Introduction

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Geopressure: an introduction to the thematic collection

Richard E. Swarbrick

Earth Sciences, University of Durham, Durham, UK
Correspondence: swarbrick@geopressureconsult.com

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This thematic collection resulted from a conference organized by Durham University and the Geological Society of London entitled 'Geopressure 2021: Managing uncertainty in geopressure by integrating geoscience and engineering'. Originally to be held in March 2020 at Durham, the conference took place a year later online, due to Covid, but drew an even larger number of participants than anticipated from across the globe. A total of 140 participants were registered for the 3-day event. Sessions were organized regionally to favour participant attendance from SE Asia and Australia in the mornings, Europe in the middle of the conference day, and the Americas in the afternoons. In fact almost all attendees stayed for the full day. The conference was organized around themes including – Geopressure Challenges; Modelling; Well operations; Uncertainty and Reservoir quality (in clastic rocks), with many case studies scattered throughout. A total of 31 oral and 12 poster presentations were included in the programme.

Geopressure, meaning both pore fluid and fracture pressure, has been a key element of subsurface drilling conditions for at least 70 years (see Dickinson 1953, at that time related to oil and gas exploration in the Gulf of Mexico shallow water play). Subsequently recognized as a global challenge, geopressure prediction and interpretation remain critical to safe drilling of wells, especially deeper than 1.0 km from the rock surface, and now highly relevant to geothermal wells, handling the safe injection and sequestration of CO_2 and storage of hydrogen and compressed air for later use in electricity generation. Durham hosted the first UK geopressure conference in 1995 primarily describing academic and service company research, with a small representation from industry looking on but at that time reluctant to offer case studies and insider information. Later European conferences brought increasing industry involvement with a willingness to share experiences and data plus greater geographic spread. This thematic collection represents the latest conference where a full mix of academic and industry contributors describe some of our current understanding of how both fluid and rock systems operate in relation to variations in pressure and stress, with direct application to operational requirements for safe drilling and management of subsurface resources.

The papers in this thematic collection span the breadth of the conference and are organized here around regionality – from global to basin-scale to field-scale. Despite studies from European and SE Asia basins, however, what remains clear from this selection of papers is the continued dominance of observations from Gulf of Mexico basins, including field data, laboratory results and computer simulation.

Birchall *et al.* (2022) provide the first truly global review of underpressure, a relatively rare phenomena under natural (geological) conditions, i.e. not related to extraction of reservoir fluids with corresponding reduction in both pore fluid and fracture pressures. Documenting the location of natural underpressure from 29 locations across both geographical and tectonic settings provides insights into the potential explanation for fluid pressures which are below hydrostatic. The authors' analysis favours uplift as the principal cause, always geologically recent and often associated with deglaciation, whilst being observed exclusively in low permeability reservoirs associated with claystone/shale sequences. Underpressure as high as 60 MPa can contribute to drilling challenges when not expected or incorrectly predicted.

All other papers are focused on sediments with overpressure, i.e. pore fluid pressures above hydrostatic. Overpressure has mainly been modelled using elastic compression with no time-dependent behaviour. You *et al.* (2022) tackle the role of creep in the development of overpressure to explain higher consolidation states than predicted in deeply buried, older rocks, using modelling incorporating both elastic and visco-elastic compression. Their results using Gulf of Mexico resedimented mudrocks may help to explain why sediments in older basins have lower porosity than in younger basins subjected to the same effective stress history, a result which emphasizes the need to consider age in predictive models for pore fluid pressure.

Direct pore fluid pressure measurements, especially in complex wells in highly overpressured sediments, tend to be rare. Lee *et al.* (2022) demonstrate how data from fluid influxes into boreholes when mud pressure fails to balance formation pore fluid pressure, known as 'kicks', can be used as a direct measurement of pore fluid pressures, often when other techniques are not possible. They document how field data should be examined, primarily from drilling records, to assess the validity of such a measurement, and present a new generic classification for kicks.

Zablocki *et al.* (2022) used laboratory methods to assess the impact of clay fraction (proportion of the rock grains below 2 µm grain size) on rock strength with implications for estimating fracture pressure, using smectite-rich, Gulf of Mexico mudrocks as their field data. Yang and Aplin (2004) had examined mudrock porosity-effective stress relationships in relation to clay fraction applied to Gulf of Mexico and North Sea mudrocks but for pore fluid pressure prediction. Zablocki *et al.* (2022) show how variations in clay fraction in mudrocks when tested over consolidation stresses up to 10 MPa generate different stress ratio, Ko, paths and effective friction angles, and apply their findings to borehole stability when planning wells through similar mudrock sequences.

