

Selection and Characterization of Geological Sites able to Host a Pilot-Scale CO₂ Storage in the Paris Basin (*GéoCarbone-PICOREF*)

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Résumé — Choix et caractérisation de sites géologiques propices à l'installation d'un pilote pour le stockage de CO₂ dans le bassin de Paris (*GéoCarbone-PICOREF*) — Le projet *GéoCarbone-PICOREF* avait pour objectif de caractériser des sites propices à la réalisation d'un pilote national de stockage du CO₂ en réservoir géologique perméable. Deux types de réservoir ont été examinés : des aquifères profonds, et des gisements d'hydrocarbures en voie d'épuisement. Les sites devaient être choisis de manière que le pilote puisse tester des problématiques qui concernent les futurs stockages de grande taille.

GéoCarbone-PICOREF a d'abord sélectionné une "Zone régionale" d'environ 200 × 150 km dans le bassin de Paris, qui présente les avantages suivants :

- l'information géologique y est largement disponible, grâce aux travaux d'exploration pétrolière depuis 50 ans ;
- de grands aquifères salins y sont présents, dans les carbonates du Jurassique moyen situés en général entre 1500 et 1800 m de profondeur, et dans les formations gréseuses du Trias, entre 2000 et 3000 m ;
- il existe plusieurs gisements d'hydrocarbures en voie d'épuisement : offrant des capacités de stockage moindres, leur intérêt est d'être bien connus sur le plan géologique et d'être dotés de bonnes qualités en termes de piégeage géologique.

Après avoir retraité 750 km de lignes sismiques, et avoir assemblé celles-ci selon six coupes calées sur des données de puits, on a précisé sur la Zone régionale :

- les grandes caractéristiques des aquifères concernés ;
- la localisation des failles ;
- la continuité des couches très peu perméables situées au-dessus des réservoirs.

Ces études ont permis de choisir un “Secteur”, d’environ 70 × 70 km, au sein duquel on a ensuite affiné l’investigation géologique : 450 km supplémentaires de lignes sismiques, collecte exhaustive des données de puits, caractérisation fine des propriétés réservoir. Des observations de terrain ont été faites sur des roches équivalentes portées à l’affleurement. Un modèle géologique et informatique complet du Secteur a été construit à partir de ces données. Il permet de générer des maillages pour la simulation de divers comportements attendus suite à l’injection de CO₂ (déplacement et dissipation du gaz dans les couches réservoir, modification des pressions et des contraintes, déformation mécanique des terrains, interaction entre l’eau acidifiée et les minéraux, etc.).

Parallèlement, le projet a pu avoir accès à toutes les données pétrolières du gisement de Saint-Martin de Bossenay, situé dans la partie Est du Secteur. Grâce à cette opportunité, on a montré quel parti pouvait être tiré, pour un pilote, d’un gisement d’hydrocarbures déjà largement exploité, doté d’un piège géologique qui a retenu des hydrocarbures pendant des millions d’années, et sur lequel un opérateur industriel dispose d’une infrastructure et d’un savoir-faire.

Abstract — Selection and Characterization of Geological Sites able to Host a Pilot-Scale CO₂ Storage in the Paris Basin (GéoCarbone-PICOREF) — *The objective of the GéoCarbone-PICOREF project was to select and characterize geological sites where CO₂ storage in permeable reservoir could be tested at the pilot scale. Both options of storage in deep saline aquifer and in depleted hydrocarbon field were considered. The typical size envisioned for the pilot was 100 kt CO₂ per year.*

GéoCarbone-PICOREF initially focused on a “Regional Domain”, ca. 200 × 150 km, in the Paris Basin. It was attractive for the following reasons:

- *detailed geological data is available, due to 50 years of petroleum exploration;*
- *basin-scale deep saline aquifers are present, with a preliminary estimate of storage capacity which is at the Gt CO₂ level, namely the carbonate Oolithe Blanche Formation, of Middle Jurassic age, generally located between 1500 and 1800 m depths in the studied area, and several sandstone formations of Triassic age, located between 2000 and 3000 m;*
- *several depleted oil fields exist: although offering storage capacities at a much lower level, they do represent very well constrained geological environments, with proven sealing properties;*
- *several sources of pure CO₂ were identified in the area, at a flow rate compatible with the pilot size, that would avoid capture costs.*

750 km of seismic lines were reprocessed and organized in six sections fitted on well logs. This first dataset provided improved representations of:

- *the gross features of the considered aquifers in the Regional Domain;*
- *the structural scheme;*
- *lateral continuity of the sealing cap rocks.*

An inventory of the environmental characteristics was also made, including human occupancy, protected areas, water resource, natural hazards, potential conflicts of use with other resources of the subsurface, etc. From all these criteria, a more restricted geographical domain named the “Sector”, ca. 70 × 70 km, was chosen, the most appropriate for further selection of storage site(s).

The geological characterization of the Sector has been as exhaustive as possible, with the reprocessing of additional 450 km of seismic lines, and the collection of a complete well-data base (146 petroleum wells). At this scale a relatively detailed characterization of the sedimentary layers could be done, in particular the formations potentially rich in aquifer units. For the Middle Jurassic carbonates observations were made on analogue sediments outcropping 150 km to the east of the Sector. A geological and numerical 3-D representation of the whole sedimentary pile of the Sector area was built. It forms a basis for constructing grids used by codes able to simulate various processes induced by CO₂ injection (displacement of the fluids, pressure build-up and release, mechanical deformation, mineral interactions, control of the parameters used to check the local sealing efficiency, etc.).

In parallel with that work on aquifers, GéoCarbone-PICOREF has access to all the petroleum data, including production data and reservoir modelling, of the Saint-Martin de Bossenay oil field, localized in the eastern part of the Sector. This was an opportunity to apply a comparable methodology and to test the capabilities of modelling codes to the specific case of a depleted hydrocarbon field, and to show some of the advantages of such a context with respect to a pilot-scale CO₂ injection.

INTRODUCTION

Since 2003, French public authorities have paid a growing attention to the geological storage of carbon dioxide. In 2004 they decided to contribute some funding to a project supported by a consortium of partners from industry, national institutes and academic research. The aim of this project PICOREF (*Pilote pour l'Injection de CO₂ dans les Réservoirs géologiques, En France*) was to select and characterize appropriate sites where a pilot-scale storage of carbon dioxide (CO₂) could eventually be carried out. Two options were considered for the storage reservoir, either a deep saline aquifer or a depleted hydrocarbon field. Due to the allocated budget, no seismic survey or drilling operation could be possible. It was thus decided to focus on the south-eastern part of Paris Basin, because in this area – the first petroleum region in France – many data would be available for investigating the subsurface capabilities with respect to CO₂ storage. In addition, one of the project partners provided the opportunity to access the whole petroleum dataset from an oil field located in the same region, namely Saint-Martin de Bossenay (referred to below as SMB). In 2005 this project was continued in the framework of the newly created ANR (*Agence Nationale de la Recherche*), inserted in a larger, more ambitious research program called *GéoCarbone*, that included five projects able to investigate more thoroughly different questions linked to the repository of CO₂ in geological formations: *GéoCarbone-PICOREF* focused on geological aspects and site selection; *GéoCarbone-Intégrité* on cap-rock properties (see Fleury *et al.*, this issue); *GéoCarbone-Injectivité* on the problems linked to the “injectivity” of CO₂ (see Lombard *et al.*, this issue); *GéoCarbone-Monitoring* on the selection of appropriate approaches for storage monitoring (see Fabriol *et al.*, this issue); and *GéoCarbone-Carbonation* on geochemical aspects, and the possibility on the long term to have a significant proportion of the injected gas trapped as

carbonate minerals (see P. Benezeth, B. Menez and C. Noiriel (eds), 2009). As far as it was possible, these projects tried to use examples relevant for a future storage in the Paris Basin.

The type of pilot-site project prepared by PICOREF was assigned to the objective of testing solutions and answering questions related to the future storage of large CO₂ quantities. The aquifer reservoirs of the Paris Basin where such a perspective can be conceived are located in the Middle Jurassic (Dogger) carbonates, with mainly the *Oolithe Blanche* Formation of Upper Bathonian age, and in the Triassic silico-clastic sediments, with marine sandstones of Rhaetian age and continental sandstones of Scythian?/Anisian to Norian age (*Grès de Donnemarie* and *Grès de Chaunoy* Formations) (*Fig. 1*). The Paris Basin is an intra-continental basin deposited on hercynian basement. The major part of sediments is of Mesozoic age. The Cenozoic deposits are relatively thin, and to the east and south-east Alpine tectonics has uplifted and eroded several hundred metres of the sedimentary cover. This does represent a very different context from younger, still active sedimentary settings such as the North Sea, where relatively recent reservoir facies can be met which did not suffer yet significant compaction and burial diagenesis. In contrast, for the geological formations to be studied here it could happen that the reservoir quality is poor or questionable, either in terms of storage capacity or in terms of fluid “injectivity”. The relatively fair reservoir properties noted in some Triassic aquifer units when approaching the uplifted eastern border of the basin is counteracted by a drop of salinity value, and the use of these units for water supply. A gross capacity estimate drawn from the results of the European GESTCO project is presented in Table 1 (Bonijoly *et al.*, 2003). However it was obtained using a value of 6% for the efficiency coefficient (*sensu* Scott Frailey in DOE, 2008), that according to the

TABLE 1

First appraisal of storage capacity in the Dogger and Keuper aquifers of the Paris Basin, presented by the European GESTCO project (Bonijoly *et al.*, 2003). Dogger corresponds to the *Oolithe Blanche* Formation, and Keuper mainly to the Rhaetian and *Grès de Chaunoy* sandstones. An estimation including *Grès de Donnemarie* Formation and Buntandstein sandstones reaches 22 Gt_{CO₂} for the whole Triassic section.

	Surface area	Net thickness	Porosity	Porous volume	ρ _{CO₂}	Theoretical CO ₂ mass	“Realistic” CO ₂ mass	Efficiency coefficient	CO ₂ mass in traps
Unit	km ²	m	vol. %	m ³	t.m ⁻³	Mt _{CO₂}	Mt _{CO₂}	%	Mt _{CO₂}
Keuper	27 500	25	15	1.03E+11	0.70	72 188	4 331	6.0	130
Dogger	15 000	100	10	1.50E+11	0.48	72 000	4 320	6.0	9

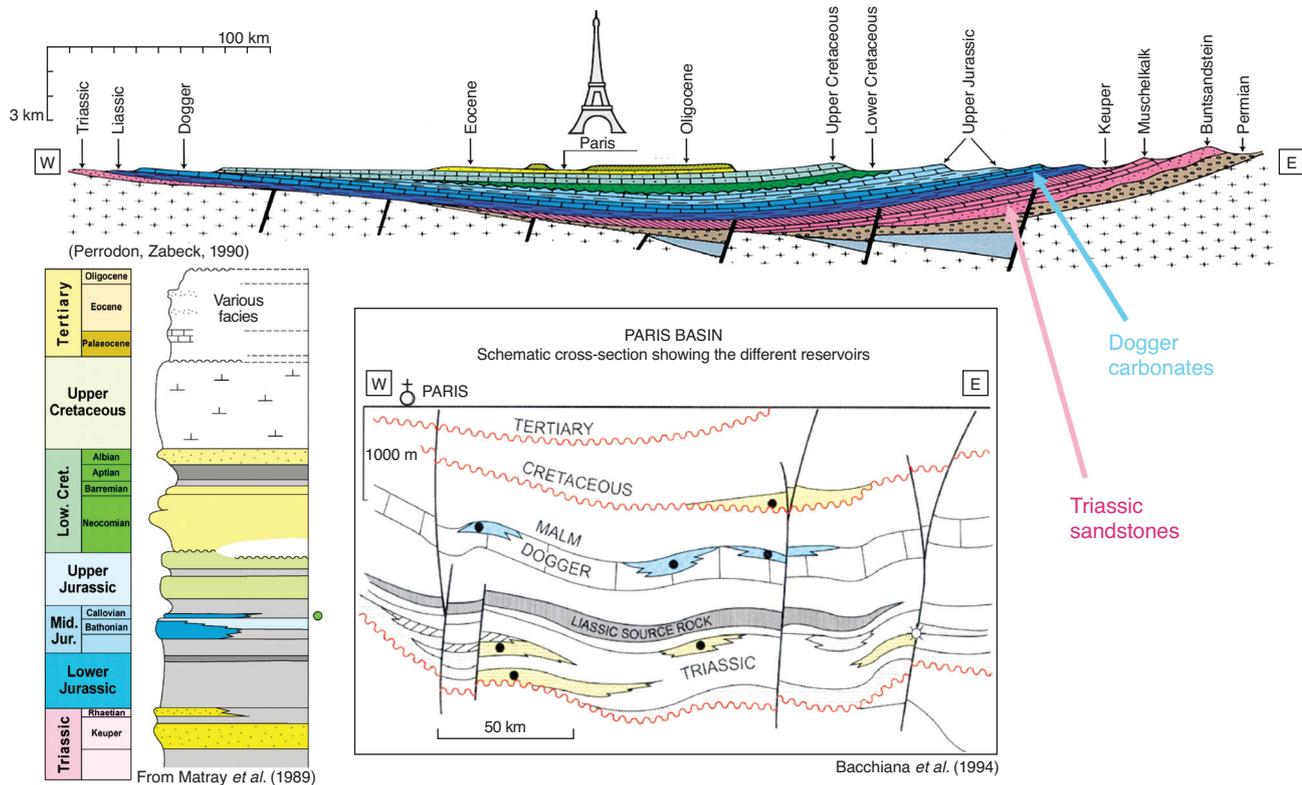


Figure 1

Two schematic cross sections of the Paris Basin sedimentary cover, and a lithostratigraphic column showing the geographic and geologic situation of the Triassic and Dogger (Middle Jurassic) aquifer formations examined in the present study (illustrations modified from Matray *et al.*, 1989; Perrodon and Zabeck, 1990; Bacchiana *et al.*, 1994).

cited document should be considered a too high value at this step of capacity evaluation.

Since five decades petroleum exploration has been active in the Paris Basin. Several tens of oil fields have been exploited, east and south-east of Paris city (*Fig. 1*), mostly in Dogger carbonates (*Comblanchien* and *Dalle Nacrée* Formations, respectively of Upper Bathonian and Lower Callovian age) and in the above-mentioned Triassic sandstones (Delmas *et al.*, 2002). The SMB oil field was exploited between 1959 and 1995 (*Shell*), then closed between 1995 and 2005, and finally opened again (*Société de Maintenance Pétrolière*). Oil is present in the *Dalle Nacrée* Formation and in the upper part of the *Comblanchien* Formation.

The geological disposal of carbon dioxide will involve strong requirements in terms of subsurface characterization and storage-behaviour simulation. Several demands will have to be met, under public authority licensing and control:

- at the local scale of a given storage facility, the protection of environment, potable waters, and human settings from any damaging impact, among which direct CO₂ release,

chemical pollution consecutive to displaced natural substance or co-injected gas, and soil deformation;

- at the global scale, a limited allowance of CO₂ migration back to the atmosphere (annual seepage rate lower than 0.01%, according to Hepple and Benson, 2005), a requisite condition for CCS being an efficient technology with respect to climate-change mitigation;
- an optimal use of the reservoir capacity offered by target formations, because the volumes of CO₂ to be stored are huge, and the resources offered by deep reservoirs are more and more attractive (geothermal energy, various storage types, etc.);
- an accurate prediction of pressure change inside the host and neighbour formations, and of any risk of long-distance interference with other activity linked to these formations;
- an accurate prediction of the fluid movements (CO₂, water, hydrocarbons, etc.);
- monitoring plans, and monitoring results able to check year after year the predictions made;
- plans for corrective action if the storage performance does not conform to the permitted storage notice.

For answering the above-listed demands, two steps of geological studies will be necessary:

- the geological formations and subsurface features concerned by the storage site will have to be described in a sufficiently exhaustive way, including not only the host reservoir but also the sealing formations, any pathway of a possible gas migration (faults, wellbores, etc.), and the aquifer units at a regional scale;
- detailed simulations of the storage evolution will have to be performed, either for the case of a normal, expected behaviour, or for the case of degraded situations identified by risk analysis.

Guidelines for the organization of such studies are now available (e.g., the summary report of the Weyburn project, by Whittaker *et al.*, 2004; Carbon Sequestration Leadership Forum reports; the *Best Manual Practice* by Chadwick *et al.*, 2007; IOGCC reports cited by Bachu, 2008; the *Directive* of the European Parliament, 2008; or Kaldi and Gibson-Poole, Eds., 2008). The work undertaken in PICOREF followed similar plan. In this article we present results of the geological investigations that were performed to describe and characterize the architecture and properties of the sedimentary cover in the area of interest. We explain how three-dimension numerical blocks representing the sedimentary pile inside an appropriate domain of the basin were built, and how such blocks can be used to generate grids adapted to the simulation of various processes induced by CO₂ injection. Finally, we show some of the simulations obtained to predict the behaviour of injected CO₂.

