SKM 3413 - DRILLING ENGINEERING

Chapter 5 – Formation Pressures

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Contents

- Pressure concepts
- Pressure relations
- Abnormal pressures (causes/origin)
- Prediction & detection of abnormal pressures
- Formation fracture gradients

Define the following terms:

- Balanced pressure
- Underbalanced pressure
- Overbalanced pressure
- True vertical depth (TVD)
- Measured depth (MD)

PRESSURE CONCEPTS

- The different formation pressures encountered in an area play a vital role both during exploration and exploitation of potential hydrocarbon resources reservoir
- The different kinds of reservoir pressure which are usually encountered during the course of drilling are broadly divided into three main components:
  a. Hydrostatic pressure
  b. Overburden pressure
  c. Formation pressure

a. Hydrostatic pressure (P_{hyd})

- Hydrostatic pressure is defined as the pressure which is exerted by a column of water extending from a stratum to a surface
- Hydrostatic P is caused by unit weight & vertical height of a fluid column
- The size & shape of this fluid column have no effect on the magnitude of this pressure:

$$P = \rho g h$$

where: P = hydrostatic pressure
ρ = average density
g = gravity value
h = height of the column

- In terms of drilling operations, we can write:

$$\boxed{p_{hyd} = 0.052\rho_m h}$$

$$P_{hyd} = 0.052\rho_w (SG)h$$

$$\text{since} \quad \rho_w = 8.33 \text{ ppg}$$

$$P = 0.052(8.33)(SG)h = 0.433(SG)h$$

$$\therefore \text{ hyd. P gradient, } \frac{P}{h} = 0.433(SG)$$

- Typical average of hyd. P gradient:
  - ✓ 0.433 psi/ft $\rightarrow$ fresh water
  - ✓ 0.465 psi/ft $\rightarrow$ salt water

<u>Example</u>: Calculate the hydrostatic pressure of 10.5 ppg mud in a well at 5,000 ft.

<u>Solution</u>:

$$P_{hyd} = 0.052\,\rho\,h$$

$$= 0.052\,(10.5)\,(5,000) = 2,730 \text{ psi}$$

<u>Example</u>: Calculate the hydrostatic pressure of 40 °API oil in a well at 5,000 ft.

<u>Solution</u>:

$$SG = \frac{141.5}{131.5 + 40} = 0.825$$

$$P_{hyd} = 0.433\,(SG)\,h$$

$$= 0.433\,(0.825)\,(5,000) = 1,786 \text{ psi}$$

- The hydrostatic P gradient is affected by the concentration of dissolved solids (i.e. salts) and gases in the fluid column at different or varying temperature gradients
- An increase in the dissolved solids slightly increases the normal pressure gradient, while increasing amount of gases in solution and higher temperature would decrease the normal hydrostatic pressure gradient

i.e. salt concentration ↑, normal P gradient ↑
gases in solution ↑, normal P gradient ↓
temperature ↑, normal P gradient ↓

b. Overburden pressure (P_o)

- Overburden pressure are also sometimes called load, lithostatic or geostatic pressures
- This P originates from the combined weight of the formation matrix (rock) & the fluids (water, oil, gas) in the pore space overlying the formation of Interest

$$P_o = \frac{weight\ (fluid + rock\ matrix)}{area}$$

$$\text{but,}\quad \text{weight of fluid} = \rho V$$

$$P_o = \frac{\rho_{fl}\,\phi\,(Ah) + \rho_{ma}\,(1-\phi)\,(Ah)}{A}$$

$$\boxed{P_o = h\left[\phi\rho_{fl} + (1-\phi)\,\rho_{ma}\right]}$$

- Sediment porosity decrease under the effect of burial (compaction), is proportional to the increase in overburden pressure
- In the case of clays, this reduction is essentially dependent on the weight of the sediments (see figure below)
- If clay porosity and depth are represented on arithmetical scales, the relationship between these two parameters is an exponential function

- In sandstones and carbonates, this relationship is a function of many parameters other than compaction, such as diagenetic effects, sorting, original composition and so on.
- A decrease in porosity is necessarily accompanied by an increase in bulk density
- In the upper part of the sedimentary column, the bulk density increase gradient is much steeper than at depth (see figure below)

- The total of overburden pressure is supported by:
  i. pore pressure
  ii. rock gain pressure

i. Pore pressure

- The pore pressure of a formation refers to that portion of the overburden pressure which is not supported by the rock matrix, but rather by the fluids or gases which exist in the pore spaces of the formation
- Normal pore pressure is equal to the hydrostatic pressure of a water column from that depth to the surface
- If for some reason communication between fluids contained at depth and surface fluids is interrupted, fluids will be unable to flow and normally equalize the pressures within the system
- Thus fluids become entrapped within the formation and, in the case of over pressured formation, the grain to grain pressure decreases as the fluids within the interstices effectively "floats" the overburden
- If the pore pressure is less than normal hydrostatic pressure the formation is said to be subnormally pressured
- If the pore pressure at that depth exceeds the expected hydrostatic pressure for that depth the zone is termed abnormally pressured

ii. Rock grain pressure

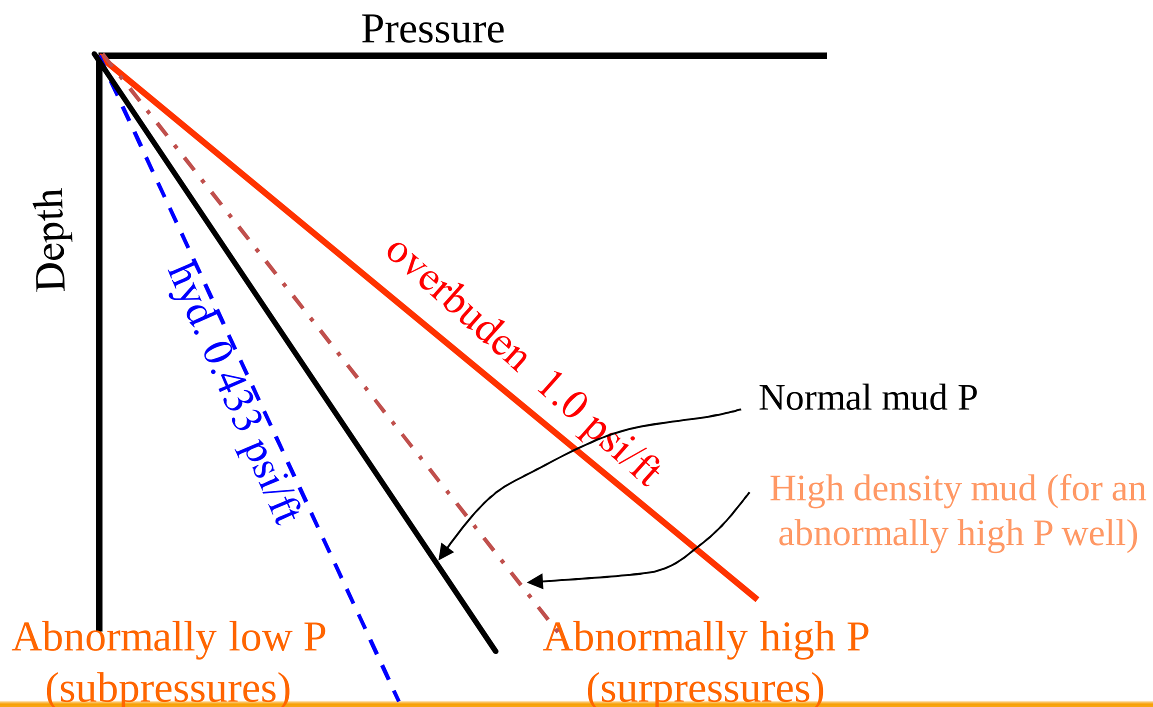
- Since individual grains often do not exist within a rock formation the rock grain pressure refers to a theoretical fraction of the overburden pressure which is supported by the rock matrix of the formation
- Since a rock mass is not homogeneous, pressures will not be exerted equally in all directions as is the case with fluid pressures

c. Formation Pressure (P_f)

- P_f is the pressure acting upon the fluids (water, oil, gas) in the pore space of the formation (= pore pressure = formation fluids pressure)
- Expressed either in psi, atmosphere or kg/cm^2
- Normal formation P in any geologic setting will equal the hydrostatic head (i.e. hydrostatic P) of water from the surface to the subsurface formation
- Normal hydrostatic reservoir pressures normally correspond to original reservoir pressures, i.e. pressures that existed before the natural pressure equilibrium of formation was disturbed by production
- Any deviation from the normal trend is called abnormal P

