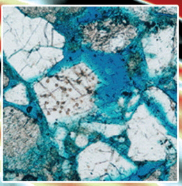
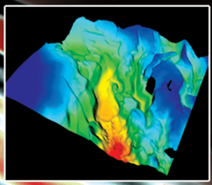
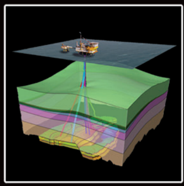

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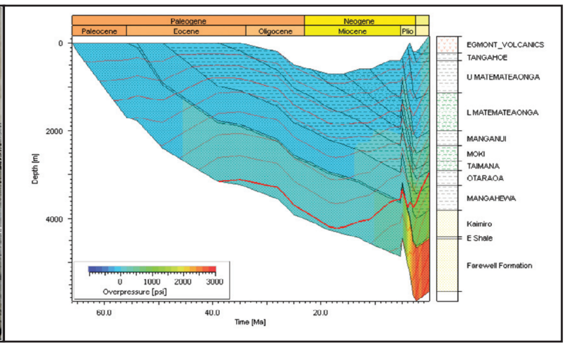

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CONFERENCE PROGRAMME

Day One	
	Virtual Registration
10.00	**Welcome**
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	Session One: GeoPressure history and challenges
	Tom Sinclair & Binh Nyugen
10.10	**Tracing the history of geopressure and its prediction** Richard Swarbrick*, Swarbrick GeoPressure Consultancy Limited*
10.30	**Origin of Overpressure in Offshore Suriname and Implications for Pore Pressure Prediction** Mark Tingay, *Petronas*
10.50	**Assessing magnitude of loading and unloading to total overpressure: the case study from the Lower Kutai Basin** Agus M. Ramdhan, *Department of Geology, Institut Teknologi Bandung, Indonesia*
11.10	**Discussion**
11.20	**BREAK**
	Session Two: Pore Pressure and Stress Modelling
11.30	**Integrated coupled workflow for drilling mechanics derived pore pressure and geomechanical predictions** Wim Lekens, *Geoprovider AS*
11.50	**3D PP and Geomechanics: Work Smarter and Faster Integrating Geoscience with Machine Learning** Sam Green, *Ikon Science*
12.10	**Pore Pressure Prediction as an Integrated Cross Discipline Approach in Green Field Exploration: 1) Assessing all Scenarios** Yury Gorbunov, *Shell* **Pore Pressure Prediction as an Integrated Cross Discipline Approach in Green Field Exploration: 2) Rock Property Modelling for Pore Pressure Prediction and Basin Modelling** Ruarri J. Day-Stirrat, *Shell*
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	Session Eight: Operations
10.50	**Mud volcanoes from around the world and their link to geopressured** Mark Tingay *Petronas*
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12.00	**Geomechanics Challenges and Lessons from Planning and Drilling High Angle Wells** Alexandre R. Saré, *BP*
12.20	**Pore and Fracture Pressure Results of High Pressure Drilling Campaign in Niger Delta** Raghu K. Chunduru, *Shell*
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13.20	**Flash Talks & Discussion** **Pore pressure integration** • **A Review of Industry Best Practice in Real-Time Pore Pressure Analysis,** Mark Tingay, *Petronas* • **Capillary capacity estimation of mudrocks in exploration: Empirical workflow and validation using a case study,** Sara Martínez, *Repsol* • **Integrated Pore Pressure Prediction in Complex Geological Settings,** Iftikhar Ahmed Satti, *University of Azad Jammu and Kashmir, Muzaffarabad, Pakistan* • **Is it useful to estimate hydrocarbon column heights from seal capacity?** Richard Swarbrick, *University of Durham and Swarbrick GeoPressure*
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14.30	**A Discussion of Accuracy and Uncertainty in Pore Pressure, In Situ Stress and Fracture Gradient Estimation during Exploration and Production** Tony Addis, *Addis & Yassir FZ LLC*
14.50	**Compaction and Pore Pressure Prediction in Different Tectonic Environments** Peter Flemings, *The Jackson School of Geosciences at the University of Texas*
15.10	**Overpressure at the Macondo Well and its impact on the Deepwater Horizon blowout** F. William M. Pinkton, Peter Flemings, *University of Texas at Austin*
15.30	**Discussion**
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Session Ten: Operations continued
Flash Talks & Discussion Pore pressure integration
Session Eleven: Uncertainty 2 & Macondo Case Study

Convenors:

Nicholas Pierpoint: I am the Energy Group (GSL) representative on the convening committee for this conference. Nearly 40 years' experience in the oil and gas industry and over two decades as manager of global geological operations at BG Group. My role within the BG organisation provided opportunities to make a significant contribution to safe well delivery in terms of HSSE and meeting well objectives in a wide range of challenging environments. I am a Chartered Geologist.

Richard Swarbrick, Swarbrick GeoPressure Consultancy Limited
Richard is a geologist by training, spent 10 years with Mobil and re-entered University at Durham to teach petroleum geology and basin studies with research into subsurface pressures. He founded GeoPressure Technology, a consultancy and training company whilst at at Durham. He is now semi-retired – but continues to teach industry short-courses and maintains an interest in geopressure research.

Stuart Jones is an associate Professor in sedimentology at Durham University, UK. His research interests lie in the area of siliciclastic depositional systems, diagenesis of both modern and ancient settings and the application of sedimentology to geoenergy. Stuart's research has focused on continental sedimentology and evolution within a variety of tectonic basin settings and under the influence of a variety of climatic regimes. This is undertaken through the joint application of subsurface and outcrop sedimentological data for improved model development and reducing subsurface risk and uncertainty. Recent research on how overpressure and early diagenetic cements can maintain high porosities in reservoir sandstones is guiding better reservoir predictions for High-Pressure High-Temperature (HPHT) systems. He is the current academic lead for the GeoPOP4 industry research consortium researching geopressure in sedimentary basins. He currently has a research group of 8 postgraduates and 2 Postdocs and has successfully supervised >30 postgraduates.

Session One: GeoPressure history and challenges

Tracing the history of geopressure and its prediction

Richard E. Swarbrick,
University of Durham and Swarbrick GeoPressure Consultancy

Abstract
First reports on geopressure challenge came mainly from the Gulf of Mexico (GOM), starting with description of geopressure distribution, including a sharp transition zone, at the base of the sand-rich upper delta deposits (Dickenson, 1953). The origin of the geopressure was deemed to be disequilibrium compaction in the shales. By the end of the 1960s two principal methods for geopressure estimation from wireline data and/or prediction from seismic velocity data were published (Equivalent Depth Method by Hottman & Johnson, 1965 and Eaton Method after Ben Eaton's 1967 paper) with relationships based on data and illustrative examples from the GOM. Both relationships are solutions to the Terzaghi Equation relating total stress to pore fluid pressure and effective stress, and often assuming a total vertical stress gradient of 1.0 psi/ft. The primary pressure data available to calibrate these relationships at that time were from build-up plots in DSTs and rare formation interval tests. Soon afterwards, aquathermal pressure (Barker, 1972), illite-smectite transformation (Colten-Bradley 1979; Bruce, 1984) and gas generation (Barker, 1990) added additional mechanisms to a growing pot of explanations for geopressured reservoirs.

The next stage of evolution on the challenge of geopressure prediction began when different evolutionary vertical effective stress pathways were recognised between continuous burial (loading) and burial followed by fluid expansion and/or uplift (unloading; Bowers, 1994). Bowers loading and unloading relationships provide numerical solutions for pore pressure from vertical effective stress using velocity and was especially applicable to the growing ability to create 3-D pressure volumes from seismic interval velocity data at that time. Whilst aquathermal fluid expansion remains the only "pure" elastic fluid expansion (unloading) mechanism during burial, gas generation from oil to gas cracking and late-stage gas generation can be realistically assumed to behave in a similar manner in respect of both velocity and density behaviour in the shales. Bowers (1995) showed that plotting velocity vs density would reveal the evolution with depth from a compaction/loading trend to an unloading trend where fluid expansion reduces effective stress on the rock framework.

The coincidence of geopressure development where smectite transforms to illite (with increasing temperature) in shales and where kerogen transforms to oil then gas in source rock shales (with increasing temperature) has variably been explained as a volume expansion mechanism and hence could also be handled as an unloading phenomena. However, Osborne & Swarbrick (1997) suggested that there is only minimal volume expansion when smectite transforms to illite, and GeoPOP research (1997, unpublished) confirmed that there is volume reduction takes place during early maturity of all types of hydrocarbon source rocks, at least until there is significant gas generated (e.g. during late oil generation), already shown for Type 2 kerogen by Ungerer et al. (1991). Osborne & Swarbrick (1997) suggested that load transfer (essentially an increase in compressibility and potential porosity loss needed to balance the imposed stress as the grain-to-grain framework weakens) could explain the geopressure development during these sediment changes. Lahann (2002) and Lahann & Swarbrick (2011) provided further quantification for geopressure development from smectite to illite transformation in GOM, but also opened up the possibility for other framework weakening mechanisms in multiple diagenetic reactions in shales.

The influence of temperature on shale properties was explored by Dutta (1987) and links to several key papers examining chemical compaction processes, with Hermanrud et al (1998) and Sargeant et al. (2015) developing approaches and solutions. The key challenge with chemical compaction globally is that traditional porosity-based methods predict low/no

geopressure when these are low porosity shales, under-predicting the high geopressure reservoirs (and associated shales?). It is quite possible that much of the overpressure originates from disequilibrium compaction but that the porosity was lost through diagenetic processes in the presence of high geopressure. Hoesni (2004) and Swarbrick (2012) have captured the wider methodology for using velocity-density trends with increasing depth/temperature on velocity-density cross-plots to identify geopressure mechanisms (loading/disequilibrium compaction vs fluid expansion vs load transfer) as well as the expected pathways for chemical compaction processes.

Finally, as stated, basic methodology for pore pressure prediction works well when shales experience disequilibrium compaction, and calibration is particularly effective when down-hole tools measure pressure in thin shales. However, many offset wells have pressures measured only in thick reservoirs, where there is a strong possibility of long-distance fluid transfer, either within confined reservoirs or open aquifers. In these cases, calibration of the PPP from shales can be misleading with lateral transfer (deeper geopressure transferred to shallower reservoirs along an open but confined pathway) and lateral drainage (systematically lower reservoir pressures than the associated shales due to escape of fluids to the surface). Assessing the influence of lateral transfer (sometimes referred to as the “centroid” method) demands careful examination to the burial and structuration history.

The presentation will conclude with a summary of the main challenges for future drilling, including reference to non-shale lithologies (e.g. carbonates and fractured basement reservoirs) as well as the impact of new tools to measure low permeability rocks.

Bio

Richard is a geologist by training, spent 10 years with Mobil and re-entered University at Durham to teach petroleum geology and basin studies with research into subsurface pressures. He founded GeoPressure Technology, a consultancy and training company whilst at at Durham. He is now semi-retired – but continues to teach industry short-courses and maintains an interest in geopressure research.

Origin of Overpressure in Offshore Suriname and Implications for Pore Pressure Prediction

Mark Tingay, M Affan B M Arus, Liew Guo Hong, Hannah Bt A Kahar, Aisyah Bt M Nordin, Herry Maulana, Ritchie Martua Simamora
Petronas

Abstract
The offshore Mesozoic-Cenozoic Suriname-Guyana basin is an area of intense exploration activity and hosts numerous major hydrocarbon fields. However, an analysis of historical drilling operations highlights that operators have frequently under-predicted pore pressures pre-drill, resulting in numerous complications and non-productive time in exploration wells. This study conducted a detailed analysis of the petrophysical and geological characteristics of overpressure in 8 wells offshore Suriname to examine the origins of overpressure and improve regional pore pressure prediction and drilling safety. Overpressures are encountered in almost all wells studied, with pore pressure gradients observed up to 17.3ppg. The onset of overpressure is typically in Pleistocene to Miocene clay-rich sequences ranging from 700-1400m below mud line, and is consistent with pore pressures expected from calculated fluid retention depths based on local deposition rates. Velocity-vertical effective stress analysis and sonic-density analysis of shales indicates that overpressures are almost entirely generated by disequilibrium compaction. However, there are indications of additional minor overpressure generated by fluid expansion mechanisms in some Cretaceous sequences. Furthermore, the regional shale petrophysical database compiled for this study revealed, for the first time, a clear break in shale petrophysical properties across the Cretaceous-Tertiary boundary. Drilling issues arising from under-prediction of pore pressures pre-drill are found to primarily be the result of incorrect setting of the normal compaction trend, and particularly failure to break the normal compaction trend across the K-T boundary. Further complexities arise from difficulties in undertaking pore pressure in Cretaceous sequences containing carbonates and potential fluid expansion overpressures. Finally, this study highlights the importance of undertaking regional overpressure analyses in order to identify geological controls and trends on pore pressure, and thus avoid drilling issues that arise from conducting pore pressure prediction on a well by well basis.

Bio
Dr Tingay has over 20 years experience in overpressure analysis, pore pressure prediction and petroleum geomechanics. He graduated with a PhD in 2003 and has since had various roles in academia and industry and is currently head of pore pressure and geomechanics at PETRONAS and an adjunct associate professor at the University of Adelaide.

Calculating loading and unloading contibutions to overpressure by applying effective stress-velocity relation: the case study of Pekawai area, southern edge of Kutai Basin

Agus M. Ramdhan[1] Hotma S. Yusuf[1] Lambok M.Hutasoit[1]
[1]*Department of Geology, Institut Teknologi Bandung, Indonesia*

In order to estimate overpressure magnitude accurately, it is of paramount importance to understand its generating mechanism, and then apply appropriate method to estimate overpressure for each generating mechanism. In the Pekawai Area, there are several wells penetrating hard overpressure zone. Figure 1 is an example of a well penetrating hard overpressure zone in this area. It can be seen that starting from the depth ~6000 ft, sonic and density shows a relatively constant value down to the depth ~9000 ft. Starting from the depth of ~9000 ft, density log increases a little bit and then shows a relatively constant value down to the TD of this well (~11220 ft). Based on this circumstance, it is interpreted that top of overpressure is located at the depth of ~6000 ft.

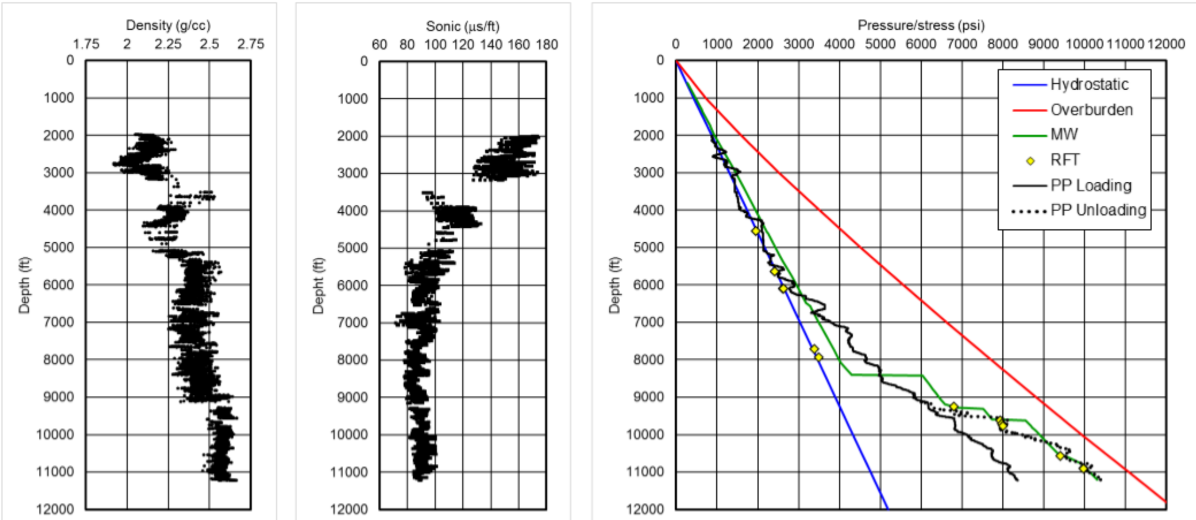


Figure 1. Density and sonic logs in shale section and pressure/stress depth plot in a well in Pekawai Area

To analyse the generating mechanism of overpressure, we construct velocity – density cross plot as shown in Figure 2. It can be seen that down to the depth ~9000 ft, both hydrostatic (surface – 6000 ft) and overpressure points (6000 – 9000 ft) are located on the same compaction trend, indicating that overpressure in the interval of 6000 – 9000 ft is caused by loading mechanism leading to disequilibrium compaction. Meanwhile, starting from 9000 – 11220 ft, the overpressure data are located off the compaction trend, meaning that unloading starts to contribute to overpressure in this interval, in addition loading mechanism. Source rock maturation data from this area indicates that onset of hydrocarbon generation coincides with onset of unloading overpressure, and therefore, it is interpreted that the cause of unloading is hydrocarbon generation.

To estimate the contribution of loading to overpressure in this well, we apply Bower's equation for loading (Bowers' 1995). The effective stress – velocity for loading in this well was obtained by interpolating sonic log in hydrostatically pressured section (surface – 6000 ft). The resulted equation is: $\sigma' = \left(\frac{v-5000}{0.1947}\right)^{1/1.29625272}$; where σ' = effective stress (psi) and v = velocity (ft/s).

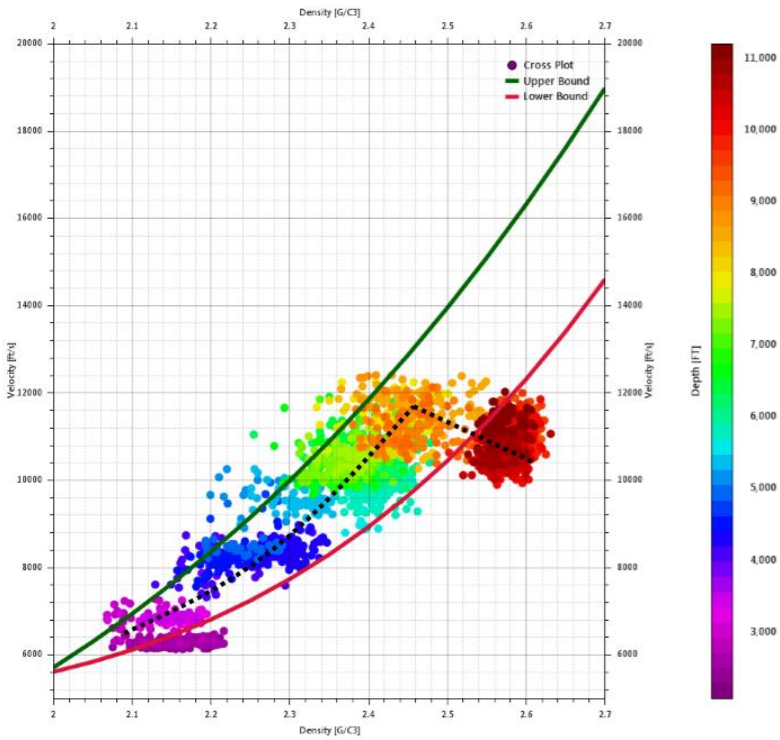


Figure 2. Velocity – density cross plot for the well in Figure 1.

The effective stress resulted from this step also serves as maximum effective stress ($\sigma'_{\max}$) that has ever experienced by sediments prior to unloading. Given that overburden-depth equation for this well is $\sigma' = 0.2772z^{1.1386}$, where σ' = overburden (psi) and z = depth (ft), the resulted loading overpressure magnitude is shown in Figure 1. It can be seen that the magnitude of loading overpressure is increasing with increasing depth.

To estimate total magnitude of overpressure where unloading takes place (9000 – 11220 ft), we apply Bowers' method for unloading. The effective stress – velocity equation for unloading section is:

$$\sigma' = \sigma'_{\max}\left[\frac{1}{\sigma'_{\max}}\left(\frac{v-5000}{0.1947}\right)^{1/1.29625272}\right]^3$$

. As mentioned above, $\sigma'_{\max}$ equals to effective stress resulted from effective stress – velocity relation for loading mechanism. The total overpressure magnitude resulted from this equation is also shown in Figure 1. It can be seen that overpressure magnitude estimated from this method can match RFT points in hard overpressure zone where unloading, in addition to loading, contributes to overpressure magnitude.

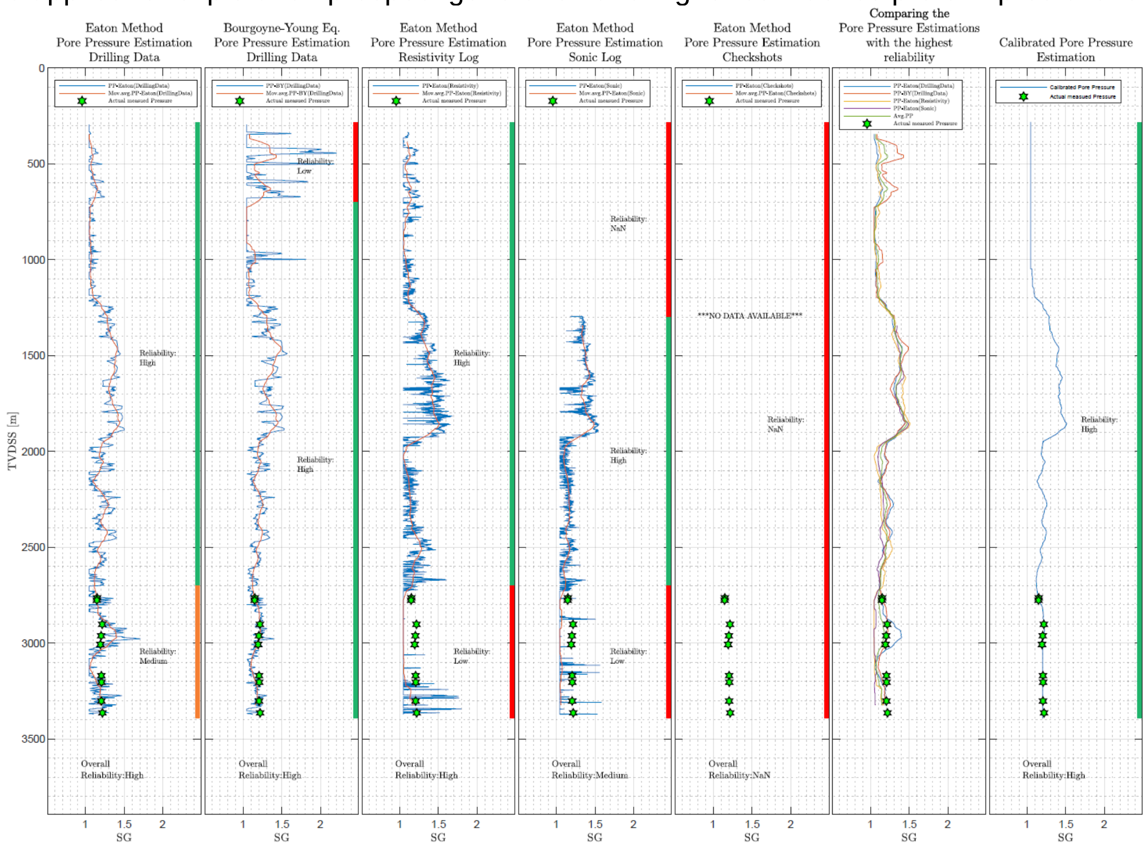
It is also worth to note that at least down to the depth of 8000 ft, the estimated pore pressure (mudrock pressure) is higher than shale pressure. This circumstance can be explained by lateral reservoir drainage, since at least down to the depth of 8000 ft, the sequence is still dominated by laterally connected sandstone body. In the neighboring field, this lateral drainage has proven to trap hydrocarbon hydrodynamically (tilted hydrocarbon-water contacts).

Session Two: Pore Pressure and Stress Modelling

Integrated coupled workflow for drilling mechanics derived pore pressure and geomechanical predictions

W.A.H. Lekens[1], H. Grimsmo Busengdal[1] and H. Blikra[1]
[1]*Geoprovider AS*

Abstract
Standard velocity and resistivity based pore prediction methods are highly effective in areas with physical compaction, “clean” shales and good calibrated datasets. Predictions in more complex lithologies, zones with chemical compaction and poor datasets remain a major challenge. During drilling operations standard methods are often supplied with drilling exponent assessments as an additional tool. However, integrating drilling mechanics at a pre-drill stage remains surprisingly rare. A workflow was developed comparing all applicable pressure and stress predictions, including Eaton and Bourgoyne-Young drilling mechanics based predictions. Results were compared to each other and available measured pressure and leakoff test data. Collapse gradient, minimum stress and fracture gradients were validated against drilling experience. The calculations were also checked for internal consistency against material constants like the internal friction angle, Poisson’s ratio and Biot’s coefficient. The pressure and 3D stress calculation are coupled, and the validity of the results are assessed against the structural stress regime to avoid physically impossible solutions. Results from wells from the North Sea and the Norwegian Sea show a higher confidence and better accuracy in the prediction of the drilling window. Reversing the calculations also provides a model for mudweight optimisation and quantifying the resulting improvements in drilling speed. The methodology sets the scene for systematic basin studies with a high number of wells which can be applied for exploration prospect generation and higher confidence pre-drill predictions.



