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Gehad Youssef Helal

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Abstract

This essay deals with the study of stratigraphic sequenceadaptability (source, reservoir, and cap).

The origin of petroleum will be considered to be from organic sources, the diagenesis of fundamental organic compounds contained in organic matter accumulated with sediment under anaerobic conditions in a low- energy environment. Clays are important source rocks of petroleum.

Petroleum store in permeable rocks under the influences of gravity and the hydrodynamic field unit it can migrate no further and accumulates in at raptor disperses at the surface .

The concentration of oil and from the reservoir rock into an accumulation commercialize is the final step in the formation of a pool.

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الملخص العربي

صخور المصدر :

هى الصخور القادره على تحويل المواد العضويه الى مواد بتروليه تحت ضعط و حراره معينه

ويمكن تقسيم الصخور المصدر إلى أربع فئات رئيسية على الأقل و هم : (فعال ، محتمل ، بقايا فعالة و أنفق) كما أن يكون المصدر صخرة ، و يجب أن يكون للصخور ثلاث ميزات و هم : (كمية المواد العضوية و القدره على إنتاج الهيدروكربونات المنقولة و النضج الحراري)

هناك العديد من أنواع الصخور المصدر وتتشكل صخور المصدر من النوع 1 من بقايا الطحالب المودعة تحت ظروف نقص الأكسجين في البحيرات العميقة كما تتشكل صخور المصدر من النوع 2 من بقايا العوالق البحرية والبقايا البكتيرية المحفوظة تحت ظروف موكسده في البيئات البحرية و كذلك تتشكل صخور المصدر من النوع 3 من المواد النباتية األرضية التي تم تحللها بالبكتيريا والفطريات تحت ظروف موكسده .

الصخر الخازن :

خزان الصخور هي الصخور التي لديها القدرة على تخزين السوائل داخل المسام، بحيث السوائل (المياه والنفط والغاز) يمكن أن تتراكم ، الخزان الصخري هو صخر يحتوي على مسامية، نفاذية، تراكم هيدروكربوني كاف وآلية ختم لتشكيل خزان يمكن أن تنتج منه التدفقات التجارية من الهيدروكربونات.

هناك عدة أنواع من الصخور الخزان منها : الصخور الحجر الرملي الخزان، كربونات الخزان الصخور، سيليسيكلاستيك خزان.

مسامية الخزان هو الخاصية التي تقول كيف يسهل اختراق الصخور. ويعرف أيضا بأنه مقياس لقدرة صخور الخزان على احتواء السوائل أو تخزينها.

أنواع المسامية الأولية هي: (بين الجسيمات ،داخل الجسيمات).

كما ناتحظ أن المسامية الثانوية هي المسامية التي تشكلت بعد ترسب يؤدي إلى زوجين آخرين من أنواع الخزانات و هم : (حل المسامية و مسامية مكسورة) .

النفاذية هو مقياس لقدرة السائل لتمرير من خلال المتوسطة التي يسهل اختراقها النفاذية هي واحدة من المهم لتحديد خزان فعال .

الصخر الحابس :

هو الصخور التي تمنع تدفق من فلويد معين في درجة حرارة معينة والضغط والظروف الجيوكيميائية و هناك عدة أنواع من الصخور الحابسة .

الصخر الحابس هي نموذجية للتسلسل الأرجواني في حالة من الضغط المستمر النوع الاول :

النوع الثانى : يرتبط الصخر لحابس مع الصخور ضغط خارج الحد من اللدونة وقد فقدت القدرة على الانتفاخ على اتصال مع الماء هذه الصخور لا تحتوي على تورم المعادن الطينية

النوع الثالث : الصخر الحابس هي نموذجية للصخور مع مصفوفة جامدة والتكسير الشديد. وتطور هذه الصخور أساسا على المنصات القديمة في المناطق ذات الحركة التكتونية المنخفضة.

Tanta University

Faculty of Science

Geology Department

An Essay on

Source, Reservoir and Cap Rocks

Essay Submitted to the Geology Department, Faculty of Science, Tanta University, in Partial Fulfillment of Requirement of the Degree of B.SC. In Geophysics

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"4Th Year Geophysics"

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Prof. Dr.

Hamza Khalil

“Prof. of Stratigraphy”

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جامعة طنطا

كلية العلوم

قسم الجيولوجيا

بحث في

صخور المصدر و الخزان والغطاء

بحث لاستكمال متطلبات الحصول علي درجة البكالوريوسفي الجيوفيزياء

إعداد:

جهاد يوسف يوسف هلال

"رابعة جيوفيزياء"

إشراف:

أ.د.

حمزة خليل

٢٠١٧

Chapter one

Introduction

Both crude oil and natural gas occur naturally in subsurface deposits. Crude oil is a black liquid that is sold to refineries to be refined into products such as gasoline and lubricating oil. Natural gas is a colorless, odorless gas that is sold to gas pipelines to be transported and burned for its heat content. There are many different types of crude oils and natural gases, some more valuable than others. Heavy crude oils are very thick and viscous and are difficult or impossible to produce. Light crude oils are very fluid, relatively easy to produce, rich in gasoline, and more valuable.

Some natural gases burn with more heat than others and are more valuable. Some natural gases also contain almost pure liquid gasoline called condensate that separates from the gas when it is produced. Condensate is almost as valuable as crude oil. Sulfur is a bad impurity in both natural gas and crude oil. Sour crude oils contain sulfur, and sour natural gases contain hydrogen sulfide and are less valuable. The crust of the earth in oil- and gas-producing areas is composed of sedimentary rock layers. Sedimentary rocks can be source and reservoir rocks for gas and oil.

These rocks are called sedimentary rocks because they are composed of sediments that were formerly loose particles such as sand grains, mud, and seashells or salts that precipitated out of water. Sedimentary rocks are millions of years old and were deposited when the sea level rose and covered the land many times in the past. These sediments are relatively simple materials such as sands deposited along beaches, mud deposited on the sea bottom, and beds of seashells. Ancient sediments, piled layer upon layer, form the sedimentary rocks that are now sandstones composed of sand grains, shales composed of mud particles, and limestones composed of seashells. These are drilled to find and produce oil and gas.

The source of gas and oil is the organic matter (dead plant and animal material) that is buried and preserved in some ancient sedimentary rocks. They rise due to buoyancy through fractures in the subsurface rocks. The rising gas and oil can intersect reservoir rock, which is a sedimentary rock layer that contains billions of tiny spaces called pores.

A common reservoir rock is sandstone, composed of sand grains like those on a beach. Sand grains are like spheres, there is no way the grains will fit together perfectly. There are pore spaces between the sand grains on a beach and in a sandstone rock. Porosity is the percent of reservoir rock that is pore space, and it is commonly 10 to 30%. The gas and oil flow into the pores of the reservoir rock layer. Because the reservoir rock also contains water, the gas and oil will continue to rise by flowing from pore to pore to pore up.

The movement of gas and oil up the angle of the reservoir rock toward the surface is called migration. As the gas and oil migrates up along the reservoir rock, it can encounter a trap. A trap is a high point in the reservoir rock where the gas or oil is stopped and concentrated. In the trap, the fluids separate according to their density. The gas is the lightest and goes to the top of the trap to fill the pores of the reservoir rock and form the free gas cap.

The oil goes to the middle to fill the pores and form the oil reservoir. The saltwater, the heaviest, goes to the bottom. To complete the trap, a caprock must overlie the reservoir rock. The caprock is a seal that does not allow fluids to flow through it. Without a caprock, the oil and gas would leak up to the surface. Two common sedimentary rocks that can be caprocks are shale and salt.

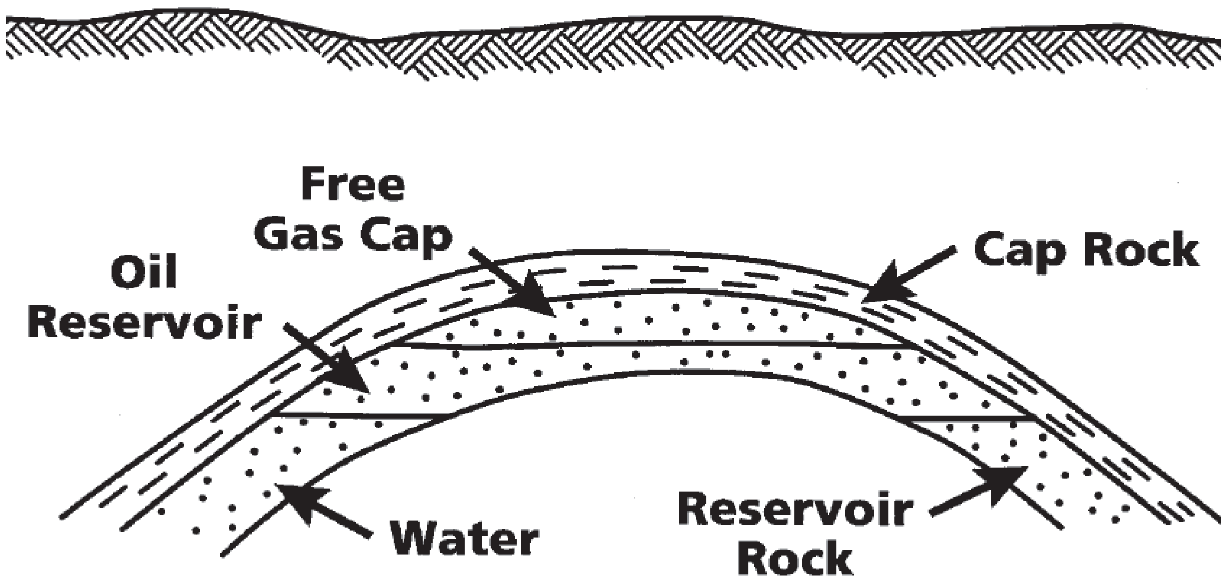

Fig.1. Source, Reservoir and Cap Rocks

Most gas and oil deposits are located in basins where sedimentary rocks are relatively thick. Subsurface deposits of gas and oil are found by locating traps. In some areas, the rock layers that crop out on the surface can be projected into the subsurface to discover traps. Today, these surface rocks can be mapped using photographs from airplanes and satellites. In the subsurface, the rocks in different wells that have already been drilled are matched by correlation to make cross sections, and maps of the depths to the top of subsurface reservoir rocks and their thickness are drawn.

