



Geological modelling of overpressures in tertiary deltas: Application of a one-dimensional fit-for-purpose model

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Abstract

A model has been developed to calculate the overpressure history of low-permeability sediments found in undercompacted regions. It employs user-defined relationships that describe the correlation between porosity/permeability and effective stress. This model has been effectively validated in wells located in the Niger and Baram deltas. As the modelling process facilitates the estimation of both upper and lower limits of overpressures in a new exploration well, it establishes an uncertainty envelope. The most crucial factor influencing its implementation success is prior knowledge of the stratigraphy. An illustration from the Niger Delta demonstrates how modelling, in conjunction with formation-strength analysis, reduces uncertainties in overpressure predictions. Furthermore, the model indicates a zone of enhanced retention capacity within a sand-rich sequence at greater depths, which favourably affects exploration potential. Based on my experience, it is advisable to integrate geologic modelling into routine pore-pressure prediction during exploration.

Keywords: Pore pressure prediction, modelling, exploration, Niger Delta, Baram Delta, headroom

Introduction

Accurate forecasts of pore pressure and formation strength are critical prerequisites for the safe and economical execution of high-pressure, high-temperature (HPHT) wells. The Niger Delta has experienced kicks reaching up to 5000 psi, and significant overpressures have led to wells being halted before reaching their intended target depths. Most operating companies estimate overpressures by utilising geological correlations with analogous regions or by extrapolating pressure information along interpreted or presumed aquifers. Evaluations of drilling and mud reports, along with general and wellbore seismic data, can aid in making precise predictions. Nevertheless, in HPHT regions, where depths and pressures are higher, seismic data tends to be unreliable. This holds for both the Baram and Niger Deltas seismic data.

Real-time pore pressure prediction (RTPPP) is based on the correlation between the degree of undercompaction, which indicates a porosity level exceeding the norm for a given depth, and the occurrence of overpressure. The prediction of pore pressure before drilling is also connected to this same correlation. Modelling pore pressures throughout geological time aids pre-drill pore pressure prediction. It is crucial for the effective design of wells and the procurement of long-lead items necessary for safe drilling operations. Furthermore, it provides a more quantitative evaluation of the processes involved in the development of overpressures. A comprehensive understanding of this evolution will facilitate the identification of relationships between effective stress—defined as the overburden stress minus the fluid pressure—log expressions (such as porosity) and seismic velocities. The influence of temperature and the mechanisms that generate overpressure can be evaluated, which will contribute to the development of a robust geological model for converting into pore pressures. The proposed models should undergo blind testing in drilled wells and be calibrated for use in future exploration wells. The modelling improved our understanding of the main

geological factors responsible for the generation of mild and hard overpressures.

The Geological Model

The Terzaghi principle ^[1] states that the stress from the overburden is sustained by both the rock framework and the pore fluids. The stress supported by the framework is known as vertical effective stress (VES), whereas the component of stress due to the fluid is termed pore pressure and is inherently isotropic. Overpressures may arise from various mechanisms that either augment the volume of fluids in the subsurface or diminish the available pore volume. The mechanisms responsible for generating overpressure include disequilibrium compaction, hydrocarbon generation, aquathermal expansion, and diagenesis. These mechanisms are summarised by Osborne & Swarbrick ^[2].

Pore and fracture pressure prediction modelling was based on an analysis of key offset well data (logs, checkshots, stratigraphic interpretation, pressure and well tests, and drilling reports), seismic velocity, and geological information. In general, the history of overpressure (OP) in mudrock sediments located in undercompacted regions is calculated. The model accounts for aquathermal effects and variations in water viscosity caused by temperature changes. The fundamental inputs for stratigraphy include estimates of low- and high-permeability layers, burial history, temperature history, and the relationship between porosity and permeability under effective stress (Figure 1). Careful interpretation of shale-velocity and shale-porosity trends, which was facilitated by the analysis of calliper, gamma ray, neutron, density, and resistivity logs. The model assumes vertical fluid flow, and it is essential to validate this assumption before modelling. One might encounter a situation involving horizontally fault-transmitting pressures. It is crucial to account for lateral fluid flow and its impact on pressure history. Algorithms that align with trends in porosity and permeability with respect to effective stress are vital for accurate predictions. Clastic rocks and unconsolidated sands exhibit permeabilities in the range of