Typical example with imperfect datasets providing complementary pore pressure predictions.

Bio

Wim Lekens is a geologist working as CTO in Geoprovider in Norway, focused on the development of new geoscience technology. He received his Master degree in Geology from University of Ghent, Belgium in 2000, an MSc in Marine Geotechnics in 2001 from the university of Bangor, UK and his PhD in Geology from the University of Bergen in Norway in 2006. He started his career working for Shell as an exploration geologist and worked for companies like Engie and Suncor.

3D PP and Geomechanics: Work Smarter and Faster Integrating Geoscience with Machine Learning

Sam Green and Ehsan Zabihi-Naeini
Ikon Science

Abstract
In any complex play, conventional or unconventional, the technical challenges of changing lithostratigraphy, multiple facies, variable rock properties, and the inter-relationship of pore pressure and geomechanics, leads to a call for more consistent, sophisticated, and faster analytical tools. For example, in unconventional plays, given the comparatively short drilling times, wells are drilled and data are acquired at an unprecedented rate; thus a solution to generate robust results that aid in future, business critical decision making are required. For example, in the Permian Basin, a typical well takes approximately 3-4 weeks to complete from rig up to release, and given that major operators can have upwards of 25 rigs running concurrently means, on average, a new well is completed every 1-2 days. Therefore, performing manual, consecutive workflows for petrophysics, pore pressure, and wellbore stability prediction can be impractical due to turnaround considerations and the multiple personnel required. This paper demonstrates how the integration of machine learning into pressure and stress prediction workflows can improve not just the turnaround time to generate results but to improve the effectiveness of those results by providing standardized input data, and, in 3D applications, factor in additional geospatial data that are not typically included in such an explicit manner.

Theory
There are two categories of machine learning workflows applicable to the challenges of predicting rock properties in the sub-surface. The first workflow utilizes 1D data, i.e., well data, in which a model is calibrated to data from a relatively small number of wells in the relevant basin or sub-basin. In the application phase, the calibrated model is applied to all other wells in the same region of interest. This workflow is primarily about efficiency, for example, train a supervised model to predict porosity on 10 wells with manual interpretation, and apply to a further 90 wells. Application of this type of machine learning workflow allows personnel to focus on adding value to the interpretation process by fine-tuning the training data by feeding back information from the blind test wells, rather spending a significant amount of time repeating standard workflows on a large number of wells which may still need to be modified once the results are generated.
The second workflow utilizes 1D data in which a model is calibrated to the data from all wells, or a representative sub-set of the wells, in and around a 3D seismic volume. In the application phase, the calibrated model is applied in 3D to seismic attributes and/or seismic inversion results (e.g., elastic properties), potentially simultaneously. This workflow is mostly about improving accuracy and confidence. To date, upscaling the well-based models into 3D has been performed using Rock Physics Models (calibrated to well data) to transform elastic properties into rock properties such as porosity or pore pressure. Machine learning improves on this by incorporating more information than using only the elastic properties; such as well coordinates (so that lateral trends are captured), depth below datum (to incorporate variation in compaction trends), and temperature information.
Case Studies: Moray Firth, CNS; Delaware Basin, Permian Basin
Three forms of machine learning will be demonstrated: 1) a network trained to predict volumes of shale, sand, dolomite, calcite, kerogen and also porosity simultaneously from standard wireline logs; 2) a network designed to cascade from the network above, and to reproduce the manually predicted pore pressure / stresses per well. These are examples of using a sub-set of wells to generate efficiency in petrophysical modelling that underpins the development of a robust pore pressure mode. The third network follows on from the

networks above, focussing on predicting pore pressure, Shmin, SHmax, and volume of kerogen, based solely on Vp, Vs, and Rho logs. Designing a network in such manner allows one to not only predict these properties at wells with limited available logs but also be able to predict based on inverted elastic properties from seismic data.

Once a suite of geologically-realistic 3D properties have been generated from the model(s) then those properties can be used to provide key feedback into the drilling process, not only advising on physical drilling parameters but also informing on optimal well locations and geosteering through sweet-spot detection. Furthermore, the 3D pore pressure model from this study can be shown to correlate with cumulative production values from blind horizontal wells such that areas of high pressure relate to higher producing wells, thereby informing on business critical decisions as well as providing the property volumes required to aid operational decisions in the safe, efficient drilling of future wells.

Figure 1 Mapping sweet-spots using cut-offs for pore pressure, minimum horizontal stress, and volume of kerogen

Conclusions

A supervised deep neural network approach is presented as an innovative tool for solving the complex inter-relationships between petrophysical, pore pressure, and geomechanics analysis enabling the use of all existing, newly acquired, and interpreted data to devise solutions which simultaneously integrate myriad data types in both 1D and 3D applications. The results show a promising outlook for the application of deep learning to save valuable turnaround time in integrated studies. Importantly, given that pressure and stress are critical to safe drilling and, along with relevant mineral volumes, are key drivers to identify areas of high production in low permeability reservoirs, i.e., sweet-spot detection, it is of obvious importance for the industry to develop safe and innovative methods to keep pace with the drilling activity and to harness all existing and newly acquired data effectively.

Acknowledgements

The authors thank Devon Energy Corporation for permission to publish the case study. Seismic data were provided courtesy of Fairfield Geotechnologies.

Bio

Sam is the Technical Manager – Wells, EA & ME for Ikon Science and principle trainer in geopressure theory for Ikon Science, having joined in 2008. Sam has experience in all aspects of pressure analysis in many challenging geological plays in a wide range of geographical settings across all continents other than Antarctica.

Sam has published on topics as diverse as unconventional pore pressure prediction, deep-water frontier pressure modelling, pressure in carbonates and hydrodynamics.

Sam has a BSc in Geology and a PhD in Structural Geology from the University of Manchester and an MSc in Structural Geology with Geophysics from the University of Leeds.

Pore Pressure Prediction as an Integrated Cross Discipline Approach in Green Field Exploration: 1) Assessing all Scenarios

Yury Gorbunov[1]**,** Brent Couzens-Schultz[1], Ruarri J. Day-Stirrat[1], Willem Hack[1]
[1]*Shell International Exploration and Production, Inc.*

Summary:

As deeper, hotter and more complex geology is drilled, the technical difficulties in predicting pressure, designing a well and safely drilling through complex overpressures are rapidly increasing. “Wildcat” settings have become extremely challenging and require innovative techniques and cross discipline integration to be utilized for executing a safe and successful drilling strategy. Experience from several recent projects from planning to execution stage are highlighted.

Main:

Overpressure generation mechanisms include: disequilibrium compaction; and mechanisms attributed to hydrocarbon generation, aqua-thermal expansion, and clay mineral diagenesis with contribution of each overpressure mechanism dependent on the geological settings. Overpressures driven by fluid expansion and load transfer mechanisms are often referred to as “unloading”.

Overpressure generated from disequilibrium compaction (“loading”) can be assessed using traditional industry methods driven by the relationship between porosity and effective stress. Elevated temperature, thermally driven mechanisms such as clay mineral diagenesis, and fluid expansion can all be the cause of overpressure (“unloading”) mechanisms which may be significantly underestimated using traditional techniques.

In the case of compaction disequilibrium, the velocity (or density)–stress follows a single relationship but where the generation of overpressure is due to clay diagenesis there may be a different velocity/density/stress behaviour (Figure 1). Presence of diageneses itself does not necessary result in the overpressure but enables certain pressure scenarios to be evaluated during the predrill phase and, consequently, influences the execute phase of drilling.

Several recently drilled wells in the complex pressure and geological settings can be used to illustrate challenges and solutions in the life time of the projects from planning to execution phases.

During the execution phase to mitigate uncertainty originating from pre-drill modeling, real-time pore pressure monitoring (RTPPP) in combination with Managed Pressure Drilling (MPD) has been used to enable corrective measures to avoid incidents. Real-time pore pressure monitoring in the wells with “unloading” pressure mechanism might be challenging, with the biggest uncertainty originating from poorly constrained additional pressure mechanism(s), identification of a transition point between pressure regimes (shallower and deeper), and gradient of the transition zone, critical in narrow margin wells. Those type of wells often require a flexible casing plan and availability of well pressure management equipment such as MPD.

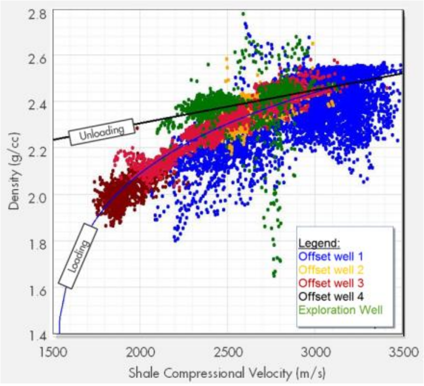


Figure 1. The shale compressional velocity vs density correlation with trend line showing "loading" and "unloading" trends.

MPD provides a closed-loop circulation system and allows rapid responses to changing well conditions by supplying additional backpressure on top of drilling fluids, by using a rotating control head, which seals around the drill pipe and by routing the return flow of drilling fluids through a choke system. There are several benefits of MPD system. In narrow margin pore pressure and fracture gradient situations there is increased downhole pressure control, early kick detection with almost instantaneous response to influx or fluid losses, real-time pore pressure and formation strength measurements, reduced down-time due to pressure events, casings strings and well evaluation time.

Conclusion:

Several recent wells targeted deeper, high temperature objectives where thermal processes in shales might lead to an additional overpressure generation and significant lithology changes. Porosity related logs (density, velocity), mineralogical data and results of forward modeling are good indicators of additional pressure mechanisms and/or presence of lithology change within a mudstone-rich zone. Feasibility of certain subsurface scenarios involving the presence of additional pressure mechanisms and resulting level of uncertainty has a strong influence on well design and operational strategy. A recent example of MPD deployment in narrow margin drilling caused by presence of additional overpressure will be discussed.

Bio

Yury Gorbunov, Msc and PhD in physics. Joined Shell in 2011 , worked on proprietary algorithm for seismic interpretation, processing and visualization. In 2013 joined Shell pore pressure group.

Pore Pressure Prediction as an Integrated Cross Discipline Approach in Green Field Exploration: 2) Rock Property Modelling for Pore Pressure Prediction and Basin Modelling

Ruarri J. Day-Stirrat[1], Yury Gorbunov[1], Quintijn Clevis[2], Brent Couzens-Schultz[1], Willem Hack[1], L. Taras Bryndzia[1]
[1]Shell International Exploration and Production Inc.
[2]Shell Global Solutions

Summary:

In clastic systems diagenesis in the reservoir section is considered a key risk for porosity occlusion and workflows exist to better understand diagenetic mineral reactions that affect reservoir quality using inputs from basin modelling and rock property information. In Tertiary mudstone systems smectite illitization is one of the most ubiquitous diagenetic reactions. The transformation of smectite to illite is controlled by a combination of temperature, time, and potassium availability, with concomitant release of silica, water, and cations. Associated with this change in mineralogy is a change in rock fabric, cation exchange response, grain density and formation brine salinity.

Main:

In the clay mineralogy community, tools for assessing smectite illitization and sustainable hydration states of smectite have changed significantly in the last decade due to the advent of X-ray diffraction profile modelling. The potential route from a smectite-rich mudstone to an illite-rich mudstone appears to follow a non-unique reaction pathway. Regardless of the exact route, key petrophysical properties such as grain density, cation exchange capacity and surface area are also impacted by this change.

Associated with changes in our understanding around the details of smectite illitization, the complexity and fidelity of basin modelling has also increased. When calibrated basin model outputs are combined with empirically derived diagenetic reaction kinetics, pre-drill smectite illitization predictions can be made, along with associated calculations of grain density, fabric, and pore fluid volumes.

A key learning from this exercise is that temperature alone is not the sole predictor of smectite illitization, rather, it is sediment age that plays a significant role (Figure 1). In a very general sense, the paradigm of smectite illitization occurring at ~100°C stands but a consideration of sediment age and the vagaries of the burial history are also significant factors.

In conventional settings, this understanding can be convolved with pore pressure prediction to assess rock property trends and potentially flag overpressure mechanisms or simply lower their likelihood and add weight to the pressure system scenario probabilities.

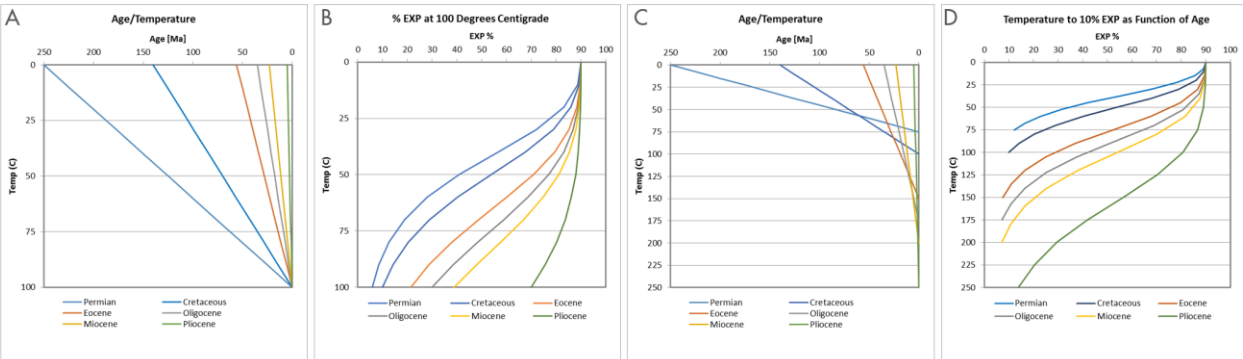


Figure 1. Linear burial histories to 100°C for sediments of different ages (A), (B) resultant degrees of expandability (sensu stricto % smectite in illite-smectite), (C) linear burial histories for sediments of different ages to temperatures that result in 10% expandability (D).

Conversely, in unconventional hydrocarbon settings, typically from sediments that are much older than conventional targets, smectite illitization modelling combined with age dating can be used together with isotopic equilibrium between rock and fluid to constrain the timing of smectite illitization. Here, higher formation pressures are advantageous in producing from low porosity and low permeability formations (8-10% porosity, and pore throat radii of ~20nm) with the absence of aquifer support or reservoir compressibility, and where hydraulic fracturing is required to stimulate the formation. In these settings, the mineral diagenetic history is often significantly more advanced than the organic maturity would suggest, and the preservation of overpressures (often apparently long lived) generated by any mechanism significantly benefit production.

Conclusion:

Several recent wells targeted deep, high temperature objectives where thermal processes in shales might lead to overpressure generation and significant lithology changes. Porosity related logs (density, velocity), mineralogical data and results of forward modelling may be potential indicators of pressure mechanisms and/or presence of lithology change within a mudstone-rich zone. The feasibility of certain subsurface scenarios involving lithology changes has a strong influence on well design and operational strategy. Further, the iterative loops in basin modelling can be better informed by model-based arguments around the lithology properties in the deep parts of the basin.

Bio

Ruarri Day-Stirrat has a B.Sc. (honors) degree in Geology from Cardiff University and a Ph.D. from Newcastle University. In the past 15 years, he has been active in diagenesis and physical property investigations of fine-grained clastics and has a special interest in clay minerals. He has worked for Shell International Exploration and Production Inc. in Houston since 2011 after a Postdoctoral Fellowship at the University of Texas at Austin.

Flash Talks & Discussion
Pore pressure modelling and Geomechanics

Coupling Seismic Pore Pressure Prediction with Geomechanical Modeling

Mahdi Heidari[1], **Maria A. Nikolinakou[2],** Peter B. Flemings[3]
[1]Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin
[2]Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin
[3]Department of Geological Sciences and Institute for Geophysics, Jackson School of Geosciences, The University of Texas at Austin

Abstract
We couple geomechanical modeling with seismic velocity to enhance the prediction of pore pressure and stresses in complex geologic settings. Standard effective-stress methods use only vertical stress to predict pore pressure from seismic velocity, assuming that sediments undergo purely vertical, uniaxial-strain compression. In complex settings, such as those with significant tectonic activity, or those near salt, faults, or folds, the magnitude and orientation of strains and stresses can significantly differ from those under uniaxial-strain condition. To consider the effect of these complexities, we use both mean and shear stress to estimate pore pressure. We develop a relationship between velocity and effective mean and shear stress based on critical soil mechanics. Shear stress is obtained from a geomechanical model and used in the established relationship to calculate effective mean stress from velocity. The effective mean stress is then subtracted from total mean stress, obtained from the geomechanical model, to calculate pore pressure. The geomechanical model is used to explicitly predict the full stress tensor. Because we incorporate the predicted pore pressures into the geomechanical model, the predicted stresses are consistent with the predicted pore pressures (see Heidari et al., 2018 for a detailed account of the method).

We apply our method along with the standard, vertical-effective-stress method to predict pore pressure and stresses around a salt body beneath the Sigsbee Escarpment in the Mad Dog field, Gulf of Mexico. Both methods are constrained to the same pore-pressure data along a calibration well and then used to predict pore pressure and stresses across the salt basin. We find that salt and basin bathymetry substantially perturb stresses compared to those under uniaxial-strain condition. Our method predicts measured pore-pressure gradients along a subsalt well better than the standard, vertical method by nearly one pound per gallon (ppg). We calculate the least principal stress and the drilling margin (Fig. 1) and show that, along a vertical profile near salt, the standard, vertical method underestimates the window by nearly half a pound per gallon (ppg).

Heidari, M., Nikolinakou, M. A., and Flemings, P. B., 2018, Coupling geomechanical modeling with seismic pressure prediction: GEOPHYSICS, v. 83, no. 5, p. B253-B267.

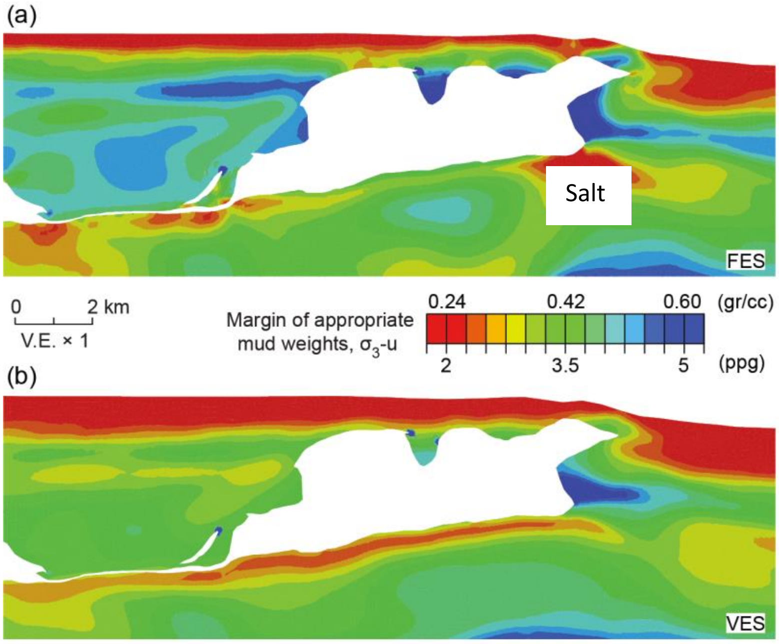


Figure 1: Margin of appropriate mud weights for drilling wellbores, i.e., difference of minimum stress and pore pressure, as predicted by FES and VES methods in Equivalent Mud Weight ($EMW\ (\text{ppg}) = \frac{Pressure,\ stress\ (\text{MPa})}{Depth\ (\text{km})} * 0.85\ \frac{(\text{ppg})}{(\text{MPa/km})}$ Salt Prediction of FES method. (b) Prediction of VES method. FES method predicts narrower margin below right bottom corner of salt and larger margin along majority of subsalt compared to VES method.

Bio

Maria Nikolinakou is a Research Scientist at the Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin. She studies pressure and stress in complex geologic settings, such as salt systems, thrust belts, and unloaded basins. Maria is a Civil/Geotechnical Engineer from NTUA, Greece, with a doctorate on theoretical soil mechanics from MIT. Before joining UT, Maria did a postdoc in Shell with the depleted drilling team.

Pore pressure prediction based on the Full Effective Stress (FES) method

Glyn Richards[1], Daniel Roberts[1], Adam Bere[1], Toby Harrold[2], Sara Martinez[3], Marius Tilita[3]
[1]*Rockfield*
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[3]*Repsol*

Industry standard velocity-based pore pressure prediction is based on the Vertical Effective Stress (VES) method (e.g. Bowers, Eaton), where uniaxial compaction is assumed. In more complex geological settings (e.g. near salt structures or under tectonic compression), advanced prediction methods which account for the contribution of lateral and/or shear strains may be more appropriate. The Full Effective Stress (FES) method (Heidari, Nikolinakou & Flemings, 2018) seeks to address this issue by accounting for the additional contribution of both lateral and shear strains, whereby pore pressure calculation is conducted in terms of the full effective stress tensor. Stress perturbations and interactions around complex, three-dimensional salt structures are extracted from a static geomechanical model. The geomechanical model is updated with FES pore pressure predictions such that a fully-reconciled stress and pore pressure solution is achieved.

Two case studies involving stress and pore pressure prediction around offshore salt structures are presented, the first from the Gulf of Mexico, the second from the Tarfaya Basin near the Canary Islands. In both case studies, minimum stress and pore pressure prediction were validated against a range of post-drill data with encouraging results. The model results correlate very well with minimum stress observations. The FES method predicts elevated pressure relative to the VES method and the range in predicted pore pressure compares well with the spread in measured data. At Sandia, the model successfully predicted the observed narrowing of the drilling window which would not otherwise have been detected. The modelling was of value in informing operational decision making such as setting of casing depth. Predictions of minimum stress were considered reliable and the model continues to be used during field development, for well planning and drilling risk assessment. The models can be refined as more data becomes available. The results support the notion that lateral and shear strains in the vicinity of the salt may contribute to elevated pore pressure.

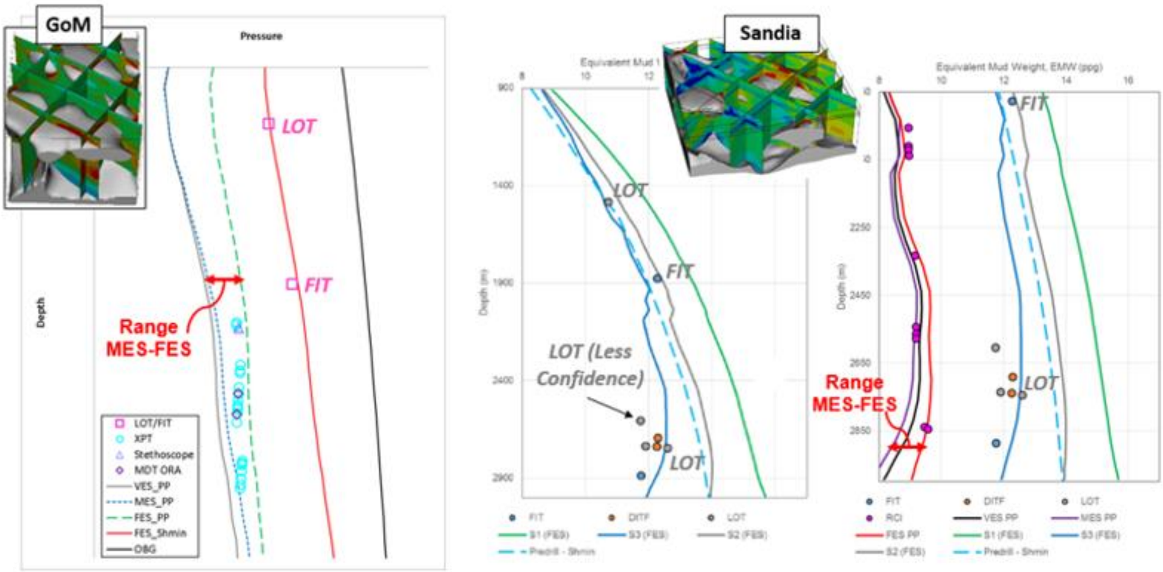

Figure 1: Post-drill validation of minimum stress and FES pore pressure predictions

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Know More about the Unknowns by Integrating Pore Pressure Inputs for Exploration Derisking

Sanjeev Bordoloi
Business Lead, Remote Operations | Baker Hughes

As the industry slowly comes out of the latest pandemic-driven downturn, drilling activity is expected to pick-up this year. However, focused exploration efforts globally is expected to be muted for some more time, as the industry tries to conserve capital and prioritize spending in assets with immediate to short-term returns. With the oil companies having made huge cuts in their exploration budgets, the industry focus is expected to be on near-field exploration as the resource replacement ratio is at a historic low. Both these developments make it extremely important for us to start including all the relevant subsurface attributes that can help derisk the exploration portfolios for success as well as drive down cost.

