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Overburden Stress Estimation in Shallow Sediments Where Density Log is Unavailable: A Geomechanical Approach

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Abstract: ***Understanding pore pressure is critical to safe well drilling. The lack of density logs in shallow sediments, both onshore and offshore, limits overburden-stress estimation, the first step and essential for pore-pressure prediction. Although various methods routinely generate pseudo-density logs and integrate them with density logs from deeper intervals, these approaches lack a solid geomechanical basis. Shallow sediments are unconsolidated and exhibit plastic behaviour, so extending the elastic model used for deeper sediments is inappropriate. Collecting geotechnical data is therefore essential to building a reliable density model for shallow sediments and, consequently, pore-pressure and fracture-stress models that can mitigate shallow hazards and support safe drilling. This paper introduces a methodology for evaluating the geotechnical properties of shallow sediments and for developing an integrated model that is geomechanically sound and suitable for use along the shallow well trajectory.***

Keywords: Density, Overburden, porosity, soil boring, elastic, plastic, LOT, pseudo-density

1. Introduction

Accurate pore-pressure information is essential for safe, cost-effective well construction. Pore-pressure, fracture-pressure, and geomechanical studies all require accurate estimates of overburden stress- the combined weight of the materials above the depth of interest. Most pore-pressure prediction (PPP) methods calculate vertical effective stress and combine it with overburden to predict pore pressure. Fracture pressure is often calculated as a function of overburden (OVB) and pore pressure (PP). This means every pore-pressure analysis must estimate three key outputs: the overburden gradient (OBG), pore pressure (PP), and fracture gradient (FG). Because errors in these estimates can propagate throughout the geomechanical model, OBG is critical for evaluating geopressures and stresses[1]. Calculating overburden stress may seem fairly straightforward, but precision is vital because it affects estimates of pore pressure and horizontal stresses.

OBG is calculated using density (RHOB) log data. Overburden stress is also called lithostatic stress or vertical stress. Shallow density logs rarely begin at the mudline, leaving a crucial gap in the OBG used to predict PP and FG. Because OBG is a key input for all compaction-based pore-pressure models, this disparity immediately affects PP predictions. We compute pseudo-RHOB for the shallow region using multiple equations and integrate it with Logging-while-drilling (LWD)/wireline RHOB log data because density log data do not extend to the surface or bottom. This paper proposes a viable geomechanically based procedure and addresses problems with various approaches to close the shallow-section density data gap.

2. Overburden Stress

Overburden stress at a given depth is the stress exerted by the weight of the overlying sediments; therefore, it can be determined from rock bulk density using the following equation-A[2,3,4,5,6,7,8]. Polynomial and exponential models as a function of depth below the surface or mudline reproduce the overburden gradient properly[6,9,10]. Since bulk density, ρ_b, measures the weight of rock and pore fluids, overburden pressure at a given depth can be calculated by integrating the bulk density-depth profile. For continuously stratified strata, the overburden pressure at depth z is a function of the parameters z, P_0, and g, and is given by

$$P(z) = P_0 + g\int_0^z \rho(z)dz \qquad \textbf{Equation A}$$

q(z) is the density of the overlying rock at depth z, and g is the acceleration due to gravity. P_0 is the datum pressure, like the pressure at the surface. The equation implies that gravitational acceleration is constant over z since it is outside the integral. Strictly speaking, for almost all boundary conditions, 'g' should appear inside the integrand since g depends on distance from the mass. However, because g varies little over depths that are a very small fraction of the Earth's radius, it is often placed outside the integral in practice for most near-surface applications that assess lithostatic pressure. For offshore sediments, the hydrostatic pressure from water depth must also be considered (equation B).

$$p_{over} = \int_o^{D_w} g\,\rho_w\,dD + \int_{D_w}^{D} g\,\rho_b\,dD \qquad \textbf{Equation B}$$

The most reliable bulk-density data come from in situ measurements with a gamma-gamma formation density log. However, such data are rarely available above the surface-casing setting depth. For quality control, density readings from washout zones—where the caliper exceeds 12 inches—are excluded. The excluded intervals also showed signs of tool sticking and, where possible, were cross-checked against other drilling events. Formation density logs can be inaccurate in large-diameter boreholes, so a pilot hole may be needed to obtain reliable measurements in shallow sediments. LWD

tools can also measure formation density, but they require boreholes no larger than 14 inches in diameter. A pilot hole may therefore be needed for accurate density measurements in the upper marine sediments. However, borehole conditions affect uncorrected density-log readings, and including water depth can introduce bias[1].

During sedimentation, shales and sands compact as younger layers accumulate above them, reducing their porosity and thickness while expelling pore water in response to increasing overburden weight. The overburden pressure gradient measures how the pressure exerted by overlying rock on underlying rock changes with depth[11]. This gradient varies according to the degree of compaction and burial depth.

3. Significance of shallow sediment strength determination

Sedimentary deposits below the seafloor to a depth of roughly 3000 feet are referred to in this research as shallow sediments (SS). Compared to deeper sediments, SS are qualitatively softer and more ductile. A thorough understanding of, and ability to forecast, overburden pressure in formations directly affects the exploration and development stages of a well's life[12]. This forecast is based on evaluating a formation's vertical effective stress and pore pressure, which can also predict anomalous pressures.