1 DATA AND METHOD

Most of the data that were used come from petroleum exploration. According to the French law seismic lines and development-well data older than 10 years are publicly available, whereas onshore wildcat data can be consulted immediately after drilling. Additional information was drawn from literature, in particular the results obtained during the exploitation of Dogger geothermal energy in the Paris area (Rojas *et al.*, 1990).

During a first step of the work a relatively large “Regional Domain”, ca. 17 000 km², was considered. 67 public and recent seismic lines of good quality (734 km) were selected and spliced, forming six regional profiles (Fig. 2). They were reprocessed by *Geophysical Services Ltd.*, according to a sequential program defined by F. Hanot (*BRGM*). In this processing static corrections at the pre-stack level include a 13-layers velocity model for Cenozoic sediments, specific corrections for the Upper Cretaceous (Senonian) chalk, and a geological model for the older sediments. Well-to-well correlation sections were built as close as possible to the six regional profiles, with the aim to facilitate the interpretation of seismics. Eight horizons were identified: Ho-1 (top

Cenomanian), Ho-2 (top Portlandian), Ho-3 (top Dogger carbonates), Ho-4 (top Toarcian), Ho-5 (top Domerian), Ho-6 (top Rhaetian), Ho-7 (top Middle Carnian), Ho-8 (top Palaeozoic substratum). However, in many places Ho-7 and Ho-8 could not be clearly recognized.

Geological considerations deduced from the investigation at regional scale, combined with various environmental and economic considerations, led to delineate a more restricted area, ca. 4900 km², that was named the PICOREF “Sector” (Fig. 2). This area was considered as the most appropriate for further selection of pilot-scale storage sites. It was chosen to include, near its eastern boundary, the SMB site.

During a second step of the work an additional, denser grid of seismic lines (450 km) was selected in the Sector, and reprocessed in the same way. An exhaustive database was collected from the 146 petroleum wells of the Sector that reached the Jurassic, including geological descriptions, wireline logs, core analysis (density, porosity, permeability), and well-test data (pressure, temperature, water salinity). Part of this database is presented by Delmas *et al.* (this issue). Twelve horizons could be identified on the reprocessed seismic lines of the Sector, where the chosen sections have a particularly good quality and resolution: Ho-1 (top Cenomanian), Ho-1·1 (top Aptian), Ho-2 (top Portlandian), Ho-2·1 (top Kimmeridgian), Ho-3 (top Dogger carbonates), Ho-3·1 (top Upper Bathonian *Oolithe Blanche* Formation), Ho-3·2 (bottom Upper Bathonian *Oolithe Blanche*), Ho-3·3 (top Bajocian *Ostrea Acuminata* marls), Ho-3·4 (bottom Bajocian *Ostrea Acuminata* marls), Ho-4 (top Toarcian), Ho-5 (top Domerian), Ho-6 (top Rhaetian). Ho-2·1, Ho-3 and Ho-3·4 are the best observed horizons, whereas Ho-5 and Ho-6 are sometimes poorly characterized. A line crossing the SMB field structure illustrates this interpretation (Fig. 3). A new structural map was generated from the considered seismic sections and well data. Finally, a 3-D numerical block that represents the sedimentary column in the Sector was built. For practical reasons, the detailed characterization of sediments was split between two partners, *BRGM* and *IFP*, that focused on Middle Jurassic - Cretaceous succession, and on Triassic - Liassic one, respectively. Correlatively, two geo-modeller softwares were used for building the 3-D block, namely *EarthVision* in *BRGM* and *GOCAD* in *IFP*.

In parallel with this work oriented towards storage in aquifer, a 3-D numerical block was constructed for SMB, from another set of local seismic lines (not reprocessed) and from well data. *GOCAD* was used also for this work.

A geo-modeller software aims in particular at representing geological geometries in 3-D from scattered data. It allows interpolation of data in 3-D from every point of the chosen area:

- for this purpose, *EarthVision* uses 2-D grids to facilitate computations and displays of 3-D surfaces (Dynamic

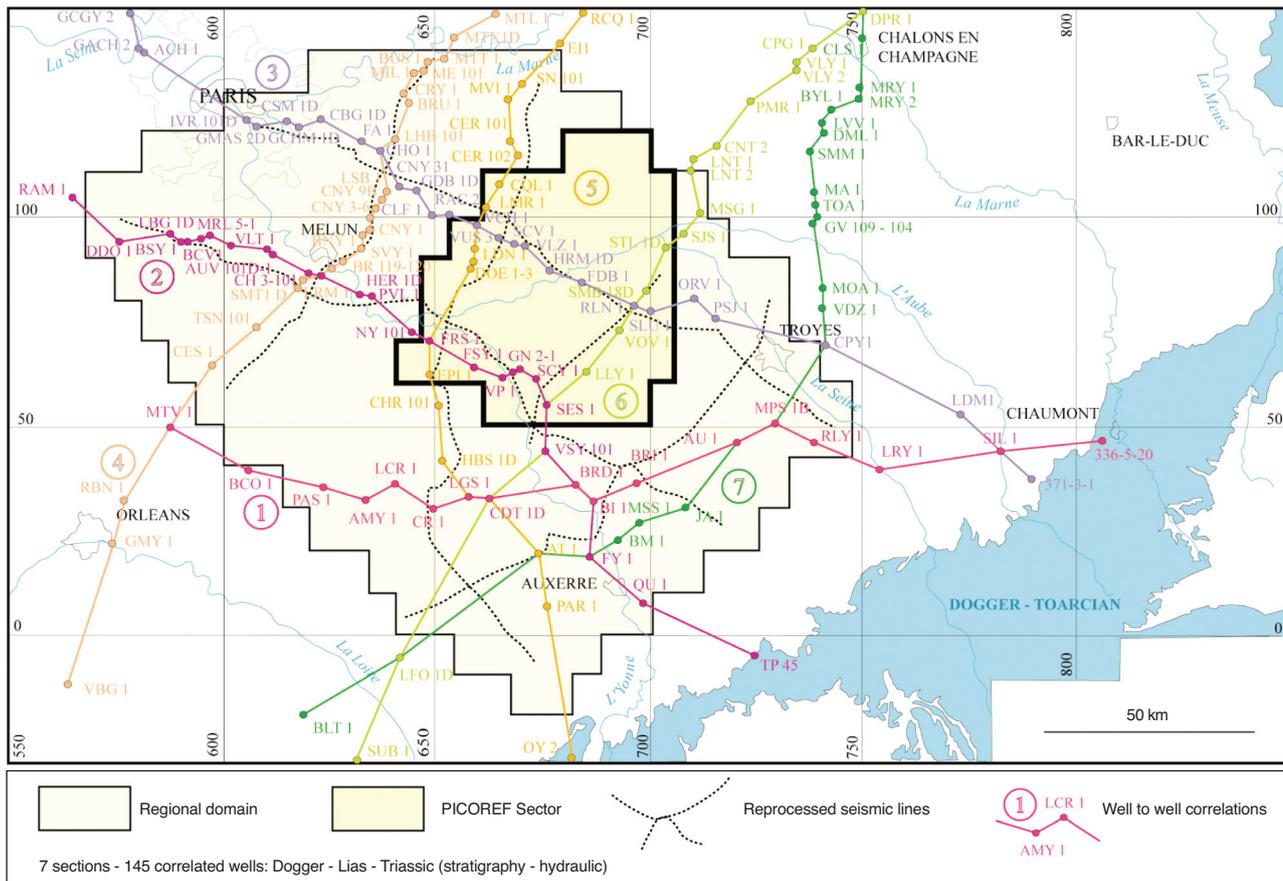


Figure 2

Trace of the seismic lines and of the well-to-well correlation sections considered in the PICOREF “Regional domain”. The location of the “Sector”, area selected after a first step of the study, is also shown on the map.

Graphics, 2002). EarthVision 2-D grids are surface models which contain Z-values at regularly spaced points in a rectangular matrix. The grid spacing is the distance between two grid nodes. It can be determined automatically depending on the number of scattered data and their geometry in space or can be set by the user. For instance, in the PICOREF EarthVision model, a grid spacing of 250 m was chosen for all the horizon surfaces – regular grid spacing for fault surfaces was calculated automatically by the software. Exports of horizon surfaces have been done through 2-D grids with this regular grid spacing of 250 m;

- in GOCAD the top of a sedimentary layer is a surface, described in a discrete way by a number of points. Each point is defined by x, y, z coordinates, and by connexions to other points (organized in triangles). Some points are constrained by data: well markers are considered as “hard data” that should be rigorously honoured by the model, as opposed to seismic data and geological interpretation

defined as “soft data” which influence the interpolation without being precisely honoured. The other points are interpolated according to given constraints such as the distance between points, the interpolation method, and soft data. For the present work, the interpolation method used was the “kriging with trend”, available in the “Structural Modelling Workflow” (Mallet, 2002), and the triangles size was 1500 m.

The 3-D blocks form a basis from which numerical grids can be defined in order to apply specific simulation codes. Many of the properties attributed to grid elements, *e.g.*, porosity, permeability, mechanical modules, etc., come from the well data of the area. For Dogger carbonates it was possible to study direct lateral equivalents, that nicely outcrop *ca.* 80 km updip in quarries of Burgundy. The observations collected improved the representation of reservoir sediments in the models, particularly as concerns the description of fractures and the representation of *Comblanchien* Formation at SMB. In addition, the permeability data resulting from core

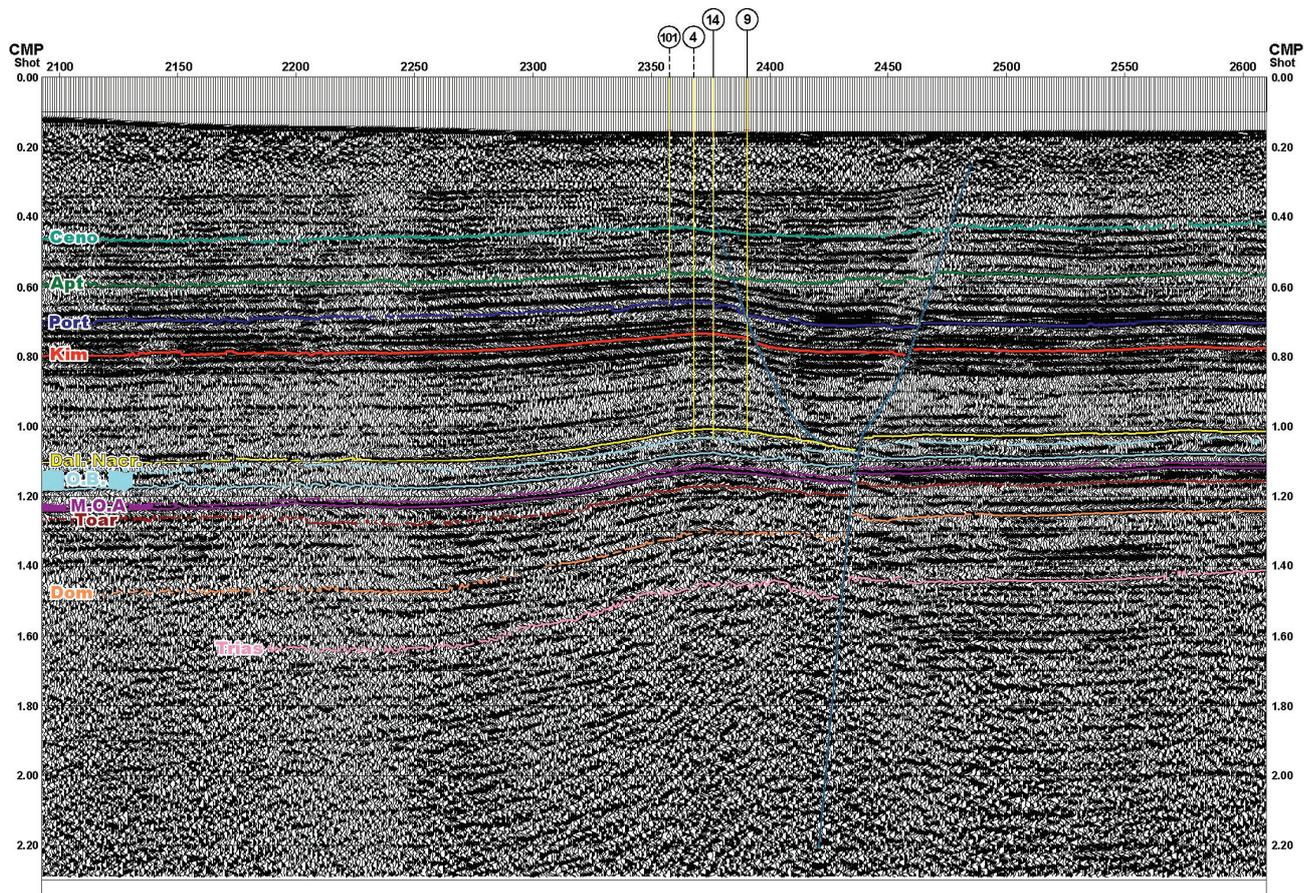


Figure 3

Seismic section through the Saint-Martin de Bossenay structure and oil field (SMB). The section has been reprocessed according to the sequential program indicated in text. Interpreted horizons: Ho-1 (top Cenomanian), Ho-1·1 (top Aptian), Ho-2 (top Portlandian), Ho-2·1 (top Kimmeridgian), Ho-3 (*Dalle Nacrée*, i.e., top Dogger carbonates), Upper Bathonian *Oolithe Blanche* Formation between Ho-3·1 and Ho-3·2, Bajocian *Ostrea Acuminata* marls between Ho-3·3 and Ho-3·4, Ho-4 (top Toarcian), Ho-5 (top Domerian), and Ho-6 (top Rhaetian).

analysis were compared to permeability and transmissivity values obtained at larger scales, either from well tests, or from published basin-scale modelling studies. A collection of permeability values at various scales was thus available to improve the characterization of carbonates in models dealing with fluid transport.

For the aquifers of the Sector fluid-flow simulations were carried out in the Dogger section using TOUGHREACT, a code from LBNL (Xu and Pruess, 1998; Xu *et al.*, 2005), and in the Triassic section using COORES™, a code from IFP (Trenty *et al.*, 2006). Both codes include a modelling of geochemical reactions that can occur between water and minerals. For SMB, two reservoir models were used, an old one provided together with the production data, and a new one that was created in PICOREF. A pure storage scenario was simulated with the old model, and with the FIRST reservoir-engineering code from IFP, according to a methodology of use adapted to the CO₂ context (Barroux,

2003a, b). This scenario, which represents a storage “maximum”, was considered for computing the mechanical impact of injection (Vidal-Gilbert *et al.*, 2008). The new reservoir model was built in order to introduce a more realistic representation of the sediments, to take into account better geological constraints, and to facilitate the use of new data provided by the present-day field operator. The new model was calibrated on production data using ECLIPSE software (Schlumberger, 2007), then this calibration was imported in a COORES™ application. Unfortunately, the modelling work with COORES™, dedicated to the simulation of CO₂ injection in the oil field, has not been terminated in time to be presented here.

Specific 2-D modelling work was carried out in relation with CO₂ in the Dogger carbonates. On one hand, the mechanical impact of injection was calculated with a full coupled hydro-mechanical model, using FLAC2D/TPflow software (ITASCA, 2001). On the other hand, the localization

of carbonate dissolution and reservoir alteration induced by pH drop of CO₂-rich water was explored, using the reactive-transport code COORES™.

2 GEOLOGICAL DESCRIPTION AND INTERPRETATION

2.1 Reprocessed Seismic Lines

In Figure 4 one of the two E-W regional transects illustrates the reprocessed seismic lines. A difficulty for their interpretation comes from the heterogeneous character of the spliced seismic segments. As the acquisition parameters of the initial lines were not necessarily the same, differences of resolution may appear from one segment to the next, and the interpreter has to come back to well data for smoothing the plotted horizons. 186 wells were taken into account for this work. The flat character of the sedimentary series and the scarcity of local geological structures is a striking feature of the Paris Basin, particularly well expressed in the studied Regional Domain, and well known from petroleum exploration (Duval, 1992).

The following step was to convert time to depth. 55 wells only, mainly in the Sector area, provided the needed velocity

data. In the time-to-depth conversion process interval velocities were preferred to average velocities, because in this way cross-cutting between two superposed seismic horizons is avoided. The section through SMB, already shown in Figure 3, illustrates the conversion result (Fig. 5). In the Sector area the top of Dogger carbonates lies between 1500 and 1800 m depth. Layers gently deepen towards the northwest with a slope *ca.* 0.75°. Triassic sandstones lie between 2000 and 3300 m. The marine sandstones formation of Rhaetian age, with top lying between 2030 and 2720 m, shows its maximum thickness, 30 to 40 m, in the northern half part of the Sector and further towards the northeast. The *Grès de Chaunoy* Formation is not present (it is present only in a NNE-SSW narrow trend between Paris and the Sector), whereas the *Grès de Donnemarie* Formation, with top lying between 2210 and 2950 m, shows its best development here, up to 350 m. As mentioned, in many places seismic horizons of Triassic series (Ho-6, Ho-7) are poorly defined, so that isobaths of Triassic aquifers were mainly constrained by well data. 41 wells of the Sector recognized the whole Rhaetian section and 30 wells drilled the whole *Grès de Donnemarie* Formation. 18 from the latter 30 wells provided cores, from any Triassic potential reservoir. An isopach map of the limestone *Oolithe Blanche* Formation could be drawn from converted seismic controlled by 54 wells (Fig. 6).

