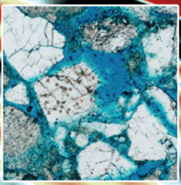
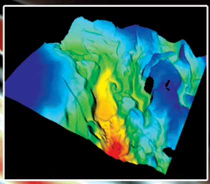
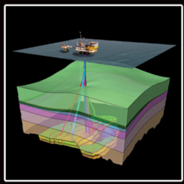

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Development and Production Geology of Carbonate Reservoirs

11-12 May 2022

The Geological Society, Burlington House, Piccadilly, London

Carbonate reservoirs constitute some of the most important sources of global oil and gas production. They form the world's largest oil and gas accumulations, the world's highest-producing fields, and have some of the longest production histories. Significant new carbonate discoveries continue to be made, and carbonates are also a source of geothermal energy or may be utilised for gas storage.

Successful development of supergiant carbonate reservoirs can result in plateau production that may last for decades, giving high ultimate recovery factors. But, carbonate reservoirs can also be some of the most complex in terms of reservoir quality and heterogeneity. Many give disappointing ultimate recovery factors and some are deemed uncommercial with current technologies. Fundamental geological understanding, sufficient and appropriate geological and dynamic data, and the construction of effective models are the keys to optimising the exploitation of such reservoirs.

This conference will focus on how lessons learned from more than a century of discovery, appraisal and development of carbonate reservoirs may be applied to emerging discoveries. It will bring together the experiences of diverse operators with an objective of highlighting best practices for the geological characterization of carbonate reservoirs from appraisal to production.

Potential session themes:

- Excess permeability – blessing or curse?
- Pores vs stratigraphy – what controls dynamic reservoir behaviour?
- Reservoir analogues – how useful are they?
- Static modelling of carbonate reservoirs – how predictive can we be?
- Multiscale/multidisciplinary dynamic reservoir characterization – how can we integrate geology effectively?
- Improving recovery/revitalising old carbonate fields – adding value through geological understanding.

Planned field trips:

The Carboniferous platforms of Derbyshire, led by Pete Gutteridge, Cambridge Carbonates.
Zechstein carbonates of the north-east of England, led by Geospatial Research Ltd.

Convenors:

Alun Williams
Equinor

Andrew Barnett
Shell

Anna Matthews
BP

Björn Seyfang
Equinor

Ivan Fabuel-Perez
ExxonMobil

Jo Garland
Cambridge Carbonates

Paul Wright
National Museum of Wales and Consultant

Trevor Burchette
Royal Holloway, University of London and CRG Ltd

Confirmed Keynotes:

Mishrif Formation reservoirs of Rumaila Field
BP

Pre-salt reservoirs of Lula Field
Petrobras

For further information please contact:

Sarah Woodcock, sarah.woodcock@geolsoc.org.uk

Development and Production Geology of Carbonate Reservoirs

11-12 May 2022

Hybrid – The Geological Society London & Zoom

Final Programme

Day One	
08.30	**Registration**
08.50	**Welcome**
	Session One: O&G
09.00	**KEYNOTE: Tupi Field** **Saulo Pedrinha, *Petrobras***
09.40	**Importance of core for carbonate reservoir evaluation in the Pre-Salt of the Santos Basin, Brazil** Hannah Wood, *Shell*
10.10	**Discrete Zones of Elevated Permeability (DZEP) in Middle Eastern Carbonate Reservoirs – Causes and Consequences** Nigel E. Cross, *Independent Consultant, Dubai*
10.40	**BREAK**
11.00	**KEYNOTE: The Mishrif Reservoir: a modern future for a historic carbonate field** Anna Matthews, BP
11.40 virtual	**Macro-sweep assessment in carbonate reservoirs** Joachim E. Amthor, *Shell Brasil Exploration and Production*
12.10 virtual	**Cherts, Spiculites, and Collapse Breccias – The Unusual Reservoir Facies of the Gohta Discovery, Loppa High, SW Barents Sea** Niels Rameil, *Lundin Energy Norway*
12.40	**LUNCH**
	Session Two: The Energy Transition
13.40	**KEYNOTE: Geothermal exploration and development of a karstified carbonate reservoir on a basin scale: a story from the north Alpine Foreland Basin (Germany)** **Daniel Bendias & Kilian Beichel, *SWM Services GmbH***
14.20	**Temperature decline at a geothermal production well: unique insights into a karstified reservoir** Thorsten Hörbrand, *SWM Services GmbH*
14.50	**Development of karstified and naturally fractured carbonate aquifers as geothermal reservoirs** Tim Pharaoh, *BGS*
15.20	**BREAK**
15.40	**Upscaling of geological properties in a world-class carbonate geothermal system in France: from core scale to 3D regional reservoir dimension** Hadrien Thomas, *Université Paris-Saclay*

16.10 virtual	**Geological characterization of fractured carbonate fields aimed to CO2 storage applications: an example from the Ragusa offshore (Malta Plateau, Eastern Sicily Channel)** Mariagiada Maiorana, *University of Palermo*
16.40	**Karst in carbonate reservoirs** Alberto Riva, *University of Ferrara, Department of Physics and Earth Sciences*
17.10	**End of day one** **Drinks reception in lower library**
18.20	**End**

	Day Two
08.30	**Registration**
08.50	**Welcome**
09.00	**KEYNOTE: Applied carbonate studies in a rapidly-changing industry** **Trevor Burchette, Royal Holloway University of London and CRG Ltd & Paul Wright, National Museum of Wales**
	Session Three: Modelling and Outcrops
09.40	**Static-dynamic reservoir modelling of a carbonate field onshore Italy: tackling challenges from an effective multidisciplinary integration of vintage data** Raffaele Di Cuia, *Delta Energy*
10.10	**Quantifying the modifications of microporosity geometry during burial** Aurelien G. Meyer, *Natural History Museum of Denmark*
10.40	**BREAK**
11.00 virtual	**Petrophysical understanding of the pore system and reservoir connectivity of Mishrif carbonate in the South Iraq for permeability prediction by combing FZI with MNR** Ibrahim B. Milad, *BP*
11.30	**Scale-free distribution of the carbonate pore system: an example from San Salvador Island, Bahamas using multidisciplinary data** Paul Moore, *ExxonMobil*
12.00 virtual	**A new numerical method for modelling sedimentary facies coupled with geobodies distributions: the case of the lacustrine carbonates and microbialites of the Yacoraite formation (Salta, Argentina)** Vanessa Teles, *IFP Energies nouvelles*
12.30	**3D geological modelling of outcropping carbonate platforms in the Dolomites: how useful are they?** Alberto Riva, *University of Ferrara, Department of Physics and Earth Sciences*
13.00	**LUNCH**
	Session Four: Oil & Gas
14.00	**KEYNOTE: Multiscale/multidisciplinary data driven reservoir characterisation of a fractured carbonate field in Kurdistan** **Claire Sena, *DNO ASA***
14.40	**High K layer in the R1 Inferior Reservoir and its impact on the gas souring in the Miskar field** Andrew Barnett, *Shell*

15.10 virtual	**Reservoir characterisation and fluid recovery in carbonate mudrocks: integrating multi-scale geology and engineering to enhance recovery** J. Frederick Sarg, *Colorado School of Mines*
15.40	**BREAK**
16.00	**The production geologist adds value to carbonate assets: some examples of how it is done** Edward Follows, *Shell*
16.30	**Porosity Depth Saturation (PDS) model: a tool to quantify mesogenetic leaching in carbonate reservoirs** Christian Perrin, *North Oil Company, Qatar*
17.00	**Sum-up and close of conference** Conference convenors
17.15	**End of day two**

Posters
Sedimentary environment and diagenetic control on pore space heterogeneity in continental carbonates (Cenozoic, Paris Basin) Kevin Moreau, *Université Paris-Saclay*
VIRTUAL: The geological/petrophysical facies models of the Cenomanian-Turonian Mishrif carbonate platform deposits: a case analysis of a giant oil reserve in the Mesopotamian Basin Yang (Young) Li, *The University of Manchester*
Contribution of drone photogrammetry to 3D outcrop modelling of facies, porosity, and permeability heterogeneities in carbonate reservoirs (Paris Basin, Middle Jurassic) Hadrien Thomas, *Université Paris-Saclay*
Towards integrated experimental and modelling workflows for multi-scale diagenetic rock-typing of carbonate reservoirs: feasibility study on Indiana limestone (Lower Carboniferous, Mississippian) Fadi H. Nader, *IFP Energies Nouvelles*
Coupled sedimentologic and petroacoustic characterization of surface-exposed Middle Jurassic carbonate rock analogues to the 'Oolithe Blanche' geothermal reservoir target of the Paris Basin Fadi H. Nader, *IFP Energies Nouvelles*

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ORAL ABSTRACTS
(In Programme Order)

Session One: O&G

Keynote – TUPI FIELD

Saulo Pedrinha, Petrobras

Discovered in the year 2006 in the Santos, Tupi field currently has more than 100 drilled wells, holding the largest database in the Brazilian Pre-Salt Province. It is worth to highlight the huge available rock information (more than 4000 sidewall samples and 700m of cores), in addition to 3D seismic, well logs, petrophysical analysis and dynamic data including well tests, pressure and production/injection history.

This vast data collection allows the understanding of the main depositional controls involved in the genesis of the reservoir rocks and the how they are distributed. This ultimately serves as a background to understand the variations of the main petrophysical properties affecting the fluid dynamics in the reservoir, and, consequently, to support a robust strategic development plan for the production.

Deposited in a stressing lacustrine setting in the context of the opening of South Atlantic Ocean, the Barra Velha Formation (Aptian) corresponds to the main reservoir interval of the field. From its genetic and environmental significance, especially the energetic conditions and water depth, the identified sedimentary facies in this interval were grouped into six (6) facies associations: Carbonates with well-developed shrub-like textures (InSitu-shrubs); Carbonates with incipient shrub-like or crust-like textures (InSitu-incip); Reworked Carbonates (RC); Reworked Carbonates with siliciclastic content (RC-si); Low energy (LE) and Lithologies with high content of Clay minerals (Clay).

The analysis of the facies associations stacking patterns along all wells allowed the construction of a high resolution sequential stratigraphic framework, supporting the understanding of the lake environmental conditions evolution - in space and time - and, consequently, the sedimentary facies distribution in Lula field geological record.

The reservoir vertical and lateral facies distribution has been represented in 3D geocellular models - within a high-resolution stratigraphic framework - by using the conceptual geological model and all the hard data gathered in order to obtain a more reliable distribution of the petrophysical properties. The depositional facies control a rock-type classification, which is based on porosity, permeability, pore-throat size distribution and relative permeability to support the oil volume estimates, fluid flow modeling and finally the development plan of the field.

Importance of core for carbonate reservoir evaluation in the Pre-Salt of the Santos Basin, Brazil

Hannah Wood[1], Andrew Barnett[1], Ed Follows[1], Priscila Ribeiro[2], Jaydip Guha[1], Runer Avila[2]
[1]Shell, Shell Centre, London, SE17NA, U.K. (hannah.wood@shell.com)
[2]Shell, Brasil Petróleo Ltda, Av. República do Chile, 330, CEP 20031-170, Rio de Janeiro, Brazil

The lacustrine carbonates of the Barra Velha Formation are a prolific reservoir in the Santos Basin, Brazil. In many fields, they comprise decimetre- to metre-scale cycles composed of laminated calcimudstones, spherulitic and shrub-dominated facies. However, locally these cycles are replaced by decametre packages of re-worked shrub grainstone and in-situ shrub framestone with significant (>30°) depositional dips. The latter have several possible interpretations (e.g. fault block highs, carbonate mounds) but the integration of seismic, borehole image (BHI) log and core datasets converges on a working concept model of aggrading carbonate mounds that developed in a lake setting. The core datasets reveal a distinctive depositional fabric within the carbonate mounds.

From a production geology standpoint, the crucial difference between mound-dominated and cyclothem-dominated successions is their permeability architecture. Cyclothem-dominated intervals show prominent and laterally continuous, decimetre-scale vertical matrix permeability variations. Mound-dominated intervals lack fine-scale paleo-horizontal layering and exhibit a greater prevalence of irregular, cm-scale conduits and higher vertical permeability. This difference can only be reliably characterised via the integration of core samples with other datasets and has a significant quantified impact on sweep and production performance.

Discrete Zones of Elevated Permeability (DZEP) in Middle Eastern Carbonate Reservoirs – Causes and Consequences

Nigel E. Cross[1] and Trevor P. Burchette[2]
[1] Independent Consultant, Dubai, UAE. nigel.cross@hotmail.co.uk
[2] Dept. Earth Sciences, Royal Holloway University of London, Egham, UK and Carbonate Reservoir Geoconsulting Ltd., Tonbridge, UK. tpburchette@gmail.com

Giant carbonate petroleum reservoirs of the Middle East exhibit a range of heterogeneities, comprising variable combinations of primary depositional and stratigraphic, and secondary diagenetic and structural, characteristics, the latter often reorganizing or overprinting the former. These produce diverse permeability architectures which exert a profound impact on reservoir performance, especially during secondary recovery where fluids are injected into the reservoir to arrest pressure decline. Of particular importance are laterally persistent, discrete networks of elevated permeability that typically make up a volumetrically minor proportion of the reservoir and yet significantly impact fluid flow. The various depositional/stratigraphic, diagenetic, and structural origins of elevated permeability in Middle Eastern carbonate reservoirs are considered here and their impact on reservoir performance is discussed.

The term "discrete zone of enhanced permeability" or DZEP is used here to denote all geological sources of permeability with sufficient contrast to background reservoir properties, generally at least an order of magnitude, that they exert a disproportionate impact on reservoir flow. Those with a depositional origin are commonly coarse-grained layers, often 'event' beds, or parasequence tops or bases, intercalated with lime mud-rich deposits in offshore or platform interior settings. Other sources include bioturbation horizons, grainy clinothems, and bed-scale grain-size variations in shelf margin shoal deposits. Diagenetically-related DZEP are typically dissolution horizons (e.g., karst) with mouldic and vuggy (fabric selective and non-fabric selective) pore networks, sometimes accentuated by cementation layers and often with coarse-grained depositional pre-cursors. They can also include highly permeable dolomitized intervals. DZEP with a structural origin include fracture-populated damage zones associated with reservoir-traversing fault systems, fracture corridors, isolated fractures, and concentrations of fractures corresponding to bed-scale variations in mechanical stratigraphy (e.g., minerology, facies, cementation/stylotised horizons and/or bed thickness).

The characterization of DZEP can be achieved using a range of static datasets (e.g., core, image logs), but their importance as preferential flow pathways requires dynamic information most commonly derived from production logs and other reservoir surveillance data (e.g., PLT/ILT, TDT/RST, tracers). Pressure transient analysis of pressure build-up well tests and in-reservoir interference tests can quantify effective permeability at the reservoir scale including excess permeability often not captured by well data, which are generally obtained at the core-scale. This can include further sources of non-matrix permeability to create a more complete picture of reservoir-scale permeability networks.

These varied sources of matrix and non-matrix permeability combine in many cases to produce complex lateral and vertical networks. During initial natural depletion DZEP can dominate the production profile and increase well productivity. However, the same intervals often become thief zones that preferentially control reservoir flow during secondary recovery. Thief zones often cause flow conformance issues within the reservoir, channelized flow leading to heterogeneous sweep, cross-zone flow, bypassed pay, and earlier-than-expected water or gas breakthrough in production wells. The recognition of such features requires collection of the correct data at an early stage in reservoir description and the inclusion of these into static geological reservoir models in order to optimise the long-term cost of field development and maximise recovery.

Keynote – "The Mishrif Reservoir: A Modern Future for a Historic Carbonate Field"

Anna Matthews, bp

The Mishrif is a large, carbonate reservoir in the Rumaila field in southern Iraq. It came on-line in 1973 and produced under depletion drive for nearly 20 years. During that time, reservoir pressure in the Mishrif dropped significantly, and the rate of production decline increased sharply. In 2010, BP entered a Technical Service Contract with the Iraqi government and the Rumaila Operating Organization (ROO) was formed. As ROO operator, BP acquired 3D seismic across the field which supported a re-development programme. For the Mishrif reservoir, BP changed the development strategy from a line-drive to an inverted 9-spot water flood programme and, after a successful pilot, initiated water injection in North Mishrif. The result was a record-breaking ramp-up in Mishrif oil production that spanned four years. BP has demonstrated that pressure support through water injection is imperative to the delivery of the Mishrif production targets.

Looking forward, understanding the highly heterogeneous nature of the Mishrif reservoir will play a crucial role in maximizing drainage and sweep efficiency. By integrating geologic description with dynamic performance, we can guide water injection and target poorly swept areas with new wells. BP is leveraging non-geologic software, data science techniques, and agile working practices to interpret the vast Mishrif dataset quickly and efficiently. We continue to modernize geologic interpretation as we build future production for Iraq.

Macro-sweep Assessment in Carbonate Reservoirs

Joachim E. Amthor, Shell Brasil Exploration and Production
joachim.j.amthor@shell.com
Ellen Zijlstra, Shell Kuwait Exploration and Production
John van Wunnik, Shell Global Solutions International

One of the challenges for the development of carbonate reservoirs is to make realistic estimates of the target recovery factors for different oil reservoirs. These are used to identify which reservoirs are underperforming and therefore require a more ambitious development plan or a different recovery methodology. Commonly carbonate oilfields are developed using improved oil recovery (IOR) techniques, such as waterflooding. For many fields the plan is to follow this with the application of enhanced oil recovery (EOR) techniques.

A semi-analytical method for calculating recovery factors, which is valid for all recovery mechanisms based on flooding a reservoir with a liquid, has been developed and applied to analysing the IOR and EOR portfolio of Petroleum Development Oman's (PDO). The method is based on describing the total recovery factor as the net result of macroscopic and microscopic displacement efficiency. These two components are merged into the so-called PDO Tubes Model.

From analysing 80 PDO reservoirs, both clastic and carbonates, several interesting observations can be made:

The macro-sweep recovery factor depends mainly on two parameters, the permeability heterogeneity (sigma K) and the connected volume (CV).
A comparison between Natih, Shuaiba, Kharaib and Ara formations carbonates and Ghariff, Al Khalata and Haima formations sandstone reservoirs reveals that the analysed carbonate reservoirs are more homogeneous than their clastic counterparts.

Carbonate fields with low fault frequency, low matrix permeability and low sigma K (i.e. matrix-dominated Shuaiba Formation outer-ramp/basin carbonate mudstone-dominated reservoirs) have a good macro sweep, and water floods can potentially do better than expected in the long run. The main challenge is to inject sufficient water, since permeability is low.

Carbonate fields with high fault frequencies, higher matrix permeability and high sigma K (i.e. Shuaiba Formation carbonate ramp-margin reservoirs with locally rudist grainstone/rudstones that act as thief zones and faulted Ara Formation intrasalt reservoirs) tend to have poor macro sweep.

These observations are key input to improve the construction of fit-for-purpose static models with meaningful sensitivities which focus on permeability heterogeneity and connectivity.

