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Pore Pressure and Fracture Pressure Determinations in Deepwater

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Most deepwater wells penetrate overpressured formations and require several strings of protective casing in the first few thousand feet of sediments below the sea floor. Well control problems and aborted operations (unable to set more casing strings) are not uncommon.

Because of the associated risks and high costs, accurate pre-drill and while-drilling pore pressure predictions are critical

This report sets out the basic methodology for determining pore pressure and fracture pressure in deepwater. It also describes a new centroid model and lists ideas for future improvements.

Two main points are made: 1) A well drilled *directly* at the crest of a large overpressured structure is at considerable risk of mechanical failure and, 2) the models for pressure prediction require a precise value for overburden pressure.

Definitions and Nomenclature

Hydrostatic Pressure is the pressure in a column of salt water as illustrated in Figure 1. Overburden Pressure is that exerted by the combined weight of the sediments plus the weight of the sea water. Pore Pressure is the fluid pressure in the shales and reservoirs. Normal Pressure is a pore pressure value equal to hydrostatic. Overpressure is a value greater than hydrostatic. And, Fracture Pressure is the borehole pressure required to initiate fracturing and lost circulation

Overburden gradient (O), **pressure gradient (P)**, and **fracture gradient (F)** are defined as the respective pressures divided by the true vertical depth referenced to the derrick floor, i.e. referenced to the top of the mud column. Pressure gradient is therefore equivalent to the mud density required to exactly balance formation pore pressure. All the gradients decrease as the rig floor elevation increases i.e. as the air gap increases. In this report gradients are expressed in pounds per gallon (ppg) where 1 psi/ft = 19.25 ppg = 2.31 g/cc. Measured depth (D), water depth (W), and air gap (A) are expressed in feet, where 1 meter = 3.281 feet.

Pressure Cell are isolated compartments or reservoir with finite permeability sealed on all six sides by shale. As shown in Figure 1, the pore pressure in a cell increases with depth at a rate parallel to the hydrostatic line - or less if hydrocarbon bearing.

Prediction of Overburden Pressure

The overburden gradient is related to height of the water column and the sediment column by the equation:

$$O = [(8.5)(W) + (\rho_{\text{avg}})(D-W-A)]/D$$

where: ρ_{avg} is the average density of the sediment in ppg, and 8.5 is the assumed sea water density.

One simple way to estimate ρ_{avg} , when direct density measurements are not available, is to use a compaction relationship based on regional density data such as:

$$\rho_{avg} = 16.3 + \{(D-W-A)/3125\}^{0.6}$$

As an example, if W and A are 2000 feet and 50 feet, respectively, the overburden gradient is 13.7 ppg if D is 5200 feet and 16.7 ppg if D is 12300 feet.

Another popular method to estimate ρ_{avg} is to convert resistivity¹ or acoustic^{2,12} data to bulk density. However, use of these methods requires discretion because of temperature and clay effects on the porosity transforms (e.g. problems with the standard Wyllie time average equation in shales). Use of a text book value of 1 psi/ft (19.25 ppg) as an estimate for the overburden gradient is also not recommended for deepwater interpretations.

Prediction of Fracture Pressure

Fracture pressure is assumed equal to the minimum horizontal stress. The ratio of minimum horizontal effective stress to vertical effective stress (k) is defined as follows:

$$k = (F-P) / (O-P)$$

Rearranging terms results in the standard fracture gradient formula:

$$F = (k)(O-P) + P$$

Stress ratio, k, has been estimated using several approaches as listed below:

Empirical: $k = (0.039)(D-W/4-A)^{0.33}$;or

Uniaxial strain $k = (\nu)/(1-\nu)$; or ...

Plastic^{3,4} $k = 1$; or

Solidity¹ $k = (1-\phi)$;or

Hoop stress $k = (2\nu)/(1-\nu)$;or

Failure^{5,6} $k = 1/[(\mu^2+1)^{0.5}+\mu]^2$; or

Fault angle $k = 1/\tan^2\theta$

Where: ν is Poisson's ratio, ϕ is fractional porosity, μ is the coefficient of friction, θ is the angle of faults measured from the horizontal, and where the constants in the empirical method have been derived by the author from leak off test (LOT) data from the Gulf of Mexico.