A detailed understanding of the prevalent pressure regime can provide many invaluable insights for exploration – from basinal understanding, petroleum system modeling and prospectivity analysis to operational risk mitigation.

A holistic approach to interpreting pore pressure and thereby generating a detailed understanding of the pressure attributes can help us in:

- Data conditioning: from seismic processing to attribute analysis
- Understanding prospect maturation: from source rock maturity, reservoir quality and hydrocarbon migration to seal integrity analysis
- Well planning: from mud window optimization to optimal well placement

Pore pressure prediction is now increasingly being used as an exploration tool – not only to safely drill costly wells, but also for acreage selection and to aid in risking and ranking of exploration portfolios.

Moreover, fluid pressure understanding, once integrated with geological inferences, improves our understanding of trapping mechanisms, reservoir connectivity and seal integrity. Integration of seismic facies analysis with pore pressure understanding also helps in developing a better sequence stratigraphic perception and leads to a more holistic integration with the geological model.

It is time for us to explore and adopt different ways to modify our conventional thought processes, workflows and approaches by looking at different ways to integrate pore pressure attributes to help achieve exploration success and also to drill successful wells with minimum NPT (Non Productive Time).

Bio

Close to 25 years of industry experience in upstream oil and gas industry – working for both Operator and Service companies. He is a recognized expert in pore pressure modeling with extensive experience in geomechanical studies and wellbore stability analyses, along with seismic interpretation and sequence stratigraphy, subsurface modeling, deep water and HPHT well planning, operations and wellsite geology. Also experienced in managing global consulting business with P&L responsibilities along with sales and business development of oilfield products & services.

Presently based in London, United Kingdom and responsible for enabling remote operations strategy as part of business transformation initiative. Fast pacing Baker Hughes's Shift to Remote strategy in line with the industry's growing demand for remote-based service delivery from planning to execution.

Sanjeev holds a Master's Degree in Geology and holds the position of Business Lead, Remote Operations & Growth Initiatives for Oil Field Services (OFS) of Baker Hughes Ltd.

Session Three: Operartions 1

Dealing with pore pressure in complex stress regimes

Federica Ferrari, Pamela Tempone, Alfredo Pugliese
ENI

Abstract
Traditional pore pressure prediction methods are based on seismic velocities and compaction curves. They work properly only in vertical-stress-dominated tertiary basins, when compaction disequilibrium conditions occur. In case of complex stress regimes, where the vertical stress is not the prevalent stress, the traditional approaches of pore pressure estimation are not fully adequate and typically underestimate the pore pressure. In such a case, geomechanical modelling can be a useful tool for calculating the stress regime and the related pore pressure. Nevertheless, models are necessarily simplified representation of the real-world behaviour, and consequently the results are approximations. This occurs especially during the exploration phase, when both the input data and the modelling results are affected by high uncertainty.

This abstract presents the geomechanical forward modelling of a thrust belt, where high overpressure conditions are generated by tectonic forces. The geomechanical model was run along a bi-dimensional simplified geological section, tens of kilometres long. The geological section captures the tectonic-structural setting at present day, as a result of several deformation phases. The geological history of the area was sketched into four main events, namely deposition, collision, subduction and erosion; then, each phase, with a simplified geological timeframe, was implemented in the geomechanical forward modelling. Faults were included in the model, and slip movement was allowed along them.

The lithological units were grouped into seven main units, characterized by uniform geomechanical behaviour. Specific material properties, in terms of bulk density, porosity, elastic modulus, Biot coefficient and Poisson ratio, were assigned to each unit. These properties were derived from triaxial lab tests carried out on plugs taken from bottom-hole cores of offset wells. It is worthy to note that cores are available mainly in the reservoir units, allowing a good characterization of these levels. However, no direct information commonly come from overburden and/or shaly formations, where overpressure develops. Thus, the characterization of the non-reservoir layers is often based on values available in the literature as analogue geological settings, leading to a higher uncertainty.

The geomechanical modelling results capture the variations of stresses along the geological section, by highlighting the areas where the maximum horizontal stress overcomes the vertical stress, with subsequent underestimation of the pore pressure if the traditional seismic-derived approach is applied. However, the pore pressure results plotted along the well trajectories are highly approximated, due to the following simplifications used in the model. Firstly, the sketched geological section tens of kilometres long led to a coarse meshing and to a simplified representation of the geological subsurface. Secondly, the geological history was necessarily simplified into four main principal events, and simulation times were attributed to each event according to the interpretation of the geological history of the area. Thirdly, the material parameterization of non-reservoir units was affected by a high uncertainty, due to the lacking of lab data. Eventually, the geomechanical characterization assumed homogenous properties within each unit, neglecting local variations of the geomechanical properties.

According to the level of details and despite the uncertainty in the data, the geomechanical model was able to identify the global stress variations along the geological section, with particular reference to the areas characterized by high compressive stress, where high

overpressure is due to tectonic forces. In such areas, according to the stress regime, the overburden resulted to be the minimum or the mean stress, and the differences between the principal stresses decrease with depth as the overpressure develops. When localized pore pressure variations along the wells are crucial for well planning, the prediction needs a local refinement of the geomechanical model, and a greater level of detail in the data and local well calibration are worth.

Bio

Federica Ferrari is a geomechanics specialist and works in the operations geology team in Eni. Federica deals with pre-drilling pore pressure prediction, post-drilling interpretation, Leak-Off test analyses and estimation of geomechanical properties from well logs and lab tests. In the last months, she worked on digitalization and real-time artificial intelligence applications. Federica joined Eni in 2017, when she decided to move from academia to industry.

Federica is an Engineering Geologist and holds a PhD in rock mechanics discussed at the University of Milano, with a research period at the ETH of Zürich (in Switzerland). Her PhD focused on rock mass characterization, using geostatistics, from direct measurements and photogrammetry. Federica was a research associate at the University of Newcastle in Australia, working on rockfall hazard and risk management in open pit coal mines. She got postdoc positions at the University of Milano and at the Politecnico di Torino in the Petroleum Engineering group.

The Value of Downhole Temperature Response for the Early Kick and Thief Zones Detection in HPHT Naturally Fractured Carbonates Reservoirs

Juan Almeida[1]**,** Sanjeev Bordoloi**,** Massiel Rangel, **Jose Cornielis** and Michael Reese
[1] *Baker Hughes*

Carbonate reservoirs hold a significant portion of the world's oil reserves, and subsequently new conceivable techniques are needed to constantly evaluate and optimally develop these reservoirs. However, these reservoirs present major challenges due to heterogeneity of rock properties, preexisting fracture networks, vugs and abrupt lithological changes, which make drilling operations more difficult than in most siliciclastic environments.
Lost circulation and kicks in fractured formations during drilling are the biggest costs in terms of non-productive time (NPT), unit mud cost and safety issues. These challenges, in part, are due to inefficient attempt to use standard borehole stability and pore pressure prediction methods, which are not viable and not applicable for carbonates.
When the drilling is deeper, the risk of a blowout due to late kick detection increases. Bottom-up circulation for deep wells could be too late (2-4 hours). While waiting for indications that a kick may be occurring, the kick's volume and intensity grows in the borehole. Thus, the time spent waiting for kick indicators reduces the driller's ability to mitigate the potential impacts of a blowout.
Surface logging service (SLS) is the most common and basic method of kick and mud loss detection. It relies on drilling fluid returns to the rig floor or mud pit to detect a kick from the surrounding formation. Seismic attributes, image logs and acoustic technology can identify thief zones, but not always predict what lies ahead and reduce mud losses risks during the drilling in fractured carbonates reservoirs. An alternative way is possible by looking into flow behavior of mud losses (flow in/out) and associated downhole temperature and pressure response.
Logging-while-drilling (LWD) and pressure-while-drilling (PWD) provide the advantage of offering real-time downhole temperature and pressure data on the annulus. While drilling, the bottom-hole temperature (BHT) shows a distinct linear trend with increasing depth. When drilling ceases, but circulation continues, the wellbore undergoes cooling. Because kicks will change the local physical properties of annular fluids, downhole temperature and pressure measurements are among the first indicators that a formation fluid has invaded the wellbore.
This work describes and validates a technique for using downhole pressure and temperature data in combination with surface logging services (SLS), logging while drilling (LWD), managed pressure drilling (MPD) and drilling parameters to facilitate early kick and thief zones detection. This paper will use real examples from the Gulf of Mexico: 1) to explain the importance and benefits of using downhole temperature response to minimize the fluid loss volume and kicks in an HPHT carbonates environment, and 2) how a full understanding of geomechanics in carbonate rocks and lessons learned can play a critical role in developing contingency plans to effectively manage losses and kicks when they occur.

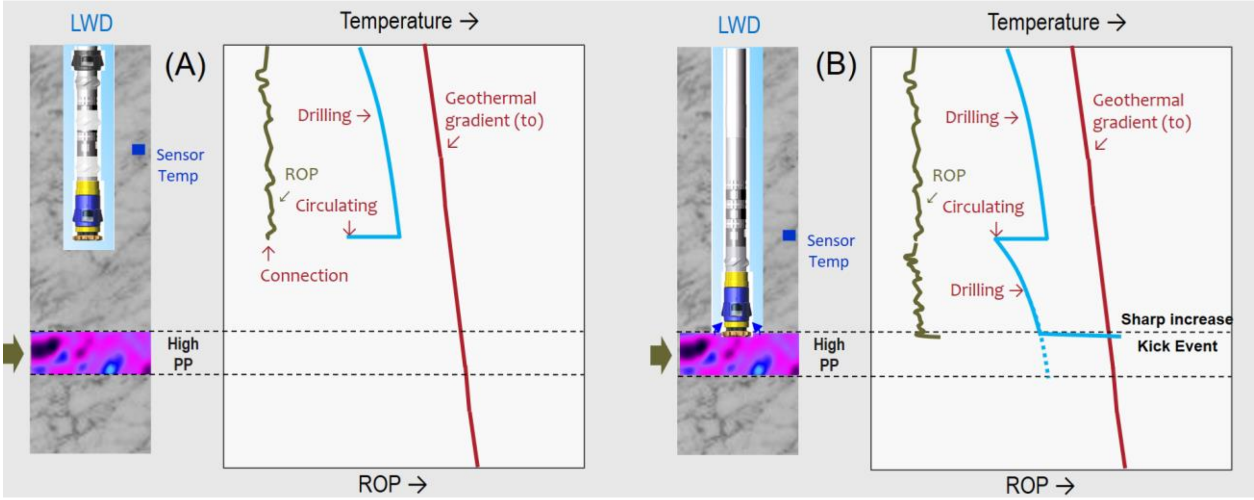

Figure 2. (A) Normal temperature behavior during drilling (B) Kicks are characterized by a sharp increase in temperature

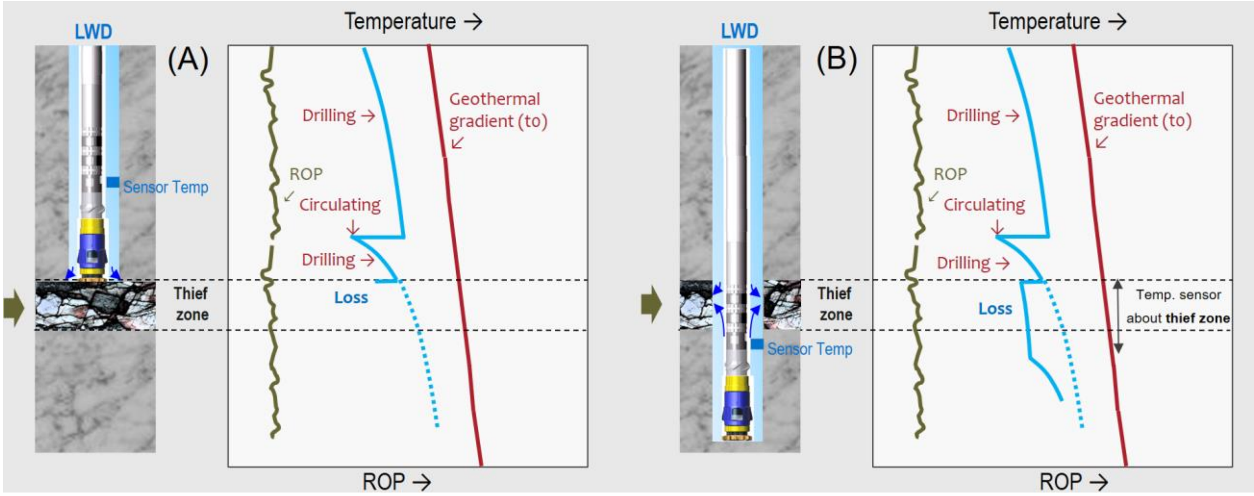

Figure 3. (A) Losses exhibits a lower temperature. (B) Downhole temperature increases below thief zone

Getting more value & understanding from mud hydrostatic pressures for well execution.

Toby Harrold[1], Pascal Rouille[1] and Sara Martinez[2]
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[2] *Repsol Exploracion SA, Calle Mendez Alvaro, 44, Madrid 28045 SPAIN*

Abstract
Drilling hydrostatic mud pressure measurements can provide a very valuable source of pressure information when drilling and evaluating a well. They are commonly taken by wireline or LWD tools as part of the procedure to assure the quality control of the formation pressure measurement. Mud pressures are also recorded by annular pressure while drilling tools included in the bottom hole assembly to measure the equivalent static density (ESD) and equivalent circulating density (ECD) of the mud close to the bit.
Less commonly recorded but very simple are continuous hydrostatic pressure profiles taken when a wireline tool is lowered into or pulled out of the hole. This source of information can be gathered while running a WL pore pressure measurement run and used to detect reductions or increases in MW downhole. These can in turn identify sources of influx, cross flows, mud degradation etc. Such changes are not possible to interpret from the surface or isolated down hole pressures. This presentation will share two examples of continuous hydrostatic profiles, their interpretation and use in the respective wells with a recommendation that more such data be gathered in the future to help with safe execution of wells.
The technology of annular pressure measurements is very simple and involves leaving the pressure tool open and the gauge recording while lowering the wireline tool into the hole or pulling it out of the hole. This can be requested and performed simply and transparently to the rest of the operations. The results are a continuous measurement of pressure in psi, bars or kPa against measured depth. This data can have its own value when plotted up against the pore pressure and fracture gradient plot in absolute pressure. The data can also be converted to equivalent mud weight by simply dividing the pressure by its vertical depth and the gravitational constant to transform it to ppg or g/cc.
$\rho_{ave} = P_{hyd^a} / Z^a / 1.4223$
Where: ρ_{ave} = average density of fluid in g/cc
P_{hyd^a} = mud hydrostatic pressure at point A in psi
Z^a = vertical depth at point A in metres.
1.4223 = gravitational constant
The greater value in some wells comes from converting the continuous profile of pressure into a continuous mud density profile.
$\rho_{int} = (P_{hyd^a} - P_{hyd^b}) / (Z^a - Z^b) / 1.4223$
Where: ρ_{int} = average density of fluid in g/cc
P_{hyd^a} = mud hydrostatic pressure at point A in psi.
Z^a = vertical depth at point A in metres.
P_{hyd^b} = mud hydrostatic pressure at point B in psi.
Z^b = vertical depth at point B in metres.
1.4223 = gravitational constant
This equation will give a profile of the mud density along the wellbore at the depth interval selected, as shown in Figure 1. It is recommended to try various intervals as the data can be quite noisy which can result in a very spiky profile when too narrow an interval is chosen or too smooth if the calculation is made over a coarse interval. An optimal profile can reveal density variation on a several metre scale as shown in figure 1 that show changes in fluid composition within the wellbore due to degradation of the mud properties or by influx and migration of lighter fluids.

Example 1 shows a profile from a vertical well drilled into a thick karstic / fractured formation with Darcy permeability that resulted in an influx and losses and the mud hydrostatic coming into equilibrium with the formation for the permeable interval. The continuous hydrostatic log was run because the porosity size and distribution in the formation made it very hard to get direct pressure measurements, also, the nature of the reservoir fluid made sampling very difficult too. Use of the hydrostatic mud profile was able to show where the formation was permeable and in balance with the formation and where there were lower permeability intervals. The density of the fluid in the borehole matched that of the eventual sample gathered from the well.

Example 2 shows an exploration well drilled close to balance conditions in a narrow pore pressure fracture gradient section. The well displayed a complicated log and drilling gas signature giving uncertainty to the pore pressure conditions downhole. A hydrostatic pressure profile was measured to help reduce the uncertainty on the conditions and revealed a localised reduction in mud density resulting from a limited volume of gas coming into the wellbore during static conditions. The pressures from the XPT run confirmed the pressures were highest in that interval, that the permeabilties were low and informed the forward plan for drilling of the well.

Other examples have revealed unexpected mud weight degradation that could have significant impact on wells that are to be suspended for any period of time with MW expected to represent one of the barriers.

The results of these logs significantly influenced the understanding of the downhole mud weight evolution and were used to reduce time in data acquisition and improve planning for abandonment / control of wells. Given the low additional cost and simplicity of acquiring such data when running a conventional wireline pressure measurement run, it is recommended to gather more data to assist with future well operations.

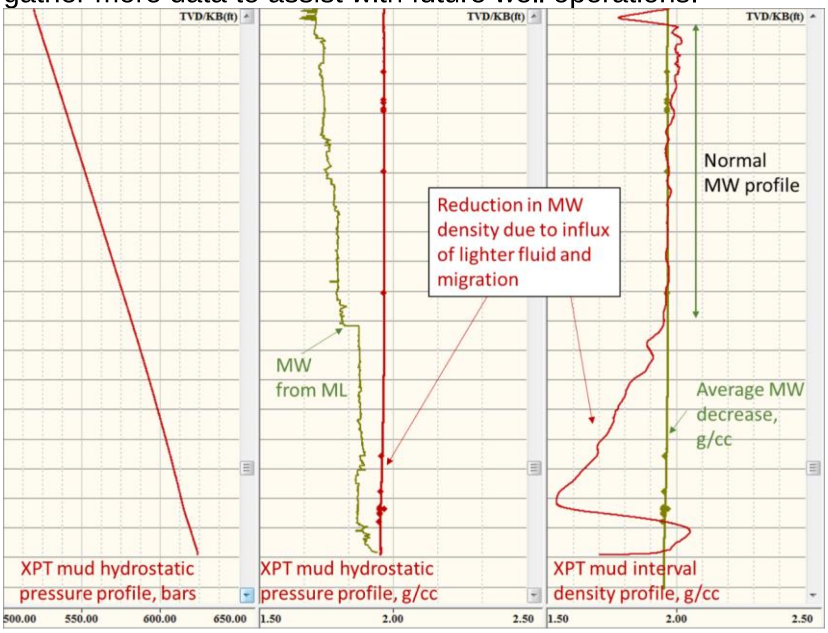

Figure 4 Pressure vs depth plot for Well 2 showing mud hydrostatic pressure in bars (track 1); calculated average MW profile, drilling MW from the mud log and hydrostatic pressure measurements from XPT stations in g/cc (track 2). Calculated interval mud weight density plus calculated average MW density showing a reduction in MW where fluid has been entering the wellbore are shown in track 3.

Bio

Toby Harrold received his BSc in Geology from the University of Birmingham and his PhD in pore pressure prediction from the University of Durham. He has >20 years' experience specializing in pore pressure, fracture gradient and wellbore stability prediction and the application to well planning, well execution, field development and abandonment. He worked for BP for 14 years, and at Repsol for 7 years managing their global Geohazards team of seven specialists. In 2020 he co-founded P-Ten Geomechanical Services to deliver specialist pore pressure and geomechanical studies. Toby has led consortia participation, co-chaired several technical conferences and is the Geohazards representative for the EPSP safety panel for the IODP.

Jasmine: The challenges of unlocking infill wells in a variably depleted HPHT field

Brian MacLeod
Chrysaor

Abstract
Jasmine is an HPHT gas condensate field situated on the J-Ridge in UK Central North Sea. The primary reservoir is the moderate net to gross fluvial Joanne Sandstone Member of the Triassic Skagerrak Formation. This is overlain in parts of the field by secondary Triassic and Jurassic reservoirs.

The field was first discovered in 2006, and following the appraisal, five pre-production development wells were drilled from a wellhead platform between 2011 and 2013. To date over 76 MMboe has been produced from the field.

The field had an initial reservoir pressure of 11,650 psia and temperature of 339°F at -14,500 ft TVDSS.

There have been 3 infill wells drilled during a post-production phase into the main West Limb structure to date, with a fourth well currently under construction. Despite the challenges posed by the variability of the reservoir depletion and the ever-diminishing drilling window, these infill wells offer incremental production and represent an opportunity that is worth pursuing.

With increased reservoir depletion comes increased well cost, time and risk. In some parts of the field the reservoir is expected to be variably depleted by up to 9,500 psi. Understanding the reservoir pressure and how this impacts the drilling window is critical for ensuring success and unlocking further wells.

This presentation will focus on the challenges associated with PPFG interpretation in an environment where data acquisition is severely compromised, and look at how the drilling window can be managed to successfully deliver these wells.

Bio

A Geoscience graduate from the University of Aberdeen, Brian has been working in the oil industry for over 20 years in a variety of interesting roles. Having served his time offshore as a Logging Geologist and Data Engineer, he made the move onshore into an Operations and then Technical Training role with a major oilfield service company. As well as enjoying a fair amount of international travel the training role provided him with the opportunity to develop his interest in all things PPFG related.

Keen to get back to the coal face, Brian returned to active operations with a major operator in 2011, working as a Wellsite and Operations Geologist in the UK North Sea and West of Shetland. He joined ConocoPhillips UK in 2013 and has been the Geological Services Team Lead since 2018. As the PPFG lead at Chrysaor, Brian has developed and refined in-house pore pressure prediction best practices, incorporating geomechanics and wellbore stability into the workflow in recent years.

Session Four: Case Studies 1

Quantifying pore-pressure and pore-pressure evolution in sedimentary basins using fluid escape pipes

C. Kirkham[1], J. Cartwright[1], M. Foschi[1], N. Hodgson[2], K. Rodriguez[2], David James[3]
[1]*Earth Sciences Department, University of Oxford*
[2]*Searcher*
[3]*Cwmystwyth*

Abstract
We present an example of episodic fluid venting through a thick salt sheet in the Eastern Mediterranean and demonstrate a method for quantifying pore-pressure and pore-pressure evolution through time in a deep reservoir. We show using 3D seismic reflection data a linearly distributed trail of 21 fluid escape pipes that have gone through the thick Messinian salt in the North Levant Basin, Eastern Mediterranean (Fig. 1). The Messinian salt has undergone a Pliocene to Recent phase of gravity driven deformation, leading to flow of the salt and translation of its overburden in a basinward direction. The fluid escape pipes root to a pre-salt sandstone reservoir within a large NE-SW oriented anticlinal trap named Oceanus and formed at regular intervals of 50-100 k.a. over the last 1.7 m.y. Each fluid expulsion episode and their timings are recorded by erosive pockmark craters at the outlets of the fluid escape pipes. These pockmarks formed by venting of highly overpressured fluids at the present day and palaeo seafloors. Gas related amplitude anomalies adjacent to and overlying the fluid escape pipes point toward the presence of gas charged pre-salt sediments.

The fluid escape pipes represent natural blowout pipes that formed by the upward propagation of hydraulic fractures through 3 km of sealing claystone and salt. Interpreting episodic venting in fluid escape pipes using seismic reflection data is typically challenging. This is because the pockmark craters attributed to palaeo expulsion episodes are usually shrouded within the pipe's vertical zone of low coherency. The fluid venting overlying Oceanus is distinctive in that each fluid escape pipe has been deformed in the Messinian salt and each pockmark offset NW from its original forming location by the flowing salt and translation of the overburden over the last 1.7 m.y. This interpretation of episodic expulsion synchronous to basinward salt flow has led to the recognition of several other linear trails of fluids escape pipes and pockmarks overlying pre-salt folds in the North Levant Basin.

