Baker Hughes INTEQ

Formation Pressure Evaluation

Reference Guide

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PREFACE

The main objectives of this Formation Pressure Evaluation Reference Guide are to:

1. Educate Baker Hughes INTEQ field personnel to a basic level of pressure evaluation expertise
2. Provide a comprehensive reference to for experienced Baker Hughes INTEQ field personnel
3. Foster constructive thought and continued development of Baker Hughes INTEQ personnel in the management of formation pressures

This reference guide is based upon several Baker Hughes INTEQ sources (EXLOG's *Theory And Evaluation of Formation Pressures Manual*, Eastman Teleco's *Pore Pressure Course*, Milpark's *Drilling Fluid Technology Manual)*, many new ideas from published articles, along with information and feedback from field-based personnel. These have been incorporated into this revision. It is hoped that the topics will generate interest and will allow field personnel to follow up on the new lines of thought referenced in this manual, and return their comments to their local Training and Development department.

Ease of introduction is provided by the detailed table of contents and the glossary of terms, definitions and formulae should make access to background information more rapid. References are listed at the end of each section. Should the reader of this manual require a copy of a reference, if a copy is unavailable from the field office, please contact the Baker Hughes INTEQ Training and Development department in Houston, Texas.

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Chapter 1

What is Pressure Evaluation?

The evaluation of formation pressures is an integral part of the well planning and formation evaluation process. For example, in order to drill a well safely and economically, it is necessary to know the pore pressure and fracture pressure so that the mud density can be optimized to provide sufficient overbalance, while being low enough so that formation integrity is not compromised (see Figure 1-1).

In areas where exploration and production histories are established, offset data sets can be used to provide detailed profiles of expected pressures for those wells about to be drilled. Seismic data, log information (wireline, FEMWD, FEL and various pressure logs) and direct pressure measurements (DST, RFT and production testing) can all be used.

This information, while extremely valuable, can be subject to regional variations and should be considered a guide at best, and at worst misleading. It is vital that during the course of a well methods be adopted to evaluate changes in the formation pressures. This “real-time” information can then be used to update the initial well prognosis.

By using modern methods and industry accepted concepts (outlined in this manual), relationships between petroleum geology and drilling engineering can be interpreted to give accurate estimations of formation pressures at any point during the course of a well. In addition, mathematical models and algorithms can be used to predict formation fracture pressure following the first pressure integrity (Leak-Off) test in a competent formation.

The successful estimation of formation pressures requires the correct application of methods and evaluation procedures, and the knowledge, skill and experience of those personnel entrusted with this type of work. Effective communication with rig site personnel (Operator, Drilling Contractor, Service Companies) is also extremely important.

In all instances, teamwork is the key.

Requirements of Pressure Evaluation Personnel

The individual providing pressure evaluation services for Baker Hughes INTEQ must be an person with extensive field experience. They must have a thorough understanding of drilling engineering, have excellent communication skills, and be knowledgeable of logging procedures and interpretation techniques. This person must have witnessed pressure evaluation services first-hand, and have played a part in these services by recording and interpreting such information as drill rate, MWD and wireline log traces, formation gas, drill cuttings and rig site sensor parameters.

The Baker Hughes INTEQ **DrillByte**® service has an unprecedented amount of computing power, which can be used to collect, store, process and interpret vast amounts of drilling and geological data, and to produce a variety of plots, logs and reports. It is a highly effective tool that can be used to provide pressure evaluation personnel with the means to make accurate decisions and quantitative estimations of formation pressures, and to eliminate the need to make lengthy, laborious repetitive calculations.

Even with all this advanced technology, pressure evaluation still requires experience, good judgement and teamwork to be successful.

Responsibilities

When Baker Hughes INTEQ field personnel are asked to perform formation pressure evaluation services, they accept a great deal of responsibility. The decisions and reports made during the course of their duties are of genuine importance to the drilling operation. As a result, their reports must be accurate, subject to critical examination in difficult situations, and must be substantiated.

These personnel must work in close cooperation with the Operator's engineers and geologists, the rig superintendent, mud engineer and others at the local base. Their ability to communicate with these personnel is a vital component of the service.

During the performance of their duties, the pressure evaluation personnel will find that some wells are trouble-free and very undemanding. This, however, is no reason to reduce the quantity or quality of their observations and record-keeping. On the other hand, some wells will place so much stress and responsibility on them, that their knowledge and capabilities are tested to the utmost. Every well is different, and knowledge is gained from every circumstance. The completion of a demanding assignment, which results in the attainment of total depth with minimum hole problems and maximum information is the most rewarding aspect of the job.

Instrumentation

Pressure evaluation personnel should be trained in the use of the various calculators and computers available within Baker Hughes INTEQ. Such equipment is invaluable when making pressure calculations. Several Engineering Assistance Programs (EAP) are available in **DrillByte**.

A sophisticated pressure evaluation package **GeoPress**™ is included in **DrillByte** (version 2.0+) and should be used whenever it is available. In general, the amount of instrumentation used in pressure evaluation will vary with each particular job. Figure 1-2 illustrates the variety of equipment and parameters available to pressure evaluation personnel.

When used, FEMWD services can provide many parameters that can be valuable in formation pressure evaluation. Parameters such as Gamma Ray, Resistivity, Neutron Porosity and Formation Density can be used effectively during pressure evaluation. Composite logs, combining the FEMWD and surface logging data are important sources of interpretation, evaluation and correlation material.

Secondary equipment can also be important sources of formation pressure variables. Services which include mud density (In and Out), mud temperature (In and Out), mud conductivity (In and Out), Mud Flow, Pit Volume Totalizer, Shale Density, and Shale Factor proves invaluable when monitoring formation pressures. To ensure its effectiveness, whenever any of these services are included in the logging unit, the pressure evaluation personnel are required to know how to operate, calibrate and troubleshoot this secondary equipment, in addition to interpreting the acquired data.

Logs and Reports

A complete record of formation pressure data and evaluation results is important for the communication of information while drilling. This record is also of value in the development of future exploration and drilling plans.

In the pressure evaluation aspects of their work, the wellsite personnel are responsible for the production of a group of pressure logs and reports. Examples of **DrillByte** plots include:

- Drilling Data Pressure Log
- Temperature Data Log
- Wireline Data Pressure Log
- Miscellaneous Data Logs (i.e. Shale Data Pressure Log)
- Pressure Evaluation Log
- Various FEMWD Composite Logs

In addition to the logs, pressure data and comments are reported daily to the Operator on **DrillByte** morning reports (Appendix F).

At the completion of the well, all of the information in the pressure evaluation reports and logs, are combined with the formation evaluation and engineering information, which is then compiled into a Final Well Report (FWR) for the client.

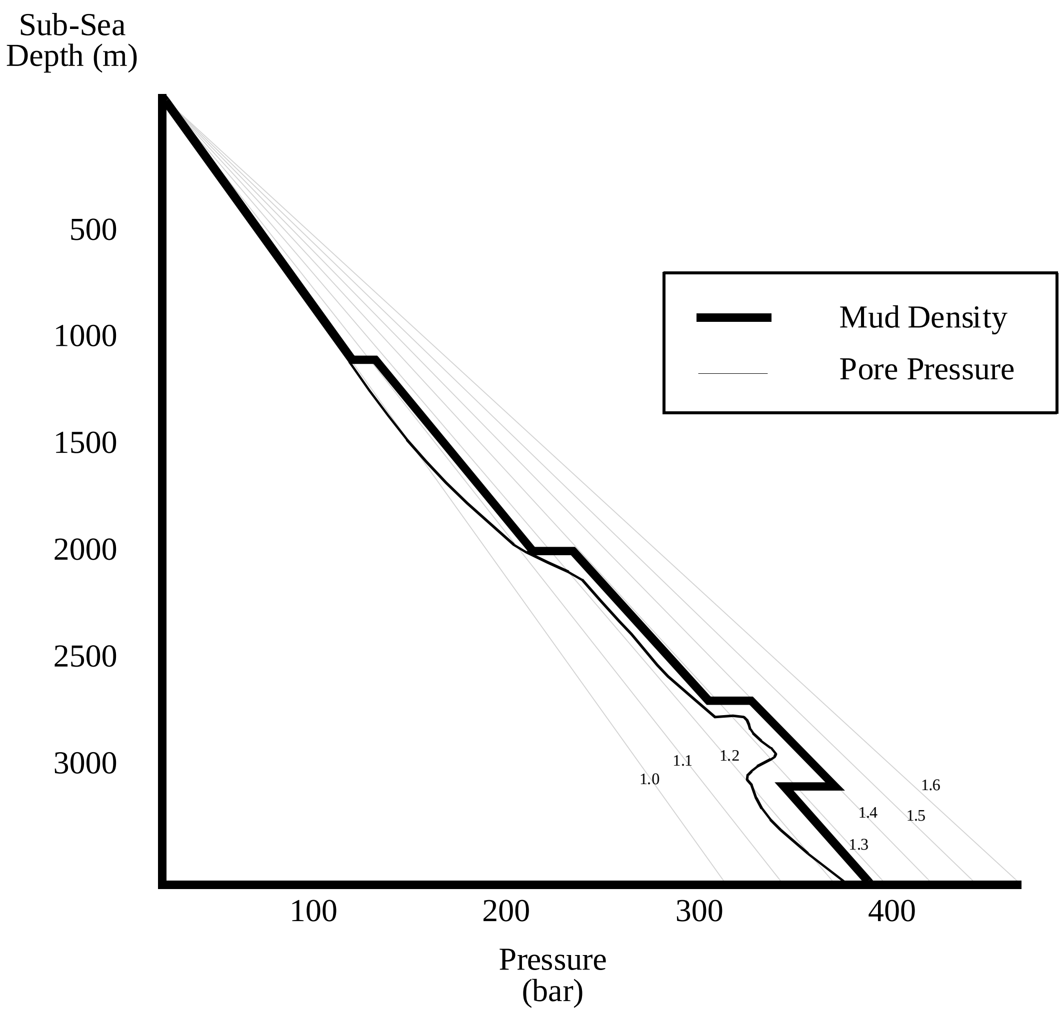

Figure 1-1 Pressure Diagram Plot

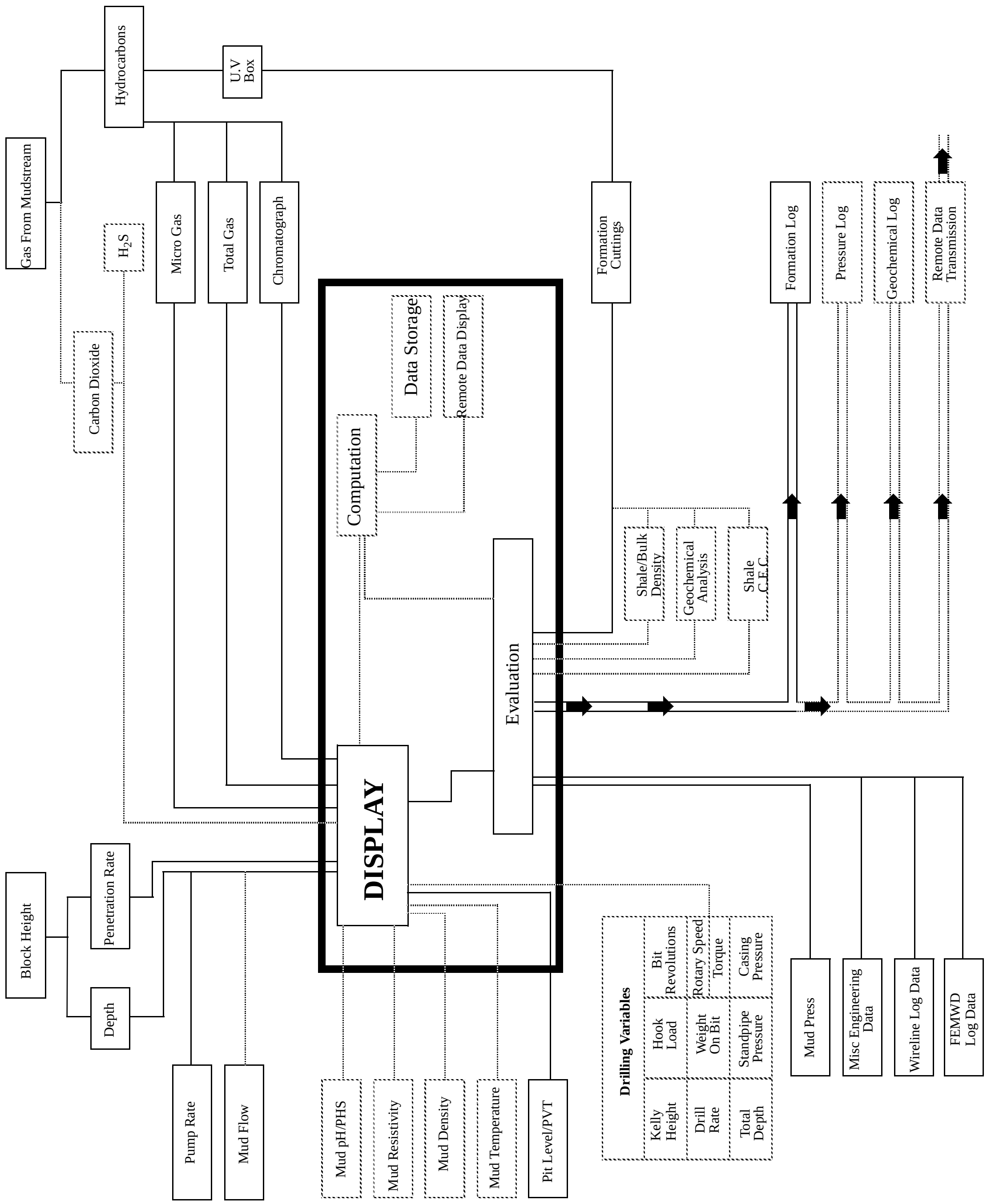

Figure 1-2Logging Unit Systems and Information Flow

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Chapter **2**

Origins Of Abnormal Pressure

In most geological settings, a “normal” set of parameters can be used to predict what formation pressures might be encountered while drilling. If these conditions always prevailed there would hardly ever be any problems in tailoring a drilling fluid system to control the well.

Unfortunately, various geological and mechanical variables conspire to produce pore pressures that are higher (or lower) than the “normal”.

What information does the well planner have at their disposal to predict formation pressures for upcoming wells? The geological history of the area to be drilled is usually known. This, combined with a knowledge of how abnormal pressures develop in different geological settings, can enable the well planner to anticipate the location, extent and potential magnitude of possible pressure problems.

The fundamental difference between normally and abnormally pressured rocks is that in abnormally pressured zones the pore fluids no longer communicate 100% efficiently with the water-table (surface communication). Some mechanism is providing a seal or cap to interfere with the fluid column and preventing it from achieving normal hydrostatic equilibrium.

Once the continuity of the fluid column has been broken, the pore fluids can be acted upon in a number of ways. For example, if we picture the area of abnormal pressure as a compartment, it can be present in three different conditions; 1) it may be perfectly sealed like a balloon, 2) it may slowly leak like a punctured tire, or 3) it may be so leaky that it holds pressure for a short period of time (these very leaky seals are not often knowingly drilled but have other geologically important roles, such as being the cause of major landslips and slope failures).

The criteria that determines the efficiency of the seal, or cap rock are:

- its permeability
- its thickness
- the magnitude of differential pressure
- the time over which pressure changes have occurred

The best seal would be a perfectly impermeable, plastic rock, capable of retaining its integrity and encapsulating a fluid-filled porous rock. An example of such a lithology is salt. As a result, salt can be the cause of many severe pressure problems. The most common seals that are drilled in the oilfields are claystones and shales. Though it would be a mistake to suggest that all claystone/shale sequences are impermeable, even the thickest ones, but a favorable combination of low permeability and sufficient thickness can sustain quite substantial overpressures, especially if the rock still has sufficient tensile strength.

Quite often, owing to slight permeability, there can be a pressure halo around the abnormally pressured zone which stretches as far as the next change in vertical permeability. This gradual leakage of pressure means that overpressures are very transient (in geologic terms), unless the pressure is constantly replenished by some other charging mechanism.

Bradley, in his 1975 paper, showed that there only needs to be a leakage of one “drop” of water per square centimeter every year for 300 years to bleed off a differential pressure of 1000 psi. This is well within the permeability range of many shales.

For this reason, the larger abnormal pressures are more likely to be encountered where the processes that formed them are recent or still active and seal efficiency is still very high.

How Does Abnormal Pressure Develop?

The discussion thus far has centered around different aspects of the subsurface rock/fluid system. It has been mentioned that in order to produce a pressure that is “abnormal” in a water-filled rock, a seal is required and this seal may be of varying efficiency.

In order to describe the various pressure developing mechanisms (some proven and some only postulated) some simple analogies are required. The simplest is a cocoa tin full of water (see Figure 2-1). The tin has finite volume, a certain tensile strength and a sealing efficiency dependent on how firmly the lid is fixed on. To change the internal pressure in the tin we can do one of two things: 1) change the volume of the tin or 2) change the volume of the liquid. It is also important to consider the liquid in the absence of any gas cap (like a half empty cola bottle) since gas has a high compressibility and a low hydrostatic effect, which can lead to very different pressures at the top of the compartment from those that would have been encountered in the absence of gas.

First, look at systems where the compartment size changes, but not in equilibrium with the fluid (i.e. no fluid enters or escapes), then compare them with systems where the compartment size remains fixed, although these are by no means easy distinctions to make.

As we look at these mechanisms and the geological environment in which they occur, we will see that a knowledge of how pressure anomalies develop really can help the well planner to anticipate troublesome zones.

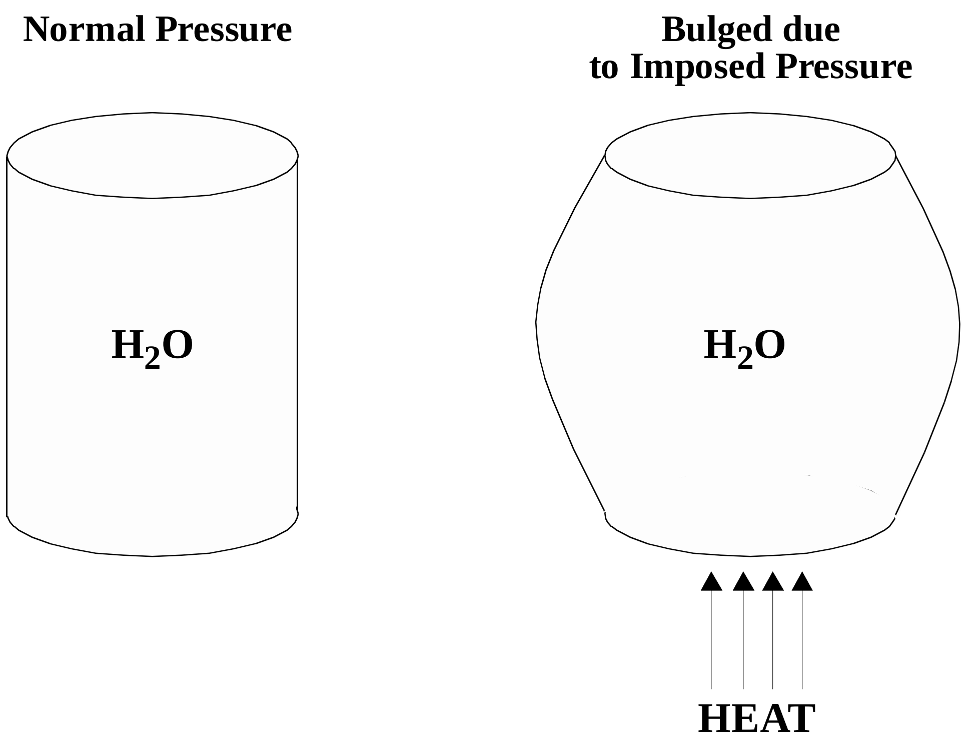

Figure 2-1: Imposed Pressure on a Cocoa Tin

Lower Pressure Environments

Changing Compartment Size

If the confining pressure on a compartment is reduced, the compartment (if flexible) will relax and expand. If no fluid can enter the system those already inside it are required to fill a larger space. Thus the pressure drops.

Geological Settings

In areas where erosion has removed a significant thickness of the overburden, the more elastic sediments (like shales and claystones) may relax sufficiently to undergo an increase in pore volume. Also, this volume increase may draw in fluids from interbedded and surrounding porous rocks (i.e. lenticular sands) resulting in depletion of pressure in those sands. If the fluid available for the entire area is insufficient, the whole system, including clays, will be underpressured.

Temperature

Temperature is a complicating factor, but generally “decompressed expansion” in areas of uplift and erosion will lead to subnormal pressure. Nearly 60% of the rocks in the USA are subnormally pressured. In an underpressured compartment the seal is entirely matrix supported.

Changing Fluid Volume

The simplest form of fluid change, and the most common cause of lower-than-normal pressure, is depletion of reservoirs and aquifers through production. As such, in mature fields it is not uncommon to encounter underpressured sands. In the absence of a matrix supported seal, the consequence will be compaction of the reservoir and surface subsidence as the matrix takes on the full load. The subsidence of the sea bed above the Ekofisk field in the North Sea is a good example.

As mentioned above, temperature has an effect on the “decompressional expansion”, and an increase in temperature gradient at the same time as the erosion may compensated for (or even over-compensate for) the loss of the imposed pressure. For this reason the areas most likely to be underpressured are those that were originally hot and undercompacted. This kind of situation can prevail in interior basins with high heat flows, but which don’t become subsequently filled during the later sag phase.

Things That Look Like Underpressure

A low water table, or an aquifer with an outcrop below the water table, will show a pressure that is (for drilling purposes) subnormal (See Figure 2-2).

Subnormal pressure is not as dramatic as overpressure, but the resulting loss of circulation and consequent loss of hydrostatic pressure control in the well can be even more catastrophic than a “simple” kick from overpressure, and can be far more difficult to control.

The Prediction and Detection of Overpressure

For optimum safety, it is necessary to know (even before the well is drilled) what types of pressure regimes may exist at depth. If this kind of information is not available, the safety of the well will depend upon the expertise of those monitoring the drilling operations to detect the onset of changing pressure. The origins of abnormal pressure are many and varied; and although each mechanism is relatively simple when taken in isolation, they combine to form rather complex sets of interacting influences.

The knowledge of local pressure regimes can also be used to assist in deciding where the well is placed. Oil and gas can be driven upwards by buoyancy or horizontal and downwards by pressure differentials, so by avoiding those reservoirs at higher pressures the risk of drilling into overpressure can be reduced. It can, however, result in a dry hole by drilling into a reservoir where the hydrocarbons have been expelled.

Each sedimentary basin, although similar to others on a gross scale, is unique in its own geologic history. In complex basins with “interesting” histories we begin to approach levels of interaction which make efforts to predict overpressure difficult (and at worst futile). If this is the case, how can we ever hope to plan a well with confidence?

Tried and trusted methods reduce complex models into simple ones, and then restrict predictive modelling to simple basins. This is by far the most preferable, since many of the past failures have involved taking a nice simple model out of its home basin. This is one reason why the preferred areas for research and modelling are the Gulf Coast of the USA, other Tertiary Deltas (e.g. Niger and Nile) and the North Sea Tertiary sequence. The preferred lithologies for modelling are always clay dominated siliciclastic sequences and carbonates. The modeled formations are those deeper compartments emplaced late in the basin’s history.

In pressure evaluation, there are two classes of prospect generation; 1) those areas where drilling has taken place, and 2) wildcat areas.

In the first case, increased data density, provides for better well planning (if the data is interpreted correctly), because it is always possible to be mislead by ambiguous well data. The “Bendo pressure gradient” is a name to watch out for, because it often means that the pore pressure was determined by the mud density used, and this may not always be in perfect balance.

In the second case we have nothing to fall back on except general models, surface observations, and pre-well geophysical data.

Formation Pressure Models

Basin modelling to predict sub-surface pressures has mainly concentrated on the historical (on a geologic time scale) ebb and flow of formation pressures in order to predict possible accumulations of hydrocarbons. Recent models include England, et al (1987) and Mann and Mackenzie (1990).

The latter used a 2-D model to predict abnormal pressure in rapidly subsiding siliciclastic sequences, above an impermeable basement. The model is based entirely upon vertical migration and the changing vertical permeability of the sediments as they are buried. The only over-pressuring mechanism invoked is simple compaction disequilibrium. There is a very good approximation in this model to the actual pressures in the Gulf of Mexico to 4000m, the Northern North Sea to 5000m, the Haltenbanken (Norway) to 3500m and the Nile Delta to 4000m. This suggests that compaction disequilibrium is indeed the dominant mechanism at these depths, in offshore Tertiary clays and sands. This ties in fairly well with the two tier basin model of Hunt (1990).

A more comprehensive model was described by Ungerer, et al (1990) which takes into account the complex thermal history and fluid dynamics of a basin. Again, the emphasis is on predicting hydrocarbon migration and accumulation, but the model appears able to produce a good approximation of the pressure profile. Whether the profile is better than the simple model of Mann and Mackenzie is not clear. (A Haltenbanken-type example is given in both papers and both appear to work well). It would appear though that the Ungerer Model is better in older, more complex basins.

Mudford and Best's (1989) model incorporates temperature and compactional effects on permeability, as well as hydrocarbon generation. Work on the Ventura gas field led them to conclude that compaction disequilibrium was dominant, even though sedimentation was slow.

Unfortunately, both models need good data in the form of an accurate lithostratigraphy. So they will be of little use in a completely new setting unless seismically derived lithostratigraphy is determined.

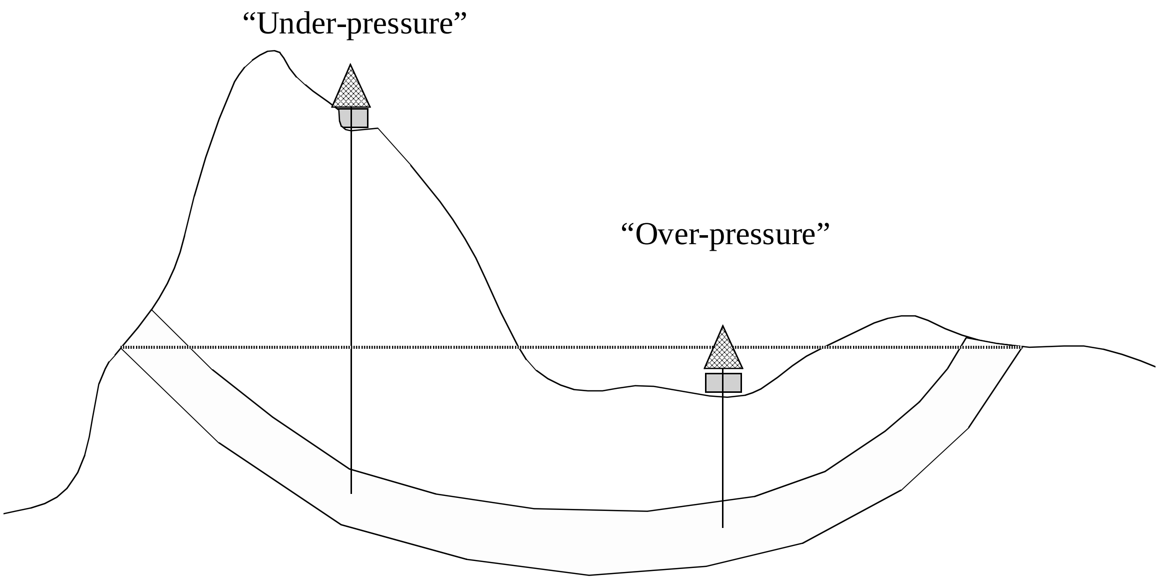

Figure 2-2: Piezometric Surface Effect on Pore Pressure

Compaction Disequilibrium

As can be seen, compaction disequilibrium is a common cause of abnormal pressure. This is especially true in rapidly filling (Tertiary) sedimentary basins. Passive plate margins, with one or more large deltas (i.e. Gulf of Mexico, Niger Delta, etc.) are common areas for this type of geopressure.

Under “normal” circumstances the sediments deposited at the delta front will dewater as the matrix material reshuffles itself (See Figure 2-3) under the influence of gravity and the overburden created by the deposition of even more overlying sediment. The dewatering process (See Figure 2-4) relies on slow, continuous permeability that ultimately connects with the surface/water table, allowing the pore fluid pressure to remain hydrostatic.

If seasonal changes in load (the switching of a channel) or a change in sediment source occurs, the quantity and/or type of sediment can change abruptly. A change from a clay/silt/sand mixture to clay alone can easily restrict the dewatering process to those clays/silts adjacent to a sand layer. Rapid loading by a huge thickness of the same clay/silt sediment may tip the dewatering balance temporarily in favor of overpressure. In actual fact, the dewatering process is rarely perfectly “normal”.

This lack of dewatering conspires to cause the matrix stress between the grains to become “locked” as burial continues, and causes the pore fluids to be responsible for carrying the remaining overburden. The process will continue until the fluid pressure finds relief by rupturing the seal. This rupture can occur at pressures below the overburden if the rock is brittle or even as much as 40% above the overburden if the rocks have enough tensile strength. Since compaction disequilibrium is common in younger clays, a frequent result of this effect is a suite of mud diapirs, mud lumps, and sand volcanoes.

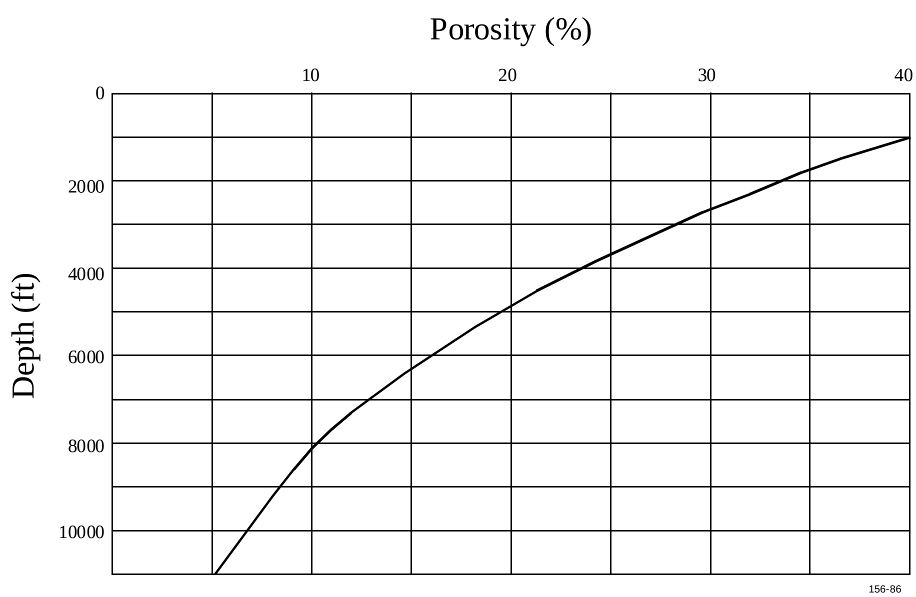

Figure 2-3: Porosity/Depth relationship for a typical compacting clay sequence

In the Mississippi River delta, these lumps (where the high pressures have reached the surface) are seen as small islands. Similar islands of mud have erupted in Indonesia. The pressures can sometimes be relieved by systems of sub-vertical faults above the diapir or by growth fault systems. The high pressures in these shale masses are a major contributing factor in the formation of massive “growth faults” that cut across the delta, trapping the rollover anticlines (which often form traps for oil and gas in the hanging-wall). The faults may also trap oil on the foot-wall side where the movement has brought sands against shales to seal them.

Fault movement and the presence of sand also helps to both segregate and redistribute pressures. Pressure anomalies are often laterally sealed by a clay smeared fault-plane, which can also have zones of mineralization associated with it. For this reason when drilling through growth faults it may be necessary to increase the mud density.

When normal faults move, the fault plane separates slightly or “dilates” (because of the high injected fluid pressure) and as it does, it allows the high pressure to communicate with any lower pressure potential along the fault plane. This can be the surface or a sand body adjacent to the fault. If the fault closes, any sands so charged are often resealed against shales and lay in wait for unsuspecting drillers. The problem is theoretically more acute in the distal part of the delta, where sands are thin and for any given throw are more likely to reseal against shales, instead of ending up next to another sand which would allow the pressure to dissipate.

A further complication is that any clay overpressured by compaction disequilibrium will tend to charge any adjacent sands which are at lower pressures, with the risk of creating an overpressured permeable zone (See Figure 2-5). If the bed thickness is sufficient, the edges of the clay will bleed down first, compact, and seal the original overpressured area in the middle by virtue of the reduced permeability at the edge.

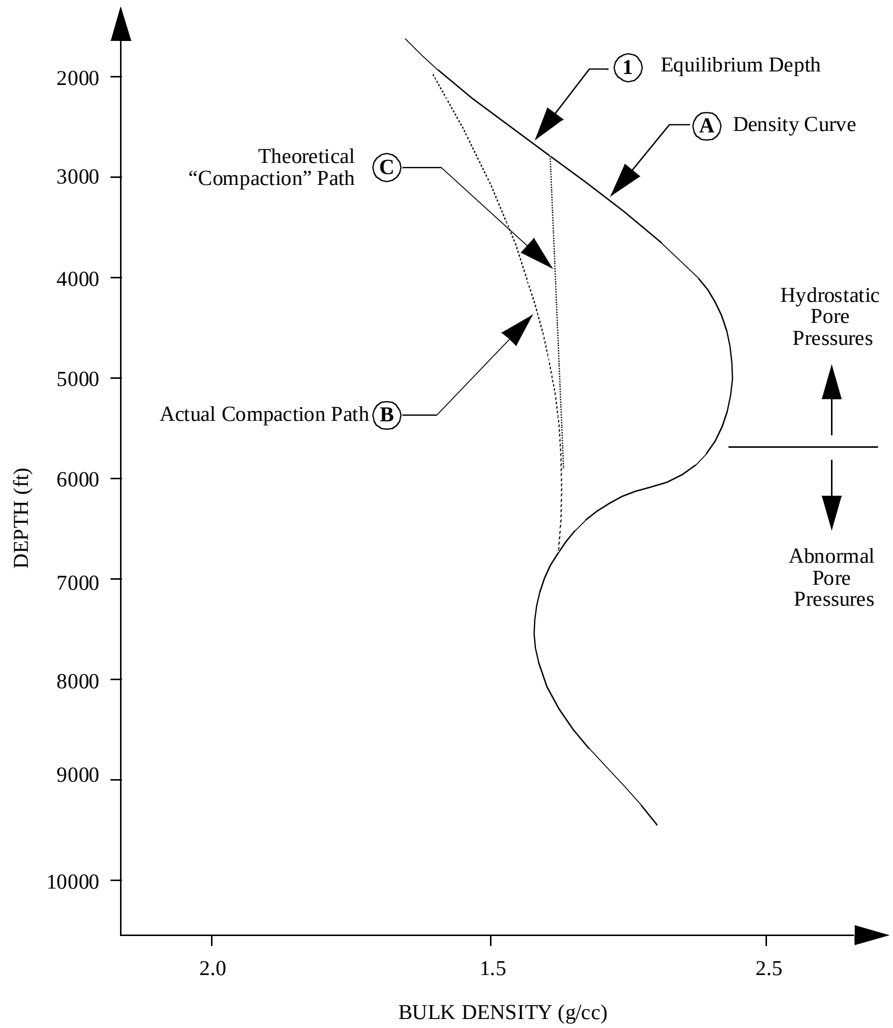

Figure 2-4: Bulk Density reversal in an abnormal pore pressure zone

Tectonics

The process of overthrusting in the earth's crust is itself dependent upon overpressure, without the lubrication of overpressured fluids at the base of the thrust, the huge rock masses could not move in the way that they do (See Figure 2-6). The almost total lack of deformation along many thrusts shows the efficiency of the fluids in the faulting process.

It is possible to drill into a thrust which is still at high pressure, but generally their significance is two-fold.

1. It may load the underlying sediments and, if seals are present, impose an extra pressure on the contained pore fluids. This may

also change the geothermal gradient seriously enough to alter the pressure.

2. It can lift compartments to higher levels without rupturing.

The phase before thrusting can also induce pressure. In the foreland basins of active mountain building thrust belts the horizontal stresses can reach twice the overburden before faulting occurs, any of that stress which acts directly on the pore fluids must necessarily cause excess pressure.

The Qum oilfield in Iran is one of the best examples of pressure in the base of a thrust. The limestone below the thrust remains overpressured.

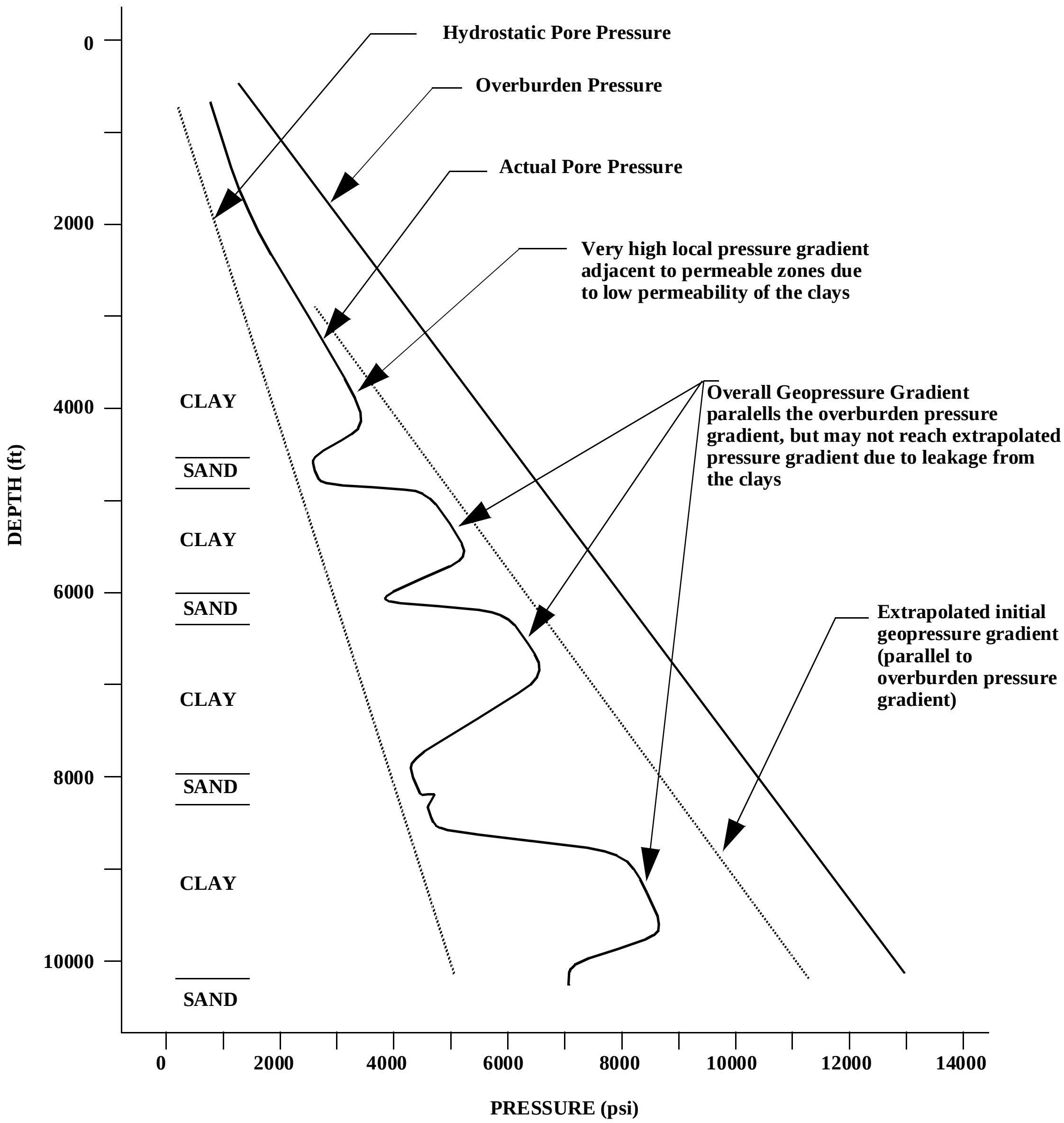

Figure 2-5: Typical Pore Pressure Depth plot of compaction disequilibrium geopressures

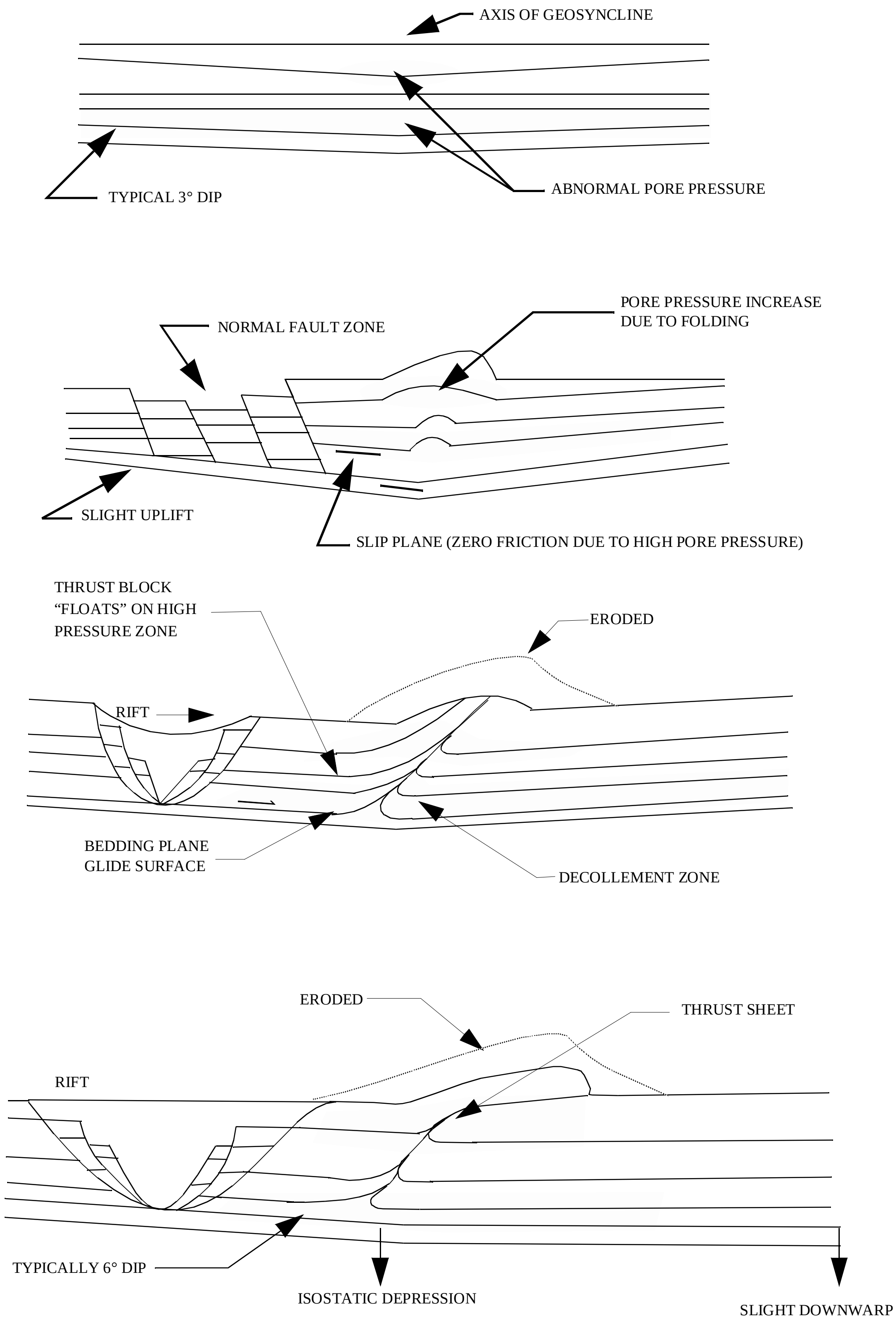

Figure 2-6: Idealized diagram of zones of abnormal pressure

Diagenesis

The physical/chemical transformation of one rock or mineral into another is often cited as a cause of overpressures. Many minerals will undergo a chemical metamorphoses at relatively low temperatures, long before true metamorphism occurs. A classic example is the transition of gypsum to anhydrite ($CaSO_4$ x $2H_2O$ to $CaSO_4$) in which there is a total volume change of about 50% with the expulsion of water. Normally this change occurs at about 40°C, at relatively shallow depths.

Conversely, pressures may be generated by the change from a high density porous rock to a lower density, less porous rock. A good example of this is de-dolomitization. Under the right conditions dolomite ($CaMgCO_3$) will turn into calcite ($CaCO_3$). Since calcite crystals occupy more space than dolomite, with the absence of fractures, they will tend to squeeze out any remaining pore fluids.

Such a condition should only occur when the connate water is replaced by a fresher fluid (which can also rehydrate gypsum). This process is probably restricted to near surface sediments.

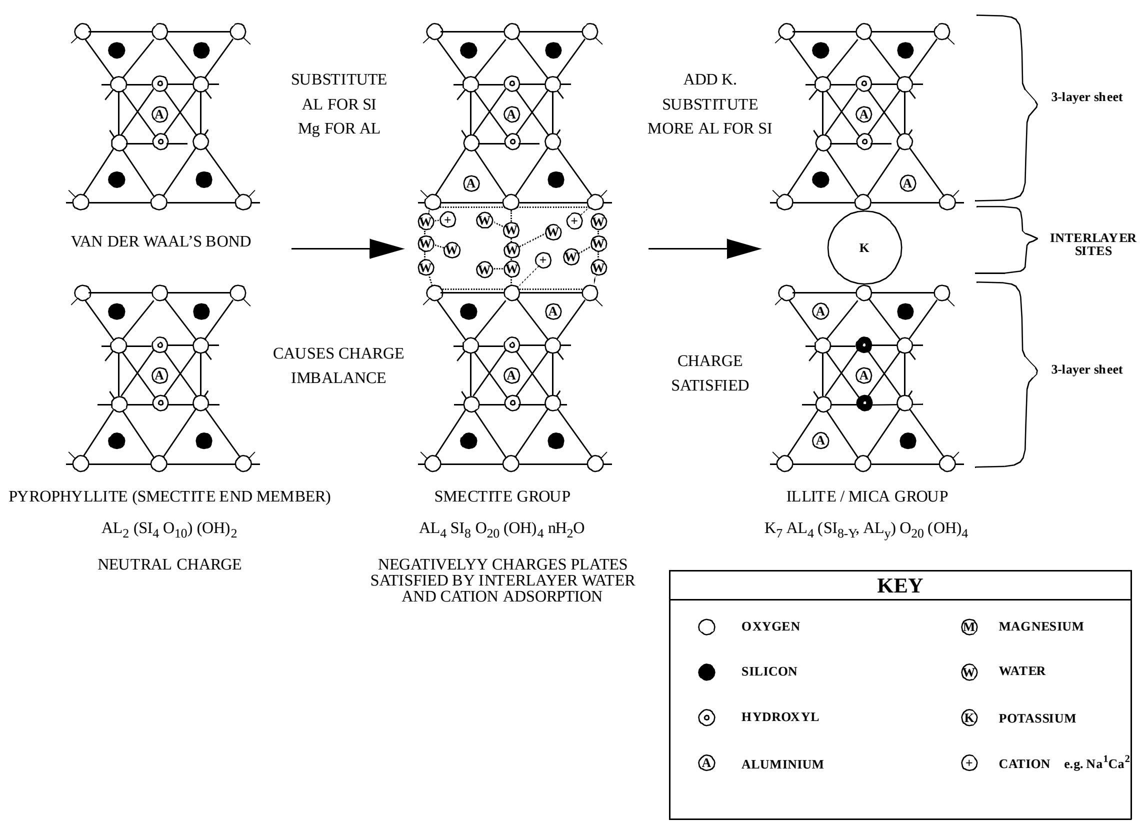

Figure 2-7: Changes in ionic substitution in three-layered sheets

Clay Diagenesis

The diagenetic changes that occur in some types of clays are widely held to be the cause, either directly or indirectly, of overpressure.

The precise nature of this mechanism has been hotly debated over the last twenty years.

The basic premise of this mechanism is that the surficial, younger argillaceous sediments are often rich in a smectite clay called montmorillonite (See Figure 2-7). The significant feature of the smectite group, is its very high surface area. These clay platelets are held together by a weak electromagnetic force (Van der Waal's bonds), and there is a considerable amount of area to which up to ten layers of water can bond (See Figure 2-8). The result is a low density "swelling clay", much like bentonite (a smectite clay), the major component of drilling fluids.

Smectite clays go through a number of changes with burial. Initially, increasing pressure will drive out the loosely bound water (a process similar to normal compaction), but as the number of layers is reduced, the pressure required to release the remaining water increases (See Figure 2-9). Ultimately, only high temperature and chemical processes will release the last layer, which can be bound with metallic cations (See Figure 2-10).

Virginia Colton-Bradley (1987), studied the purely physical dewatering of smectites and its potential role in the development of overpressure. She concluded that smectites in the pore spaces of sand, under hydraulic pressure, lose their last two water layers with great difficulty. When smectites within a shale, are subjected to lithostatic pressure and a temperature of 67° - 81° C the penultimate layer will be displaced. A further rise in temperature to 172° - 192° C is required to drive off the last layer, which is very closely bound between the clay plates.

These critical temperatures are raised under the influence of local overburden and although the initial dewatering may actually cause some overpressures, the resulting extra hydraulic pressure will also tend to inhibit further dewatering. Therefore, under most conditions the simple dewatering process will not lead to excessive overpressure, since there is a negative feedback loop at work. However, there is also the chemical diagenesis to consider.

The threshold temperature for the loss of the penultimate water layer is roughly the same at which hydrocarbons are generated. At this point the smectites can turn into illite clays (See Figure 2-11).

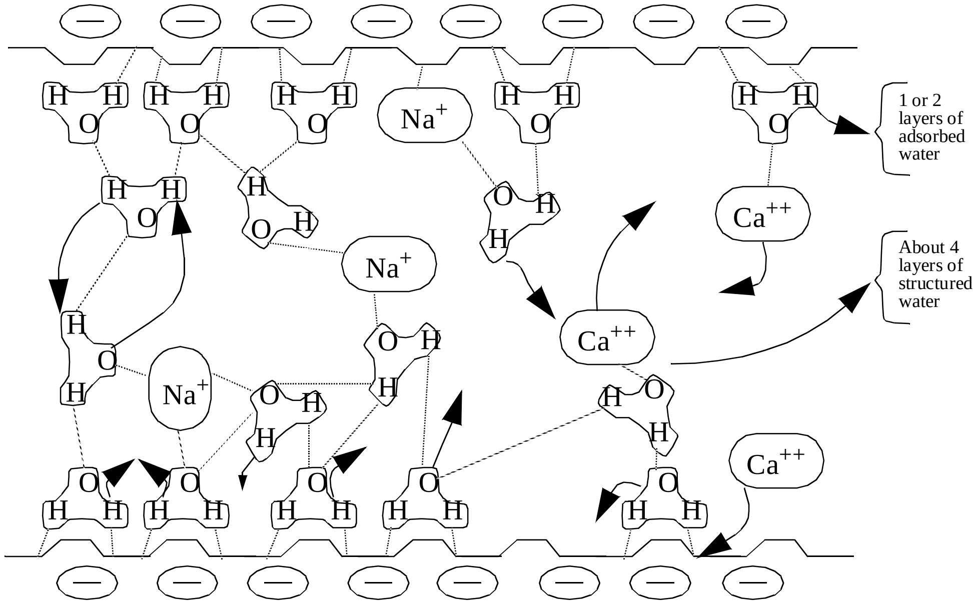

Figure 2-8: Hydrogen bonded water and exchangeable cations

Depending upon the type of smectite (K or Na smectites react more quickly than Ca or Mg smectites), the presence of available cations like K^+ will satisfy the surface charges in place of water and collapse the clay into the more compact illite-type.

The remaining water is released into the new porosity created by the reduction in clay volume. Theories that this last water is super dense and “fluffed up” on its release have recently been backed up by theoretical studies. Monte Carlo simulation suggest a density of up to 1.3 g/cc(in a magnesium smectite). Total volume change is in the order of 6 percent.

Colton-Bradley also suggested that the bound water acidity (in Bronsted acidity) increases as the water layers are gradually lost.These factors also tend to drive the smectite clay into illite.

Other workers have found large variations in the temperature required to initiate simple, physical smectite dehydration. Bruce (1984) found a threshold temperature of 71° C in the Mississippi River and over 150° C in the Niger delta. He suggests that cation availability may partly control it.

The real links between overpressure and smectite/illite transformation appear to be more closely related to the higher density of the illite packets and the consequent loss of vertical permeability through the zone. In this way the clay is not always the direct source of the pressure but rather a mechanism for capping pressure, especially if hydrocarbons are beginning to form, or water is being driven upward by other processes.

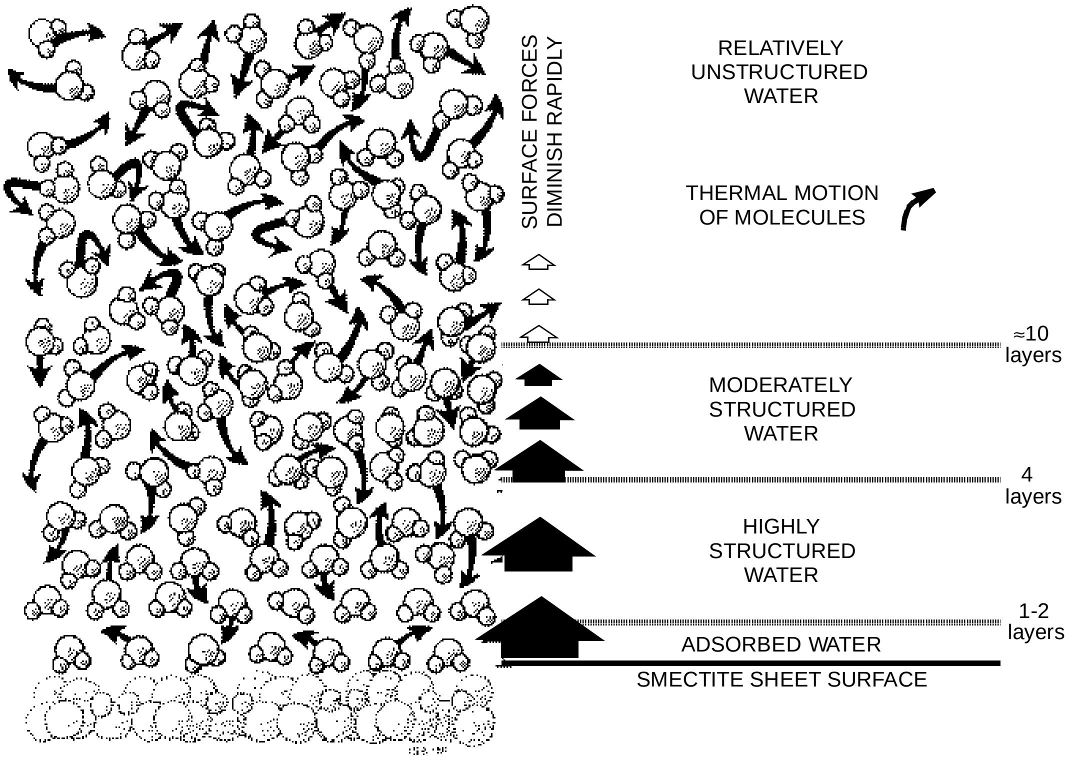

Figure 2-9: Dynamic Structuring of water

Freed and Peacor (1989) studied the exact relationship between pressure and percentage of illite packets. They found that normal pressures stopped when the transformation began, and continued to rise through the zone of increasing illite. From this, it appears that 40% to 50% illite is sufficient to retard vertical permeability. This ties in well with the classic shale transition zone and throws new light on its possible development.

Recent work also helps to understand the “illite free” overpressure that was normally ascribed to compaction disequilibrium. It may be inferred that the hydrostatic pressure and “frozen” matrix stress have prevented simple dewatering, which are seen at shallower depths. At greater depths, the permeability effects of illite probably dominate.

In any clay-type pressure interpretation, we must consider the following:

- Was there any original smectite? Some basins contain very little. As an example of this variability, smectite comprises 40% of the clay in the Northern Atlantic but only 20% in the Southern Atlantic. In the south western part of the Indian Ocean it reaches concentrations as high as 80% (Biscayne 1964 - cited in Reike + Chilingeran).

- Is there any sand present, which can act as a conduit to leak fluid away from the simple dehydration (or any other) mechanisms? The old “sand-count” as a means of assessing overall vertical permeability now has a more practical use.
- At what depth, below the surface, does the combination of temperature and pore-water chemistry in the basin lead to the formation of illite rich zones?
- What has happened geologically since the zone formed? Has the basin subsided or been elevated? Has the local heat flow changed?

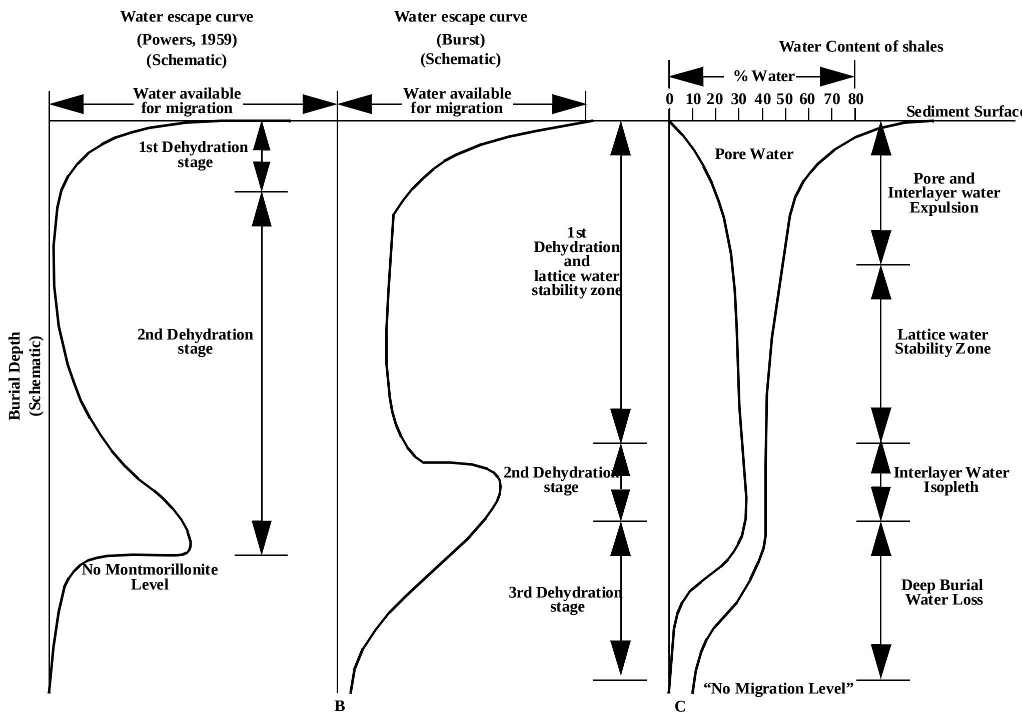

Figure 2-10: Hypothetical dehydration curves of Montmorillonite sediments with depth and temperature

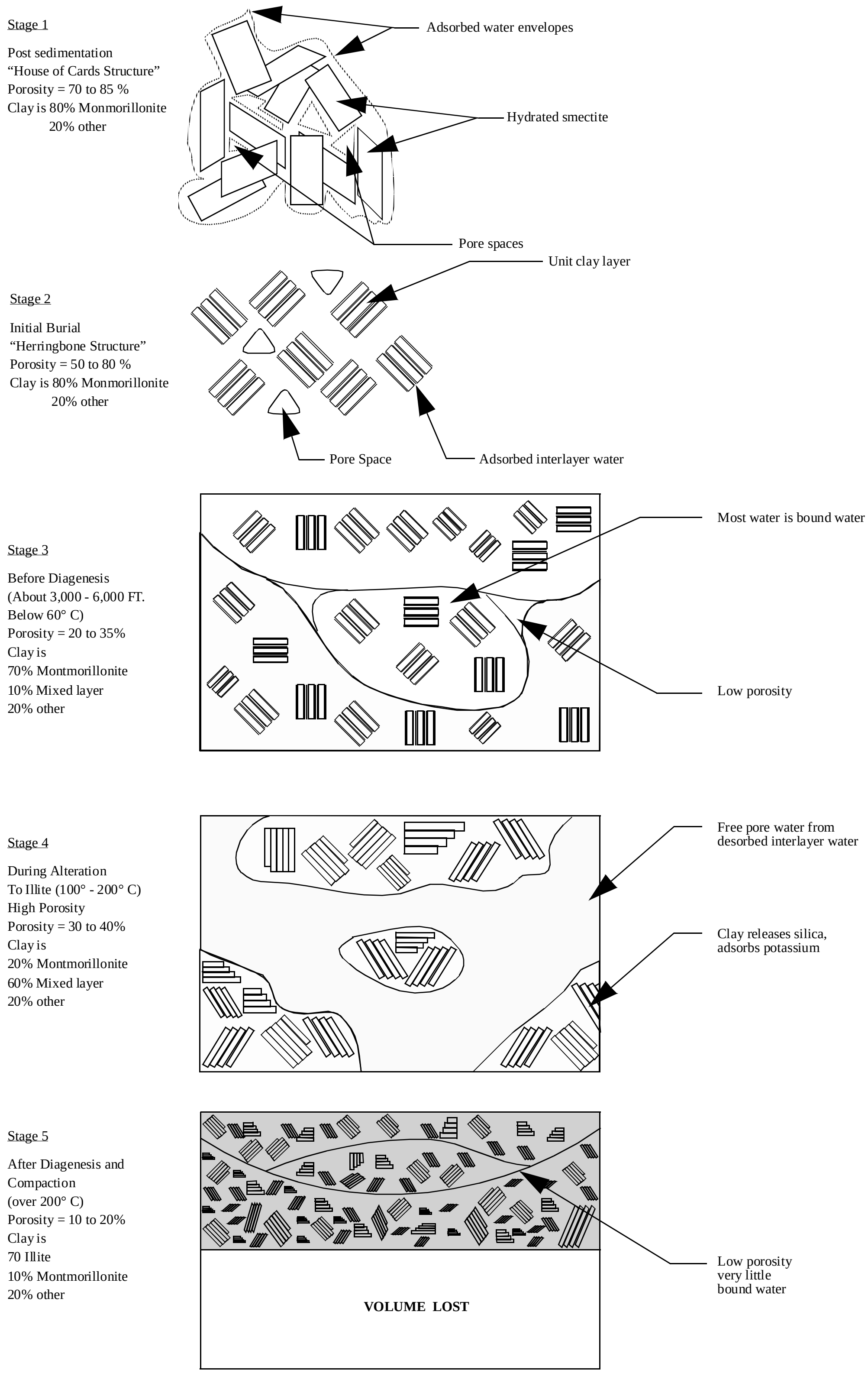

Figure 2-11: Diagenetic stages in the alteration of montmorillonite to illite

Aquathermal Pressuring

Nobody can be in any doubt that if a tin of water was placed over a fire it will ultimately pop its lid. This analogy is important as an origin of overpressure. It was mentioned previously that the change in temperature, associated with cooling can cause a reduction in pressure. On the other hand, how much of a risk is temperature to drilling (See Figure 2-12).

To heat a rock it must move to a higher geothermal gradient (i.e. bury it). The gradient itself, however, is regionally variable; some interior basins are cool, some active continental margins are hot.

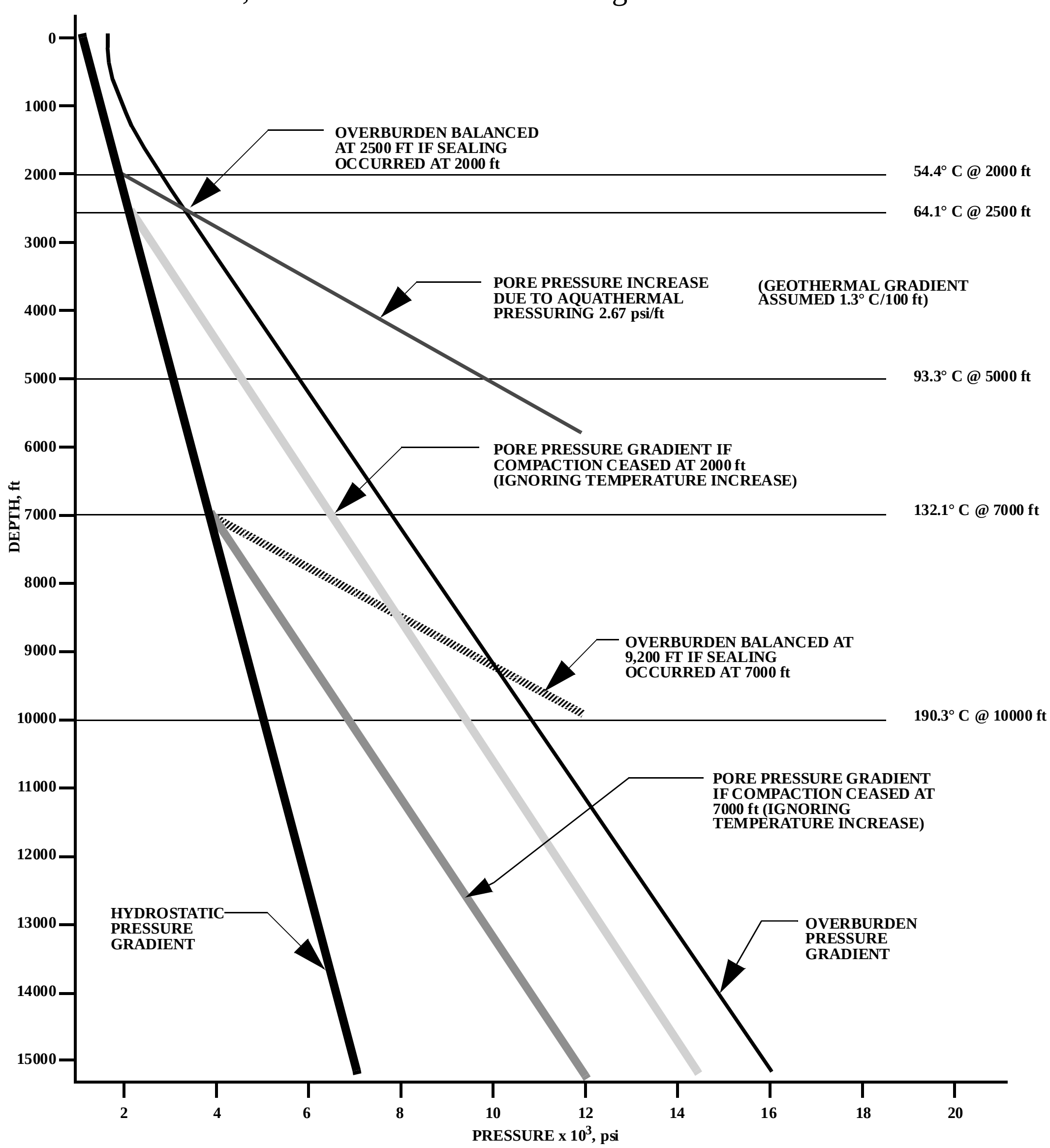

Figure 2-12: Pore pressure increases with geothermal gradient

The actual rate of expansion in aqueous brines and the resulting increases in pressure was documented by Barker in 1972, and criticized by Daines in 1980. The point of contention is not so much “does water expand” or “does the expansion cause pressure” but “can the seal really hold the pressure?”

The volume increase required to produce pressure is in the order of 0.05%, well within the leakage or tensile capabilities of all but the stiffest, toughest, and most impermeable seals. It is, on balance, more likely that aquathermal pressuring is an extra drive that ruptures seals, moves fluids and pressures, generally keeping the systems dynamic. Temperature also drives the convection of fluids in the upper parts of many basins, redistributing ions that can affect diagenesis.

Osmosis

Osmosis is the movement ions in water down a water concentration gradient (i.e. from fresh to saline). The ions will continue to move until the salinities balance or pressure prevents further movement.

That pressure is postulated to be as much as 4000 psi in the subsurface, where shales can act as the semipermeable membranes.

Imposed Pressure

In some cases a system may exists with no pressure anomaly but with a reasonable seal. The previous pressures may have leaked away, leaving behind a compartment ready to receive pressure from an external source. Formations like this can be recharged from a number of sources, from faults (as already discussed) and even by drilling.

The most obvious man-made charging comes about during production, when fluids are pumped into a reservoir to replace the extracted hydrocarbons. As an example, in the Unita basin the Rangely field waterflooding has raised the pressure from abnormally low to a 0.6 psi/ft (1.39 bar/m) high, causing earthquakes on a nearby strike-strip fault. (Raleigh 1972).

Faults

As discussed earlier, normal faults and thrust faults are the result of various stress imbalances in the crust and superficial sediments. They are often caused by, helped by, or linked to overpressure. When moving and dilating, pressures can easily be transferred. This can result in moving fluids to a previously lower potential or bleeding pressure off, returning it back to hydrostatic.

Faults are also good lateral seals.

Seismic Or Fault Pumping

A model for generating overpressure which has attracted increasing interest through the 1980's is "seismic" or "fault" pumping. Rocks under stress tend to act like a heart, and pump fluid from one location to another. Based on studies of rock dilatancy during earthquakes, this theory proposes that the rock stresses which can cause wrench faulting and earthquakes can affect the pore volume of rocks.

Examination of vein mineralization by Sibson (1975) indicated that the zoning of the minerals was caused by discontinuous, episodic, passage of fluid through the veins. Further work by Burley, et al (1989), invokes this seismic pumping mechanism and links it to pore water salinity changes inferred from the cementation history of the Tartan reservoir in the UK North Sea.

These episodic influxes of hot mineralized fluids show up as distinct phases in quartz and carbonate veins.

Another diagenetic evidence for the expulsion of fluids from deep pressure compartments is cited in Jansa and Urrea '90. The dissolution of carbonates is linked to the highly acidic fluids developed when CO_2 dissolves under pressure in the presence of organic acids. Both are linked to kerogen maturation.

When pores expand, they will do so in the direction of least stress (σ_3), before the "valve" contracts. The vertical distance over which the pushed fluids will travel is reckoned (by Burley) to be as much as 2000 meters.

The source pushing the hot fluids can come from various mechanisms; tectonic forces or "thermobaric" drives working on the fluids caused by diagenetic mechanisms (like hydrocarbon maturation or smectite dehydration).

In any event, the hot fluids are injected, in a slow rhythmic fashion to higher levels. The incidental evidence for this rhythmic flow is also recorded in the work of researchers like Hunt (1990), who identified cycles of fluid "breakout" followed by resealing at intervals of thousands of years. Hunt's fluid pumps are principally of thermobaric origin and are also responsible for hydrocarbon migration into zones of lower pressure as the basin sinks, his ideas follow closely the work of Powley.

Tigert, in his thesis "*Pressure Seals and Their Diagenetic Zebra Structure Patterns*", found alternating cemented and porous bands in transition zones, while other workers have found slightly fractured pressure seals infilled with calcite and silica. These bands are on the scale of one inch of cement to each foot of clean sand (Powley). In nearly all cases it appears that the faults along which the fluids flow and the "valve" area become so mineralized and sclerotic that they eventually seal up completely.

General Basin Structure

Most deep basins appear to be divided into two zones. From the surface to 10,000 feet, the systems are widespread, convective and hydrostatic, with combinations of the various in situ mechanisms causing overpressure. This normally shows up as forms of simple compaction disequilibrium.

Below 10,000 ft. the basins are layered cells or compartments with boundaries that cut through lithological and stratigraphic boundaries. It is in this deep basin setting, at high temperatures and pressures that the real seismic pumping operates (rather than simple fault charging).

As the basin subsides hydrocarbons mature, collect, and are expelled with hot fluids repeatedly pumped upwards to create the zoned seals, areas of abnormally hot fluid, and lateral seals. Some hydrocarbon occurrences have been linked to breaches in the lateral seals (since hydrocarbons do not tend to accumulate in areas of high pressure potential). When a compartment breaches, it tends to be the hydrocarbons that leave and not the water. This link to the location of hydrocarbons was the main impetus for the work by several oil companies on pressure compartments. It should be stressed that the work is best applied on its home territory (i.e. North America) and is exportable only with care.

Gas Hydrates & Pingos

In deep, cold oceans and in the polar regions a variety of situations exist where dangerous overpressures can develop.

- Gas hydrates are frozen mixtures of methane contained in cystalline water. Because of the arrangement of the methane within the ice, it can store > 160 times more gas per unit volume than free gas. When drilled, they can release massive amounts of gas.
- Biogenic and seeping gas can also collect below permafrost.
- A well known symptom of water overpressure caused by ice is the “pingo”, a form of mud-lump in the tundra, these anticlinal-looking mounds grow in the winter due to the freezing of shoaling lakes, trapping the water and compressing it.

A common piece of advice in permafrost areas is to “never spud on a pingo”.

When drilling in cold areas the use of a heavy mud with a high heat capacity can make matters worse by melting the ice around the borehole.

The presence of gas hydrates may also cause elevated temperatures in the well since they act as insulators to the underlying rock.

Paleopressures, Uplift and the Effects of Structure

“Paleopressure” is old pressure in a new place. The relationship between depth, pressure and fluid density clearly shows how an enclosed but normally pressured compartment at great depth can be turned into an “overpressured” one by lifting it to a shallower depth. If the pressure is maintained at half the previous depth, twice the drilling fluid density is required to balance it. This phenomenon is relatively rare but in some areas, locally common.

Since the combination of circumstances required to lift a pressured compartment without breaching it are so special in a particularly favorable setting it may happen more than once. Classic settings for this are: (a) In mountain building zones where thrusts and isostatic adjustments can cause the rocks to rise. In the South American Andes some very high pressures have been caused like this; (b) In areas of wrench tectonics where blocks may be “popped-up” or inverted having previously been in low basins. If the cover is young and flexible high pressure may be preserved. Some areas around the British Isles exhibit this and are rendered virtually undrillable; (c) Inside salt domes.

