Baker Hughes INTEQ

Petroleum Geology

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BAKER HUGHES

INTEQ

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Preface

At Baker Hughes INTEQ, we have always prided ourselves on our people and their level of professionalism, experience, responsiveness and adaptability at the wellsite, where time, money and effective operations depends on rapid, reliable information management. IN-FACTS, a system for training, developing and providing professional advancement for field operations personnel, is the method behind these applications.

The IN-FACTS program provides a standardized career development path which utilizes a progression of both formal and hands-on learning, to turn potential into fully developed expertise. IN-FACTS is the tool that enables Baker Hughes INTEQ personnel to embark on, and develop successful careers within INTEQ, Baker Hughes, and the oil industry.

IN-FACTS is structured to provide an easily understood, orderly flow of learning experiences. These may or may not be in the same specialty, and allow our personnel to concentrate in one area, or to branch out into other disciplines. Movement through the IN-FACTS career progression is determined by industry experience, skills, and knowledge acquired through rigsite work and a variety of formal and informal training programs.

The training programs are modular, and are composed of formal course work, self-paced learning packages, and on-the-job training.

Module L5, Formation Evaluation Geologist, requirements include increased knowledge of sedimentary geology and expanded knowledge of those geologic aspects which affect formation evaluation. This module will focus around geologic evaluation and interpretation.

After successful completion of this module, further course work is composed of:

- Advanced Wireline/MWD Procedures - Module L6
- Drilling Engineering - Module C3
- Consultant Wellsite Geologist - Module G1

These modules will provide a continuing source of education and training in a variety of wellsite operations to promote confidence and self-motivation in individuals, and ultimately produces management professionals with true “hands-on” field experience.

The L5, Formation Evaluation Geologist, Module is the entry point for becoming a wellsite geologist.

Learn and enjoy!

Acknowledgments

Chapter 5

Dresser Atlas, Well Logging and Interpretation Techniques, 1982

AAPG, Basic Well Log Analysis For Geologists, 1982

Schlumberger, Log Interpretation Charts, 1984

AAPG, Well Log Formation Evaluation, 1983

AAPG, Concepts and Methods of Subsurface Facies Analysis, 1978

Rider, The Geological Interpretation of Well Logs, 1991

Instructions On Project Completion

The aim of this workbook project is to provide you with the information on various formation evaluation topics that can best be studied outside a classroom. It is not the intention of the Training Department that you complete all the assignments as soon as possible. This workbook project should allow you to spend enough time on each particular subject in order to thoroughly understand those aspects of geologic evaluation and interpretation as they apply to every day wellsite operations. This workbook includes:

- Sedimentary Petrology
- Sedimentary Structures
- Sedimentary Environments
- Reservoir Geology
- Wireline/MWD Logs in Formation Evaluation
- Introduction to Seismic Surveying
- Introduction to Geochemistry
- Introduction to Well Testing

At the end of each chapter there will be “Self-Check” exercises, which are designed to assist you in understanding the information covered in the chapter. Do not proceed until you are confident that you fully understand the concepts, calculations, and applications of the chapter's subject matter. Direct any questions you may have to the Training Department.

When you have completed the workbook assignments, there will be several “Return” assignments. These are to be completed and returned to the regional/area Training Department. Using these assignments, the Training Department will be able to assist you in the next step in completing the module requirements. It is in your best interest to stay in contact with your Training Department.

This workbook is designed to review those aspects of sedimentary geology that are unique to the oil industry and to increase your knowledge and understanding of formation evaluation using those geologic principles.

There is a lot to learn, and remember, the learning process will never end. There are no real shortcuts. You will be required to learn for yourself, with guidance and assistance from experienced field personnel and the Training Department.

The aim of the training you receive at Baker Hughes INTEQ is to develop your individual skills and knowledge to make you a fully competent, reliable professional within the oil industry. IN-FACTS is designed to assist you in this.

Important

Do not read the text or practice the exercises in the workbook during your normal work schedule

During this time you are expected to work, not study!

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Sedimentary Petrology

Upon completion of this section, you should be able to:

- Understand those aspects of clastic, carbonate and evaporite petrology as they pertain to petroleum reservoirs
- List the important properties in clastic, carbonate and evaporite petrology
- Explain how clastic, carbonate and evaporite rocks are classified
- Understand the Rock Color Chart method of describing rock colors

Additional Review/Reading Material

AAPG, *A Color Illustrated Guide to Constituents, Textures, Cements, and Porosities of Sandstones and Associated Rocks,* Memoir #28

AAPG, *A Color Illustrated Guide to Carbonate Rock Constituents, Textures, Cements and Porosities,* Memoir #27

AAPG, *Classification of Carbonate Rocks*, Memoir #1

Greensmith, J.T., *Petrology of the Sedimentary Rocks*, Allen & Unwin Ltd, 1978

Sedimentary Petrology

The topic of sedimentary rocks is such a broad topic that manuals have been written on each specific rock texture. Because of the broad subject matter, this section will briefly deal with those textures that pertain to cuttings samples obtained at the wellsite, and how the Wellsite Geologist can better use those properties to form opinions, recommendations and interpretations as to the geologic nature, structure and depositional environment of those formations.

Clastic Petrology

Clastics are the most common sedimentary rocks that are drilled in the oil field. These include gravels, sands and clays, along with their consolidated forms conglomerates, sandstones and shales. Many times these rocks form the three requirements for a commercial petroleum accumulation; the source rock, the reservoir rock and the cap rock. In this section, clastic rocks will be defined as those rocks formed from pre-existing rocks whose constituents were transported by some mechanism (wind, water, glacial ice) to the area of deposition.

Sediment Texture

Clastic sediment textures have been described in previous modules (i.e. *Advanced Logging Procedures Workbook*), and a complete understanding is necessary for both cuttings sample and core descriptions. This description will form the basis of all subsequent interpretation of the cuttings, the rock and the formation.

The most commonly described clastic textures include:

Grain Size: This parameter (Figure 1-1) reflects (1) the kinds and sizes of particles available from different kinds of bedrock or pre-existing sediments, (2) the resistance of particles to weathering, erosion, and abrasion, and (3) the processes of transportation and deposition.

Some authors go into great detail about the statistical analysis of grain size and sorting to predict depositional environment. Though they are not expected to perform statistical analyses at the wellsite, the geologist should understand the key words and topics concerning:

1. The scales defining the various grain size delineations
2. Frequency distribution curves depicting skewness

3. Sorting and how the terms relate to depositional environments'

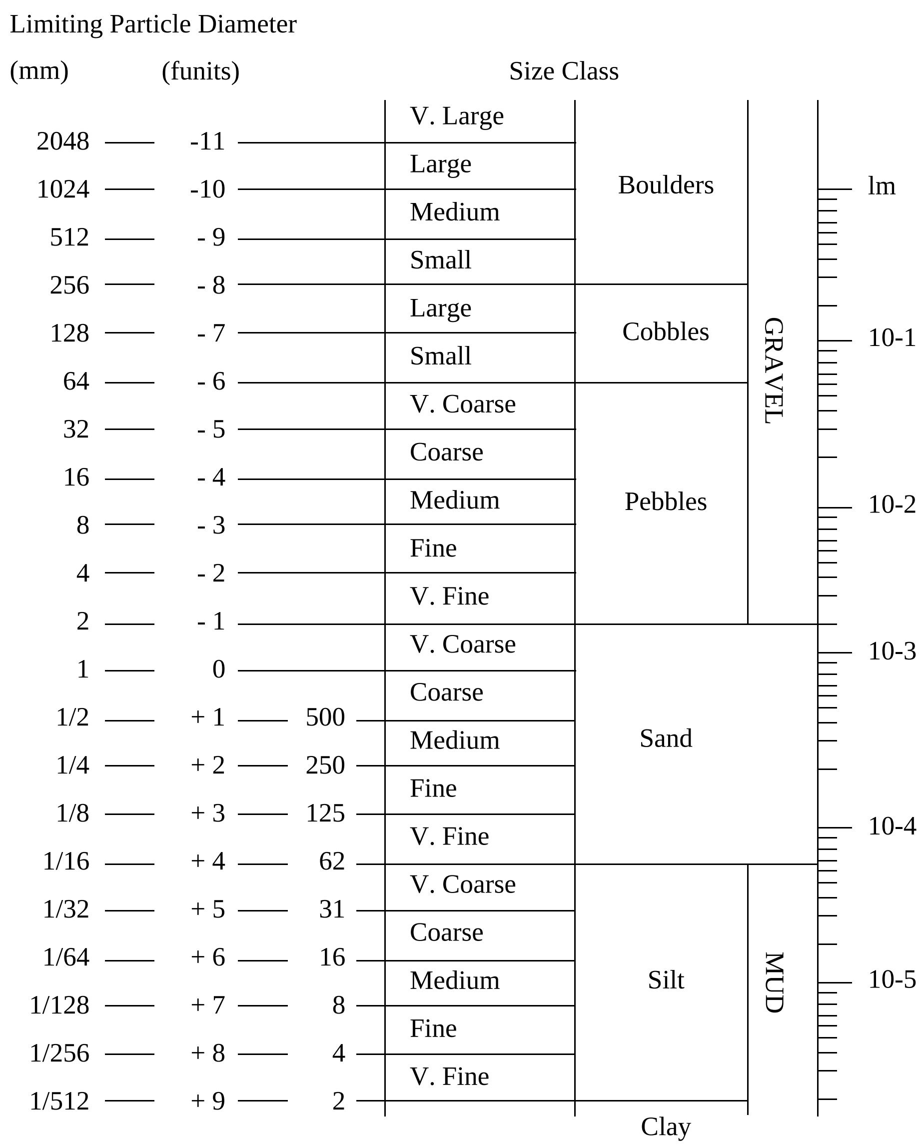


Figure 1-1 Standard Grain Size Classification

Grain Shape: Shape (Figure 1-2) describes the geometric form of particles, which reflects the origin, history, and internal lattice structure of the particles. Many times qualitative information on processes can be obtained from the shape of particles. Particle shape is modified by abrasion during transport, being dependent upon; (1) initial shape when liberated from the source rock, (2) composition, (3) hardness, brittleness, or toughness, (4) inherited partings, (5) size, (6) agent of transport, (7) rigors of transport, and (8) other random effects.

Grain Texture: Transport in running water does not significantly affect the shape of hard sand-size particles. However, transport by water, wind, and glacial ice does affect the surface textures. Abrasion creates pits, fractures and various surface markings reflect the origin of the particle. As the environment of transport changes, or becomes affected by other lithification cycles, the surface patterns of particles can reflect a complex history. Old markings become obscured and new ones take their places. When this happens, reconstruction of the particles history using surface features is only partially feasible.

Grain Fabric: The porosity of sediments varies according to the size, shape, and fabric of the framework particles, and the presence of any cementing agent between the particles. The fabric is affected by the manner in which the particles were laid down and the resulting structure of the inter pore connections.

Sphericity: The degree to which a particle approximates the shape of a sphere. This expresses how equal the three mutually perpendicular dimensions of a particle are to one another. The rock type controls the sphericity.

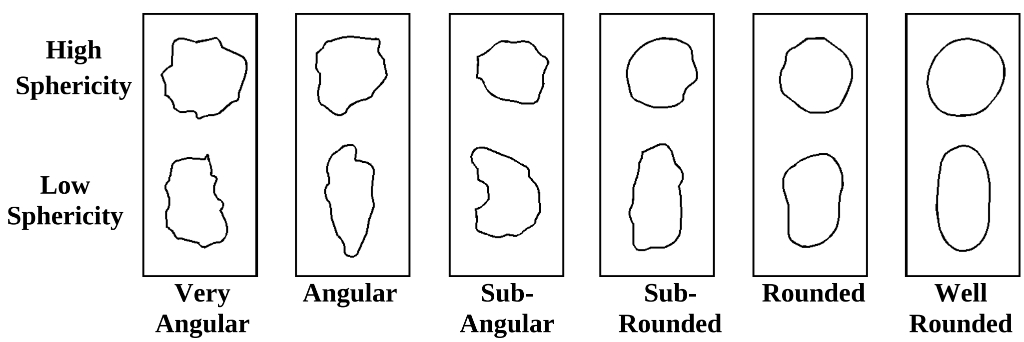


Figure 1-2 Grain Shape based on roundness and sphericity

Roundness: This attribute of form relates to the sharpness or curvature of any edges and corners. The visual roundness scale contains six classes: very angular sub-angular, sub-rounded, rounded, and well rounded. Reconstruction of detailed geologic events using shape is generally not possible.

Grain Contacts: The morphology of the contacts between particles is related to the original packing and the degree and amount of any pressure solution. The number and type of contacts (Figure 1-3) depends upon imposed stresses and particle dissolution resulting from the overburden or from deformation. The primary parameter concerning grain contact is solution.

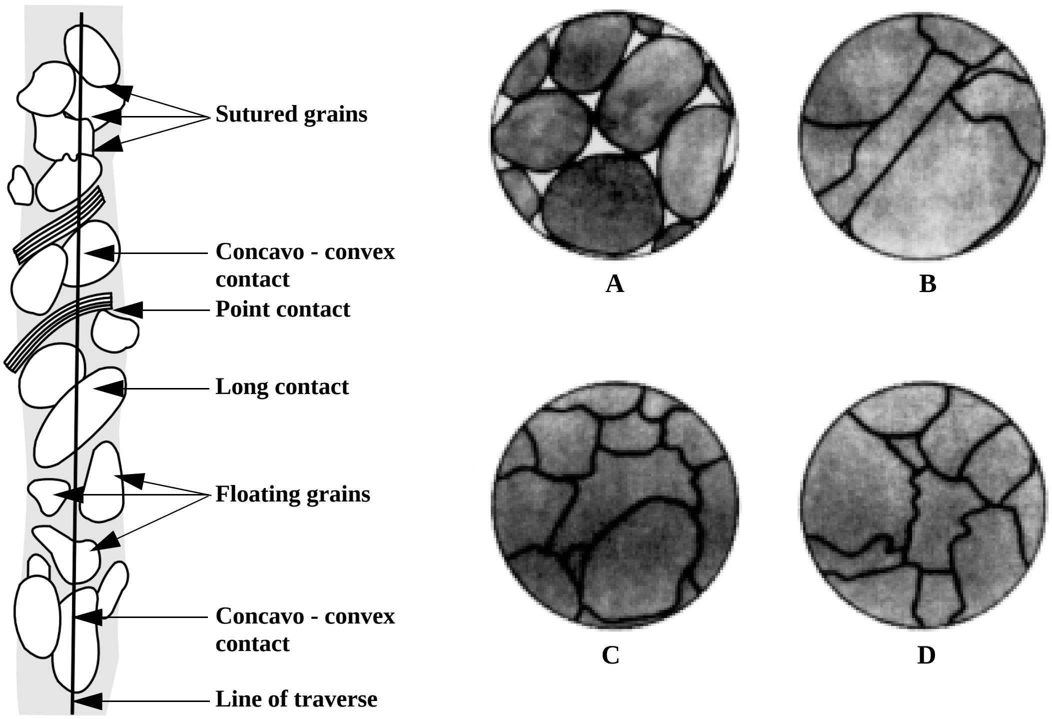


Figure 1-3 Grain Contact Terminology: A) point contact, B) long contact, C) concavo-convex, D) sutured

Components of Siliclastics

Siliclastics are composed of grains, matrix and cement. The matrix may be deposited with the grains or it maybe authigenic (developed in place; e.g., clays formed by break down of feldspars). The mineralogy is dependent upon the source area, the mechanical and chemical stability of the available minerals, and the maturity of the sediment.

Mono crystalline Quartz: This is the most common type of detrital quartz grain. The grain size is generally below 1.0 mm in diameter. It consists of a single crystalline mass.

Poly crystalline Quartz: Most common when then detrital grain size is over 1.0 mm in diameter. It is composed of interlocking grains, commonly with sutured contacts.

Intra/Extra formational Clasts: Individual constituents of the same type (intra) or unassociated (extra) sedimentary rock produced by the physical disintegration of a larger mass.

Feldspars: Group of minerals originating from igneous and metamorphic rocks, consisting of silicates of aluminum with potassium, sodium, calcium, and sometimes barium.

Authigenic Clay: Clays formed “in-place” by the degradation of other minerals, typically feldspars. These often form the matrix of arenaceous sedimentary rocks, binding grains together into consolidated sediments.

Heavy Minerals: The accessory detrital minerals, of high specific gravity, which can be separated from minerals of lesser density using high density liquids.

The classification of siliclastics is based upon the ability to distinguish feldspar grains from quartz and lithoclasts. When using a binocular microscope on cuttings or core chips, this can be difficult, though with medium and coarse sandstones it is possible. Feldspar-laden sand grains tend to be milky or translucent and do not have the glassy appearance of quartz. They are often partly replaced by clay minerals (sericitic texture) giving them a dull earthy texture. The grains can be crushed much easier than quartz and may show cleavage planes.

Muscovite mica is common in certain formations (e.g., the Rannock Formation of the Brent Group) where it appears as loose flakes within the sand grains. The geologists must make sure this mineral is not LCM!

Classification and Petrography of Sandstones

Sandstones are classified in a petrographic manner, based on microscopic studies and require an approximate, if not accurate determination of the modal composition. In spite of this, rough estimates of sandstone composition can be made at the wellsite through close scrutiny with a microscope or hand lens. Most classifications use a triangular diagram with end members of quartz, feldspar and rock fragments (Figure 1-4). The triangle is divided into various fields, and rocks with a modal analysis falling within a particular field are given a particular name. It really doesn't matter which system is studied concerning the classification of sandstones, because rocks-types are constant.

Sandstone Classification (Pettijohn): Pettijohn divides sandstones into two major groups, based on texture. That is, whether the sandstones are composed of only grains (arenites) or contain more than 15% matrix (wackes). As stated, this classification is primarily concerned with the mineralogy of the sediment and presence or absence of a matrix. It is independent of the depositional environment, although some lithologies are more common in certain environments.

Polymict/Monomictic Conglomerates: Polymictic conglomerates, otherwise known as breccias, contain a variety of pebbles and boulders, whereas mono or oligo-mictic conglomerates consist of only one pebble type only.

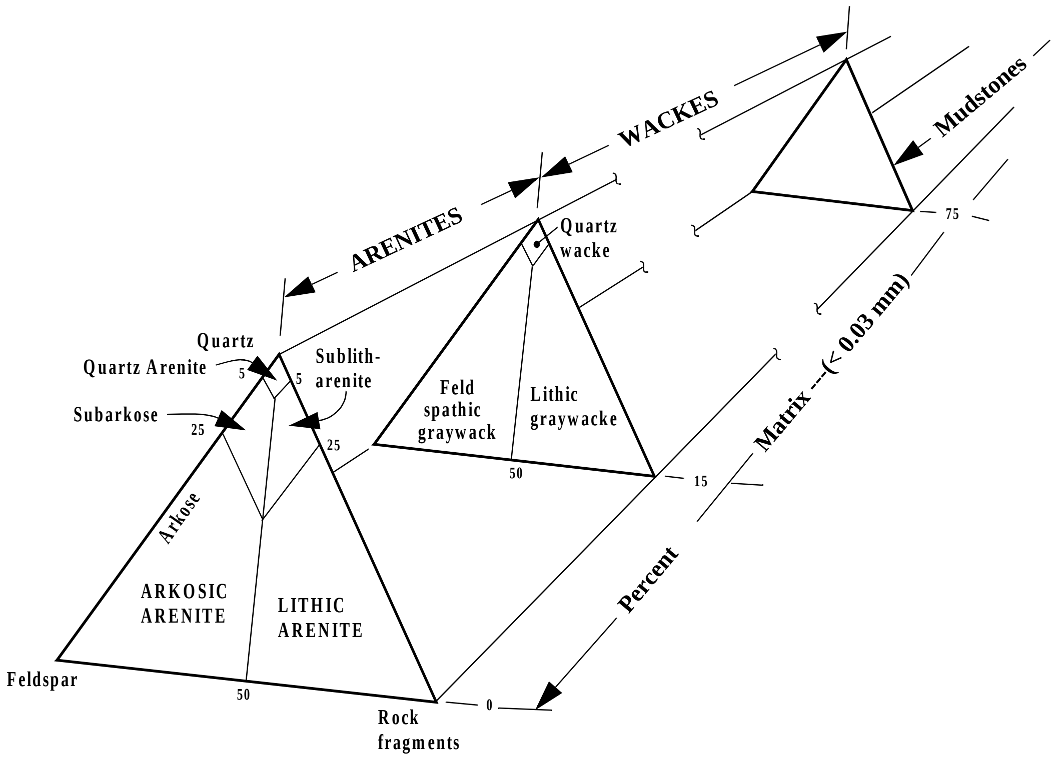


Figure 1-4 Classification of Sandstones

Litharenite: An arenite where the rock fragments exceed 25% and is greater than the feldspar content.

Quartz Arenite: Where the sand is composed of more than 95% quartz grains.

Arkose: A sandstone containing 25% or more of feldspars, usually derived from the disintegration of acid igneous rocks of granitoid texture. The minerals of an arkose may accumulate in-place or be transported to the site of deposition.

Ganister: A quartz arenite formed by extensive in-situ leaching (paleosoil).

Wackes: The wackes are the transitional group between arenites and mudrocks. The most familiar is the greywacke and two types are recognized: feldspathic and lithic.

Stylolites: These are thin seams of clay and insoluble material which run parallel to bedding in a limestone or sandstone. These are produced from pressure solution along planes as the result of stress. The clay which fills the seams is insoluble residue derived from limestone solution.

Quartz Cements: At the wellsite, the presence of quartz cement is often inferred from a negative reaction to 10% HCL. There maybe two stages or more of cementation (e.g. early quartz overgrowth cement followed by calcite cementation) and it is not always possible to distinguish the primary cementing agent. However, with cuttings of medium to coarse sandstone, it maybe possible to distinguish quartz overgrowth cements.

Under low magnification, cuttings may have a sparkled appearance which, under high magnification, is due to crystal facets developing around sand grains, giving them an euhedral shape. The overgrowth can often be broken off with a sample probe. What looks like an angular sand grain often on removal of the overgrowth turns out to be a rounded or well rounded grain. In red bed sandstones quartz, overgrowth can be common and the boundary between the grain and the overgrowth is often demarcated by hematite staining.

Calcite Cementation: Calcium carbonate cement generally occurs as calcite crystals, which, as they grow from pore to pore, form a poikilitic fabric of crystals enclosing the sand grains. The grains frequently appear to “float” in the crystals. Detailed observation often shows that grain boundaries are corroded, suggesting that some replacement has occurred. Calcite cementation is the result of alkaline fluids moving through the pores.

1. Poi kilo topic Crystals: This is a textural designation, denoting a situation in which small granular crystals of calcium carbonate are irregularly scattered, without common orientation, in a larger crystal of another mineral.
2. Drusy Calcite Spar: In many limestones, two distinct generations can be distinguished. The cement that occupies the majority of the original pore space is clear, equant calcite, referred to as sparite, drusy sparite or orthospar.

The delineating features that identify this cement are; (1) its location between grains and skeletons, (2) its generally clear nature, (3) the presence of planar inter crystalline boundaries, (4) a drusy fabric, and (5) crystals with a preferred orientation of optical axis which is normal to the substrate.

There is often a displacement of grains by cement giving the sandstone the appearance of being matrix supported. This is particularly likely with poi kilo topic calcite. The matrix supported fabric maybe accentuated in cuttings as the cement is often crushed up by the bit, forming a partial rock flour. Geologists at the wellsite have often been confused by this, and described calcite cemented sandstone as arenaceous limestone.

Authigenesis: This implies the formation of a mineral during or after deposition. Within the oil fields, this is important because the secondary formation of clays can affect the potential productivity of reservoirs. Prior to recent studies, it was assumed that all clays in a reservoir were included during deposition. However, now it is recognized that many clays are formed in-place. Illite and kaolinite are the most common authigenic clays.

There is a positive aspect to clay authigenesis in the sense that the formation of clays is usually an early (the first diagenetic event) occurrence. This can inhibit the later formation of quartz cements and these clays are often removed by various chemical treatments prior to production.

Kaolinite: The kaolinite group of minerals is characterized by a two-layer lattice, consisting of one octahedral or gibbsite layer linked to one silica tetrahedral layer. This lattice does not expand with water content (unlike the smectite group). No replacements by iron or magnesium in the gibbsite layer are known. Kaolinite can sometimes be distinguished as off-white, non-calcareous patches in cuttings and cores.

Porosity and Permeability

When one discusses porosity and permeability in the oil fields, the primary concerns are the concepts of absolute and effective porosity. A reservoir will have a given amount of void space. If these voids are not connected, production will be limited. This “effective” porosity, in conjunction with permeability, dictates the ultimate quality of the reservoir.

Porosity consists of primary and secondary forms. Primary porosity is formed when the sediment is originally deposited. Secondary porosity results from diagenesis by solution and replacement. Some clastic porosity forms from tectonic activity.

The primary porosity in sandstones is principally interparticle (between the grains). Though not true theoretically, as a general rule, the larger the grain size, the higher the porosity. This porosity will decrease during the formation of clays and alteration products after deposition. Compaction and cementation after deposition will also reduce the absolute porosity. Generally, porosity decreases as depth increases. However, cementation is the principal process leading to porosity loss in sandstones.

There are three types of pore communication within clastics:

1. Catenary porosity - pores that have communication with others via 2 or more pore throats.
2. Cul-de-sac porosity - those that have communication via only 1 throat.
3. Closed pore communication.

Types 1 and 2 make up “effective porosity”. Darcy's law for permeability is only valid when 1 fluid phase is present. When more than one fluid is present (the norm in any reservoir) the term effective permeability is sometimes used, meaning one rock may have three permeability values; effective permeability for oil, water and gas.

Permeability can vary greatly depending on orientation (e.g. vertical permeability maybe far lower than horizontal permeability) for the same rock, especially if micas are abundant. Permeability may also be strongly influenced by cross-bedding and other sedimentary structures.

Mudrocks

Although sandstones and limestones are of primary concern in oil and gas exploration, the most abundant sediments are mudrocks (shales, claystones, etc.). These comprise about half of all the sediments. Mudrocks (Table 1-1) are deposited in practically every environment, with the primary environments of deposition being river floodplains, lakes, large deltas, the continental shelves and platforms, and the ocean floors.

Mudrocks (Figure 1-5) are primarily distinguished by the number of mineral layers that their structure contain. The kaolinite group is probably the best known of the two-layer clay minerals.

Another major type of clay mineral is the three layer group. These have sheet structures composed of two layers of silica tetrahedra interleaved with aluminum di- and tri-octahedra. The most widely known examples are the smectite and illite groups.

Table 1-1: Chemical Analysis of Typical Clay Minerals

	Kaolinite	Montmorillonite	Illite	Chlorite	Glauconite
SiO_2	45.44	51.14	42.96	26.28	52.64
Al_2O_3	38.52	19.76	28.97	25.20	5.78
Fe_2O_3	0.80	0.83	2.27	-	17.88
FeO	-	-	0.57	8.70	3.85
MgO	0.08	3.22	1.32	26.96	3.43
CaO	0.08	1.62	0.67	0.28	0.12
Na_2O	0.66	0.04	0.13	-	0.18
K_2O	0.14	0.11	7.47	-	7.42
H_2O-	0.60	14.81	3.22	-	2.83
H_2O+	13.60	7.99	6.03	11.70	5.86

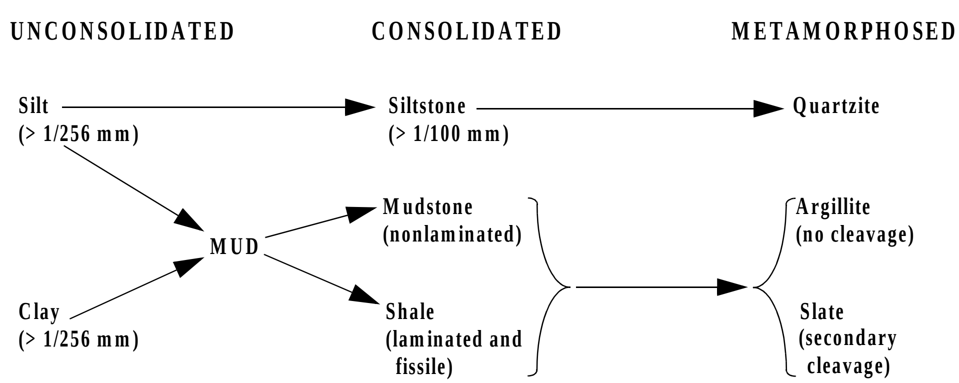


Figure 1-5 Terminology of Mudrocks

Numerous types of accessory minerals can be found in clays. These take various chemical forms. These include:

1. Siderite and calcite are precipitants and early diagenetic concretions and nodules.
2. Authigenic pyrite, marcasite, and pyrrhotite grains and nodules formed by the insitu reduction of iron salts by organic activity.
3. Organic matter in the form of humic colloids or solid animal and plant remains.
4. Ferric oxide, usually in a hydrated state.
5. Aluminum hydroxides that are deposited to form bauxite clays.

Smectites are three-layer clays. This group includes such common clays as montmorillonite and nontrite. The clay's ionic lattice is capable of expanding and including water between the layers. This hydration causes many problems during the drilling process.

The illite group consists of non-expanding layers that have a chemical make-up that is similar to muscovite and sericitic mica. This type of clay also includes glauconite.

Mixed layer clays include the chlorite group. These clays have a prominence of ferrous ions. The mineral layers are “mixed”, with chlorites having an alternate two-layer and three-layer arrangement of ions. Other variations are commonly given names such as kaolinite-illite rather than a distinct designation.

Carbonate Petrology

Successful hydrocarbon exploration in carbonate rocks is a difficult and complex problem. Carbonate rocks have complicated and varied depositional patterns, and are subject to extensive post-depositional alteration which can radically alter the original porosity and permeability relationships.

Components of Limestones

In general, the term *limestone* is applied only to those rocks in which the carbonate fraction exceeds the non-carbonate constituents (greater than 50% $CaCO_3$), and is used for those rocks in which the carbonate fraction is composed primarily of calcite or aragonite. The term *dolomite* is reserved for those rocks which are composed mainly of the mineral dolomite (calcium-magnesium carbonate) even though dolomite is a lime-bearing rock (see Table 1-2:).

Table 1-2: Principle Differences Between Calcite and Dolomite

	CALCITE	DOLOMITE
Crystal Habit (in rocks)	Anhedral rarely rhombohedral	Rhombohedral may be zoned
Chemical Formula	$CaCO_3$	$CaMg(CO_3)_2$
Specific Gravity	2.71	2.87
Solubility in HCl	Readily soluble in cold dilute acid	Very slowly soluble in cold dilute acid
Staining	Readily takes a Alizarin Red S stain	Not stained by Alizarin Red S
Weathering	Does not become buff or pink	Weathers buff or pink

Unfortunately, the term limestone has become a catch-all phrase for a diverse group of rocks. Some are fragmental or detrital, which have been mechanically transported and deposited, while others are chemical or biochemical precipitates which form in-place. The simple usage of limestone obscures rather than clarifies the origins of these rocks. This is why many in the geological sciences have developed classification schemes that use such terms as “calcarenite” (see Table 1-3:).

Many of the allochems (grains) in carbonates can be identified in cuttings and core chips, especially if the rock is etched in 10% HCl before it is described.

Table 1-3: Criteria for Distinguishing Between Limestone Types

AUTOCHTHONOUS LIMESTONES	ALLOCHTHONOUS LIMESTONES
Associated with Shales	Associated with Or tho quartzites
Grades into calcareous shales and mudstones	Grades into and is interbedded with or tho quartzites and calcareous sandstones
Interstices between fossils filled with lime mud	Interstices filled with clear calcite cement
Bryozoan-encrusted fossils	Contains rolled follils
Unsorted as to size	Sorted as to size
Fossils articulated	Fossils disarticulated
Reef structures	Cross-Bedded

Ooids

These are small spherical or sub spherical, accretionary bodies, 0.25 to 2.0 mm in diameter, (if the bodies are over 2.0 mm, they are referred to as pisolites). They usually have a nucleus, with concentric or radial structures, or both. They are usually calcareous, but can be siliceous, hematitic, or of other compositions.

Ooids typically form in agitated waters where they are moved as sand waves, dunes and ripples by water currents and wave action. Such environments vary from shoals near the edge of marine platforms, to areas between barrier islands at delta mouths, lagoons, lakes and tidal flats, in both fresh and hyper saline waters. Although the precise mechanism of formation is not known, one generally accepted theory states that bacterial activity within organic matter creates a micro-environment that aids the precipitation of carbonates. Another mechanism suggest that amino acids promote calcification. The calcitic ooids of ancient limestones usually have a radial fabric comprised of large, wedge-shaped crystals. The concentric pattern of original growth lines is sometimes apparent.

Coated Grains

These are distinguished from normal ooids, in that only one lamella is developed around a mineral or skeletal grain nucleus. Another term that is applied for this phenomena is “superficial ooids”.

Peloids

These are pseudo-oolites which have bodies but lack internal structures. These are generally fecal pellets or degraded oolites that have been altered by micritization. Peloids can have a grain structure that contains well worn intraclasts of micrites. They are found in sediments laid down in protected environments such as lagoons and tidal flats.

Peloids have several origins. Peloids which are well rounded, spherical, ovoid or rod shaped, and roughly the same size range (well sorted) are probably fecal in origin. Irregular and less “well sorted” peloids are often caused by the micritization of bioclasts and ooids by endolithic algae. Some peloids are small intraclasts formed from partially lithified carbonate muds.

Compaction and digeneses can often alter the appearance of peloidal grainstones and packstones giving them a fabric called *Structure Grumeleuse*, which is a clotted texture.

Intraclasts

These are lithified or partially lithified fragments found in carbonates. Micritic flakes or pieces of rocks are common, and usually form in desiccated tidal flats. If these form in sufficient quantities, they can form edgewise conglomerates or flakestones.

Micrite Envelopes

These are formed from the altered outer parts of skeletal grains and not “coatings” over those grains. They form when coccoid algae bore into the grains after deposition. A repetition of this process gives the altered zone a dark appearance under a microscope. The material that precipitates after the boring is micrite.

Stromatolites

Around since the Pre-Cambrian, stromatolites are laminated, but otherwise structureless calcareous deposits, that are formed when carbonaceous particles are trapped and bonded onto an algal mat. They are commonly called fossil calcareous algae. The structure can vary from flat laminations, small mound-like structures, columnar structures, to various “fingered” and branching forms.

Oncolites

Unlike the normal “fixed” stromatolites, this form of algae is free and mobile. It typically has a concentrically structured body, resembling concretions and may be thought of as a “tumble weed” algal mat that picks up the carbonate particles and grows, not unlike the snow ball that grows as it is pushed along the surface of the snow field.

Classification of Limestone

Limestones are commonly classified using one of three systems (Figure 1-6). The first divides limestones by separating them by grain size. Calcirudites have most of their grains greater than 2mm. Calcarenites have grain sizes between 2mm and 62 µm. Calcilutites have most of their grains less than 62µm. Folk designed a system that delineates limestones through composition. Chief components being allochems (particles or grains), matrix, and cement. Allochems are often abbreviated and tacked on to micrite or sparite to form a more definite description (e.g., oo-micrite). The third type of common classification used is by Dunham. Dunham classifies limestones on the basis of texture. These include grainstones (grains without matrix), packstones (grains that touch and have matrix in between), wackestones (where coarse grains float in a matrix), and mudstones (a few grains in a predominate micrite lithology).

Carbonate Cementation

At the wellsite, there is very little that can be recorded concerning carbonate cementation without the use of acetate peals or thin sections. However, the main types of cements include:

1. Neomorphism - Many limestones show evidence of changes in grain size and crystallinity with aging. In some cases, grain enlargement involves a single element in the rock. In other cases, it involves the whole rock. This process of replacement, often labeled as re crystallization, was renamed by Robert Folk (1965) to neomorphism, and this term is intended to include all alterations from one mineral, similar minerals or polymorphs.

   When considering this transformation in calcium carbonate, it is only necessary to consider the processes that take place in the presence of water; non-aqueous limestone transformations are unlikely to take place. The two major alterations are; 1) Transformation of aragonite to calcite and 2) Re crystallization of calcite from calcite. This alteration can take several forms:

   a. Microspar-pseudo spar in calcilutites

   b. Calcitization of aragonite skeletons

   c. Replacement of acicular cements by fibrous calcite

4. Miniscus cement - A microspar-pseudo spar cement formed in calcilutites that is characterized by irregular or curved inter crystalline boundaries.

5. Isopachous cement - Where the calcite cement forms roughly equal layers on pre-existing grains.

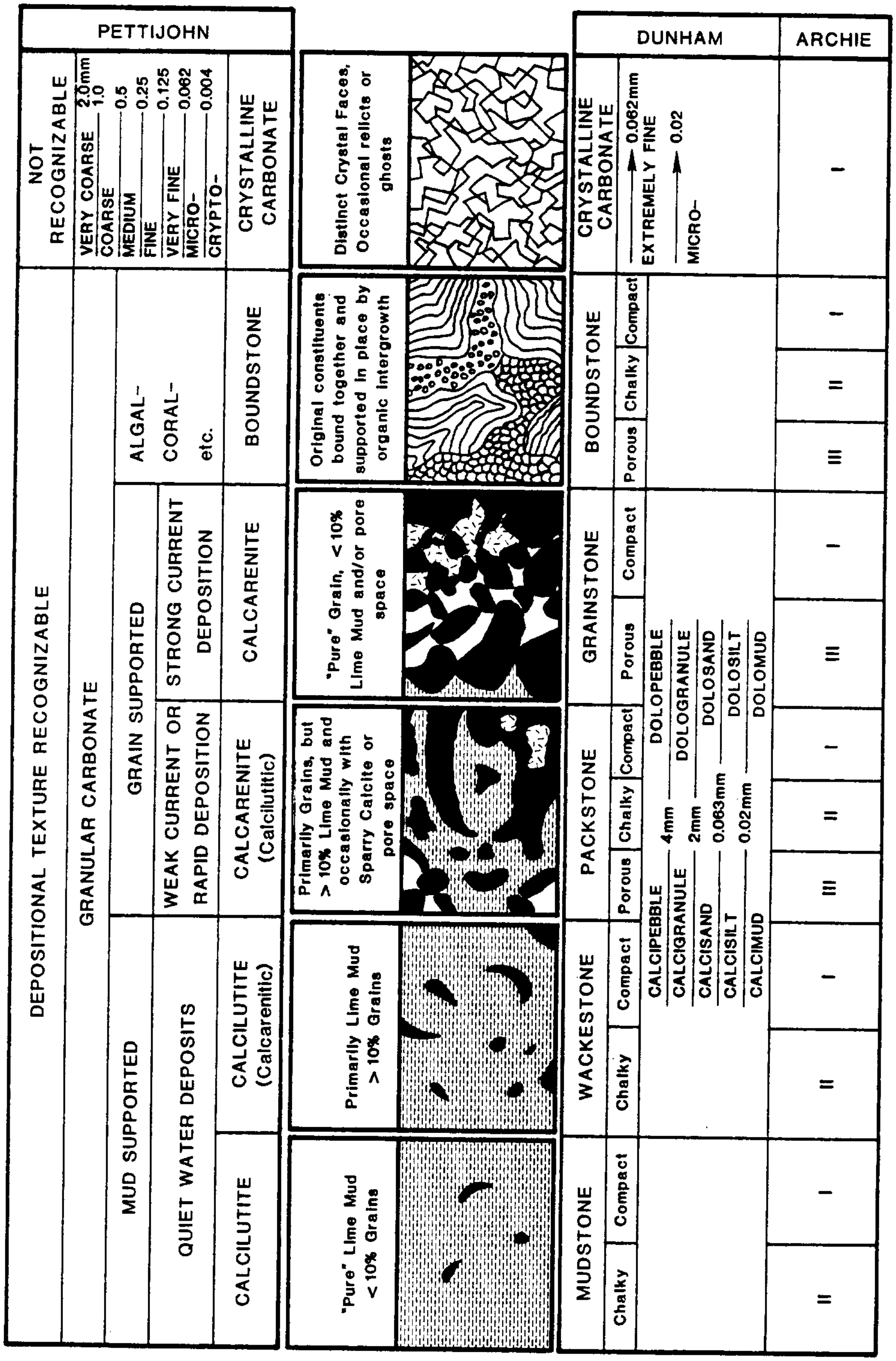


Figure 1-6 Limestone/Carbonate Classification Systems

6. Syntaxial cement - This cement appears as rims or outgrowths on framework grains. The outgrowth is clear calcite separate from the original cement which may have had other inclusions.

Dolomitization

This is the process whereby limestone becomes dolomite by the substitution of magnesium carbonate for a portion of the calcium carbonate. The replacement is usually a small occurrence and rarely will all the original limestone be involved. There are several types of data that suggest that the replacement of limestone to form dolomite has taken place:

1. Automorphic boundaries of dolomite against calcite, clastic quartz and glauconite.
2. The inclusion of clastic quartz in dolomite crystals.
3. Transection of oolites, fossil structures by dolomite crystals.
4. Original calcite, bioclasts, and oolite textures that exhibit shadowy pal imp set patterns.
5. Structural control of dolomite distribution.
6. Transgression of stratigraphic planes by calcite-dolomite boundaries.

When dolomitization occurs, there is a 12% to 13% increase in porosity. Many of the large oil fields in the Middle East are in dolomite reservoirs. Partial dolomitization significantly enhances permeability in parts of the Smackover Formation in the southern states of the U.S.A. However, in the majority of cases there is no significant increase in porosity when the calcite-dolomite transformation takes place.

The timing of dolomite conversion is unclear. The process can take place during deposition before burial, or after burial, but before tectonism. Evidence suggests that it is likely an early replacement, since it is unlikely that moving waters could have resulted in dolomitization over large geographical areas.

Porosity in Carbonates

Porosities in carbonates are often much lower and far more patchy than in sandstones, making the job of picking porosity/permeability trends by the reservoir geologist very difficult. Though there are several classification systems used for porosity in carbonates, the two most one often used at the well site are the Archie system and Choquette & Pray.

The Archie classification system (Figure 1-7) for carbonate porosity is generally used by Shell and its affiliated companies (QGPC, NAM). The classification is divided into two parts, Matrix Type and Vug Size.

Matrix Types	
I	Compact, interlocking crystals or fully cemented grains
II	Chalky texture, grain size less than 20 microns (not visible under microscope)
III	Partially cemented grains or dolomite rhombs

VUG Sizes	
A	non visible, less than 20 microns
B	20 - 125 microns (coarse silt to very fine sand size)
C	125 microns - 2 mm
D	Greater than 2 mm

Figure 1-7 Archie Carbonate Classification System

When describing porosity, the two parts are combined (e.g. IA for a compact limestone with no visible porosity or IIIC a granular limestone with vugs). Combinations of matrix or vug type can occur (e.g. I/IIA), and the percentage of different vug size can be included - IIIB5C3.

If the Archie system is being used, the descriptors are usually placed after the Dunham classification (e.g. LS: Grnst, IIIA).

The Choquette and Pray classification system is a more descriptive/generic classification system and the most widely used. It consists of four parts, Porosity Type plus 3 modifying terms covering size and shape of pores, timing and process of origin, and abundance (see Table 1-4:).

According to Choquette and Pray, there are fifteen recognizable types of carbonate porosity. These are grouped according to the environment in which they are commonly created or according to the degree of rock fabric control over their creation:)

Table 1-4: Choquette & Pray Classification System (next three tables)

	FABRIC SELECTIVE
Interparticle	Largely primary porosity, can be enhanced by secondary dissolution of grains
Inter crystalline	Main porosity type in dolomites
Intra particle	Within bioclasts, maybe primary or secondary poor interconnection of pores hence poor permeability. Important porosity type in Rudist (a reef building lamellibranch) rich limestones in the Cretaceous of the Middle East.
Moldic	Secondary porosity caused dissolution of unstable allochems e.g. aragonitic shells. Can be an important porosity type in grainstones and packstones but in wackestones gives patchy in-effective porosity. Terms such as Biomouldic, Oomoldic porosity are often used defining the mold.
Fenestral	Read section 4.6.3. which describes this type of porosity. Note also what is said about Stromatactis cavities. Fenestral porosity maybe large but permeabilities are often low.

Table 1-4: Choquette & Pray Classification System (next three tables)

Shelter	Primary porosity also known as Umbrella cavities, that occurs below shell fragments. Can enhance porosity in grainstones
Growth framework	Primary porosity caused by reef building organisms where porosity gets “trapped by growth of the framework of minor importance.

	FABRIC SELECTIVE OR NOT
Breccia	Caused by fracturing where the breccia has interparticle porosity. Often caused by dissolution of underlying evaporites. Examples include collapse breccias in the Zechstein of North East England
Boring	Created by boring organisms in consolidated sediments such as hard grounds.
Burrowing	Created by burrowing organisms in unconsolidated sediments.
Shrinkage	Created by shrinkage of sediment. Very minor importance.

	NON FABRIC SELECTIVE
Fractures	Can be tectonic in origin, caused by halokinesis (salt diapirism), slumping, or dissolution of underlying evaporites. Diapiric induced fractures are an important porosity type in the chalk reservoirs of the North Sea such as the Dan and Ekofisk fields. Fracture porosity can sometimes be recognized from wireline logs by cycle skipping on sonic logs and random bag-o-nails patterns on a dipmeter log. When describing cores, care must be taken to distinguish natural fractures from coring induced fracturing. Fracturing is probably natural if: 1. there is calcite cementation along fracture 2. fracture is enclosed in core 3. sets of parallel fractures are seen in one core 4. slickensides seen along fractures 5. fractures are relatively planar.
Channel	Elongated pores caused mostly by solution along fractures.
Vugs	Pores greater than 0.0625 mm (lower boundary of very fine sand) and not dependant on fabric. Note Archie's definition of a vug is largely dependant on size and doesn't stipulate non-fabric dependent.
Caverns	Man sized or larger pores. To paraphrase Selley a cavern is a pore “large enough to contain one crouched mudlogger”! Caverns have been documented in the Middle East and in Texas (Fusselman Limestone).

Porosity modifiers are generally used with carbonate porosity. Such modifiers include:

1. Time of formation: Primary porosity (e.g. interparticle) can be caused at time of deposition or pre-deposition (e.g. primary intra particle). Secondary porosity can be created in early diagenic (epogenic or meteoric), burial diagenisis (mesogenetic) or late diagenic (telegenic). The later is when the carbonate, long buried, is effected by an inconformity (karst formation).
2. Process and Direction or Stage: These terms show the type and process of pore modification (e.g. solution enlarged, sediment filled, etc.).
3. Size Modifiers: Size range of pores
4. Abundance Modifiers: Percentage or ratio of different pore types.

All four terms can be combined, generally in the following order: genetic modifier, size, type, abundance (e.g. Cementation reduced primary meso-interparticle porosity, 10%).