Because density log data do not extend to the surface or seabed, making it an incomplete dataset, we use several equations to calculate pseudo-RHOB for the shallow section, generate synthetic density curves, and integrate them with LWD/wireline RHOB log data. This paper examines issues associated with different methods for closing the shallow-section density data gap. PP is typically predicted in shale zones, then calibrated using the most reliable direct pressure measurements in sands and log data from adjacent shales. An incorrect overburden definition causes errors in pore pressure, fracture pressure, and the drilling window.

Ideally, determine overburden stress from in-situ density data. Because these data are unavailable in pre-drill studies, use offset data or an overburden model. A common quick fix is to assume a simple, constant overburden gradient—usually 0.9 psi/ft or 1.0 psi/ft—or apply one to intervals missing from the density log. However, a simple overburden function or trend is inappropriate because lithology and sediment compaction can change abruptly with depth[2]. Vertical stress is a key input in many fracture-gradient relationships and pore-pressure prediction techniques[13,14].

Estimating formation pore pressure requires knowing the overburden load in an area, which is commonly determined by vertically integrating density data. Where total vertical stress is strongly influenced by topography (e.g., onshore valleys and subsea canyons) or lateral density variations (e.g., salt domes), vertical integration may overestimate or underestimate total vertical stress, leading to inaccurate pore-pressure predictions. Ozan Cem (2010) shows that topography and lateral density variations can significantly affect pore-pressure predictions when total vertical stress is calculated by vertical integration[15].

In extended-reach and highly deviated wells, evaluate potential lateral density variations. These may arise from increasing water depth, topographic changes, or intrusive bodies whose densities differ substantially from those of the host rock. Figures 1a, 1b, and 2 illustrate real-world cases in which overburden conditions vary along the well trajectory[16,17]. In addition, for vertical wells in areas with pronounced topography or lateral density variations, integrating density vertically may overestimate or underestimate the total vertical stress.

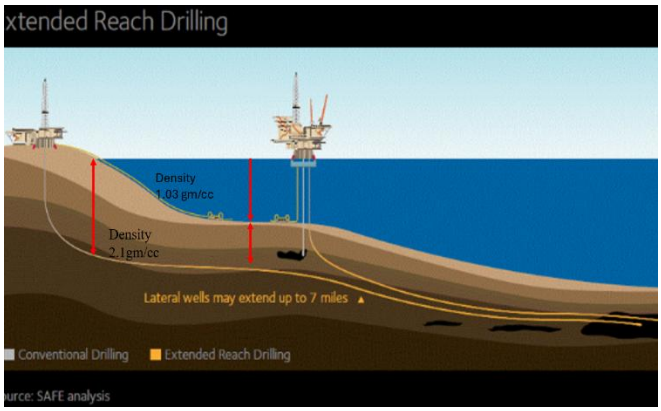


Figure 1 (a): An ERD well drilled from the coastline to an offshore target[16]

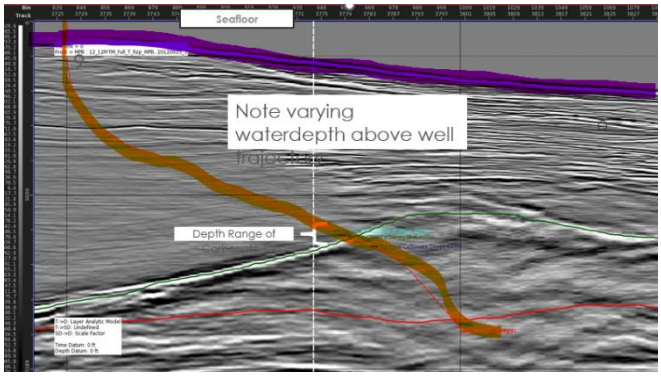


Figure 1(b): A directional exploration well from shallow waters to deeper waters in Luconia, Far East.

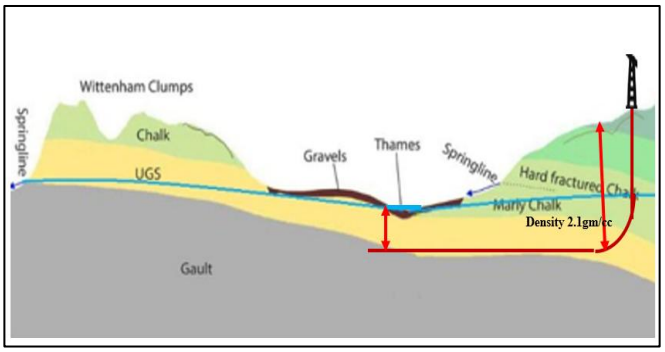


Figure 2: Highly deviated well drilled in the highlands under the Thames River[17]

4. Issues with Overburden Gradient (OBG) calculation

In practice, density logs spanning the entire interval from the mudline to TD are rare, and measurements are often missing from the first few hundred metres of a borehole. In such cases,

use the available geological information to develop a reasonable estimate. As a rule of thumb, assume a density of approximately 1.8 gm/cm³ at the mudline in soft sediments (i.e., offshore), with density increasing exponentially with depth. Onshore, 2.1 gm/cm³ is a reasonable initial value at the surface. How you define the density profile in shallow sections can significantly affect the estimated overburden stress at reservoir depths. Always account for lithologic changes that may produce abrupt density variations, such as anhydrite or thick carbonate intervals.

Several methods can estimate the pseudo-density of the shallow or upper well interval when no density log is available. This pseudo-density can be combined with LWD/wireline density data to produce a composite density profile for the entire well. OBG is then calculated from this composite density. When direct density measurements are unavailable or do not extend to the surface, regional density data are often used to derive a compaction relationship.