Chapter 2

Source Rock

A *source rock* is a rock that can generate natural gas and/or crude oil. Gas and oil form from ancient organic matter preserved in sedimentary rocks. As sediments are deposited, both inorganic mineral grains, such as sands and mud, and organic matter (dead plants and animals) are mixed. Most organic matter is lost on the surface by decay, a process of oxidation. The decaying organic matter on land gets oxygen from the air, and the decaying organic matter on the ocean bottom gets the oxygen from out of the water. Some organic matter, however, is preserved. It was either rapidly buried by other sediments before it decayed or was deposited on the bottom of a sea with stagnant, oxygen-free waters.

The black color in sedimentary rocks comes primarily from its organic content. Black-colored, organic-rich sedimentary rocks include coal, shale, and some limestones. When woody plant material is buried, it is transformed into coal and methane gas (CH4) by temperature and time. This is why coal mines are dangerous; they contain methane gas and sometimes explode. Coal deposits are drilled to produce *coal seam* or *coal bed gas*, which is pure methane gas.

Shale is the most common sedimentary rock, and many are black. Black shale commonly has 1 to 3% organic matter by weight and can have up to 20%. Green or gray shale has only about 0.5% organic matter. Black shales contain a large variety of organic matter that includes single-celled plants and animals that live floating in the ocean, algae, spores, pollen and bacteria. They have the right chemical composition to generate both natural gas and crude oil. In some areas, such as North Africa and the Middle East, organic-rich dark limestones are also source rocks.

The first factor to be assessed in an exploration play in an area yet to be drilled is whether a source rock is present. If so, then we ask, “How good is it? Will it generate oil or gas? Has it generated hydrocarbons already?” To answer these questions, we must know the basics of what constitutes a source rock, how to classify source rocks, and how to estimate potential. This article provides a background in these fundamentals.

2.1. Definitions of source rock types

Source rocks can be divided into at least four major categories:

1. Potential
2. Effective
3. Relic effective
4. Spent

These categories and their definitions are shown in the table below.

Type	Definition
Potential source rock	Rock which contains organic matter in sufficient quantity to generate and expel hydrocarbons if subjected to increased thermal maturation.
Effective source rock	Rock which contains organic matter and is presently generating and/or expelling hydrocarbons to form commercial accumulations.
Relic effective source rock	An effective source rock which has ceased generating and expelling hydrocarbons due to a thermal cooling event such as uplift or erosion before exhausting its organic matter supply.
Spent source rock	An active source rock which has exhausted its ability to generate and expel hydrocarbons either through lack of sufficient organic matter or due to reaching an overmature state.

2.2. Characterizing source rocks

To be a source rock, a rock must have three features:

- Quantity of organic matter
- Quality capable of yielding moveable hydrocarbons
- Thermal maturity

The first two components are products of the depositional setting. The third is a function of the structural and tectonic history of the province.

2.3. Determining source rock potential

The quantity of organic matter is commonly assessed by a measure of the total organic carbon (TOC) contained in a rock. Quality is measured by determining the types of kerogen contained in the organic matter. Thermal maturity is most often estimated by using vitrinite reflectance measurements and data from pyrolysis analyses.

The table below shows the most common methods used to determine the potential of a source rock.

To determine…	**Measure…**
Quantity of source rock	Total organic carbon (TOC) present in the source rock
Quality of source rock	• Proportions of individual kerogens • Prevalence of long-chain hydrocarbons
Thermal maturity of source rock	• Vitrinite reflectance • Pyrolysis Tmax

2.4. Types of source rocks

Source rocks are classified from the types of kerogen that they contain, which in turn governs the type of hydrocarbons that will be generated.

A. Type 1 source rocks are formed from algal remains deposited under anoxic conditions in deep lakes: they tend to generate waxy crude oils when submitted to thermal stress during deep burial.

B. Type 2 source rocks are formed from marine planktonic and bacterial remains preserved under anoxic conditions in marine environments: they produce both oil and gas when thermally cracked during deep burial.
C. Type 3 source rocks are formed from terrestrial plant material that has been decomposed by bacteria and fungi under oxic or sub-oxic conditions: they tend to generate mostly gas with associated light oils when thermally cracked during deep burial. Most coals and coaly shales are generally Type 3 source rocks.

2.5. Maturation and expulsion

With increasing burial by later sediments and increase in temperature, the kerogen within the rock begins to break down. This thermal degradation or cracking releases shorter chain hydrocarbons from the original large and complex molecules occurring in the kerogen.

The hydrocarbons generated from thermally mature source rock are first expelled, along with other pore fluids, due to the effects of internal source rock over-pressuring caused by hydrocarbon generation as well as by compaction. Once released into porous and permeable carrier beds or into faults planes, oil and gas then move upwards towards the surface in an overall buoyancy-driven process known as *secondary migration*.

2.6. Mapping source rocks in sedimentary basins

Areas underlain by thermally mature generative source rocks in a sedimentary basin are called *generative basins or depressions* or else *hydrocarbon kitchens*. Mapping those regional oil and gas generative "hydrocarbon kitchens" is feasible by integrating the existing source rock data into seismic depth maps that structurally follow the source horizon(s). It has been statistically observed at a world scale that zones of high success ratios in finding oil and gas generally correlate in most basin types (such as intracratonic or rift basins) with the mapped "generative depressions". Cases of long distance oil migration into shallow traps away from the "generative depressions" are usually found in foreland basins.Besides pointing to zones of high petroleum potential within a sedimentary basin, subsurface mapping of a source rock's degree of thermal maturity is also the basic tool to identify and broadly delineate shale gas plays.

2.7. World class source rock

Certain source rocks are referred to as "world class", meaning that they are not only of very high quality but are also thick and of wide geographical distribution. Examples include:

- Middle Devonian to lower Mississippian widespread marine anoxic oil and gas source beds in the Mid-Continent and Appalachia: (e.g. the Bakken Formation of the Williston Basin, the Antrim Shale of the Michigan Basin, the Marcellus Shale of the Appalachian Basin).
- Kimmeridge Clay – This upper Jurassic marine mudstone or its stratigraphic equivalents generated most of the oil found in the North Sea and the Norwegian Sea.
- La Luna Shale – This late Cretaceous Turonian formation generated most of the oil in Venezuela.
- Late Carboniferous coals – Coals of this age generated most of the gas in the southern North Sea, the Netherlands Basin and the northwest German Basin.
- Hanifa Formation – This upper Jurassic laminated carbonate-rich unit has sourced the oil in the giant Ghawar field in Saudi Arabia.

Chapter 3

Reservoir Rock

Reservoir Rocks are the rocks that have ability to store fluids inside its pores, so that the fluids (water, oil and gas) can be accumulated. In petroleum geology, reservoir is one of the elements of petroleum system that can accumulate hydrocarbons (oil or gas). Reservoir rock must be has good porosity and permeability to accumulate and drain oil in economical quantities.

A fundamental property of a reservoir rock is its porosity. However, for it to be an effective reservoir rock, THE fundamental property is permeability. Both porosity and permeability are geometric properties of a rock and both are the result of its lithologic (composition) character. The physical composition of a rock and the textural properties (geometric properties such as the sizes and shapes of the constituent grains, the manner of their packing) are what is important when discussing reservoir rocks and not so much the age of the rock.

3.1. The properties of reservoir rocks

According to Society of Petroleum Engineers Glossary, a reservoir rock is a rock containing porosity, permeability, sufficient hydrocarbon accumulation and a sealing mechanism to form a reservoir from which commercial flows of hydrocarbons can be produced. Porosity and permeability are the reservoir rock most significant physical properties.

A fundamental property of a reservoir rock between them is porosity. However, for explorationists, an effective reservoir rock, the most fundamental reservoir rock property is its permeability. Both of them are geometric properties are the result of its lithological, structural and compositional behavior (composition). These physical compositions of a rock and the textural properties are geometric such as sizes and shapes of the rock grains, their arrangement system and packaging.

The efficiency of reservoir rock account on different important properties, however in this paper discussing on reservoir rocks properties, porosity and permeability are main topics to focus on. As discussed in last paper (Assignment I, 2014) petroleum system is made of different elements which encompass reservoir rock. Moreover, it is found in a sedimentary basin whereby explorationists are able to study its stratigraphy and its sedimentology (rock history) to determine if there is a likeliness of the existence of petroleum system.

After they (explorationists) come up with concluding the existence of a petroleum system, they go for further scientific tests-collecting different data and analyzing them to be able to decide about drilling and completion of a petroleum system. Significant part of their scientific studies on particular petroleum system is on estimating the possible quantity of hydrocarbons (crude oil) that may be present there. The reservoir content is estimated by means studying rock properties which can be determined in a direct way or indirectly.

The indirect are done through laboratory measurements on core samples of reservoir rock of interest which constitutes direct methods of porosity data acquisition. This is done by measuring a bulk and their pore (empty spaces in a rock). Its bulk volume is gravimetrically determined when a core-sample is having an irregular shape. A petroleum system may have one or more reservoir rocks, and reservoir rocks may have different property basing on their types. Types of reservoir rock depend on kinds of their contents, composition, morphology and sedimentology.