Evaporites

Evaporites (Table 1-5:) are formed by the precipitation of salts from highly saline solutions or brines. The most common evaporites are gypsum, and anhydrite. Less common are the chlorides, polyhalites, and potash salts. Evaporites form in warm, shallow marine environments and restricted basins where the sea water resupply is intermittent. This is usually associated with an arid environment where rain water cannot keep the dissolved salts in solution. Typical areas that are potential sites for evaporite formation in the modern world are marginal salt pans, marine salinas, lagoons, and relict seas.

When dealing with the sulfate minerals, below 500 to 700 meters, all calcium sulphate will occur as the non-hydrated form, Anhydrite. The transition depth from gypsum to anhydrite depends on the salinity of the pore waters and temperature. At the well site, anhydrite is often seen as bright white, amorphous to lumpy, soft cuttings when drilling with water based mud. This appearance of the cuttings is partly caused by the hydration of the anhydrite to gypsum by the drilling mud.

Table 1-5: Principal Sedimentary Evaporites

Class	State	Species	Formula
CHLORIDES	Anhydrous	Halite Sylvite	NaCl KCl
	Hydrous	Bischofite Carnallite	$MgCl_2 \cdot 6H_2O$ $KMgCl_3 \cdot 6H_2O$
SULFATES	Anhydrous	Glauberite Anhydrite Barite Langbeinite	$Na_2SO_4 \cdot CaSO_4$ $CaSO_4$ $BaSO_4$ $K_2SO_4 \cdot 2MgSO_4$
	Hydrous	Mirabilite Kieserite Gypsum Polyhalite Hexanhydrite Epsomite Kainite	$Na_2SO_4 \cdot 4H_2O$ $MgSO_4 \cdot H_2O$ $CaSO_4 \cdot 2H_2O$ $Ca_2K_2Mg(SO_4)_4 \cdot 2H_2O$ $MgSO_4 \cdot 6H_2O$ $MgSO_4 \cdot 7H_2O$ $4KCl \cdot 4MgSO_4 \cdot 11H_2O$

Chicken Wire Anhydrite

This is where gypsum crystals are replaced by a fine mesh of equant and lens shaped anhydrite crystals. This can result in close packed nodules of anhydrite with the host rock limited to thin stringers. Very often the host sediment has a "chicken-wire" structure.

Enterolithic Anhydrite

This is where anhydrite is deposited as thin beds of coalesced nodules. They are often contorted and buckled, making up what is known as the enterolithic texture.

Sabka Cycles

These are high intertidal to supratidal flats that provide an environment for gypsum and anhydrite deposition. The sediments are precipitated from pore waters in the vadose and upper phreatic zones. They also form within the exposed sediment around salt lakes and playas This is, in other words, a subaerial process. The process is often cyclic and repeated episodes result in series of evaporite beds.

Laminated Anhydrite

Thin laminations of anhydrite and associated minerals, such as calcite and organic matter. They typically are seen in the lower sections of massive basinal evaporite sequences. The often great lateral extent of these deposits suggests that they are formed by precipitation in fairly deep basins, somewhat below the energetic action of sea surface agitation.

Often the laminae will not be totally laminar and can be contorted and buckled, reflecting the plastic nature of the sediments when horizontal stress is applied.

Aphanitic Texture

This is one of the primary textures found in anhydrites. It is a fine equant mosaic in ancient nodular deposits. Coarse, granular mosaics, fibrous crystals, and fibro-radiating aggregates can be formed by re crystallization of the anhydrite.

Evaporite Cycles

Cyclic precipitation is seen to have been a contributing factor in a large portion of evaporite deposits. When the original volume of water supplied to a basin in one episode is reduced by half, the precipitation of a little iron oxide and calcium carbonate begins. When the volume is further decreased to one-fifth of the original volume, gypsum is formed. $NaCl$ will precipitate when the volume is lessened to one-tenth. Further reduction in volume leads to the appearance of sulfates and chlorides of magnesium and finally to $NaBr$ and KCl. This progression of "chemical rock" types will not always be present, due to widely varying brine temperatures and basin orientations.

Ironstones

Though they are relatively rare, rocks that are unusually rich in iron are experienced at the well-site. Since the average shale contains roughly 6.5% FeO and Fe_2O_3, the term “ironstone” is a relative delineation. The only condition is that the sediments possess a significantly higher than normal proportion of iron in their make-up.

The most common criteria to separate iron-rich sediments from those of lesser concentrations is the red to rust coloration that is visible in samples. If the environment of deposition was anerobic, this coloration may not be present, causing the iron minerals to impart a dark, often black hue.

Color Of Sedimentary Rocks

The color of sedimentary rocks is of great value when determining depositional environments, organic content and accessory mineral descriptions. Though there is no “standard” color description format, colors are easily recognized in wet cuttings samples.

Standardization of Color Descriptions

There have been several attempts to standardize color descriptions within the geologic profession, and unfortunately they have not been very successful. In 1948, the “Rock Color Chart” was prepared by a geologic committee and issued by the National Research Council. Since that time, these color standards have been accepted as the ideal method to describe color in rocks, even though few geologists use the chart in routine sample examination. There are several reasons for its non-use within the oilfields:

1. Considerable time is required to make effective use of the chart
2. Color details are not very diagnostic when correlating subsurface formations
3. There are many variables which can affect describing colors
    a. the intensity and color of the light used during descriptions
    b. the size, thickness and grain-size of the samples
    c. the moisture content of the samples
    d. the magnification of the binocular microscope
    e. the eyes of the geologist making the examination
4. Each company uses its own semi-standard terminology

Nevertheless, the Rock Color Chart continues to be used and exerts considerable influence whenever standardization is mentioned, and it appears that with the continued push towards standardization, its use will increase. To many geologists, the common color terms used in sample descriptions can refer to such a wide range of colors, that confusion can result (see Table 1-6: Related Color Descriptions, on page 1-26).

The Rock-Color Chart is based on the Munsell color system. This system places all colors on a sphere, which has a neutral gray axis (the "N" color) grading from white (N9) at the top to black (N1) at the bottom. The property of lightness is called "value".

Around the equator of this color sphere are the ten major hues:

Red	(R)	Blue-Green	(BG)
Red-Purple	(RP)	Green	(G)
Purple	(P)	Green-Yellow	(GY)
Purple-Blue	(PB)	Yellow	(Y)
Blue	(B)	Yellow-Red	(YR)

Each of these hues is divided into 10 subdivisions (1R to 10R), so that 5 marks the middle of the hue and 10 marks the boundary between one hue and the next.

As the colors move away from the neutral axis the chroma (degree of saturation) of the color increases, so that the most vivid colors are on the circumference of the sphere

Colors are labeled using a hue, value and chroma alpha-numeric designation. For example, 5YR 6/4 means the color is in the middle of the yellow-red hue (5YR), above the middle of the value axis (6), and a little to the right of the axis (4).

Colors and Sedimentary Environments

The color of sedimentary rocks is controlled by 3 main factors:

1. Oxidation state of iron
2. Amount of carbonaceous material
3. Presence of colored minerals

Oxidation State of Iron

The most important minerals in imparting color to a sediment are the iron minerals. Sediments having iron, in its oxidized state, are generally red to brown. Those having iron in its reduced state are generally gray to green.

Sedimentary "Red Beds" get their color from iron in the ferric state (Fe_3+), predominantly from the mineral hematite. The hematite staining can easily be seen on the surface of sand grains or disseminated throughout mudrocks. Yellow brown colors are often caused by the presence of hydrated forms of ferric oxide, usually Geothite or Limonite.

Table 1-6: Related Color Descriptions

Description Color	Related Colors	Rock Color Chart Colors
Cream	Pale Orange Pale Yellowish Orange Grayish Yellow Yellowish Gray	10YR 8/2 10YR 8/6 5Y 8/4 5Y 8/1
Tan	Olive Gray	5Y 5/6
Light Buff	Olive Gray Grayish Orange	5Y 5/6 10YR 7/4
Buff	Dark Yellowish Orange Dusky Yellow	10YR 6/6 5Y 6/4
Dark Buff	Yellowish Brown	10YR 5/4
Maroon	Moderate Red Very Dark Red Dark Reddish Brown	5R 4/6 5R 2/6 10R 3/4
Black	Grayish Black Black	N2 N1

Where iron is in the ferrous state (Fe_2+), the rock is often green. This coloration can occur throughout the rock, or as reduction spots or bands. In claystones, if rock is generally red with green bands or streaks, the green colored parts are often seen to be more silty or associated with fractures providing conduits for reducing pore waters.

Carbonaceous Material

The presence of organic matter will give rocks a grey or dark brown color. This color will increase to black with increasing carbonaceous material content. This is also an indication of deposition in a reducing environment. The dark color is often strengthened by the presence of very fine disseminated pyrite, (which in itself would color the rock a dark grey). Cuttings containing abundant mature or near mature Type I and Type II kerogen will often have a maroon/brown color under high magnification.

Colored Minerals

Green color in sediments is generally due to the presence of chlorite, glauconite or chamosite. The “greensands” are caused by glauconite, which commonly occurs in shallow marine sands. The green coloration is caused by fine nodules or pellets of dark green glauconite. Glauconite rarely stains the surface of the sand grains. Any green staining on the sand grains is usually caused by chamosite. A transition with depth can occur with greensands. As depth increases, the green sandstones change to a yellow-brown color. This is caused by ground waters oxidizing and hydrating the glauconite, changing it to limonite or goethite. An example of this is seen in the Wealden basin of Southern England, where the so-called greensand becomes yellow around 500 ft.

Where feldspars are common (arkoses), the rock may appear pink, due to presence of orthoclase. Many red beds are arkoses and much of the staining is caused by feldspars and hematite. Blue is a rare color in sedimentary rocks, but can occur in patches in tuffaceous claystones due to the presence of zeolites.

Mixtures of the components can give rise to a number of colors such as buff and olive.

Color Patterns in Sedimentary Rocks

The color patterns in sedimentary rocks can be due to either its mineral composition or to secondary alteration (weathering, leaching by groundwater, replacement or recystallization of minerals, etc.), making some of the patterns representative of other physical attributes (cementation, structure, etc.). Comparative descriptions of color patterns, such as “salt and pepper”, should be avoided because they are too general and non-objective. The most common color pattern descriptions include:

Staining - refers to either superficial color or an uneven color of obviously secondary origin in porous rocks.

Speckling - refers to disseminated fine spots of color in a differently colored background with relatively clear boundaries.

Spotting - refers to scattered medium to large spots of color with relatively clear boundaries.

Mottling - refers to two or more colors with irregular and gradational boundaries.

Banding - refers to two or more colors with relatively parallel, regular and distinct boundaries.

•Notes•

Self-Check Exercises: Sedimentary Petrology

1. What are the seven major textures in clastic which, when described, will form the basis of all subsequent interpretation?

   a.
   b.
   c.
   d.
   e.
   f.
   g.

2. What are the three components of siliclastic rocks?

   a.
   b.
   c.

3. What forms the general basis when describing siliclastic rocks?

4. What is the difference between a litharenite, quartz arenite, an arkose and a greywacke?

5. What are the three different clay groups making up mudrocks, and how are they different?

   a.
   b.
   c.

6. Why is the term “limestone” not generally correct when describing the origin of carbonate rocks?

7. What is the difference between an ooid, a coated grain and a peloid?

8. How do the three major limestone classification systems differ?

9. What is dolomitization?

10. How to the “Archie” and “Choquette and Pray” carbonate porosity classification systems differ?

11. How do evaporites form, and what three are the most common?

12. What two parameters regulate the depth at which gypsum transforms into anhydrite?

13. What is the criteria used to distinguish an iron-rich shale from an "ironstone"?

14. What three factors controls the color of sedimentary rocks?

    a.

    b.

    c.

15. What two variables cause color patterns in sedimentary rocks?

•Notes•

Chapter 2

Sedimentary Structures

Upon completion of this section, you should be able to:

- Describe the various types of sedimentary structures
- List and describe bedding types
- Determine primary bedding structures in cores
- Understand how bedding structures are deformed
- Explain several types of erosional structures

Additional Review/Reading Material

Reineck, H. and Singh, I., *Depositional Sedimentary Environments*, Springer-Verlag, 1986

Greensmith, J.T., *Petrology of the Sedimentary Rocks*, Allen & Unwin Ltd, 1978

EXLOG, *Formation Pressure Evaluation*, 1996

•Notes•

Sedimentary Structures

Sedimentary structures are used to identify the agents of deposition and the resulting changes in that depositional environments that the sediments experienced after they were laid down (see Table 2-1). At the wellsite, one of the most important structure that can be recognized from cores and, at times, cuttings samples is the bedding type.

Table 2-1: Classification of Sedimentary Structures

Inorganic Mechanical (primary)	**Structures** Chemical (secondary)	**Organic Structures**
A. Bedding: Geometry 1. Laminations 2. Wavy Bedding	A. Solution Structures 1. Stylolites 2. Corrosion zones 3. Vugs, Oolicasts	A. Petrifactions
B. Bedding: Internal Structures 1. Cross-Bedding 2. Ripple-Bedding 3. Graded Bedding 4. Growth Bedding	B. Accretionary Structures 1. Nodules 2. Concretions 3. Crystal Aggregates 4. Veinlets 5. Color Banding	B. Bedding 1. Stromatolites
C. Bedding Plane Markings (on sole) 1. Scour or Current Marks 2. Tool Marks	C. Composite Structures 1. Geodes 2. Septaria 3. Cone-in-Cone	C. Miscellaneous 1. Borings 2. Tracks & Trails 3. Casts & Molds 4. Fecal Pellets
D. Bedding Plane Markings (on surface) 1. Wave & Swash marks 2. Rain Pits & Prints 3. Parting lineation		
E. Deformed Bedding 1. Load & Founder structures 2. Synsedimentary folds 3. Sandstone dikes & sills		

Bedding

Bedding is probably the most important feature of a sedimentary rock, and as such is the most widely used term in describing a sedimentary sequence. A "single bed" is generally described as a sedimentation unit which has been deposited under essentially constant physical conditions. This single bed is separated from adjoining beds by bedding planes. These bedding planes are visible because of some textural or compositional change between one bed and another.

Bedding is divided into five major types for ease of description:

1. Regular or massive bedding
2. Laminated bedding
3. Graded bedding
4. Current or cross-bedding
5. Slump, or convolute bedding

For example, regular bedding is indicated by parallel bedding surfaces; that is, those divisions in the lithology indicating a pause in the normal process of sedimentation. Between a given set of bedding surfaces, formations are normally uniform, indicating a constant source and transport of sediments (Figure 2-1).

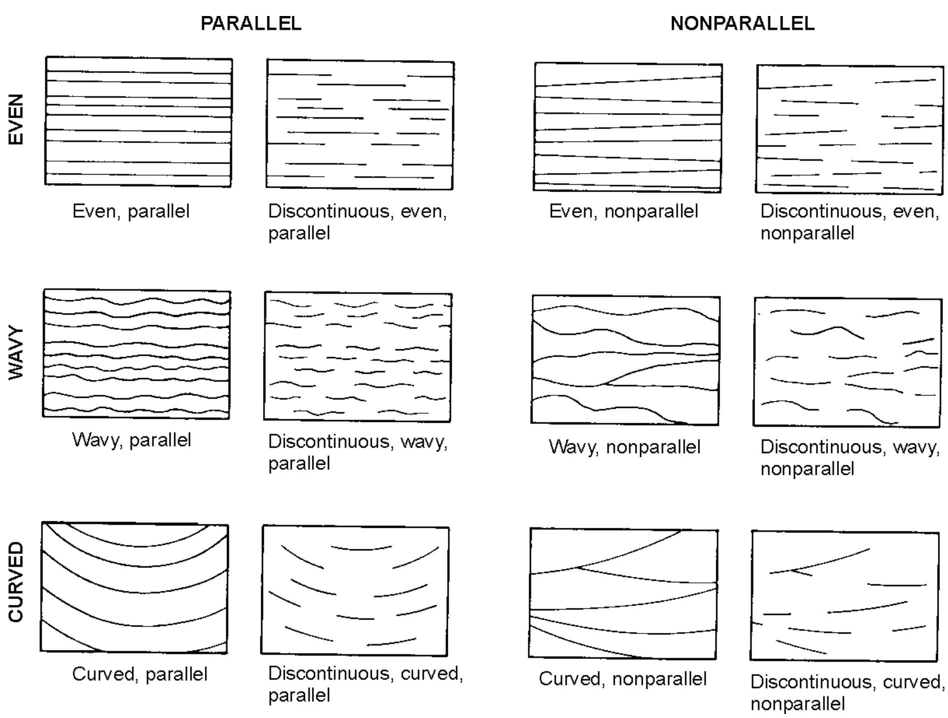


Figure 2-1 Different shapes that can be acquired by beds.

Another way of describing bedding is through analysis of the lithology's thickness and its lateral continuity. This allows the division of beds into four gross classifications:

1. Beds more or less equal in thickness.
2. Beds that are not equal in thickness and are laterally uniform and continuous.
3. Beds that are unequal in thickness, but still continuous.
4. Beds that are unequal in thickness and are laterally variable and discontinuous.

Although there is no absolute correlation between bed thickness and grain size, there is a significant relationship. If you look at turbidites as a case in point, the further you go away from the supra-fan channel, the finer the grains will be. This is primarily due to a significant drop in the energy available for transportation. For this same reason, the overall thickness of those beds will be less. This relation of grain size, bedding thickness, and energy (mode) of transport is true for most of the depositional processes.

The dip of the bedding surfaces is characteristic and structurally significant when recognized in a core sample in the same way it is in a outcrop. Remember, the long axis of the core represents a section of formation cut parallel to the well bore and probably won't be vertical. Because the drill string will likely rotate during the coring process, it is impossible to determine the actual strike of the bedding, unless the core was taken using a specially oriented core barrel.

Other than a bed's thickness and areal extent, the next significant features that can be examined are the internal structures. Two major types of structures are recognized, cross bedding and graded bedding (Figure 2-2). These structures can be identified in most clastic rocks, regardless of the grain size.

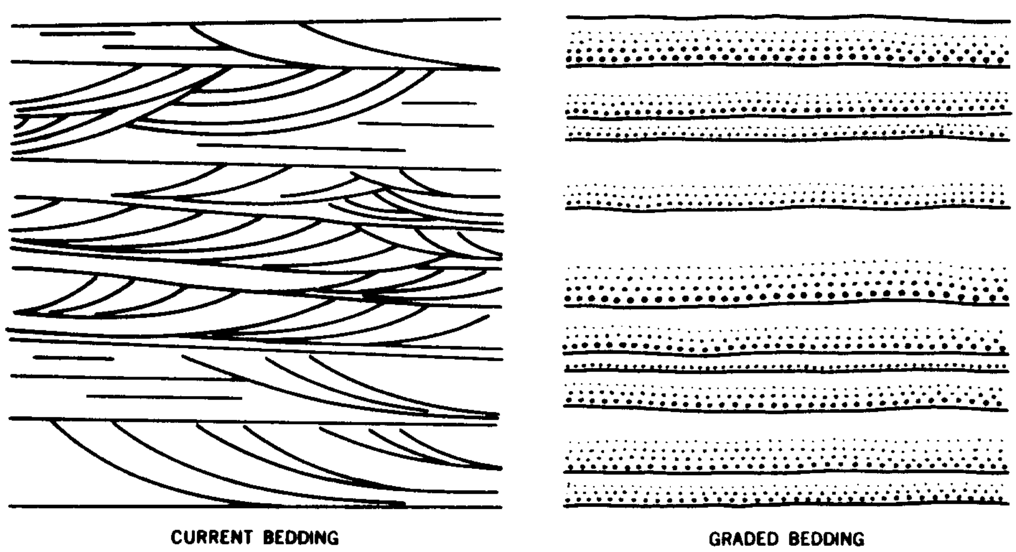


Figure 2-2 Cross Bedding and Graded Bedding.

Cross bedding is an internal structure of the rock which results from the movement of a very large ripple or wave of sand. If sand waves are relatively small, the resulting sediments are referred to as ripple bedding. Cross bedding is also known as cross lamination, current bedding, diagonal bedding, and false bedding. Generally, this type of bedding can be thought of as being inclined bedding and is normally restricted as internal bedding within a single unit of sediments.

There are two major types of cross bedding. One is a simple tabular set, with protruding layers that are nearly planar. The other type is a trough shaped set of cross strata which usually have curved surfaces (Figure 2-3). As a general rule, exact distinction of a bed set is often difficult, since the beds usually don't fit precisely into either model.

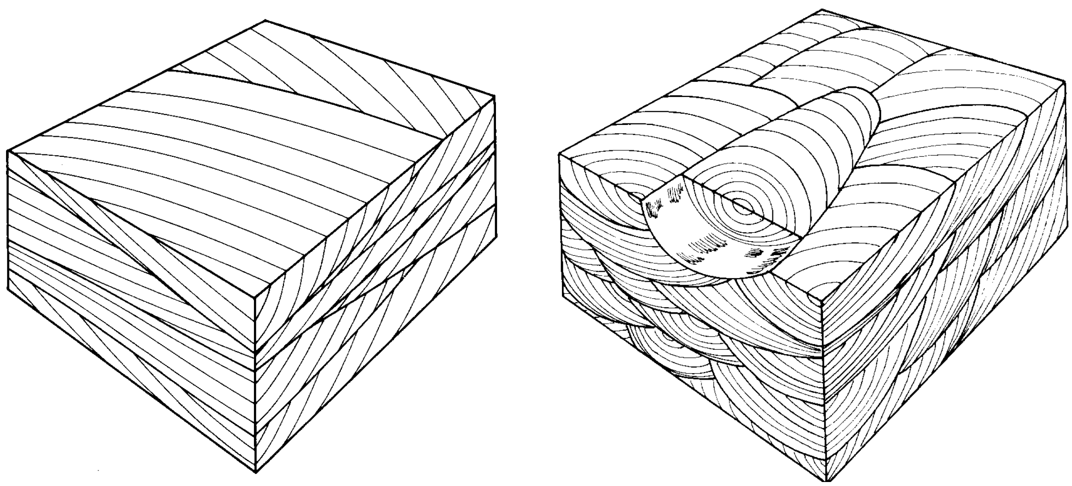


Figure 2-3 Planar and Wavy Cross-Bedding

The scale of the cross bedding in sediments deposited below water level appears to be related to the water depth. As can be seen at a modern day beach, the overall sand wave length and height will increase as the water depth increases. The same affect is present in streams. Even if the total volume flowing in a stream remains constant, the deeper the water at a given point, the longer and higher the sand waves will be. This association allows the geologist to make gross assumptions about the relative depth of sediment deposition when examining the scale of cross bedding.

Graded bedding, or the progressional change in grain size throughout a bed's thickness, is very important to geologists in determining the original top and bottom of a bed as it was laid down. This is especially true in deep water turbidite deposits, where the gradation from coarse to fine sand, or an opposite relationship, can lead to important conclusions concerning the depositional history of sediments (Figure 2-4).

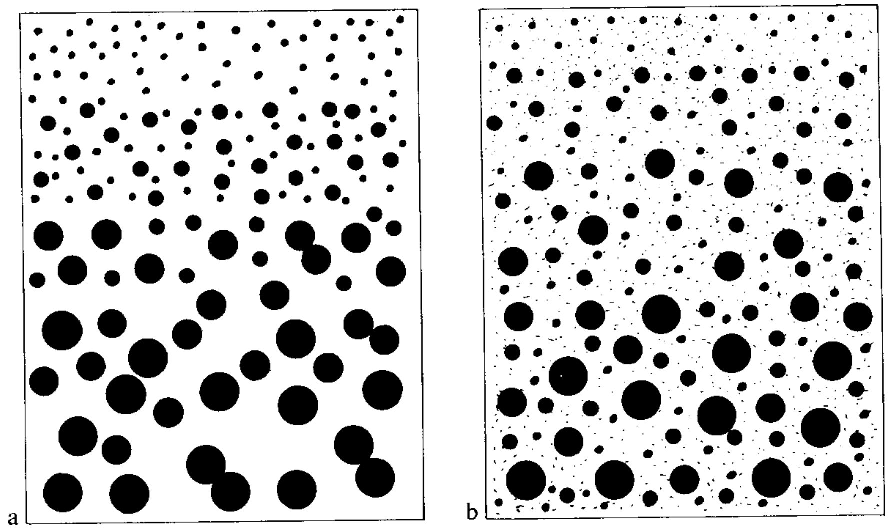


Figure 2-4 Two basic types of graded bedding; a) no fines and b) fines present as matrix.

Graded beds are deposited from a current that is progressively losing energy. These beds may range from several centimeters to more than a meter thick, and usually the thicker the graded bed, the coarser the sediments will be at the unit's base. Sometimes, the basal rock is composed of gravel.

Graded beds are best described using a depositional model known as the "Bouma Cycle" (Figure 2-5). Bouma recognized during his study of turbidites that the "ideal" graded bed is composed of five basic parts:

1. The lowest unit is definitely graded and is usually the thickest part of the sequence.
2. The second section commonly displays rippled cross lamination.
3. The third unit is composed of indistinctly laminated sandy or silty pelitic sediments.
4. A poorly defined and often not recognizable unit with horizontal lamination.
5. An upper pelitic interval.

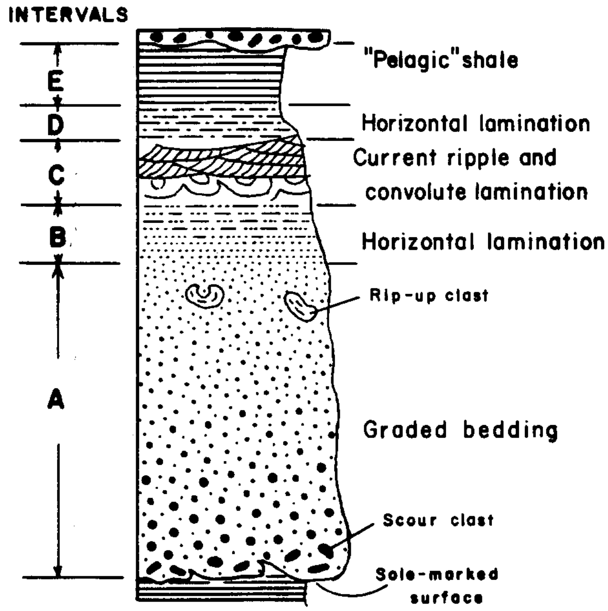


Figure 2-5 Graded bedding in an "ideal" Bouma cycle.

Quite often this cycle is not complete, due to the erosional affects of subsequent depositional cycles. It is not surprising, after looking at the character of the Bouma sequence, that many geologists feel that most graded beds are a result of turbidity current type sedimentation. The paleofaunal zones reconstructed from graded beds almost always suggest the sediments were laid down in deep marine waters.

Primary Bedding Structures

Primary bedding structures, are related through flow velocity, grain size, and bed form (Figure 2-6). For example, planar lamination and primary current lineation are associated with fine to medium sands in the upper flow regime. However, there can be planar lamination without primary current lineation in the lower flow regime, if the sand is coarse.

Planar Lamination

Planar laminations in a sediment are generally well developed, and the bedding planes are essentially parallel to the bounding surfaces of the bed. This type of structure is most often recognized in fine grained sediments (i.e. clays and shales). They are formed either from the alteration of sediment supply to an area or the supply of a different sediment type to that same area. Such changes can result from shifting currents, climatic changes, or catastrophic episodes such as storms or floods. Well developed laminations suggest that deposition has occurred in a relatively quiet environment. For example, lacustrine shales often display the greatest development of fine laminations.

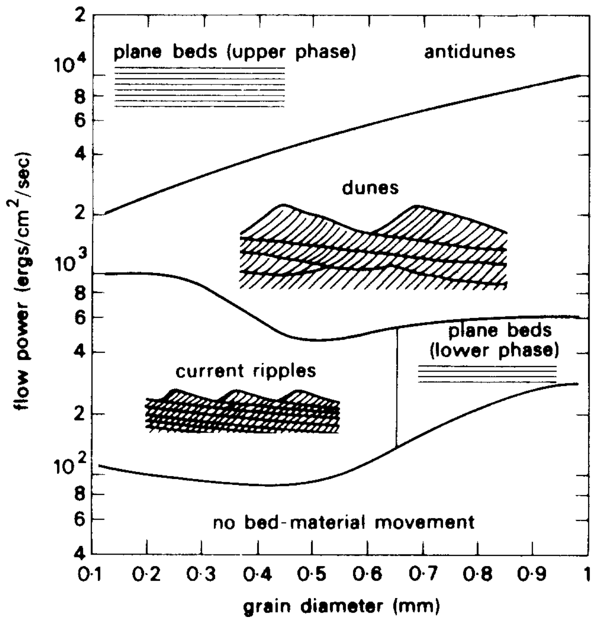


Figure 2-6 Relationship between flow velocity, grain size and bed form.

Tabular Cross Lamination/Bedding

This form of cross bedding is where the bedding contacts are essentially planar. The traces of the bedding foresets are straight lines and the bedding planes generally reflect the primary direction of the transporting current. They exhibit relatively consistent scales, inclinations, and azimuths, with average inclinations of 15 to 20 degrees.

Trough Cross Lamination/Bedding

This type of bedding surface is trough shaped and cross strata usually have curved surfaces. Small scale cross bedding of this type has been called “rib and furrow” or “micro-cross lamination”. The foresets are the product of ripple migration. The structure of the cross bedded unit is determined by the morphology of the ripple.

Lenticular/Flaser Bedding

These result from an irregular stacking of ripple bedding. The sedimentary assemblage obviously results from ripple bedding, but there is no consistent pattern.

Lenticular bedding predominates when clay is the major sediment. As sedimentation of sand increases, the lenses become connected, resulting in wavy bedding. As sand deposition becomes dominant, flaser bedding is produced. At first there are some connections between mud drapes, giving what is sometimes called “bifurcated wavy flaser bedding”. When clay deposition is restricted to ripple troughs, simple flaser bedding dominates (Figure 2-7).

Climbing Ripple Lamination

Ripples can be superimposed, so that the ripples appear not have migrated. It is more common to observe a progressive migration of the crests so that it appears that the ripples “climbed” the stoss side of underlying ripples.

There are two types of climbing ripple laminations, one where the boundary between sets are erosive and there is no stoss side preservation, and another where the stoss side is preserved, giving wavy lamination.

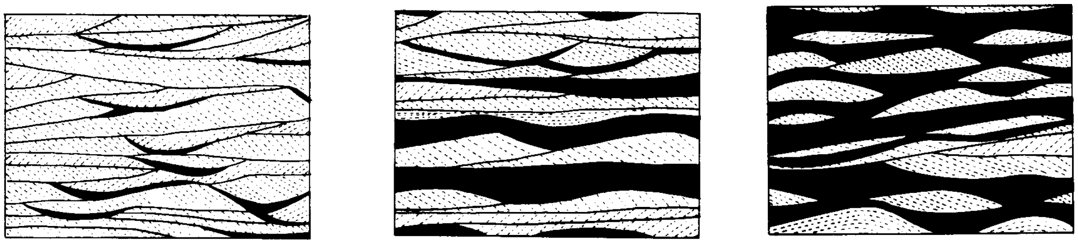


Figure 2-7 Flaser, Wavy and Lenticular Bedding.

Synaresis Cracks

These cracks are formed by spontaneous dehydration of gel-like materials in the sediment, even when the sediment is in a wet environment. This process also explains patterns of cracks in formations of unusual make-up, such as dolomitic mudstones. It is often impossible to distinguish these cracks from those formed by desiccation.

Desiccation Cracks

Muds often form cracked patterns as they dry out and lose some of their original volume. This is especially true of smectites (clays that adsorb water between their lattices). However, desiccation cracks have also been found in non-argillaceous lithologies such as micritic limestones. Mud cracks can not form in pure sands, because they form from shrinkage; some decrease in overall sediment volume must occur for cracks to form. Mud cracks most often form in intertidal zones, playa lakes, and overbank flats of floodplains.

Normally, cracks taper downward and eventually pinch together. Often, they are filled with clastic sediments coarser than the clay that the cracks were formed in. If the bed that has been cracked is very thin, the failures can extend to the underlaying bedding surface. This results in isolated pieces of the desiccated lithology. Often, the detached pieces are slightly separated, and can be rotated or overturned.

Post Depositional Deformed Bedding

Post depositional deformation of bedding can occur, regardless of the of the mode of deposition. For example, gravity displacements can occur during sedimentation or shortly afterward. Many beds give indications that the deformation took place as the sediments were being laid down. Three mechanisms seem to be prevalent:

1. Movement can be largely vertical, such as the adjustment of a sand laying over a clay due to a unstable density stratification.
2. Large lateral movement may result from instability on an oversteepened depositional slope.
3. The process related to sedimentary sills and dikes that can form from injection of gelled material into adjacent lithologies.

String Convolute Bedding

This is a form of post depositional structure that resembles slump bedding. The deformation is greatest in the upper portions of the affected beds, with faulting and fracturing usually absent. It probably results from surface drag of waning eddy currents that flow over soft sediment, or from load deformation that is simultaneous with deposition. This type of structure is most commonly associated with turbidite deposits, although it is also recognized in fluvio-deltaic and littoral deposits.

Load Structures

These result from soft sediment deformation. Load casts are one type of smaller load structure that is closely associated with sole marks. These are irregular bulging features on the base of sandstone beds that overlay shales. Unlike flute casts, they differ in their lack of symmetry and orientation. In addition, they are not remanent casts of scours, but result from the downward protrusion of sands and deformation of upper clay laminations.

They can originate in any depositional environment where sands are deposited over water saturated, unstable clays (Figure 2-8).

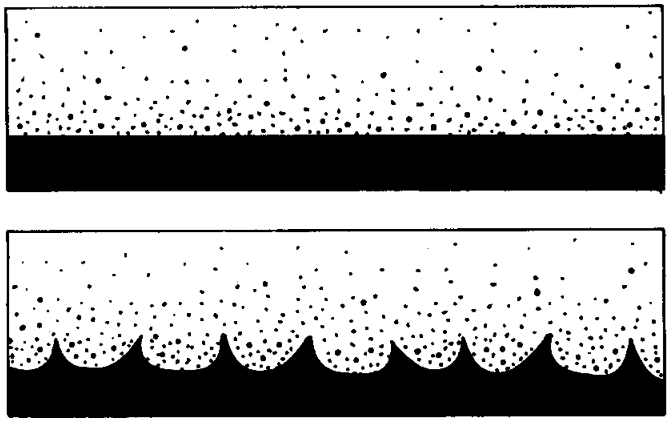


Figure 2-8 Load structures developing on the lower surface of a sand layer resting on a clay layer.

Flame Structures

This is a type of load structure that demonstrates there was preferred orientation during deformation. These occur due to the presence of pre-existing linear projections, usually flute marks. Very often these are shales that project into overlaying sand and resemble “flames” in the cross-sectional view.

Ball and Pillow

Sands can display “pillow” like structures, like the pillow lavas associated with submarine basalt flows. These structures form from soft sediment deformation which takes place before the emplacement of overlaying sediments. The balls can also be composed of limestone, if they were true sands at the time of deposition.

The structures are largely representative of the lower part of the affected bed. Generally, they are imperfect spheres and ellipsoids, and occasionally form kidney and mushroom shapes. Any internal structure they possess is likely to be deformed.

Dish and Pillar

These are most common in thick turbidite sandstones. They are related to sheet dewatering structures and form as vertical to sub-vertical sheets, a few millimeters wide. These sheet dewatering structures are composed of clean sand, in comparison to their more clay-rich host sandstones.

Erosional Structures

These are sedimentary structures that have formed after the deposition of the formation, and can occur before the sediment is consolidated or after consolidation due to uplift.

Flute Marks

Flute marks are initiated by current scouring and are formed when the erosional voids are filled with sand and welded to an overlaying sand bed. They will appear as raised features in outcrops, and vary in shape, size, and areal arrangement. The flute is slightly elevated, elongated, and has a mound-like form with a bulbous up-current nose. The down-current end flares and eventually merges with the bedding plane. They may resemble load casts, but differ in that the flute is cut or eroded and cuts across the laminations in underlaying material.

It is probable that they are formed by eddys when conditions are right and scouring can take place. The type and nature of the flow conditions dictate the flute mark magnitude.

Groove Marks

These are linear ridges on the bases of sandstone beds which form by the infilling of grooves cut into the underlaying mudrock. They can occur singly or in profusion, all of which are parallel to or deviate from a common orientation.

Groove marks are formed by the gouging action of water borne materials that are forced against the underlaying mud (Figure 2-9). They are common in turbidite sediments, but can form in other environments, such as on floodplains and shallow marine shelves.

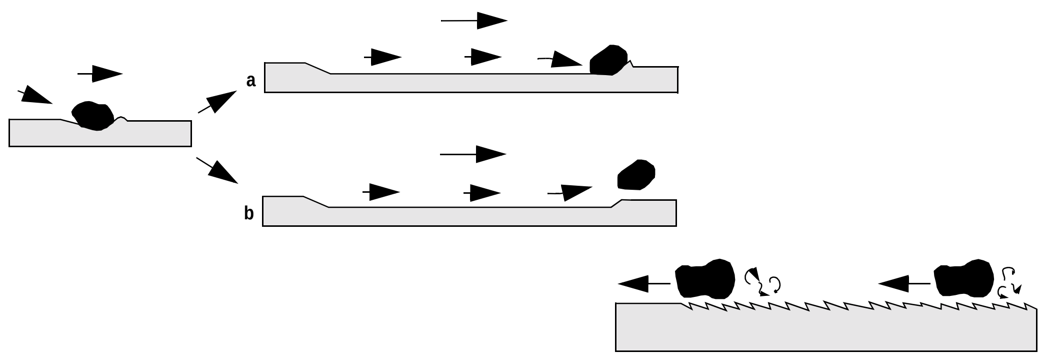


Figure 2-9 The development of a groove mark caused by a moving object.

Impact Marks

These are formed by objects striking the sediment surface as they are carried along by currents. The potential objects causing the marks include fossils, pebbles, or lumps of sediment. Various types of these marks include prods, bounces, brushes, skips, and roll marks.

Note: *The erosional structures described above are sometimes collectively referred to as Sole Marks. They are produced in environments with episodic sedimentation of coarser material with a continuous background of mud deposition. The most common process that could include all these structures is submarine fan, turbidite sedimentation. However, sole marks can be produced by storm surges in shallow marine shelves, crevasse splays on floodplains and sheet floods in alluvial fans.*

Gutter Casts

These are larger scale scour marks that occur as isolated ridges on the bottom bedding plane of sandstones. They are usually slightly to moderately sinuous of several meters in length and up to 10 cm deep and wide. They may be associated with smaller sole structures such as tool marks. They are formed by sand laden water, flowing in a helical pattern that is scouring soft sediment.

Sole Marks in Cores

Sole marks can sometimes be seen in cores; obviously, the smaller types are more likely to be noticed. The core will often break along a sandstone/shale boundary, allowing you to view the sole. The nature of the contact seen in the core can sometimes indicate the presence of sole marks.

Bio-genic Sedimentary Structures

Bio-genic structures result from bioturbation, the post-depositional disturbance of sediments by living organisms. This can occur by the organisms moving across the surface of sediment or burrowing into the first few centimeters. It is usually contemporaneous with deposition (Figure 2-10).

The magnitude of the structures vary, from the surface trails left by large terrestrial vertebrates to burrows of small marine invertebrates. The organisms that cause these alterations in the sediments have a dual affect. They physically and chemically alter the original deposit, and they give some useful information about the bottom conditions at the time of deposition. Depending on the location, these animals can affect up to 90% of the sediment surface. As a result, this biological action can completely destroy primary laminations and the original orientation of sediment particles.

There are usually significant changes in the formations porosity and permeability. This can help determine the origin and magnitude of any abnormal pore pressures. It can also enhance the tendency for slumping and sliding on steep continental margins, as the sediment shear strength is decreased.

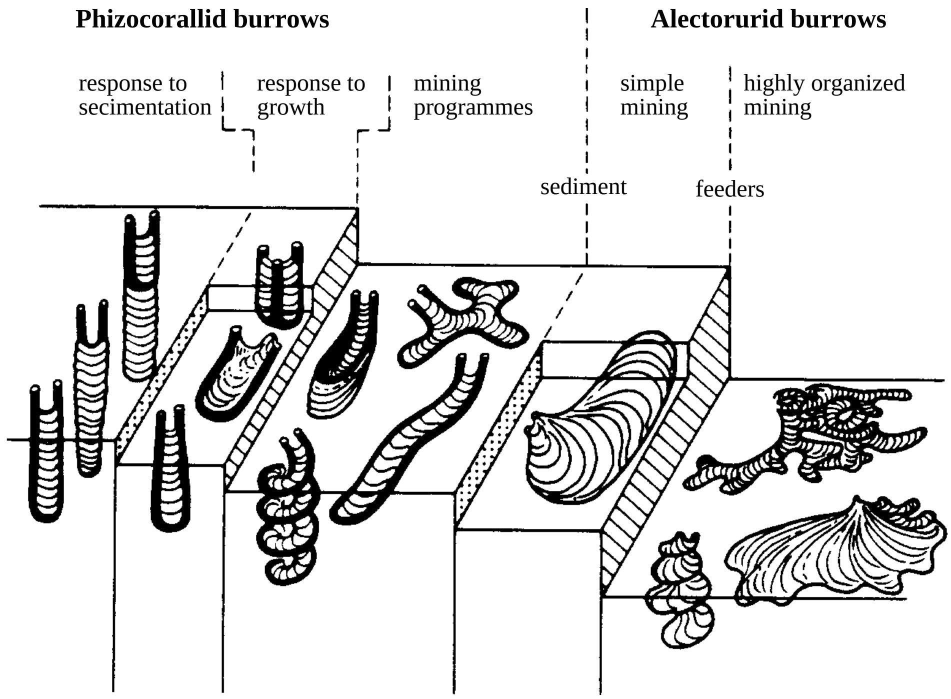


Figure 2-10 Sedimentary structures caused by living organisms.

On the other hand, the increased conduits for pore water migration can enhance cementation, especially in areas where calcareous sediments are deposited.

The greatest variety and density of bioturbated sediments are found on marine shelf deposits. More structurally complicated, but less common bioturbation structures can be found in turbidite deposits. Simple burrows are more common in terrestrial (fresh and brackish water) sediments.

•Notes•

Self-Check Exercises: Sedimentary Structures

1. What is the geologic conclusion that can be drawn when formations are uniform between a given set of bedding surfaces?

2. What are two parameters that are used in describing bedding surfaces?

   a.

   b.

3. What are two major structures, that can be recognized in cores, in most clastic rocks, regardless of grain size?

   a.

   b.

4. What is Cross Bedding?

5. What makes it possible for a geologist to provide a relative indication of the water depth during sediment deposition, when examining cross bedding?

6. What is Graded Bedding?

7. When examining grading bedding, based on it's thickness, what can be stated about the base of the formation?

8. What can be said about the depositional environment of formations exhibiting graded bedding?

9. What type of sediments most clearly show planar laminations, and what is the best example?

10. In what types of depositional environments are desiccation cracks found?

11. What is the difference between load casts and flute marks?

12. What types of material can form impact marks in sediments?

13. What is the term used to describe large scale scour marks?

14. Why are bio-genic sedimentary structures considered contemporaneous with deposition of the sediment?

15. Where are bio-genic sedimentary structures most commonly found?

•Notes•

Chapter 3

Sedimentary Environments

Upon completion of this section, you should be able to:

- Define facies as it applies to depositional environments
- Describe the types of alluvial environments
- Understand the various models describing deltaic and barrier island environments
- Describe the types of carbonate despositional environments

Additional Review/Reading Material

Visher, Glenn, *Exploration Stratigraphy*, Pennwell Books, 1990

AAPG, *Sandstone Depositional Environments*, Memoir #31

AAPG, *Carbonate Depositional Environments*, Memoir #33

Reineck, H. and Singh, I., *Depositional Sedimentary Environments*, Springer-Verlag, 1986

Selley, R.C., *Ancient Sedimentary Environments*, Cornell University Press, 1980

•Notes•

Chapter 3

Sedimentary Environments

The major types of criteria used in recognizing sedimentary environments are the physical, chemical, and biological characteristics preserved in the sediment. These are features that may be determined from a single outcrop or subsurface core. Where a larger number of samples are available, criteria of a much larger magnitude - namely, the lateral and vertical facies relationships and three dimensional geometric framework of the strata - can be employed. This greatly strengthens and broadens the process of environmental interpretation.

The physical characteristics that are of principal value include bedding characteristics, the nature of formation contacts, sedimentary structures, and directional properties such as flute casts, asymmetrical ripple marks, and preferred orientation of grains. Chemical analysis concentrates on the gross composition of the rock. The major mineral constituents and authegenic minerals can be especially useful in environmental determination. The ratios of major elements, such as calcium and magnesium, provide additional environmental clues. Evidence of solution or accumulation of nodules allows further insight. Organic materials play a major role in the overall analysis. The floral and faunal assemblages, together with relative abundances and ratios of the various forms, is very useful.

The lateral and vertical facies relationships and the three dimensional framework can greatly strengthen the environmental interpretation and at the same time add an important regional aspect to the determinations. It has been possible not only to define the depositional environments, but to establish regional trends that can be extrapolated to adjacent areas for the purpose of determining future areas of hydrocarbon exploration.

Facies And Facies Sequences

Facies

A facies is a body of rock with specific characteristics. It is properly defined on the basis of color, bedding, composition, texture, fossils, and sedimentary structures. However, the term “facies” is also used in many other senses. It is used as a strict observational sense of a rock product (sandstone facies), in a genetic sense for the products of a process by which a rock is thought to have formed (turbidite facies), in an environmental sense for the environment in which a rock is thought to have formed (fluvial facies), and as a tecto-facies (post-orogenic facies). All these uses are acceptable, as long as you remember which concept is being used.

Facies distributions and changes are dependant on a number of interrelated influences, which include:

- Sedimentary Processes
- Sediment supply
- Climate
- Tectonics
- Sea Level changes
- Biological Activity
- Water Chemistry
- Volcanism

Facies Sequence

A facies sequence is a series of facies that pass gradually from one into another. A sequence can have an abrupt or erosive boundary, or be bounded by a hiatus, as indicated by a rootlet bed, reworking, or early diagenesis.

Clastic environments have two important types of sequences. In one, there is a coarsening upward sequence that develops above a sharp or erosional base; a second type is the fining upward sequence. This is important in interpretation of depositional environments, because grain size is normally a measure of the hydraulic power at the time of deposition and a coarsening upward sequence indicates an increase in flow power. This may be due to shallowing as a delta, shoreline, or river crevasse builds out into deeper water, or to progradation of a submarine fan. Fining upward sequences can be formed by a migrating point bar in a river or by filling of an abandoned channel.