Halokinesis causes the formation of overpressure in a variety of ways, one of which is to trap porous rocks and carry them to shallower depths. Salt is plastic, light and has no porosity so it is the ideal medium to seal porous rocks. When it flows as a wall, stock or diapir it can develop internal vortices like a billowing cloud of smoke, which can trap, encapsulate and lift the surrounding country rock. These fragments, usually dolomite or anhydrite, are referred to as “rafts” (See Figure 2-13), although they are not floating they are being swept upwards on a very slow plume. They can contain gas (including H_2S), oil or water and may appear quite unexpectedly. They may be solitary or in clusters. Either way, they are a significant hazard to drilling and are difficult to control. One common practice is to bleed them down, since they usually have limited extent. At the wellsite the observed rate of depletion should give some idea of how long the process may take. In the worst cases one raft will “blow-out” into another leaving the rig operator to wait until equilibrium is established.

Generally, no transitions into the raft are observed.

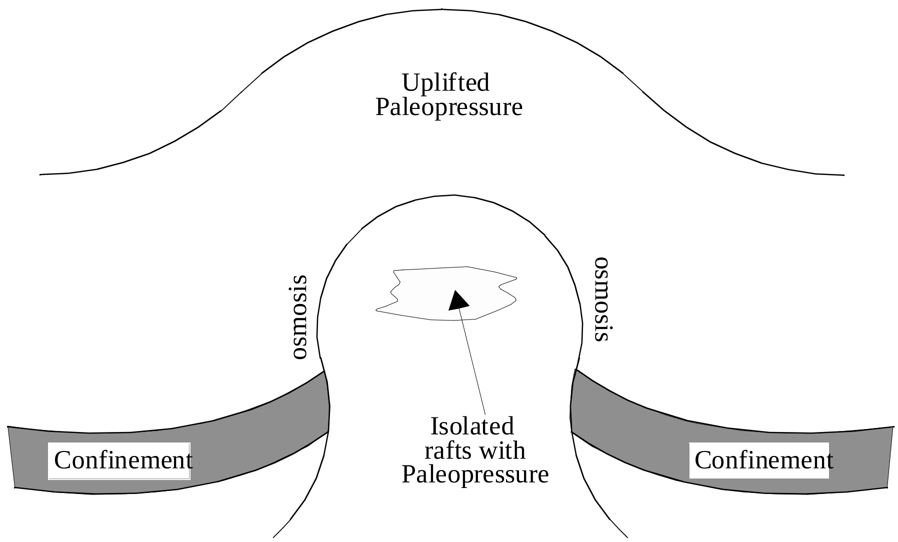

Figure 2-13: Pore Pressure affected by Halokinisis

Within a completely sealed compartment Pascal's law states that any pressure imposed internally is distributed equally around the compartment, regardless of, and in addition to, hydrostatic pressures.

In this way an equally pressured compartment with any structural elevation will demonstrate higher pressures at the highest (shallowest) point and from thereon down through the compartment the pressures encountered will equal the overpressure of the fluid within the compartment. This can occur on the flanks of diapirs or in small lenses of sand on anticlines.

Further complications arise if gas is present, since the overpressure experienced at the top of the structure is supplemented by the lack of hydrostatic control by the gas and the buoyancy of the water below. This additional pressure is a function of the difference between the density gradients of water and gas, multiplied by the vertical height. At the base of the gas column the pressure is the highest overpressure plus the (minimal) gas hydrostatic. At the base of the system it is the top overpressure value plus the continued hydrostatic, (i.e. water or oil plus gas).

Evaporite Deposits

Evaporite deposits can play a significant role in the generation of geopressures, generally by one of three ways:

Sealing Role

Since evaporites are totally impermeable, they become an almost perfect seal to fluid movement. This barrier to the vertical expulsion of fluids from underlying sediments, together with restricted lateral drainage can produce overpressured zones in formations underlying evaporite sequences. The mobility of these formations, such as halite, also means that any fractures that develop can be quickly repaired, maintaining the salt's effectiveness as a seal. This mobility can have the opposite effect by creating "holes" in the formation where the salt used to be and allowing some fluid drainage.

Tectonism

Movement of salt domes can affect pore pressure in a number of ways:

1. Previously deep lying sediments may be pushed closer to the surface while maintaining their original pore pressure. They are no longer "normal" when compared to surrounding formations.
2. Isolated rafts of permeable rock may become trapped within the salt dome and also be transported to higher levels, while maintaining their original pore pressures.
3. Pierced formations may become isolated and lateral drainage may become restricted.
4. Osmosis may become important if sediments containing different pore fluid salinities are brought closer together, separated by a semi-permeable clay membrane.

Sulphate Diagenesis

Sulphate diagenesis can assist in the generation of geopressured zones in manner similar to that of montmorillonite dehydration. Gypsum is the precipitated form of Calcium Sulphate. Transformation to anhydrite occurs fairly early on in the burial process, generally above 40°C (The presence of salt will lower this temperature to around 25°C, with pressure an important factor). The change from gypsum to anhydrite involves the production of free water into pore spaces. If this is limited, and lateral drainage is restricted, then increases in pore pressure could result. Water amounting to up to 38% of the original volume may be released, but since the change often occurs at shallow depths, it is usually possible for most of the expelled water to escape.

Hydrocarbon Generation And Migration

The breakdown products of organic molecules are among the most significant agents in producing overpressure, particularly in very shallow and very deep settings. The pressures they create are largely unrelated to compaction, and because of this the methods used to detect geopressures caused by compaction disequilibrium will not work well. The combination of this, along with the growing number of deep wells, requiring on-site pressure monitoring, is one of the greatest challenges for the “pressure engineer” today.

Biogenic Methane

Any organic material trapped within sediments, without previously being oxidized, is a prime target for bacterial decay and slow cooking. This decay produces pockets of shallow gas since, much like the generation of marsh-gas, the temperatures are generally too low to produce any oils, and the organic matter tends to be of terrestrial origin (lignites, peat, etc.). The bacteria present in the ground water acts to produce this methane gas

Some shallow gas may have originated at greater depths and has seeped as a plume into the surface sediments, where it becomes trapped under the surface clays or permafrost.

Cellulose can be broken down into both methane and carbon dioxide

$$\mathbf{C_6H_{10}O_5 \rightarrow CO_2 + CH_4}$$

The methane and carbon dioxide, if they escape to the surface, can be the origin of calcareous nodules on the seabed and may form mounds or diapirs where the gas has displaced the fluid from the recently deposited clays. this will cause the clays to have extra buoyancy relative to their surroundings. Any further gas leakage will cause gas plumes into the sea. Where the gas seepage does not change the clays, the result may be deep craters and pock-marks in the seabed.

Shallow gas can create significant drilling hazards.

Due to the low fracture gradients within the sediments, diverter lines or dynamic kill methods are generally used. Avoidance of shallow gas by close attention to high resolution seismic, or other offset data is important. The drilling of small diameter pilot holes and the use of MWD resistivity tools can enhance detection and prevent problems from developing.

Thermochemical Generation

The majority of hydrocarbons in the subsurface are formed by the deep burial and thermal maturation of kerogens. This process generally occurs within a specific “window” of temperatures, and the particular local combination of time, temperature and type of organic matter (e.g. is it algal or terrestrial plant debris) will produce oils (heavy or light), gases (dry or wet) or condensates plus some other very significant non-hydrocarbon compounds.

In this last category, the most important to overpressure and well safety are carbon dioxide, hydrogen sulfide and other acid gases. These can all lead to quite dramatic changes in pore fluid chemistry, which can radically affect diagenesis in the surrounding rocks.

The temperature range associated with the normal “oil window” begins at 65^{o}C and proceeds to 150^{o}C. Gas occurs as the increasingly smaller “dryer” molecules are produced, since the temperature continues to increase. Ultimately, beyond about 230^{o}C, metamorphic processes take over and any remaining carbon is reduced to graphite. The depths that correspond to the various windows will vary from basin to basin, and with time, but it is not unreasonable to say that the oil window starts at about 7000 ft (2000m), peaks at about 14,000 ft and ends about 17,000 ft. This assumes an average geothermal gradient.

The type of hydrocarbon present has the most dramatic effect on any overpressure produced. Although oil is lighter than water and will rise through water because of its buoyancy during secondary migration, it is the production of gas that has the most serious consequences. Gas expands much more than oil or water, and whenever it is trapped, it reduces the hydrostatic control.

The production of hydrocarbons from organic matter, and light hydrocarbons from heavies, also increases the total number of molecules and therefore increases the space they occupy. If there is adequate drainage then no pressure increases will occur. Where drainage is restricted, pore pressures can increase and with continued compaction, since less water is expelled, the remaining pore water may become saturated with gas. If the free gas is unable to escape, then the pore pressure will rise. This increase in pore pressure may assist in causing small cracks and fissures to form which may help in migration of hydrocarbons to reservoir rocks (and results in reduction of pore pressures).

If the hydrocarbons move into permeable rocks that have restricted drainage then they could be subject to increased pore pressure by external charging (imposed pressures). Some undercompacted claystones show high gas values, which may help to confirm this mechanism as an origin of geopressured zones. Where hydrocarbon generation has occurred there are often high residual levels of CO_2 as a result of the original high organic content of the formation.

Hydrocarbon Gradient

The presence of hydrocarbons in the pore fluid column will cause variations in the pore fluid gradients, and therefore in the magnitude of the pore pressure. Both oil and gas have lower fluid densities than water and their presence will create lower than expected pore pressure gradients. Where gas is present as a free gas cap, overlain by impermeable rocks, its compressibility can result in a higher than expected pore pressure gradient, until the oil or water column is reached. Then the pore pressures would return to normal.

In producing fields, reservoir depletion may cause reductions in pore pressure (below normal for the area) which could result in drilling problems such as lost circulation or stuck pipe.

Alternatively fluid injection for enhanced recovery may produce higher than expected pore pressures over limited areas.

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•Notes•

Chapter 3

Pressure Engineering

The preceding chapter dealt with the generally "accepted" theories which tend to provide explanations for the various anomalous pressure-related phenomena that are encountered during oil exploration. Some of these theories originated in the laboratory, while some developed from field experience. As was seen, much of the context surrounding the pressure-related theories is geologically oriented.

In order for these ideas to be gainfully employed by the individual (geologist or engineer) for geopressure evaluation, it is necessary to provide some numerical expressions which will enable those academic theories to be workable in an engineering environment.

The task at hand then is to apply geological training to an engineering field, and to in do this geologists and engineers must work closely with one another. This is not always an easy thing to do, mainly because both disciplines have different frames of reference. At the wellsite (or in the office), communication between engineers and geologists often requires various degrees of tact and diplomacy to get ideas or recommendations across to the other. Those individuals engaged in geopressure evaluation must be able to bridge that gap in order to maintain efficient and effective communication at all times.

To facilitate this, it is everyone's responsibility to; 1) observe what is going on downhole and how the geological and engineering parameters relate to one another, 2) learn from those parameters by observing trends and performing the necessary calculations, and 3) act on the results.

It is an age-old axiom "to know the rig activity at all times". All of this involves communication, and it is vital to the success of the operation.

Hydrostatic Pressure

Hydrostatic pressure is defined as the pressure exerted by a column of water at any given point in that column, with the water at rest. It is the pressure due to the density and vertical height of the fluid column.

In oil field terminology, hydrostatic pressure is determined using:

Equation 3-1

$$P = 0.0519 \times W \times D$$

where

P = hydrostatic pressure (psi)
W = water density (lb/gal)
D = vertical depth (ft)

The number 0.0519 is a conversion factor for the oilfield imperial units (psi, lb/gal, ft) and is derived as follows:

There are 7.48 gallons in one cubic foot

There are 144 square inches in one square foot

hence

$$lb/gal \times 7.48\ gal/ft^3 \times \frac{1}{144}\ ft^2/in^2 = psi/\text{ft}$$

therefore

$$\frac{7.48}{144} = psi/ft/lb/gal$$

$$0.0519 = psi/ft/lb/gal$$

So fresh water, having a density of 8.34 lb/gal, or 62.35 lb/ft^3, exerts a pressure of

$$8.34 \text{ x } 0.0519 = 0.433 \ psi/ft$$

Similarly, using S.I. units:

Equation 3-2

$$P(kPa) = W(kg/m^3) \text{ x } D(m) \text{ x } 0.0098$$

Water

The most important component of the system we are about to investigate is water. As mentioned earlier, below the local water table (or sea level) the pore spaces within the rock are not empty, they contain fluids. For the lucky few explorers it may be oil, gas or condensate but, more commonly, it will be water (a “dry hole” is in reality a water-wet well).

The importance of the water as a pore fluid is that the “overpressure” referred to in this manual and other sources, is often generated, transmitted and expressed by the pore water. With this in mind, the first step in working out whether a zone is overpressured or underpressured is to define normality. That is, what is “normal” fluid pressure?

Many sources (especially older ones) state that “normal pressure is 0.465 psi/ft”, which is like saying that all the pore fluids, from surface to T.D. are 1.06 g/cc. This is a sweeping assumption and does not take into account regional variations in seawater density, or pore water salinity variations with depth.

In this manual “normal pressure” will be the static pressure exerted by the pore fluids in a rock when there is no outside influence. The only contributors to this pressure will be; 1) the density of the fluid, 2) gravity, and 3) the height of the fluid column. The rock grains within the system have no effect on the pressure exerted by the pore fluids.

How is the pressure affected by the geometry of the system? In general, water will always find its own level and exert a pressure, regardless of the geometry (shape) of the “container” (See Figure 3-1) and for this reason we can disregard the obviously convoluted interconnections (“tortuosity”) that make up effective porosity within a rock. Since our interest is in essentially static, or at least slow moving systems, it is also possible to disregard any pressure built up by the viscosity of water flowing through the narrow pore throats within the formations.

The fluid pressure of most concern is referred to as the “normal hydrostatic pressure”. Once this normal hydrostatic pressure is determined, it will become the baseline for all measurements and estimations. In any well drilled anywhere in the world, to keep the pore fluids out of the well-bore and to minimize invasion of the rock by mud filtrate, the hydrostatic pressure of the drilling fluid must counter-balance the hydrostatic pressure of the pore fluid. This is known as “balanced drilling”.

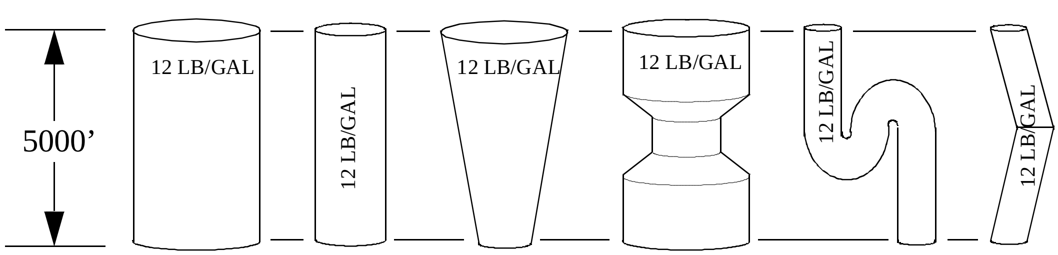
For this reason, in order to drill a “normally pressured” well efficiently, a drilling fluid must be used that produces the same pressure at the bottom as is exerted by the various pore fluids in the rocks adjacent to the well-bore.

This concept is best illustrated using a U-tube with symmetrical arms (See Figure 3-2). One arm is the pore space, the other the well-bore annulus. Both are filled with fluids of equal density. When perfectly balanced there is no movement from one side to the other, and the level on both sides is the same.

It takes a little thought to visualize that the “Pore Space” side of the U-tube would not only be more tortuous but will rarely contain only one fluid density at a constant temperature. Also, when circulating, the drilling fluid will exert pressures related to its flow and viscosity.

In offshore wells it is typical to find fluids of sea water density continuing into the subsurface (if the sediments are of “recent” marine origin) and then changing (abruptly or gradually) depending on the environment of deposition, exposure to meteoric or flowing water, mineralization in the rocks, and temperature and pressure, into fluids of differing densities.

On the well-bore side of the U-tube only temperature and pressure are variable in the column. The density of the fluid (drilling mud) at surface conditions should be constant and homogenous.



HP = 0.0519 x 12 x 5000 = 3114 psi

Figure 3-1: Hydrostatic Pressure

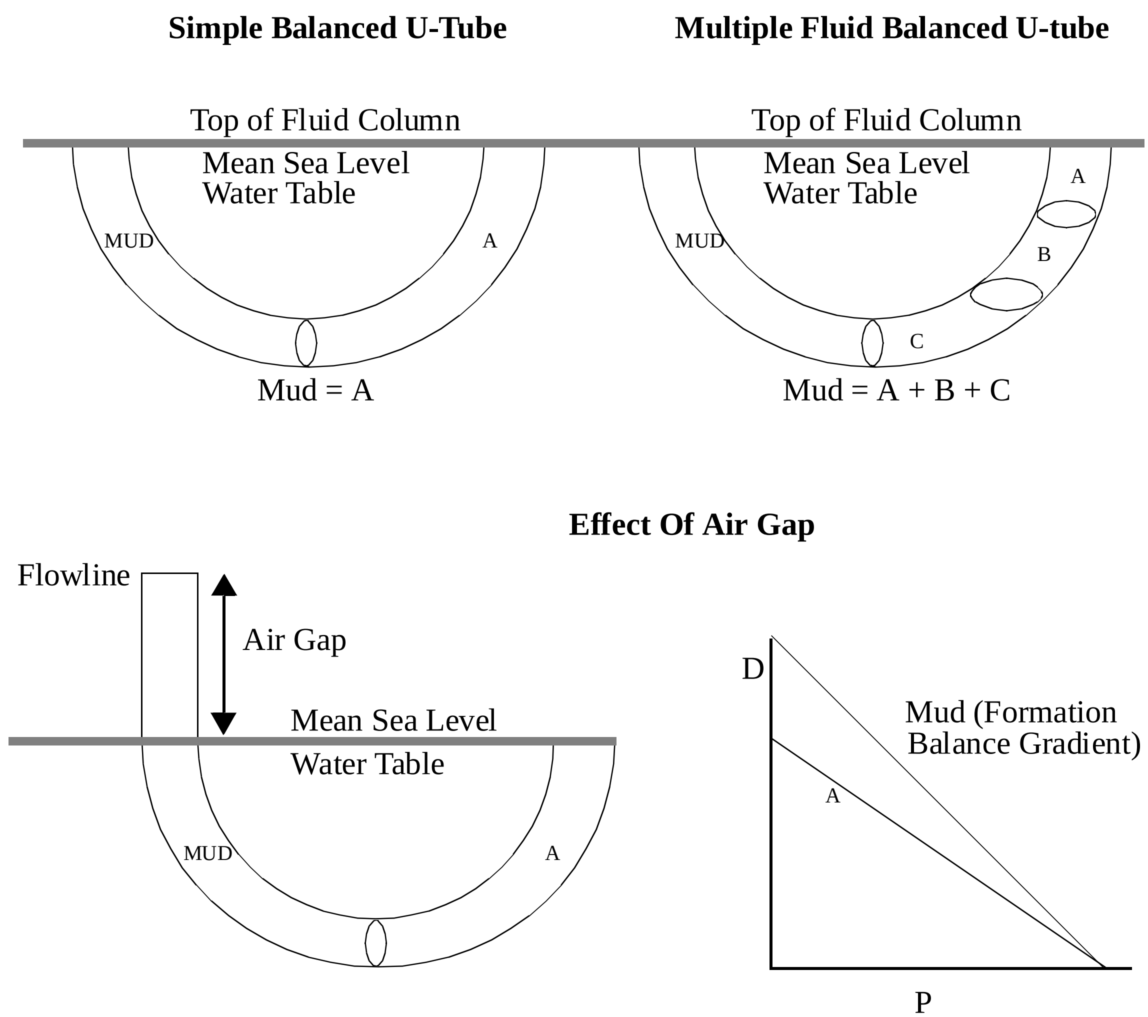


Figure 3-2: Simple “U” & “J” Tubes

If there is any doubt as to how variable the density of pore water can be, consider that in the UK North Sea Brent Field, the Lower Brent connate water has a specific gravity of 1.04 g/cc, nearly the same as the 1.03 g/cc of modern North Sea water. However, in the Southern Gas Basin of the North Sea, the sea water density is roughly similar, but the connate pore water in the Rotliegende reservoir is about 1.2 g/cc (about 16% higher).

Therefore, any assumptions made about “normal pressures” in the Brent field will not be applicable to (say) the Leman field. This also disregards the water-compaction, temperature-expansion pressure effects at depth (which are relatively small) and any changes related to dissolved gases and heavy solids (which may be large). Most of the lesser effects tend to counter one another.

From this discussion, it is obvious that the first thing a well planner or pressure engineer must do is establish the normal gradient for the well. As was seen, this will definitely have an impact on the specifications for the drilling fluid program.

Until now the U-tube analogy consisted of arms of equal height. It kept things simple, but few rigs are actually configured this way.

On any rig but a swamp-barge in a delta or a land-rig in a marsh, the return flow-line (which is the top of the mud-column in the annulus) will be considerably higher than the water table or sea-level. In order to model this situation we need a “J-tube” analogy (See Figure 3-2), where the high side is the annulus and the low side is the drilled formation. Imagine filling the J-tube with water, and using basic physics, the water will run out of the open low-side until it reaches its natural level. This is because we have unbalanced the equation for hydrostatic pressure at the bottom

Equation 3-3

$$P = SG \text{ x } Gravity \text{ x } D_v$$

by increasing D_v in the annulus. To restore equilibrium and make the total pressure the same on both sides without emptying the high side (lost circulation), we must increase the confining pressure on the low side “A” back into equilibrium.

Since we can’t change the force of gravity (9.8 m/s) we must alter the density of the fluid in the high side (the drilling fluid). This is difficult if the fluid is pure water (only non-water based solutions are less than 1 g/cc) but perfectly feasible if the original fluid is a brine.

This is exactly analogous to the situation on most rigs, since pore fluids and sea waters are normally brines.

In complete our discussion; to balance the low side of the tube and avoid displacing it, a slightly lighter fluid is needed on the high side. On rigs, it is much easier to refer to the pressure that is needed for balanced drilling in terms of mud density, rather than spend a lot of time in conversion and re-conversion of units before taking the required action.

Another consideration is the effect of the “air-gap” (the difference in elevation between the top of the mud column and the top of the pore fluid column). It is the difference in height between the two arms of the “J” tube and creates the difference in density required to balance the pressure at the bottom. The required density on the high side will vary when the difference in height changes.

The effects of tides or ship ballasting are minor, however a large change in the air gap can occur when a semi-submersible rig is replaced by a drilling/ production platform with three times the previous air-gap, and hence the extra length of mud column. For this reason any pre-drilling calculations, post-well analyses or offset comparisons must; 1) start with the pressure at the bottom of the U or J-tube, then 2) at any depth in the well, correct for the new air-gap or distance to the water-table.

This calculation starts with using simple units of pressure.

Units Of Pressure

“Pressure” is measured in a variety of units, and can be expressed in an even greater variety. At times, this can be a daunting prospect, with plenty of equations and a plethora of abbreviations and conversion factors. At the core, however there are some very simple ideas that will serve in any pressure related task, from killing a well to calculating the “riser margin”.

Pressure is basically a measure of force over a unit area. In the “API” or oilfield system, it is measured in pounds per square inch (psi). In the metric(SI) system it is in a multiple of the Pascal (Pa), most commonly Bars (100,000 Pa), the meteorological unit of barometric pressure. A Pascal is one Newton force per square meter, and a Newton is the force required to accelerate a 1 kilogram mass at 1 meter per second.

Sometimes “atmospheres” (atm) are used as the units of measurement. Atmospheres are very close to bars but are different enough to introduce significant errors if no conversion is made when comparing data (especially at high pressures).

Figure 3-3 illustrates how measured pressure at any point increases steadily as you move down a column, in direct proportion to the depth and density of fluid. If the density of the fluid changes, so does the slope of the curve.

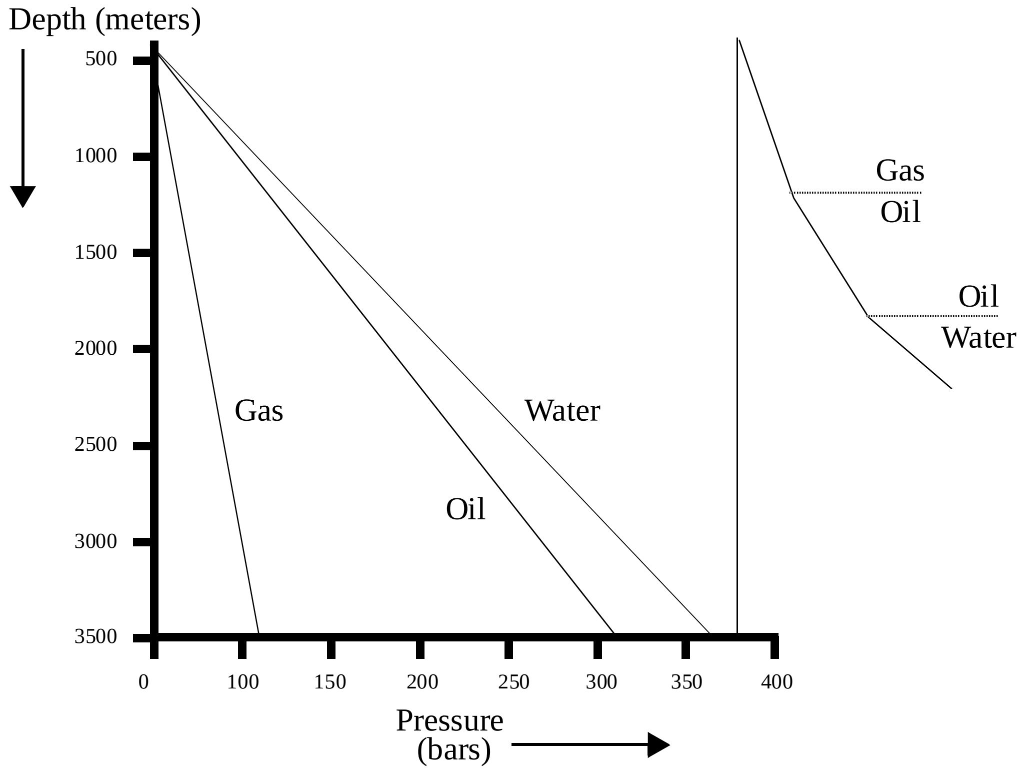


Figure 3-3: Pressure Gradients of Water / Oil / Gas

Figure 3-4 shows how a column of three different water densities produces a stepped curve. Rearrangement of the three alters the local pressure at the base of each segment but produces the same overall pressure at the bottom.

If this were an actual well, requiring a single mud density in the annulus to balance the pressure at the bottom, we would need to know how the total fluid pressure was related to depth, as if the pore fluid was of one uniform density.

The slope of each individual pressure/depth curve is called the ***pressure gradien***t, and is a measure of the rate of pressure change over depth (psi/ft or bar/m) and will be constant whenever the fluid density is constant.

In Figure 3-4, the mud density gradient required to balance the sum of all three fluid pressures at depth is none of the individual densities, but it is a fluid required to produce the average gradient (i.e. a line taken from surface to the total pressure at bottom). So it will be lighter than that of the densest fluid in the column but denser than the lightest. This is easy to visualize when remembering the simple U-tube well and J-tube model. The only difference being that when calculating the mud gradient to be used, we sum the formation pressures on the low side of the J-tube to get the pore pressure gradient, and then divide that pressure by the depth of the high-side (to the flowline) to get the perfect mud density gradient.

This mud gradient is called the ***Formation Balance Gradient*** (FBG) with units in psi/ft, bar/m or mud density (***Equivalent Mud Density,*** EQMW).

The actual mud density to drill the well is generally the FBG plus a safety margin determined by the operating company.

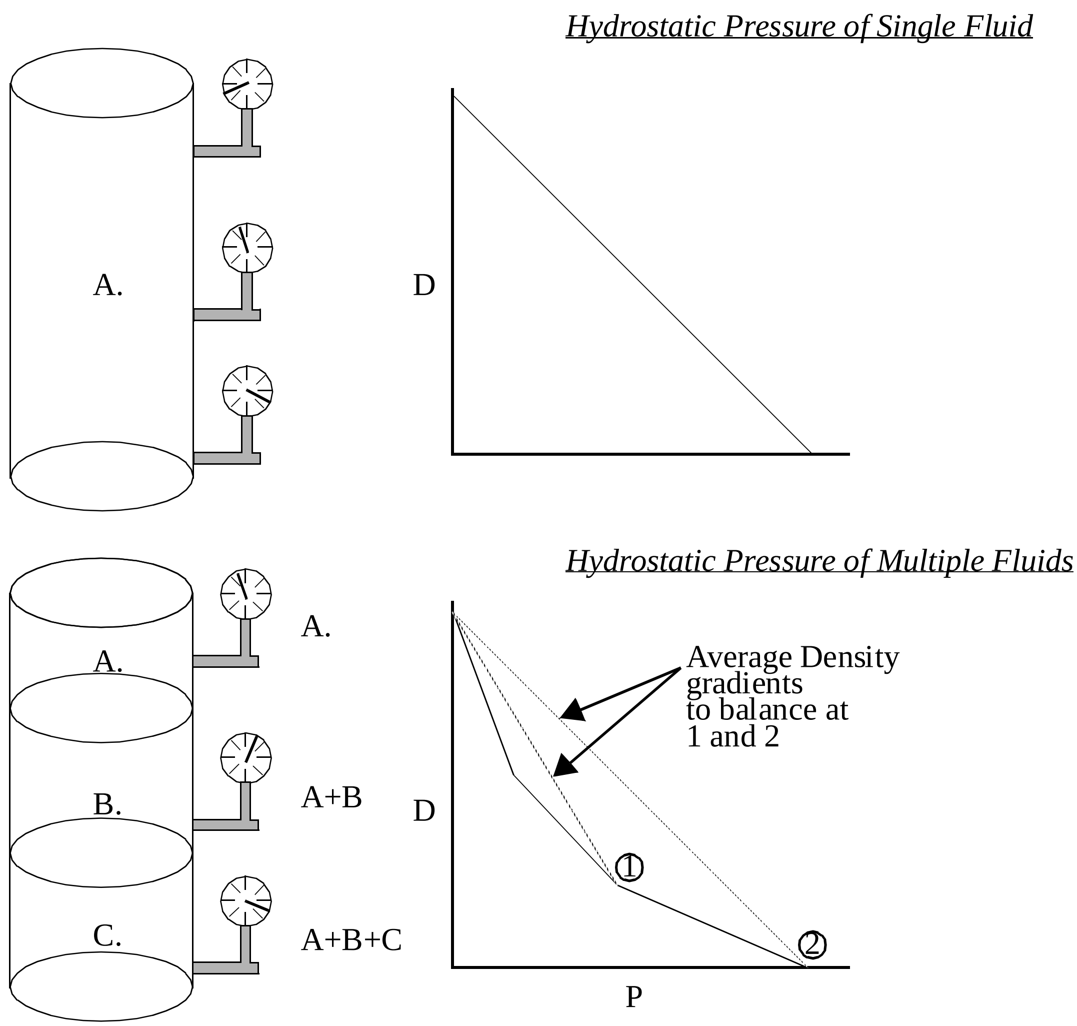


Figure 3-4: Hydrostatic Pressure of Single & Multiple Fluids

Equivalent Wellsite Units

It is important to realize that the pressure units (g/cc, lb/gal, psi/ft) or their equivalents, express a gradient or pressure per unit depth. However, at the wellsite it is more common to refer to the drilling mud density as mud weight (still expressed in lb/gal or g/cc). Notice that specific gravity (s.g.) is not a density. Specific gravity is the ratio of a density compared to the density of water, and hence has no units. Oilfield accuracy tolerances allow s.g. to be numerically equal to the material's density in g/cc.

It is convenient to relate various pressures by their resultant gradient relative to a fixed datum, usually the RKB (rotary kelly bushing) or rig floor. However, since the mud level (the flowline) is below the RKB, all gradients should be referenced to the flowline. Normally the distance from the RKB to flowline is around 5 to 10 feet, and it is important to realize that this distance is sufficient to cause significant gradient differences at shallow depths. At greater depths, the distance from RKB to flowline becomes insignificant when calculating gradients, but for sake of consistency, **all gradients are calculated from the flowline**. Also, the FBG is usually spoken of in pounds per gallon or specific gravity (this makes comparisons with mud density simple). However, when writing reports, take care to use the correct terminology (i.e. FBG at 10,000 ft is 15.7 lb/gal EQMW, pore pressure is 8148 psi).

The gradient that the pore fluid density produces alone is called the normal pore pressure gradient. Hence, this gradient is dependent upon the density of the pore waters and will vary from area to area.

Onshore (Rocky Mountain area), the water is relatively fresh, and has a normal pore pressure gradient of approximately 1.0 s.g. (8.34 lb/gal EQMW).

In the U.S. Gulf Coast area, waters are more saline, with a normal pore pressure gradient of around 1.03 s.g. (8.6 lb/gal EQMW).

In other offshore areas, seawater density and pore water density may vary from slightly saline (8.5 lb/gal) to saturated saline (9.9 lb/gal). Since salinity varies with depth and formation, the average value may not be valid for all depths. Because of this, when planning a well a log-derived pressure-versus-depth profile should be determined.

As stated above, salinity of the formation water can be dependent upon lithology. In certain evaporites, saturated saltwater has a gradient of 0.520 psi/ft. Therefore, knowledge of the depositional environment is important. For example, if you were drilling in the Zechstein basin, a calculated pressure gradient of 0.520 psi/ft would not be very significant, whereas in a fresh-water basin it would indicate a large overpressure.

Before a well is drilled, an estimate of the normal pore pressure gradient should be found. This can be obtained from actual density measurements, direct pressure measurements from offset wells, SP and resistivity log interpretation (see Appendix C), or by assuming that the density is the same as seawater (if offshore) or that onshore the water is fresh.

If the well is a rank wildcat and no previous data is available, it is assumed that the normal pore pressure gradient is 8.34 lb/gal (onshore) or seawater density (8.5 to 9 lb/gal) if offshore.

Formation Water Type	Salinity Chloride mg/Liter	ppm NaC1	Normal Pressure Gradient (psi/ft)	Equivalent Mud weight (lb/gal)
Fresh Water	0	0	0.433	8.34
Brackish Water	6,098 12,287 24,921	10,062 20,273 41,120	0.435 0.438 0.444	8.37 8.43 8.55
Seawater	33,000	54,450	0.448	8.63
Saltwater	37,912 51,296 64,987	62,554 84,638 197,228	0.451 0.457 0.464	8.67 8.80 8.92
Typical Offshore Gradient	65,287 79,065 93,507 108,373 123,604 139,320 155,440 171,905 188,895	107,709 130,457 154,286 178,815 203,946 229,878 256,476 283,643 311,676	0.465 0.470 0.477 0.484 0.490 0.497 0.504 0.511 0.518	8.96 9.04 9.17 9.30 9.43 9.56 9.71 9.83 9.97
Saturated Seawater	191,600	316,140	0.519	9.99

Figure 3-5: Variation of Hydrostatic pressure with formation water salinity

If the normal pore pressure gradient is 8.34 lb/gal, then the pore pressure at 5000 feet is

$$5000 \text{ x } 8.34 \text{ x } 0.0519 = 2164\ psi$$

If the normal pore pressure gradient is 8.7 lb/gal, the pore pressure at 5000 feet is

$$5000 \text{ x } 8.7 \text{ x } 0.0519 = 2258\ psi$$

Note that the apparent small change in gradient produces a large change in pore pressure at depth. This is accentuated as depth increases, therefore it is very important that accurate normal pore pressure gradients be obtained.

The Rock

Discussions thus far have centered around pore fluids. This was necessary because fluid pressures in a normally pressured system act equally in all directions and only support fluids. They play no significant part in supporting the rock matrix. If that is the case, what is supporting the rock grains, the cementing material, and the interstitial material within the rock? The “rock” is the short answer. The weight of overlying sediment is supported by the grain to grain contact and is primarily a force acting downwards under gravity. A component of the fluid pressure also acts downwards, and provides a medium in which the rock grains gain buoyancy according to their displacement. So the total grain to grain load is rock mass minus its buoyancy.

The process of compaction, with the concomitant shuffling of grains, and creation of more complex grain boundaries (like pressure sutures), is driven by a steady increase in matrix pressure with depth.When calculating this matrix pressure, the raw data used is bulk density (ρ_b).

The total vertical pressure acting on any horizontal plane in the sediment is referred to as the ***Overburden*** and consists of two components, matrix pressure and pore pressure.

Equation 3-4

$$S = P + \sigma \qquad\qquad \sigma = Matrix\ Pressure$$

Total overburden pressure (S) at any depth can be calculated from the overlying rock bulk densities and cumulative pressures. Since the pore fluid pressure may be known or closely estimated in a normally pressured sequence, the matrix pressure can be found by subtraction, without any need to calculate the buoyant force. By determining bulk density directly, the need to extract the buoyed matrix density from the rock is removed.

By subtracting P from S, providing that both are either instantaneous pressures (psi, bar, atm) or from the same datum (sea level, RKB) we can find the matrix stress (σ) at any depth, if the rock is normally compacted.

$$\sigma = S - P$$

In this calculation the ***Overburden Gradient*** is always taken from the same datum as the Formation Balance Gradient (at sea the first interval will be water, not rock).

Notice that all gradients presented by Baker Hughes INTEQ refer to the flowline unless otherwise stated.

Data For Overburden

In order to covert bulk density (g/cc) into a pressure gradient (psi/ft) a conversion constant is necessary. Since the average density of a thick sedimentary sequence is approximately 2.31 g/cc, and with depth the overburden gradient will be about 19.2 lb/gal or 1 psi/ft, the conversion constant becomes:

$$1 \text{ psi/ft} \div 2.31 \text{ g/cc} = 0.433 \text{ psi/ft /g/cc}$$

Overburden can then be calculated using:

Equation 3-5

$$S = 0.433 \int_{O}^{Z} \rho(z) dz$$

As mentioned earlier, the basic data for overburden gradient calculations is the bulk density of the rock ($\rho_{\mathbf{b}}$). This can be either measured directly or calculated after measuring the other components of the formation since:

Equation 3-6

$$\rho_b = \varnothing \text{ x } \rho_f + (1 - \varnothing)\rho_m$$

where:

$\rho_{\mathbf{b}}$ =	formation bulk density (g/cc)
$\rho_{\mathbf{f}}$ =	average density of the pore fluid (g/cc)
$\rho_{\mathbf{m}}$ =	matrix density (g/cc)
Ø =	porosity (fractional)

From this relationship, it can be seen that as Ø approaches 1, ρ_b approaches ρ_f, and conversely as Ø approaches 0, ρ_b approaches ρ_m.

If all densities are known, the porosity can be determined using:

Equation 3-7

$$\varnothing = \frac{\rho_m - \rho_b}{\rho_m - \rho_f}$$

Typical matrix and fluid densities are:

Lithology	Matrix Density (g/cc)
Sandstone	2.65
Limestone	2.71
Dolomite	2.87
Anhydrite	2.98
Halite	2.03
Gypsum	2.35
Clay	~2.7-2.8
Fresh Water	1.0
Salt Water	1.15
Oil	0.80

Figure 3-6: Typical Densities of Rocks and Fluids

Several sources of density data include:

1. Density measurements of rock samples using “shale density” techniques. This normally involves placing shale cuttings in a liquid of known density (in a series of jars, or in a fluid column of a known density gradient). Formation “bulk density” can be found using a standard mud balance (the “pycnometer” method), a mercury balance, or by measuring the displacement in water of small test-tubes full of cuttings.
2. Measurements of rock in situ. Using density logs to directly measure the electron density and the bulk density of the rock around the borehole, or from core samples at surface.
3. Measurements of Porosity. The porosity value can then be put into Equation 3-6
    - Neutron Porosity Logs
    - Nuclear Magnetic Resonance studies of cuttings
    - Sonic Logs
4. Offset Tables - any of the previously mentioned data or some curves constructed for the region before drilling, providing that the data are not too offset either by structure or distance.

Limitations on these data sources are:

1. Shale Density - the density values obtained by jars and columns is relatively good, but rather dependent upon the state of hydration of the shales, which can vary with mud type and the degree of washing. Inorganic (Zinc Bromide) columns are more susceptible to this than organic (Bromoform/Neothene) columns.

However, the increase in toxicity is not offset by the slight improvement in accuracy and range.

2. The mud balance method is highly dependent on the experience of the operator.

Measurement of density in situ.

1. This is the best method, since any elastic compression is taken into account. Allowance can also be made for some of the effects that can distort density data, like gas filled porosity (which shows up as a very low density unrelated to the porosity). However, in most cases it can be read directly from the log, provided the quality control curve on the log stays within limits. The biggest drawback with the wireline density log is that most companies only run it over deeper, critical sections (owing to expense). MWD density or MWD porosity tools can provide more continuous data.

   In the absence of density log data the next best thing is a calculation of bulk density using sonic log data.

   If porosity is known, and basic data for matrix and water densities (Figure 3-6) the bulk density can be calculated.

2. Regional curves (Figure 3-7) and tables are sometimes provided to the service company by the operating company. When these are available, caution is advised. When pooled data is used to construct local overburden gradients, it is immediately obvious that the validity of this type of data depends heavily on the density of offset data. In mature areas the curves should always be better.

Be very wary of the overburden curves (Figure 3-8) and tables that appear on some well-programs. They may have been derived from previous well data, which came from a previous well, which came from the geologists' or engineers' estimates, etc.

Be sure of the provenance of the data, and if you aren't sure, calculate the curve. In addition, remember to update and re-calculate when better data become available. In the first stages of the well the only data may be "shale densities". These are fine in the interim but should be checked against log data at casing points, and if a significant discrepancy exists, the curves must be re-calculated.

If this seems too much to ask, imagine having to work with somebody else's gradients and not knowing whether the calculated values (which are used to ensure the safety of the rig) are derived from the best possible data.

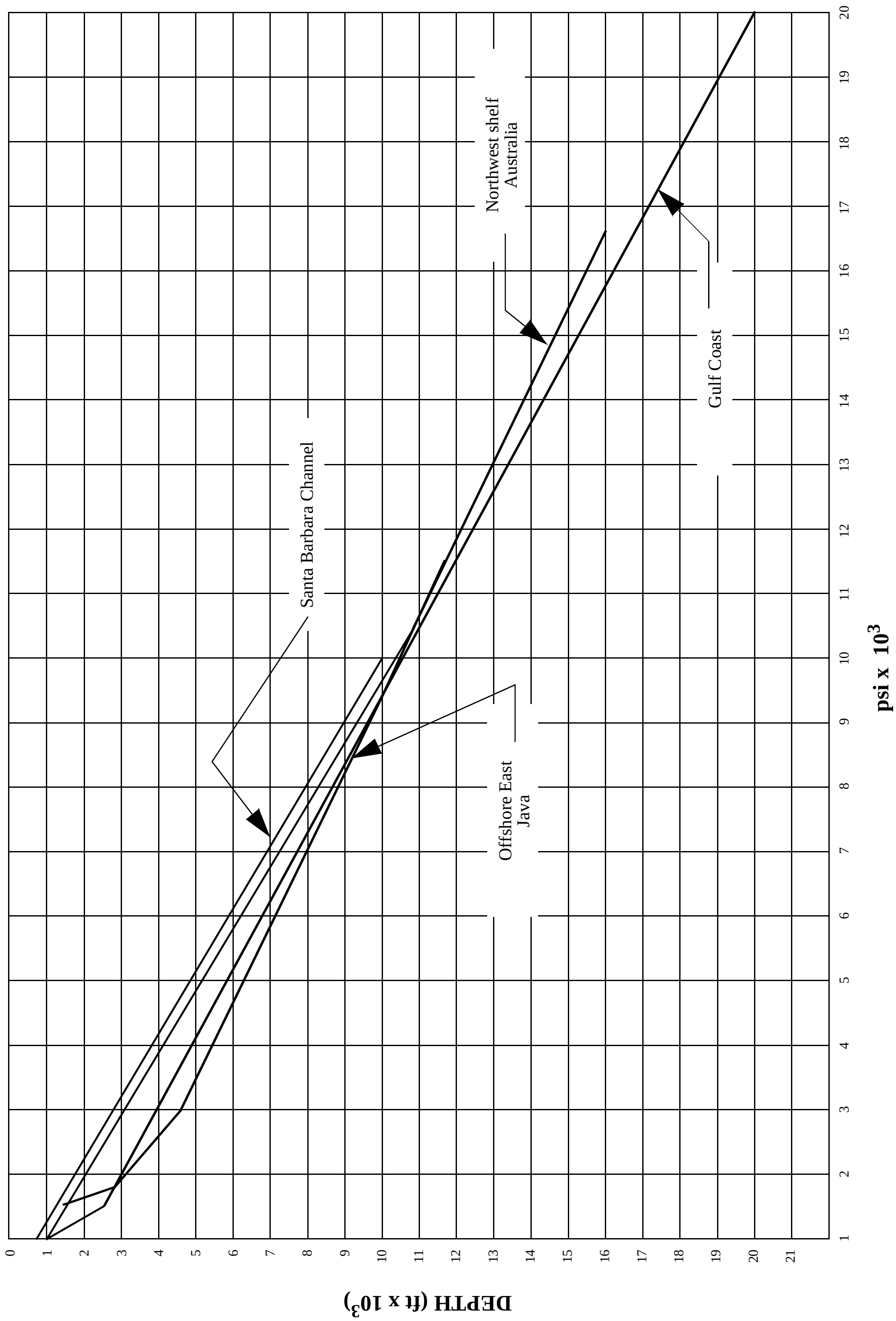


Figure 3-7: Typical Overburden Pressures

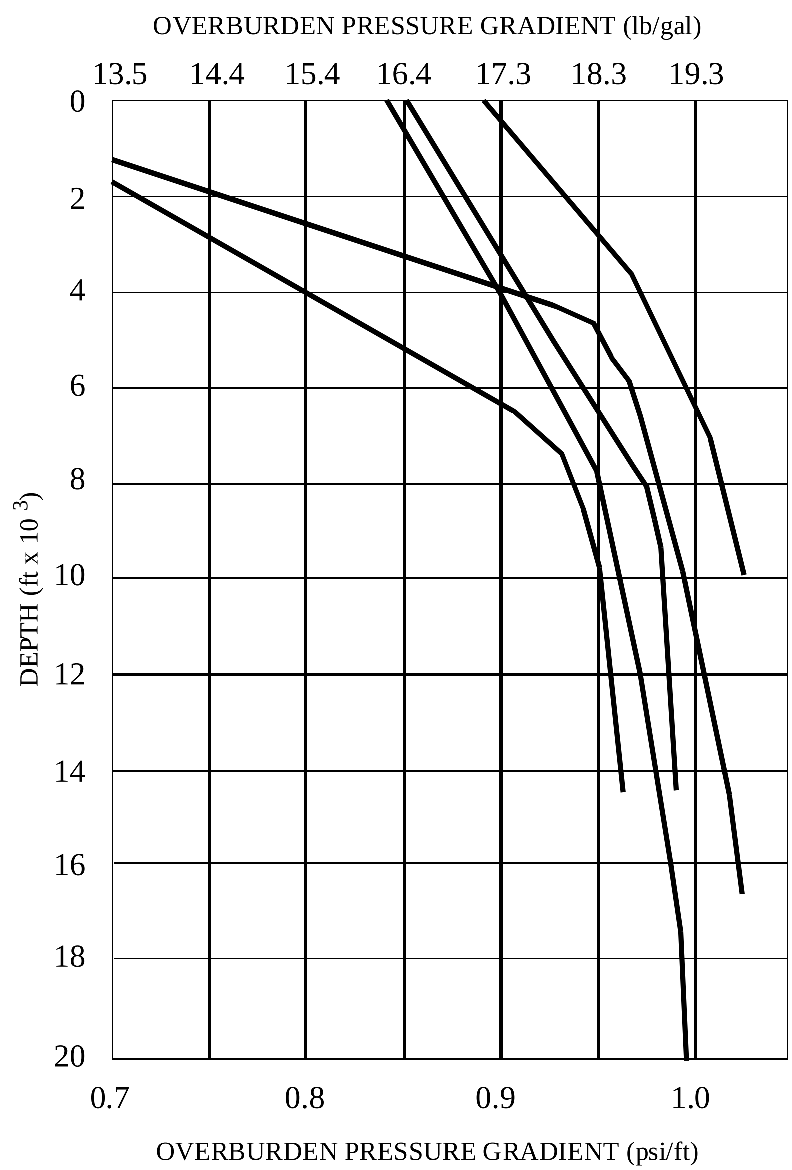


Figure 3-8: Typical Overburden Pressure Gradients

Other Pressure Measurements

As previously stated, pore pressures may range from abnormally low, through hydrostatic (normal) to abnormally high. The various evaluation techniques for abnormal pore pressures are fully described in Chapter .

While drilling, pore pressures are automatically referenced to the flowline, but due to the differences in height between flowline and the water table (onshore) and flowline and sea level (offshore), gradients measured during drilling will not be actual pore pressure gradients but will represent the pressure of a fluid required to balance the pressures at that depth, from the flowline. This can be illustrated as follows:

- **Offshore**: water depth 450 feet, seawater density 8.6 lb/gal. Assume normal pore pressure gradient is 8.6 lb/gal, and the depth of interest is 1000 ft. The RKB to sea level is 60 ft, RKB to flowline is 5 ft.

  actual pore pressure at 1000 ft
  940 x 8.6 x 0.0519 =420 psi

  actual pore pressure gradient = 8.6 lb/gal (0.446 psi/ft)

  pore pressure gradient from flowline
  420 ÷ (995 x 0.0519) = 8.1 lb/gal (0.422 psi/ft)

- **Onshore**: Depth to water table is 220 feet, water density is 8.34 lb/gal, flowline to ground level is 45 feet, depth of interest is 1000 feet.

  actual pore pressure at 1000
  780 x 8.34 x 0.0519 = 338 psi

  actual pore pressure gradient = 8.34 lb/gal (0.433 psi/ft)

  pore pressure gradient from flowline
  338 ÷ (1000 x 0.0519) = 6.5 lb/gal (0.338 psi/ft)

It is clear that at shallow depths, the differences are extremely important.

For this reason, the gradient as measured from the flowline is termed the Formation Balance Gradient (FBG), and this is equal to the mud density required to balance the pore pressure. The values calculated for the hypothetical cases (both onshore and offshore), 6.5 lb/gal and 8.1 lb/gal, are thus the mud densities needed to balance the pore pressures at 1000 feet for those conditions. Obviously, no water-based drilling mud can be as light as these, and this represents a major problem in drilling shallow holes where fracture pressures are often approached and exceeded, resulting in lost circulation and no returns.

The Formation Balance Gradient

As mentioned above, the formation balance gradient is the pore pressure gradient referenced to the flowline, and when expressed in terms of mud density (lb/gal), it expresses the mud density which is necessary to balance the pore pressure at the depth of interest. Figure 3-9 shows an example worksheet for calculating normal FBG. Figure 3-10 shows the relationship between the actual fluid density and the FBG (EQMW), which is the gradient referenced to the flowline.

At the wellsite, some of these terms are used synonymously, which results in confusion if they are not fully understood:

- Local Pressure Gradient is used in this manual to describe the actual rate of pressure change with depth at a point in the formation. Where fluid communication exists, it is simply the hydrostatic pressure gradient. When expressed in units of density it is equal to the actual fluid density present at the point. Only when pressure is increasing at a non-hydrostatic gradient (that is, in a transition zone) will it be higher. Though the only “true” gradient (that is, rate of change) term, it is rarely directly applicable to wellsite pressure calculations.

The following gross gradient (that is, pressure divided by depth) terms have more common practical use.

- Pore Pressure Gradient is pressure per unit /depth, measured from the top of the formation fluid column. Onshore it is measured from the level of the water table, and offshore it is measured from the sea level.
- Formation Balance Gradient is pressure per unit depth, measured from the flowline. It is precisely equal to Equivalent Mud Density (EQMW), so the terms may be used interchangeably. The Formation Balance Gradient is thus always less than the Pore Pressure Gradient, but is exactly equal to the static mud density required in the borehole to balance formation pore pressure. This term was first defined by EXLOG and is standard in all Baker Hughes INTEQ programs and logs.
- Normal Formation Balance Gradient is the normal hydrostatic pressure gradient measured from the flowline. The following examples illustrate the particular relationships between these gradients.

Figure 3-9: Normal FBG Calculation Worksheet

Depth (ft)				Interval (ft)	FLUID DENSITY		Hydrostatic Pressure (PSI)	Total Hydrostatic Pressure (PSI)	Formation Balance Gradient		
RKB		Below Flowline									
From	To	From	To		g/cc	lb/gal			psi/ft	lb/gal	
1	2	3 = 1 - D_{fl}	4 = 2 - D_{fl}	5 = 4 - 3	6	7 = 8.34 x 6	8 = 0.0519 x 5 x 7	9 = $\sum 8$	10 = $\frac{9}{8}$	11 = $\frac{10}{0.0519}$	
RKB (0)	FL (9)	—	—	9	—	—	—	—	—	—	
FL (9)	Water Table (280)	0	271	271	—	—	—	—	—	—	
280	700	271	691	420	1.00	8.34	182	182	0.286	5.1	FRESH
700	1000	1000	991	300	1.00	8.34	130	312	0.314	6.1	
1000	1500	991	1491	500	1.01	8.42	219	530	0.356	6.9	BRACKISH
1500	2000	1491	1991	500	1.01	8.42	219	749	0.376	7.2	
2000	3000	1991	2991	1000	1.01	8.42	437	1186	0.397	7.6	
3000	3800	2991	3791	800	1.01	8.42	350	1536	0.405	7.8	
3800	4000	3791	3991	200	1.14	9.51	99	1634	0.410	7.9	SALINE
4000	4500	3991	4491	500	1.14	9.51	247	1881	0.419	8.1	

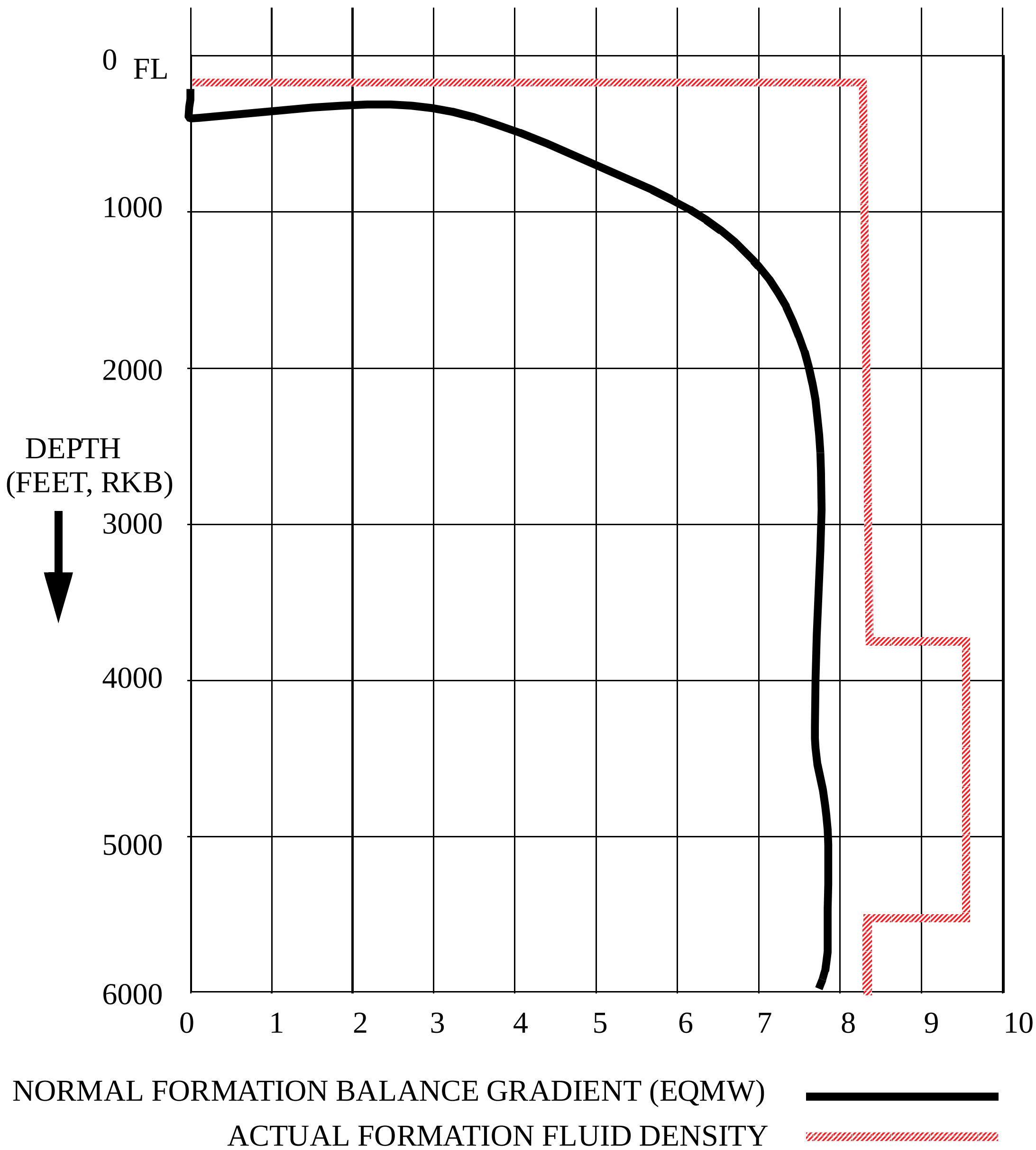


Figure 3-10: Actual formation fluid density and FBG

To further illustrate these concepts, assume:

- Pore water density: 1.06 g/cc (8.8 lb/gal)
- Offshore rig with a water depth of: 320 ft

- Air Gap: 60 ft (flowline to sea level)

Then, at the seafloor:

Pore Pressure: 320 x 8.8 x 0.0519 = 146.2 psi
Normal FBG: 146.2 ÷ (380 x 0.0519) = 7.4 lb/gal

in comparison to the actual fluid pressure gradient of 8.8 lb/gal

At 3000 ft (below flowline):

Pore Pressure: 2940 x 8.8 x 0.0519 = 1343 psi
Normal FBG:1343 ÷ (3000 x 0.0519) = 8.6 lb/gal

in comparison to the actual pore pressure gradient of 8.8 lb/gal.

At 10,000 ft (below flowline):

Pore Pressure: 9940 x 8.8 x 0.0519 = 4540 psi
Normal FBG: 4540 ÷ (10,000 x 0.0519) = 8.7 lb/gal

in comparison to the actual pore pressure gradient of 8.8 lb/gal

With depth, it is apparent that the Normal Formation Balance Gradient will approach the actual pore pressure gradient asymptotically. In the above case, as the pore pressure gradient remains constant (equal to hydrostatic), the Normal Formation Balance Gradient is the same as the equivalent mud density that will precisely balance the pore pressure at any point.

Using the same rig situation, but with geopressures:

At 3000 ft (below flowline): Pore pressure gradient: 10.5 lb/gal

Pore Pressure: 2940 x 10.5 x 0.0519 = 1602 psi
FBG: 1602 ÷ (3000 x 0.0519) = 10.3 lb/gal

At 10,000 ft (below flowline): Pore pressure gradient: 10.5 lb/gal

Pore Pressure: 9940 x 10.5 x 0.0519 = 5417 psi
FBG: 5417 ÷ (10,000 x 0.0519) = 10.4 lb/gal

In these cases, the Formation Balance Gradient equals the Equivalent Mud Density, but the Normal Formation Balance Gradient remains the same as in the first example, (i.e. 7.4 lb/gal, 8.6 lb/gal and 8.7 lb/gal at seabed, 3000 and 10,000 feet).

This is shown schematically in Figure 3-11.

The formation balance gradient at any point in the hole is actually measured as EQMW. It is thus necessary to convert this gradient to a pressure (psi or its metric equivalent) by the use of simple equations.

Fracture pressures can also be converted to equivalent mud densities. However, since fracture pressures vary considerably with changing lithology and pore pressures, the term “fracture pressure gradient” becomes almost meaningless. Nonetheless, at any point in the hole, the calculated fracture pressure can be converted to an EQMW (this represents the mud density necessary to cause that pressure at that depth). By converting fracture pressure to EQMW, convenience is gained - particularly for immediate well planning - but it should be remembered that equivalent mud density is a gradient referring to the mud in the hole, and not a property of the formation.

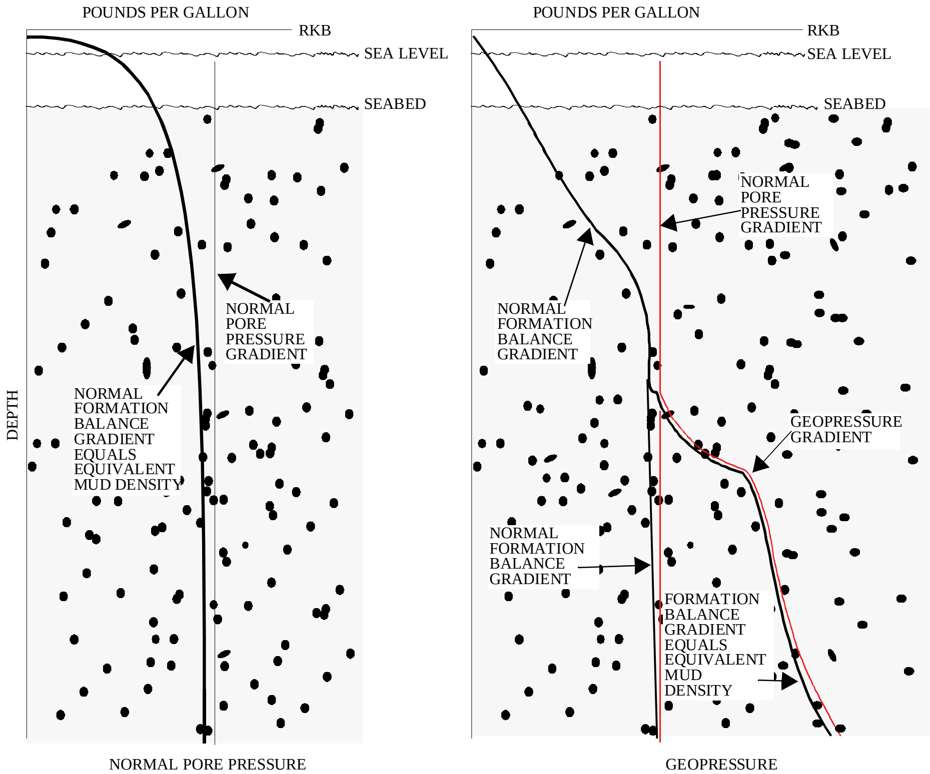


Figure 3-11: Relationships between normal PP, normal FBG, FBG, and EQMW

Effective Overburden Pressure

The effective overburden pressure is that portion of the overburden pressure that is not supported by the pore pressure. It is calculated by

Equation 3-8

$$\sigma_1 = S - P$$

where:

σ_1 = effective overburden pressure (psi)
S = total overburden pressure (psi)
P = pore pressure (psi)

The term σ_1 has no application in geopressure evaluation apart from fracture pressure calculations, nevertheless it is important in understanding the relationship between pore pressure and overburden pressure.

As the pore pressure increases, more and more of the overburden becomes supported by the pore fluids, reducing the effective overburden pressure. When the pore pressure is equal to the overburden pressure, the effective overburden pressure is zero; and when this occurs, gravity sliding, diapirism, and other induced deformation may occur.

The effective overburden pressure is the pressure which causes compaction. Therefore, even in geopressured formations compaction will still occur, albeit at a slower rate, unless the pore pressure is equal to the overburden pressure (Figure 3-12).

If the geopressured zone is thought to be caused by compaction disequilibrium, the pore pressure will increase at the same rate as the overburden pressure, and the effective overburden pressure will remain constant. The expected rate of pore pressure increase can then be calculated using:

Equation 3-9

$$P = S - \sigma_1$$

An example of these calculations follows:

At 5000 feet, the OBG is 17.1 lb/gal and the formation balance gradient is equal to 10.0 lb/gal. If the geopressure was caused by compaction disequilibrium, what would the pore pressure be at 10,000 ft?

Overburden Pressure (S) at 5000 ft:

$$17.1 \text{ x } 5000 \text{ x } 0.0519 = 4437 \text{ psi}$$

Pore Pressure (P) at 5000 ft:

$$10 \text{ x } 5000 \text{ x } 0.0519 = 2595 \text{ psi}$$

Effective Overburden Pressure (σ_1)at 5000 ft:

$$4437 - 2595 = 1842 \text{ psi}$$

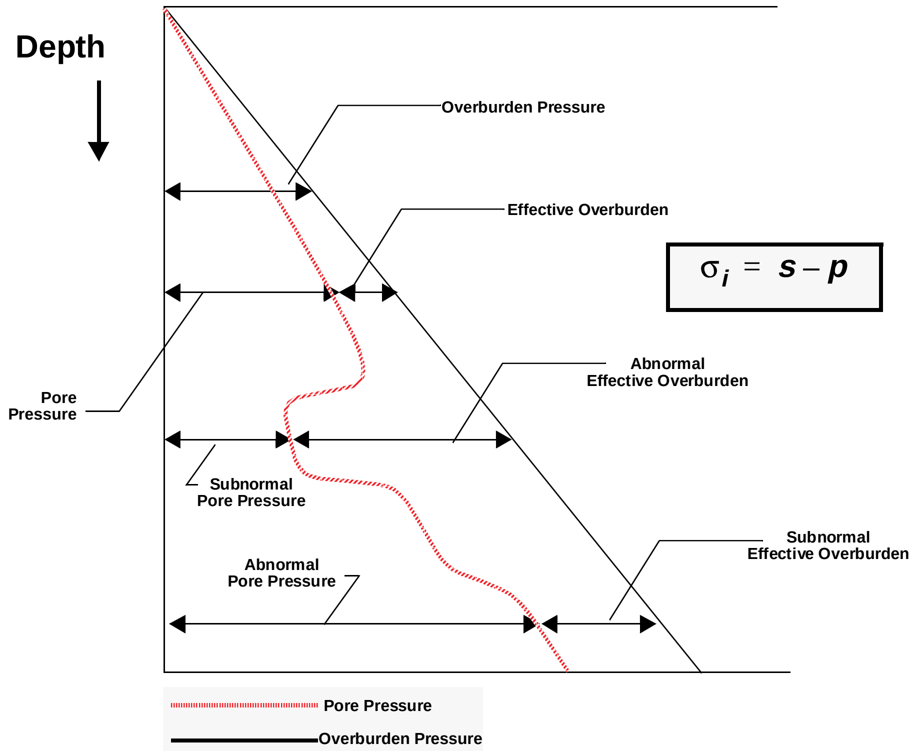


Figure 3-12: Effective overburden pressure in normal and geopressured formations

The effective overburden pressure could also be obtained by simply subtracting the two gradients and converting the answer to pressure:

$$\sigma_1 = (OBG - FBG) \times 5000 \times 0.0519$$

However, this method is not recommended because the effective overburden pressure remains constant with compaction disequilibrium, not the gradient.

At 10,000 ft, OBG = 18.2 lb/gal

Overburden Pressure (S) at 10,000 ft:

$$18.2 \times 10{,}000 \times 0.0519 = 9446 \text{ psi}$$

As the effective overburden pressure remained constant,

Pore Pressure (P) at 10,000 ft:

$$9446 - 1842 = 7604 \text{ psi}$$

Formation Balance Gradient (FBG at 10,000 ft:)

$$7604 \div (10000 \times 0.0519) = 14.7 \text{ lb/gal}$$

Effective Circulating Density

In order to make full use of the formation pressures determined in pressure evaluation work, it is essential that the pressures existing in and imposed by the mud circulating system be known and fully understood.

The density of the drilling fluid itself does not remain constant throughout its cycle. For example, the weight of suspended cuttings in the annulus normally increases the effective density of the mud and therefore the hydrostatic pressure imposed at the bottom of the hole.

An important factor in consideration of true bottomhole pressure is the effective back pressure imposed on the bottom due to annular pressure losses. When circulating through an open flowline, the measured mud pressure at the surface (casing pressure) will be zero. Since a certain amount of pump pressure was required to circulate the drilling mud, those pressure losses must be accounted for.

Frictional effects in the annulus present a restriction to fluid flow, and a certain amount of pump pressure is required to overcome this restriction. This restriction acts in the same way as a closed-in choke applying a back pressure to the bottom of the hole, in addition to the hydrostatic pressure. The total pressure at the bottom of the hole during circulation is termed the ***BottomHole Circulating Pressure (BHCP)***, and its equivalent mud density is termed the ***Effective Circulating Density (ECD)***.

The extent of the flow restrictions and pressure losses is dependent upon the total depth, annular dimensions, fluid viscosity, and flow regime, (laminar or turbulent). Using the conventional Bingham model for drilling fluids, the pressure losses can be approximated using:

Equation 3-10

$$Pla = \frac{L \text{ x } YP}{A \text{ x } (I.D - O.D)} + \frac{PV \text{ x } L \text{ x } V}{B \text{ x } (I.D - O.D)^2}$$

where:

Pla	= annular pressure loss (psi)
L	= measured length of section (ft)
YP	= yield point (lb/100 ft^2)
I.D. - O.D.	= hole (or casing) I.D. minus pipe (or collar) O.D.(in)
PV	= plastic viscosity (centipoise; cps)
V	= annular velocity (ft/min)
A	= 225 for drillpipe, 200 for annulus
B	= 90,000 for drillpipe, 60,000 for annulus

This equation provides pressure losses in a pipe or annulus containing fluid moving in laminar flow, and tends to give slightly inflated values.

Equation 3-11

$$Annular\ Velocity\ (ft/min)\ =\ \frac{24.51 \text{ x } gallons\ per\ minute}{(I.D^{2} - O.D^{2})}$$

When using tapered strings or in partially cased holes, the total pressure loss will be the sum of the pressure losses calculated for the individual annular segments.

Equation 3-12

$$ECD\ =\ W + \frac{\sum Pla}{0.0519 \text{ x } D}$$

where:

ECD	= effective circulating density (lb/gal)
ΣPla	= total annular pressure loss (psi)
W	= mud density (lb/gal)
D	= vertical depth (ft)

Equation 3-13

$$BHCP\ =\ \sum Pla + (W \text{ x } D \text{ x } 0.0519)$$

$$= ECD \text{ x } D \text{ x } 0.0519$$

where:

BHCP	= bottomhole circulating pressure (psi)

Notice that in calculating pressure losses the actual measured length of the flow path is used. The sum of these will be the total measured depth of the well. When converting this pressure loss to an equivalent mud density (Equation 3-12), the vertical depth must be used since a hydrostatic column of fluid is being considered.

Using the Power Law Model annular pressure losses can be defined as:

Equation 3-14

$$Pla = \frac{L\tau}{300(I.D - O.D)}$$

where
- Pla = annular pressure loss (psi)
- L = measured length of section (ft)
- τ = shear stress (lb/100 ft^2)
- I.D.- O.D.= hole (or casing) I.D. minus pipe (or collar) O.D. (inches)

Since the Power Law Model usually approximates more closely to true fluid behavior, it will produce a more accurate annular pressure loss.

Swab and Surge Pressures

When the pipe is tripped from the borehole, bottomhole pressure will be reduced due to the swabbing action of the drillstring. As the pipe moves upward, frictional forces between the pipe, mud and borehole wall will cause a pressure reduction. The maximum effect of this pressure reduction on the mud density will be immediately below the bit. The maximum overall pressure reduction will occur at the bottom of the hole, due to this “plunger” effect. An open drillstring will allow some fluid to flow through the jets, allowing some degree of pressure-relief, but if the drillstring has a float or downhole B.O.P., swabbing pressures will be at a maximum. As a general rule of thumb, this pressure reduction can be at least the same as the annular pressure losses. Actual values will depend on pipe pulling speeds and hole conditions. A ***safe weight to trip*** can be determined from the annular pressure losses using:

Equation 3-15

$$W_{trip} \le W - \frac{\sum Pla}{0.0519 \text{ x } D}$$

Pressure reductions due to swabbing can be serious when drilling geopressured intervals, as the lowering of the BHCP/ECD may cause the well to flow.

See Figure 3-13 for a typical swab/surge printout from EAP programs.

Large changes in mud density or effective mud density should be avoided, because changes brought about that are unexpected in magnitude may lead to severe hole problems.