several darcys, whereas mudrock, which has a permeability of less than 1 millidarcy, generates overpressures at a geologically plausible sedimentation rate. Consequently, the permeabilities of sands do not require modelling, and the pressure gradient can be treated as hydrostatic. In short, the modelling of the wells' drilling history points to a complex overpressure environment, constrained by stratigraphy and driven by three main processes: disequilibrium compaction in shales, lateral pressure transfer by sands, and a process responsible for generating hard overpressure.

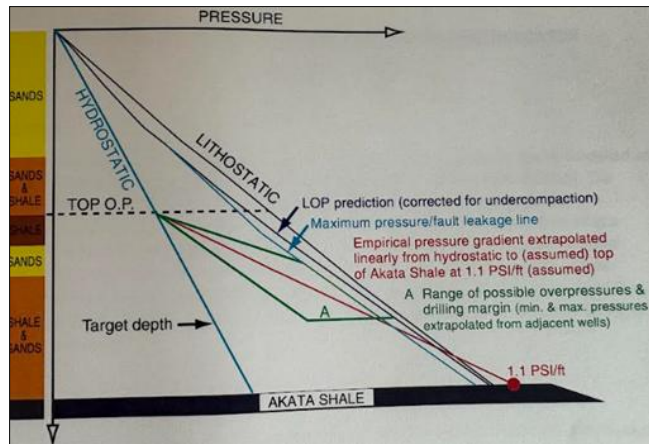


Fig 1: Pressure Prediction based on geological modelling

Applications in the Niger Delta and the Baram Deltas

In the Niger Delta, utilising a comprehensive dataset, overpressures are consistently modelled at the regional level, and additional low-permeability layers have been incorporated. In the test well, the stratigraphy has been streamlined into 10 layers, and the modelled burial history matches the current thicknesses of the stratigraphic units. The well exhibits a moderate pressure increase down to 400m and a significant rise down to the drilled depth. The evolution of pressure demonstrates the initial accumulation of overpressures during the rapid burial in the Lower Miocene. The responses from the sonic and resistivity logs support this. The pore-pressure prediction for the Agbada well is shown in Figure 2.

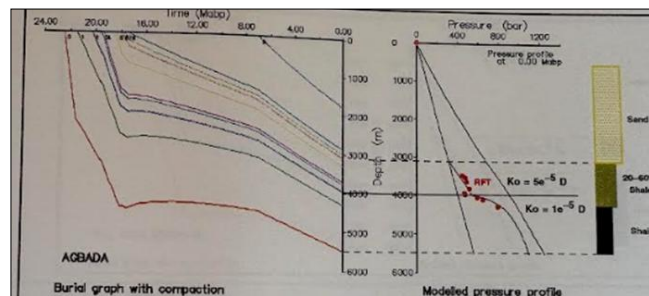


Fig 2: Modelled burial history and pressure profile of Agbada well

The Baram well was designed based on the geological principle of undercompaction. A two-layer stratigraphic model was employed for Well Puffin. The gamma-ray log indicated the top of overpressure through a transition from sand to a shale-dominant package. The mud weight data corroborate the emergence of overpressures. It is believed that the top of the overpressure aligns with a shift from topset to foreset facies. The pore-pressure prediction for the Puffin well is shown in Figure 3.

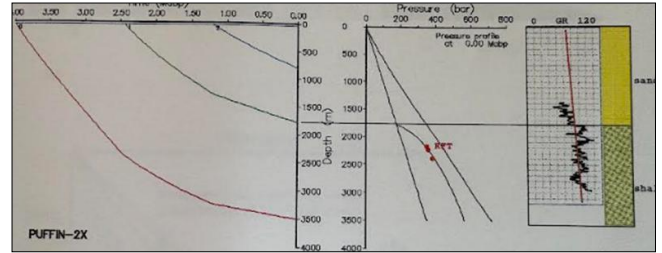


Fig 3: Modelled burial history and pressure profile of Puffin well

Stratigraphic control on overpressures

The maximum flooding surface (MFS) represents the furthest inland position of the shoreline or marine sediments. In deltaic environments, it frequently indicates the most significant development of shale-prone facies, thus serving as the most extensive seals. It is logical to expect variations in overpressure to accompany these widespread sealing horizons. Nevertheless, there are only a few instances that demonstrate a strong correlation between the maximum flooding surface (as determined from well ties, log analysis, and well stratigraphy) and the pressure regime.

