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Dionisos: a model of multiple resources

Putting geological structures into equations and describing the processes involved in the formation of rocks, fluids and complex flows, in order to translate the rich diversity of natural media into numerical models: that's the ambition of the Geosciences Division.

Our researchers study geological objects covering spatial scales from the nanometer to hundreds of kilometers, and time scales from a hundredth of a second to a million years. Their aim is to remove the barriers inherent to the multiphysical/multiscale character of the phenomena that govern major natural systems: taking into account heterogeneities and uncertainties, changes in scale, and data acquisition to develop and validate models.

This work has many applications, from petroleum exploration to enhanced oil recovery and fluid storage, all of which posing major economic and environmental challenges. The examples presented here illustrate the diversity of topics covered, the wide range of skills at work and the scientific quality of the research work carried out.

I hope you enjoy this issue of the newsletter,

Olga Vizika-Kavvadias,
Director of the Geosciences Division

Continental shelves, the underwater extension of continents, are rich in natural resources of sedimentary origin. Searching for new resources in these poorly explored frontier zones, like those of the African continental shelf, is a major challenge for oil exploration.

Assessing the economic potential of these zones requires a detailed understanding of sedimentary basins in order to localize and characterize their petroleum systems.

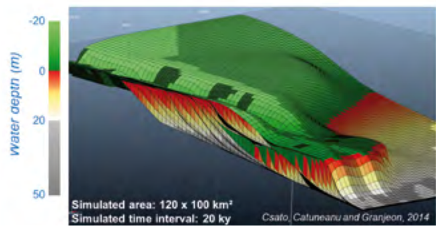
The DionisosFlow™ numerical stratigraphic model developed by IFPEN[1] enables regional and geological scale simulation of the physical processes behind the sedimentary series studied: basin deformation, sediment production, discharge and transport.

This modeling solution has recently been further improved to describe sedimentary processes more accurately, with a more detailed modeling of sediment transport, the simulation of climate impacts on soil erodibility and river transport of sediment, and the formation of incised valleys, sources of turbiditic systems that are the focus of so much continental shelf exploration projects.

Used in conjunction with CougarFlow™, the numerical optimization package for petroleum systems, DionisosFlow™ makes it possible to estimate uncertainties related to basin-scale sediment distribution by working with geological parameters such as variations in sea level, rainfall, ocean temperature, or basin deformation[2].

To improve the characterization of organic sediment distribution and nature, IFPEN has launched the DORS (Dionisos Organic Rich Sediment) JIP which aims to model the production, degradation and preservation of organic matter.

Further work is also in progress to optimize the integration of seismic and well data to facilitate the use of this stratigraphic modeling approach in operational situations.



Numerical modeling of climate cycle impact on incised valley formation and delta growth.

(1) **D. Granjeon,** Int. Assoc. Sedimentol. Spec. Publ., 2014, 46, 453-472.
DOI: 10.1002/9781118920435.ch16

(2) Csato, Istvan, Catuneanu, Octavian, **D. Granjeon,** Journal of Sedimentary Research, 2014, 84 (5), 1-13.
DOI: 10.2110/jsr.2014.36

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History-based models chart the future of reservoirs

The goal of geological reservoir monitoring for hydrocarbon production or gas storage (methane, CO_2, etc.) is to monitor fluid distribution over time. Reservoir behavior can be anticipated on the basis of predictive flow simulations calibrated against data gathered continuously or on a repetitive basis.

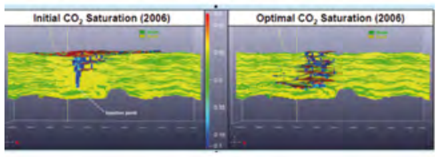
Repetitive seismics (4D) has emerged as an effective technique for achieving this objective. Data acquired from the Sleipner CO_2 storage site in the Norwegian North Sea *(Science@ifpen issue 7)* before and after gas injection have enabled the CO_2 plume to be effectively imaged *in situ*.

However, the dynamic behavior of CO_2 in the sandy host formation remained difficult to discern, because it is controlled by meter-thick layers of shales whose distribution was poorly known.

The teams at IFPEN have solved this problem, beginning with the provision of an appropriate initial geological model for the reservoir simulation. It is constrained by seismic attributes that discriminate sands from shales within the formation, without petro-elastic modeling and therefore without the need for calibration data. Comparing the 4D measurements with the simulation results made it possible to update the sand/shale distribution using an appropriate matching strategy[1, 2].