Cherts, Spiculites, and Collapse Breccias – The Unusual Reservoir Facies of the Gohta Discovery, Loppa High, SW Barents Sea

Niels Rameil1, Michał Matysik2, Lars Stemmerik3, Snorre Olaussen4, Ingrid Piene Gianotten1 and Harald Brunstad1
1 Lundin Energy Norway, Strandveien 4, 1366 Lysaker, Norway (niels.rameil@lundin-energy.com)
2 Institute of Geological Sciences, Jagiellonian University, Gronostajowa 3a, 30-387, Kraków, Poland
3 Geological Survey of Denmark and Greenland (GEUS), Øster Voldgade 10, 1350 Copenhagen K, Denmark
4 The University Centre in Svalbard (UNIS), P.O. Box 156, 9171 Longyearbyen, Norway

The Gohta discovery is located in the south-western Barents Sea (PL492), ca. 160 km offshore northern Norway, on a down-faulted area ("Gohta Terrace") at the southwestern-most edge of the Loppa High. In 2013, the discovery well 7120/1-3 ("Gohta-1") found oil with an overlying gas column in the karstified spiculitic carbonates of the lower Røye Formation (Tempelfjorden Group, Late Permian) and coarse-grained clastics that drape the Permo-Triassic unconformity.

The karstified interval in the lower Røye Formation immediately underlies the unconformity. It is represented by the infill of several stacked collapsed cave systems, consisting of spiculitic clasts in a dolomitized matrix. Caves are vertically separated by cave roofs and massive, nodular, and mottled spiculite facies. Below the karstified interval follow several hundred metres of non-porous spiculitic wackestones. The main phase of karstification is most likely linked to an extensional tectonic phase, resulting in rotational tilting, local tectonic uplift, and prolonged subaerial exposure of the Gohta structure during the late Permian to Early Triassic. Regional evidence for erosion and karstification from seismic data and cores is widespread and includes drainage systems, canyons, sinkholes, irregular topography, and collapse breccias.

In well 7120/1-3 the best reservoir properties are found within the collapsed cave fill. Dominant pore systems are (1) intercrystalline pores between dolomite crystals in the breccia matrix and (2) uncemented interspicule pores and central parts of spicule molds within clast margins. In stark contrast, the primary depositional facies (unaltered "host rocks"), exhibit low porosity and permeability values, rarely exceeding 10% and 1 mD, respectively. Chert concretions are completely tight, but occasionally cut by open fractures. In this context, the Gohta reservoir can be classified as a karst reservoir or, more technically correct, a *buried palaeokarst reservoir*.

Spiculitic cherts are uncommon reservoir rocks and, compared to sandstones and carbonates, their porosity evolution is poorly understood. We propose a genetic model that explains the observed porous margins of spiculitic breccia clasts by local redistribution of silica in the course of their diagenetic history. During burial transformation of opal-A to opal-CT, associated growth of silica concretions in the centre of spiculitic clasts left the clast margins depleted in SiO_2 and thus highly porous. Subsequent transformation of opal-CT to quartz resulted in precipitation of texture-preserving quartz and chalcedony cements. Chertification was post-dated by dolomitization, which affected mainly the micritic matrix of cave-collapse facies. Later diagenesis is of minor importance and includes chemical compaction and some calcite cementation.

In summary, the Røye Formation buried palaeokarst reservoir owes its – for fine-grained spiculitic carbonates surprisingly good – properties to a complex interplay of karstification, cave collapse, silicification, and dolomitization. We propose to interpret the porosity found in the margins of spiculitic clasts as an inherent process of silica diagenesis and not as a consequence of dissolution by freshwater or hydrothermal fluids, unless massive non-fabric-selective dissolution of quartz and chalcedony cements in a spiculitic texture can be documented.

Session Two: The Energy Transistion

Keynote – Geothermal Exploration and Development of a Karstified Carbonate Reservoir on a Basin Scale – A Story from the North Alpine Foreland Basin (Germany)

Daniel Bendias & Kilian Beichel, *SWM Services GmbH*

Kilian Beichel (beichel.kilian@swm.de)[1], **Daniel Bendias (bendias.daniel@swm.de)[1],** Johannes Linde[1], Franz Böhm[1] and Dietfried Bruss ([1] SWM Services GmbH)

The first geothermal wells in the Greater Munich Area (South Germany) were drilled in the 1990`s by local municipalities for district heating. Since then the geothermal industry slowly but steadily evolved from small scale low tech and low budget activities to increasingly complex projects featuring high-resolution 3D seismic exploration and multilateral wells. A favorable political framework, a generally quite productive regional reservoir as well as the adaptation of oil and gas G&G workflows for exploration have led to a booming geothermal industry in Bavaria. To this date almost 50 geothermal wells have been drilled, over 90% have been successful and are still in production to date.

The local energy supplier Stadtwerke München (SWM) has become the first developer that successfully realised multiple geothermal projects. In order to cover the renewable heat demand of the city of Munich, SWM plans to systematically develop the Alpine Foreland Basin on a regional scale around Munich for geothermal use.

The main target reservoir for geothermal exploration in the area are carbonates from the Upper Jurassic Malm Formation. In the up to 600m thick carbonate sequence different lithofacies types can be identified based on their seismic signatures, like massive bioherm build-ups or bedded basinal/lagoonal deposits (

Figure 2). Additional, structural features like karst collapse (sinkholes) and displacements (faults) are identified.

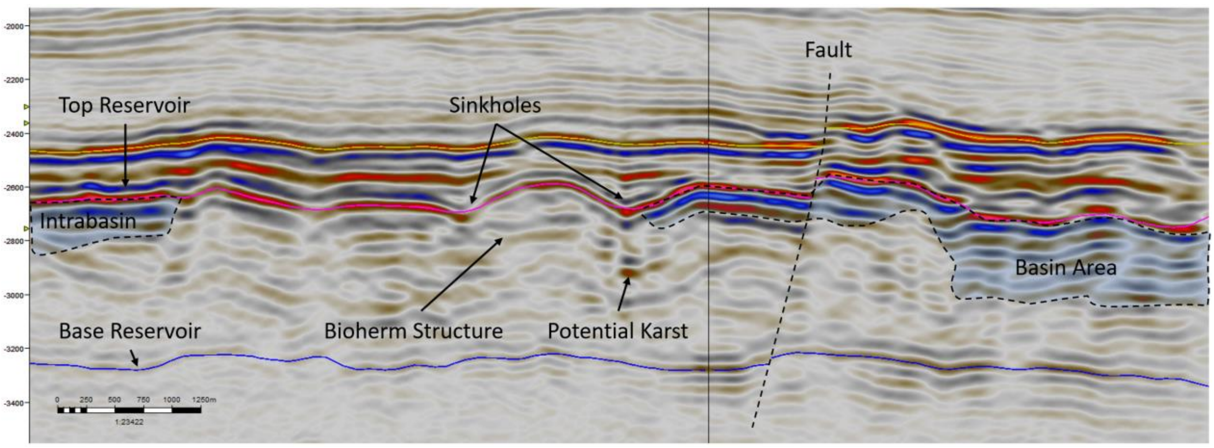

Figure 1: Typical seismic cross-section focussed on the geothermal reservoir section, showing top and base reservoir and identified geological features that impact the reservoir quality.

Reservoir properties appear to be controlled by a complex interplay between primary facies, diagenetic effects such as dolomitization and intense syn- and post depositional karstification (

Figure 2). The hydraulic productivity and the sustainability of heat production from the reservoir is highly dependent on a combination of matrix and karst permeability with strong lateral and vertical variations.

Subsurface information ranging from 1D well data to 3D seismic volumes highlights, how and where karstification may have impacted the reservoir. Global seal level curves as well as local tectonic development of the area link reservoir properties to sequence stratigraphy and will eventually allow for even more successful geothermal exploration in the area.

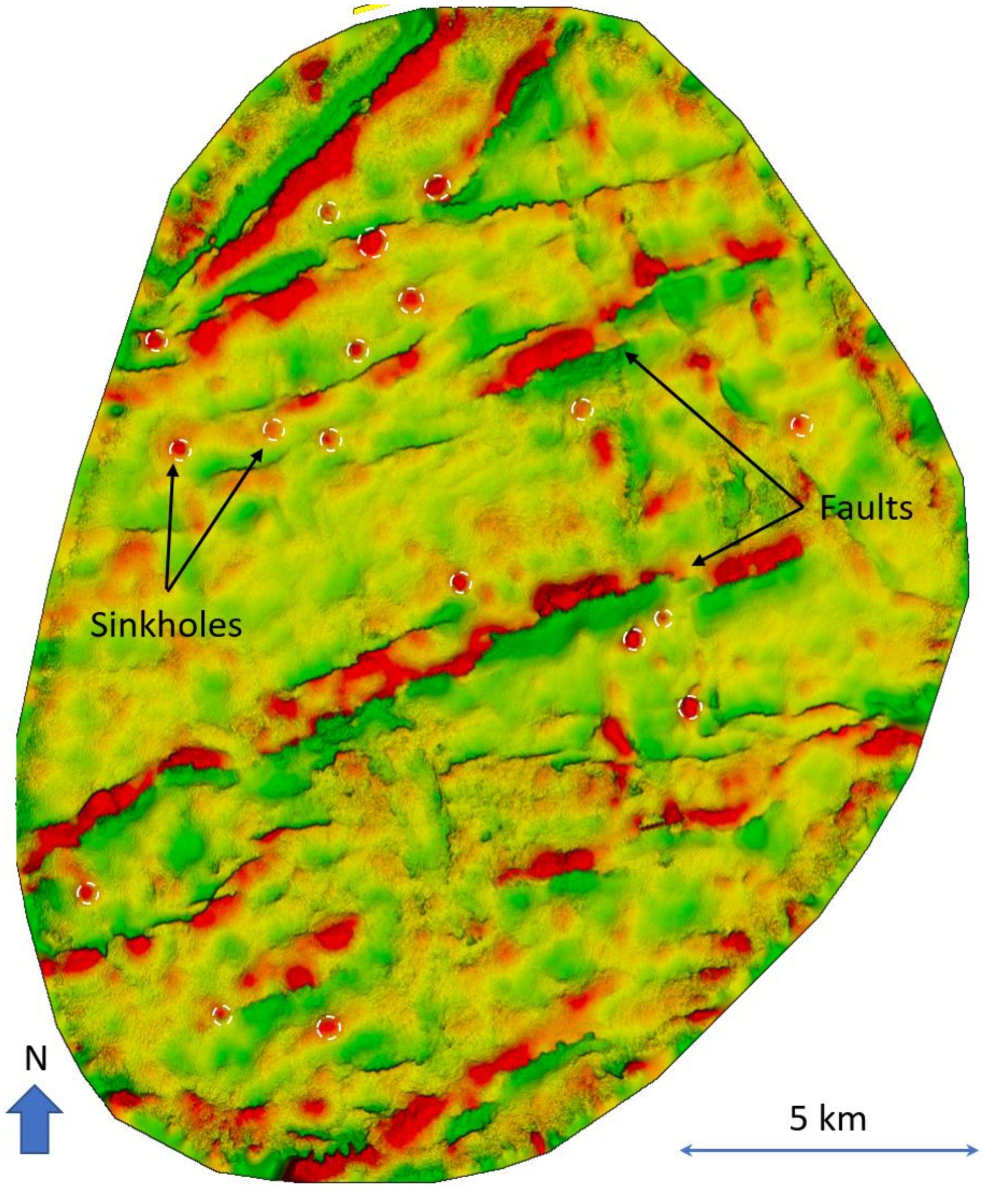

Figure 2: Difference map of smoothed and unsmoothed surface from a reflector above the top of the reservoir. Positive/green and negative/red thickness difference patterns support the mapping of faults and collapse structures like karst features (sinkholes).

Temperature decline at a geothermal production well: Unique insights into a karstified reservoir

Thorsten Hörbrand*[1], Mischa Schweingruber[1], Johannes Linde[1], Alexandros Savvatis[2]
* *hoerbrand.thorsten@swm.de*
[1] SWM Services GmbH, [2] Erdwerk GmbH

Geothermal projects, which are arranged in doublets (one producer and one injector) can offer unique insights into the governing hydraulic regime in the reservoir. We present the case of a project south-east of Munich, where a decline of the production temperature occurred after about 3 years of production. This case is unusual for the aquifer, where the remaining 17 doublets are still producing at the initial production temperature. Some of them with a longer production history. The wells were drilled into the Upper Jurassic carbonate aquifer of the German molasse basin to a depth of > 3500 m TVD. The producer is highly productive with thermal water flow rates exceeding 100 l/s (54,300 bbl/d). In addition to the existing image logs and PTS (pressure-temperature-spinner) logs which were available after drilling, a series of tests were conducted in order to improve the understanding of the geologic features which hydraulically connect the wells. The tests comprise a temperature log, monitoring of the hydrochemical composition and a hydraulic tracer test.

The well-logs show a concentration of inflow zones at the top of the formation of the injection well. Strong indications for karstification can be seen in the image log in that area (e.g. as in Figure 3). At the producer, PTS data are unfortunately not available, but a temperature log has recently been acquired after initial temperature decline. It shows a distinct temperature reduction in a zone of strong karstification. The observed dataset strongly indicates that karstification represents the dominant hydraulic feature. Due to the temperature decline, carbonate dissolution processes occur in the reservoir, which can be monitored in the chemical composition of the produced water. The dissolution processes show, that the (karstified) hi-perm zones in the reservoir are highly dolomitized.

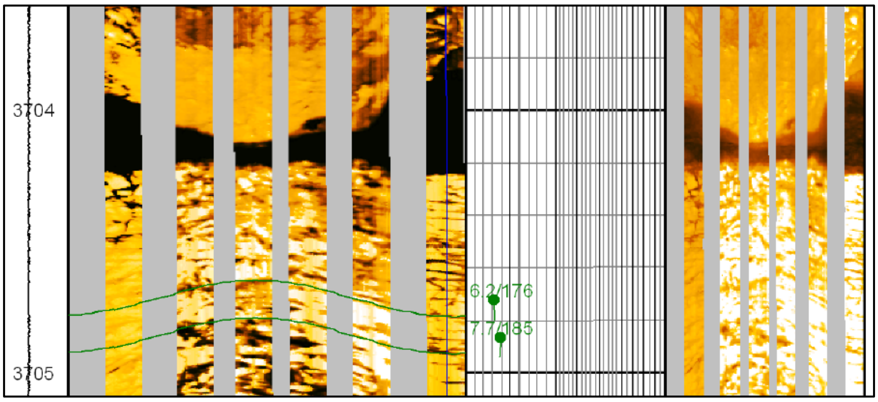

Figure 3: Example for karstification (in black) on an image log of the injection well.

In 2018, prior to the existence of data from the hydraulic tracer test, a first history match was done for the production temperature decline, observed at the producer. This history match is in good agreement with the currently observed wellhead temperatures, but significantly overestimates the tracer breakthrough. Therefore, a new history matching study was conducted, which honors the tracer and temperature data. The combination of these datasets significantly reduced the amount of possible solutions and provides a unique situation for understanding the reservoir architecture. The results indicate the necessity of a complex permeability distribution of the hi-perm (karst) zones in the reservoir and the presence of a significant amount of matrix with reduced permeability.

Development of karstified and naturally fractured carbonate aquifers as geothermal reservoirs

Tim Pharaoh, Corinna Abesser, Tim Kearsey, Darren Jones, Tom Randles and the BGS Geothermal Energy Team
tcp@bgs.ac.uk

The UK government's commitment to net zero CO_2 emissions by 2050 will require enormous changes to the economy and to personal lifestyles. Geothermal energy represents a key technology for the transition to a decarbonised economy and at present, is virtually untapped in the UK. By contrast, in France, The Netherlands, Belgium and Germany, exploration for, and exploitation of, these resources, has become increasingly successful in the last 20 years.

Development of the ultradeep resource for power generation has now commenced in Cornwall (United Downs and Eden projects), exploiting the granite system at >4km depth. Exploration for low-moderate temperature ('low-medium enthalpy') resources, at shallower depth, for example in the sedimentary basins which occupy most of central and southern Britain, has however, been slow to commence. Thick limestones of Mississippian age (359 to 323 Ma) are one such potential deep geothermal resource, widely present at outcrop or concealed within deep basins. When conditions are favourable, Carboniferous limestones may offer greater permeabilities than clastic rocks at comparable depth. Although less predictable than other deep geothermal resources (e.g. granites and basinal Permo-Triassic strata), such limestones are present at depth across many of the UK urban centres and could supply significant energy to district heating schemes.

BGS has started a research programme within its Geothermal Energy Team that will combine data from existing boreholes and geophysical surveys, geological mapping, and field evidence, to improve understanding of the permeability distribution and transmissivity within Carboniferous limestones, and identify areas where more detailed investigations are needed. Although Carboniferous limestones on structural blocks and basin margins are generally hard and compact, with low porosity and permeability and negligible inter-granular flow, the ability of the rocks to transmit water may be significantly increased by processes such as penecontemporaneous karstification ('palaeokarst') (Narayan et al., 2017), evaporite dissolution, dolomitisation, mineralisation, faulting and fracturing. Surface manifestations of hot water at depth are the warm springs at Bath and Bristol, the Taff Valley and the Peak District which issue thermal waters at temperatures between 16-48 ˚C. Understanding and predicting where these processes have occurred is key to unlocking the geothermal potential, and structural interpretation is a major component of this analysis.

An assessment has been made on the spatial distribution, depth, and temperature of the Carboniferous limestone across central and southern Britain, to north and south of the Welsh-Anglo-Brabant Massif, with the Carboniferous limestone ranging in depths from outcrop to 5 km depth. Geothermal gradients of 28.7°C/km and 31.3°C/km respectively, were calculated and temperature maps created (Fig.1) ranging from 50-70°C in platform areas, and reaching over 100°C in basinal areas such as Cheshire Basin. Based on this analysis geothermal "sweet-spots" have been identified to minimise geological risk. Areas in the East Midlands, East Yorkshire/Humberside, Winchester, and Salisbury displaying suitable temperatures (60-80°C) to supply district heating systems. The Cheshire Basin may offer temperature high enough for power generation (100°C), however knowledge of the limestones here is limited. Lower temperatures (40-50°C) in parts of Nottingham and Lincolnshire may offer geothermal heat to horticultural and balneological applications or could provide district heating in combination with heat pumps. BGS has continued this assessment through a basin-scale heat-in-place assessment of the Carboniferous limestone, the results of which shall be presented at this conference.

Even in a country with a subsurface as well-mapped as The Netherlands, subsurface uncertainty has been recognised as a major risk for exploration (Dutch Geothermal Master Plan 2018). Furthermore, the drilling of expensive doublet systems without adequate geophysical prognosis is unthinkable.