5. Common OBP Estimation Methods

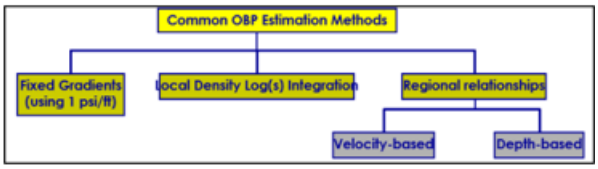


Figure 3: Common overburden estimation techniques

Figure 3 shows the most commonly used estimation methods. If data are unavailable, an overburden stress gradient of 1 psi/ft is often assumed for onshore settings[18,19]. However, vertical stress can vary considerably between sedimentary basins and should therefore be determined from local data whenever possible. The studies by Tingay et al. (2003)[20] in the Baram Basin and, more recently, by Smye et al. (2021)[21] in the Permian Basin provide excellent case studies. Lithology, lithification, water-column thickness, and uplift history all influence vertical stress and may cause it to deviate from the 1 psi/ft gradient. Accordingly, published studies report vertical stress gradients ranging from 0.85 psi/ft in deep-water settings to 1.17 psi/ft in uplifted onshore terrains. In some basins with extensive datasets, researchers have developed empirical relationships that provide reasonable overburden stress estimates when direct data are lacking.

Dickinson's (1953) seminal article on Gulf Coast pressure popularised using a mean sedimentary-rock density of 2.3 g/cm³, particularly in Tertiary deltas[22]. This value is widely used in part because it yields an overburden-stress gradient of 1.0 psi/ft (22.63 MPa/km); consequently, many studies assume a vertical stress gradient of 22.63 MPa/km without checking it against local data[23,24].

The fixed gradient of 1 psi/ft is often used for quick estimates and corresponds to a mudrock porosity of 24%. It consistently overestimates pressure in the shallow section and underestimates it in the deeper section. It is not recommended except for scoping studies. Fixed-gradient OBP models should be avoided.

5.1 Overburden pressure (OBP) Estimation: Local Density Logs

When data quality is high, this approach- which incorporates density logs- is the most accurate. However, density logs are obtained in WBM, and mud chemistry may affect seal-integrity predictions. Missing density logs immediately below the mudline can introduce errors, and thick beds of different lithologies (such as chalk or salt) can affect the profile. OBP can be sensitive to lithologic variations, so use caution. The density of the lithology and the density of the mudrock it replaces determine the impact. Use oil-based mud density data wherever possible due to near-borehole modification.

5.2 OBP Estimation: Velocity-based

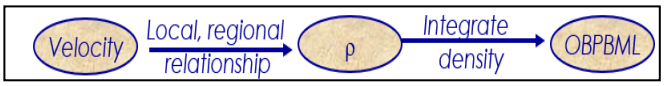


Figure 4: Velocity-based overburden estimation technique

In Velocity-based OBP, exercise caution, as input velocity errors introduce errors in the OBP BML. Local (well-based) models can be useful, but use caution with unlogged sections, extrapolation, varying geology, and setting. Depth-based (power-law) relationships often work well, particularly in areas with simple burial histories, tectonics, and stable lithology.

6. Overburden Stress Analysis

Understanding how porosity changes with overburden pressure in shales is key. Sub-regional and regional overburden stress models (also known as lithostatic or vertical principal stress) using edited and upscaled density logs were derived. If rock density is unknown, overburden pressure can be estimated using the porosity trend with depth[5]. Density-versus-depth trends are approximated using Athy's model[25] (Formulae 1 and 2). This model was fit to the multi-well density data by optimising the "critical" (surface) porosity and compaction coefficient while keeping the fluid density constant at 1.0 gm/cc and the matrix density at 2.67 g/cm3 (i.e., the average mudrock grain density obtained from XRD analysis).

The overburden stress model required integration of the density trend, which was done using the following analytical formula derived from equation (2), assuming that density and pressure units are gm/cc and psi, respectively:

$$\phi = \phi_{crit} * e^{(-C*Zgl)} \quad (1)$$

$$\rho = \rho_{matrix} - (\rho_{matrix} - \rho_{water})\phi_{crit} \exp(-C * Zgl) \quad (2)$$

where ϕ is mudock porosity, ϕ_{crit} - critical or surface porosity, C - compaction factor, Zgl - vertical depth from the ground level, ρ_{matrix} - matrix density, and ρ_{water} - water density

String of Pearls mudrock : $\phi_{crit} = 0.474$, $C = 8.425E\text{-}5$ [1/ft], $\rho_{matrix} = 2.67$ [g/cc], $\rho_{water} = 1$ [g/cc]

$$OBP = 0.4335 * \left[\rho_{matrix} Z_{gl} - \frac{\phi_{crit}}{C}(\rho_{matrix} - \rho_{water})(1 - \exp(-C * Zbml))\right] \quad (3)$$

Figure 5a shows the Niger Delta sub-regional density trend as a red line. A large spread of density points in this plot is caused by frequently changing lithology (alternating sand/shale layers). However, the data spread and associated

uncertainties are dramatically reduced after integration; see the overburden trends in Figure 5b. This is because the overall net-to-gross does not change significantly laterally in the shallow and middle sections. Differences between the sub-regional overburden trend and lithostatic stresses computed from individual density logs are within a 100 psi range at 15,000 ft, which is relatively small given that the overburden stress at this depth is approximately 14,000 psi. The shallow section density was extrapolated.

A regional trend for the whole Niger Delta onshore area was estimated using the following parameters: "critical" porosity = 0.453, compaction = 8.115E-5 1/ft, fluid = 1.03 gm/cc, matrix density = 2.65 g/cm3. These parameters were used to analyse HPHT wells outside the sub-region.