Consider an example: If pore pressure is normal (i.e. P is 8.5 ppg) and D and O are 5200 feet and 13.4 ppg respectively from the last example, fracture gradient is 11.6 ppg, assuming a k of 0.63 from the empirical approach.

Prediction of Pore Pressure in Shales

Pore pressure prediction models can be grouped into horizontal or vertical categories. Both categories apply to pre-drill and while-drilling models that use seismic velocity, acoustic travel time, or resistivity data.

Vertical models sometimes referred to as explicit^{7,8} or closed loop¹ assume, given a value for porosity, effective stress (i.e. O-P) can be determined uniquely. As illustrated in Figure 2, a vertical line on a depth versus velocity plot defines a constant porosity line and (if the assumption is right) a constant effective stress line. An example is the classical equivalent depth relationship:

$$P = O - (O_e - 8.5)(D_e/D)$$

where: O_e and D_e are the overburden gradient and the depth where the vertical line crosses the compaction line and 8.5 is an assumed normal pressure gradient. For example, in Figure 2 where

(D_e/D) is 0.42 and O and O_e have been estimated in previous exercises, the vertical-derived pore pressure is 13.9 ppg.

Horizontal models, on the other hand, assume that the pore pressure is empirically related to the ratio of the measured parameter (e.g. velocity) to the expected value at the trend line at the same depth. An example is the Eaton⁹ relationship:

$$P = O - (O - 8.5)(M/E)^x$$

where: M/E is a ratio of the measured value (i.e. resistivity, velocity or acoustic travel time) to the expected value at trend line at the same depth, and x is an empirical exponent. The horizontal derived pressure in Figure 2 is 14.1 ppg assuming a value of 3 for the exponent. (Use 1.2 for resistivity data.)

Horizontal methods that correlate M/E directly to pore pressure without an overburden term (e.g. Hottmann and Johnson) require local calibration to account for changes in water depth and should be used with discretion.

Limitations of the Two Models

A limitation of the vertical models is the effect of formation temperature. The method developed by the author to temperature correct resistivity data uses an Exxon¹⁰ temperature algorithm as illustrated in Figure 3. Other methods^{1,7} use a log to porosity transform which intrinsically compensates for temperature (generally with other temperature algorithms).

A limitation of the horizontal models is the compaction trend line. As illustrated in Figure 2, the trend line has to be extrapolated to the depth of interest assuming a straight line or curved shaped. Where the trend line cannot be defined explicitly, a useful compaction relationship is:

$$\phi = 0.41 - (D - W - A)/45,455$$

where ϕ is fractional porosity and the constant, 0.41, is adjusted to fit available data. If $(D - W - A)$ is $> 17,500$ feet, set ϕ equal to 0.025.

Given the above porosity depth relation, the normal trend line values can be derived for acoustic travel time, velocity or resistivity using a porosity transform such as:

$$\phi = (43/t_{ma})(1 - t_{ma}/t)$$

where t_{ma} and t are matrix and bulk acoustic travel times, respectively, in units of microseconds per foot.

There are other uncertainties in the vertical models¹¹. Scott and Thomsen¹² suggest that observed apparent porosity reversals e.g. at a depth of 8500 feet in Figure 3, may be a stress effect and not an actual porosity reversal as assumed in the models. Another uncertainty in both models is the normal pressure gradient; it can be as high as 8.95 ppg.

The Centroid Concept

In practice, the pore pressure value derived in an overpressured shale is not equal to that in the adjacent reservoir except at a centroid depth. This concept developed by Amoco¹³ is an extension of work by Shell¹⁴. It is a simple concept that has now been presented by several companies as a self evident procedure.

As show in Figure 1, the centroid is the depth where the pore pressure in the cell and in the shale are in equilibrium. Above a centroid the pore pressure in the cell decreases at a hydrostatic rate with decreasing depth while that in the shale decreases at a faster overburden rate. The net effect is that

the pressure in shales is about 50 psi lower than the pressure in the juxtaposed reservoir for each 100 feet above the centroid. The effect is larger if hydrocarbons are present because of buoyancy.