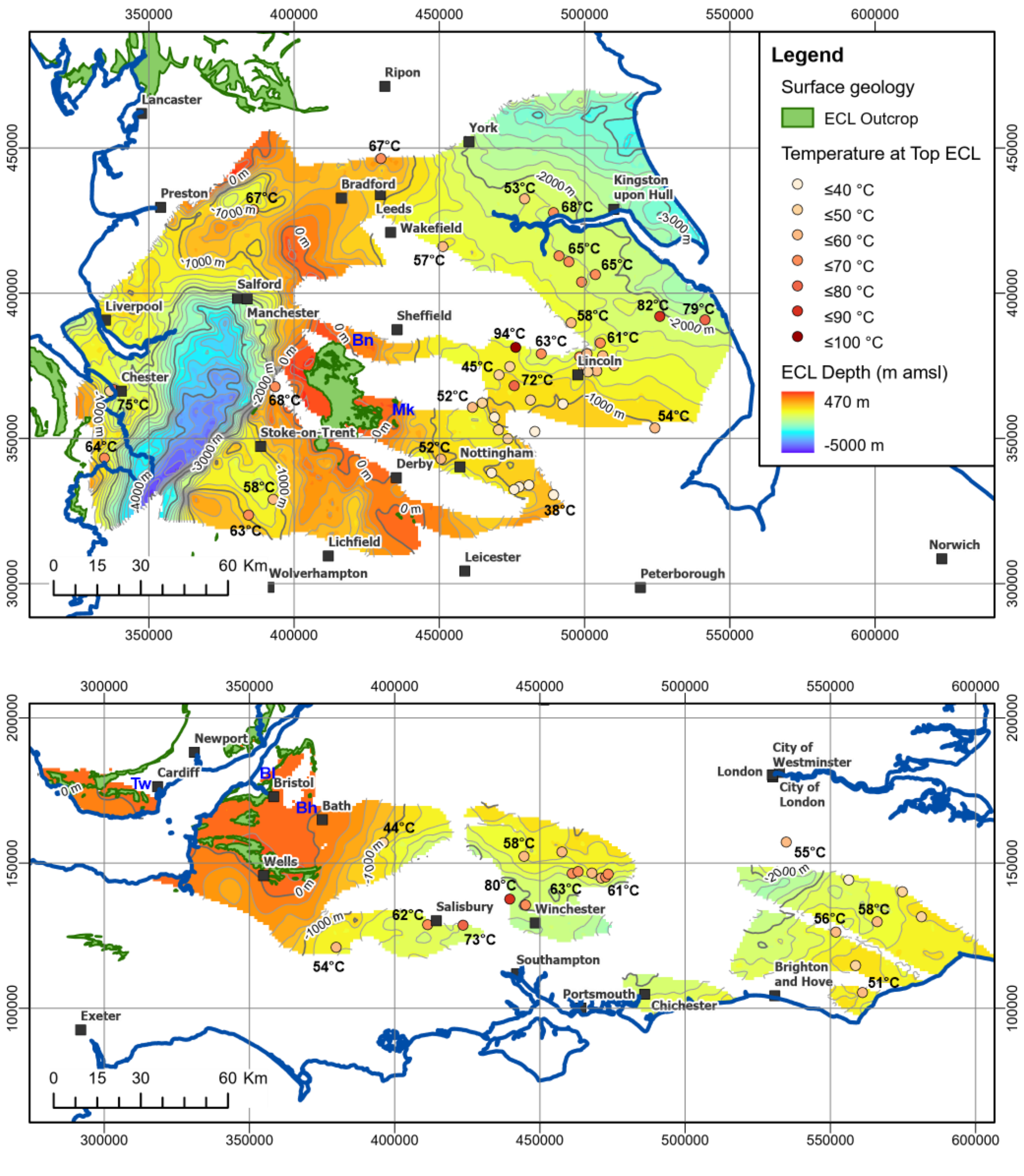

Figure 1. Calculated temperature at the top of the Carboniferous limestone plotted on a map of depth (in metres, relative to mean sea level) in southern Britain. Outcrop of limestones is highlighted in solid green colour.

Closed loop systems using downhole pumps and single well completions may offer a more cost-effective solution, as well as reducing the risk of induced seismicity associated with doublet systems. While the geological and tectonic settings of the UK preclude the presence of near-surface high-temperature resources, a number of low- to moderate-temperature sources have been identified.

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Upscaling of geological properties in a world-class carbonate geothermal system in France: from core scale to 3D regional reservoir dimension

Hadrien Thomas[1*], Benjamin Brigaud[1], Thomas Blaise[1], Elodie Zordan[2], Hermann Zeyen[1], Maxime Catinat[1], Simon Andrieu[3,4], Emmanuel Mouche[5], Elisabeth Rosenberg[6], Marc Fleury[6]

[1]*Université Paris-Saclay, CNRS, GEOPS, 91405 Orsay, France*

[2]*Schlumberger, Digital & Integration, 1 Rue Henri Becquerel, 92140 Clamart, France*

[3]*BRGM, 3 avenue Claude Guillemin, BP 36009, 45060 Orléans, France*

[4]*Department of Geoscience, Aarhus University, Høegh-Guldbergs Gade 2, 8000 Aarhus C, Denmark*

[5]*Université Paris-Saclay, CNRS, CEA, UVSQ, Laboratoire des sciences du climat et de l'environnement, 91191, Gif-sur-Yvette, France*

[6]*IFPEN*

** Corresponding author: hadrien.thomas@universite-paris-saclay.fr*

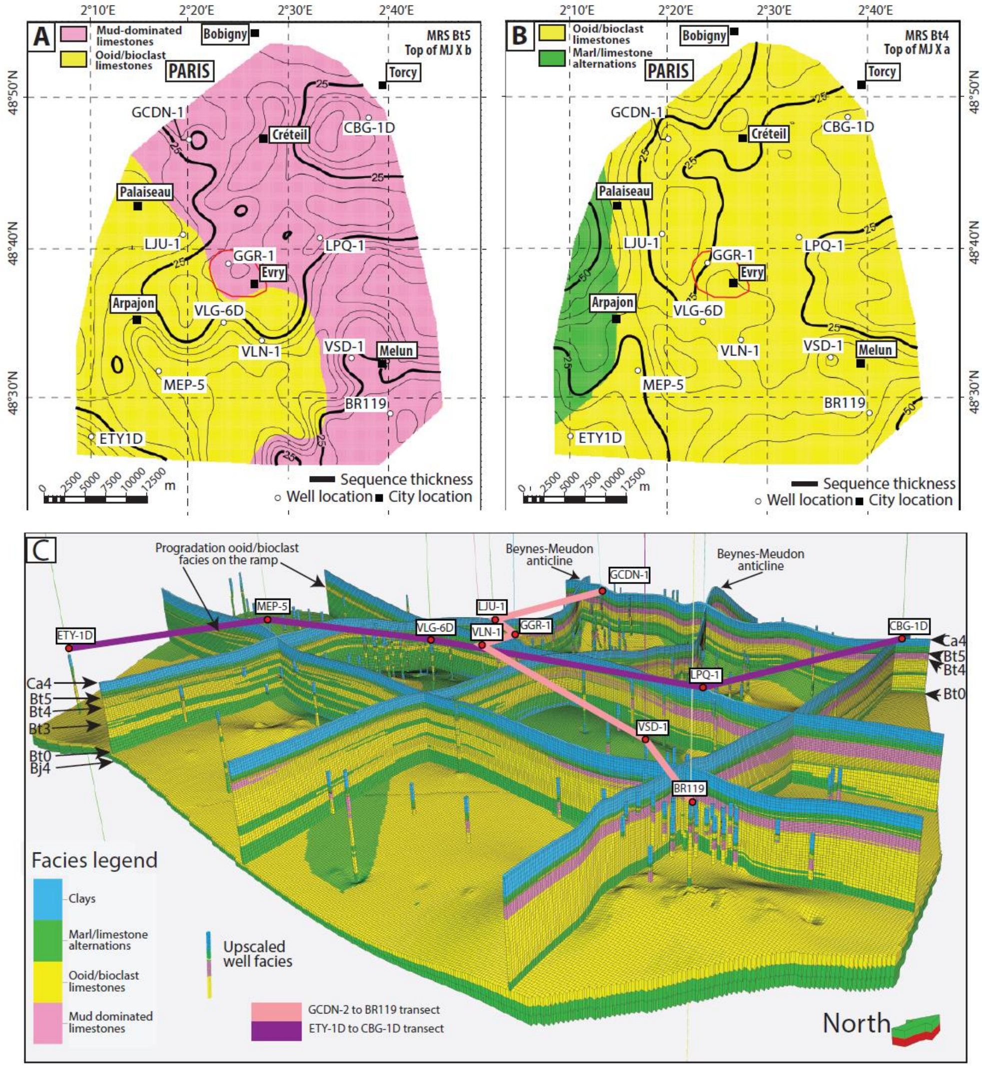

Figure 4 - A- Facies map at the top of Bt5 maximum regressive surface with the thickness (black line) of the sequence MJXb deposits. Isolines every 5 meters. B- Facies map at the top of Bt4 maximum regressive surface with the thickness of sequence MJXa deposits. Isolines every 5 meters. C- View of the entire 3D model with 6 vertical cross-sections showing facies associations architecture. Facies association are upscaled in each well and the 3 cell layers at the bottom of the facies model are also displayed. The red ellipse on Figs. A and B marks the area of the detailed model presented in Fig. 2

With about 12 million inhabitants, the greater Paris area concentrates more than 40 heating network production units, exploiting the heat capacity of a 1.5 km deep aquifer. With about 250 MW of capacity installed, it is one of the most productive aquifers in the world for direct space heating. The current challenge for Paris will be to increase by a factor 3 the geothermal energy to reduce our dependence on fossil fuels for heating networks (40% in 2020 in France). For a better management of this resource in the future, we have created a digital database and a 3D geological model of this aquifer in an area of roughly 2500km^2 (Figure 4) located south of Paris. Using a compilation of data from 166 wells, a high-resolution 3D geological model of 12.2 million cells has been constructed using sedimentary facies, sequence stratigraphy, porosity (ϕ), and permeability (k). About 20% of oolitic and bioclastic facies show good reservoir quality (ϕ > 13% and k > 350 mD), especially in the two targeted sequences MJXa and MJXb (Figure 4). These facies are located into giant dunes in sequence MJXa and into a shoal/barrier in sequence MJXb, prograding from east to west. Variogramme analysis of well information using Petrel software indicates in these facies show permeable zones that forms average patches of 1600 m x 1100 m with thickness of 4 m, elongated and perpendicular to the depositional slope (**Error! Reference source not found.**). This model helps to better apprehend the heterogeneity of the reservoir for geothermal prospection, and to reduce the risk during well implantation of future doublets. Detailed local models may be extracted to better anticipate the implantation of new doublets in areas with already densely spaced existing doublets (**Error! Reference source not found.**).

"Geological characterization of fractured carbonate fields aimed to CO2 storage applications: an example from the Ragusa offshore (Malta Plateau, Eastern Sicily Channel)"

Mariagiada Maiorana*, Attilio Sulli
Department of Earth and Marine Science, University of Palermo, Via Archirafi 20-22, 90123, Palermo, Italy -

Corresponding author: mariagiada.maiorana@unipa.it

Considering the international climate agreement reached during the COP26, which requires a reduction in CO2 emissions of at least 55% by 2050, this study has focused on selected oil fields in the Ragusa offshore, that could be converted into CO2 storage sites. The present study deals with a stratigraphic and structural analysis of previously identified carbonate petroleum systems in the Malta Plateau, located in southeastern Sicily offshore. The area consists of a carbonate platform succession that, following a phase of rifting occurred in the upper Triassic (Rhaetian) due to the Tethyan regional extension, has undergone the formation of a basin with anoxic conditions known as Streppenosa Basin. Consequently, the sediments of the main reservoirs and seals located within that basin and on the structural highs were deposited, forming respectively the Streppenosa/Siracusa and Noto/Buccheri Formations. The platform went through several tectonic phases dominated by numerous left-lateral strike slip and extensional faults which have caused its displacement into an alternation of pull-apart basins and structural highs constituted by biohermal deposits. This work aims to improve the knowledge about the caprock and the reservoir's integrity, fundamental characteristic in the case of conversion of the oil fields into CCUS (Carbon Capture Utilization and Storage) sites. To achieve these goals many multichannel seismic reflection profiles, calibrated with stratigraphic logs from hydrocarbon exploration wells, have been analyzed and the main faults and fractures were modelled in a 3D model using Move 2017 (Midland Valley). After identifying the main horizons delimiting the reservoirs and seals, it was also evaluated the risk of leakage from a possible CO2 injection. This evaluation is fundamental because in case of carbon dioxide leakage along faults and pre-existing fractures, not only the entire project can be put at risk but can be effects on human health and safety and on the marine environment.

Karst in carbonate reservoirs: from seismic to model

Riva, Alberto – Department of Physics and Earth Sciences, University of Ferrara, Italy – email: alberto.riva@unife.it
Pace, Paolo – G.E. Plan Consulting, Petroleum Geosciences, Ferrara, Italy
Ricciato, Angelo –G.E. Plan Consulting, Petroleum Geosciences, Ferrara, Italy
Battara, Enrica –G.E. Plan Consulting, Petroleum Geosciences, Ferrara, Italy

Karst characterization is critical to understand the permeability and connectivity in carbonates: this becomes even more important when we are dealing with hydrocarbon and geothermal reservoirs.

Usually, the first approach for karst characterization in the subsurface comes from 3D seismic analysis, if available.

Seismic quality is then a key factor for extracting and visualizing karst features. The simple interpretation of the horizon representing the top karsted surface allows a first approach to identify karst morphologies, such as sinkholes, channels, hills and pinnacles. A morphometric analysis of the karsted horizon helps to identify the karst type and maturity, but it is biased by the resolution of seismic data, that means at least 20m or more of vertical resolution. Minor features need to be extracted by using detection methods, rather than resolving them. The detection methods should also be used to recognize the subsurface karst, but should be calibrated with well data, in order to avoid interpretations based on artifacts.

The use of other attributes, such as coherence, similarity, etc., tends to limit the capability of resolving minor features, below seismic resolution. The simple use of a single attribute could be misleading, so we developed a multi-attribute workflow, by comparing different maps generated from different seismic attributes. In the presented case, spectral blending, amplitude gradients, dip-steered minimum similarity, spectral amplitude, 3D curvature and dip deviation were combined allowing us to extract geometric features that are then interpreted as karst: the obvious question is if they are real or not.

Moving from seismic to a reservoir model implies a detailed knowledge of karst features recognized in seismic and a proper understanding of their development (paleohydrology, paleoclimate, etc), coupled with the use of outcrop analogues. The problem of using a single seismic-based input is that the features below seismic resolution could be missed: outcrop analogues are in this case extremely helpful to fill the scale gap between wells and seismic.

On the other hand, we should be careful about the scale of the interpreted objects in seismic, that should be verified with geological analogues: the presence of seismic features similar to caves with sizes of several tens of meters could be often (not always) questioned due to their excessive size. A database of karst analogues in the world is the extremely useful in this phase, to compare the morphometry of karst features identified in seismic with real examples.

In this case, we show an example of island karst and how to model it starting from seismic data, and coupling it with outcrop analogues.

Session Three: Modelling and Outcrops

Keynote - Applied carbonate studies in a rapidly-changing industry

Trevor Burchette, Royal Holloway University of London and CRG Ltd
Paul Wright, National Museum of Wales

Trevor Burchette[1] and V. Paul Wright[2]
[1]tpburchette@gmail.com
[2]v.vpw@btopenworld.com

We live in an era of urgent and necessary change to the world's energy supply and it seems likely, although not currently for reasons of dwindling resources, that the present geoscience cohort has witnessed the acme of the petroleum industry. While there is a clear correlation between humanity's use of fossil fuels and global climate change which must be addressed, the petroleum industry is often castigated as the root cause of the problem. In reality, we are all culpable in this state of affairs, simply by existing, consuming and doing the things we do. The petroleum industry has, however, also been a principal driving force in the progress of the geosciences over many decades and has effectively enabled our current society. Without the economic imperative behind the search for hydrocarbon resources, we would still be many decades away from acquiring our present body of geoscience knowledge and much of it would, in all likelihood, simply never have been collected. This is particularly true for carbonate sediments and rocks as these form not only many of the world's largest oil and gas fields, but also offer unique insight into 3+ billion years of physical, chemical and biological processes, essential context for our understanding of present climate change.

A connection between applied carbonate studies, to date most relevant to the petroleum industry, and alternative *subsurface* energy sources or CO_2 mitigation efforts may not appear obvious. However, carbonate rocks play a major role in emerging geothermal energy opportunities around the globe, and shallow low-temperature groundwater systems in carbonates and carbonate petroleum reservoirs are being widely evaluated for this purpose in Europe, North America and beyond. CO_2 injection is the most widely used tertiary EOR mechanism in mature US carbonate reservoirs and is also under trial in several Middle East countries; large reservoirs in carbonate-evaporite systems could also ultimately also be utilised for secure CO_2 storage, particularly as compositional reservoir models are likely to be already available. As in the petroleum industry, both of these subsurface activities require a detailed knowledge of the carbonate reservoir system being utilised. They rely on the same earth-investigation and analytical tools, workflows and understanding developed almost exclusively over many decades by or for the petroleum industry and so this aspect can be seen as an evolutionary, rather than a revolutionary, transition.

Progress over the last 20 or so years in applied carbonate studies has been "steady". One could point to a better understanding of carbonate platform slopes and how fine-grained carbonate sediment is redistributed in deep water, derived largely from studies of modern systems and from seismic interpretation of ancient systems. This is particularly relevant to chalk and hemipelagic facies deposition which has been shown on industry seismic data to be considerably more dynamic than hitherto suspected. The architecture of shallow-water carbonate depositional systems, and the fact that many shallow-water carbonates are deposited as diffuse mosaics rather than linear facies belts have also come into focus as a result of carbonate reservoir studies. New solutions to the age old problem of micrite diagenesis have emerged and the extent of hypogene dissolution of carbonates, increasingly recognised in major carbonate petroleum provinces, has become a "mainstream" concept. And then there are things we had no inkling about 20 years ago, such as mantle CO_2-controlled, hyper-alkaline, lacustrine mega-carbonate systems with complex clay-carbonate interactions of the South Atlantic Pre-Salt.

Static-dynamic reservoir modelling of a carbonate field onshore Italy: tackle challenges from an effective multidisciplinary integration of vintage data

Paolo Pace[1], Raffaele Di Cuia[2], Jon Treen[2], Igor Bagno[3], Mario Pagés[3], Alejandro Primera[3] & Julio Marre[4]
[1]*G.E. Plan Consulting, Petroleum Geosciences, Ferrara, Italy* paolo.pace@geplan.it
[2]*Delta Energy Ltd, London, UK*
[3]*Primera Reservoir Ltd, London, UK*
[4]*Miramar, Oslo, Norway*

Naturally fractured carbonate (NFC) reservoirs typically exhibit a high degree of internal complexity that occurs at a wide range of scales resulting from the interaction of matrix and fracture heterogeneities. Matrix heterogeneity includes a variety of primary depositional textures and diagenetic modification, whereas fracture heterogeneity is dependent on the distribution and characteristics of the fault and fracture (F&F) network. Consequently, NFC reservoirs often have a dual-porosity/dual-permeability flow behaviour, reflecting the interaction of matrix and fracture porosity/permeability systems. For a more realistic assessment of the in-place hydrocarbon reserves and accurate forward prediction of the flow behaviour, both matrix and fracture heterogeneities have to be unravelled carefully and integrated when approaching the static and dynamic modelling of NFC reservoirs. In this contribution, we present how the challenges related to the static and dynamic modelling have been addressed by an effective multidisciplinary integration of vintage data in an old carbonate field onshore southern Italy.