PRESSURE RELATIONS

- If $P_f > P_{hyd} \Rightarrow$ abnormally high formation P (surpressures/over pressures)
- If $P_f < P_{hyd} \Rightarrow$ subnormal (subpressures)
- Surpressures occuring more frequently than subpressures



- Subsurface P & stress concepts are related:

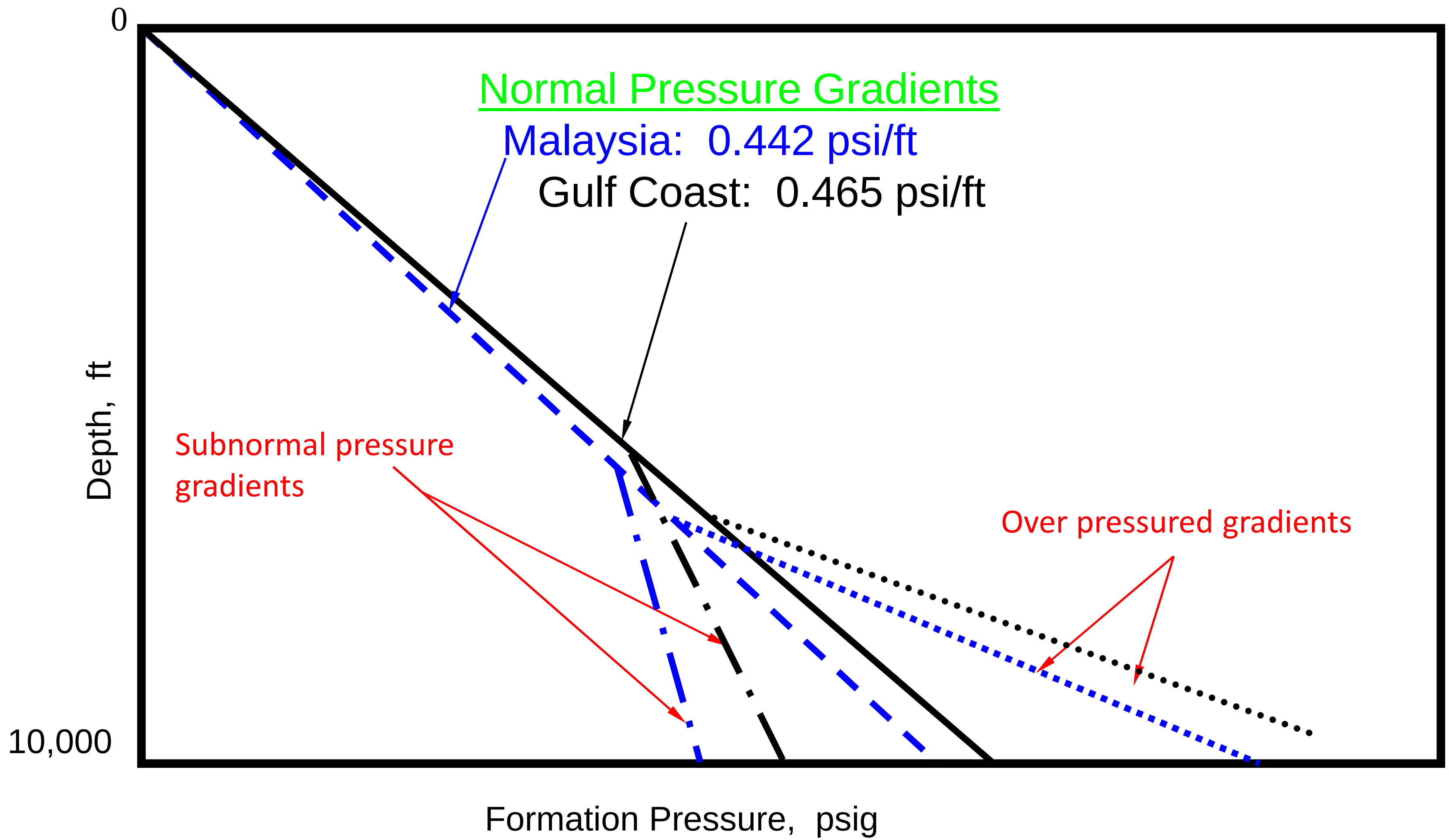
  $P_o = P_f + \delta$

  $\delta \rightarrow$ grain to grain P (matrix stress, effective stress, vertical rock-frame stress)

- In normal P environments ($P_f = P_{hyd}$), the matrix stress supports the overburden load due to grain-to-grain contacts
- Any reduction in this direct grain-to-grain stress

  ($\delta \rightarrow 0$) will cause the pore fluid to support part of the overburden $\rightarrow P_f > P_{hyd}$ (abnormal P)

Normal and Abnormal Formation Pressures



The influence of formation pressures on the drilling operation

- In order to maintain hole stability (by preventing borehole collapse and also to prevent the influx of formation fluids into the wellbore):
  - It is necessary to maintain a borehole P which is slightly overbalances the formation P
  - $\therefore$ to drill the well in safety $\rightarrow$ necessary to know or to predict the pressures within the formation to be drilled

A technique for predicting formation pressures would be helpful for the following reasons:

- Assist in selecting adequate mud weight to ensure well safety
- Prevent the use of excessive mud weights leading to fracture or losses
- Prevention of hole collapse or sloughing of shales
- Assist in correct design of casing schemes to ensure optimum completion and maximum productivity

Normal pore pressure gradients in specific geographic area.

Region	Pore Pressure Gradient psi/ft	Pore Pressure Gradient kPa/m
Anadarko Basin	0.433	9.64
California	0.439	9.77
Gulf of Mexico	0.465	10.35
Mackenzie Delta	0.442	9.84
Malaysia	0.442	9.84
North Sea	0.452	10.06
Rocky Mountains	0.436	9.71
Santa Barbara Channel	0.452	10.06
West Africa	0.442	9.84
West Texas	0.433	9.64

Example: Based on the above Table, determine the normal formation pressure which is to be expected at a depth of 9,000 ft in (a) Malaysia, and (b) Gulf of Mexico

Solution: (a) P = (0.442 psi/ft)(9,000 ft) = 3,978 psi

(b) P = (0.465 psi/ft)(9,000 ft) = 4,185 psi

Example: A formation is to be hydraulically fractured at the depth of 10,000 ft. The fracturing fluid has a SG of 0.85. If the formation break down at 80% of the theoretical overburden pressure, what pump pressure will be required for the break down?

Solution:

Expected bottom hole break-down pressure = (0.8)(1 psi/ft)(10,000 ft)
= 8,000 psi

Hydrostatic head of fluid = 0.433(SG)h
= (0.433)(0.85)(10,000 ft)
= 3,681 psi

Requires pump pressure = 8,000 psi – 3,681 psi
= 4,319 psi

Example: During the drilling of a well, a protective string of 10 ¾ in. casing was set and cemented at a depth of 5,000 ft. A BOP, which provides for sealing the annular space between the drill pipe and the protective casing, was mounted on the top of the protective casing. The drilling mud weighs 10.4 ppg. Assuming that the well is full of mud, and that the formation will hold 70% of the theoretical overburden pressure, how much pressure can be held against the well by the BOP?

Solution: Since the casing may be assumed strong enough to contain internal pressures above the 5,000 ft setting depth, the shallowest depth subject to analysis is 5,000 ft.

Assumed bottom hole break-down P at 5,000 ft = (0.7)(1 psi/ft)(5,000 ft)

= 3,500 psi

Hydrostatic mud head = 0.052 rh

= (0.052)(10.4 ppg)(5,000 ft) = 2,704 psi

Pressure held by BOP = 3,500 psi – 2,704 psi = 796 psi

Example: A formation has a pressure of 4,000 psi at 7,500 ft. The operator desires to have a safety allowance of 300 psi opposite the formation. What is the required density of the mud?