It is therefore now possible to produce a reservoir model that is consistent with the geology and capable of correctly simulating the first years of CO_2 injection by using 4D seismic techniques.

Open to further enhancement with the inclusion of other seismic data, this model could be the basis for longer-term simulations that take account of fluid-rock interactions. Applied to petroleum reservoirs, this methodology makes it possible to predict field behavior and to optimize future operations.



Distribution of sand (yellow), shale (green) and CO_2 (blue) within the reservoir. Left: initial simulation before model calibration. Right: enhanced simulation by calibration against 4D seismic data.

(1) ***K. Labat, N. Delépine, V. Clochard*** *and P. Ricarte. OGST, 2012. DOI: 10.2516/ogst/2012006*

(2) ***A. Fornel & A. Estublier***, *Energy Procedia, 2013. DOI: 10.1016/j.egypro.2013.06.401*

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(Multi)scale access to reservoirs

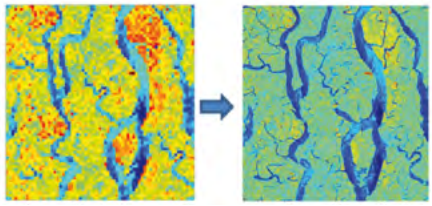
Digital modeling of petroleum reservoirs is an essential tool for optimal oilfield exploitation. It requires the integration of available static (well log, seismic) data and dynamic (production) data. These data are used to characterize the many parameters of reservoir models, and in particular to predict the spatial distribution of petrophysical properties. However, the relationship between these parameters and the data is usually a complex one. Moreover, building a model that is consistent with the data thus requires the simulation of fluid flows for multiple models, which usually imposes a very heavy cost in terms of computing time.

To reduce this cost, it is possible to make use of intermediate digital models of lower resolution based on a coarser mesh size or a simplified description of the physical reality. Using the information generated by these models to facilitate the integration of data in the detailed model is the basis of multiscale modeling approaches.

Methods developed at IFPEN consist of producing the distribution of petrophysical properties[1] in a cascading sequence: the values calculated at a given mesh size provide the trend for generating a new distribution on a finer grid. More specifically, this method makes it possible to adjust the spatial resolution of the parameters to be calibrated to match the level of information contributed by the various dynamic data.

Another investigated approach is the construction of meta-models known as multi-fidelity models to approximate the results produced by the simulator at the most detailed level[2]. These meta-models are defined by combining flow simulations performed with the detailed reservoir model and with lower resolution models. Integration of the less costly simulations reduces the demand on the simulator at the most detailed level to deliver appreciable time savings.

Given the demand for increasingly accurate and realistic reservoir models, multiscale methods appear to offer high-potential resources.



Properties at coarse scale   Properties at fine scale

Multiscale simulation of petrophysical property distribution.

(1) ***C. Gardet, M. Le Ravalec,*** *E. Gloagen, Mathematical Geosciences, 2014, 46(3), 315-336. DOI: 10.1007/s11004-013-9480-3*

(2) ***V. Gervais, A. Thenon, M. Le Ravalec,*** *Second EAGE Integrated Reservoir Modelling Conference, Dubaï, 2014. DOI: 10.3997/2214-4609.20147475*

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When the Earth gives up its CO_2

The carbon dioxide (CO_2) often present in gas deposits sometimes occurs in high concentrations (>50%), which can be disadvantageous for exploitation of this resource.

Where naturally occurring CO_2 has an organic origin (e.g. bacterial), it is recognizable in the carbon isotope signature. However, its many inorganic sources are difficult to identify. Nevertheless, their recognition is crucial in the process of targeting exploration.

One initial approach to identification is to characterize the associated "noble gases" (helium, argon, neon, etc.), either in terms of the origin of the gaseous mixture, or as process indicators of its migration. For more than 10 years, IFPEN has operated and expanded a laboratory dedicated to noble gas analysis. The work done by its researchers has shown that the CO_2 contained in the Presalt deposits offshore Brazil originated in the continental mantle[1].

Another approach is based on modeling the reactions that form CO_2 from the carbonated minerals of sediments[2]. This modeling protocol makes it possible to demonstrate that, under the conditions prevailing at the bottom of some sedimentary basins (up to 500°C and 250 MPa), the CO_2 originates from metamorphic changes in the terrestrial crust. It now forms an integral part of a prototype version of TemisFlow™, software used to quantify petroleum systems to assess their exploration potential.

