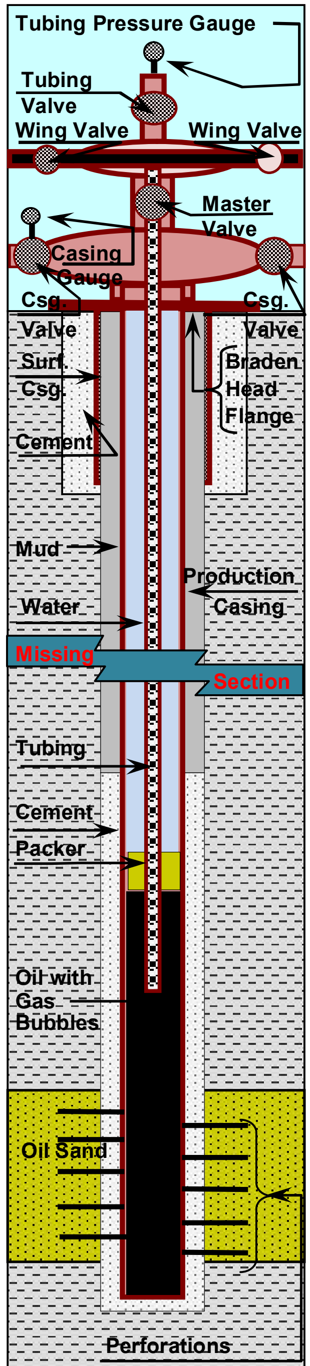

Figure 5-37 A drawing illustrating an oil-producing well with packer, tubing and Christmas tree.

The ideal well is one that flows by itself without requiring a lifting apparatus of some sort. Natural gas provides the motivation, the energy and thus the ability for that to come about. You may remember that oil and natural gas generally exist together in a reservoir in varying proportions. There are so called dry gas wells which produce little or no liquid and even some oil reservoirs with little or no gas in them but most deposits contain a combination of the two. As the oil moves into the casing and up the tubing, the lighter hydrocarbon components as well as the natural gas coming out of solution in bubbles provide the necessary lift to reach the surface. That is, they decrease the specific gravity of the fluid column such that the reservoir pressure is sufficient to lift the fluid. This action is most efficient when the well is produced through tubing seated in a packer. The same is true for a well producing mostly gas with some liquids. Thus, tubing is needed in every well for various reasons and packers improve production in many of them.

A TOUR FROM THE BOTTOM UP

The packer is a device that isolates the producing zone from the annulus between casing and tubing. It is firmly anchored in place by metal teeth, which bite into the casing while a rubber packing-element seals off the space between packer body and casing. Similarly the tubing is firmly anchored in the packer with a seal around its point of insertion or the connection of the two elements. Thus any fluid entering the well from the formation must rise up the tubing to find its way to the surface.

Figure 5-37 indicates the mixture of hydrocarbons entering the well via the perforations as fluid. As the pressure drops the more volatile elements break out of solution forming bubbles of gas. The packer forces all fluid movement up hole through the tubing to the surface controls contained on the Christmas tree. The production casing has been set a little below the oil sand and cemented with the cement rising several hundred feet above the zone of interest. Mud is left in place above the cement to maintain the integrity of the hole. The packer was set just a little above the producing zone, typically about 10 feet. This is often done on a wire line by companies such as Schlumberger but may also be set with the tubing. The casing annulus (space between the tubing and casing walls) above the packer is usually filled with salt water to minimize the pressure differential the packing element must restrain and thus improve its reliability. As we near the surface, we find the surface casing with its Braden head flange and associated cement, which was discussed earlier. That brings us to the surface control system with its many valves.

THE WELL HEAD OR CHRISTMAS TREE

I suppose the Christmas tree got its name from the many valves and gauges attached to it. A really complex tree can reach 15 feet in the air and have numerous valves and gauges to control the operation of all the associated plumbing. Such a tree could resemble a real Christmas tree with all its ornaments. I have drawn about the simplest variety I can visualize so as to be able to explain the more important principles involved. Notice it is mounted on the Braden Head Flange, which is welded to the top of the surface casing. This flange, you'll remember, is the reference point for all depth-measurements made in the well.

THE CASING HANGER

The next element up I'll call the casing hanger. Actually the casing hanger would be only a part of it. Be kind, I can't remember all the names involved. This element has a flange on the bottom of it, which allows it to be bolted to the

Braden Head Flange with an appropriate seal. Within this unit is a bowl and seal, which holds the top of the production casing and seals the connection from the atmosphere. This constitutes the actual casing hanger. On either end of the unit are valves and connections to allow the attachment of pipes and/or gauges. Typically a gauge will be mounted on one end as shown and a pipe with a control valve on the other. These are used to monitor pressure change in the casing, which are indicative of down-hole problems, as well as allow the operator to pump fluid into or out of the casing when so demanded. They help him control the well and to decide what remedial action is necessary.

THE MASTER VALVE

Flanged to the top of the casing unit is a master valve, used to shut the well in. High pressure wells typically have two master valves with the bottom one acting as a backup. This is a necessary safety consideration because valves can and do go bad through use and need to be changed from time to time. For simplicity, I show only one. If a second were to be used, it would be mounted in tandem with the first.

THE TUBING HANGER

On top of this master valve unit, is the tubing hanger or at least the unit, which contains said hanger. It anchors the top end of the tubing and provides the necessary seal to the outside world. Notice this unit is also flanged to the top of the master valve unit just as the latter was to the Braden Head Flange. This unit also has a valve on either side, each of which is termed a wing valve. Oil can flow through either valve as necessary through surface requirement.

to the production facilities. Associated with each valve is a choke or opening of a specific size, which controls the oil flow and tubing pressure. Also gauges are provided to monitor pressure on the exit end of the choke. Two valves are required so either can be serviced without interrupting oil production. On the very top of the tubing unit is a pressure gauge and valve. These provide the means to monitor tubing pressure and to change gauges respectively, if and when necessary.

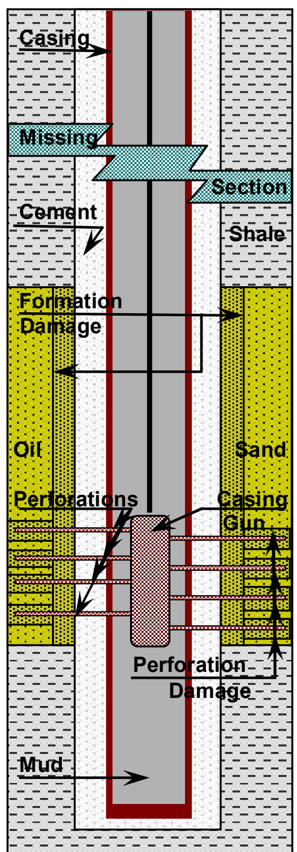

Figure 5-38 A simplified drawing of a perforating job with a casing gun & associated damage.

WELL COMPLETION CHOICES

I have alluded to the fact that there are several different ways to complete an oil or gas well. All require the well to be kept under control for safety reasons as well as just plain practicality. In fact there are so many different types of completions, depending upon reservoir conditions and operator preferences that I couldn't begin to cover all of them. Consequently, I will discuss only two basic types, which are really the basis for all the other variations except maybe open-hole completions and gravel packs. These latter two don't require wire line services (my trade) and so I'll ignore them and stick with the ones I'm most familiar with, namely casing completions and through tubing completions.