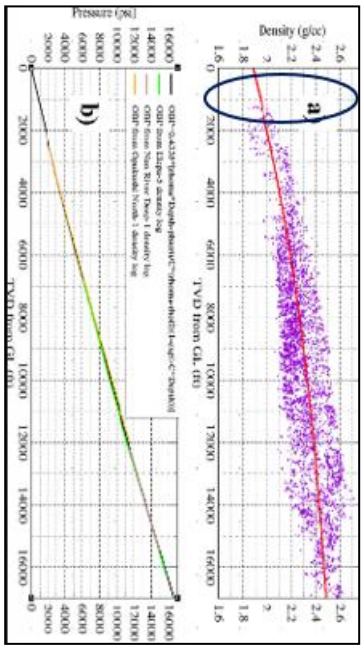


Figure 5 (a): Subregional density trend and 5b.Overburden trend

7. Shallow Overburden Methods

Several pseudo-density generation approaches are used when shallow RHOB is missing. These are proven interactive methods to fill the Shallow Density Gap. When direct density measurements are unavailable or do not start at the surface, a compaction relationship based on regional density data is often used. This methodology has inherent shortcomings and inaccuracies, as shallow rocks are unconsolidated and have different geomechanical properties. Several methods commonly determine overburden density.

1) Extrapolation: The synthetic density is extrapolated up to the mud line using three control points using the equation

$$\rho_{extrapolated} = \rho_{mudline} + A_0 \times (TVD - AirGap - WaterDepth)^{\alpha}$$

2) Gardner's equation: Converts sonic/seismic interval velocity to density; widely used but sensitive to lithology and requires basin-specific calibration26.
3) Amoco empirical relationship[27]: Another velocity-to-density transform used in shallow sections. The synthetic density is estimated by an empirical equation based on statistical data of the Gulf of Mexico.

$$\rho_{Amoco} = \rho_{mudline} + A_0 \times [(TVD - AirGap - WaterDepth)/3125]^{\alpha}$$

4) Faust's equation[28]: Uses resistivity when seismic resolution is poor or sonic data unavailable.
5) Miller's equation[29]: More reliable for shallow sediments (upper 1000–2000 ft), especially when seismic data are unavailable. The synthetic density is computed from sediment porosity.

$$\rho_{Miller} = \rho_{matrix}(1 - \varphi_{Miller}) + \rho_{water}\varphi_{Miller}$$

$$\phi_{Miller} = \phi_a + \phi_b e^{\left(-k*(TVD-AirGap-WaterDepth)^{\frac{1}{N}}\right)}$$

where Ó is the sediment porosity at greater depth, the sediment porosity fitting parameter equal to mudline porosity minus 7 (default 0.35 p.u), k is the porosity decline factor (default 0.0035), and N is the curvature parameter set at the default 1.09.

6) **Sayers[30]:** An introduction to velocity-based pore pressure estimation. The synthetic density is calculated as a function of TVD.

$$\rho_{Sayers} = \rho_0 + a \times (TVD - WaterDepth - AirGap)^b$$

where P_0 is the density in g/cm3 at the ground floor TVD (default 1.9532 gm/cm3). a is the Equation factor (default 0.0015338). b is the Equation exponent (default 0.6). Density is calculated as a function of TVD.

7) **Traugott[31]**: An empirical model of diminishing porosity with depth derived from an exponential fit of Gulf Coast Miocene sediment density data is used to determine the synthetic density. To better replicate the near-mudline high porosity and rapid compaction shown in shallow core porosity data for the deepwater Gulf of Mexico, we created a shallow porosity degradation model. A straightforward depth shift along the porosity curve accounts for uplift. To estimate the horizontal stress component of the mean stress, we assume normal pore pressure and a passive margin for vertical effective stress. This is predicated on calculating bulk density and integrating it to calculate overburden. Starting at mudline, the procedure gradually calculates density using the overburden gradient estimate from the preceding phase.

$$\rho_{surf} = \rho_{fl} \times \phi_0 + (1 - \phi_0) \times \rho_{gr}$$

8) **Constant density assumption**: A simple fallback until the first measured RHOB point, though less accurate.
9) **Pseudo-logs from seismic velocities:** Fresh velocity analysis, interval velocity conversion, and Gardner transform to generate synthetic sonic and density logs; validated in some shallow hazard studies.
10) The user can have a density-sonic plot from an offset well and might use the relationship to compute RHOB from sonic/interval velocity instead of the Gardner equation.
11) Even users can consider a constant density value till the top of LWD/wireline RHOB.
12) Mudlogging service providers (MLU) can provide measured shale densities for the shallow sections, provided it is not riserless drilling with cuttings ending up on the seabed, to generate synthetic RHOB and use as reference RHOB for the shallow section after correlation in the next well.

In some cases, only offset-well LWD resistivity data were available (seismic had very low resolution, and the well seismic tie was unavailable). Faust equation[28,32,33] and Gardner equation[26] were applied.

A shallow bulk density trend was constructed using local area knowledge of near-mudline data (as mentioned above) and an exponential density fit (Figure 6) from mudline to the first available measured density point. This density trend was then composited with the density log and used to estimate overburden at all offset wells (example: Brunei).