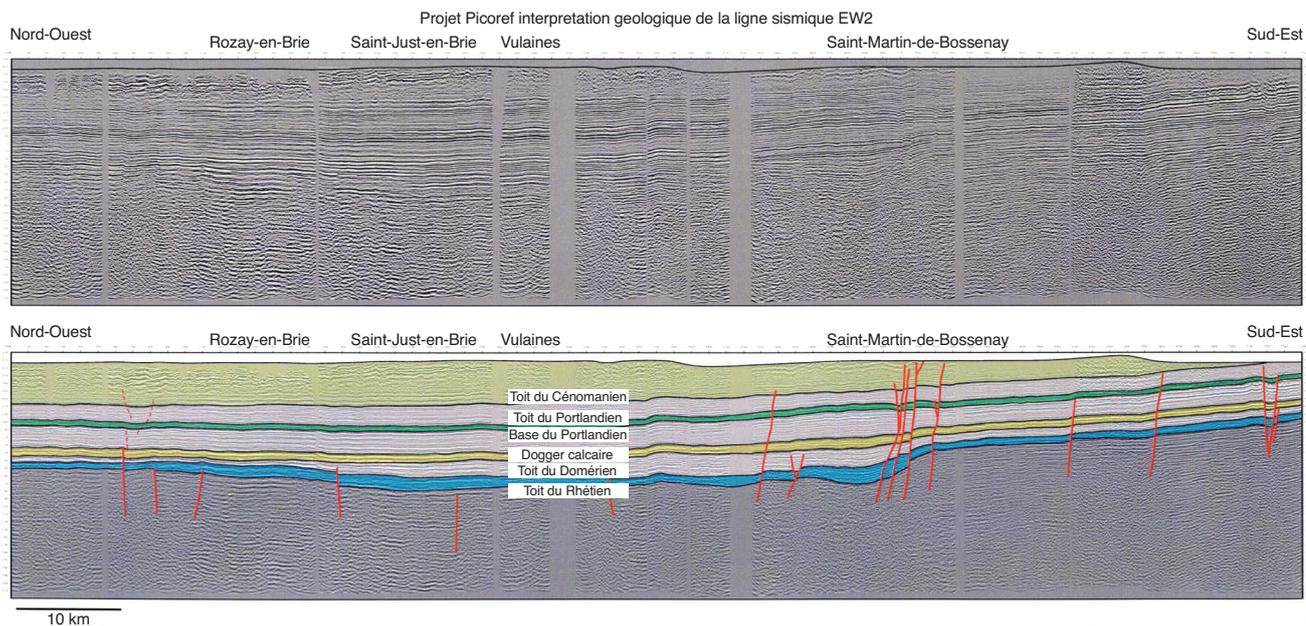


Figure 4

The EW seismic transect (along profile N.3 in Fig. 2):

- after reprocessing by the sequential program indicated in text (top picture);
- with the geological interpretation of 8 markers proposed at the regional scale: Ho-1 (top Cenomanian), Ho-2 (top Portlandian), Ho-3 (top Dogger carbonates), Ho-4 (top Toarcian), Ho-5 (top Domerian), Ho-6 (top Rhaetian), Ho-7 (top Middle Carnian), Ho-8 (top Palaeozoic substratum) (bottom picture).

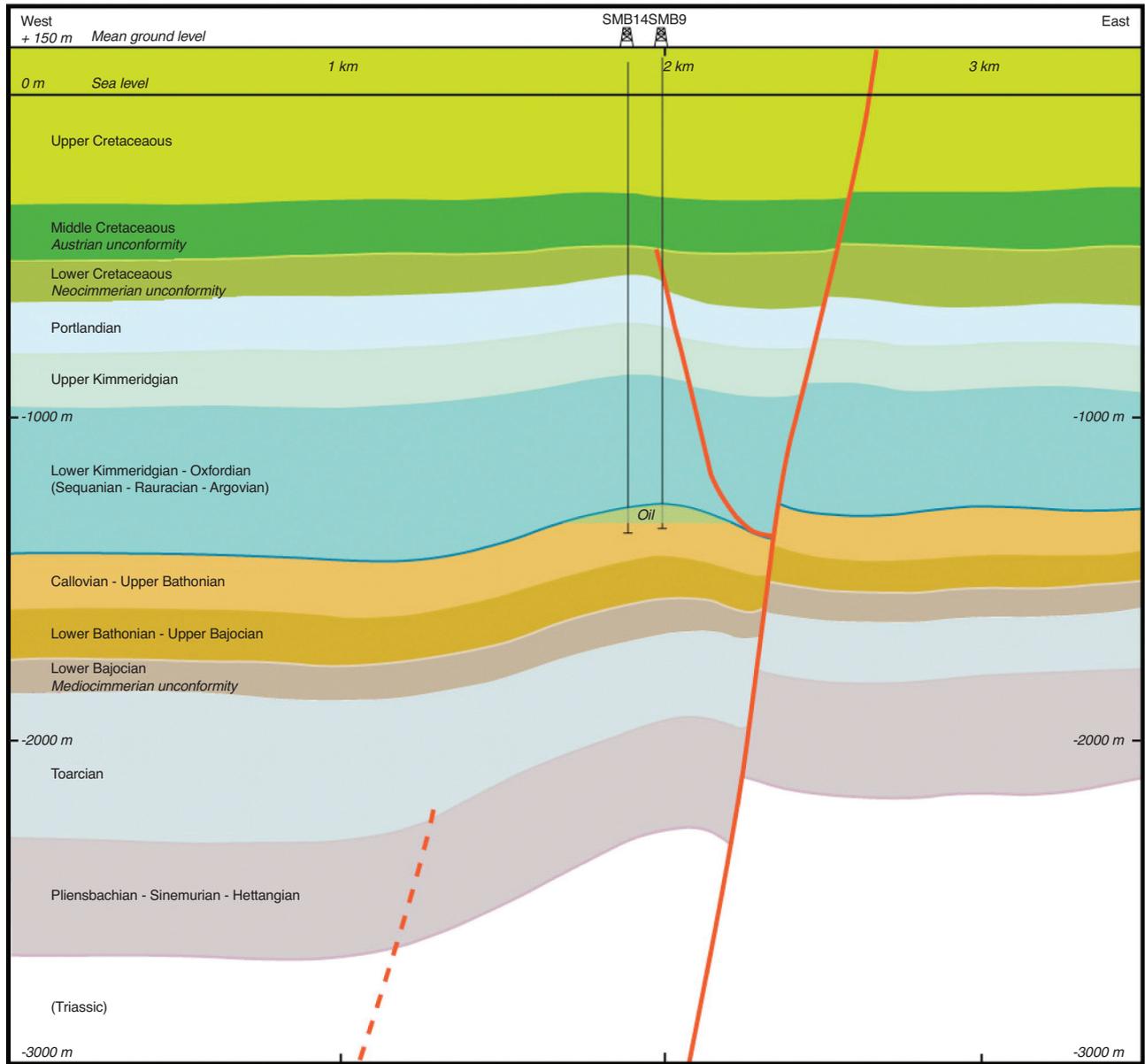


Figure 5

Depth-converted section obtained from the reprocessed seismic profile presented in Figure 3 (SMB structure) and seismic-velocity profile available for the SMB-17 well.

A major fact for CO₂ storage in the Regional Domain studied by PICOREF is that the occurrence of structural trapping is scarce or absent. Concerning the sealing capacities offered by the Triassic and Liassic series of the Sector, the fluvial sandstones of the *Grès de Donnemarie* Formation are capped by 250 m of continental marls/anhydrite layers, and the marine Rhaetian reservoirs by 300 to 400 m of Liassic marls. The confinement of *Oolithe Blanche* Formation is discussed below. The thickness of the potential reservoirs and

seals has been one of the criteria used in the delineation of the Sector area.

Another important result obtained from seismic reprocessing was the design of a new structural scheme. Only the main faults, showing a larger than half-phase throw, *i.e.*, a minimum of 20 m throw, were picked (*Fig. 7*). Due to the excellent static corrections many features that were previously interpreted as faults (*e.g.*, Delmas *et al.*, 2002) do not appear anymore. The low density of faults on map has been also a

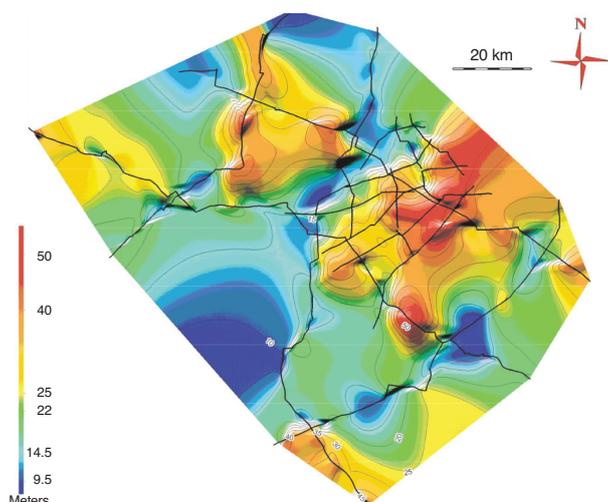


Figure 6

Map of the *Oolithe Blanche* Formation isopach contours (in metres), obtained after time-to-depth conversion using velocity profiles of 55 wells.

criterion for the choice of the Sector limits. However, a main regional fault of the Paris Basin, namely the Saint-Martin de Bossenay Fault, passes through the Sector close to its eastern margin. The SMB oil field was thus included in the Sector and the geological syntheses made on the two areas could be mutually beneficial.

This first step of geological description, based on the reprocessing and interpretation of *ca.* 1200 km of seismic lines, and on the collection of stratigraphic markers from the complete set of wells, provided a constrained architecture for the earth model at the Sector scale, including the succession of sedimentary layers and the faults to be considered. In particular, it allowed drawing isopach maps of target formations, and it showed the scarcity of structural trapping in the studied area.

2.2 Hydrogeology

As noted above, well data were intensively used for seismic interpretation. The well-to-well correlation sections identified in Figure 2 have been drawn using lithological columns characterized from all the available well-log and core-analysis data. For most wells, unfortunately, numerical versions of the logs are not available and paper logs had to be used. The sedimentary pile was subdivided in six main tectono-stratigraphic systems. Following a screening procedure based on composite log (“quick look procedure”), the correlation sections were represented in two distinct ways: 1) as stratigraphic sections (*e.g.*, Fig. 5 at SMB – see also Fig. 3 in Delmas *et al.*, this issue), and 2) as “hydraulic” (hydro-geo-

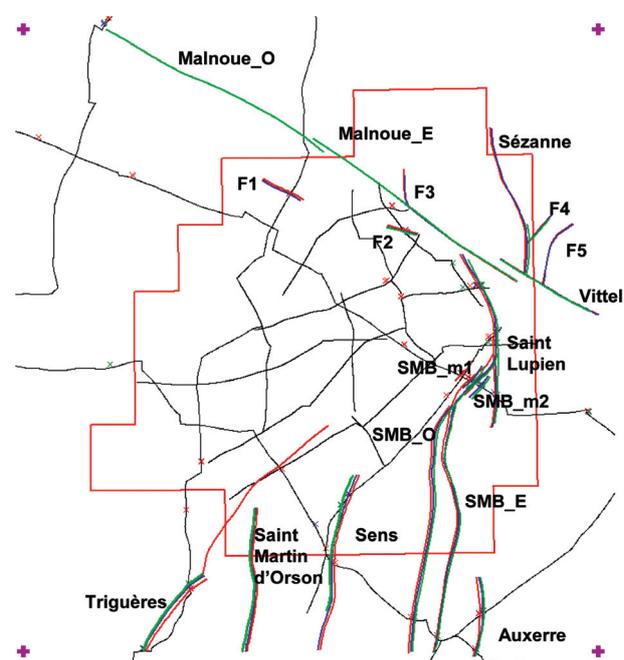


Figure 7

New structural interpretation proposed at the PICOREF Sector scale. Better homogeneity of the data (reprocessed seismic lines and well-to-well correlation profiles) allowed to simplify and make more consistent the pre-existing structural map.

logical) sections, where according to the features recorded by standard logs three types of intervals could be distinguished in terms of reservoir quality, namely *aquifer* intervals, that have a chance to contain reservoir capacities and flow units, *aquitard* intervals, that should delay fluid flow, and *aquiclude* intervals, that will probably stop fluid flow (the best potential seals). Unfortunately, because of the poor quality of the material used, it was not possible to quantitatively characterize, with cut-off values, the three types of sediments. The description scale was chosen to fit with the resolution of reprocessed seismic lines. The minimal thickness of the depicted hydraulic intervals is *ca.* one metre. In the example Delmas *et al.* (this issue) give of such an hydraulic section (their Fig. 4), the *Oolithe Blanche* Formation, mainly composed of oolitic grainstone, typically appears as an “aquifer” interval, the *Comblanchien* Formation where lagoonal calcareous mudstone and wackestone dominate is, at least partly, seen as an “aquitard” interval, and the Middle Callovian *Marnes de Massingy* Formation or the Upper Bajocian *Ostrea acuminata* Marls Formation are noted as “aquiclude” intervals. Figure 8 shows other examples for the Dogger formations. It must be stressed that in such hydraulic-oriented sections a term-to-term correspondence between interval type and hydraulic conductivity is not

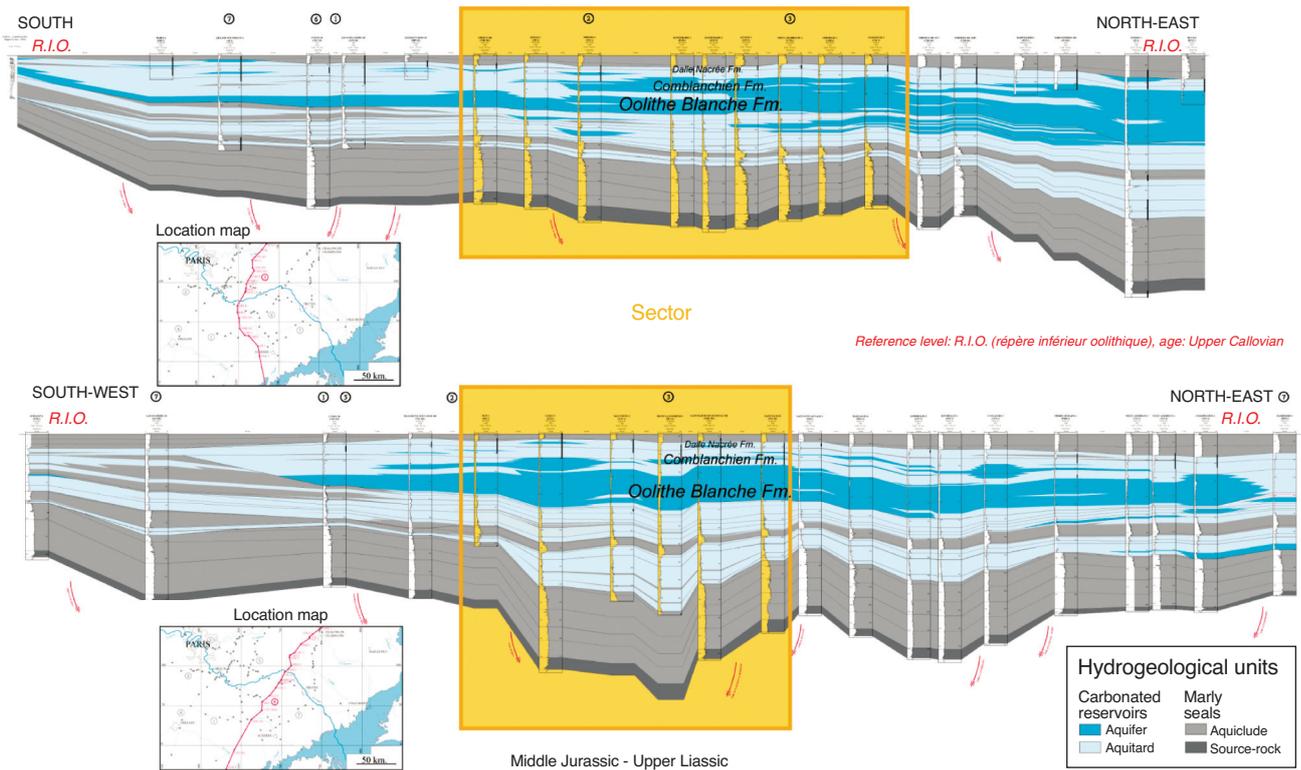


Figure 8

Example of well-to-well correlation profiles with indication of hydraulic properties deduced from well logs. The two sections illustrate the distribution of potential aquifer units (dark blue), *i.e.*, parts of the formations that contain sediments with a relatively high porosity, inside the Dogger carbonates. Carbonates with a lower porosity appear in light blue. Clay-rich, potentially good seals are represented in grey. The top of Middle Jurassic was taken horizontal for the representation.

straightforward. This is particularly true in carbonate series, where diagenetic processes and fracturing play a foreground role in the distribution of porosity and permeability. Due to the lack of systematic testing or coring, the “aquifer” quality of an interval could be recognized only from porosity-sensitive log parameters. Even plotting wireline log measurements in front of core-analysis permeability leads frequently to surprises in these sediments. The most rewarding approach would be to compare and inter-calibrate well-test results, log signatures and sedimentological/petrographical core analysis, unfortunately most of the test archives examined for the present work were not explicit enough to be interpreted in terms of flow value (or transmissivity value). In the few tests for which this work could be done, transmissivity reaches between one and two orders of magnitude higher values than the transmissivity value deduced from core measurements. This fact is well known in a large area around Paris, west of the Sector, where since more than twenty years the *Oolithe Blanche* Formation has been exploited for geothermal energy (Menjzo *et al.*, 1990). Water is produced and re-injected by

coupled wells. From the whole 100 to 150 m Bathonian carbonates opened to production, observations showed that only 10 to 20 metre-scale layers, cumulating *ca.* 20 m of sediments, are really productive. In addition, the producing layers cannot be precisely correlated on a km-scale distance. The situation is simpler in the silico-clastic series of Triassic age, nevertheless, even in the “aquifer” intervals – represented by a yellow colour in the sections as shown by the example of Figure 9 – more precise data show that sandstone can be present only as relatively thin, metre-scale, recurrent beds inside clay-rich sediments (Fig. 10).