CASING COMPLETIONS

In a casing completion, drilling mud of proper weight is used to control the well. This means the pressure the hydrostatic head exerts at the zone to be completed is kept 200 to 300 pounds greater than that of the reservoir. Completion services of various sorts can then be run without concern about the well blowing out or beginning to flow. When the operator is ready to perforate with a wire line company, the necessary guns are lowered into the well in groups of 2 or 3 and fired at the appropriate depth. See figure 5-38. Finally, with that operation completed, tubing is run in the hole and the mud removed via circulation. This last step is done with the wellhead in place to provide the necessary control once the well begins to flow. Usually a good deal of effort is needed such as acidizing and swabbing to clean the well up or bring it to its expected potential as a producer. This is necessary because of formation damage occurring during drilling as well as during completion (see figure 5-38). The two to three hundred pound differential pressure exerted by the mud column during completion further invades the formation around each perforation. This adds to the damage the reservoir suffered during drilling through the swelling of clays and deposition of mud particles. To some extent this offsets the deep penetration provided with large casing guns and even rules out their use in particularly sensitive formations. Efforts have been made to spot oil or another fluid compatible with the formation in the casing prior to perforating. This maintains the hydrostatic head needed for control and allows the compatible fluid to enter each perforation and minimizes damage. Even so some damage does occur and debris from the perforating operation also lodges in the perforation and is packed there by the differential pressure of the mud column. As a result, the trend in recent years has been to move more and more towards so-called "through tubing completions" as illustrated in figure 5-39.

THROUGH TUBING COMPLETIONS

In the through tubing completion, the mud is removed from the casing prior to perforating and replaced with salt water for compatibility, in most cases. The wellhead is then put in place. Through swabbing, a process much like pumping, the fluid level within the casing is lowered to the desired level. This adjusts the hydrostatic pressure within the casing to some value less (usually 200 to 300 pounds) than the formation pressure for perforation purposes. A wire line company is then brought into the scene to provide the perforating service. They provide their own pressure control equipment and attach to the wellhead just above the tubing as shown in figure 5-39. Sufficient riser (an external casing) is used to completely cover the equipment to be lowered into the well. A rubber seal or grease seal sometimes referred to as a lubricator provides the necessary hydraulic seal around the cable connected to the tool. The master valve is opened and the tools are lowered into the well where they are properly positioned opposite the zone to be completed.

The gun is often held against the side of the casing by magnets to provide deeper penetration. With the detonation of the gun, the excess formation pressure immediately forces formation fluid into the well bore or casing preventing further damage including deposition of perforating debris. This action cleans the perforations as the formation fluid (oil or gas) flows into the casing. Under the conditions described, the well would flow or begin to produce while the wire line tools were still in the well if no control was available. This, of course, is undesirable for a number of reasons and the equipment (riser and lubricator) provided by the wire-line company shuts it off. The guns and associated equipment are then raised into the riser and the master valve is closed to shut the well in. The pressure equipment provided by the wire line company is then removed from the wellhead and the well operator proceeds to finish the completion by hooking up the many valves, gauges and surface tubing for the oil collection.

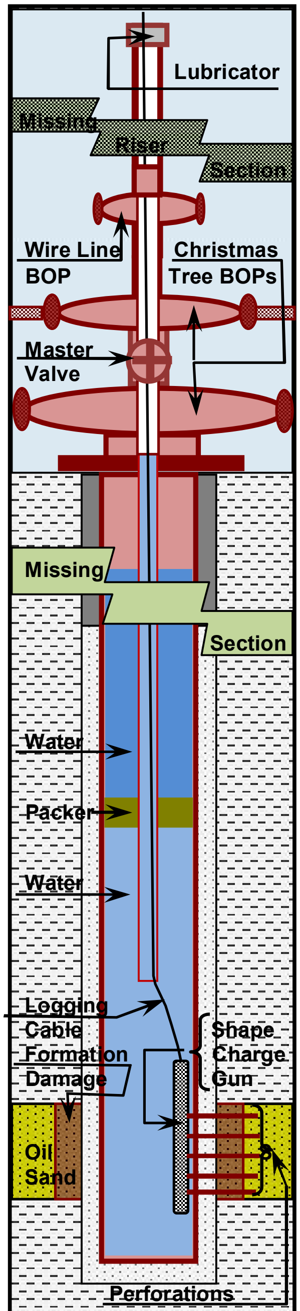

Figure 5-39 A simplified drawing of a through tubing perforating job.

The smaller size of the through tubing gun significantly reduces the depth of penetration of the through tubing gun compared to the casing gun in spite of magnetic positioning and other efforts used to improve its performance. Thus it is not always the choice. Experience in various formations and geographical areas by oil operators dictate their choice and the casing gun still has a large following. It is by far the best selection when a fracturing operation follows the perforating job, which just happens to be part of the next subject. It should also be noted that both casing guns and through tubing guns come in various sizes to accommodate the common casing and tubing diameters offered to the industry. In chapter 8, I'll introduce you to a variety of gun sizes and types Schlumberger had available, most of which I had some experience with.

SPECIAL COMPLETION FLUIDS

Earlier, we spoke of formation damage due to drilling mud and incompatible completion fluids, which significantly reduced the formation permeability or its capability to allow fluid flow. Such damage can be minimized through the use of low water loss mud and/or special mud. It can also be neutralized to an extent with various acid treatments and even perforations, which extend through it to the virgin formation. In the latter case, spotting a compatible fluid (one which doesn't alter the formation permeability) in the casing at the level to be perforated can help achieve the operator's objective of by-passing the damaged zone. As indicated earlier, its movement into the perforation doesn't cause additional damage. However, the perforating action itself still produces a certain amount of debris, which must be cleaned out to allow unrestricted fluid flow. We'll talk more about the debris later, i.e. how it is produced and eliminated, in chapter eight. For now, just remember such debris exists.

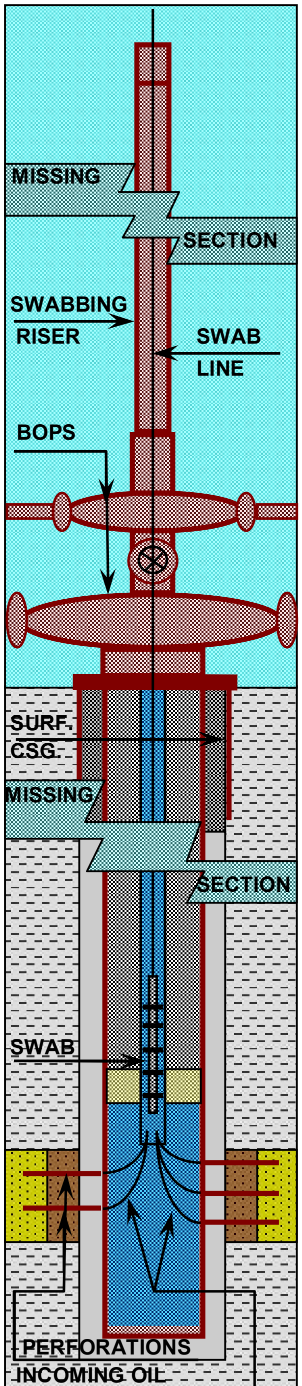

Figure 5-40 An illustration of the swabbing operation.