Numerous gas discoveries (>35 tcf) have been made in the nearby South Levant Basin, hosted in Lower Miocene sandstone reservoirs (Tamar sands) within NW-SE oriented pre-salt anticlinal traps. Lateral seismic correlation indicates a high degree of similarity in stratigraphy between the Tamar gas field in the South Levant Basin and Oceanus in the North Levant Basin. Hence, an equivalent Lower Miocene reservoir is assumed to be the source of overpressured fluids at Oceanus. The minimum requirement for the formation of the overlying hydraulic fracture pipes is reservoir pore-pressure at least equal to the fracture gradient. The fracture gradient for the succession at Oceanus can be derived from nearby wells in the Tamar Field. We use a present day depth section and reconstructed depth section at the formation time of the first fluid escape pipe to quantify the pressure conditions in the reservoir for the first venting episode (85.3 MPa) and the most recent venting episode (81.2 MPa). We find that pore-pressure generation of ~30 MPa since the end of salt deposition (5.33 m.a.) would be required if the reservoir was originally hydrostatically pressured similar to the Tamar reservoir. The timings of the 19 intervening pockmarks between the first and most recent venting episodes allowed us to produce pressure vs time plots, revealing a saw-tooth pressure recharge in the reservoir.

The only process in this basin capable of generating the magnitudes of pressure and reliably recharging pressure to the fracture gradient a subsequent 20 times is tectonic overpressuring, with hydrocarbon buoyancy potentially playing a lesser role. Although salt poses a formidable seal in hydrocarbon systems, it can be breached by hydraulic fracturing. Where sealed by claystone and salt, pre-salt sandstone reservoirs can host exceptionally high overpressure. Future observation of episodic venting should hopefully lead to further application of the quantitative approach demonstrated here and lead to a greater understanding of development of the extreme overpressures at depth and of pressure evolution. It is imperative that these pre-salt pressure conditions be recognised as they define the conditions in which it is safe to drill and aid in seal de-risking.

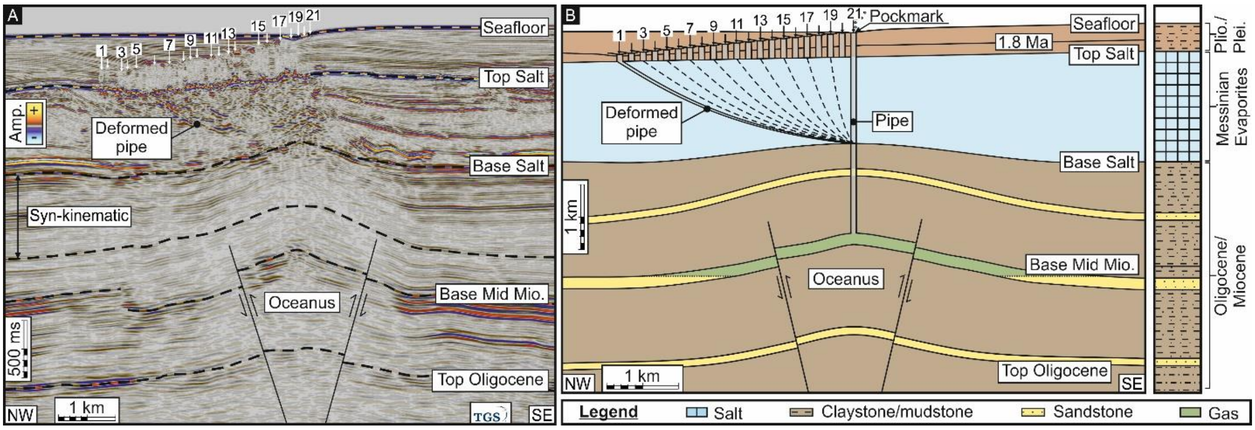

Figure 1. Episodic fluid venting through the thick Messinian salt in the Eastern Mediterranean. A: A seismic profile through the pre-salt anticline named Oceanus and the linear trail of fluid escape pipes and pockmarks that overlie it. The numbered white arrows highlight the pockmarks at the outlet of each fluid escape pipe, numbered 1-21 in order of their formation. B: A depth-converted cross-section through Oceanus and the linear trail of fluid escape pipes and pockmarks, with a simplified stratigraphic column. The dashed lines transecting the Messinian Evaporites represent deformed pipes.

Bio

Dr Chris Kirkham holds a B.Sc. and a Ph.D. from Cardiff University and is at present a postdoctoral researcher in the Department of Earth Sciences, Oxford University. He is an expert seismic interpreter and specializes in the recognition and interpretation of pressure dynamics within sedimentary basins and in the analysis of fluid flow and mobile media such as mud and salt. Chris' main research aims have been: 1) to further our understanding of how fluids and mobilised sediments migrate upwards through subsurface seals and what pressure dynamics in the deep aquifer/reservoir or mud source have driven their ascent; 2) develop new and novel methodologies for interpreting salt tectonics deformation and salt flow kinematics, using intra-salt deformation structures and naturally forming vertical fluid migration features through salt seals as markers for deformation.

Overpressure in The Baram Delta Requires Practical Solutions for Well Design and Drilling

W Aisyah W M Kamil, Frank Wijnands, Ismatul Hani Idris, Farahin Razali, M Nizam M Zin

Introduction

There are 9 producing fields in the Baram Delta, offshore Sarawak with an estimated STOIIP of about 4BSTP. Six major fields have been in production for more than 40 years. Producing structures in the Baram Delta are of deltaic origin and are usually located next to large growth faults with more recent anticlines formed at oblique angles to the faults, thus providing excellent 3 or 4-way dip closure.

There is current interest in drilling deeper into Baram Delta structures, mainly because the deepest wells still found indications of hydrocarbon. Amplitude and QI work on new, better quality seismic data suggests that there is potential for hydrocarbon accumulations below current producing zones. A few deep wells penetrated through sharp pressure ramps, and proved the presence of hydrocarbon at deeper, highly overpressured reservoirs.

Field Observations

The region is characterized by stacked reservoir/seal pairs of deltaic origin over long vertical sections with a normal hydrostatic pressure regime, which contains commercial oil and gas volumes in several structures. For all the known structures, this is followed by a sudden transition zone with a sharp pressure ramp, and deeper, high pressure reservoirs which may or may not contain commercial hydrocarbons. Interestingly, relatively thin shales can hold extremely high pressure differentials and retain hydrocarbons. For instance, a 13 m shale in well T Deep separated two reservoirs with a 6000 psi pressure difference. To ensure safe drilling operations for deep wells, it is crucial to refine our ability to predict location and magnitude of such pressure ramps.

Field observation shows that the location of the pressure ramp is not controlled by stratigraphy, depth or temperature. Even within a single field, the ramp may be found several seal/reservoir pairs deeper or shallower depending on the presence of small faults. The pressure magnitudes also vary.

Pore Pressure Prediction

Various methods were utilized in attempts to model and predict the pressure ramp and pressure magnitude. Log responses show only small effects due to pore pressure so that they may indicate the location of the pressure ramp but not the magnitude. Likewise, seismic interval velocities may show small inversions indicating the top of OP but usually only where offset wells were available to guide velocity picking. Basin modelling techniques have not been able to capture the sharp pressure ramp presence in Baram Delta

We believe that the overpressure mechanism in the Baram Delta is not primarily controlled by disequilibrium compaction. This is based on the observed log data responses and also on the fact that attempts to model the steep pressure ramps with basin modelling techniques have been unsuccessful. It is not possible for thin shales to hold very high pressures over the required time periods with the kind of shale permeabilities that are used by basin modellers. It is possible that the whole system is more dynamic than previously modeled. We assume that deep seated faults experience occasional slip, which allows migration of fluids and pressure to shallower reservoirs. If such fluid movements occur much more often than usually assumed, perhaps even a leaky seal can still maintain a very large pressure differential.

Drilling

In practice, we have to rely on well design contingencies and careful real-time pore pressure interpretation to drill wells in the Baram Delta. In a recent well in the B field, a pressure ramp from ~9 to 16 ppg occurred over a 30 m shale, directly below producing and severely depleted reservoirs. Its location was correctly predicted and detected and a casing was successfully placed within the ramp. The pressure below the ramp was interpreted from RT observations and a series of deeper, high reservoirs were drilled safely until an unexpected second pressure ramp was encountered, which necessitated the TD of the well.

Bio

Wan Aisyah Wan Mohd Kamil is a geoscientist at PETRONAS with a keen interest in Pore Pressure and Geomechanics. She graduated from the University of Michigan, Ann Arbor with a B.S. Geological Sciences in 2012. Her contribution in Upstream Exploration is mainly in subsurface studies related to pre-drill pore pressure prediction and Wellbore Stability Analysis. Her working experience is mainly focused in Offshore Sabah and Offshore Sarawak in Malaysia.

Impact of tectonic uplift- erosion on geopressures : an example from the andaman sea

Clare Blenter[1] ,Vincent Delgorgue[1], Olivier Chailan[1], Charlie Kergaravat[1], Benoît Hauville[2], Pascal Le Nen[2]
[1]Total SA, E&P, Exploration, Technical centre, Pau, France; 2 Total E&P Asia Pacific, Singapore

Introduction
A complex geological history can significantly complicate the ability to predict the pore pressure evolution in a sedimentary basin. It is especially the case in frontier domains when the area of interest has been affected by multiple uplift and erosion events, where timing, speed and magnitude present large uncertainties due to lack of calibration. Consequently, the reconstruction of the compaction history is fundamental when using seismic velocities to derive pore pressure. This case study refers to a frontier carbonate prospect located in broad dextral shear zone in forearc geological setting. The recent interpretation of the structural evolution of this basin significantly impacted the pore pressure evaluation at prospect scale, as well as the drillability of the structure.

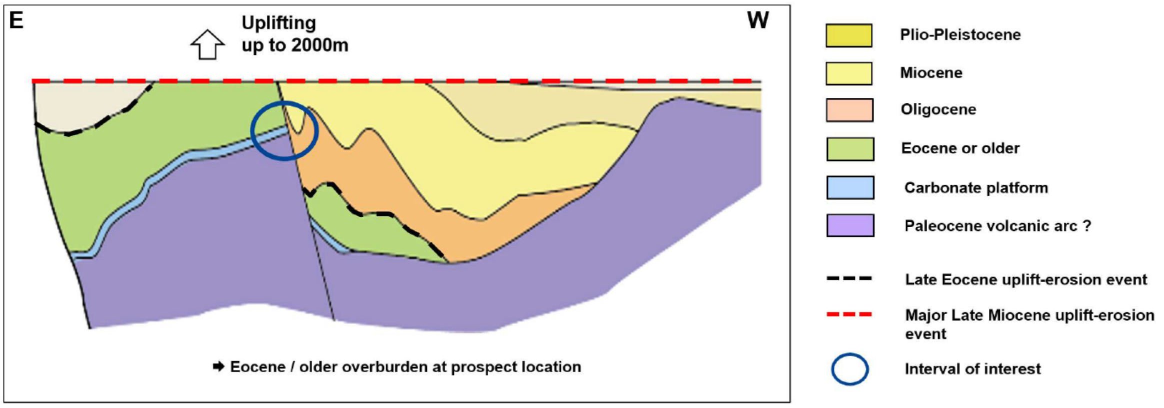

Figure 1
Simple schematic section showing the evolution of the geological model as the study went by

Results
The prospect is affected by strong uplifts and wrench faulting since Neogene in response to highly oblique convergence between Indian plate and West Burma-Sibumasu blocks. Additionally, a strike-slip regime occurred in Late Miocene that created an inversion of a major Oligocene normal fault crossing the basin. Therefore, the prominent high corresponds to the edge of the Mid Eocene and older depocenter inside a broader inverted domain.

Analysis from adjacent basin to the west suggests that abnormal compaction and hence overpressure would have been present at the initial stage of the formation of the basin, with the main source of overpressure being compaction disequilibrium. Furthermore, a strong unloading effect was generated by two major periods of uplift and erosion; first in the Mid-Eocene, then a second since the Late Miocene (~10My). In the base case scenario, this would have removed 2500m of sediment. The timing, speed and amount of erosion related to this major event is of critical importance as it controls the magnitude of pressure encountered at the prospect location.

From this initial pressure state and considering the recent and major uplift undergone at the prospect location, it is very unlikely that the pressure born by the formation before uplift could have been dissipated during the uplifting of the series, taking into account the shale prone nature of the overburden (pelagic deep water shales). The uplift and erosion rate is estimated at 250m/My for the base case applied to already compacted rocks. As a comparison, a burial rate of 250m/My in uncompacted shale dominated sediments generally lead to the development of strong undercompaction. The effect of unloading is thus very similar to a disequilibrium state in this case. The formation cannot dissipate the excess pressure due to a lack of drainage, resulting in the preservation of a very high overpressure. Sensitivity tests were performed on the amplitude of uplift and erosion. It appears that from 2000m and further, the formation would experience hydrofracturing from the surface to the reservoir depth.

Then, two scenarios can be considered:

1- In a fully closed system, the pore pressure would equilibrate at the Fracture Closure Pressure (FCP) and hence would leave no drilling window.

2- Partial pressure dissipation could occur via hydrofracturing, or lateral transfer in permeable layers, maintaining a tight drilling window.

The use of seismic data over the area allowed to qualitatively assess the compaction state of the formations. A low velocity anomaly is characterizing the whole overburden from a depth starting around 150m below the sea bed. Such shallow onset was justified by the transient state in which the area is, where overpressures are currently dissipated.

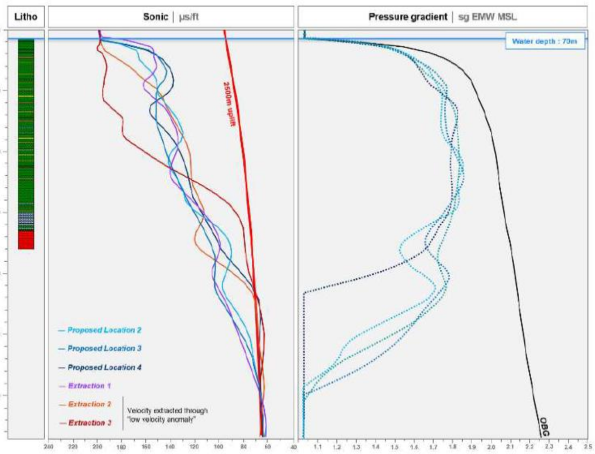

Figure 2

Pshale sensitivity from seismic velocity extractions inside the basin Analog basins in onshore areas, where similar timing and magnitude of uplift were experienced, showed similar behaviour based on mud weight dataset. This model is further strengthened by the observation of “Christmas tree”-shaped seismic anomaly cross-cutting the overburden sediments and capped by recent and thin sediments, interpreted as inactive mud-volcanoes.

Conclusions

In this case study, overpressure is interpreted to be mainly controlled by the timing, magnitude and speed of the uplift-erosion process since Late Miocene, where at least 2500m of material was removed. Consequently, the overpressure mechanism is mainly unloading effect. We suggest that significant unloading of sediments in very short and recent period of geological time is moving high initial pressures to much shallower depths generating a strong disequilibrium state that can lead to the development of intense fluid escape phenomenon like mud volcanoes.

Bio

She started her career at young age by gaining experience in operation thanks to 4 years on (and off) the rigsite as a wellsite geologist in various countries. In 2018, she went back to school - in IFP school - to improve her knowledge in petroleum geoscience. She recently returned to operations world as she is currently working in Pore Pressure Prediction team in Pau, where she has the chance to help both exploration and development teams preparing and following the drilling of wells in a safe manner.

Session Five: Energy Transition

The Role Of Pore Pressure & Geomechanics In CCS: NZT/NEP Overview

Louise Duffy, David Ashby, Tim Wynn, Nicolas Bouffin, Fiona Sutherland, Robin Eve

Net Zero Teesside (NZT) as part of Northern Endurance Partnership (NEP) is planned to be the first decarbonised industrial cluster in the UK by 2030. CO2 will be captured at a combined cycle gas turbine (CCGT) power station and other industries in Teesside and the CO2 compressed and piped out to the Endurance structure in the Southern North Sea (SNS).
The Endurance structure was evaluated previously for CO2 storage and assessed as an excellent storage candidate due to its size, good reservoir quality and proximity to Teesside. bp and partners inherited the project on behalf of OGCI Climate Investments in 2019, with formation of the NEP in 2020 comprising bp, ENI, Equinor, national Grid, Shell and Total.
In this paper we discuss containment and the role that understanding pore pressures and geomechanics can play, using NZT/NEP as a case study. Fundamental factors for successful CO2 storage are containment, capacity, injectivity and monitorability. Endurance is a very large 4-way dip-closure (~25km x 8km) providing significant CO2 storage potential. CO2 will be injected (in supercritical phase) mid structure, gradually moving towards the crest. Pressure increases within the structure in the CO2 “column” and also within the brine leg. CO2 will be contained within the spill-point of that structure. Multiple work programs have been executed to ensure this containment, including many that are pore pressure & geomechanics related.
Vertical and lateral continuity of seals is supported by top-down and bottom-up evidence and seal rock properties measured. Faulting in the overburden over Endurance is well imaged down to the top of the Rot Halite unit, which is inferred to act as a detachment here and therefore, overburden faults are not interpreted as extending through the seal, into the reservoir. There are no imaged faults in the reservoir, though this may be due to seismic data quality or absence of impedance contrasts in the reservoir, rather than the absence of structure. To ensure downside outcomes were fully addressed, scenarios were generated to look at the impact of faults and compartmentalisation within the reservoir in dynamic simulations and also unlikely scenarios where faults were extended through the seal for geomechanical modelling.
Pore pressures are approximately normal with influence of salinity variation seemingly apparent. Geomechanical modelling has tested a wide range of scenarios and none of the simulations using the key pressure cases displayed any plastic failure or reactivation of faults. Setting reservoir pressure limits drew on key inputs and an estimate of Shmin of the primary seal at the Endurance crest to set upper limit. Normal operating limits will be set below this by some margin, taking into account multiple factors, for example, projected pressure increase over periods between monitoring program items such as Pressure Fall-Offs (PFO).
Pore pressure understanding and geomechanics can be integral to successful CO2 storage. As such, work programs have been ongoing since the earliest stages of NZT/NEP project development to ensure long-term containment of CO2 within the robust Endurance structure.

Bio
Currently Senior Geologist on the Net Zero Teesside CCS project and also Leader of the Pore Pressure & Geomechanics Community of Practice.

Following completion of a Geoscience MSci at Durham University, joined TGS in 2005 working as a Petroleum Systems Analyst for 2 years. Subsequently, completed a petroleum systems, pressure and geomechanics focused PhD at Newcastle University with Shell. Joined BP in 2011 and have worked numerous roles across geology, petroleum systems and pore pressure prediction in Exploration and Reservoir Development. This has included involvement in activities around the world including Egypt, Libya, Indonesia, GoM, Mauritania, Senegal, China, Kuwait, Azerbaijan, UK and Norway.

The role of pore pressure analysis in deep geothermal energy – examples from the North Alpine Foreland Basin, SE Germany

Michael C. Drews[1]
[1]*Professorship of Geothermal Technologies, Technical University of Munich*

Deep geothermal energy has the potential of playing a major role in the World's energy transition, both in terms of electricity generation and large scale district heating. Thereby, deep geothermal energy is generally divided into hydrothermal or petrothermal systems. The latter are also known as enhanced geothermal systems and require reservoir stimulation, while hydrothermal systems produce hot water from an already producible reservoir. Despite its potential, a utilization of deep geothermal energy comparable to oil and gas exploration and production of is restricted to only a few regions in the world. One of these regions is the North Alpine Foreland Basin in SE Germany (also known as Bavarian Molasse Basin). Here, 25 hydrothermal projects have been successfully implemented by several smaller operators over the last 20 years and 5-10 additional projects are currently planned to be executed in the next 1-2 years. In total >300 MWth and >35 MWel are currently generated for both electricity generation and district heating from depths between 500 to 5000 mTVD. Only 4 projects did not yield sufficient production rates and had to be abandoned or halted, resulting in an exceptionally low exploration risk. In contrast, many of the deeper projects (>2500 mTVD) experienced significant drilling problems, which are mostly related to abnormal pore pressures (both overpressure and underpressure) and the complex stress field. This talk will give a short overview of the pore pressure distribution in the North Alpine Foreland Basin followed by a review of the role, impact and challenges of pore pressure analysis for deep geothermal energy exploration, drilling and production.

Bio

Michael Drews is a graduated geologist from the University of Mainz, Germany and gained his PhD for his thesis about effective permeability modelling of heterogeneous mudstones from Newcastle University within the context of the Caprocks Project. After receiving his PhD Michael worked as a pore pressure specialist in deep water oil and gas exploration and operations in Houston, Texas. In 2016 Michael moved back to German academia, and works as a Geomechanics researcher in deep geothermal energy since then. In 2019, Michael accepted a tenure track professorship in Geothermal Technologies at the Technical University of Munich.

Impacts and lessons learned from underpressure at a test CO2 injection site in Svalbard, High-Arctic Norway

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Between 2007 and 2015, eight wells were drilled as part of the Longyearbyen CO2 Lab study in Svalbard. The study aimed at determining the feasibility of injecting and storing liquid carbon dioxide (captured from the local coal power station) in Triassic and Jurassic sandstones sealed by a Late Jurassic shale. Both the reservoir and caprock outcrop fifteen kilometers to the north of the drill site. It was, therefore, a surprise when wellbore DH4 encountered pressures of 60 bar (870 psi) below hydrostatic in the target reservoir at approximately 700 m depth (Figure 1). Such severe underpressure precludes the possibility of injecting CO2 in a liquid phase. This underpressure also has implications relating to hydrocarbon exploration in the Norwegian northern Barents shelf.

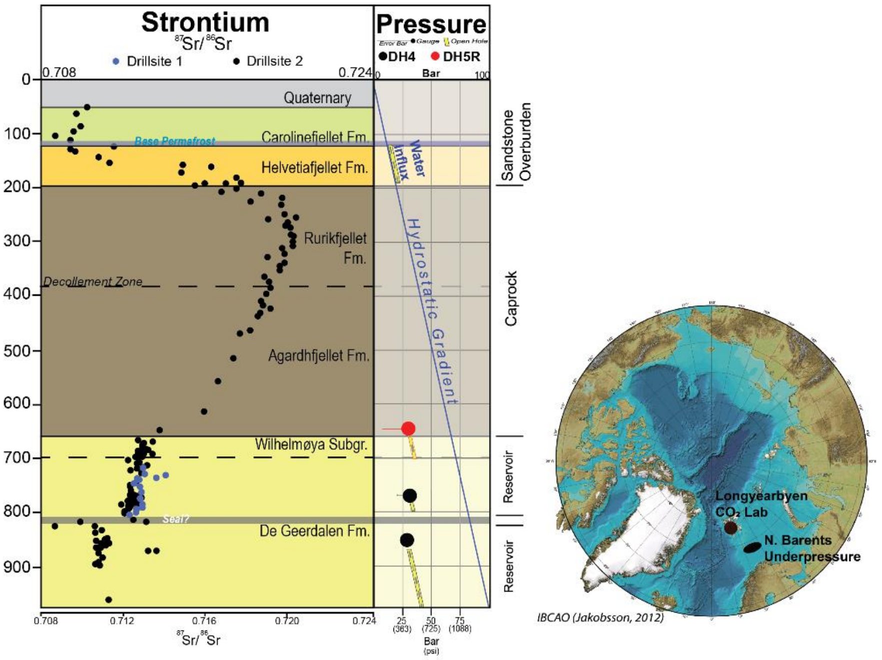


Figure 1 – Pressure and strontium isotopes encountered in the DH4 wellbore of the Longyearbyen CO2 Lab (location inset right) from Birchall et al, 2020. Severe underpressure in the reservoir precludes liquid injection of carbon dioxide. Strontium isotope data indicates fluid flow from the reservoir into the overlying caprock.

Though milder underpressure had previously been encountered in the region in the 1980s, results from the Longyearbyen CO2 Lab and more recent exploration drilling in the northern Barents demonstrate it is a more widespread phenomena in the region.

Genesis of naturally occurring underpressure is poorly documented in academia. In order to better understand the underpressure encountered in the Barents, we compiled a global review of all known occurrences (Figure 2). We identified natural underpressure in 29 basins and note that it is relatively low magnitude and occurs at much shallower depths in comparison to overpressure. Nearly all occurrences of underpressure are in areas of well documented uplift (tectonic or isostatic) and typically occurs in low permeability rocks.