3.2. Types of reservoir rocks.

As a rock to be named a reservoir has to be a porous and permeable lithological structure. It encompasses sedimentary rocks. These sedimentary rocks may be made of sandstones (quartz sand or arksosic sandstone), carbonates mud or dolomite. Dolomites mostly form good reservoirs because the common reason behind it is that there is Mg, 13% smaller than Ca in a way that during dolomitization, there is a total decrease in volume of the material by 13%, here by 13% porosity is gained.

3.2.1. Sandstone reservoir rocks

The term sand refers to a specific grain with sizes between (62 µm – 2 mm). The performance of the sandstone as a reservoir rock is described by its combination of porosity and permeability depending on the degree to which the sand dominates its. The favorable texture is depicted by packaging of similar sized grains, not a combination of coarse and fine grained composition. The best sandstone reservoirs are those that are composed mainly of quartz grains of sand size of nearly equal sizes or silica cement, with minimal fragmented particles. Sandstone reservoirs are generally 25 meters thick.

3.2.2. Carbonate reservoir rocks.

The most fascinating aspects of carbonate reservoir rocks are their content. Carbonates are usually made of fossils which “range from the very small single cell to the larger shelled animals”. Most carbonate rocks are deposited at or in very close neighborhood to their site of creation. The "best-sorted" carbonate rocks are Oolites in which encompass grains of the same size and shapes even though Oolites are poorly sorted.

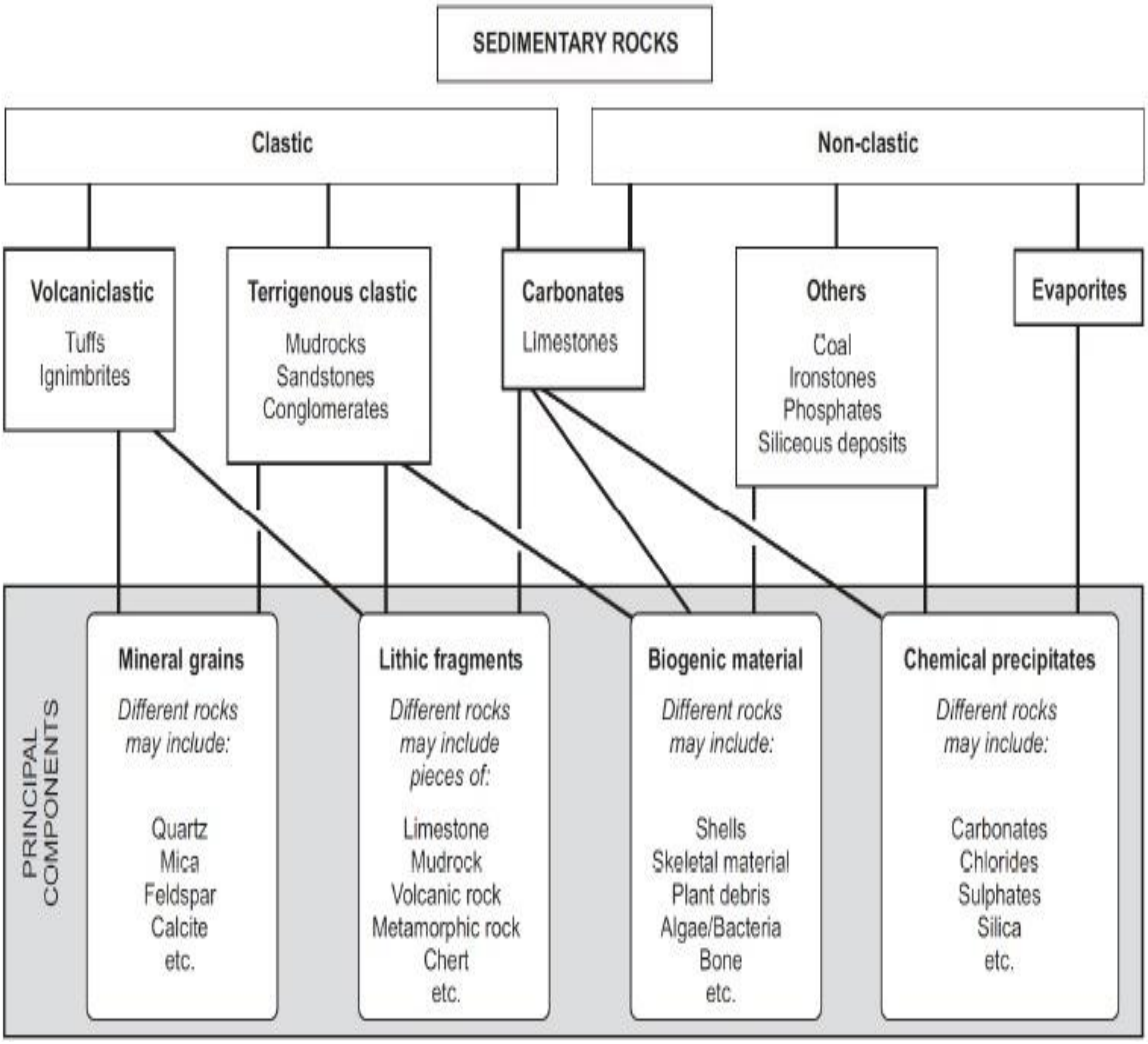

Fig. 2. Scheme of classification of reservoir rocks. (Adapted from Nichols,2009, from lecture handout by Alamsyah).

3.2.3. Siliciclastic Reservoir

Siliciclastic sedimentary rocks are the most abundant of the sedimentary rock. They are formed from the detritus left over from the weathering of igneous, metamorphic, and older sedimentary rocks.

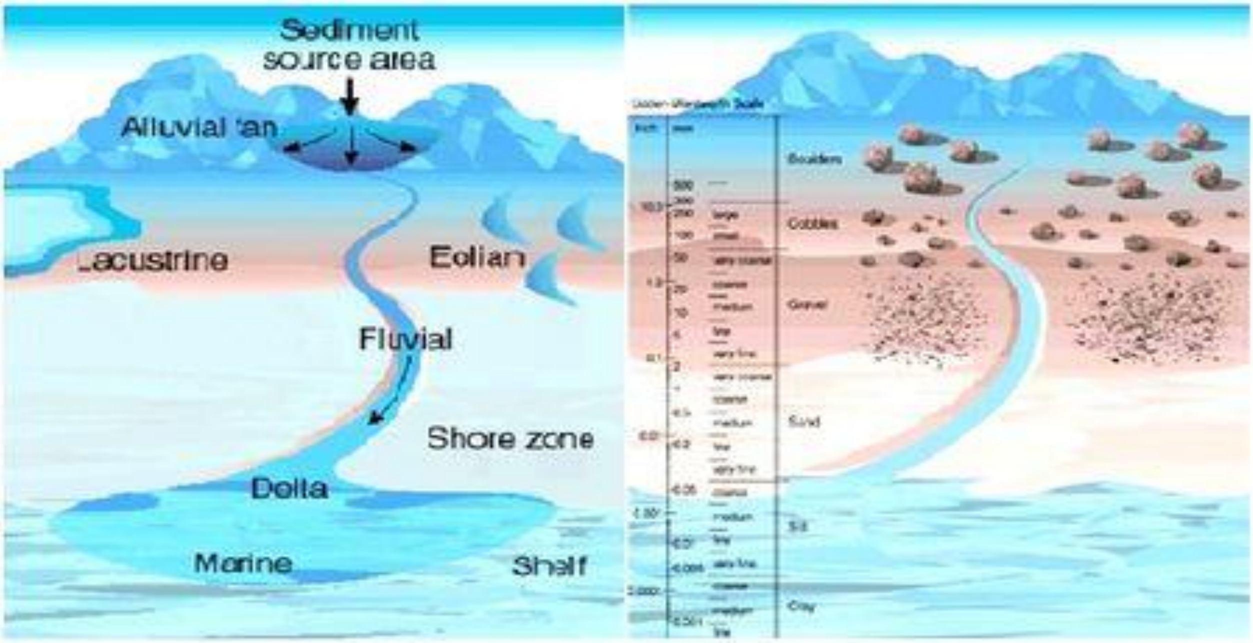

Fig. 3. Depositional environment and grain size.

3.2.4. Shallow and Deep Marine Reservoir

According to type of sedimentary rock, hydrocarbon reservoir can be divided into two groups. There are clastic sedimentary rock and non clastic sedimentary rock. On the clastic sedimentary, contained some precipitation area, as one in marine area. Rock Type can be formed in deposition marine areas such as shelf sandstone and turbidity sandstone.

Shelf sandstones: formed from precipitating in the shallow marine area. Sands transported by water current from river to shallow marine area. Because of that process, has been formed sands body around the grow delta and maybe form the fan like in delta.

Turbidity sandstones: rock formed in deep marine area with rotation force existing rotation deep current so as formed the coarse layer which has interaction with shale layer in the deep marine. Shape from deposition of turbidity sandstones can be like a lens, duct, or fans.

3.2.5. Lacustrine Reservoir

This type of reservoir formed in basin containing water surrounded by land and initially formed by tectonic processes, volcanic, rifting, soil movement, and the erosion by the wind on the coast or in land. The texture of sedimentary rocks in the environments usually granules grained and the size between 2 mm – 4 mm.

3.2.6. Eolian Reservoir

Formed in large areas with the accumulation of sand deposition. The sediment resulting from wind-blown sand. The clastic texture of the environment is granules (2 mm – 4 mm) and coarse (over 2 mm).