Solution:

$$P = 0.052\,\rho\, h$$

$$\therefore \ \rho = \frac{P}{0.052\,h}$$

$$= \frac{4{,}000\ psi\ \ formation\ pressure + 300\ psi\ safety\ allowance}{(0.052)(7{,}500\ ft)}$$

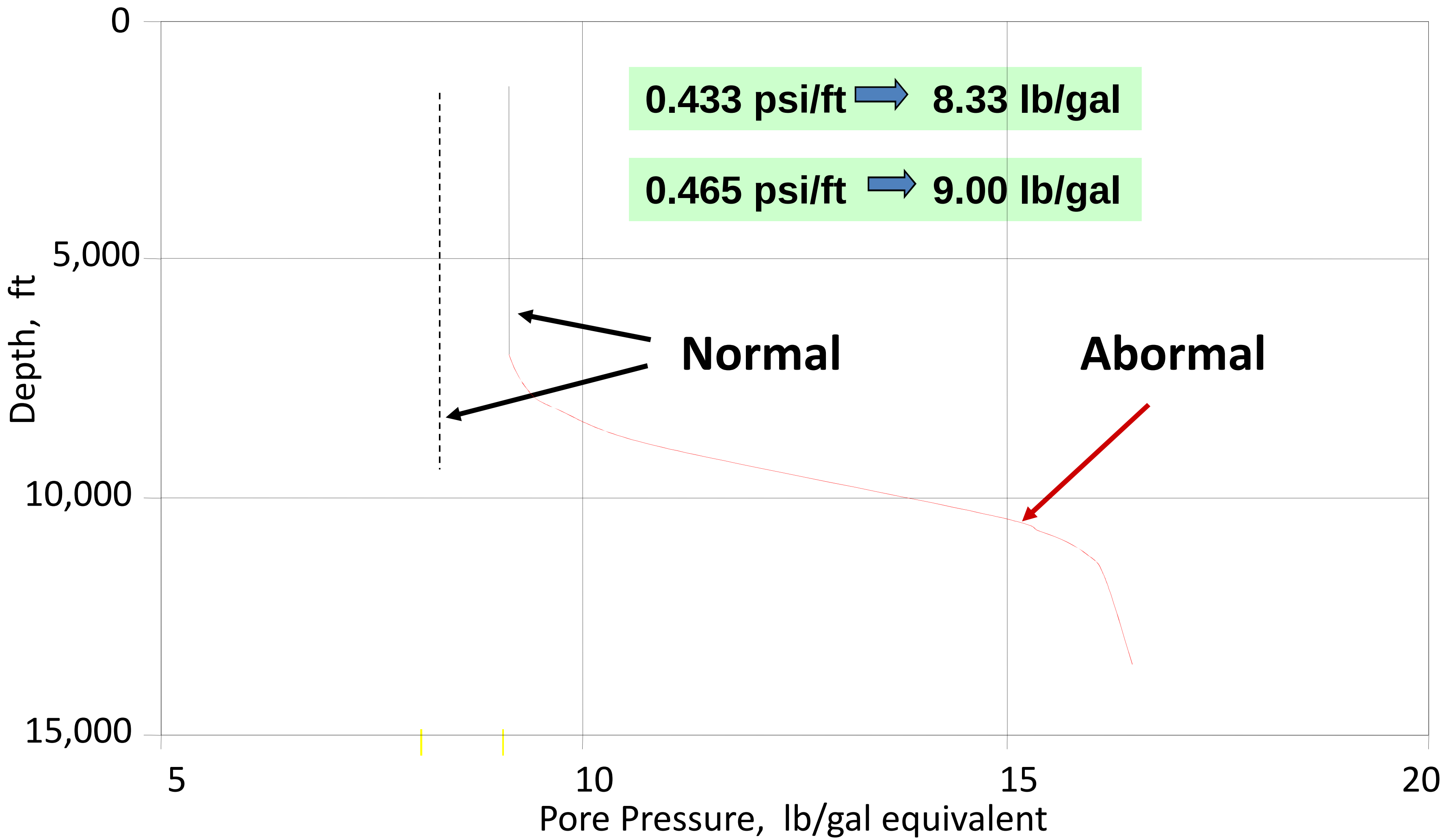
$$= 11.0\ ppg$$

ABNORMAL PRESSURE

- Technical difficulties are often encountered in petroleum exploration when drilling abnormally pressured zones. Such pressures are a worldwide phenomenon
- Most petroleum provinces exhibit abnormal pressure. In fact, abnormal pressure occurs to varying degrees in nearly all sedimentary basins
- In petroleum exploration, the consequences of abnormal pressures may be both desirable and undesirable
- The quality of a drilling programme depends on how well the formation pressure is known
- Wherever there is risk of abnormal pressure, the drilling method to be used must consist in continuously evaluating formation pressure as precisely as possible and adapting the drilling programme accordingly

- A normal, hydrostatic pressured geologic environment can be visualized as a hydraulically “open” system (i.e. permeable). Fluid communicating formations allow establishment and/or reestablishment of hydrostatic conditions
- Conversely, abnormally high formation P systems are essentially “closed”, preventing, or at least greatly resisting, fluid communication
- Technically, any deviation in naturally occurring formation P from what is considered the normal hydrostatic P gradient is abnormal P, whether the deviation is higher or lower
- High P is called “abnormal P” & sometimes as surpressure, trapped P, geopressure or overpressure
- Low P is also called “abnormal P” & sometimes as subpressure or subnormal pressure

Density of mud required to control this pore pressure



Pore pressure vs. depth

Drilling problems associated with abnormal pressures

- When drilling through a formation, sufficient hydrostatic ρ_m must be maintained to prevent:
  - the borehole collapsing
  - the influx of formation fluids
- Mud density must be increase
- If the overbalance is too great, this may lead to:
  - reduced penetration rates (due to chip hold down effect)
  - lost circulation (flow of mud into formation)
  - breakdown of formation (exceeding the fracture gradient)
  - excessive differential pressure causing stuck pipe

Pressure seals

- Common to both subnormal pressures and overpressures is a sealing mechanism which prevent equalization of the pressures within the abnormally pressured zone and the rest of the geological sequence
- The origin of a P seal is physical, chemical or may be a result of the combination of the two (see table below):

Type of seal	Nature of trap	Examples
Vertical	Massive shales and siltstones Massive salt Anhydrite Gypsum Limestone, marl, chalk Dolomite	Gulf Coast, USA, Zechstein, North Germany, North Sea, Middle East, USA, USSR
Transverse	Faults Salts and shale diapers	Worldwide
Combination of vertical and transverse		Worldwide

a. <u>Physical seal</u>

This can be a gravity fault during deposition of a finer grained material or the deposition of a carbonate, salt or other non-porous material caused by a long period of high T & low rainfall

b. <u>Chemical seal</u>

This refer to the chemical deposition of $CaCO_3$ i.e. in warm waters, thus restricting average permeability. Another example is chemical diagenesis during compaction of organic material associated with normal deposition

c. <u>Physical-chemical seal</u>

This category refers to those in which a physical change triggers off a chemical reaction or alternatively a chemical change which triggers a physical change, e.g. the gypsum–evaporite action

Causes of abnormal pressures

Potential reasons for	
Subnormal Pressure Gradients	**Overpressured Gradients**
Thermal expansion	Incomplete sediment compaction
Formation foreshortening	Faulting
Depletion	Phase Changes during compaction
Precipitation	Massive rock salt deposition
Potentiometric surface	Salt diaperism
Epeirogenic movement	Tectonic compression
	Repressuring from deeper levels
	Generations of hydrocarbons

Note: Abnormal pressure may have many origin, frequently a combination of geologic, physical, geochemical & mechanical processes

Origins for generation of abnormal fluid pressure (after Fertl)

1. Piezometric fluid level (artesian water system)
2. Reservoir structure
3. Repressuring of reservoir rock
4. Rate of sedimentation and depositional environment
5. Paleopressures
6. Tectonic activities
   a. Faults
   b. Shale diapirism (mud volcanoes)
   c. Salt diapirism
   d. Sandstone dikes
   e. Earthquake
7. Osmotic phenomena
8. Diagenesis phenomena
9. Massive areal rock salt deposition
10. Permafrost environment
11. Thermodynamic and bichemical causes

1. Piezometric fluid level (artesian water system)

Generally, artesian pressures are present under the following conditions:

- Porous & permeable aquifers are sandwiched between impermeable beds, such as shales
- These aquifers are deformed in such a way as to exhibit a high intake to produce the necessary hydraulic head

2. Reservoir structure

- In sealed reservoir rock, such as lenticular reservoirs, dipping formations & anticlines, formation pressures is normal for the deepest part of the zone but it will be transmitted to the shallower end, where they will cause abnormal P conditions (see figure)
- In the presence of the anticlines, abnormal P are encountered in the potential pay section, whereas abnormal hydrostatic P conditions still may exist at & below the oil/water contact
- In very large structures (e.g. Middle East), overpressures resulting from P differences in oil/water system and particularly gas/water systems are known to approach the geostatic P of the overburden (e.g. in Iran $\rightarrow$ 0.9 psi/ft)