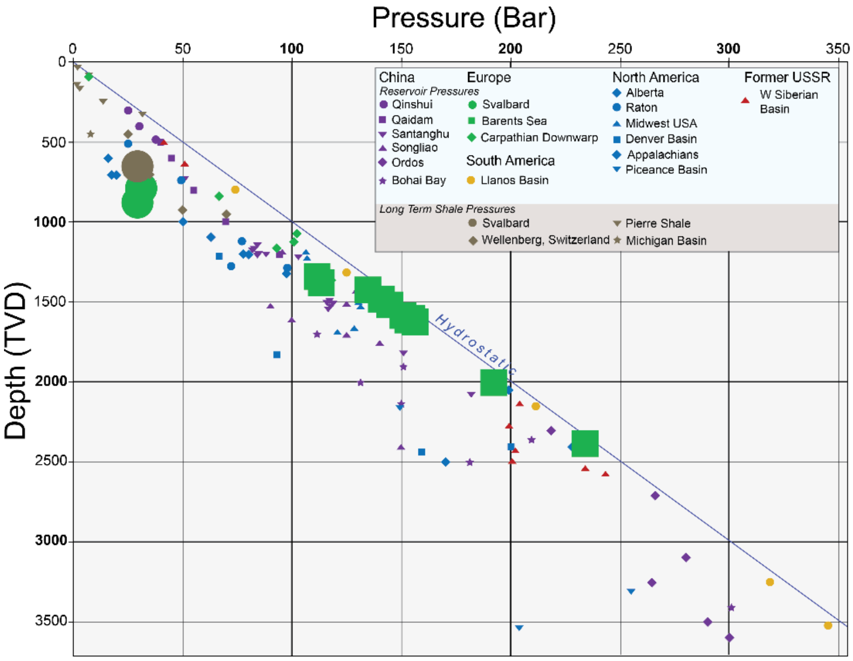


Figure 2 – Aquifer underpressures from around the world with the Barents shelf occurrences highlighted.

Although the underpressure in the Barents Sea are the only cases documented offshore, the geology of the area is remarkably similar to other occurrences. Firstly, recent and severe uplift has occurred throughout the northern Barents and in Svalbard and, secondly, the underpressure occurs in a very low permeability reservoir (< 2mD).

The role that mudrocks play in the development of underpressure appears to be critical in some examples. Data from the nuclear waste industry has identified severe underpressure from long-term pressure tests. Underpressure was also directly measured in the caprock of the Longyearbyen CO2 Lab where a gas influx into shut-in wellbore came from the organic rich caprock. The gas in the wellbore was allowed to equilibrate with the formation which was measured to be approximately 30 bar below hydrostatic.

Direct measurements of underpressure in the caprock and strontium isotope data (Figure 1) all indicate that underpressure most likely in the recent geological past (i.e., the past few kyr). Fluid from the reservoir has subsequently been drawn into the caprock at a greater rate than it can be replenished laterally though the very low permeability reservoir.

Fundamentally, the recent formation of underpressure and fluid flow from reservoir into the caprock mean that using pressure data in this region should be carried out with care. Recently generated, out-of-equilibrium pressures do not provide evidence of good seals (lateral or vertical). Indeed, fluid flow into the caprock suggests the opposite.

Bio

Since early 2017, Tom has been living and working in the world's northernmost town of Longyearbyen, in the Norwegian archipelago of Svalbard. He recently defended his PhD with the University of Oslo and the University Centre in Svalbard, where his work focused on the pore-pressure regimes of the Norwegian Barents Shelf. Tom graduated with a degree in Geology from Durham University in 2012, where he also worked as an intern for Ikon GeoPressure. He completed his master's in Petroleum Geoscience at Aberdeen University in 2013 and was subsequently hired onto Maersk Oil's graduate scheme, and as an exploration geologist before moving north.

Session Six: Uncertainty 1

Overpressure development and uncertainty analysis on Western Mediterranean evaporites

Michael Stanley Dale, Hector Marin-Moreno, and Ismael Falcon-Suarez
National Oceanographic Centre, University of Southampton Waterfront Campus, European Way, UK

Evaporites have long been recognised as impermeable seals that create some of the world's highest subsalt reservoir pressures (Warren, 2016). However, studies show that salts can retain open pore spaces and connected pore-fluid pathways (Figure 1a). In this study, we quantitatively assess the impact of uncertainties in halite rock petrophysical properties on the overpressure generation and dissipation within evaporites of the Western Mediterranean. We use 1-D models and consider (i) boundary conditions of zero overpressure at the top of the models, representing the seabed, and zero flow at the bottom and (ii) overpressure generation only by disequilibrium compaction. Our approach to estimating overpressure reconstructs the sedimentation history at several locations of the Western Mediterranean basin and satisfies present day geological and seismic observations.
We evaluated the impact of uncertainty in evaporite rock initial surface porosity and permeability on overpressure development of homogenous halite. We considered halite thicknesses from 200 to 1000 m and a depositional time of 50 Kyr (Roveri et al. 2014). The largest number was selected based on halite thickness estimates of 600 to 1000 m, obtained from seismic interpretation of the Western Mediterranean.
We used halite permeabilities from 10-16 to 10-22 m2 based on global literature ranges, derived from a combination of laboratory tests, modelled and inferred values; and our experimental data (Figure 1a).

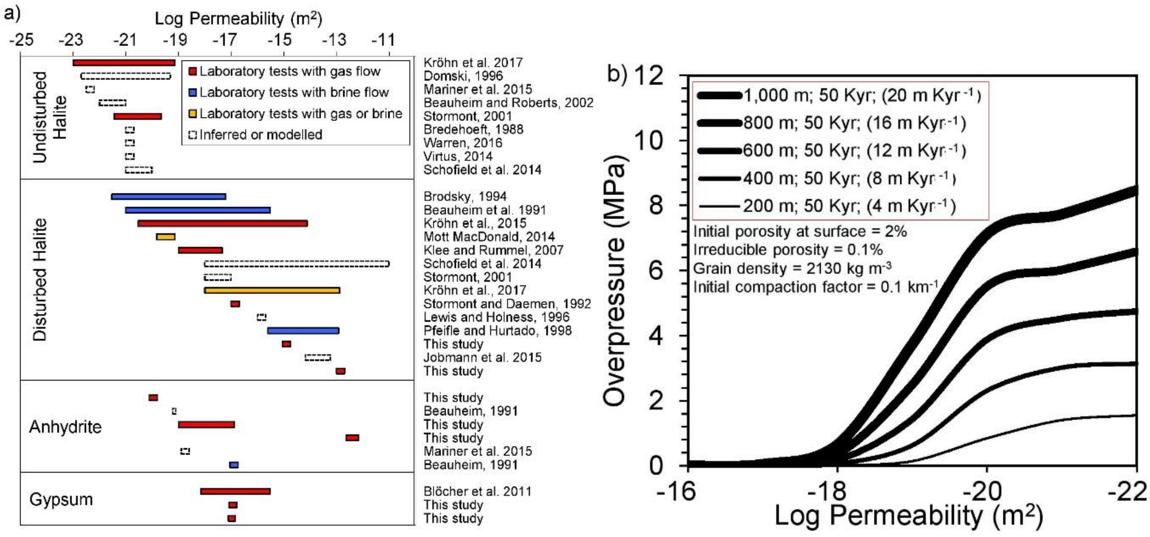


Figure 5: a) Global permeability ranges of evaporites, collected from literature. Included in this study are laboratory results of permeability obtained for Permian and Miocene anhydrite, Miocene gypsum and fractured Miocene halite. b) Overpressure modelled for Messinian halite with ranges in surface permeability from 10-16 to 10-22 m2.

Halite with permeability above 10-17 m2 generate hydrostatic pressures. When the permeability drops below a threshold of about 10-18 m2, halite with thickness greater than 600 m develop overpressure above 1 MPa (Figure 1b). In contrast, halite with thickness of 200 m require a lower permeability below 10-20 m2 to generate and maintain the same overpressure magnitude. The two orders of magnitude difference in threshold permeability is related with the ability of permeability to dissipate overpressure for a given length scale and time scale. In our

models, for the same time scale, the thinner the sequence the shorter the distance the fluid needs to travel to dissipate overpressure, and so the lower the permeability needs to be to generate and maintain the same amount of overpressure. For halite thicknesses ranging from 600 to 1000 m and a permeability of 10-20 m2, moderate to high overpressure develops ranging from 3.9 to 7.1 MPa. Below 10-21 m2, that being the permeability of undamaged halite, overpressure for a 1000 m halite remains high at 7.7 to 8.5 MPa. When comparison is made for permeability ranges from 10-20 and 10-22 m2, minor variation in overpressure up to 1.3 MPa is obtained.
Shallow halite layers like that of the Saline Valley in California display porosities less than 10% with no visible porosity and tightly cemented layers below a depth of 45 m (Casas et al. 1989). In our study, lower connected porosities of 1.0% to 2.7% were obtained from laboratory testing of shallow Messinian halite, collected in Sicily (Figure 2a). Integrating literature sources and our laboratory tests of porosity, we tested the impact of uncertainty in initial surface porosity from 0.1% to 4.0% on overpressure. For an initial surface porosity of 1.0%, a significant increase in overpressure up to 6.5 MPa is obtained for a 1000 m thick halite (Figure 2b). For initial surface porosities above 1.0%, overpressure plateaus with only minor increase in overpressure by about 0.9 MPa.

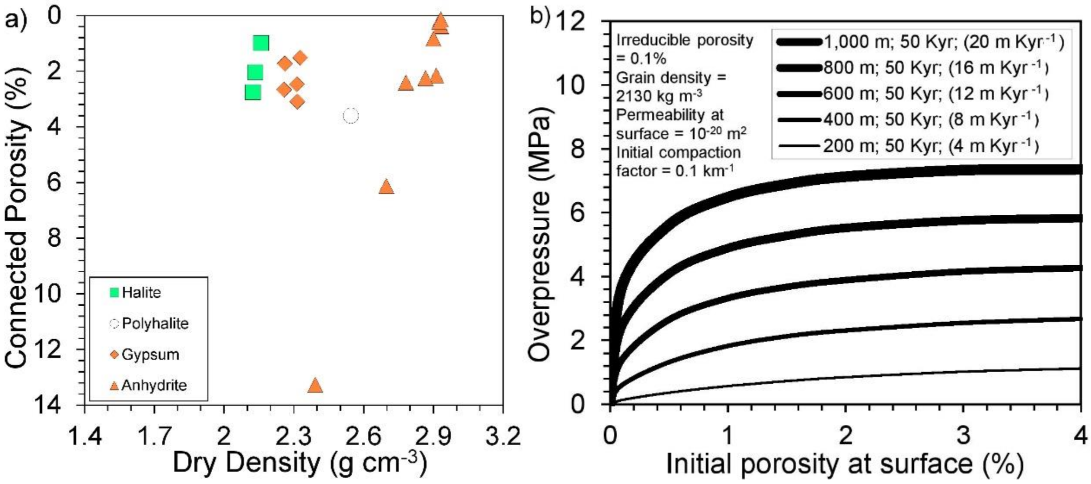


Figure 6: a) Dry density and effective porosity measurements for Permian and Miocene evaporites, obtained from laboratory testing as part of this study. b) Overpressure modelled for Messinian halite with ranges in surface porosity from 0.1 to 4.0%.
From the application of our method to the Western Mediterranean, we conclude that high overpressure within the halite can be caused by permeabilities lower than 10-18 m2.

Bio
Michael Dale is a Marie Sklodowska Curie Early-Stage Researcher and PhD student at the National Oceanography Centre in the UK, focusing on numerical modelling of overpressure in salt basins, and geophysical and hydromechanical laboratory testing of evaporites. His background is highly multidisciplinary including +12 years' experience as a senior exploration geologist for the Oil and Gas Industry, and expertise in pore pressure prediction, wellbore stability, basin analysis, numerical modelling, structural geology, and experimental rock physics.

Flash Talks & Discussion
Mudrock compaction and case studies

The Effect of Stress and Lithology on Mudrock Compaction and Lateral Stress Ratio

Mark Zablocki[1], Jack Germaine[1], Peter Flemings[2]
[1]*Tufts University, UT GeoFluids*
[2]*University of Texas Austin, UT GeoFluids*

The mechanical compaction of mudrocks is sensitive to lithology. Compression curves in void ratio log effective stress space (e-log σ’v) for clay rich mudrocks are concave up indicating large initial changes in pore space and stiffening behavior at high stress. The compression curves of silt rich mudrocks in e-logσ’v space are concave down indicating small initial changes in pore space, until particle breakage occurs. Uniaxial consolidation experiments on resedimented clay-silt mixtures up to 100 MPa vertical effective stress, illuminates how compression behavior varies as a function of clay fraction during burial. The laboratory measurements of mudrock compression are approximated with a porosity by log effective stress equation relating clay content (<2 μm particle size) to an intercept and to a slope to provide an estimate of compression as a function of stress and lithology. Figure 1A presents the uniaxial compression data in e-log σ’v space and Figure 1B presents the estimated porosity for a silt clay mixture between 0% and 65% clay over a 0 to 100 MPa effective stress range.

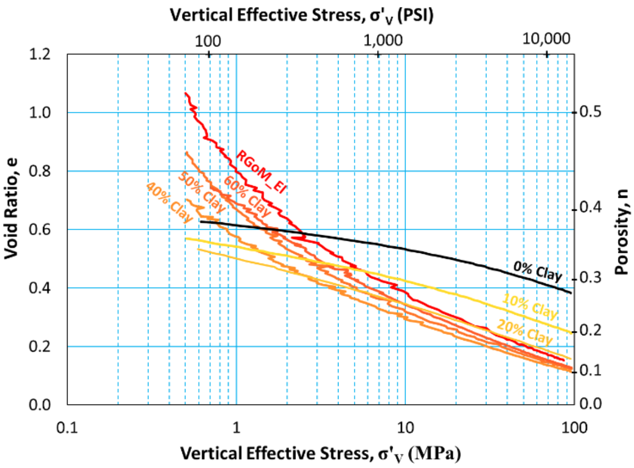


Figure 1A

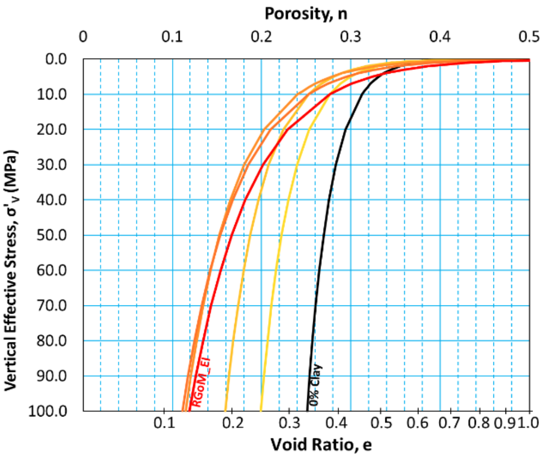


Figure 1B

The lateral stress ratio (K0) defined as the horizontal effective stress by the vertical effective stress under uniaxial strain, increases with an increase in clay content or effective stress. Computer controlled K0 consolidation triaxial experiments performed on resedimented clay-silt mixtures with clay contents varying between 30% and 65%; consolidated to vertical effective stresses of 1 MPa and 10 MPa provide insight on the variation of K with stress and lithology. The clay-silt mixtures consist of a mudrock from the Gulf of Mexico admixed with a manufactured crushed quartz silt. The laboratory measurements of K0 were fit with a power-law function to provide a model to approximate K0 as a function of stress and lithology. Figure 2A presents the variation in K0 measured in triaxial consolidation tests performed on specimens varying between 30% to 65% clay to a maximum vertical effective stress of 1 MPa and 10 MPa. Figure 2B presents the modeled K0 values as a function of lithology and stress up to 25 MPa, the dashed lines indicate the model for that silt-clay mixture is beyond the maximum stress of the laboratory measurements.

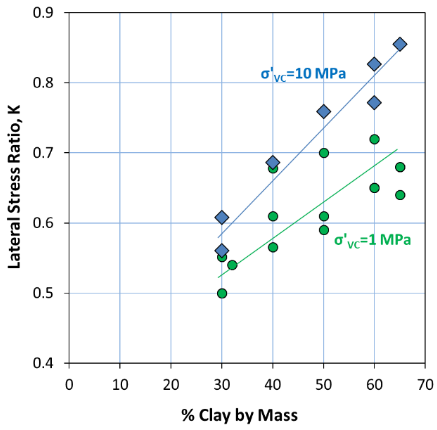


Figure 12A Figure 2A

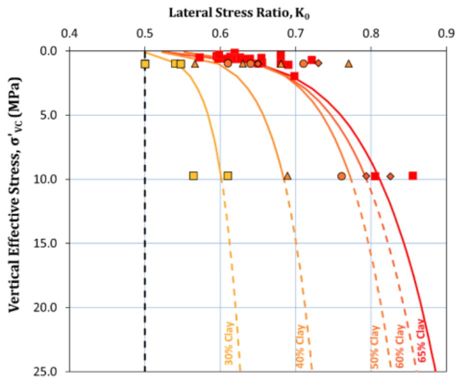


Figure 22B Figure 2A

These data can be combined to provide a complete description of fracture gradient as a function of stress and composition. I will present an example based on the Macondo pore pressure profile as shown in Figure 3. Figure 3A presents the modeled lateral stress ratio by true vertical depth subsea (TVDSS) in ft based on interpreted lithology from the Macondo well mud logs. Figure 3B presents the resulting fracture gradient.

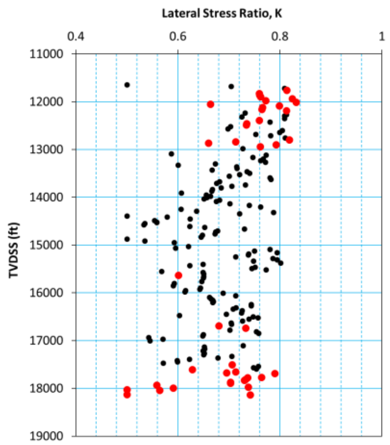


Figure 33A Figure 2A

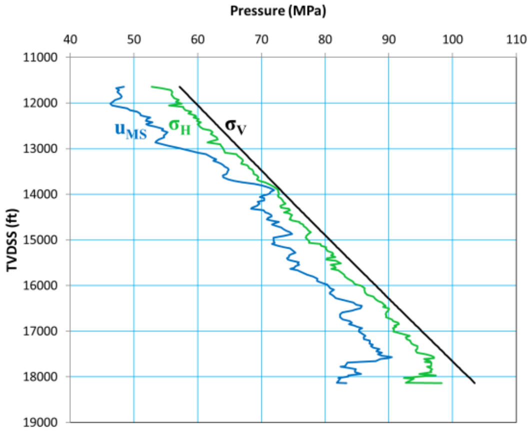


Figure 43B Figure 2A

Bio

Mark Zablocki is a doctoral candidate within the geosystems engineering program at Tufts University, a researcher within the UT Geofluids consortium, and a licensed Professional Engineer working for Haley & Aldrich, Inc. out of their Boston, MA office.

Recognising the importance of quantifying and correcting for Total Organic Carbon (TOC) to reduce uncertainty in pore pressure prediction

Sam Green and Lev Vernik
Ikon Science

Pore pressure prediction in shales undergoing compaction, including mechanical and chemical diagenesis, is customarily related to the mechanism referred to as disequilibrium compaction. However, even when this mechanism is established and the normal compaction trend in sonic velocity, as a proxy for shale porosity, is well constrained, the pore pressure prediction may be in error because of the lithological variation in shale composition. Presence of organic matter in excess amounts in shale formations that have never been exposed to the pressure-temperature conditions in the oil window is an example of these lithological effects, causing marked overprediction of pore pressure in thermally immature mudrocks. This necessitates implementation of bulk density and sonic velocity log corrections in organic-rich shales prior to performing any pore pressure prediction. In this paper we show how these corrections can be made, and the outcomes of the pore pressure prediction are dramatically improved by using combination of rock physics models relating bulk density to total organic carbon (TOC) and P-wave velocity to bulk density in organic-rich and conventional shales, respectively.

Theory

There are many case studies on TOC in the published literature, each one records a similar relationship where the measured wireline data shows a decrease in readings (which implies an increase in porosity) as the TOC content increases. Whilst there is inevitable scatter in the data published, the trend of reducing log response with increasing TOC is evident in all studies. The reason for the scatter is most likely explained by at least one of the following rock properties: (1) level of maturity, (2) grain density of the inorganic phase, and (3) level of compaction/diagenesis, which impacts the total porosity which relates to pore pressure. For any given shale, the maturity of a particular interval can be considered relatively constant, and, thus, can be eliminated as a major cause of variation in log response over limited depth ranges. A similar assumption can be applied to the mineralogy, i.e., within a given limited interval of shale with a common provenance the mineralogy may be relatively constant and, thus, not a significant source of scatter in the data.

Therefore, it is variation in compaction (porosity) which has the main impact on the magnitude of pore pressure and it is here that the variation in TOC can have a large impact as it creates an apparent variation in porosity that can lead to erroneous magnitudes of the predicted pressures. To demonstrate that irrespective of keeping the porosity constant there is a demonstrable impact of TOC on log response, two industry standard methods for predicting TOC magnitude will be used to illustrate this hypothesis; the relationship of bulk density to TOC (Vernik, 2016) and the DeltaLogR model (Passey et al., 1990). The critical impact of this work is that variation in TOC will lead to non-unique solutions for the vertical effective stress as a function of density, and as TOC tends to soften/slow the elastic response this will lead to elevated pore pressure predictions that may not be valid.

Case Study: Immature Kimmeridge Clay Formation, UKCS

To illustrate the workflow, a case study from well 21/25-2, which drilled through the Kimmeridge Clay Formation in the North Sea, will be presented. This well intersects the Kimmeridge Clay at depths less than 2400 mTVDss, hence, is at temperatures below the oil window. A rock physics model linking TOC to bulk density will be used to generate a correction for the effects of TOC leading to more realistic pore pressure prediction magnitudes. The corrected bulk density will then be transformed in to compressional velocity using another rock physics model as velocity data remain the most commonly used data type for pore pressure prediction.

The pressure predictions from the measured (uncorrected) wireline data suggest very high pore pressure in the upper Kimmeridge Clay, where the TOC ranges from 6-12 wt%, which are clearly erroneous as the mudweight used to drill this interval is significantly lower magnitude. Note that no kicks were reported, and the predicted pore pressures are in excess of the Leak-Off Tests at the overlying and underlying casing shoes implying a pore pressure higher than fracture gradient which is clearly unrealistic. The predicted pressures, based on the TOC corrected logs, generate sensible magnitudes, with a reasonably constant vertical effective stress profile over the Kimmeridge Clay, and stay close to the mudweight whilst staying on trend with the underlying RFT data in the Fulmar Formation.

The red and blue pressure curves in the figure above are the uncorrected and corrected predictions from bulk density data respectively.

Conclusions

Pore pressure prediction in shales is customarily related to the mechanism referred to disequilibrium compaction. However, even when this prediction is well constrained by well data, the pore pressure prediction may be in error because of the lithological variation in shale composition. Identification and quantification of Total Organic Carbon (TOC) has long been recognised in hydrocarbon exploration but the impact TOC has on pore pressure prediction has never been properly addressed. Increased organic content within a rock leads to a reduction in the velocity and density. Unless recognised, and corrected for, the change in log response due to TOC will lead to an overprediction of the pore pressure as it implies a porosity increase (increase in pore fluid pressure) that is not present. In this paper it will be shown that a rock physics model that links TOC and bulk density can be utilised to correct the measured bulk density in immature shales, and, when limited to immature shale, the correction can be extended to velocity data using simple industry-standard models.