Another effect illustrated in Figure 1 is that the equivalent mud weight *increases* toward the crest in each cell while it *decreases* in the bounding shales (with a corresponding decrease in fracture pressure in the shales). It is not uncommon to have a pore pressure in the reservoir at the crest equal to the fracture pressure of the overlying shale.

A well drilled directly at a crest can lose returns into the seal (with mud pumps on) and have flow from the reservoirs (with pumps off)..

Two guidelines apply: 1) to correct for the centroid effect, add 50 psi to shale derived pore pressure for each 100 feet of structure; and, 2) do not drill directly at the crest of high relief, overpressured structures.

Recommendations

The following are several recommended procedures and options.

- Use both a vertical and horizontal model when making pressure predictions. Since the two are independent, agreement provides verification.
- Modify vertical prediction models as a function of the orthogonal mean effective stress instead of vertical effective stress, i.e. $(O-P)(1+2k)/3$ instead of $(O-P)$. Because k tends to increase with depth, the resultant pore pressure predictions will be higher using mean stress values (and more aligned with measurements?).
- Determine what drives the shape of the normal compaction trend - porosity (ϕ), solidity ($1-\phi$), or void ratio $\phi/(1-\phi)$? Is it straight or curved on a semi-log plot?
- Develop a relation for the acoustic matrix travel time as a function of effective stress. The author has derived the following equation but it is only an approximation:
$$t_m = (95)[O-P](D-W-A)]^{-0.5} + (15)(\text{clay fraction})$$
- Continue the open communication at the pressure workshops hosted by the American Association of Drilling Engineers (AADE). To enhance well safety in the industry, Amoco supports the continuing release of technology like the centroid concept.

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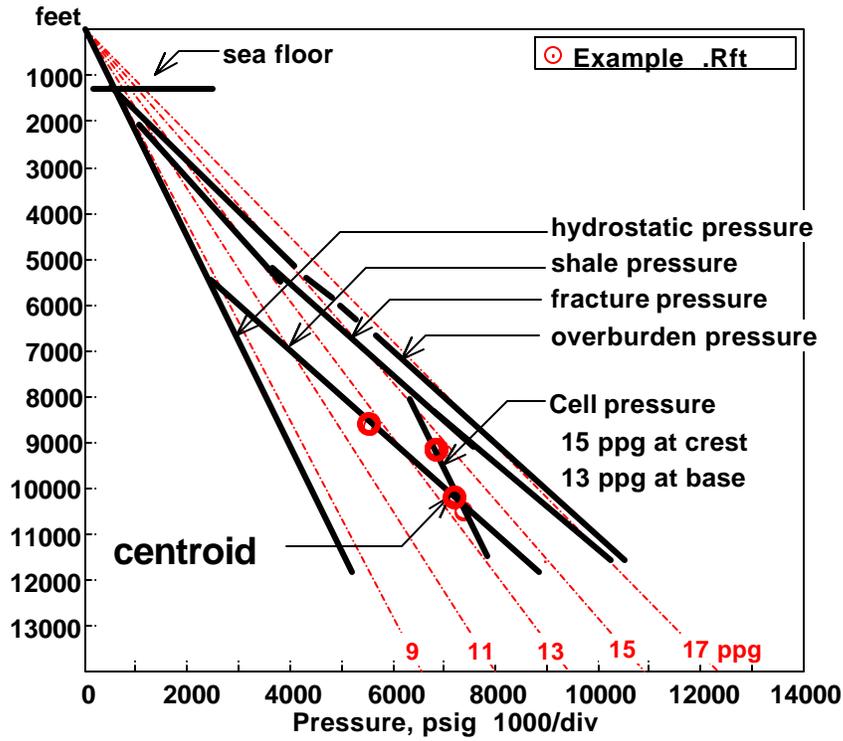


Fig 1. A pressure plot of depth versus pressure illustrating terminology.