3. Repressuring of reservoir rock

Normal or low pressured reservoir rocks, particularly at shallow depth, containing formation water and/or hydrocarbon may sometimes be pressured up and/or repressured due to hydraulic communication with deeper, higher pressured formations, such as (see Figure):

- Behind casing in old wells or boreholes with faulty cement job
- Along “leaky” fault zones
- As a result of casing leak in old wells
- While drilling a sequence of permeable formations exhibiting drastically different pore fluid pressures (causing recharge saltwater

4. Rate of sedimentation and depositional environment

- “Rapid loading” can cause abnormal P interstitial water is likely to be trapped and isolated from communicating with the surface
- In this situation the sediment cannot compact and the contained water is subjected not only to hydrostatic forces, but also to the weight of newly deposited sediment, therefore it will created high pressure zone
- The normal sedimentation process involves the deposition of layers of various rock particles

5. Paleopressures

Such abnormal formation pressures can only exist in older rock which have been completely enclosed by massive, dense & essentially impermeable rocks or in completely sealed formation uplifted to a shallower depth

6. Tectonic activities

Abnormally high pore fluid pressures may result from local & regional faulting, folding, lateral sliding & slipping, squeezing caused by down-dropping of fault blocks, diapiric salt and/or shake movements, earthquakes, sandstones dikes

7. Osmotic phenomena

- Osmosis is the spontaneous flow of water into a solution or the flow from a more dilute to more concentrated solution, when the two are separated from each other by a suitable membrane

- Shale can act as semi-permeable membrane

8. Diagenesis phenomena

- Diagenesis is a term that refers to the chemical alteration of rock minerals by geological processes
- Diagenesis is the post-depositional alteration of sediment & its constituent minerals
- Processes of diagenesis include:
  - formation of new minerals
  - redistribution & recrystallization of the substances in sediments
  - lithification

9. Massive areal rock salt deposition

- Salt is totally impermeable to fluids & transforms under pseudoplastic movement (recrystallization effect), thereby exerting pressure equal to the overburden load in all directions
- Underlying formations have no fluid escape possibilities, thus remaining unconsolidated & becoming overpressured

10. Permafrost environment

- In permafrost regions, unfrozen areas exist in many places, such as under deep lake
- Drastic changes in climate and/or surface conditions cause permafrost encroachment, thereby trapping an unfrozen area in a essentially closed system
- As freezing proceeds, a buildup of abnormally high formation pressures occurs in unfrozen pockets. These structures are called pingos

11. Thermodynamic & biochemical causes

- Changes in formation T will also change the fluid P
- The figure suggest that pressure in an isolated volume increases with increasing T more rapidly in the surrounding fluids
- Breakdown of hydrocarbon molecules into simple compounds increases their volume
- Volume changes is due to catalytic reactions, radioactive decay, bacterial reaction, and/or T changes
- Decomposition of organic matter through bacterial actions form pockets of methane under excessive pressure

PREDICTION & DETECTION OF ABNORMAL PRESSURES

There are many methods to predict, detect & evaluate formation fluid pressures (see Table on the next slide)

Most of the methods can be subdivided into qualitative & quantitative detection method as shown in the table below (this table contains only those method that are applicable during the drilling phase of a well)

Pressure detection methods while drilling

Qualitative methods	**Quantitative methods**
Paleontology	**Log analysis**
Offset well correlation	**porosity detection**
Temperature anomalies	**resistivity (conductivity)**
Gas counting	**sonic**
Mud and/or cutting resistivity	**Bulk density**
Delta chlorides	**Drilling equation**
Cuttings character	**d_c exponent**
Hole condition	**computerized drilling models**
Cuttings content (shale factor)	**Kicks**

Predict

Detect

Confirm/
Evaluate

Source of data	Pressure indicators	Time of recording
Geophysical methods	Seismic (formation velocity) Gravity Magnetics Electrical prospecting methods	Prior to spudding well
Drilling parameters	Drilling rate d-exponent and Modified d-exponent Drilling rate equations Drilling porosity and formation pressure logs Logging while drilling Torque, Drag	While drilling (no delay)
Drilling mud parameters	Mud-gas cutting Flow-line mud weight Pressure kicks Flow-line temperature Resistivity, chloride ions & other novel concepts Pit level and total pit volume Hole fill-up Mud flow rate	While drilling (delayed by the time required for mud return)
Shale cuttings parameters	Bulk density Shale factor Volume, shape and size Novel, miscellaneous methods	While drilling (delayed by the time required for mud return)
Well logging	Electrical surveys (resistivity, conductivity, etc) Interval transit time Bulk density Hydrogen index Thermal neutron capture cross section Nuclear magnetic resonance Downhole gravity data	After drilling
Direct pressure measuring device	Pressure bombs Drill-stem test Wireline formation test	When well is tested or completed

Techniques available to predict, detect and evaluate overpressures (after Fertl)

There are 3 general classifications can be proposed (see the previous table):

Predictive techniques

These can be considered as those geophysical techniques applied to the initial exploration phase. The methods will predict the existence of conditions in which abnormal P may be found

Detection techniques *(will concentrate on this techniques)*

Applies to those aspects & parameters which can be monitored during the drilling process & can alert the drilling crew to the fact that they have encountered a transition zone/abnormally pressured zone

Confirmation techniques

Relates to those methods which can be applied after the hole has been successfully drilled to confirm and quantify abnormal formation pore pressures

Detection of Abnormal Formation Pressures

There are 3 categories of sources of data which will allow the detection of abnormal pressures, namely:

A. Drilling parameters

This categories refers to the observation of drilling parameters & the application of empirical drilling rate calculations which utilize a pore P dependent term

B. Drilling mud

This category refers to the affect that an abnormal P zone may have on the drilling fluid, e.g. increase in T, influx of hydrocarbon, etc.

C. Drill cuttings

This section comprises methods used to investigate the nature of the detecting the cuttings from the sealing zone cuttings, generally with specific reference to detecting the cuttings from the sealing zone

A. Drilling Parameters

- The concept behind the use of drilling parameter is that:
  - Upon approaching an abnormal pressured zone it is possible that the seal zones will present itself as a zone of greater compaction which will give decreased penetration rates
  - Upon entering the abnormally pressured zone, the rock many become &
    & this will result in increased penetration rates

1. Drilling rate (penetration rate)

- Drilling rate breaks have been used for many years to distinguish sand from shale
- However, the apparent relation of penetration rate to variations in pore fluids P has been recognized
- Basically, drilling rate is a function of WOB, rotary speed (rpm), bit type & size, hydraulics, drilling fluid & formation characteristics
- Penetration rate decrease uniformly (due to compaction) with depth (assuming all the above parameters are constant)

2. d-exponent (normalized rate of penetration)

- Since it is not always a possible to control/maintain WOB, rpm, etc. (as discussed previously), an improved method has been developed which allows plotting of a normalized penetration rate (d–exp.) vs. depth
- Data required to calculate the d-exp. (a dimensionless no.) are the penetration rate , bit size (diameter), WOB & rotary speed:

$$d = \frac{\log(R/60N)}{\log(12W/10^6 D)}$$

R = rate of penetration (ft/hr)