Name	Morphology	Number of slipfaces	Wind direction	Sand supply (relative)	Relative size
Sheet	Sheetlike with broad flat surface	None	Multidirectional	Abundant	Large, thick
Stringer	Thin elongate strip	None	Unidirectional	Sparse	Extensive, thin
Dome	Circular or elliptical mound	None	Bidirectional	Sparse	Small, thin
Barchan	Crescent	1	Unidirectional	Sparse	Small, thin
Barchanoid ridge	Row of connected crescents	1	Unidirectional	Abundant	Large, thick
Transverse ridge	Asymmetrical ridge	1	Unidirectional	Very abundant	Large, thick
Parabolic	U-shape	1 or more	Unidirectional	Abundant	Large, thick
Linear (Seif)	Symmetrical ridge	2	Bidirectional	Sparse	Extensive, thin
Reversing	Asymmetrical ridge	2	Bidirectional		Small, thin
Star	Central peak with 3 or more arms	3 or more	Multidirectional	Sparse	Small, thin
Blowout	Circular rim of depression	1 or more	Multidirectional	Variable	Small

SOURCE: Adapted from McKee 1979*a*.

Fig. 4. Modern dunes classification (Adapted from McKee, 1979)

3.2.7. Fluvial Reservoir

Type reservoir generated by the flow of the river where the process is formed by 3the erosion, transport and deposition of forming depositional formation.

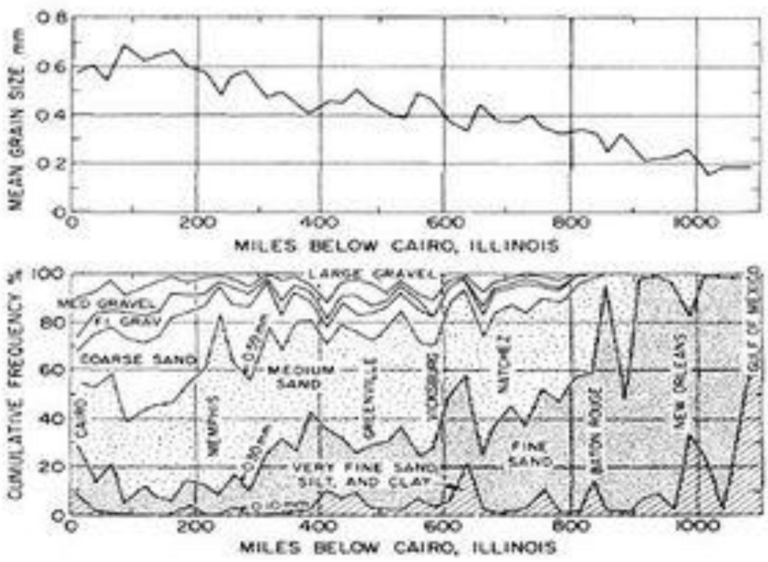

Fig. 5. Change in grain size of bed load in Mississippi River from Cairo, Illinois, to the mouth. (Form U.S. Army Corps of Engineers 1935 in Berg 1985).

3.2.8. Deltaic Reservoir

On this type of reservoir, it was formed by the accumulation of lacustrine sediments. Very fine grain sediment rocks.

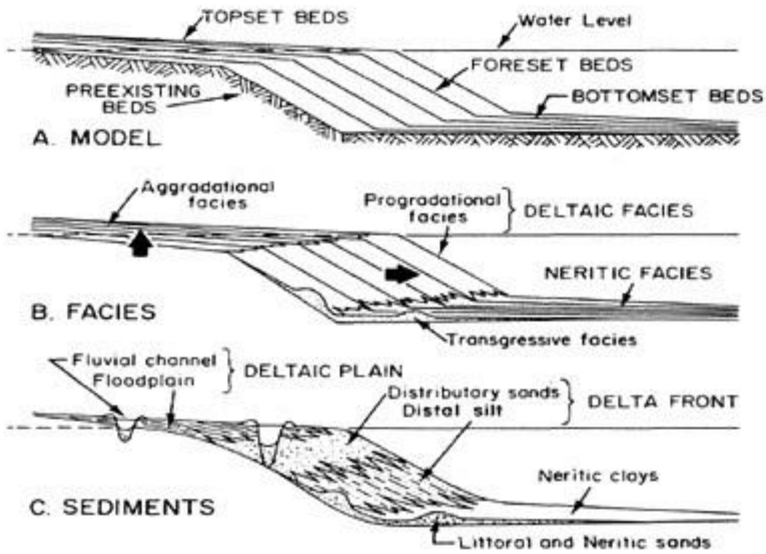

Fig.6. Diagrammatic cross sections of depositional units within deltas. (A) Delta Concept of Gilbert (1885) showing topset, foreset, and bottomset beds; (B) Deltaic and neritic facies from Frazier (1967); (C) Sediment types and depositional units of an idealized delta.

3.2.9. Carbonate Reservoir

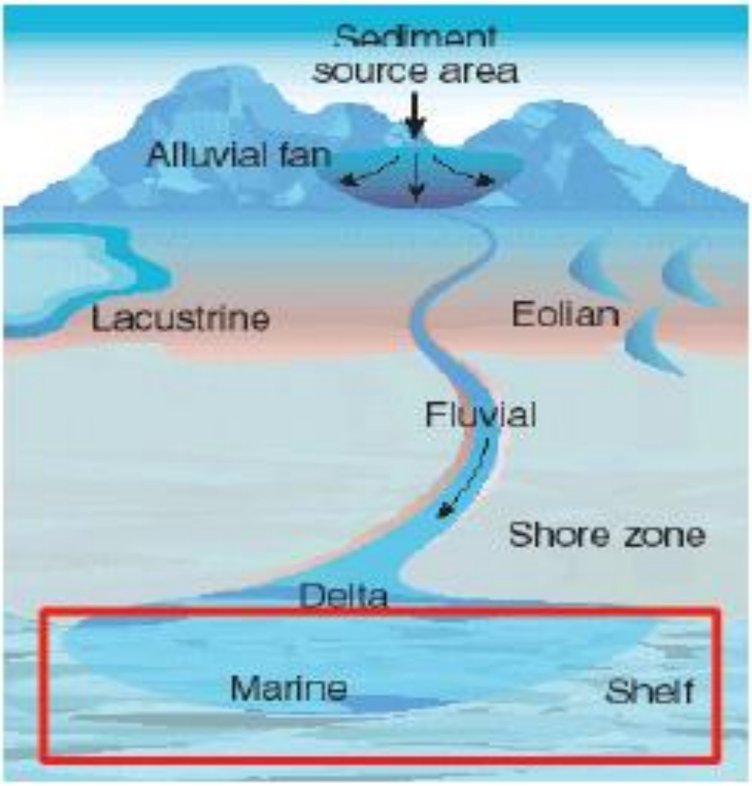

Fig. 7. Depositional environment of marine carbonate.

Adapted from Alamsyah Carbonate rocks is a sedimentary rocks with carbonate fraction more than 50%. Carbonate rocks can be used as a reservoir because of its porosity and permeability. Carbonate rocks can be classified to clastic and non clastic sediment. Its environmental formation is Tropic Ocean. The porosity concept of a carbonate rock might be a little bit more complex than other rocks, because of its vary secondary porous, from carbonate dissolution made from skeletal remain and microbe with cement. Almost all of carbonate reservoir type accumulated as a shallow marine sedimentary, except on a pelagic chalk and deep marine re-sediment reservoir carbonate in Mexico seas. Carbonate reservoir rocks can be found as a clastic limestone, carbonate framework (reef), and dolomite.

3.2.10. Reef Reservoir

Reef is a framework made of sea organism containing skeletal, grow in shallow clean water where sunlight can reach as nutrition. Reef distribution is varies, some on the edge of the shelf and become a barrier, some scattered called patch reef. Patch reef can reach a few kilometer sizes while barrier can be elongated along the edge and limit the exposure with basin. Meanwhile the shape of a reef can be a pole (pinnacle) or lengthened (fringing). Both can become a good reservoir. Reef is a non-clastic carbonate rocks without transportation process on its formation.

Fig. 8. Reef habitat in the shallow sea. Adapted from Alamsyah

3.2.11. Clastic Limestone

Clastic limestone usually associated with oolit and become a pretty good reservoir. Limestone associated with oolit often referred to as calcarenite. The Deposition is in shallow marine environments along the coast with high energy (strong wave currents). Porosity may be extremely high because of the dissolution, but permeability is not far from 5 milidarcy. It is called clastic because oolit associated with limestone is present through the transport process before finally deposited.

3.2.12. Dolomite

Dolomite formed by processes of calcite dolomitization from other carbonates (e.g. limestone). Dolomitization occurred not long after the process of sedimentation. Dolomitization process can be reviewed as the secretion of magnesium contained in sea water into the compounds associated with carbonate Dolomite production begins from the Pre-Cambrium, continued from Paleozoic to Mesozoic, up to Tertiary time. Calcite will be replaced with the dolomite compound that has smaller volume, so that the space between the pores of the rock grew wide.

This resulted in the cavities. Calcite that has not been dolomitized will dissolve quickly and arising secondary pores, sometimes with very large size. Dolomite has its price of porosity as high as limestone porosity, which is about 20-30%. However, permeability is very high, reaching up to 5 mills Darcy to 2 Darcy. Hence, dolomite carbonate reservoirs has higher production of hydrocarbon than limestone. According Zenger (1980) estimates that 80% of carbonate reservoirs in the USA contains dolomite, while the 20% rest of it contains limestone.

3.2.13. Afanitic Limestone

Afanitic limestone formed in shallow ocean areas with low levels of energy, such as for example in the lagoon. This limestone has a very fine grain size and tight. However, the porosity and permeability was appeared by the events of dissolution and cracking that causing this type of limestone have secondary porosity. Thus, it can be a reservoir of oil.

3.3. Another Type of Reservoir

Although the porosity and permeability are poor, shale, silt stone, limestone can even act as reservoir due to fractures in the rock body (secondary porosity – secondary permeability). For example, an oil field in Florence, Colorado which is having shale (Lower – Upper Cretaceous) as reservoir rock.