The effect of an unpredicted high pore pressure ramp on wellbore instability of an appraisal well. A case study from offshore Niger Delta

Dr. Nader Fardin[1], Ameen H. Shehu[2], Samaila Idi Ardo[2], Tamara Oueidat[1], Dr. Lekan Aluko[1], Reza Nazarian[1], Ayodele Jegede[1]
[1]PetroVision Energy Services
[2]Nigerian National Petroleum Corporation

A deep drilling campaign was conceived from the exploratory work carried out on the deeper prospects of a producing field by the stakeholders of the field as part of the further field development plan in order to add reserves and production.
The planned appraisal well was to target deeper reservoirs below the producing interval in the field. These deepest reservoirs were discovered by an exploration well which was drilled to test the potentials of the deep prospect. The exploration well was the deepest well drilled in the field and was a successful exploratory well as it discovered the deepest reservoirs with about 100 feet (30m) of net oil column. The exploratory well was drilled as a vertical well on the flank of the structure.
In order to appraise the discovery made by the exploratory well, an appraisal well was drilled to further delineate the deepest reservoir discovered by the exploratory well. The Well was drilled to a depth above the target depth where a very high unexpected pore pressures was encountered in the immediate overlying shale column that led to an increase in the mud weight required during drilling the well. This led to dynamic mud losses resulting from the fracturing of the drilled formations and when the well was static, a back flow was experienced from the formation with heavy gas cuts in the mud. Attempts were made to reduce the mud weight, but it was practically impossible to drill with lower mud weights. These events led to another stuck pipe and the pipe was cut free at the free-point and the side-track plugged. This led to another attempt to side-track the well. Unfortunately, the side-track also had a stuck pipe within the same shale interval. This led to the termination of the well above the targeted reservoirs.
This poster investigated the root causes of the unexpected highly over-pressured shale formation above the target reservoir by a comprehensive post-drill geomechanics study on the appraisal well in order to delineate potential drilling risk for the field and subsequently, optimize drilling practices and drilling design to mitigate risk and improve drilling performance of the upcoming planned wells.
The results of this study shows that the main root causes for unsuccessful drilling the appraisal Well B to reach its planned TD are as follows:
• Improper casing design,
• Inadequate Hole Cleaning,
• Fractured/Faulted Formation,
• Overpressured Formations,

It is recommended that, to improve drilling performance and ultimately reduce uncertainty in geopressured and wellbore stability, it is essential to delineate and forecast potential drilling

risks that might be encountered during drilling by integrating geoscience knowledge and engineering practice. Managing a well construction program effectively in geomechanically sensitive formations, requires understanding the mechanisms that cause well failure by detailed geoscience studies which includes geological, geophysical, petrophysical and geomechanical investigation.
A calibrated geomechanical model can then be developed to predict the critical conditions for well instability. The pre-drill geomechanics model must be built well ahead of commencing a drilling campaign in order to help operator in designing the well planning program. Real Time/Relevant Time geomechanics support is highly recommended to update the geomechanics model and reduce uncertainties ahead of the bit.

Bio
Dr Nader Fardin is a proficient principal geomechanics engineer with a proven track record in performing high level geomechanical analysis and geomechanics support for a number of consulting companies and operators worldwide. He is well respected as a leading technical expert in the geomechanics communities, have developed a sound practical, theoretical and analytical understanding of geomechanics through substantial experience, career progression and continued professional development, both within previous appointments and now within PetroVision. Nader has got extensive professional research and consulting activities as technical expert in geomechanics, spanning over 20 years of experience for several companies. These experiences includes geomechanics projects such as wellbore stability analysis; gas injection and cap rock integrity; real time drilling geomechanics; fault integrity analysis; hydraulic fracture modelling; pore pressure prediction; sand production prediction and 3D/4D reservoir geomechanics for the fields in the Caspian Sea, Middle East, West Africa, Europe and the North Sea.

Case study exploration well with steep pressure ramp/narrow operating MW-window: RT-PP interpretation, verify pre-drill model with observations from execution phase

Oliver Knoop[1] R. Knezevic, A. Hollerer, Th. Kühn, M. Riedl, A. Meledeth
[1]OMV E&P

Exploration well targeting a large 4-way dip closure in the Vienna basin. High pressure expected of up to 2.25 SG. Geomechanical model done in 2015 from offsetwell data showing the pore-pressure developing from a steep pressure ramp. Poster/Flash-Talk shows the planning and execution phase comparing the pre-drill model to the observations gathered during drilling and RT-PP interpretation from LWD data as well as drilling parameters.

Main challenges during planning phase and observations while execution will be presented. RT-PP interpretation (mainly from LWD Acoustic & Resistivity and Dexp/Dc) and updates on WBS while drilling showing verification of the predrill model. In addition to drilling parameters and cuttings/cavings and other observations, gas wetness/balance and character was analyzed during drilling.

Final outcome:
Predrill model compared/verified with observations while drilling. Drilling of high-pressure exploration well with narrow MW-window. Limits and uncertainties will be highlighted.

Bio
Being a geologist as a background (MSc. Geology from University of Hannover) I joined the Oil & Gas Industry in 2005. I went through a very classic carrier path starting as a mud-logger,

going through quite some experience as a wellsite geologist & consultant and finally in 2012 I joined OMV E&P GmbH as an operations-geologist. Dealing mostly with complex wells in Austria I build a deeper expertise with pore-pressure issues very early. Within OMV I took part in some internal R&D projects and prepared myself an internal study dealing with managing/monitoring and prediction of pore-pressures. With OMV´s newly formed ´Drilling cockpit´ I took over the role as SME for operational PP interpretation for wells operated by OMV globally.

Session Seven: Case Studies 2

Sub-salt Pore Pressure Modeling from Basin-Scale Plumbing and Sealing Elements

Matt Legg[1], Melton Hows[1], Matt Hauser[1], Brent Couzens[1]
[1]*Shell Exploration and Production, Houston, TX*

Analysis of an extensive sub-salt interval in the U.S. Gulf of Mexico was undertaken in preparation for a well test of a previously unpenetrated sub-basin. Regionally extensive zones of broad pressure communication (e.g. on geologic timeline & basin-scale) were observed (Cells A, B & C in figure 1), but sharp pressure increases of up to 3000 psi above the background trend exist in some wells. These ramps (Cells D & E, figure 1) presented a challenge as the team lacked a reliable model to explain their genesis. The anomalies, calibrated by formation test measurements in permeable zones, revealed no simple pattern with depth or stratigraphy; sub-salt seismic velocities were likewise not able to resolve the pressure distribution.

A subsurface mapping approach was adopted, whereby zones of pressure connectivity are mapped to their potential bounding elements. In instances of four-way closure by salt, the pressure regime in the sub-salt mini-basin is primarily a function of depth below the base-salt overburden minimum ,or “salt-seal” (Hauser, 2020). Salt seals are considered here to be primary seals, exerting first-order control on the pressure regime of a cell (fig. 2, yellow stars). Other primary seals include weld surfaces, major faults, and stratigraphic isolation from an adjacent, lower-pressured cell. Within a cell, finer scale pressure distribution is governed by intra-basin faulting, distribution of depositional seals (shales, marls, etc.), and lateral extension (or pinch-out) of reservoirs. Pressures in a particular bed are predicted as a function of depth below the event crest, considered to be the leak point (red dots, figure 2).

By mapping all of these bounding elements and evaluating their sealing capacity, an aggregate pressure model was constructed which provided a good match with observed pressures. On the basis of this structural model, potential pressures in the target sub-basin (Cell F) could then be evaluated, weighing viable subsurface interpretations and their pressure implications.

The seal-limit methodology is valuable when conventional methods such as velocity-based models or offset data are unavailable or uncalibrated. It is also useful as an independent test of more conventional methods. The sub-surface carries uncertainty, and our confidence in the resulting PPFG predictions from trap limits is a function of seismic image resolution, data quality/availability, and sub-surface mapping rigor (for purposes of plumbing and seal characterization). In cases of relatively poor data, multiple scenarios are modeled and tested to inform predictive ranges. In the case-study shown here, a reliable framework has been developed, calibrated by dozens of wells across four inter-related mini-basins.

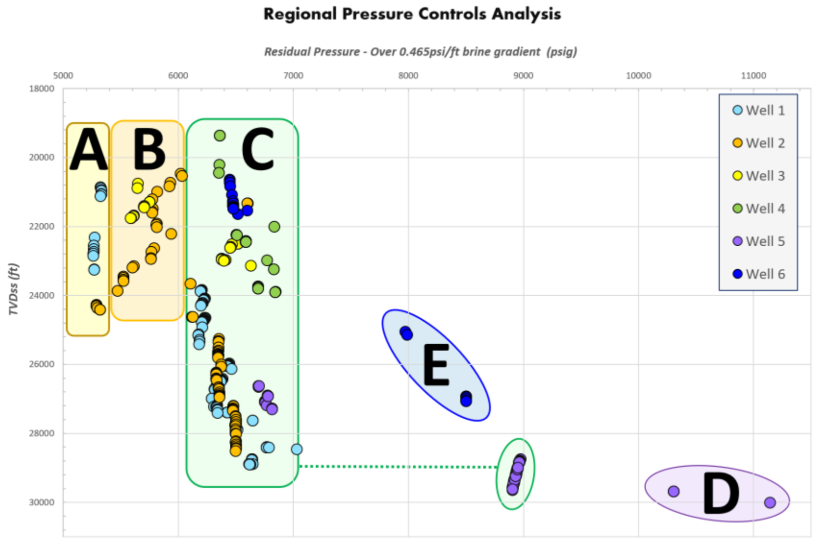


Figure 1. Residual pressure plot (hydrostatic gradient subtracted), pressure "cells" group data that share a primary sealing element.

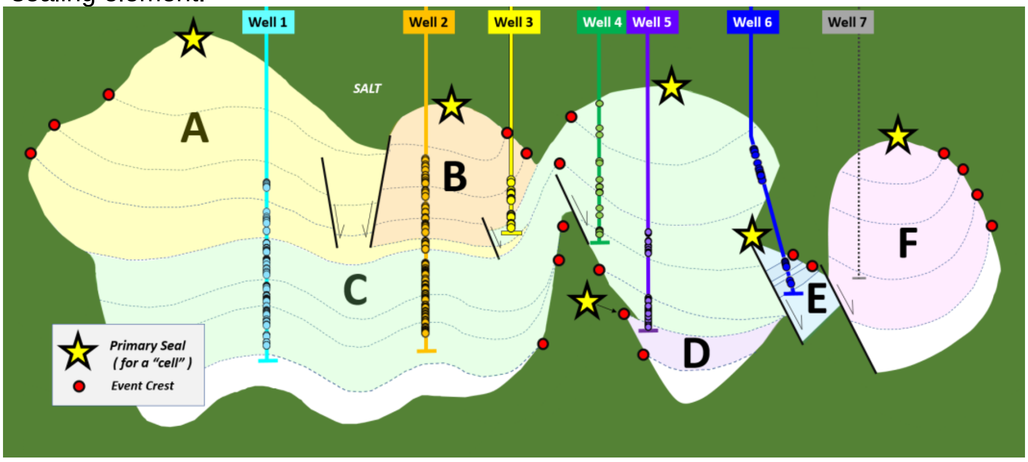


Figure 2. Cartoon illustration of the trap-limits controlling the overpressures plotted in figure 1. Cell A – regional salt-seal; Cell B – local salt-seal, laterally fault-bounded; Cell C – regional salt-seal: large swaths of stratigraphy connect to adjacent basin's crest. Cell D – event crests underneath deep protrusion of salt; Cell E – fault seal, which leaks in favor of failure into the overlying salt-wing; Cell F – predicted to be salt-seal controlled.
Stratigraphy and relative position of wells are schematic for the purposes of illustrating all in one cartoon, in favor of accuracy with respect to the gross pressure cells and zones of connectivity. No two wells in this sampling show hydraulic connectivity for the entirety of their shared stratigraphy.

Bio

Matt is a pore pressure prediction specialist and geologist with Shell Oil. Originally from Battle Creek, MI, Matt obtained his B.S. in Geoscience from the University of Iowa in 2006 and M.S. in Geoscience from Penn State in 2010. He joined Shell in Jan 2011 in Houston where he worked for 7 years as a seismic interpreter in the Deepwater Gulf of Mexico Exploration asset. Matt joined the pore pressure specialist team in 2018. He is currently an associate subject matter expert for pore pressure and fracture gradient prediction within Shell. Matt currently lives in Houston, TX and enjoys jazz music, ice hockey, and downhill skiing in his free time.

Mechanisms generating fluid overpressure at the trench of subduction zones

M.A. Nikolinakou[1], B. Gao[2], P.B. Flemings[3], D.M. Saffer[3]
[1] *Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin; mariakat@mail.utexas.edu*
[2] *Berger Geosciences, Houston, TX*
[3] *Institute of Geophysics and Department of Geological Sciences, Jackson School of Geosciences, The University of Texas at Austin*

We simulate the evolution of pore pressure and stress in an evolving accretionary wedge and its footwall sediments using a geomechanical model that couples loading, drainage, and sediment compression, due to the evolution of mean-effective and shear stress. A transition zone forms near the trench, where accreted sediments undergo a change in loading path from vertical burial to lateral compression and elevated shear. This zone initiates about 5 km in advance of the trench and extends about 10 km into the wedge, depending on sediment hydrologic properties and rate of plate convergence. In this transition zone, fluid overpressure increases more rapidly than the overburden stress (Figure 1a, b). We employ constitutive laws from critical state soil mechanics to quantify the contribution of each mechanism and find that shear-induced pore pressures increase, on average, at twice the rate of the mean-induced pressures. As a result, pore pressures in the hanging wall are higher than the footwall, and lead to notable dewatering at the trench area (Figure 1c). In addition, these elevated pore pressures lead to a broad zone of reduced effective normal stress - and thus profoundly low strength - along the basal décollement, despite progressively increasing burial depth. Our geomechanical approach provides a more complete estimation of pore pressure and porosity loss at the trench of subduction zones (Figure 1). Furthermore, our analysis illuminates the important role of shear in driving a rapid increase in pore pressure at the trench and the subsequent decrease in décollement strength. This provides a possible mechanical explanation for a wide range of observed behaviors, including the development of protothrust zones, widespread occurrence of shallow slow earthquake phenomena, and the propagation of large shallow coseismic slip and resulting tsunami hazard.

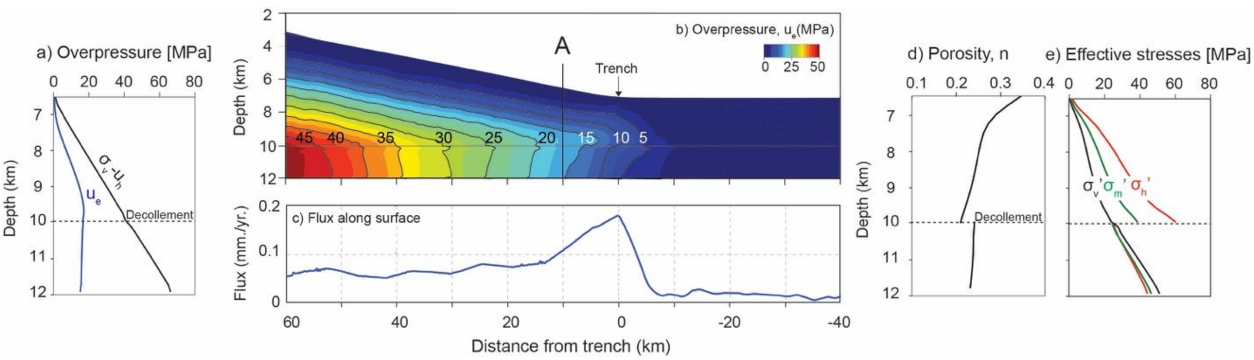


Figure 1: Transient evolutionary geomechanical model of an accretionary wedge: a) profile of overpressure, ue, along A (shown in panel b); b) contours of overpressure at the trench of the accretionary wedge; c) flux along the seafloor at the trench; d) profile of porosity, n, along A; e) profiles of vertical (□'v; black), mean (□'m; green) and horizontal (□'h; red) effective stress at A.

Case study on the Tubular Bells -Kodiak basin Miocene sediments with learnings from the recently drilled Esox and Oldfield wells

Matthew Reilly
Geological Advisor
PPFG - Operations
HESS

The Antares Salt Body (Mississippi Canyon Blocks 724-728) is proximal to or a major trapping element of the Tubular Bells, Esox, Kodiak and Devil's tower Oil fields. The regional pore pressure of the Antares Basin shows an interesting history of fluid flow which has changed over time due to the Salt Tectonic and depositional evolution of the basin. Deep Lower Miocene sediments were deposited in larger and more open structural settings where as the Shallower Upper Miocene Sediments are more confined. High sedimentation rates in the Lower Miocene resulted in vertical salt diapirs, Salt walls and turtle structures. Conversely relatively lower sedimentation rates in the Upper Miocene resulted in lateral salt movement which constricted basins. High sedimentation rates are generally associated with Higher Pressures; however, due to basin connectivity, the inverse is seen through the stratigraphic section at T-Bells, Esox and Kodiak fields. We present the result of two recently (2019) drilled exploration wells that recovered pressure measurements from previously unpenetrated upper Miocene section in this basin. Regionally the Lower Miocene sand pressures are 'regressed' relative to the surrounding shales and can be clearly seen to be 'leaking' at a high point in the basin. In the shallower Upper Miocene section, the pore pressures are elevated around the Antares Salt body. The acoustic to pore pressure relationships across this Upper Miocene section varies from field to field and by depositional setting. Furthermore, pore pressure directly surrounding the Antares salt body may be elevated to stress induced from the salt body itself.

Bio

Matthew Reilly, 'Technical Authority for PPFG' at Hess- Started his career following his dad around on geological field trips from the age of 7. He attended Durham University for Undergraduate and then went stateside to Penn State for his Graduate degree. Matt has spent his professional career at Hess as a geoscientist where he has had the opportunity to work a large spectrum of basins across the world from Peru to Malaysia and many in between. Matt has had a keen interest in pore pressure for 15yrs and recently focused on innovation via Machine Learning techniques.

Pressure Prediction in Unloaded (Unconventional) Basins. Case Study: Delaware Basin

Landon Lockhart[1], Peter Flemings[2], Maria A Nikolinakou[3]
[1] *Department of Geological Sciences, Jackson School of Geosciences, The University of Texas at Austin*
[2] *Institute of Geophysics and Department of Geological Sciences, Jackson School of Geosciences, The University of Texas at Austin*
[3] *Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin*
Oral

I present a methodology to predict pore pressure in the eastern portion of the Delaware Basin that accounts for the 7,000 feet of erosional unloading that has occurred. In this location, pore pressure is approximately hydrostatic from the Delaware Mountain Group to the Bone Spring Formation (Fig. 1). Beneath the Bone Spring Formation, overpressures (u_e) reach an overpressure ratio ($\lambda^* = u_e/(\sigma_v - u_h)$) of 0.81, where σ_v is the vertical total stress, and u_h the hydrostatic pressure.

I couple two processes to predict pressure. First, I model the effects of unloading on the velocity-effective stress relationship using the approach described by Bowers (1995):

$v = v_0 + a\left[\sigma'_{max}\left(\frac{\sigma_v'}{\sigma_{max}'}\right)^{\frac{1}{U}}\right]^b$ (Equation 1)

where v is velocity, v_0 is velocity at zero effective stress, σ'_v is the vertical effective stress, σ'_{max} is the maximum vertical effective stress to which the material has been subjected, U is a measure of the plasticity of the material, and a and b are lithology-dependent constants. I cross-plot velocity versus vertical effective stress in the hydrostatic interval and apply the following equation to shift the measured vertical effective stresses laterally to a point which corresponds to the "paleo" virgin curve (σ'_{vc}):

$\sigma_{vc}' = \sigma_{max}'\left(\frac{\sigma_v'}{\sigma_{max}'}\right)^{\frac{1}{U}}$, (Equation 2)

I compute σ'_{vc} assuming U=8 and calculate σ'_{max} given the current vertical effective stress plus the change in total vertical stress less the change in hydrostatic pressure ($\sigma'_v + \Delta\sigma_v - \Delta u_h$). I fit a power-law regression through velocity versus σ'_{vc} to obtain a and b in Eq 1.

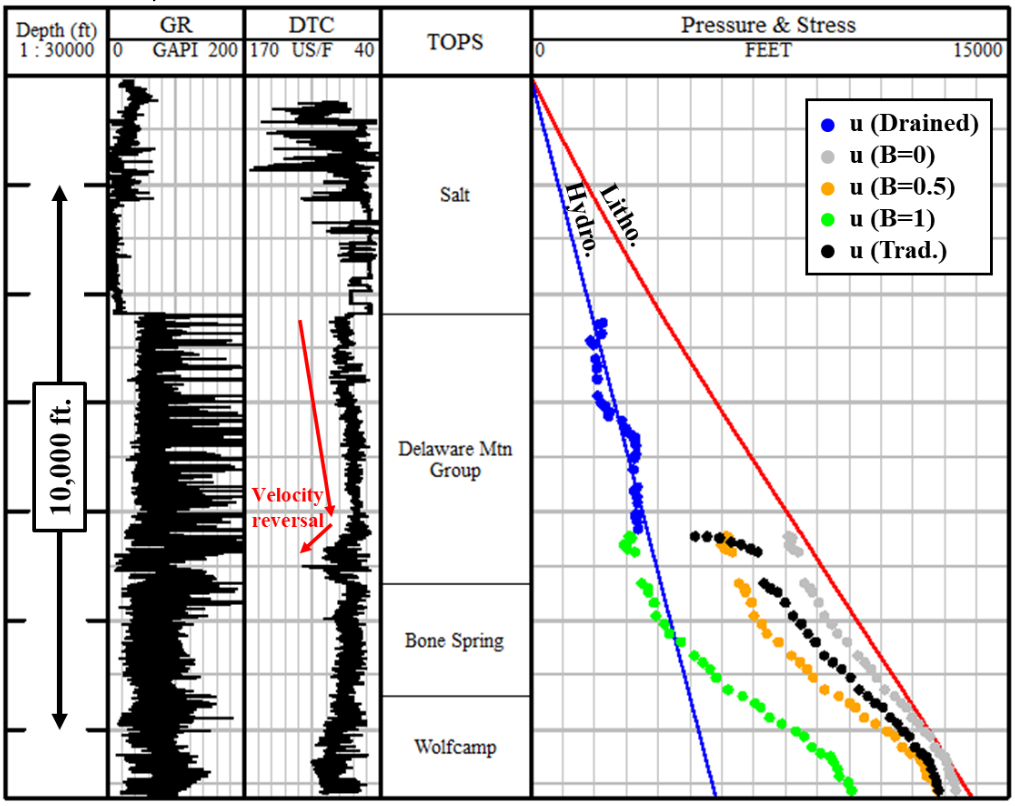
Second, I consider the effect of unloading on the pore pressure through application of Skempton's pore pressure coefficient (B):

$\sigma'_{max} = \sigma_v' + \Delta\sigma_v(1 - B)$ (Equation 3)

Pore pressure change due to undrained loading depends on the ratio of bulk (β) and fluid (β_f) compressibility. Equation 3 calculates the change in pore pressure that occurred due to unloading.

Finally, I combine the results from Equation 1 and Equation 3 and directly predict the present-day pore pressures. Lower values of B or U result in higher predicted pressures (Fig. 1). For the Delaware Basin, I find that a B=0.75 (Eq. 3) with an assumed unloading parameter U=8 (Eq. 1) predict pore pressures that most closely match the observed pressures. In future work, I will determine B from loading-unloading experiments in the laboratory, and estimate U from velocity measurements made during unloading.

Figure 1: Calibration and pore pressure predictions in measured well. In the hydrostatic section of the measured well (base of salt to ~8300 ft), unloading model (Eq. 1) is calibrated and tested for validation (blue dots). Model is then used to predict pore pressure in deeper, overpressured section (8300 ft to bottom of well), or in other wells with various Skempton's pore pressure coefficients (B; Eq. 3). Gray dots represent predicted pore pressures with a B=0; orange dots represent predicted pore pressures with a B=0.5; green dots represent predicted pore pressures with a B=1; and black dots represent pore pressures predicted using a traditional normal compaction trend.



Bio

Landon Lockhart is a PhD candidate in the Jackson School of Geosciences at The University of Texas at Austin. His research is focused on understanding how the geologic history controls the present state and evolution of pressure and stress in the Permian Basin. Specifically, he is measuring the deformation behavior of mudrocks in the laboratory, and will use these results with field data to develop a model to predict pore pressure and stress in unloaded, unconventional basins. Landon serves as the President of the American Rock Mechanics Association – UT student chapter, and is an active member of the UT GeoFluids consortium, AAPG, ad AGU. He earned a M.S. degree in geological sciences from the University of Texas at Austin, and received his B.S. degree in geology from Oklahoma State University.

Session Eight: Reservoir quality and pressure

Reservoir Quality in Overpressured Submarine Fan Systems of NW Borneo Deepwater Fold-Thrust Belt

Sudirman Dawing[1,2], Stuart J Jones[1], Mark B Allen[1] & M Nizar Othman[2]
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[2]*PETRONAS Carigali Sdn. Bhd., PETRONAS Twin Towers, 50088 K. Lumpur, Malaysia*

The continental shelf and slope areas of NW Borneo are well known from drilling and high quality 3D-seismic-reflection data. The NW Borneo shelf and slope mainly consists of middle Miocene to recent prograding shallow-marine clastic sediments and deepwater turbidite fan systems that locally can attain thicknesses of over 10 km. The continental slope of NW Borneo is underlain by a large, basinward-thinning, middle Miocene to Holocene deep-water clastic wedge that is deformed by numerous compressional folds and thrusts. Despite significant research and exploration efforts in deep-water fold thrust belt (DWFTB) of NW Borneo in recent years, there are still questions in regard to controls of reservoir quality for the deep submarine fan systems.