Walther's Law

Walther's Law states that “the various deposits of the same facies area and, similarly, the sum of the rocks of different facies areas were formed beside each other in space, but in a crustal profile we see them lying on top of each other...it is a basic statement of far-reaching significance that only those facies and facies areas can be superimposed, without a break, that can be observed beside each other at the present time." This is interpreted to mean that facies occurring in a conformable vertical sequence were formed in aerially adjacent environments and the facies in vertical contact must be the product of neighboring environments.

Continental Environments

Alluvial Fans

Alluvial fans (Figure 3-1) are localized and their shape approximates a segment of a cone. They develop in areas of high relief, where there is a abundant supply of sediment. These fans may develop in humid environments, but are best known in arid regions where erosional processes are not as active. They can pass downward through a variety of sedimentary environments, or build into lakes, alluvial or deltaic plains, tidal flats, and deep water basins.

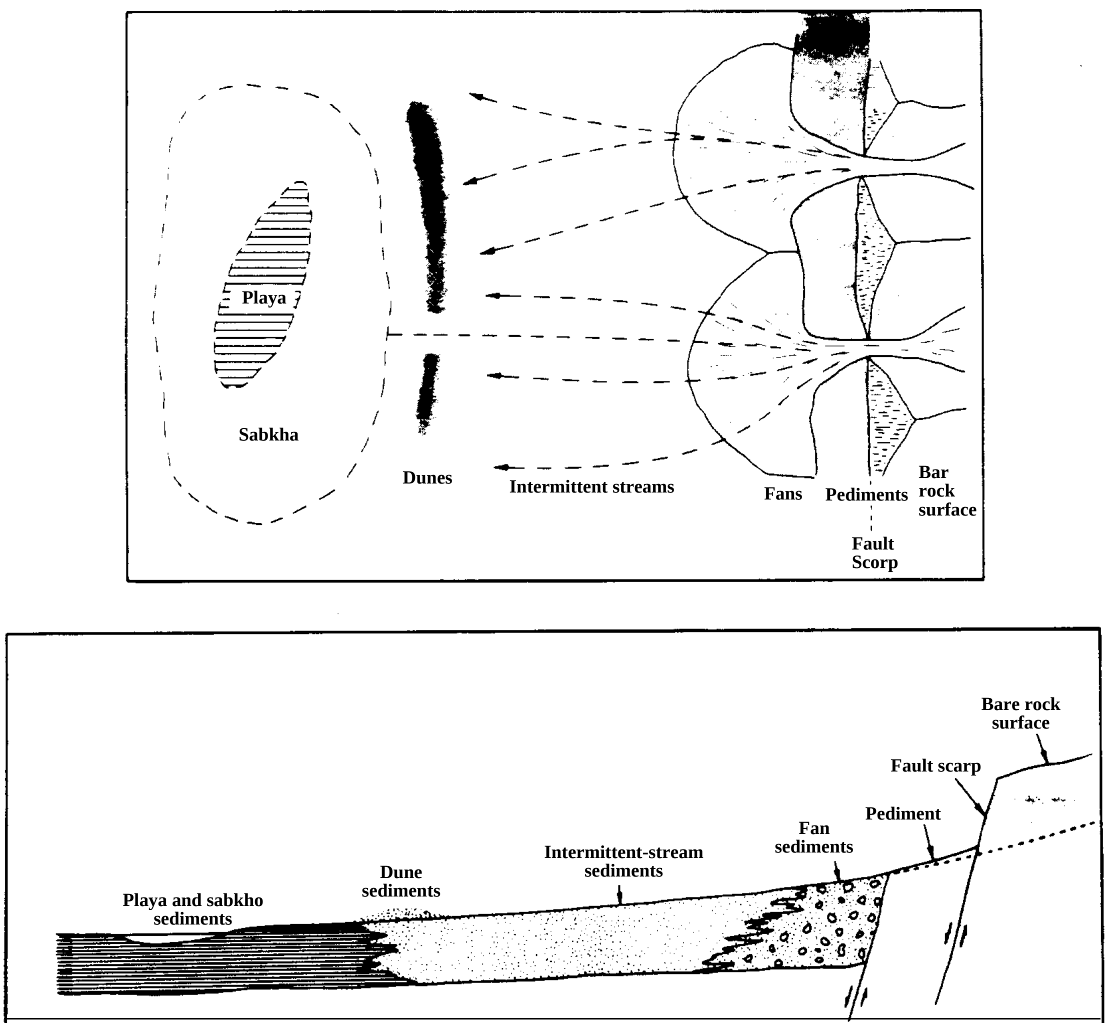


Figure 3-1 Map View (A) and Cross-Section (B) of Alluvial Fan Environment

The size of a fan is controlled by the size of the basin that is receiving the sediment. The relief of a fan, from the head to the distal areas, will vary with the size of the fan. Most fans have a concave upward profile.

They are of limited economic significance (for petroleum), due to poor permeabilities and porosities; the sands and conglomerates are generally very argillaceous. Alluvial fan facies are encountered in the Triassic of the North Sea, particularly as part of the Skagerrak Formation in the Norwegian-Danish basin. Some finds have been made in the Skaggerak and Gassum Formations in blocks 22/24 of the UK sector, with the Skua and Marnock fields having significant reserves of gas/condensate. However the major part of these formations are of alluvial flood plain facies.

Lithology -matrix and clast supported conglomerates, texturally and compositionally immature argillaceous sandstones. Often red beds.

Structures - generally massive, some cross-bedding and imbrication in the conglomerates.

Braided Stream Environments

Braided sedimentary environments (Figure 3-2) are those areas in which river flow diverges and rejoins around bars within a more or less defined channel. Settings which commonly produce pebbly braided channels are glacial outwash areas, humid fans, and wadis of semiarid regions. The seasonal fluctuations of stream water flows determine the type of medium features that are found in proglacial sediments. Outwash fans and plains have complex channel patterns, with the main flow usually restricted to a well defined zone.

The braided pattern is caused by bars which develop on several magnitudes of sizes. While the bars can form and split the flow under steady discharge rates, most of the bar development is related to discharge fluctuations. The types of bars include three major variations; Longitudinal bars, Bars in curved channel reaches, and Transverse bars.

Longitudinal bars are diamond or lozenge shaped, and are the most obvious form in pebbly braided streams. Bars in curved channel reaches can be attached to either bank and are commonly extensions and modifications to the flanks of larger longitudinal bars. Transverse bars are most common in sandy, low sinuosity streams, but also occur in pebbly ones.

The main structures that have presentation potential are channels, pebble imbrication, cross bedding, ripples and ripple cross lamination, and sand lineations.

Crevasse splay deposits are thin sandstones within floodplain claystones and siltstones, deposited by meandering rivers that have breached their banks. Structures not destroyed by rootlet disturbance can have sedimentary structures characteristic to turbidites, such as sole marks and climbing ripple laminations.

The geometry of deposits of meandering and braided deposits are quite different and have a strong significance in their value as petroleum reservoirs.

Meandering rivers tend to stay in narrow meander belts, building cyclic facies sequences of point bar and flood plain deposits, that result in a ribbon-like geometry of sandstone bodies. The meander belts can suddenly change there course through a process known as avulsion.

Braided river deposits tend to have a far higher sand to clay/silt ratio, with sandstones (and/or conglomerates) having a greater lateral extent.

Lithology - Predominantly coarse sands and conglomerates, often red colored with no organic material. Sandstones are often Arkosic and or Lithic. Thin intraformational conglomerates are common.

Structures - Tabular and trough cross-stratification caused by migration of bars, sand waves and dunes. Imbrication is common in conglomerates. Minor cross-lamination is caused by ripple migration in abandoned channels or in near-full channels. There is an occasional finning upwards sequence representing filling of channels.

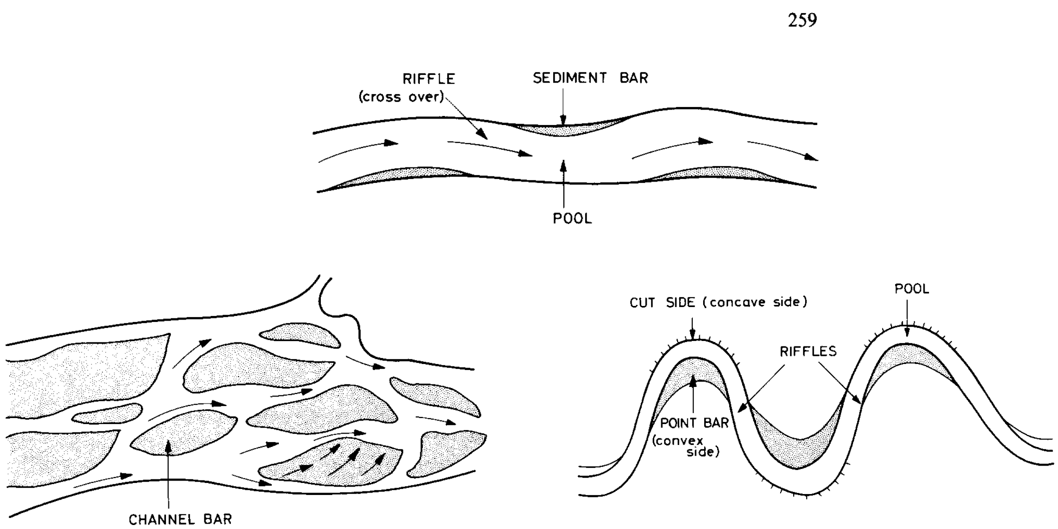


Figure 3-2 Straight, Braided and Meandering Channel Patterns

Meandering River Deposits

Meandering rivers (see Figure 3-2) have a more developed distribution of channel processes and greater distinction between channel and overbank deposits than braided streams. Meandering channels, unlike braided channels, occupy only a small part of their floodplain at a given time. The shifting of the channel is a function of channel sinuosity. The position of the meander belt is stabilized by clay plugs generated by frequent channel cut-offs. An alluvial ridge, with a accompanying flood bank, is built along the sides of the channel above the level of the floodplain. Since this is an unstable situation, the channel will occasionally breach the ridge and establish a new course as the majority of the current diverts through the breach.

Water flow in the meander bends follow a helical pattern. The surface component is toward the outer bank and the bottom component is toward the inner bank. This results in erosion along the outside of the meander bend and deposition along the inside. The meander will prograde laterally and result in the formation of what are known as point bars. The meander process is influenced by the lithologies adjacent to it. Old meander cut-offs that are exposed along the erosional bank of new meanders will partially determine the shape of the bank, because the old meanders are often filled with cohesive clay plugs.

Point bars have approximately horizontal surfaces at about the same level as the surrounding flood plains. The outer erosional side of the channel is concave, while the inner depositional side (the point bar surface) is convex.

Scroll bars are ridges of sand that develop some distance down the point bar surface and are elongated more or less parallel to the contours of the surface. They impart a roughly concentric topography on the surface of the point bars, which represents consecutive scroll bar additions. Lateral migration of the channel results in a tabular sand body, overlaying a nearly horizontal erosional surface that can have an associated lag conglomerate. The sands generally have a fining upward sequence and are cross bedded with a upward reduction of the set size.

Lithology - Medium to fine sandstones, claystones and siltstones, with a roughly 50/50 ratio of sandstones to mudrocks. It may also contain minor conglomerates and coals. Sandstones are generally arkosic. Possible caliche is present in mudrocks or siderite nodules.

Structures - Channel scour surfaces, with coarse lag deposits followed by trough cross bedding, flat bedding and then ripple cross-lamination. Flood plain deposits may have thin crevasse splay sandstones with sole marks and climbing ripple lamination.

Eolian Facies

Eolian facies are those sediments that are reworked and laid down through the action of wind currents. Since deserts are at a depositional equilibrium, that is they are areas of neither net erosion or deposition, ancient eolian sediments will primarily be composed of sands. This is because larger grains will not be transported by the wind and fine grains will be blown or washed away. This results in major deposits of sand grains that are very clean and relatively homogenous in size.

Because the physics of fluvial and eolian transport mechanisms are very similar, the resulting sedimentary structures are much the same. The bed forms will include asymmetric ripples and mega-ripples. Although there is no distinctive shape to wind blown sediments, several types of dunes that can be recognized. These are; Lunate or Barchan, Stellate, Longitudinal and Transverse (Figure 3-3).

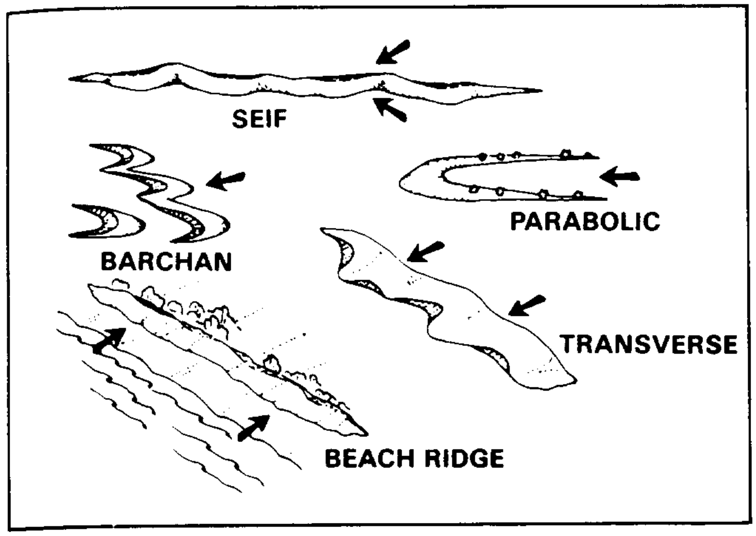


Figure 3-3 Dune Types, Arrows Indicate With Direction

Barchan dunes are one of the better known type of dunes. Like most dunes, they have a low angle surface on the front (windward side) and a steep rear (downwind side). They are cuspate shaped in plan view, with the point of the cusp oriented downwind. Barchans are “lone” dunes that form away form the major sand accumulations and typically migrate across flat surfaces.

Stellate dunes can grow to relatively large magnitudes and occur in jumbled patterns in sand seas and where the seas meet escarpments.

Longitudinal dunes can be quite common with their crest axes being orientated perpendicular to each other or the primary wind direction. They overlay flat desert surfaces and have no net deposition taking place.

Transverse dunes are the most important type of dunal structure. They are not singular features and are prolific, migrating over the rear of downwind dunes.

Interdunal sediments are composed of massive or flat bedded sands and granules that are coarser than the sands included in the adjacent dunal features. They form permeability barriers that can slow down interformational fluid movement. They can possibly serve as source rocks, because they often serve as traps for large amounts of organic material.

Lithology - Fine to coarse sandstones, well sorted, well rounded, possibly frosted, generally quartz arenites, no mica, no glauconite, no carbonaceous material, possible presence of dreikanters, red coloration. There are often sharp differences in grain size between laminae. It may contain minor claystone deposits with mica from interdune areas.

Structures - Dominated by large scale cross-bedding. Inter dune deposits may show mud flakes and adhesion ripples. There may often be many intra-formational unconformities (reactivation surfaces). In cores, a gradual increase in angle of dip of lamination from sub-horizontal to steep can often be seen representing the toeset (base) of dune to the foreset.

Table 3-1: Alluvial Sand Facies
Facies Characteristics

	TEXTURES	STRUCTURES	CONTACTS	DIMENSIONS	BIOTA	RESERVOIR POTENTIAL
POINT BAR	Medium to coarse grained sand, depending upon river size and gradient. Gravel sometimes at base, fine sand at top	Festoon crossbeds; ripple marks; flute casts; slump structures; convolute bedding; massive to thin bedded	Lateral and basal contacts sharp; top contact gradationalor sharp	Individual deposits are elliptical to semielliptical; they may occur singly or in a complex system of dissected, partial and whole elliptical deposits. The long axis of known producing single deposits varies from 1 to 10 miles. Individual deposits may be as thick as 180 feet	No indigenous flora; wood fragments, twigs, leaves sometimes on bedding planes. Fauna rare; fresh water mollusks and ostracodes sometimes present; transported forms may occur	Excellent
BRAIDED STREAM	Sand size most common but ranging from cobbles to silt and clay, with clay forming thin lenses of irregular extent	Festoon and cross laminations; load casts; flute casts; current-ripple and megaripple marks. Parallel bedding not common. Graded bedding not common	Sharp on all confining sides	Known producing individual deposits vary between 1/2 to 1 1/2 miles in width.They may be as thick as 150 feet	Rare; may contain few fresh water forms and nonindigeneous types	Excellent
ALLUVIAL FAN	Heterogenous mixture of large boulders to clay-size sediments	Massive; bedding tends to parallel surface of fan; stratification good; graded bedding; cross stratification; current-ripple marks, imbrication	Sharp; near toe of fan can be gradational	Individual deposits are fan-shaped wedges, with a maximum thickness as great as 1000 feet. Fans commonly coalesce to form a more of less linearbelt of thick coarse material	Wood fragments and debris locally common; fauna rare	Fair to Excellent

Barrier Island And Near Shore Environments

Barrier islands are long, narrow sand bodies that can occur within deltas, along delta fronts, and in oceanic and lacustrine environments with no direct connection to deltas. They are more likely to form when there is a steady supply of sand to the coast, the depositional basin has a limited tidal range, and the coastal plain is moderately stable with a low gradient.

Barrier islands are formed by wave processes. The processes must result in waves that are altered so that they transport sediment as they approach a beach and generate near shore currents capable of transporting sediment, and have temporary fluctuations between calm and stormy weather. These factors work in concert to remove sand from the shore area, transport it to deeper water where the wave action is diminished, and deposit the sands. Orbital water currents in the foreshore area concentrate the sands in the characteristic bars that parallel the shoreface (Figure 3-4).

The marine parts of barrier and beach environments can be split into several zones based on the main process operating. There are several different terms in use for the zones:

Backshore Above mean high tide, with low angle land and dipping laminae; maybe eolian dune at top.

Foreshore Between high and low tide. A swash zone, with wedge shape sets of low angle seaward dipping laminae. Possibly minor ripple and dune lamination. Heavy mineral concentrations.

Shoreface Between low water mark and fair weather wave base. Varied structurally, with low angle seaward dipping lamination and/or dune cross bedding. Ripple lamination more common towards base of sequence. Abundant bioturbation.

Upper Offshore
Below fair weather base, but above stormweather base. Interbedded thin sandstones and claystones may be present, with the sandstones showing hummocky and swaley cross-stratification (these being interpreted as storm deposits). Maybe intense bioturbation.

Barrier islands formed in areas with high tidal ranges, are cut by numerous tidal inlets, which can migrate along the barrier due to longshore drift reworking the foreshore/ backshore and upper shoreface deposits. Fining upward channel-fill sequences with dune trough and planar cross-bedding, show bipolar current directions and possibly herringbone cross-stratification. Tidal inlets are often associated with ebb and flood tidal deltas.

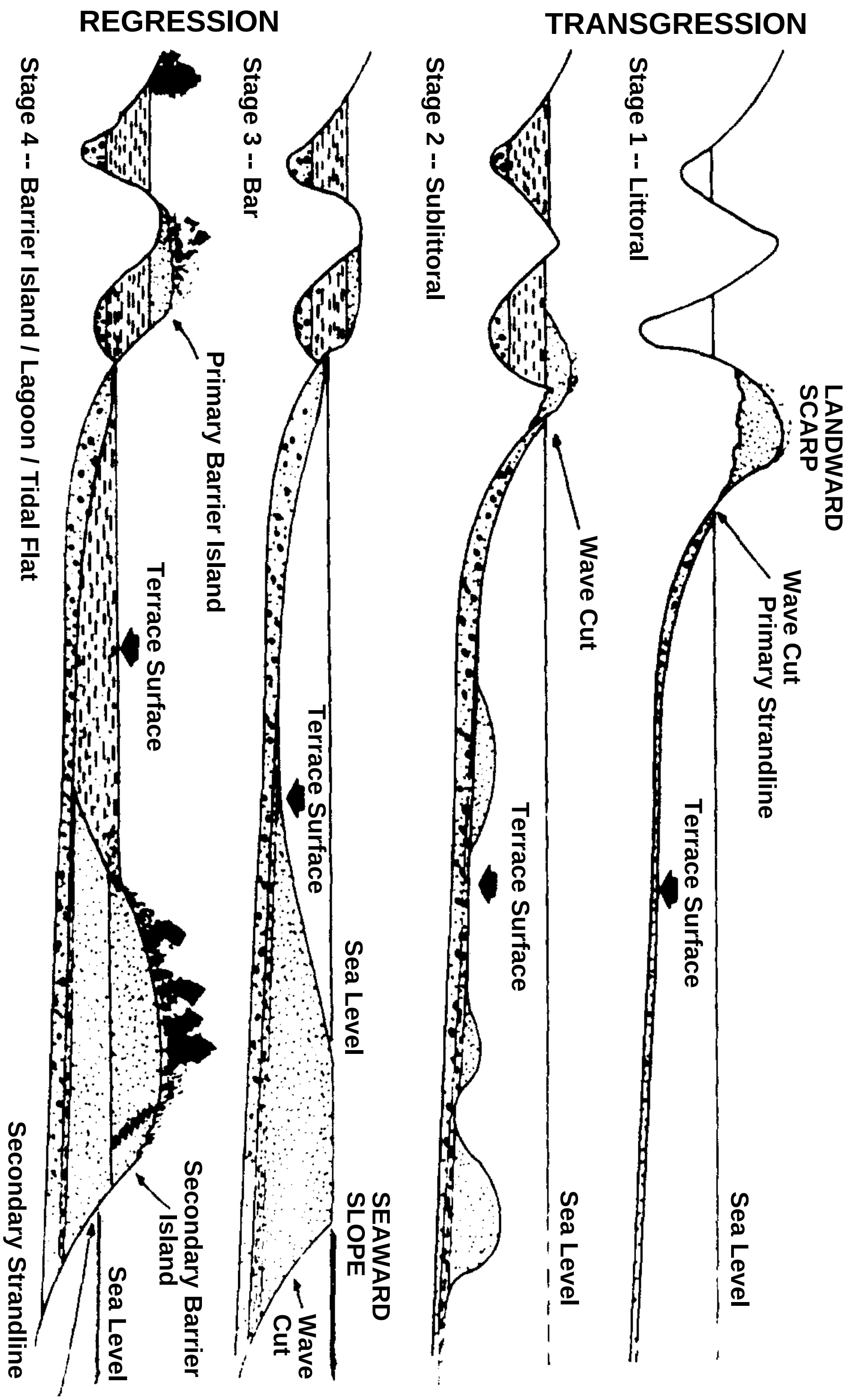


Figure 3-4 Barrier Island Environment

Table 3-2: Nearshore Sand Facies
Facies Characteristics
Barrier Island Deposits

	TEXTURES	STRUCTURES	CONTACTS	DIMENSIONS	BIOTA	RESERVOIR POTENTIAL
DUNE	Very well sorted sand	Crossbedded and oxidized sand; roots and root impressions; organic rich mottled zones common; few burrows	Upper: Gradational if overlain by marsh deposits, sharp if transgressed and overlain by offshore marine deposits	Linear in plan view with smooth seaward margin and irregular landward margin; biconvex in cross-section (if transgressed, top may be flattened). A few tens of feet to more than 70 feet thick; commonly 1 to 4 miles wide and more than a hundred miles in length. Long dimension parallel to depositional strike and basin margin; barrier island chains commonly show seaward offsets in down-current direction	Terrestial vegetation and animals	Excellent
BEACH	Well sorted sand with local concentrations of shell debris	Characterized by fine laminae dipping both landward and seaward; few steeply dipping crossbeds locally developed	Lower: Shoreface gradational into offshore marine deposits; tidal channel contact erosional		Inner-neritic assemblage; commonly broken and abraded	Excellent
SHOREFACE	Generally well sorted sand	Massive to faintly laminated with minor cross-bedding and shell layers. Burrowed locally	Lateral: Gradational landward with lagoon and marsh deposits		Shallow (0 to 60 feet deep) inner-neritic assemblage; generally well preserved	Fair to Good
OFFSHORE	Generally finer grained than shoreface; silty sand to clay silt	Faintly laminated to massive with sand lenses and peat layers locally developed	Gradational seaward with offshore clay		Mid to inner neritic assemblage	None to Very Poor
TIDAL CHANNEL	Sand and shell hash; granule to pebble sized shell fragments near base; grain size decreases upwards	Gently-dipping laminations to well-developed crossbeds; minor burrows			Mixed brackish and inner neritic assemblage	Excellent

Table 3-3: Nearshore Sand Facies
Facies Characteristics
Lagoon, Bay, Tidal-Delta and Tidal-Flat Deposits

	TEXTURES	STRUCTURES	CONTACTS	DIMENSIONS	BIOTA	RESERVOIR POTENTIAL
LAGOON	Generally fine-grained, but in some areas may be sandy (e.g. along back barrier margins and near tidal channels)	Finely laminated to structureless. Burrows and shell fragments common	Upper: Gradational with algal-flat and marsh sediments, sharp with tidal delta sediments Lower: Sharp with underlying barrier-island facies	Long axis parallel to barrier island trend; commonly only a few miles wide, tens to hundreds of miles long	Brackish-water to mixed brackish-water and marine assemblage	Fair to Very poor
BAY	Generally fine-grained, silty clay to clayey silt	Finely laminated to structureless. Burrows and shell fragments common	Upper: Gradational with marsh Lower: Sharp with underlying fluvial deposits	Long axis normal to basin margin; thickness and extent of deposits variable	Fresh-to-brackish water faunal assemblage	Very poor to Fair
LAGOON TIDAL DELTA	Typically well sorted sand, commonly grading finer downward	Faintly laminated to cross laminated, burrowed and mottled with dark organic material. Shell debris common	Upper: Gradational to sharp with marsh, lagoon or bay deposits Lower: Sharp with underlying lagoon deposits	Lobate outline, commonly several miles long and wide. Several feet to tens of feet thick	Mixed brackish-water and marine faunal assemblage	Fair to Good
TIDAL FLAT	Generally sandy, grading upward and landward into clay. Near tidal channels becomes coarser	Flaser bedding, clay infilling in sand ripples or the reverse. Near tidal channels cross laminations and shell debris common	Upper: Gradational with marsh or bay sediments. Grades laterally into coarses tidal-channel sediments Lower: Gradational with lagoon or marsh sediments, sharp with barrier island facies	Variable in trend and extent; generally developed along lagoon sand coastal margins parallel to depositional strike. Thickness in stable areas equal to tidal range	Mixed fresh-to-brackish water to marine faunal assemblage	None to Excellent

Table 3-4: Nearshore Sand Facies
Facies Characteristics
Stranded-Beach and Mud-Flat Deposits

	TEXTURES	STRUCTURES	CONTACTS	DIMENSIONS	BIOTA	RESERVOIR POTENTIAL
MARSH	Peat and organic-rich silty clay. Locally may include oyster beds, wood fragments, roots and root clasts	Laminated, burrowed to structureless. Minute slump structures and contorted bedding. Woody fragments and plant material	Upper: Sharp, with marsh clay overlying Lower: Gradational into shoreface sand and clay	Long, narrow, bifurcating ridges with smooth seaward margin and irregular landward margin, biconvex in cross-section having steep seaward	Varies from fresh top brackish-marine depending on proximity to shore; abundant vegetal material	None
MUD FLAT	Silty clay; root fibers common in upper part where covered by marsh	Massive to faintly laminated	Lateral: Interfingers with mud-flat clay and marsh	slope and gentle landward slope. Commonly from 5 to 25 feet thick; individual ridges vary from several	Shallow inner-neritic forms except near river mouths where brackish-marine assemblages dominate	None
BEACH	Well-sorted sand with local concentrations of shell debris	Fine laminae dipping both landward and seaward; steeply dipping cross-beds locally developed		hundred feet to 1/4-mile wide; composite ridges exceed a mile in width, length varies from a few hundred feet to more than 30 miles. Long	Mixed nearshore marine and brackish-marine assemblage, commonly broken and abraded	Fair to Good
SHOREFACE	Generally well-sorted sand with locally developed fine-sand lenses enclosed in silty clay	Massive to faintly laminated with minor cross-bedding. Abundant sand-filled burrows. Ripple marks common		dimension parallel to depositional strike and basin margin	Shallow (0 to 60 feet deep) inner-neritic assemblage	Poor to Fair
OFFSHORE	Generally fine-grained, sandy silt to silty clay	Massive to faintly laminated with sand lenses and peat layers locally developed			Inner-neritic assemblage	Very Poor

Deltaic Environments

Deltas are distinct extensions from the shoreline where rivers enter marine or fresh-water depositional basins and supply sediments faster than the basin processes can redistribute them. They can assume a variety of morphologies, depending on the type of supplied sediments, the rate of deposition, the hydraulic gradient, and the energy and flow system of basin currents.

The primary character of a delta usually results from the struggle between fluvial and basinal processes. The most important feature of the catch basin is the overall energy regime that is in contest with the introduction of river borne sediments. Delta types are largely determined in terms of the hydraulic energy system and this relationship is reflected in their resulting morphologies. Through an understanding of modern deltaic development, it is possible for the Petroleum Geologist to reconstruct the history of ancient deltas. This is fortunate, because deltaic sediments are one of the most common types of deposits examined for hydrocarbon accumulations.

Alluvial Sediments and The Sediment Basin

The types of sediments supplied to the marine basins have a large influence on the sediments that are eventually accumulated in deltas. Some of the important points that must be considered are:

- The amount of sediment supplied versus the reworking ability of the basin
- The grain sizes of supplied sediments
- Fluctuations in alluvial discharge that can affect the grain sizes of supplied sediments
- The timing of fluctuations in fluvial discharge versus fluctuations in basinal energy regimes.

The nature of basin characteristics and processes also affect the progress and morphology of deltaic sedimentation. The development will be influenced by basin water salinity, basin shape, size and bathymetry, energy regimes, subsidence rates, tectonic activity, and sea level fluctuations.

Delta Models

Deltas have been divided into two basic morphologies (Figure 3-5). Each type of delta is distinguished by its own characteristic morphology and facies pattern.

1. Highly constructive deltas dominated by fluvial processes
    a. Lobate
    b. Birdsfoot

2. Highly destructive deltas dominated by basinal processes
   a. Wave dominated
   b. Tide dominated

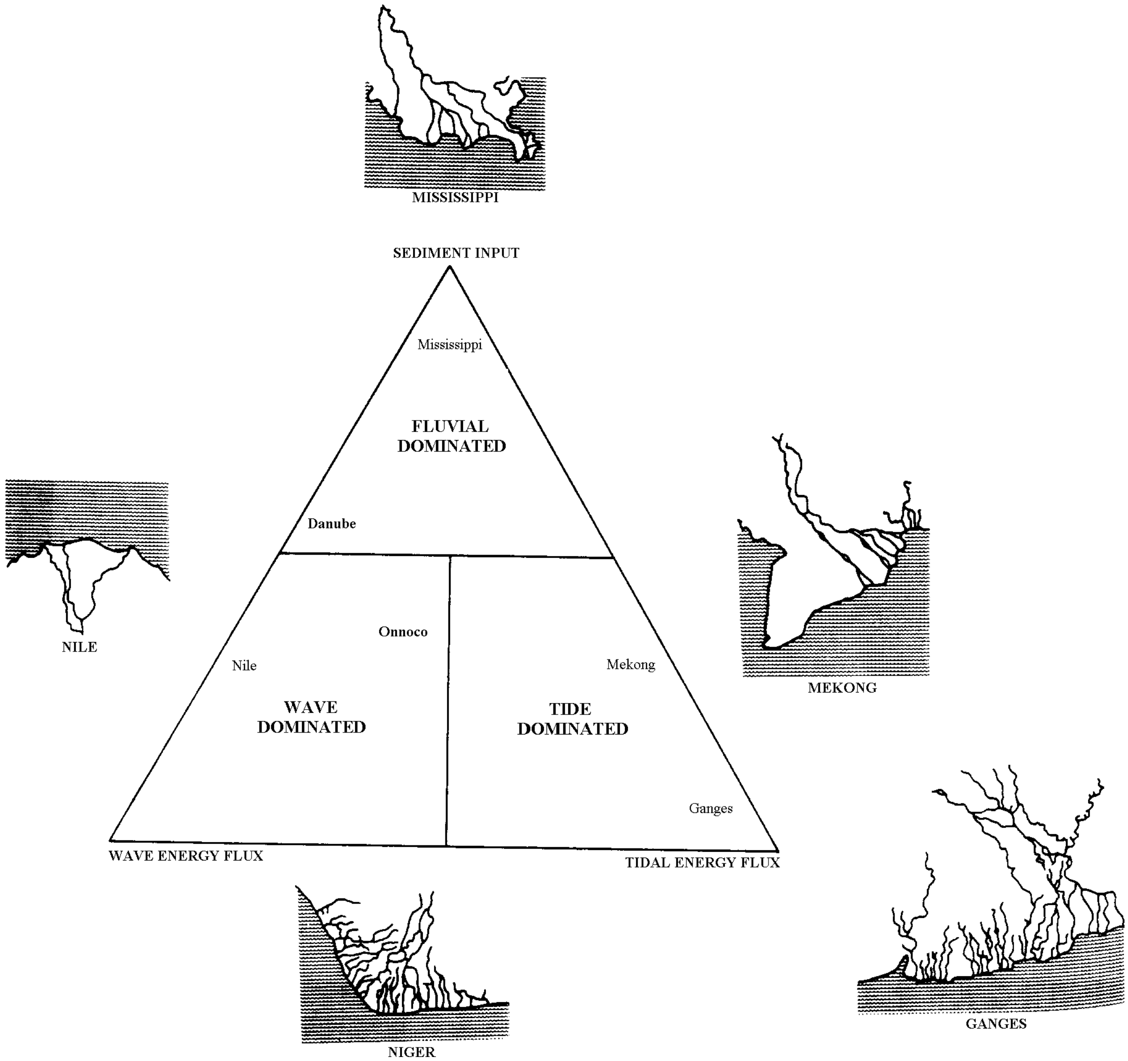


Figure 3-5 Delta Types, With Five Examples

Fluvial Dominated Deltas

These are characterized by unidirectional flow patterns. Highly sinuous patterns are common, although deltas with sporadic discharge and high bed loads can develop braided patterns.

Facies and sequences resemble alluvial channel deposits with erosive basal sequences and basal lag. Some are multi-story sequences with repeated cut and fill within the channels. There is an overall fining upward of the channel sequences, resulting from lateral channel migration or channel abandonment. Large scale bank slumping, resulting from scour of the banks, can also be an important feature.

The inter distributary areas are enclosed, shallow-water environments with quiet or stagnate waters.These facies and sequences are dominated by flood generated events:

1. Overbank flooding in evolving sheet flows of sediment laden waters.
2. Crevasse splays which are locally produced aprons resulting from sudden incursions of sediment laden waters which deposit sediments over a limited area in the lower flanks of levees and bay floors.
3. Minor mouth bar/crevasse channel couplets consisting of semi-permanent crevasse channels and small scale mouth bars. When the couplets are closely spaced, a laterally continuous front can advance into the basin, resulting in sub deltaic lobes, such as in the modern Mississippi delta.

Tide Dominated Deltas

In regions that have medium to high tidal ranges, marine waters can be trapped in the delta plain during times of maximum sea level. As the tide drops, tidal currents will predominate in the lower inter distributaries as these waters escape. This results in distinctive distributary channels that have low sinuosities and funnel shaped forms with high width to depth ratios. Dune bedforms are predominate in channels, but complex mazes of sand bars and mudflats occur where distributaries meet. In some deltas, the major bedforms in the lower extents of their distributary channels are linear sand ridges aligned parallel with the overall channel trend.

Inter distributary areas are composed of lagoons, small tidal creeks, and intertidal flats. These areas are sensitive to the regional climate, because they are exposed between tidal inundations.

Wave Dominated Deltas

Wave processes redistribute most of the sediment supplied to the delta front. This results in a regular beach shoreline, with a minor protrusion at the distributary mouth and a steep delta front. Distributary mouth bars cannot develop. In this case, overall growth involves the entire delta front instead of localized accumulations, as occurs in sediment dominated deltas; growth is usually slow. Old beach ridge complexes occur behind the delta front and reflect shoreline changes in the position of distributary channels.

Bioturbated, fossiliferous muds pass upward in to alternating mud, silt, and sand beds with associated scouring, grading and cross lamination. The final sediments are well sorted sands, representing the high energy beach front. Aeolian sands can be found behind the delta front, although these are not likely preserved in ancient sediments.

Recognition of Ancient Delta Types

Various properties can be studied to recognize ancient deltas:

- Vertical facies sequences are important in recognizing regime defined deltas
- Lateral, regional facies relationships allow reconstruction of proximal/ distal and axial/lateral changes
- Isopach maps can identify the concentrations of sands and hopefully provide insight to delta channel locations
- Abandonment marker horizons can reflect sand distributions and indirectly indicate the delta type

Growth Faults in Alluvially Dominated Deltas

Growth faults result from compaction disequilibrium and are found most often in deltas with prolific net sediment accumulation and high shale/sand ratios. The overpressured clays are abnormally high in porosity and therefore relatively plastic, compared to adjacent sediments. This results in the generation of mud diapirs, which serve as “weak” spots that allow sediment failure, instigating spoon-shaped growth faults with maximum throws in the center. Rollover anticlines form along the contact with the upthrown sides of these faults, resulting in structurally-high contour closers. This type of “high” serves as the trap for many oil accumulations.

Case Studies - Deltaic Environments

The Brent Group is one of the most productive plays in the North Sea. It was deposited in a northerly prograding wave dominated delta. The name BRENT is a contraction of Broom, Rannoch, Etive, Ness and Tarbert:

Broom Formation

A thin, poorly sorted arkosic sandstone of uncertain origin; possibly sub-littoral.

Rannoch Formation

Delta front sandstone deposit, rich in muscovite mica (often quite coarse and easily mistaken for LCM). The mica often occurs as mica-rich laminae separated by mica poor laminae and were not disturbed by bioturbation. Shows cross-bedding, interpreted by some (Richard and Brown 1986) as Hummocky Cross Stratification. The laminae are important in production as they inhibit vertical permeability.

Etive Formation

This formation consists of well sorted quartz arenites and, along with the Rannoch, makes up the majority of reservoir volume. It was deposited in a regressive barrier island environment at the delta front. Locally, areas of high permeability occur where tidal channels cut the barrier.

Ness Formation

This Formation was deposited on the delta top in lagoonal and fluvial plain environments and consists of shales and sandstones and thin coals. The sandstones are often of ribbon-like geometry having been deposited in distributary channels, but are also deposited as mini deltas where the channels empty out into the back-barrier lagoon, building distributary mouth bars. There is a prominent shale bed called the Mid Ness shale in the central East Shetland basin which is used as a marker bed for seismic interpretation and correlation.

Tarbert Formation

This is a sequence of sandstones with minor shales deposited in a shallow marine environment and represents a transgression.

Table 3-5: Deltaic Sand Facies
Facies Characteristics
Delta Plain Deposits

	TEXTURES	STRUCTURES	CONTACTS	DIMENSIONS	BIOTA	RESERVOIR POTENTIAL
POINT BAR	Well-sorted, medium to fine-grained sand with minor quantity of silt, grades downward into coarse sand and pebbles at base of unit	Current-rippled near top, small-scale crossbeds below, large-scale crossbeds at base, layers of plant material & pebbles convoluted beds, mud balls	Upper: Gradational-sharp with natural-levee, marsh, bay sediments Lower: Sharp with stream-mouth bar or other fluvial sediments	Several tens of feet thick, a mile or more in width; multiple point bars may extend many miles along meander belt, commonly at high angle to basin margin	Commonly barren; may hold wood fragments, fresh-water shells and reworked fauna of older deposits	Excellent
ABANDONED CHANNEL	Gradational sequence from coarse at the base to fine silt and clay at the top; clays at the top commonly are organic rich	Small to large scale cross-bedding, slump features; organic debris; laminations in finer grained upper part of channel fill, burrows; clay clasts near base	Upper: Gradational into marsh deposits Lower: Sharp with under-lying and lateral stream-mouth bar, delta front and prodelta sediments	Thickness from a few feet up to 300 feet, depending on size of distributary; hundreds of feet to tens of miles along channel length	Essentially barren; may hold fresh-water forms and near the top may contain a brackish-water fauna; re-worked fauna of older deposits may be present	Fair
CREVASSE FAN	Sand and silty sand with inter-beds of sandy silt and silty clay within sequences of sandy to silty clay (marsh, bay, swamp deposits)	Laminated with irregular layers, current rippled, crossbedded, slump structures	Upper: Gradational with bay, marsh and natural-levee sediments Lower: Sharp with bay, marsh and natural-levee sediments	Thickness from a few feet to several tens of feet; areal extent relatively small; individual sands rarely cover more than a few square miles	Shallow-marine, brackish and fresh water forms	Poor
MARSH - SWAMP	Peat and organic-rich silty clay; scattered lenses of silty sand	Laminated, burrowed to structureless; small scale slump structures and contorted bedding; abundant wood fragments and plant material	Upper: Gradational with transgressive bay, crevasse, channel or point bar Lower: Gradational with stream-mouth bar, bach, crevasse, channel, point bar	Individual beds range from a few inches to several tens of feet in thickness; areal coverage to several hundred square miles; commonly form time-marker coal layers	Fresh, brackish or saline; roots, plants remains and diatoms common	None
NATURAL LEVEE	Sand, silt and clay near stream; sandy clay to silty clay away from stream; plant debris common	Laminated to burrowed and root mottled, original laminations and crossbeds commonly disturbed	Upper: Gradational with marsh, swamp, bay; laterally gradational with marsh, swamp, crevasse; sharp with channel fill Lower: Gradational with stream-mouth bar	From a few feet to many tens of feet in thickness; linear bodies may extend for many tens of miles along channel trace	Very sparse fresh to brackish water assemblages; some marine forms may be carried in by storms; peaty layers and wood fragments common	Very Poor

Table 3-6: Deltaic Sand Facies
Facies Characteristics
Stream-Mouth Bar, Beach-Ridge and Delta-Margin Island Deposits

	TEXTURES	STRUCTURES	CONTACTS	DIMENSIONS	BIOTA	RESERVOIR POTENTIAL
STEAM-MOUTH BAR (closely-spaced distributaries shoal water)	Clean, well-sorted sand adjacent to streams; silty sand and silty clay between; cleaner sand in central part, silty sand above and below	Parallel laminated crossbedded; may contain plant fragments; silt and clay lenses more common away from main streams and seaward as well	Upper: Gradational into levee, marsh or bay sediments, contact sharp where channeled	May cover several hundred iles. Irregular in areal extent. Thickness irregular, being greatest near streams; several tens of feet thick to less than 10 feet thick, depending on water depth	Fauna not common, but may have mixture of fresh-water and nearshore type	Very Good
STREAM-MOUTH BAR (widely-spaced distributaries deep water)	Central zone of clean, well-sorted sand grading outward in all directions into transitional zones of finer grained sediments	Parallel laminated unidirectional crossbedding in central sand zone; small scale ripples common; plant fragments; scattered laminae of silt and clay occur locally in interbedded material	Lower: Gradational into delta front deposits (interedded sand and silty clay)	Width up to 5 miles, length up to 15 miles and thickness up to 300 ft, smaller dimensions for smaller streams	General scarity of fauna, although may hold fresh-water shells and plant debris. Reworked faunas of older deposits may be present	Very Good
BEACH RIDGE	Clean, well-sorted sand at top, (dune, beach, shoreface) grading downward into silty sand at base (lower shoreface)	Parallel laminated local low-angle crossbeds; burrows in lower part (shoreface) shells and plant fragments common	Upper: Gradational into marsh, bay sediments or sharply overlain by tidal, channel and tidal-flat sediments Lower: Gradational into pro-delta	Sheetlike, covering area of delta lobe; biconvex in cross-section; thickness tens of feet (greater in actively subsiding areas)	Inner-neritic fauna for beach and shoreface zone; terrestial for dune section; brackish to nearly fresh water where stream discharge is high	Excellent
DELTA-MARGIN ISLAND	Clean, well-sorted sand, free of silt and clay, in upper part of section; grades downward into alternating sand and silty clay, in lower shoreface	Structures typical of dune (crossbedding), beach (shells) and shoreface (mottling)	Upper: Gradationally overlain by fine-grained offshore sediments where subsidence is rapid Lower: May sharply overlie prodelta, delta-front or delta-plain sediments	Thickness up to 60 feet, Maximum width of sand body about 2 miles, and up to 10 miles long	Shoreface sands carry normal inner-neritic fauna; dune sands may hold a few terrestial shells	Excellent

Submarine Fans And Turbidites

Turbidite sediments get their name from the process through which they are emplaced: turbidity currents. These currents are rolling, turbulent masses of flow that have dispersed sediments incorporated in them; they remain in suspension because of the hydraulic energy of the flow.

These sediments are originally deposited on the upper margins of continental slopes. Accumulation continues until the mass is great enough to exceed the sediment's cohesive strength. Failure occurs through a slumping mechanism and down slope movement begins. As the sediments move, they are taken into suspension with the surrounding waters and a turbide flow is produced.

The turbide flow will continue down slope until it reaches a lower hydraulic gradient. The gradient eventually can not supply the energy levels necessary for suspension of coarser grain sediments and initial deposition of pebbles and cobbles will occur. As the turbide flow experiences lower gradients, smaller grains will fall out of suspension. The waning process will continue until clays are eventually deposited (Figure 3-6).