The Benevento oilfield was discovered in the early 1970s and appraised by means of two vertical wells. The structural setting and the play concept are similar to the well-known, prolific Tempa Rossa and Val d'Agri oilfields, which are located along the same trend further SE. The Turonian-Lower Miocene is characterised by tight carbonates, with low matrix porosity (average core porosity φ=1.4%, maximum core porosity φ=9%) and permeability (average core k=1.5 mD, maximum core k=73 mD), and it is considered to be a fractured carbonate reservoir. The Benevento-2 exploration discovery well reached the Lower Cretaceous (Barremian) of the Apulian Platform at a TD of 3278 m SSTVD and tested oil in the Upper Cretaceous. The first exploration well, Benevento-1, stopped (2484 m SSTVD) in the Miocene carbonates without reaching the main Upper Cretaceous reservoir due to technical issues. The Benevento-3 appraisal well tested light oil and gas; then it was put on production after a long-term test for six years. The well produced 1.14 MMbbl of light oil (34° API) under natural flow. The peak rate was 732 bbl/day of oil, 128 bbl/day of water and 18 MMscfd of gas.

Initially, the workflow involved the interpretation, mapping, reconstruction and depth conversion of the structure form the available 2D seismic lines and well data modelled into a structural framework by using also knowledge and insights from surface and subsurface analogues in the region. The structural framework was then used as input the stair-step gridding.

The petrophysical analysis envisaged CPI on the Benevento-2 and 3 wells by using mostly RHOB, DT and GR logs for deriving the effective matrix porosity and geomechanical parameters. This was also combined with the facies and well-log analysis for defining the reservoir zonation. The effective porosity was upscaled to the wells and then stochastically to the entire grid (Figure 1), whereas some of the other rock properties, as the matrix permeability from RCA, were upscaled via co-kriging with porosity. The upscaled porosity derived from CPI showed a good fit with the core plug data.

Petrophysical properties from the fault and fracture (F&F) network, such as fracture porosity (Figure 1) and directional-dependent permeability, were incorporated by developing a multi-scale and multi-scenario DFN modelling. This was carried out after a thorough and reasoned characterisation of the F&Fs by integrating the available data with strain modelling, outcrop analogues. The present-day stress field was derived from literature and active tectonics.

The Benevento field appeared to be quite complex from the point of view of reservoir fluid characterisation. The key challenges were related to high content of carbon dioxide (more than 90%) in the reservoir gas and its super-critical state at reservoir conditions. Also because of an extensive oil column and nature of reservoir fluids, the compositional variation was observed (the oil gravity varied from 45° to 34° API). The cross-sectional reservoir simulation models were built to test and validate the assumptions made with regards to the fluids phase conditions and distribution across the Benevento reservoir.

As the matrix porosity and permeability of Benevento reservoir were low, the transition zone was expected to be extensive. Using the capillary pressure data from analogue Val d'Agri field it was estimated to be as high as 150 meters with the average oil saturations in the matrix of 35%.

The dynamic modelling workflow included the calibration and validation of DFN cases (their concepts and derived properties). The production tests performed in the Benevento-2 and Benevento-3 wells in 1974 and 1976 were simulated using the sector models to validate the DFN model output fracture permeabilities. That helped to make firm conclusions on reservoir configuration and parameters and to predict dynamic behaviour under various development scenarios.

This study showed how the challenges related to the characterisation and modelling of a complex fractured carbonate reservoir of an old oil field have been successfully handled by adopting an alternative and effective multidisciplinary integration of vintage data.

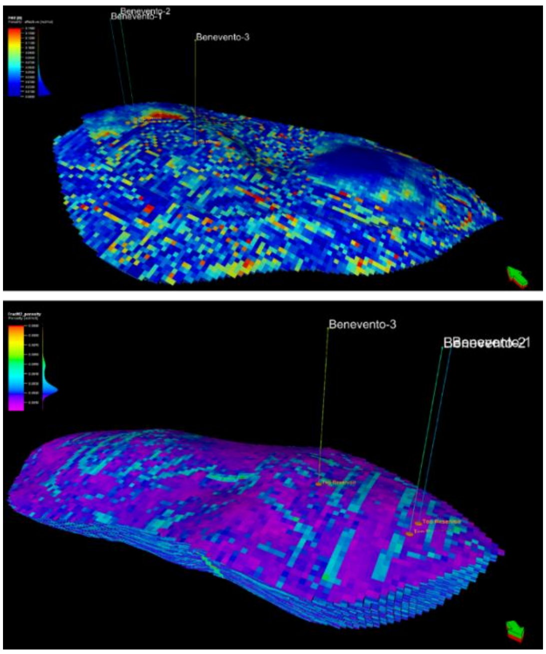

Figure 1. Matrix porosity property upscaled to the reservoir grid (top image); fracture porosity property upscaled from a modelled DFN scenario (bottom image).

Quantifying the modifications of microporosity geometry during burial

Aurelien G. Meyer[1,] Lars Stemmerik[1], Meysam Nourani[2]
1. Natural History Museum of Denmark, Øster Voldgade 5-7, 1350, Copenhagen K, Denmark
2. Geological Survey of Denmark and Greenland, Øster Voldgade 10, 1350, Copenhagen K, Denmark
Meyer-aur@bluewin.ch

Quantifying pore space properties such as pore and throat sizes, aspect ratio and spatial distribution has important implications on fluid flow prediction in hydrocarbon reservoirs or geological carbon storage. Yet these analyses usually require costly instruments as well as long and complex experimental procedures, particularly where microporous lithologies are involved. This study documents the first application of automated mathematical morphology to investigate microporosity from two-dimensional (2D) scanning electron microscope (SEM).

Mathematical morphology consists of modifying the shape of an object such as an individual pore using a circular structuring element (SE) over successive cycles of SE expansion. Each cycle is composed of two operations, namely erosion and dilation. i.e. E-D cycle. During erosion, a layer of pixels corresponding to the SE radius is removed from the object whilst dilation adds a layer of pixels of the same thickness around the remaining object. Critically, erosion removes all features in which the SE does not fit, resulting in an increasingly globular object until its complete removal during a final cycle. Morphology subdivides image porosity into two components, namely rough and smooth porosity The “smooth” component of a pore corresponds to the single largest inscribed SE in each pore and represents the pore body. Rough porosity includes all pore elements around the largest inscribed SE (i.e. SP) such as branches, corners and throats. The entire procedure of image segmentation, erosion-dilation and porosity analysis was implemented in the programming language R and could be ran overnight over hundreds of SEM images (running time ~3 min. / image).

For this study, microporous chalk samples (n = 105) were collected from quarries and offshore hydrocarbon reservoirs. Six chalk lithotypes (L) are defined based on their mineralogical composition, clay and silica content as well as the average size of chalk particles (GS). The latter is used as a proxy for the diagenetic overprint, while the burial-diagenetic model offers a framework for the different lithotypes and their respective pore space properties.

The diagenetic evolution of microporous limestones during burial has previously been established and can be summarized as follows: (1) ooze deposition and dewatering (burial < 300 m), (2) lithification via mechanical compaction and grain-bridging cementation (300–1000 m), (3) complete cementation due to pressure solution, or texture preservation thanks to pore fluid overpressure and oil invasion (> 1000 m). Moreover, particles tend to increase in size as a result of diagenesis, i.e. recrystallization or cementation.

Image analysis quantifies the evolution of microporosity during burial. During shallow to intermediate burial (< 1000 m), the effect of mineralogy on pore topology appears more dramatic than after further burial. From the same outcrop previously buried to ca. 700 m, pure chalk yields total porosity of 45–50%, greater than clay-rich chalk (35–40%). Moreover, pore (PBD) and throat (PTD) dimensions are on average significantly greater in pure chalk (4.15 and 0.73 μm, respectively) than in clay-rich chalk (2.85 and 0.28 μm, respectively).

Interestingly, particles in both lithologies share many similarities, including their size (GS = 1.3 μm) and shapes, resulting in a mudstone texture. This suggests that compaction rather than calcite cementation explains the difference in porosity properties.

At greater burial depths (> 1000 m), the lithostatic pressure becomes high enough to trigger pressure solution, particularly where clay minerals are present. Cementation becomes pervasive and produces compact limestones characterised by large clusters of coalescent calcite crystals (3–10 μm; mean = 5.13 μm). Total porosity is strongly reduced as a result (6–11%) while pore body and throat dimensions drop to 1.58 and 0.03 μm, respectively. A high aspect ratio (88.1) and lower proportion of rough porosity relative to total image porosity suggest that throats are proportionally more affected than pore bodies. Cementation leads to less dendritic, more globular and isolated pores. Where processes such as overpressure and oil charge have helped preserve porosity during deep burial (20–30%), pore and throat dimensions were locked to moderately high values (> 2.0 and 0.1 μm, respectively), even in silica- and clay-rich chalk. These measurements demonstrate that the pore network of microporous limestones changes in size and connectedness as a result of diagenesis and mineralogical composition. Clay content, calcite and silica cementation, and compaction work together to reduce the size of pore elements. Image analysis provides an insight into the relations between grain size, diagenesis and pore network architecture.

Moreover, this study proposes an possible application of mathematical morphology. The pore aspect ratio (AR) influences single phase flow through porosity since Poiseuille-type laminar flow dominates in tubular capillaries whilst turbulent flow occurs in conical conduits under a wider range of pressure. The AR also plays a critical role in controlling the sweep efficiency in multi-phase flow systems by influencing the occurrence of the snap-off phenomenon. Because of the technical difficulty to measure this parameter on real rocks, its effects on single and multi-phase fluid flow through microporous rocks are unknown. This study documents the first application of image analysis to estimate a mean pore-to-throat AR via the PBD/PTD proxy. Further work should aim at establishing a link between image-based AR and fluid flow properties at the pore-scale by performing laboratory flow simulations on core samples from which the latter has been previously estimated. Not only can mathematical morphology quantify pore space properties that are fundamental in pore network and flow modelling, but by being applicable on large datasets at low costs, it could be included in any geological or petrophysical study.

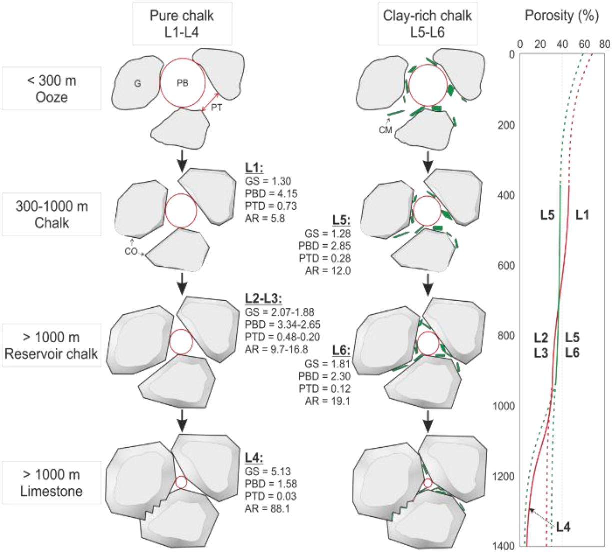

Figure 5: after Meyer et al. 2019, Modifications of chalk microporosity geometry during burial – An application of mathematical morphology, in *Marine and Petr. Geol*. 212-224

Petrophysical Understanding of The Pores System And Reservoir Connectivity Of Mishrif Carbonate In South Iraq For Permeability Prediction By Combining Fzi With Nmr

Ibrahim B. Milad; Russell Farmer and Milad Saidian (BP)

The Rumaila field is in South East Iraq contains multiple reservoir intervals, including the Upper Cretaceous Mishrif carbonate reservoir, one of the major reservoirs in the world, that has been producing at considerable oil rates for more than 50 years. With billions of barrels yet to be recovered it is expected to play a significant role in sustaining Rumaila production for decades. Reservoir pressure has dropped due to historical production and, therefore, large scale water injection is planned to support and enhance future production rates and oil recovery.

One of the key subsurface challenges in carbonate reservoirs is to understand the geological setting and characterise reservoir complexity and heterogeneity, with permeability being one of the key factors in understanding sweep behavior and predicting production and injection rates. Rumaila has extensive surveillance programs and production and saturation logs in particular are used to refine static and dynamic models and to better characterise individual well performance. With more than 1,000 well penetrations to date, efficient management of wells is key to optimising production.

It was recognized several years ago that the available log and core datasets at that time did not enable a fully characterised model of the pore system, resulting in a large uncertainty in the permeability model. As a result, four new wells were cored, and advanced modern logs acquired to expand the datasets to support a rebuilding of rock typing and permeability models to better understand pore system distributions and the extent and impact of heterogeneity in the Mishrif reservoir.

This paper presents a workflow that utilises NMR logs, NMR core analysis and FZI techniques to predict permeability. The approach is focussed on distinguishing between different pore types by estimating the relative proportion of large pores (Large Pores Index - LPI) from NMR data and using this as an input to enhance the prediction of FZI rock types and subsequently the prediction of permeability. The results show a significant improvement in permeability estimates compared to more traditional approaches.

The improvement in permeability prediction has been reflected in better predictions of production and injection indexes, improved understanding of sweep behaviour and the prediction of timing for water breakthrough, leading to more optimal management of reservoir performance. Moreover, at the well level, the new model has resulted in enhanced completion decisions for newly drilled wells, as well as ongoing well-work operations (additional perforation and re-perforation campaigns) on existing producers and injectors.

Scale-Free Distribution of the Carbonate Pore System: An Example from San Salvador Island, Bahamas using Multidisciplinary Data

Paul J. Moore[1,2], Fermin Fernandez-Ibanez[2], Charles I. Breithaupt[2], Eric M. Bunge[2], Shawn M. Fullmer[2], Michelle Dafov[3], and William C. Reese[2]
[1]ExxonMobil Research Qatar, Doha, Qatar, [2]ExxonMobil Upstream Research Company, Spring, Texas, USA, ExxonMobil Upstream Oil & Gas Company, Spring, Texas, USA
Contact e-mail: pj.moore@exxonmobil.com

Numerous studies have evaluated size-frequency relationships in geologic applications including lakes (e.g., Downing et al, 2006, Cael and Seekell, 2016), mineral deposits (Shen, 2011), earthquakes (Steacy and McCloskey, 1999), moon craters (Newman, 2005), and fractures (Ross, 1986; Marrett et al., 1999). Over the past few decades, considerable attention has been given to quantify the size-frequency distribution of the carbonate pore system across multiple scales from evaluating mm-to-cm pore size distributions in reservoirs and aquifers (e.g., Anselmetti et al., 1998; Buono et al., 2019; Masuoka and Nakaya, 2021) to m-scale distributions of sinkholes and caves across various landscapes (e.g., Galve et al., 2011; Yizhaq et al., 2017; Pardo-Igúzquiza et al., 2015; 2020). Such research efforts have demonstrated how carbonate pores commonly follow a power-law distribution over some defined scale of observation. Consequently, power-law distributions in these systems suggests that self-similar processes are likely driving carbonate pore evolution across multiple scales, and thus should be independent of the scale of observation (Mandelbrot, 1982).

For the first time to our knowledge, we show the size-frequency distribution from a single carbonate pore system that captures features ranging from 100s of microns to 100s of meter in size, resulting in a distribution of pore sizes that span over 9 orders of magnitude. Using a multidisciplinary dataset from San Salvador Island, Bahamas, data were collected from 103 high resolution scans (<1 micron/pixel) of thin sections (25 mm diameter) from core, acoustic borehole images from the walls of six vertical wells (73 mm diameter), and a bare earth digital elevation model (DEM) derived from airborne Light Detection and Ranging (LiDAR) remote sensing over all of San Salvador Island (~95 km^2). We analyzed pores from thin sections using the Quantitative Digital Petrography (QDP) approach of Buono et al. (2019) (Figure 1). Borehole enlargements related to open pores such as vugs and caves were quantified using the transit time of the reflected acoustic signal, which generates a travel-time image of the borehole wall that can be used to extract open features at the cm-m scale (Figure 2). We utilized the LiDAR DEM (0.2 meter horizontal resolution; vertical resolution of 5-15 cm depending on the beam angle) to quantify karst depressions at the m-scale. The size of select karst depressions were surveyed via field excursions to validate the depression size observed from LiDAR. We quantified depression metrics using a pattern recognition algorithm adapted from Jasiewicz and Stepinski (2013), which defines landforms known as "geomorphons" and extracts morphometrics within polygon enclosures (Figure 3).

We statistically analyzed the pore areas extracted from these datasets to find the optimal x_{min} value by selecting the one that results in the minimal Kolmogorov-Smirnov distance to obtain a best power-law fit. In heavy-tailed distributions the small values of the data typically do not follow a power-law distribution due to truncation bias. Conversely, large data points that fall off the power-law distribution are likely the result of a censoring effect that is most pronounced on the LiDAR data (Figure 3C). Consequently, any data above x_{max} and below x_{min} are ignored for fitting purposes. Honoring a minimal Kolmogov-Smirnov distance, we obtained power-laws that fit the datasets over 1.2, 1.5, and 2.5 orders of magnitude for the pore sizes extracted from thin section data, borehole images, and LiDAR, respectively (Figures 1C, 2C, and 3C).

Results show that the thin section and LiDAR derived pore areas share a common fractal dimension – i.e., slope = 2.3 (Figures 1C and 3C). This agreement suggests that the area, and likely the volume, of pores represent a single fractal, resulting from a self-similar system that is independent of the scale of observation. In contrast, the size-frequency distribution of the pores evaluated from image logs yields a power-law fit with a slope of 2.1 (Figure 2C). Although the pores observed at the borehole scale are likely part of the same self-similar system, we believe the difference in slope likely results from challenges associated with accurately quantifying pore areas in the borehole. Such challenges include: (1) variability in data acquisition conditions; (2) uncertainty on adequate travel-time threshold; and (3) accuracy of pore area. In addition, borehole wall integrity is highly variable between wells and its roughness can impact the ability to detect smaller scaler features from travel-time only, which will shift the power-law slope to a lower value. For these reasons, we found that the acoustic image may not be an optimal dataset to test fractal dimension at the borehole scale. Consequently, we are currently evaluating different quantification techniques at the borehole scale using whole core, such as deriving pore areas from high resolution digital images of a slabbed core face and whole core computed tomography.

Although additional work remains to resolve the pore size distribution at the borehole scale, our findings show a fractal scaling across two extreme scale datasets (thin sections and LiDAR) that span over 9 orders of magnitude in pore size from the same carbonate system, which to our knowledge has never been reported before. Such fractal scaling can be used to more accurately predict the distribution and abundance of pores in reservoirs and aquifers, which is necessary for modeling and managing groundwater resources, hydrocarbon reservoirs, and carbon capture.