There could be opportunities for stratigraphic trapping, nevertheless, for Dogger carbonates it seems that such opportunities are not present in the Sector, and, should they exist for Triassic sandstones, they cannot be defined with precision from the available information. Combined with the scarcity of structural trapping, this fact has an important consequence. The main trapping mechanisms that will operate to confine the injected gas into the discussed aquifer formations will be hydrodynamic trapping, capillarity, and –

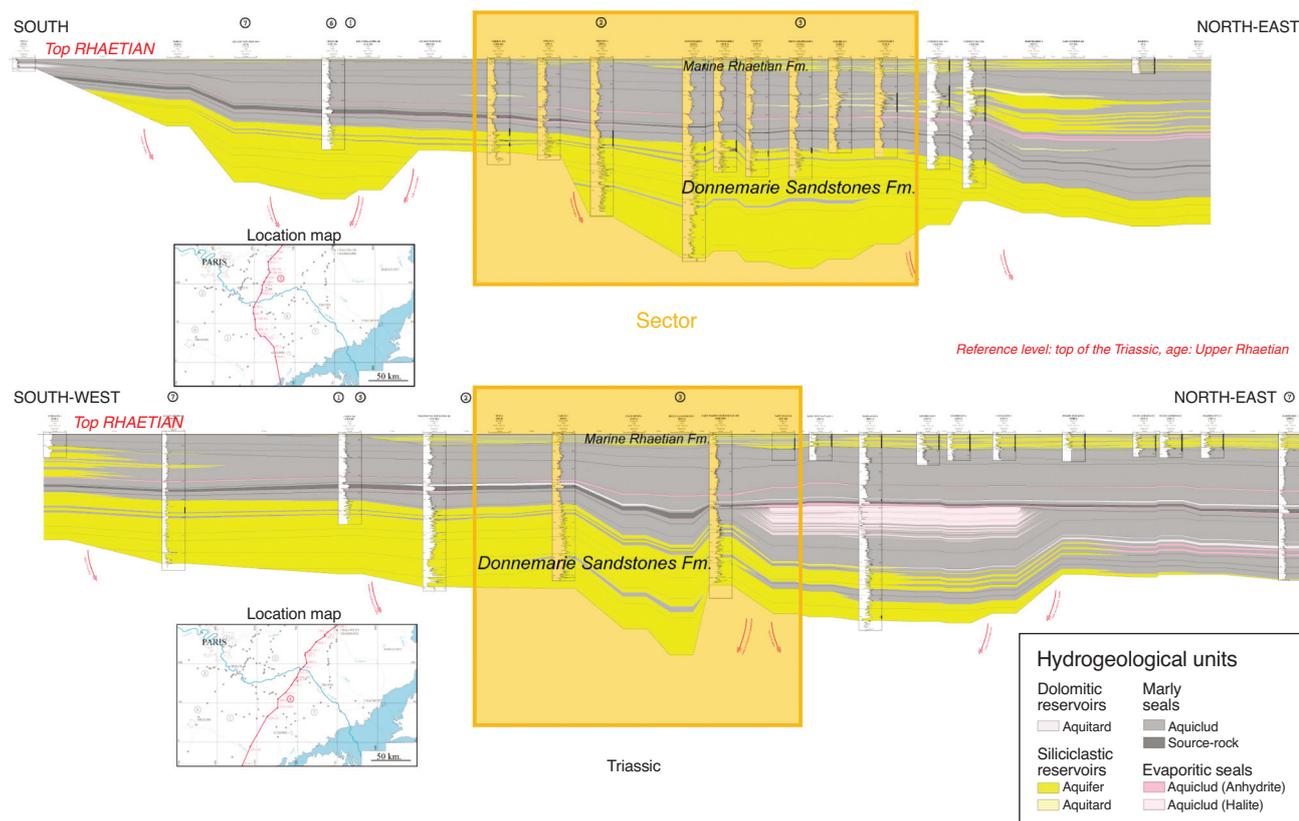


Figure 9

Example of well-to-well correlation profiles with indication of hydraulic properties deduced from well logs. The two sections illustrate the distribution of potential aquifer sandstone-rich units (yellow) inside the Triassic silico-clastic series. Clay-rich, potentially good seals are represented in grey. The top of Triassic was taken horizontal for the representation.

probably on longer term – solubilization in water. The same situation is anticipated for most parts of the Paris Basin, especially when dealing with large CO₂ storages (100 Mt and more). Moreover, in contrast with Triassic sandstone formations directly sealed by a clay-rich cap rock, the *Oolithe Blanche* Formation is overlain by the pure-carbonate mudstone facies of the *Comblanchien* Formation, to which it also passes laterally. These fine-grained facies, heterogenous and fractured, should behave as an aquitard more than an aquiclide. Such conditions give particular importance to the understanding of natural hydrodynamism. Collected well-test results in the Regional Domain provided pressure values, from which piezometric maps could be deduced. For the Dogger carbonates 233 values were analysed, of which 80 correspond to tests carried out in geothermal wells. The latter, much longer than tests usually made in petroleum wells (20 to 24 hours instead of few hours), served as a reference dataset. In general *P* values from petroleum wells consistently confirm the unique pressure-depth trend, close to hydrostatic, observed in the whole Bathonian-Callovian section. There is no compartmentalization between the

carbonate formations. The areal distribution of hydraulic head is compatible with a moderate regional flow oriented from the outcrops present in the east and the south-east of the basin, towards the north-west of the basin (order of magnitude 10 cm·yr⁻¹). Many observations made during oil production in several fields of the area confirm the “aquifer activity” of the whole Dogger. The pressure build-up at SMB, during the ten years the field was closed (1995-2005), is another expression of the same fact. For the Triassic reservoirs much less values are available. In the *Grès de Donnemarie* Formation very low pressure gradients exert their influence from a large south portion of the Sector towards the north, and should result in water-flow velocities in the order of 1 cm·yr⁻¹. This large-scale vision of regional flow does not exclude local perturbations, due in particular to salinity gradients.

Well-test data also provided values of water salinity and temperature. Concerning Dogger the database was completed for the whole Regional Domain, with 256 data in Bathonian and 115 in Callovian, whereas concerning the Triassic

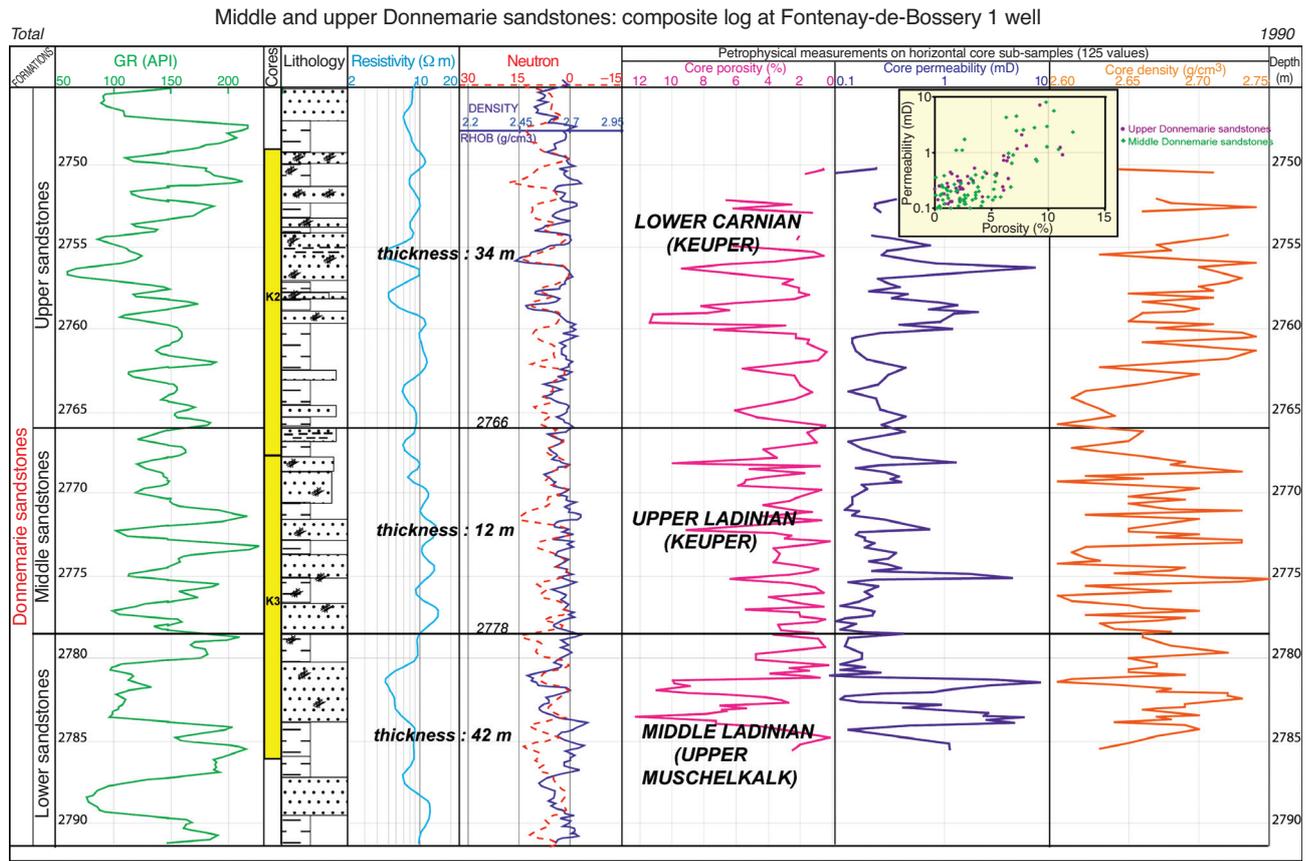


Figure 10

Example showing the detailed distribution of shales and sandstones, and the corresponding reservoir properties, in the Grès de Donnemarie Formation of the Fontenay-de-Bossery 1 exploration well.

sandstones only the values for the Sector area were taken into account, with 3 data in Rhaetian, and 9 in Grès de Donnemarie Formation. Average temperature in Dogger is 65°C. In Bathonian carbonates of the Sector salinity increases from 5 g·L⁻¹ to 25 g·L⁻¹ from south-east to north-west (Fig. 11). Temperature (resp. salinity) values indicate 84 to 115°C (resp. 2 to 10 g·L⁻¹) in Rhaetian, and from 97 to 115°C (resp. 60 to 200 g·L⁻¹) in Grès de Donnemarie Formation. The considered formations do not belong to the group of aquifer layers protected as a water resource in this part of the basin, nevertheless, the low salinity values except in Grès de Donnemarie Formation must be noted.

In conclusion, the second step of geological description provided a qualitative representation of the way hydraulic units are distributed at the Sector scale (aquifer vs aquitard vs aquiclude). Although not excluded, stratigraphic traps could not be clearly localized. The trapping mechanisms to be expected for CO₂ are hydrodynamic trapping, capillary trapping, and solubilization in water. For the main aquifer

section of the Dogger a large collection of well tests constrained a representation of natural hydrodynamism at the regional scale. Water flow is ca. 10 cm·yr⁻¹, towards the north-west. Though much less constrained, water flow in the main Triassic aquifer section of the Sector is 10 times less, oriented northwards. Maps of temperature and salinity of the target formations were also drawn. Finally, an important feature of the Oolithe Blanche carbonate Formation is that its immediate cap rock is an aquitard, not an aquiclude. This fact should render more difficult the appraisal of confining properties offered by storage sites located in this formation.

2.3 Sedimentological Features and Fracturation

Equivalent lateral terms of the Dogger carbonates can be observed from outcrops of Burgundy (s.l.). Oolithe Blanche Formation is nicely and freshly exposed in quarries, where it is exploited as a building stone (Fig. 12a). During PICOREF typical facies successions were described there, and interpreted

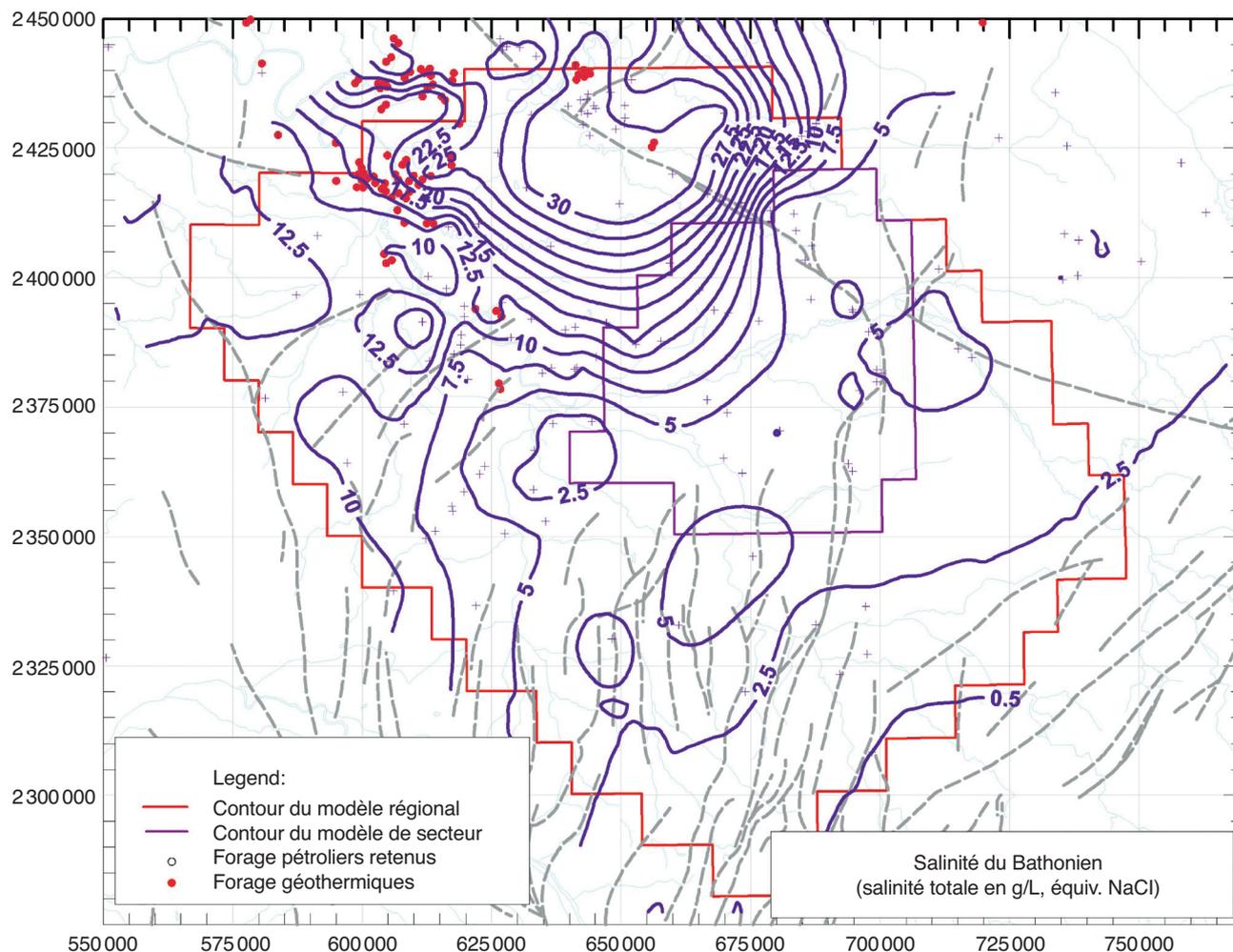


Figure 11

Water salinity distribution in the Bathonian formations (*Oolithe Blanche* and *Comblanchien*), at the scale of the PICOREF Regional Domain. The perimeter of the Sector area is also indicated. Note the relatively low values ($<10 \text{ g}\cdot\text{L}^{-1}$) in a large south-eastern part of the domain, including most of the Sector, and the local increase of salinity values in the north-western part of the Sector.

in terms of depositional environment. This work improved already existing conceptual models (Floquet *et al.*, 1989; Gaumet *et al.*, 1996). However, a quantitative sedimentological model calibrated on field/sub-surface data and applicable for instance in a geostatistical approach of reservoir description is not available yet for this formation. Observations of *Comblanchien* (Fig. 12b) and *Dalle Nacrée* (Fig. 12c) Formations, and comparison with cored sections of the Saint-Martin de Bossenay wells, were determinant for improving the geological representation of the carbonate units which form the reservoirs of the SMB oil field, respectively the *Comblanchien* “D” and “C” units, and the *Dalle Nacrée* “B” and “A” units (see Fig. 5 by Delmas *et al.*, this issue). In particular, recurrent dolomite-rich layers could be correlated and

interpreted in the *Comblanchien* Formation at the quarry scale, and afterwards we came across the same pattern in SMB Unit D (core observations) and could correlate it throughout the field using well logs. The new reservoir model thus splits Unit D in four sub-units that correspond to sedimentary sequences terminated by a dolomitized layer. Its performance for simulating the reservoir behaviour in the *Comblanchien* Formation during production history is much better than with the old model.