As part of this study 15 exploration and appraisal wells were used targeting the Middle Miocene fan system from 1500 m to the deepest of 5000 m TVDSS and located towards the crestal part of the thrusted hanging wall of growth anticlines. Pressure data was gathered from a number of data sources including wireline logs (MDT, RFT), Mudlogging Pressure calculation and pressure prediction from 3D seismic datasets across the growth anticlines. Reservoir properties were compiled from the wireline log data, core analysis, facies models and petrophysical evaluation and combined with interpreted 3D Seismic and detailed burial history modelling. A focus on best reservoir quality from the submarine fans has restricted the facies used in this study to confined channelized, unconfined sheet flood, sand dominated lobes and sand lobe fringe components for the Middle Miocene sandy fan system.

Examination of petrography, pore pressure and routine core analysis datasets showed a positive correlation between high fluid overpressure and enhanced reservoir quality with depth for the sand dominated facies components. This presentation will explore the role played by pore fluid pressures and calibration with seismic attribute quantitative interpretation and depositional models. The results are critical for understanding reservoir distribution and effectiveness across the DWFTB of NW Borneo and provide important insights into the controls on reservoir quality of deeply buried sandstone reservoirs in compaction dominated, high sedimentation basin settings.

Bio

Sudirman is a postgraduate PhD student at the Earth Sciences Department, Durham University. His research is focusing on the deepwater fold-thrust belt NW Borneo, in addressing the controlling factor of the reservoir distribution and effectiveness. His work mainly using Geological and Geophysical softwares in interpreting and evaluating seismic and well data. He is interested in developing methodology in addressing the issues regarding petroleum system in frontier for hydrocarbon exploration.

Influence of Pore Pressure and Effective Stress on Quartz Cementation in Sandstones: Evidence from North Sea Fulmar and Gulf of Mexico Wilcox Sandstones

Olakunle J. Oye[1], Andrew C. Aplin[1], Stuart J. Jones[1], Jon G. Gluyas[1], Leon Bowen[2], Joseph Harwood[3], Ian J. Orland[4], and John W. Valley[4]
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[2]Department of Physics, Durham University, Durham, DH1 3LE, UK
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It is well established that the development of overpressure within sedimentary basins reduces vertical effective stress (VES) and inhibits compaction, thus preserving porosity. However, the influence of vertical effective stress on pressure dissolution and related quartz cementation in sandstones has been under-appreciated in many clastic reservoir studies that have favoured temperature as the key control on quartz cementation. Commonly used models suppose that quartz cementation is controlled by temperature-related precipitation kinetics and that the supply of silica is largely irrelevant. However, it is generally considered that a key source of silica for quartz cement is from intergranular pressure dissolution, the rate of which is influenced by VES. This study integrates quantitative petrographic data, high spatial resolution oxygen isotope analyses of quartz cement, basin modelling, and a kinetic model for quartz cementation to understand the relevance of VES to quartz cementation by investigating clay-poor sandstones of the Upper Jurassic Fulmar Formation from Elgin Field in the UK Central Graben and Paleocene-Eocene Wilcox Group from Rotherwood Field in the Texas Gulf Coast. These sandstones have distinctly different histories of vertical effective stress (VES) and temperature. The study not only shows that most or all the silica for quartz cement can be derived from intergranular pressure dissolution, but that the extent of intergranular pressure dissolution and related quartz cementation correlates strongly with VES and poorly with temperature. Oxygen isotope data obtained from the quartz cements yield temperature ranges for quartz precipitation which are taken to indicate that the rate of quartz cementation is more strongly related to the history of VES rather than the history of temperature. This analysis suggests that it is the vertical effective stress history, rather than the temperature history, that exerts the greatest influence on quartz cementation. This work has significant implications for understanding how overpressure and VES influence porosity preservation in high pressure, high temperature (HPHT) reservoirs, and would also aid the development of better reservoir quality predictive models for prospective HPHT reservoirs.

Bio

Olakunle is a geoscientist with significant years of experience in hydrocarbon exploration and production gained through academic research and the oil and gas industry. His experience extends across highly diverse geological settings like the Niger Delta, the North Sea, the Gulf of Mexico, and offshore South West Australia. He holds an MSc in Petroleum Geochemistry from the University of Newcastle upon Tyne and a PhD in Geology from Durham University.

Session Nine: Operations

A Whirlwind Global Tour of Mud Volcanoes

Mark Tingay
Petronas

There are over 300 active onshore mud volcanoes globally, and many more offshore. Mud volcanoes are subsurface fluid escape features in which overpressures drive fluids, gases and subsurface sediments to the surface. As such, mud volcanoes offer a unique window into the subsurface petroleum system, help us understand how overpressures are generated and dissipated, how fluids flow through sedimentary basins, and can be used to aid in hydrocarbon exploration. But, this presentation isn't going to look at any of that.

This talk will give a whirlwind tour of 15 mud volcanoes in 15 minutes and tackle some of the largely irrelevant, but nonetheless interesting, questions you probably never thought to ask about these fascinating geological features. Questions like when were mud volcanoes first described? Which mud volcanoes are best for bathing in? Do mud volcanoes play 'peek-a-boo'? Why do people throw coconuts into them and where can I go to eat one (a mud volcano, not a coconut)?

Session Ten: Operations continued

Gas Response and Overpressure Magnitude in Tight Formations: Elgin-Franklin Experience

Gareth Yardley, Leon Barens and Chris Cruickshank
Total E&P UK Limited

The presence or absence of gas response (e.g. connection gases, trip gases etc.) during drilling is often used to assess the formation pressure magnitude in tight formations. Gas response is particularly valuable for pressure assessment where lithology, burial history or source of overpressure means that log based analysis is inappropriate. The assessment of pressures from gas response is often subjective as direct measurements of pressure in such tight formations are rarely available. Understanding the significance of any gas response is vital for real time pressure monitoring during drilling as it can guide subsequent actions.

The Elgin and Franklin fields in the UK Central North Sea have deep (>5km) HPHT Jurassic Fulmar reservoirs with pre-production pressures of around 1100 bars. The overburden above the reservoirs has been subject to extensive study and recent wells have targeted data collection in this interval. Several suites of pressure data have been acquired using Baker Hughes' FTeX tool which can measure pressures in ultra-low permeability formations. These data define the full pressure profile through the overburden and provide a unique data set for understanding the relationship between gas response and overpressure in tight formations. Pressures are hydrostatic in the Palaeocene and rise progressively until the reservoirs. This section (~2000m) is dominated by tight lithologies and includes the Cretaceous Chalk Group and claystones of the Lower Cretaceous and Upper Jurassic. Traditional log based pressure analysis is ineffective here and gas response is the main pressure assessment tool.

The gas response during drilling of the overburden has been studied in conjunction with the downhole mud pressures and the actual formation pressure profile. The study shows the relationship between magnitude of the gas response observed and the level of balance between the mud and formation pressures in the overburden at Elgin-Franklin.

Bio
Gareth Yardley, has a PhD from Edinburgh University which was followed by more than 7 years post-doc research in the Department of Petroleum Engineering at Heriot Watt University working on the industry funded Overpressure project "GeoPOP". Gareth has had pore pressure related roles in Shell and Maersk Oil and is currently the PPP Specialist in Total's Aberdeen office.

Overburden Pressure Data Interpretation of the Elgin-Franklin Cluster, Central North Sea

Leon Barens, **Chris Cruickshank**, Jesse Clark, and Gareth Yardley
Total E&P UK, Total House, Tarland Road, Westhill AB32 6JZ, Scotland

The Elgin-Franklin field cluster is located within the North Sea Central Graben, 240km East of Aberdeen. The Franklin field was discovered in 1986 followed by the Elgin Field in 1991. Subsequently, the Glenelg and West Franklin fields were discovered in 1999 and 2004 respectively. The fields were produced under Ultra High Pressure and High Temperature (uHPHT) conditions with an initial reservoir pressure of ~1100bars and a reservoir temperature of ~190°C. The Elgin-Franklin field cluster is dominantly produced from the Upper Jurassic Fulmar Formation, overlain by ~5km of clastic and carbonate stratigraphy. Until recently, the overburden has been relatively under-characterised from a pore pressure data perspective. Here we present the interpretation of newly acquired pore pressure data within the overburden of the Elgin-Franklin cluster.

Latest generation wireline formation pressure testing tools has enabled reliable and accurate pore pressure acquisitions within micro-Darcy overburden formations. Good interaction with contractor and pre-job planning ensured successful and safe acquisitions. High data confidence was obtained through repeatable build-ups which were further calibrated with core measurements. Accurate pore pressure acquisition has enabled overburden gradients to be established on the Elgin-Franklin field cluster for the first time.

Two overburden pore pressure trends have been established separated by a low mobility zone; (1) a stratigraphically deeper, geomechanically controlled gradient that follows the S3 fracture gradient and (2) a stratigraphically shallower lower pressure gradient that deflects from the S3 fracture gradient to a hydrostatic pressure regime.

It is interpreted that hydrostatic Palaeocene sands act as a regional pressure drain to the underlying overburden until the top of a low mobility zone within the Lower Tor Formation. The overburden formations underlying the low mobility zone are not impacted by the regional pressure drainage system of these Palaeocene sands. This pressure trend follows the S3 fracture gradient indicating a geomechanical control. Variations in the stratigraphically shallower pressure gradient have been identified on Elgin and Franklin and are interpreted to be due to variations in Palaeocene sand presence and consequently drain effectiveness.

Bio
Chris Cruickshank joined TOTAL E&P in 2008 following graduation from the University of Aberdeen with an MSc in Petroleum Geoscience. His experience includes New Venture, Wellsite and Asset Geology roles within the North Sea, Russia, Nigeria and Mexico. Chris is currently an Asset Geologist for the Elgin-Franklin field cluster.

Geomechanics Challenges and Lessons from Planning and Drilling High Angle Wells

Alexandre R. Saré, Jianguo X. Zhang, Stephen T. Edwards, Martin Albertin
BP Exploration & Production Inc

High angle wells have been planned and executed in the deepwater Gulf of Mexico to increase reserves recovery. Understanding the magnitude and orientation of in-situ stresses is fundamental for efficient drilling of these high deviated wells. A geomechanical model which shows the impact of wellbore trajectory on wellbore instability and fracture gradient can have significant impact on picking an optimum mud weight to thread the needle between wellbore collapse and induced tensile fractures. Previous drilling experience, well data and field tests can be utilized to develop and calibrate the model. This paper presents two cases: (a) data from three wellbores with different inclinations (one pilot with no significant issue and two sidetracks with significant losses) were used to develop, calibrate and test the model; (b) upcoming high angle well planned considering previous lessons. The goal is to share lessons that could contribute for future high angle wells planning aiming to reduce risk of lost circulation and wellbore instability.
The initial plan was to drill a pilot hole to decrease the geological uncertainty and also measure the reservoir pressure. Afterwards, a sidetrack would land setting a liner into the top of the reservoir followed by a high angle production section. As shown in **Error! Reference source not found.**a, three wellbores were drilled: pilot, ST01, and ST01BP01. The pilot hole was drilled with an inclination of 59° without indications of wellbore instability and losses. The ST01 penetrated the reservoir at 71° with massive losses and lower ECD than the pilot leading to a bypass. Finally, ST01BP01 was drilled to higher inclination of 75° and significant loss occurred at even lower ECD.
Observations from these three boreholes suggest a correlation between well trajectory and fracture gradient: the higher the wellbore deviation, the lower the fracture gradient. An example for the effects of well trajectory on fracture gradient is shown in Figure 7b. It is shown that FG is lower while drilling along maximum horizontal stress and the effect of well inclination on FG. Therefore, the FG decreases as inclination increases. Far field minimum horizontal stress (Sh) is also included for a contextual comparison.

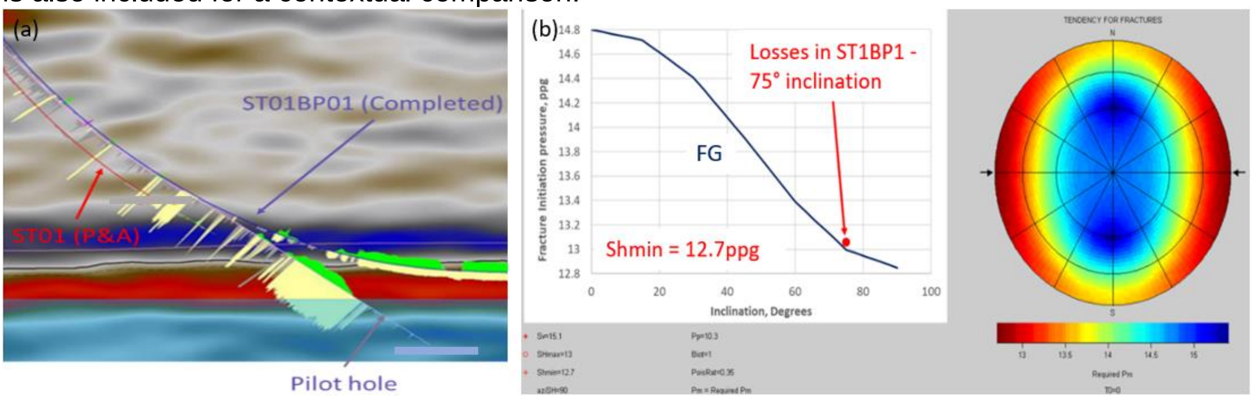


Figure 7 - As-built trajectory and effect of well inclination on FG

Another high angle well has been planned considering main geomechanical lessons learned from the previous well. The high angle portion will penetrate different lithologies which triggered a wellbore stability evaluation. A parametric study (Figure 8) was developed assuming different Unconfined Compressional Strength (UCS) scenarios along possible well inclination and the results supplied the drilling window planning. The azimuth of maximum horizontal (Azi SHMax) stress uncertainty adds another complexity to the well design. Depending on the assumptions the required collapse pressure could vary around 0.6ppg for different well trajectories (Figure 9).

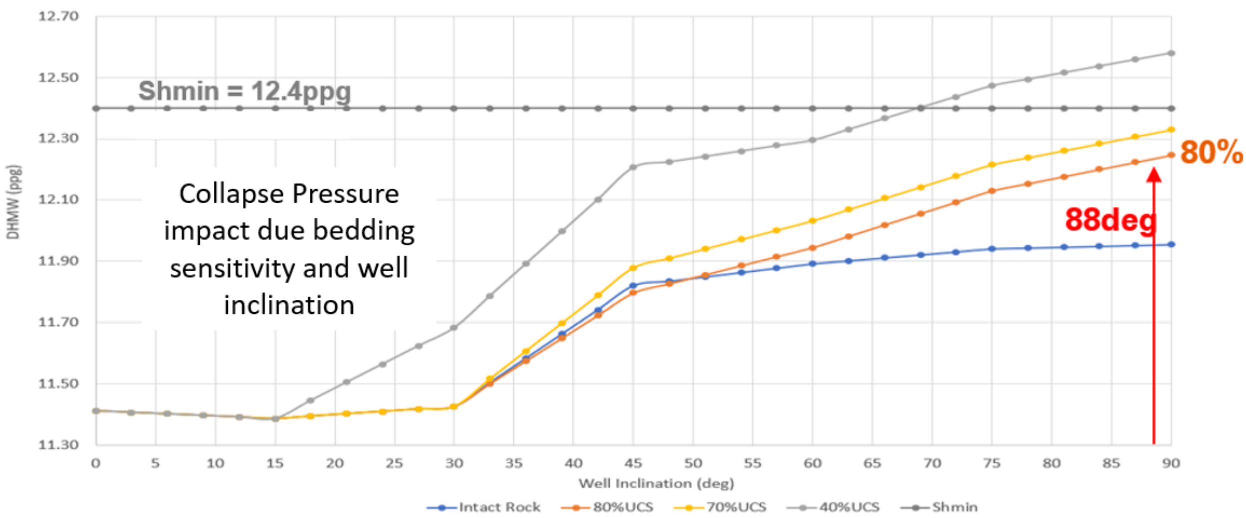
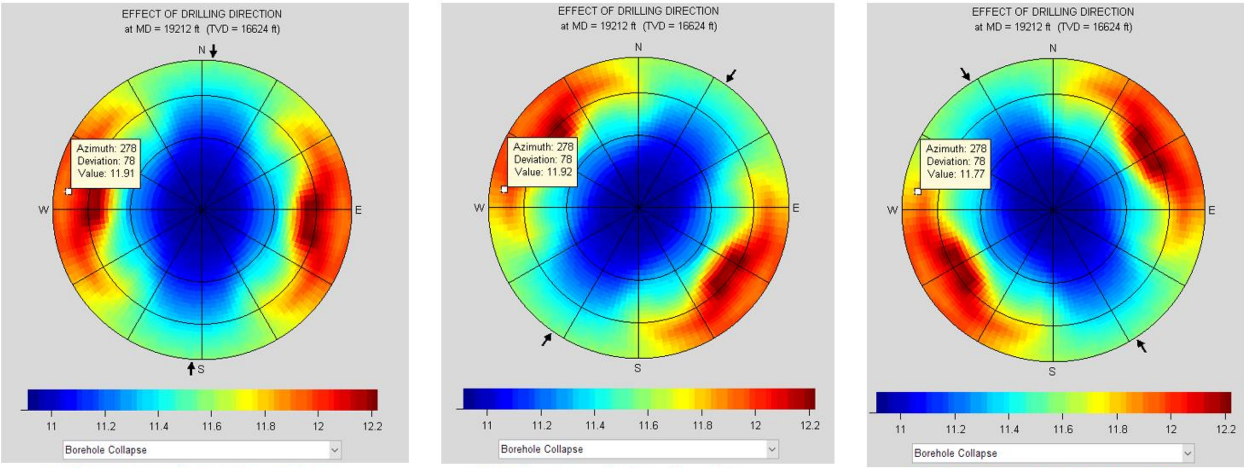


Figure 8 - Collapse Pressure evaluation assuming UCS and well inclination variation



If SHMax Azimuth 4° - Cp = 11.9ppg

If SHMax Azimuth 35° - Cp = 11.9ppg

If SHMax Azimuth 147° - Cp = 11.7ppg

Figure 9 – Azi SHMax influence on well design

Pore and Fracture Pressure Results of High Pressure Drilling Campaign in Niger Delta

Raghu K. Chunduru[1], Otuka K. Umahi[1], Pratap K. Nair[1], Brent A. Couzens-Schultz[1], Celestine IC. Ugwu[2], and Daniel W. Agbaire[2]
[1]Shell International Exploration and Production
[2]Shell Petroleum Development Company of Nigeria Ltd

Over the past few years, Shell Petroleum Development Company (SPDC) has successfully drilled several high pressure (HP) exploration wells in the central swamp depobelt of the Niger delta using a rig with 15K drill capacity. Some of the key technical challenges in drilling these wells included: narrow drilling margins, high pressures, the presence and magnitude of multiple pressure ramps, depth uncertainty, legacy seismic data with ~3.5km cable length and lack of suitable analogue wells. In order to overcome some of these challenges we deployed state-of-the-art tools and technologies across multidisciplinary teams. The pre-drill and real-time pore pressure [PP] predictions played a significant role in the design and subsequent safe drilling of the wells. Real-time PP measurements allowed the recalibration of the pre-drill PP models, and look-ahead vertical seismic profile [VSP] inversion velocities provided PP prediction ahead of the bit. The measured pressures in these HP reservoirs came largely within the low and high case range of pre-drill PP prediction except for one deeper objective, where a kick was experienced due to the actual PP being higher than the maximum pre-drill predicted. The data and the learnings obtained from the HP campaign provided many insights including: the pressure mechanisms, the pressure magnitude, the number of pressure ramps, the depth uncertainty, the role of technology, and the importance of communication protocols. These learnings will be fully integrated in future HP campaigns especially in Niger Delta.

Flash Talks & Discussion
Pore pressure integration

A Review of Industry Best Practice in Real-Time Pore Pressure Analysis

Mark Tingay
Petronas

This presentation summarizes the current industry best practices in real-time pore pressure prediction, based on direct discussions with 22 subject matter experts, literature review, and an analysis of relevant presentations from six major pore pressure conferences (since 2010). Industry best practices are identified to relate to four major themes, namely personnel roles, responsibilities and requirements; training and competency verification; communications protocols, and; methods, workflows and technology. In particular, communications protocols are regarded as the primary source of concern and real-time pore pressure issues amongst subject matter experts. The wide range of inputs herein represents an exhaustive review of industry practice in real-time pore pressure analysis. This review forms a guideline for how pore pressure analysis while drilling can be improved throughout the industry, and thus help optimize well operations and mitigate against well control incidents.

Capillary capacity estimation of mudrocks in exploration: Empirical workflow and validation using a case study

Sara Martínez [1], Germán Saceda [1], Toby Harrold [1], Andre Vayssaire [1] Kevin Meyer [1]
[1] *Repsol Exploración S.A., Méndez Alvaro 44, 28045, Madrid, Spain*

Introduction
In Exploration, the seal is one the key elements of the petroleum system controlling the amount of hydrocarbons a structure can hold. For this reason, a significant effort should be made to quantify the presence and effectiveness of the top seal both at present day and through time to improve decision making, increase the chance of discovery as well as the safe execution of the well.

In general, the assessment on the seal membrane capacity in exploration is poorly constrained mainly due to lack of data or predictive workflows. With the lack of data acquisition in wells, the opportunity to learn and better understand the seal and its properties is often lost. An empirical approach to estimate capillary pressure in conventional mud rock seals is proposed based on estimates of porosity or effective stress of shales / mud rock sealing formations. This workflow covers the estimation of shale porosity from different sources of data and the relationships to calculate the capillary entry pressure and maximum hydrocarbon columns. The equations and empirical relationships are based on published work.

Estimating shale porosity
The analysis involves a full review of the seal interval and the offset well data. To estimate the shale porosity, first, the sonic log from available offset well data can be used to calculate porosity using the Raiga-Clemenceau equation (Issler, 1992). Secondly, the effective stress estimated in the offset wells is used to estimate the pore pressure in the seal and the porosity.
Estimating capillary entry pressure
Over the past years, several authors have worked to establish equations that model percolation and migration of hydrocarbons through different lithologies. Those equations generally relate

porosity / permeability relationships to pore throat distributions, which are in-turn used to derive the capillary pressure. A lithology library has been chosen for different types of mud rock based on the fraction of clay-sized particles (Yang and Aplin, 2010). For each of the mudrocks a capillary pressure vs porosity trend has been established. From this method, the mercury / air capillary pressure is estimated.
Once the mercury / air capillary entry pressure is estimated, it can be corrected to the expected HC fluid using an estimate of the interfacial tension (IFT) of the hydrocarbon. Relationships between the hydrocarbon density, temperature and IFT are available in the literature and software. The IFT matrix from the Permedia software for basin modelling is used in this workflow.

Maximum hydrocarbon column height

The final step of the workflow is to calculate the column height that seal can hold with the estimated capillary pressure. It is fundamental to assess the pore pressure of the cap-rock, which, together with the capillary entry pressure, represent the resistive forces impeding vertical fluid flow.

Validation of a membrane seal capacity workflow using a case study

The workflow has been applied in two exploratory wells using the effective stress and published relationships from Yang and Aplin, 2010, to estimate the capillary pressure. A second approach is considered using the interval velocity to estimate shale porosity and capillary pressure for the mudrock expected in the area. MICP were performed in sidewall core plugs and cuttings intervals in the two wells.
After an extensive drilling campaign, the initial dataset from two wells was built up to thirteen wells testing the same top seal units in the same basin area. With this greater amount of data, three trend lines were fit to represent P10, Pmean and P90 maximum gas columns expected in the basin as a function of the burial depth.

Using both the database and the empirical workflow, each exploratory well in the area has a membrane seal assessment and hydrocarbon column prediction which will allow better ranking of prospective areas of the basin. Figure 10, shows the gas columns expected from the effective stress and interval velocity method for four offset wells, the resulting columns using the empirical workflow plot within the P10 to P90 ranges which is consistent with the gathered data.