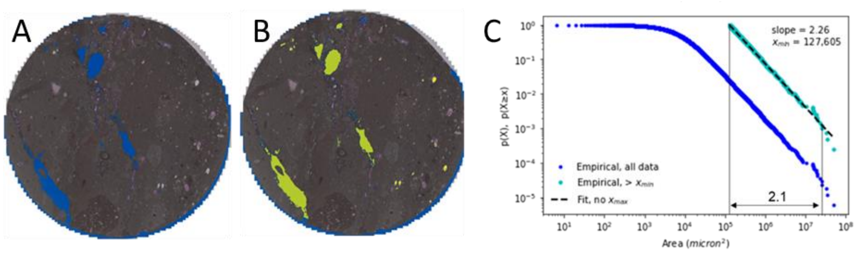

Figure 1. Size distribution of pores from thin section. A) High resolution image of thin section (25 mm diameter). B) Image showing quantified pore space (yellow). C) Cumulative frequency distribution of all pore areas for all thin sections and size frequency distribution of pore areas greater than x_{min} with power-law fit resulting from minimum Kolmogov-Smirnov distance.

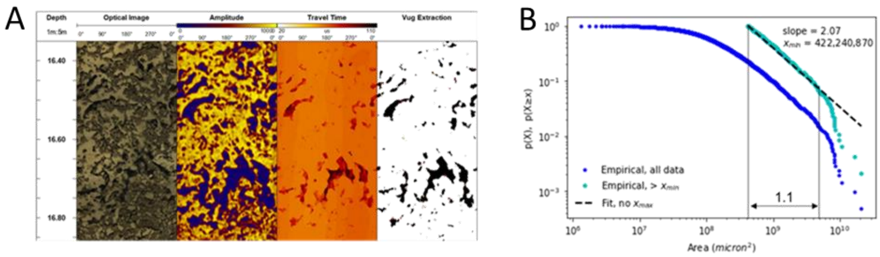

Figure 2. Size distribution of pores from borehole. A) Borehole images, from left to right, optical, amplitude, travel time, pore extraction. B) Cumulative frequency distribution of all pore areas for all boreholes and size frequency distribution of pore areas greater than x_{min} with power-law fit resulting from minimum Kolmogov-Smirnov distance.

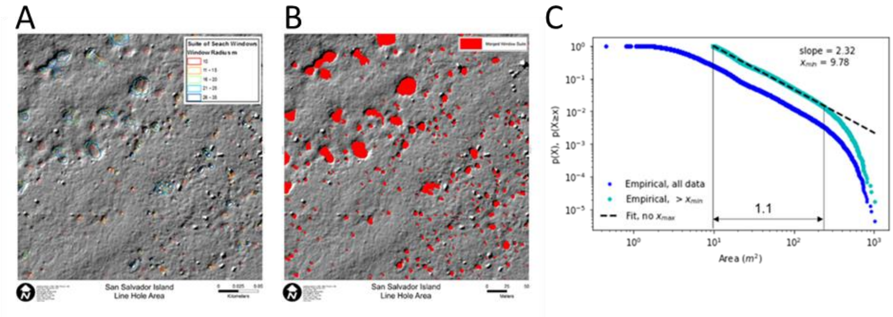

Figure 3. Size distribution of depressions from LiDAR. A) Digital elevation model of a 3x3 km area outlining geomorphon area for different search windows. B) Suit of geomporphs – i.e. depressions; C) Cumulative frequency distribution of all depression areas for the entire San Salvador Island (blue) and size frequency distribution of sinkhole areas greater than x_{min} with power-law fit resulting from minimum

A new numerical method for modelling sedimentary facies coupled with geobodies distributions: the case of the lacustrine carbonates and microbialites of the Yacoraite formation (Salta, Argentina)

Vanessa Teles[1], Youri Hamon[1], Rémy Deschamps[1], Sébastien Rohais[1], Fadi H. Nader[1]
[1]IFP Energies nouvelles, 1 et 4 avenue de Bois-Préau, 92852 Rueil-Malmaison, France – Email : vanessa.teles@ifpen.fr

Carbonate reservoir heterogeneity is controlled by several inter-related factors. From sedimentary environments, specific and local carbonate factories, diagenetic evolution to potential fractures, numerous parameters influence the spatial distribution of the present-day petrophysical parameters. Numerical modelling should be built based upon both observed local data and geological interpretation or knowledge in order to realistically represent complex heterogeneity.

The Yacoraite Formation, located in the Salta basin (Argentina), is a lacustrine microbialite-bearing formation. Four major sedimentary facies associations and depositional environments interpreted in the studied area : i) sandflat to mudflat on either deltaic or paleo-high marginal areas; ii) carbonates in shore environments; iii) carbonates in offshore setting; and iv) anoxic facies in deeper offshore settings. In addition, a high diversity of microbialites forms were observed: planar mats, isolated to coalescent domal stromatolites, high-energy agglutinated stromatolites, domal thrombolites and planar thrombolites. Some of these microbial structures span laterally over several hundreds of meters to a few meters adding heterogeneity to the reservoir. It should be noted that each microbialite facies is not associated with a single sedimentary facies. Along with basin-scale field observations, seventeen detailed sedimentary sections with a vertical resolution of 10 cm were described in terms of sedimentary facies on one hand and microbialite forms on the other.

Based on these data, an innovative numerical approach was carried out in order to simulate microbialite facies in parallel with sedimentary facies in a 3D reservoir-scale (8.5 x 5 km^2) geological model with a grid cell resolution of 100x100 m^2 horizontally and 10 cm in the vertical direction. The applied bi-variate plurigaussian method is able to simulate two distinct discrete or categorical variables, here sedimentary facies and microbialite facies. Each variable is simulated by a complete plurigaussian method whose parameters are defined based on: i) expected spatial continuity of each facies; ii) spatial organization of the different facies inferred from the interpreted depositional environments; and iii) the vertical proportions of facies observed in the dataset. The bi-variate plurigaussian method couples the two complete plurigaussian method taking into account the quantified occurrence of the latter within the first.

The resulting geological numerical model is constrained by the section/well data, and then compared to the geological model, and finally validated with the field observations both for the sedimentary facies distribution and for the microbialite facies distribution. The bi-variate plurigaussian method provides also an integrative representation of the two distributions by means of “mixed facies” (Figure 1), an association of microbialite and sedimentary facies. The latter allows to visualize both distributions and gives a one-glance representation of the reservoir heterogeneity which would constrain the petrophysical parameter distribution.

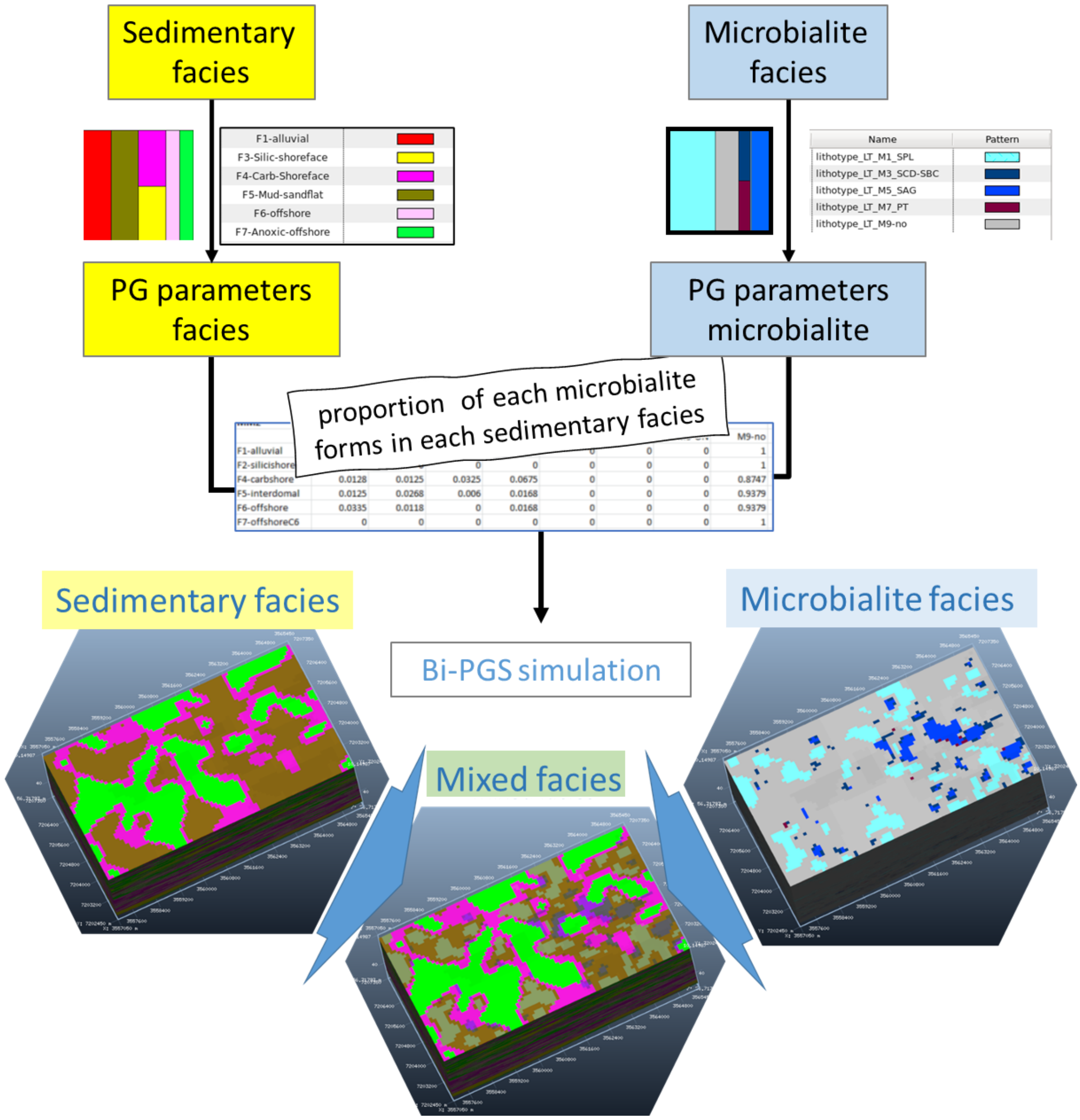

Figure 1: Top part: illustration of the applied bi-variate plurigaussian method;

bottom part: 3D simulated reservoir-scale model grid showing distributions of sedimentary facies, microbialite facies and their association in a “mixed facies” representation.

3D geological modeling of outcropping carbonate platforms in the Dolomites: how useful are they?

Riva, Alberto – *Department of Physics and Earth Sciences, University of Ferrara, Italy* – email: *alberto.riva@unife.it*
Piero Gianolla – *Department of Physics and Earth Sciences, University of Ferrara, Italy*
Marcello Caggiati – *Department of Physics and Earth Sciences, University of Ferrara, Italy*

The Dolomites region (northern Italy) is considered one of the best areas where to observe and to study isolated Triassic carbonate platforms with outstanding exposures at reservoir scale. Preserved depositional geometires and the availability of an accurate sequence stratigraphic framework allows us to understand properly the development of these platforms through time and space.

In this study we analyze two 3D geological models built on the Anisian-Ladinian Sciliar/Schlern platform and the Ladinian-Carnian Sella platform. Both models were developed using state-of-the-art geological modelling software, after a detailed geological mapping using DGPS.

The Sciliar/Schlern Carbonate Platform shows a slightly arcuate margin facing a deep basin, where potential source rocks sedimented. In this model, we examine the interaction of the platform with the basin within three 3rd order-depositional sequences, in order to recognize and depict the aggrading and prograding geometries and the facies distribution.

The Sella platform is interesting for showing progradational geometries over a mixed clastic/carbonates basin starting from a pre-existing topographic high. Present-day facies variability is relatively low, due to relatively early dolomitization. However, an interesting aspect of this platform is that it allows a detailed fracture modeling at different scales, including not only the massive slope carbonates of Ladinian-Carnian age, but also the younger well bedded Dolomia Principale. In particular it gives the opportunity to test how we develop fracture models in the subsurface, comparing them to a reservoir-scale example. More generally, 3D modeling of outcropping platforms could be extremely useful as the models were developed with the same techniques used for characterization of subsurface reservoirs, allowing us to understand how to improve the subsurface modeling workflow.

Session Four: Oil&Gas

Keynote - Multiscale/multidisciplinary data driven reservoir characterization of a fractured carbonate field in Kurdistan.

Claire Sena, DNO ASA

C. M. Sena, M. Musial, G. Tischler, E. Funk, K. Canner, A. Barliansyah K. B. Mitchell, A. Nozari, S. Quental.
DNO ASA, Dokkveien 1, N-0250 Oslo Norway. Claire.sena@dno.no

The combination of traditional subsurface interpretation techniques with advanced data analytics is a key stepping stone for better predicting reservoir quality specially in heterogeneous and complex geological systems. The Peshkabir oil and gas field, located under the Peshkabir mountain in the north of the Kurdistan Region of Iraq (KRI) and within the Tawke PSC (figure 1), is one of such heterogeneous systems. Its initial well oil rates vary significantly and cannot be simply correlated to varying fracture intensities measured at the wells. Understanding which fractures matter and what influences reservoir deliverability is a question of major importance for maximizing oil production.

The Peshkabir structure is a fault-propagation fold, narrow and elongated (2.5 km wide and 16.5 km long), interpreted to have formed by far field compression resulting in the inversion of East-West oriented, south-dipping normal faults with a potential detachment at Cambrian level that decouples the sedimentary cover from the crystalline basement. The Peshkabir petroleum system consist of a Lower Jurassic to Maastrichian carbonate platform, which contain both the source rock and the reservoir interval. The produced oils are sourced from the Callovian – Lower Kimmeridgian Naokelekan Formation deposited in an anoxic reducing depositional environment dominated by a carbonate lithology. The carbonate reservoirs include karstified vuggy zones, hydrothermal dolomite in addition to an extensively developed fractured network (figure 2).

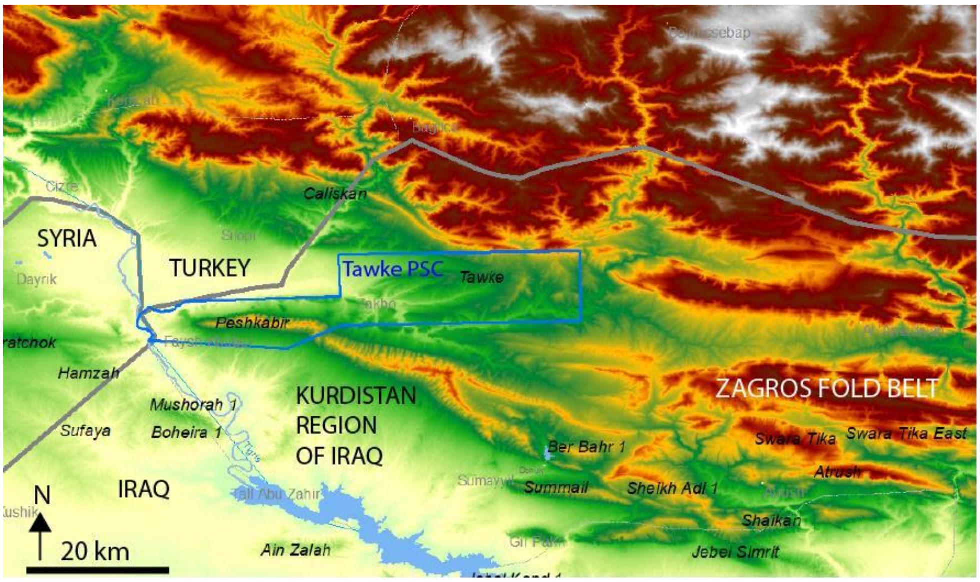

__Figure 1__ Location of the Peshkabir field. Elevation, field names from IHS in italic, and the outline of the Tawke PSC are shown.

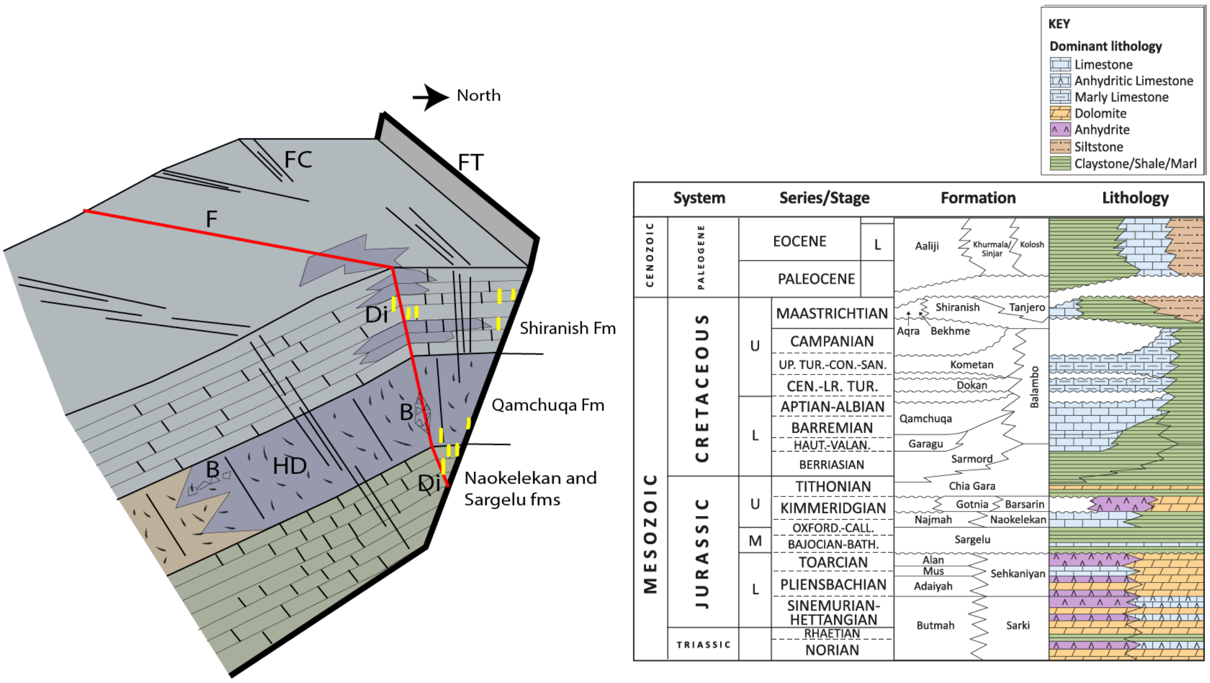

Figure 2 *Geological conceptual model of the Peshkabir field highlighting the geological processes that influence reservoir deliverability. FT – Frontal thrust, F – Generic Fault that can have a normal or reverse throw, FC – Fracture corridor, HD – Hydrothermal dolomite, Di – Solution enlarged fractures, B – Breccias. Stratigraphy modified from English et al. 2015.*

This paper presents a geological conceptual model for the Peshkabir field and an application of python-based data science techniques to identify key predictors for reservoir deliverability from drilling, logging and production data. We demonstrate that the major advantage of the application of advanced data analytics to heterogeneous fields is that it can enable the recognition of patterns and associations in a complex, high-dimensional parameter environment whereas traditional interpretation methods typically only allow for the comparison of two or three parameters at a time. This method allows to integrate dynamic and static data effectively and empowers the interpreter to incorporate all the available insights which coupled with domain knowledge allows for true data- driven decision making.

We acknowledge DNO ASA, Genel Energy and the Ministry of Natural Resources of the Kurdistan Regional Government for continued support and permission to publish this abstract.