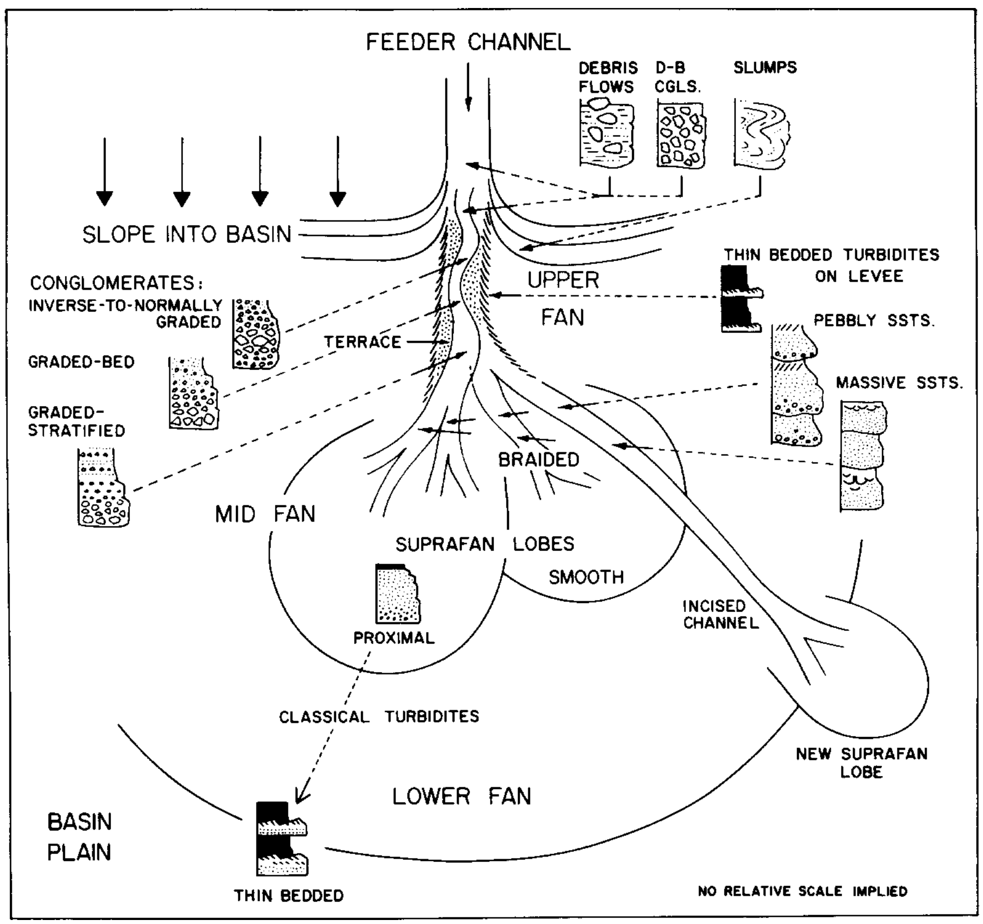


Figure 3-6 Submarine Fan Depositional Environment

Morphology of the Depositional System

In the “ideal” model, turbidity currents are channelized during transport by submarine canyons that begin at the edge of the continental shelf. The upper portions of the channels are formed by erosion of softer shelf sediments by the abrasive action of turbidity currents. In the lower reaches of channels, where primary deposition of coarser sediments occurs, channels are maintained by over-bank turbidity current flooding that builds channel bank relief, much like rivers build natural levees in alluvial systems.

Submarine fans will form at the terminus of a submarine channel, where the channel has a minimum hydraulic gradient. These fans have distinct morphologies, similar to modern deposition dominated deltas. There are multiple bifurcations of the primary submarine channel, resulting in local deposition of sediment fans. These fans have distinct shore-ward limits, but their distal edges are often impossible to determine because they merge into abyssal plain clays.

The submarine fan surfaces have steeper slopes than the surrounding abyssal plains. This relief is developed due to deposition on the fan surfaces. The highest proportions of sand will be found near the middle of the fans, since coarser sediments will be deposited near the fan channels, with fine sediments being deposited in the distal fan areas.

Fans will grow in relief and areal extent until the hydraulic gradient potential is great enough that the channel will shift laterally or total channel abandonment will occur. Abandonment will result in formation of a new fan and deposition on the old fan will halt immediately. Channel wandering leaves sediments that have a gradual fining upward trend. Most often, study of ancient rocks shows that both types of events will be intermingled in the stratigraphic record.

The progradation of a fan sequence should give a coarsening and thickening upward sequence. Very distal fan turbidites are thin, with perhaps no scour marks, and only have C, D and E Bouma zones. These very distal turbidites are often known as “tiger stripe” facies. More proximal sandstone units are thicker, composed of coarser sands, and have a more complete Bouma sequence. Proximal turbidites can have abundant, thick lenticular channel-fill sands interbedded with the more classic turbidites. Near the top of the sequence, there are debris flow conglomerates and slumped beds may be present.

Lithology

Because turbidites are transported in chaotic flow regimes, and future turbidity events can destroy evidence of previous flows, it is uncommon to find a complete sedimentation sequence. However, Bouma has described an ideal turbidite sediment sequence after studying these deposits in several continents.

Table 3-7: Turbidite Sand Facies
Facies Characteristics

	TEXTURES	STRUCTURES	CONTACTS	DIMENSIONS	BIOTA	RESERVOIR POTENTIAL
TURBIDITE SANDS	Sands and gravels; graded and intercolated with, and enclosed by pelagic shales	Graded bedding, locally massive; laminated or crossbedded; contorted shale inclusions and wood fragments common: flute casts, groove casts, load casts, ripple marks, contorted beds	Upper boundary sharp to transitional Lower boundary sharp	Thickness: few inches to more than 50 ft, thins downward and towards margins of fan Extent: few hundred feet to a few hundred miles	Displaced shallow-water flora and fauna Pelagic shales have deeper water fauna such as foraminifera, radiolarians and floating forms	Very poor to excellent

These sediments and their relationships will vary widely. This variation can result from post depositional erosion, submarine fan accretion, fan and/or channel abandonment, or proximal depositional events. When a worker is examining these sediments in the subsurface, net sand isopach maps and paleofaunal markers are the primary tools for turbidite identification. For example:

Grain Size	Bouma Division	Interpretation
Mud	E - Generally Shale	Pelagic of fine grained, low density turbidity current
Sand-Silt	D - Upper parallel laminae	Distinct contact with lower zone
Sand-Silt	C - Ripples, convoluted laminae	Lower part of lower flow regime
Sand	B - Plane parallel laminae	Upper flow regime, plan bed
Sand - Granular at Base	A - Massive Graded	Upper flow regime, rapid deposition and quick bed

Exploration Considerations

Turbidite deposits are of recent interest in exploration because they are rich in hydrocarbons. Initial oil migration will be towards the fan apex. However, with isostatic adjustment to their thicker sediment load, older fan deposits have a tendency to reverse their dip. Initial updip migration can be reversed over the fan area. An anticline, developed seaward of such an area, could entrap a large portion of oil generated in a basin. The Ventura Avenue oil field, on the United States West Coast, is one such field.

Carbonate Environments

The dominance of carbonate deposits on certain sectors of the world's continental shelves is dependant on two major factors: a relative lack of sedimentation and associated high organic productivity. The rate of organic productivity in the marine environment progressively increases from higher to lower latitudes as solar illumination increases.

Shelf carbonates, however, are not restricted to areas 30 degrees on either side of the equator. Temperature combines with other variables such as salinity, carbon dioxide balance, water depth, nature of local current settings, light penetration, effective length of day, and other factors to control shelf carbonate sedimentation. However, salinity and temperature seem to be the major controls.

Two major skeletal-grain associations have been identified:

1. Temperate-water carbonates - the chlorozoan type
2. Warm water carbonates which also include hermatypic corals and calcareous green algae. Recent non-skeletal grains are also distributed in a systematic way, based on the grain-types
    a. Non-skeletal grains absent
    b. Only pellets present
    c. Ooliths and/or aggregates present with or without pellets

The oolith/aggregate association is essentially restricted to chlorozoan areas, whereas the pellet association extends into regions occupied by the foramol assemblage.

Environmental Zones

Because carbonates are extremely diverse in their character and variations, this discussion will stress environments and associated rocks formed in sub-tropical carbonate shelve zones.

Subtropical and dominantly chlorozoan belt carbonate shelves fall into two major categories:

1. Protected shelf lagoons of the Bahamian, Florida, Belize, Batabano, and Great Barrier Reef types.
2. Open shelves which include Yucatan, Western Florida, Western North Atlantic, Eastern Gulf of Mexico, and North Australia.

Shelf lagoons consist of shallow water enclosed within topographic barriers, which have formed as coral and coralgal reefs, islands and shoals. The outer margin usually rises from great depths. The edge barriers result in a protected area that has a low energy environment. Mud dominates because of the calm seas. The only circulation results from currents generated by winds and tides.

Open shelves incline towards a shelf break, and wave action can influence the entire area. There can be a fair proportion of coarse-grained detritus. These coarse grains can be composed of clean calcarenite, with finer grained carbonate in the deeper outer margins.

Sub-tropical carbonate shelve zones can be divided into five major environmental regions:

1. **Supratidal Zone -** the supratidal zone is located above the highest normal spring tides. Regions such as Florida can have episodes of evaporite deposition when dry seasons prevail. But, these will be dissolved when rainy conditions reoccur. Marshes develop and are frequently flushed by fresh water. Blue-green algae grows there and the algal crusts form on carbonate muds. In arid regions, the vuggy, laminated lime muds that form are usually only disturbed by the growth of evaporites, such as anhydrite and gypsum.

2. **Shore Zone** - the shore zone typically consists of a complex of intertidal flats, channels, levees, and beach ridges. In arid environments, a variety of algal mats are often developed. More humid regions have laminated sediments that are bioturbated. The Bahama intertidal flats, which are smaller than supralittoral marshes, are primarily composed of pellets. Most of the sediments are supplied from adjacent marine areas and are introduced during stormy periods.

   Channels in this environment form complex distributary and tributary systems that serve as major paths for tidal exchange. Their sediments range from coquina to carbonate mud. Channel bars are made up of shells, lithified mudlumps, and pellets. Dolomitic and mudclast conglomerate inclusions result from channel migration and the overall sequence is fining upward.

3. **Marine Platform** - marine platforms can be mainly composed of lime-sand or lime-mud deposits, varying with the regional energy. In the lower energy environments, such as broad areas, the deposits will be mostly pelletic muds that are bioturbated. The presence of grasses serves to trap various sediments and it is common for the shelf to be blanketed with sand size material. Patch corals can also be present.

   High energy environments favor the formation of sand belts with associated sand waves and bars. Many coated grains, such as ooids, form in these areas and can be carried to the platforms later. There is usually a minimum of shallow water fauna in the more mobile sand belts, because of the sediment's instability. Algal mats will form in these areas when energy is at a minimum. Areas that experience short, mild periods of agitation can have formation of cemented aggregations composed of shell fragments, ooids, and pellets cemented by microspar. Larger mounds, stabilized by grass, can also be formed when the energy level is low. Skeletal sands will predominate on the platform in the higher energy areas, particularly near shelf edges.

4. **Reef Belt** - these include barrier reefs, fringing reefs, and atolls, which are the major types of modern carbonate accumulations. Upwelling and slope steepness are only a few of the factors that decide whether reefs will form.

5. **Shelf Slope** - fringing reefs are important in their own regard, but also affect the growth of shelf carbonate deposits by sheltering the shelves from high energy waves and currents. Atolls stand alone from other reefal types because they are shallow water areas in open ocean areas. Buttress shaped corals grow on the wave resistant ridges that lay between chutes transecting the reef fringe. Sediments range from the corals at the reef fringe, to reef derived coral-algal rubble, to foraminiferal lime muds in the distal interior. Shelf slopes adjacent to open oceans are characterized by pelagic sediments. Planktonic foraminifera and nannoplankton, that are implaced by mass flows, predominate.

Lithologies and Facies

Although shallow water carbonate shelf facies are highly variable, both locally and among associated areas, there is a general association of facies that can be observed. Following is a synopsis of the nine zones:

1. **Basin** (fine clastics, carbonates, evaporites) - dark shale or silt, thin limestones. Evaporites fill the basin if desiccation occurs. Very even lamination on millimeter scale; rhythmic bedding; occasional ripple cross lamination.

2. **Open Marine Neritic** (carbonates, shale) - very fossiliferous. Limestone with marl interbeds. Bioturbated; thin to medium bedded with nodular layers.

3. **Toe or Slope Carbonates** - Fine grained limestone, locally cherty. Minor lamination; often massive beds; lenses of graded sediment; lithoclasts and exotic blocks.

4. **Foreslope** (Bedded fine grained sediments with slumps. Foreset debris and lime sands. Lime mud masses) - Lithology variable depending upon water turbulence up slope, sedimentary breccias and lime sands. Slumps; forese bedding; slope build-ups; exotic blocks.

5. **Organic Build-Up** (Boundstone, encrusting masses, bafflestone) - massive limestone and dolomite. Massive organic structure or open framework with roofed cavities; injection dikes; sometimes stromatactis.

6. **Sand on Edge of Platform** (shoal lime sands; islands with dune sands) - Calcarenitic-oolitic lime sand or dolomite. Medium to large scale cross bedding.

7. **Open Platform** (Lime sand bodies; wackestone-mudstone areas, bioherms; areas of terrigenous clastics) - Variable carbonates and terrigenous clastics. Intense bioturbation.

8. **Restricted Platform** (Bioclastic wackestone, lagoons, and bays; Lithoclastic sand in tidal channels; lime mud on tidal flats; fine-grained terrigenous clastic interbeds) - Often dolomite and dolomitic limestone. Birdseye, stromatolites, fine laminations, dolomitic crusts; cross bedded sand in channels.

9. **Platform Evaporites** (Nodular anhydrite and dolomite on salt flats; Laminated evaporites in desiccated ponds) - Irregularly laminated dolomite and anhydrite locally can grade into red beds. Anhydrite after gypsum nodular rosettes; chicken wire and blades; irregular lamination; caliche.

Table 3-8: Differences Between Siliclastic and Carbonate Sediments

(from Fundamentals of Diplog® Analysis, Atlas Wireline Services, 1987)

CARBONATE SEDIMENTS	SILICLASTIC SEDIMENTS
The majority of the sediments occur in shallow, tropical environments	Climate is no constraint, sediments occur worldwide and at all depths
The majority of the sediments are marine	Sediments are both terrestrial and marine
The grain size of sediments generally reflects the size of the organism skeletons and calcified hard parts	The grain size of sediments reflects the hydraulic energy in the environment
The presence of lime mud often indicates prolific growth of organisms whose calcified portions are mud-sized crystals	The presence of mud indicates settling out of suspension
Shallow water lime-sand bodies result primarily from localized physiochemical or biological fixation of carbonate	Shallow water sand bodies result from the interaction of currents and waves
Localized build-up of sediments without accompanying change in hydraulic regime alter the character of surrounding sedimentary environments	Changes in sedimentary environments are generally brought about by wide- spread changes in the hydraulic regimes
Sediments are commonly cemented on the sea floor	Sediments remain unconsolidated in the environment of deposition and on the sea floor
Periodic exposure of sediments during deposition results in intensive diagenesis, especially cementation and recrystallization	Periodic exposure of sediments during deposition leaves sediments relatively unaffected
The characteristics of various sedimentary facies is destroyed during low-grade metamorphism	The characteristics of sedimentary facies survives low-grade metamorphism

Table 3-9: Depositional Environment and Their Effect on Preservation of Organic Material

Growth Environment of Organism	Transport Mode To Depositional Environment	Depositional Environment	Conditions in Depositional Environment	Preservation of Organic Material	Type of Organic	Fossil Fuel Potential
Land	Vertical Sedimentation	Swamp	Low energy; little oxygen; little bacterial activity; little admixed mineral matter	Quality unoxidized Quantity very high	Woody	Coal
Land	Vertical Sedimentation	Eutrophic Lake	Low energy; some oxygen; moderate anaerobic bacterial activity; low to moderate admixed mineral matter	Quality relatively unoxidized Quantity high	Woody and Algal	None
Land	Fluvial	River	High energy; much oxygen; high aerobic bacterial activity; high admixed mineral matter	Quality unoxidized Quantity low	Woody	Gas some Oil
Lacustrine	Vertical Sedimentation	Stratified Lake	Low energy; little oxygen; little bacterial activity; water stratification; moderate admixed mineral matter	Quality unoxidized Quantity high to very high	Algal	Oil
Marine	Coastal Currents	Coastal Marsh Deltaic	High energy; much oxygen; high aerobic bacterial activity; high admixed mineral matter	Quality reworked by bacteria Quantity low to moderate	Algal	Oil
Marine-Brackish	Vertical Sedimentation	Quiet Bays or Non-Circulating Water	Low energy; water stratification; little oxygen; low anaerobic bacterial activity; low admixed mineral matter	Quality unoxidized Quantity high	Algal and Woody	Oil
Marine	Vertical Sedimentation	Continental Shelf	little oxygen; low bacterial activity; chemical precipitation of minerals	Quality unoxidized Quantity high	Algal	Oil
Marine	Vertical Sedimentation	Deep Ocean, Abyssal Plain	Low energy; high oxygen from bottom currents; high aerobic bacterial activity	Quality highly oxidized Quantity very low	Algal	None

Terminology

Algal Flat Surface of low relief on which environmental conditions, resulting from repeated inundation by hypersaline waters, are ideal for the growth of algae.

Back Barrier Lagoon-ward or landward side of a barrier island, commonly the lee side.

Backshore The zone of beach lying landward from the berm crest.

Bar An elongate slightly submerged sand body. May or may not be exposed at low tide.

Bay Recess in the shoreline commonly bonded at the seaward margin by capes, headlands or barrier islands.

Beach Gently sloping shore washed by waves and tides, divisible into foreshore (between low-tide line and limit of uprush at high-tide) and backshore (covered by water only during storms or periods of very high tide).

Berm The nearly level part of a beach landward of the foreshore.

Crevasse A break in a natural levee or other stream embankment.

Crevasse Fan The sheet of sediment flaring outward from a crevasse, commonly formed as a small delta in an interdistribuary trough.

Flaser Bedding Structure formed by infilling of a ripple mark by sediment of a different size, reflecting a change in current intensity.

Flood Plain The area affected by river deposition.

Fluvial Produced by the action of streams; the process of stream flow.

Foreshore The seaward sloping part of the beach lying between the berm crest and the low water line.

Lagoon Shallow elongate body of water between the mainland and a barrier island where circulation is commonly restricted and access to marine waters is only through inlets.

Lagoonal Tidal Delta Slightly submerged, fan-shaped tract developed through tidal action at the lagoon-ward end of a tidal inlet.

Marsh Tract of soft, wet land at or slightly above sea level, commonly covered by very shallow waters and usually vegetated by reeds, grasses, and small shrubs.

Meander Belt Meandering streams restricted to alluvial belts.

Mud Flat Muddy, low lying strip of ground along the shore which is submerged by the rise of the tide.

Natural Levee
A long alluvial ridge built up on the banks of a stream by sediments derived from flood waters.

Offshore Comparatively flat surface extending seaward from the outer margin of the shoreface.

Point Bar Sediment deposited on the inside of a migrating meander loop of a stream or distributary.

Shoreface Relatively narrow slope seaward of the low-tide line whose outer limit coincides with the seaward extent of sand deposition, commonly at about 30-foot depths.

Stranded Beach
Ridge of sand, formerly at the shoreline, that has been isolated from the coast by subsequent development of marshes and mud flats.

Tidal Channel
Natural waterway maintained by tidal flow (tidal inlet is a tidal channel between barriers).

Tidal Flat Surface which is alternately covered and exposed by flooding and ebbing tides, may occupy broad mainland tracts open to marine waters or bay and lagoonal areas behind barrier.

Self-Check Exercises: Sedimentary Environments

1. What are the physical characteristics that are used to assist the geologist in recognizing sedimentary environments?

   a.

   b.

   c.

   d.

2. What is a sedimentary facies?

3. Why are alluvial fan sedimentary environments of limited significant for petroleum exploration?

4. In what types of sedimentary settings are braided streams found?

   a.

   b.

   c.

   d.

5. What is the general lithology of an eolian facies deposit?

6. What determines the character of a deltaic facies environment?

7. What basinal characteristics and processes affect the morphology of deltaic sedimentation?

   a.

   b.

   c.

   d.

   e.

   f.

8. What are the three classifications of delta models?

   a.

   b.

   c.

9. How do wave processes influence the formation of barrier islands?

10. Where do submarine fans form?

11. How does sediment grain size correlate with the turbidite “Bouma” divisions?

12. What two factors determine whether carbonate deposition takes place?

    a.

    b.

13. What are the two major controls on carbonate sedimentation?

    a.

    b.

14. List the five environmental zones within sub-tropical carbonate shelves.

    a.

    b.

    c.

    d.

    e.

15. Of the various depositional environments, which two are unlikely to have any hydrocarbon potential?

•Notes•

Chapter 4

Reservoir Geology

Upon completion of this section, you should be able to:

- Understand the components required to form a petroleum reservoir
- Explain how pressure and temperature affect the fluids in a reservoir
- Classify a crude oil based on its chemical and physical characteristics
- Understand and explain the geological factors concerning water saturation
- Describe the various trapping mechanisms
- List the types of geological maps used in delineating petroleum reservoirs

Additional Review/Reading Material

Baker Hughes INTEQ, *Oil Field Familiarization Manual*, 1996

Levorsen, A.I., *Geology of Petroleum*, W.H. Freeman and Company, 1967

Dickey, Parke, *Petroleum Development Geology*, Pennwell Books, 1986

McElory, D.P., *Fundamentals of Petroleum Maps*, Gulf Publishing Company, 1987

•Notes•

Reservoir Geology

A petroleum reservoir is a subsurface formation containing gas, oil, and water in varying proportions. These fluids are contained in the pore spaces of rock formations, among the grains of sandstones or in cavities of carbonates. The pore spaces are interconnected so the fluids can move through the reservoir. These porous formations have to be sealed in such a way so that the only method of escape for the fluids is through the wellbore.

Much of the preliminary information on the reservoir geology can be found in the “Oil Field Familiarization Manual”. This information should be reviewed.

Physical Characteristics

In order to have a hydrocarbon producing reservoir, the following conditions must exist:

1. There must be a body of rock having sufficient porosity (ϕ) to contain the reservoir fluids and permeability (k) to permit their movement.
2. The rocks must contain hydrocarbons in commercial quantities.
3. There must be some natural driving force within the reservoir, usually gas or water, to allow the fluids to move to the surface.

Special attention must be given to #3. Oil in itself does not have a stored force or energy; that is, it cannot move itself. The only stored energy in the reservoir is in the form of gas or water under pressure which can move the oil into the wellbore. When this energy has been spent, only the slow method of gravity drainage remains to move the oil into the wellbore. However, gravity does not always work efficiently to move oil in the right direction to reach a wellbore.

The porosity of a formation is its capacity to contain fluids. Porosity can vary from less than 5% in tightly cemented sandstones to more than 30% for unconsolidated sands. In reality, accurate determination of formation porosity is an extremely difficult matter. While it is true that laboratory technicians who specialize in this work can make accurate determinations on cores taken from a reservoir section, the physical characteristics of most reservoirs vary over such wide ranges that it is difficult to arrive at any figure that can be correctly called “average porosity “for that formation. This is especially true when dealing with carbonates, since the porosities and permeabilities are dependant on the nature of the rock developed during deposition and the diagenetic/solution processes. The relationship between porosity and permeability for a given formation is not necessarily a close or direct one. However, high porosity is often associated with high permeability.

Reservoir Pressure

The fluids in the pores of the reservoir rock are under a certain degree of pressure, generally called “reservoir pressure” or “formation pressure”. A normal reservoir pressure at the oil-water contact approximates very closely the hydrostatic pressure of a column of saltwater at that depth. The hydrostatic pressure gradient varies somewhat, depending upon the amount of dissolved salts in the formation water. The “normal”, fully marine water, has about 55,000 ppm of dissolved salts, and a pressure gradient of approximately 0.446 psi/ft. Reservoirs can contain fluids under pressures as high as 1.00 psi/ft.

In abnormally pressured reservoirs, clastics can be partially supported by the fluid pressure and partially by the grain-to-grain contact. When this abnormal pressure is reduced through production, compaction of the reservoir bed will occur. If left unchecked, this subsurface compaction can cause serious problems, for example it can cause casing to collapse and be the cause of subsidence, which can be expressed all the way to the surface.

Reservoir Fluids

Petroleum reservoirs usually contain three main fluids; crude oil, natural gas and water, with minor constituents being acid gases (carbon dioxide and hydrogen sulfide) and hydrocarbon solids (bitumen, asphalt, etc.). These components will vary considerably in combination and proportion within each reservoir. In addition, each component's presence, quality, phase and quantity will vary from reservoir to reservoir.

The hydrocarbons found in subsurface formations are made up of five important elements (Table 4-1:) and can be found in different states (Table 4-2:). Oil can be heavy and viscous (low API gravity), it can contain no dissolved gas or condensate, or it can contain large amount of dissolved gas. In most reservoirs, the most common fluid will be water, generally the connate, saline water.

Table 4-1: Elemental Composition of Oil, Asphalt and Kerogen

ELEMENT	OIL	ASPHALT	KEROGEN
Carbon	84.5	84	79
Hydrogen	13	10	6
Sulfur	1.5	3	5
Nitrogen	0.5	1	2
Oxygen	0.5	2	8

Table 4-2: Petroleum Fluid Classification

PHASE	FLUID TYPE	GAS/OIL RATIO (ft^3/bbl)
Liquid	Black Oil	0 - 2000
Liquid	Volatile Oil	1700 - 3300
Liquid/Gas	Condensate	3000 - 150,000
Gas	Wet Gas	150,000 -
Gas	Dry Gas	No Oil Produced

Crude Oil

Only a small quantity of the fluids in a reservoir is crude oil (petroleum), but this small fraction is the most important in terms of production. The chemical composition of this oil will vary, especially in hydrocarbon type, as well as its physical properties such as color, gravity and viscosity.

The most common unit of measurement for produced oil is the **barrel**. This is equal to 42 gallons (U.S.) and weighs approximately 310 pounds. During production, oil is measured in barrels per day. The number of barrels of oil the well produces, or is capable of producing, in the first twenty-four hours is known as its “initial production”.

Oil in the ground is usually measured by the volume of “oil in place”, which is the acre-feet of pore space (calculated from core or wireline/MWD log analysis) multiplied by the percentage of oil saturation (from core analysis). To obtain the amount of recoverable oil, the oil-in-place is multiplied by a “shrinkage factor” (a measure of the decline in volume of oil as the gas comes out of solution at the surface), then multiplied by a “recovery factor” (the amount of oil that can be recovered, based on porosity, permeability and type of reservoir energy type).

Chemical Composition of Crude Oils

Most crude oils (Table 4-3:) will be classified as either “paraffin-based” composed of saturated, straight-chained hydrocarbons, having the general formula C_nH_{2n+2}, which are the most common type of crudes (and generally termed light oils) or “naphthalenic-based”, composed of saturated, closed-ring hydrocarbons having the general formula C_nH_{2n}, which tend to be both heavy and sour crudes.

Another hydrocarbon group that may be present, in minor quantities, are the “aromatic-based”, or benzene series. These are strong smelling, unsaturated, closed-ring hydrocarbons, with the general formula C_nH_{2n-6}. Though the percentage of aromatics is usually small (<10%), they can be as high as 30%.

Other minor constituents of crude oil include; 1) sulfur, as free sulfur, hydrogen sulfide, or mercaptans, 2) nitrogen, 3) oxygen, and 4) minute amounts of solid organic and inorganic materials.

Table 4-3: Typical Composition of Crude Oil

COMPONENT	SIZE	%VOLUME	TYPE	% WEIGHT
Gasoline	C5 - C10	27	Paraffins	25
Kerosine	C11 - C13	13	Naphthenes	50
Diesel	C14 - C18	12	Aromatics	17
Gas Oil	C19 - C25	10	Asphaltics	8
Lub Oil	C26 - C40	20		
Remainder	C40+	18		

Physical Properties of Crude Oil

There are a number of important physical properties that are related to the chemical composition of crude oils. The most common are density (gravity), volume and viscosity. Several other physical properties worth mentioning are refractive index (RI), fluorescence, pour point and flash point.

Density/Gravity: The density of crude oil is usually measured in “specific gravity”. Specific gravity is the ratio of one substance to an equal volume of pure water, at a standard temperature (generally 60°F (15°C)). The API gravity scale, used in the petroleum industry, is an arbitrary one, and does not have a straight-line relationship with specific gravity or any other physical property, such as viscosity. High values of API gravity correspond to low specific gravities, and low values of API gravity correspond to high specific gravities.

Volume: Oil within the reservoir contains dissolved gas, and the volume of oil in the solution depends on the “gas-oil ratio” (GOR) and reservoir pressure. The GOR is the number of cubic feet of gas per barrel of oil. The amount of gas that may be dissolved in oil depends on pressure, increasing the pressure will increases the volume in solution, and this will continue until the saturation pressure is reached. This pressure is called “the bubble point”, and when the pressure falls below this point, gas will come out of solution.

The factor that must be applied to a barrel of reservoir oil to convert it to an equivalent amount of “stock-tank” oil is known as the shrinkage factor (e.g. the fractional volume of oil in the stock-tank obtainable from one barrel of oil and its dissolved gas in the reservoir). The factor that is applied to a barrel of stock-tank oil to convert it to an equivalent amount of reservoir oil is known as the formation-volume factor (e.g. the volume of reservoir oil necessary to yield one barrel of stock-tank oil). Shrinkage factors range between 0.63 to 0.88, and formation-volume factors range between 1.14 to 1.60.

Viscosity: The viscosity of crude oil is generally dependent on the amount of dissolved gas and the temperature (i.e. the more gas in solution and the higher the temperature, the lower the viscosity). As more and more gas gets dissolved in crude oil, its viscosity gets lower, the API gravity gets higher, and its specific gravity gets lower. The viscosity of oil will be at its minimum at its saturation pressure.

Refractive Index: The refractive index (RI) is dependent on the density of a substance. It is essentially a measure of how a beam of light is bent when passing through the substance. Hand-held refractometers are available which can determine the API gravity (density) of oils. These refractometers require only a small amount of oil and are relatively accurate. The refractive indices for oil range from 1.39 to 1.49 (the lower the API gravity, the higher the RI).

Fluorescence: The fluorescence property of oil is commonly used in mud logging to determine the API gravity of oil. Fluorescence color is observed under an ultra-violet light, with the higher gravity oils having a lighter color and the lower gravity oils having a darker color.

Pour Point: The pour point of an oil is the temperature at which it will no longer flow. The pour point of oils range from -70°F to +90°F (-56.7°C to +32°C). If an oil's pour point is above the surface temperature (for example, in winter months), the paraffins in the oil will precipitate and the oil will not flow until it is heated.

Flash Point: This is the temperature at which vapors rising off the surface of a heated oil will ignite with a flash, when a flame is passed over the surface.

Natural Gas

The “natural” gas that occurs in a reservoir consists of low-boiling point alkane hydrocarbons, which range from small quantities dissolved in oil to 100 percent of the fluids in the reservoir. In addition to the hydrocarbon gases, there may be gaseous impurities consisting of hydrogen sulfide, nitrogen, and carbon dioxide (Table 4-4:).

Natural gas is usually classified as “associated”, when it occurs with oil or “non-associated” when it occurs alone. In an associated reservoirs, when the oil becomes saturated, the excess gas will form a “gas cap” above the oil and be produced as “free gas”. When the oil is under-saturated, then the bubble point (the temperature and pressure when the gas comes out of solution) must be reached before gas is produced. With high enough temperatures and pressures, some of the alkanes will become a liquid and become indistinguishable from oil.

The gas in reservoirs is made up of the lower end of the alkane series of hydrocarbons (the two main gases being methane and ethane). The remainder of the low end, propane, butane, pentane and hexane will either be gases or liquids, depending on the temperatures and pressures (since the temperature of a reservoir is more or less constant, pressure changes usually dictate whether the fluid is a gas or liquid).

Classifications of gas include “dry gas” (less than 0.1 gallons of natural gas liquids per 1,000 cubic feet) or “wet gas” (0.3 or more natural gas liquid per 1,000 cubic feet). The natural gas of commerce generally has the following composition:

Methane	72.3%,
Ethane	14.4%,
Carbon Dioxide	0.5%,
Nitrogen	12.8%,

and ranges from 900 to 1200 BTU per cubic foot.

Reservoir Water

Water is the most common fluid encountered in the subsurface. In a most uncharacteristic definition, a "dry hole" is one which contains no commercial hydrocarbons, but contains water. As the fluids separate out within a reservoir, water having the highest specific gravity, will form the base of the fluid column. The water below the oil/water contact is known as "bottom-water" or "edge-water".

Classification of Reservoir Water

Most hydrocarbons reservoirs form in aquifers. These aquifers being formed from either meteoric water (water fallen as rain and percolating downwards) or connate water (the sea water in which the sediments were deposited) filling the pore spaces within the rocks.

Table 4-4: Physical Properties of Common Reservoir Gases

Compound	Molecular Weight (O = 16)	Boiling Point (°C)	Critical Temperature (°C)	Critical Pressure (psia)	Density @ Liquid (Water=1)	16°C,14.7 psia Gas (Air=1)
Hydrogen	2.016	-252.7	-239.9	188.0	0.0700	0.0696
Methane	16.042	-161.5	-82.5	673.1	-	0.5550
Ethane	30.068	-88.5	32.3	708.3	-	1.0460
Propane	44.094	-42.1	96.8	617.4	0.5077	1.5470
N-Butane	58.120	-0.5	152.0	550.7	0.5844	2.0710
Iso Butane	58.120	-11.7	135.0	529.1	0.5631	2.0670
N-Pentane	72.146	36.1	196.6	489.5	0.6312	2.4906
Iso Pentane	72.146	27.9	187.8	483.0	0.6248	2.4906
Neo Pentane	72.146	9.5	160.6	464.0	0.6010	2.4906
Carbon Dioxide	44.010	-78.5	31.1	1073.0	0.8159	1.5194
Hydrogen Sulfide	34.076	-60.3	100.4	1306	0.7900	1.1764
Oxygen	32.000	-183.0	-118.8	730.0	1.1400	1.1047
Nitrogen	28.016	-195.8	-147.1	492.0	0.8080	0.9672
Water	18.016	100.0	374.1	3206.0	1.0000	0.6220

There will be interstitial water filling the pore spaces within the formation that is absorbed on the mineral surface of the rock or held in capillary openings by capillary pressure. The amount of this interstitial water will range from 10 to 50 percent, or more, of the pore space, the remainder being filled by hydrocarbons.

As this interstitial water increases towards the bottom of the reservoir, it grades into free water (filling the interconnections between the pore spaces), eventually becoming the bottom-water.

Water Saturation

Much of the information concerning water saturation (Sw), especially how it is calculated using wireline/MWD variables, will not be covered in this section. The information presented here should provide a better “geologic picture” on how the interstitial water saturation affects the other fluids in the reservoir, and how these aspects must be taken into account during wireline/MWD log analysis.

There is a general relationship between the amount of interstitial water and porosity, permeability and grain size in the reservoir. As a general rule in formation evaluation, as the percentage of reservoir water increases, the permeability, porosity and grain size decreases. In addition, the capillary pressure increases in smaller pores, retaining more water in the pore spaces. This interstitial and absorbed water is not as important in large pore sizes or in fracture porosity.

The amount of recoverable hydrocarbons is directly based on the amount of water in the pore spaces. Therefore water volumes are a necessary calculation before any hydrocarbon production calculation takes place. Because the oil is in direct contact with the water (e.g. there is only a water-rock contact and a oil-water contact in the pore spaces), the water tends to surround the oil in the pore spaces.

This interstitial water, and their dissolved salts, form the basis of wireline/ MWD resistivity measurements. As seen above, when the percentage increases, the resistivity can decrease to such an extent to mask the high resitivitives of oil and gas, leading to misinterpretation of the wireline/MWD curves. When the interstitial water is below 10 percent, the resistivities approach infinity.

The Trap

An old saying in the oil field goes something like this; “first, you have to have a trap” (see Table 4-5:). Once hydrocarbons have been generated and expelled from a source rock, migration must occur for economic quantities to accumulate. The path for this movement can take place through the reservoir rock itself, or through fracture systems. Obviously, a barrier or trap is needed to impede the migration. A trap is produced by a set of geological conditions which cause oil and gas to be retained in a porous reservoir, or at least allowed to escape at a negligible rate (Figure 4-1). Shales and evaporites make good seals, although any unfractured rock that has a displacement leakage-pressure higher than that of the hydrocarbon accumulation can be a reservoir.

Most traps are not filled to their structural or stratigraphic spill points. It is possible for a trap to overfill and leak subsequent, migrated hydrocarbons to higher trapping mechanisms. Several major oil fields of the world (specifically in some areas of the Middle East) are comprised of numerous traps that have overfilled and “spilled” hydrocarbons into higher traps. It is important for the exploration geologist to recognize this phenomena, since successful extension of some fields will be dependant on the appreciation of this process. In the first stage of filling a trap, there will be stratification of gas, oil, and water above the spill point. In later stages, hydrocarbons fill the trap to the spill point. Since oil will be structurally lower than gas, subsequently migrated oil will spill over to the next higher structure. In the final stage, gas moving from below enters the trap, but a equal volume spills out at the same time, any oil with the gas will bypass the trap entirely.

Table 4-5: Relationships between sedimentary environment and type of trap.

Environment		Trap Type
Continental	Eolian	Pinchout
	Fluvial	Channel
		Strike Valley
Coastal	Barrier Bar	Shoestring
	Delta	Channel Crevasse-splay and mouth bar Growth-fault-related
Deep Marine		Submarine fan pinchout or paleotopographic closure Submarine channel

Incomplete filling of a trap is more likely to be the result of a seal not sustaining the greater hydrocarbon column pressure, rather than being the result of insufficient oil and gas to fill the trap. For this reason, traps are often filled to capacity and yet have water levels far below the spill point.

Traps for oil and gas under hydrostatic conditions have two general trapping mechanisms:

An arched upper surface
An up-dip termination of the reservoir

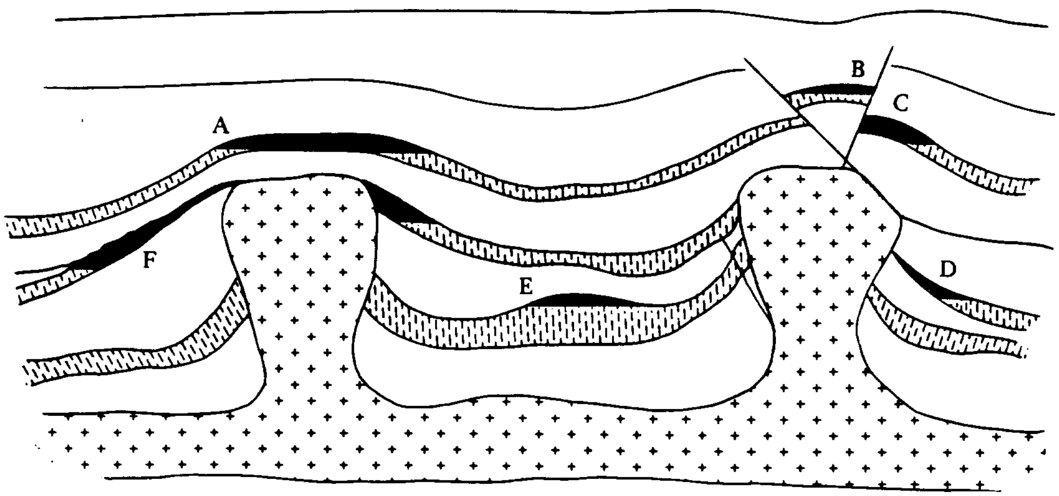


Figure 4-1 Types Of Traps That Develop Through Salt Movement (A-Domal Trap, B&C-Fault Traps, D-Pinchout Trap, E-Anticlinal Trap, and F-Truncation Trap)

Traps for hydrocarbons under hydrostatic conditions are of structural or stratigraphic origin, either alone or in combination, and have horizontal gas-water or oil-water contacts. Hydrodynamic (moving liquid) traps (Figure 4-2) may also occur in different structural environments, but they are characterized by inclined gas or oil-water contacts.

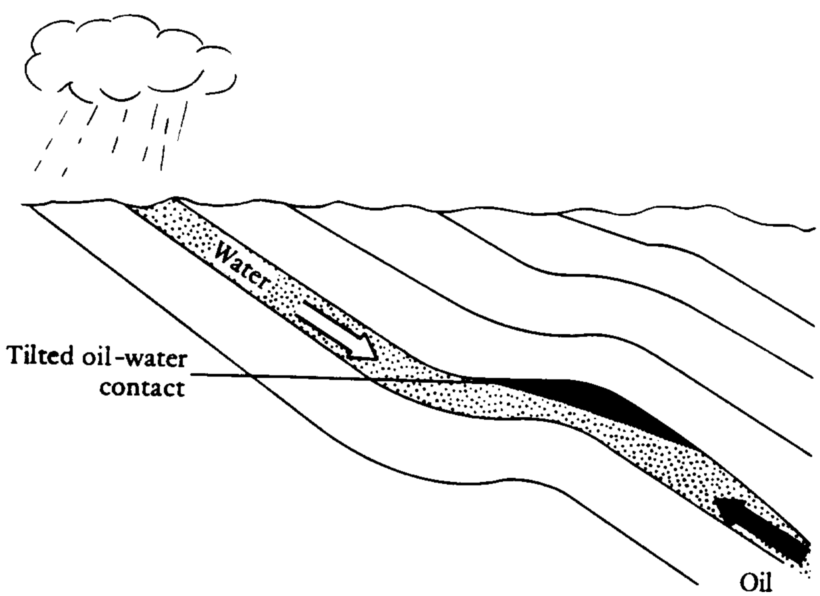


Figure 4-2 Example Of A Hydrodynamic Trap

Anticlinal Traps

These vary widely in shape and size. However, they all have a common characteristic in that a gas-water or oil-water contact completely surrounds an accumulation of hydrocarbons (Figure 4-3). The structure generally extends through a considerable thickness of formation so that traps are formed in all the potential reservoir rocks.

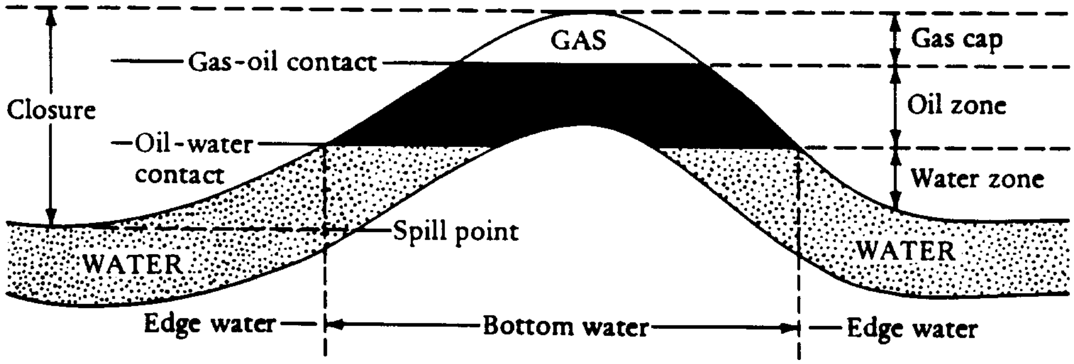


Figure 4-3 Cross-section Of A Simple Anticlinal Trap

Fault Traps

These traps depend upon the effectiveness of the seal at the face of the fault. The seal may be the result of placing different types of formations side by side, for example, shale against sand (Figure 4-4), or it may be caused by impermeable material called "gouge" within the fault zone itself (Figure 4-5). A simple fault trap may occur where structural contours provide closure against a single fault. However, in other structural configurations, such as a monocline, two or three faults may be required to form a trap. Fault trap accumulations tend to be elongated and parallel to the fault trend. A common type of fault trap is that formed when growth faults develop. This is common in deltaic sediments where there is a stratigraphic section that has had prolific deposition during its accumulation.

The following are definitions of the various terms encountered by the Wellsite Geologist when reviewing maps, trapping mechanisms, and when preparing the Final Well Report.

Throw and Heave - Throw and heave are measured in a vertical section that is perpendicular to the strike of the fault. The throw is the vertical component of the dip separation in such a section. Heave is the horizontal component of the dip separation.

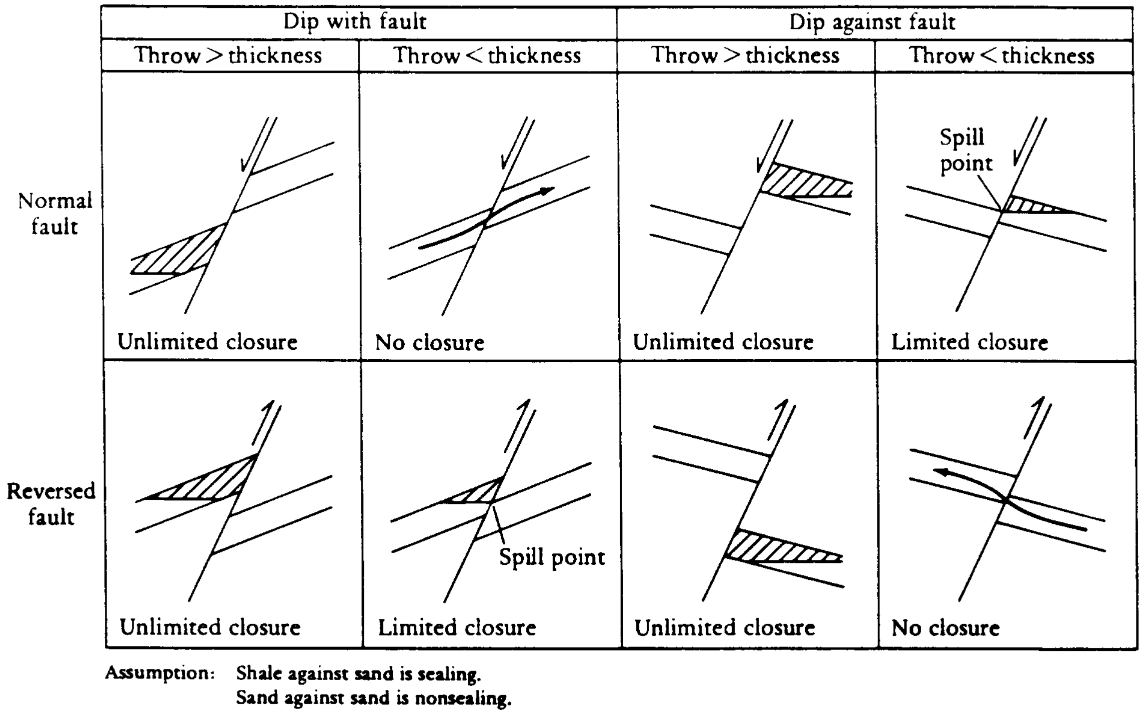


Figure 4-4 Eight Configurations Of Traps Associated With Faulting

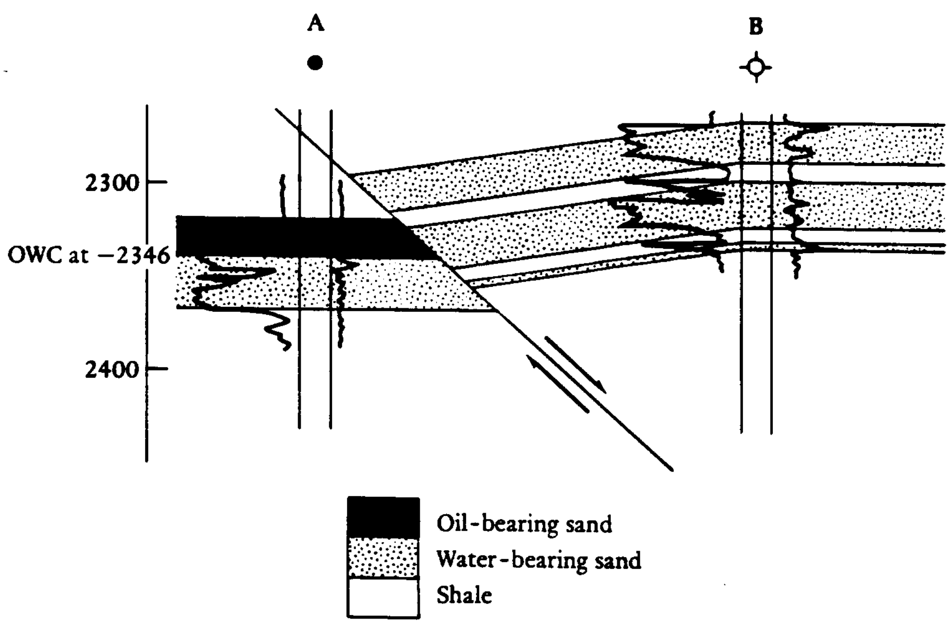


Figure 4-5 Fault Sealing, Caused By Impermeable Material, Along A Permeable Sand

Synthetic Fault - These are faults that form along points of weak rock that are secondary to larger faults. They can assume various orientations, dependant on the regional tectonic stress regimes. This may include numerous en-echelon stress relief faults or faults accompanying diapirs.