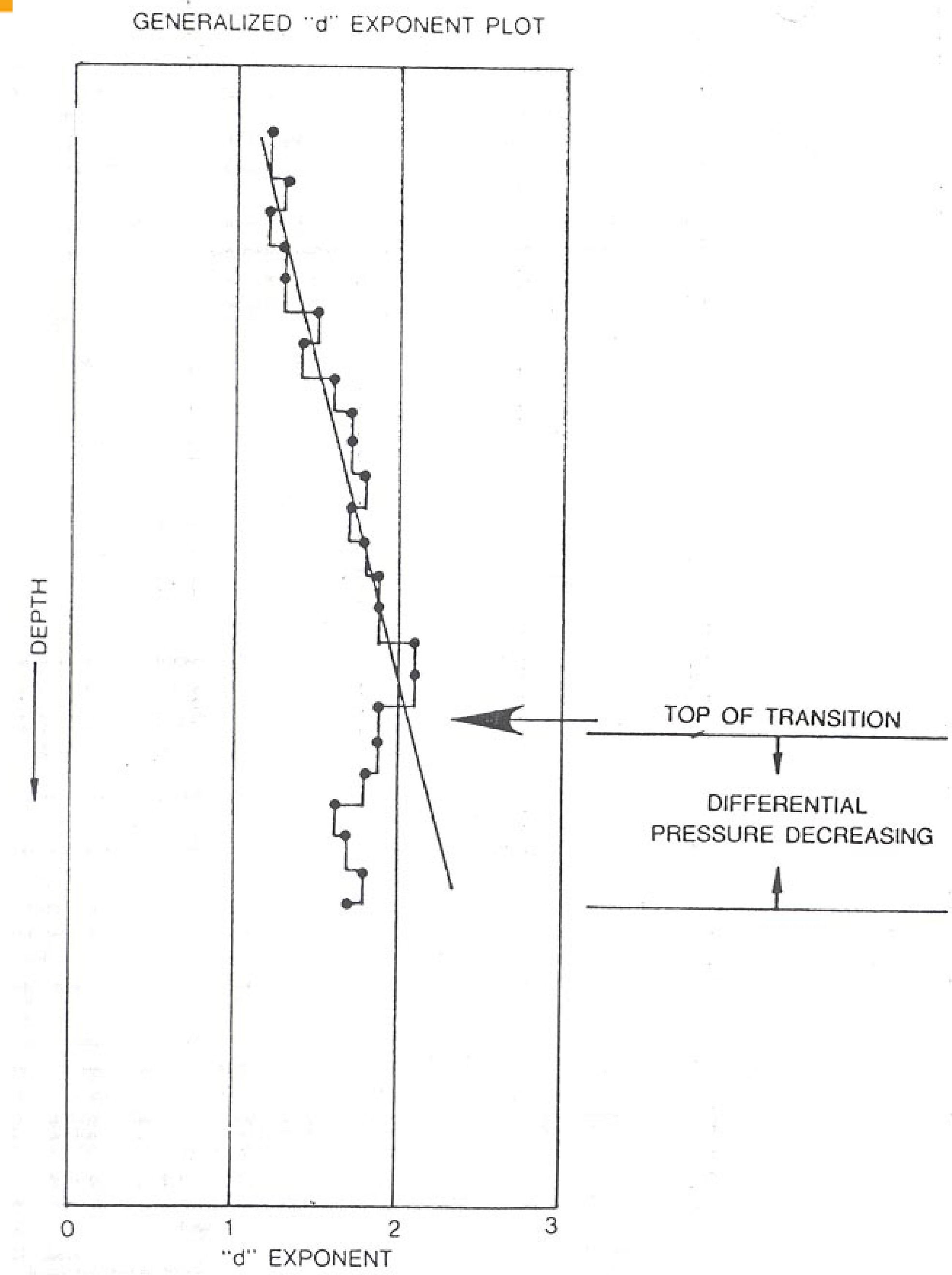
N = rotary speed (rpm)

W = WOB (lbs)

D = bit diameter (in.)

- Overpressured zone can be identified by plotting d-exponent vs depth
- For accurate results the following conditions must exist:
  - no abrupt changes in WOB or RPM should occur, i.e. keep WOB and RPM as constant as possible
  - to reduce the dependence on lithology the equation should be applied over small depth increments only (plot every 10 ft)
  - a good thick shale is required to establish a reliable trend line

- Basically, plots of d–exponent vs depth show an increasing trend with depth
- In transition zones & overpressure environments, the calculated d-value diverge from the normal trend to lower than normal values (see figure)
- Computed d-values are affected by any change in R, N, W & D. Thus changes in bit size & type, bit weight, etc. will affect the d-exponent
- Lithology change, mud weight change will also affect d-exponent



3. Modified d-exponent

- Since the d-exponent is influenced by mud weight variations, a modification has been introduced to normalize the d-exponent for the effective mud weight such as:

$$d_c = d \bullet (\rho_n / \rho_e)$$

where:

d_c = modified (corrected) d-exponent

ρ_n = mud ρ equal to a normal formation pore p gradient

ρ_e = Equilibrium mud ρ at the bit while circulating

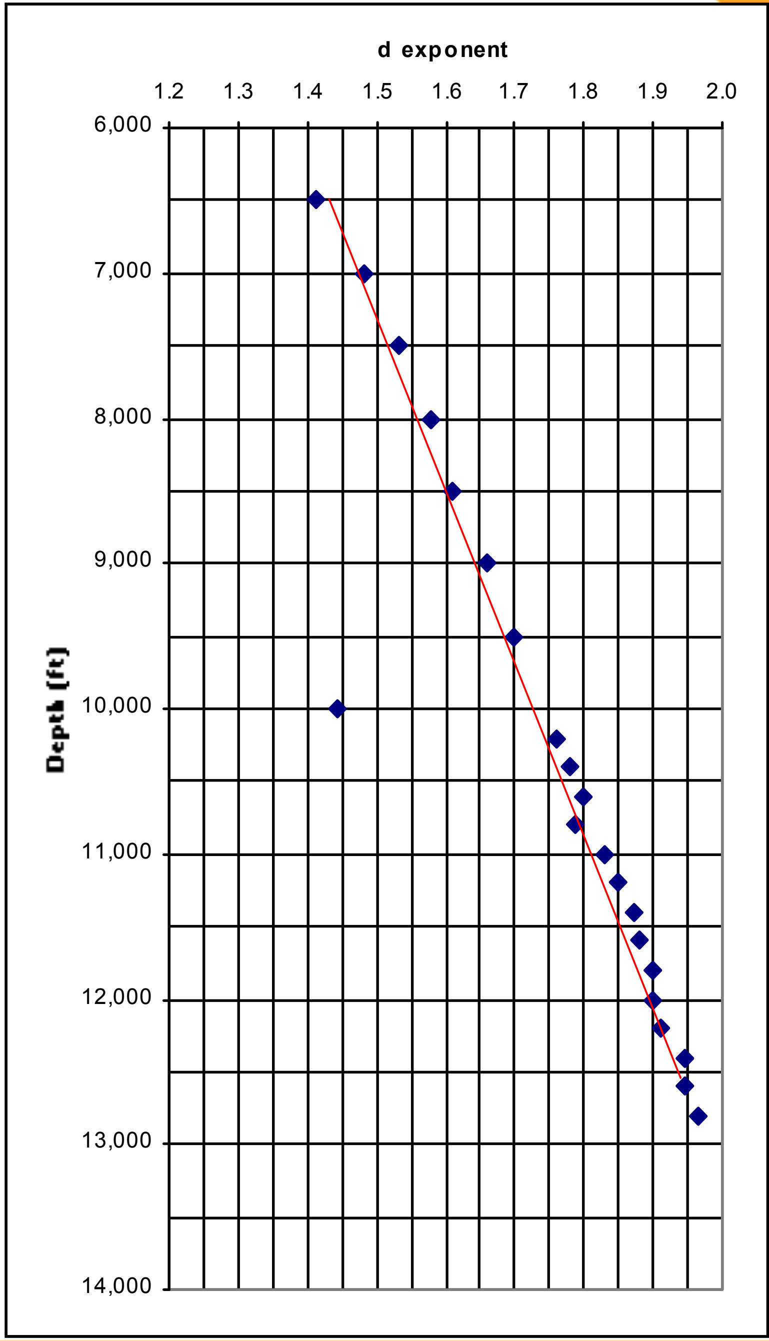
Example:

The following table is obtained from a well drilled at Alpha field. Assuming the normal formation pressure of 9.0 ppg:

a. Make a plot of d-exponent vs. depth using Cartesian coordinates
b. Make a plot of d-exponent vs. depth using semi-log
c. Make a plot of modified d-exponent vs. depth using Cartesian coordinates
d. Make a plot of modified d-exponent vs. depth using semi-log
e. Determine the depth of upper zone of abnormal pressure
f. Can the d-exponent be used to determine the abnormal pressure in this case? Give your reasons