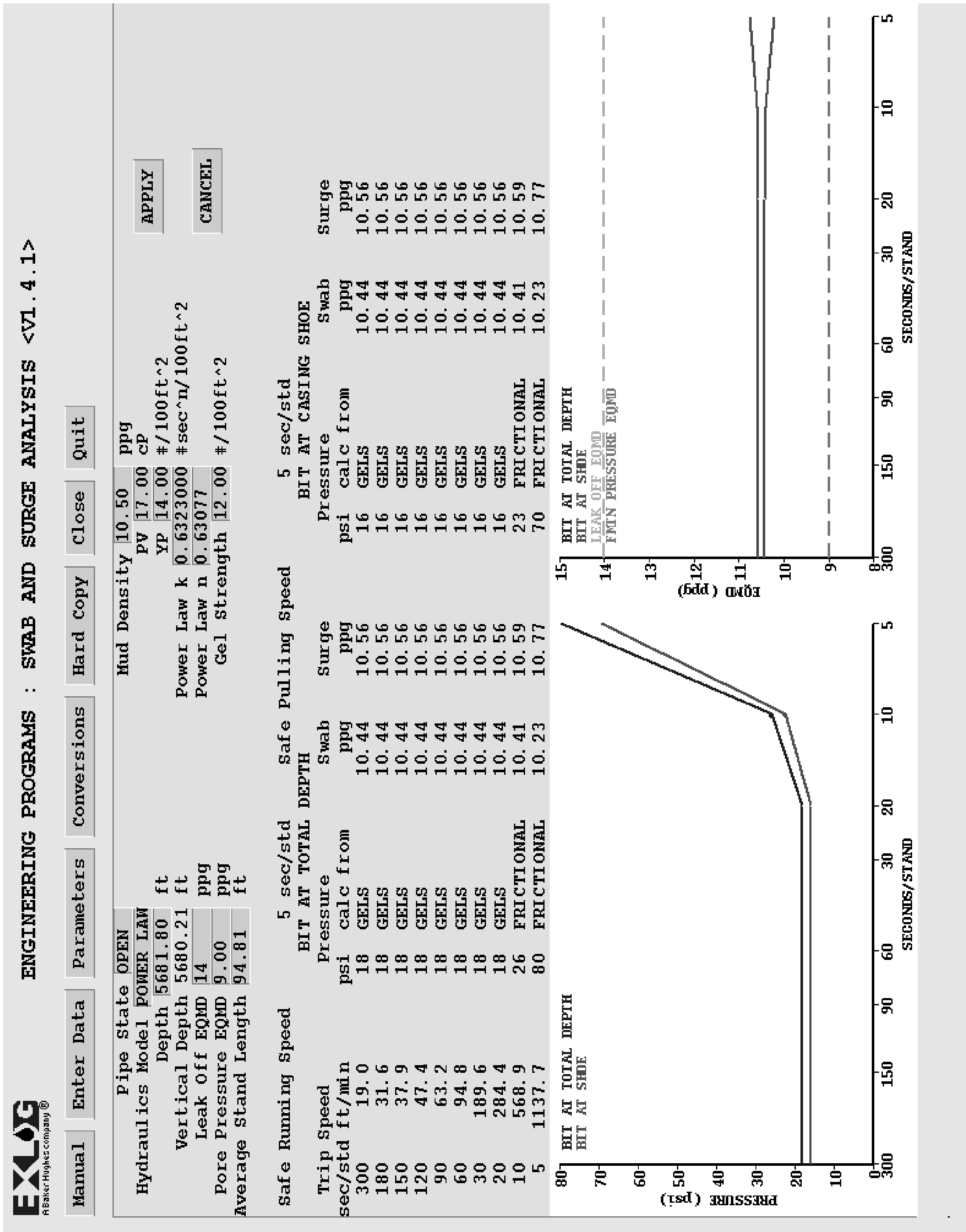


Figure 3-13: DrillByte Swab And Surge Analyses

Riser Margin

In some countries, particularly Norway, regulations state that on floating rigs, the mud density used must be capable of balancing the formation pressure when the marine-riser is removed. An example of such an instance is when surface casing is being run on offshore wells, necessitating (in some cases) removal of the riser. In this case, the calculations are performed as if the system were a mixed density U tube (with seawater on the well-bore side from sea level to seabed, and drilling fluid from the seabed down).

The following example illustrates a possible series of events.

A floating rig is in 250 ft of water. The air gap is 45 ft, RKB to flowline is 5 ft, and 30-inch casing was set at 600 ft. The BOP's and riser were installed, and hole was drilled to the 20-inch casing point at 1500 ft. High gas shows were recorded at 800 and 1100 ft, with a mud density of 9.5 lb/gal. In order to run 20-inch casing, it is necessary to pull the riser.

With 9.5 lb/gal mud in the hole, the following pressures are present:

hydrostatic pressure:

at 600 ft: 9.5 x (600-5) x 0.0519 = 293 psi
at 800 ft: 9.5 x (800-5) x 0.0519 = 392 psi
at 1100 ft: 9.5 x (1100-5) x 0.0519 = 540 psi
at 1500 ft: 9.5 x (1500-5) x 0.0519 = 737 psi

In order to pull the riser, it is first necessary to displace it with seawater (density 8.5 lb/gal). When this is done, the resultant pressures would be:

At seabed, hydrostatic pressure: (250 + 45 - 5) x 8.5 x 0.0519 = 128 psi
… at 600 ft: (600-295) x 9.5 x 0.0519 + 128 = 278 psi
… at 800 ft: (800-295) x 9.5 x 0.0519 + 128 = 377 psi
… at 1100 ft: (1100-295) x 9.5 x 0.0519 + 128 = 525 psi
… at 1500 ft: (1500-295) x 9.5 x 0.0519 + 128 = 722 psi

Resulting gradients of EQMD are

at 600 ft	9.0 lb/gal
at 800 ft	9.1 lb/gal
at 1100 ft	9.2 lb/gal
at 1500 ft	9.3 lb/gal

Notice that the gradients at 800 ft and 1100 ft (9.1 and 9.2) are now much less than the original 9.5 lb/gal used when drilling. If these zones are permeable gas zones of between 9.0 and 9.5 lb/gal formation balance gradient, a problem may result when the riser is disconnected.

When the riser is disconnected, the fluid level in the riser falls to sea level, causing further reduction in pressure:

At seabed, hydrostatic pressure:	250 x 8.5 x 0.0519	= 110 psi
	... at 600 ft: (600-295) x 9.5 x 0.0519 + 110	= 260 psi
	... at 800 ft: (800-295) x 9.5 x 0.0519 + 110	= 359 psi
	...at 1100 ft: (1100-295) x 9.5 x 0.0519 + 110	= 507 psi
	...at 1500 ft: (1500-295) x 9.5 x 0.0519 + 110	= 704 psi

Resulting gradients of EQMD are

at 600 ft	8.4 lb/gal
at 800 ft	8.7 lb/gal
at 1100 ft	8.9 lb/gal
at 1500 ft	9.1 lb/gal

Note that the reduction of only 18 psi throughout the column, caused by disconnecting the riser, lowered the gradients sufficiently to create major underbalance. The zones at 800 and 1100 ft may flow, and with the riser disconnected, controlling the well would be extremely difficult.

In order to keep a 9.5 lb/gal gradient at 1100 ft, it will be necessary to increase the mud density in the hole before disconnecting the riser. The new mud density can be calculated as follows.

Equation 3-16

$$New\ Mud\ Density\ =\ \frac{(D \text{ x } \mathrm{W}) - 8.5(Dw - BOP_L)}{D - Dw - A + BOP_L}$$

where

D	= vertical depth of hole (ft, from flowline)
W	= mud density in the hole (lb/gal)
Dw	= water depth (ft)
BOP_L	= height of BOP stack from seabed to riser connector (ft)
A	= distance from flowline to sea level (ft)
8.5	= density of seawater (lb/gal)

Using the above example where the height of the BOP stack is 35 ft, in order to keep 9.5 lb/gal gradient at 1100 ft, the new mud density must be

$$W\ =\ \frac{(1095 \text{ x } 9.5) - 8.5(250 - 35)}{1095 - 250 - 40 + 35}\ =\ 10.2 \text{ lb/gal}$$

This increase in mud density, or riser margin, must be known at all times as the well is being drilled. Should a situation arise whereby it becomes necessary to move off location (e.g., storms, ice movements, rig damage, etc.), the logging geologist should be able to provide the operator with the riser margin whenever necessary. It is important to note that the riser margin in shallow sediments and very deep water may be too high (the mud density increase cannot be circulated) as the minimum formation fracture pressure may be exceeded. In these situations a rig may have two risers, one for drilling top hole, and when surface casing has been set, the riser is exchanged for the narrower one. It may be necessary, however, to attempt to drill surface hole without a riser, but this can be hazardous if shallow gas is encountered.

Sources Of Fluid Density Data

One aspect of pressure evaluation for well planners is anticipating the basic pressure gradients for the well. If an error exists in the basic data set, it will “infect” (to a greater or lesser extent) all subsequent calculations, which not only affects rig economics, but also well safety.

When using the Formation Balance Gradient (or Pore Pressure), the normal curve must come from a set of pore fluid densities measured at or near the well using some form of sampling that provides unequivocal results.

Unfortunately, this is virtually impossible after the well has been drilled, let alone while it is being drilled, and certainly not possible before the well is spudded. In most cases, any error margin on the FBG will be determined from offset data density.

Several sources of fluid density data, and their usefulness include:

- Production Samples - High quality data but usually over very restricted DST intervals.
- RFT Samples - High quality data but usually only close to the potential reservoir.
- RFT Pressure - This “average” pressure gradient can be “contaminated” with overpressure and thus cannot be back-calculated to give a real fluid density.
- Mud Chlorides - Shows very gross changes in pore water salinity.
- Formation Resistivity - Logs run over most of the well give the total resistivity and, if porosity data is available, (usually from sonic in top and intermediate hole and Neutron-Density logs below) then the formation water resistivity (Rw) can be calculated. Rw can be used to derive parts per million NaCl concentration and thus give an indication of the density of the fluid.
- Rw Tables - Rw is the total resistivity of the water and can only be converted to a density by assuming that all the ionic activity is caused by NaCl, and thus it fails to differentiate between other salts and dissolved gases with different densities.

For this reason the resulting density is usually a “NaCl equivalent”. In areas with high concentrations of other ions (i.e. magnesium which is equivalent to as much as twice the amount of sodium salt in its electrical conductivity), calculations can lead to an overestimation of fluid density. Similarly, underestimates can occur where calcium or hydrogen sulphide (a dense gas) are present in high concentrations.

Despite these limitations, the Rw data available from tables and catalogues in mature areas (and while drilling) have a distinct advantage over the other sources because they are available over entire wells. This enables a more realistic density profile to be built up. A number of charts and tables are available which convert Rw to specific gravity at fixed temperatures (NaCl Equivalent) and empirical algorithms are available (see Appendix C).

This considers situations where data is available. What if (as happens in 90% of cases) no data exists. Is it possible to guess?

At sea we can resort to a primitive “wireline” tool - a bucket on a rope. Sample the seawater and weigh it using a mud balance, and then construct a Formation Balance Gradient using that value. Onshore, we may not even know where the water table is until it is drilled, let alone estimate the salinity of the water. In cases where the densities are not known, a reasonable estimate can be used and extrapolated. At a later date the values can be reassessed, providing that the initial estimate is consistent and justifiable.

Studies of water density variations with depth, in deltaic basins with no buried aquifers, suggests that the first 1000m are dominated by circulating meteoric water. The subsequent 2000m by a connate water showing a gradually increase in salinity and change in ionic composition. Waters deeper than 3000m are of a chemically reducing nature, with a high but uniform salinity. The levels of gases dissolved in the waters tends to vary in direct proportion with salinity. Finally, salinity tends to increase towards the center of a basin.

•Notes•

Chapter 4

Pore Pressure Evaluation Techniques

Introduction

Drilling into a geopressured zone will generally cause a change in a number of basic formation/drilling relationships. This change is usually seen as a reversal of a gradual depth-related trend in a lithologically uniform formation. Several reasons for this change include:

- Compaction will increase uniformly with depth in a normal pressured clay rock. A geopressured zone may be poorly compacted relative to those zones overlying it.
- Porosity and water content decrease uniformly with depth in a normal pressured clay rock. A geopressured zone in which dewatering has been slowed will show a reversal in this trend, with an increased water content and increased porosity.
- Other factors relating to fluid movement, such as ionic concentrations, hydrocarbon saturations, etc. an be different in geopressured zones.
- Differential pressure across bottom, which increases with depth when a normal pressured formation is drilled with a constant mud density, will decrease or even reverse when a geopressured zone is penetrated.

Thus, any measurable parameter which reflects any or all of these factors can be used as a means of interpreting changes in formation pressure and eventually for evaluating and obtaining quantitative estimates of formation pore pressures.

Remember, however, that these properties and the parameters that reflect them vary between lithologies, and that a drilling break or reversal of a trend may simply indicate a lithological change has occurred, requiring a new trend to be established. Similarly, minor lithological variations introduce minor variations in the individual parameters. Care should be taken in the interpretation to account for these lithological variations.

Before the introduction of a Pressure Evaluation Log Suite and specialized recording systems, there were a number of ways of detecting geopressures.

In one sense, as pressure-related data increases, older methods are being replaced or revised. This is both desirable and expected. However, it is crucial not to rely on any methods to such an extent that good logging practices and experience are ignored. Similarly, when only a Formation Evaluation Log is being plotted, the logging geologist should be constantly alert to the occurrence of these geopressure-indicative phenomena and, should they occur, report them immediately to the operator and make a note of the suspected geopressure on the FEL.

Recognizing the existence of geopressure is an essential first stage in overall well control. By itself, it is an excellent tool for well evaluation, economics and safety. For optimum well control, it is necessary that not only the presence but also the magnitude of a pressure abnormality be known. Complete well control is an ideal that even with the best equipment and personnel is not normally reached. Drilling activity, lithological changes, and the type and history of geopressure all affect the degree of accuracy with which its magnitude may be estimated. When reporting this information, the individual should always specify their confidence level and never be afraid to express uncertainty.

Pressure determinations by direct measurement also have disadvantages, and are generally made only after a pressure abnormality has been entered and a permeable zone encountered. These methods are therefore severely limited for real-time well planning, although they may be of value in preparing future well prognoses.

In areas where sufficient data is available, it is usually possible to prepare correlation charts and transparent pressure readers which relate trend deviation to known formation pressure data. These charts can then be used for future wells, to estimate pressure from trend deviations. However, they are reliable only in the area for which they were prepared. Minor variations within the area result in the pressure determination being a vague, qualitative estimate at best, and attempts to use a chart outside its area of preparation, even in an area of similar geological setting, can be disastrous.

Attempts to use cap-rock deviation as a pressure indicator have rarely proved to be of value. In addition to the limitations on the geopressure deviation methods, the efficiency of the “seal” can be affected by mineralogical variations and by vertical extent (e.g. a thick seal of moderate permeability may be as efficient as a thin seal of low permeability). Furthermore, the magnitude of the pressure abnormality contained by the seal will be dependent upon the overall thickness of sediments within the sealed zone, the presence of flow conduits below the seal, and the age of the formations. In cases where correlation has been possible between cap-rock deviation and known pressure data, there are generally thin, discrete cap rocks above relatively uniform pressure abnormalities. These cases have proved to be severely restricted geographically. While the collation of such data should be carried out, and can prove valuable in certain areas, little faith should be placed in the method.

Before a new well commences, a pre-spud meeting should be arranged. During this meeting all relevant data from nearby wells, seismic anomalies, and geological data should be collected and discussed in order that suspected problem zones can be delineated and analyzed. This opportunity can also be used to ascertain communication channels, reporting procedures, and to review the drilling prognosis to ensure that suitable measures are planned in the event of encountering geopressures.

Geophysical & Other Surface Methods

Geophysical methods fall into three broad categories:

- Seismic
- Gravity
- Magnetic

Other physical methods are more chemically based and aim to detect pressure in a very indirect way. For example, high pressure in a hydrocarbon reservoir can be the cause of leakage to the surface, either through the cap-rock or faults. The seepage of hydrocarbons to the surface can be detected by satellite imaging systems (which pick up the discoloration of vegetation) and, at sea techniques like laser fluorscan may show up leakages of some hydrocarbons to the sea surface. Another exotic method is side-scan sonar, which can show plumes of gas leaving the sea-bed. Deep seismic can also show “gas chimneys” leaking.

Seismic Data

The success and accuracy to which geophysicists can predict formation boundaries in the subsurface through seismic interpretation has been used to great advantage in determining possible hydrocarbon provinces. Formations down to 20,000 ft depth can be delineated to about 98% accuracy, but below this accuracy deteriorates rapidly. However, with a different geophone spread, greater resolution (better than 1 percent error) can be consistently obtained for predicting formation tops below 20,000 ft. The highest accuracy can be consistently maintained in an area in which the geology is relatively well known (e.g. in a Tertiary section of simple sand/shale sequence, seismic data can not only predict formation boundaries, but subtle reflections allow interpretation of small fault movements and unconformities). In rank wildcat areas, the lack of data on subsurface lithologies and geologic age is a major handicap in interpreting even formation boundaries.

The response of reflection seismography techniques to overpressure depends upon there being an acoustic velocity contrast between the overpressure and the surrounding rock. This can be caused by a change in lithology, a change in the contained pore fluids, or a change in the cementation of the same basic lithology.

Because of these limitations, the only aspect of overpressure readily detectable on a seismic section are those caused by dramatic changes. This normally means the interpreter is looking for a “bright spot” (the returning wave has a very high amplitude, caused by reflection from a low velocity layer). Since the most frequent cause of low density and hence velocity is gas-filled porosity, this phenomenon is used when searching shallow and intermediate seismic for signs of shallow gas. If gas is suspected, the rig can be relocated or precautions can be taken to minimize the risk of a shallow-gas blowout.

The other source of pressure data from seismic surveys is derived via the “normal moveout” correction. In this process, the arrivals at all the geophones (which may be in the hundreds) from one common depth point (CDP) are plotted side by side. Because the time taken for the sound to reach the furthest geophone is much greater than that taken to reach the closest (even though the reflection is from exactly the same point) the signals when plotted side by side on a vertical time scale will show a curve. Since the object of seismic processing is to sum (or “stack”) all the arrivals from one point (to reinforce the signal and remove noise) it is necessary to have all like peaks corrected to the same time. The correction required to bring the furthest signal into line with the closest is done by a computer using various models. When all the arrivals have been corrected, it is normally assumed that the velocity profile used by the computer to achieve the final result has become a good representation of the true situation. The individual velocities used can then be plotted versus depth. In theory they should show a steady increase with depth and compaction. Deviation to the low velocity side of the trend can be interpreted as a change in pore fluid or porosity, both possible indications of overpressure.

Construction of several velocity curves with depth, from surrounding areas should adequately delineate the normal compaction trend for the area. In a gross sense the resultant curves should be representative of the sonic velocity within the formations to be drilled.

A major drawback with this method is the uncertain nature of the subsurface stratigraphy. Unless the lithostratigraphy is well known, it may be that changes in velocity are indicative of changes in lithology. Based on the model used to correct the seismic traces, changes in lithology may not be delineated by these curves.

In order for geopressured intervals to be recognized, a knowledge of the geology is necessary to increase accuracy. For example, a limestone/ dolomite sequence overlying a thick clay interval will show the characteristic velocity reversal which also occurs across the normally-pressured/geopressured transition in shales. Figure 4-1 shows typical velocity analyses for different lithological sections. A very similar curve can be produced by the vertical seismic profile (VSP) in a borehole.

Even though velocity is usually translated into transit time for the convenience of subsequent correlation with the sonic log, the interpretation remains the same, except that an increase in transit time is synonymous with a decrease in velocity.

Since sound velocity through a material is mainly dependent upon its elasticity and density (and considerably modified by porosity, pore geometry, and other anisotropies), the normal response is for velocity to increase with depth. Departure from this normal trend is generally due either to gross lithological changes or geopressure, which specifically results in a departure to lower velocities with depth.

In a rank wildcat well it is best to assume that any departure to lower velocities with depth is due to geopressure. In this way, the well can be safely planned. In areas of well known geology, a geopressured zone can be recognized with a far greater degree of certainty, as the lithological characteristics would be known.

Pennebaker (1968) indicated that if the rock type remains constant (i.e. uniform clays), the degree of a departure to lower velocities is directly related to the increase in pore pressure. Figure 4-2 shows this relationship. A calibration curve (Figure 4-3) was developed for Gulf Coast wells, and for broad estimates it should suffice for other Tertiary basins.

To estimate the formation balance gradient from velocity analysis, it is necessary to extrapolate the normal trend developed in hydrostatically pressured formations. At the depth of interest, determine the ratio of $\Delta T / \Delta T_n$ (if the velocity analysis is calibrated in transit time), or convert velocity to interval transit time using:

Equation 4-1

$$T = \frac{10^6}{V}$$

where:

T = interval transit time (μsec/ft)

V = velocity (1000 ft/sec)

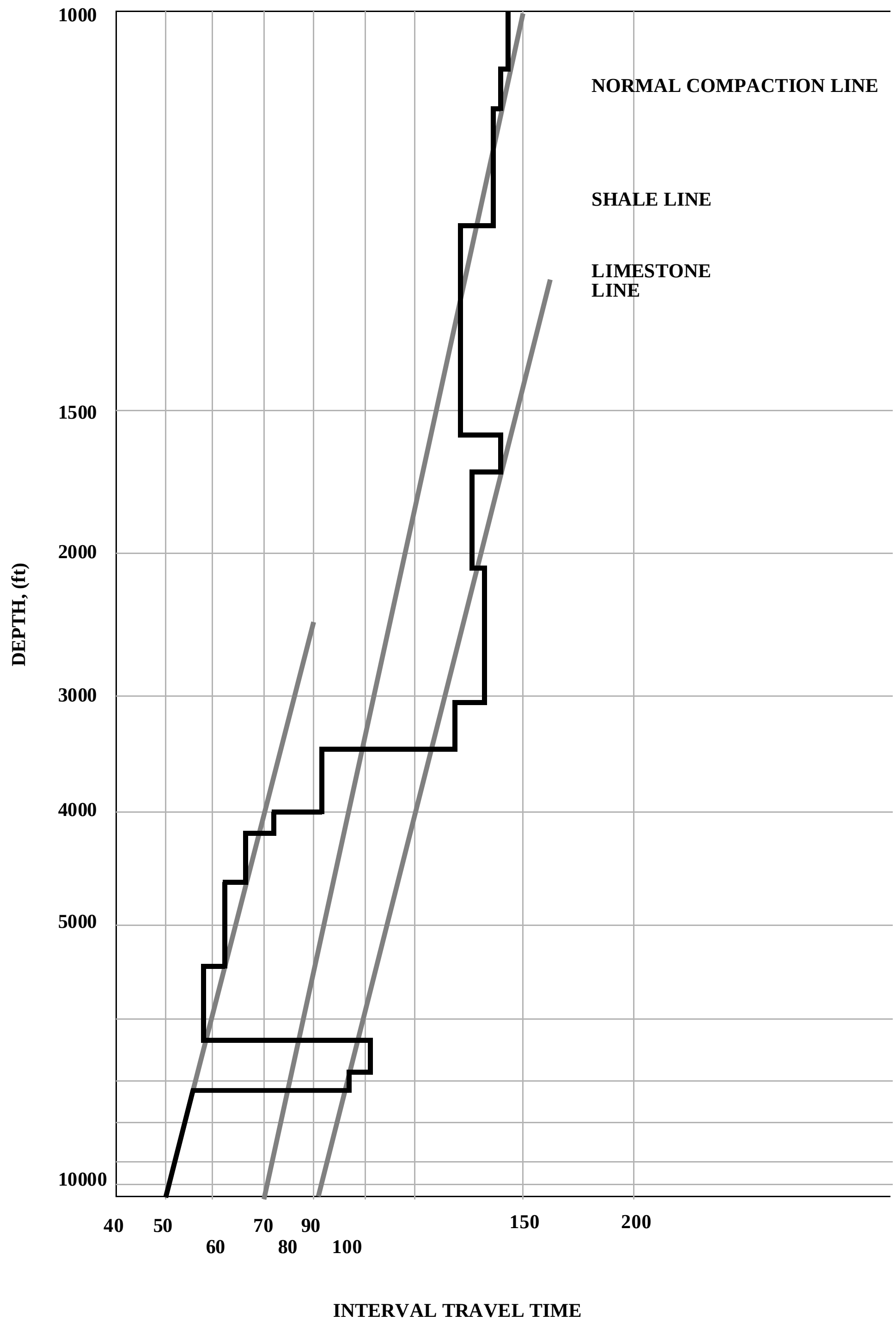


Figure 4-1: Interval transit time variations with compaction and lithology

Use the resulting ratio with Figure 4-3 to obtain an estimate of the formation balance gradient at the depth of interest. Since the velocity analyses (in µsec/ft) is plotted on a log-log grid: the normal compaction trend approximates a straight line on a log depth-scale, facilitating normal trend extrapolation.

Common sources of error in velocity analyses are due to dipping beds, faults, multiple reflections, curved ray paths, processing, and interpretation. Usually the best quality velocity analyses is obtained from good quality seismic sections: good reflections give good root mean squared velocities (Reynolds, 1970).

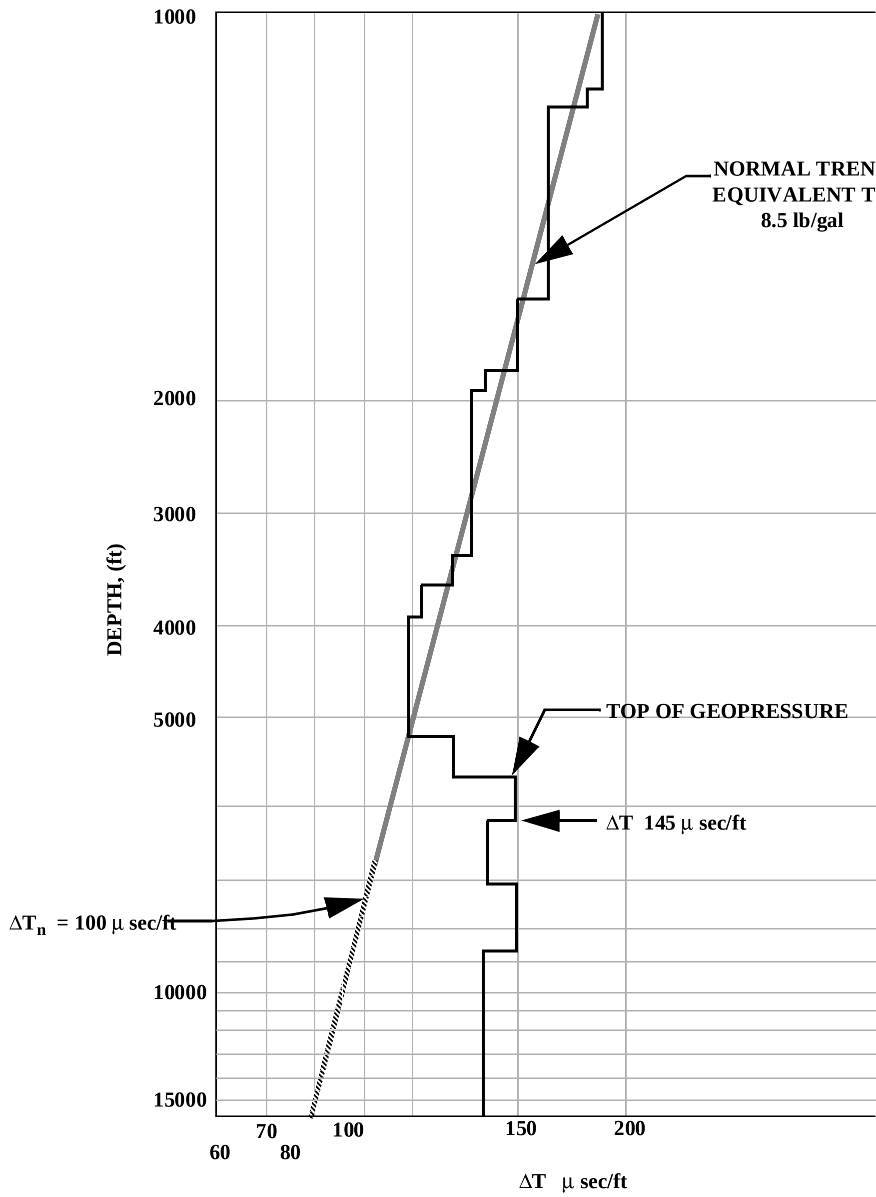


Figure 4-2: Interval transit time variation with pore pressure

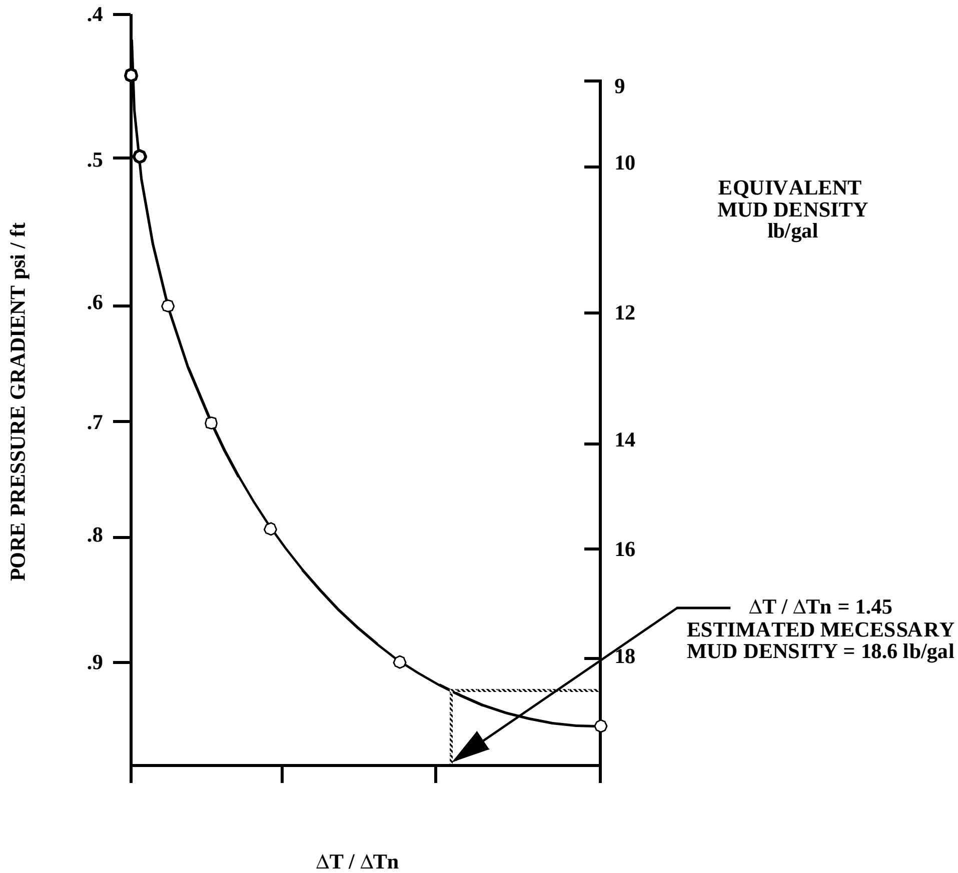


Figure 4-3: Geopressure evaluation from interval transit time

Seismic data can also present an ambiguous picture if bands of low density material (like lignite or cochina) are present. These are often distinguishable from gas on the basis that they will tend to be parallel with the local structure, usually a gentle anticline. Any gas/water contact will be horizontal, unless distorted by local hydrodynamics.

In the deep subsurface, the gas/oil or gas/water contact can show up in a similar fashion. There is more room for confusion at greater depths, since some zones of cementation which were influenced by long-lost hydrocarbons may still show up as velocity contrasts cutting the structure. If, instead of shallow or intermediate data, a deep section is used to search for shallow gas, it is preferable to use a “true amplitude” section (where the event amplitude has not been progressively adjusted for depth), the gas will then still show itself as a very vigorous “bright spot”.

Another use of deep seismic sections is to look for the effects of overpressure or signs that the basin is likely to have caused overpressure. This can be a simple matter of looking for salt or mud diapirs, or a more involved process of searching for subsidence, erosion and thermal histories for conditions conducive to the development of abnormal pressure.

Gravity Data

The use of gravity data to pick up geopressure is also based on the notion that overpressured rocks will have an abnormally low density and high fluid content. While this is certainly not always true, it is often the case in younger rocks.

Since the indications provided by gravity surveys is usually very coarse (i.e. is there a basin present or not), its use is limited. High resolution gravity data can indicate low density diapiric structures below the surface.

Magnetic Data

Although listed by some authors as a possible tool for finding overpressure, it is of very limited use. There is some correlation between hydrocarbons and the valence state of iron in the soil, which may show up around seeps from overpressured compartments.

Drilling Parameters

Mud Density/Gas Relationship

Differential pressure is the difference between the ECD and the formation balance gradient. In most drilling situations, it is desirable to maintain the mud density slightly higher than the formation balance gradient. The resulting differential pressure can then be calculated using:

Equation 4-2

$$(W \text{ x } D \text{ x } 0.0519) - (FBG \text{ x } D \text{ x } 0.0519) = \Delta P$$

where:

W =	mud density (lb/gal)
D =	depth (ft)
FBG =	formation balance gradient (lb/gal)
ΔP =	differential pressure (psi)

Substituting ECD for W gives the differential pressure while drilling. ΔP should be positive during all drilling operations, therefore accurate pore pressure estimations are necessary.

Differential pressure is one of the major factors that affects the amount of gas that enters the mud, and is therefore related to the amount of gas that will be measured at the surface. By interpretation of the gas magnitude/formation/mud density relationships a very good estimate of the formation balance gradient can be obtained. For example:

A 12.25-inch hole is being drilled at 2000 feet with a mud density of 9 lb/gal, and the formation balance gradient is 8.6 lb/gal.

$$\begin{aligned}\Delta P &= (9 \times 2000 \times 0.0519) - (8.6 \times 2000 \times 0.0519)\\ &= (9 - 8.6) \times 2000 \times 0.0519\\ &= 42 \text{ psi}\end{aligned}$$

The same parameters at 15,000 ft:

$$\begin{aligned}\Delta P &= (9 - 8.6) \times 15{,}000 \times 0.0519\\ &= 311 \text{ psi}\end{aligned}$$

Even though the pressure differences in shallow hole are relatively small, hey are nevertheless extremely important.

The volume of gas released from a drilled formation will be dependent upon the porosity, permeability, gas saturation, and differential pressure. Thus if the differential pressure is high, less gas will be released from a sand bed than from a clay bed if all variables (except the permeability) are the same. Conversely, if the differential pressure is low or negative, far more gas will be released from a sand than from a clay with the same porosity, gas saturation and pore pressure, because permeability is higher.

Negative differential pressure (while drilling) complicates interpretations because gas influx will be continually occurring. This is shown by increasing background gas particularly, when just circulating. Negative differential pressure while tripping may result in swabbing, a kick, or severely gas-cut mud upon recirculation. A very small or close-to-zero differential pressure can cause connection gases to be produced from permeable formations. Connection gases produced from clays are indicative of reasonably high negative differential pressure.

Figure 4-4 demonstrates the effect of varying differential pressure on gas show magnitude. The total gas curves for two wells drilled through a similar section are shown. The data for both wells has been normalized to reduce the effects of hole diameter, rate of penetration, mud pump output, and surface extraction efficiency. (This procedure is explained in the *Advanced Logging Procedures Workbook*). Well A was drilled using a constant mud density, whereas in well B mud density was controlled to maintain a constant positive differential pressure (overbalance).

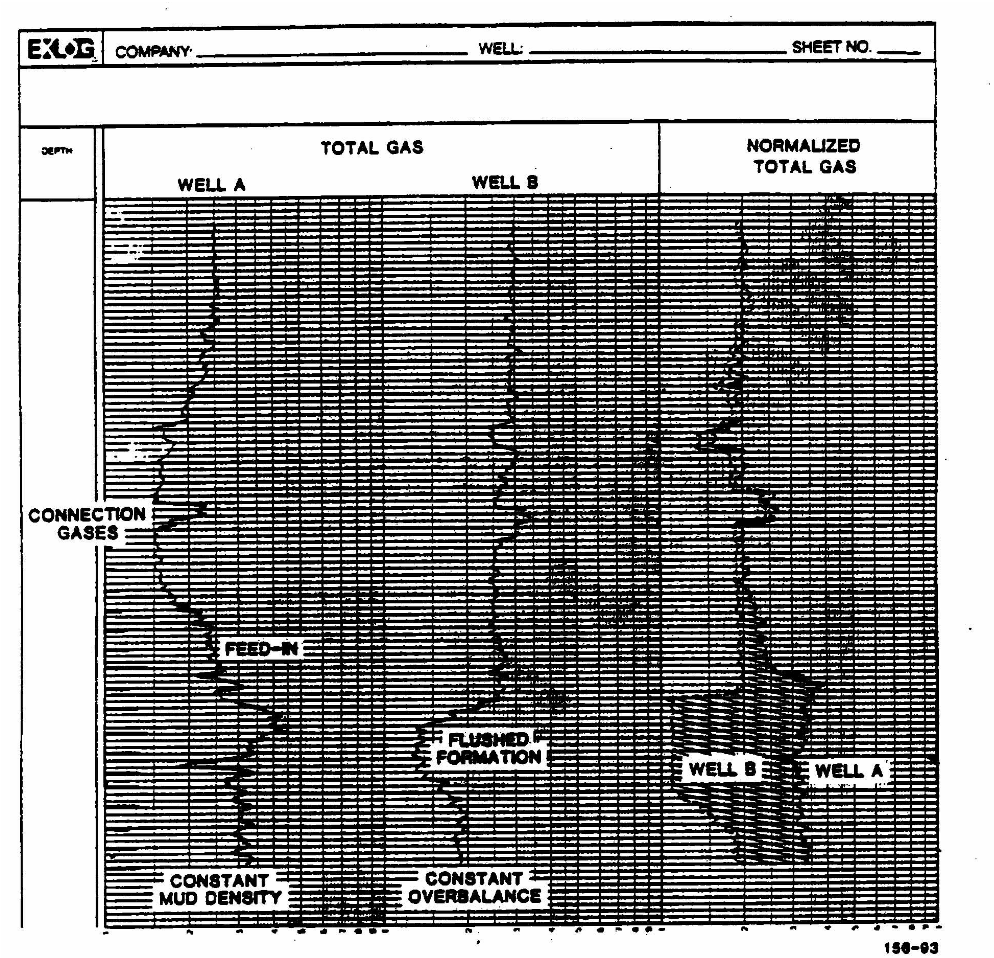


Figure 4-4: The effect of differential pressure on gas show magnitude

In the upper portion, the two gas curves are similar and the normalized gas curves overlay almost exactly. In the lower portion, a progressive deviation between the two wells is seen which is somewhat reduced but remains evident even in the normalized curves. We can interpret this as being due to penetration into a transition zone.

In Well A, maintaining a constant mud density results in a decreasing overbalance and eventually an underbalance (or increasing negative differential pressure). Connection gases occur and become larger with deeper penetration. Additionally, gas feed-in from the underbalanced borehole wall causes an increase in background gas which, since it is not a product of fresh-cut formation, cannot be accounted for in the normalization calculation.

Well B, on which a constant overbalance was maintained by increases in mud density did not show increases in gas background or connection gases. Indeed, if any zone showed good permeability, the overbalance probably resulted in flushing gas away from the borehole and a reduction in the observed total gas.

By careful observation of these various phenomena, a fairly accurate log of differential pressure (and hence pore pressure) can be determined. This information should be used in conjunction with the other pore pressure determination techniques.

A large gas show in surface hole is indicative of very high porosity and gas saturation, since shallow gas does not expand very much before it reaches the surface. This is in comparison to gas from deep formations which expands enormously as it approaches the surface.

Gas-Cut Mud

Mud density reduction due to gas cutting is generally not a cause for concern. It can however, cause serious problems in top-hole sections.

Most of the gas that causes gas cutting is that liberated from the cuttings. As the cuttings are circulated up the hole, pressure is reduced, and the gas in the pores will expand and be released into the mud. The amount of gas entering the mud system can be determined (Goldsmith, 1972) using:

Equation 4-3

$$G_V = \left(\frac{d}{24}\right)^2 \times \frac{\pi \times R}{60} \times \varnothing \times Sg \times 7.48$$

where:

G_v = rate of gas entering the mudstream at reservoir pressure (gal/min)
R = rate of penetration (ft/hr)
d = hole diameter (inches)
Ø = porosity (fractional)
S_g = gas saturation (fractional)

For example, using:

d = 8.5
R= 85
Ø = 0.25
Sg = 0.70

with a reservoir pressure at 15,000 ft of 7000 psi

Equation 4-4

$$V = \left(\frac{8.5}{24}\right)^2 \text{ x } \frac{\pi \text{ x } 85}{60} \text{ x } 0.25 \text{ x } 0.7 \text{ x } 7.48$$

V = 0.731 gal/min at 7000 psi

The gas volume each minute at atmospheric pressure (14.7 psi), using the ideal gas law (neglecting temperature effects) is:

Equation 4-5

$$G_{va} = G_v \text{ x } \frac{P}{14.7} = 0.731 \text{ x } \frac{7000}{14.7} = 348 \; gal/min \; at \; atm \; prs$$

Therefore, when the gas reaches the surface, the volume of gas flowing with the mud is about 350 gallons each minute. If the normal flow is 280 gallons per minute, using a 9.2 lb/gal, the gas mixed with 280 gallons of mud each minute, results in a mud density of:

Equation 4-6

$$W_I = \frac{mud(gpm)}{mud(gpm) + gas(gpm)} \text{ x } W_2 = \frac{280}{280 + 350} \text{ x } 9.2 \; lb/gal = 4.1 \; lb/gal$$

where:

W_1 = gas-cut mud density (lb/gal)

W_2 = uncut mud density (lb/gal)

Increasing the mud density will not reduce this gas cutting, as the hydrostatic pressure of 9.2 lb/gal mud at 15,000 feet is 7162 psi, 162 psi greater than the reservoir (pore) pressure.

As can be seen, the decrease in bottomhole pressure caused by this drastic gas cutting is negligible in deep wells, but can be a major problem in surface hole. For this reason large gas shows and concomitant mud cutting at shallow depth should be treated with the utmost caution.

The pressure reduction caused by mud-cutting is given by (Goldsmith, 1972):

:

$$\Delta P = 14.7\left(\frac{W_2 - W_1}{W_1}\right)\ln\left(\frac{3.53 \text{ x } W_2 \text{ x } D}{1000}\right)$$

where:

P	= pressure reduction caused by mud cutting (psi)
W_1	= gas-cut mud density at the flowline (lb/gal)
W_2	= uncut mud density (lb/gal)
D	= depth of gas zone (ft)

Using information from the previous example:

$$\Delta P = \quad 14.7\left(\frac{9.2 - 4.1}{4.1}\right)\ln\left(\frac{3.53 \text{ x } 9.2 \text{ x } 15000}{1000}\right) \quad = 113 \text{ psi}$$

Therefore, the actual mud gradient at 15,000 feet is

W	= (7162 - 113) x 15,000 x 0.0519
	= 9.1 lb/gal

For gas-cut mud in shallow hole, however, the problem becomes greatly magnified. For example: Hole size is 12.25 inches, rate of penetration is 500 ft/hour, depth is 1000 feet. Formation has 30% porosity with 70% gas saturation, formation pore pressure is 467 psi (9 lb/gal), mud density is 9.2 lb/gal, and pump rate is 450 gal/min. Gas entering the mud system is:

:

$$\left(\frac{12.25}{24}\right)^2 \text{ x } \left(\frac{\pi \text{ x } 500}{60}\right) \text{ x } 0.3 \text{ x } 0.7 \text{ x } 7.48 = 10.7 \; gal/min \; at \; 467 \; psi$$

Gas volume each minute at atmospheric pressure is:

Equation 4-7

$$10.7 \text{ x } \frac{467}{14.7} = 340 \; gal/min \; at \; atmospheric \; pressure$$

The resultant mud density is:

Equation 4-8

$$\frac{450}{450 + 340} \text{ x } 9.2 = 5.2\ lb/gal$$

Thus, pressure reduction at 1000 feet is:

Equation 4-9

$$\Delta P = 14.7\left(\frac{9.2 - 5.2}{5.2}\right)\ln\left(\frac{3.53 \text{ x } 9.2 \text{ x } 1000}{1000}\right) = 39\ psi$$

Although the pressure reduction appears to be small, only 39 psi, the resultant mud gradient at 1000 feet is:

$$(9.2 \text{ x } 1000 \text{ x } 0.0519) - 39 = 438\ psi$$

$$\frac{438}{(1000 \text{ x } 0.0519)} = 8.4 \text{ lb/gal}$$

The mud gradient is reduced from 9.2 lb/gal to 8.4 lb/gal by a reduction 39 psi at 1000 feet. Clearly, if the formation pore pressure gradient is 9 lb/gal at 1000 feet the well will kick if this situation is permitted to occur.

WARNING

Gas-cut mud at shallow depths may be extremely hazardous as a severe kick and loss of well control can result!

These calculations do not take into account the effect of temperature on gas expansion; consequently, the gas volumes calculated at the surface are slightly larger than actual volumes, and the amount of mud density reduction is on the high side. Temperature and compressibility have a small effect on gas expansion when compared to pressure.

Note: *Due to the difficulty of estimating formation temperatures and obtaining realistic values for gas compressibility, the calculations above only take pressure into account; the accuracy is sufficient for this particular application.*

At shallow depths, the temperature effect is insignificant and the calculated values are very close to actual gas expansion. At greater depths where the temperature change relative to surface conditions is considerable, the calculated values are optimistic; however, as was shown in the first example, gas-cut mud from deep sections causes no great difficulties.

Cuttings Character

During normal surface logging procedures, drill cuttings are sieved and graded to a size that is assumed to be representative of the bottom of the hole. The larger fragments are considered to be cavings from the wall of the borehole and play no part in the compilation of a lithological log. In geopressure evaluation, these cavings play a major role.

The presence of cavings in a sample indicates that the borehole wall is unstable. The most noticeable and usually the most predictive of geopressures are those of clay and shale. Other lithologies (coal and sand) will cave as a matter of course, hence interpretations should not include those cavings. The amount of cavings in the bulk sample is also an indication of the degree of instability of the borehole walls.

Simply watching the cuttings traverse the shaker screens will give a reasonable indication of the amount and size of the cavings in relation to the bulk sample. For this reason it is vital that those individuals involved in pressure evaluation not only supervise how the samples are collected, but also regularly check the shakers to see whether cavings are being ignored. Cavings are produced through several mechanisms, the most common are:

- underbalanced drilling
- stress relief

Abrasion of the walls by the drillpipe will also cause cavings but generally these will not be discernible from cuttings due to their small size. If the pore pressure is higher than the hydrostatic pressure in the borehole, the pressure differential will cause the pore fluids to move towards the borehole. In impermeable formations, the resultant pressure gradient adjacent to the borehole wall may become so great as to overcome the tensile strength of the rock. When this occurs, the rock fails in tension, and cavings are formed. This process is illustrated in Figure 4-5.

Since, all parts of the earth's crust contain stresses that change with depth, area, lithology, history, etc., drilling a borehole relieves some stresses other than those in the vertical plane, while the hole geometry in relation to some stresses acts to concentrate them. If the borehole wall is insufficiently supported by the mud column, it may fail either in compression due to the vertical stress, or in tension due to the horizontal stress, or both. This process is illustrated in Figure 4-6

The drilling process will cause the formation of micro-cracks and fractures in the rock and these act as areas of stress concentration and potential initial failure points. Thus it is sometimes noticed that part of a borehole may cave copiously for a short period of time, and then become stable. This is due to the removal of the damaged zone adjacent to the borehole. A formation which is more coherent is then exposed which will absorb the extra energy (drillstring interactions and fluid velocity) without failing.

Cavings produced due to underbalanced drilling are typically long, dark, splintery, concave and delicate. Their typical appearance is illustrated in Figure 4-7a. Cavings produced due to stress relief tend to be more blocky and can vary in size tremendously, depending on the formation characteristics. Examples are shown in Figure 4-7b.

Remember, if the cavings are clays, they may react with the mud and lose their distinctive morphology. Interpretations based on reactive clays should be pursued with caution.

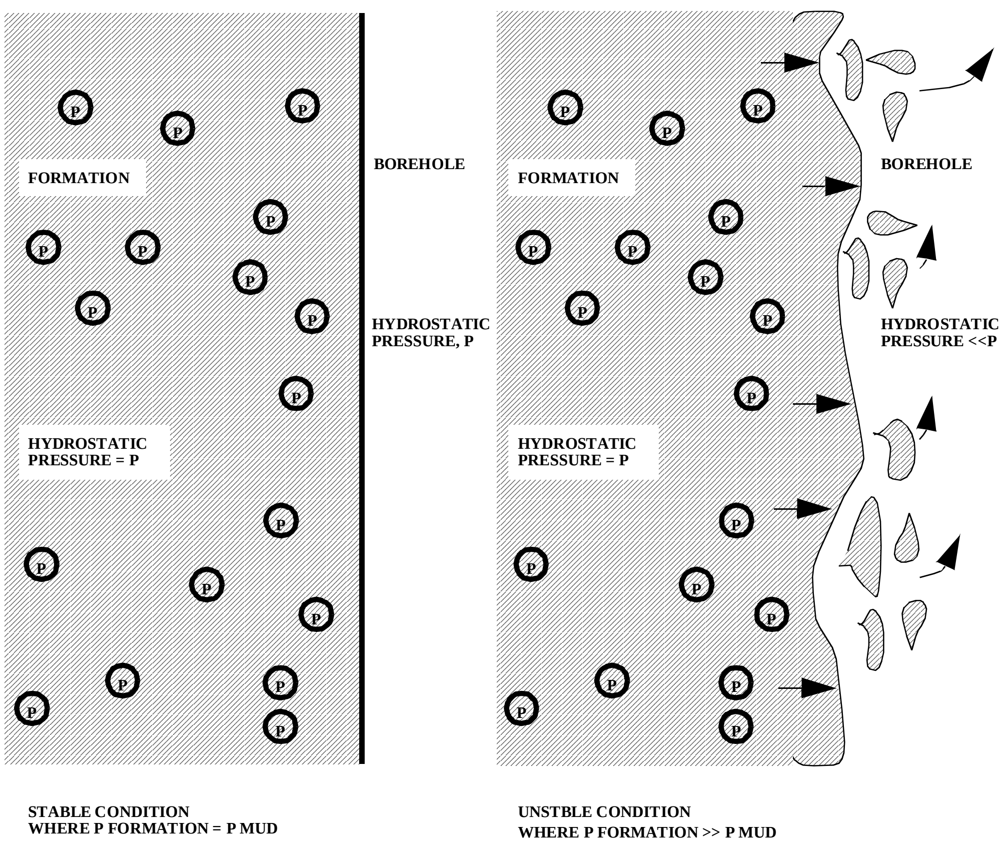


Figure 4-5: Cavings produced due to underbalanced drilling

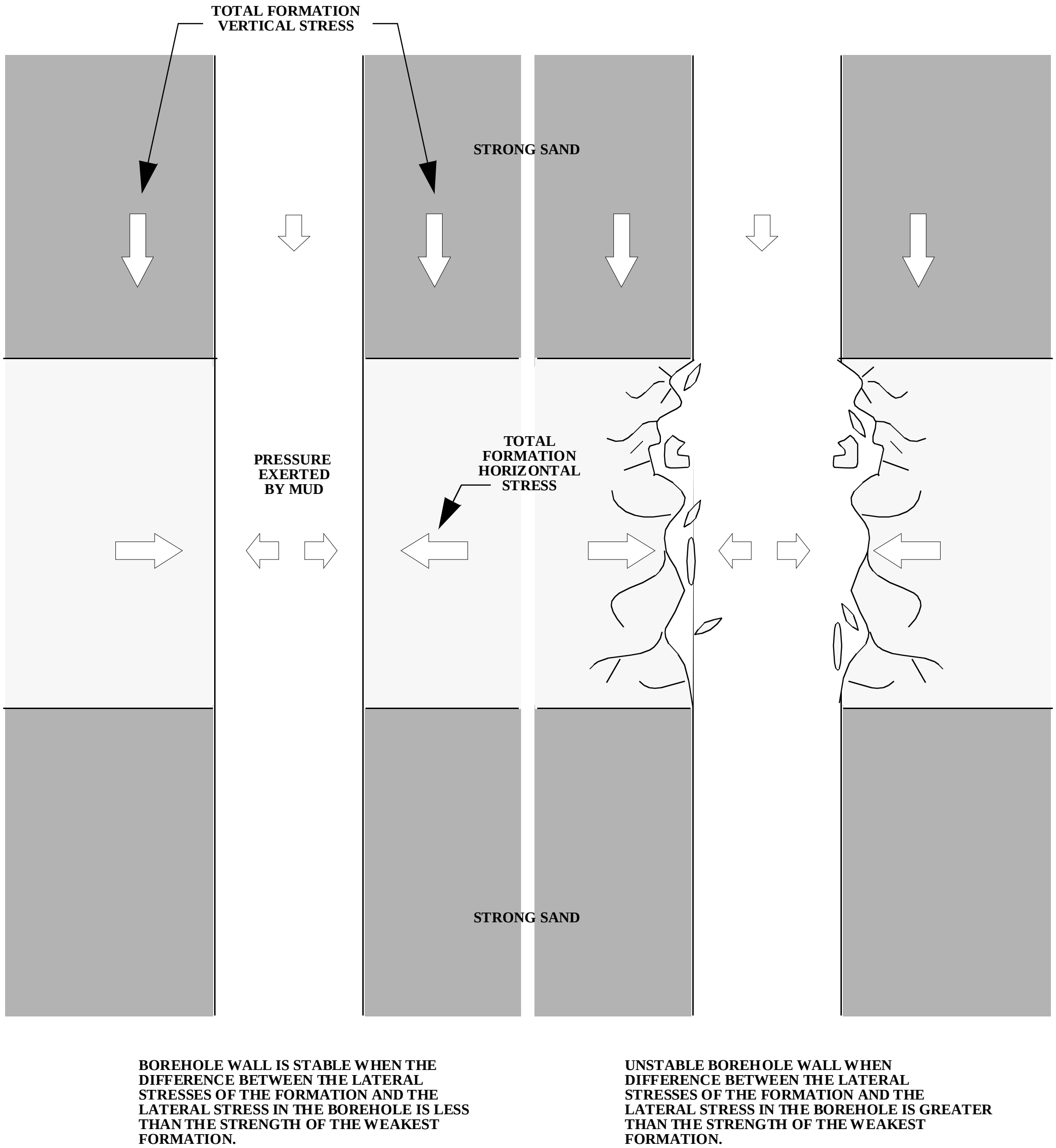


Figure 4-6: Cavings produced due to stress relief and compressional failure

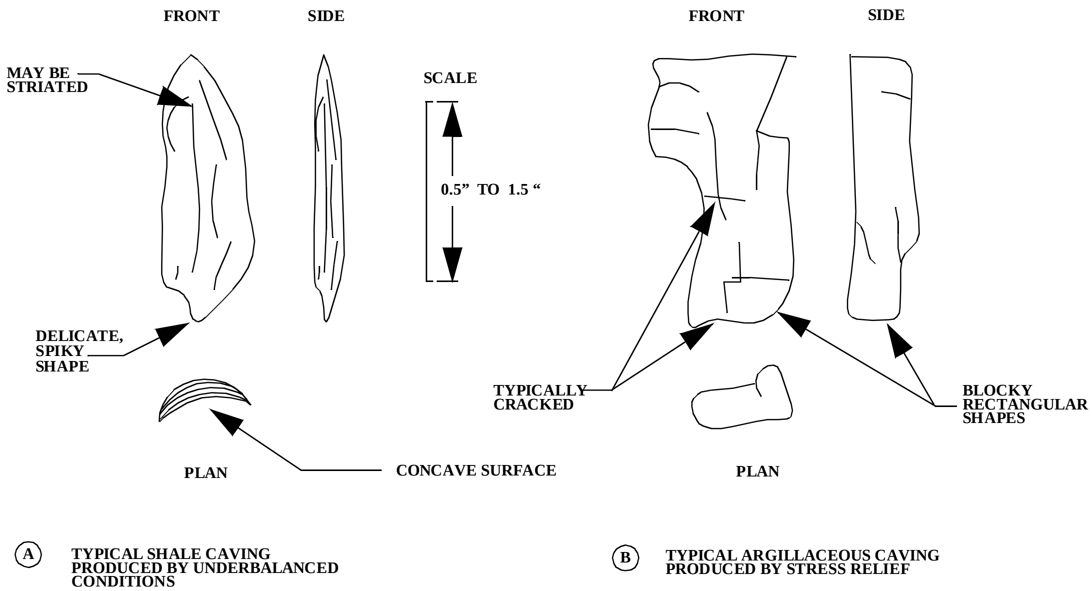


Figure 4-7: Typical cavings produced by underbalance and stress relief

Hole Behavior

When a condition of near balance occurs (for example, ECD will balance formation pressure but mud density alone will not), there will be a tendency for fluid to flow into the borehole. If permeability exists, the well may kick. If permeability is low, insufficient fluid will flow to cause a kick, but there will be large amounts of trip and connection gases.

Where the fluid is unable to flow, spalling or caving occurs. These effects will be recognized by increased torque when drilling, drag on trips and connections, and bottom fill after trips. Normal drag after drilling new hole is of the order of 10,000 to 20,000 pounds, depending upon hole and drillstring geometries. Drag consistently and significantly greater than the "normal" is indicative of unstable borehole conditions. Deviated holes will, of course, incur much higher consistent drag.

The occurrence of connection gas indicates that a condition of imbalance exists when the hole is swabbed at connections. Similarly, when localized gas shows (trip gas, connection gas, gas sands) do not fall off rapidly but linger, often accompanied by a gradual unexplained increase of background gas, a condition of underbalance is indicated.

Clay rocks are a major source of the hydrocarbons, that are normally flushed out of with the pore water during compaction These will eventually flow into permeable zones which constitute the reservoir. Since such flushing does not take place in a geopressured clay rock, the rocks generally carry a far higher hydrocarbon saturation than normal. This will be reflected at surface by an increase in background gas, and, since clay rocks have low permeabilities, by high cuttings gas or blender gas.

This is not true of all geopressured clay rocks. If a clay contained no organic debris at deposition, it will contain no hydrocarbons - in either its normal pressured or geopressured state.

Occasionally an apparent paradox may exist: considerable hole drag precludes the possibility of pulling out of the hole, and continued circulation does not release significant debris. An interpretation may be that a degree of differential sticking is occurring, hence to cure the problem the mud density should be reduced. Another interpretation may be that part of the hole is producing cavings that are not immediately circulated out of the hole (information on cuttings transport can be found in the *Advanced Logging Procedures Manual*), in which case the mud density should be increased. Careful analysis of all geopressure evaluation data should indicate whether the problem is due to overbalance or underbalance. If the problem remains unsolvable, the mud density should be first increased slightly to see if the drag is cured; if not, the pipe may become differentially stuck - but this may be rapidly cured by lowering the mud density to below the original density.

Drilling Exponents

The rate at which a formation can be drilled is determined by a number of factors, some of which are:

- **Force Applied**: This is the effective weight-on-bit per unit area of bit cutting structure. This factor includes bit size, tooth shape and distribution, actual weight-on-bit and threshold force (the minimum force at which the bit will drill)

  Note: *In areas where the S.I. metric system is used, it is common to substitute the term force-on-bit for the traditional weight-on-bit. In this manual we will use the original term, with the reminder that the terms weight and force-on-bit are in all cases synonymous and refer to the sum of the vertical components of all forces acting on the bit, the most important of which is the buoyed weight of that portion of the bottom-hole assembly which is in tension. The quantity is expressed in units of force, that is pounds-force (lb-f), kilograms-force (kg-f), poundals (pdl), or newtons (N).*

- **Rotary Speed**: The rate at which force is applied and the duration of the force.

- **Tooth Efficiency**: This is a variable term based on the original cutting structure efficiency, minimum effective cutting structure (i.e. the point of tooth wear at which the bit ceases to drill) and the rate at which the bit loses efficiency.
- **Differential Pressure**: This affects the efficiency of the drilling process by controlling the rate at which cuttings are cleared from bottom of the hole.
- **Drilling Hydraulics**: This is controlled by pump pressure, flow rate, nozzle sizes, and mud rheology. If too little hydraulic action is applied there will be inefficient hole cleaning, and penetration rate will suffer. Hydraulic action in excess of that necessary for efficient hole cleaning increases penetration rate by the jetting action ahead of the bit.
- **Matrix Strength**: Although some of the typical sedimentary rock-forming minerals possess high compressive strengths, the binding forces between each mineral grain is generally very weak or even nonexistent. Hence, an unconsolidated sand has a much lower matrix strength than a consolidated sand. It is similar with carbonates: pore geometry may be such that the matrix can be either weak or competent. Matrix strength may thus be the converse of “drillability” in the drilling industry.
- **Formation Compaction**: This is related to matrix strength in that it defines porosity distribution; formation compaction simply increases the ratio of matrix material to pore space. Since it is easier to penetrate a pore rather than solid matrix, compaction may not change the actual matrix strength but will affect drilling response as it increases.

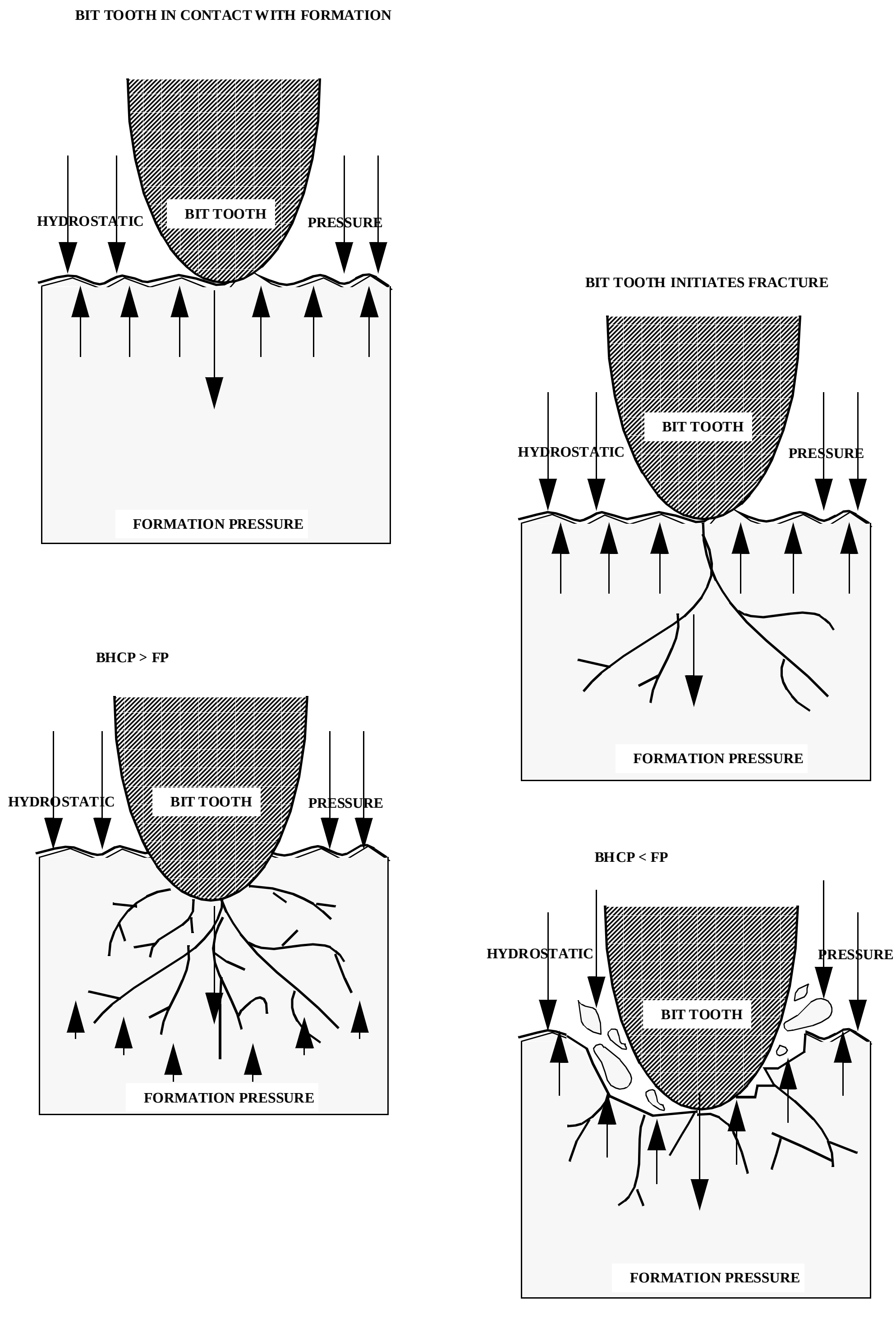


Figure 4-8: How drillability is affected by differential pressure in hard formations

When a bit's tooth penetrates a hard formation, it forms a cone of crushed rock immediately beneath the tooth, and cracks form in the rock (See Figure 4-8). In plastic formations the material will be gouged rather than crushed. The formation of cracks alone will not make hole. The cuttings must be removed as they are formed. The most effective force for the removal of cuttings is high-velocity jetting by the bit.

The ease with which cuttings are removed (and hence the penetration rate) depend upon the differential pressure across bottom (the difference between bottom hole circulating pressure and formation pore pressure). If circulating pressure is much larger than formation pressure (overbalance), cuttings will be held down against bottom by the excess differential pressure. As the overbalance is decreased, these effects are reduced, cuttings will be removed more easily and penetration rate will increase. If formation pressure increases sufficiently for it to exceed the circulating pressure (underbalance), mud filter cake ceases to form and cuttings are forced away from the formation, with a consequent increase in penetration rate.

Large 'cavings' can produced, under conditions of very high underbalance, from beneath the bit resulting from slight tooth impact causing failure. Upon logging the hole, the caliper logs may show remarkably in-gauge hole, even though the volume of these "cavings" was copious during drilling.

Thus with constant drilling conditions in a uniform lithology, it can be seen that the rate of penetration can be controlled by differential pressure alone. Rate of penetration would decrease uniformly with depth as compaction increases. Upon entering a geopressure transition zone, decreasing compaction and differential pressure across bottom would lead to an increase in penetration rate.

A number of "drillability" or normalized drill rate formulations have been proposed to remove the effects of the many drilling variables. For the best application of these formulations, direct data monitoring and computation equipment are necessary. However, field application has shown that, when such equipment is not available, the easiest and most reliable method is the "d-exponent." This formulation allows control of the major drilling variables, and has proved so successful that most of the more complex "drillability" formulations are extensions and refinements of the basic "d-exponent.".

D-exponent

Bingham (1965) proposed that the relationship between penetration rate, weight on bit, rotary speed, and bit diameter may be expressed in the following general form:

Equation 4-10

$$\frac{R}{N} = a\left(\frac{W}{B}\right)^{d}$$

where:

R	= penetration rate (ft/min)
N	= rotary speed (rpm)
B	= bit diameter (in)
W	= weight on bit (lb)
a	= matrix strength constant (dimensionless)
d	= formation “drillability” exponent (dimensionless)

Jorden and Shirley (1966) solved Equation 4-10 for “d”, inserted constants to allow common oilfield units to be used, and plotted the output on semi-log paper which produced values of d-exponent in a convenient workable range. Most important, however, they let “a” be unity, removing the need to derive empirical matrix strength constants, but made the d-exponent lithology specific:

Equation 4-11

$$d = \frac{\log\left(\frac{R}{60N}\right)}{\log\left(\frac{12W}{10^{6}B}\right)}$$

where:

d	= drilling exponent (dimensionless)
R	= rate of penetration (ft/hr)
N	= rotary speed (rpm)
W	= weight on bit (lbs)
B	= bit diameter (inches)

In a constant lithology, the d-exponent should increase as the depth, compaction and differential pressure across bottom increase. Upon penetration of a geopressured zone, compaction and differential pressure will decrease and will be reflected by a decrease in the d-exponent (Figure 4-9).

Since differential pressure is dependent upon the mud density as well as formation pore pressure, whenever there is any change in the mud density this will promote an unwanted change in the d-exponent.

Rehm and McClendon (1971) proposed this correction:

Equation 4-12

$$Dxc = d \text{ x } \frac{N.FBG}{ECD}$$

where:

d	= d-exponent
Dxc	= corrected d-exponent
N.FBG	= normal formation balance gradient - EQMD (lb/gal)
ECD	= effective circulating density (lb/gal)

This correction was empirically derived but has been applied worldwide with much success. The use of actual mud density in place of ECD has been found to be acceptable within normal limits of accuracy. The ECD should, however, be used when available.

Factors not considered by the Dxc in its basic form are drilling hydraulics, tooth efficiency and matrix strength:

- Drilling hydraulics become important in large holes where efficient hole cleaning is impossible, and in soft formations where jetting will make a large contribution to drilling.
- Matrix strength controls both magnitude and rate of change of the Dxc with depth.
- Tooth efficiency affects the Dxc in two possible ways: (1) tooth wear will cause a gradual increase in the Dxc (i.e. decrease in ROP), and (2) a change of bit type may produce a change in the Dxc, especially if the change is a radical one (from a roller cone bit to a fixed cutter bit).
- If differential pressure becomes too large, the simple ratio correction will not completely compensate for its effect on the drill rate.

In addition, the relationships among force applied (W/B), rotary speed (N), differential pressure (N.FBG/ECD), and rate of penetration (R) are more complex than the Dxc formulation would imply. While working within “normal” working ranges, radical changes in any of these parameters (for example, change in hole size after setting casing) may result in a change in the Dxc.

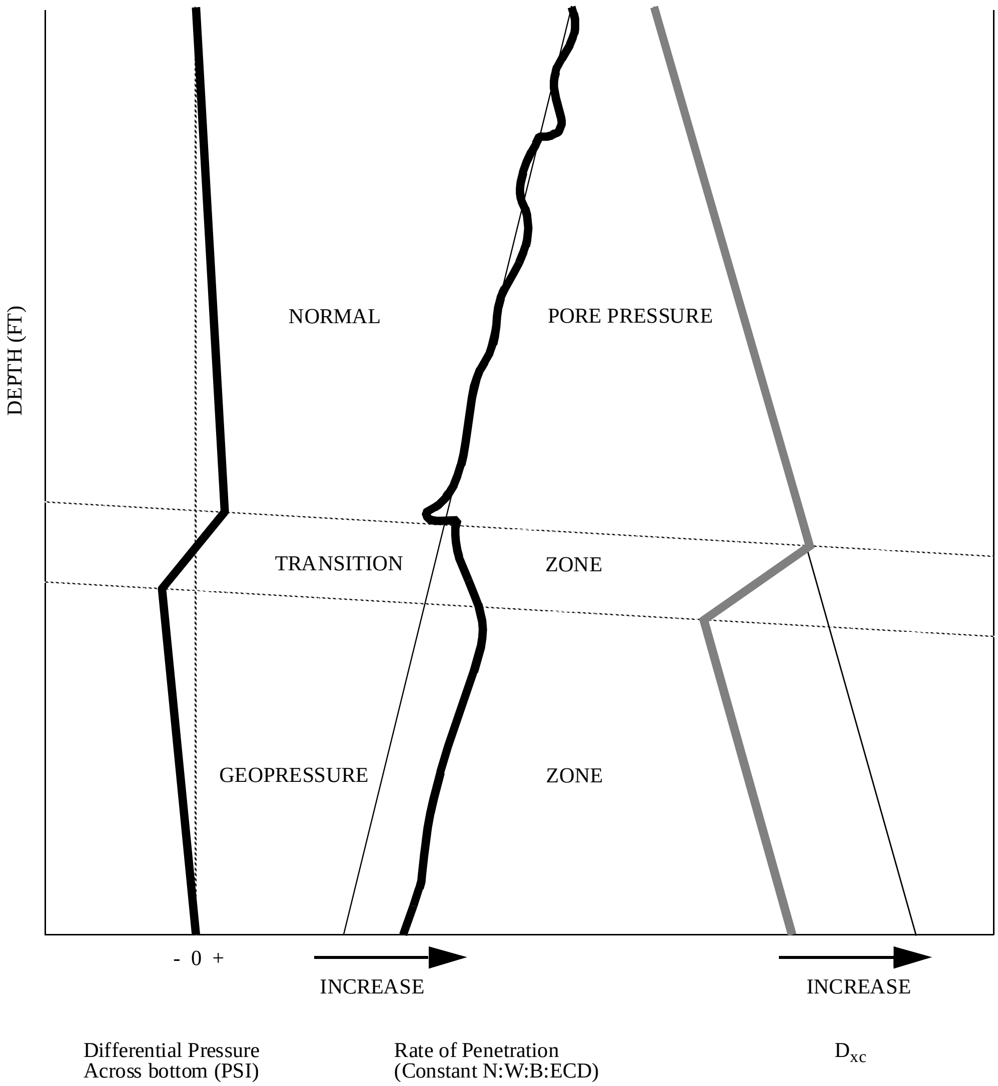


Figure 4-9: Highly stylized curves showing typical response in transition and geopressured zones

When more advanced formulations and computational equipment are available, allowances can be made for the unwanted changes in the Dxc. By plotting Dxc's manually, it is possible to remove their effect by plotting smoothed curves. However, it is better practice is to annotate trend offsets with notes explaining their origin.

The Dxc can be plotted on either semi-log or rectangular coordinate grids, and in either case will produce an approximately linear, normal, compaction trend line. Practice has shown that the semi-logarithmic grid gives a more efficient data display and is a more suitable format when formation pressure estimates are made from Dxc values.

Equation 4-13

$$Dxc = \frac{\log\left(\frac{R}{60N}\right)}{\log\left(\frac{12W}{(10^3B)}\right)} \text{ x } \frac{N.FBG}{ECD}$$

where:

Dxc	= corrected d-exponent (dimensionless)
R	= rate of penetration (ft/hr)
N	= rotary speed (rpm)
B	= hole diameter (inches)
N.FBG	= normal formation balance gradient (lb/gal)
ECD	= effective circulating density (lb/gal)
W	= weight on bit (1000 lbs)

or in the metric form:

Equation 4-14

$$Dxc = \frac{\log\left(\frac{R}{18.29N}\right)}{\log\left(\frac{W}{14.88B}\right)} \text{ x } \frac{N.FBG}{ECD}$$

with

R in m/hr
N in rpm
W in tonnes (1000 Kg)
B in cm
N.FBG and ECD in g/cc

A Dxc plot should be commenced as soon as drilling begins, and ideally should be calculated and plotted every 5 to 10 feet. If penetration rates are too fast, it may be necessary to work in 20-ft intervals.

Major causes of “scatter” in a Dxc plot are:

- Lithological variation: The Dxc value is dependent upon matrix strength and will therefore change when ever the lithology changes. Where lithological variations are relatively minor (e.g. silty laminations in claystone) it may be necessary to adjust the normal trend line in compensate for the changes. Where there are major lithological variations (e.g. interbedded sands and shales), it may be necessary to develop a normal compaction trend line for each lithology (See Figure 4-10).