SWABBING A WELL

Such cleansing might take place through swabbing which reduces the hydrostatic head and allows the formation pressure to push the reservoir fluid and accompanying debris from the perforations into the casing. Consider figure 5-40 for a moment. The swabbing action is akin to unplugging a commode with the old toilet plunger and can go on for days before the operator is satisfied. Come to think of it, I believe I've operated on a toilet for about the same length of time before freeing things up. Anyway, the swabbing tool is covered with a riser at the surface in case the well comes in (the purpose of the operation). It is lowered well down into the tubing near the packer and is then drawn quickly to the surface. The cups are cylindrical in shape and just fit the tubing internal diameter (I.D.). Consequently, they lift the fluid in the tubing, be it water, oil or a combination, which lowers the pressure at the perforations and creates a sucking action drawing fluid and debris from the perforations. With repeated runs of the swab, the perforations are usually cleaned, at least to a degree, and the well will begin to flow providing, of course, the reservoir pressure is sufficiently high.

However, even with the ability to swab a well, the through tubing approach, mentioned earlier, with a significant differential pressure into the casing seems more effective, at least in higher permeability formations. It seems the instantaneous back-pressure into the well after detonation of the gun is still the superior way to clean out perforations and minimize damage to the formation by the well fluid. The reader can see, I feel certain, that the many choices available to the operator of the well, results in multiple approaches.

DRILL STEM TESTING

A drill stem test might be thought of as a temporary completion, which allows the operator to evaluate the zone in question without going to the expense of running casing. This is better done soon after the zone is penetrated because of the greater chance of success. As additional hole is drilled, the condition of the hole higher up usually degrades through erosion of the borehole wall and, particularly so in shale beds. However, some zones are not recognized as having potential until after resistivity and associated logs are run. If an operator desires to run a drill stem test (DST) to confirm the log information, such may be possible but the chance of success is less if the zone is very far off bottom. The two basic types, in terms of zone isolation, are the single packer method and the so-called straddle pack method. The latter name is derived from the straddling action required to completely isolate a zone from formations above and below it. Obviously, this must be accomplished if the test is to be representative of a given horizon in terms of fluid recovery and pressure information.

THE SINGLE PACKER METHOD

The single packer method applies when the need for a test is recognized, soon after a given horizon is breached. Such a situation is illustrated in figure 5-41. Usually the single packer method utilizes two packers in tandem, which act as one in case either should leak. The testing tool is attached to a so-called tail pipe, which is sufficient to reach bottom when the packers are in the desired position. It, the tail pipe, bears any weight placed on the string once the packers are inflated, preventing packer movement and consequently, the subsequent failure of either or both, during the test.

As the tool is run in the hole on the drill pipe, water is also added to the pipe interior to add sufficient weight or reduce its buoyancy and readily sink the tool. Being closed off from the mud column, the pipe is buoyant, like a ship, and tends to float. The amount of water added also determines the hydrostatic head or the pressure that will be exerted on the formation of interest once the packers are inflated. Remember, the mud column exerted enough hydrostatic pressure to prevent any gas or oil from flowing into the hole during the drilling operation. It is isolated, of course, from the zone of interest during the test.

With the packers inflated, the zone to be tested is isolated from the mud column. Then, after the tool is opened, the hydrostatic pressure exerted on the sand being tested is determined by the water cushion or height of the water column in the drill pipe. The height of the column is usually adjusted such that a negative differential of maybe 500 pounds is placed on the formation of interest. That is, the formation pressure is 500 pounds greater than is the pressure exerted by the water column. The hydrocarbon begins to enter the hole pushing the mud below the packers upward with the water. If it were gas as illustrated, the bubbles would move up much quicker than the water and as that action progressed, the density of the column would decrease. As the water begins to flow at the surface, the weight of the cushion decreases which allows the formation to produce at a faster rate. The tool might be left open long enough to get a good blow of gas, verifying its production while obtaining pressure information opposite the formation. The pressure data can be used to determine permeability as well as the flowing and shut in pressure of the formation. This is, of course, valuable information necessary for proper evaluation of the formation's productivity characteristics.

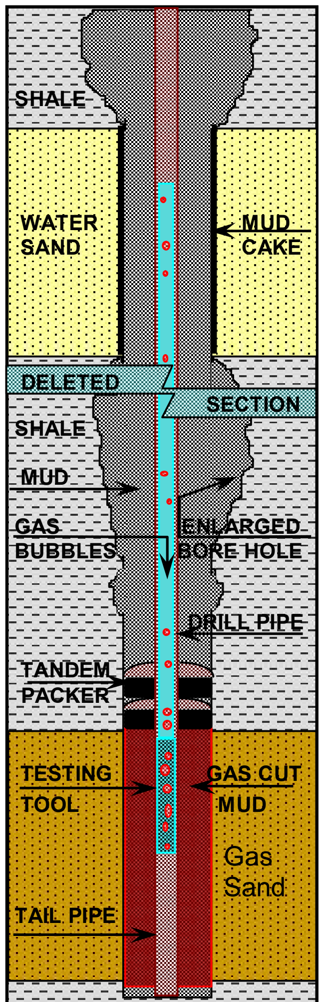

Figure 5-41 A DST illustration of the single packer method.

Once the test is complete, the packers are collapsed, which allows the mud column to, once again, control the formation flow with its higher hydrostatic pressure. Circulation can then be reestablished to remove the gas from the drill pipe as well as from the mud below the packers, which ensures the zone is safely contained before coming out of the hole to remove the tool. In the case of oil or water, the closed tool traps the fluid in the drill pipe and allows the fluid and volume to be measured at the surface as the pipe is retrieved.

THE STRADDLE TEST

As previously mentioned, sometimes a zone will be missed while drilling is progressing and zones of interest are spotted from the well resistivity logs. If they aren't too far off bottom and drill-hole condition appears favorable from the caliper logs, the operator may elect to test one or more such zones. They, of course, must be totally isolated from any other hydrocarbon or water bearing formations to be meaningful. This is done with a double set of packers, one at the top and the other at the bottom of the tested formation interval. I have illustrated such a case in figure 5-42. The basic operation is obviously the same but the equipment and its manipulation is somewhat more complicated. Notice, a tail pipe can still be run to the bottom of the hole to support any weight placed on the string during testing if the zone is reasonably close to total depth. Once again, the water cushion is so chosen that the differential pressure is from the formation into the hole once the testing tool is opened. Oil will rise through the water to some degree but obviously not like gas. The tool will be left open for some predetermined time based on the formation, etc. Seldom, if ever, would the oil flow to the surface. Rather, it will rise and fill so many stands of pipe in the allotted time. Thus, the test results will be measured in terms of the number of feet of oil recovered in the allotted time and the pressure data, which provides a measurement of reservoir parameters as just described.

HOOK WALL PACKERS

One last comment before I get off drill stem testing. At times the zone to be evaluated is several hundred feet off bottom and it isn't practical to run sufficient tail pipe to support the packers. In such cases, a so-called hook wall packer can be used to anchor the pipe to the side of the hole. My understanding, however, of this approach, is that such testing has a very low success ratio and is seldom used. To a large degree, any success would be a function of drill-hole condition and thus it would depend on the geographical area in which it took place as well as drilling techniques and the resulting borehole conditions.