Depth (ft)	Bit size (in.)	Drlling time (hrs)	WOB (lb)	N (rpm)	Mud density (ppg)
6,000	8.500	4.72	35,000	120	9.0
6,500	8.500	4.85	35,000	120	9.0
7,000	8.500	6.50	35,000	110	9.0
7,500	8.500	7.58	35,000	110	9.0
8,000	8.500	11.21	30,000	110	9.4
8,500	7.875	10.87	30,000	110	9.4
9,000	7.875	12.69	30,000	110	9.4
9,500	7.875	14.28	30,000	110	9.8
10,000	7.875	6.49	30,000	110	10.1
10,200	7.875	7.61	30,000	100	10.1
10,400	7.875	8.10	30,000	100	10.1
10,600	7.875	8.62	30,000	100	10.5
10,800	7.875	9.17	30,000	90	11.1
11,000	7.875	10.47	30,000	90	11.1
11,200	7.875	11.17	30,000	90	11.3
11,400	7.875	11.91	30,000	90	11.6
11,600	7.875	9.13	35,000	90	11.6
11,800	7.875	9.71	35,000	90	11.8
12,000	7.875	9.71	35,000	90	13.1
12,200	7.875	10.00	35,000	90	13.4
12,400	7.875	11.11	35,000	90	13.6
12,600	7.875	11.11	35,000	90	14.2
12,800	7.875	11.77	35,000	90	14.5

h (ft)	Δh (ft)	t (hr)	R = Δh/t (ft/hr)	D_h (in.)	W (lb)	N (rpm)	ρ_e (ppg)	$d = \frac{\log(R/60N)}{\log(12W/10^6 D)}$	$d_c = \rho_n / \rho_e$
6,000		4.72		8.500	35,000	120	9.0		
6,500	500	4.85	103.1	8.500	35,000	120	9.0	1.4118	1.4118
7,000	500	6.50	76.9	8.500	35,000	110	9.0	1.4803	1.4803
7,500	500	7.58	66.0	8.500	35,000	110	9.0	1.5314	1.5314
8,000	500	11.21	44.6	8.500	30,000	110	9.4	1.5805	1.5132
8,500	500	10.87	46.0	7.875	30,000	110	9.4	1.6096	1.5411
9,000	500	12.69	39.4	7.875	30,000	110	9.4	1.6598	1.5892
9,500	500	14.28	35.0	7.875	30,000	110	9.8	1.6981	1.5594
10,000	500	6.49	77.0	7.875	30,000	110	10.1	1.4425	1.2854
10,200	200	7.61	26.3	7.875	30,000	100	10.1	1.7601	1.5684
10,400	200	8.10	24.7	7.875	30,000	100	10.1	1.7804	1.5865
10,600	200	8.62	23.2	7.875	30,000	100	10.5	1.8005	1.5433
10,800	200	9.17	21.8	7.875	30,000	90	11.1	1.7864	1.4485
11,000	200	10.47	19.1	7.875	30,000	90	11.1	1.8294	1.4833
11,200	200	11.17	17.9	7.875	30,000	90	11.3	1.8504	1.4738
11,400	200	11.91	16.8	7.875	30,000	90	11.6	1.8712	1.4518
11,600	200	9.13	21.9	7.875	35,000	90	11.6	1.8789	1.4578
11,800	200	9.71	20.6	7.875	35,000	90	11.8	1.8999	1.4491
12,000	200	9.71	20.6	7.875	35,000	90	13.1	1.8999	1.3053
12,200	200	10.00	20.0	7.875	35,000	90	13.4	1.9099	1.2828
12,400	200	11.11	18.0	7.875	35,000	90	13.6	1.9459	1.2877
12,600	200	11.11	18.0	7.875	35,000	90	14.2	1.9459	1.2333
12,800	200	11.77	17.0	7.875	35,000	90	14.5	1.9655	1.2200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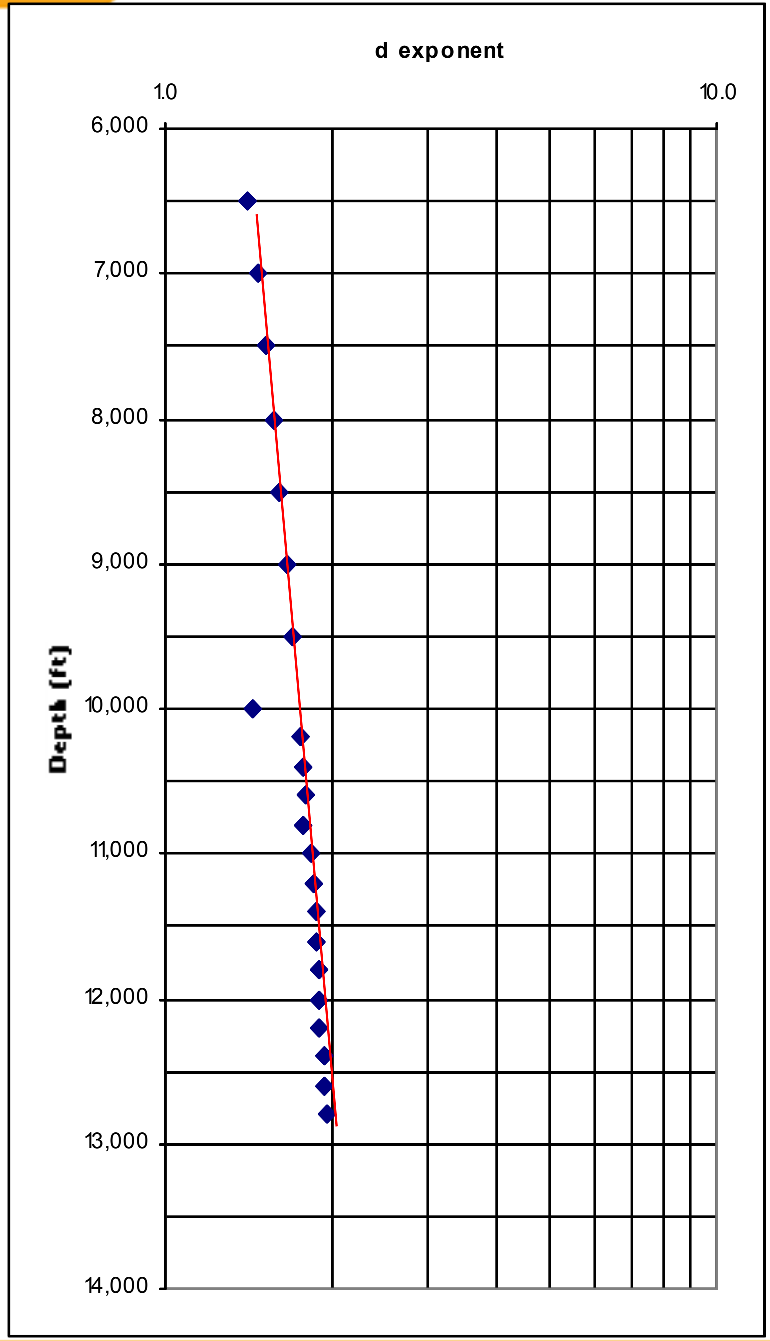
Depth (ft)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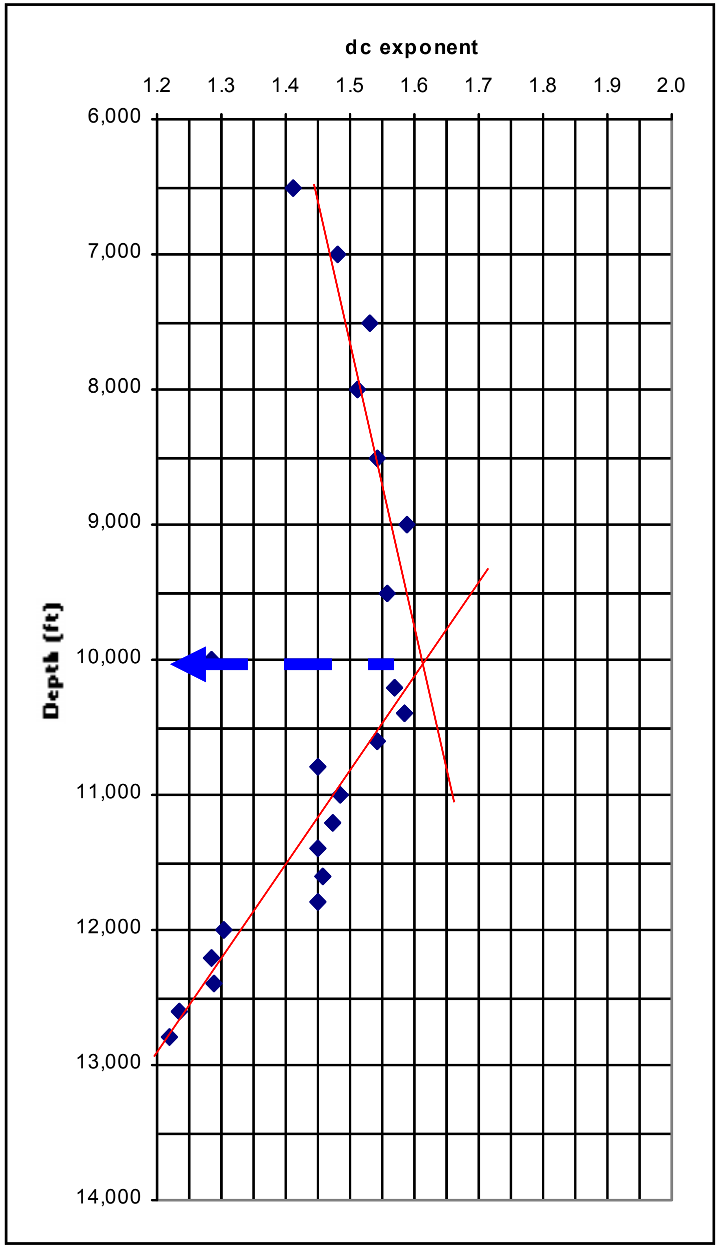
Depth (ft)