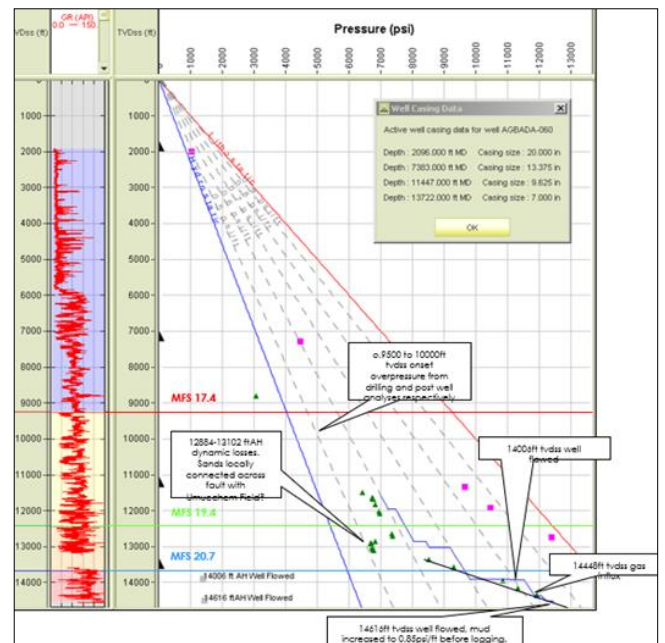


Fig 4: Stratigraphic control on overpressure in Agbada well

The Agbada deep well exemplifies a scenario in which MFS has minimal impact on the pressure regime (Figure 4):

- The onset occurs approximately 500ft beneath MFS17.4, indicating that there is no distinct control on overpressure exerted by the MFS.
- An overpressure of 1800 psi remains consistent both above and below MFS19.4, implying that it does not delineate a 'pressure regime'.
- Between MFS19.4 and 20.7, pressures fluctuate from 1800psi OP, decreasing to around 1100psi OP due to the interconnection of sands across the fault, and then rising again to approximately 2800psi OP.
- The presence of three pressure regimes within a single stratigraphic interval shows no correlation with the MFS. Furthermore, below approximately 13250 ft TVDSS to TD, the OP increases by about 3.4 psi/ft, irrespective of MFS20.7. Pressure is influenced by other sealing shales rather than the MFS.

- Instead, the OP appears to be governed by a transition from high net to gross permeable facies to lower net to gross, disconnected facies:
- The onset coincides with the transition from deltaic to shelf margin facies (a decrease in net to gross).
- A significant rise in OP below approximately 13250 ft occurs within deposits characterised by a very low net to gross slope, where discrete sands lack communication. In this context, most sands are sealed by extensive shales, and the MFS does not stand out as unique.
- Moreover, the three pressure regimes observed between MFS19.4 and 20.7 arise from certain sands being in communication across the fault into a lower-pressure foot trap.

Beneath approximately 13,250 feet TVDSS, the rapid rise in OP with depth, at a gradient of 3.4 psi/ft, raises a more intriguing question. Pressures below 0.7 psi/ft and above 0.7 psi/ft are evidently components of the same deep overpressure system, and the categorisation of 'mild' versus 'hard' overpressure for this interval is both arbitrary and misleading.

The Puffin pressure area is confined to a south-easterly-dipping half-graben, which terminates in a zone of complex faulting.

The three wells located in the region have reached the upper boundary of the overpressure system within the TB3.7 interval sands (shelf?) situated either within or beneath substantial shales (outer shelf-slope?).