Then, it shows that for other than sedimentary rocks (igneous – metamorphic) could be reservoir rock if there are in fracturing state. For example, in Cuba, the oil is obtained from ultra-base igneous rock or volcanic rock that has fractured. There are eight oil fields in Cuba in 1964 that produce 710 barrels oil per day. Reservoir from this type has a very small percentage compared to the reservoir from sedimentary rock (about 1% of the overall reservoir in the world).

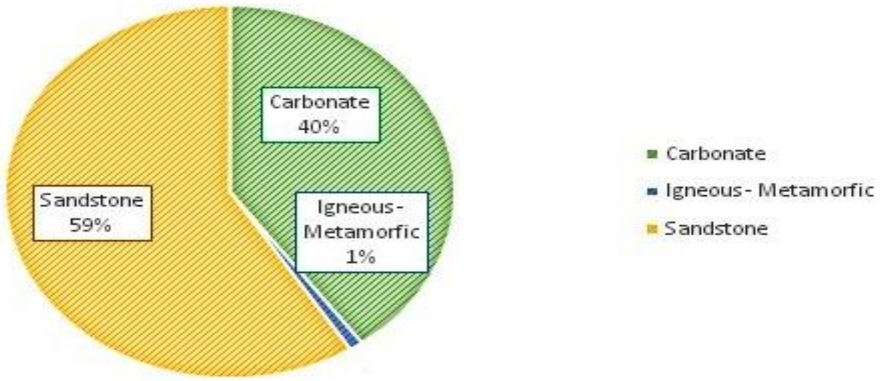

Fig. 9. Comparison of reservoir rock types around the world in 1956 (based on Knebel & Rodriguez, 1956 in Koesomadinata, 1980)

Volcanic rocks are igneous rocks that formed on the earth surface (extrusive igneous rock). Volcanic rock can be formed from mafic minerals such as olivine, pyroxene, amphibole, and biotite, or felsic minerals such as feldspar, muscovite, and quartz.[7] For example, oil obtained in Jatibarang (West Java, Indonesia), produced from fractures that occur in volcanic rock (tuff). Oil production from volcanic rock reservoir shows higher production in initially, and then shows a rapid decline in production.

3.4. Reservoir rock properties, interpretations and their significance on a petroleum system.

- Porosity of reservoir is the property that tells how porous a rock is. It is also defined as a measure of the capacity of reservoir rocks to contain or store fluids. The porosity is genetically classified basing on standard sedimentologic description of reservoir rock; there are primary and secondary porosity.

1. The primary porosity types ar-8e:

    I. Inter-particle- In this type by which rock content was quickly lost in muds and carbonate sands through compaction and cementation respectively. This type is mostly found as siliciclastic sands.

    II. Intra particle porosity by which the porosity is made of interiors of carbonate skeletal grains.

2. Secondary porosity

   It is the porosity formed after deposition leads to other couple of reservoirs types:

    I. Dissolution porosity type is made of carbonate dissolution and leaching. It is also called carbonate reservoirs.

    II. Fracture porosity which is characterized by not being voluminous.

Porosity can also be classified basing on rock morphology. There are three types of morphologies to the pore spaces which are:

A. Caternary in which the pore open to more than one throat passage.

B. Cul-de-sac in which the pore open to only one throat passage.

C. Closed pore in which there is no connection with other pores.

- Permeability is a measure of the ability of a fluid to pass through its porous medium. Permeability is one of important to determine the effective reservoir. Porosity and permeability are two properties describing the reservoir rock capacity with regard to the fluid continence. Moreover, a reservoir rock can be porous without being permeable. For example it is said to be permeable if and only if the pores “communicate”. Hence for explorationists, knowing reservoir rock permeability is a key mile stone because it is important for being used to determine if it really has sufficient commercial accumulation of oil, indeed measuring it is very difficult. The measuring of permeability can differently be understood basing on two different ways. When the porous medium is completely saturated by a single fluid, the permeability will be described ***absolute,*** become described as ***effective permeability*** when its porous medium is occupied by more than one fluid

3.5. Other factors affecting the volume of the reservoir rocks.

1. Grain size and pattern arrangement: Apart from the arrangement pattern of grains size which effect rock properties, the actual size of the grains does not affects the permeability of a neither reservoir rock nor porosity.
2. Shape of the grains: grains with high sphericity tend to pack themselves well to make a minimum pore space, the fact which increases angularity and hence pore space volume increases.
3. Sorting or uniformity of size of the grains: size of grains has an effect on reservoir properties; the more uniform the grains are sized, the great proper volume of voids spaces. Thereby mixing grains of different sizes tends to decrease total volume of void space.
4. Subsequent action to the sediments (compaction): The more grains are compacted, more the volume of void spaces decreases. However the compaction of sand is less effective than the way clay does.
5. How the grains were formed.

3.6. Methods for determining rock properties.

Reservoir rock properties such as porosity and permeability are directly or indirectly measured. The direct methods consists of measuring the core sample taken from the parallel lithological area of the reservoir rock to assess them while the indirect methods consist of using data collection, well logs, seismic, production tests, etc., the porosity data are used in the basic reservoir to evaluate volumetric calculation of fluids in the reservoir and calculating fluid saturations and geologic characterization of the reservoir

3.7. Reservoir rock properties calculation formula.

Porosity: ф= , $V_p = V_B - V_S$,

Φ symbolizes porosity, V_p (volume of all pores), Vs represents volume occupied by other particles (Matrix materials), VB represents the total volume, ꝛ represents their respective densities.

Permeability: the permeability of a reservoir reckons on the determining the flow of a fluid which depends on constan, k , Darsey constant. With q representing flow rate, A the area section of pores, µ represents viscosity constant of fluid and dp/ dL represents the infinitesimal change of flowing pressure.

3.8. Reservoir Porosity

Porosity is the void space in a rock that can store the fluids. It is measured as either a volume percentage or a fraction (expressed as a decimal). In the subsurface this volume may be filled with petroleum (oil and gas), water, a range of non hydrocarbon gasses (CO2, H2S, N2), or some combination of these.[1]

Porosity is symbolized in phi (ϕ) and its value is expressed in percentage. Porosity value calculation:

$$\phi = \frac{\text{pore volume}}{\text{bulk volume}} \times\ 100\%$$

Porosity divided into two types, absolute porosity and effective porosity. Absolute porosity is the ratio of the total pore volume in the rock to bulk volume, obtained by the calculation:

$$\phi_a = \frac{\text{total pore volume}}{\text{bulk volume}} \times \ 100\%$$

Effective porosity is the ratio of interconnected pore volume to bulk volume, obtained by calculation:

$$\phi_e = \frac{\text{total interconnected pore volume}}{\text{bulk volume}} \times \ 100\%$$

Based on the way of its formation, there are two types of porosity:

Primary porosity is porosity that formed while sedimentary rock deposited.

Secondary porosity is porosity that formed after the sedimentary rock deposited.

3.9. Reservoir Permeability

Permeability is an intrinsic property of a material that determines how easily a fluid can pass through it. In the petroleum industry, the Darcy (D) is the standard unit of permeability, but milidarcies (1 mD = 10-3 D) are more commonly used. A Darcy is defined as a flow rate of 10-2 ms-1 for a fluid of 1 cp (centipoise) under a pressure of 10-4atm m-2. Permeability in reservoir rocks may range from 0.1 mD to more than 10 D.

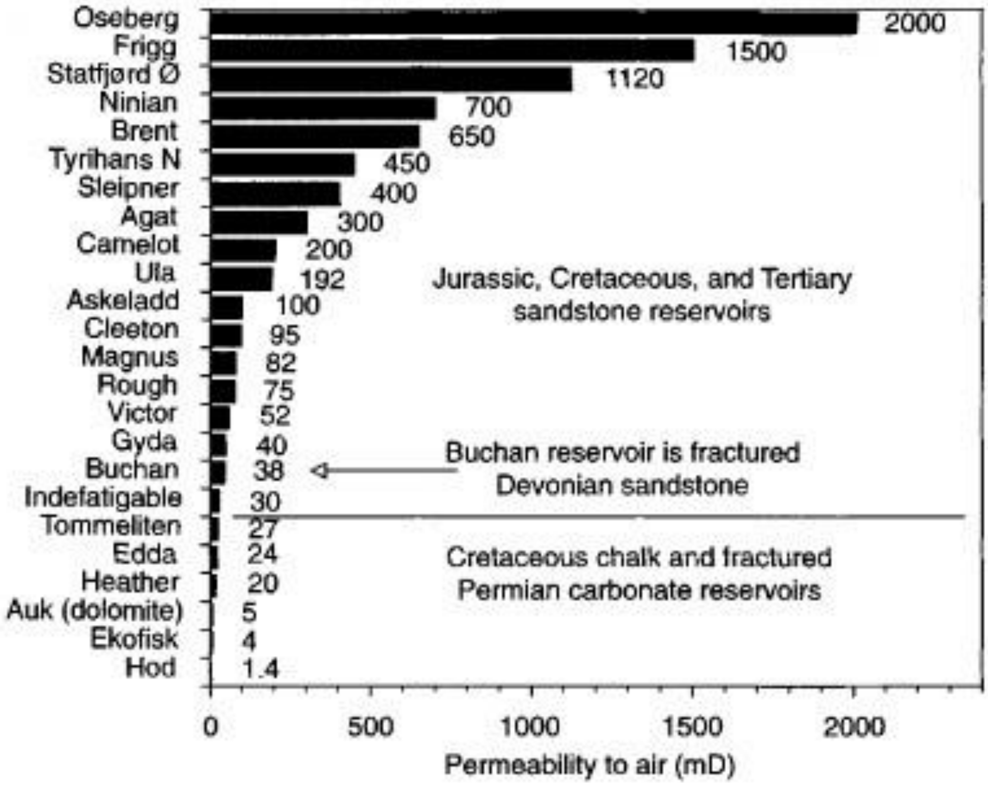

Fig .10. Average permeability for various producing fields on the UK and Norwegian continental shelves. (Gluyas et al. 2004; from Spencer et al. 1987; Abbots 1991; Gluyas et al. 1992; Oxtoby et al. 1995).