Antithetic Fault - Faults that dip opposite from the regional sedimentary rock bedding. In reality, the orientation of these faults is independent from the bedding dip and results from adjustment to regional stress relief; it does not necessarily have any relation to the bedding direction.

Hanging Wall - The hanging wall is the overhanging side of a fault that assumes 0° to 90° deviation from vertical. This term is valid whether a normal or thrust fault is being discussed.

Footwall - The footwall is the underlaying side of a normal or thrust fault that has a dip between 90° and 180° as measured from the vertical axis.

Normal Fault - A normal fault is a fault along which the hanging wall has moved relatively downward. An often used term is gravity fault, but this terminology has not been widely used because gravitational forces may have no association to the origin of the fault. Detachment faults are a special category of low-angle normal faults due to the downhill sliding of rocks from an uplifted region.

Domino faulting - These are adjustment faults that result from stress relief in areas of regional uplift. They slide in a "domino" pattern, each outer fault sliding lower than following faults.

Roll-over anticline - This is a structural deformation where the axis of a fold is inclined and may be completely overturned, depending on the amount of stress that is supplied to the area. Both limbs may dip in the same direction, but usually in different directions.

Fan Fold - A fold in which both limbs are overturned. In an anticlinal fan fold, the two limbs dip toward each other. In a synclinal fold, the two limbs dip away from each other.

Horst - A large block caught along a fault. These blocks are separated from the foot and hanging walls by faults that may or may not be accompanied by breccia. This term usually refers to such a block caught along a normal fault.

Growth faults - These are normal faults across which there is abrupt thickening of stratigraphic units, from the hanging wall side to the footwall side, and along which there is a downward increase in the displacement of stratigraphic horizons. They are normally interpreted as normal faults that are moving contemporaneously with deposition of sedimentary or volcanic rocks. They are well known in the Gulf Coast Region of the United States and are familiar around other deltaic regions with prolific deltaic sedimentation (Figure 4-6). Often, they are associated with salt domes and around the margins of intracontinental fault-bounded depositional basins.

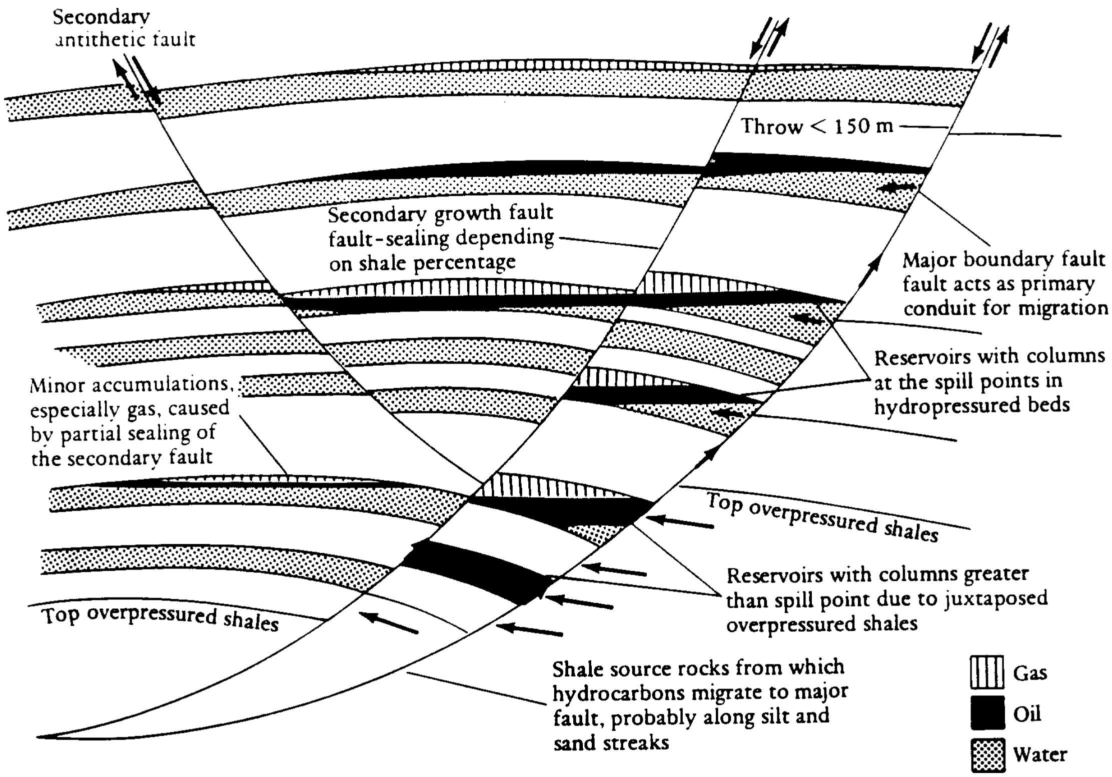


Figure 4-6 Accumulation Of Hydrocarbons (And Abnormal Pressure) Around Growth Faults

Stratigraphic Traps

These result from lateral changes that prevent continued migration of hydrocarbons in a potential reservoir lithology (Table 4-6:). Many are directly related to their environment of deposition (Figure 4-7), but others (particularly carbonates) are caused by later changes, such as dolomitization. Many large fields are associated with this kind of trap.

One type of stratigraphic trap is the “lenticular trap”. These pinch out or change permeability on all sides (Figure 4-8). Lenticular traps are fairly common in carbonates, usually occurring in the upper part of reef carbonate buildups.

Table 4-6: Classification of stratigraphic traps

Unassociated with unconformities	Depositional	Pinchouts
		Channels
		Bars
		Reefs
	Diagenetic	Porosity and/or permeability transition
Associated with unconformities	Supraunconformity	On Lap
		Strike Valley
		Channel
	Subunconformity	Truncation

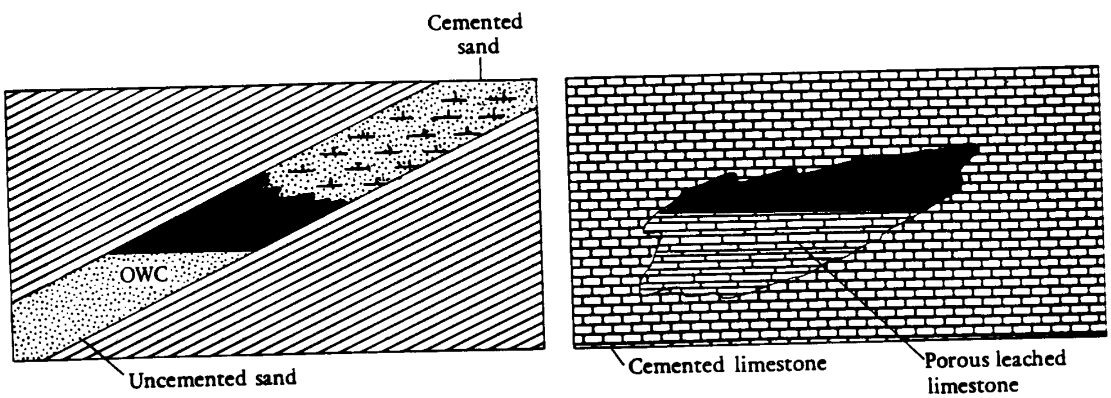


Figure 4-7 Stratigraphic Traps Resulting From Changes In Their Depositional Environment

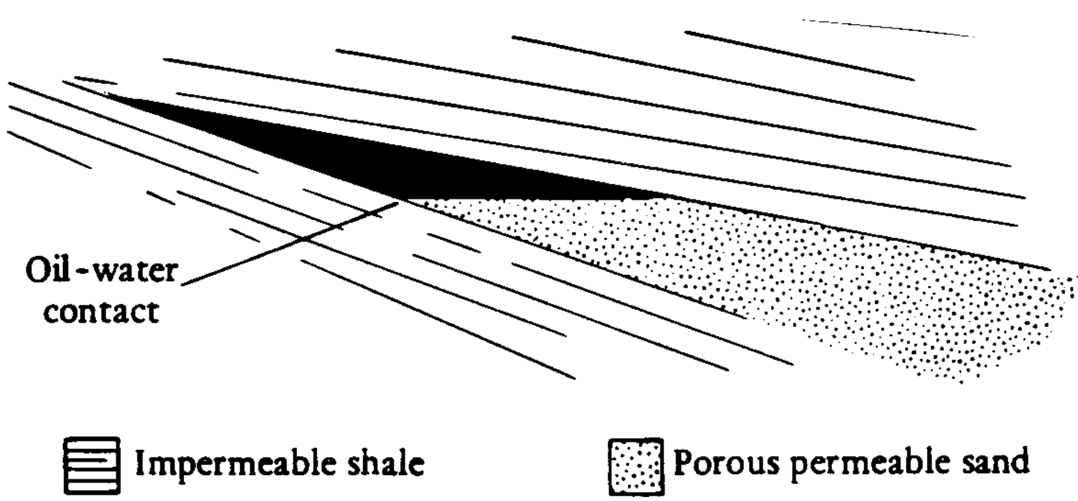


Figure 4-8 Example Of A Lenticular Trap

Natural Drive Mechanisms

To be commercially productive, a petroleum reservoir must have some form of natural drive mechanism to force the hydrocarbons to the surface through the wellbore. There are several natural drive mechanisms.

Gas Drives

When a reservoir is totally enclosed by impermeable beds, it has a constant volume and a constant pressure. Gas in the reservoir may be as a separate “gas cap” or in solution, depending on the in-situ pressures. Once a well has been drilled into the reservoir, the volume and pressure will decrease. Gas expansion and gas coming out of the solution will maintain the natural drive of the reservoir.

As production continues, the column of gas increases, measured at the surface by the GOR which measures volumes of gas after separation. Large amounts of potential energy can be stored in compressed gas, and production can continue for long periods with only minor changes in pressure and production rates.

The reservoir is a closed system, however, and after a while the gas volume will decrease, resulting in decreased flow at the surface. This reduction in pressure can leave up to 50% of the reservoir fluids in the formation before enhanced recovery methods are employed.

Water Drives

Although water is virtually incompressible, large amounts of potential energy can be stored in large volumes of water in extensive regional reservoirs. Expansion of this water to replace flowing oil will produce a less powerful, but longer enduring drive than a gas drive.

Artesian drives are unfortunately rare, but more powerful where the water volume at the reservoir is naturally enhanced by the continuous influx of water.

Water production has a lower GOR, since only the gas dissolved in oil is produced. As the oil/water transition moves upwards, increasing amounts of water will be produced with the oil. Water drives can produce up to 70% of the reservoir fluids before enhanced recovery methods need to be used.

Combination Drives

Some reservoirs have a combination of a gas drive acting downwards and a water drive acting upwards on the reservoir. To maintain production rates and percentage recovery, some enhancement to the natural drives is incorporated by adding either water or gas to the reservoir. The source of water or gas may be from another well, or that previously recovered from the same well and pumped back down to replenish the reservoir.

Reservoir Maps

The geologist should be familiar with geologic maps (i.e. cross-sections, fence diagrams) and how to correlate using those maps. In a different sense, reservoir maps are used for a different purpose. Geologic maps are used to "find" the reservoir, basically to determine where to drill the well. Reservoir maps are used to determine the particulars of that specific formation (i.e. thickness, oil/water contact, net pay, etc.). In a general sense, reservoir maps are used more in development geology.

Isochron Maps

These are contour maps derived from analyzing seismic cross sections shot in a grid pattern, therefore giving 3-dimensional coverage. The contours are lines of equal 2-way travel time, derived by interpolating between mapped reflectors. They differ from structural contour maps in that they show times, not depths, and the lowest contour values are the highest interfaces.

On a time structure map made from unmigrated seismic sections, a dipping reflector is displaced down-dip, anticlines appear wider and synclines are narrower than they are. Where it is important to resolve any uncertainties in interpretation, the seismic sections used for the construction of time-structure maps must be migrated and the time values corrected for depth.

Depth Structure Maps

These show contours of a particular horizon, with the contours representing depths to that horizon from sea-level or ground level. They may be derived from depth conversion of two way travel times, or prepared from data supplied from well logs, or a combination of both.

Subsurface structure maps usually are constructed for specific stratigraphic horizons to show in plan view the three-dimensional geometric shapes of these horizons. Because many traps are associated with faults, accurate structural interpretation is required to ensure that the geology has correctly been determined. This requires:

1. Construction of fault surface maps for all important trapping faults
2. Integration of the fault maps with structural horizon maps
3. Mapping of multiple horizons at various depths to justify and support the integrity of any structural interpretation

Isopach and Isochore Maps

These maps are produced from seismic or well data, but the contours represent thickness of a specific mapping unit. An isochore map delineates the true vertical thickness of a rock unit, and the contours represent lines of thickness between two datum planes, usually the oil water contact (OWC) and the cap rock, while an isopach map illustrates the true stratigraphic thickness of a unit. An isopached unit may be as small as an individual sand only a few feet thick, or as large as several thousand feet thick and encompassing a number of sand units.

These maps are extremely useful in determining the structural relationship responsible for a given type of sedimentation. The shape of a basin, the position of the shoreline, areas of uplift, and in some circumstances the amount of vertical uplift and erosion, can be recognized by mapping the variations in thickness of a given stratigraphic interval. Geologists use isopach maps in depositional environment studies, genetic sand studies, growth history analyses, depositional fairway studies, derivative mapping, determining the history of fault movements, and calculation of hydrocarbon volumes.

An interval isopach map delineates the true stratigraphic thickness of a specific unit. Net sand isopachs are isochore maps which represent the total aggregate vertical thickness of porous, reservoir quality rock present in particular stratigraphic intervals. A net pay isopach map is a special isochore map that delineates the thickness of reservoir quality sand which contains hydrocarbons. Sandstone percentage maps have contours that represent percentage of sandstone of a particular horizon and can help delineate particular plays.

Definitions

Artisan Flow:
Flow generated when the potentiometric surface lays above the point where a well penetrates a reservoir and exits at the surface. These wells flow without artificial aid.

Bubble Point:
The temperature and pressure at which part of a liquid begins to convert to a gas. If a certain volume of liquid is held at a constant pressure, but the temperature is allowed to increase, the point at which bubble of gas begin to appear is the bubble point. Conversely, if the temperature is held constant and the pressure reduced, the point at which gas begins to form is the bubble point.

Coning: Where the surface between two reservoir fluids (typically, the oil/water contact) is deformed upward in a “cone” shape as a result of production of the upper fluid.

Critical Point:
The pressure and temperature of a reservoir fluid where the bubble point pressure curve meets the dew point pressure curve, representing a unique state where all properties of the bubble point oil are identical to the dew point gas.

Deeper Pool Test:
An exploratory hole located within the productive area of a pool, already partly or wholly developed.

Development Well:
Well drilled within the proven area of an oil or gas reservoir to the depth of a stratigraphic zone known to be productive.

Dew Point: The temperature and pressure at which a liquid begins to condense out of a gas. If the pressure is held constant, but the temperature is reduced, the point when droplets of liquid condense out of the gas is the dew point. Conversely, if the temperature is held constant and the pressure is increased, the point at which droplets condense out of the gas is the dew point.

Extension Test Well:
Well located and drilled with the expectation of extending for a considerable distance the productive area of a partly developed pool.

Fairway: Geographical extent of a particular play.

Formation Volume Factor:
The ratio of a phase volume (water, oil, gas, or gas plus oil) at reservoir conditions, relative to the volume of a surface phase (water, oil, gas) at standard conditions resulting when the reservoir material is brought to the surface.

Gas-Oil Ratio (GOR):
The amount of surface gas that can be dissolved in a stock tank oil when brought to a specific pressure and temperature.

Gross Pay: The vertical distance from the top of the reservoir to the petroleum-water contact.

Hydrates: Compounds of frozen water that contain gas molecules. Often considered for future hydrocarbon exploitation potential.

Hydrocarbon Play:
A set of geological circumstances which combine to create the conditions necessary for the accumulation of oil or gas. These circumstances include the following:

1. Presence of suitable reservoir units
2. Presence or likelihood of cap rock and trap structure
3. Presence of suitable, mature source rock(s)
4. Availability of migration pathways

Likelihood of the above coming together in geological time such that a reservoir may form. That is, a trap formed before migration of hydrocarbons.

Migration: The movement of hydrocarbons from a source rock to an area of accumulation.

MilliDarcy: Typical oil-field measurement of reservoir rock permeability, which is one thousandth of a "Darcy", as defined by Darcy's Law.

Net Pay: That part of the "gross pay" that exists in a productive part of a reservoir.

New Field Wildcat:
A well located on a structural feature or other type of trap that previously has not produced oil or gas.

New-Pool Wildcat:
A well located to explore for a new pool on a structural feature or other type of trap already producing oil or gas, but outside the limits of the producing area.

Oil-Water Contact:
The contact between the oil and water in a reservoir that represents the deepest level of productive oil.

Permeability:
The capacity of a rock to transmit fluids. The degree of permeability depends on the size and shape of pores, the size and shape of their interconnections, and the extent of interconnections.

Pool: An inaccurate term, dating back to journalistic fantasies of vast underground lakes of oil, that describes reservoirs.

Pore Throat: The opening at the side of a rock pore that allows flow of hydrocarbons through the reservoir.

Porosity: The portion of a rock that is composed of non-rock voids. May be filled with various fluids, such as oil.

Recovery: The proportion of hydrocarbon ultimately extracted from a reservoir rock.

Reserves: Resources that can be economically extracted from the resource base.

Reservoir: A body of rock that has pores to contain oil and gas, and sufficient permeability to allow fluid migration.

Resources: Industrially useful natural materials. Are defined by economic feasibility of extraction and geological knowledge. Are sub-divided into “proven developed reserves” and “proven undeveloped reserves”.

Saturation Condition:
A condition where oil and gas are in thermodynamic equilibrium. Where the chemical forces exerted by each component in the oil phase is equal to the chemical force exerted by the same component in the gas phase. At this condition, there will be no mass transfer of components from one phase to the other.

Seal: A type of rock adjoining a reservoir that restricts leakage of hydrocarbons from a trap after it has accumulated. The seal may also enhance the accumulation of hydrocarbons by influencing the direction of migration.

Sedimentary Basin:
An area of the earth's crust that is overlain by a thick sequence of sedimentary rocks. Often, an area where hydrocarbon accumulations are found.

Service Well:
Well that is drilled or completed for the purpose of supporting production from an existing field.

Shallower Pool Test:
An exploratory well drilled in search of a new productive reservoir that is unknown, but suspected from data secured from other wells and is shallower than known productive pools.

Stratigraphic Test Well:
Drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition that might lead toward the discovery of an accumulation of hydrocarbons.

Trap: The place where oil and gas are barred from further movement so that the process of accumulation can begin to occur. Since geologists search for hydrocarbons in potentially productive traps, a trap is still a trap even if hydrocarbons are not present.

Undersaturated Condition:
A condition when an oil or a gas is in a single phase, but not at its saturation point (bubble point or dew point).

Self-Check Exercises: Reservoir Geology

1. What is meant by a well's “initial production”?

2. What three types of hydrocarbons form the majority of crude oils?

   a.

   b.

   c.

3. What is the relationship between an oil's API gravity and its specific gravity?

4. What is a reservoir's “gas-oil ratio”?

5. What is the difference between “associated” and “non-associated” natural gas?

6. When is a gas classified as a “dry gas” or a “wet gas”?

7. When the fluids within a reservoir separate, where will the formation water be positioned?

8. What is interstitial water?

9. What is the general relationship between formation water, porosity and permeability?

10. What will be the wireline/MWD resistivity measurement when the interstital water is below 10 percent?

11. Name the two main types of structural traps?

    a.

    b.

3. What is the general definition of a stratigraphic trap?

4. How do isochron contour maps differ from structure contour maps?

5. What is the difference between an isopach map and a isochore map?

6. What is a “net pay isopach” map?

•Notes•

Wireline/MWD Logs In Formation Evaluation

Upon completion of this section, you should be able to:

- Understand how wireline/MWD logs can be used for lithology and formation boundary determination
- Pin-point formation boundaries and lithology changes using wireline/MWD logs
- Determine depositional environments using the SP and Gamma Ray logs
- Calculate several mechanical properties of rocks using the acoustic log
- Determine the presence of fractures using wireline/MWD logs

Additional Review/Reading Material

Tearpock, D. & Bischke, R., *Applied Subsurface Geologic Mapping*, Prentice Hall, 1991

Selley, R.C., *Ancient Sedimentary Environments*, Cornell University Press, 1980

Debrandes, R., *Encyclopedia of Well Logging*, Gulf Publishing Company, 1985

Rider, M.H., *The Geologic Interpretation of Well Logs*, Whittles Publishing, 1991

Schlumberger, *Sedimentary Environments from Wireline Logs*, 1985

Pirson, Sylvain, *Geologic Well Log Analysis,* Gulf Publishing Company, 1983

•Notes•

Chapter 5

Wireline/MWD Logs In Formation Evaluation

The geological use of wireline logs in formation evaluation has long been neglected, mainly due to their predominant role as hydrocarbon indicators. Though this petrophysical use cannot be under-stated, with a little more insight, much more geological information can be obtained from these logs.

When wireline logs are combined with mud logs, they can be used to validate many structural and sedimentological features of the subsurface formations that were predicted from seismic data.

The use of FEMWD (Formation Evaluation Measurement-While-Drilling) services at the wellsite provides real-time information, equivalent to or better than, the data provided by wireline logs. At present FEMWD sensors include Gamma Ray, Induction-Type surveys, Focused Resistivity, and Formation Density and Neutron Porosity logs.

There are several good references regarding the geological uses of wireline information, the two most readily available are Richard Selley's *Ancient Sedimentary Environments* and Schlumberger's *Sedimentary Environments from Wireline Logs*.

The principle uses of wireline logs in formation evaluation are: 1) the determination of formation boundaries, and 2) lithology determination. With some further applications, additional uses include: 1) facies and depositional environment analysis, 2) mechanical properties of the formation, and 3) fracture determination. These applications will be covered in this chapter. There will also be a review of some of the wireline/MWD logging parameters.

The wireline/MWD logs most commonly used in formation evaluation are:

Wireline	**FEMWD**
Spontaneous Potential	Gamma Ray
Gamma Ray	Induction-type (DPR)
Short Normal	Neutron Porosity (MNP)
Density	Density (MDL)
Neutron	Short Normal
Acoustic	
Induction	
Resistivity	
Micro-Resistivity	
Dipmeter	

Basic Logging Parameters

Spontaneous Potential

The Spontaneous Potential (SP) curve is a record of the direct current (DC) voltage differences between the naturally occurring potential monitored by a movable electrode in the borehole and a fixed potential, located at the surface. This potential results from differences in salinity between the drilling fluid and formation fluids. The SP is measured in millivolts.

The SP curve is recorded on the left-hand track (Track #1) of the wireline log format. For the purposes of formation evaluation, the SP can be used to identify:

- Permeable formations
- Boundaries of permeable formations

SP readings opposite shales are relatively constant and are referred to as the “shale baseline”. Opposite permeable formations, the SP will move to the left (negative) or right (positive) depending on the difference between the drilling fluid and formation fluids.

Normally, the shale baseline is set two chart divisions from the right of the track. Then the scale (in millivolts) is set so that all permeable beds stay within the plotting limits.

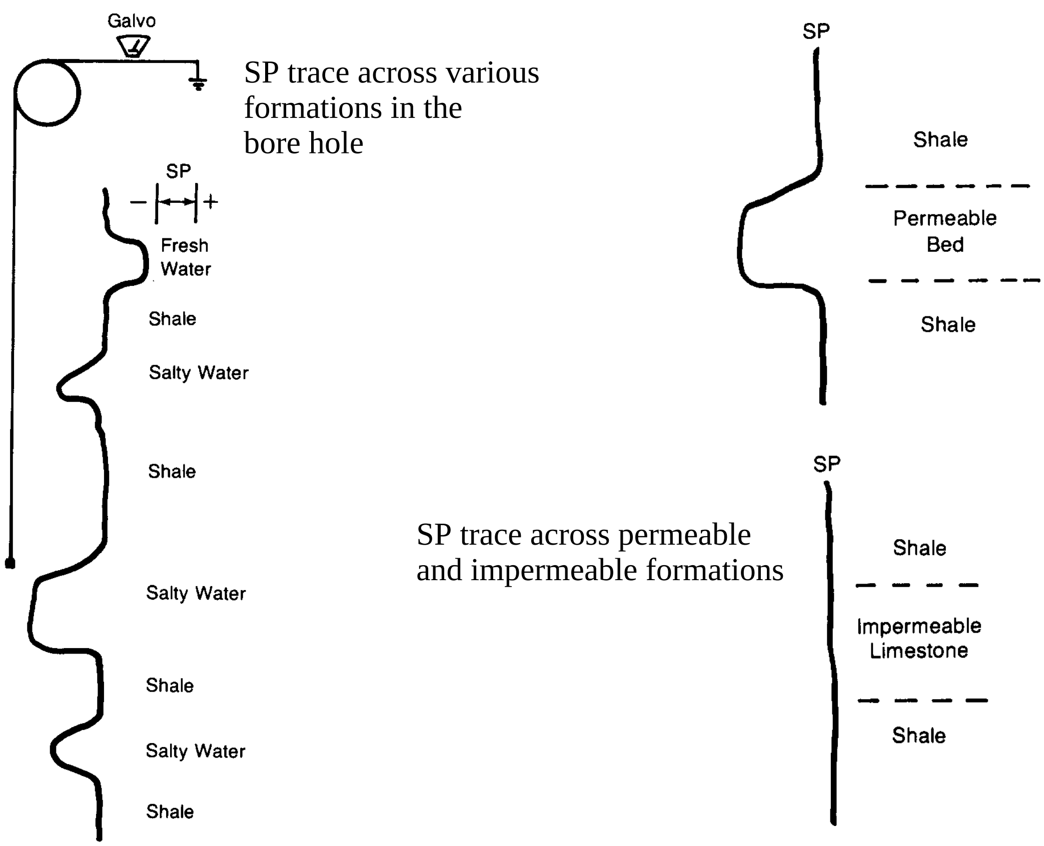


Figure 5-1 SP Traces

Gamma Ray

The Gamma Ray (GR) log measures the natural radioactivity of the formations in the borehole. The log is therefore, useful for identifying lithologies and for correlation purposes.

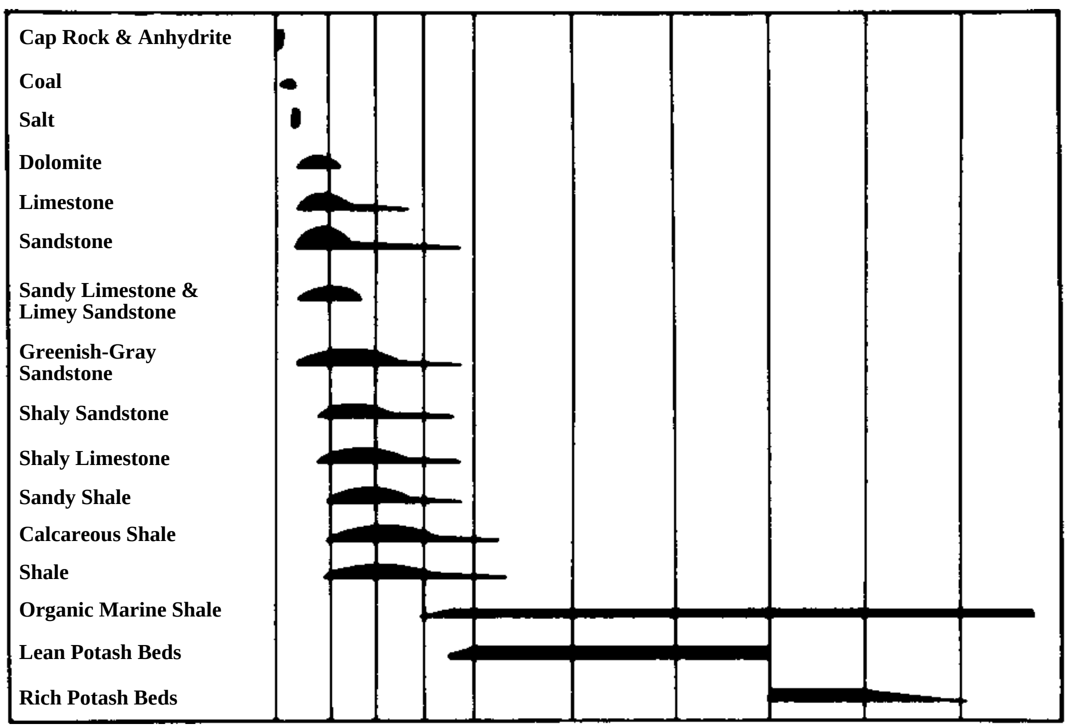
In sedimentary formations, the GR log normally reflects the shale content of the formations because of the concentration of radioactive materials in the shales\clays. Shale-free sandstones and carbonates have low gamma ray values, unless radioactive contaminants (volcanic ash, granite wash, or potassium rich fluids) are present.

The GR log can be run in cased wells and is frequently used as a substitute for the SP. As with the SP, the GR curve is recorded in Track #1, but on a reverse scale (low values to the left, high values to the right).

For the purposes of formation evaluation, the GR log can be useful for:

- Identifying Lithologies
- Correlating Between Formations
- Calculating Shale Volumes

API GAMMA RAY UNITS



The length of the line denotes the intensity range in API Gamma Ray Units. The vertical width of the line increases with the frequency of occurrence.

Figure 5-2 Gamma Ray Response in Various Rock Types

Density Log

The formation density log is a porosity log that measures the electron density of the formation. The density logging tool consists of a radioactive source that emits gamma rays into the formation and one or more gamma ray detectors, located a fixed distance from the source.

Those gamma rays emitted by the source collide with electrons in the formation, resulting in a loss of energy. Some of the gamma rays are lost to the formation, while those that reach the detector are counted. The amount of electron is being related to formation density. This density is then related to the bulk density (φ_b)of the formation in g/cm^3 The bulk density curve is recorded in Tracks #2 and #3 of the log. A density derived porosity curve is sometimes present with bulk density. Density porosity can be derived from bulk density using the following equation:

$$\Phi_D = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_f)}$$

where: ρ_{ma} = matrix density (from tables)
ρ_b = bulk density (read from the log)
ρ_f = average density of fluid (from tables)

Other formation evaluation uses of the density log include:

- Identifying Evaporite Minerals
- Evaluating Complex Lithologies

Material	**Density (seen by density log) g/cm^3**
Oil	0.80
Gas	0.08
Quartz	2.65
Calcite	2.71
Dolomite	2.875
Anhydrite	2.98
Halite	2.03
Lignite	0.63 - 1.56
Fresh Water	1.00
Saltwater (100,000 ppm)	1.067
Saltwater (200,000 ppm)	1.135

Acoustic/Sonic Log

The acoustic/sonic log is a porosity log that measures the interval transit time of a compressional wave traveling through one foot of formation. The logging sonde consists of one or more transmitters, and two or more receivers. Modern acoustic/sonic logs are borehole compensated devices.

The “interval transit time (Δt)”, in microseconds per foot (μsec/ft), is the reciprocal of the velocity of the compressional sound wave (in feet per second). Interval transit time is recorded in Tracks #2 and #3 of the log. A sonic derived porosity curve is sometimes recorded with the interval transit time. This sonic porosity is derived from the acoustic log using the following equation:

$$\Phi_S = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}$$

where: Δt_{log}= interval transit time from log
Δt_{ma} = interval transit time of the matrix material
Δt_f = interval transit time of saturating fluid

Other uses of the acoustic/sonic log for formation evaluation are:

- Identifying Lithology
- Determining the Elastic Constants of Rocks

Table 5-1: Velocities and Interval Transit Times for Common Oilfield Materials

Material	Velocity (ft/sec)	Δt (μsec/ft)
Sandstones	18,000 - 19,000	55.5 - 51.0
Limestones	21,000 - 23,000	47.5
Dolomites	23,000	43.5
Anhydrite	20,000	50.0
Halite	15,000	67.0
Casing (Iron)	17,500	57.0
Fresh Water Muds	5300	189
Salt Water Muds	5400	185

Neutron Log

Neutron logs are porosity logs that essentially measures the hydrogen concentration in a formation. In “clean” formations, where the pore spaces are filled with water or oil, the neutron log measures liquid-filled porosity.

Neutrons are created from a radioactive source in the logging sonde. When emitted, these neutrons collide with the nuclei of the formation material, and result in a loss of energy. Because the hydrogen atom has nearly the same mass as a neutron, maximum energy loss occurs when the neutrons collide with hydrogen. Therefore, maximum energy loss is a function of hydrogen content. Since hydrogen is concentrated in the pore spaces (as water or hydrocarbons), energy loss can be related to porosity.

Neutron log response will vary, depending on:

- Detector Type
- Spacing Between Source and Detector
- Lithology

These variations are compensated for by using the appropriate charts (Schlumberger charts for Schlumberger logs, etc.).

The neutron curve is recorded in apparent porosity units (limestone, dolomite or sandstone). If the formation is the same as the apparent porosity units, then the apparent porosity is equal to true porosity. If the formation is different than the apparent porosity units, the porosity must be corrected to true porosity using charts. For the purposes of formation evaluation, the neutron log is used in combination with the density log for porosity and lithology determination.

Table 5-2: Neutron Energy Losses

Element	Average Number of Collisions	Energy Loss/ Collision
Calcium	371	8%
Chlorine	316	10%
Silicon	261	12%
Oxygen	150	21%
Carbon	115	28%
Hydrogen	18	100%

Formation Boundaries

Formation boundaries are generally characterized by a change in lithology or by marked change in porosity or permeability, or both. The ability of a log to locate formation boundaries will depend on its response to a particular formation, its vertical resolution, and the degree to which it is affected, by interfering effects (borehole size, bed thickness, formation dip, etc.).

The wireline/FEMWD curves most commonly used to locate formation boundaries are:

- The Spontaneous Potential curve
- The Short-Spaced Resistivity curves
- Micro-Resistivity curves
- Gamma Ray curve

The Spontaneous Potential Curve

The SP curve provides formation boundary location with excellent vertical resolution when: 1) the logs are run in fresh muds, 2) the formations are mainly sands and shales, and 3) the formations have low to medium resistivities. Under these conditions, the inflection points on the SP curve fall very close to the boundary of the formation.

Location of the formation boundary from the SP are at the inflection points. Inflection points occur where there is the greatest potential drop. The inflection point always occurs at the bed boundary though its horizontal position within the curve may vary.

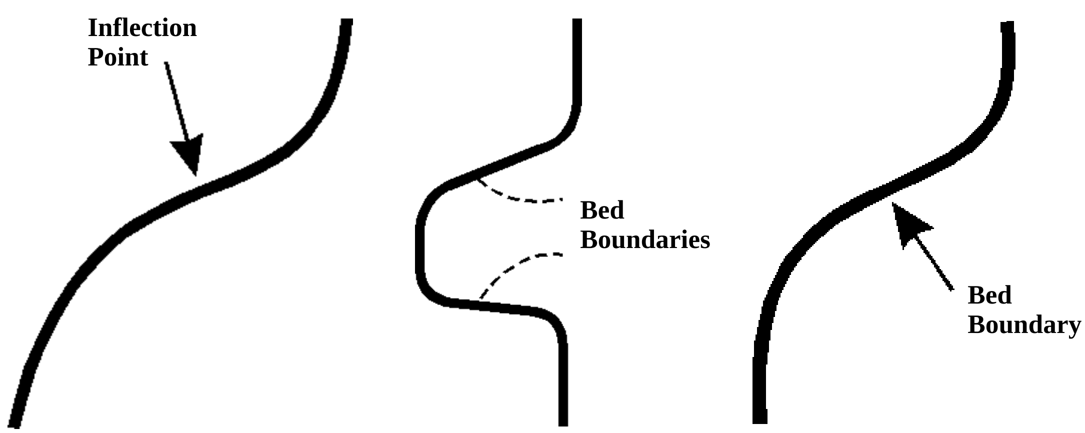


Figure 5-3 Location of Bed Boundaries Using the SP Curve

The SP will lose resolution in highly resistive beds and in beds with little or no permeability. This tool is not normally run in well where the drilling fluid is salt, oil-based or air.

Short-Spaced Resistivity Curves

The usefulness of these curves will vary according to their vertical resolution and the peculiarities of the tool's response.

The short normal (SN) is useful as long as the contrasts between the drilling fluid and formation resistivities are not too great. When using the short normal, it must be remembered that resistive beds will appear thinner by the AM spacing (16 inches), and conductive beds appear thicker by the same amount. In beds having a thickness less than the AM spacing, the short normal will show reversals. The short normal is not usually run in highly resistive formations, because the curve can become distorted.

Formation boundaries are indicated on the short normal as inflection points on the curve. These inflection points are actually one-half electrode spacing away from the higher conductive bed.

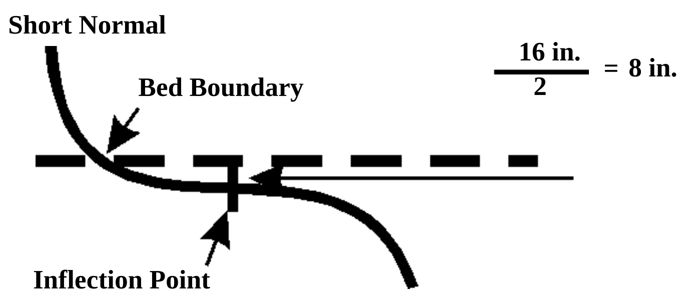


Figure 5-4 Bed Boundary Location Using the Short Normal

Laterolog curves are excellent for locating formation boundaries. Their range of application extends to very high resistive formations and there are no depth shifts or curve reversals. Curve resolution is determined by the beam width, about two feet for most tools.

Induction log curves lose vertical resolution in beds that are less than 4 feet thick. However, the presence of both resistivity and conductivity curves provide log readings with good contrast in formations ranging from low resistivities up to about 200 ohm-m.

Formation boundaries on the conductivity curve are half-way between the high the low reading that result when changing from one bed to another (Figure 5-5).

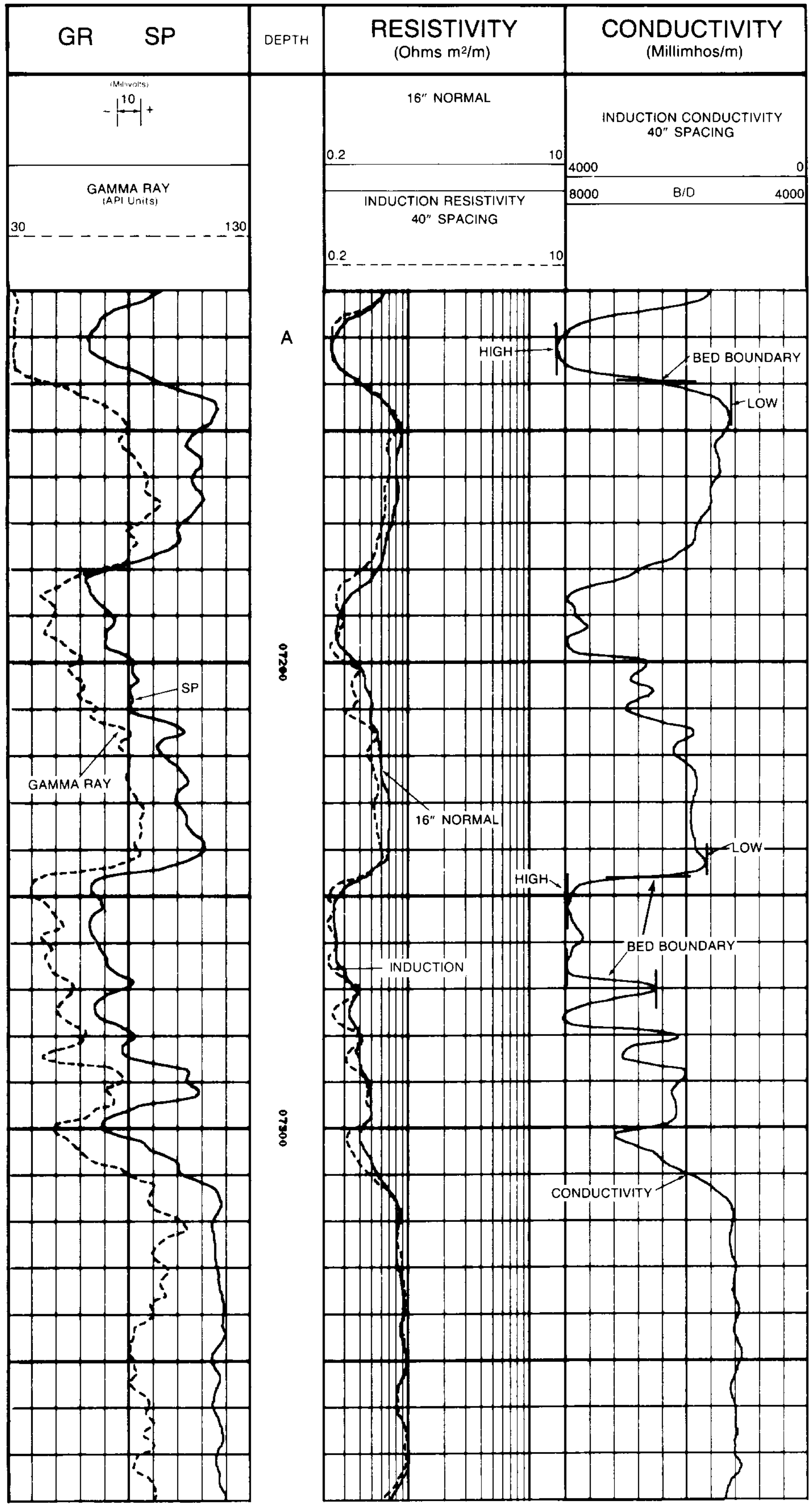


Figure 5-5 Bed Boundaries From Conductivity Curve

Micro-Resistivity Curves

Micro-resistivity logs are capable of detecting formation laminations less than 1 inch thick, if the mud cake is very thin. The use of the micro-normal and micro-inverse curves, resulting from the presence of mud cake, can indicate permeable intervals and their boundaries.

Micro-Laterologs have somewhat less vertical resolution, but are suited for use in salt-based muds and formations with high resistivities. Their response will be strongly affected by mud cakes thicker than 3/8-inch or more. However, this drawback to quantitative analysis becomes an advantage for the location of permeable formations, and therefore formation boundaries.

Gamma Ray Curve

The vertical resolution of the wireline Gamma Ray depends on the logging speed and time constant used. The time constant is used to smooth the statistically varying measurements. The higher the gamma ray intensity and the greater the detection efficiency of the tool, the better the vertical resolution.

At practical logging speeds (1800 feet/hour), Gamma Ray tools will detect beds approximately one foot thick.

The MWD Gamma Ray has the advantage of being drill rate dependent. Since few drill rates are close to logging speeds, there are more gamma ray readings per foot, and therefore greater bed resolution.

Lithology Determination Using Logs

Combination Gamma Ray Neutron-Density Log

The Gamma Ray log measures the natural radiation of a formation, and thus can function as a lithology log. It will also help differentiate shales (high gamma ray values) from sands, carbonates and anhydrites (low gamma ray values). The neutron log measures the amount of hydrogen in a formation and the density log measures the electron density of a formation.

These three logs provide a good quick-look method for lithology determination (see Figure 5-6), when there are a limited number of lithologies present.

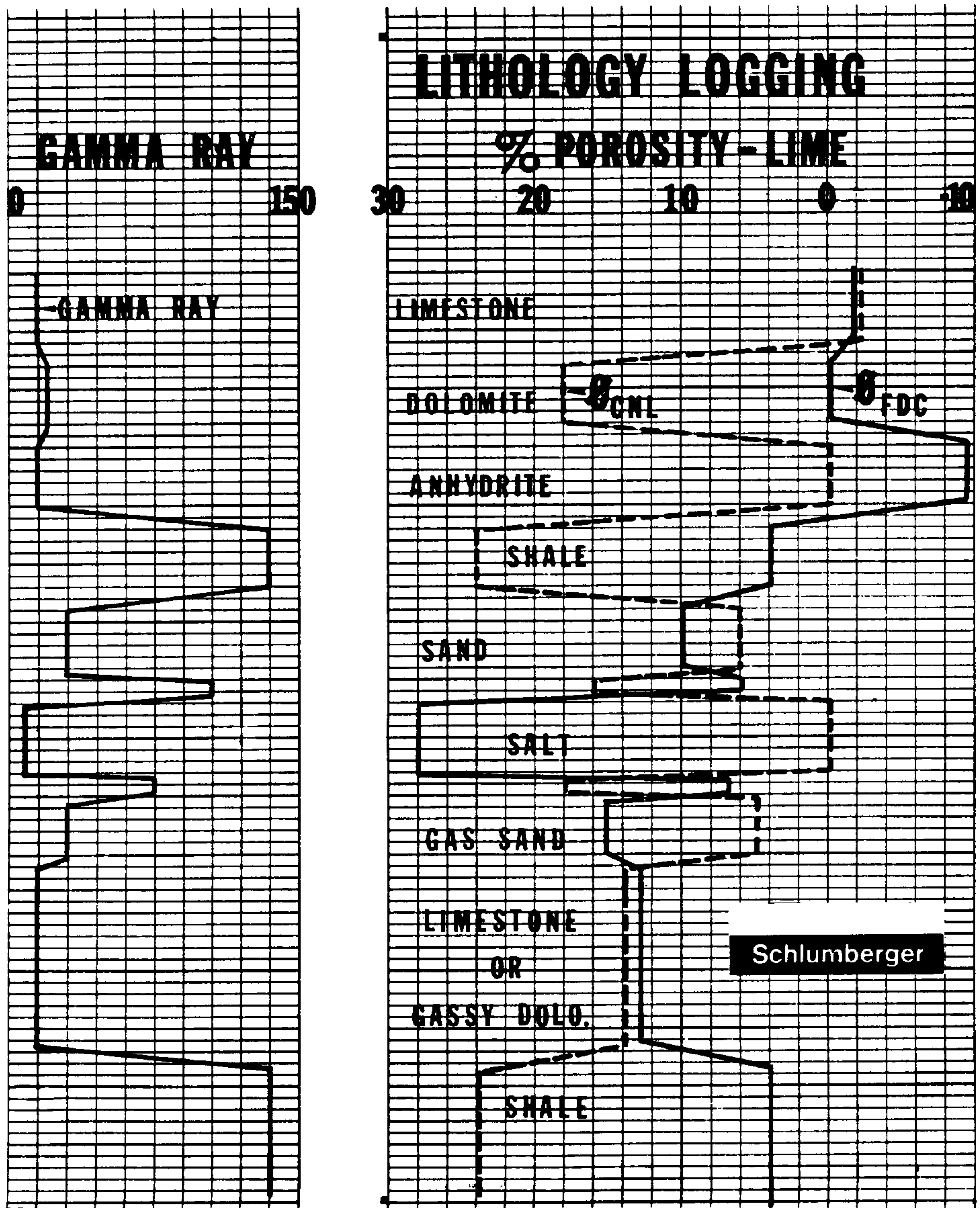


Figure 5-6 Lithology Determination Using GR and N-D Log

Porosity Log Combinations

The Neutron-Density curve overlay, with the acoustic/sonic as a cross-check is the most useful combination for lithology determination. Figure 5-7, illustrates the average responses of the logs in clean, liquid-filled, single mineral lithologies. This example also has the logs run in a fresh water drilling fluid.