Another advantage of the cutting edge in quarries is that they allow good observation of fractures (Fig. 13). For the present project a first step of the work focused on the *Comblanchien* Formation, that was observed in six quarries. Fractures are particularly well defined in the mudstone and

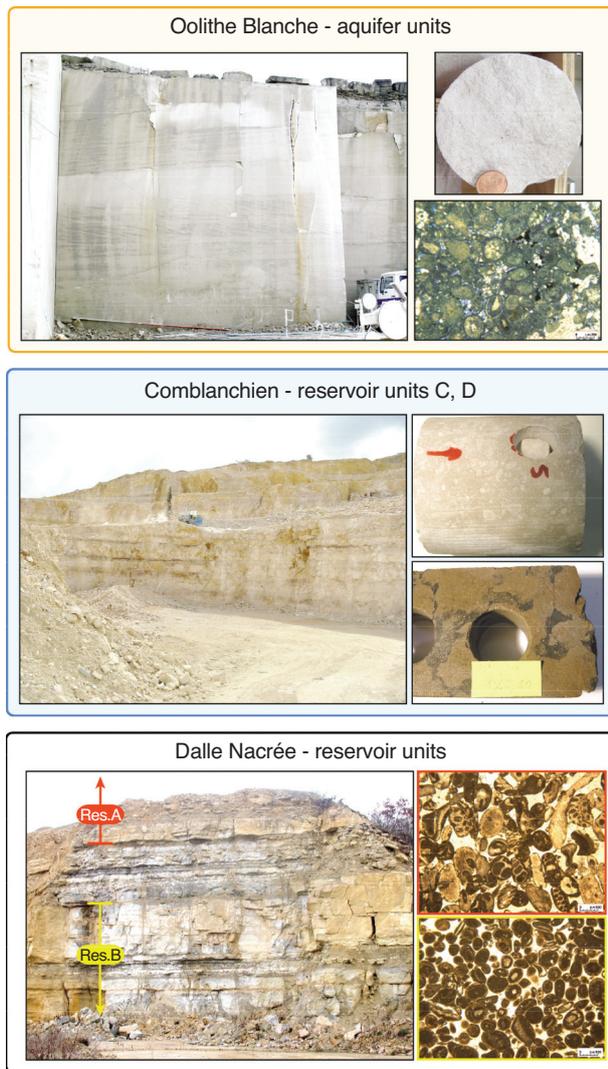


Figure 12

The Dogger carbonate formations of the Paris Basin can be observed in many quarries of Burgundy (*s.l.*), at ca. 80 km southeast of the Sector. The photographed outcrops are located in Massangis (*Oolithe Blanche*), in Plombières-lès-Dijon (*Comblanchien*), and in Chassignelles (*Dalle Nacrée*). The letters A, B, C, D, correspond to the reservoir units observed in SMB.

wackestone facies of this formation. Four families of sub-vertical fractures could be described, with a dominant one oriented N40°E, consistent with the regional tectonic stress (Cornet and Burlet, 1992). Dimensional and density parameters of the fractures were measured and the respective relationships between one family to the other in the network were systematically analysed. A second step consisted in enlarging this characterization to the neighbour formations, namely *Oolithe Blanche* and *Dalle Nacrée* ones. It is remark-

able that the fracture network families remain unchanged from one site to the other. Nevertheless, the relative importance of one family or the other may change according to the geographical location, or to the formation.

Field studies presented above, a third step of geological description, aimed at better characterizing reservoir heterogeneities and fracturation. Possible on Dogger carbonates, they allowed significant improvement of the reservoir model at SMB. They did not provide, however, a quantitative sedimentological model able to be extrapolated throughout the Sector. For the considered carbonate series, such a model does not exist. Its elaboration would call for much more data and investigations than those allowed by the present project. Triassic sandstones, in contrast, are expected to follow well-known sedimentological models. The scarcity of well data, nevertheless, makes difficult their calibration.

3 THREE-DIMENSIONAL NUMERICAL MODELS OF SUBSURFACE

Storage-behaviour prediction by numerical modelling has to consider the sedimentary pile up to the surface, not only the host reservoir and its immediate cap rock. In the sediments succession the aquifer formations must be defined with a particular accuracy, some of them eventually considered as “control aquifers” for storage monitoring (a standard concept for natural-gas storage), other ones regarded as layers to be protected from any contaminant. The geological description deduced from depth-converted seismic lines, well data and fault network has therefore to be organized in a way that would facilitate the use of various numerical codes, able to calculate specific mechanisms induced by CO₂ injection. The best approach is to build three-dimensional (3-D) earth numerical model that integrates every geological information and represents the sedimentary pile on a pertinent scale. Two such blocks were elaborated in the present study, one at the Sector scale and the other at a more restricted scale around the SMB oil field. Petrophysical properties, *e.g.*, porosity, permeability, mechanical modules, etc., can be also associated to the layers identified in the representation.

3.1 Three-Dimension Block Model for the Sector

For building the Sector block two difficulties were encountered. Dealing with Triassic series the constraints available at the Sector scale are not sufficient. It was thus decided to work at a broader scale, including all the well data of the Regional Domain and even larger, further east and south-east to the outcrops (the so-called “*Bloc bourguignon*”). Doing that way, it was possible to introduce a vision of each layer in terms of depositional environments, that helped in the geometrical reconstruction. The second difficulty has been to split the whole Dogger carbonate succession in few discrete

TABLE 2

Layers represented in the 3-D block of the Sector

Layer/ Formation	Age
<i>Tithonian</i> Formation (aquifer)	
<i>Kimmeridgian</i> marls	Kimmeridgian
<i>Lusitanian</i> Formation (aquifer)	Oxfordian - Kimmeridgian
<i>Oxfordian</i> marls	Oxfordian
<i>Massingy Marls</i> Formation	Upper Callovian
<i>Dalle Nacrée</i> Formation	Lower Callovian
<i>Comblanchien</i> Formation	Upper Bathonian
<i>Oolithe Blanche</i> Formation	Upper Bathonian
<i>Calcaire à Pholadomyes</i> (marly limestone)	Upper Bajocian - Middle Bathonian
<i>Ostrea acuminata</i> marls	
<i>Calcaire à entroques</i>	Lower Bajocian
Transition	Lias
Banc de Roc	
	Upper Domerian
	Lower Domerian
	Carnian
	Upper Lotharingian
	Middle Lotharingian
	Lower Lotharingian
	Sinemurian
	Hettangian
Rhaetian marine sandstones	Rhaetian
Continental sediments	Rhaetian
<i>Grès de Chaunoy</i> Formation	Norian
<i>Argiles de Chaville</i> Formation	Upper Carnian
<i>Dolomie de Beaumont</i> Formation	Upper Carnian
<i>Couches à Esthéries</i> Formation	Middle Carnian
<i>Marnes irisées moyennes</i> Formation	Lower Carnian
<i>Marnes irisées inférieures</i> Formation	Upper Ladinian
<i>Grès de Donnemarie</i> Formation	Upper Ladinian
<i>Lettenkohle</i> Formation	Middle Ladinian
<i>Muschelkalk</i> Formation	Lower Ladinian
<i>Middle Muschelkalk</i> Formation	Upper Anisian
<i>Lower Muschelkalk</i> Formation	Middle Anisian
<i>Grès à Volzia</i> Formation	Lower Anisian
<i>Grès des Vosges</i> Formation	Scythian
<i>Lower Buntsandstein</i> Formation	Scythian

layers that should represent at best the hydraulic structure. 41 hydraulic sections obtained from well-log data with the above-mentioned “quick-look procedure” were used for this work. In most cases an interval of porous sediments, several tens of metres in thickness, is clearly recognized (porosity values higher than 14%, and up to 30%, according to core data). It probably coincides with the *Oolithe Blanche* Formation (Fig. 14). The 3-D Sector block finally integrates 36 layers, from the *Lower Buntsandstein* Formation to the Portlandian deposits (Fig. 15), distributed as indicated in Table 2. For the time being this 3-D block does not integrate more superficial sediments.

3.2 Three-Dimension Block Model for the SMB Site

The 3-D block model of the SMB site was constructed in a 20 × 40 km area surrounding the oil field structure. It was not deduced from the reprocessed seismic sections presented above, but from a local set of 9 seismic lines (year 1980 survey). More specifically, two isochron maps (top Rhaetian and Neocomian marker) and two isobath maps (top *Dalle Nacrée* Formation and top Lower Cretaceous) elaborated from the seismic survey (Tran-Van Nhieu, 1993) were digitized, and combined with the depth of 11 horizons in 25 wells (SMB-1 to SMB-18D, SMB-201, RN-1, AP-1 and AP-2, BDG-1, SLU-1 and SLU-2). Seismic velocities available in SMB-17 and SMB-201 were used to convert to depth the two isochron maps. The horizons identified in the block model are the following: top Albian, Ho-1·2 (Neocomian marker), Ho-2·1 (top Kimmeridgian, *i.e.*, top *Marnes à Exogyres* Formation), Ho-2·2 (bottom *Marnes à Exogyres* Formation), Ho-2·3 (top *Marnes de Massingy* Formation, *i.e.*, “RIO” marker), Ho-3 (top Dogger carbonates), Ho-3·3 (top Bajocian *Ostrea Acuminata* Marls Formation), Ho-4 (top Toarcian), Ho-5 (top Domerian), Ho-6 (top Rhaetian), Ho-8 (substratum). Figure 16 illustrates the 3-D SMB block.

4 FLUID-FLOW MODELLING IN THE HOST RESERVOIR

A 3-D block as those presented in the previous section is a geological representation and a numerical framework in which diverse modelling studies can be inserted. The predictive modelling of storage behaviour forms the basis of storage design and monitoring plans. It should be central for preparing either impact studies, that describe the normal running of the operations on the site, or risk-analysis studies, that describe deteriorated situations. Regulatory authorities will require the results of such studies from the operator, at defined steps of the storage lifetime.

The spinal cord of storage modelling is the simulation of fluids pressure and movement in the host reservoir. The approach is close to the standard reservoir-engineering approach used in petroleum industry. It is focused on the part

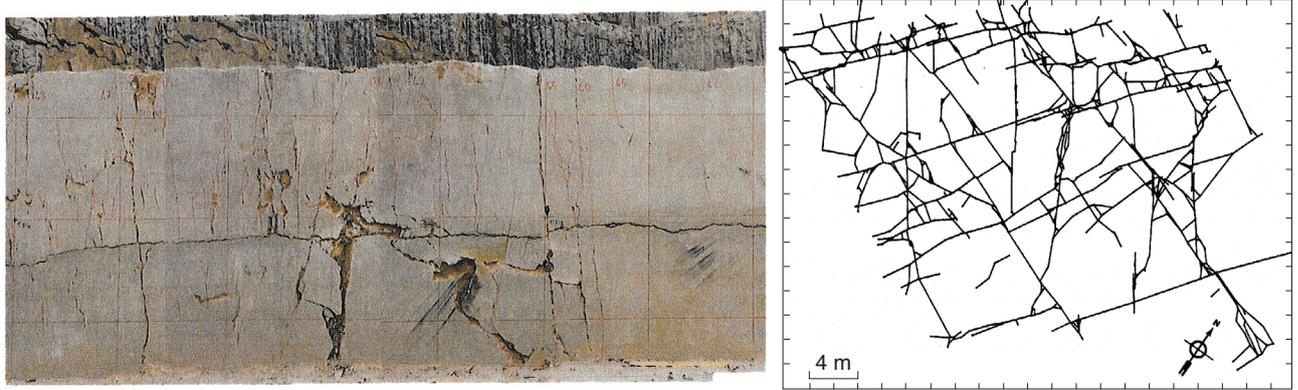


Figure 13

The cutting edges of quarries also allow a good observation of the fractures networks, here in the *Comblanchien* Formation at Massangis (illustration partly modified from Gervais, 1993).

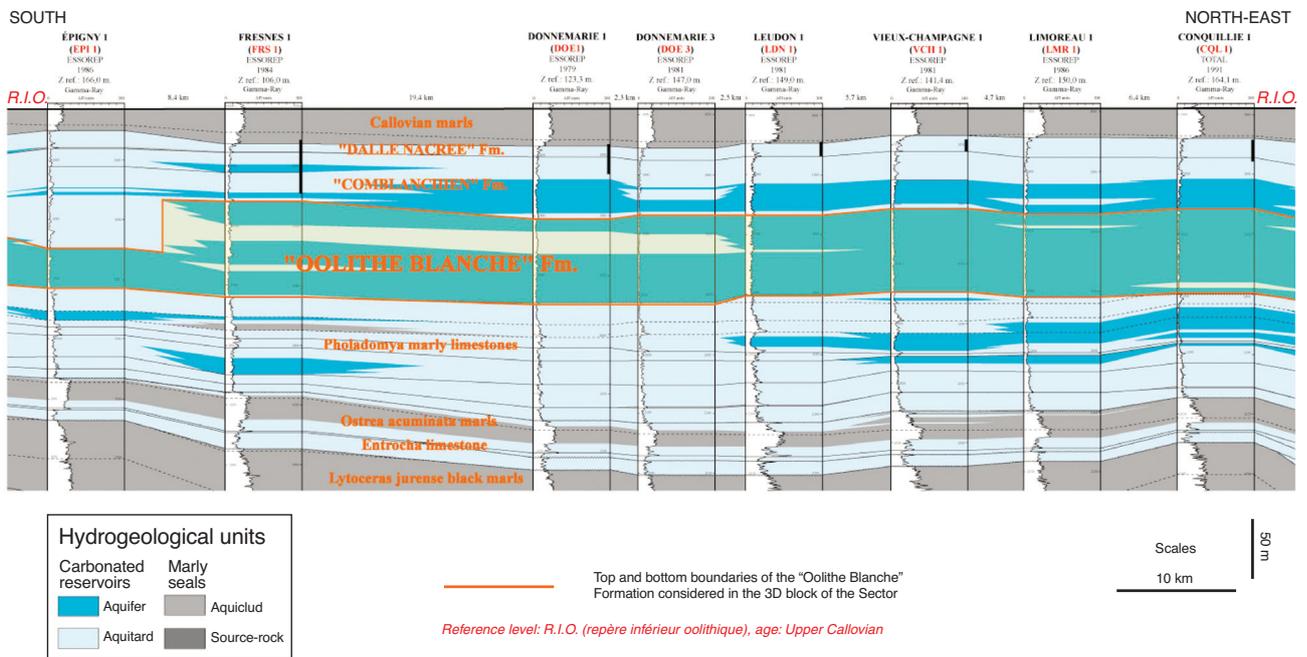


Figure 14

Example showing, on a well-to-well correlation profile, the lower and upper boundaries chosen for the *Oolithe Blanche* Formation in the 3-D block of the Sector.

of the 3-D block where is located the reservoir. It considers a given storage scheme, that must include the location of wells (for CO₂ injection, for observations, eventually for production of water/oil), and the layers they exploit in the reservoir. Input data concern:

- the reservoir layers, represented by grid elements to which porosity and directional permeability values are associated;

- the fluids (“PVT” model, density and viscosity values, solubility properties);
- the interaction between rocks and fluids (relative permeability vs saturation);
- the description of boundary conditions;
- a scenario of CO₂ injection that includes a description of the initial state of the system.