Chapter 4

Cap Rocks

Cap rock is a rock that prevents the flow of a given fluid at a certain temperature and pressure and geochemical conditions.

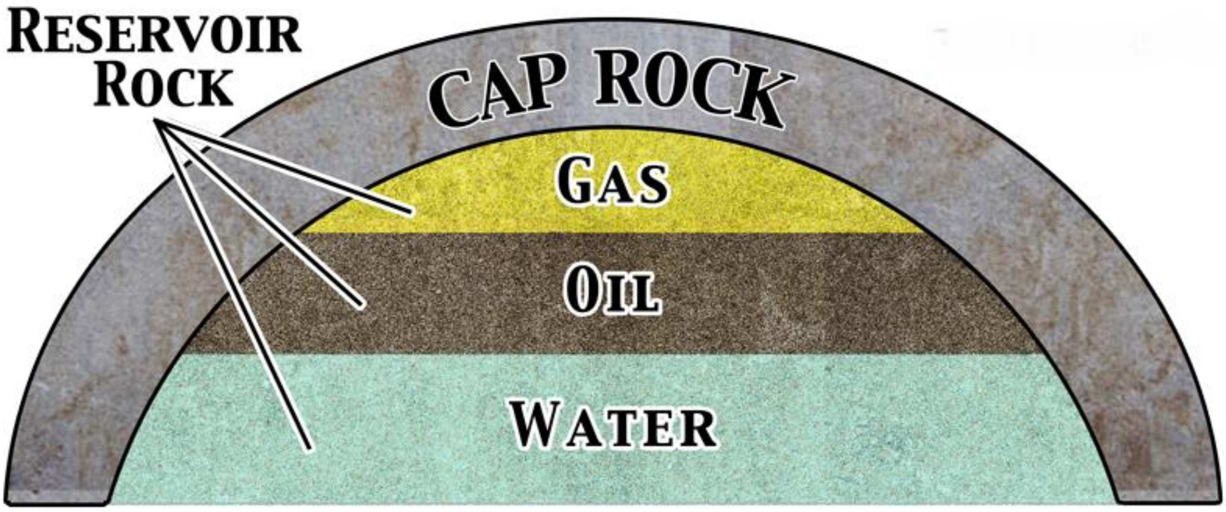

Fig .11. Cap Rocks

For a long time, the only force causing the movement of oil and gas in the subsurface was believed to be buoyancy. If so, then to form oil and gas accumulation, their migration paths must have been stopped by a roof, i.e., caprock (seal). Clays, shales, carbonates, evaporites, and their combinations can form caprocks.

The same rocks react differently to different fluids. In some cases, rocks serve as satisfactory or good conduits for water, but form barriers for oil or gas movement. In some other situations rocks yield oil but stop gas movement, etc. This is determined by capillary forces, the magnitude of which depends on fluid and rock properties (fluid density, fluid viscosity, rock structure, rock wettability) and pore size (capillary forces almost disappear when the pore diameter exceeds 0.5mm).

All aforementioned rock and fluid properties are strongly affected by the subsurface temperature and pressure and geochemical environment. Caprock is a rock that prevents the flow of a given fluid at a certain temperature and pressure and geochemical conditions. Therefore, the necessary properties of a rock to act as a seal will be different for different fluids. The same rock with different fluids may or may not have sealing properties up to a complete inversion (caprock - reservoir). The caprocks can be categorized into three types.

4.1. Types of cap rock in petroleum system

4.1.1. Type I

Caprocks are typical for argillaceous sequences in a state of continuing compaction; they are developed in areas of young subsidence of Earth's crust, with abnormally high pore water pressure. Sealing properties of these rocks are determined by the amount of capillary pressure at the contact of the reservoir and caprock, the pore pressure of water saturating the caprock, initial pressure gradient of water and the variation of hydraulic forces in the section.

Oil and gas accumulations have higher potential energy than that of the formation water. These accumulations can be stable only if this energy is equal to or less than the caprock breakthrough energy. Pore water pressure in compacting argillaceous beds is always greater than the pressure in the adjacent reservoir beds.

As a result, sealing capability of the Type I caprocks is determined by hydraulic sealing, by the amount of capillary pressure, and by the pressure at which water begins to flow through caprocks. Just the capillary pressure alone in such caprocks may exceed 100kg/cm2. This means that the Type I caprocks is capable of confining an oil accumulation having almost any column height. It appears that sealing capability of argillaceous caprocks does not depend on their thickness describes only the aforementioned caprock type.

4.1.2. Type II

Caprocks are associated with rocks compacted beyond the plasticity limit and having lost ability to swell on contact with water. Such rocks do not contain swelling clay minerals, and interstitial water contains surfactants. Consequently, pore water in these rocks does not have initial pressure gradient.

This type of caprocks is encountered mostly in the Paleozoic and Mesozoic sediments of young and old platforms. There are no clear-cut overpressure environments there, but there is a relatively clear hydrodynamic subdivision in the section. the hydrodynamic environment may improve or lower the sealing capability of caprocks. In an extreme case, the water potential in the reservoir may exceed the water potential of the bed overlying the caprock by the value of capillary pressure.

In such a situation, the caprock will be open for the vertical flow of hydrocarbons, and the trap will not exist even when potential distribution in the reservoir bed is favorable.

4.1.3. Type III

Caprocks are typical for rocks with a rigid matrix and intense fracturing. Such caprocks are mainly developed over the old platforms in regions of low tectonic mobility, with no detectable hydrodynamic breakdown of the section. Formation water potential in such regions is practically equal throughout the section and corresponds to the calculated hydrostatic potential.

The correlation between clay mineralogy and their sealing properties are as follows "The permanency in the composition of the silicate layer is a characteristic of the kaolinite group minerals. As a result, replacements within the lattice are very rare and the charges within a layer are compensated.

The connection between silicate layers in the C-axis direction is implemented through hydrogen atoms, which prevents the lattice from expanding, ruling out the penetration of water and polar organic liquids. The silicate layer in the montmorillonite mineral group is variable due to a common isomorphic replacement in octahedral and narrower tetrahedral sheets. This replacement results in the disruption of the lattice neutrality.

Extra charge that occurs with such replacements is compensated by exchange ions. Ion properties that maintain lattice neutrality in montmorillonite minerals (valence, size of the ion radius, polarization, etc.) define the capability of the lattice to expand along the C-axis. As a result, water and polar organic liquids can penetrate the interlayer spaces. This, in turn, leads to an increase in the volume, which drastically lowers permeability and some other properties, but at the same time improves sealing capabilities.

The silicate layer of the illite mineral group is similar to the montmorillonite one. However, the excessive negative charge of the lattice is due mainly to the isomorphic replacements within tetrahedral sheets. The proximity between the source of negative charge and basal surfaces causes a stronger connection between the silicate layers of illite group compared to montmorillonite’s."

Admixture of sand and silt degrades the sealing properties of clays. Especially important are the textural changes due to this admixture. Not only the mineral composition of a rock and organic matter content, but also the pore water are important in forming the major sealing properties of clays, such as degree of swelling and compressibility.

The relatively low-temperature pore water is retained in argillaceous rocks up to a temperature of 100C to 150C. The temperature of water removal is higher when the concentration of dissolved components is higher.

Pore water is located within pores of argillaceous rocks, and at the surfaces and along the edges of individual microblocks and microaggregates that comprise clays. The interlayer water causes swelling in montmorillonites and in degraded illites. The order in water molecules positioning, relative to the clay mineral blocks and aggregates, is rapidly altered with an increase in distance between these blocks and aggregates.

Thus, a very important information for the evaluation of the role water plays in the formation of sealing properties is the knowledge of the structural status of the layer in an immediate contact with the particles surface, and the role the cations having different charge density play in the preservation of water molecules structure.

Exchange ions play a leading role in the formation of "water clouds" around microaggregates and microblocks of montmorillonite minerals and an insignificant role, with kaolinite minerals. The role played by the illite group minerals occupies an intermediate position. Carbonates caprocks include micro- and fine-grained, massive and laminated limestones. Almost all limestones are dolomitized to some extent and are subject to fracturing.

This adversely affects their sealing properties. Carbonates with a substantial clay content have laminated texture. As a rule, this results in a deterioration rather than an improvement of sealing properties due to the emergence of weakness zones at the contact between different lithologies. Evaporite seals, which are common, include salt, anhydrite, and sometimes shales.

It is a common (and probably erroneous) belief that such seals are the best and most reliable. Brittleness of these rocks at the surface conditions contradicts that belief. Besides, cores recovered in the Dnieper-Donets Basin and North Caspian Basin display macro- and microscopic fractures, which sometimes cut monolithic salt crystals. The fractures may be healed by secondary salt, but often contain traces of oil and sometimes gas bubbles. Sometimes core samples are completely saturated with oil.

Permeability measured at the surface conditions can reach 100–150mD and even higher. It was established, however, that these rocks easily become plastic even at a relatively low hydrostatic or, even, uniaxial pressure (o100MPa) and the properties change with temperature. Some people considered plasticity as an important sealing property. In this connection, they believe that salt has the best sealing properties.

They also believe that the reliability of caprock is not directly related to its thickness. Thus, properties of evaporites as seals change widely during the catagenesis (and in time). Similar changes also affect the other types of seals albeit not so obviously. Inclusions, such as organic matter, silt, clay or carbonate particles degrade sealing properties of evaporites due to the formation of zones of weakness around such inclusions.