dc exponent
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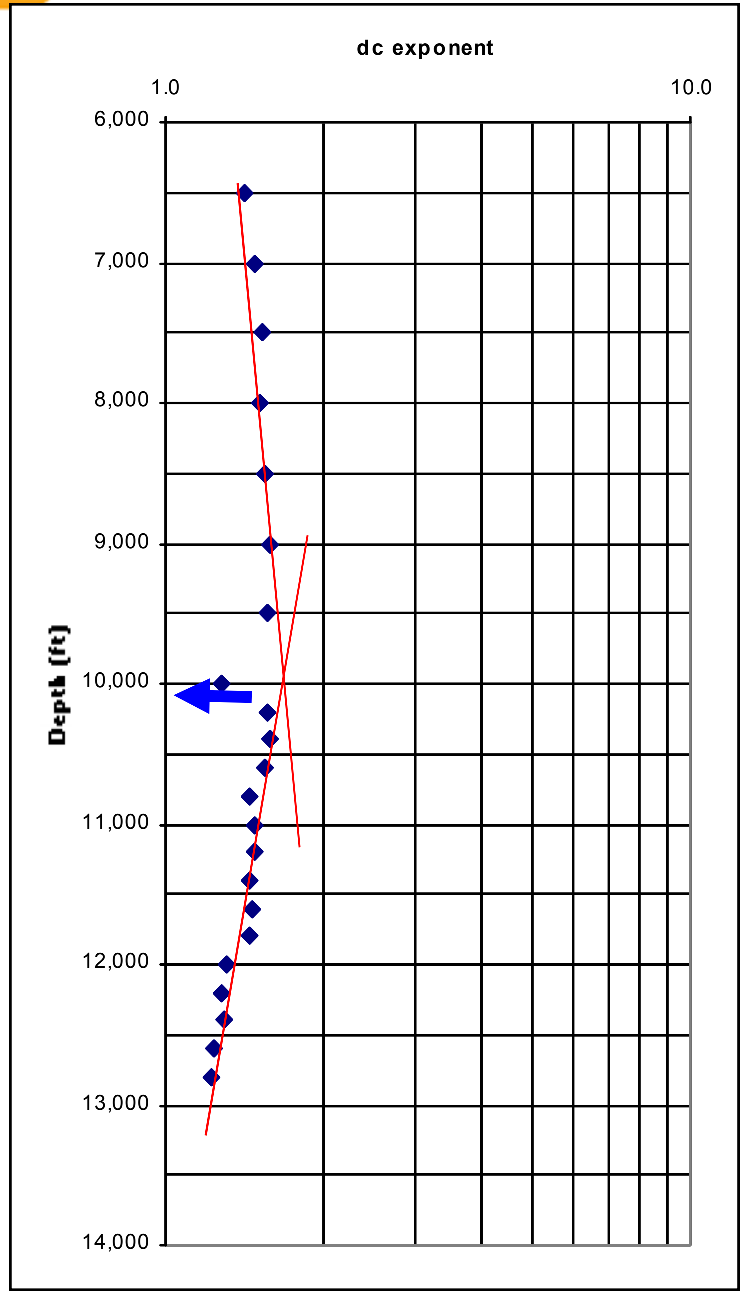
Depth (ft)


dc exponent
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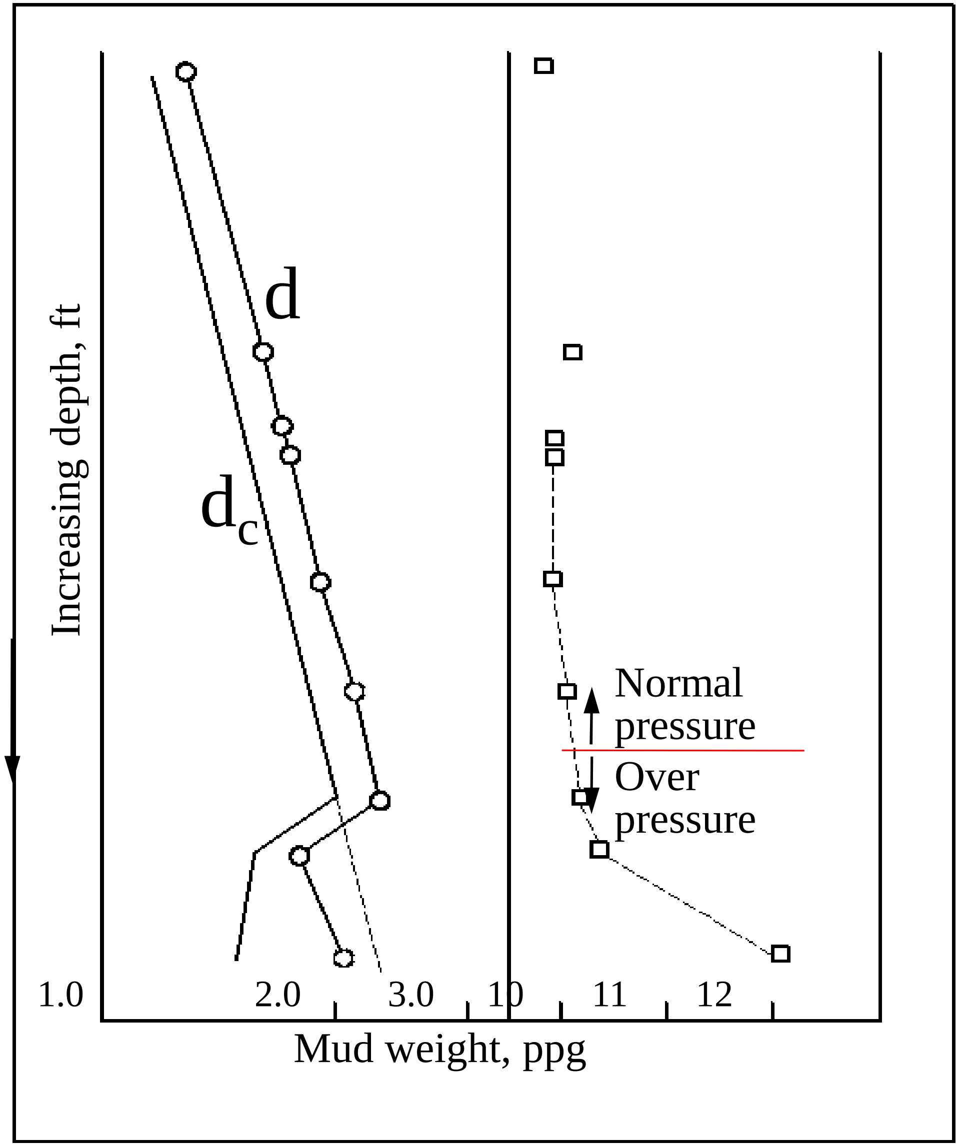
Depth (ft)

Comparison of d and d_c-exponents



Comparison of d and d_c exponents used in geopressure detection. Both exponents may be used for estimating the top of an overpressured zone, but d_c is more quantitative since it considers mud weight effects on drilling rate.

$$\frac{P}{D} = \frac{S}{D} - \left[\frac{S}{D} - \left(\frac{P}{D}\right)_n\right]\left[\frac{d_{co}}{d_{cn}}\right]^{1.2}$$

$\frac{P}{D}$ = fluid pressure gradient (psi/ft)