Given the growing interest in natural gas and the deep geological resources, both these methodological options are promising. They open the way for a broader approach to other essential fluid components from deep beneath the earth (abiotic CH_4, H_2, H_2S, N_2, etc.).

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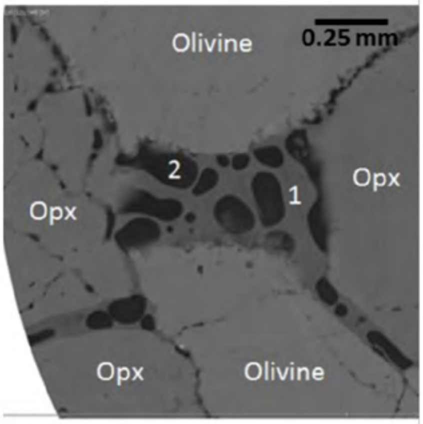

CO_2 vesicles in veins of magma between the minerals of a peridotite (much of the Earth's mantle is derived from this rock). PhD thesis of Laura Créon (2015).

(1) **V. Rouchon** and al., Miner. Magazine, 2013.
DOI: 10.1180/minmag.2013.077.5.18

(2) **X. Courtial** and al., Geoch. Cosmoch. Acta, 2014.
DOI: 10.1016/j.gca.2014.07.028

An innovative 3D approach for simulating flow networks

The modeling of hydrocarbon reservoirs in fractured geological environments is a longstanding strength of IFPEN. These reservoirs (approximately 30% of proved reserves) display preferential flow paths that have an impact, favorable or not, on the petroleum production, accompanied by high levels of uncertainty.

The process of producing a precise and detailed description of these fractured environments to optimize exploitation of their reserves and to minimize economic risks is complex, due to its multiscale character and to the high number of interdependent parameters. So for computer simulation, a minimum level of fracture network discretization is required to achieve the optimal compromise between computing cost and result accuracy.

The difficulty lies in the marked contrasts between matrix and fractures, which make the numerical problem poorly conditioned and pose substantial difficulties in terms of mesh size.

IFPEN has developed an innovative, completely 3D discretization method[1] based on algorithmic geometry and appropriate approximations of flow. Its principle was supported by theoretical arguments[2] and validated by testing prior to being carried out on real case studies of fractured reservoirs.

As a result, it is now possible to directly simulate flows in networks that may contain several millions of fractures.

This progress also enables to account for geomechanical coupling between matrix and fractures. The improved representation of transient exchanges between matrix and fractures is relevant to other areas of subsurface energy exploitation or fluid storage.

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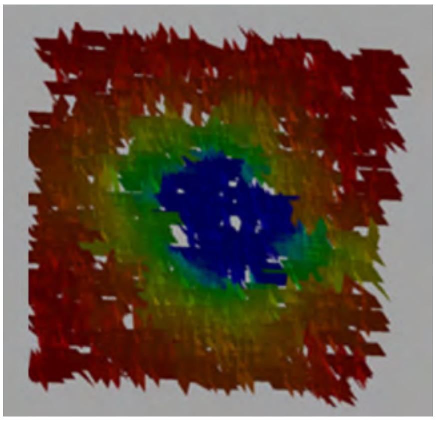


Pressure map of a random network of thousands of fractures, with the pumping well at the center.

(1) **N. Khvoenkova** and **M. Delorme**, Peer-reviewed publication, IAMG 2011, Salzburg, Austria.
DOI:10.5242/iamg.2011.0088

(2) **B. Noetinger** and **N. Jarrige**, J. Comp. Phys. 2012, 231, 23-28.
DOI:10.1016/j.jcp.2011.08.015

Pore scale imaging to understand pore-to-pore flows

Multiphase flow in natural porous media is central in a wide range of phenomena and applications in geosciences, including hydrocarbon formation and migration, oil and gas production, increased and enhanced oil recovery as well as CO_2 injection and sequestration and soil remediation.

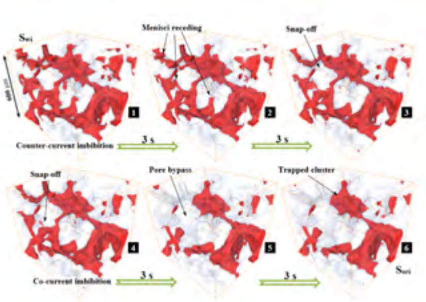
In order to improve our understanding of the flow mechanisms at the pore scale, IFPEN has developed a digital laboratory that combines 3D image acquisition and processing with simulation to access different petrophysical properties.