A careful study of numerous logs from Dnieper-Donets Basin showed the presence of clay interbeds between the top of accumulation and the evaporite sequence in all cases. It appears that these interbeds in most cases act as caprock.

4.2. Characteristics of the Caprock

A large amount of expertise regarding caprock performance is available from hydrocarbon exploration, production, and storage operations. However, while there are many similarities in seal performance criteria, there are also key differences that must be considered when storage of CO_2 is being evaluated, as a caprock that is adequate for hydrocarbon storage may not be adequate for CO_2 storage. For example, in terms of seal capacity and resistance to fracturing, the most effective sedimentary seals for hydrocarbons are gas hydrates followed by evaporites In comparison, methane gas hydrates should not under any circumstances be considered as a potential seal for CO_2 storage reservoirs due to the high probability of an exchange reaction occurring, indeed they should be classed as a geohazard and avoided To form an effective seal for CO_2 storage purposes the sealing lithology needs to be:

- impermeable to CO_2
- unfaulted and relatively ductile (resistance to fracturing)
- laterally continuous, maintaining a constancy of properties over a large area

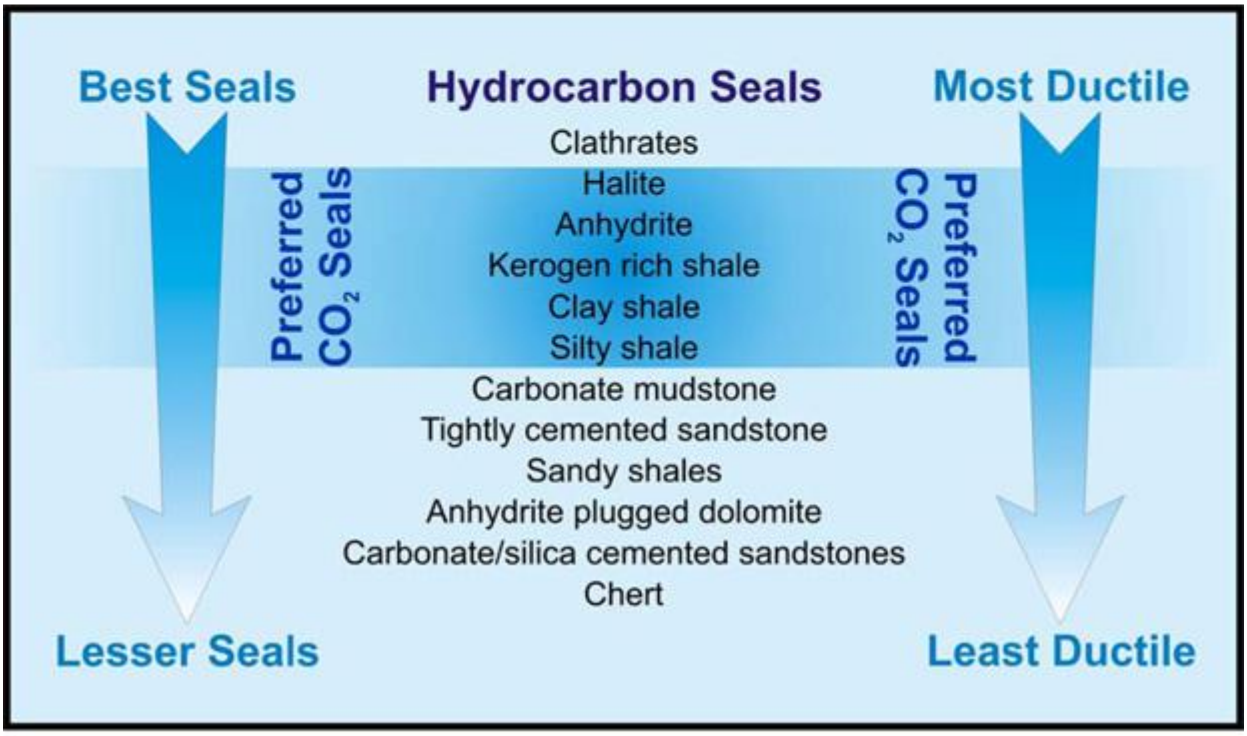

Fig. 12. Preferred seals for CO_2 storage reservoirs in comparison to hydrocarbon reservoir seals

Differing ability to form a hydrocarbon seal is related to inherent ductility in the subsurface (after Warren, 2007 & Downey, 1984). For CO_2 storage additional factors must be taken into account - most notably potential chemical interactions with methane hydrates and carbonates.

Caprocks considered suitable for CO_2 storage operations include evaporites (e.g. halite or anhydrite), shales and mudstones (e.g. Bachu, 2005). In their site selection framework, Pawar et al. (2006) also include carbonates. These caprock types are discussed below in relation to their ability to form an effective seal for CO_2 storage purposes.

4.2.1. Seal Capacity & Permeability

A fundamental requirement for an effective seal is that the entry pressure of the caprock be greater than the buoyancy pressure of the CO_2 stored in the reservoir beneath.

The seal entry pressure or seal capacity is the capillary pressure at which CO_2 will leak into the pore space of the caprock.

This is dependent on both rock and fluid parameters. Rock parameters include the size distribution of continuous pore throats – the small space at the point where two grains meet which connects two larger pore spaces. Fluid parameters include the fluids (or gases) present (e.g. CO_2, hydrocarbons, water), the density of the fluids, and the interfacial tension of the fluids.

The permeability of a rock is a measure of its ability to transmit fluids, and is a function of pore space distribution and connectivity (e.g. porosity and pore throat distribution). The units of permeability are length^2, and it is typically quoted in darcies (d) or millidarcies (md), where 1 d (10^3 md) is approximately equal to 10^{-12} m^2. Formations that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as evaporites, shales and siltstones, tend to be finer grained or of a mixed grain size, with smaller, fewer, or less interconnected pores.

Massive bedded halite (sodium chloride; NaCl) units contain few if any interconnected pore throats, and the permeability of halite is very low with typical values less than 10^{-6} md, and some of the tighter halites having permeabilities as low as 10^{-7} to 10^{-9} md (Ehgartner & Tidwell, 2000; Beauheim and Roberts, 2002; Warren, 2007). Massive anhydrites (calcium sulphate; $CaSO_4$) also have low permeabilities in the region of 10^{-5} md (Beauheim and Roberts, 2002), and entry pressures for massive evaporite deposits are correspondingly high (Warren, 2007).

Molecular diffusion of CO_2 through halite is also restricted, as the distance between NaCl lattice units is 2.8 x10^{-10} m (2.8 Å), while the molecular diameter of CO_2 is somewhat larger at 3.34 x10^{-10} m (3.34 Å).

A typical shale seal has a permeability of 10^{-1} to 10^{-5} md, with rare values as low as 10^{-8} (Warren, 2007). Shales tend to be water bearing, and typically have entry pressures that are lower than those of evaporites by a factor of 2-3 (Warren, 2007). Even though shales are respectable seals, over time shale can allow substantial diffusive leakage of methane and even liquid hydrocarbons via inherent microporosity (less so if the shales are organic rich), and could be expected to also allow diffusive leakage of CO_2.

4.2.2. Faulting & Fracturing

The caprock should ideally be unfaulted, as faults could provide migration pathways for the CO_2 to leak out of the reservoir. Thus, extensively faulted and fractured sedimentary basins are not good candidates for CO_2 storage, unless the faults and fractures are sealed (closed) and CO_2 injection will not reopen them (Bachu, 2005). It is this selection criterion that makes seismically active areas unattractive as potential storage targets (Bachu, 2005).

In some situations, for example in faulted halite layers, faults can become resealed, and therefore do not present a migration pathway. Other types of sealed faults also exist (e.g. clay or shale fault smears or gouges), and are indeed often responsible for the formation of structural traps. However, their sealing nature would need to be confirmed by detailed analysis to ensure the integrity of the storage site.

In some instances, while the fault itself is effectively impermeable and sealed to lateral cross-fault flow, there may be a high permeability damage zone in the adjacent rocks that will act as a migration pathway through the top seal (e.g. CO_2 leakage in the northern Paradox Basin, Utah; Shipton et al., 2005). As highlighted by Fisher & Knipe (2001), there is a lack of definitive models to explain why in some circumstances faults act as conduits for fluids, whereas in others they form barriers.

In an effort to improve understanding, these authors recommended the creation of a quality controlled database containing examples of how faults affect fluid flow in petroleum reservoirs, noting that ultimately any method developed to predict fluid flow properties of faults requires an understanding of the main controls on fault permeability (Fisher & Knipe, 2001).

The importance of faults as flow conduits can be simply illustrated by comparing flow through a rock with low permeability to flow through an unsealed fault or damage zone. Assuming Darcian flow (flow is directly proportional to permeability), then if we consider a rock unit 1 km in length on each side with a relatively low permeability of 10^{-}

[8] md, and cut by a fault with a permeability of 1 md (low compared to a typical reservoir permeability of ~100-200 md), then that fault only has to be 10 µm wide for flow through the fault to equal flow through the entire rock unit (or looking at it another way, flow through a unit area of the fault will be 10^8 times faster than flow through the rock).

With the probable exception of thick halite deposits, almost all potential caprocks will at some time in their burial history be subject to microfracturing and leakage – i.e. most reservoirs are inherently 'leaky'. In a study considering the world's giant oilfields, Macgregor (1996) concluded that on a geological timescale oil pools are dynamic short lived phenomena, where the median age of 350 giant oilfields is 35 Ma, and one third of these fields show evidence for post-entrapment destructive processes.