Lahann and Swarbrick (2022) examine the effectiveness of Poisson's ratio as a rock property to predict borehole failure (often referred to simply as fracture pressure). They note that several techniques for calibration of appropriate values of Poisson's ratio yield significantly different trends with increasing depth, proposing explanations for the differences and recommendations for adopting specific methods in fracture pressure prediction. Globally representative datasets (including Gulf of Mexico) show Poisson's ratio/stress ratio values derived from *in situ* data (Leak-Off tests) are relatively constant over depth ranges up to 5–6 km. They note, therefore, that use of static (lab) and dynamic (seismic and borehole log data) Poisson's ratio values will lead to substantial underestimation of fracture pressure if applied to pre-drill predictions.

Rapid loading of compressible sediment such as shale is the mechanism used to explain overpressure in many sedimentary basins and provides the optimum conditions to evaluate rock properties such as density and sonic/seismic velocity in relation to effective stress (total stress minus pore fluid pressure). Ramdhan and O'Connor (2022) explore pore fluid pressure profiles in single wells from the three Indonesian basins and illustrate a revised methodology using logged sonic velocity and density data to discriminate between loading and unloading. Sonic velocity v. density cross-plots illustrate the depth intervals where loading is assumed. The availability of density log data then allows them to estimate the magnitude of overpressure resulting from unloading mechanisms, such as clay diagenesis and gas generation, thereby improving pore pressure prediction in these basins. The paper emphasizes the importance of acquiring density log data in wells: to apply this technique but also more generally for accurate determination of total vertical stress, needed in most published pore fluid and fracture gradient algorithms.

Vejbaek (2022) aims to explain vertical and lateral variation in pore fluid pressure in sediments from the northern part of the Danish North Sea. Modelling of these pressures was performed using Eaton's approach applied to both resistivity and sonic velocity logs through the Tertiary and Jurassic sequences, noting the difficulty applying the same approach through chalk. The author explores the impact of ephemeral ice-loading, assumed to have a duration of about 20 k years: only the upper few hundred metres experience compaction with no time for drainage from deeper rocks where the rock properties from the pre-glacial period are restored at the end of glaciation. The author concludes that in the Danish Central Graben the pressure seal is provided by the Paleocene to mid-Miocene shales, without contribution from the chalk, unlike some other work from the UK/Norwegian Central Graben (see Swarbrick *et al.* (2010) as an example). Overpressure measured in Danish Central Graben Jurassic reservoirs correlates with depth and is attributed to hydrocarbon maturation.

Drews *et al.* (2022) focus on drilling issues in relation to deep geothermal wells in the North Alpine Foreland Basin where overpressure reduces drilling rates by up to 40%. Pressure data acquired from wells drilled for oil and gas in the stratigraphic section above can be used in improving drilling success and costs in pursuit of deep geothermal energy in the same areas.

Macleod (2022) tackles the challenge of pore pressure prediction in reservoirs undergoing depletion during production. The Jasmine Field in the Central North Sea basin is a high-pressure high-temperature (HPHT) gas condensate discovery with 7 years of production at the time of writing. Direct pressure data are exclusively in the discovery and first infill well, drilled post-production start. A method is shown for reservoir pore pressure estimation using resistivity profiles from all subsequent wells drilled during continued production, calibrated to the direct pressures measured in the early wells. Fracture pressure was estimated using a Lahann and Swarbrick (2017) model calibrated locally to available LOT and FIT data. Input of pore fluid pressure from the new method in infill wells gave good match to available fracture pressure calibration, including mud losses and estimate of fracture strength from dynamic FITs.

There is no doubt that this conference will not be the last as there continues to be active research interest in universities and industry. The likelihood is for future events to include case studies from field data involving both permanent CO_2 sequestration involving both depleted oil/gas fields and saline aquifers, and hydrogen/compressed air stored for shorter periods of time in suitable repositories such as salt caverns. The author expects growing interest in storage volume assessment related to fracture strength of the seals surrounding storage reservoirs including safe pressure limits to guarantee low or no losses. Pressure prediction remains a significant challenge to safe drilling in the subsurface in many areas: consideration of depleted pore fluid and coupled fracture pressures in areas of oil/gas extraction is needed when planning CO_2 and other gas storage.

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