High K layer in the R1 Inferior reservoir and its impact on gas souring in the Miskar Field, offshore Tunisia

Haifa KHALDI[1], Andrew BARNETT[2] and Paul WRIGHT[3]
[1]Shell Tunisia Upstream, [2]Shell Centre, London, [3]PW Carbonate Geoscience

The identification and mapping of potential reservoir issues based on sedimentology at an early stage in reservoir development can prove critical when problems arise later in the management of a field. In this case, potential thief zones were mapped in the late 1990's even though no water injection was planned but having such documentation proved critical when, 10 years later, gas souring problems could be rapidly addressed. Non-hydrocarbon gases pose a serious risk to technical and economic feasibility of hydrocarbon development projects in the Gabes Basin, offshore Tunisia, such as the Miskar Field. Whereas N_2 mainly impacts in place and recoverable hydrocarbon volumes, CO_2 is increasingly seen as an environmentally destructive gas and high H_2S concentrations are a safety hazard. Additionally, there are limitations on the concentration of H_2S that the Miskar pipeline can handle for gas transport to shore. Consequently, understanding the origin and distribution of the High K (> 1 Darcy) layers in the R1 reservoir is critical to identify preferential pathways for gas migration and resulting gas souring. A sampling program is in place to record the level of H_2S on a well-by-well basis and assess the origin of H_2S at the specific well location. H_2S well monitoring started in June 2009 and confirmed the occurrence of H_2S migration from the terrace sour gas area to the core sweet gas area as shown in the Figure 1 below.

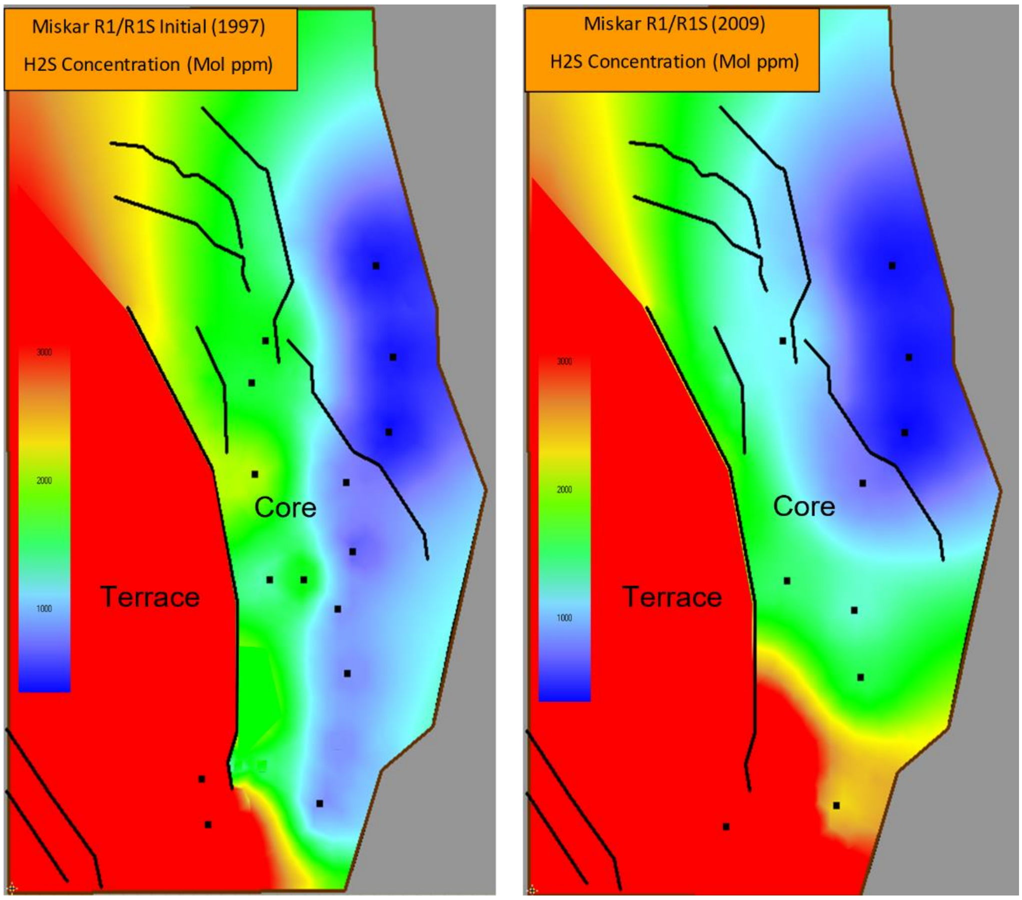

Figure 1. Miskar Field H_2S concentrations over time.

The Late Cretaceous (Coniacian-Turonian) R1 Superior and Inferior reservoirs form an interval *ca*. 95 m thick within Miskar Field. The lower R1 Inferior comprises a homogenous, upward shallowing succession (*ca*. 20 m thick) of shoreface to foreshore carbonates. This passes upwards into a highly heterogeneous backshoal, lagoonal-peritidal succession (*ca*.13 m thick) which straddles the R1 Inferior/Superior boundary (Figure 2). The conformably overlying R1 Superior comprises a package of highly layered, cyclic outer to inner ramp deposits (*ca*. 60 m thick).

Reservoir quality is good throughout much of the R1 and is mainly facies (grain-size) controlled. Petrophysical properties within the R1 Inferior are, in general, much better than in the R1 Superior. Porosity ranges from 12 to 25 % and permeability from 5 mD to 8 D. Gas souring is controlled by a high permeability streak which corresponds to bioclastic rudstones which developed as rudist-dominated gravels deposited at the shoreface-foreshore interface (Figure 2 and 3). Identifying this thin interval in un-cored wells and predicting its lateral continuity is essential to minimize the impact of gas souring on field development.

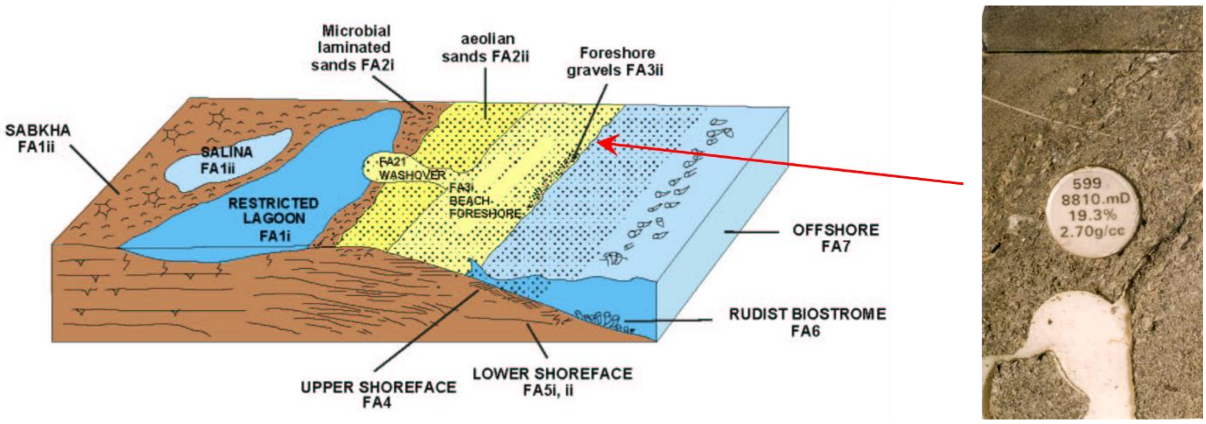

Figure 2. Depositional model for the R1 Inferior and lowermost R1 Superior reservoir of Miskar Field.

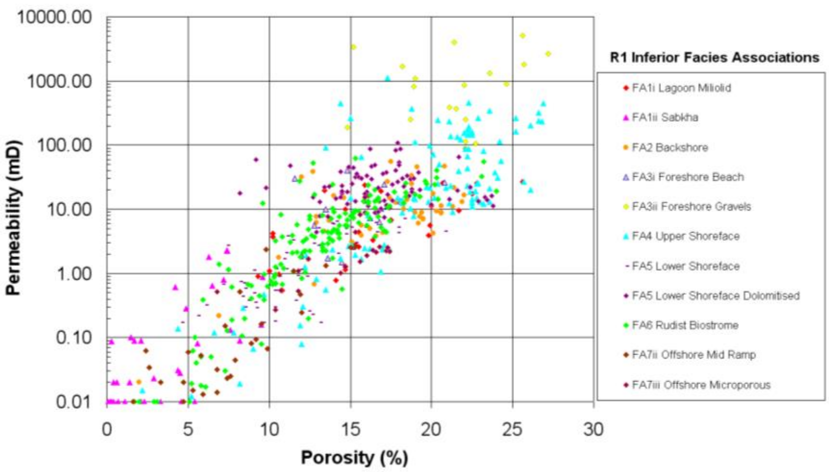

Figure 3. Core plug porosity vs. permeability cross-plot for the R1 Inferior and lowermost R1 Superior reservoir of Miskar Field.

Reservoir Characterization and Fluid Recovery in Carbonate Mudrocks – Integrating Multi-scale Geology and Engineering to Enhance Recovery

J. Frederick Sarg, D. Jobe, A. Franklin, H. Kazemi, M. Alsuwaidi, and W. Alameri
Dept. of Geology & Geol. Engineering & Dept. of Petroleum Engineering
Colorado School of Mines, Golden, Colorado 80401 USA
jsarg@mines.edu

The majority of carbonate reservoir rocks have been developed using conventional development schemes, owing to the presence of macropores that are the product of depositional textures modified by diagenesis. Carbonate reservoir heterogeneity is complex, due to ternary porosity distributions composed of matrix, vugs, and fractures. Recently, matrix-related microporosity has been recognized as an important control on storage capacity and hydraulic conductivity of hydrocarbons. With the advancement of completion technologies for low-permeability reservoirs, quantifying the matrix-related microporosity, understanding pore size and pore throat distributions has become increasingly important. Matrix porosity contribution is often overshadowed by the relative contribution from vugs and fractures, yet it is the matrix pore network that effectively ‘‘feeds’’ the vugs and fractures.

Understanding these complex pore systems requires 1st-order interpretation of large-scale stratigraphy and the contained lithofacies flow units. An example from the Permian of West Texas illustrates the integration of stratigraphic geometry and the contained lithofacies distribution to define flow units. Scaling down to reservoir mudrocks that lack macropores and contain pores that are less than a micrometer in size put these heterogeneous reservoirs in context to better define their flow paths and producibility. Examples come from mud-dominated reservoirs from the Arabian Peninsula and unconventional mudrocks from the Bakken–Three Forks reservoirs of the Williston basin. These mudrocks have porosities that range from <5% to >20%, and permeabilities that are most commonly <<1 mD.

Porosity is quantitatively estimated by petrographic image analysis and QEMSCAN® analysis. Estimated porosities are compared with measured porosity from a Core Measurement System (CMS)® 300 automated permeameter. Porosity and pore throat distributions are determined by mercury porosimetry and nitrogen gas adsorption to capture both micropore and nanopore distributions. Results show distinct differences in porosity, permeability, surface area, and tortuosity among different facies. Pore size distributions indicate bimodal micro- and nano-pore systems that vary across different lithofacies. These variations are related to subtle differences in physical rock properties.

Lithology and lithofacies were the first-order control on reservoir quality for the Three Forks Formation (Devonian) dolomite, dolomitic siltstone, and claystone. The coarsest textures were cemented early, and claystone failed to retain porosity upon burial. Clayey dolomites retained microporosity, and where this microporosity has a significant volume of larger micropores, oil saturation occurred. Lack of larger micropores resulted in water wet rock.

Lithology, lithofacies, and diagenesis-controlled reservoir quality in both the Thamama IA (Figure 1), and the Lower Bab Member (Figure 2) (Cretaceous) mudrocks of the Arabian Peninsula. Porosity, permeability, and pore architecture were strongly influenced by lithofacies in the Thamama IA. Significant volumes of larger, elongate and micro-vug to meso-vug pores appear to enhance flow. Dolomitized Thalassinoides burrows had the best permeability and best flow. The Lower Bab Member mudstones were entirely limestone and also showed pore characteristics linked to lithofacies. In all lithofacies, permeability was very low. Lithofacies 1, rich in coccoliths, has significant isolated intraparticle porosity (Figure 2), and the clay-rich lithofacies (Lithofacies 3) showed significant micrite recrystallization and fused fabrics. The less compacted, coccolith-rich lithofacies (Lithofacies 1) had the best permeability.

If a general conclusion can be drawn from these examples, it is that dolomite and a bimodal distribution of microporosity favors producibility. Effective fluid flow requires a significant volume of larger micropores and/or fractures to access and connect smaller micropores and nanopores. Economic producibility may require some combination of long horizontal wells, multiple frac stages, and gas injection to liberate oil from these micro- and nano-pores.

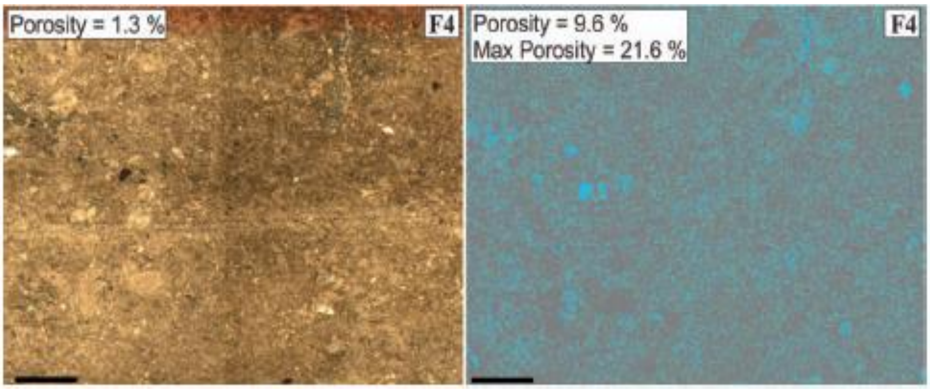

Figure 1. Photomicrograph and QEMSCAN image analysis of the Thamama IA sample F4.

Scale bars = 1 mm. (F4) wackestone with interparticle and intraparticle macropores to micropores (left). QEMSCAN-BSE porosity maps as well as the calculated porosity and maximum porosity. The porosity increase from the QEMSCAN-BSE image is predominantly in the matrix. Porosity is calculated by pixel counting. Gray pixels represent mineral, blue pixels represent the porosity value, and green pixels represent the pore–mineral transition. The addition of the blue and green pixels represents the maximum potential porosity value.

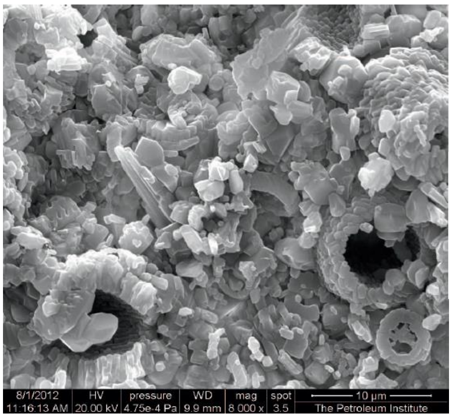

Figure 2. SEM photograph showing intercrystalline and coccolith intraparticle micro-and nano-porosity in Lower Bab Member lime mudstone.

The production geologist adds value to carbonate assets; some examples of how it is done.

E Follows, Shell London

Production geologists significantly enhance the value of producing carbonate assets. Geologists are at the heart of drawing together multidisciplinary data sets to conceptualise and parameterise reservoir permeability architecture at and between wells, and then effectively communicate the impact on hydrocarbon recovery to decision makers. The presented examples highlight how geological interpretation made a difference in dynamic characterisation of gas and oil producing carbonate reservoirs under a range of recovery processes. The examples also illustrate technological developments that continue to improve geological insight in turn enhancing field development and management.

Summarising integrated field examples into reservoir plumbing diagrams is a great way to communicate understanding of reservoir uncertainty both in terms of discrete concepts as well as ranges. Plumbing diagrams are critical to interfacing with an environment craving engineering certainty, both at concept selection but also in seeking new opportunities in brown field development. Conceptual permeability architecture sketches capture realisations, cover different scales, are generally quick to update, entice multidisciplinary discussion, and can be designed for green field development through to abandonment guidance.

Depletion gas production from Miocene reefal buildups in Malaysia is challenged by aquifer water breakthrough with uneven contact rise. Low porosity units within the reefs represent low permeability flooding surfaces, or exposure related cementation events that can retard aquifer encroachment or represent high permeable conduits. These features can be used in well management both in placement and zonal isolation. Prior to this analysis, gas producers were known to cut water through unexpected water breakthrough. The use of 4D seismic data has shown which geobodies matter in the aquifer rise, providing value to the asset to sustain dry gas production. Example compiled from Warrlich et al.

In fields operating under GOGD (gas oil gravity drainage) in the Middle East, long production lives can be sustained with oil draining slowly under gravity into a more permeable network connecting to producers in the oil rim. Efficient oil offtake minimises unwanted gas in constrained facilities. In this Cretaceous example from Oman, vertical core data was invaluable to calibrate the rock fabrics to saturation logging. The detailed analysis of horizontal well borehole image and surveillance data relative to well placement in the stratigraphy identified reduced fracture counts in some of the nodular dominated sequences. Engineers, reluctant to drill matrix wells in a “fractured” reservoir, required multiple data sources to onboard with the idea. Drilling these Natih C2 wells added significant oil production, obtained by positioning horizontal producers in the less fractured stratigraphy with much lower gas cuts.

Waterflood typically involves injecting water into an oil reservoir to provide pressure support and sweep to producers. In South Iraq, typically Mishrif Formation fields produce from a grid of vertical wells in broad anticlines. Central injectors support outer producers in these pattern floods. Oil column heights span several hundred meters of stratigraphy from microporous wacke-packstone intervals, channelised tidal channel fills to rudist shoal dominated horizons. The geologist can again add value in managing pattern flood vertical conformance by tying production logging data into reservoir characterisation. Unlocking resource volumes in microporous reservoirs will be a key metric of future success.

A key theme is the geologist’s understanding provides a great framework for integration.

Porosity Depth Saturation (PDS) model – a tool to quantify mesogenetic leaching in carbonate reservoirs

Christian Perrin, Vincent Franzi, Guillaume Berthereau
North Oil Company, Qatar
christian.perrin@noc.qa

Carbonate oil reservoirs typically display anomalously high porosities compared to their water filled counterparts, and this has been largely discussed in the literature. Also, numerous authors proposed that oil related acidic components are responsible for the leaching of the carbonate host rock, hence the abnormally high porosity. This so-called mesogenetic dissolution model related to oil emplacement was questioned by Ehrenberg et al. [1] in a review pointing at the consistent lack of quantitative analysis.

In response, a quantitative model relating Porosity, Depth and oil Saturation has recently been proposed [2]. In its formulation, the PDS model decouples the compaction occurring in the water domain to the partial porosity preservation occurring once the oil enters the reservoir (Fig. 1). The porosity preservation originates from the zero solubility of calcium carbonate in oil, limiting the porosity loss with burial depth associated to chemical compaction.