3D images of porous media samples are first acquired by a laboratory X-ray micro-tomography. These images are then processed and analyzed to extract the topological properties of the porous network.

These imaging techniques also provide a direct visualization of fluids present within a pore network. Experiments conducted at the SLS (the Swiss Light Source based in the Paul Scherrer Institute) have made it possible to achieve real-time monitoring of the movement of two immiscible fluids in a porous medium, with a temporal resolution of around one second[1]. It has therefore been possible to analyze the mechanisms that govern flows at the individual pore scale, like the capillary disconnection responsible for the trapping of the non-wetting phase (oil or gas), or for the ganglion dynamics causing oil bank formation in enhanced recovery process[2].

Once injected into a numerical simulator, the image-derived data make it possible to reproduce the two phase flow in the porous space of the rock, and thereby to infer the spatial distribution of fluid phases, as well as the properties of the medium at a macroscopic scale: capillary pressure, absolute or relative permeability, capillary desaturation curve, etc.

With an appropriate up-scaling, these models will eventually make it possible to feed petroleum reservoir simulators with petrophysical data that was previously very expensive to obtain, or even completely inaccessible, using standard measurement methods.



Trapping of the oil phase (red) following a spontaneous imbibition of the rock, captured by ultra-fast tomography.

(1) ***S. Youssef, E. Rosenberg, E. Deschamps, R. Oughanem,*** *E. Maire, R. Mokso. SCA 2014 Conference.*

(2) ***R. Oughanem, S. Youssef, D. Bauer, Y. Peysson,*** *E. Maire,* ***O. Vizika,*** *TIPM, 2015, 109, 673-692. DOI: 10.1007/s11242-015-0542-5*

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Awards

• ***Vincent Crombez,*** *a geosciences PhD student, came second in the European student paper competition run by the Society of Petroleum Engineers (SPE) at the European finals in Budapest for his thesis "Distribution of Sedimentary Heterogeneities in Shale Plays: Insight from Sequence Stratigraphy, Multi-Proxies Analysis and Stratigraphic Modeling of the Montney and Doig Formations – W-Canada" (June 2015).*

• ***IFP School*** *won the "Best Training Resource" category of the Cegos and AEF E-Learning Excellence Awards for its MOOC on sustainable mobility (11 June 2015).*

• ***Claudio Antonio Pereira da Fonte,*** *a research engineer working in mixture modeling, was awarded the EFCE Young Researcher Award in Mixing 2015 at the 15th European Conference on Mixing. His award was made in recognition of the excellence of his research work in terms of new approaches, greater depth and dissemination of results (July 2015).*

• ***Marie Guehl,*** *a PhD student working on catalysis and separation, received a French Chemistry Society award at the CFS' 15: Chemistry and Energy Transition Conference. She made a brilliant presentation of her work on the development of hybrid catalytic systems for the selective recovery of biosourced products with specific properties (July 2015).*

News

The newly launched "IFP Energies nouvelles and COP21" Facebook page (www.facebook.com/ifpencop21) contains articles, interviews with IFPEN researchers, a quiz, etc.

Publications

• *OGST – Revue d'IFP Energies nouvelles – Issue 3, volume 70 (2015). Issue focusing on the Nextlab 2014 scientific meeting.*

• *OGST – Revue d'IFP Energies nouvelles – Issue 4, volume 70 (2015). Issue focusing on the European SiteChar project.*

(http://ogst.ifpenergiesnouvelles.fr).

HDR

• ***Loïc Sorbier,*** *HDR awarded by Claude Bernard University (Lyon I) for his work on "The contribution made by techniques for the characterization of heterogeneous catalysts in internal diffusional limitation".*

Upcoming scientific events

• *IFP Energies nouvelles' "Rencontres scientifiques" event* ***– SimRace –*** *8-10 December 2015, IFPEN Rueil-Malmaison - www.rs-simrace.com*

• *IFP Energies nouvelles' "Rencontres scientifiques" event* ***– SMILE 2016 –*** *6-8 April 2016, IFPEN Rueil-Malmaison - www.rs-smile2016.com*

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