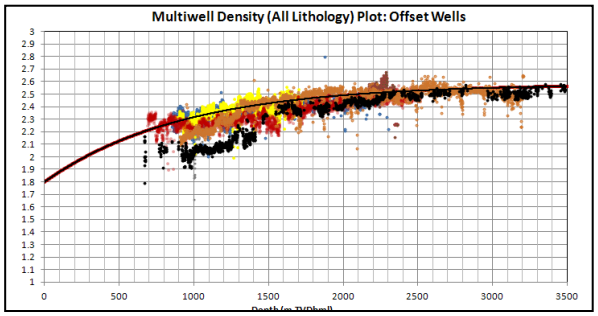


Figure 6: Multi-well density trend- offshore Brunei

An exponential trend was fitted to the data points and used as a proxy for density when measured density data were unavailable. Based on this trend, an approximate mudline density of 1.8 g/cc was adopted for the proposed and offset wells. Where shallow-section density data were unavailable, the trend was applied to the offset wells from the seabed to the top of the available density log. To improve the prediction, actual density logs from the offset wells and velocity-derived density at the proposed well were used.

Several methods can compute pseudo-density for the shallow/upper part of the well, where no density log is available. The pseudo-density can be integrated with LWD/wireline density to get a composite density profile for the full well. OBG is calculated with this composite density.

8. Strategies adopted by oil companies

Formation bulk density data are required to calculate overburden pressure from the surface to the depth of interest, so synthetic density logs must be estimated for intervals where such data are unavailable. Synthetic logs are produced for intervals with no available log or where the original logs were considered poor quality due to unfavourable borehole conditions**.**

Comparing measured and expected formation bulk density can provide quality control even in wells with density logs, especially in rugose wellbores. Formation bulk density is often calculated from compressional-wave velocity using empirical correlations when density logs are unavailable or affected by poor hole conditions or fluid migration from WBM. For brine-saturated rocks in a variety of sedimentary basins, Gardner's model[26] is one of the most widely used relationships. The pseudo-density logs over that range are obtained using the Miller equation[29] since the Sonic log is absent above 500 m. The synthetic log and original density log of a Mumbai offshore shallow water well show a good match. Miller's method has been used to generate the shallow density log from 500 m. Even with available density logs, comparing measured bulk density with predicted values is an effective quality-control measure, particularly in rugose boreholes; this was attempted for the same well.

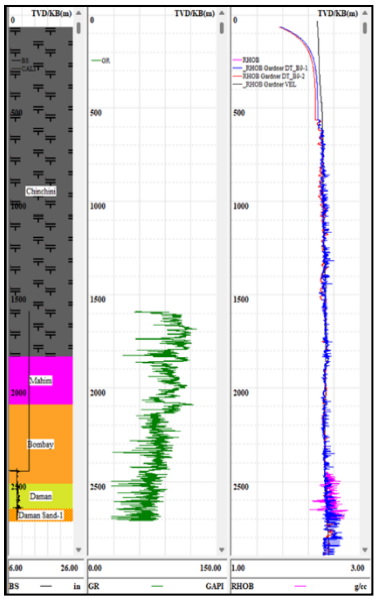


Figure 7: Synthetic shallow density log in a Mumbai offshore well

Even when wireline density coverage is adequate to produce a well's overburden profile, the density data require careful quality control. This is especially important where hole enlargements cause the pad-based density tool to underestimate rock density over an interval. In such cases, a sonic log can provide an alternative by constructing a sonic-derived density curve[26], as sonic data are less affected by borehole conditions. Comparing measured density with sonic-derived density is recommended for calibrating Gardner's equation.

9. Overburden Pressure: Velocity to Density Transform

In this phase of the semi-regional study, we developed a velocity-to-density transform by cross-plotting acoustic-log velocity against density-log data from all available offset wells. The resulting modified Gardner equation was then applied to estimate density at the proposed well site using seismic velocities. A velocity-density transform was derived using the actual density and acoustic logs at offset well locations (Figure 8).

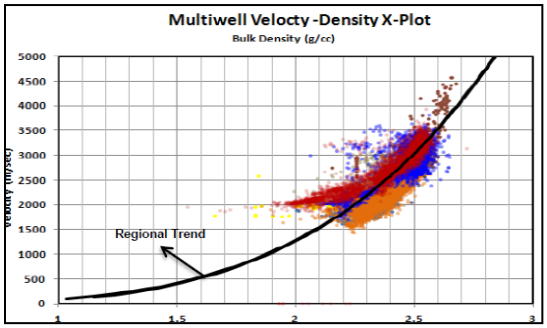


Figure 8: Example of a multi-well velocity-to-density Gardner plot

10. Practical Workflow being followed for addressing Shallow Data Gaps

1) Perform a fresh seismic velocity analysis (RMS → interval velocity).
2) Convert interval velocity to sonic and density using Gardner, Miller, or Amoco relationships.
3) Merge pseudo-density with measured RHOB to create a composite OBG.

Sonic travel times derived from well logs or seismic data can also estimate formation bulk density. However, Rocha (1993)[34] reported poor agreement between sonic-derived density values and density-log values in the Gulf of Mexico's upper marine sediments. This problem arises from uncertainty about which matrix travel-time values apply to shallow clay sediments. Cuttings density measurements are sometimes available from drilling in shallow sediments. However, the bulk density of cuttings can change substantially when confining pressure is released, and the cuttings are exposed to drilling fluid.