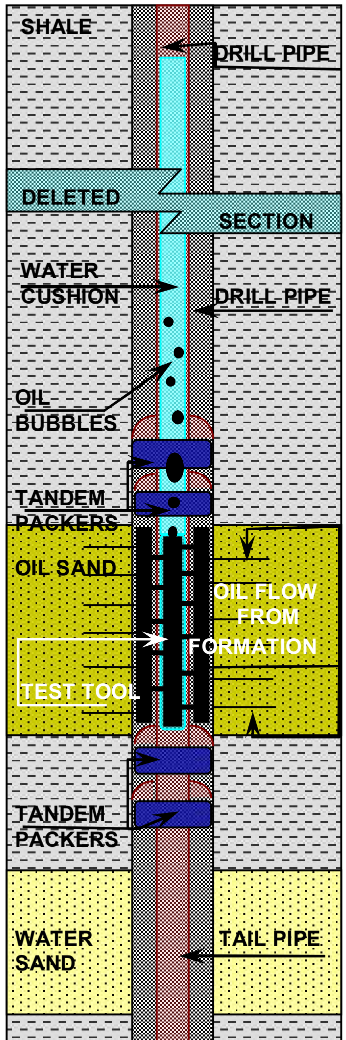

Figure 5-42 A DST illustration depicting a straddle pack test.

CONVENTIONAL CORING

Regardless of well logs and drill-stem testing, a geologist likes to get his hands on a piece of the rock and I'm not talking about Prudential. Much data can be gained from an actual sample of the rock by evaluating its various parameters such as porosity, permeability and lithology as well as cementation characteristics and natural fracturing. This is where the conventional core comes in with its hands-on opportunities.

PICKING A CORING POINT

It is expensive in terms of time and money to core unwanted formation. Consequently, one of the big problems faced by the geologist is picking a coring point or depth to begin the operation. You see, an ideal coring point is exactly at the top of the formation of interest, which hasn't yet been cut. The geologist only knows its approximate depth based on correlation with other wells in which the same horizon appears and through drill cuttings as well as the drill time log. Sometimes, as the bit nears the desired depth, a logging company, such as Schlumberger, will be called out to run a correlation log. With this they can usually pick the top of the target zone within a couple of feet. However, one can appreciate that missing the zone of interest is not unusual and fear of such often creates a great deal of stress, particularly, in a young geologist's life. He must call out the coring company a little ahead of time to prepare their tools. He must constantly evaluate the drill cuttings arriving at the surface. Coring too soon costs money and wastes rig time. Coring too late can result in lost opportunity to properly evaluate an important part of the target formation. The decision is his based on his evaluation of the situation, even though he is in frequent communication with higher authorities.

AN EXAMPLE OF REALITY

I remember one friend of mine who worked for McCallister Fuel in central Montana who had such an experience. I dropped by the well and found him nervous as a balloon next to a pinwheel. It seems he had ordered the coring to begin too high and pulled a shale core from above the zone. He went back to drilling and noticed some sand in the cuttings. Immediately he ordered the core again and lo and behold, he came up with another shale core. Much to his chagrin, he had cored shale above the zone, drilled the target zone and cored shale, once again just below it. Now he had to report his results to his boss in Billings who would surely be an unhappy camper.

THE CORING OPERATION

Getting back to the coring operation once again, consider figure 5-43 as I try to explain what goes on. The drill collar is fitted with a core barrel, which is designed to catch and hold the core so it can't slide back out of the drill collar. In addition, a special bit is used which has an open end about three inches in diameter. Typically, it is diamond studded with commercial grade diamonds set in steel, especially hardened. The exterior dimension of the bit might be typically 7 inches and the access hole for the core 3 inches. As the bit drills deeper into the rock, the 3-inch core moves up into the barrel where it is secured by metal fingers, which are designed so it can't slip back down. Once the core is pulled, the rock inside the barrel comes out of the hole with the string. In the example illustrated in figure 5-43, the coring has begun just a little above the sand and a foot or so of shale is recovered on top of the sandstone. At the surface the core barrel would be removed from the drill collar much like a Totco as the bit is taken off. The geologist then carefully removes the core from the barrel and lays it out on the catwalk where it is measured and described in lithologic terms. If a core is broken, great pains are taken to piece it together in the most logical form and thus assure a proper and realistic description. This is necessary because of core lithology variations.

CONVENTIONAL CORING DRAWBACKS

This particular operation has several drawbacks. First of all, it is somewhat blind and the geologist cores on faith that his objective is where he calculated it to be. If the rock is unconsolidated, as in some areas of the gulf coast, the core may fall apart and be lost. Similarly, in highly fractured rock, core recovery may be poor. Considering the operation is quite expensive in terms of rig time, it can frequently be a poor investment. It seems to have its greatest application once a field is discovered and formation depths as well as rock physical conditions are well known. The results are used in all types of reservoir studies.

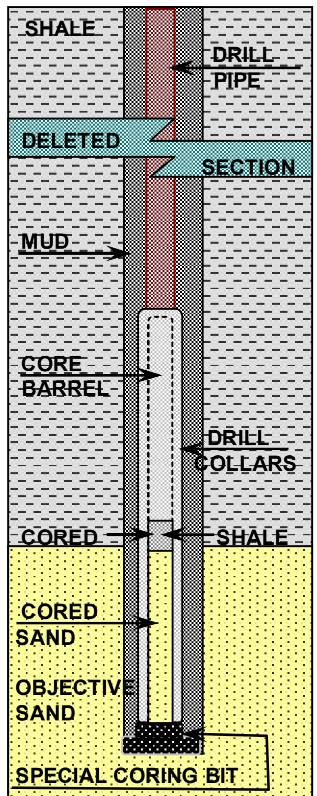

Figure 5-43 An illustration of a typical coring operation.

FORMATION STIMULATION

Although some of the previous operations and techniques discussed might seem to be a form of formation stimulation, they really fall into the category of repairing or compensating for formation damage. Stimulation of a reservoir rock, per se, refers more to the improvement of the rock's native permeability than it does to overcoming formation damage. The technique came into being because some reservoir rock containing large reserves of hydrocarbon, particularly gas, were so tight or had such low permeability that even gas simply wouldn't flow into the well bore at a reasonable rate. Some vehicle was needed to reach out into the reservoir and increase its ability to deliver the gas, contained in the reservoir's pore space, to the well bore for production.

ACIDIZING THE FORMATION

In carbonate reservoirs hydrochloric acid is often used to stimulate production. A carbonate's porosity is normally vugular in nature, which has no relationship with vulgar. That is, void spaces of various sizes have been dissolved out of the rock by percolating ground water. The porosity (the percent of void space in the rock) can be appreciable with very little connecting permeability. This can be improved by simply pumping acid back into the rock through the existing channels. The $CaCO_3$, Calcium Carbonate, which makes up a limestone, is readily dissolved by the acid, which opens up flow channels in the limestone so the reservoir fluid can move more freely into the well bore.

No excessive pressure is used, only a sufficient amount to move the acid through existing channels. This process is known as acidizing and is very common where carbonate reservoirs exist.

FRACTURING THE SURROUNDING ROCK

Another form of reservoir stimulation is known as "fraccing", short for fracturing the rock of the objective reservoir. Earlier, I mentioned the possibility of fracturing formations in a drilling well if pipe was lowered too fast. The drill string acts as a piston pushing the mud ahead of it and building up pressures high enough to cause tensile failure in some rocks below the string. That, of course, is undesirable because it can easily result in lost circulation or loss of mud returns at the surface in a drilling well. See figures 5-21 and 5-22 to refresh your memory. Now we are talking in terms of fracturing or splitting the rock on purpose but in a controlled way. This will increase reservoir permeability and effective borehole size by exposing more of the reservoir rock's surface area to the well bore. That is, we pick the rock we want to split, our reservoir, and do so as efficiently as we can by pumping thousands of gallons of fluid into the rock to open it and then follow that with sand or some other granular material to hold the fracture open after the operation.