$\frac{S}{D}$ = overburden gradient (psi/ft)

$\left(\frac{P}{D}\right)_n$ = "normal" hydrostatic gradient (psi/ft)

d_{co} = observed d_c at given depth

d_{cn} = d_c from normal trend (i.e. extrapolated) at given depth

B. DRILLING MUD PARAMETERS

1. Mud-gas cuttings
2. Flowline mud weight
3. Flowline temperature
4. Pit level & total pit volume
5. Mud flowrate

1. Mud-gas cuttings

Gas can be evolved in 2 ways:

a. <u>From shale cuttings</u>

Gas is commonly associated with shale & especially overpressured shales which have a high ϕ. Drilled shale cuttings can release gas as it expands as they move up the annulus in the drilling fluid

b. <u>Direct influx</u>

The influx of gas can occur as the result of directly removing the overbalance p or during the making of connections when pulling back the drill string, produces a tendency to swab

2. Flowline mud weight

- The mud weight as measured at the flowline will be influenced by any foreign fluid influx
- Gas is more readily noticeable because of the ρ difference, but water is more difficult to isolate
- Continuous measurement of mud weight is a most useful technique, e.g. using a radioactive densometer

3. Flowline temperature

- Water has a lower heat conductivity than shale (≈ 60%)
- Heat rising through the earth toward the surface will normally establish an even T gradient but when the water content is higher as in under compacted shale, the T tend to be higher & decrease rapidly through the transition zone before establishing a steady gradient through the normal P interval (see figure)
- Problem → when flow is stopped, mud in the hole near the surface cools while deeper mud heats & pit mud approaches ambient T. When circulating resumes, mud from the flowline slowly heats up to some equilibrium value

4. Pit level and total pit volume

- Variations in the total mud volume can be monitored by pit level indicators
- The increase or decrease in the pit volume may be related to lost circulation, fluid influx, gas influx, etc.

5. Mud flow rate

- Any abnormal rise in pit level caused by mud flow from the annulus will also be reflected in an increasing flow rate, which can be measured by a standard flowmeter

C. DRILL CUTTINGS PARAMETERS

There are a number of analytical techniques involving the use of drill cuttings mostly associated with the identification of under-compacted shales:

1. Density of shale cuttings
2. Shale factor
3. Volume, shape and size of shale cuttings

1. Density of shale cuttings

- The density will vary with the degree of compaction and is given by the following relationship:

$$\rho_{sh} = \phi\rho_w + (1- \phi)\ \rho_g$$

- Bulk ρ in normally compacted shales increases with depth in normally pressured reservoirs, a plot of bulk ρ with depth should be a straight line as it will show increased compaction with depth for a constant lithology

3. Volume, shape and size of shale cuttings

- An increased in penetration rate will results in an increased volume of cuttings
- Additionally, the shape and size of the cuttings will change
- In transition zone the cuttings shape will show an angular and sharp edges and large cutting size

Formation Fracture Gradient

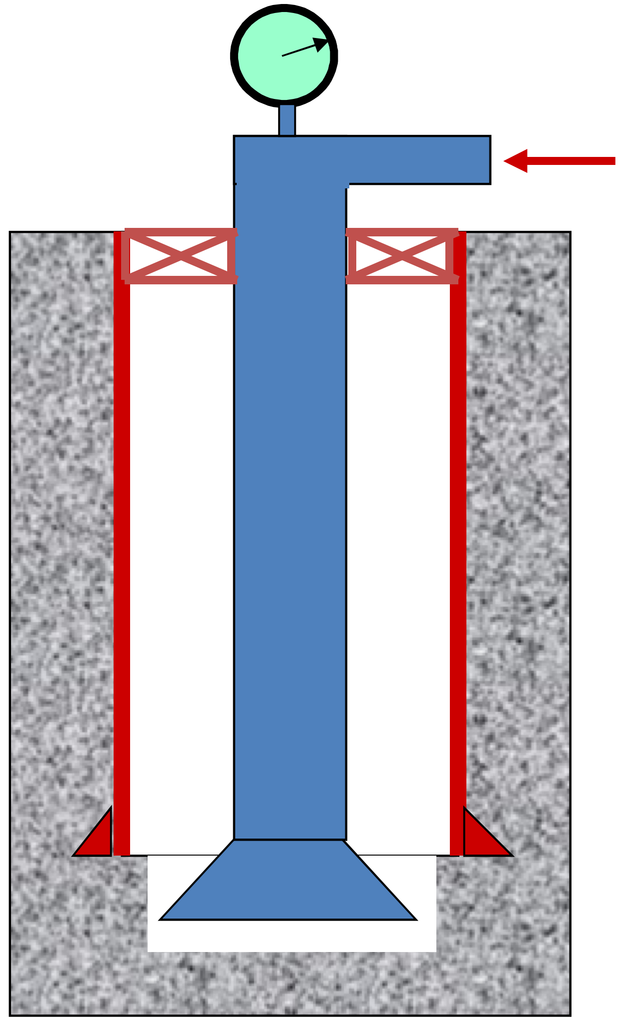
Definition:

Fracture gradient is a measure of how the strength of the rock (i.e. its resistance to break down) varies with depth.

- In planning the mud programme, it is useful to know the max MW which can be used at any particular depth
- This maximum MW is defined by the fracture gradient
- The MW used in the well must lie between the formation pressure gradient and the fracture gradient
- Knowledge of the fracture gradient is vital when drilling through an overpressured zone

Leak-off Test

- Formation breakdown/fracture gradients are determined by leak-off tests → quantitative
- Procedure:
  - Run and cement casing
  - Drill about 5 - 10 ft below the casing shoe
  - Close the BOPs
  - Pump slowly and monitor the pressure
  - At the point where pressure begins to bleed off stop pumping



Tri-axial Test

- Leak-off tests –expensive
- Alternative: Tri-axial Test, much cheaper
  - Used core sample taken at pre determined depth
  - Used Tri-axial machine

Fracture Gradient Predictions

- Many attempts have been made to predict fracture gradients from known pore pressure gradients
  - Hubbert and Willis
  - Matthews and Kelly
  - Pennebaker
  - Ben Eaton
  - Christman
  - Etc.
- All are somewhat similar. In this lesson only Hubbert and Willis's, Matthews and Kelly's and Ben Eaton's methods will be discussed

Hubbert and Willis

- Based on the assumption that fraction occurred when the applied fluid pressure exceeded the total minimum effective stresses and formation pressure

$$G_f = \frac{1}{3}\frac{\sigma_\nu}{D} + \frac{2}{3}\frac{P_f}{D}$$

G_f = fracture gradient (psi/ft)
σ_ν = overburden stresses (psi)
D = depth of interest (ft)
P_f = formation pressure (psi)

- Predicts higher fracture gradient in abnormal pressured formation and lower fracture gradient in subnormal pressured formation
- Not suitable for soft rock formation like in the Gulf of Mexico and northern part of North Sea area

Matthews and Kelly

- Proposed the method for use in sedimentary rocks

$$G_f = G_p + \frac{\sigma K_i}{D}$$

G_f = fracture gradient (psi/ft)
G_p = pore pressure gradient psi/ft
K_i = matrix stress coefficient
σ = matrix stress (psi)
D = depth of interest (ft)

- K_i relates the actual matrix stress to the normal matrix stress and can be obtained from charts

Eaton

- The most widely used in petroleum industries

$$G_f = (G_o - G_p)\left(\frac{\nu}{1-\nu}\right) + G_p$$

G_f = fracture gradient (psi/ft)
G_o = overburden gradient (psi/ft)
G_p = pore pressure gradient (observed or predicted) (psi/ft)
ν = Poisson's ratio

$$\frac{\sigma_1}{\sigma_p} = \frac{\nu}{1-\nu}, \qquad \frac{\sigma_1}{\sigma_p} = \frac{1}{3}\ (\mathit{from\ lab.\ test})$$

- Field tests however show that ν may range from 0.25 to 0.5 at which point the rock becomes plastic (stresses equal in all directions).

Summary of procedures

In planning a well using formation pressures and fracture pressures the following procedure applies:

- analyse and plot log data or d-exponent from an offset well
- draw in the normal trend line, and extrapolate below the transition zone
- calculate a typical overburden gradient using density logs from offset wells
- calculate formation pressure gradients from equations (e.g. Eaton)
- use known formation and fracture gradients and overburden data to calculate a typical Poisson's ratio plot
- calculate fracture gradient at any depth