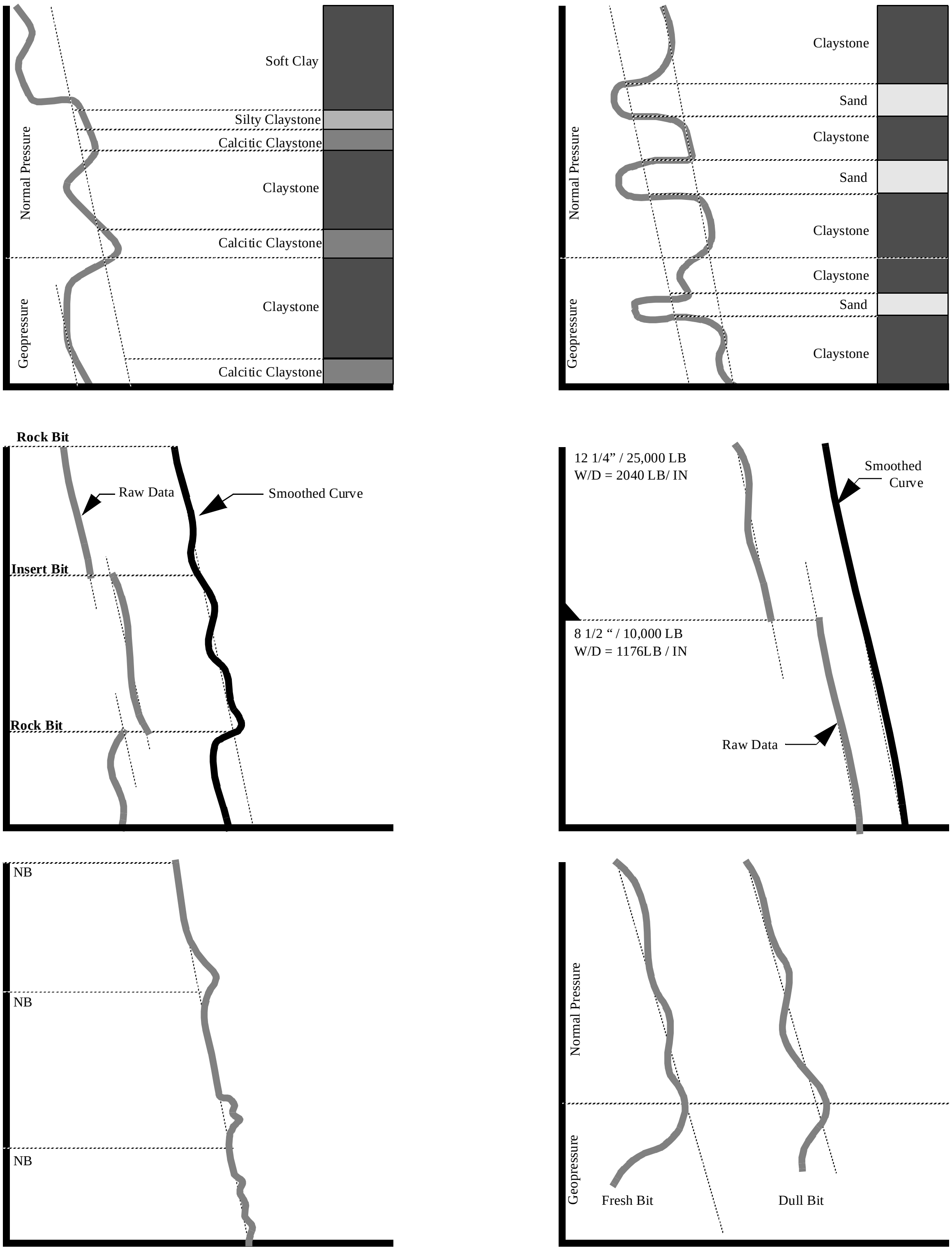


Figure 4-10: Schematic Dxc Responses

- Drilling hydraulics: When ever the drilling hydraulics are changed, or there is a change in the susceptibility of the formation to jetting, there will be a change in the Dxc. It is usual for shallow unconsolidated sediments will be jetted rather than drilled, and pump pressure should be plotted along side the Dxc in shallow formations, to show how fluctuations in pump pressure are related to the change in Dxc.
- Bit types: Different drilling mechanisms with different bits cause changes in drilling response which is reflected by Dxc scatter and trend offsets.

Offsets caused by bit wear are generally disregarded (after careful evaluation). When drilling into a transition zone with a dull bit will make evaluation difficult, since changes in rate of penetration will be less marked, and the decrease in the Dxc due to decreased differential pressure may be partially or even totally masked by the increase due to bit wear.

Modern, high-speed, soft formation journal-bearing insert bits drill just as fast and last longer than comparable milled tooth bits. A past convention, when insert type bits were used, was to subtract 1 inch off the diameter of the bit, in order to avoid shifting trend lines. This practice is not necessary, because insert bits now drill just as efficiently as milled-tooth counterparts. Furthermore, since diamond bits drill by scraping action alone (rotary speed will be directly proportional to rate of penetration), the Dxc model should be more applicable to diamond bits than to roller cone types; again, the practice of subtracting 1 inch from the bit diameter should be avoided.

As will all pressure evaluation parameters, it is essential that the Dxc not be considered in isolation. An instantaneous decision based on the Dxc should be conditional upon confirmation (after lag time) by other parameters, and that there has been no change in lithology. Therefore, it is not normally sufficient to trip on the basis of Dxc alone. Returns should be circulated whenever a Dxc deviation is seen and before any trip, when ever:

- A transition zone is drilled with a dull bit
- No decrease in Dxc is seen
- A geopressured sand is penetrated with a pore pressure which is just balanced by the mud density

because,

- An abrasive sand can remove the last of the bit’s effective cutting structure and the bit ceases to drill
- It has been decided to trip the bit without circulating since no pressure indications have been seen
- When the trip begins, swabbing action reduces bottomhole pressure and the sand kicks

The above situations may be construed as a failure of pressure methods, but in fact they are a failure to apply the methods correctly.

The geologist should make full use of all available information including geological prognoses and offset drilling data (i.e. expected bit life, bit grades when pulled, etc.), and must fully understand the limitations of individual data and the value of data combinations.

Large variations in weight-on-bit will not be fully accounted for in the Dxc formulation and will result in offsets in the normal trend line. A trend shift may also occur at hole size changes. It is recommended that when geopressures are expected, the drilling parameters (W, N, B, ECD) should be changed as little as possible.

The contribution of formation compaction may be less than that of other parameters since formations of similar age and lithology may produce normal compaction trend lines with remarkably constant slopes, while variations in lithology may produce different slopes. Similarly, a radical difference in age may produce some change in slope, especially where uplift and erosion have occurred between periods of deposition. For example, in the northern North Sea Basin, shale trends in the Tertiary and Cretaceous will not exhibit full continuity.

Using a simple ratio method, it is possible to relate Dxc deviations (on a semi-log plot) to the magnitude of geopressure:

Equation 4-15

$$P_o = P_n \times \frac{Dxc_n}{Dxc_o}$$

where:

- P_o = actual pore pressure at depth of interest (psi) or formation balance gradient (lb/gal EQMD)
- P_n = normal pore pressure (psi) or FBG (lb/gal EQMD)
- Dxc_o = observed Dxc at depth of interest
- Dxc_n = expected Dxc on normal trend line at depth of interest.

By rearranging this equation in the form

Equation 4-16

$$Dxc_o = Dxc_n \times \frac{P_n}{P_o}$$

with known values of Dxc_n and P_n at two depths, it is possible to substitute values of P_o and calculate the equivalent Dxc_o.

Using the two calculated Dxc_o values it is possible to plot formation balance gradient lines onto the Dxc plot which will be parallel to the normal trend line (Figure 4-11).

Note: *Certain transparent overlays (pressure readers) are available, ready-marked with equal formation balance gradient lines, so that formation balance gradients can be read directly from the plot. These overlays are prepared using Equation 4-16, using a standard depth scale and log cycle. Use of a different depth scale or log cycle will alter the slope and spacing of the equal formation balance gradient lines and render the overlay useless. Because of the possibility of such errors, Baker Hughes INTEQ suggests that transparent pressure readers never be used.*

Dxc trend lines should be established as soon as possible, and as drilling progresses (based on additional evidence) it will be necessary to alter those predetermined gradients. As such, the position of “normal” trends should be established with great care, though personal selection may be in conflict with another’s interpretation. Modification of trends does not detract from the role of Dxc as a geopressure indicator, it only changes its quantitative meaning. When additional information is available, it is possible that the normal trends will have to be changed, thus necessitating reinterpretation of the magnitude of geopressure zones. When displacing the trend to lower values; however, justification must be found for the apparently over-compacted lithologies above the anomaly. For maximum credibility to be maintained in Dxc interpretations, all other geopressure indicators must support, as far as possible, conclusions drawn from the plot.

Dxc trend lines are normally placed using two different techniques, which may not be apparent to the individual geologist. Some geologists interpret a normal trend in shallow formations and then extrapolate this trend to greater depths. Others interpret normal trends for specific intervals only, changing position and slope to coincide with the majority of points in a particular lithology. Both methods contain inherent pitfalls, some of which can make pore pressure evaluation rather difficult.

It was stated above that the normal Dxc trend is approximately linear. While this is true over short depth intervals, attempting to extend a linear trend over a long interval is not mathematically correct. Doing so assumes that Dxc is an exponential function of depth, when in actuality it is probably closer to a logarithmic function. This being the case, a normal trend on semi-logarithmic paper will produce a curve that gradually steepens with depth. In a normally pressured area, this curved normal Dxc trend line is almost universally observed.

If the above is true, then as the normal trend steepens with depth, on a semi-log grid, it will be necessary to change the straight line trend to a line of greater gradient, but an overall “shift” should not be necessary. Therefore, extrapolation of a normal trend (established in shallow formations) to greater depths may diverge from the actual normal trend; and if geopressures are encountered, the calculated pore pressure will be in excess of the actual magnitude. Geologists who are thus in favor of extrapolating normal trends should be aware of the possibility that their “normal” trend may not be representative at depth.

Geologists who change normal trends with lithological variations generally inadvertently steepen trends with depth, reflecting the true behavior of the normal trend on semi-log paper. Hence these trends may be more accurate, and pore pressure calculations may be more meaningful. The best rule to follow in trend placement is to make the trend fit the data - not to some preconceived idea of how the data should behave.

With Dxc scatter and normal trend changes aside, the overall placement of a normal trend (for example, during the latter stages of a well) may be largely dependent on the previously encountered lithologies. As shown in (Figure 4-10(a)), the normal trend for claystones passes through the majority of Dxc points but falls above the silty zone and below the calcitic horizons. Also, the shallow unconsolidated clays were subject to jetting (resulting in considerably lower Dxc values). Note that the upward extrapolation of the normal trend passes to the right of these points. However, a curved normal trend, briefly described above, fits this schematic data well. (Figure 4-10(b)) illustrates normal trend development in alternating sands and shales. This diagram represents an extreme case, and the actual Dxc response in such sequences usually shows an increase in scatter, rather than distinct trend development.

These problems with placing a normal trend only accentuate the rule that geopressure magnitude should not be based on Dxc calculations alone.

Moreover, interpretation techniques must also contain the proviso that the normal trend may steepen with depth, but shifting trends should not be necessary. In fact, theoretical justification for a shifted trend is not available.

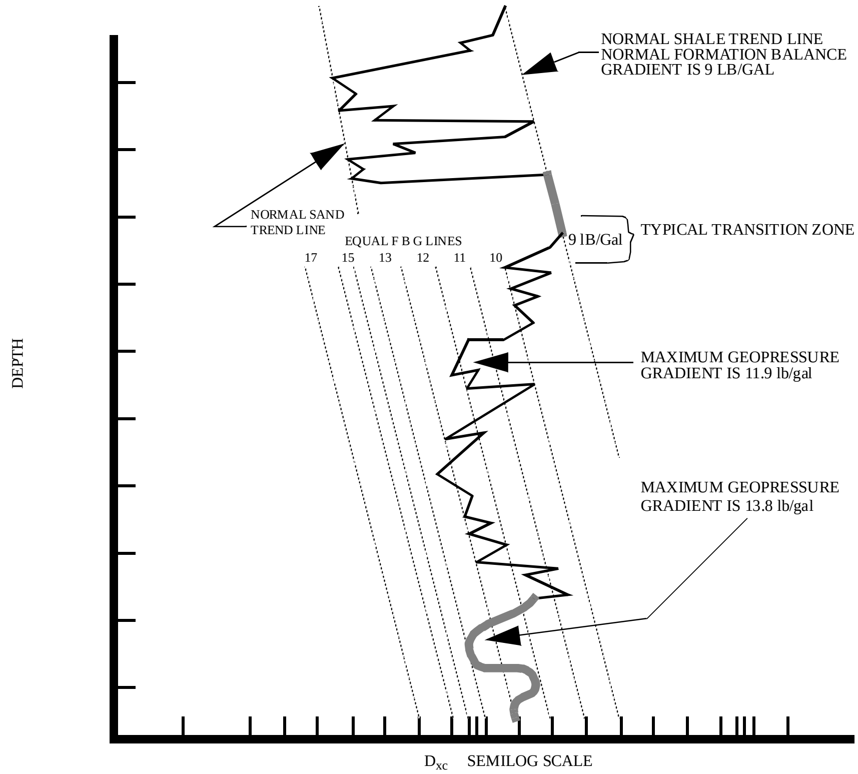


Figure 4-11: Example of the formation pore pressure gradients from the Dxc plot

Second Generation Exponents

Because the Dxc is still affected by several drilling factors, which are not taken into account by the Dxc formula, several oil-field service companies and authors have derived equations and formulas to try and compensate for those other drilling factors. Several of these “second generation” normalized drill rate formulas include:

- Nx & Nxb (EXLOG)
- Sigmalog (Geoservices & AGIP)
- Combs formula (1968)
- Normalized Drill Rate (1980)
- LNDR (Baroid)
- A exponent (Anadrill)

These are basically refined Dxc’s that attempts to more closely reflect the various drilling/formation interactions. Where Dxc assumes a linear response between RPM and rate of penetration, the above try to model the interaction to a non-linear relationship modified by tooth efficiency and an effective RPM term. Also, the contribution that hydraulics makes in the drilling process may also be normalized, resulting in a drilling exponent that changes more as a result of lithological or pore pressure change, rather than fluctuation caused by bit wear or simplistic drilling parameter modeling.

These second generation exponents are generally location specific, and the derivation of the information to determine pore pressure is usually not available to the public. As such, they should be used with care. Discussion of these formation evaluation tools is limited due to their proprietary nature.

Shale Density

Shale density determination has often proved very effective in determining the degree of undercompaction and consequent abnormal pore pressure in shale bodies. The shale density kits provided by Baker Hughes INTEQ are intended for the rapid determination shale density from drilled cuttings. The three methods of determining shale density from cuttings are:

1. Single-solution
2. Multi-solution
3. Mercury pump

The single-and multi-solution shale density kits work on the same principle (Archimedes Buoyancy Principle), which states that a liquid exerts an upward force on an immersed body equal to the weight of liquid displaced.

The kits consist either of a variable-density single solution, or a set of liquids of varying densities. By placing a piece of shale in such a liquid, its density can be determined as it either sinks or floats through the liquid.

An accurate determination of shale bulk density can be obtained utilizing a mercury pump. It is known as the “Kobe Method.” In essence, the difference between the reference volume and the sample volume will determine the bulk density.

Shale density determination can be of great value since it provides information on the compaction of the shale. Under normal conditions, shale density should increase with depth. Any deviation from this consistent trend can indicate that geopressures exist. The magnitude of the bulk density change will vary with the type and magnitude of the geopressure. Bulk density may also decrease, but it may remain constant (due to lithology) or continue to increase at a lower rate than the previously established trend due to the geopressure mechanism (see Figure 4-12).

It has been observed that shale density can decrease as much as 0.5 g/cc or more. When this reduction occurs over a significant depth interval, the calculated overburden gradient may reverse.

A low density zone may also be the result of a change in lithologic character. Fissility, plasticity, carbonate content, color change and other differences may or may not be apparent, unless the sample is observed under a microscope prior to it being placed in the density solution.

Measurements based on cuttings in water-based muds usually are too low, simply due to the adsorption characteristics of clays. Likewise, density measurements taken from wireline/MWD logs can also give false indications. Specifically, the density logs can be affected by a rugose hole, and the shallow depth of investigation may not read beyond the hydrated zone. The result is erroneously low readings, causing excessively high calculated porosities. The sonic log will also be greatly affected by hydrated clays, resulting in very high transit times, high porosities and low calculated bulk densities.

Values may be successfully obtained from these logs when water-based muds are used, but caution should be exercised as errors may exist as explained above.

The best densities are those obtained from wells drilled with less reactive muds such as diesel types. Both actual cutting densities and log densities should be more accurate, as the clay should remain in their virgin state.

Several methods are used for measurement of shale bulk density:

- ***Pycnometer method***: Using a container with repeatable volume, this involves measuring change of weight due to displacement of fluid by sample. The most practical application of this method at the wellsite is to use a mud balance.

  Place enough cuttings in the cup so that the balance indicates 8.34 lb/gal (density of fresh water) with the cap on. Fill the cup with water and weigh again. The new reading is W_2 in the following equation:

Equation 4-17

$$Bulk\ Density\ (g/\mathrm{cc})\ =\ \frac{8.34}{16.68 - W_2}$$

- ***Mercury pump method***: The bulk volume of a known weight of sample is measured. The bulk weight of a prepared sample is first established using an accurate chemical balance. The bulk volume of selected cuttings is then determined using a high-pressure mercury pump by the Kobe system (Boyle's Law Principle) at a pressure of about 24 psi, which is recorded on the attached pressure gauge. Mercury is used to compress the air around the cuttings but does not contact the sample material.

> **Note:** *This is contrary to the older procedure in which bulk volume is measured under atmospheric pressure with the bleed-off valve open at the top of the sample chamber, allowing the mercury to contact the sample. This method should not be used.*

The accuracy of this instrument and the large amount of sample used (25 g ≅ 2000 individual shale cuttings) give good consistent results. Due to the high degree of accuracy and convenience in operation, this method should be used whenever possible; however, very careful and consistent sample handling is necessary for best results.

- ***Buoyancy method***: The sample is weighed in air and in liquid of known density.
- ***Density comparison methods***: The simplest of these is the “Float-and-Sink” method. Shale cuttings are immersed in fluid mixtures of different densities in which they will either float or sink, depending on relative densities. This method is cheap and quick, but is limited in sensitivity due to large difference in densities of available fluids (approximately 0.1 to 0.05 g/cc), and ease of contamination of calibrated fluids.
- ***Density gradient method***: This consists of a fluid column in which density varies uniformly with depth. This is prepared by the partial mixing of a light and a heavy fluid (water and zinc bromide) in which beads of known density are suspended. A calibration curve of density versus depth is prepared. Shale cuttings immersed in the column will sink to the level at which their density is the same as the fluid. Depth is recorded and density read off from the calibration curve. A major disadvantage of this method is the rapid deterioration of the column due to vibration experienced on some offshore rigs, the expense and time consumption of reproducing the column due to the large volumes.

Both heavy liquid methods, while being quick and simple, have the disadvantage of determining the density of individual cuttings. Special care must be taken to ensure that cuttings are true bottomhole cuttings, and several determinations should be made for each interval in order to avoid anomalous results. Six or eight cuttings should be chosen which are representative and free of dust or cracks which may trap air, and of water film which will cause enough surface tension between the water and density fluid to cause erroneous readings.

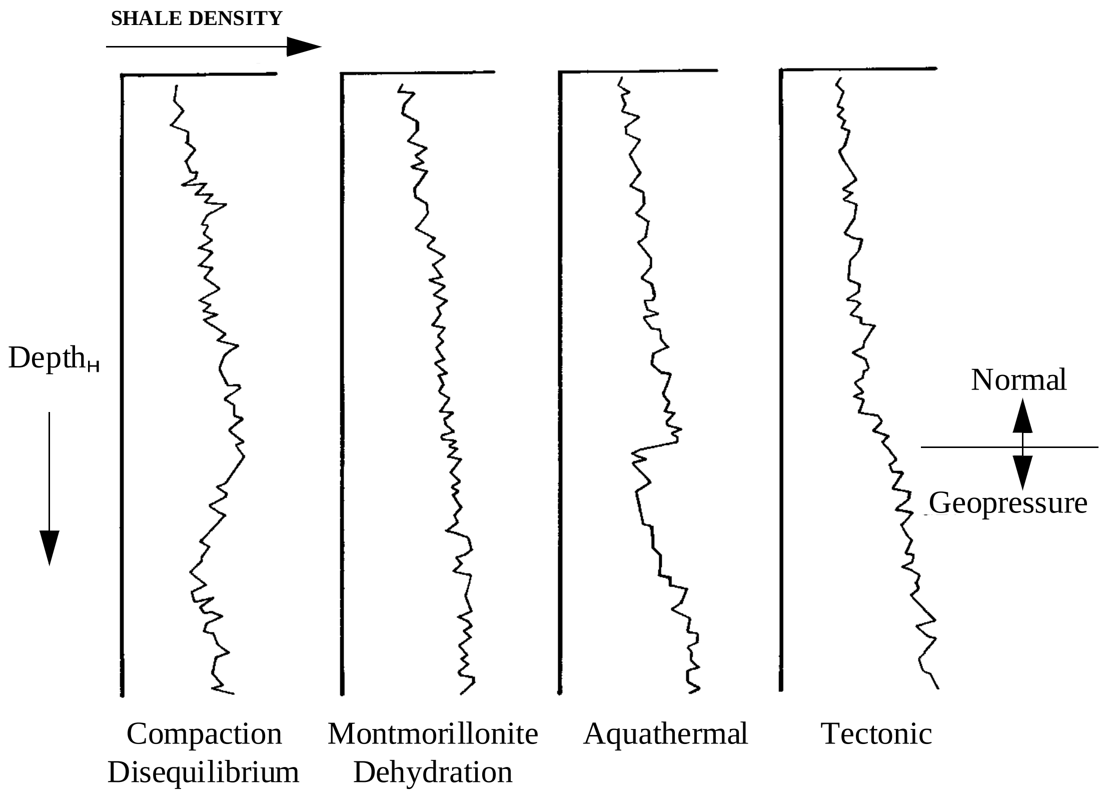


Figure 4-12: Ideal clay density responses in geopressured zones caused by different mechanisms

Increases in density beyond the normal trend, due to decreased porosity or calcification should be carefully noted as these may constitute cap rocks above geopressures. Precipitation of pyrite or high iron concentrations result in abnormally high bulk densities in clays and shales. In some wells it has been postulated that the occurrence of pyrite in shales can mask the density reduction caused by the porosity increase. Careful microscopic examination of clays will indicate the occurrence of very fine pyrite, and high iron concentrations will be indicated by a red/brown color. Pore pressure interpretations cannot be accomplished utilizing shale density if heavy minerals are present. However, since shale density is mainly used for qualitative purposes in geopressure evaluation, the role of the other geopressure indicators remains unchanged.

Any decrease in density (without change in clay character) should be recognized as a pressure transition zone.

Recognition of a normal bulk density trend line may be difficult due to the degree of scatter in the rectangular coordinate plot. A semi-log plot considerably reduces this scatter, but since the normal bulk density range is between 1.6 and0 2.7 g/cc, it results in a more distorted trend line and difficulty in recognizing deviations.

Shale Factor

In Chapter it was shown that various clay types have different cation exchange capacities and consequently different adsorption capacities. It was also shown that a smectite-type clay will undergo diagenesis to illite with increasing temperature and ionic exchange. In order for diagenesis to proceed, water must be flushed from the clays. If exchange cations are not available(i.e. potassium) a montmorillonite clay will lose its water but will not convert to illite. Thus if this type of clay is drilled with a water-based mud, the clay will hydrate and cause drilling problems.

Shale factor is a measure of the cation exchange capacity (CEC) of clays. This cation exchange capacity will decrease as clays convert from montmorillonite-type to illite-type (with temperature and thus with depth). Pure montmorillonite clays have a CEC of approximately 100 meq/100 g, while pure illites (showing no swelling characteristics), have a CEC generally between 10 and 40 meq/100 g. Kaolinites have a CEC of approximately 10 meq/100 g.

It is only the smectite group (which includes bentonite and montmorillonite) that have an affinity for water. Thus any clay/shale zone that contains smectites will have an affinity for water in an amount generally proportional to the montmorillonite content. This will be shown by a proportional value in shale factor. Note that the shale factor as measured at the wellsite will not give values corresponding to actual chemical cation exchange capacity. This is due to impurities in the sample, methodology, experimental error, and the fact that the methylene blue dye (used in the titration) is a very large molecule and is not readily absorbed into interlayer sites.

A reasonably fast method for shale factor determination is:

1. Take representative clay/shale cuttings from the sample and dry it in the oven.
2. Grind the clay to a fine powder with the motar and pestle.
3. Weigh approximately 0.5 g of the powder on a balance, and add this to a solution of distilled water and a few drops of 5N sulfuric acid in a metal blender measuring cup.
4. Heat the clay suspension to boiling on the hot plate, stirring continuously.
5. Add methylene blue dye slowly, and regularly remove a drop of the solution on the stirrer and place the drop on filter paper, noting whether the fluid is colored. Generally, the solids in the

droplet remain in a localized spot on the filter paper while the water spreads away from the central spot, so any coloration in the halo may be readily seen.

6. Add methylene blue dye until the end-point is reached. This occurs when the halo of blue dye first occurs.

7. Calculate the shale factor, using:

Equation 4-18

$$shale\ factor\ =\ \frac{100}{sample\ mass\ g}\ \text{x}\ vol\ ml\ \text{x}\ (normality\ of\ methylene\ blue\ solution)$$

where:

vol = volume of methylene blue used when end-point was reached

For example:

sample mass	= 0.5 g
volume of titrate	= 25 ml
normality of dye	= 0.01

$$\text{shale factor} = \frac{100}{0.5}\ \text{x}\ 25\ \text{x}\ 0.01$$

$$= 50\ \text{meq/100 g}$$

A more accurate, but more time-consuming procedure is:

1. Take a clay sample, add about 20 ml of water, and disintegrate sample in the blender.

2. Acidize the suspension with a few drops of 5N sulfuric acid. If there are polymers in the drilling fluid, it will be necessary to add several drops of hydrogen peroxide to the sample.

3. Sieve the solution through a 180-mesh screen in order to remove sand, lime, etc.

4. Put the suspension into the mud filter press, and allow the water to almost cease flowing from the press before disconnecting the pressured air supply.

5. Weigh 0.5 g of the filter cake that is on the filter paper.

6. Proceed with the titration in the same manner as described above.

This latter method may be more accurate in gumbo clays.

If the clay is calcareous, and calcimetry is also being run, shale factor may be corrected for carbonate content.

Equation 4-19

$$true\ shale\ factor = \frac{100}{100 - carbonate\ \%} \times (apparent\ shale\ factor)$$

For example:

A calcareous clay has a carbonate content of 37%, and an apparent shale factor of 16:

$$true\ shale\ factor = \frac{100}{100 - 37} \times 16 = 25\ meq/100g$$

Shale factor can be a useful lithologic indicator, as shown in Figure 4-13.

The abrupt shift in shale factor from the normal sand/shale sequences to a much more compact sediment at 6705 ft, along with the break in the compaction trend, defined the top of a 3000-ft section of missing sediments (15 million years), was thought to be caused by continental movement and erosion in the shallower continental shelf at that time in the geologic history of Australia. Even in the normally-pressured low shale-factor shales and carbonates of greater geologic age, there can be occasional anomalies from pressured shale stringers (as at 11,500 ft).

Theoretically, shale factor should be capable of indicating whether montmorillonite dehydration or compaction disequilibrium was the major mechanism in generating an apparent geopressure.

Geopressures caused by compaction disequilibrium indicate that the pressured zone is immature with respect to the shallower, normally pressured sediments. This implies that diagenesis has been restricted by the inefficiency of the dewatering process, resulting in clays containing a larger proportion of montmorillonite within the geopressure zone. Shale factor would thus indicate a decrease at the top of the geopressured zone, an increase within the zone, then a decrease as the pore pressure gradients decline (Figure 4-14). Any overall increase in shale factor within a geopressured zone is indicative that compaction disequilibrium has played a part in its formation.

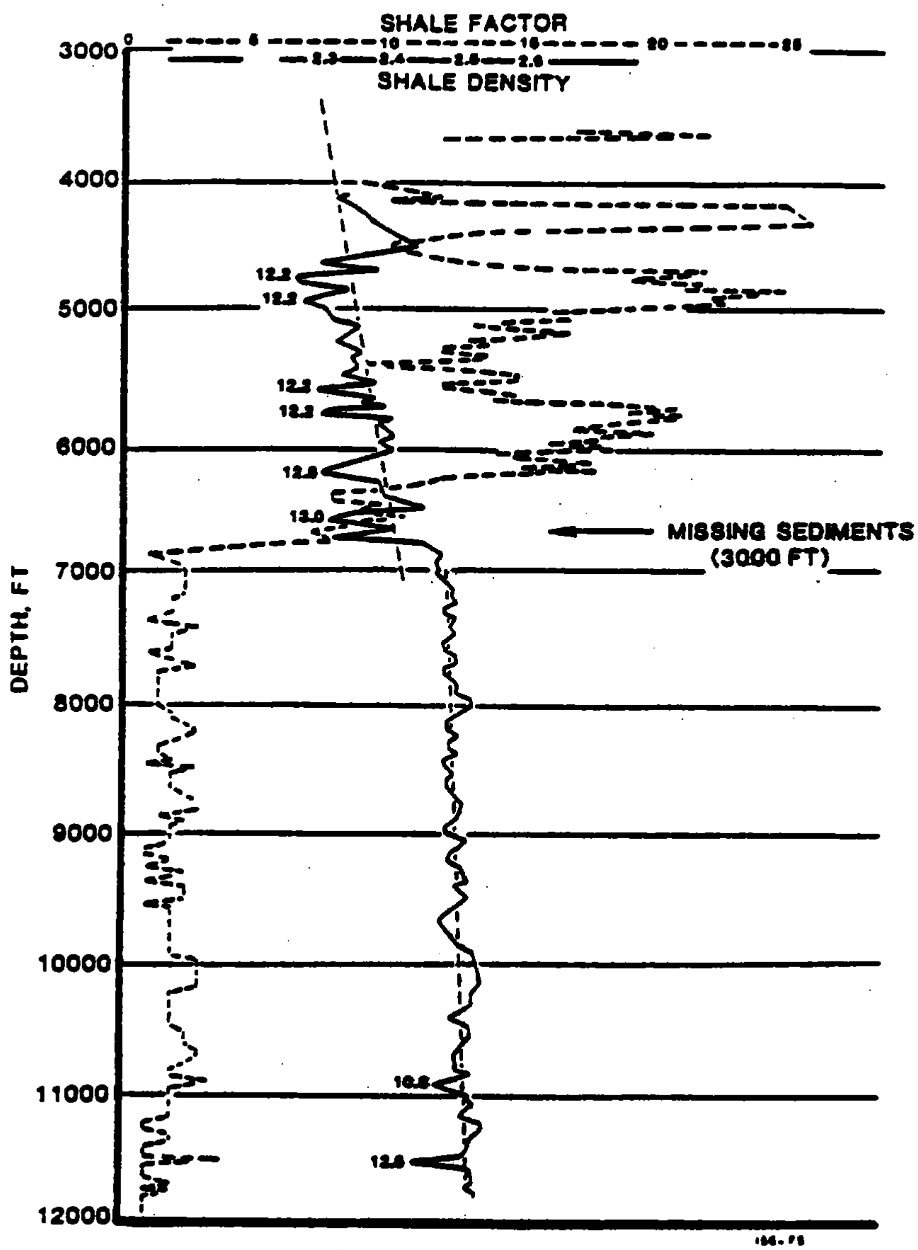


Figure 4-13: Shale factor can be a good indicator of large changes in clay composition, aiding in geological interpretation

If, however, a geopressured zone was caused by montmorillonite dehydration, then upon entering the interval a sharp decrease in montmorillonite content should be observed. Hence the geopressured zone will contain less montmorillonite, as it has been converted to illite, releasing to the pore spaces water which been unable to escape fast enough and resulting in a pore pressure increase. Shale factor will thus decrease in the pressured zone (Figure 4-14).

Shale factor cannot be a quantitative geopressure indicator. The differing responses described above are not definitive, and geopressure has to be indicated from other sources before an interpretation using shale factor can be achieved. Also, geopressures caused by montmorillonite dehydration and compaction disequilibrium may not cause a change in shale factor. If geopressures were caused by processes (i.e. aquathermal pressuring) which are independent of matrix composition, a change may not be reflected in shale factor with depth.

In the past, the consensus was that shale factor will increase in geopressured zones and can act as an indicator. Re-evaluation of the various geopressure mechanisms show that this is not necessarily the case. However, as was seen, shale factor should be capable of delineating between compaction disequilibrium and montmorillonite dehydration as the major geopressure mechanism.

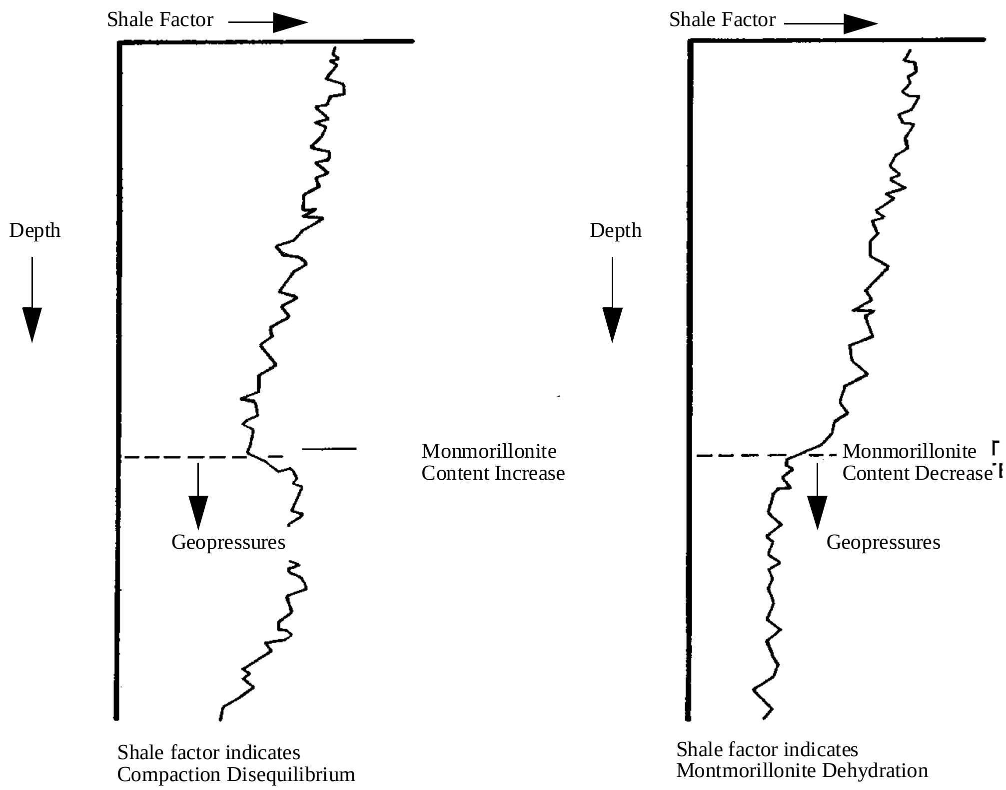


Figure 4-14: Shale factor response in geopressures, caused by compaction disequilibrium or montmorillonite dehydration

Temperature

The geothermal gradient, or the rate at which subsurface temperatures increase with depth, can be calculated from:

Equation 4-20

$$G = 100\frac{(T_{F_2} - T_{F_1})}{(D_2 - D_1)}$$

where:

G	= geothermal gradient (°C/100 ft)
T_{F1}	= temperature (°C at depth D_1, ft)
T_{F2}	= temperature (°C at depth D_2, ft)

For any given area, the geothermal gradient is usually assumed to be constant. While the average gradient across normally pressured formations may be constant, pressured formations exhibit abnormally high geothermal gradients. This is due to heat flow through the various substances.

There is a constant flow of heat from the earth’s core to the surface, and the total flow of heat across any depth increment will be constant. However, the temperature differential across an increment depends upon the thermal conductivity of the material. Since overall heat-flow to the earth’s surface is generally constant within any particular area, the heat flux through the various formations with depth is in equilibrium. The rate of change of temperature across a formation with a low thermal conductivity (due mainly to high porosity) will be high; conversely, a low geothermal gradient is indicative of high thermal conductivity formations (i.e., lower porosity).

Water and hydrocarbon migration to shallower depths may also affect the geothermal gradient. Pore fluids, as insulators, retain heat, so during migration these hot fluids will modify the temperatures of the formations they pass through and ultimately become trapped in. Note that this mechanism changes the geothermal gradient due to the relocation of hot fluids, rather than attributing gradient fluctuation to porosity. Fowler (1980) cited examples from the Middle East, Canada, and Alaska and other U.S. oilfields, having geothermal gradient bulges which possibly indicates the entrapment of hot fluids from greater depths. The mechanism may also be related to montmorillonite dehydration, in that the huge volumes of water released from the clays can provide the impetus for migration. “Dead” basins (no source rocks) have been shown to exhibit normal geothermal gradients, hence on initial exploration wells the geothermal gradient may well indicate the potential of the whole area.

Any insulating zone will produce a distortion in the isothermal lines which normally run perpendicular to the lines of heat flow (Figure 4-15; Lewis and Rose, 1970). Because of the high geothermal gradient, these will be more closely spaced in this insulating zone. In the zones above and below, the isothermal lines are more widely spaced, in compensation, and these zones exhibit a reduced geothermal gradient. The converse occurs in beds of high thermal conductivity, like sands and some limestones.

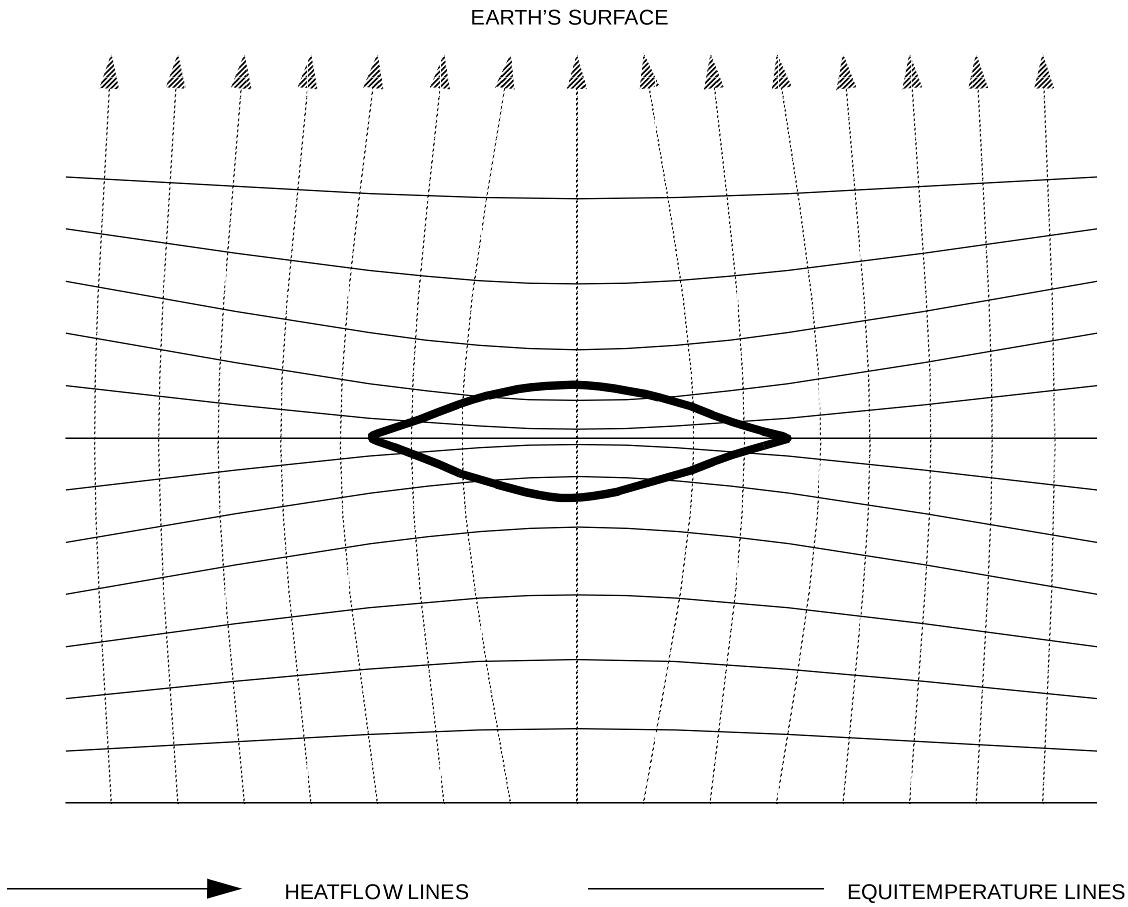


Figure 4-15: Distribution of heat-flow and isotherms around an insulating (geopressured) zone

Since water has a thermal conductivity of about one-third to one-sixth that of most matrix materials, it can be seen that the thermal conductivity will be directly related to the degree of formation compaction. The higher-than-normal water content of geopressured shales reduces this thermal conductivity. Therefore, the top of a geopressured zone is marked by a sharp increase in geothermal gradient, and as such, the temperature of the mud at the flowline may reflect the geotemperature change.

Monitoring and recording flowline temperature is a practical method to determine temperature gradient, provided variable factors such as pump rate, lag time, ambient temperature, lithology, and temperature changes at the surface (due to mud mixing and chemical treatments), can be accounted for. In areas where large annual temperature variations occur, considerable differences may be noted in flowline temperatures. Even diurnal temperature fluctuations can cause a 10°C variation in flowline temperature while drilling.

Prior to reaching a geopressured zone, a temperature transition zone will be encountered in which, due to distortion of the isothermal lines, there will be a reduction in geothermal gradient (Figure 4-16). It has been found in practice that this effect is reflected in the flowline temperature gradient, even to the extent of a fall in flowline temperature (i.e. a negative gradient), followed by an extremely large increase in flowline temperature as the geopressured zone is penetrated (Figure 4-17).

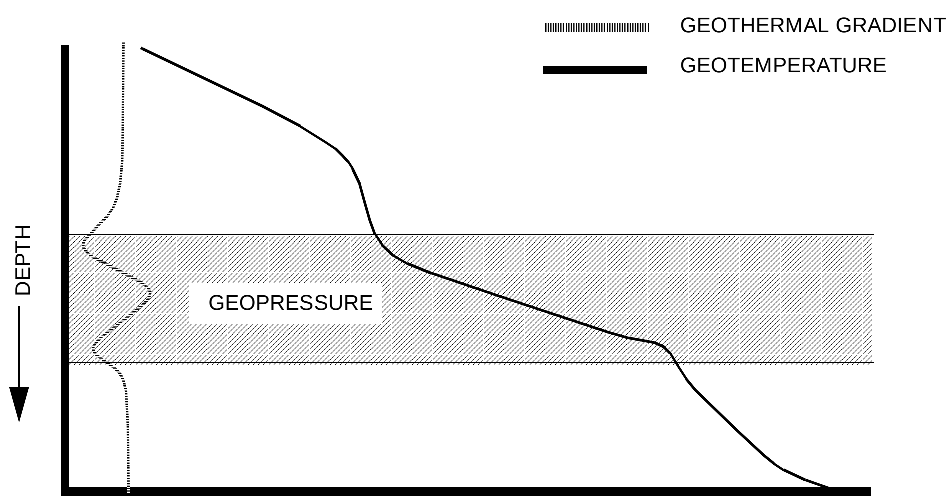


Figure 4-16: Theoretical change of geothermal gradient through an insulating (high porosity/geopressured) zone

A dual temperature probe system with sensors in the flowline and suction pit is effective in removing surface effects, if lagged differential temperature is plotted.

It is normally sufficient for the points to be plotted at 30-ft intervals unless more frequent temperature variations are noticed. Points plotted at 10-ft intervals allow more accurate data and better resolution for improved interpretation. Note should be made of breaks in circulation, mud additive additions, water additions, or other significant events.

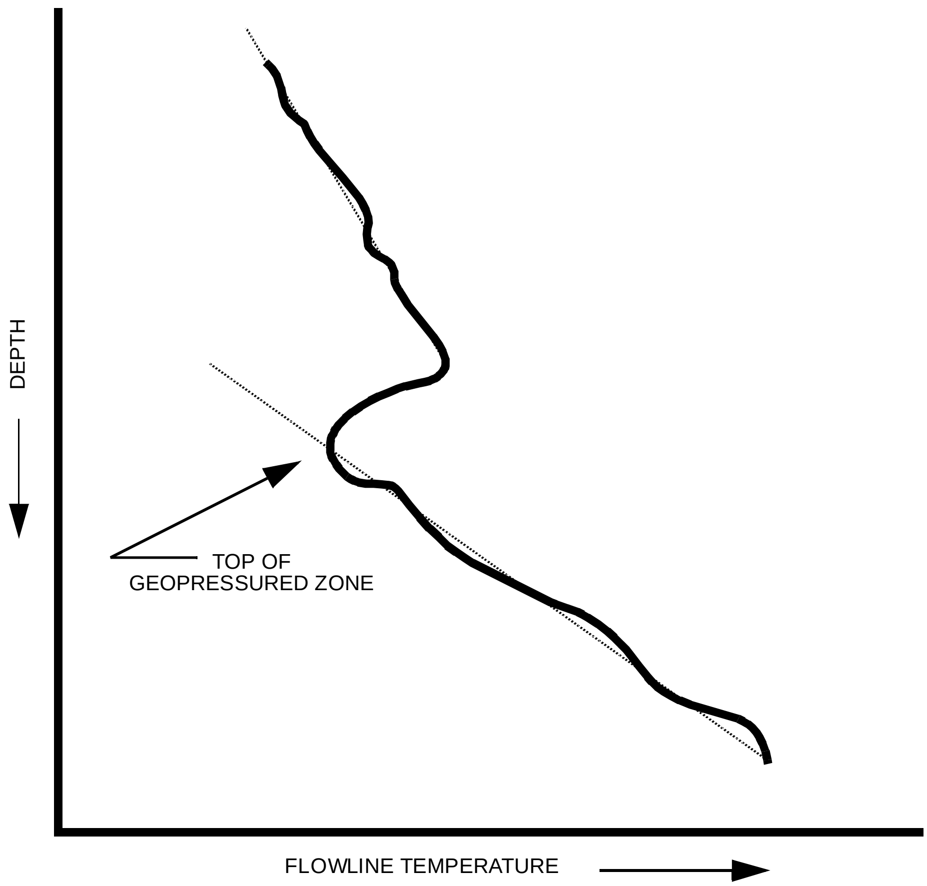


Figure 4-17: Expected flowline temperature response on drilling through a geopressured interval

It has been found that the temperature curve will be broken when the bit is changed, during short trips or other downtime, and a certain time is necessary for the mud system to reestablish a temperature equilibrium when circulation resumes. The rate at which this thermal equilibrium is re-established may be significant, as a more rapid reestablishment may indicate an increased geothermal gradient.

A fluid variable which can affect the rate of reestablishment is total mud volume. The practice of reducing the active pit volume to a minimum, dictated by hole size, aids in reducing the time required to attain equilibrium after tripping and reduces the circulation time needed to stabilize flowline temperature.

A discontinuity in the plot also occurs at each casing depth, which corresponds to a change in hole size. A higher annular velocity in open hole reduces the amount of heat gained from exposed formations, and a lower annular velocity in the marine riser increases the amount of heat lost to the sea. However, these factors only lead to a change in measured temperature; the rate of change of temperature should remain unchanged.

Since pressure predictions are based on temperature gradient rather than on temperature magnitude, each depth segment between discontinuities can be analyzed separately for gradient trends. It is also helpful to replot a smoothed curve of segments end-to-end without regard for absolute temperature values. In certain cases it has been found that, instead of plotting the individual segments as an end-to-end smoothed curve, end-to-end plotting of the individual segment trend lines may be of value. This trend-to-trend smoothed curve is merely a graphical method of removing irrelevant scatter from the plot. However, due to geopressures, the change in flowline temperature may be so that this curve smoothing may cause the anomaly to disappear. It is therefore suggested that both plots be prepared in order to facilitate interpretations (Figure 4-18).

The reduction in temperature gradient caused by the distortion of isothermal lines may be noticed before the geopressured zone is encountered; that is, an advance warning of geopressure may be given. Thus a fall in flowline temperature gradient followed by a sharp rise when the geopressure transition zone is drilled provides a warning that even closer attention must be paid to other drilling parameters in order to achieve confirmation of possible geopressures. However, like other methods of pressure evaluation, flowline temperature reflects a varying physical parameter in an assumed constant rock type; therefore, changes in lithology must be closely monitored in order to avoid false indications.

Wilson and Bush (1973) proposed that flowline temperature gradients can predict geopressure occurrence by use of a gradient factor:

Equation 4-21

$$GF = \frac{G}{Gn}$$

where:

GF	= gradient factor
G	= flowline temperature gradient
Gn	= normal geothermal gradient

This gradient factor can be calculated for each 100-ft interval, then averaged every 100 feet for the preceding 200-ft interval. Zero and negative temperature gradients are recorded as zero values. Apparently, a gradient factor of 2.0 or more is indicative of a geopressure. However, due to the unreliability of most flowline temperature plots in reflecting actual geothermal gradients, and the possibility that gradient factor may not be representative within a particular area, this method should be treated with caution. It may be more valuable for onshore wells.

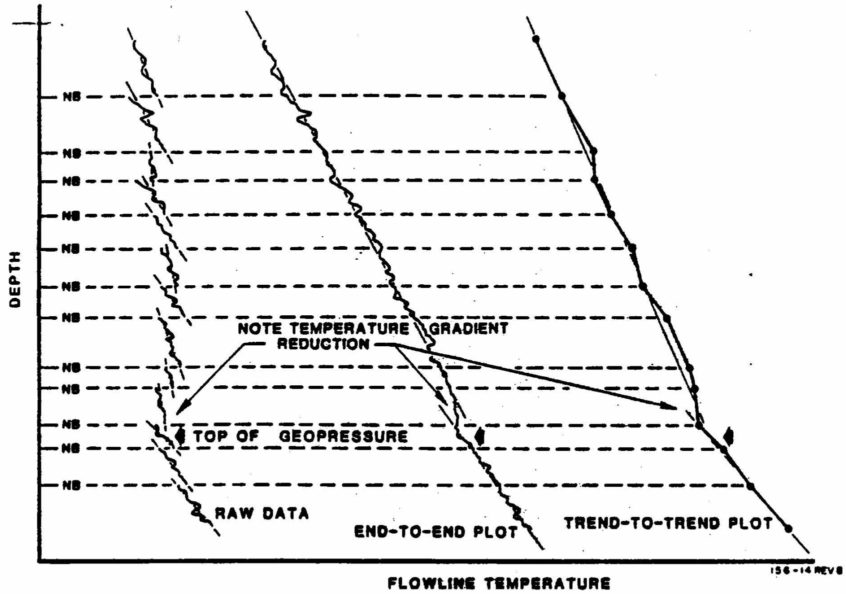


Figure 4-18: Plots of flowline temperature, smoothed end-to-end plot and trend-to-trend

After a trip, mud temperature will reach a maximum on bottoms-up. A plot of this maximum temperature (after regaining circulation from a period of downtime) can closely approximate geothermal trends. Monitoring these peaks may aid in geothermal trend interpretations.

Wireline log temperature data and Temp-Plate data can also be included on temperature plots, in addition to:

- flowline temperature
- end-to-end flowline temperature
- trend-to-trend flowline temperature
- differential mud temperature (ΔT)

Most wireline logging tools contain a maximum-recording thermometer, and the temperature recorded is included on each log heading. This temperature will usually increase with time as the logging program progresses.

Using a modified Horner plot, it is possible to estimate true formation temperature. It is assumed that the maximum temperature will occur at total depth (TD). The Horner expression was originally developed for pressure build-up predictions for reservoir (DST) analysis, but was modified by Dowdle and Cobb (1975) to model temperature build-up. Although mathematically incorrect, actual formation temperature can be closely estimated, particularly when circulation periods are short. The theory of the calculation is that, during drilling and circulation, the cool mud reduces the temperature of the formation. This results in a temperature gradient that increases away from the borehole, to a point where the formation temperature is undisturbed. When circulation ceases, heat is transferred into the mud in the borehole, the temperature gradient surrounding the borehole decreases, and the radius of disturbance decreases. Hence by extrapolating the temperature increase to infinite time, it should be possible to calculate the actual formation temperature. This expression is:

Equation 4-22

$$T = T_f - C\log\frac{t_c + t_l}{t_L}$$

where:

T_f	= true formation temperature
T	= measured temperature
C	= constant
t_c	= circulation time at TD
t_L	= time since circulation stopped

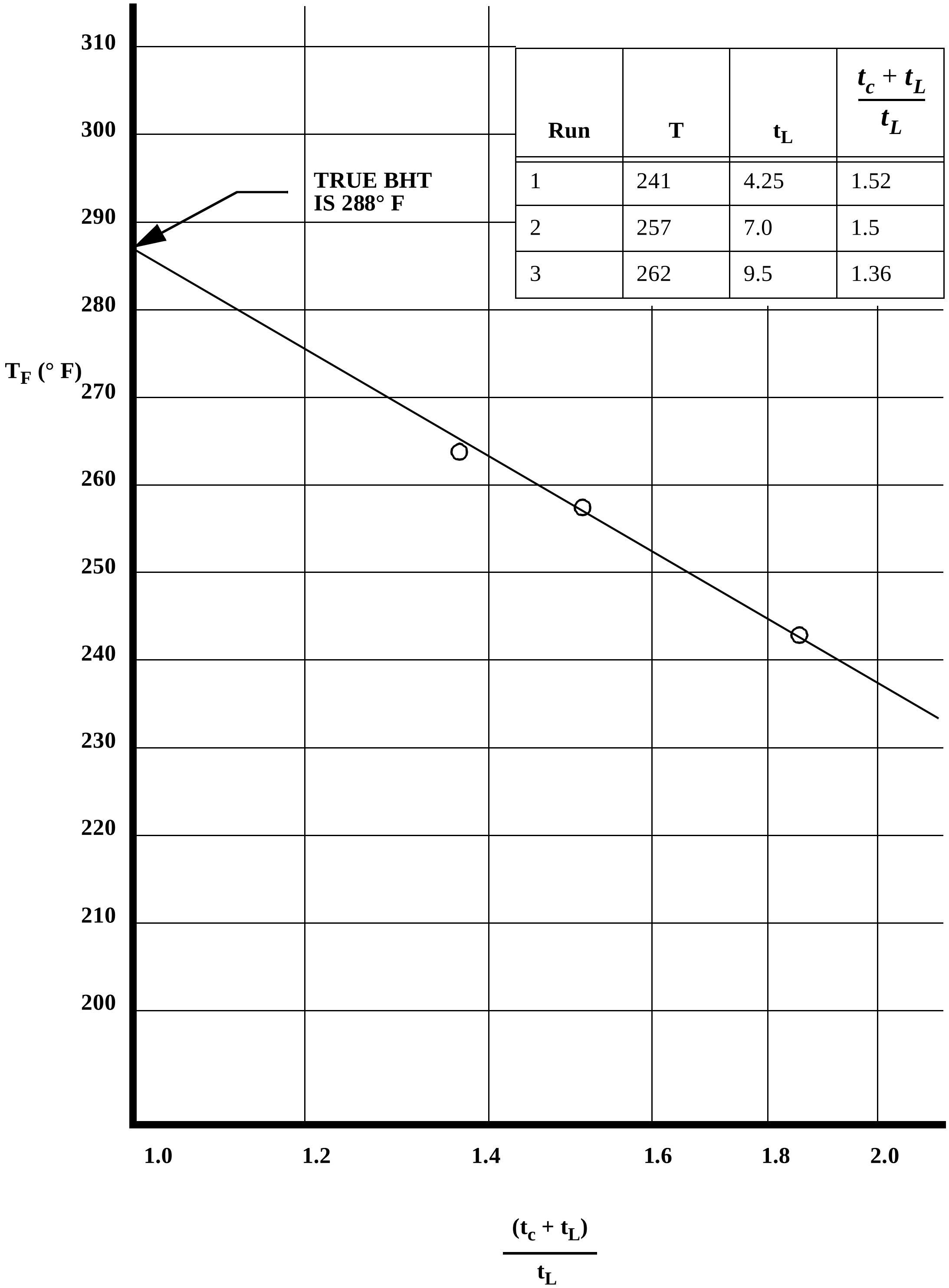
Thus a plot of T against $(t_c + t_L)/t_L$ on semi-log paper should be linear, and when extrapolated to a time ratio of unity, the result should be a close estimate of formation temperature (Figure 4-19).

The same points from Figure 4-19 have been replotted on Figure 4-20, showing a possibly easier method of displaying the data. Note that the grid on Figure 4-19 is semi-log, whereas it is linear in Figure 4-20. Points on Figure 4-20 were plotted using the relation

Equation 4-23

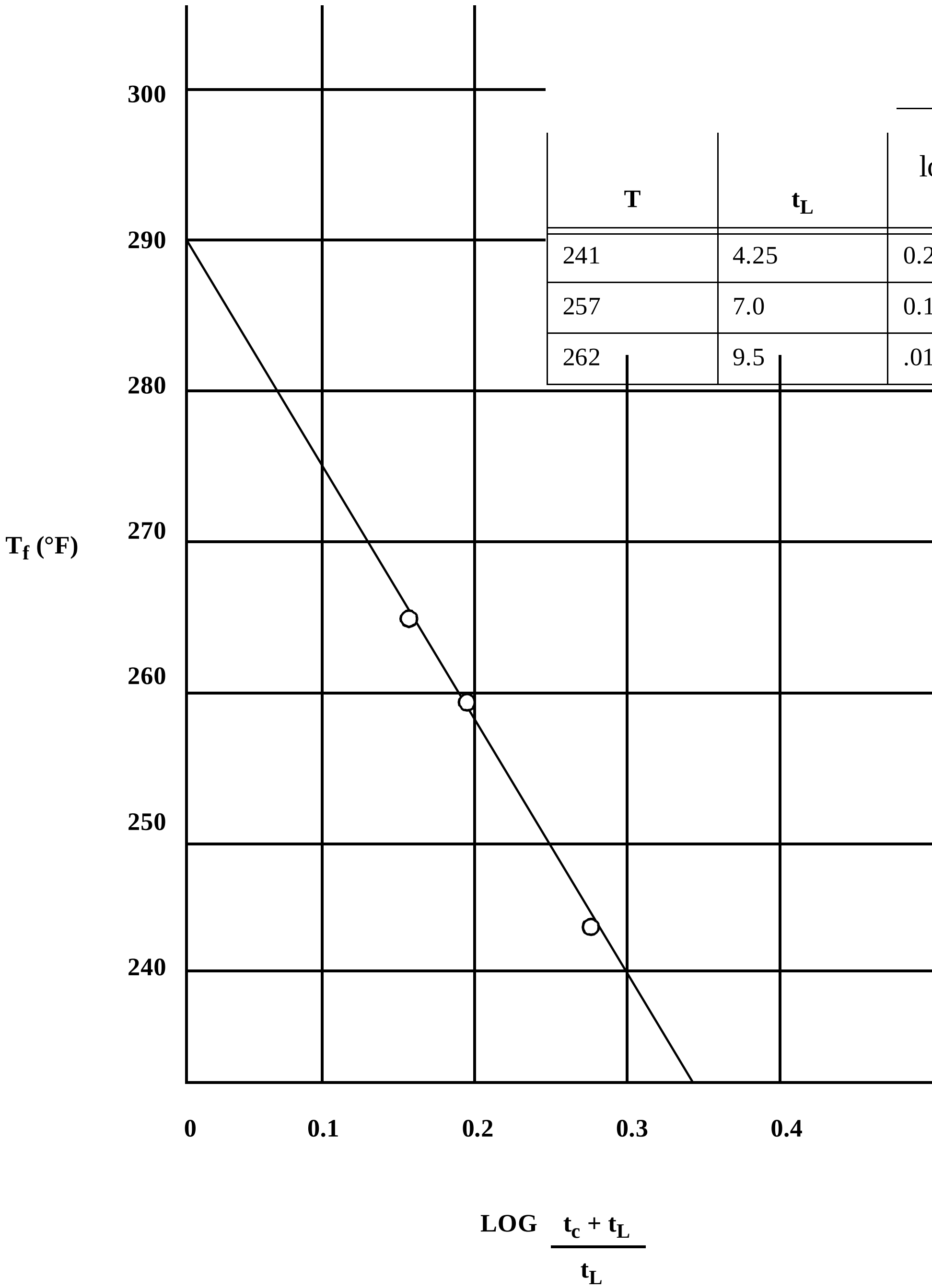
$$\log\frac{t_c + t_L}{t_L}$$

against measured temperature. Extrapolation of points using the latter relationship allows a smaller margin of error when drawing lines through a scatter of points. The near normal intercept of the gradient with the temperature axis allows precise temperature determinations.



Run	T	t_L	$\frac{t_c + t_L}{t_L}$
1	241	4.25	1.52
2	257	7.0	1.5
3	262	9.5	1.36

Figure 4-19: Horner-type plot for graphic solution of true bottomhole temperature



T	t_L	$\log \frac{t_c + t_L}{t_l}$
241	4.25	0.28
257	7.0	0.176
262	9.5	.0133

Figure 4-20: Horner-type plot of linear X-axis. Note less scatter in points

A mathematical method was proposed by Nwachukwu (1976) which utilizes a modified Lachenbruch-Brewer equation, which basically states that if three temperature points are available, this can prove to be a useful cross-check with the Horner plot. The equation must be solved for T_f:

Equation 4-24

$$\frac{T_f(t_2 - t_1) + [(T_1 \times t_1) - (T_2 \times t_2)]}{T_2 - T_1} = \frac{T_f(t_3 - t_1) + [(T_1 \times t_1) - (T_3 \times t_3)]}{T_3 - T_1}$$

where:

T_1	= recorded BHT, log run 1
T_2	= recorded BHT, log run 2
T_3	= recorded BHT, log run 3
t_1	= time since circulation stopped, log run 1
t_2	= time since circulation stopped, log run 2
t_3	= time since circulation stopped, log run 3
T_f	= true formation temperature

For example,

log run 1, time since circulation stopped = 4 hours
log run 2, time since circulation stopped = 7 hours, 50 minutes
log run 3, time since circulation stopped = 11 hours, 10 minutes

Measured temperatures were 210°F, 219°F and 225°F.

Hence,

$$\frac{T_f(7.83 - 4) + [(4 \times 210) - (7.83 \times 219)]}{219 - 210} = \frac{T_f(11.16 - 4) + [(4 \times 210) - (11.16 \times 225)]}{225 - 210}$$

$$\frac{T_f \times 3.83 - 874.8}{9} = \frac{T_f \times 7.16 - 1671}{15}$$

$$T_f = \frac{(15 \times 874.8) - (9 \times 1671)}{(15 \times 3.83) - (9 \times 7.16)}$$

$$T_f = 274.2$$

Depending on the particular environment, one method may be found to be more accurate than the other, but for wildcat use they both should be sufficiently close to actual formation temperature.

After each logging run, the estimated bottomhole temperature should be plotted, and between the successive depths, the average geothermal gradient can be calculated from Equation 4-20. Between logging runs, a useful check on geothermal gradient can be achieved by using Temp Plates. These can be more accurate than flowline temperature and ΔT monitoring, particularly on offshore rigs.

Temp Plates are self-adhesive sensors containing hermetically sealed heat-sensitive elements which change chemical structure at given calibrated temperatures. When exposed to the rated temperature, the indicator turns from pastel grey to black. This chemical reaction is completed in less than 1 second and is accurate to within 1% of the calibrated temperature. The change is also permanent and irreversible.

The Temp Plate can be attached to a survey tool as shown in Figure 4-21, ensuring that the Temp Plate does not come adrift, by wrapping it with tape. It is advisable to put a higher range Temp Plate on the clock when the present Temp Plate has two spots exposed.

The Temp Plate should be left on the survey tool until all spots are exposed. The spots may turn light grey with repeated exposure to near reactive temperature, but they will not turn black until the reference temperature has been exceeded.

Note: *Do not place the Temp Plates on the exterior of the go-devil, wireline tool, etc. Field testing has shown that contact with diesel muds and high pressures (greater than 2000 psi) render measurements useless. They must be placed in a sealed environment, isolated from pressure and reactive fluids.*

Use caution when evaluating the Temp Plate readings since the condition of the mud system and the plate's position in the drillstring will affect its performance. The length of time circulation was terminated prior to running the Temp Plate affects mud temperature stabilization, and this time period increases with depth. Since steel is a relatively good conductor of heat when compared to mud, high temperatures generated by a rotating drilling assembly and bit can produce artificially high readings, particularly if there has not been sufficient circulation time to dissipate it. Although the Temp Plates turn black upon reaching the reactive temperature, they will pass through darkening shades of grey before reaching this point, but this transition is very rapid.

The adhesive strength of Temp Plates is very good. This means that a wide range of plates can be stuck onto the survey tool early in the operation, and they need be removed only when all the heat sensors on a plate have been exposed. This ensures that minimal interference occurs with the running of the survey and that a successful reading is achieved.

Temp Plates are available in various ranges with a resolution of 1% of their reactive value, and each contains four calibrated temperature indicator disks. Each Temp Plate has a 20°C range. The total temperature interval including all the Temp Plates is from 35°C to 215°C.

Since the resolution of each temperature range is 5°C, this range may be too small to detect the anomalous geothermal gradients due to geopressures, and when compounded with the problem of not recording actual mud temperature (because the plate is inside the survey tool), actual temperature measurements may be questionable. However, gross trends should still be recognizable, and one of the major advantages of using Temp Plates is to delineate the “oil window.”

Today, drilling occurs offshore in increasing water depths and colder environments, resulting in reduced effectiveness of FLT data. Additionally, in deeper sections of some wells, small hole sizes and reduced pump rates mean that the circulating mud at the surface does not truly reflect changes in geothermal gradient as indicated by other downhole temperature measuring techniques.

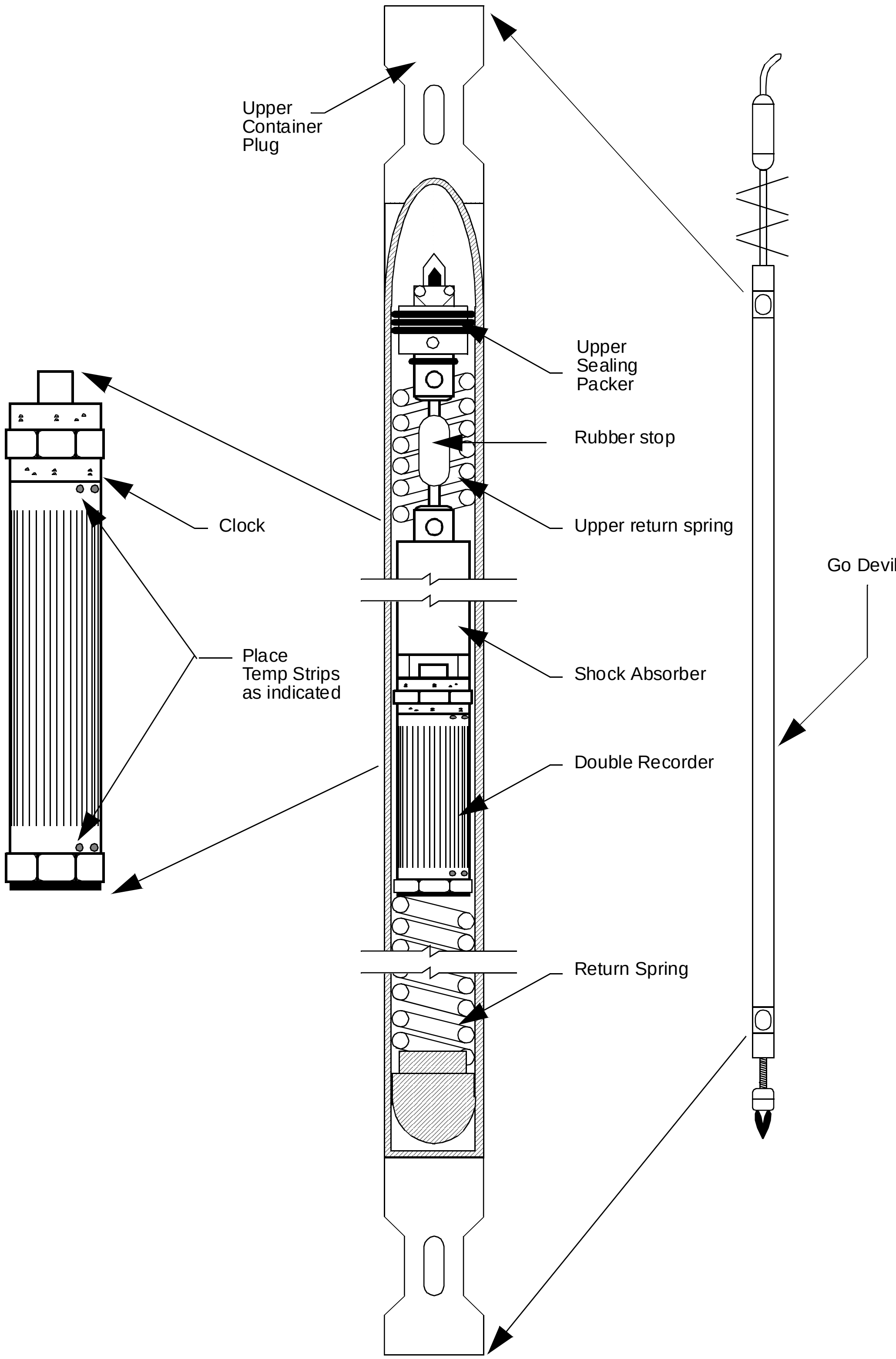


Figure 4-21: Location of Temperature Plates in deviation survey tool

Mud Resistivity/Conductivity

The standard units for fluid electrical properties are ohm-meters for resistivity and mmhos/meter for conductivity. The usual range for drilling fluids and formation waters is between 0.01 and 10 ohm-meters.

Equation 4-25

$$R = \frac{1000}{C}$$

where:

R = resistivity (ohm-meters)
C = conductivity (mmhos/m)

If conductivity is monitored at the flowline and the mud pits, a conversion can be made to chlorides, and a differential, ΔCl, can be plotted and used as an indicator of geopressures. Schmidt (1973) surveyed pore water chemistry from sidewall cores in Louisiana and found that dissolved solid concentrations in normally pressured sandstones were around 600 to 180,000 mg/l; and in geopressured sands the range was 16,000 to 26,000 mg/l. The average range for normal pressure sands was 120,000 to 170,000 mg/l, and shales had ranges of 10,000 and 70,000 mg/l. In geopressured sections, the shale and sand pore water composition is similar at approximately 20,000 mg/l. If these changes could be detected in the returning mud, the meter would indicate low resistivity in normal-pressured sands, high resistivity in normal-pressured shales, and high resistivity in geopressured sands and shales.

Past theory had suggested that geopressured sands should be highly saline and thus produce low resistivities. Data from the area tested by Schmidt suggested otherwise; however, this does not mean that the results obtained are universal.

For a change to be measured in drilling mud, there should be a large salinity contrast between mud filtrate and formation fluids. It would appear that a change would be more apparent when fresh water muds are in use. Saline muds would severely mask small changes caused by fluctuating pore water chemistry. It is strongly doubted whether a flowline conductivity sensor could detect changes in formation water concentrations simply due to the fact that the volume of pore water released from cuttings is infinitesimal in comparison to the mud volume. However, influx from permeable formations may be seen as changes either way, depending on relative salinities, and warnings of underbalance can be given. In the U.S. Gulf Coast, differential mud conductivity or “delta chlorides” appears to be reliable in pinpointing slight pore water influxes, and cab be a valuable differential pressure indicator (Figure 4-22). If sufficient difference exists between mud and formation water salinity, the response is similar to ditch gas, showing influx at connections or increasing feed-in due to underbalance.