Various cross-plot combinations (Neutron-Density, Neutron-Sonic, Density-Sonic) are also available.

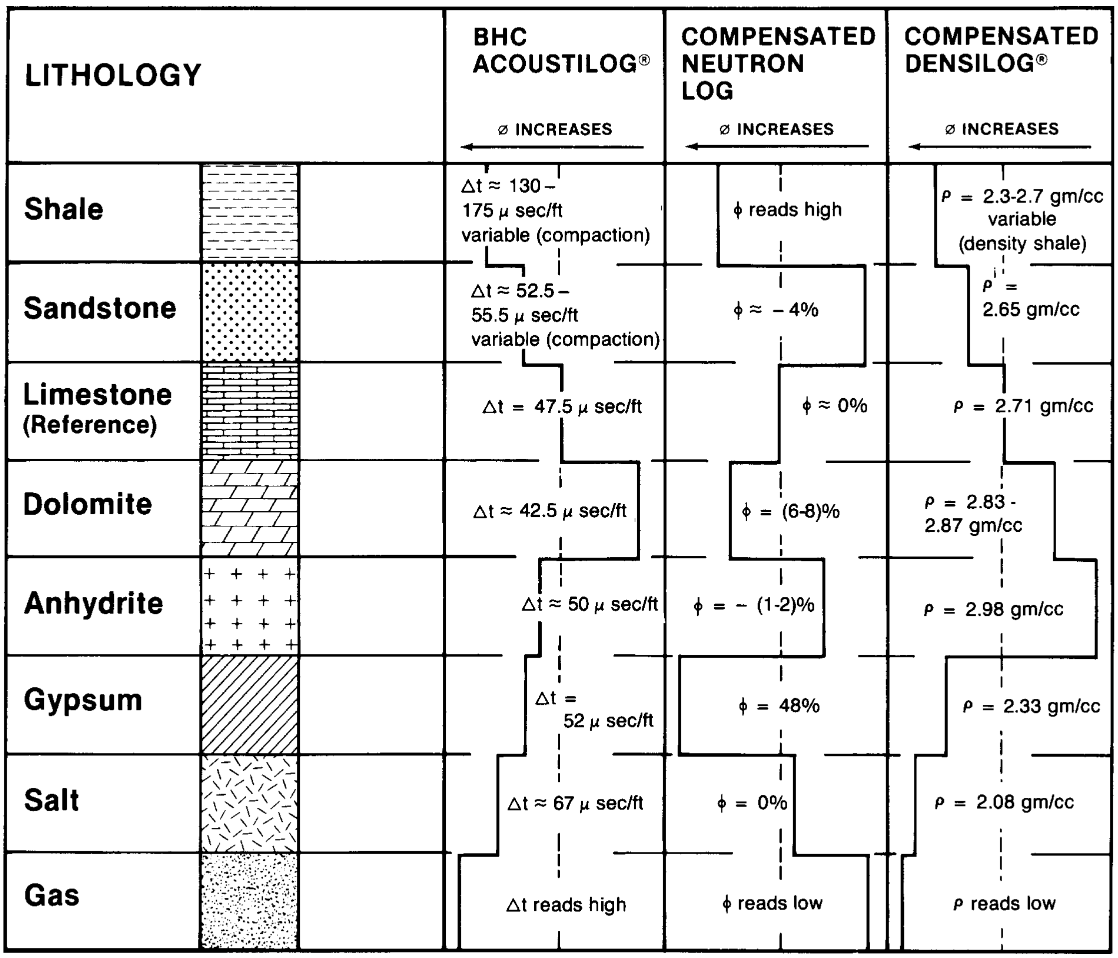


Figure 5-7 Lithology Using Porosity Log Combinations

Complex Lithology Plots

Complex lithology plots require the use of data from the three porosity logs (density, neutron and acoustic/sonic), as well as specific charts and cross-plots. The two most common lithology plots are the M-N Plot and the MID (Matrix Identification) Plot.

The M-N Plot requires all three porosity logs to calculate the lithology dependent (porosity independent) variables M and N. The “M” is calculated from the acoustic/sonic and density logs, and the “N” from the neutron and density logs. The values obtained for M and N are then plotted on a chart to determine the approximate make-up of lithology for the interval.

The MID Plot also required data from the three porosity logs and the use of several cross-plot charts. The first step is to determine the values for the apparent matrix parameters using neutron, density and acoustic/sonic data from the logs. The fluid type (saline or fresh) and neutron log type (sidewall or compensated) must be known. The cross-plot-obtained apparent matrix parameters are then plotted on a MID chart. This plot will generally form a pattern which will identify the major rock type by its proximity to the labeled points on the plot.

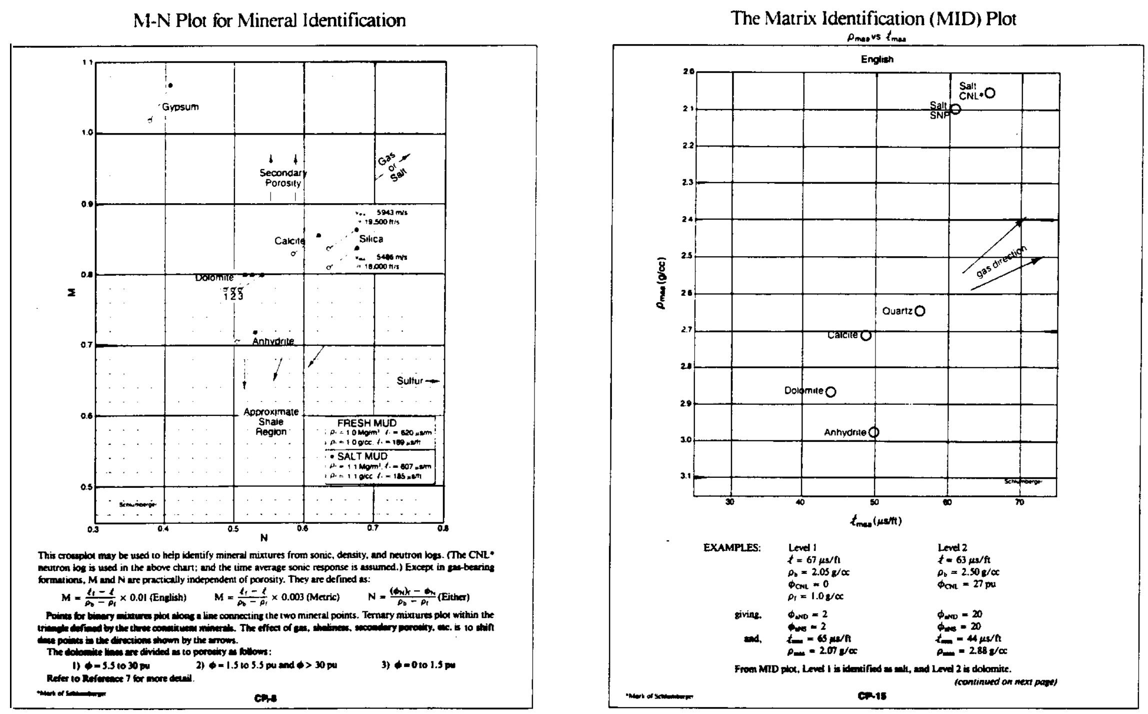


Figure 5-8 Complex Lithology Plots

Shale Volume

Because shales are more radioactive than sands or carbonates, Gamma Ray logs (wireline or MWD) can be used to calculate the volume of shale in selected formations.

The first step in the calculation of shale volume is the determination of the "Gamma Ray Index". This is accomplished using:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

where: GR_{log} = Gamma Ray reading from log
GR_{min} = minimum Gamma Ray reading (clean sand or carbonate)
GR_{max} = maximum Gamma Ray reading (shale)

Once Gamma Ray Index has been calculated, the shale volume is found from the applicable charts or using the following formulas.

For Tertiary Rocks: $Vsh = 0.083[2^{(3.7 \times IGR)} - 1.0]$

For Older Rocks: $Vsh = 0.33[2^{(2 \times IGR)} - 1.0]$

It must be remembered that this “shale volume” is only an estimate. Very few shale formations are pure shale (or clean shales), many are composed of clays (of various types) and siltstone, thus making max a little dubious.

Most oil companies have their own shale volume calculations, which are much more complicated than the above formula.

Facies And Depositional Environment Analysis

In the previous sections, it was noted that many wireline/FEMWD logs provide lithologic information, some more than others. To better interpret the geologic setting, the curves have to be examined in a slightly different manner. This section will concentrate on those logs which can assist in the understanding of various geologic processes and the nature of hydrocarbon trapping mechanisms.

The SP Curve and Geologic Environments

As mentioned earlier, the SP curve generally reflects lithologic variations within formations that were drilled. This is the main reason the SP is used for correlation purposes. If the wells are closely spaced, the SP can assist in the delineating the depositional history of sand formations.

The first item in interpreting the depositional history of a sand formation is the thickness of that sand. This is accomplished by reading the depth scale, then calculating the amount of footage between the two inflection points on the SP curve.

The next item is the amount of negative deflection. A very high negative response indicates a clean, well-sorted sand, while a low negative response indicates a shaly sand.

If there were a sharp break between a sand and a shale, it would indicate a rapid change in the energy distribution. These rapid changes in energy are associated with areas where small differences in water depth or energy distribution cause considerable variation in the depositional environment. On the other hand, a broad transition on the SP curve would imply more stable conditions during deposition and few variations in the depositional environment.

A serrated shape on the SP curve suggests rapid transitions and disruptive conditions. If the SP curve decreases upward (moves towards the shale line) it would suggest a decreasing sedimentation rate, and an overall decrease in energy (as in a fluvial environment). If the SP curve increases upward (or becomes more negative), it would suggest a coarsening upward sequence (as in a regressive marine environment) where the energy is higher at the top of the sequence.

Although it is not possible to classify all zones using the SP curve, there are several distinct responses which have shown good correlation with their depositional environment (Figure 5-9). They are:

Regressive Marine - Resulting from higher energy nearshore sediments being progressively deposited over lower energy offshore sediments (Figure 5-9a).

Channels and Point Bars - Resulting from decreasing energy, where a basal unconformity is overlain by massive well-sorted sands, which in turn are overlain by interbedded siltstones, sands and clays. The clay content increasing towards the top of the section (Figure 5-9b)

<u>Transitional-Deltaic</u>- Resulting from abrupt transitions of sedimentation on both top and bottom of the section (Figure 5-9c).

<u>Transgressive</u> - Resulting from lower energy offshore sediments being progressively deposited over higher energy nearshore sediments (Figure 5-9d).

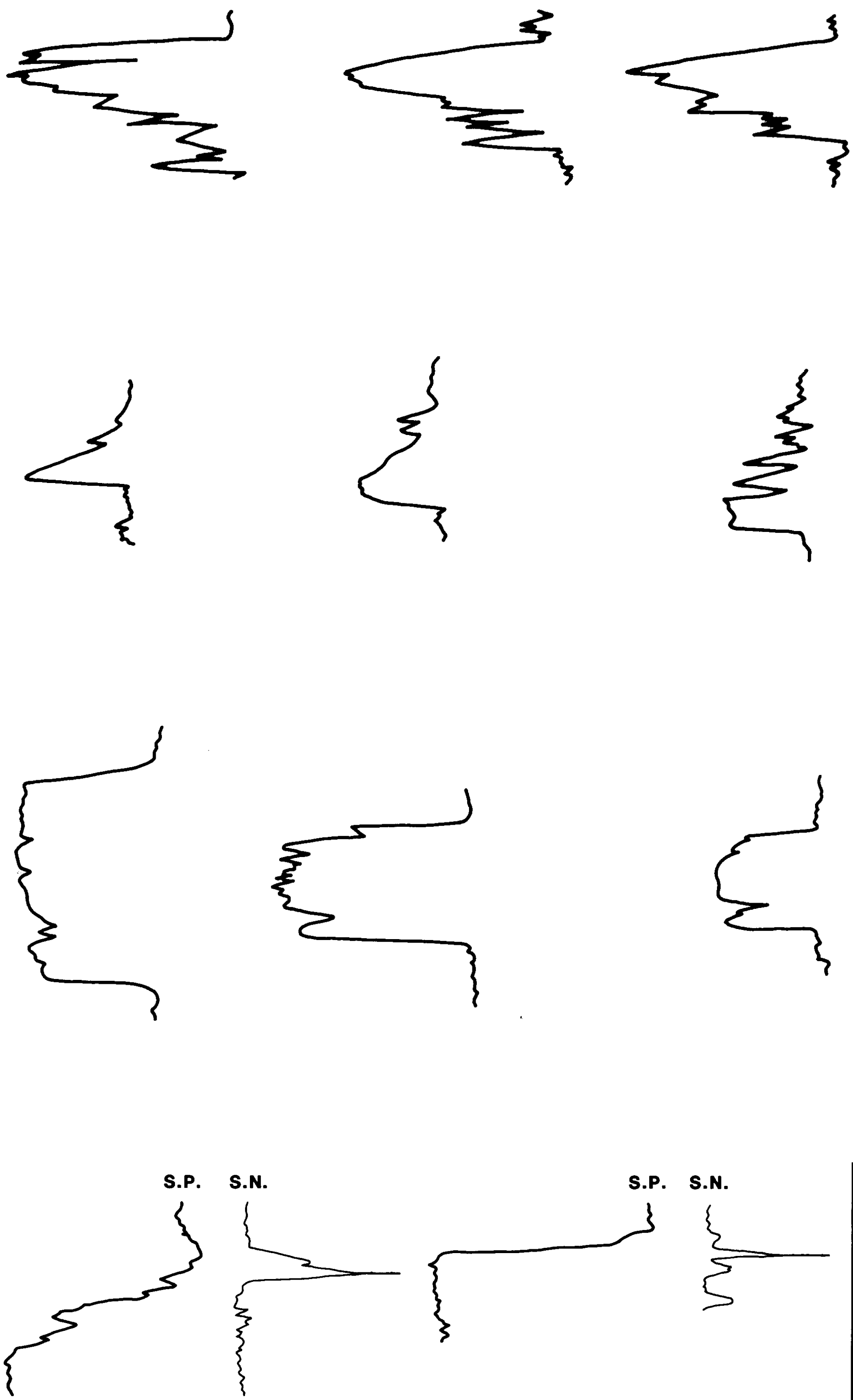


Figure 5-9a
Regressive Marine

Figure 5-9b
Channel - Point Bar

Figure 5-9c
Transitional - Deltai

Figure 5-9d
Transgressive

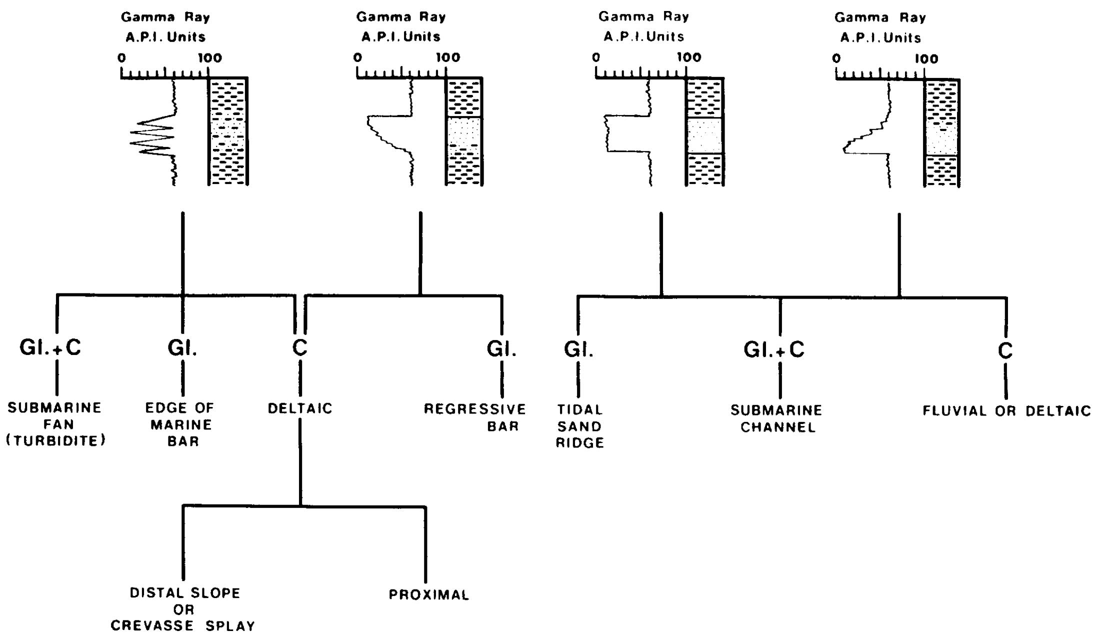
Figure 5-9 Sedimentary Environments from the SP Curve

The Gamma Ray Curve and Geologic Environments

Richard Selley, in 1976, proposed a relatively simple method to distinguish clastic depositional environments using the Gamma Ray curve and the presence (or absence) of glauconite and carbonaceous material.

The Gamma Ray curve being very similar to the SP curve, was used in a similar manner. Glauconite was used as the marine indicator, and carbonaceous detritus being used as a non-marine indicator and winnowing index.

Selley's interpretation of depositional environments is illustrated in Figure 5-10. *Gl* means glauconite is present and *C* means carbonaceous material is present.



Characteristic log motifs. From left to right: thinly interbedded sand & shale: an upward coarsening profile with an abrupt upper sand/shale contact: a uniform sand with abrupt upper & lower contacts & furthest right, an upward fining sand: shale sequence with an abrupt base.
Non of these log patterns are diagnostic on their own. Coupled with data on the distribution of glauconite & carbonaceous detritus however they define the origin of a number of sand bodies.

Figure 5-10 Depositional Environments Using Gamma Ray Log

Geometry of the SP and GR Curves

When using the SP and GR curves to interpret the depositional environment of sand bodies, we are basically trying to characterize the sand, based on the geometrical shape of the curve. When classifying the shape of either curve, there are several parameters to keep in mind. They are (Figure 5-11):

Upper Contact	**Lower Contact**
Abrupt	Abrupt
Gradational	Gradational

Curve Shape	**Curve Characteristics**
decreasing upwards (bell)	Smooth
increasing upwards (funnel)	Serrated
stable (cylinder)	Complex
irregular	

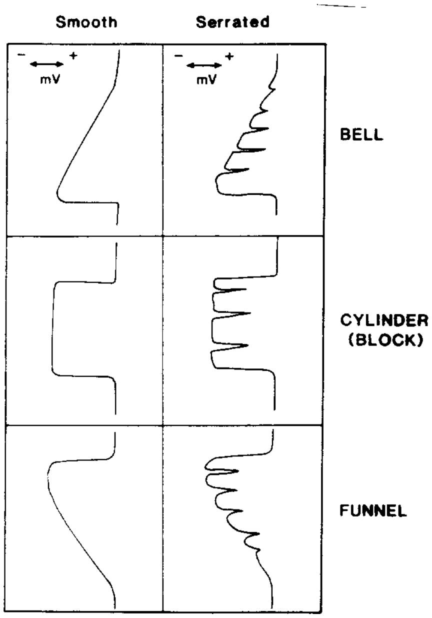


Figure 5-11a: Curve Shape

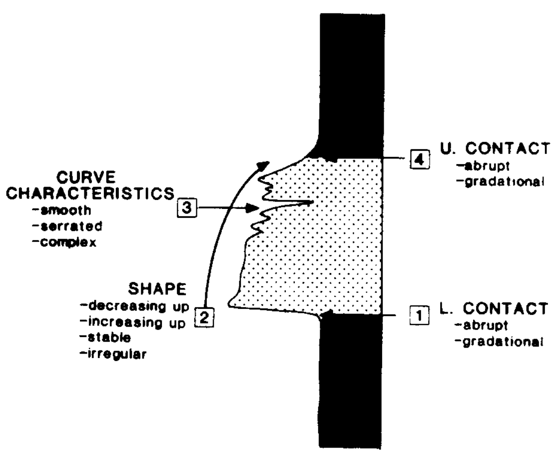


Figure 5-11b: Geometrical Characteristics

Figure 5-11 Curve Shape and Characteristics

Cautions

Trying to describe the SP or GR curve using these eleven parameters is no easy feat. However, once the curve is classified, the next step is to try and understand the origin of the shape, and several methods have been described in this section. Even when the curves are classified and described, caution is advised. For example:

SP: A tight sand may look like a shale

GR: Zircon, micas and glauconite will deflect the curve

Wireline and FEMWD information, in particular the SP and GR curves, can be valuable tools in formation evaluation, but as has been mention many times before, it is most prudent to use all the geologic tools available (cuttings samples, mud logs, etc.) when evaluating formations for hydrocarbon potential or geologic settings.

Formation Mechanical Properties

It is possible to determine rock strength by using velocities and densities from well logs. The rock strength referred to is that implied by the elastic constants, such as Poisson's Ratio, Shear Modulus, Bulk Modulus and Young's Modulus. These properties can be measured directly (from core samples) or can be calculated using velocity and density measurements (from well logs).

Acoustic Waves

There are many types of acoustic waves that are propagated through formations during acoustic/sonic logging runs. In general though, only the compressional waves are used because they have the highest velocity. These compressional waves are soon followed by shear waves, Rayleigh waves and other acoustic waves. When calculating rock properties, the most commonly used are the compressional and shear waves.

As stated, the compressional wave is the wave with the highest velocity. It is the same type of wave that is sent when people are speaking. The particle motion from compressional waves is in the same direction as the wave movement. Another property of compressional waves is that they can propagate in gases, liquids and solids.

Shear waves are a little slower than compressional waves. These waves propagate only in solids that are essentially elastic. The particle motion is at right angles to wave front propagation, hence the shearing action that they are named after.

The total wave that is seen in acoustic/sonic logs is generally a combination of the various waves. The compressional wave arrives at the receiver first, followed by the shear wave (which usually overlap some of the compressional wave) and then the other waves arrive. The final observed wave is the sum or combination of all the waves. The impacting of a compressional wave moving from a liquid to a solid results in the formation of a shear wave.

Elastic Constants From Well Log Data

The elastic properties of the subsurface rocks are affected by a number of geological factors, such as depth of burial, anisotropy, diastrophism, and lithology type. The specific transit times from the sonic tools are also influenced by these geologic factors, as well as by porosity. The rocks texture and geological history determine the rocks elastic properties more than its mineral composition.

Determination of a rocks elastic constants can be accomplished using the shear and compressional velocities (or in the case of well logs, the travel times) through the formation and the bulk density of that formation.

There is considerable evidence that a good correlation exists between the intrinsic strength of the rock and its elastic constants, making the calculation of these constants even more important. The shear modulus appears to be the most important elastic parameter in comparing the strength of different formations. In terms of well logging parameters and in practical units, the elastic constants are expressed as:

$$\text{Youngs Modulus} = \frac{\rho_b}{\Delta t_S^2} \times \left(\frac{3\Delta t_S^2 - 4\Delta t_C^2}{\Delta t_S^2 - \Delta t_C^2}\right) \times (1.34 \times 10^{10})$$

$$\text{Bulk Modulus} = \rho_b \times \left(\frac{3\Delta t_S^2 - 4\Delta t_C^2}{3\Delta t_S^2 - \Delta t_C^2}\right) \times (1.34 \times 10^{10})$$

$$\text{Shear Modulus} = \frac{\rho_b}{\Delta t_S^2} \times (1.34 \times 10^{10})$$

$$\text{Poisson's Ratio} = 0.5 \times \left(\frac{\Delta t_S^2 - 2\Delta t_C^2}{\Delta t_S^2 - \Delta t_C^2}\right) \times (1.34 \times 10^{10})$$

where: ρ_b = Bulk Density (g/cm^3)
Δt_s = Shear Wave Travel Time (μsec/ft)
Δt_c = Compressional Wave Travel Time (μsec/ft)

The conversion factor in the above equations accounts for the units of specific travel time (μsec/ft) instead of sec/cm, and elastic moduli (lb/in^2) instead of dynes/cm^2. Therefore:

$$\frac{10^{12} \times 30.48^2 \times 14.22}{1000 \times 980} = 1.34 \times 10^{10}$$

Fracture Detection From Well Logs

At the present time, there are no logging tools designed to specifically detect fractures, even though fractures affect the responses of many logging tools. Unfortunately, these effects are usually subtle and a very through understanding of tool responses, and experience in log interpretation is necessary to detect fractures from logs.

Before looking at wireline logs for fractures, several other sources of information must be examined, they are:

1. Nature of the formations - is there a local history of naturally occurring fractures within that formation?
2. Sharp increases in the drill rate - fractures usually exhibit abnormal increases in rate of penetration when drilled (also check the type of bit being used).
3. Presence of crystals in the drill cuttings- fractures in the subsurface can be filled by mineral deposits (calcite, silica, etc.) which will be present in the cuttings.
4. Lost circulation during drilling - Open fractures will usually cause lost circulation during drilling, the severity being an indication of the size and/or length.

These sources can be reviewed in the pre-well prognosis and during the course of the well. This review will allow a closer inspection of the wireline logs, especially at zones that exhibited one or more of the above indications of fracturing.

Acoustic/Sonic Log Response

Fracture detection using acoustic responses requires the use of the compressional and shear wave.

Both wave trains tend to be reduced while transversing fractures, and the amount of wave attenuation depends on the angle of the fracture to the vertical. Shear waves are highly attenuated while travelling across horizontal fractures, while the compressional wave are more affected by high angle fractures.

The most common acoustic/sonic tool used for fracture detection is the Variable Density Log (VDL). Using this tool, fractures are indicated by sudden changes in the wave train. Since this log does measure both shear and compressional waves, any differences in acoustical impedance will show up as blurred zones, with a chevron-like pattern.

Unfortunately, such patterns can also be caused by diameter changes in the borehole and alternating thin bed lithologies.

The borehole compensated sonic (BHC) log will give an indication of secondary porosity. If sonic porosity is considerably less than porosity from the density or density-neutron logs, the difference is usually attributed to fractures or fracture porosity.

Caliper Log Response

Whenever a fracture zone is drilled, the area around the fracture will usually enlarged, due to the rock breaking down with fragments falling into the borehole. Borehole enlargement, or borehole elongation, when the borehole is expected to be in-gauge can be an indication of fractures. To provide for the best possible indications, a multi-arm, multi-directional caliper should be used (i.e. a four-arm caliper).

As most of us realize, many factors besides fracture will result in borehole enlargement. In addition, if a fractured zone causes lost circulation, LCM is usually added to the drilling fluid. If the LCM is successful in sealing the fractures, the build-up of LCM across the fractured zone can cause the caliper to read "less" than the bit size.

Density Log Response

The correction curve ($\Delta\varphi$)on the density log can also be a fracture indicator. This correction curve is usually used to correct the density curve for mudcake thickness and for the tool not seating itself against the side of the borehole (borehole rugosity). It will, however, respond to an open, fluid-filled fracture if the borehole is in-gauge. When this occurs, an active, erratic $\Delta\varphi$, may indicate fractures.

Since the correction curve was designed to respond to washouts, a close scrutiny of the caliper is necessary to identify fractures. Also, since the $\Delta\varphi$ curve "sees" only a small portion of the borehole, it may miss a fracture that does not follow the long axis of the borehole.

Resistivity Log Response

Resistivity logs can be quite effective in locating fractures, based on the principle that deeper reading resistivity device will be less affected than a shallow reading resistivity device.

Following this line of thinking, if the SFL or LL8 readings exhibit spurious low-resistivity responses, and the deep and medium resistivity readings do not mimic that response, fractures may be indicated. Fracture intensity can be related to resistivity separation.

Litho-Density Log Response

The P_e measurement of a LDT can indicate mud-filled fractures. The photoelectric cross section of barite is 267, limestone is 4.9 and sandstone is 1.85. A mud-filled fracture in a limestone or sandstone formation should be obvious, providing there is good tool-borehole contact.

Dipmeter Log Response

Since the dipmeter is basically a micro-resistivity device, when the mud filtrate fills a fracture, it will cause a lower reading from that resistivity pad. By comparing the resistivity measurements from the pads (90^o apart) fractures can be identified. This also has the advantage of being able to orient the fractures.

However, since the pads do not cover the entire borehole, fractures may be missed (i.e. the pads only cover 40% of an 8 inch borehole wall surface).

Review of Fracture Detection Using Logs

As can be seen from the above explanations, each log response has its own limitation in detecting fractures on its own. If used in combination, and with additional geologic information, fracture presence can be confirmed.

Self-Check Exercises:
Wireline/MWD Logs In Formation Evaluation

1. What three factors affect a logs ability to locate a formation boundary?

   a.

   b.

   c.

2. If all optimum conditions are met, where on a SP curve can a bed boundary be located?

3. How are micro-resistivity log curves used to detect formation boundaries?

4. Why is the FEMWD Gamma Ray curve better than the wireline Gamma Ray curve for picking formation boundaries?

5. What is the lithology if the wireline log responses are: Δt = 42.5 µsec/ft, φ_b = 2.85 g/cc, ϕ_N = 7% (limestone porosity units)?

6. Using Selley's method to determine the geologic environment, the following are noted:
   1) glauconite is present, but no carbonaceous detritus,
   2) the upper contact of the GR curve is sharp, the lower contact is gradational, and
   3) the curve shape is decreasing downwards and is serrated. What is the expected geologic environment?

7. What four elastic constants can be determined from the acoustic and density logs?

   a.

   b.

   c.

   d.

8. Which log is specifically designed to detect fractures?

9. What other sources, besides logs, are available which can indicate fractured formations?

   a.

   b.

   c.

   d.

10. How does the VDL indicate fractures?

11. How does the Litho-Density log indicate fractures?

12. What does a serrated-shaped SP curve suggest about the conditions within the depositional environment?

13. Which acoustic wave is more attenuated by high-angle fractures?

14. How does a borehole compensated (BHC) acoustic log indicate secondary porosity?

15. Which elastic constant is most important when comparing the strength of different formations?

•Notes•

Chapter 6

Introduction To Seismic Surveying

Upon completion of this section, you should be able to:

- Understand the basics of seismic surveying and seismic processing
- Explain how seismic signals are generated and recieved
- Read a seismic section
- Form general interpretations from a seismic section
- Explain the difference between seismic lithology and seismic stratigraphy

Additional Review/Reading Material

Coffeen, J.A., *Interpretating Seismic Data*, Pennwell Books, 1984

Cofeen, J.A., *Seismic Exploration Fundamentals*, Pennwell Books, 1986

Tearpock, D. & Bischke, R., *Applied Subsurface Geologic Mapping*, Prentice Hall, 1991

AAPG, *Seismic Stratigraphic Interpretation and Petroleum Exploration,* CE #16

The Open University, *Basin Analysis Techniques-Geophysical Techniques, Part 1*, 1987

AAPG, *Seismic Stratigraphy-Applications to Hydrocarbon Exploration*, Memoir #26

•Notes•

Introduction To Seismic Surveying

This chapter introduces you to the theory of seismic wave physics, the acquisition and processing of seismic data, mapping techniques utilizing velocity transit times, and concepts concerning the determination of stratigraphic facies using seismic data. It is understood that books could be written on any one of these facets and this section is intended only to provide a basic understanding of these topics to the Formation Evaluation Geologist.

Introduction

Modern seismic sections often bear a striking resemblance to stratigraphic cross sections, and many individuals are tempted to interpret them directly, without making the special corrections they require. Seismic sections show the response of the earth to seismic waves, and the position of geologic bedding planes is only one of several factors which affect the response.

Because most seismic reflections are interference composites, there is no one-to-one correspondence between seismic events and interfaces within the earth. However, with today's processing power, geophysicists can often convert subtle changes of wave shapes into stratigraphic terms. Therefore, it is important that anyone reviewing seismic data have a thorough understanding of seismic wave physics, general rock properties, and the limitations of how the data is collected and processed.

The Seismic Wave

Seismic waves are generated by a sound source at the earth's surface (Figure 6-1). These sound waves travel through subsurface bedding planes at increasingly greater depths. At each bedding interface, some of the seismic energy is reflected back towards the wave source. Surface sensors detect those reflected waves and record the wave's amplitude. At the recording station, these amplitudes will be combined with the signal's transit times. Because a portion of the energy will be returned from each subsurface boundary, several “seismic traces” will be recorded at each sensor for every surface shot.

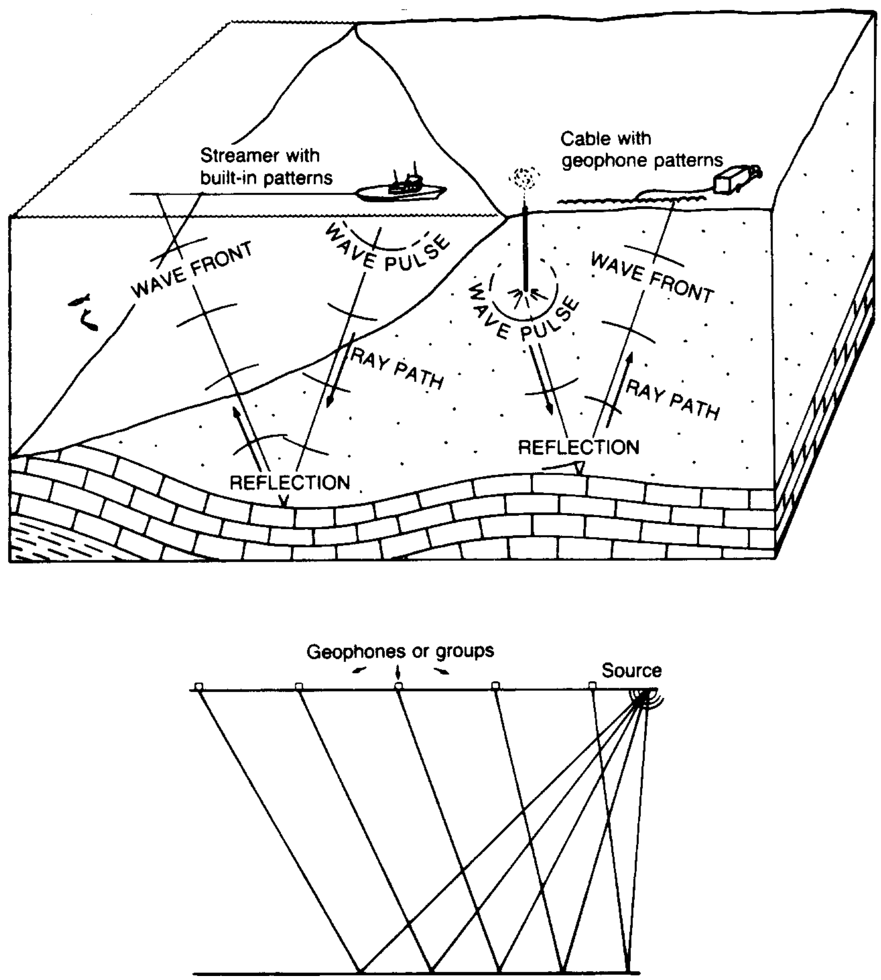


Figure 6-1 Generation of Seismic Reflections

Seismic surveying was first attempted using one reflected-wave sensor, called a “geophone” (Figure 6-2), and moving it to several different locations along a straight line. The seismic source would be repeated as this single geophone was moved from point to point. It was soon noticed that this procedure was not practical, because no “shot” ever introduced exactly the same signal. In addition, the ultimate objective was to obtain a seismic trace that contained only the primary, reflected compressional waves and no others (i.e. shear waves).This was not possible, however, because the generation of unwanted waves was inevitable when the shot occurred.

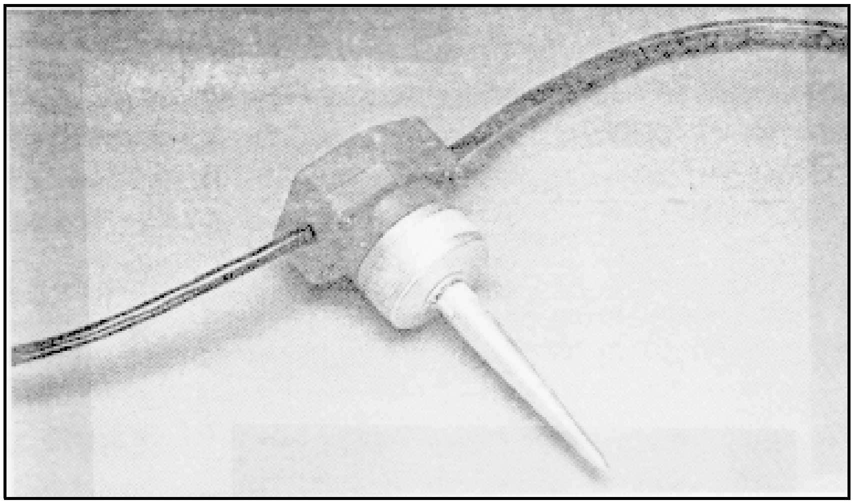


Figure 6-2 Single Geophone

Later technology introduced multi-sensor “arrays”, allowing many sensors to read the same shot from different points along the survey line. This ensured that the same source shot was read by all geophones and the noise experienced by the individual sensors was then reduced using better signal-to-noise ratios. By recording several repetitions (shots) of the reflection information, the influence of noise could be further reduced.

Ideally, the strength of the source would be great enough so that low energy noise could be ignored. This is not practical, however, because most energy sources are lacking in the higher frequencies, and since a wide range of frequencies is desirable, the only practical alternative is to use multiple sources. Further improvement can be made by measuring reflections from a single bed at more than one geophone. The recorded traces can then be added together and displayed side-by-side to form a “seismic line” that allows a two-dimensional examination of the subsurface.

Of course, this process requires much more than the simple addition of reflections measured at different sensors (Figure 6-3). One problem is that for any one reflector, the transit times vary with its offset from the source. This increase in transit time from a horizontal reflector is called “normal move out”. Signal processors using simple trigonometry to “dynamically correct” the reflection times yielded a “common-depth-point stack”. To make move out corrections easy, it is preferable that the offsets be distributed systematically over a range of distances.

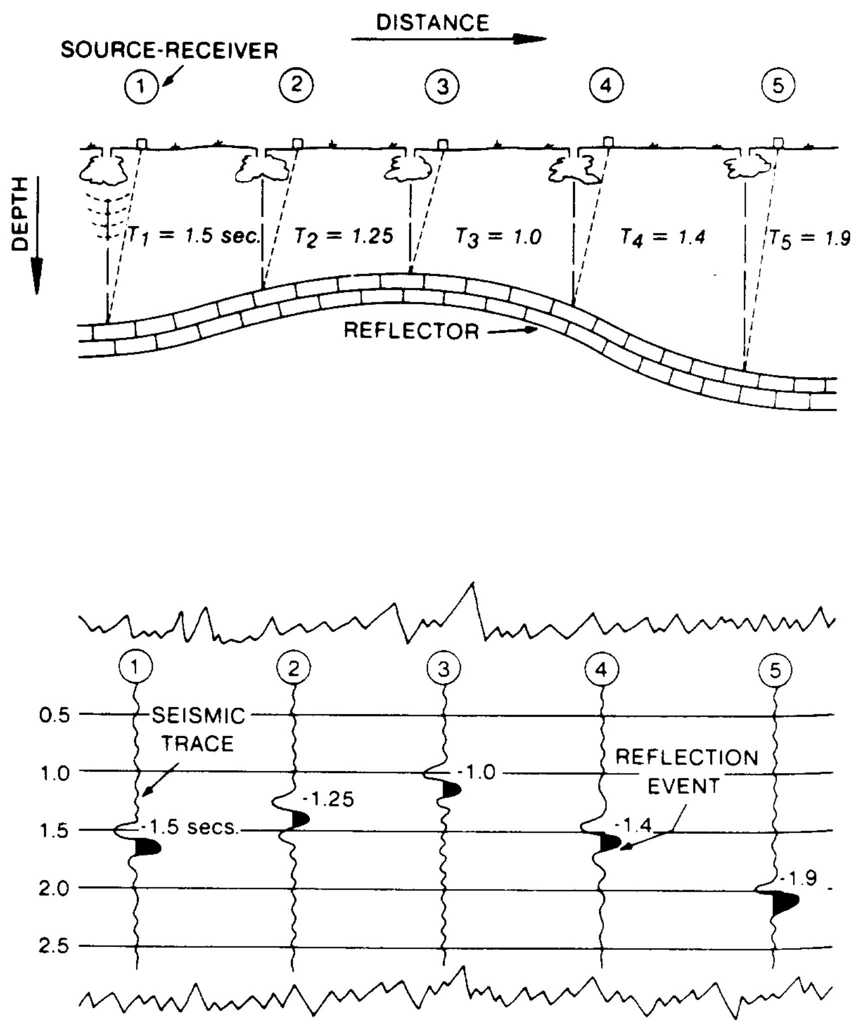


Figure 6-3 Generation of Seismic Traces

Field people and processors need to know the exact details of the source and sensor arrays to properly analyze the recordings. For example, if the data is recorded from a "pull-along" spread (the source is furthest away from the first geophone in the recording sequence), it would require different corrections than a "push-along" spread (where the source is located nearest the first geophone to be sampled).

Array Preparation and Signal Recording

A typical seismic spread contains many geophones (typically 48, 60, 96, 120, or more). Usually, the many outputs of these are brought to a single recording station, known as the "recording truck" or "recording tent". There, the signals pass through high capacity recording instruments and are saved on tape. The instruments must provide one channel for each sensor, and several additional "auxiliary" channels to be built into the recording devices.

Cables transmit the geophone signals to the recording station. Since these cables can be very long for multi-sensor recordings, and it would require a lot of work to move the entire array for extensions of the seismic survey, so the cables are manufactured in sections with highly durable connectors. When an array extension is required, one cable can be removed from the recording side and another array can be added to the far end. One alternative to moving cables is to string more segments than is necessary for the first shot. The recording station can then be moved to eliminate the first array segment and add the next extension. In this manner, multiple extensions can be facilitated without necessitating any cable movement. Of course, there is a limit to the number of extensions that can be wired to the system, and eventually it will be necessary to leap-frog some of the segments.

The general process of obtaining an on-shore measurement is:

1. A line is marked on the ground by a surveyor, using a numbered stake at each shot-point.
2. A hole is drilled in the ground at each shot-point to allow insertion of the explosive charge (Figure 6-4).

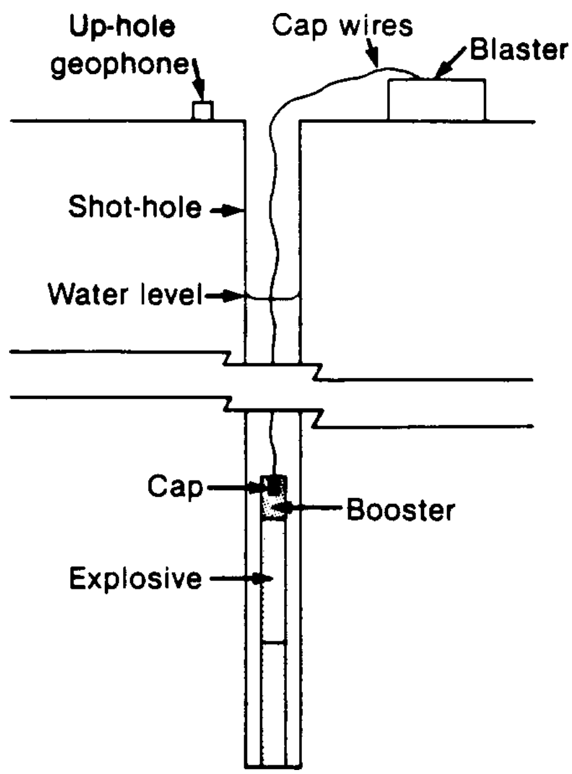


Figure 6-4 Schematic of an Onshore Shot-Hole

3. The cable sections are laid to cover the first spread, the electrical connections are wired at the recording truck and the geophones are off-loaded at each stake.
4. The “jug-hustlers” plant the geophones and connect them to the cable.
5. The observer at the recording station checks to see that the geophones are properly connected and the “shooter” loads the first explosive charge, plants a geophone nearby for reference, and connects the detonation hardware.

6. The recording observer starts the recording device and the charge is exploded.
7. The shooter moves to the second shot-point and the observer advances the “roll-along” switch in preparation for the next recording session.

Recording Instruments

Geophones used in seismic recordings are of the moving-coil type (similar to the speakers of modern stereos) and are sensitive to the particle velocity of the ground surface. Emplacement is facilitated by the attachment of a spike or base plate to the geophone (depending on the type of ground surface).

Recording station instruments (Figure 6-5) are made up of the following units and functions:

1. Roll-Along Switch - which selects geophone group to be recorded.
2. A Line Test Unit - which ensures that the geophone groups are properly connected.
3. Analog Signal Conditioning - includes pre-amplification, filtering, high-line rejection, and gain switching.
4. Digital Signal Conditioning - which digitizes the geophone signals; formats signals for tape; and allows for inclusion of auxiliary and manually-entered data.
5. A Tape Recorder - to record the digital sensor data.
6. A Clock - provides a basic reference for measurement of reflection times.
7. Auxiliary Channels - records the “shoot command” and the “up-hole” time.
8. A Playback Unit - allows the viewing of data going into the recorder for early analysis.
9. Camera - makes a permanent visible record of the data being recorded.
10. A Power Supply - provides constant voltage and surge protection for the instruments.
11. A Vertical Stacker - (optional) which allows field based summation of multiple recordings when using several sources.