We present here two simulations. Both address the injection

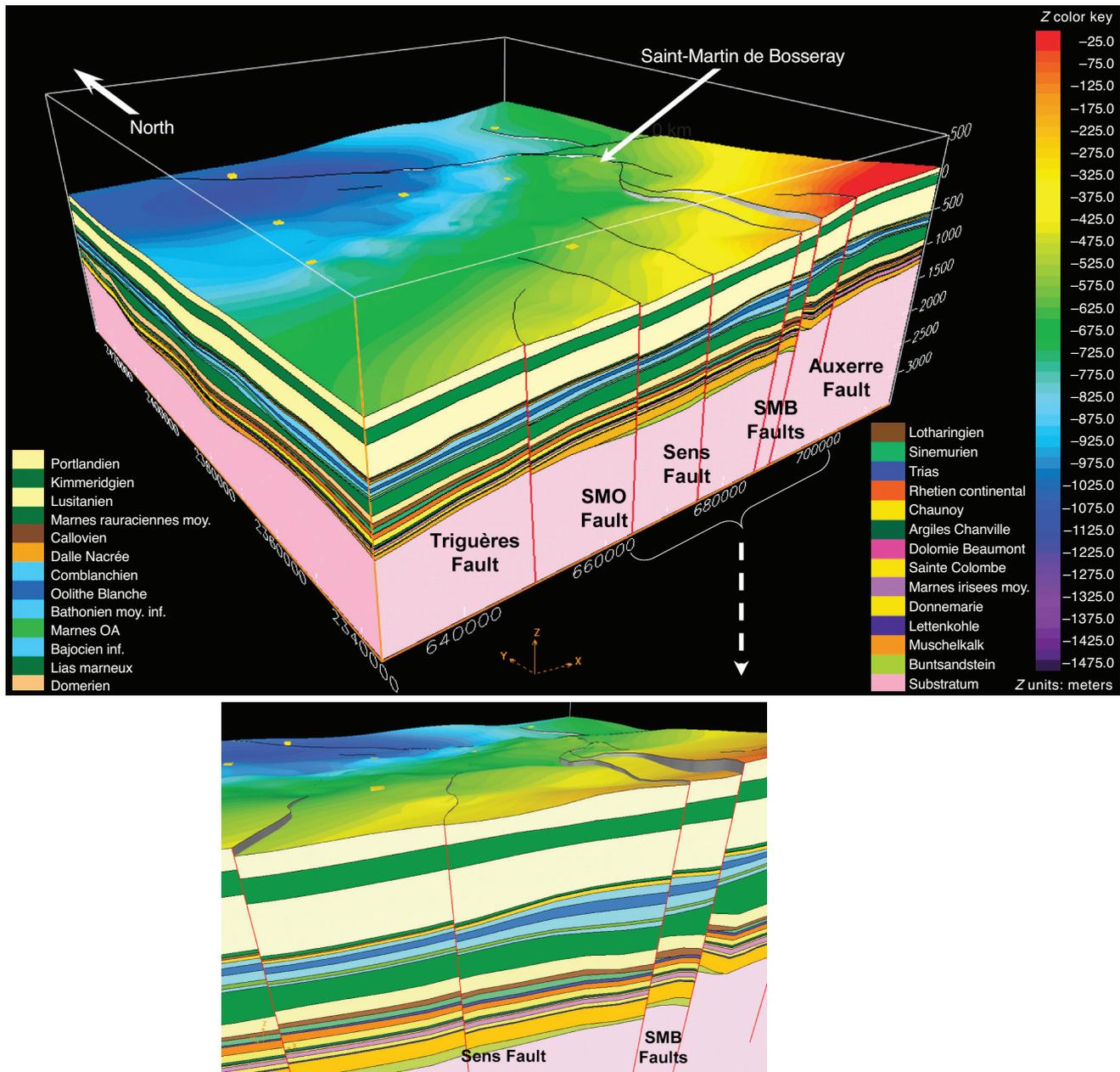


Figure 15

The 3-D numerical block representing the earth's model of the PICOREF Sector. The modelled layers are listed in Table 2.

of CO₂ at pilot scale in aquifer, with a unique injection well and no fluid production. Both were applied at the Sector scale, because this specific scale was considered optimal for the definition of boundary conditions. The modelled reservoirs are schematic because they do not take into account the lateral heterogeneity of sediments. A comparison of the two simulated situations is presented in the discussion (Sect. 7.1).

4.1 Simulation of CO₂ Injection in the Dogger Carbonates

The first simulation represents the Dogger carbonates by several layers of contrasted properties (Fig. 17). Note the thinner grid elements close to the injection zone. Porosity values were taken from the core-sample database, presented

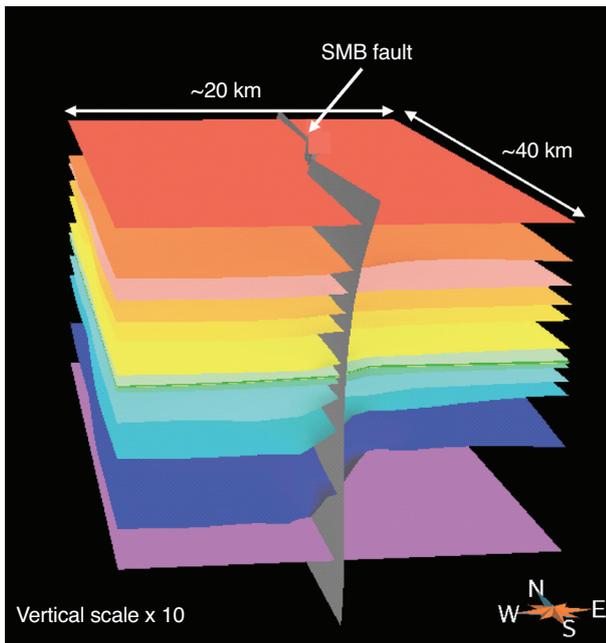


Figure 16
The 3-D numerical block representing the earth's model of the SMB site. The modelled layers are listed in Vidal-Gilbert *et al.* (2009).

and discussed by Delmas *et al.* (this issue): 22% in *Oolithe Blanche*, 7.5% in *Comblanchien*, 10% in *Dalle Nacrée* Formations, respectively. Permeability values were chosen one order of magnitude higher than values measured from cores, *i.e.*, closer to values deduced from well tests: respectively 50, 25 and 75 mD for the three formations mentioned. Permeability was considered isotropic, an assumption justified by the absence of clay, and by the fractured character of the carbonates. Three relatively thin beds are inter-layered which limit vertical permeability (porosity 7.5%, permeability 10 mD, in red colour in Fig. 17). Two thin very permeable beds were added, to mimic the properties locally encountered in these sediments (in blue, Fig. 17). A uniform temperature of 70°C was considered. Thermodynamic properties of the two fluids are those proposed by the numerical code TOUGHREACT from LBNL (Xu and Pruess, 1998; Xu *et al.*, 2005). Capillary-pressure and relative-permeability curves (CO₂ - water) experimentally measured at IFP on a Lavoux limestone were used (Egermann *et al.*, 2005a,b). The injection of 0.6 million tons CO₂, into the *Oolithe Blanche* Formation, is achieved at constant rate in a period of four years. Impervious layers are supposed to limit the system at

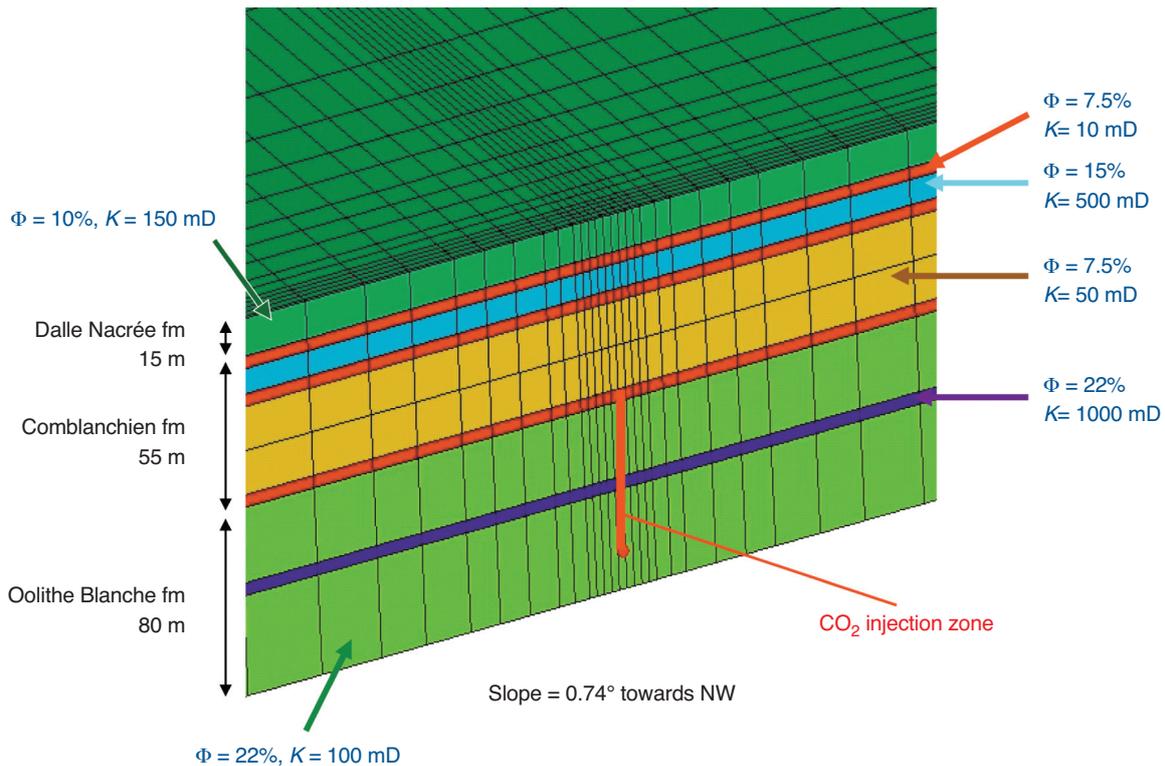


Figure 17
Part of the 3-D grid used to calculate CO₂-water movements in the Dogger formations. Relatively thin layers were considered within the formations, to represent specific rock types actually observed in the field, either in the *Oolithe Blanche* Formation (very conductive layers are known from the area exploited for geothermal energy, in the central part of Paris Basin), or in the *Comblanchien* Formation (dolomite-rich, highly permeable tops of sequence were studied from SMB and from outcrops).

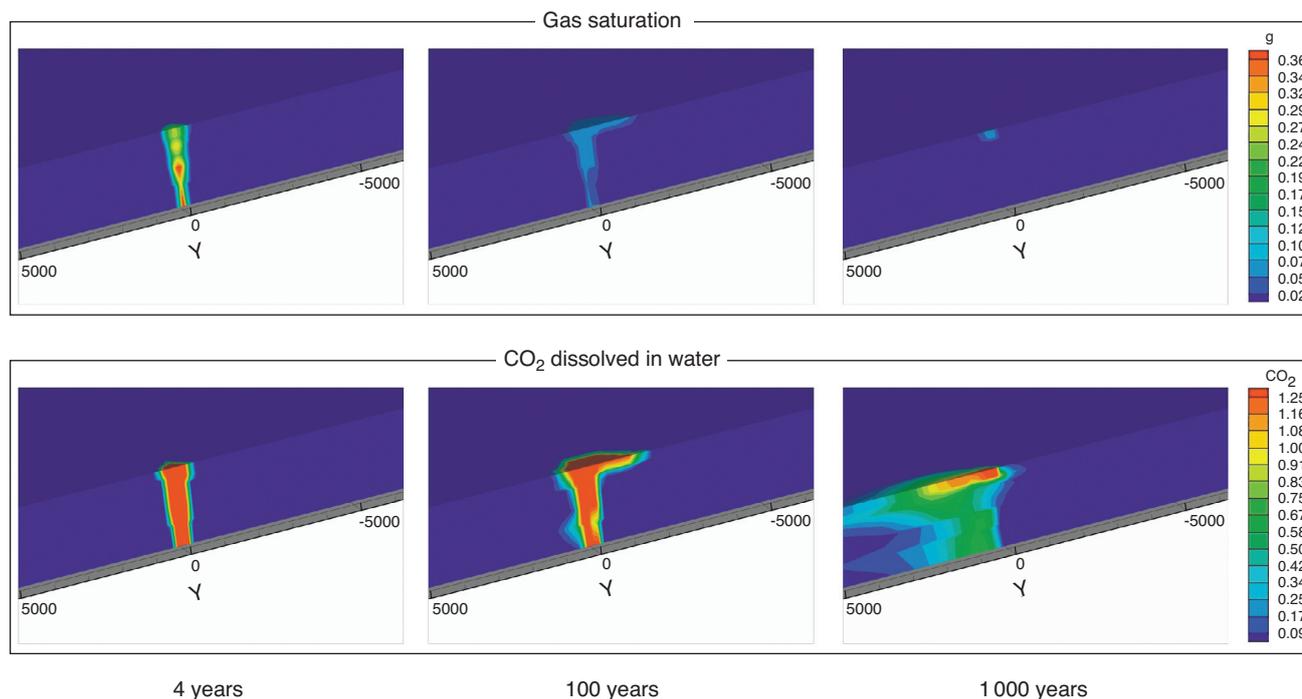


Figure 18

Location of the CO₂ “bubble” (top pictures), and quantity of dissolved CO₂ (bottom pictures), calculated by TOUGHREACT:

- at the end of the pilot-scale injection in the *Oolithe Blanche* Formation (4 years, 0.6 million tons CO₂);
- after 100 years (69% dissolved);
- after 1000 years (92% dissolved).

The slight tilt of the formations induces the buoyant gas “plume” to migrate eastwards, whereas dissolved CO₂ follows the general westwards migration of Dogger waters.

the bottom and at the top of the Dogger carbonates, whereas constant pressure values are imposed laterally. The pressure of the natural system was taken close to hydrostatic, with a value of 160 bar provided in the middle of the grid at a 1500 m depth “datum”, and a slight pressure gradient that results in a natural pore-water flow *ca.* 1 m·yr⁻¹ oriented from the south-east towards the north-west. Salinity was fixed at a value commonly measured in Dogger, *i.e.*, 25 g·L⁻¹. Figure 18 shows the position of the gas plume and the amount of CO₂ dissolved in water, at the end of injection step, after 100 years (70% of dissolution in water is then achieved), and after 2000 years (99% dissolution). The natural hydrodynamism sweeps CO₂ along the aquifer layers, *ca.* 300 m down the slope, whereas buoyancy acts in opposite direction for gas. After 2000 years, the extension of modified water mass is *ca.* 3.5 km.

4.2 Simulation of CO₂ Injection in the Rhaetian Sandstones

The second simulation concerns the Rhaetian marine sandstones. Due to the depositional environment and the

recurrent character of the sandstone facies at 10-km scale, the representation of this formation as a multi-layer reservoir is more realistic than for the other aquifer formations considered in the present study. A 3-D regular cartesian grid was extracted from the Sector geological model using the GOCAD Workflow “3D Grid Builder” (an additional script was used to ensure the grid horizontal regularity imposed by the simulation tool COORES). This grid is composed of 13 layers that represent Triassic and Liassic deposits up to Domerian sediments. The lateral dimensions of a grid element are 1 × 1 km in general, but 250 × 250 m inside a 5 × 5 km square surrounding the injection well, which was chosen close to the middle of the Sector. The Rhaetian aquifer Formation taken as the host reservoir is represented by two layers, except in the central, thinner gridded area (horizontal size cell 250 × 250 m) where it is represented by 10 layers. The sand/shale ratio is 45%. Average values of porosity (Φ), horizontal permeability (K_h) and vertical permeability (K_v) of the Rhaetian marine sandstones were taken from the core-analysis database (72 samples). Values of 14.5% were associated to Φ of the sandstone fraction, and of 10 mD (resp. 0.01 mD)

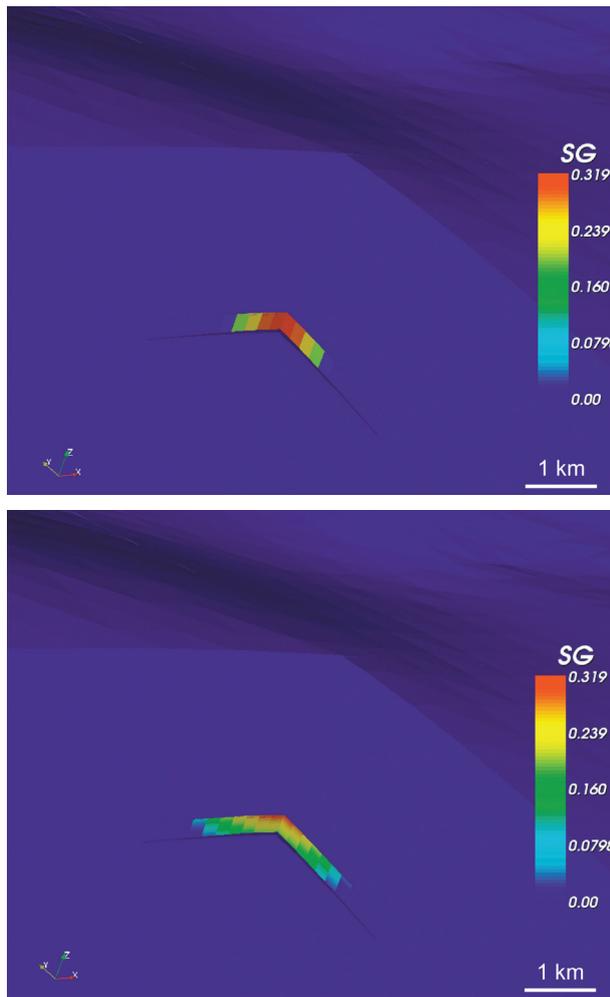


Figure 19

Location of the CO₂ “bubble” calculated by COORES™ :

- at the end of the pilot-scale injection in Rhaetian sandstones (10 years, 1.0 million tons CO₂) (top picture);
- after 1000 years (bottom picture). The formation water considered here is a 3 molal brine. In this case not favourable to dissolution, the dissolution is complete after a delay close to 10 000 years.

to K_h (resp. K_v). The multilayer reservoir characteristic is taken into account by a laterally uniform sand/shale ratio of 45% and a high permeability anisotropy. A uniform temperature of 100°C was considered. Pressure input results from piezometric head measured in different wells in the Sector. Constant pressure values were imposed laterally. The pressure of the natural system was taken close to hydrostatic, with pressure values distributed at a 1000 m “datum” between 95 bar (southern boundary) and 89 bar (northern boundary). The pressure gradient induces a natural pore-water flow of few mm·yr⁻¹ oriented from south to north.