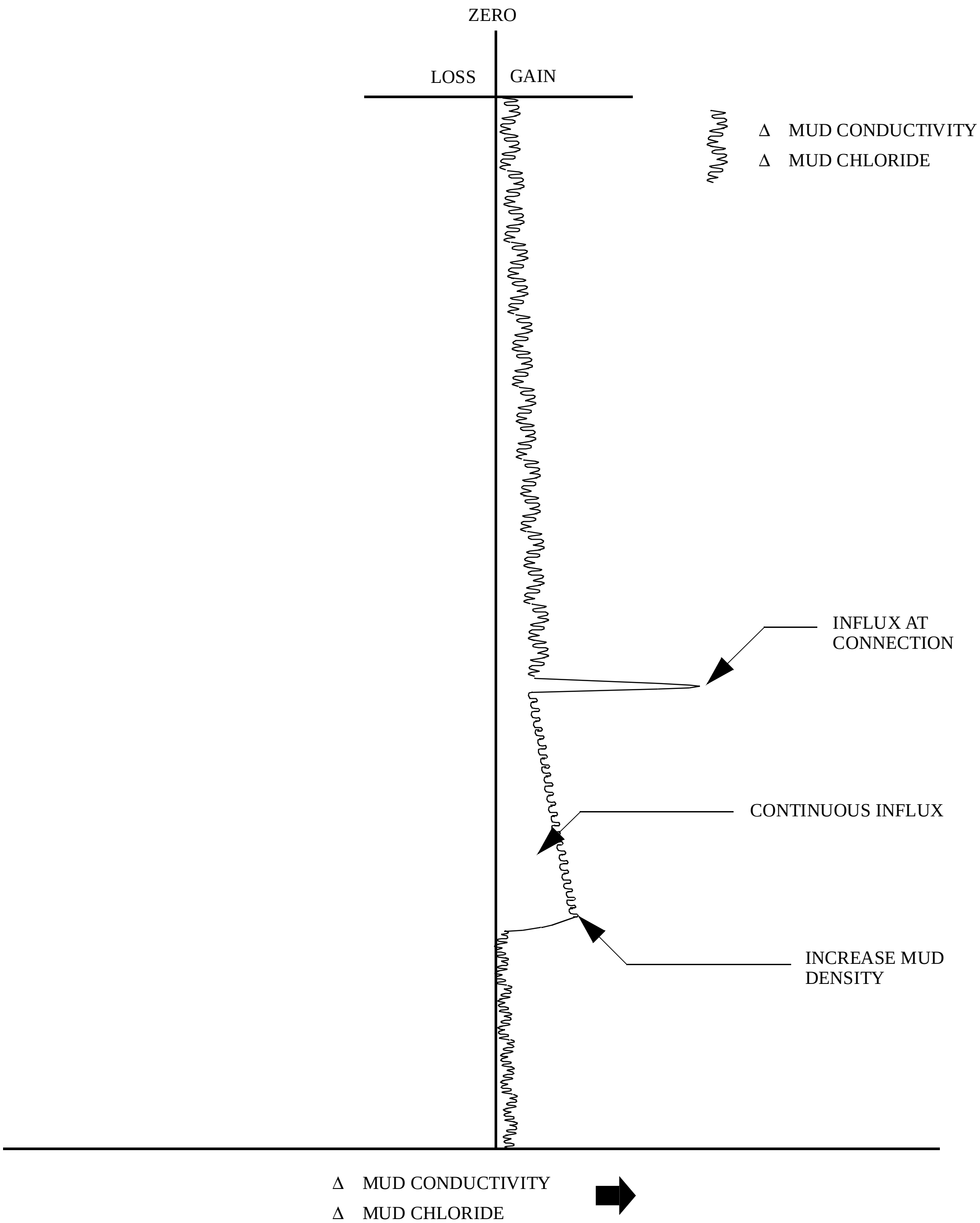


Figure 4-22: Differential mud conductivity and delta chloride log

Wireline Log Parameters

Sonic/Acoustic Log

A sonic/ acoustic device measures the interval transit time (Δt) of the formation. As the distance between the transmitters and receivers is fixed, the only variable is time, hence interval transit time is measured in μsec/ft

A compressional wave travels at approximately twice the velocity of other sound wave types. The reciprocal of this velocity, or time in seconds necessary for the compressional wave to travel a unit distance is:

Equation 4-26

$$T_C = \sqrt{\frac{\rho(1+\mu)}{3M_b(1-\mu)}}$$

where:

Tc	= time
ρ	= density of the material
M_b	= bulk modulus of elasticity (compression)
μ	= Poisson's Ratio

Acoustic travel time is therefore explicitly dependent upon the density and elasticity of the material. Since different minerals posses different densities and elasticities, laboratory measurements must be undertaken to determine their particular properties. Once these are known, it is seen that the interval transit time for a particular rock will be a measure of its porosity. Porosity may be calculated from:

Equation 4-27

$$\varnothing = \frac{\Delta t - \Delta t_m}{\Delta t_f - \Delta t_m}$$

where:

Ø	= porosity (fractional)
Δt	= transit time of particular formation
Δt_f	= transit time of pore fluids (or filtrate, as the sonic tool only measures approximately 1 inch into borehole wall)
Δt_m	= transit time of matrix

Though porosity is usually expressed as percent, the value used in log analysis equations is always fractional.

Figure 4-23 shows some typical matrix and fluid transit times.

Formation	$\Delta t_m, \mu$ sec/ft^{-1}
Sandstone	
Unconsolidated	58.8 or more
Semi-Consolidated	55.6
Consolidated	52.6
Limestone	47.6
Dolomite	43.5
Clay/Shale	167-62.5
Anhydrite	50.0
Gypsum	52.6
Quartz	55.6
Salt	66.7
Granite	50.0
Iron (casing)	57.0
Fluids	**$\Delta t_f, \mu$ sec/ft^{-1}**
Salt Water	189
Fresh Water	218
Oil	238
Methane	626
Air	910

Figure 4-23: Transit times for matrices and fluids

Since geopressures mainly originate in clays, it can be seen from Figure 4-23 that attempting to calculate porosity could be a problem. The very high transit times apply to the “house of cards” type of structure in montmorillonite clays typical in shallow, wet sediments; the lower transit times are for the more consolidated types. Porosities calculated for clays tend to be slightly high, and corrective factors are not yet available.

A sonic log run in a geopressured clay interval will show increasing transit time, (Δt), (increasing porosity) with an increasing pore pressure gradient. In the transition zone (if it exists), the Δt curve, on the log, will be seen to steadily move to the left (higher values) with depth. Typically, however, clays hydrate and wash out in pressured zones, and borehole rugosity may affect the sonic values if it is severe, to the extent of causing “cycle-skipping”. Modern tools are self-compensating for hole washout, but the problem cannot totally be removed. A useful cross-check to see if the sonic values are representative is to correlate the values with those from a seismic velocity analysis.

The theory behind quantitative geopressure evaluation using the sonic tool is fortunately independent of the amount of porosity. Since the sonic log can be a reasonable geopressure indicator: an increase in transit time, with depth, in a constant clay lithology, is due to a change (increase) in porosity (pore pressure gradient). A quantitative interpretation, based on Gulf Coast methodology, may not be as accurate in other areas, but it has been found to be a very useful tool.

As clays compact and lose porosity with depth, the measured sonic transit time also decreases. As was seen, typical values for unconsolidated clays lie between 150-200 sec/ft. A plot of clay transit times on semi-log grid should produce a linear “normal” trend with depth. Hottman and Johnson (1965) correlated transit time deviations from the normal trend to adjacent reservoir pressures, but this method was specific to Gulf Coast reservoirs. The Equivalent Depth Method, using sonic data, can be used for most geopressure determinations. Figure 4-24 illustrates the procedure.

A normal trend is extrapolated to the depth of interest. (Note: on placing the normal trend, remember that the minimum transit time is equal to the matrix transit time (zero porosity). Since rocks of zero porosity rarely exist, the slope of the normal gradient must intercept at values greater than the matrix transit time.

The formation pressure is then determined using:

Equation 4-28

$$P = (OBG_a \times D_a) - D_n(OBG_n - N.FBG)$$

where:

P	= pore pressure (psi)
OBG_a	= overburden pressure gradient at D_a (psi/ft)
OBG_n	= overburden pressure gradient at D_n (psi/ft)
D_a	= depth of interest in geopressure (ft)
D_n	= normal equivalent depth (ft)
N.FBG	= normal formation balance gradient (psi/ft)

For example,

OBG_a	= 0.920 psi/ft at D_a
OBG_n	= 0.830 psi/ft at D_n
N.FBG	= 0.465 psi/ft
P	= 0.92 x 10870 - 3300 (0.83 - 0.465)
P	= 8796 psi, or 15.6 lb/gal at D_a

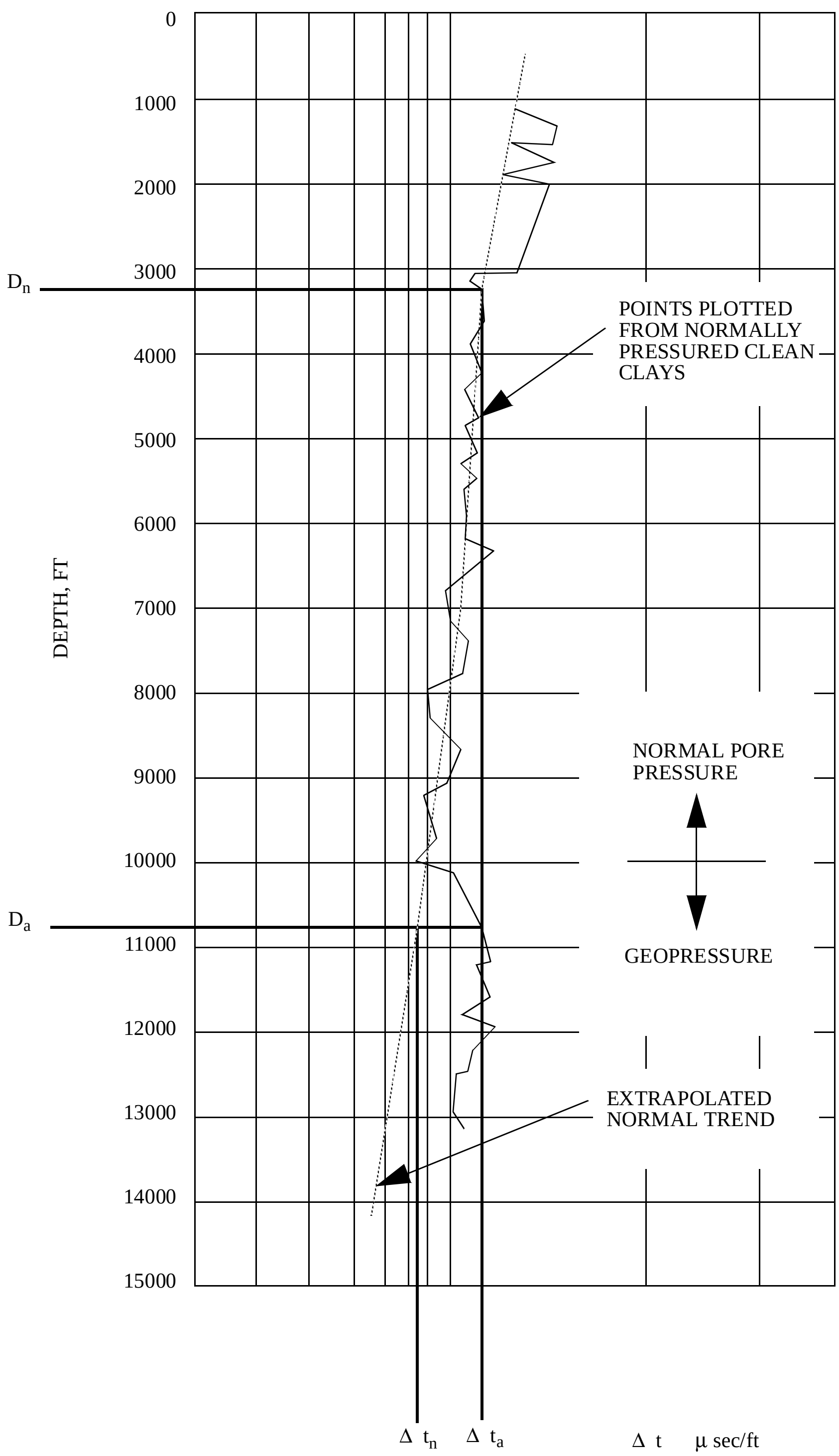


Figure 4-24: Geopressure evaluation using Equivalent Depth Method and sonic plot

Another application for the sonic log is its use for estimating overburden gradient and pressures through porosities and bulk densities. AGIP engineers Bellotti and Giacca (1978) published an empirical relationship that enabled bulk densities to be established directly from interval transit times. By calculating porosity from transit times a matrix and fluid are assumed, the densities corresponding to that particular matrix and fluid are known, and hence a bulk density can be estimated using:

Equation 4-29

$$\rho b = 2.75 - \left(2.11\left(\frac{\Delta t - 53}{\Delta t + 200}\right)\right)$$

Since porosities vary with lithological change and pore pressure, calculations should be made in each lithology with depth. Note that all rocks contribute to the overburden pressure: not just clays, hence readings should be taken from all rock types.

Another method used to obtain bulk densities is to perform the following:

1. Identify lithological changes from the mud log (or other log) and correlate with the sonic log.
2. Average transit times for each interval (eyeball is sufficient).
3. Identify matrix and obtain matrix transit time from Figure 4-23 for each interval.

For each of these intervals:

4. Calculate porosity using (Equation 4-27), using 189 µsec/ft for fluid transit time. Suggested matrix transit times for very shallow, wet clays; sub-compact clays and compact clays are 100, 70, and 65 µsec/ft, respectively. Local experience may dictate otherwise.
5. Correlate rock density with those used with the matrix and fluid densities in Figure 3-6.
6. Calculate bulk density using:

Equation 4-30

$$\rho_b = \varnothing\rho_f + (1 - \varnothing)\rho_m$$

where:

ρ_b = bulk density (g/cc)
Ø = porosity (fractional)
ρ_m = matrix density (g/cc)
ρ_f = fluid density (g/cc)

7. Overburden pressure gradients may then be calculated using equations, or by using the GeoPress Application.

Calculated porosities will be abnormally high in clay intervals that have hydrated due to mud reaction. As the depth of investigation of the sonic tool is extremely small (approximately 1 inch beyond the borehole), hydrated clays will be measured, not the true formation. Care must be taken in these situations as a low calculated overburden gradient may result; however, no quantitative correction is available.

Resistivity

Common rock-forming minerals conduct very little electricity, and effectively have zero conductivity. Any changes in the resistivity of a rock will then be dependent upon the amount of water, its salinity, the amount of hydrocarbons, and the distribution of the fluids within the rock. Thus changes in porosity, water salinity, hydrocarbon content, and porosity distribution within the same rock will cause changes in the resistivity measured by the various tools. The resistivity tools currently in use are:

- Normal and lateral types
- Micrologs
- Focused resistivity types
- Induction devices

Each has a particular use and application in petrophysical analysis. For geopressure evaluation purposes, the best logs to use are the induction and microlog types. Induction logs are intended to read the true conductivity of the undisturbed formation (C_t,). Values taken from this log are thus a function of porosity, porosity distribution and water salinity. Micrologs measures two areas: (1) a micro-lateral which is affected by mud cake, and (2) a micro-normal that measures the resistivity of the flushed zone. Since the resistivity of the mud filtrate is known and is should be the same for all flushed formations (temperature corrected), the resistivity of the flushed zone (R_{xo}) is a function of porosity and pore geometry only. However, the latter device is restricted in its use to formations of greater than 5% porosity and less than 0.5 inch of filter cake.

Whatever device is available, Gulf Coast experience has shown that a resistivity plot on semi-log scale of clean clay beds produces an increasing trend with depth. The manner in which this trend increases is not predictable in wildcat areas, but in areas of intensive drilling, normal resistivity trends should be available. Typical normal trends are shown in Figure 4-25.

The porosity increase in geopressured clays is reflected by a decrease in resistivity (provided the resistivity of the pore water has not increased). The latter proviso is not predictable in wildcat areas, hence the resistivity log must be used with caution, both as a geopressure indicator and evaluation tool. In well known areas, however, the resistivity device has been found to be a reliable indicator and quantifier.

Calculation of pore pressures are facilitated by the use of the equivalent depth expression, where deviations from the normal resistivity trend are utilized instead of transit times.

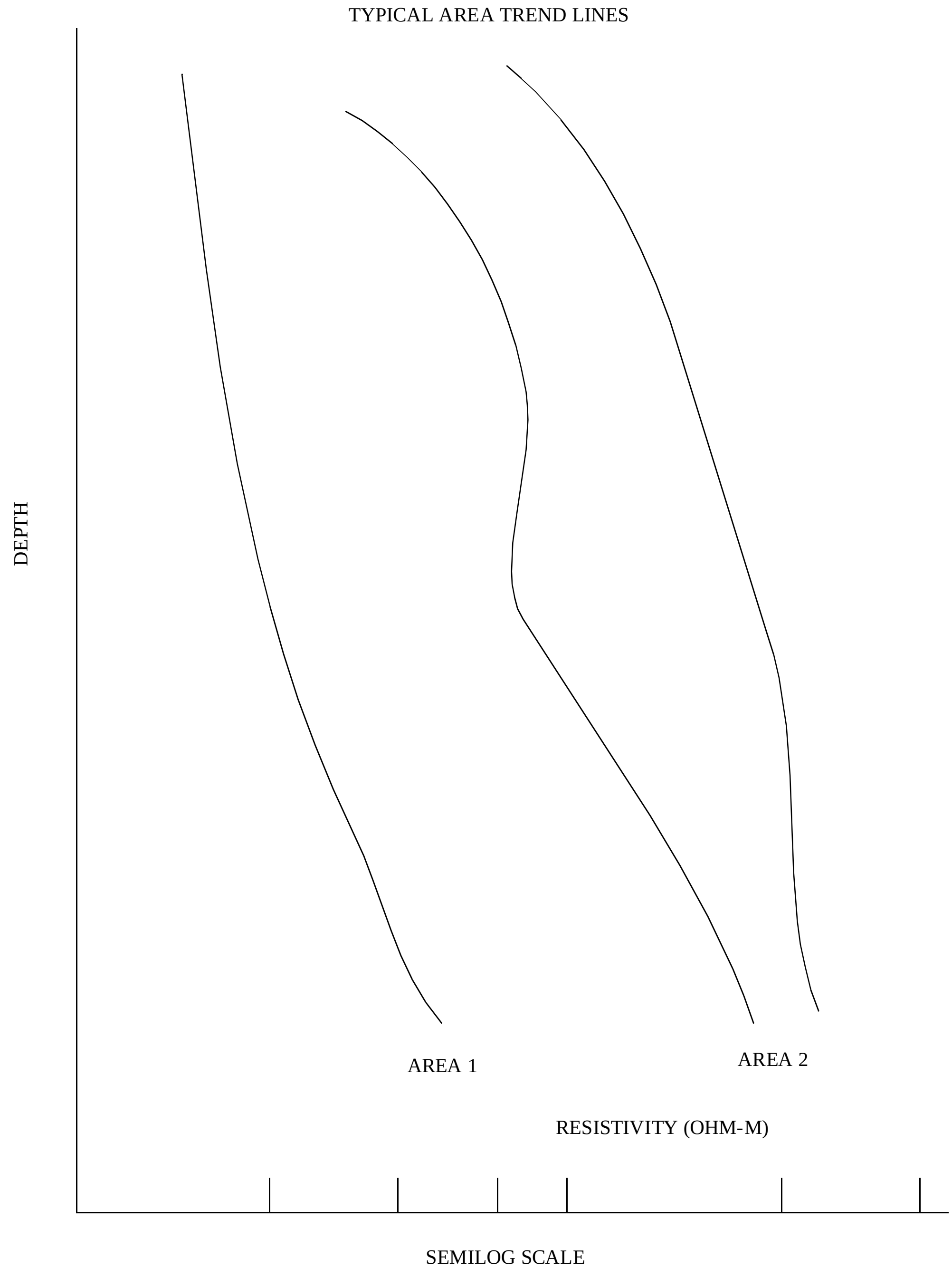


Figure 4-25: Formation resistivity typical area trend lines

Density And Neutron Logs

The density log (FDC, Densilog etc.) measures formation density by bombarding the formation with gamma rays from a cesium 137 source, and detecting the energy and amount of radiated gamma rays returning from the formation. If it is assumed that the Mass Absorption Coefficient is constant for all rocks and fluids at a specified energy level, then the amount and relative energy of returning gamma rays is a measure of the density of the material.

A neutron log bombards the formation with highly energetic neutrons. The neutrons gradually lose energy as they migrate from the source, and at very low energy levels they are captured by nuclei of the formation. The detector on the tool senses gamma radiation of absorption or low energy neutrons. The greatest energy is lost when neutrons collide with a hydrogen nucleus, because they have similar mass. Hence, the slowing of neutrons depends largely on the amount of hydrogen in the formation. In clean formations saturated with water or oil, the neutron log reflects the amount of fluid-filled porosity. Since there is a concentration of hydrogen atoms in gas, the log indicates a very low porosity. In clays, the neutron log reads all the water: bound water and pore water, hence, neutron porosities measured in clay are high.

If a density log is run, bulk density values can be taken directly off the log and used in overburden calculations. There is usually a correction curve in the density track, but this correction is one that has already been applied, and it is plotted for the sake of completeness only. The correction will be seen to be greatest in a washed-out hole, and the larger the correction, the less reliable the density values are. A plot of density with depth on a linear grid should display a gradually increasing trend with depth. Upon entering a transition or geopressured zone in shales, the density curve may be seen to decrease. If the lithology is constant, this is a definitive indication of a porosity increase. The depth of investigation of a density tool is about eight inches into the formation, hence, hydrated clay will affect the readings by causing low density values to be recorded. Calculation of porosity from the density tool produces the most accurate values overall. Use Equation 4-34 and Figure 3-6.

Equation 4-31

$$\varnothing = \frac{\rho_m - \rho_b}{\rho_m - \rho_f}$$

where:

Ø = porosity (fractional)

ρ_m = density of matrix (g/cc)

ρ_b = density from log (g/cc)
ρ_f = fluid density (g/cc)

Pore pressures can be calculated in a geopressured zone using the density log with readings taken in clean shales. The equivalent depth method can be used in the same manner as that described for the sonic log.

The neutron log is not a geopressure indicator or quantifier; however, it may show changes in the clay porosity index that may be used to indicate a predominant geopressure mechanism. Montmorillonite clays will cause rapid neutron adsorption due to their very high bound water content; hence, the porosity index will be very large. Illitic clays have much less absorbed water, hence, the porosity index should be correspondingly lower. As stated in Chapter 2, clay composition changes through a geopressured section, depending on the predominant mechanism. Neutron response may indicate:

- Compaction disequilibrium: clays within the geopressured zone are immature relative to shallower clays, hence, the neutron porosity index will increase markedly within the zone,
- Montmorillonite dehydration: clays in geopressured zones have changed to illite, releasing water to the pores; much of this water must be released otherwise the pore pressure balances the overburden and any subsequent increase will promote the formation of horizontal fractures, allowing the pressure to dissipate. The neutron response would thus be constant through the zone, or a sharp decrease at the top of the geopressure if the excess water had been released.
- Aquathermal: since this process involves compaction disequilibrium, the neutron response will increase within the geopressured zone.

MWD Logs

The development of MWD (Measurement While Drilling) technology during the 1980's has been one of the landmark events in drilling optimization and formation evaluation since rotary drilling began. The continued refinement and development of MWD services has produced benefits in wellsite safety, drilling efficiency, lithology and hydrocarbon interpretation, and formation pressure evaluation.

MWD data includes information gathered downhole, then stored and/or transmitted to the surface for interpretation and analysis. At present MWD services are divided into three categories:

- Directional Services
  - Borehole Inclination
  - Borehole Azimuth

    - Tool Face Reference
    - Circulating Temperature

- Drilling Performance Monitoring
    - True Torque-on-Bit
    - True Weight-on-Bit

- Formation Evaluation
    - Short Normal Resistivity
    - Dual Propagation Resistivity
    - Gamma Ray
    - Neutron Porosity
    - Density Lithology

Pore Pressure Evaluation

MWD data is used in much the same way as wireline log data for detection and evaluation of formation pressures. MWD information, however, has the advantage that the data sets are transmitted to the surface during drilling, making the information available for integration with offset and mud log data as the well is being drilled.

Even when the data is not transmitted, the information is available after a bit trip, as opposed to wireline information being available only at casing points. The increased use of fixed cutter bits, downhole motors and specialized mud systems in today's drilling programs means fewer trips, making the use of transmitted MWD data much more attractive.

The evaluation of pore pressure is made more efficient when offset well logs and information are readily available to MWD field personnel. This allows for better real-time analysis of the pressure parameters. For example, if offset information such as wireline resistivity, density and sonic logs are accessible, wellsite programs can derive overburden tables and pre-well pressure plots which can be used as a guide until real-time information is available.

During drilling, the earlier the downhole information is processed, the better the chances of making correct decisions pertaining to mud densities, casing points and drilling practices.

As with all pressure parameters, the effectiveness of MWD data as an aid to pore pressure evaluation depends on the quality of correlation data, the types of MWD logs being produced, the geological sequence being evaluated and the mechanism which generated the geopressure zone.

A common method for quantitative pore pressure determination is provided in Appendix D.

For formation pressure analysis, the following MWD information can be evaluated:

- Short Normal Resistivity
- Phase Difference Resistivity
- Amplitude Ratio Resistivity
- Neutron Porosity
- Density Lithology
- Gamma Ray

As stated earlier, if a geopressured zone occurs in a predominately claystone/shale sequence, caused by compaction disequilibrium (rapid loading), then any data that reflects compaction (i.e. density, porosity, resistivity) can be used. As with other drilling and logging parameters, it is necessary to establish the behavioral patterns of the parameter while drilling a normally compacted sequence, then extrapolating that behavior to greater depths, and looking for deviations from that established trend.

In other lithologies (i.e. carbonates and evaporites), the link between porosity, compaction and pore pressure is less obvious, therefore requires greater caution when evaluating the data. Cap rocks, seals and pressure charging from below due to hydrocarbon generation, may not generate transition zones that are easily identified by looking at trend lines. If there is no undercompaction or increases in porosity, then density and porosity will follow the normal trend lines. Since the pressure is caused by variations in fluid type, MWD resistivity would be most useful in determining formation pressures and could be used with those other parameters that are affected by changes in differential pressure.

MWD Resistivity Devices

Historically, most MWD resistivity data has come from 16-inch Short Normal tools. Due to invasion characteristics, this one resistivity value was limited in its effectiveness when used in evaluating Rt and water saturation. However, as a pore pressure and transition zone indicator, Short Normal data is useful because fluid invasion is restricted due to low permeability lithologies.

With the addition of the Dual Propagation Resistivity (DPR) tool to MWD services, a two curve resistivity log is possible. This tool transmits a radio wave with a frequency of 2 MHz into the formation, and the phase differences and amplitude ratios of the signal are measured between two receivers, from which resistivity information can be derived. The phase and amplitude derived resistivities have different vertical resolutions and depths of investigation, giving dual resistivity readings, similar to a dual induction wireline tool.

This MWD resistivity data will normally have a better depth resolution than equivalent wireline logs and have superior vertical resolution.

Resistivities derived from DPR tools are generally much closer to true formation resistivity (Rt) than the resistivity obtained from the MWD 16-inch SN, and is less affected by borehole condition and mud type.

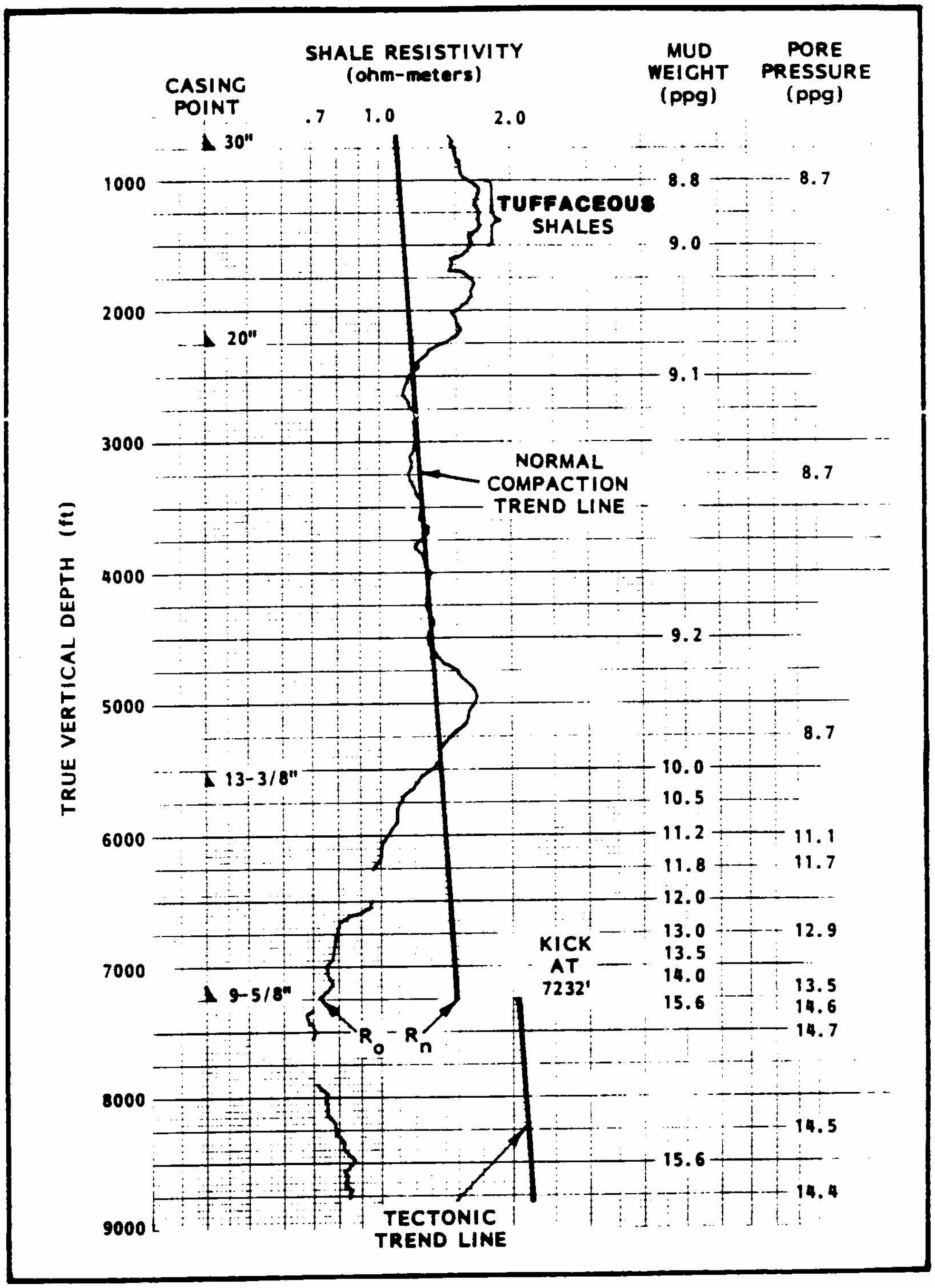
Pore Pressure and MWD Resistivity

Using MWD resistivity data for pore pressure evaluation generally follows the same methods as using wireline resistivity data. Geopressured zones caused by the undercompaction of claystones/shales will have an excess of trapped pore fluids compared to normally pressured sections at similar depths.

Those shales and claystones showing normal compaction will develop formation resistivity values increasing with depth, as the amount of pore fluid is reduced and the flow paths become more tortuous. A plot of shale resistivity versus depth on semi-log paper (Figure 4-26) will show a linear increase with depth and this behavior can be extrapolated to a greater depth. Deviations from this trend will indicate either a change in lithology or a change in pore pressure. Changes in lithology can be distinguished by using Gamma Ray information.

Lower resistivity values can be a reflection of a change in pore fluid salinity, going from a less saline solution to a more saline solution (common when drilling near salt domes). While indicating a change in the normal hydrostatic pore pressure, it does not necessarily indicate a geopressured zone.

Evaluation of geopressures in other lithologies, using MWD resistivity, where the pressures have not been caused by undercompaction is a little more difficult. Geopressures trapped by an impermeable cap rock will not show gradual movement to lower resistivities away from the established trend, but will show the increased resistivity of the cap rock followed by an abrupt change to lower resistivities upon entering the geopressured interval.



Note the normal compaction trend line and the tectonic trend line

Figure 4-26: A Shale Resistivity Plot used for Pore Pressure Calculations.

MWD Resistivity and Shallow Gas

MWD resistivity has been found to be particularly useful in identifying shallow gas zones while drilling offshore wells. Shallow gas is a significant problem because the gas is contained in loose, undercompacted formations at shallow depths, which have very low fracture gradients. Due to the compressibility of gas, the zone can be at higher pressures than the normal fluid gradients.

Detection of shallow gas zones is difficult because there is no opportunity to establish pressure trends. Also, the high drill rates and controlled drilling techniques tend to mask drilling and logging pressure parameters. If kick's occur in these shallow gas zones, they cannot be shut-in due to the low fracture pressures, and are usually controlled by using diverter lines.

Good offset data, close attention to the seismic interpretation, and drilling a small diameter pilot hole can minimize the risks. The use of MWD data can be invaluable; the sands will be identified using the Gamma Ray and the gas will be indicated by the high resistivity values.

MWD Resistivity Pore Pressure Methods

Several methods have been developed to assist in the quantification of pore pressure using MWD resistivity data. The availability of “real-time” resistivity information has allowed another quantification technique for comparison with the Dxc Ratio methods. All of these methods require an accurate overburden (S) calculation.

The method developed by Eaton is essentially an Equivalent Depth Method, which uses resistivity ratios as the qualifier.

Eaton’s technique involves both the MWD Gamma Ray and Resistivity logs. The GR log is used to identify and verify shales zones. Shale sections of between 20 to 30 feet are then chosen and the true vertical depth is noted. The resistivity value (Rsh) for that depth is then noted, corrected for any borehole effects, then recorded. Shale resistivities should be sampled as frequently as possible (at least once per 100 feet), then plotted on semi-log paper on a 1-inch to 1000 feet vertical depth scale.

Based on experience, shale resistivities usually range:

- between 1.0 to 2.0 ohm-meters for normal compaction
- as low as 0.3 ohm-meters for geopressured shales
- as high as 10.0 ohm-meters for cap rocks, silty and pyritic shales

Once the plot of observed shale resistivities is made (which is continually updated during drilling), a normal compaction shale resistivity tend line is constructed. This trend line is often a “best fit” line through the shale resistivity values in a normally-pressured section of the well (see

Figure 4-26). As with drilling exponents, all observed shale resistivities that fall on this trend line are representative of the normal pore pressure. Shale resistivities values which fall to the left of this trend usually represent geopressured shales, and values which fall to the right usually represent hard, cemented shales. Pore pressure is quantified using an equation similar to that used for drilling exponents:

$$P = S - (S - P_n)\left[\frac{R_o}{R_n}\right]^{1.2}$$

where:

P	= formation pore pressure (lbs/gal, psi, psi/ft)
S	= overburden pressure (lbs/gal, psi, psi/ft)
P_n	= Normal Pore Pressure (lbs/gal, psi, psi/ft)
R_o	= Observed Resistivity (ohm-meters)
R_n	= Normal Resistivity (ohm-meters)

Eaton's method can also be used with other pressure parameters, for example:

$$P = S - (S - P_n)\left[\frac{Dxco}{Dxce}\right]^{1.2} \text{ and } P = S - (S - P_n)\left[\frac{\Delta tn}{\Delta to}\right]^{3.0}$$

where:

Dxco	= Observed Dxc
Δtn	= Normal Sonic Transit Time
Dxce	= Expected Dxc
$\Delta$to	= Observed Sonic Transit Time

This method, although very useful when used in areas where the pressure generating mechanism is compaction related (Gulf of Mexico), the exponents require modification when used in area of “older” rocks and when compaction-related mechanisms are not the major source of the geopressures. For example, in the western part of Colombia, the exponents must be halved (1.2 becomes 0.6) to provide accurate pore pressure values.

Several recent methods which use MWD resistivity for pore pressure determination are unique in that they do not require a “normal” trend. Realizing the difficulty in drawing a normal trend from plotted data, these methods “go around” the determination of normal trends by concentrating on the matrix component in the standard overburden equation. These authors feel that if overburden (S) is determined, and if matrix stress (σ) is found, the pore pressure (P) can be easily calculated.

Therefore, much of the emphasis on MWD resistivity has shifted from determining the resistivity in a normal shale vs an abnormal shale to how the resistivity is affected by the matrix (i.e. trying to determine the matrix porosity from shale Rw and shale volume calculations).

The most common methods used are PPFG (Pore Pressure and Fracture Gradient) model (1987), Dual Shale (Bryant's) model (1989) and Alixant's method (1991). These methods require various MWD curve data, several tables of reference and each contains various "constants" which must be determined. As such, a great deal of computer power is required to run the models.

The Bryant and Alixant methods can be found in GeoPress.

MWD Gamma Ray

Pore pressure evaluation can be accomplished using MWD Gamma Ray information. The method is based on the type of lithology and the method of geopressure generation and the reasoning behind the model is that undercompacted shales generally have more porosity and lower volumetric amounts of clay minerals when compared to normally compacted shales at similar depths. The undercompacted shales continue with the same amount of clay minerals, compositionally, they are just displaced by the increased porosity (which is water-filled). Therefore, in the same volume of rock as compacted shales, the gamma ray count appears less due to the displacement by water-filled porosity, or in other words, there is a volumetric difference in Shale Content.

It has been determined that with increasing depth the gamma ray intensity tends to increase as compaction occurs and porosity decreases. When the gamma ray measurements of shales are plotted, a "normal trend" can be established and extrapolated. Deviations from the established trend, in the same lithology, can indicate a geopressured zone (Zoeller, 1983).

Several factors will also result in changes in gamma ray counts, which are not directly related to pore pressure. Changes in mineralogy within the shales/claystones can result in changes to the API gamma ray counts, without indicating increasing pore pressure. The change from a montmorillonite-rich to an illite-rich shale will result in an increase in the gamma ray counts due to the increased potassium content of the illite clay. An increased montmorillonite content with depth would therefore lead to a reduction of gamma ray counts, possibly giving a false indication of increasing pore pressure.

This natural tendency for a clay to change from a montmorillonite-type clay to an illite-type clay, with increasing depth and temperature, has been discussed in Chapter 2. Increasing montmorillonite is normally indicative of immature claystones and shales showing undercompaction and subsequently higher than expected pore pressures.

The MWD gamma ray logs are best used for the differentiation of sand/ shale lithologies. This provides excellent back-up information to other pore pressure parameters.

MWD Porosity

MWD density and neutron porosity data can be used in the same manner as wireline data to detect geopressured zones caused by undercompaction. A normal trend line can be established for both parameters, and deviations towards lower density or increased porosity, in the same lithology, can indicate an overpressured section.

The Modular Neutron Porosity (MNP) tool can be used as an indicator of hydrogen, and changes in clay mineralogy can be confused with changes in porosity. The high amount of bound water in montmorillonite clays can be interpreted as increased porosity, and therefore changes in the illite and montmorillonite content will cause shifts from the normal trend, and should not be confused with pore pressure changes. With that in mind, the use of the Neutron Porosity measurement for pore pressure detection should be avoided.

When dealing with undercompacted shales and claystones, geopressure quantification using the Modular Density Lithology (MDL) data can be accomplished using Eaton's Equivalent Depth method. However, the biggest benefit of using density data is for calculation of a “local” overburden gradient, if there is sufficient information

Where geopressures are contained beneath impermeable barriers, a long transition zone will not exist. The MWD’s high density readings and reduced porosity values can indicate potential cap rocks, and should be evaluated closely while drilling. The drill rate and formation gas information can be integrated with this MWD information to provide an early warning to an extremely dangerous situation.

Factors Affecting Formation Pressure Evaluation

Lithology

The classic sand/shale sequence of marine sediments is perhaps the easiest to evaluate for geopressures. Such lithological sequences are recognizable when displayed on the drill rate curve, Dxc plot, total gas plot, cavings occurrence, temperature plot and MWD/wireline logs. Thick shale sequences allow normal trend development, permeable sandstones provide good differential pressure estimations using the mud density/gas relationship, and geopressure trends can be constructed in shale intervals.

Massively thick clays provide excellent opportunities for drilling exponent evaluation and cavings analysis.

Thick sand/arenaceous lithologies cannot be evaluated by textbook exponent methods; great thicknesses of turbidites, greywacke, volcanics and terrigenous clastics with few intercalated argillaceous horizons exclude the possibility of developing normal shale trends; however, these sediment types will exhibit normal trends in Dxc, density, and temperature plots. As most of the geopressure evaluation techniques are based on clay analyses, arenaceous lithologies severely restrict evaluation methods. Nevertheless, differential pressure is a major clue for evaluation, and mud density/gas relationships must be utilized to the utmost. With these tools, geopressure evaluation can be achieved with confidence, albeit at a degree of detail somewhat less than that possible in argillites. Where permeability is restricted in arenaceous sediments, the possibility of a geopressure occurring below becomes increased. The change in differential pressure upon entering a higher pore pressure zone will be monitored by the Dxc: the Dxc will decrease, as it would in geopressured clays. Evaluation, however, may not be of the same order as that in clays. The ratio method (Equation 4-15) will provide a very vague estimate, as empirical justification for pressure evaluation in sand types is not yet available. Thus, geopressure techniques may be used in thick sands, but the emphasis of evaluation must be shifted from Dxc analysis to mud density/gas/ differential pressure methods, that is a qualitative evaluation of the magnitude of under- or over-balance.

Geopressure evaluation in carbonates can be the most difficult and frustrating task. Carbonate sediments can encompass the whole gamut of porosity range, permeability range, and pore geometries from huge caverns through open fractures to secondary solution types in microfossils. The characteristic variability of carbonates causes concomitant variability in geopressure plots. Argillaceous limestone and calcareous claystones can generally be evaluated (in the majority of cases) in the same manner as clays (where all the evaluation techniques apply). Clastic limestones, without a high degree of cementation, may be evaluated as sand type sequences (increase emphasis on differential pressure evaluation techniques). Well cemented, massive types (i.e. micrite, secondary cemented fossiliferous limestone etc.) can be extremely difficult to evaluate. These limestone types have highly variable permeabilities, and this is what makes evaluation difficult. If a limestone is without permeability, a transition zone cannot exist. Totally impermeable types (porous but the pores are not connected) may have extremely high pore pressures, probably caused by aquathermal mechanisms, but should not cause major drilling problems due to their impermeability. It is the permeability barrier below which is a highly pressured porous zone that provides the greatest potential danger.

As cemented limestones have a relatively high tensile strength, cavings do not appear until the degree of underbalance is large. Changes in differential pressure will affect the Dxc, but to an unpredictable extent. Bulk density measurements on cuttings should reflect the actual density, as hydration problems do not occur; hence, density measurements in limestone will indicate porosity changes; but due to the competent nature of the rock, a porosity increase does not necessarily indicate a corresponding increase in pore pressure.

Probably the only techniques of anticipating the probable occurrence of a geopressure within highly competent, massive limestones, are the various temperature plots. Again, however, the assumption is that the geopressured interval will be porous and water-filled, so that it may act as an insulator to heat. If a temperature gradient reversal does occur with depth, it can be assumed that it is a zone of considerable porosity (fluid-filled), but this could either be a fractured, vugular, dolomitized or granular interval of high or low pore pressure. In any event, drilling should proceed with great caution until the character of the anomaly is determined.

Apart from the above discussion, there can be no hard-and-fast rules laid down for geopressure evaluation in carbonates. A real experience should be developed in areas of intensive drilling in carbonates; but at all times, drilling rank wildcat wells in carbonate lithologies calls for the most diligent observations and interpretation on the part of the geologist.

Controlled Drilling

Controlled drilling offshore in top-hole sediments is commonplace and desirable. It does, however, cause problems with exponent analysis. Because the bit is not wholly drilling, and the jetting action of the bit is the major drilling mechanism, drilling exponents cannot be used in their accepted role. It is probably best to consider the as Dxc a differential pressure indicator, no matter what the drilling mechanism is, because the rate of penetration will increase as the differential pressure decreases. Since the penetration rate is controlled, and rotary speed is kept constant, Dxc changes become a function of bit weight which is allowed to vary. Bit weight should then change with formation type and character. In soft, unconsolidated clays, jetting will proceed with vigor and will be considerably aided by increasing pore pressure. Rate of penetration being controlled allows bit weight to reduce to negligible quantities, which will cause the Dxc to deflect to the left on the plot.

Thus in soft top-hole sediments, geopressure indications may well be exhibited by the Dxc plot, and this is of particular importance in attempting to ascertain the presence of shallow, pressured, gas reservoirs. However, pore pressure quantification cannot be performed from the Dxc plot in these situations, because:

- Establishment of a normal trend in top-hole is difficult
- The bit is not truly drilling, hence, the Dxc values are not indicative of actual “drilling” values
- Deviation of the Dxc points to the left may indicate increasing pore pressure but the ratio method cannot be applied in unconsolidated sediments

Mud density/gas relationships should provide a reasonably accurate estimate of pore pressure magnitude and changes.

Whether the overall drill rate is controlled by manipulating the penetration rate or by circulating between singles, a shallow gas pocket can make its presence known without warning. The client and drilling personnel must be made aware of the limitations of geopressure evaluation in shallow sediments, particularly the quantitative aspect. An unconsolidated sand containing pressured biogenic gas will not be heralded by a transition zone: the surprise element thus becomes magnified to startling proportions, so for safe top-hole drilling, drilling crew diligence must be tuned accordingly.

Hydraulics

The rate of penetration, and hence drilling exponents, are a function of the various hydraulic forces at the bit. Current exponents do not take into account the effect of changing hydraulic parameters: they assume hydraulics are 100 percent efficient and optimized. Pump efficiency, surface pressure losses and the various down-hole frictional losses can be calculated, but there is really no very accurate method of measuring them at present, in order that standard calculations can be checked.

Inefficient drilling hydraulics will suppress the drill rate and will cause inflated exponent values. Overly energetic hydraulics promote washouts, pump failure, increased bit wear and hole problems. The optimum conditions are between 60 and 70 percent of total hydraulic horsepower for maximum bit hydraulic horsepower. For maximum jet impact force, pressure loss at the bit should be approximately 50 percent of the total.

The different hydraulics involved in turbine and PDM drilling contribute to shifts in the various trends, but how much of the shift is due to the change in drilling mechanism cannot be determined.

Roller Cone Bit Selection and Bit Wear

If a bit is selected that cannot drill the formation efficiently, exponent trend response will be considerably masked. A common error is opting for an insert bit in moderately hard formations, only to find that the bit produces very sluggish drill rates. Cases are known where a geopressure transition zone was drilled with an inefficient bit; the result was a normal or slightly shallower Dxc trend, completely masking the increasing pore pressure. If this is permitted to continue, loss of the hole could occur due to sudden sloughing, or a kick taking place.

The decision to change from a milled-tooth to an insert bit is a difficult one, particularly in wildcat areas. When the change is made, geopressure indicators other than drilling exponents should be monitored with increased concentration, as the situation could be such that the different bit type can mask a transition zone.

New bit selection is partly dependent on the amount of wear that the previous bit sustained. Unfortunately, the accepted “eyeball” technology, favored by drilling crews can be so affected by extraneous phenomena that the result recorded on the drilling report may bear little resemblance to the bit in question.

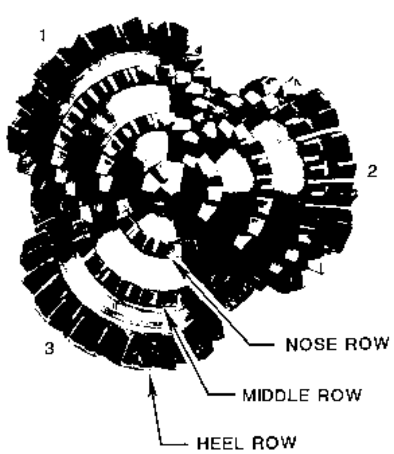
By using the standard IADC grading scheme and a simple quantitative method, bit grading becomes meaningful and may be gainfully employed when using second generation exponents. The method is not rigorous, but provides consistency and reasonable accuracy in the time-frame available.

The suggested method is as follows (See Figure 4-27)

1. Before the new bit is run, measure the height on one tooth on each row (use cone number 2 or 3).
2. Count the number of teeth on each row of that cone, and multiply the tooth height pertaining to that row by the number of teeth in that row.
3. Multiply this result by the number of cones.

Note that most bits have positional tooth and row variations, so the result will not be the actual total tooth height.

When the old bit becomes available, perform the same measurements on the same cone, and calculate the quantitative tooth wear as shown in Figure 4-27.



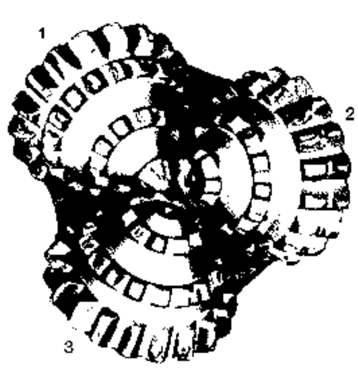
Using Number 3 Cone

Heel Row: 24 Teeth
Tooth Height: 1”
Total Height: 24”

Middle Row: 18 Teeth
Tooth Height: 0.8”
Total Height: 14.4”

Nose Row: 10 Teeth
Tooth Height: 0.8”
Total Height: 8”

Total Tooth Height for Cone: 46.4”
Total Tooth Height for Bit:
$3 \times 46.4” = 139.2”$



Using Number 3 Cone

Heel Row: 22 Teeth (2 missing)
Tooth Height: .7”
Total Height: 15.4”

Middle Row: 18 Teeth
Tooth Height: 0.5”
Total Height: 9”

Nose Row: 9 Teeth (1 missing)
Tooth Height: 0.5”
Total Height: 4.5”

Total Tooth Height for Cone: 28.9”
Total Tooth Height for Bit:
$3 \times 28.9” = 86.7”$

Bit Wear = (139.2 - 86.7) ÷ 139.2 × 100 = 37.7%

Tooth Grade = 8 × 37.7 ÷ 100 = T3

Figure 4-27: Estimation of tooth Wear

Fixed Cutter Bits (PDC, TSP, ND)

The use of fixed cutter bits, particularly the PDC type, has increased dramatically over the last few years. There are sound reasons for this, namely increased drill rates and reduced bit wear over more traditional insert type roller cone bits. There are, however problems with formation evaluation because the drilled cuttings produced by fixed cutter bits are rarely representative of the formations drilled, due to a variety of bit generated rock textures caused by the drilling action. These effects are compounded by the high rotary speeds and temperatures from downhole mud motors.

Their use also causes problems in geopressure evaluation. PDC bits drill medium-soft to medium-hard formations by a shearing action controlled largely by the efficiency of the cutters and use of the appropriate rotary speed and hydraulics. Harder formations, such as limestones or chert stringers are drilled by selecting TSP or ND bits which include pointed as well as round cutters and thus also have an element of crushing produced by weights similar to roller cone drilling.

In the softer rocks where shearing is the dominant action, the relationship between compaction, porosity and drilling parameters is not the same as in roller cone bits, and neither is the role of differential pressure and its hold down of cuttings beneath the bit. As a consequence drill rate and Dxc evaluation when using fixed cutter bits is not such a reliable indicator of pore pressures as they are when using roller cone bits. Dxc trends when using fixed cutter bits tend to be near vertical so that identifying deviations becomes very difficult, and any movement is less easily attributable to pore pressure changes.

Those fixed cutter bits designed for drilling harder formations and those with pointed cutters have an increased element of crushing and gouging in their drilling mechanism and may therefore show trends and behavior similar to roller cone bits. In this case pore pressure evaluation is more reliable.

Drilling Fluid Type

In all situations, the drilling fluid must be compatible with the formation. Specific muds can be developed for individual wells, so that formation reaction, reservoir interaction, temperature effects and rig problems can be minimized. Quite often though, it is not possible for one mud system to achieve all these goals, and it is common for mud systems to be changed during the course of the well. Again, fluid-related problems can be accentuated in wildcat areas. Complete information on the various mud systems can be obtained from manuals provided by the mud company, so it is sufficient here to simply outline possible occurrences that could hinder geopressure interpretation.

Water-based mud systems, fresh or saline, can react with hydratable clays. If a reaction does occur, clay cuttings will swell, lose their morphology and even dissolve in the mud. The result is a rapidly increasing viscosity, mud density and solids content, and a distinct absence of clay cuttings. Bulk density measurements cannot be performed on this “gumbo,” but shale factor can be performed. Clay cavings from a transition zone may not be apparent. Sonic and density log readings in clay zones will also be anomalous: sonic transit times may be high and bulk densities may be extremely low, particularly if the hole is washed out which is usual in these situations.

Inhibitive muds will combat clay hydration and help reduce hole and mud-related problems. Calcium, gypsum, spersene, saturated salt (NaCl), and ligno-sulphonate all control clay hydration to various extents, and the choice of a particular mud type is commonly made depending on their other properties. Probably the most effective clay inhibitor water-based mud is a potassium-chloride (KCl) type. This mud serves to provide potassium cations for adsorption onto the available lattice sites of montmorillonite, which collapses the expanded lattice and renders the clay non-reactive. Good clay cuttings and cavings can be obtained when these muds are used. Shale factor values from clays that have been drilled with a KCl mud type will be considerably less than the original exchange capacity. If the KCl system is kept efficient, the change in clay mineralogy may be completely masked and shale factor trends rendered meaningless. However, adsorption of potassium by montmorillonite never seems total, and some degree of hydration will occur.

Oil-based and synthetic muds are by far the best drilling fluid for aiding geopressure evaluation. All cuttings and cavings are preserved in their original form. Since no hydration occurs, shale factors and bulk density measurements are accurate, and sonic and density log curves are representative. Gas interpretation, however, is made more difficult due to the background level caused by the base oil, and slugs of fresh oil may cause further problems.

Deviated and Horizontal Wells

Pore pressure evaluation when drilling highly deviated or horizontal wells is made more difficult by the uncertainty of the actual weight-on-bit estimations used in normalized drill rate and Dxc interpretation. Surface WOB can be much higher than actual weight being applied at the bit due to drillstring friction around the collars and stabilizers. The true weight-on-bit is governed by the hole angle and the nature of the bottom hole assembly. Actual weight-on-bit measurements are even more difficult when thrusters are used.

In deviated wells there is also the increased likelihood of a downhole mud motor being used which also adds uncertainty to the Dxc calculation.

These factors are more pronounced while drilling the build section of such wells, and are less of a problem when drilling straight or tangent sections.

Extreme caution must be exercised if attempting to use drill rate or Dxc in these situations, and again more reliance may have to be placed on mud density/gas relationships and general borehole behavior.

When attempting to evaluate drilling or logging parameters in deviated wells it is also necessary to realize that compaction trends should be plotted against TVD and not measured length (Measured Depth) of the borehole.

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•Notes•

Chapter 5

Fracture Pressure

Past and Current Technology

Hydraulic fracturing techniques for well stimulation have been in use since the 1940s. During these operations, this process and the similar, costly and time-consuming occurrence of lost circulation while drilling with high mud densities, were thought to occur due to the formation of horizontal or bedding plane fractures. Lifting the overburden in this manner was the explanation put forward, totally disregarding the fact that most of the pressures in the borehole at the time of fracturing were considerably less than the total weight of the overburden.

Some theoretical studies and accurate pressure measurements made during squeeze cementing operations raised questions as to the validity of this argument of lost circulation, caused by horizontal fractures. Pressures required in boreholes are generally less than the overburden, so the only explanation was that orientation of the fractures must be vertical.

In 1949, Clark (Stanolind Oil & Gas Co.) showed how fluid flow through hydraulic fractures could be greatly increased by pumping sand with the fracturing fluid. The sand (a proppant) prevented the fractures from closing, thus providing a conduit from the reservoir into the well.

Hubbert and Willis

Among most engineers of this time there existed stubborn belief that the majority of fractures created during and after drilling were bedding-plane fractures. The Shell Oil Company, in 1955, employed M. K. Hubbert to provide a critical review of the situation, and the result was the classic paper, “Mechanics of Hydraulic Fracturing,” published in 1957.

Using accepted engineering theory, Hubbert and Willis showed that a subsurface stress regime is such that, when normal faults occur (60° to the horizontal), the minimum horizontal compressive stress is of the order of one-third to one-half of the maximum vertical compressive stress.

In the subsurface environment, there exists a system of stresses. At any point in that environment, the stresses acting upon a point can be resolved into three mutually perpendicular stresses (a maximum, intermediate, and minimum stress), σ_1, σ_2 and σ_3, respectively. (Geologists use the notation that compressive stresses are positive, engineers use the convention that tensile stresses are positive; hence in the latter case, σ_3 is the maximum compressive stress.) Stress is a pressure, or force per unit area, and always acts normal to a selected plane.

In the simplest subsurface environment (horizontal beds, horizontal topography, elastic rocks, and horizontal constraint), the maximum compressive stress (σ_1) is vertical and equal to the pressure of the overlying rocks. Since rocks are assumed to be isotropic, the horizontal stresses will be equal and will act in all directions in a horizontal plane, and are caused by a function of Poisson's ratio of the rock type and σ_1. If an additional horizontal stress is imposed on the system (i.e. a tectonic stress), the horizontal stresses will become unequal and directional, such that σ_2 is parallel to the tectonic stress and σ_3 is normal to σ_2 in the horizontal plane.

When pressures are applied in a borehole, they will create tensile stresses around the walls. If this tensile stress exceeds the horizontal compressive stress in the surrounding rocks and also overcomes the rock's tensile strength, a tensile fracture will form along the path of minimum resistance (i.e. normal to σ_3 and parallel to σ_2 and σ_1).

If σ_1 is vertical (the basin is relaxed) the tensile fractures will be vertical and oriented parallel to σ_2 (if σ_2 is greater than σ_3). If a superposed tectonic stress is imposed such that it is greater than the overburden pressure, then σ_1 is horizontal and parallel to the tectonic stress and σ_3 is vertical. To cause fracture in this case, the pressure in the hole must be slightly in excess of the total pressure of the overburden, and the fracture will be horizontal.

Hubbert and Willis overcame the problem of attempting to predict the tensile strengths of rocks in situ by observing that many closed cracks, joints and partings intersect many sections of the borehole. When this occurs, the effective tensile strength of the rocks over that interval are thus close to zero.

When an interval is hydraulically fractured, the pressure in the borehole must balance the minimum stress holding any preexisting cracks closed, and must provide an additional amount of energy to extend the cracks. If a crack exists in a compressive stress field and pressure is applied within the crack such that it balances the compressive stress acting normal to the sides of the crack, a slight increase in the pressure should produce a high tensile stress at the tip of the crack. This tensile stress easily overcomes the tensile strength of the rock, and the crack rapidly propagates.

Utilizing these assumptions, Hubbert and Willis showed that fracturing will occur when:

Equation 5-1

$$F = \frac{(S-P)}{3} + P$$

where:

F	= pressure in the borehole at point of fracture (psi)
S	= total pressure of the overburden (psi)
P	= pore pressure (psi)

Thus the minimum injection pressure required per unit depth (D) in an area of incipient normal faulting is

Equation 5-2

$$\frac{F}{D} \approx \frac{\frac{S}{D} + \frac{2P}{D}}{3}$$

This expression provided an estimate for the minimum fracture pressure that will occur in a relaxed basin, that is on the point of normal faulting. Hubbert and Willis concluded that fracture pressures will be affected by; 1) the magnitude of the preexisting regional stresses, 2) the hole geometry (including any preexisting fissures), and 3) the penetrating quality of the fracturing fluid.

To simplify the calculation, they assumed that if the value of S/D is equal to 1 psi/ft, under normal hydrostatic conditions (P/D) of 0.465 psi/ft, the minimum fracture pressure would be 0.64 psi/ft.

Hubbert and Willis' paper thus provided the theoretical and technical basis for predicting minimum fracture pressures (as well as a means to predict fracture pressures in tectonic environments and abnormal pressure zones) if the relevant parameters could be measured. However, though very important, it was not sufficient for the industry since wells drilled in areas of active normal faulting are very few and far between. The need to predict fracture pressures at any point in a borehole became necessary to plan casing programs - especially in areas where, due to high pore pressure and/ or tectonic stresses, abnormal hole conditions were the norm.

Matthews and Kelly

In 1967, Matthews and Kelly published a study in which fracture pressures could be predicted in some Gulf Coast sand reservoirs using empirical data. Since this area was undergoing extensive exploration, their data allowed safer and more economical well completions. Unfortunately, Matthews and Kelly did not further the progress made by Hubbert and Willis. They chose the minimum fracture pressure as being equal to the pore pressure, and the maximum fracture pressure equal to the pressure of the overburden. A fracture pressure that was observed to be greater than the pore pressure was thought to be due to the force necessary to overcome the “matrix load” or the “cohesive nature of the matrix.” By “using the assumption that the cohesive property of the matrix can be related to the matrix stress and hence will vary only with the degree of compaction, a relationship could be developed for calculating the fracture gradient of sedimentary formations”. This is illustrated in Figure 5-1.

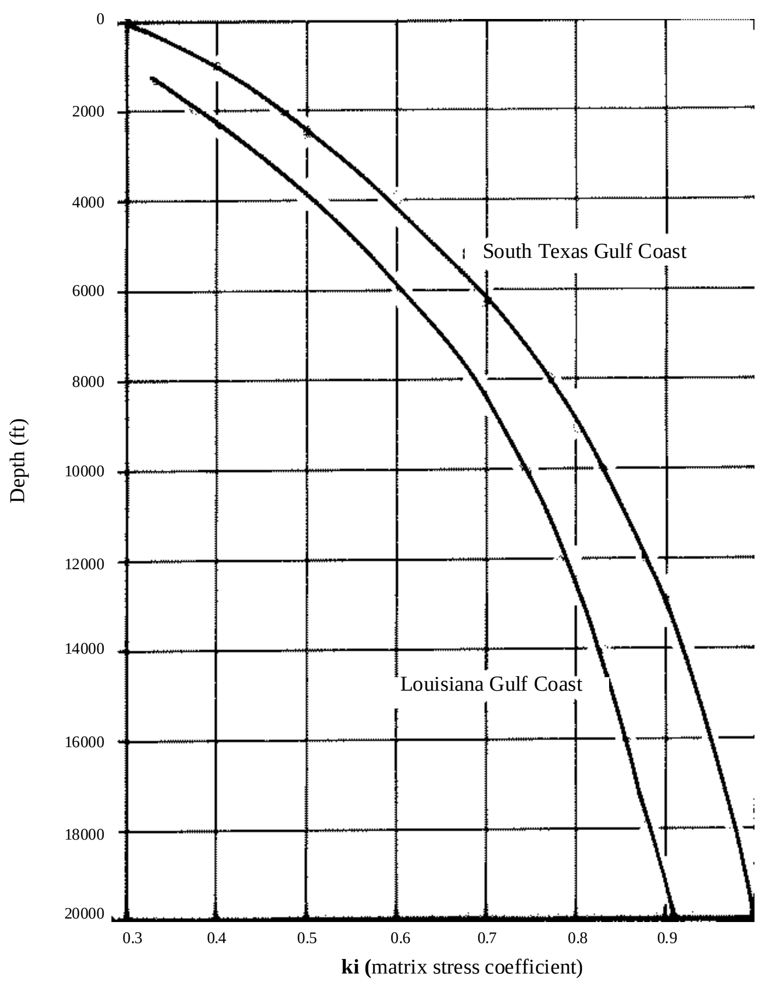

Figure 5-1: Matrix stress coefficient (ki) for Gulf Coast Sands (Matthews and Kelly, 1967)

Equation 5-3

$$\frac{F}{D} = \frac{P}{D} + ki\frac{\sigma}{D}$$

where:

σ = matrix stress at the point of interest (psi)

ki = matrix stress coefficient for the depth at which the value of would be the normal matrix stress

In developing their method, Matthews and Kelly assumed that the average normal hydrostatic gradient is 0.465 psi/ft and that the average overburden gradient is 1.0 psi/ft. In abnormally pressure zones, the increase in pore pressure (P) will produce a corresponding decrease in the matrix stress (s), since $\sigma = S - P$.

The value for ki is taken from the depth at which is σ normal.

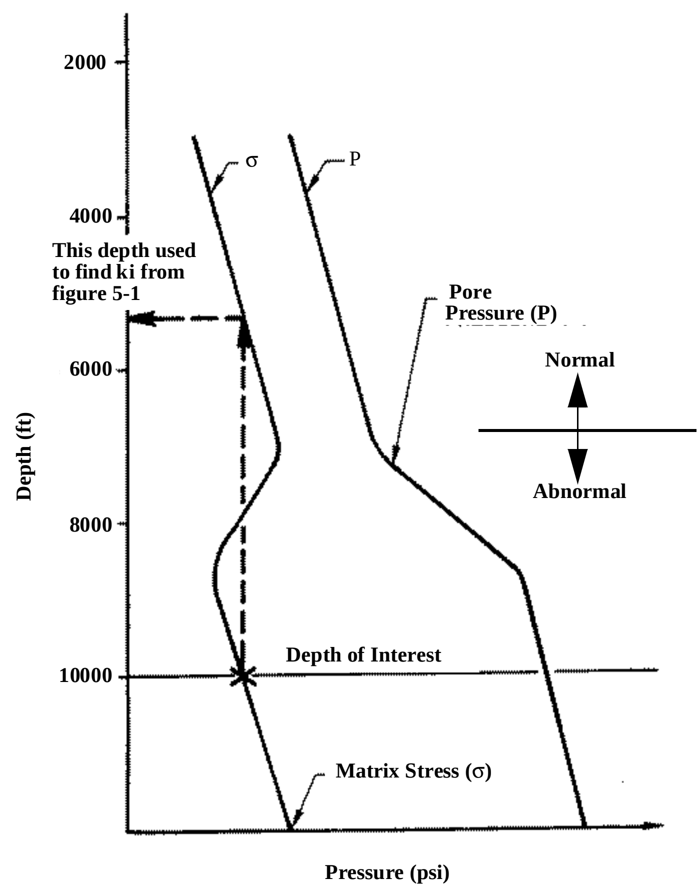

Figure 5-2: How ki is obtained from the depth at which σ is normal

These empirical values and relationships are limited solely to the area of study.

Eaton

In 1969, Eaton published a more adaptable method that took into account a variable overburden gradient. Eaton also introduced Poisson's ratio as a variable that controlled fracture pressure gradient. Poisson's ratio (μ) is formally defined as "The ratio of the lateral unit strain to the longitudinal strain in a body that has been stressed longitudinally within its elastic limit. It is an elastic constant."

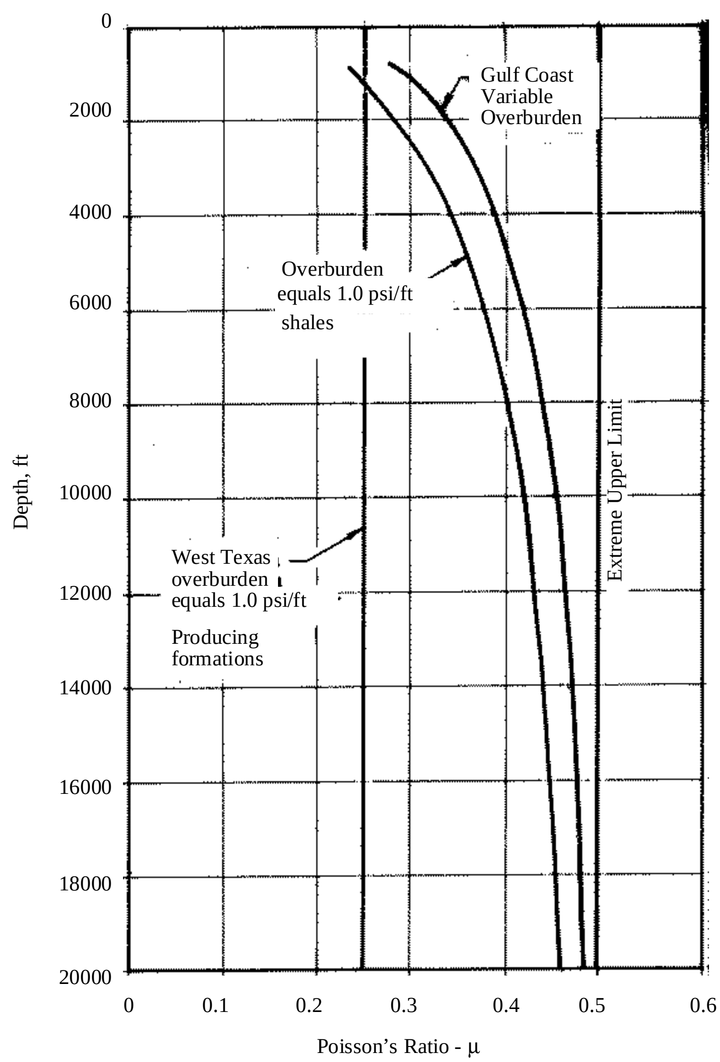

Figure 5-3: Empirical "Poisson's ratio" curves with depth for Gulf Coast Sands (Eaton, 1969)

It is thus a property of the rock itself. Eaton surmounted the problem of predicting or measuring Poisson's ratio of every in-situ rock in a borehole by resorting to an empirical relationship. Further, Eaton's "Poisson's ratio" is not a function the rock but of the regional stress field - the horizontal-to-vertical stress ratio. Thus, since Hubbert and Willis assumed that the minimum horizontal stress ia approximately $^1/_3$, it corresponds to a "Poisson's ratio" of 0.25 through the relationship

Equation 5-4

$$\frac{F}{D} = \left(\frac{S}{D} - \frac{P}{D}\right)\left(\frac{\mu}{1-\mu}\right) + \frac{P}{D}$$

when:

$\frac{S}{D} = 1.0\ psi/ft$

and

$\mu = 0.25$

Then

Equation 5-5

$$\frac{F}{D} = \frac{\left(1.0 + \frac{2P}{D}\right)}{3}$$

which is the same as Hubbert and Willis' minimum fracture gradient relation. A "Poisson's ratio" of 0.25 will predict values that are usually too low when compared with values from field data; also, the assumption that S/D = 1.0 psi will generally lead to errors (except in West Texas wells where fracture gradients are a minimum as predicted by Hubbert and Willis). Eaton presented empirical curves for "Poisson's ratio versus depth" calculated from Gulf Coast data. With depth, these curves will approach an upper limit of 0.5; that is, a longitudinal strain produces an equal lateral strain, which occurs in materials with a zero shear modulus (e.g. liquids) and in incompressible materials. These curves are thus independent of rock type, and illustrated in Figure 5-3.

The major contribution of Eaton's paper was the concept of the variable overburden. The assumption of 1 psi/ft for an overburden gradient was inaccurate; gradients were found to vary from about 0.6 psi/ft at shallow depth to slightly greater than 1.0 psi/ft at greater depths. Since overburden pressures play a major role in fracture gradient estimations, the increase in accuracy of this variable allowed better fracture gradient estimations.

Eaton's technique can be applied in other areas if the "Poisson's ratio curve" is known. Thus it is limited to areas of concentrated exploration in tectonically relaxed regions and cannot be used reliably on wildcat wells.

Eaton's assumption that Poisson's ratio was the sole "stress ratio" factor appears to be unfounded when the values of Poisson's ratio for normal sedimentary rocks are compared to those obtained from hydraulic fracturing. It is not uncommon to back-calculate a Poisson's ratio from a fracture test that has a value somewhere between 0.45 and 0.8.

Experimental determination of Poisson's ratio produces values from 0 to less than 0.5. It is important to realize that Poisson's ratio is a measure of the ability of a rock to deform (within its elastic limit) defined as the greatest stress than can be developed in a material without permanent deformation (strain) remaining when the stress is released.

Surface clays are generally so wet that they behave as liquids. With depth the rock grains themselves are responsible for a unique Poisson's ratio, but, as compaction increases, the rocks become more dense, more brittle, and elastic. This is largely due to the closure of cracks and creep of the minerals so that the rock becomes increasingly isotropic with depth. Since elastic rocks transmit seismic energy efficiently, and "plastic" rocks may transmit compressional acoustic waves but not shear waves, it may be realized that "plastic" rocks will not be encountered within drillable depths.

Anderson et al

Another empirical method was published by Anderson et al in 1973. Their aim was to derive all the necessary parameters to estimate fracture pressures from electric logs. Utilizing Biot's stress/strain relationships for porous media, they developed the following relationship

Equation 5-6

$$\frac{F}{D} = \left(\frac{2\mu}{1-\mu}\right) \text{x} \frac{S}{D} \text{x} \left(\frac{1-3\mu}{1-\mu}\right) \text{x} \frac{\alpha p}{D}$$

where:

α	= 1 - Cr/Cb
Cr	= compressibility of the solid matrix material
Cb	= compressibility of the porous rock skeleton

and can be approximated by

Equation 5-7

$$\alpha = 1 - (1 - \varnothing_D)^n$$

If n = 1, the best fit is obtained for the theoretical models.

Hence,

Equation 5-8

$$\alpha \approx \varnothing_D$$

Therefore, α is also dependent upon porosity, but is an immeasurable quantity in a drilling environment. Terzaghi experimentally found that if α = 1, then the relationship becomes

Equation 5-9

$$\frac{F}{D} = \left(\frac{2\mu}{1-\mu}\right) \text{x} \frac{S}{D} + \left(\frac{1-3\mu}{1-\mu}\right) \text{x} \frac{P}{D}$$

which is independent of porosity.

But the problem still remains for obtaining μ values for in-situ rocks. Theoretically, μ can be obtained from sonic shear and compressional velocities (Vs and Vc) in a formation, using:

Equation 5-10

$$\mu = \frac{1 - 2\left(\frac{Vs}{Vc}\right)^2}{2\left(1 - \frac{Vs}{Vc}\right)^2}$$

However, recognition of shear wave arrivals in most sedimentary sections is usually impossible. In order to obtain Poisson's ratio for Gulf Coast sands, Anderson et al made the broad assumption that "Poisson's ratio is a function of the shaliness of the sand since the shale would act essentially as a plastic bonding agent." The estimation of the shale content of the sand from sonic and density logs was accomplished using a shale index:

Equation 5-11

$$I_{sh} = \frac{\varnothing_S - \varnothing_D}{\varnothing_S}$$

where:

I_{sh}	= shaliness index
∅S	= porosity from sonic log
∅D	= porosity from density log

For a shaliness index between 0 and 40 percent, Poisson's ratio was found to vary from 0.27 to 0.33, in Gulf Coast sands. This linear relationship can be used to solve for μ:

Equation 5-12

$$\mu = A \text{ x } I_{sh} + B$$

where:

I_{sh}	= shaliness index
A	= the slope of the line
B	= the intercept on the y axis

A relationship has been developed for the data collected (i.e., from the Gulf Coast sands), and obviously other relationships occur in other sands with different clay, clay structure, sand/clay relationship, and sand types.

Additional Fracture Pressure Applications

Christman, in 1973, accented the problem of assuming a 1 psi/ft overburden gradient when drilling offshore. On offshore rigs, a high flowline elevation above sea level and drilling in deep water were shown to cause important modifications to calculated overburden and other pressure gradients.

Bradley (1979 a, b) published a complicated theoretical concept that could provide limits for borehole stability when a significant angle exists between the borehole and the regional stresses. Limits are set for failure in compression (sloughing) and failure in tension (fracture). Due to the very large number of variables involved, a computer is used to calculate and plot all the possible states of stress for all hole angles and directions. The result is an area, or "stress cloud." Changes in the variables produce changes in the shape of the stress cloud and a movement of the cloud across the mean shear stress/mean normal stress plane. A failure envelope experimentally obtained from rock failure at different confining pressures defines the limit of stability within the “stress cloud”. One application of this model is on development platforms where deviated wells are drilled.