FORMATION CONDITIONS

Before discussing the operation, let's describe some properties of the various elements involved. First, the rock is very low porosity, usually 10% or less, and is well cemented. The latter term simply means that material, such as calcium or silica, has precipitated from solution in the percolating ground waters. They bind the sand grains together and tend to block the passageways, which exist amongst the grains providing the permeability. This limits the rock's ability to provide a path for adequate fluid flow.

FLUID VISCOSITIES

Where such an operation is most effective, the reservoir fluid must be very thin or of low viscosity. Dry gas can be considered a fluid, particularly under reservoir conditions, whose viscosity is much lower than that of oils. Thus it can move through the extremely low permeability formations whereas even very light oils cannot.

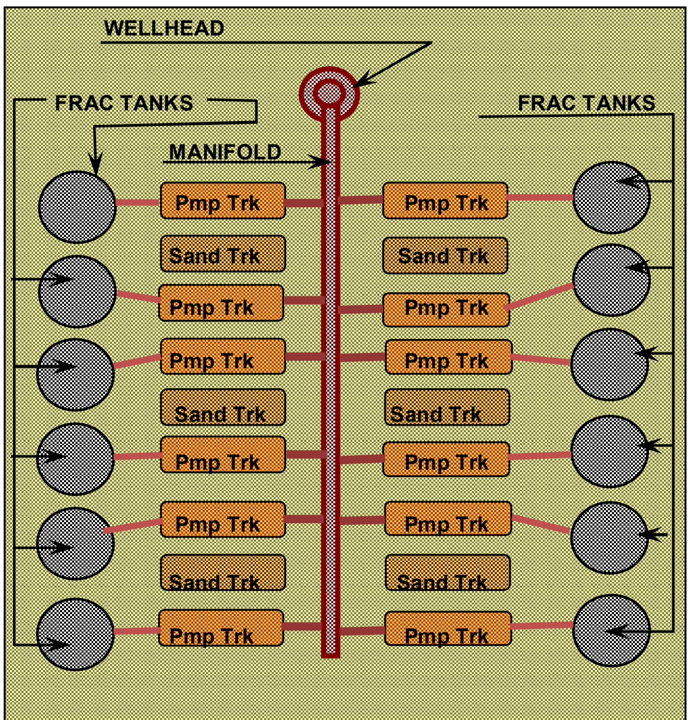

Figure 5-44 An illustration of the basic elements included in a typical facturing operation.

The fluid, which will be pumped into the reservoir to create a fracture, must be of a higher viscosity so that it cannot readily move through the native rock permeability and must rupture or break the rock open to move. Thus it is designed with a viscosity low enough for efficient pumping but high enough to prevent invasion of the rock as well as provide proper suspension of the propping agent or solid material used to hold the fracture open. It also is designed with a suitable gel strength, which aids particle suspension. Appropriate fluid salinity and other mineral contents are used to minimize incompatibility with the formation.

PROPPING AGENTS

Many different propping agents have been tried and are now used in varying degrees. Such materials as sand, glass beads, metal pellets, walnut shells and, who knows what else, have been used in that role. If the propping agent is too weak, it may be crushed by the extreme pressures, which try to close the fracture. If too soft or malleable, it will flatten out and allow fracture closure. If to angular or sharp, it may be embedded in the surrounding rock and not support the fracture. I'm not all that familiar with what is being used today but in the late eighties, glass beads and various types of sand seemed to be most popular in my limited experience. Additionally, the size of individual grains or beads is critical. They must be small enough to move into the open fracture but big enough to hold it open when the pressure is released.

EQUIPMENT REQUIREMENTS

Next would be the hydraulic horsepower considerations. Once the fracture opens, its height, depth and width is dependent upon the rate of fluid flow into the rock. The rate of flow, in turn, depends on casing size and available hydraulic pumping power. Most fracturing jobs take place through casing to maximize pipe size and all employ many truck mounted pump units. They are truly massive in terms of pump power where deeper wells are concerned and larger reservoir sections are open. Needless to say, designing a frac-job requires some real engineering.

As you might suspect, I'm not knowledgeable enough to get any deeper into the operation other than try to illustrate a basic setup. That's quite fortunate for both you and me as providing such an illustration should be the end of it. Figure 5-44 will represent my effort. As you look it over please consider my less than artistic nature as well as the fact I have never been deeply involved in such an operation. I have only witnessed a few frac jobs and have discussed a few more with engineers involved in that business. Truck and tank number vary with the size of the job and I suppose vehicle arrangement varies with available space as well as the most efficient pumping configuration. In any case my little diagram simply illustrates how such equipment might be placed around a typical well site to carry out a frac job. It gives the reader an idea of the massive amount of equipment and hydraulic horsepower required.

Realistically, a number of trucks are involved and, when they wind the engines up after breakdown to maximize fluid flow and move the propping agent into the fracture, they sound like a fleet of B-17's taking off for the Fatherland during WWII. Those involved in the operation, needless to say, must wear earplugs and any visitor better too if he hangs around long.

THE BASIC OPERATION

I believe the basic operation goes something like this. When all is ready, the pumpers begin to raise the wellhead pressure. They know the approximate pressure for breakdown or that value at which the rock actually splits creating a fracture. When breakdown occurs, all trucks begin pumping at some pre-determined rate, which is basically wide open. From the pressure profile they can tell when the fracture quits growing and the signal is given to dump the propping agent (frequently sand) into the slurry. As the sand moves down hole and begins to enter the fracture, a pressure anomaly is seen. When the fracture is packed, another anomaly is observed (a jump in pressure, I believe) and the pumps are shut down. How long pressure is held, I don't know but I assume for a long enough period of time to assure fracture stabilization. I assume it is then lowered slowly to control pressure transients.

FRACTURE DESCRIPTION

Now then, what good is all this work? How does it improve the well? Let's see if I can give some sort of an explanation, which is reasonable with the aid of figure 5-45. Remember way back in figures 5-28 and 5-29 when I was trying to explain the concept of radial flow? There I unwrapped the skins of the cylinders and represented the surface area with a rectangle. Check it out if you aren't sure. Here, the face of the fracture is essentially a rectangle whose vertical dimension is the thickness of the bed and whose horizontal dimension is the depth of the fracture. Now let's consider the fracture proper, i.e. a fissure packed with sand to keep it open. Even though it is packed with sand, its permeability is very high, almost like a pipeline from out in the formation to the casing.