These empirical equations differ in their inputs and outputs, producing composite densities that vary in the shallow section. This variation ultimately affects OBG, primarily in shallow intervals and to a lesser extent at greater depths. Extending the deeper density trend to the surface will overestimate in the shallow sediments (Figure 9)

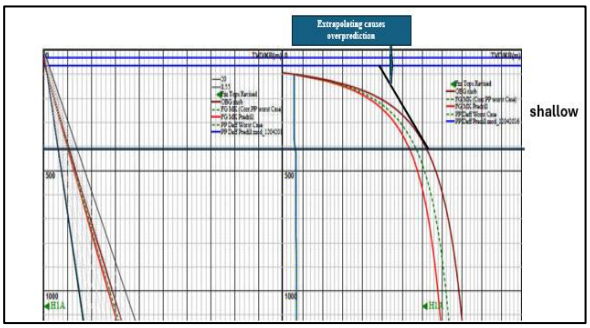


Figure 9: PPFG plot from Mumbai Offshore. Extending the OBG to the surface would cause overprediction.

11. Suggestions to adopt a different approach

Several operators have evaluated the workflow in numerous wells across multiple basins, and the methods produce OBG differences of approximately ±1 to 1.5 PPG (0.52 to 0.78 psi/ft). These differences can be minimised by applying appropriate constant values in the equations following basin-specific calibration. Since OBG is an input to pore-pressure calculations, this variation will also affect predicted pore pressure (PP). An overburden model that reflects the local geology is required.

11.1 Overburden stress in relation to porosity

Because of the issues discussed above, detailed bulk-density data are often unavailable at shallow depths. As a result, density at shallow depths often has to be extrapolated from data obtained at greater depths. This is usually done using porosity rather than bulk density. Bulk density can be expressed in terms of porosity, φ, and other variables using the following equation:

$$\rho_b = (1-\phi)\rho_{matrix} + \phi\rho_{fluid} \quad (4)$$

Bulk density is governed mainly by porosity since grain matrix density and pore-fluid density typically vary little. Porosity commonly declines exponentially with depth, so plotting porosity against depth on semilog paper often produces a nearly straight-line trend. This exponential relationship can be expressed as follows[5].

$$\rho_b = (1-\phi_0 e^{-KD_s})\rho_{grain} + \phi_0 e^{-KD_s}\rho_{fluid} \quad (5)$$

where: φ_0, and K = surface porosity and porosity decline exponent, respectively; ρ_{grain}, and ρ_{fluid} = densities of sediment matrix and pore fluid, respectively; Ds = sediment's depth.

The porosity trend model in Equation 5 does not apply to shallow marine sediments[35,36]. Instead, construct a regression model using geotechnical boring data. Empirical correlations have been developed by considering sediment lithology and curve-fitting bulk density data from soil borings in the GoM. As an example, for the sediment comprising mostly shale and clay deposits, the empirical model provides three different formulas based on the depth range as follows[35]:

$$\rho_1 = 1.37(2-e^{-D/400}) \qquad 0 \le D < 100$$
$$\rho_2 = 1.65(2-e^{-D/5500}) \qquad 100 \le D < 650$$
$$\rho_3 = 1.7(2-e^{-D/8000}) \qquad 650 \le D < 3000$$

where: ρ = density, gm/cc; and D = depth, ft.

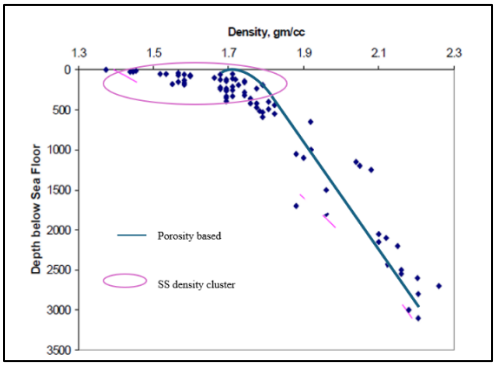


Figure 10: Comparison of SS bulk density from GoM area with prediction from the porosity-based model, modified[35]

Figure 10 indicates that the porosity-based model overestimates sediment density and therefore overestimates overburden pressure in SS.

11.2 Why the porosity trend does not apply to Shallow sediments

The geomechanical basis for adopting a different approach is that surface porosity and unconsolidated sediments have different geomechanical characteristics than deeply buried sediments.

1) The porosity trend model is not applicable to shallow marine sediments.
2) Surface porosity is high, exceeding 40%, compared with that of the deep, compacted sediments.
3) The porosity trend model in Equation 4 is not suitable for shallow marine sediments. A regression model based on

geotechnical boring data works well instead, as seen in GoM.

4) The relationship between porosity and overburden in deep sediments differs from that in shallow sediments (Figure 11).

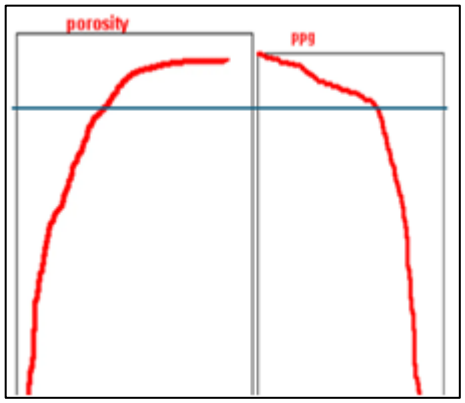


Figure 11: Porosity and Overburden trend from shallow to deeper depths

5) In-situ stress analysis is based on elastic theory and is not applicable to shallow sediments.
6) According to elastic-plastic theory, the size of the potential plastic zone and the stress distribution surrounding the wellbore determine the crucial condition for the transition from an elastic to a plastic wellbore35. Marine sands near the surface with little or no clay are usually cohesionless (c = 0) and have no tensile strength.
7) Marine clays not only have low cohesion and tensile strength but also have a low angle of internal friction (φ ~ 6 degrees)35.
8) Shallow marine clays generally exhibit plastic behaviour, so the effective horizontal matrix stress is approximately equal to the effective vertical matrix stress.
9) In shallow plastic formations, sediment failure may not occur through a true hydraulic fracture35.
10) Failure modes in which flow through the sediments occurs in pipe-like channels have been documented extensively in the geotechnical literature concerning failure of earthen dams.
11) Exit holes in the seafloor consistent with these piping-type channels have also been observed by divers and ROVs during underground blowouts (Figure 12).