Limitations and Advantages of Accepted Models

Hubbert and Willis

The fact that this theoretical model does not use empirical constants or relationships is a point in its favor. Unfortunately, however, it appears that the industry has chosen to misinterpret the object of this work - that is, to provide a means by which minimum fracture gradients may be obtained. Also, the theory may be applied in any location, providing that all the provisions are met (i.e., an area characterized by normal faulting, simple topography, and horizontal beds). The main disadvantage of this model is that it is imprecise. When hole conditions are such that very accurate fracture gradients are necessary, a minimum value is not sufficient.

Matthews and Kelly’s Method

Application of this model is limited to the Gulf Coast area since it was developed on wells in the Gulf Coast (specifically, in producing sands). Empirical values of ki can be back-calculated from a succession of fracture tests in an area, and then curves constructed so that ki can be plotted against depth. The present Matthews and Kelly curve should not be used outside the Gulf of Mexico because it relates only to Gulf Coast reservoir sands. This method can be only used within a single field in which sufficient fracture data is available to plot a ki curve which will be unique to that field.

Eaton’s Method

Eaton attempted to define the problem of determining actual subsurface stress regimes by use of “Poisson’s ratio”. Basically, the reasoning is precisely the same as Hubbert and Willis’ except that Eaton endeavors to account for a higher-than-minimum horizontal stress. He found empirically that, with a variable overburden gradient, their “stress ratio” ($\sigma 3/\sigma 1$) or ki varied non-linearly with depth. As with Matthews and Kelly’s method, ki curves have to be back-calculated from a multitude of data within a single field before accurate predictions can be made.

Anderson et al

Again, Poisson’s ratio is a necessary variable; however, in this model the ratio is a function of the rock, and not a “stress ratio” independent of rock type. Because of the difficulty of recognizing shear arrivals on sonic logs, it is empirically related to the percent clay in reservoir sands of the Gulf

Coast. Also, the rock compressibility parameter, α, is defined by a relationship which ia also empirically related to these sands;

Equation 5-13

$$\alpha = 1 - (1 - \varnothing_D)^n$$

where:

n = 1, and gives a best fit to the data

$\varnothing_D$ = porosity from the density log

If n=1, the relationship is approximated to $\alpha = \varnothing_D$ which can be applied only to those particular sands. In combination with the questionable relationship between μ and shaliness again, this method is limited to the area in which it was developed. Use in other areas will necessitate different μ and shaliness relationships to be developed, and possibly the determination for α will have to be reevaluated.

It must be noted that the last two methods were developed for sandstones. Limestones, shales and other typical sedimentary rocks could produce spurious results simply because their properties were not considered.

Estimation Of Fracture Pressure

With drilling now extending to deep waters and high latitudes, the costs of these wells are becoming exceedingly high. Deep wildcatting in areas of poor geological control can be extremely hazardous and costly for lack of adequate pore pressure and fracture pressure information. If abnormally high pore pressures are encountered, a further casing string may be necessary; and if the pressure zone is shallow in relation to the target, completion of the well can be jeopardized.

Of prime importance in these wells is an accurate assessment of kick tolerance. For this to be achieved, knowledge of the fracture pressures at any depth in the open hole is necessary. The prediction of fracture pressures in the Gulf Coast and other areas that have been extensively drilled is accomplished using empirical formulae. These can only be applied with confidence in other areas of similar geological and tectonic regime when sufficient drilling has allowed the calculations of the necessary empirical constants. However, the absence of any method by which fracture pressures may be predicted in wildcat areas has necessitated the use of the empirical formulae, with the general result that actual fracture pressures can be very different from the calculated pressures. This is due to the application of those empirically derived constants (usually representing the "stress ratio") which are unrelated to the wildcat area. Accurate information on the in-situ principal stresses is vital for the solution of the fracture pressure problem. None of the empirical formulae can accurately predict stresses in localized regions.

One hypothesis was proposed that had the capacity to resolve and extrapolate the local principal stresses, subsequent to the first fracture test in compact formation. The word "compact" can be defined as the point at which the sediment can transmit an applied stress through the grain contacts. Along with other pertinent data usually calculated on rank wildcats (overburden gradients and pore pressures), fracture pressures could then be obtained for any point within the drilled hole. Kick tolerance calculations then become more realistic when they are based on fracture pressure calculations for that specific well, so when abnormal hole conditions are encountered, the chances of completing the well are greater than if reliance is placed upon formulae containing unrelated empirical constants.

In order to hydraulically fracture the formation, it is necessary to overcome the minimum compressive stress. General formulae describe the minimum horizontal compressive effective stress as a function of the effective overburden pressure, which is empirically derived:

Equation 5-14

$$F = \sigma_3 + P$$

where:

F = fracture pressure
P = pore pressure
σ_3 = minimum compressive effective stress

and

Equation 5-15

$$\sigma_3 = K(S - P)$$

where:

K = empirical "stress ratio" constant
S = overburden pressure

As stated earlier, overburden pressure is obtained by integrating bulk density values with respect to depth:

Equation 5-16

$$S = \int_{0}^{z} (g \times \rho)\, dz$$

where:

g = acceleration due to gravity
ρ = density
z = depth

The in-situ stress regime can be calculated from

Equation 5-17

$$\sigma_3 = \sigma_t + \sigma_1\left(\frac{\mu}{1-\mu}\right)$$

where:

σ_t = superposed horizontal tectonic stress
σ_1 = maximum compressive effective stress
μ = Poisson's ratio

and

Equation 5-18

$$\sigma_1 = S - P$$

Equation 5-19

$$\frac{\sigma_t}{\sigma_1} = \beta$$

Subsurface Stress States

Effective Stresses

The concept of effective stresses was first introduced by Terzaghi in 1923 and has subsequently been used extensively in mechanical applications. Basically, a hydrostatic stress (P) within a pore fluid has no influence on deformation, which is controlled by the effective stresses. This hydrostatic stress is a “neutral” stress, one that acts in all directions and in the same amount. This stress is regarded to exist in both the solid and the liquid, so the effective stresses arise exclusively from the solid skeleton. Major studies on rock deformation (Handin et al, 1963) have shown that fracturing is controlled by the effective stresses, provided the rocks have a connected pore system:

Equation 5-20

$$\sigma'_1 = \sigma_1 - P \qquad \sigma'_2 = \sigma_2 - P \qquad \sigma'_3 = \sigma_3 - P$$

where:

σ_1 σ_2 σ_3 = principal maximum, intermediate and minimum compressive stresses
P = pore pressure
σ_1’ σ_2’ σ_3’= principal compressive effective stresses

To apply this concept to the subsurface environment it must be assumed that the permeability is sufficient to allow movement of fluid and that the pore fluid is inert, so that the effects are purely mechanical.

To illustrate the effect of pore pressure on the vertical stress, assume the overburden pressure at 10,000 ft is 9500 psi, and the pore pressure is 4671 psi. The effective vertical stress is then 9500 - 4671 = 4829 psi. If the pore pressure at 10,000 ft was 8304 psi, then the effective vertical stress would be only 1196 psi.

Theoretical Subsurface Stress States

There are two major schools of thought regarding the state of stress within the earth’s crust:

1. That the stress state is hydrostatic - the three principal stresses are equal.
2. The horizontal principal stresses are a function of the effective vertical stress and Poisson’s ratio.

The first hypothesis is generally termed Heim's rule and was described by Anderson (1942) as the "standard state." It was stated that stresses in rock tend to become equal because of their ability to creep, causing any stress differences to be eventually alleviated. This hypothesis is best illustrated by visualizing a scale model of the earth (Hubbert, 1945). Although the earth as a whole has the strength of cold steel, if it is modeled as a 4-ft-diameter sphere, it would have the strength of pancake batter and a viscosity about twice that of honey, and would weigh 6.6 tons.

The second hypothesis describes the state of stress in an elastic, flat-lying stratum of semi-infinite extent that is laterally constrained. If the weight of the overlying strata is the only source of stress, and the elongation in the horizontal directions are zero, then the relation

Equation 5-21

$$\sigma_H = \sigma'_1\left(\frac{\mu}{1-\mu}\right)$$

is derived, where σ_H and σ'_1 represent the horizontal and vertical effective stress components and μ is Poisson's ratio. If, for example, Poisson's ratio for a particular rock type is 0.25, then the horizontal stresses would be one-third that of the vertical stress, provided the theoretical conditions were satisfied. In contrast, Heim's rule states that the horizontal stresses should be equal to the vertical stress.

Common to both theoretical discussions are; 1) the assumptions that one principal total stress is vertical and equal to the weight per unit area of the overlying rocks, and 2) the horizontal normal total stress is the same in any direction in the horizontal principal plane.

The notion that the crustal stress state is largely non-hydrostatic is illustrated by the number of structures and deformation processes that necessitate unequal stress states for their formation and maintenance. Jeffreys (1952) suggested that significant stress differences occur within the upper 50 km of the earth's crust due to the existence of mountains and deep oceans.

The occurrence of large-scale structures such as grabens, shear zones, dike swarms, nappes, folds, thrust and transcurrent faults suggest that not only did large stress differences occur in the past, but the that stresses are still in a state of flux, as suggested by the occurrence of earthquakes. Some external stress, or tectonic stress, is necessary to produce these types of structures. Even in seismically inactive areas it is possible to infer a particular orientation of a tectonic stress, and it is reasonable to assume that even in the absence of tectonic structures and seismicity, a region may be subject to some tectonic stress (Jaeger and Cook, 1976).

Hafner (1951) showed that in order to obtain a hydrostatic type stress system (or "standard state") within a flat-lying stratum of infinite horizontal extent in which lateral extension is prevented, the stress system must be composed of two parts:

1. The effect of gravity (described by the second hypothesis)
2. A superposed horizontal stress which is constant in any horizontal plane but increasing uniformly with depth

Moreover, for faulting and folding to occur, the superposed horizontal stress must occur in a particular orientation within the horizontal plane. If it exists, it would be a tectonic stress, and should also increase uniformly with depth (assuming that the strata were isotropic and elastic).

The horizontal stress can be a minimum when there is no tectonic stress, such that:

Equation 5-22

$$\sigma'_3 = \sigma'_1\left(\frac{\mu}{1-\mu}\right)$$

where σ'_3 is the minimum principal horizontal effective stress, σ'_1 is the maximum principal effective stress, which is equal to the effective pressure of the overlying rocks, and μ is Poisson's ratio for the particular rock type. The largest magnitude that the horizontal effective stresses can reach is approximately three times the vertical effective stress, at which point failure occurs in the form of reverse faulting (Hubbert, 1951).

The superposed horizontal tectonic stress, σ_t, can therefore vary between the limits:

Equation 5-23

$$0 \le \sigma_t \le 3\sigma'_1 - \sigma'_1\left(\frac{\mu}{1-\mu}\right)$$

Since σ_1' is calculated by subtracting the pore pressure from the total weight the overlying strata, it can be calculated for any point in the drilled hole. The superposed horizontal stress, if present, will increase uniformly with depth, or with σ_1'. Hence it may be assumed that the σ_t/σ_t' ratio remains constant.

Ideally, Poisson's ratio for the rock type that is being drilled should be known at that moment in time, but this is not possible. However, Poisson's ratio has been experimentally measured for many rock types and is shown to be unique for a particular lithology. Poisson's ratio cannot be measured for each and every rock type, but if it is possible to divide lithological types into a grouping that can be described by a Poisson's ratio, then there exists a means by which experimental results can be applied to the same in situ lithology types.

To be able to describe the minimum horizontal stress, it is necessary to measure the magnitude of the superposed tectonic stress σ_t. This can be achieved by a fracture test. Hence, after σ_t has been determined, the total horizontal minimum stress state can be extrapolated to any point in the drilled hole.

Zero Tensile Strength Concept

Accurate estimation of actual tensile strengths in subsurface sediments is probably impossible. Fortunately, this problem disappears if the common assumption that any interval of sediment is intersected by joints and partings, is employed. Across these natural discontinuities the tensile strength is effectively zero. However, the occurrence of open joints or fissures is generally quite rare and is restricted to a particular zone or lithology. Cracks in competent sediments can form during compaction and diagenetic processes as a result of very localized stress differences. Micro-cracks are also formed due to the drilling process and the resultant stress-release at the borehole walls. Cracks that are held closed by the in-situ compressive stresses require a pressure within the borehole equal to the compressive stress, so that the pressure holding the crack closed is reduced to zero. Any increase in pressure in the borehole should allow entrance of fluid into the crack so that pressure is transmitted to the sides. This pressure will extend the crack indefinitely, provided it can be transmitted to the leading edge.

This phenomenon can be illustrated by considering a perfectly smooth, cylindrical borehole within an elastic medium, in which a crack extends to the wall of the hole. Upon an application of stress within the borehole that is slightly greater than the stress acting normal to the crack, a tensile stress is developed at the tip of the crack that approaches an infinite magnitude, as illustrated in Figure 5-4 (Hubbert and Willis, 1957).

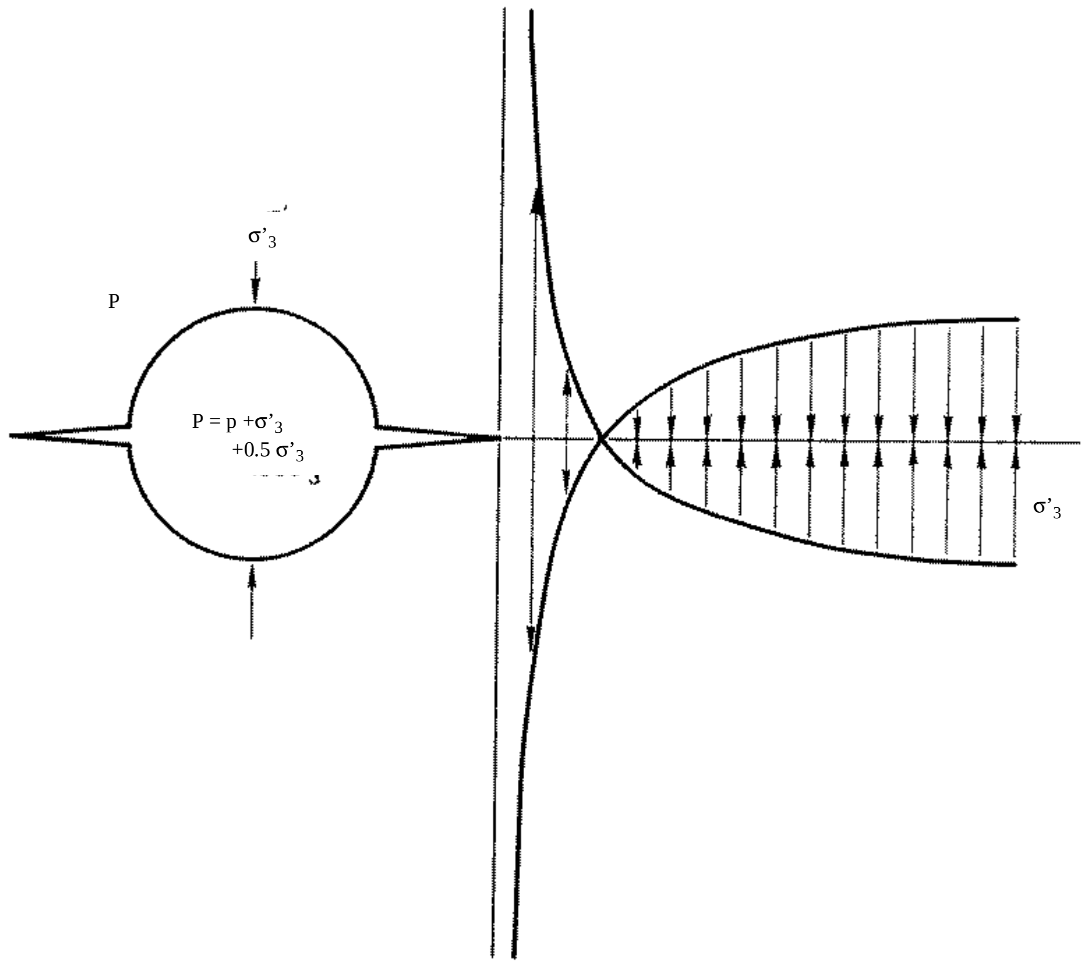

Figure 5-4: Tensile Stress produced at the tip of a crack

The minimum fracture pressure (F) within the borehole to hold open and extend an existing fracture is therefore slightly in excess of the regional horizontal stress normal to the plane of the fracture:

Equation 5-24

$$F = \sigma_t - \sigma'_1\left(\frac{\mu}{1-\mu}\right) + P$$

where:

P = pore pressure

The plane along which a fracture will start to form will be that plane across which the compressive stress is a minimum, and thus will first be reduced to zero with increasing pressure in the borehole. In the case where the horizontal compressive stress is less than the vertical compressive stress, this plane will be vertical; if the horizontal stresses are greater than the vertical stress, the plane would be horizontal.

Method

All data necessary to estimate fracture pressures can be obtained from interpretation of the first fracture test in a compact formation, parameters that are normally measured or calculated when drilling wells, and typical values for Poisson's ratio. Values of Poisson's ratio (shown in Figure 5-5), were obtained by sonic testing (Weurker, 1963). Poisson's ratio is not measured directly, but is calculated from the modulus of elasticity and modulus of rigidity:

Equation 5-25

$$Poisson's\ Ratio,\ \mu = \frac{Modulus\ of\ Elasticity}{2(Modulus\ of\ Rigidity)} - 1$$

The calculated ratio is a dynamic result and may differ from static elastic properties. This can be explained by pointing out that dynamic results which differ markedly from the static results are indicative of zones of weakness, anisotropy, or directional differences in the properties of the material (U.S. Bureau of Reclamation, 1953). These dynamic ratios should be more realistic when attempting to determine horizontal stresses at depth because of observed anisotropies, rather than static Poisson's ratios determined on carefully selected and prepared specimens. Each rock type (particularly in-situ) has its own unique Poisson's ratio (and other mechanical properties), and this will vary when the influencing parameters change.

Thus the tabulated values are presented only as an approximate guide; however, they should serve to provide reasonable estimates. When two or more minerals are intermixed (i.e. sandy clay, shaley sand), the matrix-forming rock type must be determined. If the lithology is a sand with the grains in contact with one another, and clay is the matrix (clay content is less than 30%), the Poisson's ratio is dependent on the sand type. If the clay content is greater than 30%, so that the sand grains are not in contact but are supported in the clay matrix, then Poisson's ratio is dependent on the clay type.

Rock Type	Poisson's Ratio
Clay, very wet	0.50
Clay	0.17
Conglomerate	0.20
Dolomite	0.21
Greywacke:coarse	0.07
fine	0.23
medium	0.24
Limestone:fine, micritic	0.28
medium, calcarenitic	0.31
porous	0.20
stylolytic	0.27
fossiliferous	0.09
bedded fossils	0.17
shaley	0.17
Sandstone:coarse	0.05
coarse, cement	0.10
fine	0.03
very fine	0.04
medium	0.06
poorly sorted, clayey	0.24
fossiliferous	0.01
Shale:calcareous (< 50% $CaCO_3$)	0.14
dolomitic	0.28
siliceous	0.12
silty (< 70% silt)	0.17
sandy (< 70% sand)	0.12
kerogenaceous	0.25
Siltstone	0.08
Slate	0.13
Tuff: glass	0.34

Figure 5-5: Suggested Poisson's ratios for different lithologies

Likewise, if a clay is highly calcareous (greater than 50%), the carbonate content may have a significant effect on the mechanical properties, so the Poisson's ratio for shaley limestone should be used. Greater than 80% carbonate content in a shale, or rather 20% clay in a calcareous lithologies indicates that the gradation has progressed essentially from shale to a fine limestone. Careful analysis and interpretation of cuttings and logs should provide a sound basis for selecting the correct Poisson's ratio. The weakest interval in the borehole will be that which has the lowest pore pressure and lowest Poisson's ratio. A low pore pressure in a zone that has a higher Poisson's ratio may have a higher calculated fracture pressure than another zone that has a higher pore pressure and lower Poisson's ratio. Fracture pressures calculated at changes in lithology and pore pressures will show the weakest interval in the borehole.

The result of the first fracture test in a compact formation is used to calculate the effective stress ratio of the superposed tectonic stress, if present:

Equation 5-26

$$\sigma_t = F - \left[\sigma'_1\left(\frac{\mu}{1-\mu}\right)\right] - P$$

σ_t remains directly proportional to σ_t‘, providing the strata remain close to the horizontal and the basin structure does not change significantly with depth. Since

Equation 5-27

$$\frac{\sigma_t}{\sigma'_1} = \beta$$

where β defines the stress ratio of σ_t to σ'_1, and remains constant with depth, then as σ_1‘ is known at any point within the drilled hole,

Equation 5-28

$$\sigma'_1 = S - P$$

where S and P are the overburden pressure and pore pressure, respectively:

Equation 5-29

$$\sigma_t = \sigma'_1 \text{ x } \beta$$

The overburden pressure should be accurately determined from a density log or measured bulk densities for the first fracture pressure test. It is particularly important on offshore wildcats to take into account the air gap and water depth when calculating overburden gradients (Christman, 1973). Pore pressures can be reliably estimated from drilling exponent plots, mud density/gas relationships, and sonic logs.

Accuracy of the parameters when obtaining σ_t from the first fracture test is of prime consideration, as any significant error at this point will render inaccurate fracture pressures with depth.

Since the local effective stress ratio has been determined, fracture pressures can be calculated as the well progresses, and as changes in lithology (Poisson's ratio), pore pressure, and overburden pressure occur:

Equation 5-30

$$F = \sigma_t + \sigma'_1\left(\frac{\mu}{1-\mu}\right) + P$$

Between log runs the overburden gradient should be extrapolated with a reasonable degree of accuracy by plotting overburden pressure with depth (Figure 5-6). It will be seen that the relation is approximately linear, except for the upper portion of the curve which is affected by water depth, uncompacted sediments and the air gap. Linear extrapolation of the trend may be achieved with confidence, providing the upper overburden gradient obtained from logs or bulk densities was accurate. Correction of the extrapolated trend may be necessary after subsequent logging runs, or continuously updated from bulk density measurements.

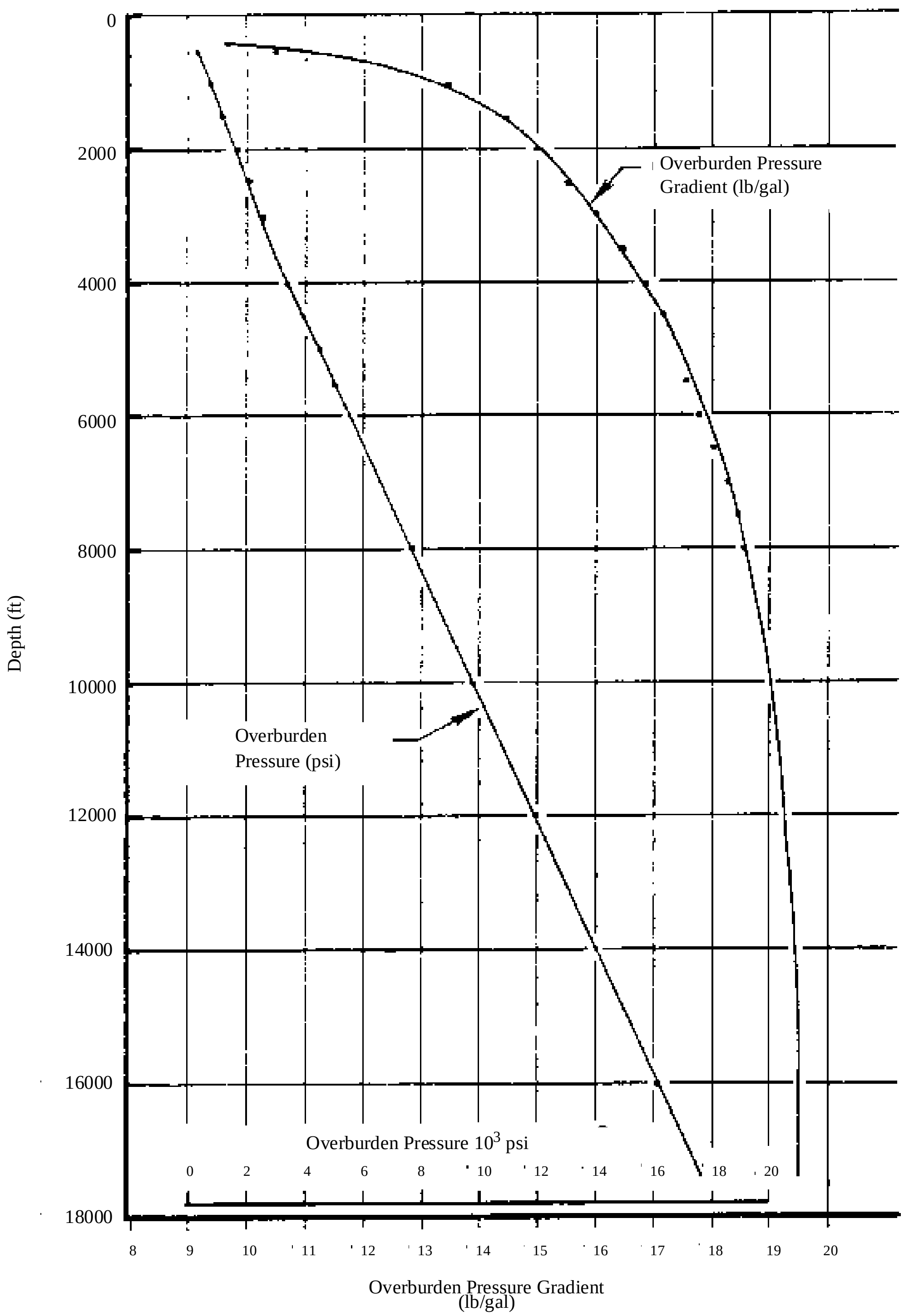

Figure 5-6: Typical overburden curve from an offshore well

A continuous, real-time plot of calculated fracture pressures with depth is thus made possible, providing the various Poisson's ratios can be adequately determined from drill cuttings. If complex or interrelated lithologies are encountered, assignment of a unique Poisson's ratio may not be immediately apparent. If several lithologies occur in the same sample, the one with the lowest Poisson's ratio should be used until confirmation is obtained from logs. If the pore pressure gradient remains constant with depth, then the σ'_1, σ_t and σ_H (with constant lithology) gradients are constant. Fluctuating pore pressure causes significant changes in all the stress gradients.

A problem that may be encountered when using this method in the field is with personnel who are familiar with Eaton's method and the use of empirical, Gulf Coast variable overburden Poisson's ratios. It will be necessary to explain to these personnel the difference in the value of Poisson's ratio used in each method. This may be done by substituting Equations (Equation 5-28 and Equation 5-29) into Equation 5-30 and dividing by vertical depth to obtain gradients, thus obtaining the equation in the form:

Equation 5-31

$$\frac{F}{D} = \left(\frac{S}{D} - \frac{P}{D}\right) \mathrm{x} \left[\left(\frac{\mu}{1-\mu}\right) + \beta\right] + \frac{P}{D}$$

which is directly comparable to Eaton's method.

Equation 5-32

$$\frac{F}{D} = \left(\frac{S}{D} - \frac{P}{D}\right)\left(\frac{\mu_e}{1-\bar{\mu}_e}\right) + \frac{P}{D}$$

where:

μ = lithology dependent Poisson's ratio

μ_e = Eaton's empirically derived Poisson's ratio

It is obvious that these two quantities are unlike and cannot be used interchangeably. The Eaton Poisson's ratio will be a function of the true Poisson's ratio and the regional stress ratio

Equation 5-33

$$\mu_e = \frac{\left[\left(\frac{\mu}{1-\mu}\right)+\beta\right]}{1+\left[\left(\frac{\mu}{1-\mu}\right)+\beta\right]}$$

When applying this Zero Tensile Strength method you must make sure that the client is familiar with its derivation. It must be explained that the method uses Poisson's ratio values dependent only upon lithology and a regional stress ratio is determined for that particular well and basin. Unlike the empirically derived Eaton quantity, the Poisson's ratio for a particular lithology does not include a regional stress component and will not vary with depth or between basins.

Several factors affect fracture test pressures, besides formation characteristics:

1. Higher mud densities appear to cause higher fracture pressures (MacPherson and Berry, 1972), although this may be due to a related increase in viscosity.
2. Smaller hole diameters may cause higher fracture pressures (Haimson and Fairhurst, 1969).
3. The rate of pressurization affects fracture pressures: high pump rates produce inflated fracture pressures (Haimson and Fairhurst, 1969). This effect is smaller than that in (2) above.
4. High mud gel strengths require higher pressures to initiate circulation. Correction for this pressure loss can be obtained from Chenevert and McClure, 1978.
5. Hole deviation significantly affects fracture pressures (Bradley, 1979).
6. Rig and sensor instrumentation probably are accurate to within 5% (Taylor and Smith, 1970). Accuracy of predicted fracture pressures is therefore limited to this range.
7. Mud penetrability does not alter the actual breakdown pressure, but it will affect the shape of the fracture pressure plot such that the point at which the total horizontal minimum stress is balanced may be obscured.

A combination of these mechanisms is probably responsible for a considerable scatter of data points. However, if fracture test procedures are kept as consistent as possible on any one well, then the results obtained should lie within the 5% instrumentation error margin.

Summary

This theoretical model attempts to describe the principal stress system within a basin of simple topography and structure. If a well is drilled nearly vertically, then the well should be approximately parallel to one of the principal stress, which is equal to the effective pressure of the overlying strata. The horizontal stresses are a combination of the stress caused by gravity and a superposed horizontal tectonic stress. The latter may be nonexistent or may reach a maximum of two or three times the vertical stress (Hubbert and Willis, 1957). The minimum horizontal stress is measured by the first fracture test in a competent formation, and as the vertical stress increases relative with depth, then the tectonic horizontal stress should increase linearly with depth (defined by a constant stress ratio, β). Since this ratio is obtained from the first fracture test, at any subsequent depth the fracture pressure can be calculated, providing pore pressure, overburden pressure and lithological relationships are known. The following may be concluded:

1. Fracture pressures may be estimated when drilling rank wildcat wells to within an error margin of approximately 5%.
2. Fracture pressures are dependent on the total minimum horizontal stress (a combination of a stress caused by gravity and a superposed tectonic stress) and the pore pressure.
3. Factors affecting actual fracture pressures can be minimized by conducting fracture tests as consistently as possible. A correction is available for gel strength (usually < 0.1 lb/gal), but changes in mud types or large changes in properties may cause significant deviation from calculated fracture pressures. It is also suggested that at least one circulation be done prior to conducting a fracture test, in order to minimize any inconsistencies in the mud column.
4. The theoretical fracture pressure formula provides an explanation for fracture pressures that equal the overburden pressure in shallow wet clays, and also indicates that if a sandstone reservoir is fractured, the fracture should not extend into or through the seal. An inherent property of a permeability seal may be the relatively high Poisson’s ratio: these rock types require a higher pressure within the borehole to balance the horizontal compressive stress, so a hydraulic fracture within an underlying permeable stratum should be confined to that stratum.

Example Calculation

For an offshore well, a12-$^{1}/_{4}$-inch pilot hole has been drilled to 1500 feet. The water depth is 200 feet, and RKB to sea level is 100 feet. The entire sequence is soft, unconsolidated clays. After drilling, the hole is opened to 26 inches, and 20-inch casing is run and cemented at 1460 feet. After drilling out the shoe, the rat hole is cleaned, a full mud circulation is allowed before pulling the bit up into the casing shoe, the annular preventer is closed and a fracture test is performed.

Fracture occurred at 14.3 lb/gal EQMW. Analysis of the data indicated that the test result is normal. The formation balance gradient was 8.6 lb/gal and the calculated overburden gradient at 1460 ft was 14.1 lb/gal. The Poisson's ratio for the wet clay would be close to 0.5. Therefore:

Equation 5-34

$$F = \sigma_t + \sigma'_1\left(\frac{\mu}{1-\mu}\right) + P$$

where:

σ_t = 0 (the rock is effectively water-supported)

σ'_1 = (14.1 - 8.6) = 5.5

μ = 0.5

P = 8.6

predicted

F = 14.1 lb/gal.

Any fractures would be horizontal.

Note: *This example cannot be used to predict further fracture tests with depth, as σt is nonexistent due to the fact that the wet, unconsolidated clays have a negligible shear strength and could not support an applied tectonic stress.*

At 3300 feet, 13-$^{3}/_{8}$-inch casing is run to 3270 feet. The formation balance gradient is still 8.6 lb/gal, the estimated overburden gradient at 3270 feet is 16.4 lb/gal, and the lithology in the 30 feet of open hole is clay with a sandstone bed at 3290 feet. The sandstone is coarse grained and well sorted. A suggested Poisson ratio for this sand is 0.05. Assuming no tectonic stress (i.e. $\sigma_t = 0$), then the predicted fracture pressure would be:

$$F_{calc} = 0 + 1332\left(\frac{0.05}{1 - 0.05}\right) + 1469\ psi$$

$$F_{calc} = 1539\ psi$$

$$= 9.0\ lb/gal$$

If the actual fracture pressure was 1911 psi, it indicates that a tectonic stress is present. σ_t is found from:

:

$$\sigma_t = F - F_{calc}$$

$$= 1911 - 1539$$

$$\sigma_t = 372\ psi$$

This σ_t value of 372 psi, indicates that a tectonic stress is apparent. In order to estimate fracture pressure with depth, the σ_t/ σ_1’ ratio has to be found:

Equation 5-35

$$\beta = \frac{\sigma_t}{\sigma'_1}$$

$$= \frac{372}{1332}$$

$$= 0.279$$

Utilizing, pore pressure estimations, estimated overburden pressure, and Poisson’s ratios for subsequent lithologies, the fracture pressure may now be estimated at any point. The tectonic stress at any depth can be found by:

Equation 5-36

$$\sigma_t = \sigma'_1 \text{ x } \beta,\ psi$$

Selection of Casing Seats

During the well planning process, correct determination of pore pressure and fracture gradient is important for selecting the depths for casing seats. While drilling, real-time knowledge of formation pressures will allow the engineer to deviate from the well plan, if conditions permit.

Pre-Well Planning

During initial planning stages, estimates of pore pressure, mud density and ECD are made to ensure that drilling can proceed without problems. Correlation wells can be used to obtain the pore pressure values used in the casing seat selection process. Values are obtained from several sources:

- Mud Logs (FEL) or other pressure logs
- Direct Pressure Measurements (DST, wireline tests and kicks)
- Semi-log plots of shale resistivity and pressure readers
- Rw calculations and salinity charts

A mud density is then chosen so that it exceeds the formation pore pressure by some “safety factor” and also provides an acceptable pressure margin when not drilling. This safety factor is generally 0.5 lb/gal or 200 to 500 psi above pore pressure (whichever is lower).

In addition to balancing formation pressures, the mud density should maintain borehole integrity, specifically:

- Prevent formations from sloughing
- Reduce the swab and surge effects when tripping or when making connections
- Prevent lost circulation
- Minimize the possibility of differential sticking

Once the mud density is determined, it is plotted versus fracture gradient. This is done so that mud density does not exceed the formation fracture gradient at any point in the open hole. Fracture gradient can be calculated using several industry standard formulas (Eaton, Matthews & Kelly, Daines, etc.). Information for these formulas includes overburden pressure (S), pore pressure (P), depth (D) and Poisson's ratio (μ). Leak-off tests and any post-well fracture data from correlation wells should be included in the fracture gradient determination.

Many companies like to subtract a “kick tolerance” from the fracture gradient, to ensure that if a kick is taken the annular pressures do not fracture the formation and cause an underground blowout.

An example of the tabulated data is shown in Figure 5-7.

Casing Seat Selection

Once the data is tabulated, the mud density, pore pressure and fracture pressure are plotted against depth (see Figure 5-8).

Once plotted, the selection of casing seats begins at the bottom of the borehole and moves towards the surface. During drilling, the mud density (hydrostatic pressure) and ECD must not exceed the formation fracture gradient.

As shown in Figure 5-8, starting at TD (point 1), a vertical line is drawn upwards until it intersects the fracture gradient curve (point 2). It will be necessary to set casing or a liner at this depth (9200 ft). Depending on the safety factor or kick tolerance, the casing may be set higher or lower than this depth.

Depth Below Sea Level (ft)	Pore psi	Pressure psi/ft	(P) lb/gal	Mud psi	Density psi/ft	(MD)* lb/gal	Fracture psi	Gradient psi/ft	(FG) lb/gal
2500	1109	0.444	8.55	1174	0.469	9.05	1431	0.572	11.03
3000	1378	0.459	8.85	1456	0.485	9.35	1790	0.597	11.50
5000	2564	0.513	9.88	2694	0.539	10.38	3285	0.657	12.66
7000	4029	0.575	11.09	4211	0.602	11.59	5584	0.798	15.37
9000	5932	0.659	12.70	6132	0.681	13.12	7408	0.823	15.86
11000	7844	0.713	13.11	7770	0.706	13.61	9317	0.847	16.32
12000	9055	0.755	14.55	9255	0.771	14.86	10550	0.879	16.94
13000	10276	0.790	15.23	10476	0.806	15.53	11814	0.909	17.51
13500	10937	0.810	15.61	11137	0.825	15.89	12472	0.924	17.80

* Mud density = Pore Pressure + 0.5 lb/gal or Pore Pressure+200 psi (whichever is lower)

Figure 5-7: Casing Seat Selection Data

Casing seat selection continues by moving horizontally to a new mud density (point 3), then vertically to the next casing seat (point 4). Again, move horizontally to the mud density curve (point 5) and finally vertically to the fracture gradient curve at point 6. The fracture gradient curve is not intersected at any point above 1400 ft.

After the depths have been chosen, it is necessary to determine what type of formation/rock type occurs at that depth. Generally, rocks that are relatively competent, resistant to wash-outs, have low permeability and high fracture pressures are chosen as the place to set the casing seat.

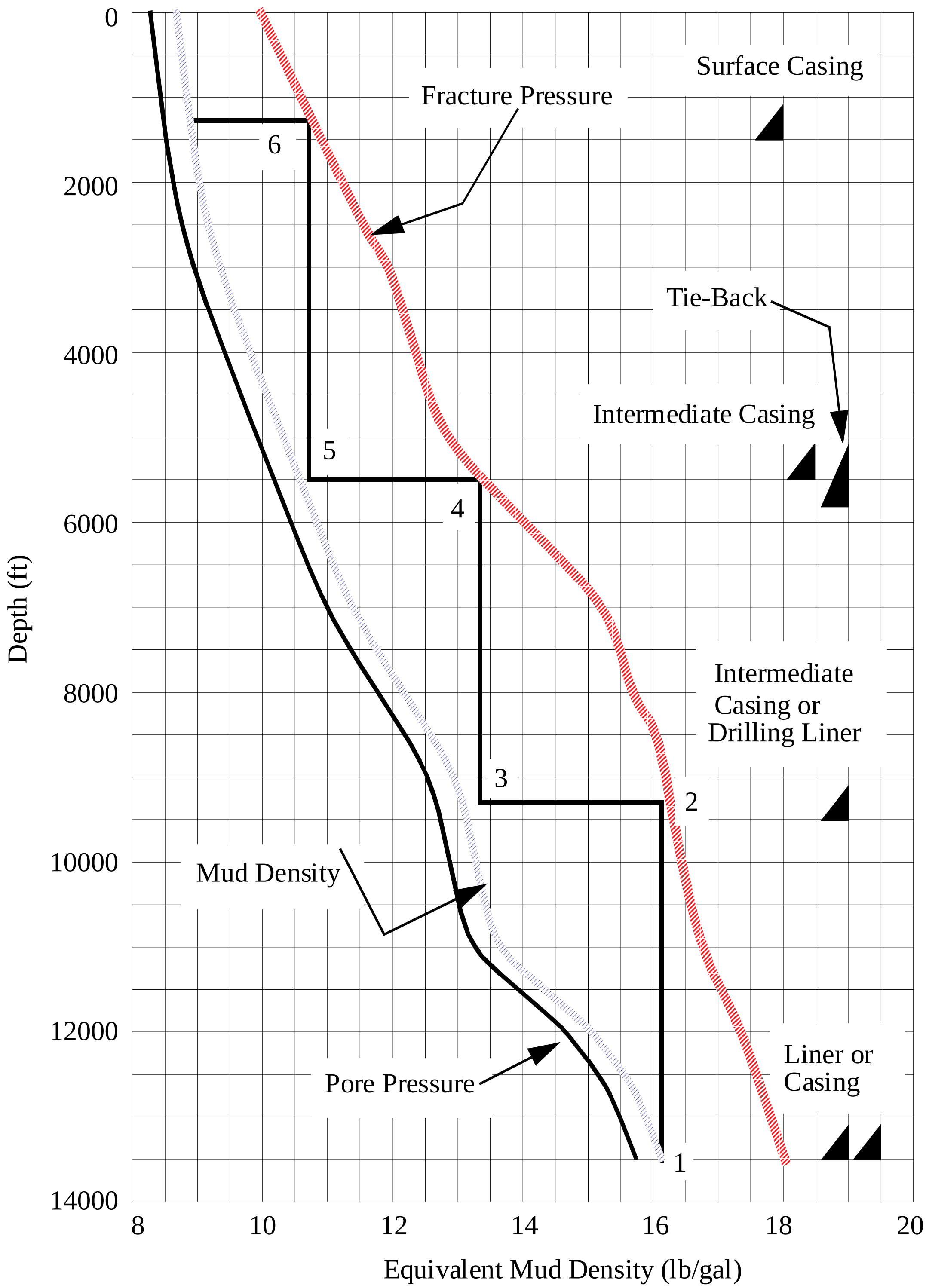

Figure 5-8: Pre-Planning Casing Seat Selection

Such rock types include, limestone, dolomite, shales and shaley sandstones, though experience in a certain area will be a better model as to where to set casing. During the course of a well, as drilling nears the projected casing depth, the mud loggers and wellsite geologist should be looking for a desirable rock where casing can be set.

For the near-surface casing strings, there are usually state, federal and national regulations which dictate the maximum and minimum setting depths for drive pipe and surface casing. These should be consulted before the final decision is made concerning the casing program.

Casing Sizes

Once the number of casing strings is determined, it is time to plan the casing sizes for the well. Casing diameters (both internal and external) will be determined by the size and type (single or dual) of completion tubing, and the production plans for the well. To enable the production casing to be set, the bit size used to drill the last section must be at least 1.5-inches larger than the O.D. of the casing to allow for the circulation of drilling fluid and cement once the casing is landed. This bit must also fit inside the last string of casing.

In the example casing plan shown in Figure 5-8, if a dual completion is planned, then the 7-inch production casing is satisfactory, and the final hole section should be drilled with an 8.5-inch bit.

To drill to TD (point 1), a 15.89 lb/gal mud will be necessary. This, in turn requires that intermediate casing or a drilling liner be set at point 3 to prevent fracturing of the formations above point 3. The same procedure is followed when determining casing sizes, bit sizes and mud densities that are required to drill to points 3 and 5.

Leak-Off Tests

A leak-off test is performed after setting casing to ensure that a competent casing seat has been found and that this formation can withstand the mud density required to reach the next casing point.

After casing has been set and the cement has dried, the leak-off test is conducted. The open hole formation will be pressure tested to either; 1) a pre-determined pressure which is below the fracture pressure, 2) a leak-off pressure, or 3) formation breakdown and fluid injection pressure (see Figure 5-9).

Regardless of the type of test, the test pressure generally does not exceed 80% of the minimum yield of the weakest casing.

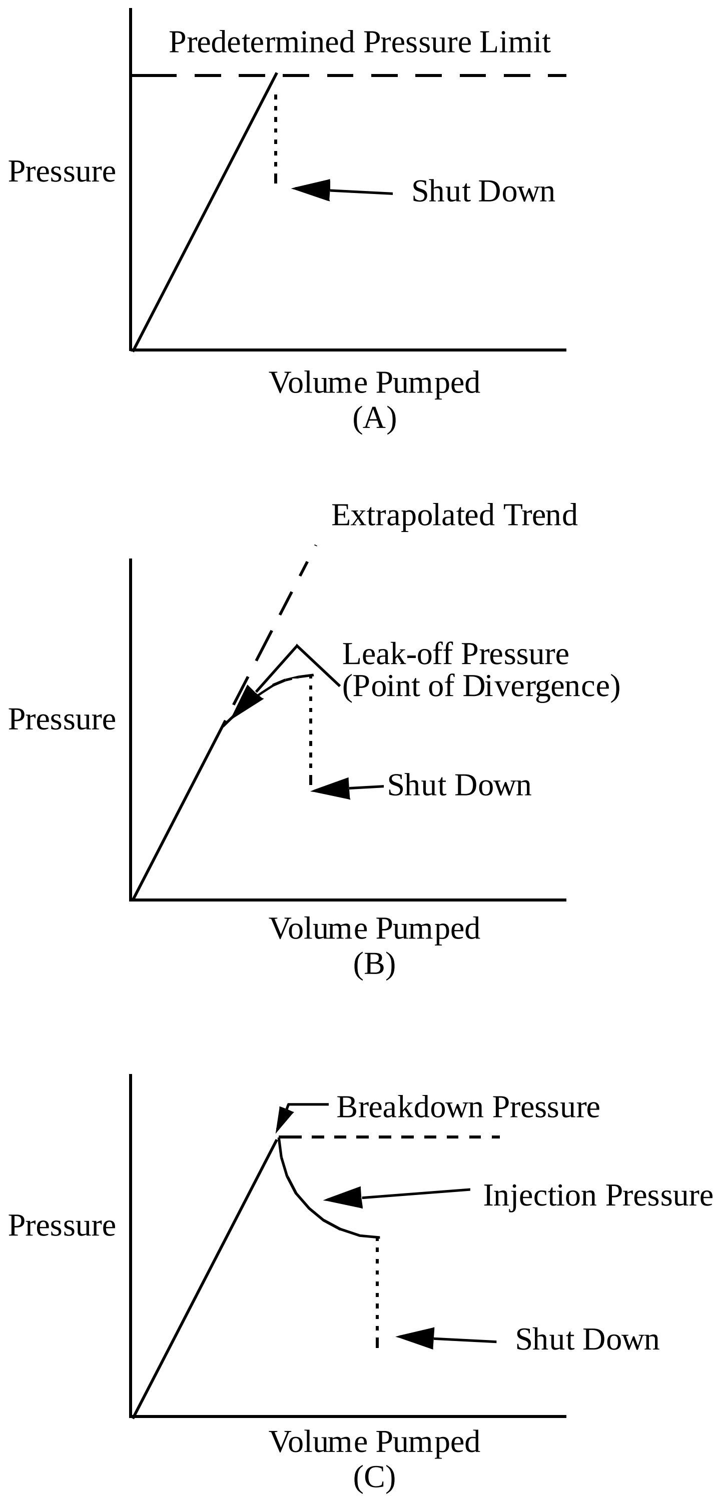

Figure 5-9: Leak-Off Test Pressure Limits

An example of the leak-off test procedures can be seen in Figure 5-10

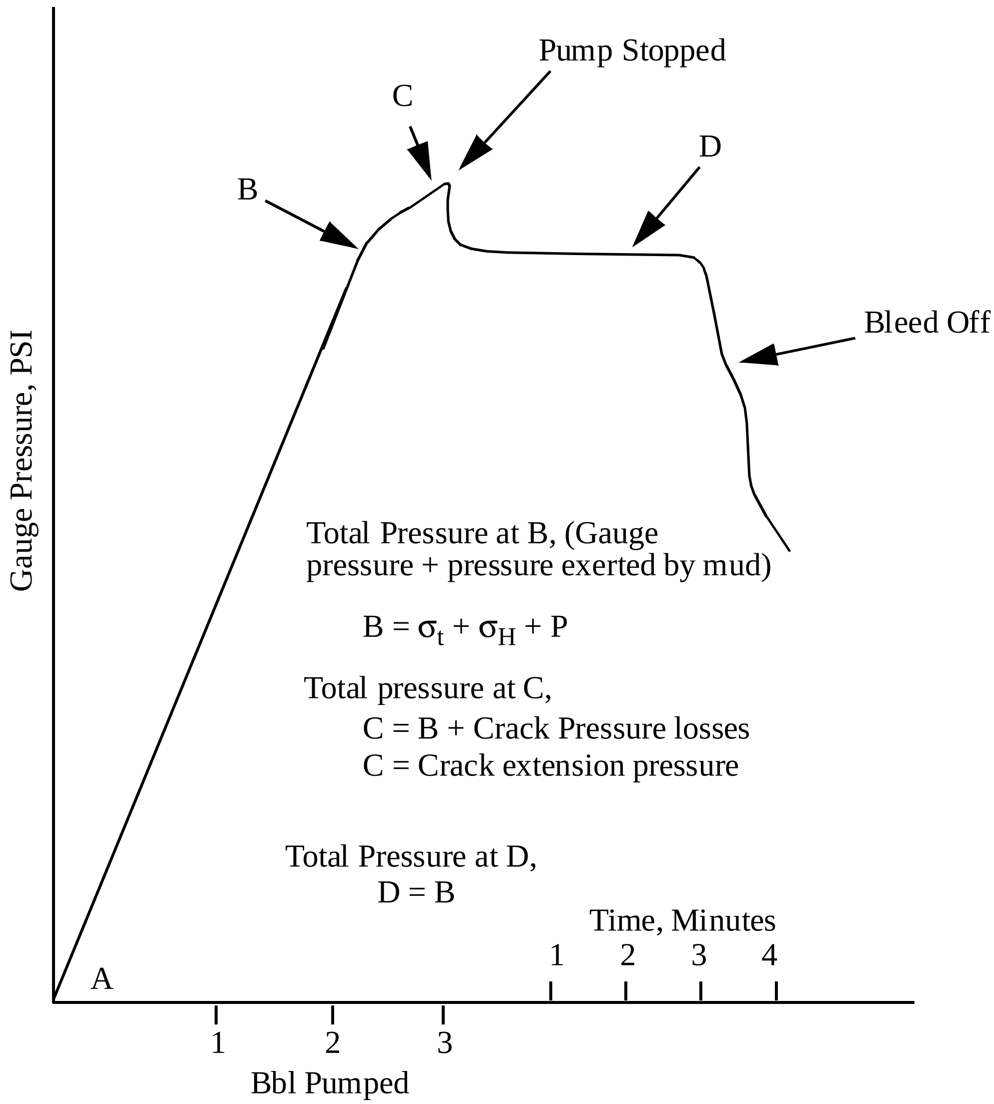

Figure 5-10: Typical Leak-Off Test Plot

Pre-Test Procedures

For a leak-off test to be preformed correctly, three parameters must be closely monitored. They are mud volume, surface pressure and pump rate. Prior to any testing, the equipment required for the monitoring of these parameters must be checked out.

1. Most cementing companies have 10 barrel tanks. This tank should be calibrated in 0.25 bbl increments.
2. Most rig pressure gauges are not accurate enough to monitor pressure in 20 psi increments. An accurate gauge or pressure recorder is required.
3. Pump rates for leak-off tests are usually 0.25 bbl/min. When mud volumes are less than one barrel, a pump rate of 1/8 bbl/min is required. Ensure the pumps can operate at that speed.

After casing is set and cemented, but before the leak-off test is conducted, several calculations concerning “anticipated” results should be performed. These pre-test results will ensure that procedures are carried out correctly and the values obtained are correct. The pre-test calculations include:

1. Anticipated leak-off test pressure
2. Annulus, drillstring and open hole volumes
3. Anticipated slope (minimum volume line) of the leak-off test
4. Frictional pressure loss to initiate circulation

Figure 5-8 will be referenced as the example:

1. The anticipated leak-off pressure is calculated using the fracture pressure derived from the empirical means during drilling or from the pre-well planning sheet (Figure 5-7) if those pressures are accurate. For example (using Figure 5-8), a 9 $^5/_8$-inch (8.835-inch ID) casing is set at 9200 ft with a mud density of 13.2 lb/gal and a fracture pressure of 15.9 lb/gal.

$$P_{LO} = (PF - MW) \times 0.0519 \times D$$

where:

P_{LO}	= Anticipated leak-off pressure (psi)
PF	= Fracture pressure at casing shoe depth (lb/gal)
MW	= Mud Density (lb/gal)
D	= Depth of casing shoe (feet)

In the example well, the anticipated leak-off pressure is:

$$P_{LO} = (15.9 - 13.2) \times 0.0519 \times 9200 = 1289 \text{ psi}$$

2. In our example well, the leak-off test will be conducted using the following drillstring:

- 5-inch drillpipe (4.276-inch ID)
- 400 feet of 6.5-inch drill collars (3-inch ID)
- 8.5-inch bit size (20 feet of open hole)

The mud volume during the leak-off is 628.4 bbls:

Annulus $(8.835^2 - 6.5^2) \times 0.000971 \times 400 = 13.9$ bbls

$(8.835^2 - 5.0^2) \times 0.000971 \times 8800 = 453.4$ bbls

Drillpipe $(3.0^2) \times 0.000971 \times 400 = 3.5$ bbls

$(4.276^2) \times 0.000971 \times 8800 = 156.2$ bbls

Open Hole $(8.5^2) \times 0.000971 \times 20 = 1.4$ bbls

3. The anticipated slope or minimum volume line represents the pressure required to compress the drilling fluid in the casing until either the open hole section fractures or leak-off into the formation occurs. The two variables which must be taken into consideration are:

- the compressibility of the components of the mud system
- the compressibility caused by the expansion of the casing

The compressibility of the drilling fluid components is shown in Figure 5-11.

Fluid Component	Compressibility (vol/vol/psi)
Water	3.0×10^{-6}
Oil	5.0×10^{-6}
Solids	0.2×10^{-6}

Figure 5-11: Compressibility Factors of Various Drilling Fluid Components

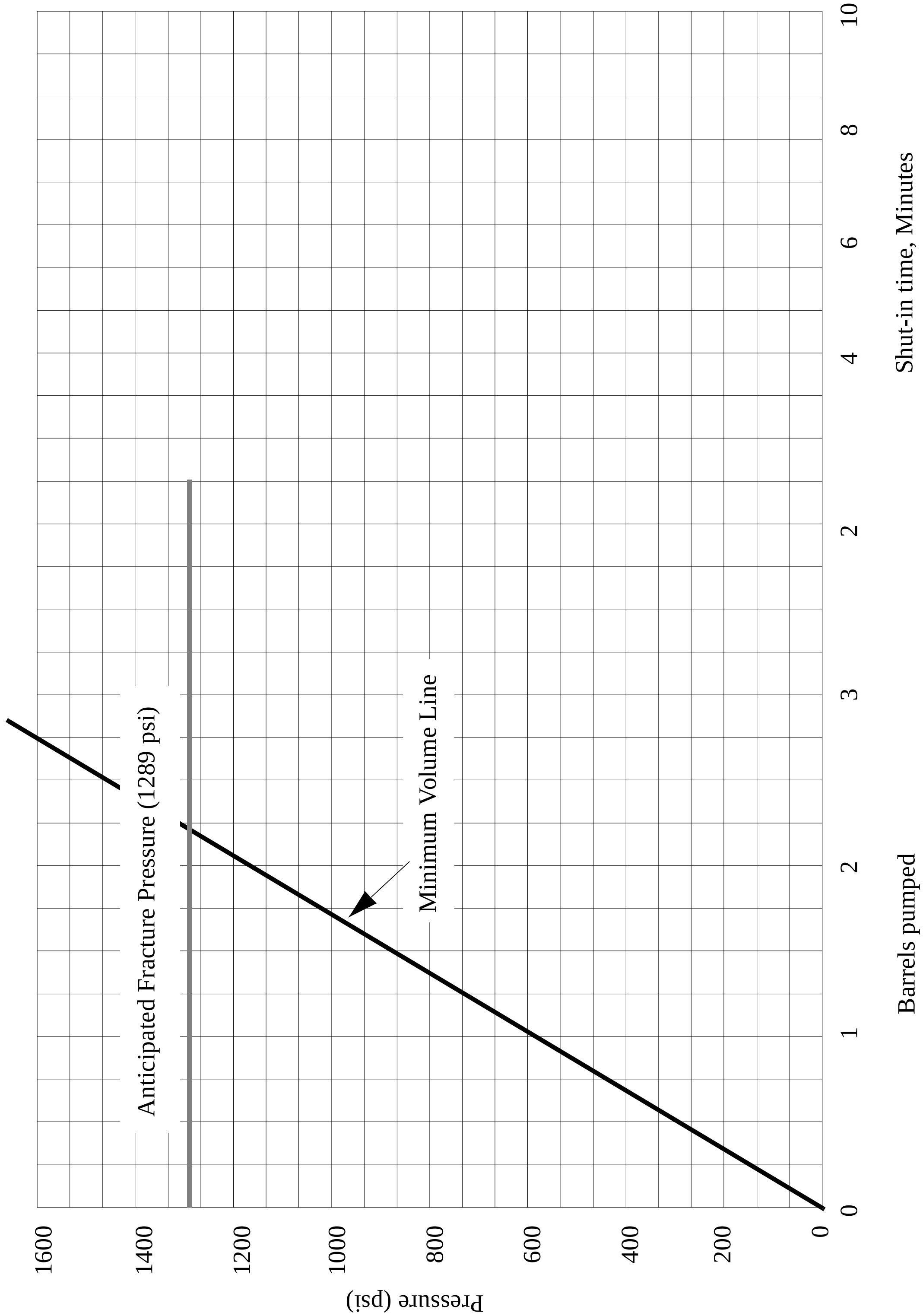

Figure 5-12: Preliminary Leak-Off Test Parameters

The volume of drilling fluid that must be pumped due to the expansion of the casing is based on the expansion of uncemented sections due to the surface pressure during the leak-off test. This volume is calculated using:

$$\Delta Vol = 2.59 \text{ x } 10^{-4} \text{ x } (R_r)^2 \frac{0.52 + 1.3(R)^2}{R^2 - 1}$$

where:

ΔVol = Increased volume due to uncemented casing, (bbl/1000 psi x 1000 ft)

R = D_o / D_i (D_o = OD of casing, D_i = ID of casing), in inches

R_r = Internal casing radius (inches)

To continue with the example, the 13.2 lb/gal drilling fluid during the leak-off test has a solids content of 15.5% (no oil), and that the upper 2000 feet of the casing/open hole is uncemented.

Drilling Fluid Compressibility:

$$C_s = 0.2 \text{ x } 10^{-6} \text{ x } 0.155 = 0.031 \text{ x } 10^{-6}$$

$$C_w = 3.0 \text{ x } 10^{-6} \text{ x } 0.845 = 2.535 \text{ x } 10^{-6}$$

$$C_m = 2.566 \text{ x } 10^{-6}$$

Casing Expansion Volume:

$$\Delta Vol = 2.59 \text{ x } 10^{-4}(4.4175)^2 \text{ x } \frac{0.52 + 1.3(1.089)}{(1.089)^2 - 1}$$

$$\Delta Vol = (0.005054 \text{ x } 11.089) \text{ x } 2 \text{ (2000 ft of uncemented section)}$$

$$\Delta Vol = 0.11 \text{ bbls}$$

The minimum drilling fluid volume becomes:

$$[628.4 \text{ x } (2.566 \text{ x } 10^{-6}) \text{ x } 1000] + 0.11 = 1.72 \text{ bbl/1000 psi}$$

or if monitoring pressure per barrel, the reciprocal is used: 581 psi/bbl

4. The frictional pressure loss to initiate circulation must be subtracted from the test results. This pressure loss is determined using:

$$\Delta P_i = \frac{\tau_g \text{ x } D}{300 \text{ x } d}$$

where:

ΔP_l	= frictional pressure loss (psi)
τ_g	= gel strength (lbs/100ft^2)
D	= depth (feet)
d	= ID of drillpipe (inches)

In the example well, if the 10 minute gel strength is 11.2 lbs/100 ft^2, then the frictional pressure loss is:

$$\Delta P_i = \frac{11.2 \text{ x } 400}{300 \text{ x } 3} + \frac{11.2 \text{ x } 8800}{300 \text{ x } 4.276} = 82 \text{ psi}$$

Once calculated, this pre-test information (anticipated fracture pressure and minimum volume line) is plotted on the leak-off test graph (Figure 5-12) to be compared with the actual test information. With the information plotted, it becomes apparent that it requires only a small volume of drilling fluid (2.22 bbls) to be pumped before the fracture pressure is reached. Since the volume is small, close attention to the pump rate, pressure build-up and mud volume pumped is important. To ensure close scrutiny, a pump rate of 0.25 bbls/min is about the lowest practical rate for a leak-off test.

Leak-Off Test Procedures

In order to acquire good leak-off test data and perform a good test, there are many details that must be watched carefully. Though standard procedures vary among oil companies, the following procedures should permit a leak-off test to be carried out effectively and with problems kept to a minimum.

1. Once the casing equipment (plugs, float collar, casing shoe) and rat hole have been drilled and cleaned, drill another 10 to 30 feet of new hole.

2. Circulate enough to clean the hole of cuttings and monitor the mud density. Ensure that the mud density throughout the hole is known.

3. Pull the bit inside the casing and close the BOP's or set the packer.

4. Have the cementing unit hook up to pump either down the drillpipe or down the annulus.

5. Slowly pump into the drillpipe or annulus (0.25 bbl/min) until bleed-off or until the pre-test fracture pressure is reached. Never exceed the pre-test fracture pressure or 80% of the minimum yield of the weakest exposed casing.

6. Record the mud volume pumped versus pressure. Monitoring can either be every 0.25 to 0.50 barrel pumped or for each 50 psi increase in annular pressure.

7. During the test, the plot of pressure versus mud volume should be a straight line until leak-off is reach, then it will deviate to the right (Figure 5-10).

8. The type of test will dictate when the pumps are shut down (Figure 5-9).

9. When the maximum test pressure is reached and the pumps shut down, the pressure is recorded every two minutes for up to twenty minutes.

10. The pressure is released by opening the BOP's or releasing the packer. Record the volume of mud recovered from the test.

Interpretation of Leak-Off Tests

When leak-off tests are conducted properly, curve characteristics should be similar to the curve seen in Figure 5-10. Deviations from this curve could indicate one of several conditions, such as:

1. leaks in the cementing lines
2. the pump changing speeds
3. a high fluid loss mud system
4. variable mud densities in the borehole
5. a bad cement job

To properly interpret the variations in curve characteristics, a process of elimination may be necessary to pin-point the cause. This usually means re-running the test and carefully monitoring the surface variables, and doing so until the surface variables are eliminated.

Figure 5-13 contains several examples that illustrates deviations from the expected curve.

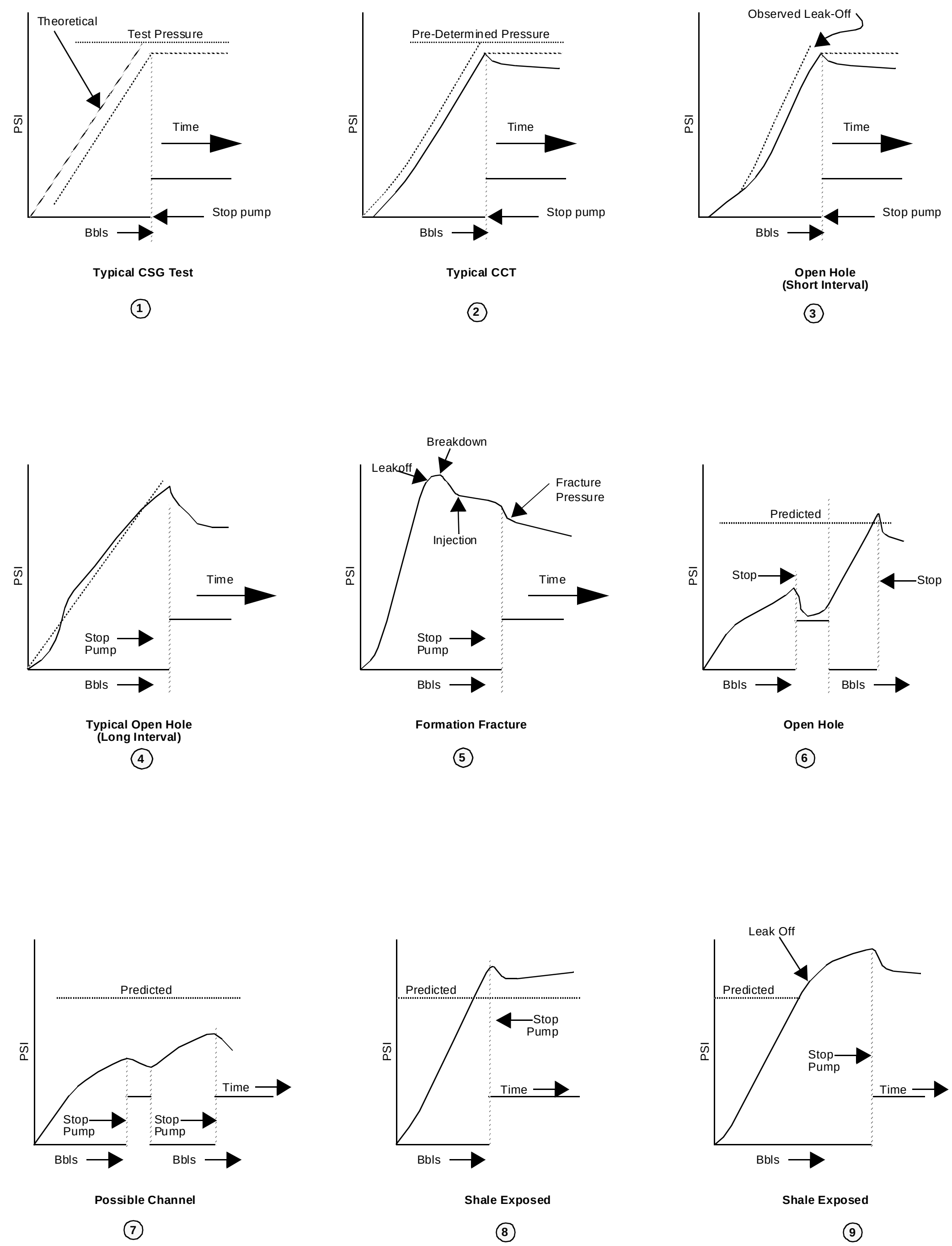

Figure 5-13: Deviations from expected leak-off curve

1. This example shows a typical casing test. Such a test is usually conducted before the float equipment is drilled.
2. A “control capability test” to ensure that the casing shoe will withstand a pre-test equivalent mud density.
3. This examples shows a leak-off test being conducted until there is a deviation from the straight line, regardless of the pre-test fracture pressure calculation.
4. When more than 30 feet of open hole are drilled, the pressure curve may vary due to permeable formations taking mud then becoming tighter as a filter cake builds up on the formation.
5. This examples illustrates a typical formation fracture and mud being pumped into the formation before the pumps are stopped. The maximum pressure this formation can now withstand is the hydrostatic pressure plus the pressure recorded after the pumps were shut down.
6. When a bend appears in the curve soon after pumping has started, it can mean a bad cement job, high filtration into a permeable zone or fluid being pumped into a formation. If the pumps are shut down and the pressure stabilizes, the test can continue. If there is an increase in pressure, then the cement job is okay.
7. When the condition shown in “6” occurs and there is no improvement in the pressure after restarting, the most probable answer is a poor cement job and a squeeze job is required.
8. When a hard, tight shale is exposed in the open hole, the leak-off test can appear as a casing test, with the pressure going above the pre-test fracture pressure.
9. This example show only shale exposed in the open hole and the leak-off test carried out to formation fracture pressure.

These examples should be taken only as a guide to leak-off tests. Experience in a certain area covering pressure testing over various formations will enhance the information provided by these examples.

Other Considerations

The assumption that the results of leak-off tests, when converted to an equivalent mud density, are taken to be the maximum mud density that the next hole section can withstand without losing circulation, is valid only in a certain set of circumstances.

If the last casing shoe was cemented in an abnormally high pore pressure zone and the pore pressure gradient then decreases significantly with depth, the fracture pressure gradient will decrease also. Limestone has a high Poisson's ratio, which will result in a higher fracture pressure than if the casing was set in a rock with a lower Poisson's ratio. Drilling out of a limestone into a sand at the same or lower pore pressure gradient will result in the sand having a lower fracture pressure gradient.

Generally, the point in any section of the open hole that has the lowest fracture pressure gradient will be that which has the lowest pore pressure gradient and lowest Poisson's ratio. Maximum mud densities for further drilling are thus dependent on those parameters in that section, not on a unique value that was determined at the casing shoe.

Once a formation has been fractured, it will be necessary to apply that same pressure to cause fracturing again. On any fracture test, when the horizontal stresses become balanced by the pressure within the borehole, the pressures will remain the same, whether the test is repeated or not. However, if a permeable formation is tested during the leak-off test, the fracture pressure plot will probably not be linear (mud volume increases produces a smaller pressure increase) due to the invasion of fluid into the formation. This has the effect of raising the pore pressure of the formation immediately adjacent to the borehole. The increase in pore pressure has the result of reducing the stress concentration at the borehole wall (resulting in a lower pressure necessary for fracturing). Once the fracture is started and is extending into the undisturbed stress field, the pressure for this extension is the same as if no invasion has occurred (Hubbert and Willis, 1957).

Fracture tests conducted offshore at shallow depths, in unconsolidated clays, can produce abnormally high fracture pressures. Wet clays can behave as liquids, such that the Poisson's ratio can approach 0.5. Also, as the pore water and absorbed water surround each clay platelet, the platelets will not be in contact with each other, but will be supported by the water. These clays will then have a negligible shear strength. The effective pore pressure would then approach the pressure exerted by the weight of the overlying sediments. When combined with a very high Poisson's ratio, it can be seen that the calculated fracture pressures may exceed the overburden pressure by a significant amount. In these instances, a horizontal fracture will form, lifting the overburden, so that the fracture pressure will be approximately equal to the overburden pressure.

At some depth, the weight of the overburden will squeeze out sufficient pore water so that the clay platelets will come into contact with one another. When this occurs, the sediment can support a superposed horizontal stress. At this stage, the Poisson's ratio for the clay will be very similar to that of a more compact clay. Fracture tests in a clay at this stage of dewatering can be used for the calculation of any additional horizontal stresses.

Unconsolidated sands at shallow depths having very good permeability can cause lost circulation problems. Although the sand may be unconsolidated, the individual grains will be in contact, so that a superposed stress can be supported, independent of the pore pressure. Poisson's ratio will be normal, depending on the sand type.

For example, if an unconsolidated sand is drilled at 2000 ft, the overburden pressure 1453 psi, and the pore pressure is normal at 892 psi. If the sand is fossiliferous, the Poisson's ratio is 0.01. Assuming the horizontal stress ratio is normal (i.e. σ_t/σ_1) at 0.2, then the calculated fracture pressure for these parameters is:

$$F = \left[\{(1453 - 892)\ x\ 0.2\} + \left\{(1453 - 892)\ x\ \frac{0.01}{0.99}\right\}\right] + 892$$

$$F = 1010 \text{ psi or } 9.7 \text{ lbs/gal at } 2000 \text{ ft}$$

It can be see that in shallow, unconsolidated sediments with a high water content (normally encountered offshore), fracture pressures can vary from overburden magnitude (in wet clays) to a little more than the pore pressure (in unconsolidated sands).

To better illustrate this phenomenon, again refer to Figure 5-10. The linear portion of the curve (AB) indicates elastic properties; pressure increases (stress) is directly proportional to volume pumped (strain). At point B, the pressure within the borehole is equal to the pore pressure plus the total minimum horizontal effective stress.

All cracks, joints and partings (within the section of open hole being tested) that lie on a vertical plane normal to this minimum horizontal stress now have no compressional forces holding them closed. From points B to C, the stress/strain proportionality no longer exists (i.e. for each unit stress a greater proportion of strain is produced). The pressure difference (C - B) is that pressure necessary to push fluids into the cracks. When the pressure within the borehole is approximately 5% greater than the total minimum horizontal stresses, an almost infinite tensile stress occurs at the tips of the cracks.

At this point the cracks extend rapidly along the path of minimum resistance (in a vertical borehole with horizontal beds it will be in a vertical plane normal to the minimum compressive stress).

If the pumps are stopped at that moment, fracture propagation will cease and the pressure will fall to point D. When the pressure in the borehole has fallen (due to the increase in volume caused by the fractures) to a pressure equal to the pore pressure plus the total minimum horizontal stresses, it should stabilize at a pressure equal to point B.

When the excess pressure is bled off, the amount of returning mud should be almost equal to the amount pumped. If the shut-in pressure (point D) is lower than point B, it would be reasonable to assume that the fractures are still open, possibly being propped opened by mud contaminants or cuttings. The larger volume produced by the open fractures causes a decrease in pressure (such that $B - D > 0$).

In this case, the amount of mud returned or bled-off is less than the amount pumped. If this occurs in permeable formations, then it is possible that significant mud losses may occur due to the highly increased surface area in the fractured zone.

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Chapter 6

Pressure Related Problems

Introduction

In general, the speed and efficiency with which a well can be drilled is dependent upon the formation balance gradient/mud density relationship. Many of the engineering safety factors also depend on this relationship. With the costs of wells continually escalating (particularly offshore), drilling time and material costs are minimized through engineering practices which attempt to produce maximum penetration rates as cheaply as possible. Instances will occur when these safety margins are negated and preference was given to cost/time activities rather than to established safety practices. Because safety should always come first, knowledge of pressure related problems is of paramount importance.

When planning exploration or wildcat wells, pre-drilling information is nonexistent or at best scarce and open to question. Accurate geologic data, engineering measurements and pressure interpretations on these types of wells is paramount. Though drilling development or delineation wells within a known province may remove the surprise element to some degree, this should never be taken for granted.

The economic aspects of drilling a well should be a prime concern for all personnel at the wellsite. Even with this in mind, the safety aspects must not be overlooked. Recognizing underbalanced conditions, reporting unexplained pit level changes, and the careful monitoring of alarm set-points are important contributions to rig safety.