The area of the fracture determines how fast gas drains into it and the well. It will be very large because the fracture is tens of feet deep. Assume it is exactly 31.4 feet deep. If we could lay both faces of the fracture end to end and wrap them in a circle, the resulting cylinder

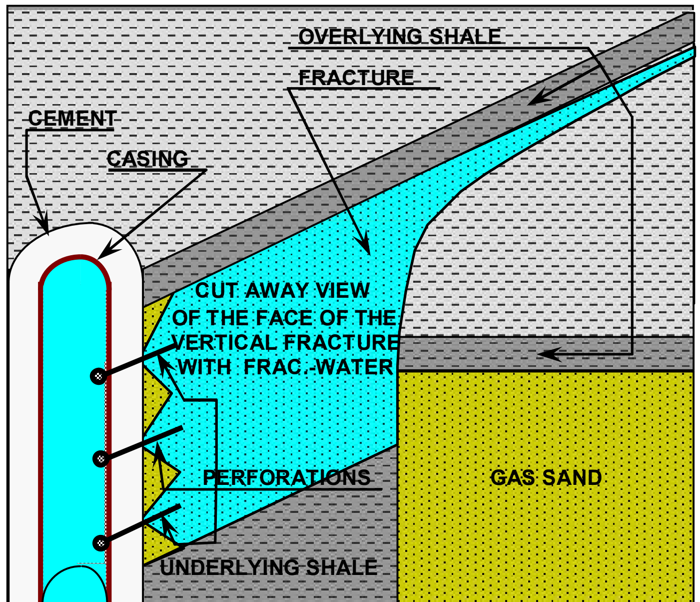

Figure 5-45 An illustration of a vertical fracture emanating from perforated casing into a sandstone.

would be ten feet in diameter or a very large hole for the gas to drain into. In fact it would have in the vicinity of 250 times the capacity of just the perforations. Such operations multiply the gas production rates by factors of hundreds and even thousands. Frac jobs are expensive but they pay for themselves many times over via increased production rates and total recovery.

Well, I suppose I ought to quit while I'm still ahead on this particular chapter since it is hardly all that it's cracked up to be as exemplified by figure 5-45. In a similar vein, I doubt that my pun has really caught your attention, let alone fractured your jovial nature, but so be it. It's difficult for one my age to rise to the break down pressure of you yunguns let alone establish sufficient word flow to really create a fissure in your emotional status and prop it open via my PUNdit word play. Oh well, so be it, old grandpas never die, they just PUN that, which proceeds from their somewhat pitiful past, with their prolific and proverbial prattle leaving the pruning of pertinent precepts to posterity. Meanwhile, the faithful, who are respectful enough to read the same, have no choice but to endure them. Besides, they hardly want a perfidious act on their part to offend grandpa lest he should become pugnacious.

HORIZONTAL DRILLING

From the subheading of this particular section one would think the subject to be out of place. What does drilling have to do with formation stimulation? Actually, the term horizontal is the key in that the drainage area exposed to the drill hole is multiplied, much like in the fracturing process, by drilling horizontally into it, which provides an associated increase in production.

This particular technique was just coming into use when I left the industry. Thus, I had little first-hand exposure to the technique and have to go more on experiences off shore, where drilling approaches the horizontal, to reach a given destination. Schlumberger problems, which aren't a part of this discussion, would be essentially the same in either case. My limited understanding of reservoir and production engineering, however, should provide the logic necessary to explain the benefits of such a technique as "horizontal drilling". Then again, it may not but as the old sage said when consulted on the top of Mount Everest, "Nothing ventured, nothing gained".

THE MATHEMATICAL MODEL

Consider figure 5-29 once again and refresh your memories regarding the choking effect of shrinking cross sectional area in the drainage of a formation as the hydrocarbon approaches the borehole. The cross sectional area in question is controlled by two parameters, i.e. the borehole size and the bed thickness of the formation being drained, as illustrated in that figure and as described by equation 2.

2) A = pi D H = πDH

The little funny looking gismo in the second part of the equation is the symbol for the Greek letter PI or the equivalent to our letter P. As you all know, it also is used to designate the constant obtained by dividing the circumference of a circle by its diameter and is numerically equal to 3.1416. Thus, pi D is the circumference of a circle or the borehole in our case. If we are talking about the area of the formation exposed to the borehole, its circumference must be multiplied by the bed thickness, which we designate as H. The area exposed is then expressed by equation 2.

With the fracture process, the effective borehole size was essentially increased. When a well is drilled horizontally into a formation of interest, the bed thickness exposed to the borehole is increased. Either approach increases the drainage area exposed to the borehole as illustrated in figure 5-46.

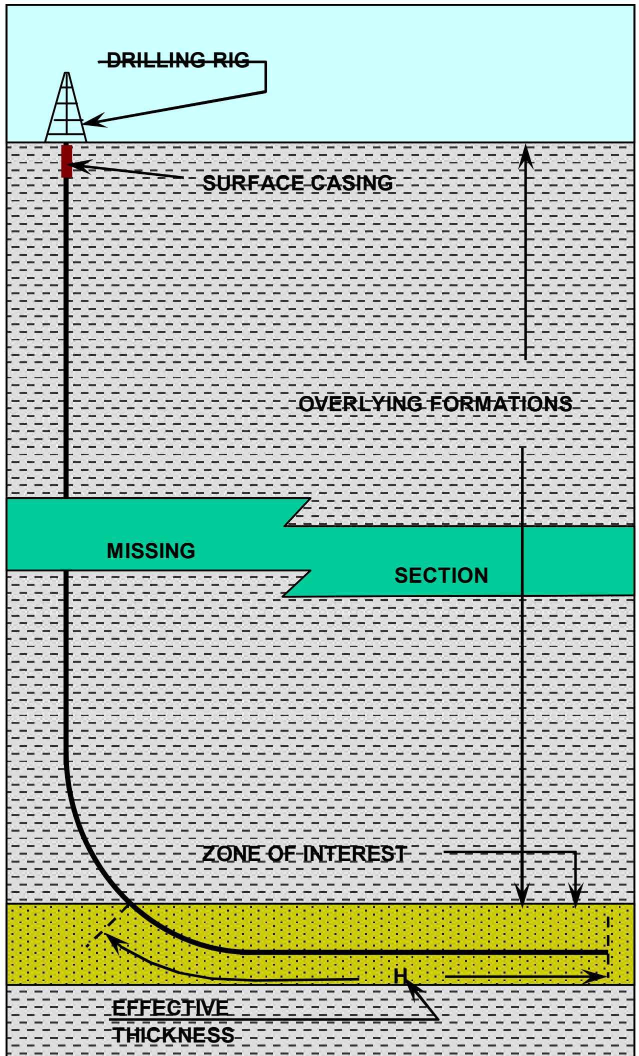

Figure 5-46 An illustration of a well drilled horizontally into a low permeability formation.

This technique is used where the formation of interest is one of very low permeability and where its depth is well established. The objective is to make this particular horizon a profitable source of hydrocarbon production by increasing the area by which it is able to drain the fluid into the borehole.

The turn of the borehole from vertical to horizontal would not be as sharp as illustrated. The rig would drill to some predetermined depth above the horizon and then the directional services would be utilized to gradually make the turn completing it once the center of the bed is reached. Never having been intimately associated with the technique, I'm not sure just far they drill horizontally. It would seem the further the better. However, I would suppose there is a maximum distance beyond which the drill pipe cannot be properly maneuvered. If they stay in the bed, the drainage area around the hole would obviously increase with horizontal distance. Thus H or the horizontal distance drilled in the bed is probably limited or dictated by mechanical considerations.

Well, I believe this particular technique is a good way to close out the chapter. You must admit it is rather startling how they can guide a drill-hole and maybe even more so how they are able to drill in the direction chosen. The basic techniques for directional drilling were developed off shore where surface location was limited to the drilling platform. Its purpose there was entirely different than that of coaxing more production from low permeability formations. Horizontal drilling is simply a different application of a proven technique.