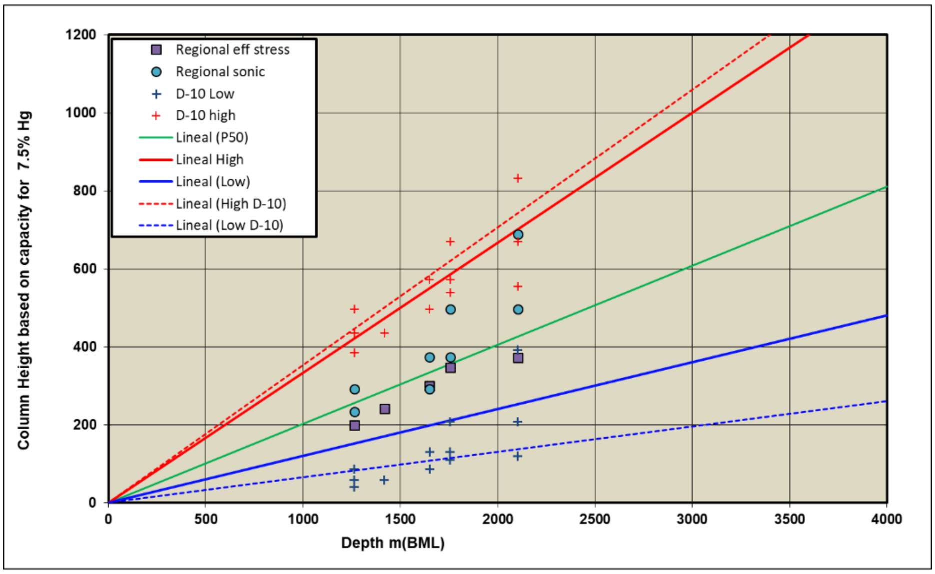


Figure 10. Database including trends of gas columns from MICP in 13 wells, gas columns have been estimated with effective stress and interval velocity for another four proposed wells and added to this are data points using the D10 approach.

Conclusions

- The presented workflow combines a number of approaches to evaluate the capillary sealing capacity of mud rocks to impact the estimates of hydrocarbon columns. The regular lack of data in exploration should not be a reason to skip the capillary seal capacity assessment. This estimate should be combined with evaluation of the other potential seal failure mechanisms prior assigning a final column height and probability for prospect evaluation.
- The empirical workflow proposed based on effective stress and Yang and Aplin relationships has been validated with MICP data from several exploratory wells.
- The use of the database ranges for P10, Pmean and P90 columns show value when estimating range of expected columns in new exploratory or appraisal wells.
- The database and the methodology might change when data is incorporated from new wells. Refinement of the probabilistic columns (P10-P90) can be revisited when new data show values outside the current ranges.
- Further work should be made to test the sensitivity of the workflow to different types of mudrocks, the porosity equations used as well as the hydrocarbon type and its temperature.

Bio

Sara Martinez is a geoscientist currently working for Repsol in the Geohazards team. She is an engineer by foundation with 9 years' experience in the oil & gas industry. She worked as operational geologist for the first three years, until she discovered the pore pressure discipline. Currently she works mainly providing the planning inputs for the exploratory projects in the company and follows the well execution from the pore pressure and geomechanical perspective too. The main achievements during the last 6 years have been; the development of the capillary seal estimation workflow and its application into pore pressure models, the integration of pore pressure discipline with basin modelling and she the use of the MES and FES Geolfluid methodology in complex tectonic basins to coupled pore pressure with geomechanics.

Integrated Pore Pressure Prediction in Complex Geological Settings

[1]**Iftikhar Ahmed Satti** and [2]Chen Xin
[1] *Institute of Geology, University of Azad Jammu and Kashmir, Muzaffarabad, Pakistan*
[2] *Geophysical Research Institute of BGP Inc., CNPC, P.R.China*

Summary:

Quantitative understanding of the pore pressure zones is very important for petroleum industry to design optimal well paths and avoid drilling hazards. Pore pressure prediction becomes more complicated in geologically complex areas where both clastic and non-clastic rocks are present. In this paper, wireline log data and drilling data of three wells is used for pore pressure prediction. 2D seismic velocity data is used to predict the pore pressure at proposed well location. Three abnormal pressure zones are identified based on the mud weight data and velocity spectrum at drilled well locations. It is highlighted that Eaton method successfully predicted the 2D pore pressure in the middle and deep zone. But, underpredicted the pore pressure in the shallow zone where high velocity anhydrite is present. However, integrated pore pressure prediction approach using seismic attribute, seismic impedance inversion, wireline logs and drilling data is useful to successfully predict the high pore pressure in the deep as well as in shallow Formation containing anhydrite.

Introduction:

Pore fluid pressure is the pressure exerted by fluids within the confined pore space of rocks. Pore pressure can be generated by different mechanisms such as undercompaction and fluid expansion. (Bowers, 1995). The magnitude of the effective in situ stress around the well bore will be effected by the changes in pore pressure. Any significant change in pore pressure in weak rocks might lead to increase in compaction and effective stress that have effect on drilling operations. Hence, knowledge of the pore pressure is useful to minimize wellbore stability problems (Zhang, 2013).The focus of this study is to predict 2D pore pressure in the field XX, located in the northern part of Iraq, in the folded zone with NW-SE faults.

Methodology:

Wireline log, drilling data and 2D seismic data of the field XX is used for this study. Eaton (1972) method is used for pore pressure prediction. The Eaton (1972) method is given as

$PP = \sigma T - (\sigma T - Pn)^* (\Delta tn / \Delta t)^{EE}$

Where, PP = Predicted Pore Pressure, σT = Total Vertical Stress, Pn = Normal/Hydrostatic Pressure, ∆t = Sonic transit time from well log, ∆tn = Normal sonic transit time when pore pressure is hydrostatic, EE = Eaton exponent (For Sonic transit time =3)

Seismic velocity is exported at well locations to calculate normal compaction trend (NCT), these NCTs are then used to calculate 2D normal compaction trend. Velocity-density relationship at well locations is used to calculate 2D density which is then converted to 2D overburden pressure.

Seismic velocity analysis is carried out to confirm the presence of high pressure zones identified using mud weight data and check the seismic velocity behavior in these zones. Seismic attribute (Peak Amplitude) and seismic impedance inversion (CSSI) is also used to predict the high pore pressure zones in the study area.

Results:

Predicted pressure along 2D seismic line is shown in Figure 1. Since the RFT data is not available, the predicted pressure is calibrated with mud weight (MW).

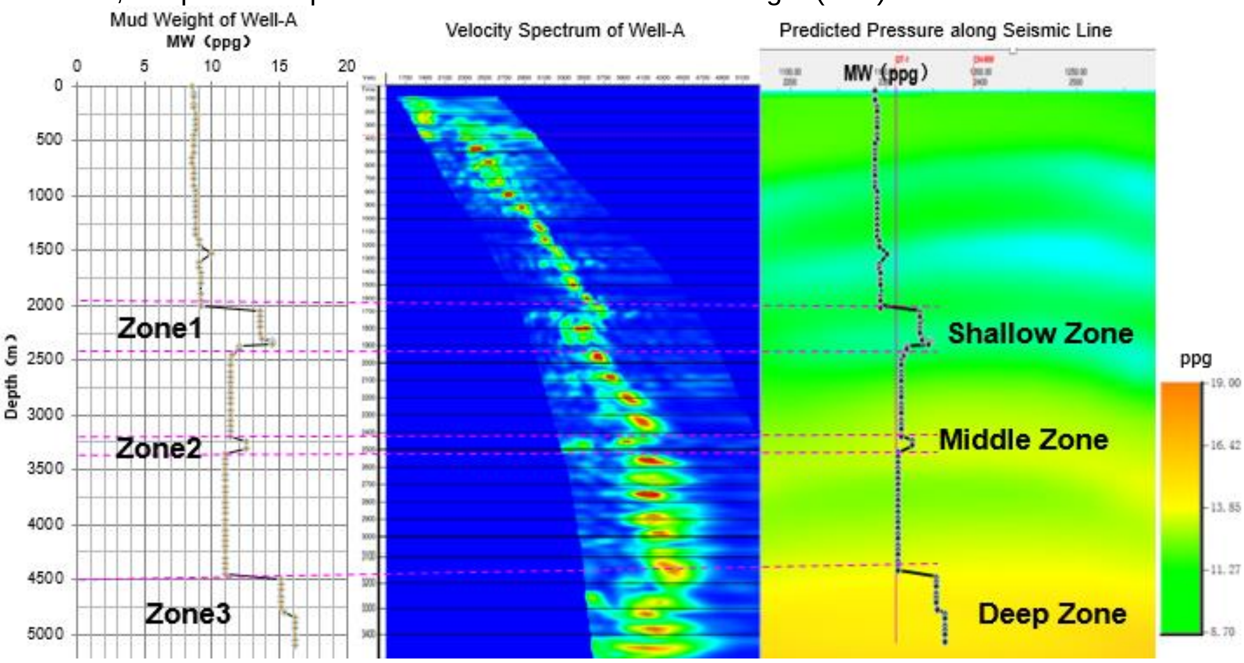


Figure 1: Mud weight and seismic velocity spectrum is showing the presence of high pore pressure zones. Velocity is low in middle and deep zone but no significant velocity drop in shallow zone due to the presence of anhydrite. Seismic velocity based 2D pore pressure prediction results matched with mud weight in middle and deep zone, but did not match in the shallow zone.

Conclusions:

Based on the pore pressure prediction results, it is concluded that the Eaton (1972) method can be used for 2D pore pressure prediction in the middle and deep zone using seismic velocity, and the pore pressure prediction results are matched with the mud weight. But, this method can't be used for 2D pore pressure prediction in shallow zone, due to clay stone contain anhydrite with high velocity. This shows it is hard to do predict pressure based on seismic velocity in anhydrite formation. Seismic impedance inversion and seismic attribute (Peak Amplitude) are useful for abnormal high pressure zone prediction in shallow Formations for proposal wells. Hence, by integrating seismic data with well logs and drilling data, abnormal high pressure zone can be predicted in both deep and shallow Formations. This integrated approach will provide more reliable pore pressure prediction results.

Bio

Iftikhar Ahmed Satti is a geophysical consultant at EARTH EXPLORER, Pakistan. Previously , he worked as an assistant professor at the Institute of Geology, University of Azad Jammu& Kashmir, Muzaffarabad, Pakistan. He also worked as a geophysicist at Geophysical Research Institute (GRI) of BGPInc.CNPC, China and as a geoscientist at LMK Resources, Islamabad, Pakistan. Satti's research interests include overpressure prediction, reservoir geomechanics, seismic interpretation, velocity modeling and basin modeling. Satti has authored or co authored more than 15 technical papers. He holds a PhD degree in petroleum geoscience from Universiti Teknologi PETRONAS (UTP), Malaysia.

Is it useful to estimate hydrocarbon column heights from seal capacity?

Richard E. Swarbrick[1], Richard W Lahann[2], Steve A. O'Connor[3]
[1]University of Durham and Swarbrick GeoPressure Consultancy, Wiltshire, UK
[2]Indiana Geological and Water Survey, Indiana, USA
[3]Global GeoPressure Advice, Durham, UK

Industry practice requires us to review of potential hydrocarbon column height limitations when the seal capacity is small, i.e. when the prospect is shallow and near-hydrostatically pressured or when the reservoir pressures are expected to be close to the fracture strength of the top seal due to pressures above hydrostatic. Traditionally, analysis is conducted at top reservoir/base seal, assuming hydrocarbon buoyancy (hydrocarbon pressure minus pore fluid pressure) cannot exceed the aquifer seal capacity (ASC), which is fracture pressure minus pore fluid pressure. The maximum hydrocarbon column height is then determined from the magnitude of the ASC and the fluid densities of the hydrocarbon and water-phase pressures. Gas columns will be shorter than oil columns for the same ASC.

There are three areas of concern in relation to the determination of hydrocarbon column height from seal capacity, namely:

1. Sensitivity of the method to the input data, especially the uncertainty with respect of the fracture strength as distinct from the pore pressure. Figure 1 illustrates the challenge of having sufficient relief on a structure for the column height estimate to exceed to uncertainty.
2. An implicit assumption that hydrocarbon buoyancy pressure can induce hydraulic failure, and
3. uncertainty about hydraulic failure mechanisms with the potential to predict partial or complete loss of hydrocarbons, as well as potential for refilling.

The supposition that determination of hydrocarbon column height by the industry standard method is the optimum way to risk filling large structures in high pressure plays will be challenged.
The assessment of ASC can, however, be used for seal breach risk which can become a routine part of trap risk in ranking prospects in low effective stress settings.

Column height uncertainty				
Assumes	(1) +/- 250 psi (17 bar) uncertainty in **ASC**			
	(2) Water density of 1.04 g/cc (0.45 psi/ft)			
Fluid	**HC Density**	**Gradient**	**Column Height (H)**	
	g/cc	**psi/ft**	**feet**	**m**
OIL	0.809	0.35	2500	762
OIL	0.693	0.30	1667	508
OIL/GAS	0.578	0.25	1250	381
GAS	0.462	0.20	1000	305
GAS	0.347	0.15	833	254
GAS	0.231	0.10	714	218

Figure 1. *Table of data to illustrate the minimum column height required for various fluids (from medium quality crude to dry gas) required to exceed the uncertainty in fracture strength. These and other considerations suggest the method may not be sufficiently sensitive to be useful in estimating hydrocarbon column heights*.

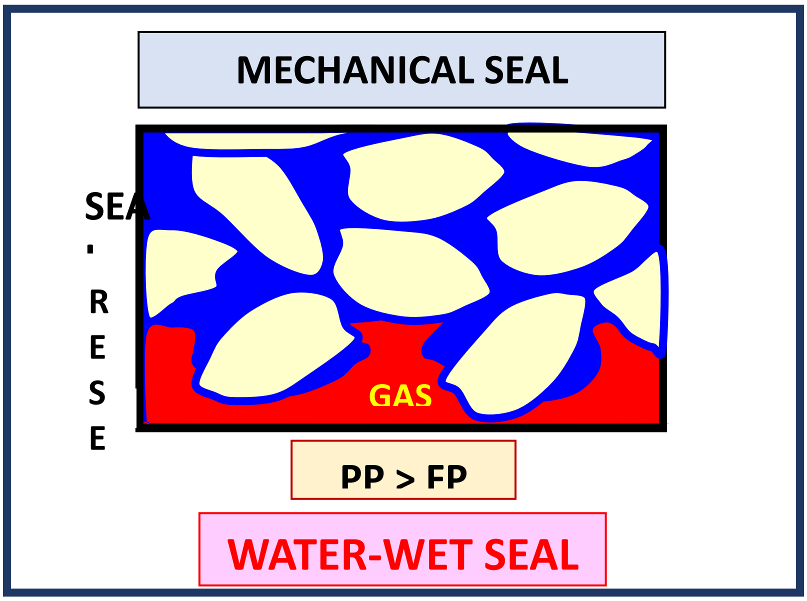


Figure 2. *Water-wet reservoirs appear to present a challenge on the mechanism for hydraulically fracturing a rock (e.g. pushing grains apart when the hydrocarbon-phase pressure is not in contact with the rock, especially in the seal).*

Session Eleven: Uncertainty 2 & Macondo Case Study

A Discussion of Accuracy and Uncertainty in Pore Pressure, In Situ Stress and Fracture Gradient Estimation during Exploration and Production

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During field exploration, development, redevelopment, or a transition to underground gas storage, sequestration and abandonment, the initial and current pore pressures and the related states of in situ stress are key design parameters required by a number of sub-surface disciplines.

Despite the introduction of new approaches and technologies to estimate pore pressures and in situ horizontal stress, fundamental questions still persist about their accuracy and uncertainty when determining these design parameters for well and field developments. These questions include: What is the accuracy limit of the current techniques for evaluating pore pressures during exploration in low permeability formations, using either log or seismic-based techniques, and ; What is the driving mechanism for horizontal stresses in particular basins and how does this uncertainty affect the accuracy of our horizontal stress and fracture gradient estimates?

This paper discusses the current accuracy of pore pressure estimates, based on standard industry techniques during exploration, and how this impacts the stress and fracture gradient estimates. The uncertainty of in situ stress and fracture gradients estimates are further investigated to quantify the accuracy that can be expected from log-based analysis used in 1D- and applied to 3D-Mechanical Earth Models. The paper discusses how these estimates can be refined for improved well and stimulation designs.

During the development and redevelopment of fields involving depletion and injection in the production phase, the stress-depletion response of the reservoir and the stress ‘rebound’ during injection are key design parameters. The uncertainty around the stress and fracture gradient evolution are considered in a historical context and the current state-of-the-art discussed, with reference to the application of 4D-Seimic analysis and fracture gradient modification through stress caging.

This paper draws upon existing pore pressure data and their re-analysis to quantify the limits of accuracy, as well as new minifrac and microfrac stress measurements and horizontal stress estimates, which allow their uncertainties to be quantified for both passive and tectonically compressive environments.

Bio
Tony Addis is a Petroleum Geomechanics Engineer and Production Technologist with 34 years of worldwide experience.

In 2018 he formed ‘Addis & Yassir FZ LLC’ in Abu Dhabi which provides independent geomechanical and sub-surface advice to the oil & gas sector.

Tony has over 50 publications, 3 patents and has been a Ph.D. examiner for the Universities of London, Adelaide & Curtin. He is also a founding member of the Petroleum Geomechanics Commission (PGC) of the ISRM.

Compaction and Pore Pressure Prediction in Different Tectonic Environments

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I use the Modified Cam Clay (MCC) soil model for plane-strain conditions (Roscoe and Burland, 1968) to estimate compaction and pore pressure of mudrocks in three tectonic environments: uniaxial strain, critically-stressed normally faulting, and critically-stressed reverse (compressional) faulting. This model takes into account the effect of mean and shear stress to the mudrock compression. The generalized compaction equation is:

$$e = e_0 + \lambda \ln\left[\frac{1+K_0}{1+K}\right] + \lambda \ln\left[\frac{\left(\frac{M}{\sqrt{3}}\right)^2 + \left(\frac{1-K_0}{1+K_0}\right)^2}{\left(\frac{M}{\sqrt{3}}\right)^2 + \left(\frac{1-K}{1+K}\right)^2}\right] - \lambda ln\sigma_v{}', \quad \text{Eq. 2.}$$

where e is void ratio, and $\sigma_v{}'$ is the vertical effective stress. M is

$$M = \frac{6sin\phi}{3-sin\phi} \quad \text{Eq. 3} \quad .$$

where ϕ is the friction angle. K is the ratio of the horizontal to vertical effective stress:

$$K = \frac{\sigma_h{}'}{\sigma_v{}'}, \quad \text{Eq. 4}$$

which is dependent on the tectonic environment: in environments with no tectonic activity (uniaxial-strain condition), $K = K_0 = \frac{2}{\sqrt{\frac{M^2}{3}+1}}$. In normally-faulted environments,

$$K = \frac{1-sin\phi}{1+sin\phi}, \quad \text{Eq. 5}$$

and in thrust-faulted environments,

$$K = \frac{1+sin\phi}{1-sin\phi}. \quad \text{Eq. 6}$$

The model needs two more parameters, e_0 and λ, in addition to the friction angle. Under uniaxial strain, Eqn. 2 reduces to

$$e = e_0 - \lambda \ln{(\sigma_v')}, \quad \text{Eq. 1}$$

This compaction equation is commonly used to describe the uniaxial compression curve of mudrocks (Yang and Aplin, 2004). e_0 is the horizontal intercept of this curve at $\sigma_v' = 1$ MPa, and λ is the slope of this curve on a plot of void ratio vs. the natural log of vertical effective stress.
The 2nd term on the right-hand side of Eq. 2 accounts for the different mean effective stress relative to the vertical effective stress in different tectonic environments. For example, for a given vertical effective stress, the mean effective stress is greater in a thrust belt than in a normal-faulting environment. The third term in Equation 2 accounts for the effect of shear on pore pressure generation.
Figure 1 illustrtaes the compaction curves for the three tectonic environments. The compaction curves on a semilog plot have always the same slope and differ only in the intercept (the void ratio at 1 MPa). For a given vertical effective stress, rocks compacted uniaxially (dashed line) are the least compacted and those compacted under reverse-faulting stress regime (solid line) are the most compacted. This is because for a given vertical effective stress, both the average effective stress $(\frac{\sigma_H'+\sigma_v'}{2})$ and the shear stress $(\frac{\sigma_H'-\sigma_v'}{2})$ are greatest in reverse faulting environments. It is less intuitive that rocks deformed in a normal faulting environment are more compacted than those compacted uniaxially (Figure 1, dash-dot line vs. solid line). For this case, the average stress (for a given vertical effective stress) for normal faulting is less than the case of uniaxial conditions, but the shear stress is greater. The increased shear overwhelms the decreased mean effective stress and as a result, rocks in the normal faulting regime are slightly more compacted than those in the uniaxial regime (Figure 1 dash-dot line).
Equation 2 is reorganized to estimate pore pressure in the three tectonic environments. I will present an example for thrust belt and uniaxial strain settings (Flemings and Saffer, 2018).

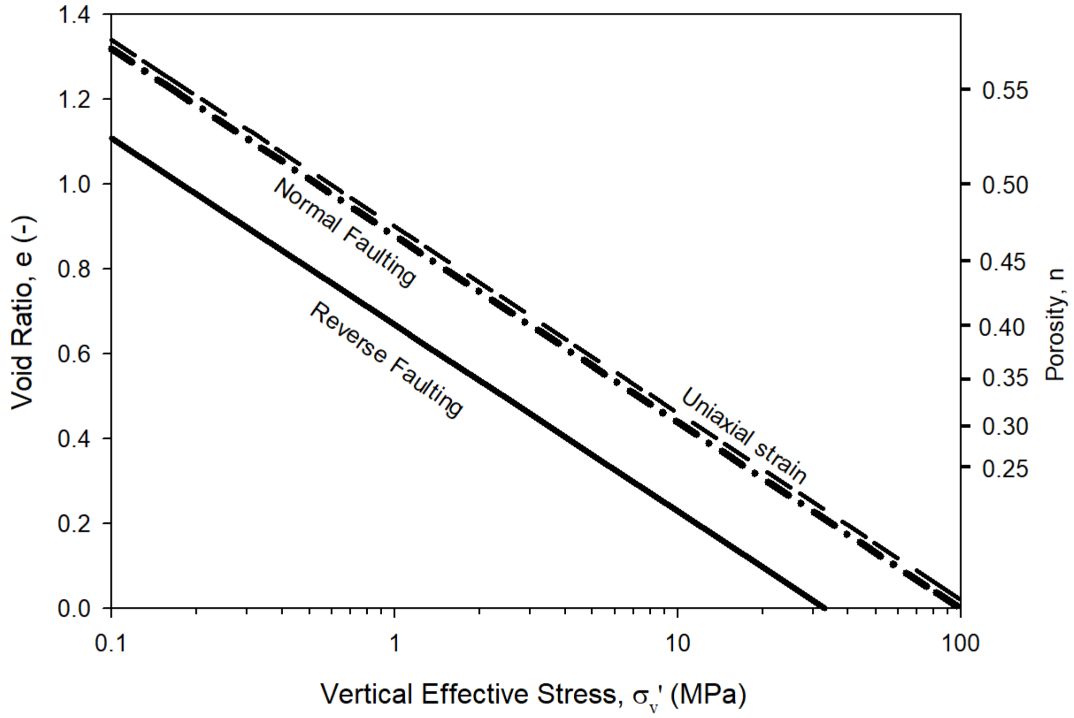

Figure 1: Compaction curves as a function of vertical effective stress for three tectonic settings: normal faulting, uniaxial compaction, and reverse faulting. For these curves, e_0 = 0.9, λ = 0.19, $\phi' = 30°$.

Overpressure at the Macondo Well and its impact on the Deepwater Horizon blowout

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At the Macondo well, the overpressure in the main reservoir is nearly identical to that within a stratigraphically equivalent sandstone at the Galapagos development 21 miles (34 km) to the south; we interpret that the reservoirs share a permeable, laterally extensive, and hydraulically connected aquifer. At Macondo, pore pressure approximately parallels the overburden stress to a depth of 17,640 ft (5,377 m) subsea and thereafter decreases abruptly by 1,200 psi (8.3 MPa) over 370 ft (113 m) as the main sandstone reservoir is approached. In contrast, at Galapagos, pore pressure increases with the overburden stress for the entire well depth. We observe a vent approximately 5 km east of the Macondo location where the main reservoir sand is at its highest structural position. We interpret that the Macondo and Galapagos fields are protected protected traps and that there is ongoing seal failure at the vent location. The pore pressure regression at Macondo was responsible for a reduction in the least principal stress. This, in combination with the extreme pore pressures within overlying strata, drastically narrowed the range of safe operational borehole pressures. These geologic phenomena produced challenging conditions for drilling, prevented successful temporary abandonment of the well, and contributed to the well's failure. We note that many of these observations have been recently published and are publicly available (Pinkston, 2017; Pinkston and Flemings, 2019).

Pinkston, F. W. M., 2017, Pore Pressure and Stress at the Macondo Well, Mississippi Canyon, Gulf of Mexico [M.S.: University of Texas, 107 p.
Pinkston, F. W. M., and Flemings, P. B., 2019, Overpressure at the Macondo Well and its impact on the Deepwater Horizon blowout: Scientific Reports, v. 9, no. 1, p. 7047.

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