- Overpressures increased to 1,300 psi across distinct sand/shale pairs as the wells penetrated the pressure transition zone (refer to the pressure-versus-depth plot).
- The overpressure stabilised at 2,000-2,400 psi within the shelfal sands of the TB3.6 interval in the wells, indicating that both wells have entered the true overpressure system (see the pressure versus depth plot).
- Therefore, this establishes the designated overpressure value for the Puffin area.
- Mud weight data obtained from the wells indicate a comparable overpressure level (2,200 psi) at total depth in the TB3.6 interval shales.

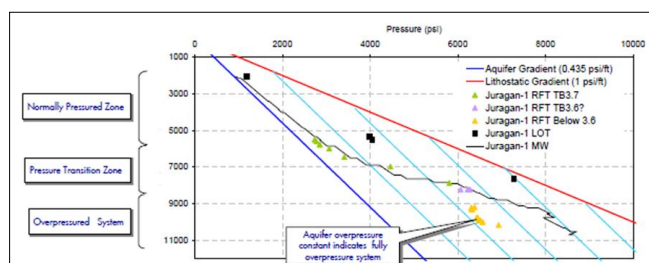


Fig 5: Stratigraphic control on overpressure in Puffin well

Implications on HPHT Prospects

Reduced uncertainties in forecasting the margin between pore pressure and formation strength enhances well planning by facilitating the selection of mud weight, casing design, and appropriate equipment for HPHT drilling. Enhanced well planning subsequently has a substantial effect on safety, expenses, and the likelihood of drilling success. The findings suggest that an increase in sand

content could expand the drilling margin at depth (Point B in Figure 6).

This also indicates that, assuming the presence of high-quality reservoir sands, the prospects are likely to contain hydrocarbons, given the potential headroom. The connections between abnormal pressures and hydrocarbon accumulations are well established, as reservoirs exhibiting fluid pressure gradients exceeding 1.96 g/cm³ have minimal production potential [3]. This correlation has also been observed in the Central Graben of the North Sea, where retention capacities below 6.8 MPa have been found to align with a higher occurrence of leaky reservoirs [4]. This demonstrates that geological modelling plays a crucial role in determining the prospectivity of deep plays. It is identified that the following are the main pressure-controlling factors:

- Disequilibrium compaction
- Lateral pressure transfer
- Late geopressure

The highly variable lithology strongly affects rock properties and often masks pressure-related changes, which further complicates pore pressure prediction. Disequilibrium compaction is the most comprehensively understood mechanism of overpressure, utilised to elucidate and measure overpressures in Tertiary basins characterised by rapid deposition and subsidence, such as the regions of the Mississippi, Orinoco, and Niger Deltas [5]. However, at greater depths in HPHT territory, other mechanisms dominate.

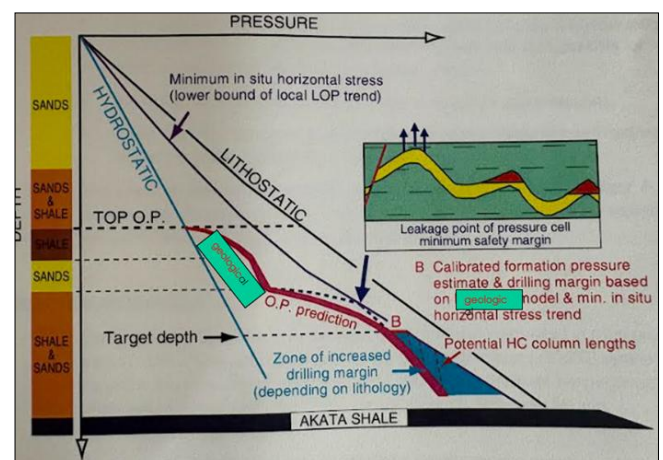


Fig 6: Headroom potential at depth below Point B

Concluding Remarks

The preceding discussions indicate that precise stratigraphic prediction is the most vital input parameter for the successful implementation of geological overpressure modelling. Accurate stratigraphy, in conjunction with the calibrated permeability/effective stress function, will aid in minimising uncertainties in pore-pressure predictions for new exploration wells. The model allows for refinements during drilling to prevent unexpected outcomes. It is recommended that geological modelling be integrated with trend analysis of formation strength in new prospects. The key elements of the modelling have been demonstrated through two examples from Nigeria and Brunei.

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