RECENT DRILLING ADVANCES

Phil was kind enough to send me a copy of the "Atlantic Monthly" which had an excellent article in it on recent improvements in exploration and drilling techniques directly related to the increased power and continuing application of computers. Because I enjoyed the article so much, I decided to include a few comments from it, which will give you an idea of the rapid advances, which have been made since I left the business. Its title is. "**THE NEW OLD ECONOMY: Oil, Computers, and the Reinvention of the Earth.** The author, Jonathan Rauch, points out that *"knowledge, not petroleum, is becoming the critical resource in the oil business".* By that, I assume he means both knowledgeable people to utilize the power of the computer and the actual knowledge gathered by those employing their efforts. The gist of the article seems to be the effect on the economy due to old businesses, such as that of oil, learning to apply the power of the computer to its many faceted activities. Though its main message may be economic in nature, I found the advances in oil exploration and drilling to be most interesting. It is these advances which I intend to quote and maybe comment on a little

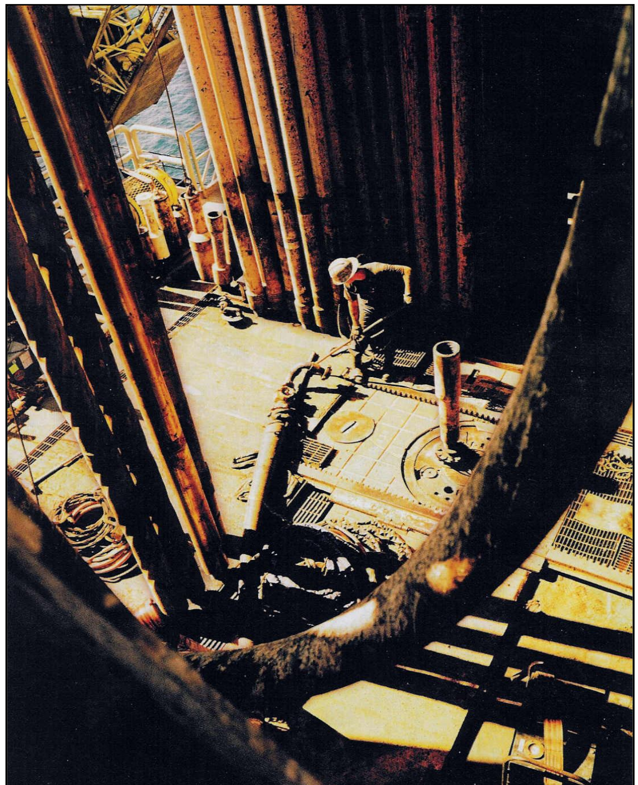

Figure 5-47 A bird's eye view of an offshore drilling rig floor from high in the derrick.

to give the reader an idea of the interesting, aggressive and even stimulating business I was associated with.

SEISMIC IMAGING

Reference was made to the accumulation of seismic data on page 182 of this chapter as well as on pages 292 and 293 of chapter six. There was also some discussion of salt domes and their masking of seismic data on page 177. Such discussion was extremely simple even in relation to the actual gathering and processing of data at that time but it will help give the layman a little basis for understanding the quotes and comments that follow. You may want to scan or rescan that material before you read this particular material. It will make the discussion clearer.

Seismic imaging simply defined refers to the ability of the geophysicist to develop an image of the internal structure of a given section of sediments by subjecting it to pulses of sound energy and measuring the time of various reflections produced as depicted in figure 7-29 of chapter 7. The example there would produce a 2D image or a vertical cross section. Of course, what the geologist really wants is a 3D image, which describes the structure in all directions.

Now, quoting the article, *"Even a small 3D survey might easily generate 200 gigabytes of data, and all the points would then need to be analyzed from every direction simultaneously".* That ability to achieve the latter objective came into being in 1975 but was of little value. Quoting, once again, *"That is when the processing revolution changed. From 1985 to 1995 the computing time needed to process a square kilometer's worth of data fell from 800 minutes to ten minutes. From 1980 to 1990 the cost of analyzing a fifty square mile seismic survey fell from $8 million to $1million. Now it's*

Figure 5-48 A view of an offshore drilling rig derrick as seen from the mouse hole.

more like $90,000." That is, at the end of the year 2000. Continuing with the article, *"Today that smallish 20 or 30 square mile survey might easily involve 25,000 geophones, 2000 echo traces per shot and 30,000 shots --- a total of more than half a million floppy discs worth of data or more than 800 gigabytes, of which each byte must be compared and reconciled with thousands of millions of others. …Schlumberger, a big oil technology company, recently announced a higher resolution technology, called Q that gathers several times as much data as anything before and pushes the computers proportionally harder".* One thing about Schlumberger is; they will squeeze all possible information from any measurement.

DIRECTIONAL DRILLING

Let's take a glimpse of modern directional drilling from the same article by quoting a few passages contained therein. I feel confident that they will surprise you with the technology involved.

"A directional well can run in any direction, though horizontal is the most common. It can approach a reservoir from whichever angle geologists deem most promising. It can twist and turn to cut through any number of reservoirs. Engineers in Brunei recently drilled a U shaped hole; first drilling downward and then horizontally for a production well and then back upward 800 feet at a 167-degree angle or almost vertically, to accomplish an additional exploration objective.

"Measurement-while-drilling appeared on the scene around 20 years ago. Behind the drill bit rode one or more instruments that kept track of the bit's location and reported back to the surface". Schlumberger entered the business at that time, as well.

Now, another quote, *"Measurement while drilling, directional drilling and 3D seismic imaging not only developed simultaneously but also developed one another".* Thus, their advances were synergistic.

Here is another quote taken from the article. *"As it happens, Baker Hughes in the late 1990s introduced a system called Auto-Trak that can adjust direction (speaking of the bit) at full speed. Just behind the drill bit rides a programmable collar, from which sprout three rudder like fins. Guided by a computer (what else?), the fins bulge or retract to point the drill bit in any direction without slowing down".*

Though the article didn't discuss the geologist's role with acquired data, I suspect it too has been radically transformed by the computer. Maps and cross-section data must surely be in computer data bases and updated with each well. The information that is so simply displayed back on pages 192-194 is quite likely displayed in much more spectacular form today. In many, if not most cases, I suspect it is displayed in three dimensions and approaches virtual reality.

SOME NEAT PHOTOS

I have included some neat photos from the same article. Of course, it is an offshore rig and probably among the best of them. Thus, it isn't representative of the typical rig but it does provide the reader with an impression of the gigantic size and complexity that such rigs reach. As you have already noticed, they are included as figures 5-47, 5-48. Each one gives a little different perspective of the rig from the particular vantage point mentioned. Now, don't you think this oil-business is some fun? Well, maybe that's an exaggeration but at least, you should admit it is interesting.

WILL THIS DEVELOPMENT WORK?

This last week, i.e. about June 9th or so of 2008, I was watching Fox News while the Governor of Montana was being interviewed via telephone. He spoke of a formation in eastern Montana called the Bakken (sp) formation. I remember the name from my days in the oil business and so my ears perked up to see what he had to say. It seems the Bakken formation has an extremely low permeability somewhat like an oil shale of western Colorado and eastern Utah. The oil shale also exists in southwestern Wyoming. Anyhow, the Bakken has many billion of barrels of oil locked up in its tight little pore spaces. This may be kerogen or the hydrocarbon referred to in the oil shales of the Utah-Colorado area. Whatever its name, oil can be derived from it and the problem of production lies in its lack of permeability. This is where the governor's comments made me sit up and listen.