Thermodynamic properties of the two fluids are those proposed by the numerical code COORES™ from IFP (Trenty *et al.*, 2006) at 100°C and 250bar. The tests presented here were achieved with a high-salinity, 3-molar brine. Analogue capillary pressure and relative-permeability curves (gas - oil - brine) of the reservoir were taken from Garcia (2005) who obtained them experimentally for the sandstone Tensleep Formation and discussed them in the context of CO₂ injection. An hypothesis was made on the capillary entry-pressure (P_{ce}) value of the marls lying at the bottom and at the top of the Rhaetian reservoir, in order to describe their hydraulic behaviour with respect to CO₂ displacement. The value of 30 bar was consistent either with the measurements provided by Carles *et al.* (this issue) and with an empirical relationship between P_{ce} and permeability given by Marshall *et al.* (2005) for clay-rich sediments. The injection of 1 million tons CO₂ is achieved at constant rate in a period of 10 years (400 m³·day⁻¹ of super-critical fluid). Figure 19 shows the gas saturation of the porous medium, *i.e.*, the position of the gas plume, 1000 years after the end of injection, in the case water is a very saline. Due to the relatively low solubility of CO₂ in such a brine (0.3 mol·L⁻¹, instead of 1.3 mol·L⁻¹ in much fresher water) and a very slow groundwater flow, gas is still present and the complete dissolution is not achieved before 10 000 years. A consequence is that the area influenced by injected gas, either as a gas phase or dissolved in water, remains relatively narrow. Finally, it was checked that the capillary pressure could never overstep the threshold value given for P_{ce} . Further simulation would be necessary to test the sensitivity of the model to different under-constrained input parameters and design injection scenarios able to enhance CO₂ trapping.

5 MODELLING THE MECHANICAL IMPACT OF STORAGE

Pressure drop in the reservoir, induced by hydrocarbon production, and symmetrically pressure build-up due to CO₂ injection, have a mechanical impact on the reservoir formation and sedimentary pile. Stress field is changed, and some strain is determined. Risk of failure in the cap rock, or in fault zone, must also be analysed. During the course of the PICOREF project two simulations of mechanical effects were achieved, the first one in the context of a low-cost storage scenario at SMB (that reaches a maximum of 3.5 million tons CO₂, injected in the lower part of the *Comblanchien* Formation in a period of 10 years), the other one in the context of the pilot-scale storage in the Dogger carbonates presented in Section 4.1 (0.6 million tons CO₂ injected in the *Oolithe Blanche* Formation in a period of 4 years) – but with a very different boundary condition for pressure. In both case it was assumed that:

- the rock materials follow the constitutive laws of linear elasticity;

- rock properties are laterally homogenous in the modelled layers;
- the mechanical properties of the rocks can be adequately described from 11 rock types defined from well logs (and not directly from core measurements).

The characterization of these rock types, and extensive results of the modelling study achieved on SMB are available in Vidal-Gilbert *et al.* (2009). A comparison between the results obtained in the two case studies is presented in the discussion (*Sect. 7.2*).

5.1 SMB Field

The approach chosen was to use the pressure distribution computed by a reservoir-engineering model as an input of the mechanical model, updated at given time steps. This is a one-way explicit “coupling”, where the very loose character of coupling is justified *a posteriori*. The code used for geomechanics computation was ABAQUS (*e.g.*, Bostrøm and Skomedal, 2004). The injection scenario, *ca.* 350 kt_{CO₂}·yr⁻¹, is at a larger scale than a pilot operation. In spite of these relatively severe engineering conditions, deformation remains moderate. The calculated maximal values of vertical strain during CO₂ injection, *ca.* 6 mm at the reservoir top, and 4.5 mm at ground surface, are about twice (but opposite in direction) those calculated for the oil-depletion field lifetime.

An analysis was made of the risk of reactivation of (sub-seismic) faults that could be present down to the reservoir, at the top of the SMB structure. Stress changes calculated were combined to a Mohr-Coulomb criterion of frictional failure, with no cohesion and a friction coefficient of 0.6. Experimental data obtained by Bemmer *et al.* (2004) on carbonates were used, and a failure criterion chosen that provides the weaker uni-axial compressive strength (value 30.8 MPa, with 9.5 MPa the value of cohesion, and 40.8° the value of internal friction angle). Different results were obtained according to the hypothesis made on horizontal stresses. If supposed constant, fault reactivation occurs for overpressure as low as 25 bar. However, horizontal stresses more probably vary with pore pressure. A test was made with pore-pressure control on horizontal stress field. If such a link is assumed, the overpressure needed to reactivate the fault is 130 bar. Finally, a more sophisticated way of calculating the impact of storage on a fault was tested, and applied to the SMB regional fault, located 2 km east of the field structure. The fault was represented by “cohesive elements”, in a 2-D grid system extracted from the 3-D grid previously used in the mechanical calculations. It was considered as a poro-elastic, undrained material. The main difficulty is to associate values to the mechanical properties of the fault. A risk of failure appears when overpressure value reaches 80 bar. Such a risk is low considering the distance between the storage reservoir and the SMB fault.

5.2 Dogger Aquifer

The second mechanical simulation concerned the Dogger aquifer (Thoraval, 2008). It used most of the mechanical properties chosen for the various layers of the SMB study. It was decided to test a full-coupled approach where effective stresses, total strains and pore pressure are resolved in the same set of “hydro-mechanical” equations. The two-dimensional mechanical FLAC2D code from ITASCA (2001), and especially the two-phase flow option, was used for these simulations. The characteristics of the reservoir layers are the same as those already presented with the Dogger aquifer simulation (*Sect. 4.1*). The injection scenario is also the same. A major difference, however, concerns the boundary condition assumed for pressure. Whereas in the fluid-flow model the distribution of natural pressures was considered unchanged by the injection of CO₂, *i.e.*, the system was perfectly open to fluid exchanges at the (distant) limits of the Sector, here these limits are assumed to be closed to fluid flow. This difference induces that the pore-pressure calculated here reach much higher values, up to 65 bar, than those obtained in the fluid-flow modelling, not more than 2 bar. An advantage of the option taken here is that it allows the evaluation of *maximum* consequences, which can be useful in a perspective of risk analysis.

Due to the 2-D nature of the model, an equivalent flow rate had to be calculated in order to return the same pressure and saturation values as those that would be obtained using a 3-D model in the same conditions. No chemical interaction between fluid and mineral phases was taken into account in the simulation. The main results are the following, after the 4-years period of injection (*Fig. 20*):

- 65 bar and 55 bar are the maximum overpressure values reached in the reservoir, respectively for CO₂ and water phase;
- horizontal and vertical effective stress variations are respectively 25 bar and 65 bar;
- the maximum induced vertical displacement reaches 3 cm vertically, at the top of *Dalle Nacrée* Formation;
- no rock-mass failure is computed either for the reservoir or for the cap rocks during the injection period and after;
- the risk of fractures shearing is null, if one assumes that their friction angle is larger than 30°.

The risk of failure was analyzed using two failure criteria (*Fig. 21*): one for shear (Mohr-Coulomb type), characterized by the R_c strength (different for *Oolithe Blanche* and *Comblanchien* rock types) and $\alpha > 30^\circ$ angle; the other for traction, characterized by the R_t strength.

6 MODELLING THE GEOCHEMICAL IMPACT OF CO₂ INJECTION IN A CARBONATE RESERVOIR

Because of the importance of carbonates as host reservoirs in the Paris Basin, the risk of geochemical dissolution due to pH

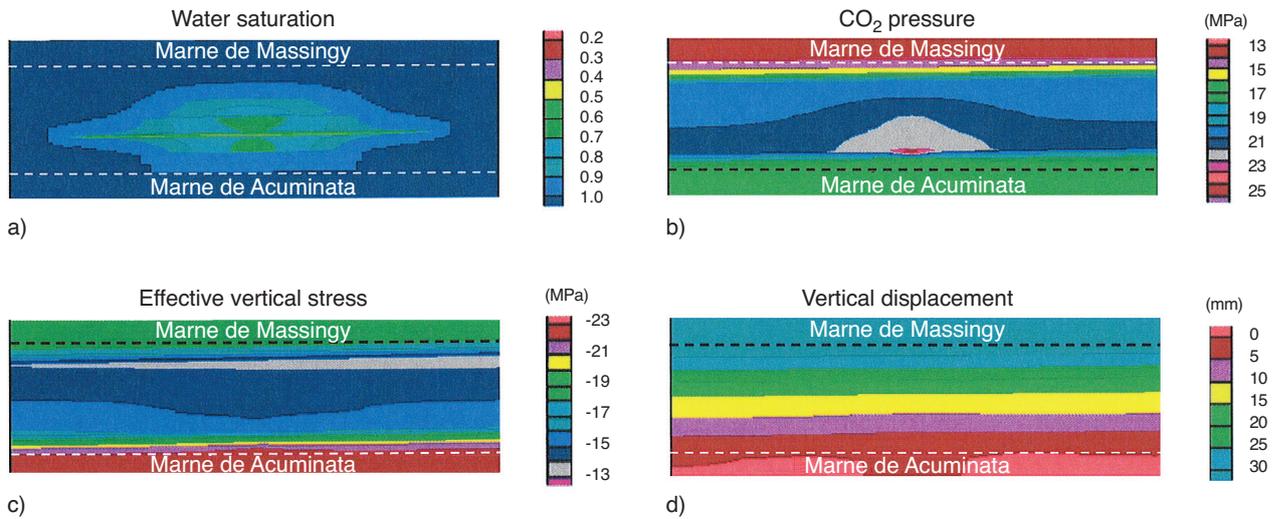


Figure 20

Geomechanical impact of CO₂ storage. Simulation considering a 4-years injection in Dogger carbonates, at a rate of 150 000 t-yr⁻¹ (pilot-scale operation). The hydraulic units of the Dogger are considered closed in the “far field” (> 30 km). Results obtained with FLAC2D, coupling hydraulic and mechanical phenomena (elasto-plastic behaviour), at the year 4 time step (end of injection): a) saturation in water; b) pressure; c) effective vertical stress; d) vertical displacement.

The maximum values obtained for over-pressure in the host reservoir, and for vertical displacement at the top of the reservoir, are respectively 60 bar and 6 mm.

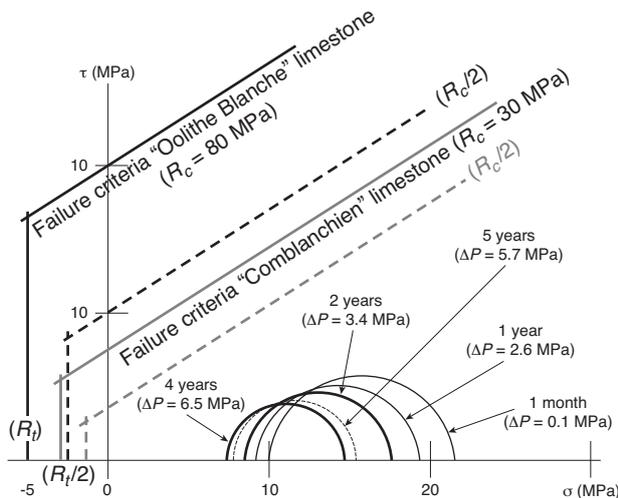


Figure 21

Geomechanical impact of CO₂ storage. Same situation as described in Figure 20. Analysis of the risk of failure into the reservoir, during and after the CO₂ injection period. Two failure criteria were used (shear and traction, see text). The Mohr circles are depicted for a point located in the middle of the injection zone.

phenomenon currently observed in natural rocks, and probably accelerated in the context of CO₂ storage, was studied by Renard *et al.* (2005) and Le Guen *et al.* (2007).

A mass balance of the dissolution reaction can be presented as a first step of the geochemical modelling approach. Calcite will dissolve, and dissolved calcium will increase, proportionally to the quantity of carbon dissolved in water. The amounts depend on temperature, pressure, and water composition. The second step, which aims at determining how much, and where, carbon is dissolved, is much more complex to decipher, because it depends on the fluid movements. The question was addressed with various 2-D models, representing either horizontal layers, or vertical sections. A simple horizontal model (*Fig. 22*) illustrates here the main result. In places where continuous drainage of CO₂ occurs, such as the surroundings of an injector well, calcite dissolution is relatively modest and evenly distributed. In contrast, massive carbonate dissolution is likely to occur in places where water poor in calcium, either coming from the aquifer or eventually injected (*e.g.*, case of a producing oil field), can enter the gas-rich domain. This should occur where a producer well maintains pressure depletion (a configuration that currently exists in field production), or in some configurations involving faults (not shown in the figure). In any zone where flows of non-equilibrated water and gas converge, the intensity of carbonate dissolution will depend on the delay during which such configuration is maintained.

drop as soon as CO₂ dissolves in water has been addressed with a particular attention. Only the short-term effects will be discussed here. The long-term coupling between mechanical stress and dissolution, the so-called “pressure-solution”

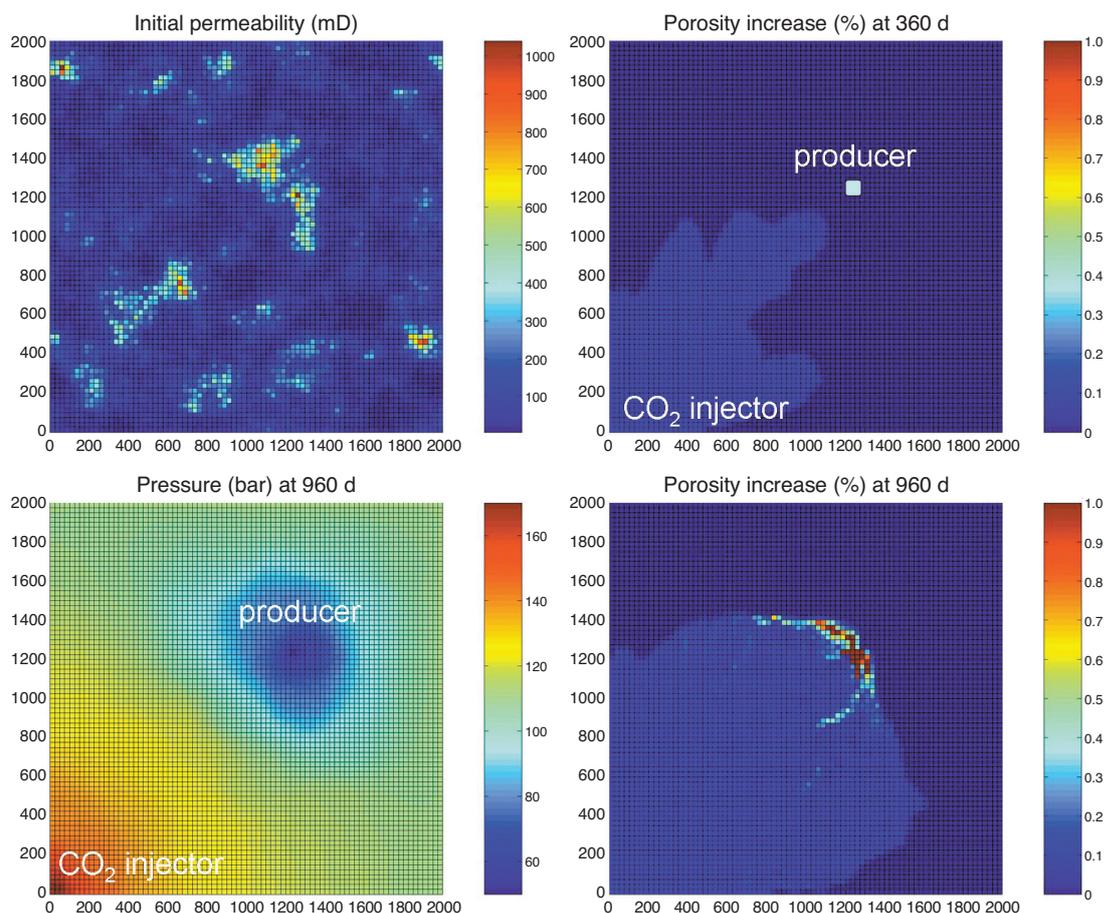


Figure 22

Geochemical impact of CO₂ injection, in a reservoir where carbonate minerals are initially present. The case study shows where are located the maximal effects of carbonate dissolution, at the convergence focus between migrating CO₂-enriched formation water and virgin formation water, in a place where a producing well is present.