Shot-Hole Drilling

The shot-hole is drilled by a modified water well drilling rig, known as a shot-hole rig. These rigs can be mounted on trucks, tracked vehicles, or marsh buggies, depending on the

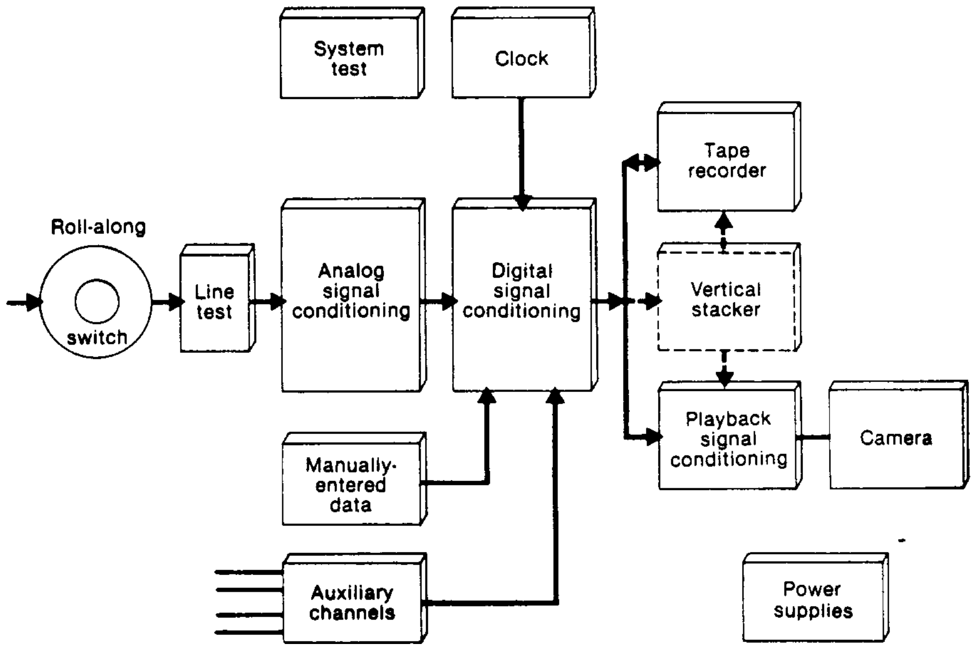


Figure 6-5 Seismic Recording Instrument Layout

location. When the terrain is impassible with land vehicles, helicopters can be used to move the rigs. These rigs can drill an average of 30 holes a day, to a depth of 50 feet. Since shot-hole drilling is a major portion of the seismic budget, rigs that drill many holes per day can significantly lower operating expenses.

The types of bits used will depend on the competence of the near-surface material. Often, jetting will be sufficient (i.e. marshy locations). When hard rock is very near the surface, a roller-cone rock bit is used. As mentioned earlier, hole depths are in the 3 to 30 meter range, though the actual depth will depend on costs, the formation, the water table, and possible ghost reflections.

The drilling fluids can be water, air, foam, or any combination. When lost circulation is a serious concern, it might be necessary to run casing.

The Seismic Source

On land, seismic work usually requires a high-velocity gelatin dynamite or other modern, stable explosives. The charges vary from 2 to 20 pounds, depending on the magnitude of the seismic source that is required. Electrical blasting caps, that serve as detonators, are inserted into the end of the charges and connected to wires which send the signal to detonate. The assembled charge is lowered into the hole or forced down with a heavy weight. A "tamping" material is added above the charge to ensure that the main force of the explosion goes outward into the formation and doesn't escape to the surface.

“Thumpers” are used as seismic sources when the near surface material is relatively competent. These systems have large weights that are suspended from the ends of trucks and a seismic signal is generated when the weight is dropped. The weight is dropped every few meters along the survey line so that sufficient energy is built up over the sensor array. This manner of generating the source signal has a distinct advantage over explosives, because the total energy expended can be easily and accurately calculated. Within the last few years, a more modern version of the thumper has been developed, called the “Vibroseis”. This system works on the same principal as the thumper, except that it is capable of vibrating the source weight on the ground surface at various frequencies. This has been an important development, because the seismic crew can now accurately select the range of frequencies that they chose to induce into the subsurface. This Vibroseis source is much better than the dynamite or thumper sources that produce those uncontrollable, wide-band frequency spectrums.

Marine seismic data acquisition works on the same basic principals as on-shore exploration, but there are some fundamental differences. For example, although off-shore seismic boats are relatively expensive to operate and maintain, the overall cost of seismic line production is generally lower. This is because there are less physical and societal obstructions to overcome. In addition, daily coverage is much greater, it is common to have total line lengths of 100 km.

The “hydrophone” arrays are towed behind the boat, eliminating the need for continuous laying of new spreads. Array locations are accurately positioned by the aid of Global Positioning Satellite (GPS) networks. Together, these two advantages allow the crews to acquire seismic data continuously, 24 hours a day, 365 days a year.

The primary difference is the manner in which the shot source is generated. In today's ecologically concerned society, the use of dynamite or similar sources is discouraged because of the potentially harmful effects on marine biota. In addition, the placement of dynamite at an optimum water depth is extremely critical for successful energy dispersion. The choice of dynamite is even less attractive because of associated noise generated by the bubbles of hot gas that rise through the water after the explosion.

Several systems have been developed to overcome the problems with dynamite and are commonly known by their trade names. One system frequently used is the gas gun. This device uses the rapid explosion of a propane/oxygen mixture to generate the initial source compression. Its advantages are that it is cheap and reliable. Disadvantages include the requirement for propane storage, on-board oxygen storage or generation, and high operating costs. Its use has dropped because of recent trends towards cheaper methods.

Another approach to generating shot sources is the steam bubble. In this system, a volume of water is displaced by steam. As the steam condenses, the resulting collapse of water into the void creates an “implosion”. This system has a major failing in that it is not possible to fire multiple, synchronized events. To combat this problem, a water gun has been developed (Figure 6-6). In this apparatus, a “bubble” of water is discharged by a gun to produce the initial low pressure zone. Surrounding water rushes into the below-hydrostatic pressure void, forming an implosion and generating the seismic shot source. Multiple guns are generally fired at one time, facilitating synthesis of a much larger source. In addition, the source wave form is smooth and extends into the high frequency range. Also, the character of the wave form is highly reproducible, minimizing source variations from shot to shot.

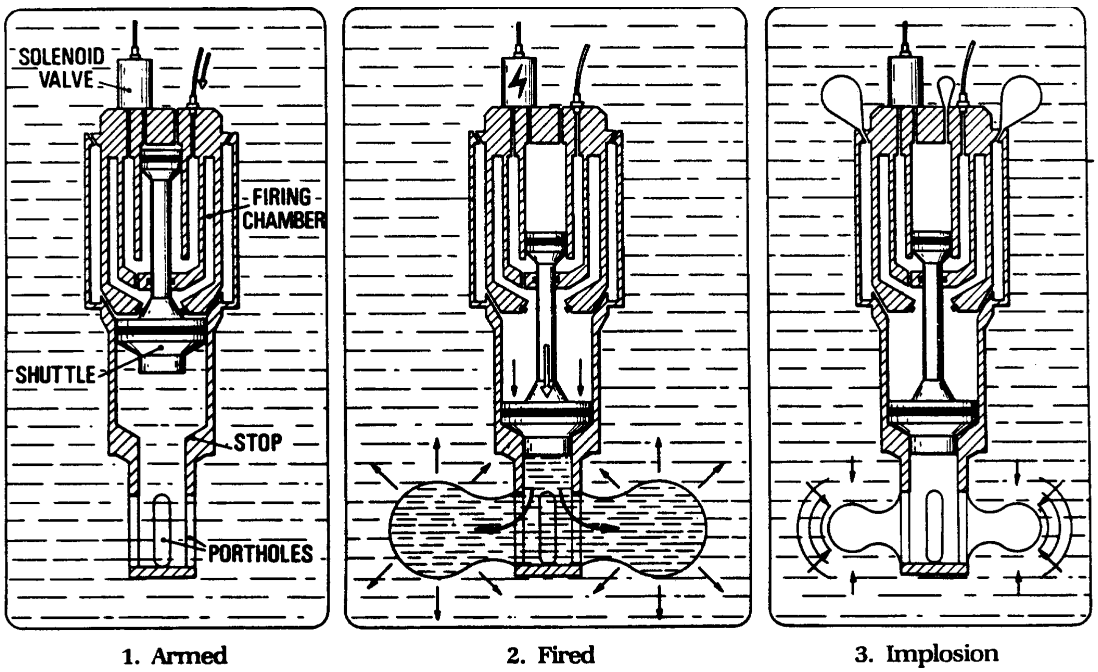


Figure 6-6 Water Gun Operation

The Seismic Section

The seismic section can be thought of as a snap-shot of the stratigraphic column underlaying a line drawn across the earth's surface (Figure 6-7). Notice the sentence did not say “straight line”, because minor obstacles, such as mountains and rivers, often preclude absolutely linear surveys.

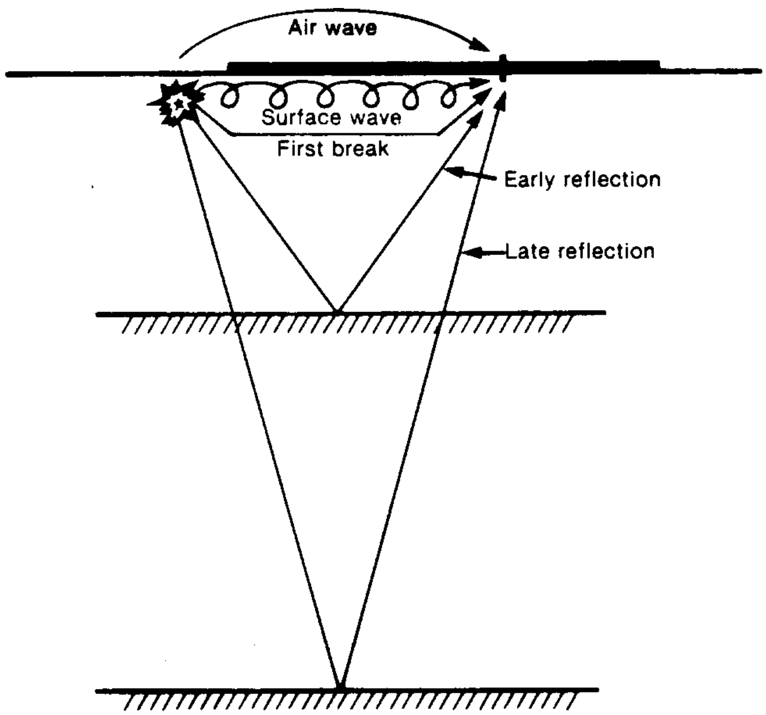


Figure 6-7 Types of Reflections from a Seismic Shot

There are numerous “crooked” lines that begin at points along the top of the section and continue some distance down the page. These lines represent the magnitudes of reflected waves picked up by the geophones or hydrophones at given transit times and are referenced from the vertical scale along the sides of the section (Figure 6-8). Because the wiggles occur due to changes in the character of the rocks (Figure 6-9), such as bed boundaries, there is a coincidence of wiggle types at about the same travel times immediately adjacent to the geophones. The areas of agreement are known as “seismic horizons”. Since the subsurface rocks are variable over large horizontal distances, wiggles that aren't very close can be quite different at a given travel time.

The companies that process seismic data attempt to make interpretation easier for the geologist/geophysicist by adding darkened emphasis to the lines of wave agreement (Figure 6-10). The areas to the right of each trace are called peaks, while the areas to the left are called troughs. The definitions aren't extremely important to know, except for the fact that the peaks will appear darker than the troughs.

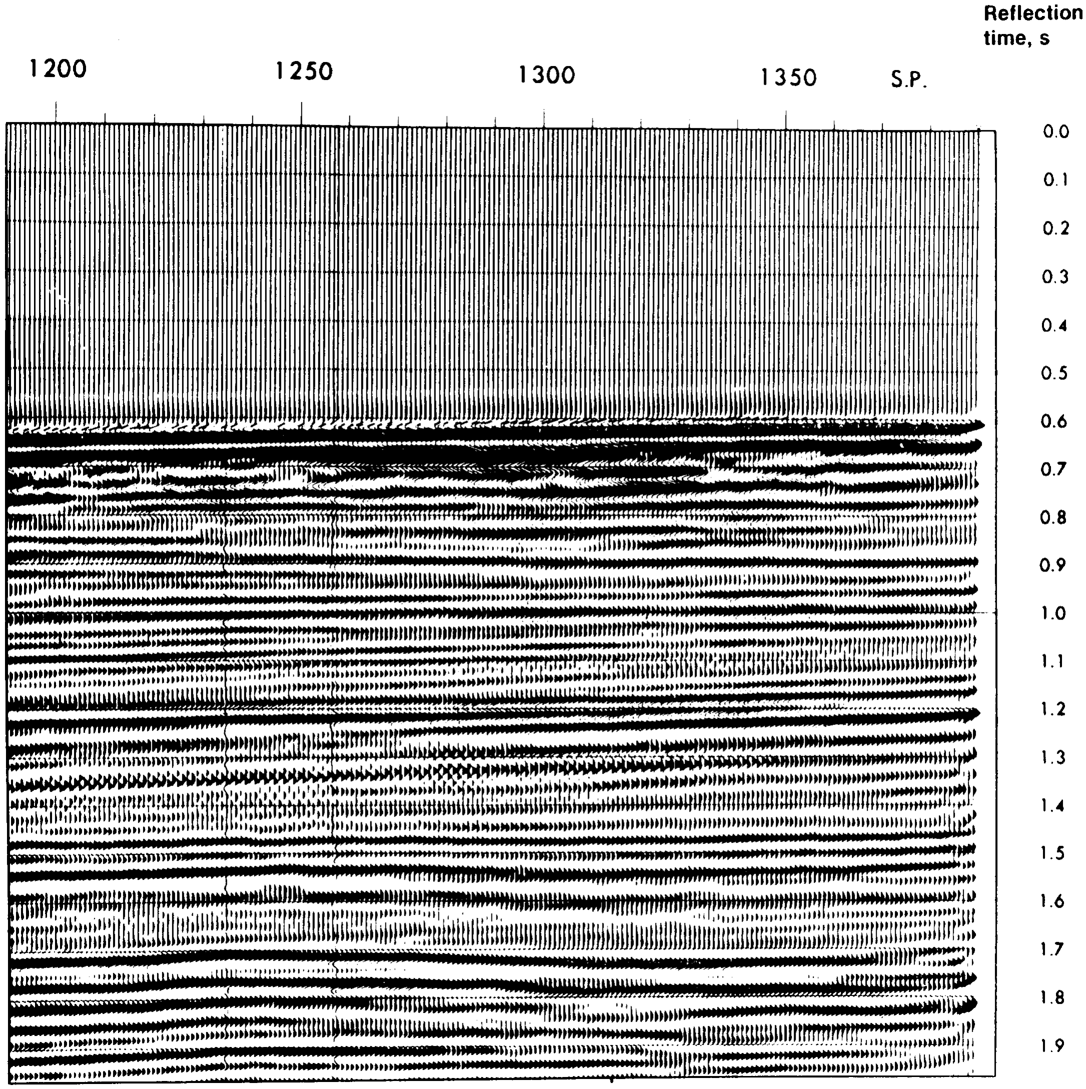


Figure 6-8 A Seismic Section

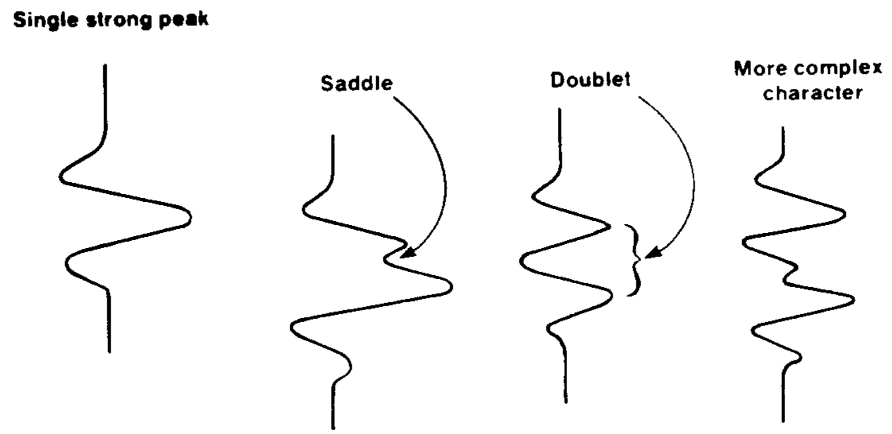


Figure 6-9 Character of Seismic Wiggles

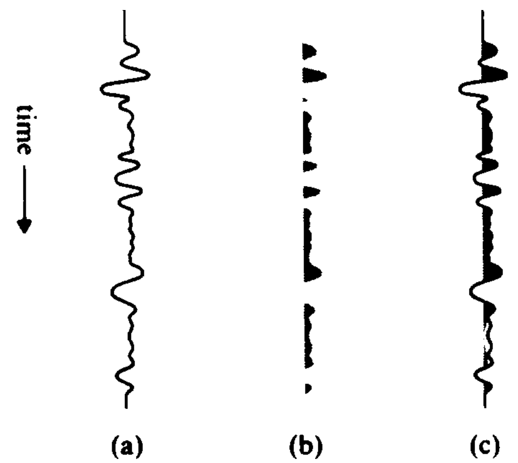


Figure 6-10 Displaying Traces

There are several aids incorporated into seismic lines to make interpretation easier. For example, horizontal lines cross the seismic trace at regular intervals which correspond to distinct times (Figure 6-11). There are also indications of where other lines cross, along the top and bottom of the page, to allow the interpreter to match lines for mapping purposes. And, like mudlogs and electric logs, there is information concerning elevations.

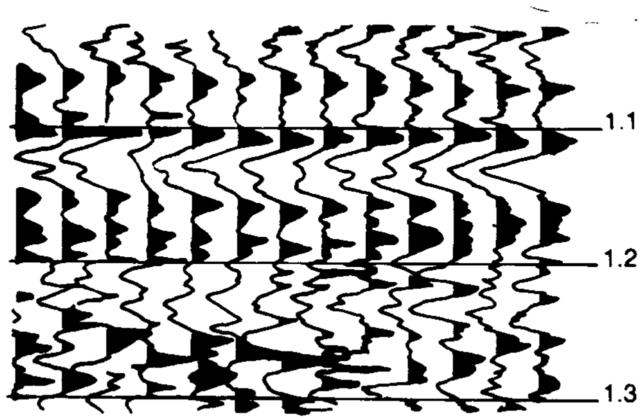


Figure 6-11 Seismic Traces and Time Intervals

Headers

Seismic headers contain much of the same information that is contained on mudlogs. One section includes the names of the client and contractor, the date that the data was gathered, how many times the data was shot, particulars on the sensors, spread layouts, energy sources, and the types of filtration that may have affected the data.

A second section indicates the name of the processing company (which can be different from the firm that shot the data), the day it was processed, and the variations of processing that were applied to the data. A third area will list any special types of processing that was performed, above and beyond the basic data manipulation. It is common to have the exact location of the line omitted, because seismic data is very expensive and often proprietary, so clients do not want everyone who might see it to immediately have this information.

Mapping With Seismic Lines

The hardest part of starting a seismic mapping session is deciding where to begin. The problem is very much the same as mapping with electric logs, in that you have a base map, a multitude of lines, a pencil in hand, and a confused look on your face. In all likelihood, the best place to start is in an area of interest, where you have the greatest amount of information from other types of data. If you have some idea of the geology beforehand, it is less likely that your initial attempt will be a futile adventure. So the best bet is to get as much correlation material as possible.

The Correlation Process

It is advisable that the first trace be along a strong, shallow reflector (seismic horizon) that continues completely across the first line. Your initial contour map will be of this horizon and it will serve as a reference for deeper reflectors. This is especially important in growth fault dominated areas where greater structural complexity, with an increasing numbers of faults, will be expected at greater depths.

After several reflector horizons have been traced across the first section, fold this section along the vertical intersect line and lay the fold along the intersect line on the next section. Then mark the new section where the horizons match reflectors at the same travel times. This allows you to accurately identify the traced horizons on the second section. Repeat this intersect identification process until the marker horizons have been identified on all seismic sections, throughout the area of coverage.

The process is relatively simple and straightforward, unless you have the misfortune of having lines that are on different scales. Ideally, it is best to have them reproduced to the same scale. If this cannot be done, it is possible to note one horizon's travel time at the line intersect point on the original section, identify this time on the new section where the two lines meet, and continue on tracing the horizon from there. This is a much less accurate method, but sometimes there are no alternatives.

Contouring The Horizon

The remainder of the mapping process is very much like working with electric logs, except that the contouring values will be seismic travel times from given reflectors, instead of actual depths. You do have a distinct advantage over electric log data in that bedding plane dips can be approximated from the seismic lines themselves, when the predominate lithologies, and therefore approximate travel times for those portions of the section, are known.

Identifying Seismic Structures

Interpretation of seismic lines requires a new way of thinking. Because a seismic line is constructed from timed reflections of waves propagated through an interval of rock and back to the surface, any conclusions drawn from the data must take into the account the variations and anomalies that can arise from the data collection process and subsequent processing. Always consider the way that different lithologies, with different porosities, will transmit the waveform.

Artificial Structures

A common problem that is encountered during seismic interpretation is the generation of an artificial structure. When a higher velocity lithology is localized within a seismic section, it can result in velocity “pull-up”. This artificial high results from the shorter travel time of the anomalous rock, and appears to show a high, when in reality it is a relatively flat bedding sequence. These structures can be identified and corrected if there is an accurate understanding of the transmission velocities of rocks above and to sides of the high-velocity zone.

Anticlines

Anticlines are the simplest type of structure to interpret from seismic data. They are characterized by an area where the reflections dip in both directions from a common point.

Of course, the anticline must have total closure to form a hydrocarbon trap and areal mapping, using several lines, is required to analyze the potential for oil and gas accumulation. Interpretation can be relatively simple when the reflections are good and the anticline is steep enough to be recognized, but not so steep that the reflections are highly distorted.

At times, an anticline can have such little relief that it is difficult to recognize. It can still be a significant trap, especially if it has a large areal extent. When a structure of this type is suspected, it can help to have the lines reprocessed with a condensed horizontal scale and an unchanged vertical scale, so that the high is emphasized.

Ancient Structures

Most sediments are laid down flat, and distortion occurs later through tectonic influences (faulting, folding slumping, etc.). The seismic sections show these features they appear now, after alteration. By marking one horizon and pushing traces up or down until a horizon is again flat, you can see what it looked like when it was deposited. You will also be able to see the approximate paleo structure below it.

The lower reflectors show the shape of deeper sediments at the time the flattened horizon was laid down. The layers on top of the flattened horizon will no longer have any geological meaning because they didn't exist when the corrected horizon was deposited.

Repeated “flattening” can be performed on various horizons, allowing you to reconstruct the geological history of the area. Once this is known, you will be able to make assumptions about how deformation could have affected adjacent areas and where traps can be located.

Fault Interpretation

Faults can play a major role in the accumulation of hydrocarbons, both in a positive and negative sense. A fault can form a seal on an up dipping porous, permeable formation, or can serve as a conduit to allow the fluids to escape. Whatever affect a fault has on the concentration of hydrocarbons, it is somewhat valid to assume that other similar fault types in the same area will have the same affects.

Normal and thrust faults can often be recognized through observation of vertical reflector offsets. This is not necessarily the case with strike-slip faults, because there is a major side-ways component of movement. If a lateral fault cuts through an area with structural highs and lows, the reflectors will appear to be showing normal faults, where one side appears to be up-thrown and the other down-thrown. Lateral faults that cut flat-laying beds might not be obvious at all, unless there is an associated component of vertical movement (which could appear as a normal fault).

Most faults cut numerous reflectors (Figure 6-12), and it is this distortion, dipping at an angle, that helps identify them. The breaks in the lines will slant down across the section. When the fault throw is small enough that the displaced horizon can be identified on both sides of the fault, the fault throw can be measured by noting the difference of travel time between the two horizons.

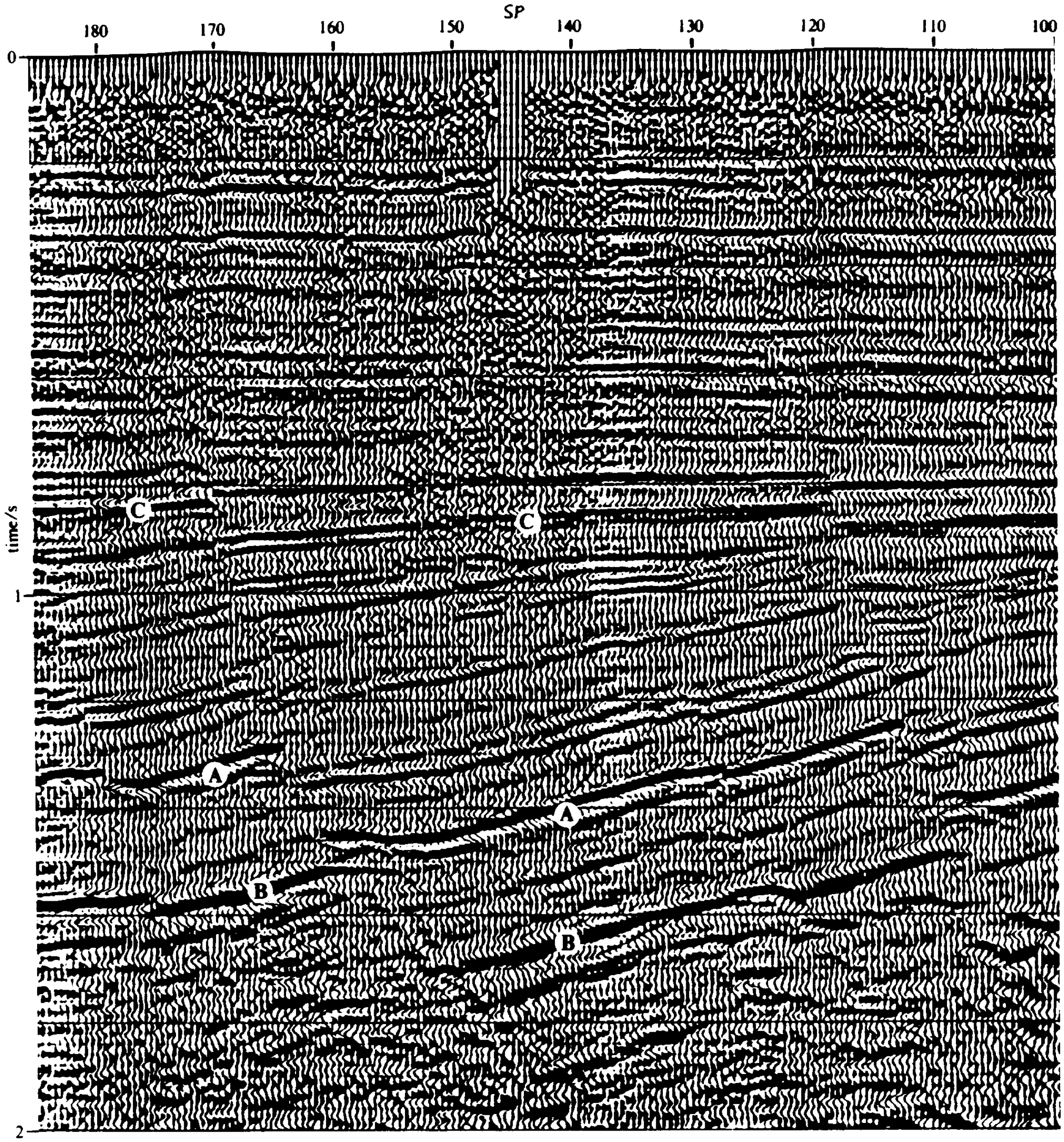


Figure 6-12 Seismic Section with a Fault Cutting Several Reflectors

Quite often, faults aren't easy to identify, many have no clear breaks and no diffractions. Identification can begin by looking for a sharp change in the dip of several reflections that change slants across the section, this could be a fault plane. There can also be a slanting line of bends in the reflections, with the dip remaining the same and an accompanying offset of horizons.

The angle of a fault is made up of a combination of time and horizontal distance. Unless the line is perpendicular to the fault trace, the angle on the section represents only one component of the fault's angle. In addition, if a seismic line runs exactly along a fault, the fault will appear horizontal on the section (and, horizontal faults are extremely hard to recognize). In general, faults are only readily recognizable if they intersect the lines at angles of 30° or more. Correlating across a fault is easier if the geological section is the same thickness on both sides. However, much of oil exploration takes place in growth-faulted areas, where there is syn-depositional fault growth. This results in thicker beds on the down thrown sides, often with intervals that are two to three times thicker than up thrown beds. The fault can continue to have movement, so that interpretation is further encumbered by the total separation of formations (with throws that can reach thousands of feet).

Faults can affect the velocities of rocks and can lead to improper interpretations of underlaying horizons. For example, if a reverse fault pushes a relatively high velocity zone over a section of the same lithology, the increased thickness can result in “push-ups” and suggest the presence of a structural high. The opposite affect could occur if the fault-influenced thickening involves relatively low velocity rock. In either case, these occurrences are very hard to interpret, because they look like entirely reasonable highs and lows. Whatever the influence a fault may have on the reflector horizons, be wary when interpreting anticlinal features that appear immediately below faults!

The Nightmare of Diapirs

Geologists and geophysicists have numerous problems with salt domes. As the low density material rises through higher density lithologies, it can grossly bend, break, and distort overlaying and abutting formations (Figure 6-13). This effects is illustrated in Figure 6-14.   The alterations can be tremendous, with multitudes of faults and small fault blocks being created.

Fortunately, rock mechanics dictate that the formations will fail in predetermined orientations, relative to the directions and magnitudes of applied stresses. In general, the overall geometry is such that there will be a pattern of faults angling out above the diapir, down thrown to the center, with the overlaying layers dropping down in stages. There may also be a network of radiating faults, that decrease in throw further away from the diapir high.

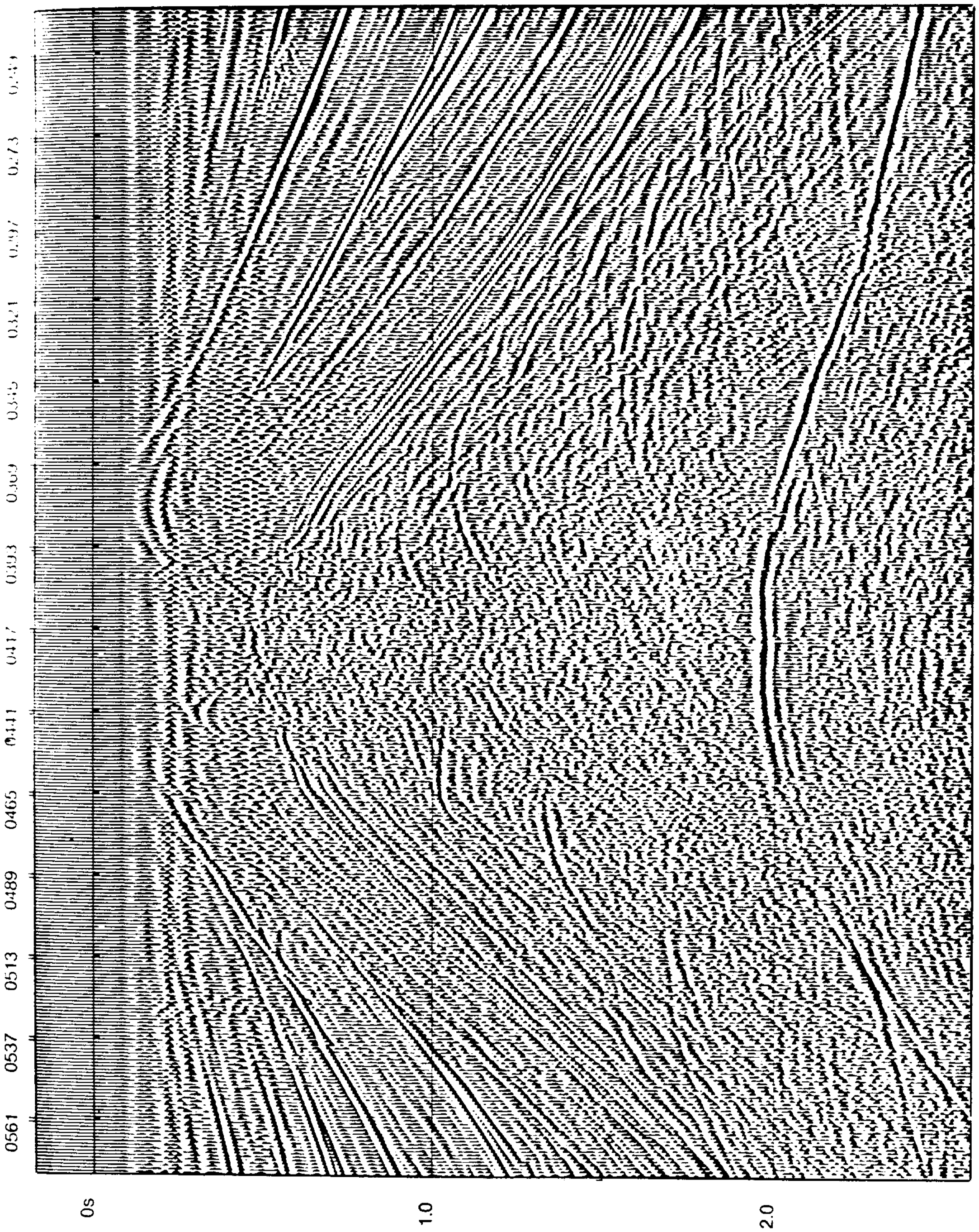


Figure 6-13 Seismic Section of a Salt Dome, Showing a Artificial “High” at 2 Seconds

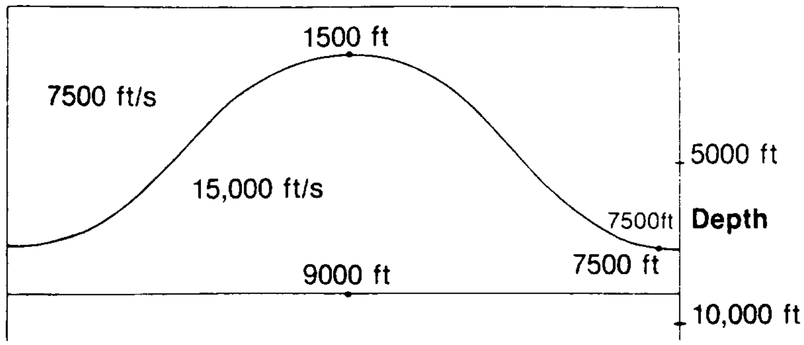


Figure 6-14 The salt in Figure 6-13, having a travel time of 15,000 ft/s, causes the seismic wave from the base of the dome to return to the surface faster than the surrounding rock, causing the reflection to appear higher than it actually is.

The nightmare begins when mapping areas around the dome, especially where there are intricate networks of very small fault blocks. The abundance of the blocks will depend on proximity to the dome and the overall amount of stress that the diapir exerted.

On seismic lines, salt diapirs are often seen as columns that extend downward to the bottom of the sections. Since the diapir lithology is fairly homogenous, there will be very few reflections inside the mass. Sometimes the top of the diapir will have a mushroom shape. Seismic waves striking from the top of the dome will not be able to “see” under the overhang. This is a severe problem because many hydrocarbon traps are formed where formations abutting the dome are warped up, resulting in stratigraphic/structural highs.

Reefs

When investigating seismic data, a reef can be thought of as any piled-up looking mass of limestone. There are other types of piles, but the distinctions are usually beyond the scope of seismic section discrimination. It is impossible to tell if the reef is in-place or is a heap of detritus, but this really doesn't matter. The main problem is finding the pile; oil and gas can accumulate in any number of these structures, as long as they are porous.

Reefs are generally easy to identify. However, these are often not the most desirable features to explore for. A textbook reef will have strong reflections on its top and bottom. Because reefs form on limestone layers, there is likely to be a reflection from the layer that humps up over the reef and maybe appears to split, one part going over and one under the reef. In other words, the reef will be a distinct mass that is isolated in the limestone surroundings.

Interpretation can be complicated, when low-velocity gas zones overlay the reef. The gas essentially lowers the overall velocity of the reef structure. If the net apparent velocity is close to the surrounding lithologies, the reef may not appear as a structural high at all. In other words, the very type of geological setting that you are searching for can be the hardest to analyze.

Since the top and base of a reef could be totally absent from your line, you would need to use other evidence to find it. Direct and indirect clues include:

- Reflections from the reef top.
- Reflections from the reef base.
- Shape.
- Dead zones in reef interiors.
- Reflections from reef interiors.
- Velocity effects on deeper horizons.
- Drapes over reefs.
- Diffractions.
- Geologic settings.

What Is The Overall Geologic Picture?

When seismic lines are examined, one is not really seeing structure and stratigraphy. Instead, you are looking at configurations of reflectors. Part of stratigraphic interpretation is accomplished by observation of parameters other than the alignments of reflectors. These include such things as velocity, amplitude, frequency, and phase. These factors yield information on lithology and pore space contents for a study called *seismic lithology*. Another part of stratigraphic interpretation, *seismic stratigraphy*, uses the reflector indicated shapes in a more general way. It concerns packets of reflectors, including the degree that they are parallel, the reflector strength, and the overall packet shape.

Study of seismic data can tell several types of things:

- Configuration of horizons
- Constituents of the rocks
- The deposition of the rocks

Separating structural and stratigraphic studies is probably a poor idea, since some of each is used in the determination of the three main types of information being sought.

Amplitude

The strength of a seismic reflection depends on the difference of velocities in the over and underlaying beds, with a stronger reflector occurring when the difference is greater. The greater the strength, the larger the swing of the trace will be; in other words, it has a bigger amplitude. The reflection amplitude will vary with alterations of pore fluid content as the layer extends laterally.

Bright spots are indicators of local changes in a layer's velocity. If the area is porous and filled with fluids that have low compressive strengths, there can be such a large velocity contrast with adjacent layers that there will be a relative amplitude reversal. Because positive wiggles are dark and negative wiggles aren't shaded, the zone will appear as a “bright spot” on the seismic line. Often, bright spots indicate the presence of gas, which has a significantly lower velocity than rock. Seismic energy travels slower in oil than in pore water, but the difference is small enough that a bright spot will not be noticeable. Fortunately, where there is oil, there is usually gas on top, so bright spots are useful in oil exploration.

Flat Spots will occur when there is a contact between a liquid and a gas in a limited area and the surrounding reflectors are not flat. The flat spot is in itself not an amplitude anomaly, but since the contact is associated with gas, the area can contain a bright spot.

A flat spot can be tilted. In one case, the beds can have been tilted after the flat spot was formed. A second type of tilt may appear when the spot is not actually tilted, but appears to be because of the velocity effect of shallower horizons.

The flat spot will be recognizable by its unique dip, compared to surrounding reflectors.

Deposition Information

Modern seismic sections are good enough that groups of reflections can be used to make assumptions about the history of deposition by using the study of seismic sequences. This discipline considers the seismic section after it is broken down into units separated by unconformities. Separate sequences are identified by their variations from adjacent reflector groups. For example, sand and shale underbids are usually strong, closely spaced reflectors. A mass with a few weak reflectors can indicate the presence of a reef or diapir. Dunes and other eolian deposits can produce many small arcs. Delta fronts have reflectors that are relatively thin nearest the delta and gradually thicken as the line progresses deeper into the sedimentary basin.

Summary

In closing, it should be remembered that the seismic sections are used to predict the geologic environment and hydrocarbon content of the subsurface, before drilling takes place. The use of the seismic reflectors has been mentioned in this chapter, and are summarized as:

Seismic Reflection Parameter	**Geologic Interpretation**
Reflection Configuration	1. Bedding Patterns
	2. Depositional Processes
	3. Erosion and Paelotopography
	4. Fluid Contacts

Seismic Reflection Parameter	**Geological Interpretation**
Reflection Continuity	1. Bedding Continuity
	2. Depositional Processes
Reflection Amplitude	1. Velocity-Density Contrast
	2. Bed Spacing
	3. Fluid Content
Reflection Frequency	1. Bed Thickness
	2. Fluid Content
Internal Velocity	1. Estimation of Lithology
	2. Estimation of Porosity
	3. Fluid Content

•Notes•

Self-Check Exercises: Introduction To Seismic Surveying

1. In geophysical terminology, what is a “single reflected-wave sensor”?

2. What is “normal moveout”?

3. What is the difference between the Vibroseis seismic source and dynamite or a “thumper'?

4. What are the advantages of marine seismic exploration over land seismic exploration?

5. On seismic traces, which are darker - peaks or troughs?

6. What type of information is often omitted from a seismic line header?

7. When looking at a seismic trace, what is the first step in seismic correlation?

8. When looking at seismic lines, what is an “artificial high”?

9. How can anticlines with low relief be recognized on seismic lines?

10. How are normal and reverse faults recognized on seismic lines?

11. How large must the fault angle be, before it is recognizable on a seismic line?

12. What is the shape of diapirs on seismic lines?

Introduction To Geochemistry

Upon completion of this section, you should be able to:

- Explain how organic matter is transformed into hydrocarbons
- Discriminate between the types of kerogen
- Understand and explain the various stages of petroleum formation
- List and evaluate the methods of source rock evaluation
- Describe subsurface geochemical logging
- Provide guidelines for geochemical log interpretation

Additional Review/Reading Material

AAPG, *Origin of Petroleum*, Reprint Series #1

AAPG, *Origin of Petroleum II*, Reprint Series #9

Huc, A.Y., *Deposition of Organic Facies,* AAPG, Studies in Geology #30

AAPG, *Petroleum Geochemistry and Basin Evaluation*, Memoir #35

AAPG, *Petroleum Geochemistry and Source Rock Potential of Carbonate Rocks*, SG #18

AAPG, *Organic Geochemistry in Petroleum Exploration*, CE #10

•Notes•

Introduction To Geochemistry

Sources Of Petroleum

Petroleum originates from a small fraction of the organic matter deposited in sedimentary environments. Out of the average “source rock”, 99% is mineral matter and 1% organic matter. Of this organic matter, 90% is kerogen and 10% bitumens. This organic matter is usually a combination of marine- and terrestrially-derived organic (plant) and zooplankton (animal), which constitutes more than 95% of the life in the oceans. Terrestrial organisms are mainly wind-blown spores and pollen, along with some woody debris from rivers and swamps.

All living matter is composed of four main constituents, lipids, proteins, carbohydrates and lignins.

Lipids These cover all organism-produced substances that are practically insoluble in water. This encompasses fatty substances such as vegetable oil, waxes and animal fats. Lipids are structurally very similar to the non-aromatic NSO compounds. Lipids are one of the main sources for petroleum.

Proteins These are high-order polymers made from individual amino acids, and account for most of the nitrogen and sulfur compounds in organisms. Therefore, most nitrogen and sulfur containing compounds found in petroleum are derived from proteins.

Carbohydrates

This is a collective name for individual sugars and their polymers. The name is derived from the formula $C_n(H_2O)_n$, which suggests hydrated carbons. Carbohydrates are not important sources for petroleum.

Lignins These are widespread in plants and are characterized by their aromatic (phenolic) structures. They are high molecular weight structures (polyphenols). The aromatic content of petroleum is derived from this group.

Table 7-1: gives the elemental composition of these constituents. Table 7-2: shows the distribution of these constituents in living matter. It can be seen that lipids are found in the lower life forms, such as algae, plankton and lower plant forms, and that lignins are found only in high-order terrestrial plants (due to its stiff, supportive structure. As can be seen, the main contributors to organic matter in sediments are; 1) phytoplankton, 2) zooplankton, 3) higher plants, and 4) bacteria.

Table 7-1: Elemental Composition (in wt %) of Organic Substances

	C	H	S	N	O
Carbohydrates	44	6			50
Lignins	63	5	0.1	0.3	31.6
Proteins	53	7	1	17	22
Lipids	76	12			24

Table 7-2: Composition (in wt %) of Living Matter

PLANTS	Proteins	Carbohydrates	Lipids	Lignins
Spruce Wood	1	66	4	29
Oak Leaves	6	52	5	37
Pine Needles	8	47	28	17
Phytoplankton	23	66	11	0
Diatoms	29	63	8	0
Spores	8	42	50	0
ANIMALS				
Zooplankton	60	22	18	0
Cephalopods	65	25	10	0
Oysters	55	33	12	0
Invertebrates	70	20	10	0

It is important to note that some geologically important biological compounds are not classified in any of the four groups. For example, chlorophyll (the green pigment in plants) is a combination of a lipid and nitrogen-containing molecules called porphyrin, connected by a carbonylic acid functional group.

Depositional Environments

Studies of present depositional environments show that the optimum requirements for accumulation and preservation of organic matter include:

- A large supply of organic matter
- An intermediate rate of sedimentation of fine-grained material
- An oxygen-poor environment to reduce oxidation and aerobic microbial degradation of dead organic matter

Continental margins have all the requirements for organic accumulation. Deltaic deposits have a rapid sedimentation rate, but it is also an aerobic environment causing degradation of the organic matter. The “benthonic zone” of the continental margin has an anaerobic environment, but little organic matter or sedimentation. Therefore, within the continental margins, only certain areas (lagoons, estuaries, deep basins within the margin) have both organic contributions, sedimentation and a reasonable anaerobic environment.

Kerogen

As organic matter matures from “biopolymers” (lipids, lignins, etc.) to something called “geopolymers” (nitrogenous and humic complexes), it is called kerogen. Kerogen is a general term describing any insoluble organic matter in sedimentary rocks. It is insoluble in water, non-oxidizing acids and organic solvents. It is best described as a heterogeneous, highly polymerized organic material, with a large amount of inter-bound aromatic rings. Kerogen has a variety of different side-chains emanating from the general aromatic nucleus. Kerogen is dispersed within sediments and is intimately associated (absorbed) into the mineral/rock. There are three major types of kerogen (Figure 7-1), each dependent on the type of source material.

Type I This type of kerogen is characterized by having a high initial hydrogen to carbon atomic ratio (H/C) of 1.5 or more, and a low oxygen to carbon atomic ratio (O/C) of less than 0.1. Type I kerogen has a hydrogen index greater than 300 and an oxygen index less than 50.

Its primary source is from algal sediments, such as lacustrine deposits. Type I kerogen is also called alginite kerogen, containing high concentrations of alkanes and fatty acids. It is the best source for oil-prone maturation, but unfortunately it is very rare.