Indeed, only 1 in 10 prospective hydrocarbon reservoirs (where geological surveys indicated the presence of potential source, reservoir and seal rocks) are found to actually contain petroleum reserves, suggesting that up to 90% have leaked over geological time (Deffeyes, 2005). In the present day petroleum leakage to the surface is thought to be occurring in roughly 50% of the 370 basins worldwide (both onshore and offshore) with known petroleum reserves (Clarke and Cleverly, 1991). Migration through faults also represents the principal mechanism that delivers CO_2 to the seafloor at natural CO_2 vent sites (see Chapter 3 and the summary of known vent sites provided in Appendix 3.A).

Further understanding of fluid and gas migration through fault zones can be obtained through the study of leaking systems as an analogue for failed storage reservoirs. To date, detailed studies on CO_2migration pathways in natural systems have focused on the more readily accessible on land systems, such as the Paradox Basin in Utah (e.g. Shipton et al., 2005). Nevertheless, hydrocarbon migration from subseafloor storage reservoirs through the seal and overburden has been widely studied and can provide valuable information on potential pathways for CO_2 leakage.

In particular, the identification of hydrocarbon leakage sites above a target storage reservoir (e.g. the presence of cold seeps, gas chimneys, pock marks or carbonate mounds) could signal the presence of flow paths through both the seal and overburden. Such a site should not be considered for CO_2 storage, unless it can be proven that the hydrocarbons originate from a different reservoir (e.g. if the target

CO_2 storage reservoir underlies the hydrocarbon reserve and is separated from it by an intact seal).

4.2.3. Seal Thickness and Continuity

Theoretically, the thickness of a seal does not contribute to seal capacity. In reality, a bed only a few cm thick is unlikely to be laterally continuous unbroken unit capable of maintaining a stable lithic character over a sizeable area. Thus seal continuity rather than measured seal capacity (e.g. entry pressure) becomes the most important factor in assessing seal quality.

Indeed, as noted by Warren (2007), average values of seal properties measured on discrete core samples are next to useless without a reliable geological model for the reservoir - what is needed is the knowledge of the likeliest weakest point in the seal across the structure of interest. A thicker seal provides many layers of contingent sealing beds and so gives a larger probability of a sealing surface being continuous over an entire target storage reservoir.

In hydrocarbon exploration, shale seals more than 50m thick and evaporate seals more than 10m thick are considered adequate for hydrocarbon trapping, while evaporate seals more than 30m thick are considered excellent (Warren, 2007).

4.2.4. The Preferred Seal Type I - Halite Caprocks

Macgregor (1996) found the main controls on oilfield preservation to be post-entrapment tectonism and seal type, concluding that the potential for giant oilfields is the greatest in quiescent basins with evaporite seals. By the same token, the greatest potential for secure storage of CO_2 on geological timescales would also be in quiescent basins with evaporite seals (personal communication S. Hazledine & Z. Shipton).

Evaporite seals with their extremely high entry pressures, very low permeability, and large lateral extents can maintain seal integrity over wide areas even when exposed to a wide range of subsurface temperature and pressure conditions. Furthermore, unlike most other rock types, halite is ductile at relatively low temperatures and pressures and will flow under differential pressure at (geologically) rapid rates of up to meters per year. This not only gives halite a low susceptibility to fracturing, but even if a halite bed fractures, those fractures will quickly reanneal and crystal lattice binding will be reestablished by a combination of flow and pressure solution induced recrystallisation (Warren, 2007). Indeed, it would appear that the only way that CO_2 could migrate through an unfractured halite bed, even by diffusion, is if the halite contains impurities than render it locally porous and make it brittle during deformation.

The ability of evaporites to form highly efficient seals is clearly demonstrated by consideration of the number of hydrocarbon reserves that are sealed by evaporites. Even though evaporites constitute less than 2% of the worlds sedimentary rocks (compared to mudstones and shales which comprise 65%), 14 of the world's 25 largest oil fields and 9 of the world's 25 largest gas fields are sealed by evaporites (Grunau, 1987; Warren, 2007).

The plastic self sealing properties of halite have also been exploited in salt cavern storage operations, where purpose made salt caverns (formed by dissolution mining of large salt deposits) have been used as hydrocarbon storage facilities and contaminated waste repositories for over 60 years. Salt caverns have also been discussed as potential CO_2 sequestration sites (Dusseault et al., 2002; Shi & Durucan, 2005). A large body of literature regarding the self sealing behaviour of halite in relation to cavern closure is available.

Despite the excellent properties of halite seals with respect to safety of CO_2 storage, they may not be widely utilized as storage reservoir caprocks due to economic driving forces (personal communication S. Haszledine). For example, the North Sea Basin contains a widespread Permian salt layer (the Zechstein Salt) which stretches from the East Coast of England to Northern Poland and reaches a depositional thickness of *c.* 1 km in the basin centre (salt tectonics in the North Sea Basin are discussed by Stewart, 2007).

Indeed, this formation forms the seal of the K1-2B demonstration storage project in the North Sea. However, the Permian salt layer is overlain by other potential storage targets such as sandstone aquifers capped by mudrocks (e.g. the Triassic Bunder Sandstone in the southern North Sea). These shallower sites may well be utilized more widely for CO_2 storage, despite the better sealing qualities of the deeper salt layer, as the costs of storage would be significantly lower.

4.2.5. The Preferred Seal Type II - Multiple Confining Layers

The ideal storage reservoir would be overlain by multiple confining layers, where if primary leakage were to occur, the CO_2 would migrate vertically through the overburden and become trapped under a second confining layer (and so on).

The new CO_2 storage facility at the Snøhvit LNG Project (operated by Statoil) is an example of a storage reservoir overlain by multiple confining layers. The following summary of the Snøhvit storage project is after Maldal & Tappel (2004):

In the Snøhvit field, the main recoverable gas volume is located in the Stø Jurassic formation. This reserve is CO_2 rich, where CO_2 is separated from the well stream and re-injected into the subsurface. The target CO_2 storage reservoir is the Tubåen formation, which is located approximately 60m beneath the Stø formation and separated from it by the Nordmela 1 and 2 formations. The Tubåen formation is dominantly sandstone, with a formation thickness of 45-75m and is expected to store 23 Mt of CO_2 over the lifetime of the Snøhvit project. Nordmela 1 and especially Nordmela 2 contain extensive shale layers (25–30 m thickness of massive shale) providing barriers to vertical migration of CO_2.

A CO_2 content of 5 mol% in an existing gas cap in the Tubåen formation, as well as proven gas reservoirs in the area with up to 80 mol% of CO_2, are strong indicators that CO_2 will be permanently sealed in this formation. Nevertheless, should leakage through the caprock occur, the CO_2 will enter the Stø formation from which it was initially extracted, i.e. it will remain separated from the ocean and atmosphere. Furthermore, primary leakage would be readily identified through an increase in the CO_2 content of the producing well streams.

4.2.6. Cautionary Note - The Importance of High Quality Seismic Surveys

Targeted discovery of a potential storage site must conduct a detailed seismic survey of the caprock seal, specifically a high resolution 3D seismic survey. The spatial resolution of traditional 2-D seismic techniques is on the order of 30m at reservoir depths of 3-4 km (at shallower depths resolution will be correspondingly better).

This may well prove insufficient to resolve key features that are determinant in the performance of the caprock (personal communication, Z. Shipton & S. Haszeldine). For example, if a salt deposit is interbedded with permeable layers with thicknesses on the order of 10m, this would most likely appear as a continuous salt deposit in a 2-D seismic survey.

Similarly, faulting where the fault throw is less than the seismic resolution would not be identified. Either of these scenarios (or a combination of the two) could result in the deposit being assessed as a suitable seal, where in fact low permeability flow paths are present. In comparison, 3-D seismics offer spatial resolution on the order of ~10m, and should provide sufficient resolution for correct caprock assessment.

Summary

1-Source Rock:

Is a rock that is capable of generating or that has generated movable quantities of hydrocarbons.

Source rocks can be divided into at least four major categories:

- Potential
- Effective
- Relic effective
- Spent

To be a source rock, a rock must have three features:

- Quantity of organic matter
- Quality capable of yielding moveable hydrocarbons
- Thermal maturity

There are several of types of source rock

- Type 1 source rocks are formed from algal remains deposited under anoxic conditions in deep lakes
- Type 2 source rocks are formed from marine planktonic and bacterial remains preserved under anoxic conditions in marine environments.
- Type 3 source rocks are formed from terrestrial plant material that has been decomposed by bacteria and fungi under oxic or sub-oxic conditions.

2-Reservoir rock

Reservoir Rocks are the rocks that have ability to store fluids inside its pores, so that the fluids (water, oil and gas) can be accumulated. Reservoir rock is a rock containing porosity, permeability, sufficient hydrocarbon accumulation and a sealing mechanism to form a reservoir from which commercial flows of hydrocarbons can be produced. There are several types of reservoir rock: Sandstone reservoir rocks , carbonates reservoir rock , Siliciclastic Reservoir .

Porosity of reservoir is the property that tells how porous a rock is. It is also defined as a measure of the capacity of reservoir rocks to contain or store fluids.

The primary porosity types are:

i) Inter-particle
ii) Intra-particle

Secondary porosity, the porosity formed after deposition leads to other couple of reservoirs types.

A. Dissolution porosity
B. Fractured porosity

Permeability is a measure of the ability of a fluid to pass through its porous medium. Permeability is one of important to determine the effective reservoir.

3-Cap rock

Cap rock is a rock that prevents the flow of a given fluid at a certain temperature and pressure and geochemical conditions.

There are several types of cap rock:

- Type1: caprocks are typical for argillaceous sequences in a state of continuing compaction
- Type2: caprocks are associated with rocks compacted beyond the plasticity limit and having lost ability to swell on contact with water. Such rocks do not contain swelling clay minerals.
- Type3: caprocks are typical for rocks with a rigid matrix and intense fracturing. Such caprocks are mainly developed over the old platforms in regions of low tectonic mobility.

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