7 DISCUSSION

A widespread use of CO₂ geological storage at a level where it becomes significant with respect to climate-change mitigation requires to consider deep saline aquifers and not only depleted hydrocarbon fields. Deep saline aquifers are relatively unexplored geological objects, often poorly known in terms of reservoir properties and connectivity, faulting, cap-rock continuity and quality, or geochemical composition (water and minerals). Their use as host formations of large-scale storage sites (several hundreds of Mt CO₂ each), as soon as 2020-2050, calls for intense efforts of exploration and characterization, including seismic surveys, wildcats drilling, and all accompanying studies able to analyze rocks and fluids. The Paris Basin illustrates a situation that should be commonly encountered in intra-continental basins where sedimentary series, relatively old (here, mainly Mesozoic),

experienced multi-phase tectonic and hydrodynamic events, that generally altered the reservoir properties and created heterogeneities in their distribution. There, it cannot be expected to find aquifer units offering as good porosity and permeability values as those met in less compacted sediments of younger, still subsiding basins (sands of the Utsira Formation, for instance). Moreover, the reservoirs to be discovered will very probably present a relatively high degree of heterogeneity, detrimental for both storage capacity and connectivity.

On the other hand, the PICOREF project showed that, even when the chance does exist that subsurface has been investigated already by petroleum industry, or for the exploitation of geothermal energy, the information available comes forward as a kind of pot pourri, in part ancient and hardly the right format to be re-worked (old tapes, paper copies), in part lost or poorly preserved (core pieces), in part

not suited – if existent – to the new targets of interest (e.g., deepest reservoirs in the Paris Basin, or, more generally, absence of data on cap rocks).

To overcome these difficulties in the short deadline of very few decades is a very challenging perspective for industry – not only in terms of financial investment, but also technically. It was beyond the scope of the PICOREF project to examine all the aspects linked either to site characterization or to the preparation of an application for obtaining a storage license. Mandatory aspects, such as the description of all existing wells that could be reached by the CO₂ perturbation, were not studied during the course of the project. Environmental aspects and risk analysis were considered but are not addressed in this paper. We would like to focus here on the discussion of some modelling results that were presented in the preceding sections. First, a comparison between the simulations of fluid flow (Sect. 4) is an opportunity to discuss the question of storage-capacity appraisal. Second, a comparison between the simulations of mechanical behaviour (Sect. 5) stresses the importance taken by the tolerance in pressure build-up allowed in the reservoir.

7.1 Comparison between Simulations of Fluid Flow (Dogger and Rhaetian), Storage Efficiency

The value of several parameters significantly differ between the two modelling situations presented in Section 4 (Dogger carbonates vs Rhaetian sandstones): overall thickness of the reservoir, anisotropy of permeability, relative permeability, temperature and pressure, water salinity, intensity of natural hydraulic movements. Other parameters present a less marked difference of value: porosity, absolute permeability, size of the grid elements, injected amount of CO₂ and injection timing. Some aspects were simulated with the same approach in one case and the other: lateral homogeneity of the sedimentary layers; boundary conditions fixed to pressure values able to explain natural water flow at the Sector scale.

So many differences make difficult a term-to-term comparison between the two simulations. However, both represent pilot-scale operations, involving comparable masses of gas, for the Rhaetian 1 Mt injected in 10 years, and for the Dogger 0.6 Mt injected in 4 years. A common result is that the area influenced by the injected gas has a very limited extension even on the long term, small compared to the Sector size. Two hypotheses likely determine such a result: the homogenous character of the reservoir layers; and the boundary conditions that were considered in terms of pressure, which suppose that injection does not induce any perturbation of natural pressure regime at the limits of the Sector – in other terms, the assumption that the aquifer is perfectly “open”.

Although the amount of injected CO₂ is larger and the porous volume available is much smaller in the Rhaetian

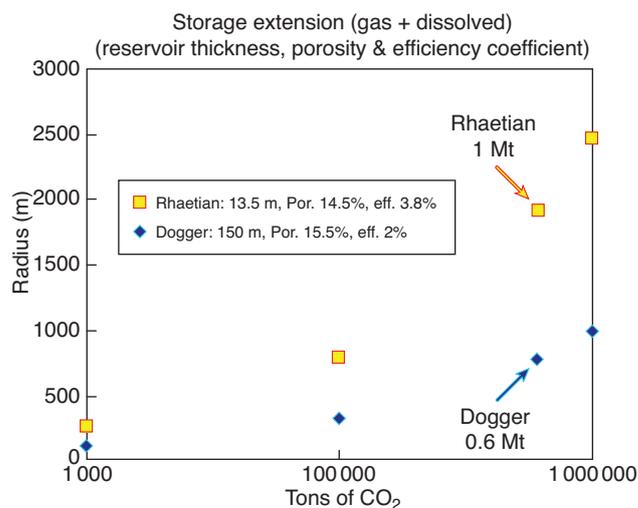


Figure 23

Storage extension and corresponding storage efficiency. The radius of the area invaded by CO₂, as a gas phase or as a substance dissolved in water, was taken from the simulations obtained in Section 4, for the date “1000 years”: 1) invasion in the Dogger aquifer units (in blue); 2) invasion in the Rhaetian sandstones (in yellow). Considering the characters of the two host reservoirs (net thickness 150 m and 13.5 m, average porosity 15.5 and 14.5%, respectively), a *storage efficiency coefficient* “eff.” can be calculated, that corresponds to the part of porosity actually occupied by CO₂ in the whole formation (see DOE, 2008 for details). This coefficient is twice higher in Rhaetian (3.0%) than in Dogger (2%).

simulation than in the Dogger one, we noted that the size of the gas bubble and of the water zone influenced by dissolved CO₂ is not considerably larger in the first case. The main explanation comes from the permeability anisotropy considered at the formation scale. It was assumed much stronger in the Rhaetian sand/shale formation ($K_h/K_v = 1000$) than in the Dogger carbonates (50, in the *Comblanchien*). This allows gas bubble to preferentially follow lateral migration pathways before reaching the top of the formation and spreading over a relatively vast area, just beneath cap rock. Such a behaviour results in a storage efficiency for Rhaetian which is almost twice the value obtained for Dogger (3.8 vs 2%) (Fig. 23). Two additional reasons are the much more limited hydrodynamism of the Rhaetian Formation compared to Dogger, and the considered high salinity that drops CO₂ solubility and maintains more CO₂ in gas phase, with less lateral influence in water.

The values calculated for storage efficiency are in the range indicated by literature, e.g., DOE (2008). Even if we must restrict the significance of our estimation, of limited relevance at a pilot scale, such low values strongly and urgently call for efforts towards the design of engineering techniques able to notably increase the part of porosity actually used for storage in a given storage site.

7.2 Comparison between Simulations of Mechanical Impact (SMB Oil Field and Dogger Aquifer)

The mechanical impact of CO₂ injection has been investigated through the simulation of two different scenarios:

- in the SMB oil field, with the injection of 3.5 million tons in the lower part of the *Comblanchien* Formation, in a period of 10 years (*Sect. 5.1*);
- in the Dogger carbonates considered as an aquifer, with the injection of 0.6 million tons in the *Oolithe Blanche* Formation, in a period of 4 years (*Sect. 5.2*).

Although the sedimentary cover was represented by the same layers and the same properties (including mechanical modules), and although the boundary conditions in the far field were assumed in a similar way, *i.e.*, closed to fluid circulation, the two models fundamentally differ in the value of pressure build-up allowed in the reservoir. At SMB, injection was stopped as soon as pressure reached 170 bar somewhere at the top of the reservoir, *i.e.*, 25 bar above the virgin pressure of the field. In the Dogger aquifer, over-pressure was authorized to reach a value of 65 bar. According to our interpretation, this difference in pressure build-up is able to explain most of the difference between the calculated deformation, respectively 6 mm and 30 mm (maximum values) at the top of the reservoir. A minor part could be due to the stronger coupling between fluid flow and mechanics performed in the second model, but this assertion would have to be checked by additional simulations.

CONCLUSION

Three large, basin-scale aquifer formations were studied during the course of the PICOREF project, the *Oolithe Blanche* Formation (carbonates), the marine sandstones of Rhaetian age, and the *Grès de Donnemarie* Formation (continental sandstones). With the *Grès de Chaunoy* Formation they represent the main deep aquifers to consider for an industrial perspective of CO₂ storage in the Paris Basin. Because of the geological age and history of the basin, these formations do not offer very good reservoir quality. Permeability measured at the core scale is commonly in the 10 mD order of magnitude. In addition, the general structure of the basin is very smooth, the sedimentary layers are flat at the 100 km scale, and it seems hopeless to find situations of structural trapping for a big storage (100 millions tons CO₂ and more). Fair conditions of stratigraphic trapping could be hoped, at least for Triassic reservoirs, but these reservoirs are much less constrained by seismic data, of relatively poor quality in this part of the sedimentary cover, or by well data than the Middle Jurassic deposits. Anyway the closure of such traps would have to be investigated by more detailed sedimentological work, and probably through the acquisition of additional data.

Inside the PICOREF Sector, the respective advantages and drawbacks of the formations studied can be summarized as follows:

Grès de Donnemarie Formation

- Advantages:
 - it is the only *saline* aquifer *sensu stricto*;
 - it is made of shale/sandstone units that correspond to a relatively well known sedimentological model of alluvial environment, accessible to stochastic reservoir modelling with a limited effort (referring in particular to the *Grès de Chaunoy* Formation reservoirs of the Chaunoy oil field studied by Eschard *et al.*, 1998);
 - it is very similar to the Stuttgart Formation (*Schilfsandstein*) in which CO₂ is injected at the Ketzin site in Germany (Förster *et al.*, 2006), so that positive repercussions could be directly expected from this pilot operation;
 - it offers large volumes (up to 300 m thickness in the Sector area, from which only a part is sandstone);
 - it should give possibilities – to be investigated more in detail – of stratigraphic trapping inside the Sector;
 - finally, it possesses a good and thick clay-rich cap rock.
- Drawbacks:
 - the *Grès de Donnemarie* Formation is not well known and well constrained;
 - it is deep (minimal depth 2210 m at top);
 - it presents low reservoir quality, either in terms of porosity or in terms of permeability (long history of compaction, and complex diagenesis).

Marine Sandstones of Rhaetian Age

- Advantages:
 - they have a relatively simple sedimentary organization, with sandstone units of large lateral extension, and probably good lateral connectivity (to be checked);
 - they present reservoir quality and homogeneity which are better than in all other Triassic sediments;
 - they are the less deep sandstone units to look to for storage (top at 2030 m);
 - they are capped by clay-rich formations of good sealing quality.
- Drawbacks:
 - the Rhaetian marine sandstones contain brackish waters (at least in the Sector area);
 - they do not offer very important volumes for future use at the industrial level.

Oolithe Blanche Formation

- Advantages:
 - it is relatively well constrained by a large collection of petroleum data and observations from outcrops;
 - it offers remarkable porosity values (oolitic grainstone), that would mean huge storage volumes *if accessible*;

- it belongs to a group of carbonate formations (Dogger) capped by a well characterized seal, namely the marls of Callovo-Oxfordian age, equivalent to the rock considered 150 km to the east for nuclear-waste repository (ANDRA, 2005).
- Drawbacks:
 - the *Oolithe Blanche* Formation shows a very complex organization in terms of hydraulic properties, with only a fraction (10 to 20%?) likely to present fair permeability values at the reservoir scale (100-1000 m);
 - it could not be integrated in an approach of stochastic reservoir modelling without a considerable additional research effort, in order to integrate the combined effects of diagenesis and fracturing;
 - it is not directly overlain by an aquiclude formation, but instead passes vertically and laterally to finer-grained carbonate facies, in such manner that the effective confinement of a given storage project will have to be studied for the whole Middle Jurassic;
 - it is a *carbonate* formation, and being so could be subject to long-term evolution such as pressure-solution, not completely understood today (Renard *et al.*, 2005; Le Guen *et al.*, 2007).

With all these facts in mind, the feasibility of hydrodynamic trapping in relatively poor reservoirs must be stressed as the key problem any large project of CO₂ storage will have to face in the Paris Basin. “Feasibility” here means either *technical* feasibility, with injection-rate capabilities and monitoring possibilities as central questions, and feasibility with respect to *regulations*. In that respect, for the time being, such storage would not be considered as possible in France. For both feasibility rationales cited, the modelling work is a crucial point. At pilot scale, the good fit between models prediction and observations will be also the pivotal question. The main PICOREF contribution in that respect was the construction of 3-D blocks, that represent the sedimentary pile of a given perimeter in a numerical way. Because abundant geological information existed in the region studied, this step appeared particularly rewarding to prepare the modelling studies needed before any storage setting up. This result was also nicely demonstrated in the case of Weyburn (*e.g.*, Whittaker *et al.*, 2004; Wilson and Monea (eds), 2004). However, a site description relying only on existing data has limitations, because such available data would not have been acquired with the objective of storing CO₂, and would not be necessarily directed to the same reservoir targets. As noted for instance, the main target of petroleum-exploration or geothermal activities in the central part of Paris Basin was the Dogger carbonate section, and consequently the Triassic sediments which present today an interest for CO₂ storage are much less documented.

Concerning the simulation of storage behaviour, PICOREF used a variety of modelling software, including codes developed with this specific CO₂-storage purpose (*e.g.*, COORES™).

Even if the time spanned on this aspect of the work was not very large during the project, it has been sufficient to check that software capacities, experimental data available (particularly two-phase flow parameters) and modellers’ experience are still insufficient for addressing several problems, that fortunately could be posed to a pilot operation, and should be essential to the realization of large-scale hydrodynamic and capillary storages in heterogeneous sediments. The first problem, investigated by Lu and Lichtner (2007) and Kang *et al.* (2008), is to find appropriate scale, or scaling-up methodologies, for describing the reservoir and defining boundary conditions, in order to calculate CO₂-water displacements and progressive CO₂ dissolution in water with enough accuracy. In that respect the simulations presented in this paper, and in similar way most of the simulations shown in recent publications, should be considered only as a preliminary approach of a much more complex real world. A second problem is to get enough field values for representing the properties of faults in modelling. Of course a pilot of limited size can dodge the fault issue, nevertheless, this important question will not be avoided at larger scale.

In summary, the PICOREF project was able to select and describe an area of the Paris Basin, called the “Sector” (*ca.* 70 × 70 km, 4900 km²), in which several sites can be considered for a pilot of storage. A variety of reservoir types and geological situations, including oil field, carbonate reservoir and sandstone reservoir, are encountered in the Sector, with a strong potential for applying pilot-scale results to other sites of the Paris Basin, in particular with the vision of large-scale CO₂ storages in aquifer. The method followed here, starting from a larger, regional area, and progressively focusing to nested scale(s), is appropriate in basins, or parts of basin, that are well documented by subsurface data (seismic lines, boreholes). In such case, the Sector scale is adequate to build a 3-D numerical block where all the relevant sedimentary layers are represented and characterized. More locally, for storage in an oil field for instance, a 3-D block is also useful but does not need as many data. The present study provided two such blocks:

- one for the Sector and investigation of the potential use of three aquifer formations (limestone *Oolithe Blanche* Formation of Middle Jurassic, Rhaetian marine sandstones, and continental sandstones of the *Grès de Chaunoy* Formation);
- the other for the SMB site (oil field in the *Comblanchien* and *Dalle Nacrée* Formations, of Middle Jurassic age).

Using the 3-D block as a framework, reservoir modelling (with a simplified representation of the sediments) and mechanical modelling were performed. In each case, two geological situations and two software could be compared (reservoir modelling of aquifer storage: Dogger carbonates and TOUGHREACT, Rhaetian sandstones and COORES™; mechanical modelling of Dogger reservoirs and above: aquifer case and FLAC, SMB case and ABAQUS). At the

pilot scale, the results obtained from distinct models but comparable situations and simulation hypotheses are roughly consistent, either in terms of CO₂-plume size or in terms of deformation. But it is obvious that introducing sedimentological heterogeneity, and considering large-scale storage, will increase the uncertainty of modelling results to a point that could eventually become unreasonable. Accordingly, we think that only a pilot-scale operation could address this problem.

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