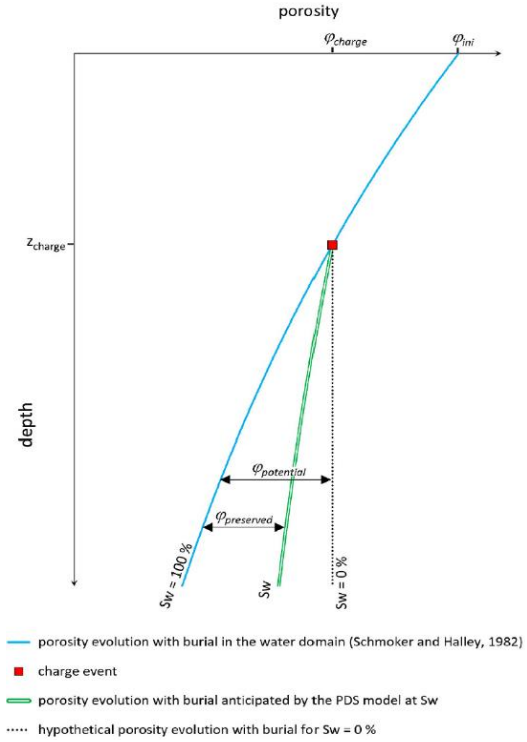

Fig. 1: The evolution of porosity with burial in carbonate reservoirs follows the Schmoker and Halley trend at S_W=100%. In the S_W=0% hypothetic scenario, the porosity does not change after charge. For any Sw, the PDS model is indicated by the double green curve.

Methodology

From the current reservoir conditions, Perrin et al. demonstrated that the PDS model can infer the reservoir burial depth at time of charge, and therefore also the time of charge. Because the formulation of the PDS model does not consider any mesogenetic leaching, any difference between the PDS derived time of charge, and the time of charge defined from conventional petroleum system analysis can be related to mesogenetic leaching. In the presence of mesogenetic leaching, the PDS model should predict an older than expected time of charge.

PDS model applied to a Qatar reservoir

The PDS model was first tested on a Cretaceous carbonate reservoir in Qatar. The Oligocene time of charge found by the PDS model (Fig. 2) is in agreement with an independent petroleum system analysis [3]. This finding excludes mesogenetic leaching as a significant source of porosity enhancement in this reservoir. Because some authors suggested that mesogenetic leaching could originate from byproducts of oil biodegradation, the ratio (Phytane/nC18) - a conventional proxy for biodegradation occurrence [4] - was evaluated. It is found that not only the crest of the field with higher porosity does not show evidence of biodegradation, but moreover the lower porosity flanks exhibit clear evidence of biodegradation. This finding puts into question the role of microorganisms to explain the mesogenetic leaching suggested by some authors.

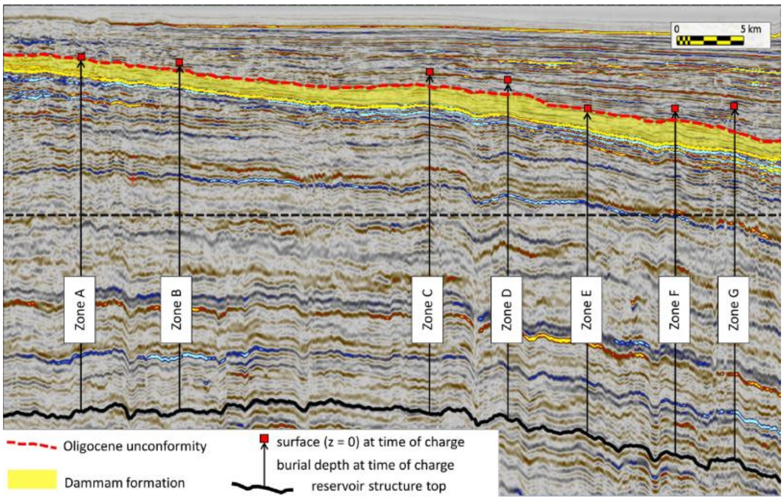

Fig 2: The depths at time of charge are represented in a seismic section for 7 zones defined in the Qatar reservoir. The seismic reflector intersecting the red square can be related to the time of charge of each zone. Note that the oldest charged compartment is Zone E, where the red square plots align on top of the Oligocene unconformity, indicates the time of charge of the reservoir. This timing is in agreement with an independent petroleum system analysis [3].

PDS model applied to the Florida Sunniland reservoir

The PDS model is then applied to the Florida Sunniland Aptian reservoir, using publicly available data. Using the range of uncertainty proposed by Schmoker and Halley [5] for the compaction trend in the water domain, the PDS model is still able to propose a time of charge in agreement with the time of charge found by a conventional petroleum system analysis [6]. This result again suggests that there is no need to invoke mesogenetic leaching to explain the current porosity of the Sunniland reservoir.

Conclusion and discussion

The PDS model has the potential to quantitatively differentiate porosity preservation from mesogenetic porosity creation. The PDS model suggests that for both Qatar and Florida reservoirs, high porosities can be explained by the preservation of porosity by oil only, without invoking mesogenetic leaching. The PDS model is an innovative method that quantitatively relates for the first time porosity, depth and saturation, three of the most important properties used to characterize carbonate oil reservoirs. Because the PDS model can also infer depth at time of charge, this attribute can additionally be used.

Thanks to its holistic approach, the PDS model provides the geologist with a new tool to understand the interdependencies of some key properties of carbonate reservoirs. So far 3D porosity modeling, oil saturation modeling and fine scale charge history impacting the flow regime (drainage, imbibition) within the reservoir have been identified as benefiting from the PDS model.

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POSTER ABSTRACTS

Sedimentary environment and diagenetic control on pore space heterogeneity in continental carbonates (Cenozoic, Paris Basin)

Kevin Moreau[1], Benjamin Brigaud[1], Simon Andrieu[2, 3], Justine Briais[2], Jean-Baptiste Regnet[4], Philippe Robion[4], Johann Schnyder[5].
1: Université Paris-Saclay, CNRS, GEOPS, Orsay Cedex, France
2: BRGM, 3 avenue Claude Guillemin, BP 36009, 45060 Orléans, France
3: Department of Geoscience, Aarhus University, Høegh-Guldbergs Gade 2, 8000 Aarhus C, Denmark
4: Cergy Paris Université, GEC, Cergy, France
5: Sorbonne Université, IsTEP, Paris, France
kevin.moreau@universite-paris-saclay.fr

The Cenozoic continental carbonate deposits of the Paris Basin feature pore space at several scales ranging from the metric scale (karstic cavities or vugs) to the micrometric scale (microporous micrite). In the great Paris area, these deposits are the substratum for geotechnical engineers who plan to build 200 km of new tunnels by 2030. These deposits are of primary importance due to their socio-economic implication, not only for geotechnical issues, but also because they form reservoirs of interest for drinking water, the future development of geological storage (heat, energy, H_2) or low-energy geothermal production. They are moreover good analogues for hydrocarbon reservoirs, such as the pre-salt offshore deposits in Brazil (Campos and Santos basins). The Cenozoic continental carbonate deposits of the Paris Basin show complex diagenesis sequences that are difficult to predict and cause major heterogeneities in the pore space attribute. They mainly consist of shifts in the diagenetic stages including dissolution, cementation (calcite, dolomite, or quartz) or mineralogical replacement in vadose or phreatic environments.

Petrographic descriptions were conducted on thirty-two outcrops and boreholes. Ninety thin sections were observed using cathodoluminescence to identify cementation stages, before performing *in situ* U-Pb geochronology on ten calcite cement generations. Based on these data, we then characterized the distribution of the pore-space development in eighteen facies along three environments: 1) a palustrine domain associated to the development of paleosoils; 2) a lacustrine/lagoonal margin, where the facies show subaerial exposure features; and 3) a carbonate mud-dominated or evaporitic internal lake or lagoon.

Compared to internal lake and lagoon facies, the lake margins and paleosoils facies display highly heterogeneous pore spaces. Paleosoils facies that contain calcretes and rhizoliths present either decimetric to micrometric porosity (cavernous, breccia, fenestral, intragrain and intergrain pores), or sparite to silica cementation. Silicification occurs more often in paleosoils in evaporitic context. Paleosoils facies show a complex pore space attribute, relying on diagenetic patterns found in four domains along a profile from the proximity of the lake to the most distant landforms: (1) Near the margin of the lake, primary porosity in calcretes is totally cemented by calcite; (2) moving away from the lake margins, calcretes porosity increases as calcite cementation decreases; silica is locally present in veins; (3) then, silicification is more abundant and calcrete porosity is filled by chalcedony;(4) farther from the lake margin, carbonates have been replaced by microcrystalline quartz; cherts present cavernous pore spaces.

Along lake margins, the most porous facies are carbonates dominated by roots, shell rich or lithoclast wackestones, where long subaerial exposure time leads to the formation of metric to micrometric porosity (cavernous, roots, moldic, and intergrain pores) in initial lacustrine facies. U-Pb geochronology shows that dissolution and cementation processes begin early after the deposit of these carbonates.

In internal lake or lagoon, some facies as bioclastic mudstones to wackestones or lithoclast wackestones without subaerial exposure features, display (1) microporosity in micrite, (2) vuggy porosity, and (3) fenestral porosity associated to microbial crusts. U-Pb data shows that dogtooth or microgranular sparite postdate carbonate deposits by millions of years. Recrystallizations of gypsum or aragonite to calcite, and calcite to dolomite are common in these diagenetic sequences.

This study shows that the diagenetic sequences in paleosoils and lake margins are different from those in the lake or lagoon, leading to different pore space morphology. Pedogenesis processes with roots activity seem to be the main factor controlling the distribution of macroporosity in the continental carbonates of the Cenozoic of the Paris Basin. The action of roots causes an increase of the macropore space and changes the primary micrite into a more porous one with an increase of the microporous space. Porosity and permeability analyses on 1.5 inch diameter plugs will be carried out to show whether these differences in the pore space geometries between the palustrine and the lacustrine facies imply difference in fluid flow. Finally, the timing of dissolution and cementation occur early in the history of palustrine rocks compared to the lacustrine ones. Itis then relevant for modelling purposes to distinguish the diagenetic evolution of internal lake deposits from those of the lake margins and paleosoils.

The geological/petrophysical facies models of the Cenomanian-Turonian Mishrif carbonate platform deposits: a case analysis of a giant oil reserve in the Mesopotamian Basin

Yang (Young) Li *†, Kaibo Shi ‡
* Department of Earth and Environmental Sciences, The University of Manchester, Manchester, M13 9PL (E-mail:leeyounger@126.com);
† School of Energy Resources, China University of Geosciences, Beijing, 100083
‡ School of Earth and Space Sciences, Peking University, Beijing, 100871

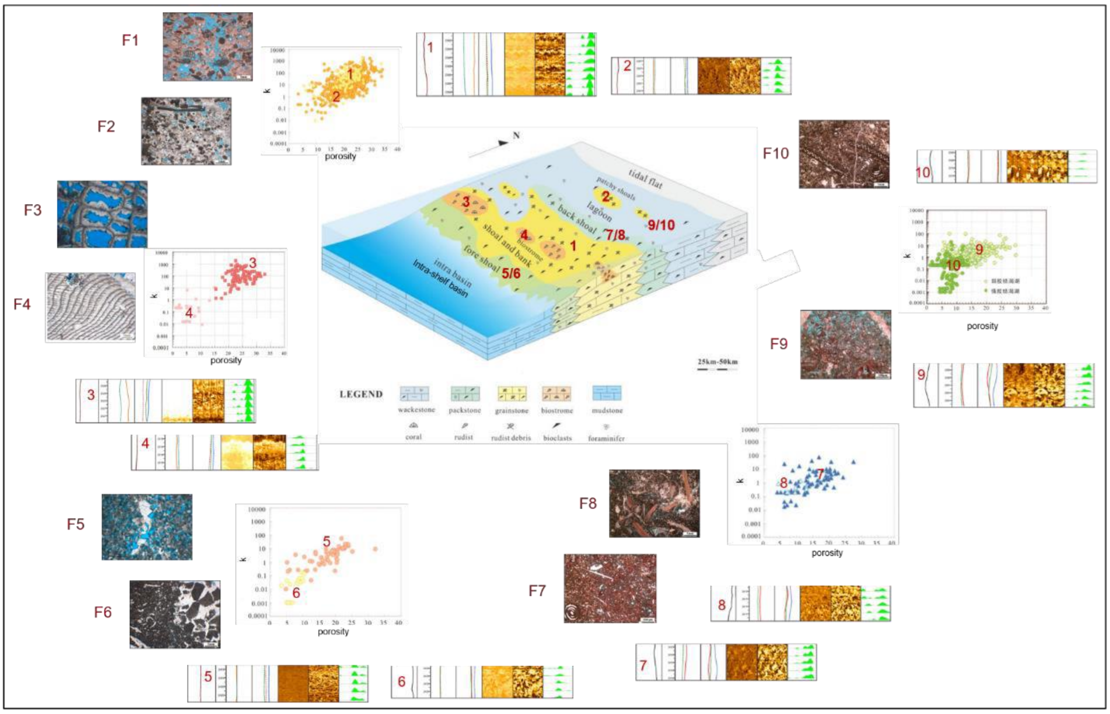
The geological and petrophysical models are fundamental knowledge for reservoir characterization. The heterogeneous nature of carbonate rocks make the challenges in the fields of sedimentology, petrophysics/geophysics and reservoir engineering sciences. However, the learnings based on integrated methodology with continuously improved understandings of subsurface geology and petrophysical dataset make good sense of carbonate reservoir models, even the rock type experiencing depositional and diagenetic processes. This study introduces a case analysis of the well-known Mishrif platform carbonate, applying the integrated method based on petrographic properties, core facies, and logging database (including conventional well logs, borehole images and downhole nuclear magnetism resonance data among 6 cored wells and over 150 open hole wells), establishing the geological/petrophysical facies models for the Mishrif carbonate, which are used to decipher the details of carbonate rocks in geological history, and provide the knowledge for exploration and development geology.

The Mishrif shallow marine carbonates located in the southern extent of the Mesopotamian basin develop in the margin of Cenomanian-Turonian carbonate platform, approaching the intra-platform basin called Najaf to the west. The facies illustrated by cores vary in meter-scale cycles, which could be well recorded by well logs when considering investigating resolution of physical methods and data qualities. The carbonate ramp deposition was supported by the published paleographic features, regional collections and petrographic facies of cores in studying reserve, including bioclatic shoals, rudist biostromes, lagoon and proximal shoal facies with decreasing water energy, such as back shoals and fore-shoals. The changings of sedimentary settings are due to the ramp base as well as the frequently eustatic levels happened in the late Cretaceous period in the region.

The diagenetic analysis was conducted based on petrographic features and geochemical data. In order to establish facies models and characterize reservoir based on the feasible workflow, the dissolution and cementation occurred in specific phase diagenetic were dominantly included in the facies models, integrating with core petrophysical data (porosity, permeability), and well logging data, though bioturbation and stylolitization also influence reservoir properties.

We recognized 10 facies models after analyzing sedimentary facies and diagenetic modifications, as well as petrophysical responses and eletrofacies (see Figure 1). These facies models provide the measures to separate the highly vuggy and vuggy grainstones from cemented rocks (e.g. packstone, pack-wackestone) in differently diagenetic modes, or micrites rising zones due to depositional changes. Additionally, these integrated models also deliver the message of dominant pore system within reservoir rocks such as the connected pores, isolated pores, mixed porosity and micropores, which leave the information for the origin of specific carbonate facies as well as reservoir flow zones.

The geological/petrophysical models provide measures to characterize the Mishrif carbonates in the early and late Mishrif period in details. Our current analysis unveil some stories about the Mishrif deposits, the evolutions and differences during Cenomanian-Turonian geological time. The models have the implications for reservoir architecture analysis, re-understanding the subsurface reservoir models, as well as production strategies, which provide comparisons for local reserves as well.



	Tract 1	Tract 2	Tract 3	Tract 4	Tract 5	Tract 6
LEGEND	GR 0 —— 80 or 0 —— 80	RS 0.1 - - - 1000 RD 0.1 —— 1000	CNL 0.45 - - - -0.15 DEN 2 - - - - 3 AC 0.1 —— 1000	Static Micro-resistivity Image	Dynamic Micro-resistivity Image	Nuclear Magnetism Resonance T2 Distribution

Figure 1. The geological/petrophysical models for the Mishrif carbonate

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Contribution of drone photogrammetry to 3D outcrop modeling of facies, porosity, and permeability heterogeneities in carbonate reservoirs (Paris Basin, Middle Jurassic)

Hadrien Thomas[1]*, Benjamin Brigaud[1], Thomas Blaise[1], Bertrand Saint-Bezar[1], Elodie Zordan[2], Hermann Zeyen[1], Simon Andrieu[3,4], Benoît Vincent[5], Hugo Chirol[1], Eric Portier[6], Emmanuel Mouche[7]
[1] *Université Paris-Saclay, CNRS, GEOPS, France*
[2] *Schlumberger, Digital & Integration, 1 Rue Henri Becquerel, 92140 Clamart, France*
[3] *BRGM, 3 avenue Claude Guillemin, BP 36009, 45060 Orléans, France*
[4] *Department of Geoscience, Aarhus University, Høegh-Guldbergs Gade 2, 8000 Aarhus C, Denmark*
[5] *Cambridge Carbonate Ltd., France*
[6] *CV Associés Engineering, France*
[7] *Université Paris-Saclay, CNRS, CEA, UVSQ, Laboratoire des sciences du climat et de l'environnement, France*
* *Corresponding author: hadrien.thomas@universite-paris-saclay.fr*

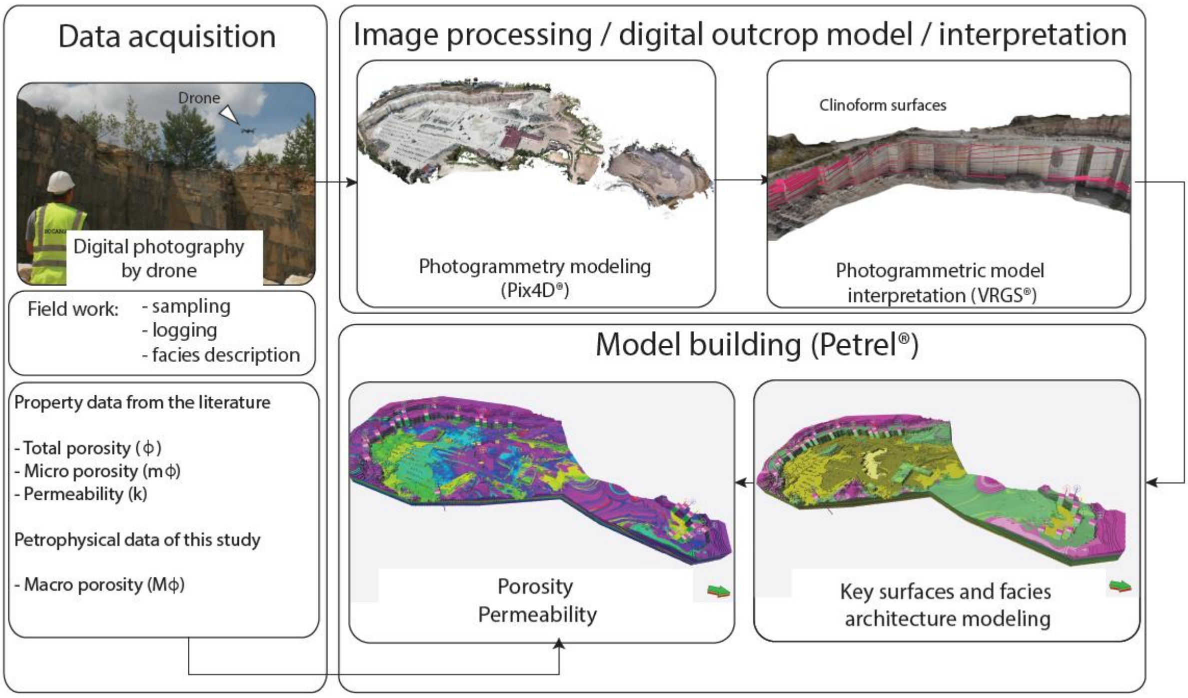

Figure 6 - Overview of the workflow for generating the 3D facies, porosity, and permeability model. First the pictures were captured by a drone equipped with 20 Mega Pixel camera and GPS during two days of field work at Massangis quarry. Sample observations were made on thin sections and macroporosity acquired by image analysis. Previous petrophysical data were collected from the literature. Images were processed using Pix4D® and the resulting Digital Outcrop Model interpreted using Virtual Reality Geological Studio (VRGS®). Facies, porosity, and permeability were modeled using Petrel® software.