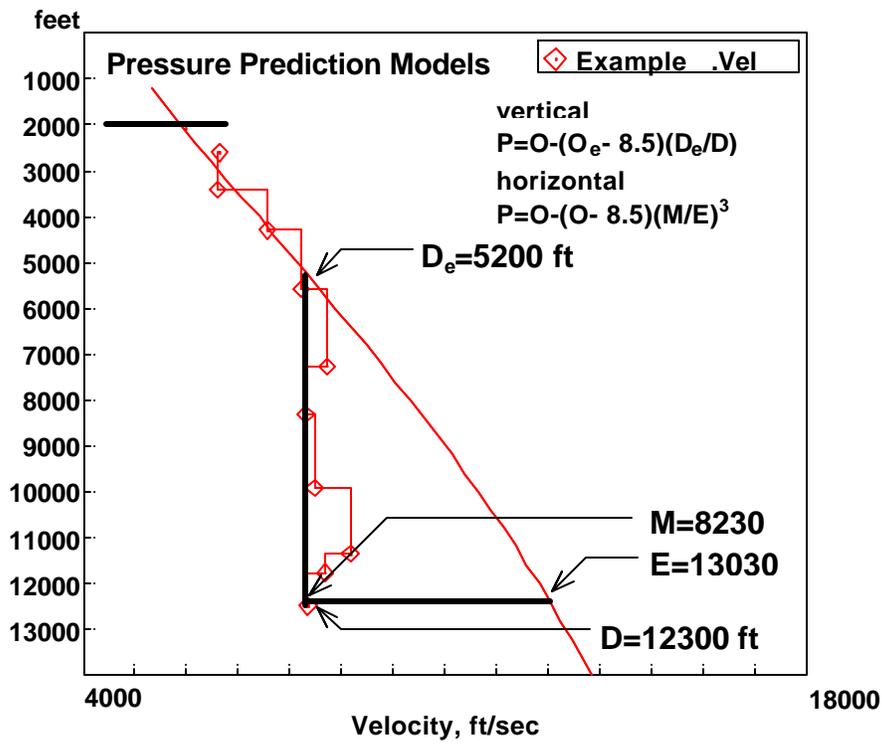


Fig 2. A plot of depth versus seismic velocity illustrating the two models. Water depth is 2000 feet.

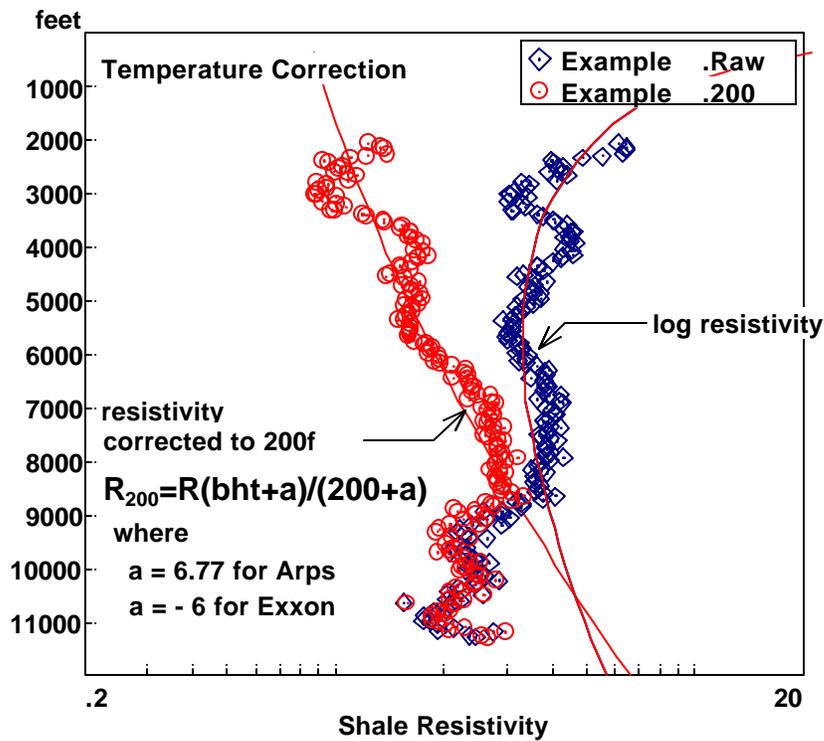


Fig. 3 - Example of resistivity data corrected for temperature. Note that the compaction trend line is much more linear with the corrected data.