Generally, the safest and most economical method to drill a well is to continuously monitor those “safety factors” which will prevent or control wellbore problems. One of these safety factor is kick tolerance, and ensuring that the estimated kick tolerance is never exceeded. In order to calculate this kick tolerance, it will be necessary to know the following parameters: potential lost circulation zones, hydraulic fracture pressures, and pore pressure.

Lost Circulation

Causes

Lost circulation occurs when whole mud is lost to the formation. The rate at which mud is lost will be dependent upon the type of formation and the mud density. Knowing this will give some idea of the severity of the situation. The six major causes for lost circulation are:

- the bit has penetrated a cavernous, vuggy formation
- the bit has penetrated open fractures or faults that are associated with a lower pressure potential
- the circulating pressure of the mud has exceeded the fracture pressure of a formation
- very poor hole-cleaning, resulting in packing-off the annulus. Mud pressure rises until fracturing occurs below the pack-off
- a zone of subnormal pore pressure has been penetrated so that either the formation has been fractured or the significant overbalance has brought about mud loss through massive filtration into the permeable formation
- the formation fractured while tripping in, or while casing was run at excessive rates

Other mud losses, which are less drastic can lead to hole problems if left unchecked. These are not wholesale losses, but rather the result of excessive filtration, due to:

- high overbalance
- high fluid loss
- weak filter cake
- highly permeable formations

The result is a continual slight loss of drilling fluid while drilling. Extensive permeability reduction in potential reservoirs, termed “skin damage,” is the result of mud plugging the pore spaces and filtrate interaction with sensitive clays in the pore spaces. Unchecked, this can render false reservoir parameters during testing; hence, all effort must be made to counteract this process.

Effects

Depending on the rate and mechanism of fluid loss, its effect can vary from a complete loss of returns to a minor reduction in return flow. If a vuggy formation is penetrated, and communication exists, the effective volume of the macro-porosity may be so great that no volume of mud may fill it. Mud losses will continue until preventive measures are taken.

A faulted or jointed formation with considerable fracture permeability causes varying rates of mud loss, depending on the permeability and the fluid pressure potential between the fractured formation and the borehole. However, the reverse may also occur: fluid pressures in the fractures may be higher than the pressure in the borehole, and the well may kick. Usually, if an extensively fractured formation is encountered, mud loss is extremely rapid and will not cease until preventive measures are performed.

If the mud density is high, in relation to the pore pressure and overburden pressure, the formation can be fractured. Mud loss is rapid, but circulation may easily be restored by reducing the mud density until the pressure reduction allows the fractures to close. This was a problem in the early days of wildcatting, and was overcome by reducing the mud density. As a result, unintentional hydraulic fracturing resulting in major fluid loss occurs less frequently today. However, experimental work with the borehole televiewer (a downhole sidewall sonar device) indicates that most of the well bores have some degree of minor hydraulic fracturing, probably caused by pressure surges when running pipe.

If a subnormal pore pressure zone is encountered, there is a good possibility that hydraulic fracturing will occur, due to the fact that the reduced pore pressure will produce a lower fracture pressure.

Continual hole fill-up and increased hook loads while tripping are an indication that the formation has been fractured at some point below the bit or last casing shoe (if running casing). This is caused by the combination of mud density and surge pressures. Usually the fractures will close when the trip is completed or when surge pressures are minimized. Losing circulation while running casing can be particularly hazardous because a poor cement job may result, allowing communication behind the casing. Many well problems occur after casing operations, and losing circulation while running or cementing the casing is often a contributing factor.

Solutions

Rapid and continual fluid loss while circulating can be caused by two different mechanisms: 1) fracturing, and 2) loss through interconnected vugs or preexisting open fractures. The first mechanism may be arrested by reducing the pump rate (thus lowering the ECD) or by modifying the mud properties (if the fracture pressure has been slightly exceeded) or alternatively, reducing the mud density. This solution also requires the addition of lost-circulation material (LCM) to attempt to bridge the vugs. If this fails, then a cement squeeze operation may be necessary.

Losing returns into a highly fractured formation can be minimized by injecting pellets or sand of decreasing size, causing the fractures to become bridged and packed. If this succeeds, then by injecting increasingly-fine material will improve the ability of the packed pellets to reduce lost circulation. Ultimately a mud filter cake may form, allowing normal drilling to resume without further losses. If packing and bridging of the fractures are unsuccessful, then the interval must be cemented off and re-drilled.

Penetration into a zone of subnormal pressure may cause other problems in addition to formation fracturing. These zones are permeable, so pipe sticking is a real danger. It may be necessary to reduce the mud density as much as possible, taking into account the open hole above this low pressure zone. Depending on their permeabilities, the formations higher up in the borehole may kick or slough severely, due to the decrease in mud density. If the amount of pressure reduction is such that further drilling will cause increased borehole instability, it may be necessary to seal that zone with cement. In rare circumstances this operation can cause the cement to flash-set, and no improvement in he situation. An impermeable seal, however, must be made before drilling can be resumed. If all else fails casing must be run, and this may necessitate several cementing operations.

Mud losses to a formation due to vugs or open fractures should not be confused with exceeding the fracture pressure. If the formation is such that a high differential pressure exists between the borehole and the fluids within the fracture or vug porosity, then mud losses will occur (providing there is ample permeability) until the pressure potential is equalized. Normally, if the vugs and fractures are interconnected, the volume required for pressure equalization is far in excess of the available mud volume. In this case, returns will not be gained until the thief zone is sealed off or the mud density is reduced so that it equals the fluid pressure in the fractures. Also, if a normally-pressured vuggy or fractured formation has very high permeability, then due to the enormous volume available in the formation, a mud at very slightly higher pressure will preferentially flow into this formation. No fracturing is involved; the formation acts as a sponge.

A formation will fracture within a fairly well-defined limit, if all the necessary conditions are present. Thus formations that are thief zones (e.g. a 10 lb/gal mud is continually lost and losses continue even when the mud density is reduced to 8.6 lb/gal) due to enormous fracture or vug porosity will have normal fracture pressures depending on the pore pressure, rock type and overburden pressure. Losses will begin when the mud pressure exceeds the fluid pressure in the fractures or vugs. The actual pore pressure within the rock itself will be very similar to the fluid pressure in the fracture unless the fracturing (i.e. fault brecciations) has occurred "recently" and the permeability of the formation is such that pore pressure/ pore fracture pressure equilibrium has yet to occur. Thus for thief zones, fracture pressure determination for that formation will be meaningless unless the flow zones are sealed

If lost circulation does occur, every attempt should be made to keep the hole full through continuous additions of drilling fluid or water. Allowing the hydrostatic pressure to fall below the pore pressure in other permeable formations can result in a kick or an underground blowout, which is exceedingly difficult to control.

In summary, lost circulation zones have enormous permeability and porosity, and mud losses will continue until the mud pressure in the borehole equals the fluid pressure in the formation. If the borehole pressure falls below the fluid pressure, the flow will reverse itself. When the thief zone is sealed by either plugging or filter cake, mud losses will cease and mud densities can then be raised to a value below the estimated fracture pressure, without further loss.

Massive Hydraulic Fracturing and Stimulation

Stimulation of a well is undertaken to allow the increased passage of fluids through the formation by; 1) the creation of fractures, 2) enlarging existing openings in the rocks adjacent to the wellbore, or 3) removing deposits that have partially blocked the openings during earlier production. Fractures may be created or widened by hydraulic fracturing and then kept open by injecting a suitable "proppant", which is held in suspension by a viscous gel. The gel is later recovered, leaving a permeable conduit from the formation to the wellbore. Explosives may also be used to create fractures.

Those intervals to be fractured are isolated by removable packers, and usually a low-viscosity, highly penetrating fluid is injected to create the initial fractures. This fluid is rapidly followed by a large volume of gel containing suitable proppants (usually very well rounded, well-sorted sand, or pellets with high crushing strength). The height and length of the created fractures can be controlled by the rate and volume of material pumped into the formation. Common fracture dimensions (calculated) for a 100-ft reservoir unit would be approximately 400 feet in length and 80 to 100 feet in vertical extent.

Acid may be injected to widen present openings through solution of the rock, and organic solvents can be used to remove clogging waxy and asphaltic deposits, or to remove filtrate and mud invasion from the well bore wall. Occasionally, reservoir permeability adjacent to the borehole is severely impaired during drilling due to excessive overbalance and fractures can be induced in these zones which will greatly improve flow without the need to restore the damaged zone to its undamaged condition.

Kicks

A kick is a well problem that should not occur. The penalty for failing to control a well can be the loss of the well, and occasionally the loss of the rig and the lives of the crew. Unreasonable procedures can in themselves cause hazardous conditions that severely jeopardize safety. Blowouts are a disaster from the viewpoint of people, economics, politics, and the environment.

Standard kick control procedures vary from rig to rig, but generally four simultaneous operations are considered.

- **Rig Control**: includes the blowout preventers, pumps, drawworks, and other rig operating equipment that is necessary. Rig control is the responsibility of the driller, and any blowout control procedure should assign these operations to the driller.
- **Mud Control**: involves adding barite for increasing the mud density, but also includes adding chemicals to the drilling mud and proper operation of the mixing systems. The mud control operations are generally the responsibility of the derrick man and mud engineer.
- **Choke Control**: includes calculating the proper pressures and time relationships as well as correctly operating the choke and monitoring the pump rate. The choke operator should be the best trained man on the rig from the viewpoint of kick control. He is required to give procedural guidance during the well killing operation.
- **Supervision**: the final element of control during a well kick. The tool pusher is the normal rig and crew supervisor and this should be his task. To assign the job of choke operator to the tool pusher is undesirable because he would then be restricted to the rig floor. The rig, during the critical well control procedure, needs a general overall supervisor, and this job is best undertaken by the tool pusher who knows both the rig and the crew.

Decisions made under kick conditions depends upon the knowledge, attitude, and judgement of the supervisor. They can be confused by crew change problems and divided responsibilities between the tool pusher and drilling foreman, or drilling engineer. So one of the most important elements of a kick control package is the establishment of a policy and procedure outlined in whatever degree of detail necessary. These procedures must be known by all members of the logging crew: it is the responsibility of the logging geologist or Unit Supervisor to obtain this information.

Causes of Kicks

There are five major causes of kicks during wellsite operations:

Failure To Keep The Hole Full

The majority of kicks occur when the bit is of bottom while tripping. When the pumps are shut down prior to tripping, there is a pressure reduction in the borehole equal to the annular pressure losses. If the mud hydrostatic pressure and the pore pressure are nearly equal, flow may occur when circulation stops. As pipe is removed, the mud-level in the borehole falls, causing a further reduction in hydrostatic pressure. The pipe displacement must be converted into pump strokes so that the correct number of strokes to fill the bore-hole is known.

Swabbing

When pipe is pulled it acts like a piston, more so below than above the bit. Both gel strength and viscosity of the mud have a large effect on swabbing. Swabbing is further increased if the mud cake is thick, the bit is balled-up, or the nozzles are blocked and a back-pressure valve is in the drillstring. The speed at which pipe is pulled has a great effect on swabbing.

In computerized logging units, an EAP Swab & Surge program provides a range of pipe pulling speeds and their corresponding swab and surge pressures. Figure 3-13 is an example of the EAP swab and surge analysis report. If swabbing does occur, pipe should be run back to bottom and the invading fluid circulated out. Surge pressures, when running into the hole (pipe or casing), may be sufficient to overcome the fracture pressure of a weak formation. The swab/surge pressure printout should be consulted, and the pipe run at a speed that produces surge pressures below the minimum fracture pressure. It is important to remember that this is necessary anywhere in borehole, as pressures are transmitted to the open hole even when the bit is inside the casing.

Insufficient Mud Density

Fewer kicks result from a low mud density than the previous two causes. If a kick occurs while drilling, due to insufficient mud density, it is possible that an oversight has occurred or that poor engineering practices were employed. In any event, trends and plots will have to be re-evaluated. Penetration into a geopressured formation without prior indication may have occurred, or a fault or unconformity may have been crossed. Also changes in lithology or drilling practices may have masked the transition zone.

Poor Well Planning

Both mud and casing programs have a great bearing on kick control. These programs must be flexible enough to allow progressively deeper casing strings to be set; other-wise a situation may arise where it is not possible to control kicks or lost circulation. Kick control is an important part of well planning, but it should not be overstated to the point that overall drilling effectiveness is reduced.

Lost Circulation

Raising the mud density to a value that exceeds the lowest fracture pressure, for fear of a kick, is not nearly as prevalent as it was in the 40's or 50's. A kick may still occur, but it is more likely to be due to fracturing a formation of lower pore pressure than an abnormally pressured zone. Rather than setting casing after drilling through a geopressured zone, the mud density is kept high to balance these formations. If the pore pressure decreases significantly, those lower pressured formations become susceptible to fracturing. If fracturing occurs, the fluid level in the annulus will drop due to lost circulation and the resulting loss in hydrostatic pressure may allow an influx of formation fluids, resulting in a kick. **The existence of an** abnormally pore pressured zone and a lost circulation zone in the same hole section are ingredients for a kick. The utmost care combined with diligent observation are necessary to successfully drill this type of well.

Recognition of Kicks

The only time a kick can occur without warning is when drilling offshore and there is no annular connection between the wellhead and the rig. However, there is never lack of indications that a kick or blowout is occurring. In the majority of situations the borehole and mud pits are a closed circulating system, and the addition of any fluid from the formation will result in a change in return flow and a change in the active pit volume.

One rare occurrence when surface recognition may be delayed is during lost circulation. The annulus is not filled and cannot be filled. When the rate of loss is greater than the rate at which fluid can be pumped into the hole, it is not possible to monitor the fluid level. A major influx may occur and not be detected at surface. To prevent this possibility the well should be shut in, and the shut-in pressures monitored. Pipe movement can be made by stripping through the BOP's and the hole filled using the choke and kill lines.

Sequence of Events

In most cases, the following distinct series of events generally lead to a kick while drilling. Some indications may not occur while others may be accentuated. Recognition of the changing trends at an early stage should allow remedial action to be taken, thus minimizing the potential hazards and costs.

1. The first indication of a kick is usually a drilling break. The increased drill rate need not necessarily indicate an increase in porosity, permeability and pressure, but it is prudent to assume that it does. The magnitude of the drilling break will vary depending on many drilling factors, but any significant drilling break should be checked for flow.

   Flow checks are performed by: (1) picking up the kelly so the kelly bushing is about 10 feet above the rig floor, (2) stopping the pumps, and (3) observing the fluid level in the bell nipple or flow line to see if the well is flowing. This may be difficult on floating rigs, because the level will fluctuate with the heave of the rig. In these instances the flow check should last at least five minutes or be conducted by circulating through the trip tank and the trip tank volume observed for a gain. If the well is flowing, it should be shut-in and any resultant pressures checked.

2. The second indication of a kick, or first confirmation that a kick is taking place, is an increase in the return flowrate in the flowline. The entrance of any formation fluid into the wellbore causes the return flowrate to increase, and this will occur concurrently with, or shortly after the drill break. The invading fluid is normally lighter than the mud, so continual influxes will further lighten the mud column and further reduce the bottomhole pressure. This, in turn, allows the rate of influx to increase. Once formation flow begins, the flow rate will be proportional to the depth of penetration into the formation.

3. Hookload may be seen to increase as a result of the lower density of the invading fluid and fluid-cut mud. If the mass flow of invading fluid is great enough, it may result in a decrease in hookload, as the drillstring is lifted by it.

4. An increase in pit volume can be the result of two separate mechanisms: (1) the increased flow rate translates into an increase in mud volume, and (2) if the kick contains gas, gas expansion will further increases the flow rate and pit volume.

5. A pump pressure decrease, along with a pump stroke rate increase becomes noticeable only when the kick fluid has been displaced some distance up the annulus.

6. A reduction in flowline mud density occurs as the invading material reaches the surface. This reduction is severe with a gas kick, but may be large or unnoticeable with a water kick,

depending on the mud density. High gas concentrations can be dissolved in oil-based drilling fluids, and as the kick fluid reaches the surface, high gas shows can occur.

It is vital that alarms be set on as many drilling parameters as possible. However, there are sufficient exceptions to the rule that make it unwise to depend upon one factor alone when observing the sequence of events. For example, continual mud mixing in the active system can mask a volume increase, and partial returns may so mask the effects of flowrate and volume increases as to make kick detection very difficult.

During Connections

When drilling close to balance conditions between mud hydrostatic pressure and pore pressure, flow into the annulus may occur when the pumps are shut off. This results from the removal of the annular pressure losses which increases the hydrostatic pressure while circulating. When the drillstring is lifted, swab pressures will further reduce the bottomhole pressure. An increase in hookload may indicate that a lighter fluid has invaded the hole. The lower the density of the invading fluid the less buoyancy it will exert on the drillstring, hence the higher hookload.

A kick taken during a connection is signaled by a sequence of events much the same as while drilling.

1. The well may flow when the pumps are first shut off. This can be monitored by the return flow sensor and a Pit Volume Totalizer.
2. An increase in pit volume may be noticed only after the connection. Usually, when the pumps are shut off, some mud from the surface equipment will flow back into the active pit. When the levels have stabilized after the pumps are restarted, an increase in level from before the connection indicates that a flow has occurred. The volume of mud from the surface equipment should be established at the start of each new job and re-established periodically as the well progresses (e.g. a 2 bbl increase on a connection may be normal, while a 3 bbl rise may be significant).
3. Pump pressure and rate changes similar to those experienced while drilling may be noted after successive connections. However, the flow will increase during each connection.
4. Mud density reductions may be similar to that while drilling.

Recognition of kicks during connections requires careful monitoring of the return flow sensor. After the pumps have been shut down, the flow sensor should indicate an absolute **“no flow”** condition. However on some rigs a long sloping flowline may cause mud to slowly trickle down after the pumps have been shut off. If this is the case, an increase in this flow will indicate a kick. Also a record of flowline mud density will disclose small mud cuts caused during connections, and may be accompanied by connection gases. Note that connection gases alone are not an indication of fluid influx during a connection.

While Tripping

Since kick control procedures are greatly simplified when the bit is near the bottom of the hole, kicks during a trip have the greatest potential danger. In addition, with the pipe out of the hole it is impossible to get heavier mud to bottom. During trips, an identical annular pressure drop occurs when the pumps are shut off.

However, because pipe is being removed, the hole must be topped up with mud regularly. If the hole does not take enough mud to replace the volume of pipe withdrawn, it is an indication that formation fluid is displacing the drilling fluid and the well is kicking. To alleviate this problem, it is common offshore to continually circulate through a trip tank while tripping out. By careful monitoring of trip tank volume against the calculated pipe displacement any discrepancy can be noticed immediately. In logging units, trip monitoring programs provide comparisons of volumes for every stand pulled. Alternatively a “trip condition log” provides a summary of the hole condition and fill up during trips.

Older offshore rigs and many land rigs may not have a trip tank, so reliance for volume checks is placed on monitoring one of the active pits and pump strokes. Pit volume monitoring provides the necessary cross-check, but because of the large surface area of the active pits, precision may be limited. The mud pumps are a reasonably efficient displacement monitor at low pressures and stroke-rates, and pump strokes are often used to measure the proper amount of fluid displacement.

It is normal for the hole to take slightly more mud than the volume of the pipe removed, due to static filtration into the formation. If a kick occurs when the bit is not on bottom, every effort must be made to run back in the hole. Modern BOP's are designed for reliable stripping through the annular preventer or ram sets, enabling the bit to be run back to bottom.

Shutting In A Kick

Kick tolerance is defined as the maximum Formation Balance Gradient that may be encountered if a kick is taken at the present depth, with the present mud density and the well is shut-in without downhole fracturing occurring.

During drilling, kick tolerance must not be exceeded because if a kick occurs there will be a considerable chance that an underground blowout will occur if the well is shut-in.

Kick Control

There are three industry recognized kick control procedures. The selection of the one to kill a well depends upon; 1) the amount and type of kick fluids that have entered the hole, 2) the rig's equipment capabilities, 3) the minimum fracture pressure in the open hole, and 4) the drilling and operating companies policies. Determination of the most suitable and safest method (assuming their company policy allows flexibility of procedures determined by the demands of the situation) involves several important considerations. These include:

- the time required to execute the complex kill procedures
- surface pressures that will occur when circulating out the kick fluids.
- downhole stresses that are applied to the formations during the kill operation.
- the complexity of the procedure itself relative to its implementation, rig capability and rig crew experience.

It is the responsibility of the tool pusher or operator's representative to decide which method to use when killing the well: under no circumstance should Baker Hughes INTEQ personnel become involved in this decision.

Each of the above points must be assessed and their relative importance to the kick situation evaluated before implementing the selected method. In the following paragraphs, elaboration of these points illustrates the reasoning behind their importance on individual situations.

The Time Factor

The total amount of time taken to implement and complete kill procedures is important if the kicking fluid is gas, because it will percolate up the annulus, increasing the annular pressure. There may be a danger of the pipe sticking, especially if a fresh water mud system is in use. Invading saline pore water may cause the mud cake to flocculate, so the bit, stabilizers and collars would be in danger of sticking.

Considerable time is involved in weighting up the mud, but more importantly is the time for the kill operation to be completed. The strains and pressures on the well, surface equipment and personnel should be minimized in the interests of safety and cost. Therefore, depending on the kick situation, the decision as to what method should be used must be based on these priorities.

The kick procedures that involve the least amount of initial waiting time are (1) the two circulation, or driller's method and (2) the concurrent method. In both of these procedures, pumping begins immediately after the shut-in pressures are recorded. However, if the time taken to weight up the mud is less than one circulation then the engineers, or one circulation method may be preferred. In certain situations the extra time required for the two circulation method may be seriously detrimental to hole stability or may cause excessive BOP wear.

Surface Pressures

If a gas kick is taken, the annular pressures may become alarmingly high during the course of the kill operation. This is due to the properties of gas as it nears the surface. If expansion is not allowed to occur, severe pressures will be placed on the annulus and surface equipment. For this reason the most reliable well killing procedures utilize a constant drillpipe pressure and variable annular pressure (through a variable choke) method.

The kill procedure that involves the least surface pressures must be used if the kick tolerance is low. Figure 6-1 shows the different surface pressure requirements for two different kick situations using the one and two circulation methods.

The first difference is noted immediately after the drillpipe is displaced with kill mud. When keeping the drillpipe pressure constant, with the constant pump rate, the casing pressure begins to decrease as a result of the higher kill mud hydrostatic pressure in the one circulation procedure. This initial decrease is not seen in the two circulation method, since the mud density has not changed, the casing pressure increases as the gas expansion displaces mud from the hole. The second pressure difference is noted when the gas approaches the surface. The two circulation method, again, has the higher pressures. The result of circulating the original mud density.

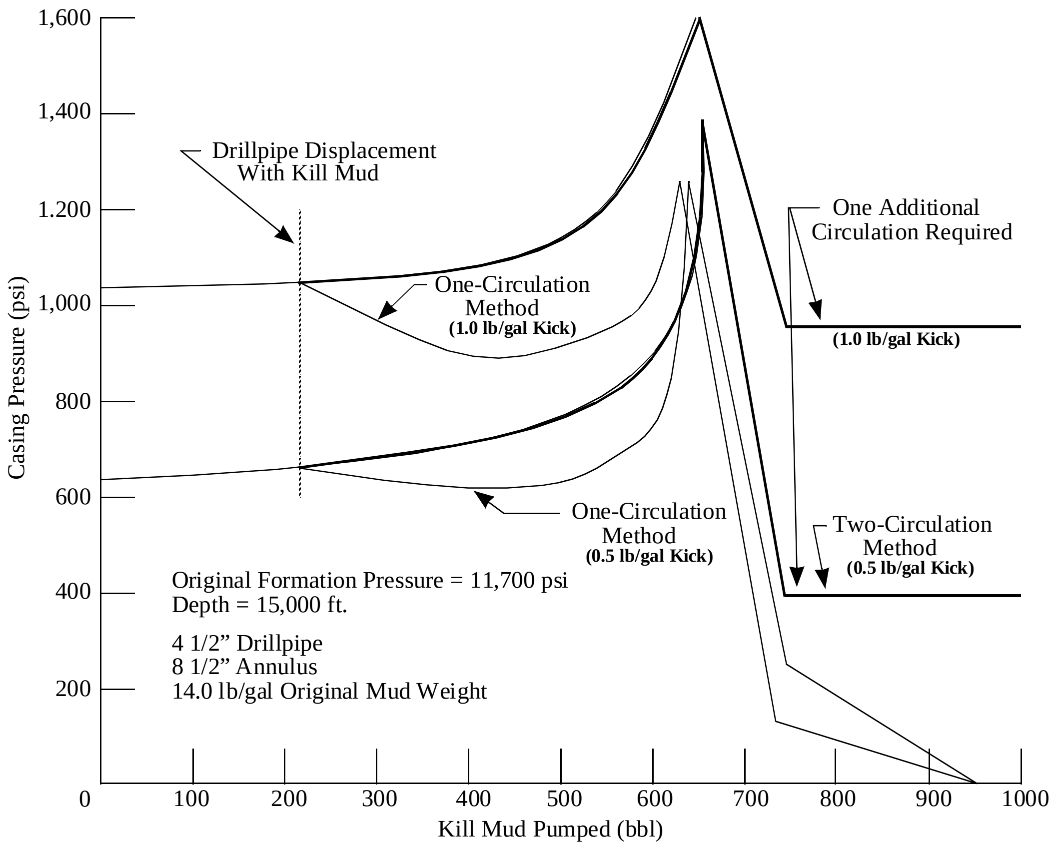

Figure 6-1: Different surface pressures produced during the one and two circulation kill methods

Also, after one complete circulation has been made, the one circulation method has killed the well, resulting in zero surface pressure, whereas the two circulation method still has pressures on the casing equal to that of the shut in drillpipe pressure.

Downhole Stresses

During kill operations, stresses in the borehole is a prime concern. If the extra stresses imposed by the kick are greater than the minimum fracture pressure in the open hole, fracturing will occur, resulting in a possible underground blowout. Similarly, a kill procedure which through its implementation, places high stresses on the wellbore should not be used in preference to others which impose lower stresses on the wellbore. Reference to these points illustrates that the one circulation method places the minimum stresses on both the wellbore and surface equipment. When a kick is circulated out the maximum stresses occur very early in the circulation - particularly in deep wells with higher pressures. At any point in the borehole, the maximum stress is imposed when the top of the kick fluid reaches that point. Generally in most cases, if fracture and lost circulation does not occur on initial shut-in, they will not occur through the kill process, if the correct procedure is chosen and implemented.

Procedural Complexity

The suitability of any process is dependent on the ease with which it may be reliably executed. If a kill procedure is difficult to comprehend and implement, its reliability is negated. The one and two circulation methods are simple in both theory and execution. Choice between the two is dependent upon the previously mentioned points, and any other limitations provided by the situation. The concurrent method is complex in operation and its reliability may be reduced through its intricacy. Because of this, many operators have discontinued its use.

It is important to repeat that pressures calculated on deviated wells must use vertical depths not measured depths. Measured lengths are only used in ECD calculations, so that the resultant pressure losses be added to the hydrostatic pressure calculated from the vertical depths.

Situations can arise when the shut-in casing pressure will approach or slightly exceed the actual or estimated minimum formation fracture pressure. In this case the well cannot be shut-in, and an alternate method of kill control must be attempted. The maximum casing pressure at the surface is determined by three factors:

1. The maximum pressure the wellhead will hold
2. The maximum pressure the casing will hold (burst pressure)
3. The maximum pressure the formation will hold

Formulae Used In Kick And Kill Procedures

1. **Hydrostatic Pressure**
   (psi): MW(lb/gal) x TVD(ft) x 0.0519
   (Kpa): MW(sg) x TVD(m) x 0.0098
   MW = Mud Weight
   TVD = True Vertical Depth

2. **Circulating Pressure (psi):**
   (MW x TVD x 0.0519) + P_{la}
   P_{la} = Annular Pressure Loss

3. **Initial Circulating Pressure (psi):**
   SPR + SIDP
   SPR = System pressure loss at kill rate (psi) usually taken at varying slow circulating rates
   SIDP = Shut-in Drillpipe Pressure (psi)

4. **Final Circulating Pressure (psi):**
   (KMW / MW) x SPR
   KMW = Kill mud weight

5. **Kill Mud Weight (lb/gal):**
   MW + (SIDP / (TVD x 0.0519))

6. **Formation Pressure (psi):**
   SIDP + (MW x TVD x 0.0519)

7. **Density of influx (ppg):**
   MW - [(SICP - SIDP)/(L x 0.0519)]
   SICP = Shut in casing pressure (psi)
   L = Length of influx (ft)

8. **Length of kick around drill collars (ft):**
   Pit Gain (bbls)/ Annular Volume around collars (bbls/ft)

9. **Length of kick, drill collars and drill pipe (ft):**
   Collar Length + (Pit Gain - Collar Annular Volume) / (D_1^2 - D_2^2 x 0.000971)
   D_1 = hole diameter (inches)
   D_2 = drillpipe diameter (inches)

10. **Gas bubble migration rate (psi/hr):**
    ΔPa / (0.0519 x MW)
    ΔPa = pressure change over time interval / time interval (hr)

11. **Barite required (sk/100 bbls mud):**
    1490 x (KMW - MW) / (35.8 - KMW)

12. **Volume increase caused by weighting up:**
    100 x (KMW - MW) / (35.8 - KMW)

The drill pipe pressure is used as a downhole pressure gauge. The casing pressure is affected by the type and amount of fluid influx.

When the density of the kick fluid is known the composition may be approximately determined;

Influx Density (psi/ft)	**Influx Type**
0.05 - 0.2	gas
0.2 - 0.4	combination of gas/oil and or seawater
0.4 - 0.5	oil or seawater

Kick Control Methods

All kick procedures require the knowledge of drillstring geometry, hole geometry, mud density, pump rates, pressure losses and fracture pressure. Particular information is required prior to initiating kill procedures.

1. Circulating pressure at kill rate
2. Surface to bit time at kill rate (in strokes and minutes)
3. Bit to surface time at kill rate (in strokes and minutes)
4. Maximum allowable surface annular pressure
5. Formula for calculating the kill mud density
6. Formula for calculating the change in circulating pressure due to the effect of the heavier mud
7. The clients policies on safety factors and trip margins

For a well to be killed successfully the pressure in the formation must be kept under control during the entire operation. Except in cases when the maximum allowable surface annular pressure will be exceeded, this policy should be strictly adhered to. The simplest method of doing this is to control the drillpipe pressure by running the pump at a constant rate and controlling the pressure by regulating the choke on the annulus.

Currently there are three main methods in practice:

1. The Driller's Method (two circulations)
2. The Wait and Weight (Engineers) method (one circulation)
3. The Concurrent Method

The EAP-PC kick and kill analysis and DrillByte kill monitor programs provide calculation of the data required in these procedures and a record of progress during their accomplishment.

The Driller's Method

When a kick occurs, the drill crew should proceed as follows:

1. Pick up the kelly and note the position of tool joints in relation to the pipe rams.
2. Stop the pumps.
3. Open the choke line.
4. Close the annular preventer or rams.
5. Close the choke.
6. Record the pit gain.
7. Record the SIDP and SICP when they are stabilized.

Calculate the kill mud density, initial and final circulating pressures, and the kick fluid gradient. If the kick is gas the bubble may start to percolate up the annulus; this causes a slow rise in pressure on the drillpipe and casing. If the pressures are seen to rise, a small amount of fluid is bled from the choke to release the “trapped pressure”. This process is repeated until the drillpipe pressure has stabilized.

The first circulation is performed using the original mud. The choke is opened slightly, at the same time the pumps are started up to kill rate. When the pumps have reached kill rate the choke is manipulated to maintain the pressure on the drillpipe at the original SIDP + the circulating pressure. As the kick fluids approach the surface, the annular pressure will rise drastically if the kick is gas. If the kick is saltwater the annular pressure will drop slightly.

When all the influx has been circulated out, the pump is stopped and the choke closed. The drillpipe pressure should be the same as the casing pressure.

During the first circulation the mud density in the pits should have been raised to the necessary kill mud density. The kill mud is circulated during the second circulation. The choke is opened slowly and the pump speed is increased to the kill rate, as the annulus pressure is kept constant. The annular pressure is kept constant by manipulating the choke until the kill mud has reached the bit. The drillpipe pressure will decrease during this operation from the initial circulating pressure to the final circulating pressure

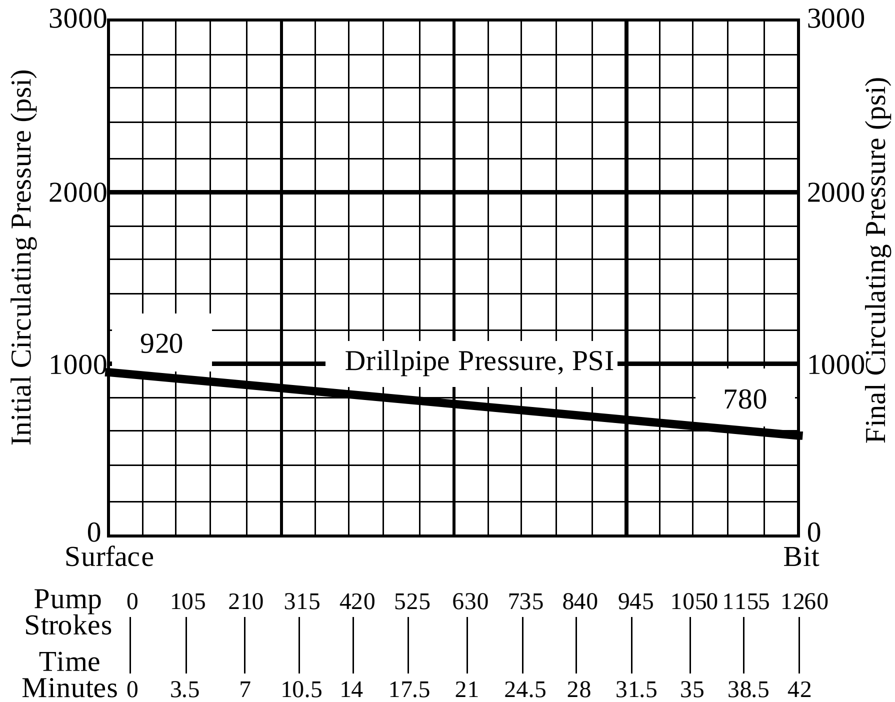

Figure 6-2: Drillpipe/pressure plot when kill mud is pumped down the drillpipe

It is good practice at this point to close the well in. The drillpipe pressure should fall to zero; if it doesn't, a few more barrels should be pumped to ensure that the kill mud has reached the bit. If the drillpipe pressure is still greater than zero when the pump is stopped and the choke closed, the kick control figures should be checked. Pumping is restarted, but now the drillpipe pressure is kept constant as the kill mud displaces that in the annulus. When the kick fluids and original mud have been displaced the choke will be wide open; the pump should be shut down and the SIDP should be zero. If so the well should then be observed for flow. The kick will be killed and mud should be circulated to condition the hole, and at the same time the trip margin (if any) should be added.

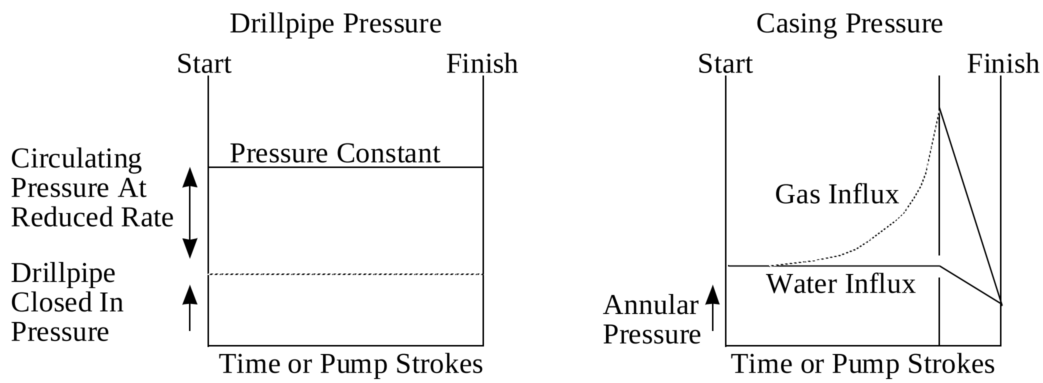

Figure 6-3: First circulation pressures during the drillers method.

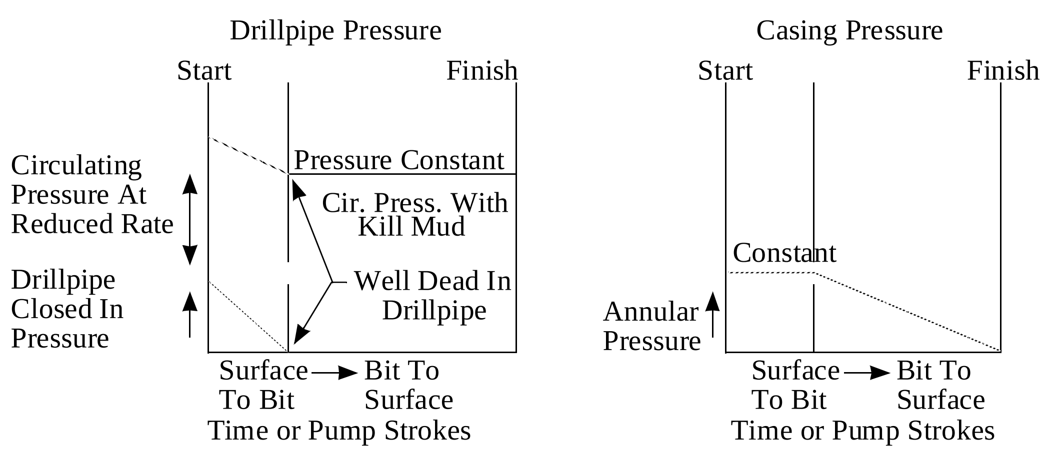

Figure 6-4: Second circulation during the drillers method.

The Engineer's Method

This is usually a more effective method of killing a kick than the driller's method, if time is not a prime concern. Kill mud is pumped into the drillpipe as soon as it is ready, which reduces the high annular pressures associated with gas kicks. The same shut-in procedures should be used as outlined in the previous paragraph.

When all the calculations have been performed, the mud density is raised immediately to the calculated kill mud density. When the kill mud is ready, the pump is started and the choke is slowly opened, while keeping the annular pressure constant until the pump has reached kill rate. The choke is then regulated in such a way as to decrease the drillpipe pressure until the kill mud reaches the bit, at which point the final circulating pressure is reached.

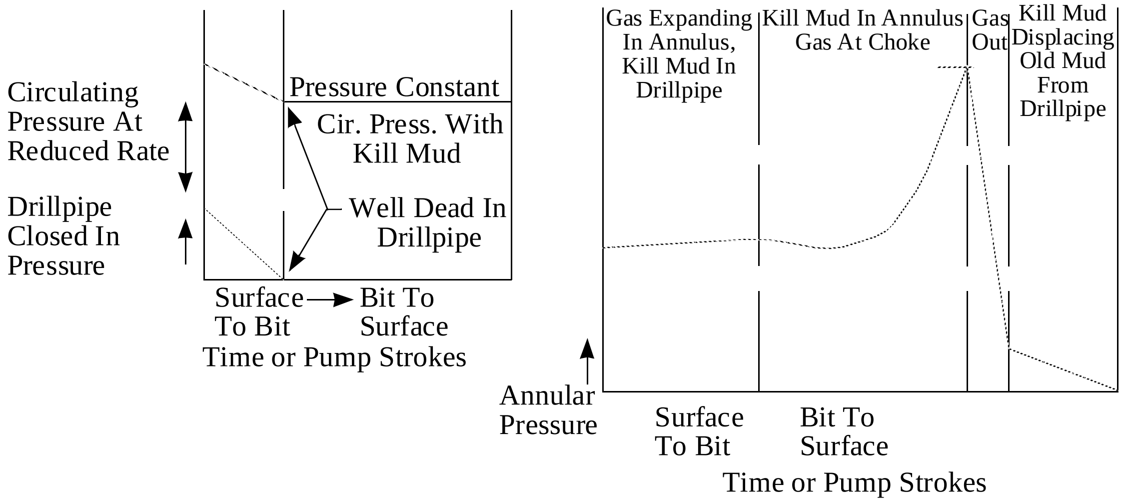

Figure 6-5: Drillpipe and annular pressure curves during the engineer's kill method

Pumping is continued, holding the drillpipe pressure constant by adjusting the choke. When the kick fluids have been displaced, and further volume has been displaced equal to the pipe volume, The SIDP should be zero. The kick should be killed and the well checked for flow. Further circulations should be performed to condition the hole and to add the trip margin. Figure 6-6 shows the variations of drillpipe and casing pressures as the kill procedure is implemented.

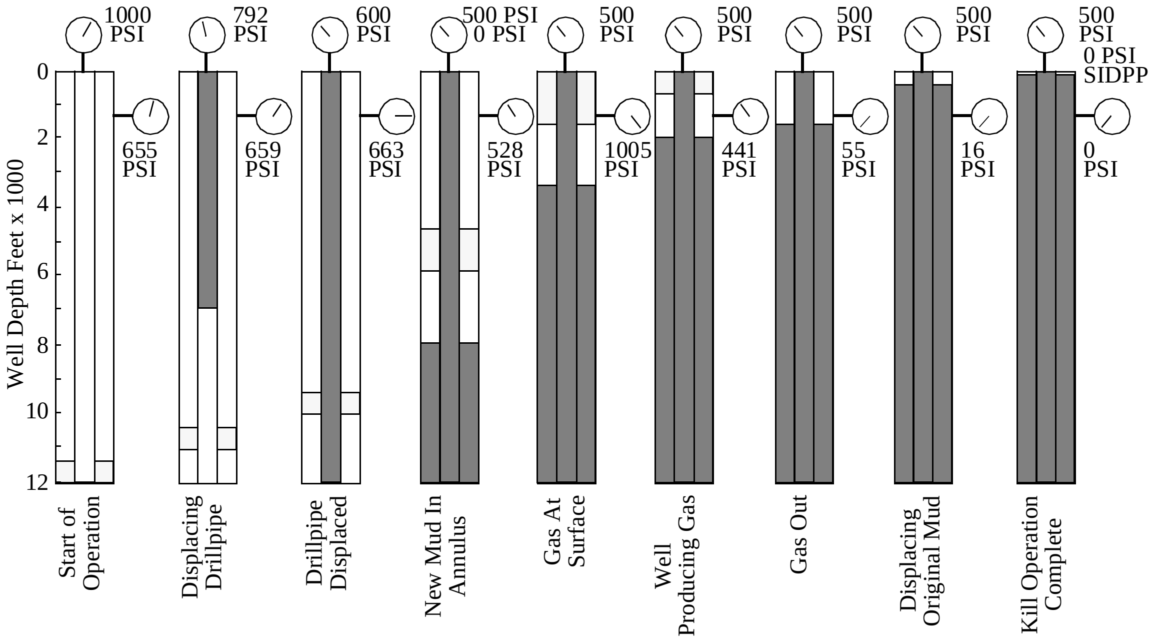

Figure 6-6: Shows diagrammatically the displacement of the original mud with kill mud, with example pressures, using the engineers method.

The Concurrent Method

This is the most complicated and unpredictable method of the three. Its main value lies in the fact that it combines the driller's and engineer's methods, so that the kill operation may be initiated upon immediate receipt of the shut-in pressures. Instead of waiting until all the surface mud has been weighted up, pumping begins immediately at the kill rate and the mud is pumped down as the density is increased. The rate at which the mud density is raised is dependant upon the mixing facilities available and the capability of the crew. The main complication of this method is that the drillpipe can be filled with muds of increasing density, making calculation of the bottomhole hydrostatic pressure (and drillpipe pressure) difficult.

Provided there is adequate supervision and communication, and the method is completely understood, this can be the most effective way of killing a kick. Figure 6-7 illustrates the irregularities in drillpipe pressure with kill mud volume, caused by the increasing density of the kill mud. The shut-in procedure is the same as that outlined previously. When all the kick information has been recorded the pump is activated slowly until the initial circulating pressure has been reached at the designated kill rate. The mud should be weighted up at the maximum possible rate, and, as the mud density changes in the suction pit the choke operator is informed. The pump strokes already passing are checked on the drillpipe pressure chart when the new density is pumped, adjusting the choke to suit the new drillpipe conditions as pre-recorded on the surface to bit graph.

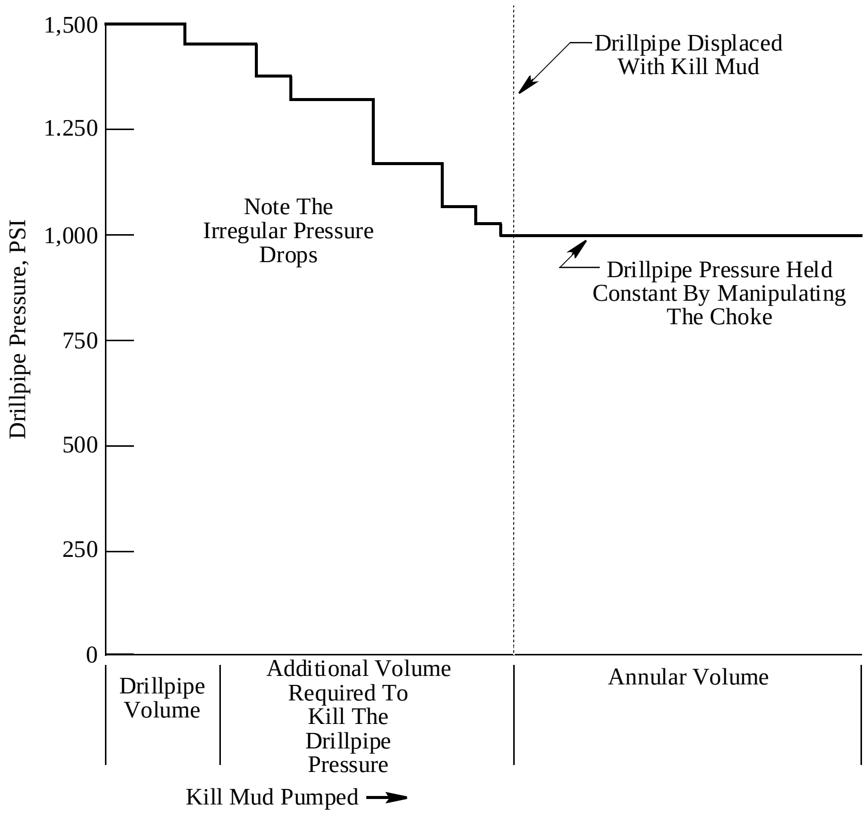

Figure 6-7: Typical irregular drillpipe pressure reductions during concurrent method

When the final kill mud reaches the bit, the final circulating pressure will be reached and from this point on the drillpipe pressure should be kept constant until the operation is completed.

Kick Tolerance

Kick tolerance is defined as the maximum Formation Balance Gradient that may be encountered when a kick taken at the present depth, using the present mud density, and the well shut-in, without downhole fracturing resulting. If the pore, fracture (actual or theoretical) and hydrostatic pressures are continually monitored, then in the majority of cases kick tolerance may be closely estimated. The limit of this pressure is usually set by the minimum fracture pressure in open hole.

It is of paramount importance that the estimated kick tolerance not be exceeded. A well cannot be drilled safely if it is exceeded because, when a kick is taken, there is considerable chance of an underground blowout when the well is shut in. The maximum surface pressure (SICPmax) will be a function of the mud density, and the depth and Fracture Pressure Gradient of the weakest formation in the open hole.

Equation 6-1

$$SICP_{max} = 0.0519 \text{ x } (FG_{min} - MW) \text{ x } D_f$$

The Formation Balance Gradient which will produce this maximum shut-in casing pressure can be calculated for a particular depth and mud density.

Equation 6-2

$$0.0519 \text{ x } K \text{ x } D_B = SICP_{max} + 0.0519 \text{ x } MW \text{ x } D_B$$

where:

$SICP_{max}$ = maximum shut-in casing pressure (psi)
FG_{min} = fracture pressure gradient of weakest formation (lb/gal)
MW = mud density (lb/gal)
D_f = vertical depth of weakest formation (ft)

Which can be restated as:

Equation 6-3

$$K = \left[\frac{D_F}{D_B}(FG_{min} - MW) + MW\right]$$

where:

K = kick tolerance (lb/gal)
D_B = vertical depth of bit (ft)

This defines the maximum formation balance gradient that may be encountered at that depth so that the well may be shut in without exceeding the lowest fracture gradient. However, this expression assumes that the kick will be detected and the well shut-in with zero influx of formation fluid. In reality, the kick tolerance will be reduced by a term involving the density and volume of invading fluid. This can be calculated from the following formula.

Equation 6-4

$$K_{min} = \left[\frac{D_F}{D_B}(FG_{min} - MW)\right] - \left[\frac{L_k}{D_B}(MW - W_k)\right] + MW$$

where:

K_{min}	= minimum kick tolerance (lb/gal)
L_k	= length of kick (ft)
W_k	= density of kick fluids (lb/gal)

The kick fluid density will vary, but will be a minimum in a gas kick. The expected influx prior to detecting a kick will depend upon the resolution of the pit-level monitoring apparatus (the equipment design and the height-to-surface area ratio of the pit). It will also depend upon the speed and efficiency of the rig crew and equipment. This value cannot be calculated but must be determined by tests, such as pit drills.

A large influx of gas will significantly decrease the kick tolerance. Therefore, if the kick tolerance with no influx is being approached, the minimum kick tolerance can be determined by the resolution of the pit-level monitoring apparatus. For safety's sake it should always be assumed that the kick will be gas. Thus the minimum noticeable pit gain (i.e. 15 bbl), should be added to the estimated pit gain that will occur (due to the time lapse from first observing the flow) to when the well is finally shut in. This shut-in period is critical, and it is usual practice to run through a pit drills and hang-off procedures regularly. An additional delay of, say, 1 minute may allow a further 20-bbl pit rise. Thus (in this case) the total minimum pit gain before the well could be shut in would be 35 bbl. This value then defines the "minimum expected kick length" in a particular hole section; thus, with a particular mud density, the reduction of kick tolerance due to gas influx can also be continually estimated. For example:

If 12-$^1/_4$ inch hole is being drilled and 642 feet of 8-inch collars are being used,

Equation 6-5

$$length\ of\ kick = \frac{1029}{(12.25^2 - 8^2)} \text{ x } 35 = 418\ feet$$

If a 15 lb/gal mud is in the hole, and assuming a kick would be gas having a density of 2 lb/gal, at a current depth of 15,000 ft and a minimum fracture pressure gradient of 16.0 lb/gal at 7,500 ft, then:

Equation 6-6

$$K_{min} = \left[\frac{D_F}{D_B}(FG_{min} - MW)\right] - \left[\frac{418}{15000}(15.0 - 2)\right] + MW$$

$$= \left[\frac{7500}{15000}(16.0 - 15.0)\right] - 0.36 + 15.0 \ lb/gal$$

$$K_{min} = 15.14 \ lb/gal$$

If the kick tolerance calculations did not take into account the minimum expected influx, then:,

$$K = \frac{7500}{15000}(16.0 - 15.0) + 15.0$$

$$K = 15.50 \ lb/gal$$

which may appear to be a reasonable safety margin if the pore pressure at 15,000 ft was estimated to be just overbalanced. But if the minimum kick influx is taken into account, the actual kick tolerance would be only 15.14 lb/gal. Furthermore, if for some reason a kick was taken and a total pit gain of 50 bbl occurred, so that the kick length was 598 ft, then the total kick tolerance would be

$$K_{min} = 0.5 - \frac{598}{15000} \text{ x } (15.0 - 2.0) + 15.0$$

$$= 0.5 - 0.52 + 15.0$$

$$K_{min} = 14.98 \ lb/gal$$

This example serves to illustrate the highly important functions of correcting the kick tolerance for influx. In this case, kick tolerance is less than mud density (i.e., the well cannot be shut in) as the shut-in casing pressure would be such that the formation would be fractured at 7500 ft and an underground blowout would occur.

It is important that the ‘minimum expected influx’ be utilized in kick tolerance estimations so that the well can be safely shut in if a gas kick is taken.

> **Note:** *The policy of Baker Hughes INTEQ in its Pressure Evaluation and DrillByte services is to calculate and plot Kick Tolerance as K in Equation 6-3. This is a defined, calculable quantity, which does not rely upon subjective assessments of rig performance.*

The “minimum kick tolerance” (K_{min}, in Equation 6-4), corrected for the invading fluid volume and density, can be calculated and reported only when the volume and density are specified by the drilling supervisor, oil company standard operating procedure, or a regulatory agency. In such circumstances Baker Hughes INTEQ personnel may assist the drilling supervisor in determining the volume and density estimates to be used, but the authorization for their use must come from a representative of the oil company.

This “minimum expected influx” will vary during the course of the well and should be re-established with regular pit drills. When it is reported on the daily Report Form, the expected influx volume and density must be reported with it, for example:

Kick Tolerance: 15.2 lb/gal with a 25 bbl of 2 lb/gal influx

Plots of Kick Tolerance on Pressure Evaluation Logs, should be of the true (zero influx) Kick Tolerance (K) only.

Operational situations may arise which will cause the kick tolerance to be exceeded. If a shut-in occurs such that the actual kick tolerance is 0.1 lb/gal above the current mud density, the well should not be killed by accepted methods if the kick is calculated to be gas. After the shut-in readings have been taken, it may be possible to kill the well by slowly pumping a large barite or gunk plug down the well (Low Choke Method), or by pumping the original mud at a high rate against a small choke backpressure (bullheading).

Since gas does not start to expand significantly until the pressure on the influx is reduced to less than 6000 psi, if a gas kick is taken, gas expansion and pressure increases will not be rapid until the influx has been circulated (or percolated) up to a level in the borehole where the pressure is less than 6000 psi. For example, if kick tolerance is becoming marginal in a deep well where casing is set at 7500 ft, as long as the mud density is greater than 15.4 lb/gal, gas expansion will not occur until the gas is inside the casing.

The accuracy of kick tolerance calculations is dependent upon the accuracy of the other geopressure evaluation techniques. In actuality, kick tolerance is the goal toward which the geopressure evaluation service is directed. Consider the terms that make up the relationship, and their description:

D_F = Vertical depth of the weakest formation; necessitates knowledge of formation type (i.e., Poisson's Ratio) and pore pressures.

D_B = Vertical depth of the bit; if the hole is deviated, we need to be able to calculate (through survey analysis) the vertical depth.

FG_{min} = Minimum fracture pressure gradient necessitates estimation of the overburden pressure gradient, pore pressure gradient (for σ_1') interpretation of the first fracture test in compact formation and back-calculation of σ_t. Then, it requires monitoring of pore pressure changes, lithological changes, and overburden pressure extrapolation as the well progresses in order to delineate the weakest formation in the borehole, and to estimate its fracture pressure.

Field personnel must be aware, either through their own experiences or through this manual, of the importance of their measurements and interpretations. Communication of the results to clients must be concise and unambiguous so that full use may be made of them. Since current safety levels are coming under greater scrutiny, government agencies are involving themselves in rig practices that have the potential to endanger lives and the environment. The establishment of kick tolerance safety levels is one of these criteria, and in some countries these laws have been established for some years. As more countries follow suit, under the impetus of more energetic exploration in hazardous areas, kick tolerance calculations will become one of the most important aspects of Baker Hughes INTEQ's Pressure Evaluation Service and DrillByte involvement at the wellsite.

“Differential” Kick Tolerance

It is conventional oilfield practice to compute and report pressure-related quantities as gradients relative to the flowline (see Chapter 3). This is a convenience which allows direct comparison of the pressure quantities to the mud density currently in use.

In some areas this convention is modified when reporting kick tolerance. A figure known as “differential kick tolerance” is reported, which is the actual kick tolerance minus the actual mud density.

Equation 6-7

$$Kick\ tolerance,\ K = \left[\frac{D_F}{D_B}(FG_{min} - MW)\right] + MW$$

The “differential” kick tolerance = (K - MW), or:

Equation 6-8

$$\Delta K = \frac{D_F}{D_B}(FG_{min} - MW)$$

Minimum kick tolerance is:

Equation 6-9

$$K_{min} = \left[\frac{D_F}{D_B}(FG_{min} - MW)\right] - \left[\frac{L_k}{D_B}(MW - W_k)\right] + MW$$

The “differential” minimum kick tolerance = (K_{min} - MW) is then:

Equation 6-10

$$\Delta K_{min} = \left[\frac{D_F}{D_B}(FG_{min} - MW)\right] - \left[\frac{L_k}{D_B}(MW - W_k)\right]$$

The rationale for this method of reporting is that this quantity will decline as the hole is deepened and when mud density is increased. When it reaches zero, the well can no longer be shut-in. This is a dramatic representation of declining, safety margins. On the other hand, it removes the direct comparability of the quantity, especially when plotted.

Baker Hughes INTEQ does not encourage the reporting of kick tolerance in this form. Field personnel who are requested to do so by a client must of course comply but should be careful to discriminate between the differential being reported and the actual term being plotted on any log or placed on any reports.

Pressures in Carbonates

As mentioned in Chapter 4 (*Factors Affecting Formation Pressure Evaluation - Lithology*), carbonates can cause problems when evaluating formation pressures. Three situations must be considered when evaluating abnormal pressure in carbonates:

- The role of carbonates are seals, cap rocks or permeability barriers
- Carbonate reservoirs entrapped within overpressured shale zones will behave as any other pressured aquifer or potential reservoir
- The development of pressure within carbonate formations

Formation Pressure Development

The study of abnormal pressure development and detection in carbonates will have many aspects which are different from those described for clastics (especially argillaceous rocks). The most important being:

- The total difference in mineralogy, and chemical and physical behavior, requires that all developmental mechanisms and causal relationships be carefully examined
- The immense variation in carbonate lithologies requires a greater geological study, in 1) the development of pressure and 2) the use of normal trends in uniform lithologies

To ensure that all personnel are “familiar” with these aspects of carbonates, a review of carbonates is necessary. More in depth information ca be found in the *Advanced Logging Procedures Workbook* and *Advanced Geological Procedures Workbook.*

Sedimentology

Carbonate classification is too large a subject to be covered here and is documented sufficiently in the above referenced workbooks. It is however necessary, in any carbonate work, to work with an agreed upon classification system. The most commonly used carbonate classification in the oil fields is the Dunham textural classification. This will ensure uniformity in sample description.

In addition to the normal sample description, the use of thin sections can be particularly valuable.

Mineralogy

Nearly all carbonates are of a mineralogically mixed character. However, identification of the species of carbonates can be invaluable in determining both the present state and clues to the developmental history of the formation. The presence of non-carbonate material plays an important role in modifying, perhaps extensively, the behavior of the carbonate rocks.

For wellsite work, the use of dilute hydrochloric acid as a diagnostic tool should not be overlooked. Also there are various types of staining techniques which are also useful. Finally, a little used piece of secondary equipment, the autocalcimeter, can be used to assist in determining the mineralogical content of the carbonate rock.

Porosity and Permeability

It is obvious that both porosity and permeability are factors of great importance in abnormal pressure development and behavior. It is the absence of permeability and hence dewatering ability that is the major cause of overpressure. Similarly, the availability and distribution of pore space in the matrix will be in close interrelationship with the degrees of pore pressure abnormality encountered. Unfortunately, in carbonates, these two functions are most elusive.

When dealing with clastic sediments, it is often acceptable to generalize that porosity and permeability are in a close consistent relationship. Similarly, shales, though often having good porosity, have infinitesimal (though not insignificant) permeability. Such generalizations rarely hold true for carbonates. the lack of uniformity in size, shape, type and distribution of porosity may lead to a highly porous rock having extremely low permeability. Conversely, the importance of fracturing in carbonates may lead to a rock which, from cuttings evaluation and even wireline/ MWD logs, appears to be tight, provides excellent permeability.

The assumption that compaction uniformly increases and porosity reciprocally decreases (with depth of burial) must be seriously doubted when giving consideration to carbonates. Although younger sedimentary carbonates (depending on their particle type) exhibit trends analogous to clay dewatering and compaction, or sand reordering and cementation, this is not a continuous or general process. The effects of diagenesis upon carbonates, sediments or evaporites is sufficient to totally obliterate any younger porosity trends. In general, it may be observed that age of burial, rather than depth, is the controlling influence upon carbonates. However, this too may be brought into doubt by secondary recrystallization processes.

Fluid Movement

The major differences between carbonates and all other rock types are results of the solubility of the matrix material. Therefore, it cannot be deduced that a present lack of matrix porosity and permeability precludes any previous fluid migration. it is possible that recrystallization, post-dating the dewatering and migration, has removed initial porosity and permeability. On the other hand, it is known that migrations of water, and accompanying hydrocarbons, may take place through effectively impermeable carbonates by a mechanism of pressure solution. This may lead to the depletion of overpressured formations or to the formation of transition zones similar to those encountered in argillaceous rocks. In other circumstances it could lead to the overpressuring of a normally pressured formation.

Matrix Strength

In the study of overpressuring in shales dues to the phenomenon of subcompaction, an important factor has been the comparatively low matrix strength leading to a decrease in matrix volume due to sedimentary loading. Such a mechanism will lead to the transfer of matrix loading onto pore fluids and hence overpressuring.

It has been observed in many areas (i.e.Anadarko Basin) that removal of overburden loading will lead to a reversal of the process. Here, uplift and erosion of the commonly overpressured Morrow-Springer has produced a substantial reduction in total overburden. This reduction in loading is accompanied by an elastic expansion due to low matrix strength. the resultant increase in pore volume, accompanied by a decrease in fluid volume (due to cooling), causes a decrease in fluid pressure from overpressure to normal and eventually subnormal pressures. Matrix strength with carbonates varies with age. However, that strength will be such that changes in matrix volume will occur only in terms of recrystallization with material loss or gain.

Furthermore, early in diagenesis, carbonates may develop sufficient lithification to prevent later significant bulk volume change. As a result, development or removal of sedimentary loading can lead to markedly different effects compared to those seen in shales.

During normal uniform sedimentation, compaction and lithification proceeds normally at such a rate as to ensure dewatering will accompany porosity reduction. However, having reached a certain level of lithification, a sufficient degree of rigidity will have been achieved to prevent any elastic volume change. Any later change in loading will produce no change in volume and hence pressure. Later, downwarp and sedimentation will produce an increased loading which may produce the following effects:

- Fixed Volume/Fluid Connection: Load transmitted normally, formation remains normally pressured
- Fixed Volume/Zone Sealed/No Temperature Change: Load transmitted to underlying formations in entirety. Formation fluid pressure remains unchanged (i.e. pressure gradient becomes subnormal as depth of burial increases). Underlying shales may therefore become overpressured from transmitted load
- Fixed Volume/Zone Sealed/Temperature Rise: If increased depth of burial is accompanied by a rise in temperature, there will be a total increase in volume due to thermal expansion. Since the coefficient of expansion of a fluid will be greater than that of the matrix, there will be an increase in porosity volume less than that required to accommodate fluid expansion (there may even be a net loss in porosity). Therefore, prevention of further fluid expansion may lead to the formation becoming abnormally pressured. Underlying shales may or may not become overpressured according to their ability to dewater.

Conversely, later uplift and erosion will produce the following effects:

- Fixed Volume/Fluid Connection: Load relieved uniformly, and the formation remains normally pressured
- Fixed Volume/Zone Sealed/No Temperature Change: Removal of loading will produce no change in formation fluid pressure (i.s. the pressure gradient becomes abnormal as depth of burial decreases). Underlying shales amy therefore become subnormally pressured as load is relieved.
- Fixed Volume/Zone Sealed/Temperature Fall: If removal of overlying sediment results in a drop in temperature, there will be a resultant decrease in fluid volume and pressure subnormality

Differential Pressure Across Bottom

Although the marked difference in matrix strength and porosity will result in marked differences between shale and carbonate drill rates (and even between differing carbonates), differential pressure across bottom will remain the controlling influence.

Formation Pore Pressure Indicators

The following section reviews the techniques of pressure detection, and their applicability to carbonates are contrasted with those methods outlined in Chapter 4.

Direct Pressure Measurements

Such measurements are equally applicable to carbonates. The lack of interrelationship between porosity and permeability may result in a variation of results within an apparent uniform section

Seismic Velocity

This method is effective for carbonates. However, extensive knowledge of lithology type, porosity distribution and fluid content is required for accurate determination.

Wireline/MWD Resistivity

This method, which depends upon a change in fluid content in overpressured sections, responds to carbonates in the same way as in shales. However, in argillaceous rocks, the effect is substantially magnified by the change in ionic concentration encountered at a transition zone due to the geochemistry of the clays. This phenomenon will not occur in carbonates; therefore, any response seen will be markedly less than that seen in an equivalently pressured shale section. Furthermore, the variability of porosity and permeability (both in amount and distribution) and the presence of clay minerals in carbonates will lead to extensive data scatter. The consequent difficulty in establishing trend lines has lead to minimal use of this method in carbonate sequences.

It is suggested that resistivity (short normal) or conductivity (induction-type) plots be made on all wells (carbonate or otherwise) as a means of accumulating information which may later prove to have value. Only after sufficient data has been gathered and cross-correlated, will significant events become evident.

Wireline/MWD Porosity Logs

These logs indicate zones of abnormally high porosity which may be overpressured. Results are not so conclusive nor so quantitative as those derived from shale plots.

Shaliness

The Spontaneous Potential curve is not a “Shale Indicator”, its response is determined by the relative salinity difference between the borehole and the formation, and the permeability of the formation. In a simple sand-shale sequence, the S.P. and Gamma Ray curves will therefore agree in their response to the (high potassium/low permeability) shales, the (low potassium/high permeability) clean sands, and the (median potassium/ median permeability) dirty sands.

In carbonate sequences, it is necessary to compare the response of the two curves in order to determine:

- High Potassium/Low Permeability Shale
- Low Potassium/Low Permeability Tight Carbonate
- Low Potassium/High Permeability Permeable Carbonate

Median responses may be similarly interpreted, and this will assist in interpreting the pressure distribution in the section of interest. Carbonates need not be tight in order to be pressured, and they will not necessarily be pressured to the same degree as surrounding shales. For example, an overpressured carbonate may occur within an underpressured shale, or vice-versa.

A further consideration when studying evaporitic carbonates (e.g. Zechstein of the North Sea) is that high gamma ray response may be due to potassium minerals other than clay minerals.

Flowline Temperature

Thermal conductivities in shales are relatively low, in fact they are quite close to those of common pore fluids:

Thermal Coductivity (cal/cm.sec.°C)

- Gas 0.1
- Oil 0.3
- Water 1.4
- Clay 2.4

Therefore, it is not surprising that although a change in geothermal (and hence flowline temperature) gradient is seen with the marked change in porosity in a subcompacted zone, there is little noticeable change with the gradual (comparatively) small decrease in porosity with depth and compaction.

Thermal conductivities in Quatrzose rocks are substantially higher and appear to be functional upon a combination of porosity and clay content, expressed as a percentage of total bulk volume

Thermal conductivities in Quatrzose rocks are substantially higher and

Table 1: Thermal Conductivities of Quartzose Rocks

Quartz (Matrix %)	Clay (Vc %)	Fluid (ϕ %)	Thermal Conductivities (cal/cm. sec. ^oC)
80 - 85	0	15 - 20	6.50
81	4	15	4.05
75	10	15	5.20
74.5	8	17.5	4.90
73.5	6.5	20	4.35
73	11	16	4.35
72	10	18	4.60
71	11	18	3.95
71	10	19	3.80
64	18.5	17.5	4.35
56.5	25	18.5	4.85
56	26.5	17.5	4.15
40	45	15	2.55
40	40	20	2.50
25	56.5	18.5	2.50

Anomalies in the table result from the slight, but significant differences between the thermal conductivities of the differing reservoir fluids and the clay. Furthermore, the distribution of clay (i.e. laminar, structural, dispersed) will affect thermal conductivity. This is because the clay will act both as a surrogate “pore fluid” filling in porosity and as an insulator decreasing grain-to-grain contact in the matrix

It is this comparatively uniform response to porosity and clay content that allows the flowline temperature technique to be used an indicator of both porosity and permeability when potential reservoirs are encountered. It is also responsible foe the importance of assuring that lithological evaluation plays a critical role when interpreting temperature data.

In carbonates, it has been found that the thermal conductivity of the matrix material is so far in excess of that of pore-fill material that porosity is only a factor inasmuch as it affects grain-to-grain contact. The material contained in the pore space, be it fluid or clay, is irrelevant. thermal conductivity of carbonate rocks varies with porosity and is an empirical factor analogous to the "cementation factor" used in log analysis. In effect, this is he degree of cementation (of a particular sediment) or crystallinity (in a crystalline rock). In mixed carbonates and evaporites, thermal conductivity increases linearly with bulk density. Thus thermal conductivity increases as porosity falls or as matrix density increases (from calcite to dolomite). it will be a maximum where anhydrite is also present in significant amounts.

This responsiveness to porosity, magnified by the extreme difference in thermal conductivity between matrix and pore-fill material, results in the flowline temperature producing far greater changes in response to pressure (an hence porosity) anomalies than those seen in clay rocks. Furthermore, formation temperature being pervasive will be little (if at all) affected by porosity distribution. Flowline temperature will therefore not suffer (as do other techniques) as a result of variation in porosity size and distribution within a carbonate. it will respond only to quantitative porosity and lithological character. The latter factor can be estimated visually. However, a far more successful method is autocalcimetry. With the aid of calcimerty, it is possible to quantitatively determine relative amounts of differing carbonates and noncarbonates.

The combination of these two data sources will lead to sensitive determination of carbonate zones of abnormal permeability, which may be overpressured. It also gives rise to he possibility that, given further study, the method may have quantitative value in the determination of formation porosities and pressures in carbonates.

Rate of Penetration

There is no theoretical reason why those methods that normalize drill rates would fail to work in carbonate sections, as long as a normally pressured carbonate trend is sufficiently established. Any practical limitations to its use are the results of changes in "drillability", which may be described as matrix strength, porosity and tooth efficiency

Matrix Strength

This factor is of course related to the empirical "cementation/crystallinity" factor discussed above (see Flowline Temperature). Because of this, it is important to remember that differing carbonates will produce characteristic drilling rates showing as much difference as those between a sandstone and a shale. It is important therefore in establishing trend lines such that different carbonates be considered as different lithologies, with different trend lines.

It is unfortunate that a pressure abnormality with its accompanying porosity change may result in or accompany a modification in this “cementation/crystallinity” factor. On the other hand, the pressure abnormality itself may be the result of recrystallization. In this case, qualitative determination of formation pressure gradient may prove difficult or even impossible. In such a situation it will be necessary to derive empirical lithology factors in order to compensate for matrix strength variations

Porosity

Porosity will of course affect drill rates, and so long as it is matrix-defined and compaction controlled, it will accompany matrix strength.

However, in carbonates, porosity is commonly not matrix-defined. Furthermore, porosity and compaction (or more correctly lithification) are not so much depth-controlled as they are age-controlled. Because of these factors, it is common to encounter in carbonate successions sudden changes in porosity type, size and distribution, leading to equally sudden changes in the rate of penetration. This of course, requires the establishment of a new trend line. Secondly, the randomness of distribution, size and type of carbonate porosity leads to considerable fluctuation of drilling rates, even in lithologically uniform formations. Recognition an placement of trend lines is thus more difficult than in more homogeneous lithologies.

Tooth Efficiency

When drilled with milled tooth bits, carbonates can cause serious loss in tooth efficiency. This may be due to a sudden early loss due to tooth breakage in hard crystalline carbonates. More importantly may be the continuous, almost linear, efficiency loss due to abrasion from the cuttings and formation. This leads to a greater-than-expected decline in the drill rate (and hence increases in Dxc) with depth on a bit run. A new bit will, of course, commence at a rate of penetration in excess of that at the end of the previous bit run, and this will decline as did that of the previous bit. The Dxc will develop a “saw-tooth” character, the initial and (if bits are run consistently) final values for each run, defining two parallel normal trend lines. With the aid of this and the pattern of previous drilling, it should be possible to estimate bit efficiency (and expected Dxc) at any point and to judge whether an expected pattern is being followed or if an abnormality is being indicated by the Dxc when it falls below its anticipated value.

Attempting to do this while dealing with other variations (previously discussed) is extremely difficult. In addition, remember that dull bits are generally unresponsive, thus adding to the difficulties in this type of situation. When such abrasive or hard conditions are expected, it is now common practice to run insert or diamond bits, sometimes with downhole motors. With these bits, tooth wear, other than by loss or breakage, will be minor and can safely be ignored during the bulk of a bit run. Due to he difference in drilling mechanisms, Dxc trends from these bits will be offset from those of milled-tooth bits.

Certain misconceptions should be discarded:

- Insert bits always drill more slowly than milled-tooth bits: WRONG. Depending upon lithology and bit selection, insert bits drill as fact, if not faster than the equivalent milled-tooth bit.
- Dxc's for insert and fixed-cutter bits should be corrected by subtracting 1-inch from the bit diameter: WRONG. This is an exercise that has been disproved, which results in the calculation of a number which is not a Dxc. It may or may not have worked in the past, but will definitely not work for modern insert and fixed cutter bits. Any correction which may be necessary is achieved by simply shifting the trend line to align with the data from the bit in question.
- The Dxc cannot be used with a fixed cutter bit/downhole motor combination (turbine/PDM): WRONG. Since a fixed cutter bit is simply a scraping tool, the rate of penetration will be more or less linear with the rotary speed.

Bulk Density

Like all other porosity tools, bulk density (in combination with calcimetry) will work well in carbonates. In fact, the normally good condition of carbonate cuttings will result in more consistent data with less secondary scatter (i.e. hydration efects).

Geological Markers

In addition to those markers for clastics, one may expect pressure abnormalities in carbonates at points in the section where relative positional changes, erosion or interruption in sedimentation have occurred (i.e. faults, unconformities, etc.).