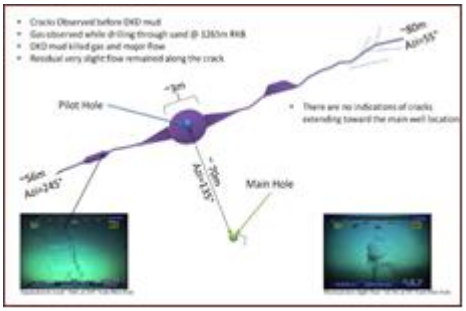


Figure 12: Seafloor Crack Observed through ROV monitoring in a deepwater well, shallow drilling[37]

12) Weak interfaces at sediment bedding planes can help promote a horizontal fracture. Moreover, an irregularity in the borehole wall must be present before the mud pressure can apply a vertical component of force to open a horizontal fracture.
13) Assuming the fracture is horizontal and that fracture initiation pressure equals vertical stress offers a much better explanation, since a uniform horizontal stress field creates no vertical stress concentration near the borehole.
14) Very soft sediments may be in a plastic state. Their in-situ stresses should be calculated from the presented formula based on elastic-plastic theory;
15) Analysis of the elastic-plastic properties of shallow sediments indicates that LOTs cannot induce vertical fractures in these sediments. Therefore, LOT analysis for shallow sediments cannot be extrapolated from theories developed for conventional LOTs in deep wells35.
16) A plastic zone generally forms around wells in shallow sediments. However, plastic deformation of the open hole does not cause nonlinear pressure–volume behaviour. Wellbore expansion during a LOT can be calculated using the elastic relationship, whether the well is in an elastic or plastic state.

12. Geotechnical tests- a geomechanical requirement

The horizontal-to-vertical effective stress ratio (Ko) is determined using fracture pressure measured by the in situ hydraulic fracture tool during the soil borings. Note that all results are close to or greater than one. The broader conclusion is that fracture pressure equals overburden stress (Figure 13).

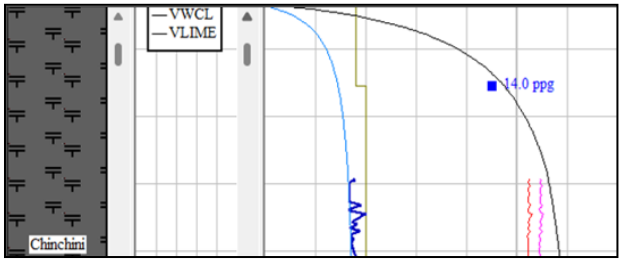


Figure 13: A shallow LOT in a Mumbai offshore well close to overburden

Rock mechanics analysis of shallow sediments examines mechanical properties—including Young's modulus (E), Poisson's ratio (μ), cohesion strength (τ0), friction angle (φ), and effective vertical stress (σv)—and shows that these properties vary because, unlike the strength of other materials, sediment strength changes with both depth and location.

Shallow sediments are softer and less rigid than deeper rocks. Some researchers also argue that "soft shales and unconsolidated sands frequently found in the Texas and Louisiana Gulf Coast can be considered to exist in a plastic state of stress"[38], that "soft, clay-rich materials like shale often act as plastic"[37], or that "shallow marine sediment behaves plastic"[34]. Since SS properties do not vary with depth in the same way they do in deeper formations (below 3,000 ft), the issue remains open to speculation.

Sediments become more plastic the closer they are to the ocean floor. Sediment with the lowest internal friction value is nearly at the boundary between plastic and elastic states at

around 450 feet. Based on the trends in Poisson's ratio, friction angle, and vertical stress, it is reasonable to predict that sediments below 500 feet may be elastic.

12.1 Bulk Density and Shear Strength Data

The key parameter for estimating sediment failure during shallow gas well control operations is how formation bulk density changes with depth[34]. Figure 14 shows a composite density-versus-depth profile for a Gulf of Mexico prospect. The lower part of the profile (circles) is based on a formation density log from a nearby well, while the upper part (triangles) is based on wet unit weight data collected from soil borings. Integrating this profile produced the overburden pressure-versus-depth curve shown in Figure 15.