This work illustrates the value of drone photogrammetry in creating a hectometer-scale geological model of complex carbonate geobodies (Figure 6). Although drone photogrammetry is now commonly used for modeling the sedimentary facies and architecture of sandstone outcrops, its use is still marginal in creating geomodels of carbonate geobodies. Drone photogrammetry can assist in generating accurate line drawing correlation and detailed architecture analysis along inaccessible vertical faces of outcrops and it provides better observations from new angles. This work models the Bathonian limestones of Massangis quarry (Burgundy) covering an area of 0.4 km² and being usually considered as an analogue of the Oolite Blanche geothermal reservoir in the center of the Paris Basin as well as for reservoir microporosity and secondary porosity associated with dedolomitization. Ten facies are described and grouped into three facies associations (FA1) clinoforms, (FA2) tidal to subtidal facies, and (FA3) lagoonal facies. The clinoforms are sets of giant marine sand waves 15–20 m high that prograded N70° across the platform as part of a regressive systems tract (Figure 6, Figure 7). Moldic rhombohedral pore spaces associated with dedolomitization are well-expressed within clinoforms and in the bioturbated levels of lagoonal facies. Drone photogrammetry combined with the "Truncated Gaussian with Trends" algorithm implemented in Petrel® software is used to create a geological model that reproduces the facies architecture observed in the quarry cliffs (Figure 7). Drone photogrammetry can be combined with field work to describe and locate facies and so constrain the spatial distribution of petrophysical properties. The combination of these tools also allows to constrain the shapes of geobodies and to extend them over the whole of the quarry for a spatial 3D visualization of the facies and petrophysical properties.

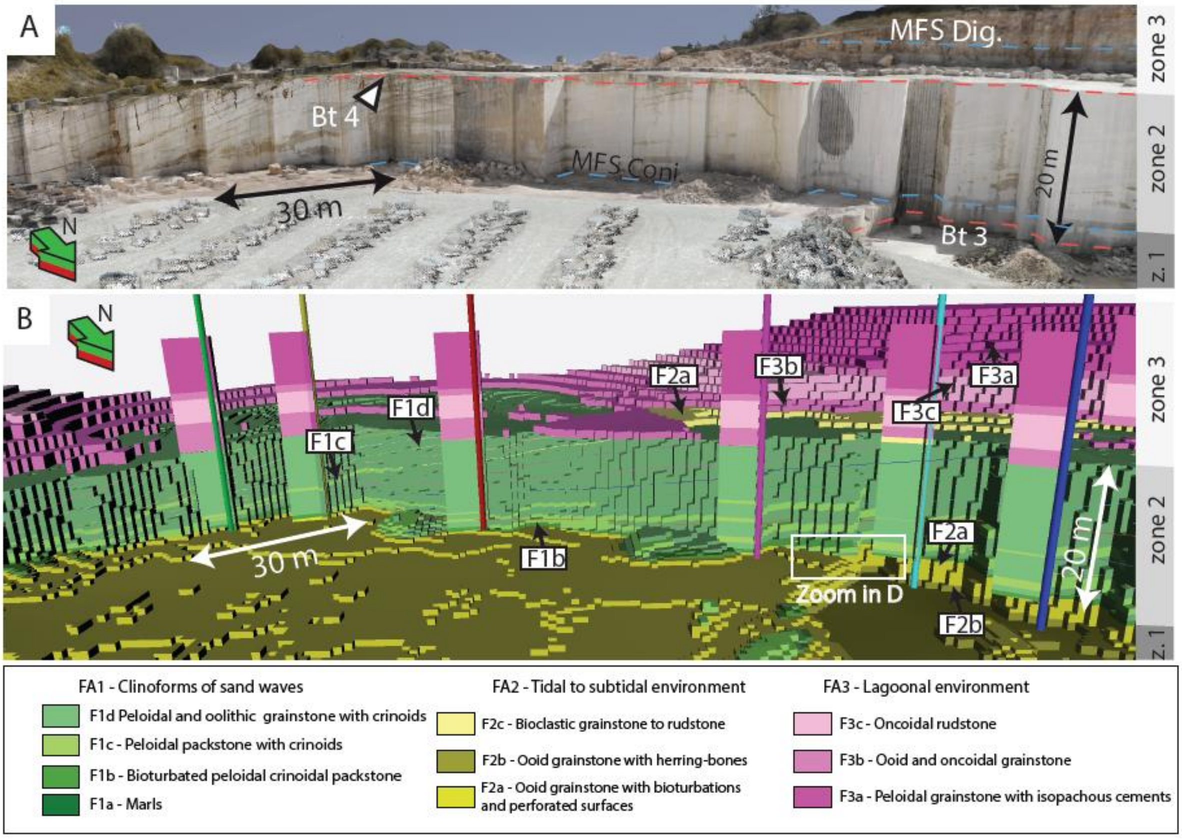

Figure 7 - A- Panoramic view of the 3D model in VRGS® B- Relief-extruded part of the same part of the quarry showing the correlation between the -eld and photographic observations and the final facies model.

Keywords: Carbonates, Digital outcrop modeling, Drone, Photogrammetry, Facies, Reservoir

Towards integrated experimental and modeling workflows for multi-scale diagenetic rock-typing of carbonate reservoirs: feasibility study on Indiana limestone (Lower Carboniferous, Mississippian)

Fadi H. Nader[1], Souhail Youssef[1], Elisabeth Bemer[1], Matthieu Mascle[1], Stéphane Renard[1]
[1] *IFP Energies Nouvelles, Rueil-Malmaison, France – email : fadi-henri.nader@ifpen.fr*

Today, carbonate reservoirs are considered somehow less suitable for sustainable energy and subsurface storage projects. This is mainly due to their complex heterogeneity and reactivity, which are believed to be controlled by several inter-related factors. Sedimentary controls, diagenetic evolution, and fracturing, thus, influence the porosity and permeability evolution and must therefore be taken into consideration for pertinent rock-typing. The latter is a necessity for constructing numerical reservoir models to predict the volumetric capacity and its evolution during geothermal energy exploitation and subsurface storage. Still, the scale-factor needs to be addressed – especially when dealing with carbonate rocks – in order to propose robust rules for flow properties of representative elementary volumes (REV) characteristic of the different scales of interest (from micro- to reservoir cell scales).

We aim to develop specific experimental and modeling integrated workflows to eventually characterize quantitatively diagenetic carbonate rock-types at varying scales. This contribution presents the approach defined to scale up from mini-plugs to macro-plugs that has been applied – through a pre-feasibility study - on the well-known Indiana limestone, a typical grainstone with porosity ranging between 10% and 20% (based on point-counting petrographic analyses). The grains are dominantly crinoid fragments (magnesium-rich calcite), while some bioclasts and peloids are also found. Two main cement types characterize the investigated rock. The major cement is syntaxial calcite overgrowth (associated to crinoids) and the minor cement is equant, granular calcite which is marked by considerable dissolution.

The key points of the approach are to combine petrophysical analyses with petroacoustic and NMR analyses to work on parameters that will also be available at the well scale. First, a series of standard petrophysical analyses (porosity, permeability, density) were performed on two different scales (i.e., macro-plug – 4 cm x 6 cm, and mini-plugs – 1 cm x 2°cm) with a downscaling approach. The effective porosity and permeability measured on the macro-plug are 16% and 208 mD. The NMR T_2 distribution is bimodal indicating the presence of micropores and macropores (68% and 32%, respectively; Figure 1). Dispersion tests were carried out using core flooding experiments performed under CT-scanner on both macro- and mini-plugs. Petroacoustic measurements were also performed at both scales on the same samples. Homogenization modeling approaches are proposed to link the properties measured on the mini-plugs to those of the macro-plug. The next step will be to upscale the different properties from the scale of the macro-plug to the well scale. The final objective is to define carbonate rock-types integrating diagenetic heterogeneities at different scales that could be used in reservoir modelling for predicting the volumetric capacity of underground storage projects and the flow efficiency for geothermal projects.

The potential impact of interactions between the injected fluid and the carbonate rock in subsurface storage applications (e.g. CO_2, H) further complexify the issue. To investigate the reactivity of carbonate reservoirs, an experimental setup was designed to perform reactive mini-core flooding. For a feasibility study, HCl acid (pH= 3) was injected through a mini-plug (for 20 hours) while performing micro-CT acquisition in IFPEN's Cal-X equipment. The effluents were analyzed, demonstrating that the dissolution process produces only Ca^{2+} (and no Mg^{2+}). The micro-CT imaging showed the development of percolating secondary porosity through a wormholing process (only 1% overall porosity increase) and an increase in permeability up to 4800 mD (initial permeability was 220 mD). 0D geochemical modeling of the dissolution process has confirmed the experimental results to a large extent.

The work and results presented in this contribution are still preliminary at this stage. Nevertheless, the proposed workflows offer a promising approach to integrate carbonate rock heterogeneities into reservoir models.

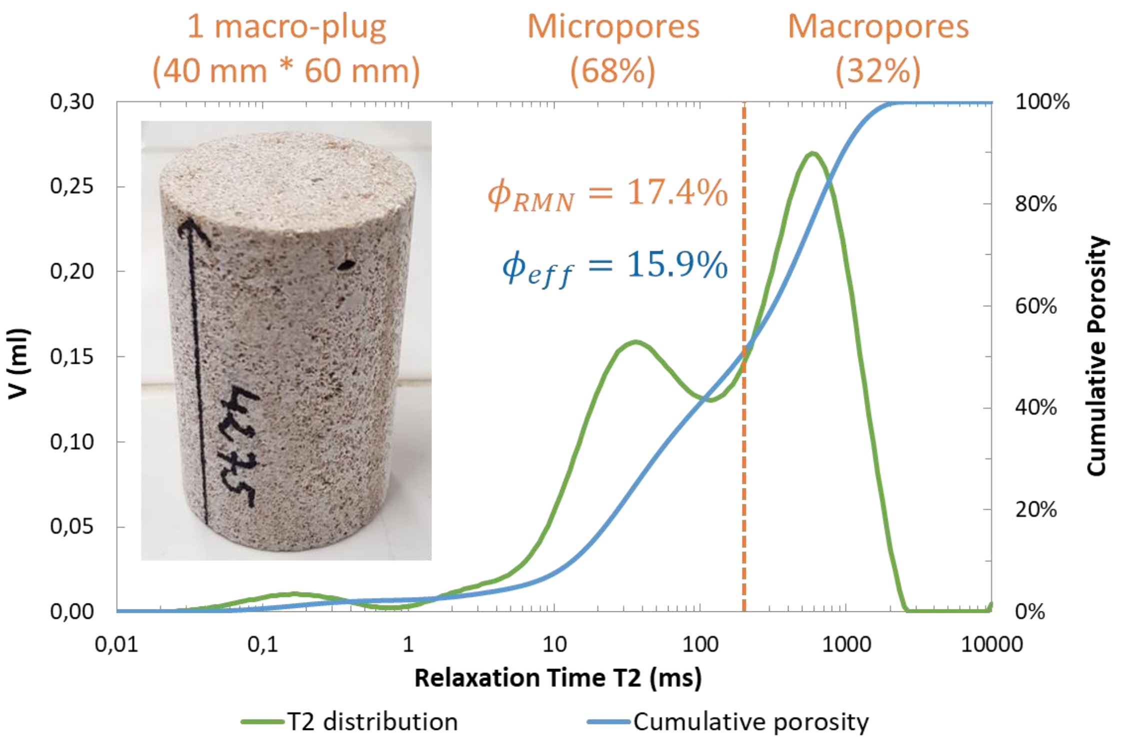

Figure 1. NMR analysis of the Indiana limestone rocks (Macro-plug), typical of carbonate grainstone reservoirs.

Coupled sedimentologic and petroacoustic characterization of surface-exposed Middle Jurassic Carbonate rocks analogues to the 'Oolithe Blanche' geothermal reservoir target of the Paris Basin

Mathilde Adelinet[1], **Fadi H. Nader[1]**, Ghina Abbani[2,3], Lama Inati[3], Benjamin Brigaud[4]
[1] *IFP Energies Nouvelles, Rueil-Malmaison, France – email : fadi-henri.nader@ifpen.fr*
[2] *Sorbonne Université, Paris, France*
[3] *National Council for Scientific Research of Lebanon, Center for Géophysics*
[4] *Université Paris-Saclay, Geosciences Laboratory (GEOPS)*

Massangis quarry, located at about 150km southeast of Paris, exposes principally Middle to Upper Bathonian carbonate rocks that are interpreted to have deposited in tidal and high energy shoreface and represent excellent analogues for the 'Oolithe Blanche' subsurface reservoirs in the Paris Basin. These reservoirs are the target for geothermal projects across the Paris region. Therefore, a proper understanding of their sedimentologic and diagenetic heterogeneities and their impacts on flow is necessary to de-risk geothermal project and achieve viable, economical future exploitation. The outcrop interval in the quarry representing the 'Oolithe Blanche' consists of two units. A basal unit, locally called 'Roche de Valanges', having approximately 7.5m of thickness and representing cross-bedded grainstones and rudstones of tidal origin. The upper unit, locally called 'Roche de Massangis', is around 20m thick and consists of large clinoforms with packestone-grainstone textures (Figure 1). The overall porosity of these facies ranges between 10 and 20% (including both intergranular, vuggy porosity and micro-porosity types). Permeability values spread from 0.1 to 5mD (Thomas et al., 2021).

Figure 1. Panoramic photograph of the large carbonate clinoforms exposed by the Massangis quarry (Burgundy, France), analogue of Middle- to Upper Bathonian 'Oolithe Blanche' reservoirs.

This contribution is based on previous work that provided new sedimentologic and diagenetic descriptions of the Massangis quarry outcrop and resulted in the construction of a 3D reservoir model (Thomas et al., 2021; Vincent et al., 2021). Coupled sedimentologic and petroacoustic field acquisition was performed. About 1000 acoustic velocities have been measured with a portative device (PL-200 equipment) at outcrop using S-wave sensors with a 40 kHz central frequency. Two types of objects have been investigated: a 2D section (12.5m wide x 2.5m high) on the uppermost part of the Valanges unit and four 1D logs (about 2-3 m high), one on the uppermost part of the Valanges unit and three on the basal part of the Massangis unit, crossing clinoform surfaces. The measurements has been done with a horizontal spacing of 40cm and a vertical spacing of 20cm. and are correlated with sedimentologic facies and diagenetic imprints (in the field, and through petrographic analyses). Velocity measurements are used to perform synthetic seismics on the 2D section using both P- and S-waves data (Figure 2). Main reflectors can be interpreted as diagenetic limits (Bailly et al., 2021).

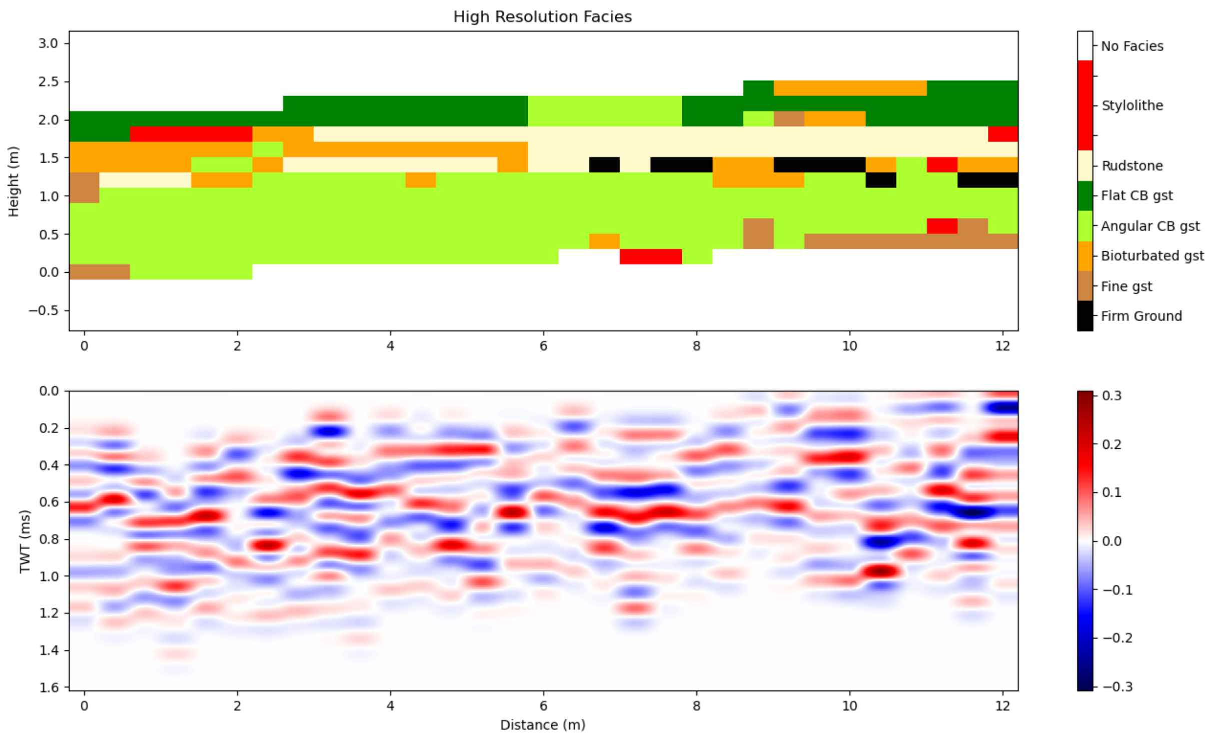

Figure 2. High-resolution facies (top) and corresponding synthetic seismic in time with a 5 kHz Ricker as wavelet (bottom).

Such results are necessary to complete the available reservoir model and to upscale flow properties from plug- to reservoir-scale. Finally, the improved 3D reservoir model, based on the outcrop study, may be used to infer the flow dynamics in the ‘Oolithe Blanche’ reservoirs, and propose strategies for successful future geothermal exploitation.

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