The governor said the technology for production from the Bakken now exists and he was giving the state's okay for the effort to move forward. He then briefly described what he knew about the method, which I will now elaborate on, adding my own understanding of the technology as I see it. I don't claim my description which follows, as being very accurate but hopefully, it will be close enough to give the reader an idea of how such production might work. By the time you read this, the method will probably be in rather common use and be described in greater detail by the media.

The governor described a typical well as one drilled vertically into the Bakken with horizontal offshoots a mile in length in all directions. He didn't specify what all directions meant but realistically it might mean in eight different directions or a horizontal offshoot every 45^{o}

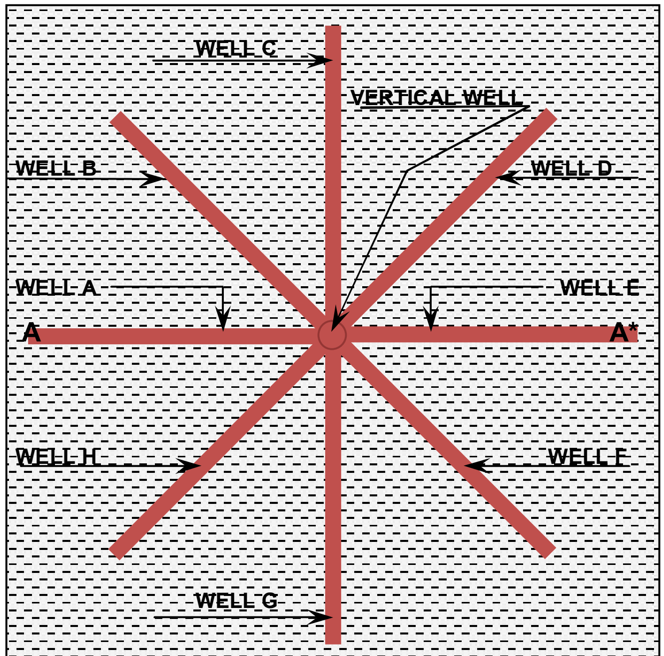

Figure 5-49 Horizontal cross-section #1 taken through the uppermost radial well configuration.

around the circumference of the borehole. One such vertical level or horizontal cross-section is displayed in figure 5-49. If the Bakken is thick enough, let's say 1000 feet, we might repeat the radial configuration just mentioned every 200 feet or five times. The number of levels would obviously be determined by formation thickness and the practical thickness of shale which might be adequately drained in an efficient manner. If five levels were the case, figure 5-49 would represent all levels. A vertical cross-section along the axis of any two horizontal offshoots would appear as illustrated in figure 5-50.

It might appear obvious that several different configurations of wells forming the horizontal offshoots would be possible. It goes without saying that drilling and reservoir engineers would consider all possibilities and maybe even experiment with two or three to obtain the best possible reservoir depletion or drainage. For instance they might drill four horizontal offshoots every 100 feet rather than eight every 200.

However, my example will stick with the eight wells at five levels in a 1000 foot Bakken shale bed, since that was my original statement. At least the reader should admit that I'm consistent, if not imaginative or original in any sense of the word, both of which I never claimed.

Now, look quickly at figure 5-50, which is a vertical cross-section taken through A – A' as illustrated in figure 5-49. It, of course, extends down through the complete Bakken formation and encompasses all the horizontal cross-sections included therein. Obviously, I have shown only two levels of the horizontal wells for my discussion because of space, leaving you to imagine the other three as being included within that missing section I designated.

Let's assume each horizontal well extends for 5000 feet, about a mile, from the central well like

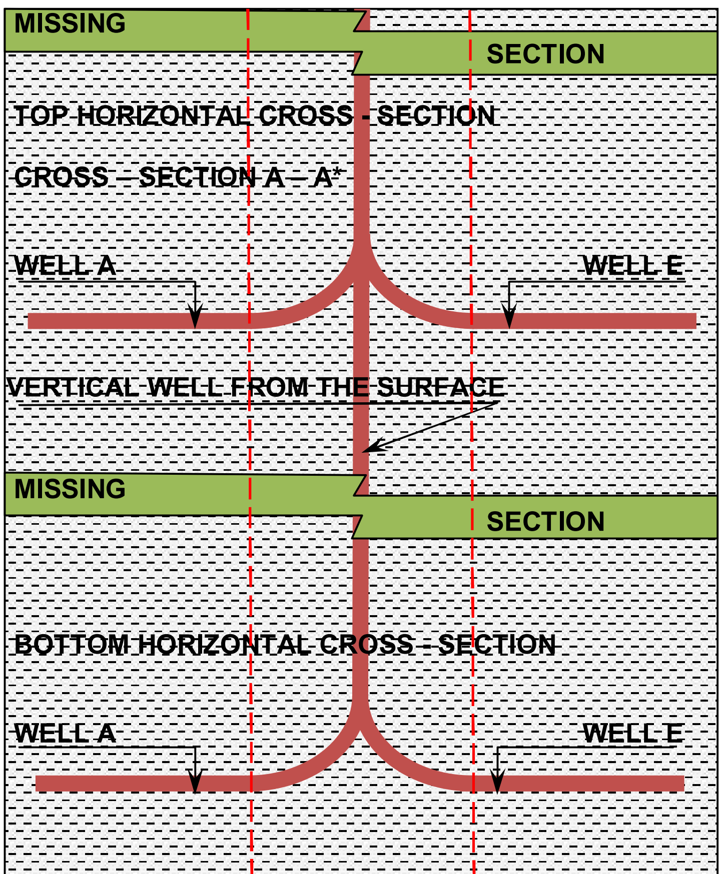

Figure 5-50 Vertical cross-section A – A* taken along the axes of horizontal wells A and E of figure 5-50.

spokes of a wheel in a radial manner every 45^0. From my previous discussion of horizontal drilling on page 234, you will remember the equation, which expressed the surface area of the borehole exposed to the formation, i.e.

A = (pi)(D)(H).

If we assume the borehole is 1 foot in diameter, the area is calculated as;

A = (3.1416)(1)(5000) = 15,708 sq. feet.

Now, let's equate that to a vertical hole of 200 feet, the distance between horizontal well levels, and see what the equivalent borehole diameter would be.

D (equivalent) = 15,708/3.1416x200, or

D = 25 feet.

Thus, each set of radial wells creates the same borehole exposure to the formation as would a 200 foot hole, which is 25 feet in diameter. With 5 levels in a 1000 foot bed, this is equivalent to drilling the complete formation with a 25 foot borehole. Such a borehole would minimize the constriction of fluid flow described on page 217. I have illustrated such a borehole in figures 5-49 and 5-50 to help the reader visualize the situation. It is represented by the red dashed superimposed lines.

As mentioned previously, fluid viscosity also affects the ability of a fluid to flow through a given permeability. We can decrease the viscosity of the oil and improve its ability to flow while in situ, i.e. within the formation, by heating it or some other stimulation method. this wouldn't be necessary for gas production and may not for lighter fluids but, I suspect the approach described might also involve pumping super heated steam into the borehole for a period of time and then releasing it so the heated oil can flow more readily into the well. As mentioned earlier, this is a technique used in the tar sands of Canada and is called the huff and puff method, after the tale of the three little pigs, I guess. As you can see, one has to look everywhere, including in the fairy tales to find appropriate names. Engineers may not be imaginative in terms of digging up names but they sure can adapt those they have become familiar with in their lives