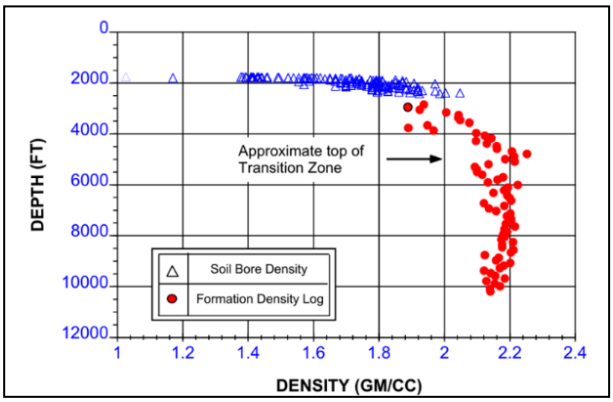


Figure 14: Soil bore density combined with deep density log[35]

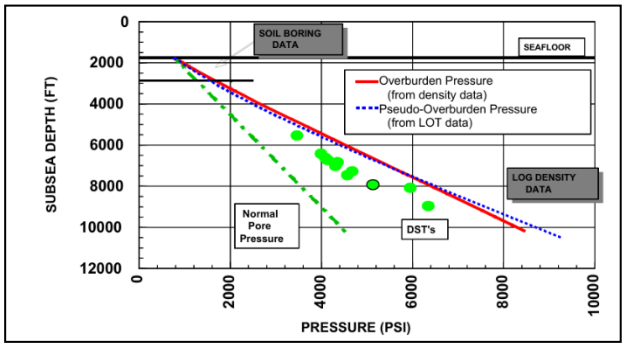


Figure 15: Overburden pressure vs depth of a GoM prospect[35]

13. Suggested Methodology

Proper sampling of near-surface geologic complexity illuminates the shallow sediments' geomechanical characteristics, which can strengthen well design and reduce uncertainty. A best practice should include the following data acquisition.

- Drill shallow pilot holes both offshore and onshore at least a few times in an area and acquire rock samples at depth. Measure cuttings density in the shallow sediments.
- The target depth can be limited to 300 ft to evaluate overburden density. However, in deep water, longer pilot holes are often drilled to check shallow hazards, which offers scope and a purposeful hole size to acquire the density log.
- First, collect standard geotechnical data, such as bulk density and shear strength.
- Next, calculate the rock mechanics properties—Young's modulus, Poisson's ratio, cohesion, and friction angle—and use them to evaluate the in-situ stress in SS.
- The upper part of the shallow sediments is better known from soil borings. This is normally done before mobilising a rig.
- The soil is rather soft, with Poisson's ratio around 0.4, Young's modulus about 3×104 psi at 300 ft, and low density with a pressure gradient around 0.73 psi/ft34. This is an example of GoM.
- A plastic zone will form around a well drilled through shallow marine sediments. Compared with leak-off tests (LOTs) in deep wells, LOTs from SS show non-linearity in early pressure-buildup plots, fewer tested points, and maximum pressure stabilisation with continued mud pumping. Also, the maximum stabilised pressure often corresponds to pressure gradients close to overburden pressure. (Figure 12).

The data collected from the proposed studies would enable the generation of a rock density-versus-depth profile, which could be integrated with the deeper density plot obtained from density logs of offset wells (Figure 16).

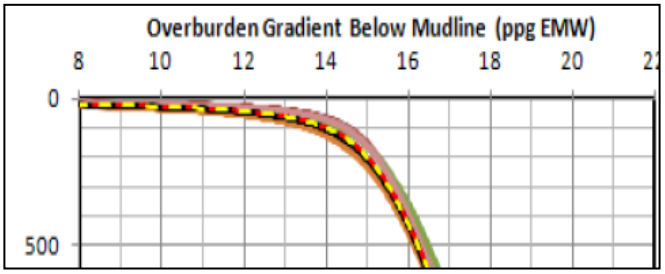


Figure 16: Integrated overburden gradient plot of shallow section of an offshore well in the Far East

14. Conclusions

Overburden gradient (OBG), pore pressure (PP), and fracture gradient (FG) are the three core outputs of any pore-pressure analysis. They are essential for selecting drilling mud weights and ensuring safe, successful drilling. Overburden stress is the pressure a formation experiences at depth due to the combined weight of overlying rocks and fluids. Density logs often do not extend to the surface or seabed. The absence of density logs in shallow onshore and offshore sediments limits overburden-stress estimation, a key component of pore-pressure prediction. Empirical equations are therefore used to generate pseudo-RHOB logs for the shallow interval, which are then combined with LWD or wireline RHOB data. However, shallow, unconsolidated sediments are softer and more ductile than deeper sediments. Their plastic behaviour differs from the elastic-plastic behaviour of deeper formations, and their rock mechanical properties—including Poisson's ratio, Young's modulus, cohesion, and friction angle—can vary substantially. Consequently, modelling shallow sediments as a continuum with deeper sediments is geomechanically invalid. Instead, geotechnical studies should establish the necessary rock mechanical properties and determine actual density rather than relying on pseudo-density. The resulting densities can then be integrated with deeper-depth densities to construct the overburden gradient. These practical measures can produce more reliable pore-

pressure and fracture-stress predictions while helping mitigate shallow geohazards.

Nomenclature

LOT = *leak-off test*
FF = *fracture gradient*
PP = *pore pressure*
OBG = *overburden gradient*
OBP = *overburden pressure*
RHOB = *density*
LWD = *logging while drilling*
PPP = *pore pressure prediction*
FIT = *formation integrity test*
Z = *depth*
WBM = *water-based mud*
Po = *datum pressure*
SS = *shallow sediments*
VES = *vertical effective stress*
Ko = *effective stress ratio*
OVB = *overburden*
ERD = *extended reach drilling*
PPP = *pore pressure prediction*
BML = *below mudline*
TD = *target depth*
Ko = *effective stress ratio*
PP-FG = *pore pressure gradient, fracture gradient*
XRD = *X-ray diffraction*
HPHT = *high pressure high temperature*
LOP = *leak-off pressure*
FFG = *formation fracture gradient*
MLU = *Mud Logging Unit*
RMS = *Root mean squared*
ROV = remotely operated vehicle
GoM = Gulf of Mexico

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Author Profile



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