Borehole and Cuttings Condition

All of the factors resulting from an underbalanced condition apply equally to carbonates, with the following modifications:

- If a carbonate has permeability, it will of course kick. If it does not have permeability, it may cave. However, the greater matrix strength of the carbonate may decrease the degree of caving, and hard crystalline carbonates may not cave at all, even though they are substantially underbalanced.
- A kick may be more difficult to anticipate in a carbonate since a change in effective porosity (and hence permeability) may occur

without a change in absolute porosity, and perhaps little or no change in the rate of penetration.

Geochemical Methods

Geochemical phenomena which occur as a consequence of the mineralogy of clays cannot be expected to occur in carbonates. However, any pressure seal can be expected to prevent migration of ions as well as fluids. Thus two methods which are worthy of further study are Flowline Conductivity and Bicarbonate Ion Concentration.

Conclusion

In a study of pressures in carbonates, it is inevitable that more questions arise than answers. However, the following conclusions are drawn:

- Pressure detection can be carried out in carbonate sections.
- Under certain circumstances, some parameters may work as well in carbonates as in clays/shales. Flowline Temperature may work better in carbonates.
- Confidence levels would be set considerable lower in both qualitative and quantitative work.
- The key to a good pressure evaluation in carbonates is complete and rigorous lithological classification using visual techniques and calcimetry.
- All data-gathering systems, regardless of their present usefulness, should be applied in order to supply information for further study.

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Glossary of Terms

Abnormal Pore Pressure: Pressure contained within a pore system that is in excess of the normal hydrostatic pore pressure. General usage is limited to description of excess pressure (see Subnormal pore pressure).

Allochthon: A mass of rocks that has been moved from its site of origin by tectonic forces, as in a thrust sheet or nappe; i.e., of foreign origin, or introduced.

Annular Pressure Loss: That pressure which is necessary to overcome the frictional forces between the annulus, drilling assembly and drilling fluid.

Aquathermal Pressure: A term proposed by Barker (1972), describing a hypothetical geopressure mechanism. If pore volume remains constant with burial and temperature increase, the thermal expansion of water (being approximately 300 times that of typical sedimentary minerals) can cause extremely rapid pore pressure increase. Water density, by definition, must remain constant.

Aquifer: A body of rock that contains sufficient saturated permeable material to conduct groundwater and to yield significant quantities of groundwater to wells and springs.

Blowout: Loss of control of a well due to an uncontrolled kick.

Bulk Density: The weight of an object (i.e. drill cuttings) divided by its volume, including the volume of its pore spaces. The general units of measurement is g/cc. This can be determined at the wellsite using a mud cup. Similar information can be obtained from MWD or wireline density logs.

Cap Rock: Originally defined to describe that rock overlying the top of a salt body, composed of anhydrite and gypsum, with minor calcite and sulfur, resulting from accumulation of the less soluble minerals of the salt body during leaching of its top. The term was used in pressure evaluation to provide an explanation for entrapment of pore waters during burial, providing a seal, thus allowing pore pressure to increase. It has been found that cap rocks are the exception rather than the rule: examination of the principles involved will show that, for a cap rock to form, a geopressure must have existed previously and undergone leakage in order to precipitate minerals above the anomaly.

Casing Seat: The setting depth for a string of casing. It is determined using geological and pressure-related information.

Cation Exchange Capacity (C.E.C.): A measure of the total amount of exchange cations of a mineral. Exchange sites are most prolific in clay minerals, particularly the smectite group. Actual cation exchange capacity varies with particle size and with the nature of the cation.

Compaction Disequilibrium: Synonymous with subcompaction is a process by which the delicate balance between rate of sedimentation, burial, porosity reductions and expulsion of pore fluids become upset by a change in any of the contributing factors, resulting in a pore pressure increase. Overall, a pressure increase is caused by the effective decrease in dewatering efficiency.

Degraded Illite: Illite that has had much of its potassium removed from the interlayer position as a result of leaching.

Diapirism: The process of rupturing domed or uplifted rocks by plastic core material, caused by the effect of geostatic load or large density differences.

Differential Pressure: At any point in the wellbore, whether the mud is circulating or static, it is the difference between the pore pressure and the pressure exerted by the mud column. Overbalance occurs when the mud pressure is greater than the pore pressure, and underbalance occurs when the mud pressure is less than the pore pressure.

Drillability: Describes the interaction between a particular bit in a particular lithology. Thus, when the correct bit is used for a particular lithology, rate of penetration is proportional to drillability.

Driller’s Method: A kick control method, using two circulations to kill the well. The first circulation circulates the kicking fluid from the wellbore, while the second circulation fills the well with kill mud.

Drilling Exponents: Methods used to normalize the drill rate in order to determine the pore pressure of the formations being drilled. Early drilling exponents took into account the basic drilling parameters. Second generation exponents take into account bit wear and formation characteristics.

Effective Circulating Density (ECD): ECD is the combination of the hydrostatic pressure of the mud in a static condition, plus the fractional forces caused by mud moving up the annulus: the annular pressure loss. Converting the sum of the pressures to a gradient gives the total effective mud density (EMD) at TD.

Effective Overburden Pressure (σ_1’): The difference between the total overburden pressure and the pore pressure at any particular point in the formation is the effective overburden pressure. It is a stress that acts vertically downwards. It is this stress that is largely responsible for compaction. Effective overburden pressure is also referred to as matrix stress, rock-grain stress, and rock-skeleton stress.

Effective Permeability: The observed permeability of a porous medium to one fluid phase which is under conditions of physical interaction (i.e., friction, surface tension) with another fluid phase present in the same pore system.

Effective Stress (σ'): Any principle stress, tensional or compressive, minus the pore pressure.

Elastic: Describe the ability of a material to return to its original shape and dimensions when the deforming forces are removed.

Electro-Osmosis: The motion of a liquid through a membrane under the influence of an applied electric field.

Engineer's Method: A kick control method, using one circulation to kill the well. This method produces the least amount of stress on the borehole. Also known as the Wait & Weight Method

Equivalent Mud Density (EQMW): A convenient reference by which any downhole or subsurface pressure, when converted to a gradient referenced to the flowline, describes the equivalent mud density that would produce that particular pressure at that particular depth.

Failure Envelope: An envelope of a series of Mohr circles, the locus of points whose coordinates on a differential stress/shear plot represent the stresses causing failure. Failure envelope is synonymous with Mohr envelope and rupture envelope.

Finite Strain: The total amount of strain (deformation) recorded by a particular structure, irrespective of episodic deformational events.

Formation Balance Gradient (FBG): The formation pore pressure gradient at a particular point referenced to the flowline. Because of the air gap and water depth, the FBG offshore is always less than the actual pore pressure gradient, becoming asymptotic at depth.

Formation-Volume Factor: The volume of a liquid at reservoir conditions divided by the volume at surface conditions.

Fracture Pressure: Is the pressure in the borehole at which whole mud is injected into the formation due to the initiation and extension of natural and pressure-induced fractures.

Gas Hydrate: Solid inclusion compounds in which the gas molecules are contained within a crystalline (ice like) framework of water molecules. The most common gas hydrate is methane.

Geopressure: A term introduced by Stuart, describing any porous formation in which the pore pressure is in excess of the normal hydrostatic pressure (see Abnormal Pore Pressure).

Geothermal Gradient: The rate of increase of temperature within the Earth with depth. The gradient will differ from place to place based upon the heat flow within the region and the thermal conductivities of the rocks and fluids.

Hydraulic Conductivity: The rate of flow of water through unit cross-sectional area under unit hydraulic gradient at the prevailing temperature. Synonymous with permeability coefficient.

Hydrostatic Pressure: The pressure exerted by the water (fluid) at any given point in a body of water (fluid) at rest. The hydrostatic pressure of groundwater is generally due to the density of the water and the vertical height of the water column.

Illite: A general name for a group of three-layer, mica-like clay minerals which are intermediate in composition and structure between muscovite and montmorillonite, and which have 10-angstrom c-axis spacings that show essentially no lattice expanding characteristics. Illite contains less potassium and more water than true micas.

Interval Transit Time (Δt): The reciprocal of sonic compressional wave velocity over a fixed distance, measured in micro-seconds per foot**.**

Ionic Filtration: A process of concentrating ions on one side of a semipermeable membrane as fluid passes through the membrane. The efficiency of the membrane in restricting ions or certain ions is a function of clay mineralogy, pore geometry, porosity, etc.

Isotropic: Describing a medium, the properties of which are the same in all directions.

Kick: An unexpected influx of formation fluids into the borehole that displaces drilling fluid and is noticed at the surface. It may be controlled by closing the blowout preventers.

Kick Tolerance: Estimated as the maximum pressure or the mud density that the weakest part of the borehole (formation, casing or surface equipment) can withstand in the event that a kick is taken.

Laminar Flow: Fluid flow in which the streamlines remain distinct and in which the flow direction at every point remains unchanged with time.

Leak-Off Test: A pressure test made at the casing seat to determine the “actual” fracture pressure of the formation. The well is shut-in and small amounts of drilling fluid is pumped into the borehole resulting in a pressure increase. The pressure which causes crack propagation is converted into an EQMW.

Matrix Stress: Synonymous with effective overburden stress or pressure.

Measurement-While-Drilling (MWD): Specialized downhole tools which measure certain formation and borehole parameters. Usually divided into two groups; Directional (D) MWD and Formation Evaluation (FE) MWD.

Montmorillonite: A member of the smectite group of swelling clays. Montmorillonite is a subgroup of expanding lattice clay minerals characterized by a three-layer crystal lattice, by deficiencies in charge in the tetrahedral and octahedral positions balanced by cations subject to exchange, and by swelling or wetting due to the adsorption of considerable interlayer water. Montmorillonites are the chief constituents of bentonite. In some terminology, montmorillonite and smectite are synonymous.

Montmorillonite Dehydration: A hypothetical geopressure-generating mechanism (initiated by temperature) that involves the release of structured monomolecular hydrogen-bonded water from montmorillonite interlayer sites to the pores, resulting in a net expansion of the water as it undergoes the phase change. Experimental evidence has shown that structured water has slightly higher density than normal water so that, upon desorption, the released water expands - resulting in pressure increase in the closed pore system.

Mylonitization: Deformation of a rock by extreme micro-brecciation without chemical reconstitution of the granulated minerals. Characteristic appearance is flinty, banded or streaked, and may contain undestroyed augen of the parent rock in a granulated matrix.

Normal Fault: A fault in which the hanging wall appears to have moved downward relative to the footwall. These are usually tensional faults with angles between 45 and 90 degrees.

Normal Formation Balance Gradient (N.FBG): The normal pore pressure gradient referenced to the flowline.

Osmosis: The spontaneous movement of water through a semipermeable membrane which separates two solutions of different concentrations, until the concentration of each solution becomes equal.

Overburden Pressure (S): The total vertical stress exerted by the weight of the overlying rocks and their contained fluids.

Permeability: A measure of the relative ease of fluid flow under unequal pressure; normal unit of measurement is the millidarcy (md).

Piezometric (Potentiometric) Surface: An imaginary surface representing the static head of groundwater and defined by the level to which water will rise in a well. The water table is a particular potentiometric surface.

Pingo: An overpressure condition which forms in permafrost areas. It occurs when unfrozen ground (taliks) are surrounded by frozen ground. When the talik begins to freeze, the pressure will cause the expanding water to uplift a permafrost bridge.

Poisson's Ratio (μ or υ): The ratio of the lateral unit strain to the longitudinal strain in a body that has been stressed longitudinally within its elastic limit.

Pore Pressure: The pressure within a formation caused by the fluids within the pore spaces.

Porosity (φ): The percentage of bulk volume of a rock that is occupied by interstices, whether isolated or connected.

Pressure Potential: In an aquifer, the rate of change of pressure head per unit of distance of flow at a given point and in a given direction. Synonymous with hydraulic gradient, hydraulic potential.

Pressure Readers: Clear plastic overlays used to determine pressure trends. They use a pressure parameter (Dxc, conductivity, travel time, etc.) versus depth to determine formation pressure.

Pseudotachylite: A dense rock produced in the compression and shear conditions associated with intense and extensive fault movements, involving extreme mylonitization and partial melting. Frictional melting occurs when water is absent, and the expansion upon the phase change allows the resultant glass to be intrusive.

Reverse Fault: A fault in which the hanging wall appears to have moved upwards relative to the footwall. These are usually compressional faults with angles generally greater than 45 degrees.

Semipermeable Membrane: A membrane that is partially but not freely or wholly permeable to particular solutions.

Shale Density: A measurement of clay or shale to assess its density with depth. It is based on the principle that the density of shale in an under-compacted zone will increase less rapidly than in a "normally pressured" environment.

Shale Factor: A measurement of the cation-exchange-capacity (CEC) of shale cuttings. It is based on the principle of decreasing smectite-type clays with depth.

Smectite: A clay group containing the minerals montmorillonite, beidellite, nontronite, saponite, hectorite and sauconite. All are swelling clay minerals.

Subcompaction: See compaction disequilibrium.

Subnormal Pore Pressure: That pressure contained within a pore system that is less than normal hydrostatic pore pressure.

Tectonic Stress: An additional applied stress, independent of gravity stresses, that is responsible ultimately for producing tectonic deformation structures.

Thrust Fault: A fault with a dip of 45° or less over much of its extent, on which the hanging wall appears to have moved upward relative to the footwall. Horizontal compression rather than vertical displacement is its characteristic feature.

Transition Zone: The interval over which the normal pressure gradient increases from hydrostatic to “abnormal” pressure. It is generally the result of the abnormal pressure “leaking” into less pressured formations.

Undercompacted: Compaction of sedimentary rock less than that normal for the existing overburden pressure. Synonymous with underconsolidation. Refer to compaction disequilibrium.

Weight: The force produced by the action of gravity on a mass.

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Formulae

Related Pressure Equations

Formation Volume Factor $B = (1 - dV_{wp}) \times (1 + dVwt)$

Darcy's Law for Permeability (Darcy) $K = \left(\frac{q \times \mu \times L}{(A \times \Delta P)}\right)$

Interval Transit Time (μsec/ft) $\Delta t = \frac{10^6}{V}$

Annular Pressure Loss (psi) $P_{LA} = \frac{L \times YP}{A \times (ID - OD)} + \frac{PV \times L \times V}{B \times (ID - OD)^2}$

Velocity (ft/min) $V = \frac{24.51 \times Q}{(ID^2 - OD^2)}$

Temperature Gradient (°C/100 ft) $G = 100\left(\frac{T_{F2} - T_{F1}}{D_2 - D_1}\right)$

Mud Resistivity (ohm-meters) $R = \frac{1000}{C}$

Sonic Log Porosity (fractional) $\phi = \frac{\Delta t_{\log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$

Density Log Porosity (fractional) $\phi = \frac{\rho_{ma} - \rho_{\log}}{\rho_{ma} - \rho_f}$

General Pressure Equations

Hydrostatic Pressure (psi) $P = 0.0519 \times MW \times TVD$

Hydrostatic Pressure (kPa) $P = 0.0098 \times MW \times TVD$

Bottomhole Circulating Pressure (psi) $BHCP = ECD \times 0.0519 \times TVD$

Equivalent Circulating Density (lb/gal) $ECD = MW + \dfrac{\sum P_{LA}}{0.0519 \times TVD}$

Differential Pressure (psi)

$$\Delta P = (MW \times TVD \times 0.0519) - (FBG \times TVD \times 0.0519)$$

Overburden

Log Derived Bulk Density (g/cc) $\rho_b = \phi\rho_f + (1 - \phi)\rho_{ma}$

Bulk Density from Sonic Log (g/cc) $\rho_b = 2.75 - 2.11\left(\dfrac{\Delta t_{\log} - 47}{\Delta t_{\log} + 200}\right)$

Bulk Density from Cuttings (g/cc) $\rho_b = \dfrac{8.34}{16.68 - W_2}$

Overburden Pressure (psi) $S = 0.433 \times \rho b_{avg} \times D_{int}$

Overburden Gradient (psi/ft) $OBG = \dfrac{\sum (0.433 \times \rho b_{avg} \times D_{int})}{\sum D_{int}}$

Effective Overburden (psi) $\sigma'_1 = S - P$

Pore Pressure

Corected Drilling Exponent

$$Dxc = \frac{\log\left(\frac{R}{60N}\right)}{\log\left(\frac{12W}{10^6 B}\right)} \times \frac{NFBG}{ECD}$$

Dxc (metric)

$$Dxc = \frac{\log\left(\frac{R}{18.29N}\right)}{\log\left(\frac{W}{14.88B}\right)} \times \frac{NFBG}{ECD}$$

Pore Pressure (lb/gal)

$$P_o = P_n \times \frac{Dxc_n}{Dxc_o}$$

Equivalent Depth Method

$$P_o = (OBG_a \times D_a) - D_n(OBG_n - NFBG)$$

Fracture Pressure

Hubbert & Willis (psi/ft)

$$P_F = \left(\frac{S-P}{3}\right) + P$$

Matthews & Kelly (psi)

$$P_F = (Ki \times \sigma) + P$$

Eaton (psi/ft)

$$P_F = (S-P)\left(\frac{\mu}{1-\mu}\right) + P$$

Daines (psi)

$$P_F = \sigma_t + \left[(S-P)\left(\frac{\mu}{1-\mu}\right)\right] + P$$

Kick Tolerance

Maximum Shut-In Casing Pressure (psi)

$$SICP_{max} = (FG_{min} - MW) \times 0.0519 \times D_f$$

Kick Tolerance (lb/gal) $K_{tol} = \left[\left(\frac{D_f}{D_b}\right)(FG_{min} - MW)\right] + MW$

Minimum Kick Tolerance (lb/gal)

$$K_{min} = \left\{\left[\left(\frac{D_f}{D_b}\right)(FG_{min} - MW)\right] - \left[\left(\frac{L_k}{D_b}\right)(MW - W_k)\right]\right\} + MW$$

Well Control

Formation Pressure (psi) $F_p = SIDP + (MW \times 0.0519 \times TVD)$

Kill Mud Density (lb/gal) $K_{MW} = \frac{SIDP + SF}{0.0519 \times TVD} + MW$

Initial Circulating Pressure (psi) $ICP = SPL + SIDP$

Final Circulating Pressure (psi) $FCP = SPL \times \frac{K_{MW}}{MW}$

Length of Kick Around Collars (ft) $L_K = \frac{Vol_K}{(ID^2 - OD^2) \times 0.000971}$

Length of Kick Around Collars and Pipe (ft)

$$L_K = C_L + \left(\frac{Vol_K - AnnVol_C}{(ID^2 - OD^2) \times 0.000971}\right)$$

Density of Influx (lb/gal) $$D_K = MW - \left(\frac{SICP - SIDP}{L_K \times 0.0519}\right)$$

Gas Bubble Migration Rate (psi/hr) $$G_R = \frac{\Delta P}{0.0519 \times MW}$$

Barite Required (sk/100 bbls mud) $$Ba = 1490 \times \left(\frac{K_{MW} - MW}{35.8 - K_{MW}}\right)$$

Eaton's Method of Pore Pressure Evaluation

Normal Trend Values

Sonic Travel Time $$\Delta t_n = \Delta t_o \left(\frac{S - P_o}{S - P_n}\right)^{0.333}$$

Resistivity $$R_n = R_o \left(\frac{S - P_o}{S - P_n}\right)^{-0.833}$$

Conductivity $$C_n = C_o \left(\frac{S - P_o}{S - P_n}\right)^{0.833}$$

Dxc $$Dxc_n = Dxc_o \left(\frac{S - P_o}{S - P_n}\right)^{-0.833}$$

Determination of Isodensity Lines

Sonic Travel Time $$\Delta t_o = \Delta t_n \left(\frac{S - P_o}{S - P_n}\right)^{-0.333}$$

Resistivity $$R_o = R_n \left(\frac{S - P_o}{S - P_n}\right)^{0.833}$$

Conductivity $$C_o = C_n \left(\frac{S - P_o}{S - P_n}\right)^{-0.833}$$

Dxc

$$Dxc_o = Dxc_n\left(\frac{S-P_o}{S-P_n}\right)^{0.833}$$

Pore Pressure Calculation

Sonic Travel Time

$$P_o = S-\left[(S-P_n)\left(\frac{\Delta t_n}{\Delta t_o}\right)^{3.0}\right]$$

Resistivity

$$P_o = S-\left[(S-P_n)\left(\frac{R_o}{R_n}\right)^{1.2}\right]$$

Conductivity

$$P_o = S-\left[(S-P_n)\left(\frac{C_n}{C_o}\right)^{1.2}\right]$$

Dxc

$$P_o = S-\left[(S-P_n)\left(\frac{Dxc_o}{Dxc_n}\right)^{1.2}\right]$$

Rw Determination Using The SP

One relatively easy and accurate method for determining Rw is from the use of the Spontaneous Potential (SP). When values are taken from the SP curve across various water-bearing permeable zones, it is possible to define the density of the pore waters by using simple formulas and conversion charts.

Since many of the pressure evaluation methods require the use of a “normal” trend, determining the value of that normal trend should be the first exercise in pressure evaluation. Rw data is invaluable for providing information on trend data and precise normal hydrostatic gradients.

The procedure for determining fluid density from wireline log data is:

Establish the Shale Baseline

Establishing the shale baseline on the SP curve is necessary in order to select shale formations from the permeable sands. During the logging run, the logging engineer will try to place the shale baseline on the second division in Track 1, or as close as possible to that second division.

Draw a line on the curve connecting the shale points. This will provide a starting point for determining the SP value in the sand zones. **The SP value is read from the shale baseline, not the track baseline.**

Correct the SP for Bed Thickness

Once the shale baseline is drawn, the SP value is determined. This is accomplished by counting the divisions in Track 1 from the shale baseline to the SP curve (to maximum constant deflection). The log header will provide the amount, in millivolts, that each division represents (the scale will generally be 20 mV, with negative values going from right to left).

Make sure that SP values are read from water-wet zones only. Using the resistivity curves in Track 2 will help. Sand zones with very low ressitivities (high conductivities) will generally be water-wet.

If the SP curve comes to a point (as opposed to having a blocky appearance), it will have to be corrected for bed thickness.

Bed boundaries from the SP are taken from points of maximum inflection on the top and bottom of the bed. If the bed is less than 30 feet thick or if the SP curve is pointed, it will require correction.

For correction, you will need the Ri/Rm ratio. The Ri value to taken from the shallow reading resistivity device (short normal, SFL, LL8, etc.) and the Rm is the mud resistivity (temperature corrected).

Bed thickness and the Ri/Rm ratio are used on the logging companies correction chart, an example is chart C-2.

Determine Formation Temperature

To determine the formation temperature of the zones of interest, you will need the surface temperature (Ts), bottom hole temperature (BHT), total depth (TD) and the depth of the zones of interest. This information is obtained from the log header.

Geothermal gradient can be determined using the logging company charts or using the standard linear regression equation:

$$y = mx + b$$

where: y = formation temperature

m = slope (geothermal gradient)

x = depth

b = constant (surface temperature)

The geothermal gradient is first determined by rearranging the formula to solve for m:

$$m = (BHT - Ts) / TD$$

The gradient (ºF/ft) is then used in the formula to determine formation temperature:

$$y = (^{o}F/ft \times TD) + Ts$$

Correct Rmf and Rm to Formation Temperature

Since the first few inches of formation adjacent to the borehole will usually be flushed with drilling fluid filtrate, its resistivity (Rmf) must be corrected to formation temperature. The drilling fluid’s resistivity (Rm) at formation temperature must also be determined, in case the SP value must be corrected. The Rm and Rmf values, at surface temperature, are obtained from the log header.

These values can be corrected using a logging company correction chart or by using the Arps formula. An example can be seen on chart C-3.

Rw Equivalent

Once all known fluid-related resistivities have been corrected to formation temperature and the SP value is determined, the Rw equivalent, or Rweq, is determined. It involves using the SP value at formation temperature to obtain the Rmf/Rweq ratio. This is done using logging company charts, as shown in C-5.

When the Rmf/Rweq ratio is found, the Rweq is determined by dividing the Rmf by the Rmf/Rweq ratio.

A mathematical relationship can also be used:

$$Rweq = Rmf \times \text{antilog}\,(SP/K)$$

where: $K = 60 + [0.133(Tf)]$

Water Resistivity to NaCl Equivalent

Once Rweq is found, it is converted to Rw, using a logging company chart. An example being chart C-4.

The Rw value is converted to NaCl ppm equivalents using another logging company chart very similar to C-3.

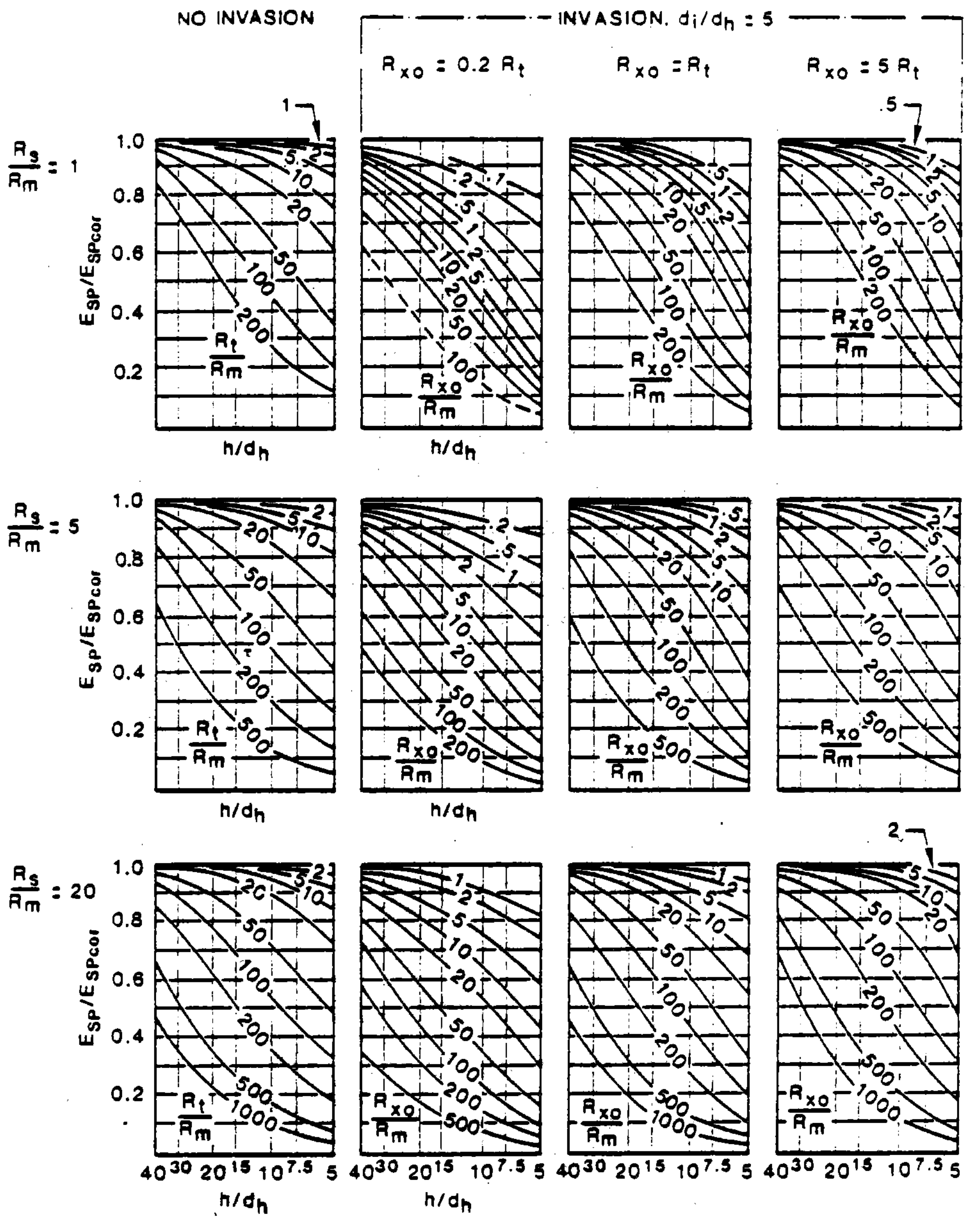
Fluid Density

The parts-per-million (ppm) NaCl equivalent is converted into a fluid density (lb/gal) and pressure gradient (psi/ft) using Figure 3-5.

Other Sources of Rw Information

As mentioned earlier, the Rw information is used to determine the fluid density and hence the value of the normal hydrostatic pressure (normal trend line). If SP data is not available or cannot be used to calculate an accurate value of Rw, water resistivity data can also be derived from a number of other sources:

- Direct resistivity measurement of a formation water sample
- Catalogues of regional water resistivity data
- Calculated from water zone test data
- Conversion from water analysis



1. SELECT ROW OF CHART FOR MOST APPROPRIATE VALUE OF R_s/R_m.
2. SELECT CHART FOR NO INVASION OR FOR INVASION OF d_i/d_h = 5, AS MORE APPROPRIATE.
3. ENTER ABSCISSA WITH VALUE OF h/d_h (RATIO OF BED THICKNESS TO HOLE DIAMETER).
4. GO VERTICALLY UP TO CURVE FOR APPROPRIATE R_t/R_m (FOR NO INVASION) OR R_{xo}/R_m (FOR INVADED CASES), INTERPOLATING BETWEEN CURVES IF NECESSARY.
5. READ E_{SP}/E_{SPcor} IN ORDINATE SCALE. CALCULATE $E_{SPcor} = E_{SP}/(E_{SPcor})$. E_{SP} IS SP FROM LOG.

156-100

Figure C-1: SP Correction Charts (for representative cases)

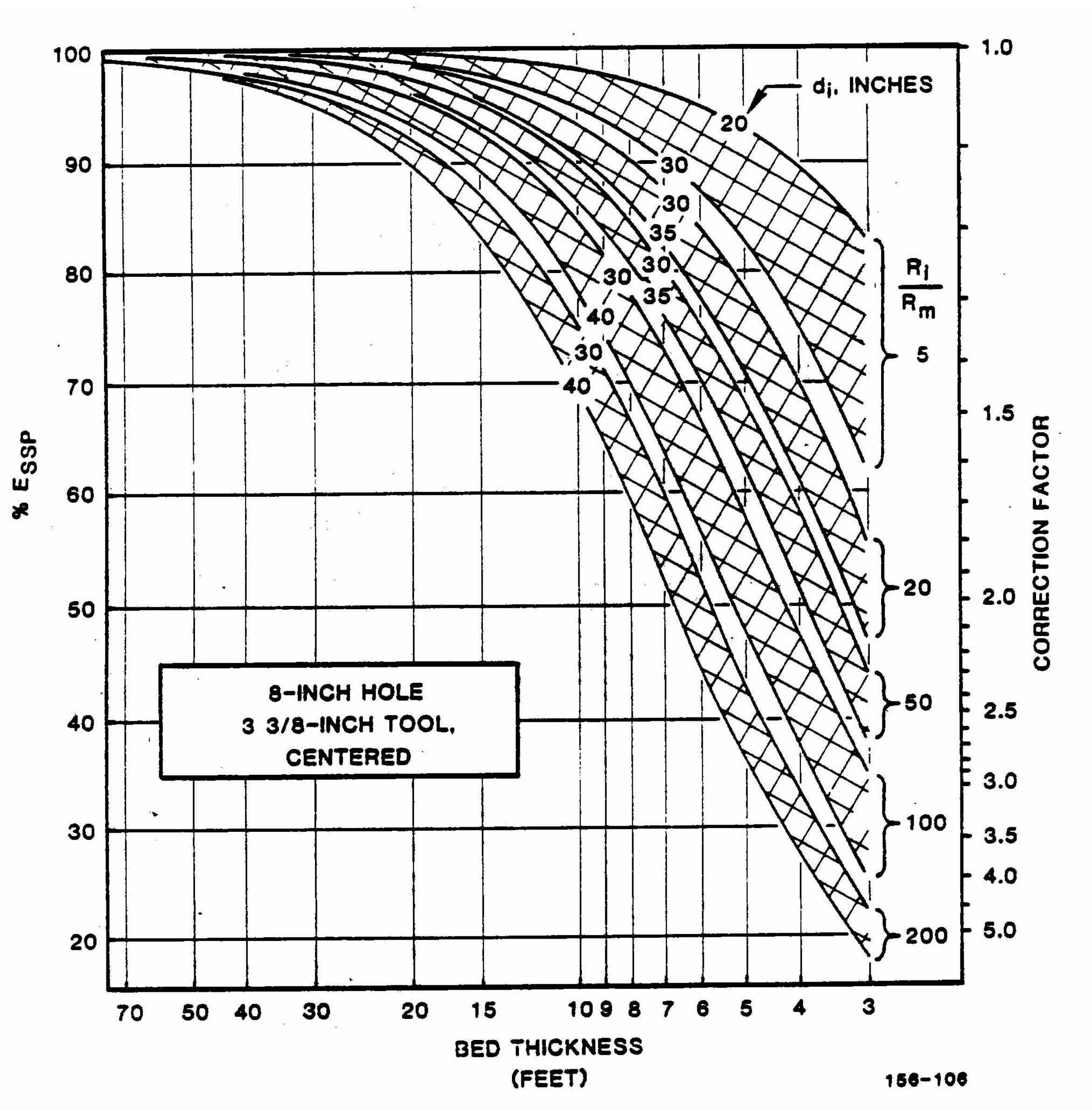


Figure C-2: SP Correction Chart (empirical)

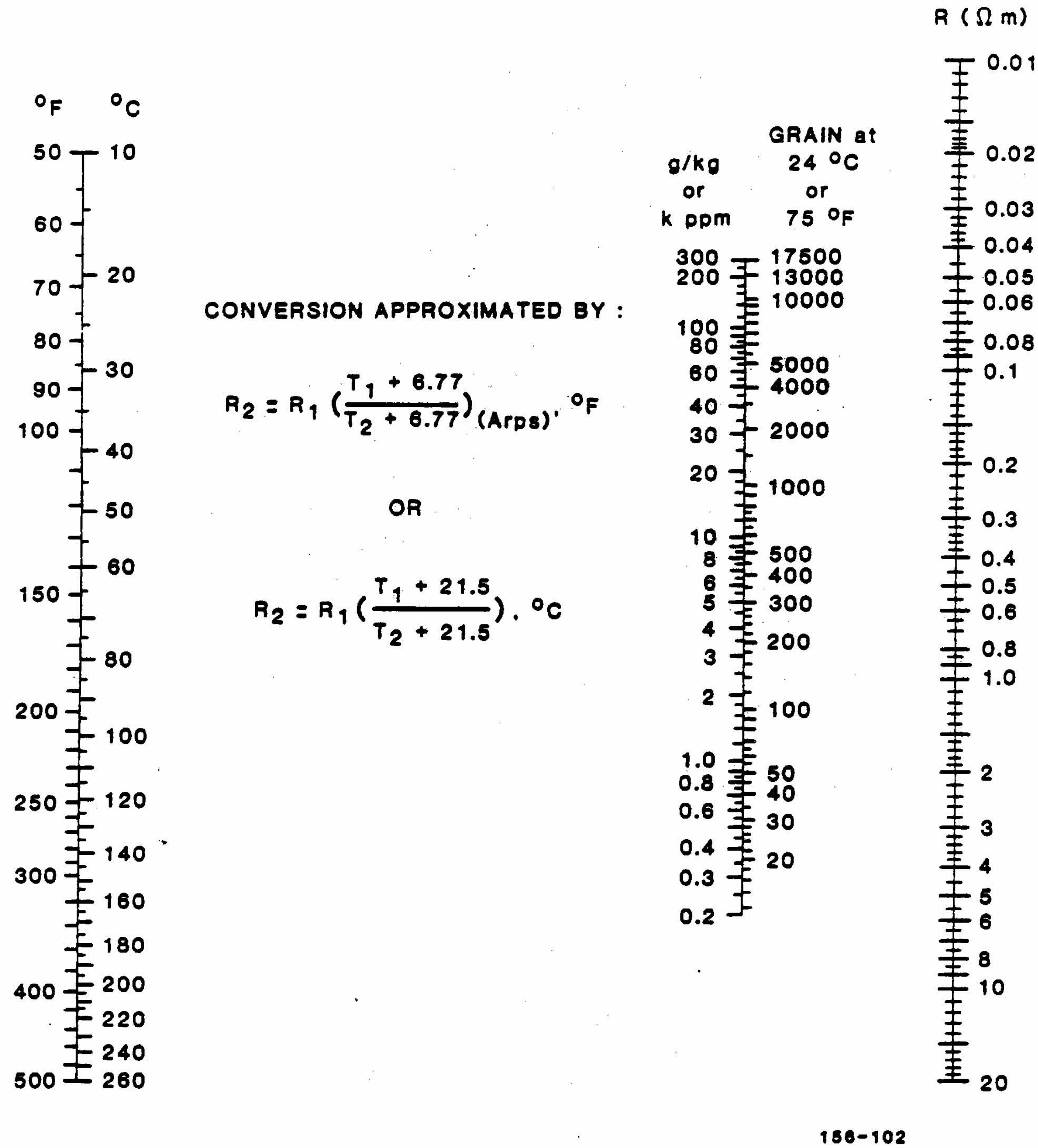


Figure C-3: Resistivity nomograph for NaCl solutions

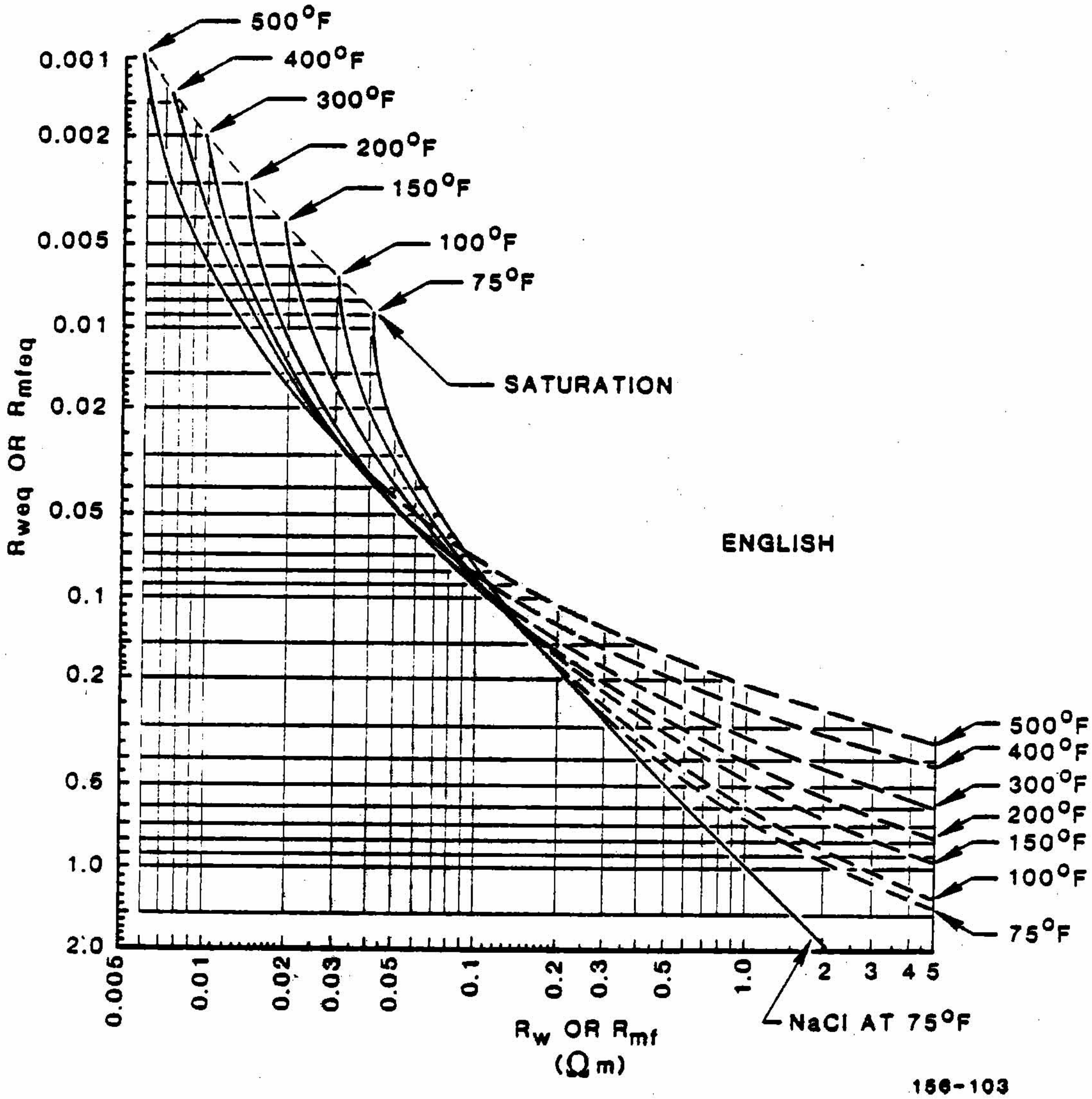


Figure C-4: Rw versus Rweq at formation temperature

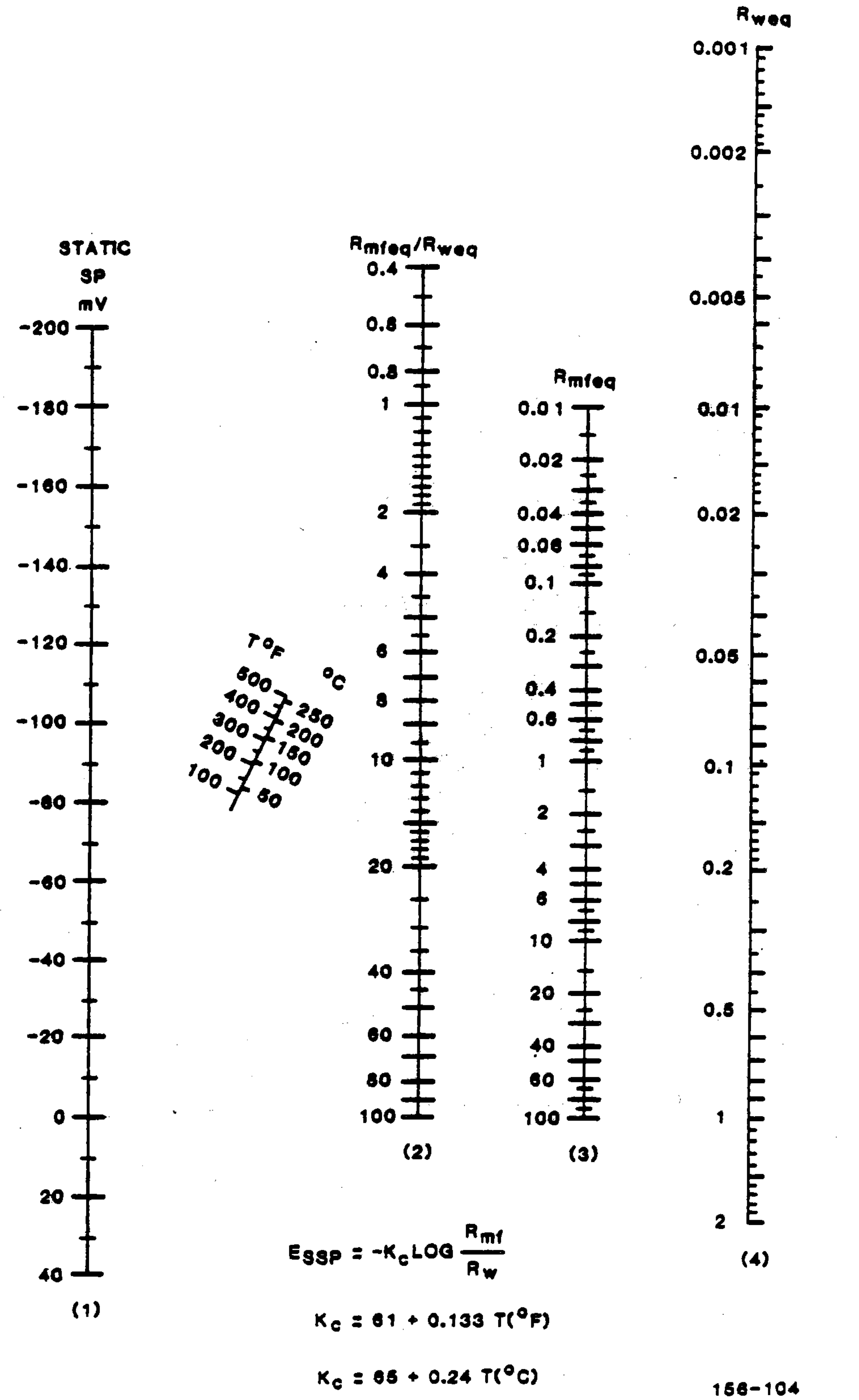


Figure C-5: Rweq determination from the SP (clean formations)

MWD & Eaton's Method

Several of the more accepted methods of pore pressure evaluation are those developed by Dr. Ben Eaton. Using several readily available parameters, Eaton's methods incorporate easy to use formulas, and have been shown to be applicable to most world-wide oil fields.

One of Eaton's pore pressure evaluation methods requires formation resistivity, which can be determined by both wireline and MWD services. Using MWD resistivity, pore pressure can be determined as soon as the information can be pulsed to the surface. To use this method several specific tasks must be performed. These tasks include:

- Determine a variable overburden pressure (S)
- Select "good" shale resistivity values from the MWD log
- Plot the shale resistivity value vs TVD on semi-log graph paper
- Establish the correct position of the "normal" trend line
- Calculate pore pressure at the depth of interest

Overburden Pressure

In most pore pressure equations, overburden pressure must be determined before any pressure calculations can begin. The bulk density data used in constructing the overburden pressure curve can be obtained from:

- Regional Tables
- Drill Cuttings
- MWD or Wireline Density Logs
- Calculated from Sonic Log Data

As mentioned in Chapter 3, once the bulk density of the rock, for a specified interval, has been determined the overburden pressure can be calculated from:

$$\mathbf{S = 0.433 \times \rho b \times Depth\ Interval}$$

Regional Overburden Tables

It is often the case that quantitative overburden values are hampered by the lack of current or offset well data. As a temporary aid to assist in such situations, regional overburden tables are generally available that have been constructed for various areas, and can be used as a starting point until well data is available.

Several such curves can be found in GeoPress.

Even though these regional tables will yield good approximations, they must be used with a bit of discretion.

Many regional tables have one thing in common, they do not include a water depth. Therefore, before they can be used offshore, adjustments must be made in the data to include the effects of water depth, water density, and the rigs air gap.

Drill Cuttings

Bulk density from drill cuttings can be determined using several techniques (these are detailed in Chapter 3). Regardless of the method, it must be stressed that whenever drill cuttings are used, there must be consistency in the method and the manner of cuttings preparation.

Drilling fluid type, cavings, and collection frequency will also affect the values derived from this analysis method.

Whichever method is used, consistency is the key.

Density Logs

MWD and wireline density logs contain bulk density data that can be read directly from the log and used in overburden calculations. Though some caution is advised (i.e. washouts, mixed lithologies, etc.), density log data is much superior to drill cuttings data or sonic log data.

Unfortunately, density logs are not commonly run from surface to total depth.

Sonic Logs

The use of sonic transit time to determine bulk density is based on the principle that the speed of a sound wave through a formation is a function of the formations's density.

Based on laboratory tests, the following formula has been derived and will yield values sufficient to use in overburden calculations:

$$\rho_b = 2.75 - \left[2.11 \times \left(\frac{\Delta t_{\log} - \Delta t_{ma}}{\Delta t_{\log} + \Delta t_f}\right)\right]$$

In normal practice the matrix (Δtma) is considered to be shale/clay, having a travel time of 47µsec/ft, and the fluid (Δtf) is considered to be 200µsec/ft.

One valuable aspect of sonic log data is the fact that it is usually available throughout the entire well.

Shale Resistivity Values

Selection of data points from the resistivity curve requires great scrutiny. Several factors that can mask resistivity values are:

- Temperature: since this will increase with depth, the resistivity will decrease for a water of a given salinity as depth increases
- Hydrocarbons: the presence of hydrocarbons in a formation will dramatically increase its resistivity
- Lithology: minor inclusions of sand or silt in a shale will cause its resistivity to change
- Undercompaction: in shallow formations, the resistivity is likely to be low
- Washouts: increases in hole diameter will cause considerable errors in resistivity values
- Organic Matter: large amounts of organic matter in shales (source rocks) will have the same effect as hydrocarbons

Since pore pressure determination requires "good' shale resistivity values, several precautions are necessary:

- Use MWD or wireline TVD logs only.
- When selecting resistivity values in shales, impermeable "good" shales can be identified by examining the GR or SP curve.
- To help identify shales, draw a "shale baseline" for the GR or SP curve.
- Once a shale has been identified, record the amplified resistivity of that shale. Make sure the shale is at least 12 feet thick. Since the resistivity of the shale is likely to vary, use the minimum resistivity value. Using the minimum value provides the maximum pore pressure estimate.

As mentioned above, whenever the resistivity value is being taken from the 16-inch SN tool (RGD), the amplified resistivity curve is used. If the value is being taken from a deeper reading device (DPR, Dual Induction), the deeper reading, Amplified Ratio (AR) or Deep Induction (ILD) curve should be used.

In addition to having the shales be at least 12 feet thick, another important factor is their proximity to sands. If possible, there should be no sand formations within 50 feet of the shales under consideration.

Though most resistivity values will not correspond "exactly" to a point on the Gamma Ray's shale baseline, when comparing the resistivity curve to the shale baseline, the points selected from the resistivity curve should not deviate more than 10 units from the shale baseline.

Formations that deviate to the right of the shale baseline may be cap rocks. The resistivity points from these intervals should be included in the resistivity plot.

Plotting Resistivity Data

Resistivity values are plotted versus TVD on 2 or 3 cycle semi-log paper. The vertical scale is linear with a 1-inch = 1000 ft scale.

The horizontal (logarithmic) scale will be used for resistivity. On 2 cycle semi-log paper the scale will usually begin at 0.1 ohm-meter, on 3 cycle paper the scale will begin at 0.01 ohm-meter.

This pore pressure plot should contain:

- the normal trend line
- resistivity data
- additional/confirmation data (i.e. gas, cuttings bulk density, etc.)
- casing points and hole size
- known pressure data (i.e. kicks, leak-off tests, DST/RFT)
- geological factors that may affect the pore pressure (i.e. faults)

Isodensity lines, using the normal trend line, can be drawn on the plot to assist in pressure evaluation. Equations for the construction of isodensity lines can be found in Appendix B.

The Normal Trend Line

The value of the "normal" trend will be based upon the fluid density in the water-wet formations. Though this will generally be the density of seawater (offshore) and fresh water (onshore), it is not always the case. The normal gradient is generally determined from the Rw, either using regional tables, analysis of test samples or calculating it from the SP curve.

The position of the trend line value can be found by calculating the normal resistivity (Rn) at a depth where the pore pressure is known (i.e. from Rw, kicks, formation tests). Calculating the normal value is done by rearranging Eaton's equation to solve for Rn:

$$Rn = Ro \times \left(\frac{S - Po}{S - Pn}\right)^{-0.833}$$

In order to correctly position the normal trend line, both the Y-intercept (relative position) and the slope must be known. If two known points are available, the Y-intercept can be determined by calculating Rn at two points and drawing a straight line between them. If only one point is available, the trend line cannot be correctly positioned, until more data exits to confirm the slope. However, one value of Rn based on a known pressure will help establish its position.

More often than not, the normal trend line will have to be adjusted or re-positioned during the course of the well. This is generally caused by some circumstance (i.e. a kick, a formation test) pointing out that the normal trend has not been correctly established. If this occurs, the known pressure point can be used to back out the Rn value, and with this value, the normal trend line can be reestablished. The most acceptable ways the normal trend line can be adjusted are:

- **Move the entire trend line, while maintaining the same slope** - When moving the entire line, make sure the pore pressure estimates in the upper part of the hole do not over-estimate the actual pore pressure.
- **Modify the slope of the trend line so that is passes through the backed-out Rn** - When changing the slope of the trend line, make sure it does not produce under-estimated pressures.
- **Create two normal trend lines** - If the two previous choices produce unrealistic pressure values in the upper hole section, it may be necessary to create another normal trend line. This action may be necessary when geologic factors have affected the subsurface (fault, fold, unconformity). Before stating geologic factors as the reason for the additional normal trend line, verify it using additional data (i.e. drill rate changes, cuttings changes, reoccurrence of previously drilled formations, etc.).

Offset data can be used to assist in determining the slope of the normal trend. If offset well data is plotted, the slope should closely approximate the well in question. The position may have to be adjusted left or right (depending on mud type and resistivity device used). Of course, if some type of geological event has occurred (faulting, unconformity, etc.) between the offset well and the well in question, offset data may not be useful.

Pore Pressure Calculations

If the normal trendline has been established correctly, any deviations from the trend should be monitored closely. Movement to the left (decreasing resistivity) generally means increasing pore pressure. Movement to the right may indicate changes in the geologic environment or geologic structure, or both.

Eaton's method, using resistivity values from MWD tools is an accurate and reliable method to determine pore pressure. Once an overburden curve has been generated and a normal trend line established, pore pressure is calculated using:

$$Po = S - \left[(S - Pn) \left(\frac{Ro}{Rn} \right)^{1.2} \right]$$

Once the pore pressure is calculated, it must be reviewed to ensure that it is correct. This generally means getting confirmation from other sources (i.e. gas content in the mud, unstable borehole conditions, large cavings, etc.).

When satisfied that the value calculated is acceptable, the company-man should be notified at once.

Regional Plot Examples

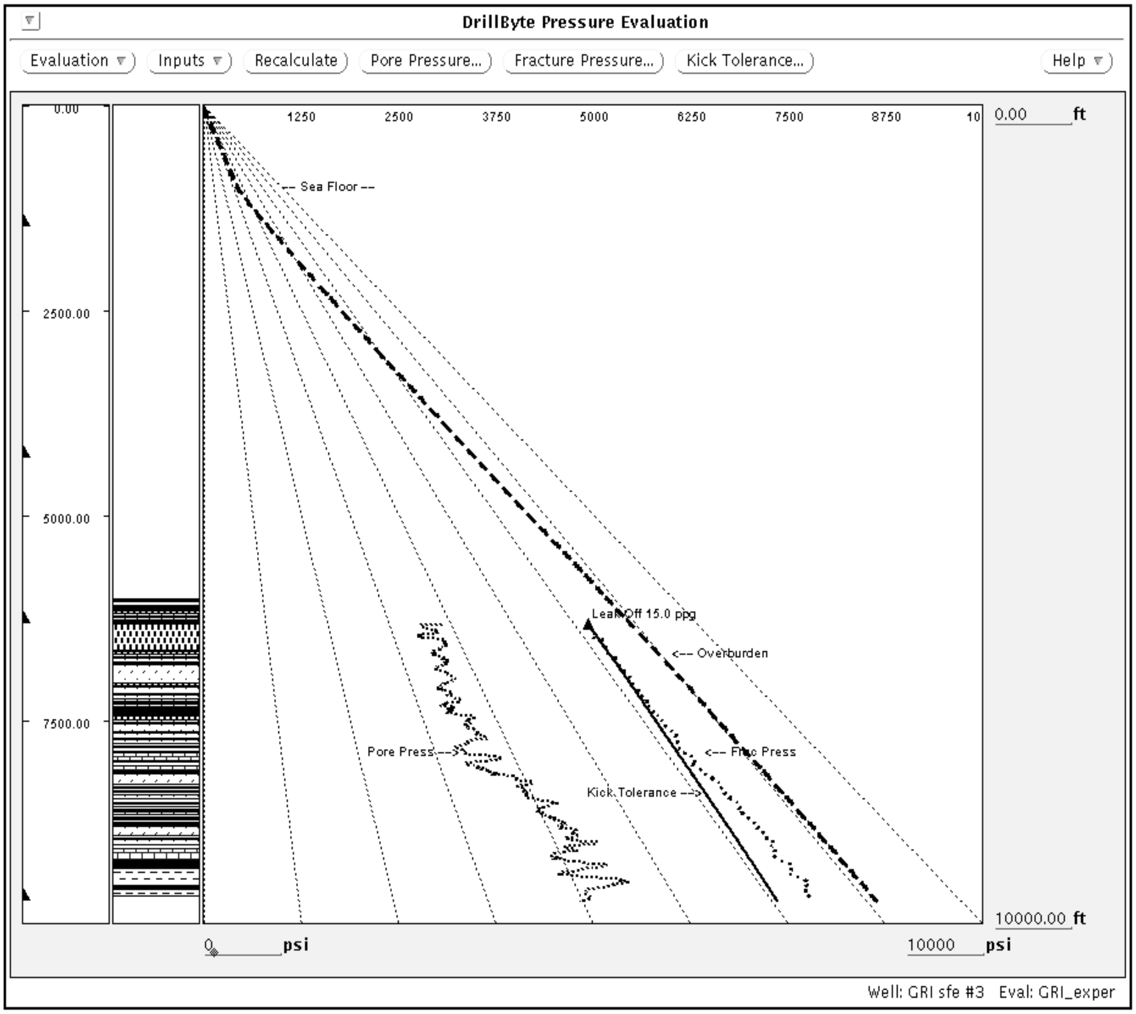


Figure E-1: GeoPress Evaluation Display — Screen shot from DrillByte

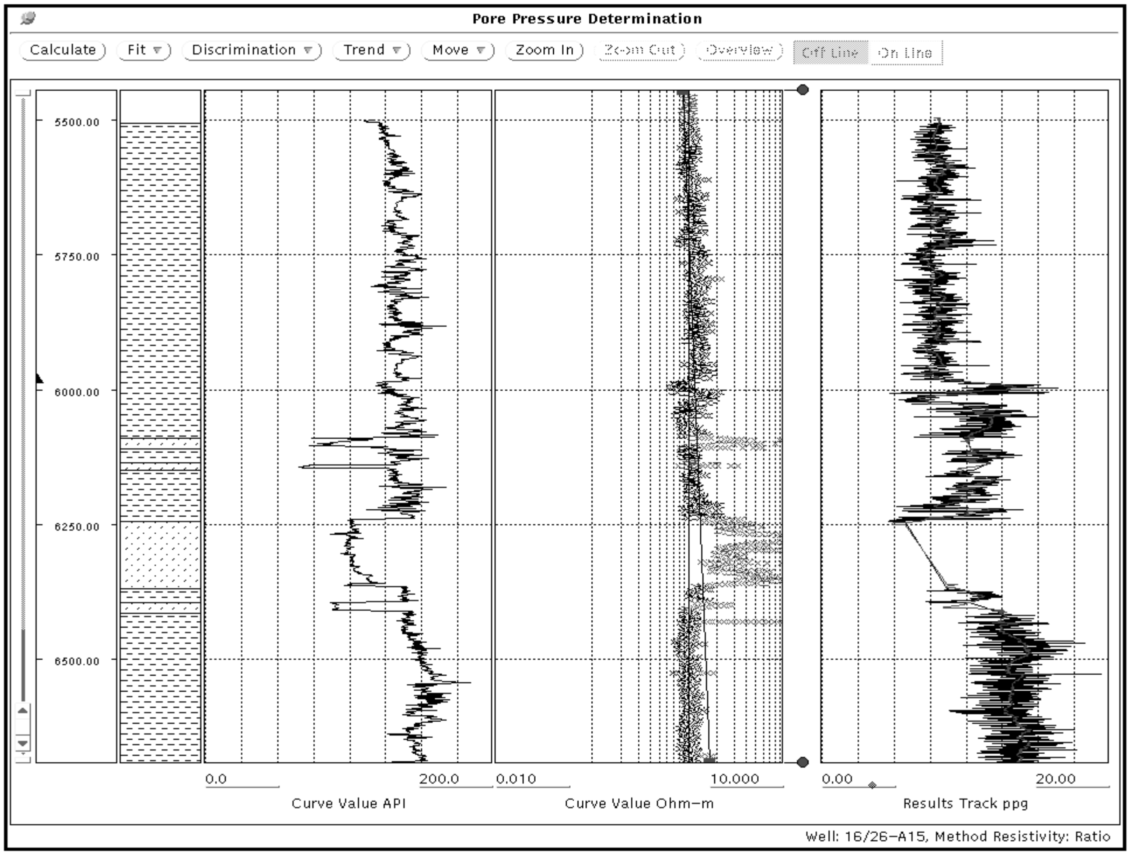


Figure E-2: GeoPress Pore Pressure Analysis — Screen shot from DrillByte

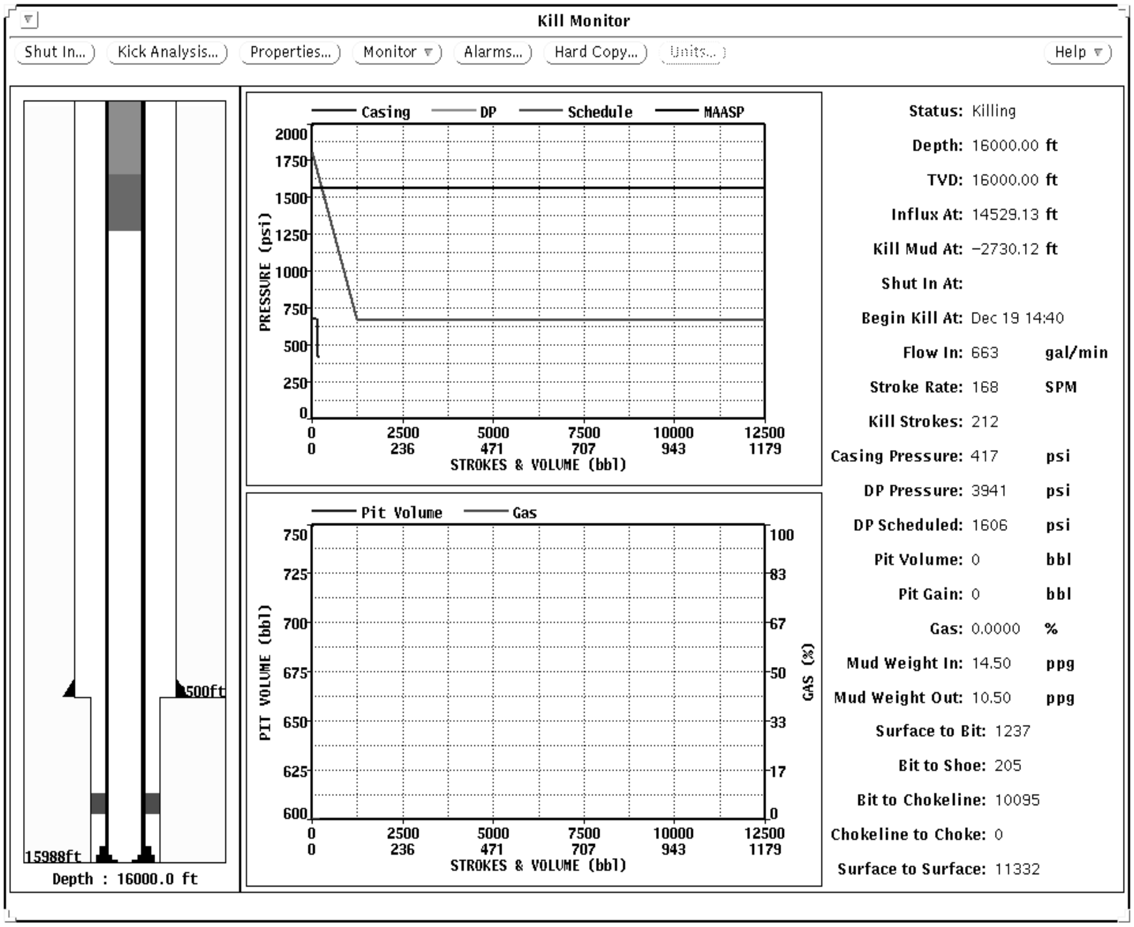


Figure E-3: Kill Monitor Display — Screen shot from DrillByte

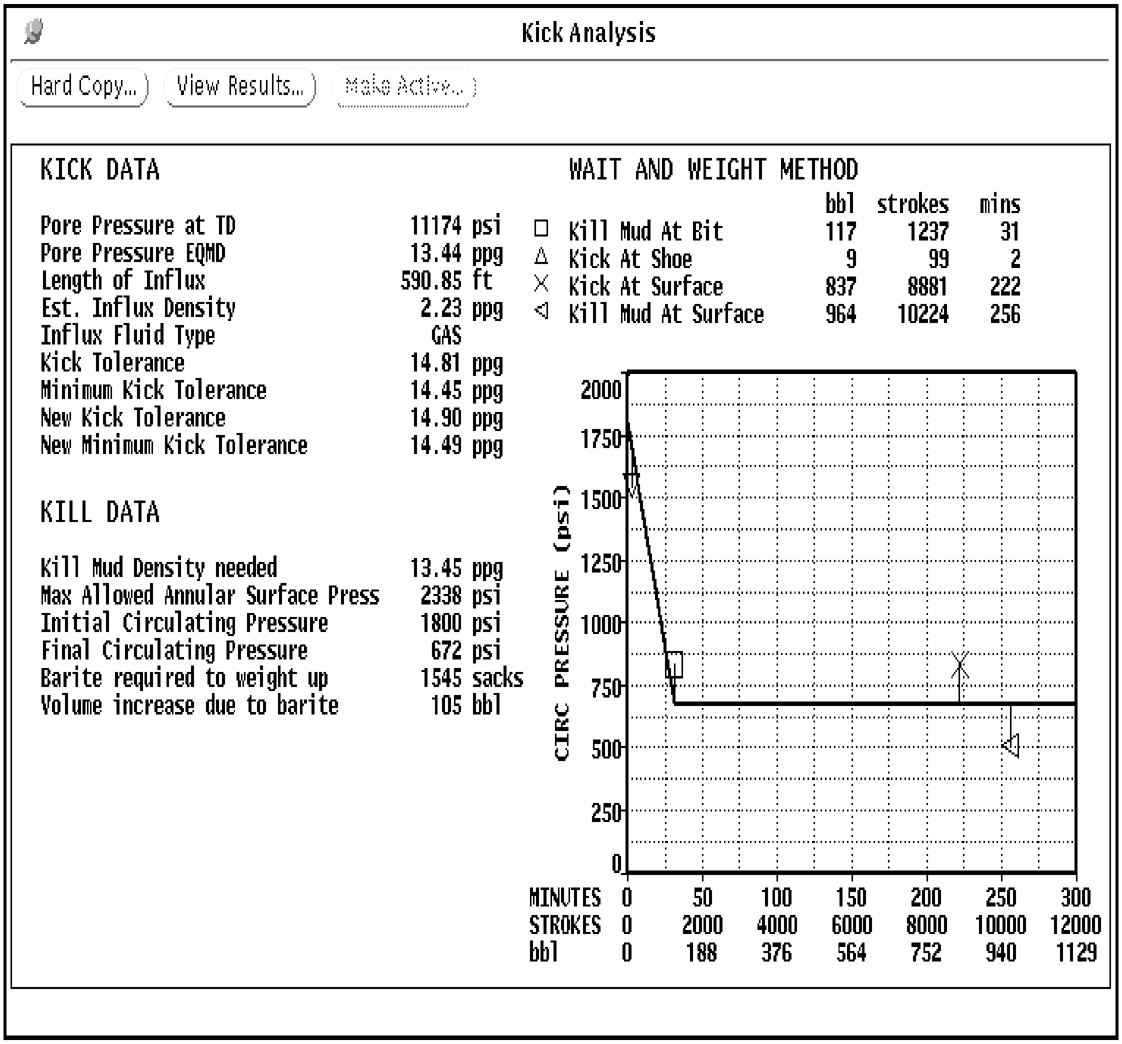


Figure E-4: Kick Analysis Display — Screen shot from DrillByte

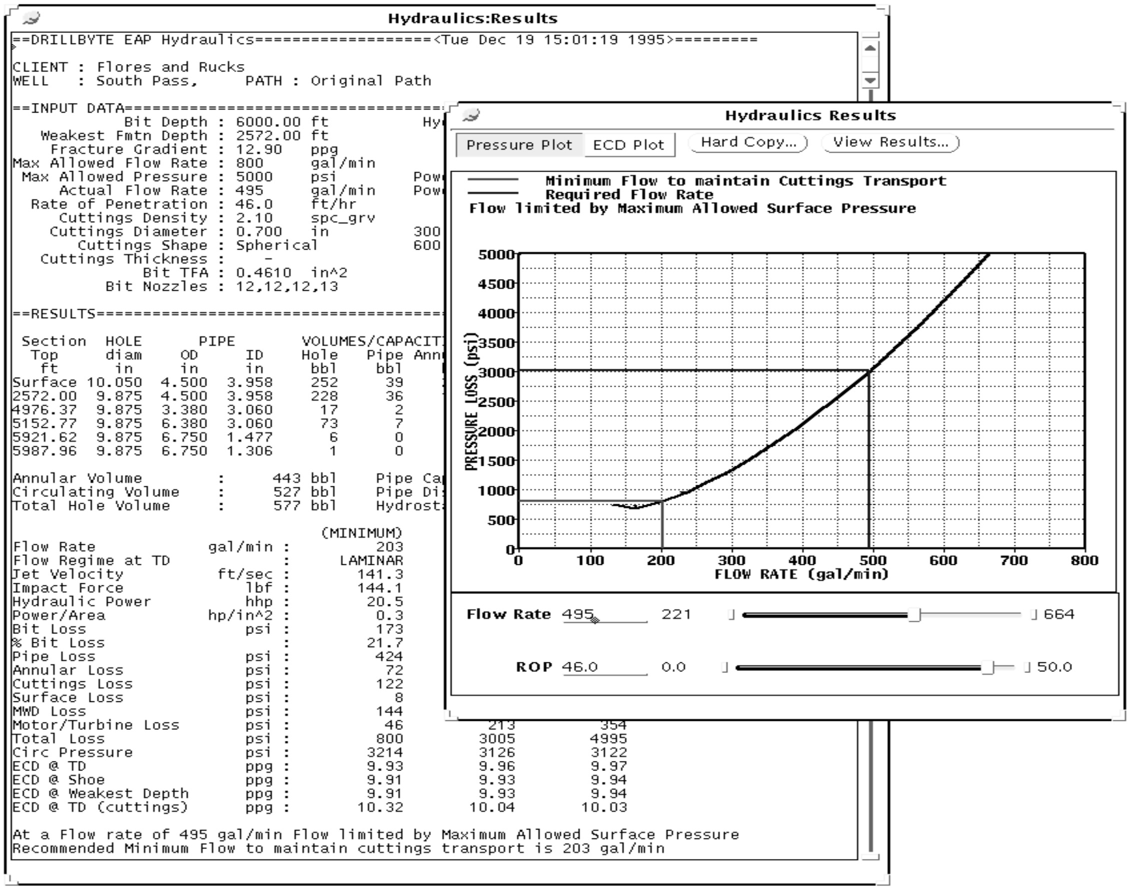


Figure E-5: Hydraulics Analysis Display — Screen shot from DrillByte

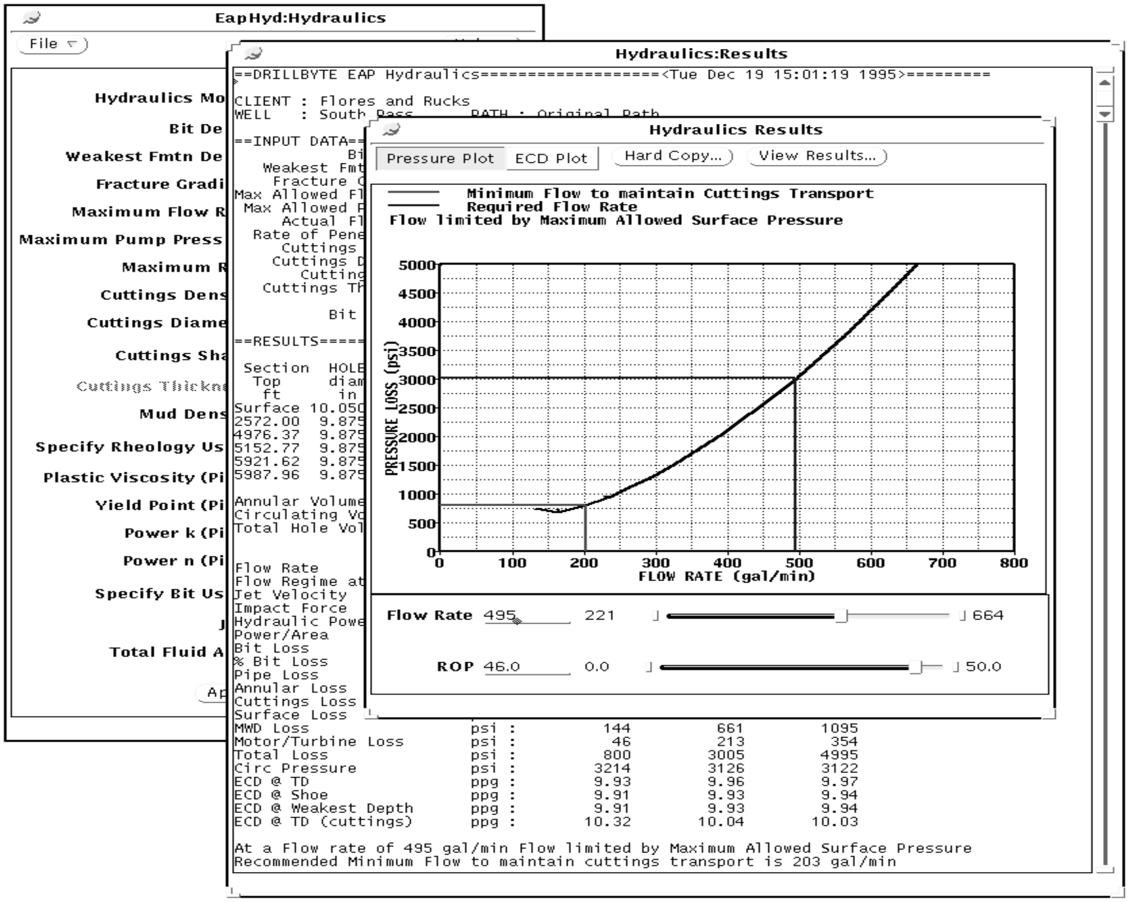


Figure E-6: Hydraulics Worksheet - Screen shot from DrillByte