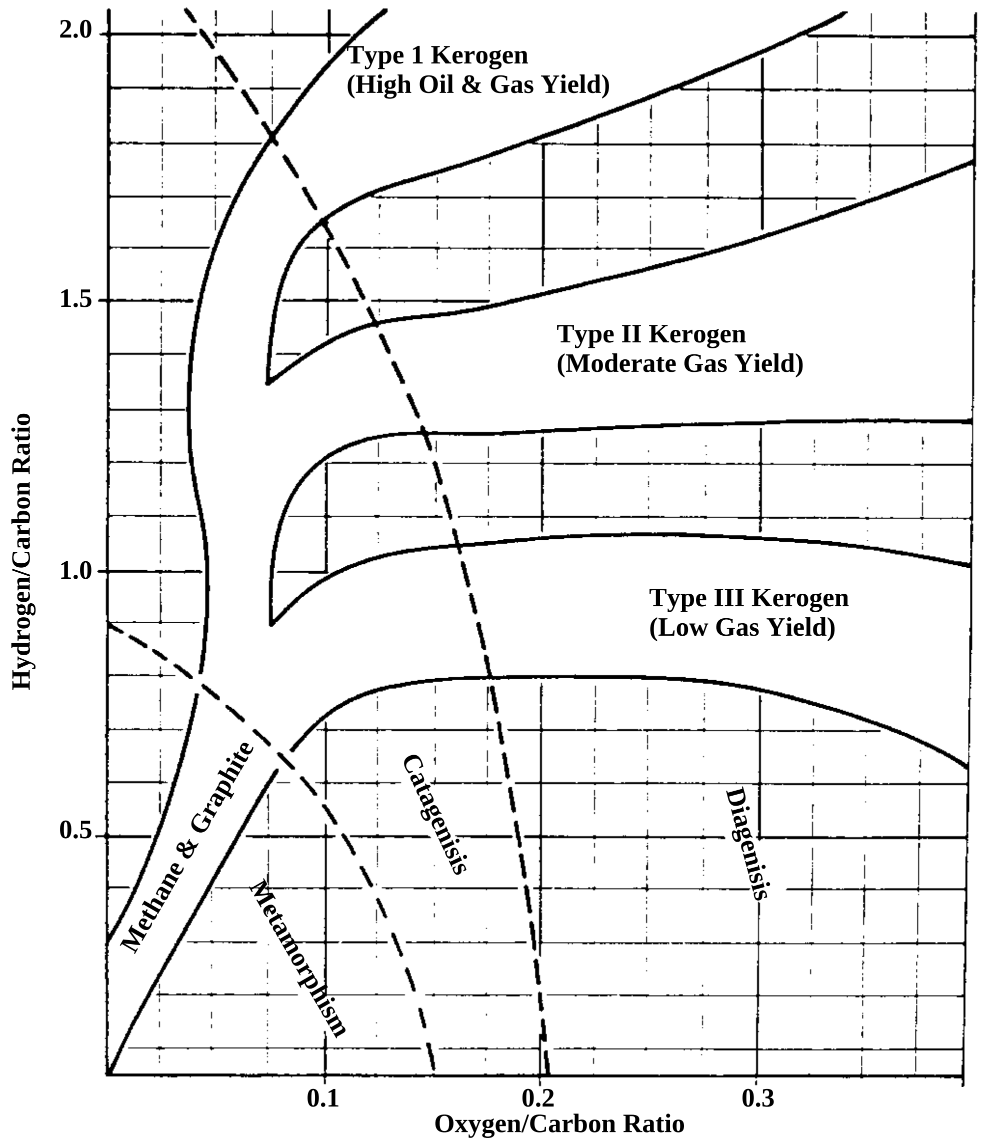


Figure 7-1 Van Krevelen Diagram Showing the Thermal Progression of Kerogen

Type II This type of kerogen has a relatively high H/C ratio (1.0 to 1.4) and a low O/C ratio (0.09 to 1.5). Type II kerogen has a hydrogen index between 200 and 300, and an oxygen index between 50 and 100. It consists of abundant moderate length aliphatic chains and naphthenic rings. Ester bonds are common and sulfur is present in substantial amounts.

Type II kerogen is also called exinite, and is usually associated with marine sediments, where autochthonous organic matter (bacteria, phytoplankton and zooplankton) have been deposited in a reducing environment. It is a good oil or gas prone kerogen. It is more common than alginite.

Type III This type of kerogen has a relatively low H/C ratio (usually < 1.0) and low O/C ratio (0.2 to 0.3). Type III kerogen has a hydrogen index below 300 and an oxygen index above 100. It contains an important proportion of polyaromatic nuclei and heteroatomic ketone and carboxylic acid groups. Aliphatic groups are a minor constituent, usually consisting of longer chains originating from higher-order plant waxes.

The main source of this type of kerogen are continental plants found in thick detrital sedimentation along continental margins. This type of kerogen is also called vitrinite. It is less favorable for oil generation, but will provide a source rock for gas.

A “Type IV” kerogen also exists, which is known as inertinite. This type of kerogen is usually associated with coal or organic matter that has been greatly oxidized.

All kerogen types experience chemical alteration during maturation. This results in the formation of petroleum, and generally begins with the loss of oxygen, followed by hydrogen, to arrive at a form of hydrocarbon. The terms “sapropelic” and “humic” organic matter are often referred to when using visual descriptions of kerogen. Humic material is thought to be derived from plant matter, while sapropelic material originates from algae or plankton.

Stages Of Petroleum Maturation

Once an organism dies, the process of petroleum generation begins. The majority of organic matter is totally oxygenated and degrades to carbon dioxide, water and small amounts of mineral matter. The organic matter that is deposited in a “reducing” environment suffers only minor oxidation.

The process of petroleum generation is divided into three stages; diagenesis, catagenesis and metagenesis. These divisions are artificial, since the process is a continuous one, without clear-cut boundaries. However, a number of different events do occur in each of the three stages, thus permitting a useful demarcation of stages. The process is one where biologically produced molecules tend to move to lower energy levels, and a final state of equilibrium (Figure 7-2).

Diagenesis

The first stage in the transformation of freshly deposited organic matter into petroleum is called diagenesis. This process begins at the sedimentary interface and extends to varying depths, but usually no deeper than a few hundred meters. In cases where the geothermal

	Carbohydrates, Lipids, Proteins, Lignins	**Biopolymers**
	Microbial Alteration and Hydrolysis *< 50°C*	
Diagenesis	**Sugars, Amino Acids, Fatty Acids, Phenols**	**Bionomers**
	Condensation, Cyclization and Polymerization *< 50°C*	
	Nitrogenous and Humic Complexes, Kerogen	**Geopolymers**
Catagenesis	*Thermocatalytic Cracking, Decarboxylation* *50 - 200°C*	
	Petroleum Hydrocarbons, Low Molecular Weight Organic Compounds	**Geonomers**
Metagenesis	*Thermal Crackin* > 200°C	
	Hydrocarbon Gases, Pyrobitumen, Graphite	**Residual Carbon**

Figure 7-2 Conversion of Organic Material into Hydrocarbons

gradient is extremely low, diagenesis may extend to a depth of 2,000 meters. During this time compaction of the sediments occurs, the temperatures and pressures are low, causing transformation to begin under mild conditions.

During early diagenesis, one of the main agents of transformation is microbial activity. Depending on the oxygen content of the sea water and sediments, microbial transformation of organic matter is either aerobic or anaerobic. Biological polymers (lipids, proteins, etc.) are destroyed by microbial activity and mild chemical reactions occur during this time. The constituent units of these biopolymers become progressively engaged in new polymer structures. The recombined polymers are the result of geological conditions and are thus called geopolymers. This early diagenetic geopolymer material is often called humin. As the humin is buried deeper by increasing overburden, it becomes progressively more polymerized and more chemically inert. A large carbon ring network develops and the material is then called kerogen.

During diagenesis, organic matter loses a great deal of oxygen in the form of H_2O and CO_2. The only significant hydrocarbon formed during diagenesis is microbial methane. Diagenesis causes a decreasing O/C, with only a slight decrease in H/C. The end of diagenesis is generally considered to be when the vitrinite component of kerogen exhibits an optical reflectance of 0.5%, under oil immersion. This also corresponds to a Rock Eval T(max) value of approximately 410°C to 420°C.

Catagenesis

As burial continues, the kerogen formed during diagenesis is exposed to increasing temperatures and pressures. Catagenesis is the stage of thermal degradation of kerogen that forms oil and gas. This stage typically occurs between the depth of several hundred to several thousand meters.

Sediments are further compacted, expelling water and altering the clay mineral fraction. The organic fraction undergoes major alteration during catagenesis. As a result of the temperature, kerogen is “cracked” to form liquid petroleum and gas. This cracking of kerogen is the breaking of the carbon-carbon bonds in the polymeric network. It is mainly the aliphatic side-chains which are cleaved off from the main aromatic kerogen network. It is these side-chains which form petroleum. Later stages of catagenesis results in the formation of methane from kerogen and also some cracking of already formed petroleum.

The main chemical change experienced during catagenesis is a decrease in H/C, resulting from the formation of hydrocarbons. The hydrogen portions of kerogen are released during the formation of petroleum, leaving behind a residue rich in carbon. This is the reason that oil-prone kerogens are rich in hydrogen relative to carbon and oxygen.

The end of catagenesis is generally accepted to be when all the major side-chains of kerogen have been cracked, and the remaining carbon network begins to take on mineralogical ordering of parallel aromatic sheets. This generally occurs at vitrinite reflectance levels of approximately 2% and T(max) values between 480°C and 490°C. It is within catagenesis that the majority of petroleum is formed. This is the “oil window”.

Metagenesis

The metagenesis stage is reached at great depths, or in areas of high geothermal gradients at shallower depths. Metagenesis usually begins at depths of approximately 4,000 meters. At this stage, kerogen has very little hydrogen remaining and is forming methane as its only hydrocarbon product. Towards the end of metagenesis, virtually no hydrocarbons are being generated from the kerogen. Throughout metagenesis, the residual carbon network takes on an increasingly ordered structure, where aromatic kerogen rings are condensed into parallel plates, as in graphite.

The H/C ratio and hydrogen index decrease only slightly during metagenesis, since most of the hydrocarbons have already been generated. The completion of metagenesis occurs at vitrinite reflectance values around 4% and T(max) values above 510^{o}C.

Gas Products Formed During Hydrocarbon Generation

There are gaseous hydrocarbons, carbon dioxide, hydrogen sulfide and other gases formed during the transformation of organic matter into petroleum. For example:

1. Methane, carbon dioxide and hydrogen sulfide can be formed by the bacterial action on the young sediments. These are referred to as biogenic gas.
2. Carbon dioxide is also formed during diagenesis when oxygen is expelled from kerogen. Diagenetic methane is also generated.
3. During the formation of oil, light hydrocarbons are generated, and become progressively more important at higher temperatures.
4. During late catagenesis and metagenesis, hydrogen sulfide is generated together with methane. It may be produced from kerogen or from liquid sulfur compounds within the crude oil. Hydrogen sulfide is particularly abundant if the organic matter itself was rich in sulfur (i.e. carbonate and carbonate-evaporite sequences). Carbon dioxide can be formed by the degradation of the crude oil by bacterial activity within the reservoir after the oil migrates to a formation with a lower temperature.

The Oil Window

The formation of oil from kerogen depends on the amount and type of source material present in the sediments and the thermal history of the kerogen. It has been conclusively determined that temperature is the most important factor affecting the generation of oil and gas from organic matter.

During the generation of petroleum from kerogen, both temperature and time play key roles. Kerogen, exposed to relatively high temperatures for a short period of time, will mature to about the same extent as kerogen which is exposed to relatively low temperatures for a longer period of time. Thus, the time and temperature history of a kerogen determines occurrence and depth at which kerogen generates oil or gas or both.

The depth range over which oil generation occurs (Figure 7-3) is known as the "oil window". This oil window is usually different for most sedimentary basins. It may cover several thousand meters or may be confined to less than a thousand meters. The depth range for the oil window is mainly a function of the past geothermal gradient and is similar to the present geothermal gradient if the subsidence history is continuous. If this assumption is correct, then the oil window can be estimated from the current downhole temperatures. However, if the tectonic history of the basin has been active, then such assumptions can lead to gross errors. The determination of the oil window is best performed by geochemical means using T(max), bitumen extraction, gas chromatography and optical methods such as vitrinite reflectance.

In the search for petroleum reservoirs, accurate determination of the oil window is important, because if an organically rich, oil-prone, source rock has not reached the oil window range of temperatures, it will not generate oil. Determination of the geologic time at which oil was generated within a reservoir is an important factor in evaluating the possibility of the presence of suitable structures to accumulate and trap the oil. If the generation of oil occurred prior to the formation of suitable reservoirs and traps, the likelihood of finding commercial quantities of oil is less certain, than if the reservoir and trap existed prior to the generation and migration of the oil.

Petroleum is found from the Precambrian to the Pleistocene, but is increasingly abundant in younger sediments. There are several reasons for this, the most notable are:

1. Older oil fields are increasingly destroyed over time.
2. The continental split during the Jurassic caused an increase in continental margins and restricted basins.

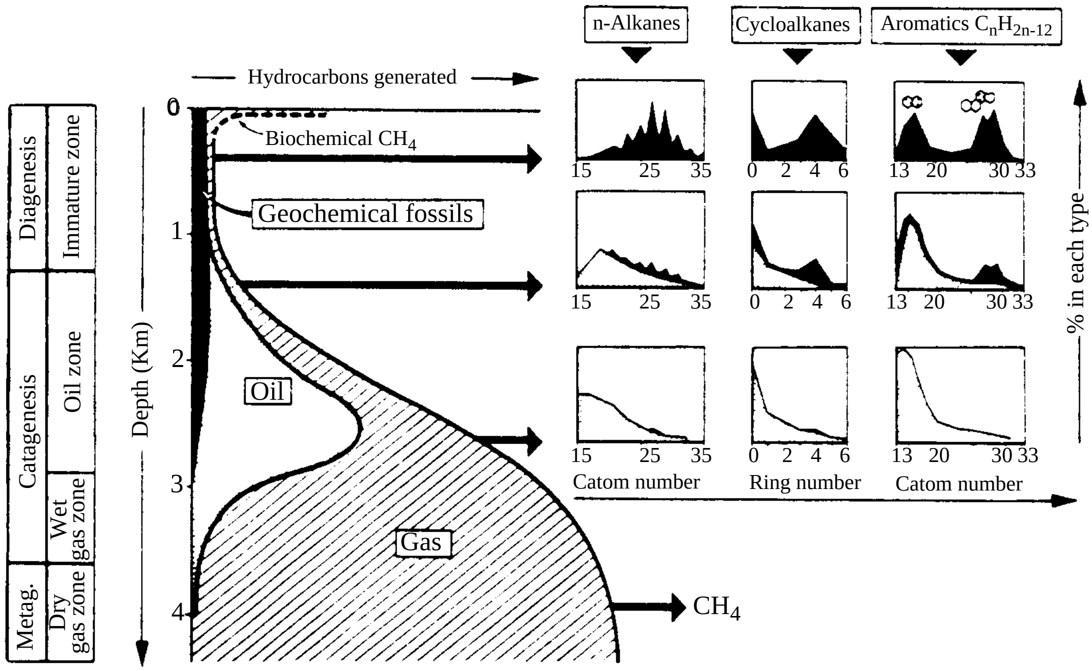


Figure 7-3 The Oil Window, and General Scheme of Hydrocarbons Produced (Modified after Taoist et al., 1974)

Methods Of Source Rock Evaluation

Pyrolysis

Pyrolysis techniques are performed directly on rock samples and offer the major clues in the systematic analysis of kerogen when using a large number of samples. The *Rock Eval* instrument provides a fast determination of the type and evolution stage of kerogen, together with a direct evaluation of hydrocarbon source potential. The type and quality of kerogen are usually interpreted on a graph derived from the traditional Van Krevelen Diagram, by replacing the H/C and O/C ratios with the hydrogen index (HI) and the Oxygen index (OI). The hydrogen and oxygen indices show a good correlation with the H/C and O/C respectively. However, the indices can be influenced by low organic content and mineral matrix. In these cases, it is advisable to use pyrolysis as a screening technique and to check any correlation with a kerogen elemental analysis. The total hydrocarbon source potential, expressed in kg/ton of rock, is also obtained directly from pyrolysis.

The maturation stage is usually obtained from T(max) (the temperature corresponding with the peak of kerogen pyrolysis). This parameter, measured on the bulk of the kerogen, has proved to be among the most reliable for characterizing thermal evolution. It is particularly valuable in the case of planktonic kerogen (Type I or Type II), where vitrinite is often scarce or absent. In addition, a composite T(max) diagram allows a visualization of the type and maturation of the kerogen.

Being fast and cheap, this type of analysis can be carried out in the laboratory or at the wellsite at selected depth intervals and the results plotted on a geochemical log, which will show hydrocarbon source potential and maturation. This log can also be used as a screening method for the selection of samples to be analyzed by more sophisticated techniques. In addition, the geochemical log provides excellent geological/geochemical correlation between different wells drilled in the same area. It can also offer an approach to the identification of facies changes across a basin.

Several versions of rock pyrolysis allow the trapping and subsequent chromatograph analysis of free hydrocarbons or hydrocarbons generated by pyrolysis, or both.

Optical Techniques: Transmitted Light

Optical techniques are widely used to characterize type and maturation of organic matter. Previous studies in transmitted light resulted in the classification of the types of organic materials present in samples. The relationship with the kerogen types defined on the basis of chemical analyses is generally clear, except for an "amorphous" type which has resulted in many discussions. Although amorphous kerogen is probably an alteration product of primary types, it is commonly considered to be dominantly algal in origin, and thus equated with Type II or Type I kerogen.

For this reason, the amorphous kerogen is considered to have a good source potential for generating oil. Systematic elemental analysis performed on a set of amorphous kerogens form various origins has determined that, although a certain number belong to Type II, the chemical composition of amorphous kerogen may spread over the entire Van Krevelen diagram. In particular, some of the H/C and O/C ratios are typical of Type III kerogen (humic material derived from terrestrial plants).

Optical studies in transmitted light may be interpreted by their geochemical logs, obtained by chemical analysis or pyrolysis. Using this, they can provide useful information on the heterogeneity of organic matter and the occurrence of recycled kerogen. Fluorescence studies can also help to separate Type I or Type II kerogens (fluorescence up to the end of the oil stage) from Type III and residual organic matter, which are generally non- or weakly fluorescent.

Optical Studies: Reflected Light

The method most often used to evaluate the maturation of kerogen and to establish the depth range associated with petroleum generation is vitrinite reflectance. This is an optical technique which measures the amount of visible light reflected from the vitrinite materials in kerogen (Figure 7-4). These optical studies in reflected light are oriented towards the characterization of maturation stages of organic matter, because it is difficult to establish a correlation between the types of kerogen (defined by their chemical composition) and the materials. Vitrinite reflectance was first used by coal petrographers to determine coal rank and now has become one of the most widely used parameters for measuring source rock maturity.

The vitrinite reflectance method is fairly laborious and requires extensive sample preparation. The method also requires a good deal of experience to accurately determine the vitrinite materials from other kerogen materials. The reflectance measurements must be made on the vitrinite particles.

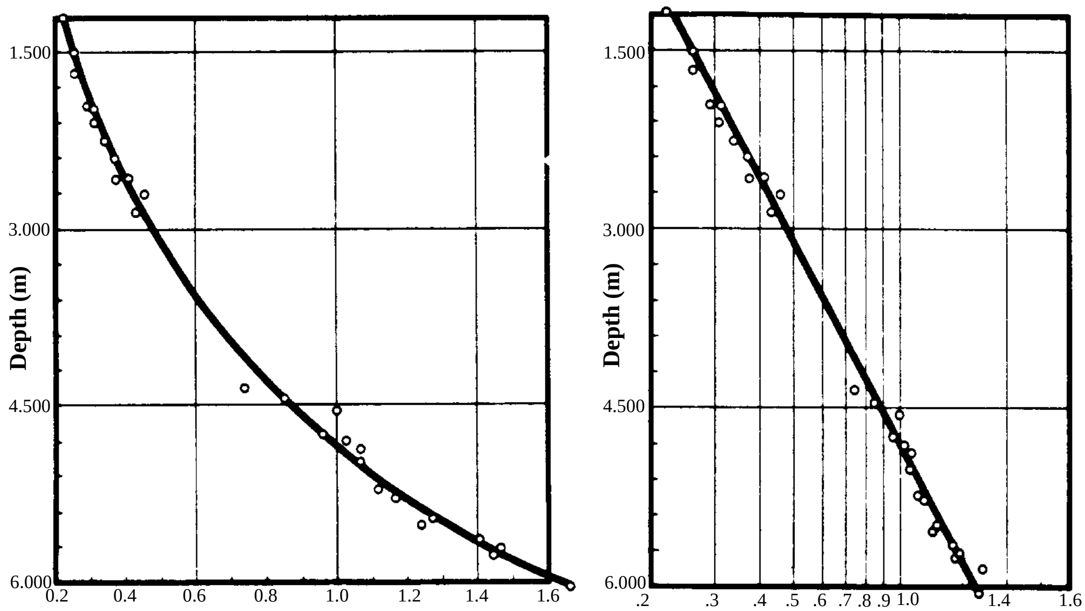


Figure 7-4 Vitrinite Reflectance Plots - Linear and Logarithmic Scales (After Dow, 1977)

Reflectance increases exponentially with depth (a straight line on a logarithmic scale). The oil window is generally accepted to be between the reflectance levels of 0.6% and 1.35%.

As mentioned earlier, the most frequently discussed aspects concerning the limitation of the method is the occurrence or identification of vitrinite and the extent of the “oil window” within the reflectance scale.

Concerning the first point, it has been shown that a limitation for using vitrinite reflectance may be the scarcity or absence of syngenetic vitrinite in the Type I and Type II kerogens. In addition, the method of selection of the material used in the measurement is of great consequence when different populations of subordinate materials are present in marine or lacustrine kerogens.

There has been many views expressed over the years about the extent of the oil window, in terms of vitrinite reflectance. There are no sharp boundaries of this zone. Kerogen may vary in composition, based on its original type, and the relative abundance of different chemical bonds. Thus, the onset of oil generation may occur relatively early (0.5% Ro) when some weaker bonds are abundant (Type II), or it may occur relatively late (0.7% Ro) when stronger C-C bonds are involved (Type I).

It should be remembered that different thermal histories (fast heating over a short period of time or slow heating over a long period of time) may result in the same vitrinite reflectance, but in different maturation levels of the non-vitrinite constituents in the organic matter (which are predominant in Type I and Type II kerogens). This phenomenon is due to the different kinetics of degradation. This would also apply to other optical indices of maturation.

Vitrinite reflectance is certainly one of the most valuable tools for measuring the maturation stage of Type III kerogen and coal. Other marine or lacustrine kerogens (Type I and Type II) may also contain particles resembling vitrinite, although their composition and the evolution of optical properties may be different. In this case, it is advisable to interpret reflectance based on kerogen type and to associate the optical index with a chemically derived parameter. The indices obtained from pyrolysis may be associated with vitrinite reflectance.

Subsurface Geochemical Logging

As with any other type of logging, the basis of all subsurface geochemical studies, whether at the prospect appraisal or basin evaluation stage, is the preparation of the geochemical log. Geochemical logs permit the identification of:

1. The presence or absence of potential source rocks for either oil or gas
2. The maturation gradient and identification of the immature, mature, and post-mature stages
3. The presence or absence of hydrocarbon shows, and the identification of the in situ or migrated character of those hydrocarbons

Geochemical logging generally consists of assembling a chain. Overall success depends on a series of distinct operations. To a large degree, it depends on the professionalism of the people that handle and process the rock samples at the wellsite and in the laboratory. For this reason, there has been a tendency to integrate geochemical logging with mud logging operations. Some critical links in the geochemical logging chain are:

1. Well site sampling operations, which will influence sample quality and how representative they are of the selected interval
2. Sample preparation at the wellsite and in the laboratory
3. Sample frequency in both cuttings and sidewall cores. This will determine the statistical accuracy of the geochemical logs
4. The geochemical methods used, and their precision and accuracy

Geochemical Logging Methods

The purpose of geochemical logging is to measure the following parameters relating to source rock evaluation in sedimentary rocks:

- Quantity of Organic Matter
- Quality of the Organic Matter
- Maturation of the Organic Matter

The knowledge of these three parameters permits accurate evaluation of the petroleum potential in those sedimentary rocks. Geochemical logging methods consist of two types; screening methods (leading to the production of the log) and more detailed methods.

Basic Screening Methods

Kerogen studies rely heavily on screening methods, and the most effective screening method is whole-rock pyrolysis (Figure 7-5). This type of screening is not new, oil companies have been using pyrolysis since the late 1960's. It is often used in combination with organic carbon measurements and with vitrinite reflectance. These combined measurements permits the construction of a relatively inexpensive, and quickly available, geochemical log. Several parameters in pyrolysis include:

Total Organic Carbon (TOC):
This indicates the richness of the organic matter in the rock. It includes both the insoluble organic matter (kerogen) and the soluble organic matter (bitumen). Organic carbon percent by itself is not a diagnostic measurement of source potential.

S2: The "hydrocarbon yield from kerogen cracking". This is a direct measurement of the rock's potential to generate hydrocarbons. It is a more useful and realistic measure of source potential than the TOC, because the TOC only measures the carbon skeleton of organic matter and is blind to the presence or absence of associated hydrogen. Hydrocarbons contain both elements.

S2/S3: This ratio is an indicator of hydrogen richness in the kerogen.

S2/TOC: This ratio relates directly to the potential of the rock to generate oil rather than gas. The higher the hydrogen richness of the kerogen, the higher the potential to generate oil.

S1: This represents the amount of free hydrocarbons that can be easily flushed out of the rock during the early part of pyrolysis. It is an important measurement for the detection of hydrocarbons.

T(max): This is the pyrolysis temperature of the S2 peak. It is a useful back-up to vitrinite reflectance, particularly in the late immature to strongly mature stage.

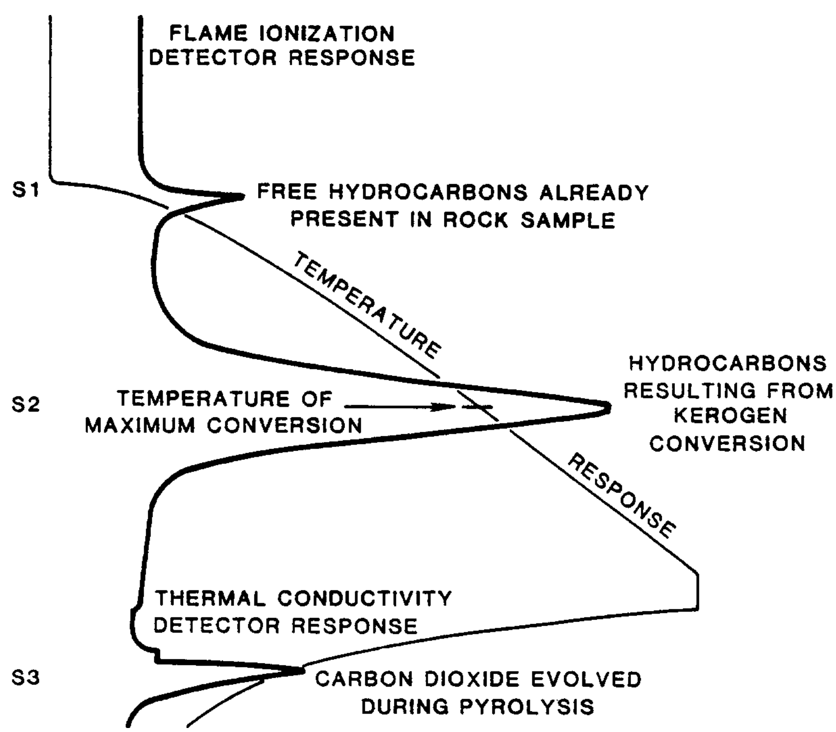


Figure 7-5 Source Rock Evaluation by Pyrolysis

Some operators like to work with canned cuttings gas as part of the screening process. Light hydrocarbon (C1 to C5 and C4 to C7) studies can be useful for quantitative show detection and to understand the migration phenomena in certain geologic settings. This type of "cuttings gas" is a questionable maturation measurement, since the gas tends to migrate upwards by diffusion in sedimentary sections. Vitrinite, which is a solid organic substance in the rock matrix, does not migrate. Mud logging gas curves, which are available at the wellsite, are also a very valuable, though often neglected, source of geochemical information.

Detailed Geochemical Methods

Soluble Organic Matter (Bitumen) Extraction

This is the production of a chromatogram detailing the C5+ hydrocarbons present in the rock. Information gained from this measurement reinforces the screening methods and helps remove ambiguities in the geochemical interpretation process. The following can be obtained through bitumen extraction:

1. It will confirm the oil-prone character of the source rock identified through kerogen studies. Mature oil-prone source rocks (with Type I or Type II kerogens) display high HC/TOC ratios (often on excess of 20%). Rocks with poor quality kerogens (gas-prone) display low organic carbon ratios. As with any analysis, these characteristics have to be observed in the context of several measurements within a vertical well profile.
2. A separate evaluation of maturation can be performed by calculating the Carbon Preference Index (CPI) on normal paraffin distributions. A CPI close to 1.0 is characteristic of a mature crude oil or rock extract. CPI determination is an excellent check, if reflectance is ambiguous, as to the placement of the top of the oil window. CPI is a direct measure of maturation on the rock-contained hydrocarbons.
3. There is a determination of the character of liquid hydrocarbons in fine-grained rocks. For instance, condensate shows can be distinguished from oil shows. The latter can be distinguished from shows given by active source rocks.
4. An additional oil-to-source rock correlation is done by comparing oils in reservoir rocks with bitumens identified in source rocks.

Elemental Analysis of Kerogen and Microscopic Kerogen Studies

When used with the Rock-Eval pyrolysis screening method, this will confirm kerogen typing. These methods were popular in the early 1970's, and can still be useful in regional facies studies and in cases where mixed kerogen types are encountered.

Pyrolysis Chromatography

This is performed when very detailed information is required.

Sampling Problems

Many geochemical logs are made from drill cuttings, complemented by sidewall cores. Three items affect the accuracy of geochemical logs when cuttings samples are used:

1. Sampling Interval
2. Sample Washing and Preservation
3. Sample Preparation in the Laboratory

Sample Interval

The smaller the sample interval for analysis, the better the geochemical log approximates reality. To appreciate this, one only needs to imagine a wireline log with a point measurement made every 300 feet. The log would be meaningless. Experience shows that widely spaced intervals do not reflect the geologic setting, and will usually miss significant zones of interest. The following intervals have been found to accurately portray the subsurface on geochemical logs:

1. Pyrolysis/Organic Carbon - every 50 ft (preferable every 30 ft)
2. Vitrinite Reflectance - every 500 ft (preferably every 300 ft)

It is meaningless to run a few isolated measurements (Rock-Eval, Vitrinite Reflectance, Hydrocarbon Extractions) which are out of geologic context, and without control of a closely spaced geochemical log. Detailed studies can be concentrated on the source rock intervals or on those areas of ambiguous data, after the screening methods.

Sample Washing and Preservation

Geochemical samples should be cleaned of drilling fluid and contaminants at the wellsite, prior to shipment and storage. If the samples are packed in plastic bags (especially mediocre plastic), it can cause problems when pyrolysis methods are used. Although kerogen studies (in principle) are not affected by the age of the samples, it is always preferable to work with freshly collected samples. Some oil companies use systematically spaced, extraction studies requiring canned cuttings collected at the wellsite and stored with a bacteriocide to prevent sample degradation.

Sample Preparation in the Laboratory

After arrival at the geochemical laboratory, the samples are usually rewashed and described. The next step is to pick representative samples of the interval. There are two different approaches to sample selection:

1. One called “positive picking” involves the selection of rock chips which are most representative of the formation of interest. This is done by a professional geologist, in possession of a composite log.

2. The other, called “negative picking”, consists of cleaning the samples of extraneous debris (rubber material, LCM, cavings, etc.) until only the cuttings of the expected formation remain.

   When oil-based muds (OBM) are used, samples for kerogen studies are generally dry-cleaned with a solvent.

In general, the best advise for sample selection is:

1. Use negative picking for screening studies using pyrolysis and organic carbon. Statistically speaking (in the context of a large number of closely spaced samples), this takes care of sampling anomalies.
2. Use controlled positive picking for the detailed geochemical studies, provided it is carried out by a trained geologist, using a detailed composite log or mud log.

As far as composite cuttings samples are concerned, although it is popular with some oil companies, it should not be done. It is best to use closely spaced spot samples only. The natural mixing of cuttings during circulation is already a problem, it needs no further compounding by artificial mixing in the laboratory.

Sidewall Cores

These provide better material for kerogen studies, particularly for vitrinite reflectance and pyrolysis/organic carbon measurements. Vitrinite reflectance studies are greatly improved in quality when using sidewall cores. However, sidewall cores can be a disappointment for bitumen extraction studies, if the mud system contains hydrocarbons or asphaltic additives. Sidewall core spacing can be narrowed down to 3 ft for important zones within a source rock section. Also clusters of sidewall cores can be shot near the same depth to obtain larger samples.

The combined use of cuttings and sidewall cores in geochemical logging is the optimum method, particularly if maturation is a critical issue.

Interpretation Problems

Interpreting a geochemical log consists of balancing a series of values and ratios obtained from various tests. These include; 1) the amount and type of organic matter in the rocks, 2) taking the existing maturation levels into account, 3) having to balance the geochemical test information with the information on mud logs, MWD logs and wireline logs, and 4) other evidence of hydrocarbon shows.

The fundamental equation is:

```
Petroleum Source Bed x Adequate Maturation = Shows of Free
Hydrocarbons
```

with the corollary:

```
Non-Source Beds x Adequate Maturation = No Free Shows of
Hydrocarbons
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Other aids to interpretation include:

1. **Maturation Range Charts** (from Demaison): The temperatures of the Rock-Eval T(max), in degrees Celsius, are temperatures reached by the instrument at the peak of S2. They are not earth temperatures. This chart (Figure 7-6) illustrates approximate earth temperatures. The numbers are real statistical averages observed in a large number of deep wells, with vitrinite reflectance, around the world. They are not the result of mathematical modelling.

2. **Vitrinite Reflectance vs. Atomic H/C of Kerogen** (modified from Do): This chart is useful for the identification of kerogen types, provided vitrinite reflectance and kerogen elemental analysis data are available (Figure 7-7).

3. **Hydrogen Index vs Oxygen Index** (modified from Espitalic): This chart is useful for identification of kerogen types, provided Rock-Eval pyrolysis and organic carbon determinations have been carried out (Figure 7-8).

4. **Hydrocarbon Preservation Windows** (modified from Dow): This is a convenient graph to plot vitrinite reflectance versus depth (Figure 7-9). It permits projection of maturation profiles below the total depth of wells and therefore, prediction of the depth to the maturation and post-maturation stages.

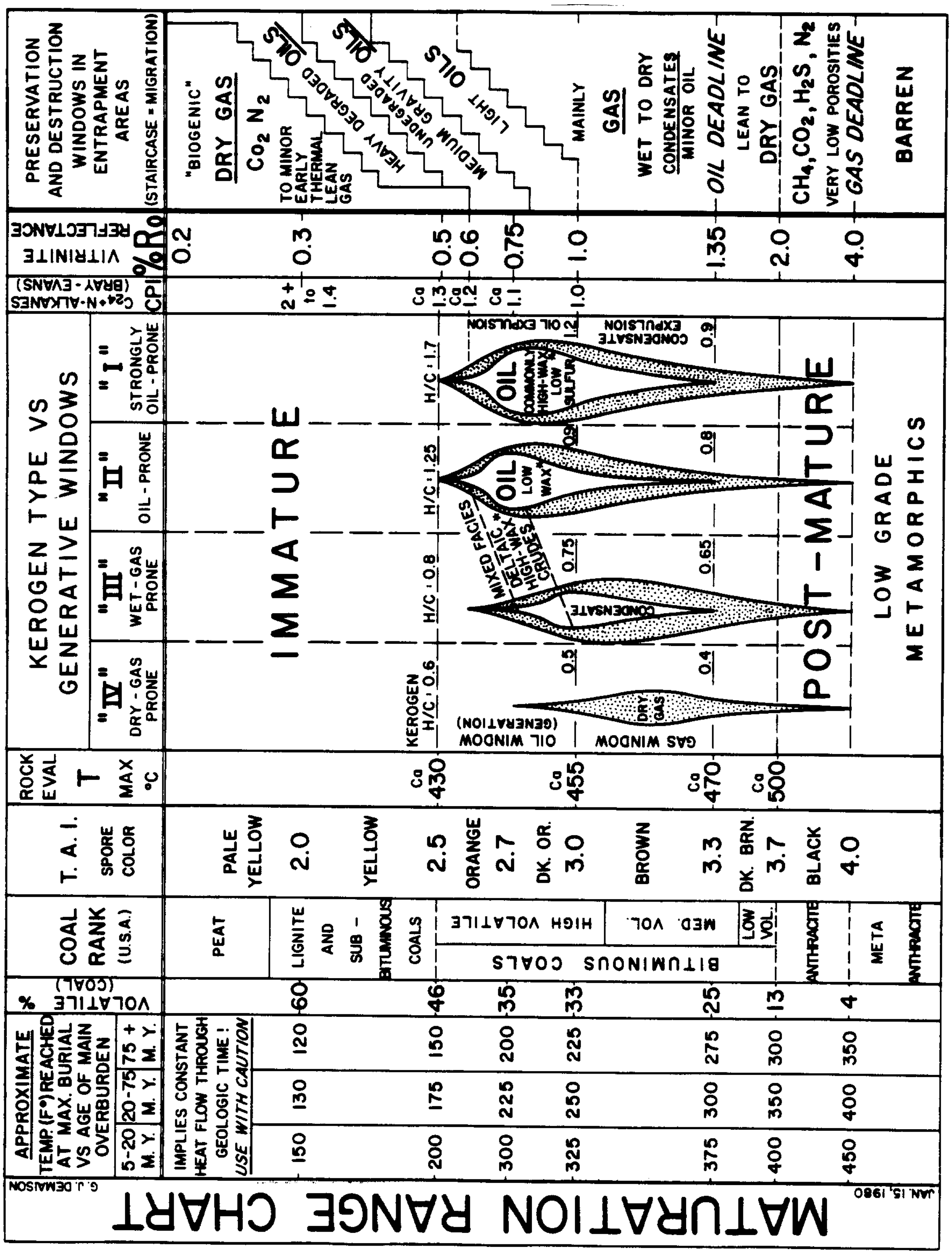


Figure 7-6 Maturation Range Chart

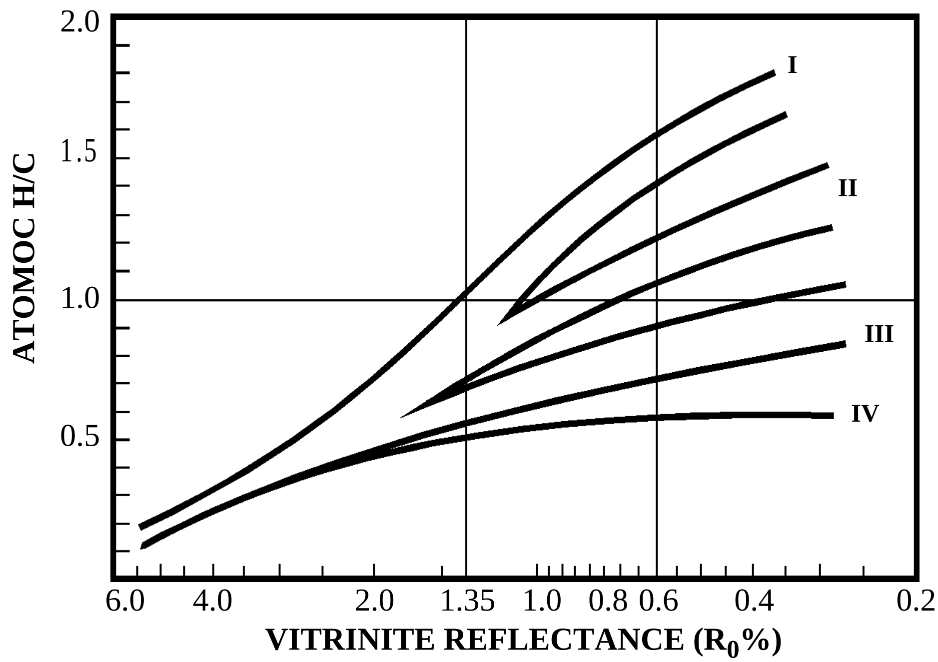


Figure 7-7 Vitrinite Reflectance vs Atomic H/C of Kerogen

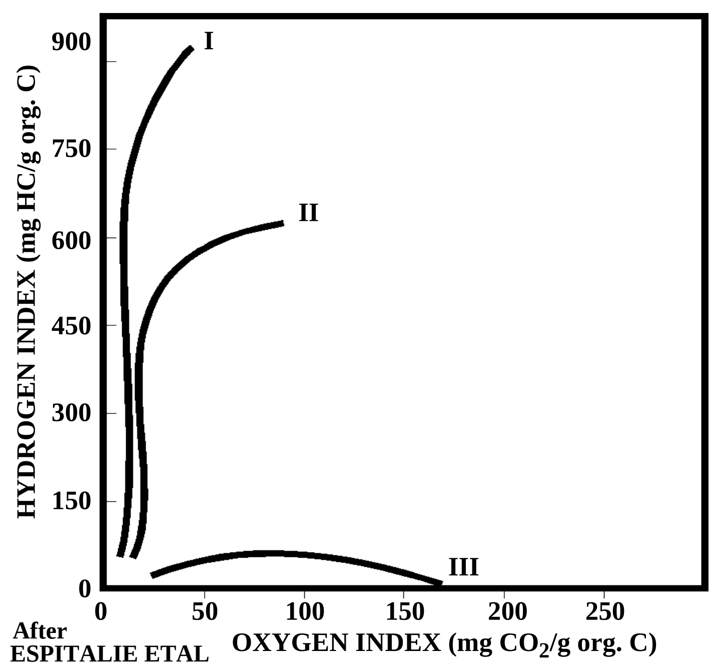


Figure 7-8 Hydrogen Index vs Oxygen Index

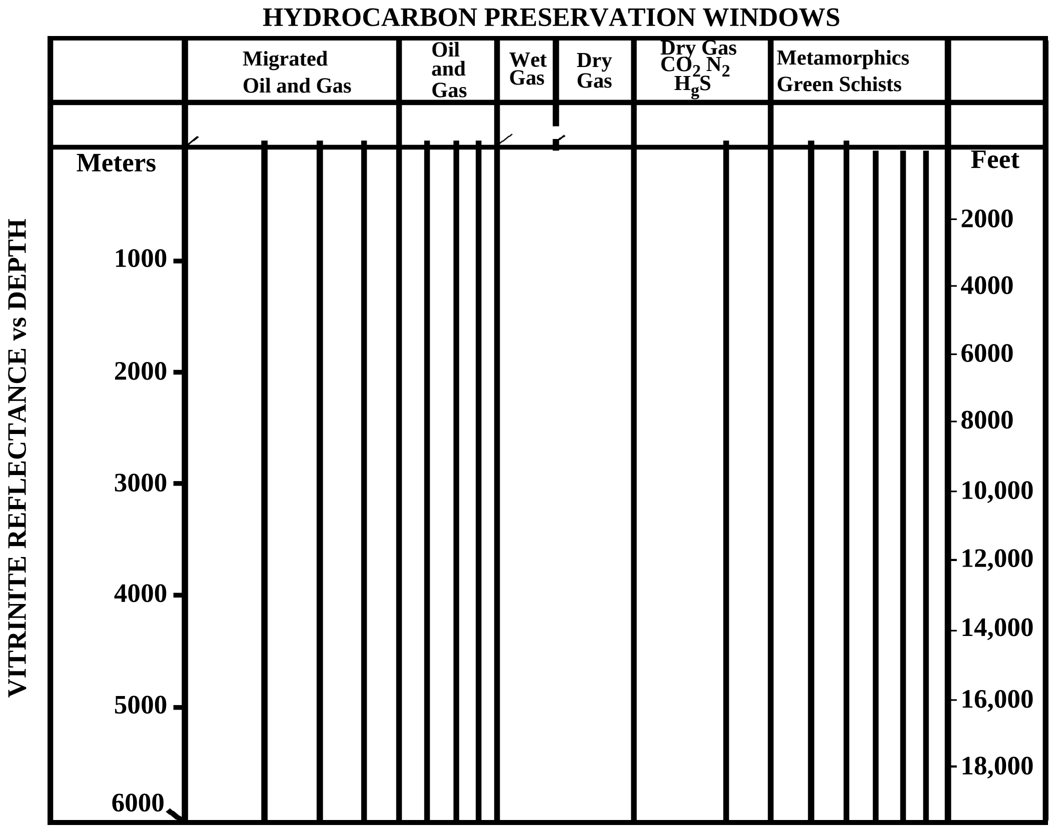


Figure 7-9 Hydrocarbon Preservation Windows Chart

General Guidelines For Users

Geochemical logs are best interpreted by geologists. Invariably, they are in a better position to integrate the geochemical data with the rest of the geologic and geophysical data, than are the laboratory specialists. Laboratory personnel are often far removed from the “big picture”, and are unprepared to understand its totality. What is true for geophysics and wireline logs is also true for geochemical logging.

For this reason:

1. It is desirable that all subsurface geochemical data be plotted on the same log. This log can then be used in reviews and technical meetings.
2. It is desirable that all explorationists learn the skills of geochemical log interpretation. These skills are easy to acquire, compared to what explorationists are expected to know in the fields of seismology and wireline logging.

Common Causes For Failure In Geochemical Logging

1. The sampling intervals for basic geochemical logging is too wide (i.e. over 100 ft per sample).
2. Sample selection is “positive” and carried out by non-geological personnel working without complete log control. The results can be so removed from reality, that their predictions are useless.
3. Exclusive reliance on non-geochemical (microscopic) methods for estimating kerogen type and amount. The incorrect assumption that all amorphous kerogen is oil-prone.
4. Absence of vitrinite reflectance measurements or vitrinite reflectance is carried out by inexperienced personnel, or the reliance on kerogen color estimation, or the exclusive reliance on light hydrocarbon studies to identify maturation stages.
5. Sections (particularly at medium and great depths) are preempted out of geochemical studies, depriving geologists of quantitative information on hydrocarbon shows obtained by light hydrocarbon studies or pyrolysis methods (i.e. Rock-Eval S1).
6. The results are presented on several disjointed data tables, rather than on a single graphic log. Geologists, in most cases, simply ignore the data.
7. Excessive delays in the delivery of the data. It comes too late to be of any use to explorationists or management. It is then likely to be filed away into oblivion.

•Notes•

Self-Check Exercises: Introduction To Geochemistry

1. What are the sources of organic matter that are deposited in sedimentary environments?

2. What are the four main contributors to organic matter in sediments?

   a.

   b.

   c.

   d.

3. What is kerogen?

4. What is the difference between “humic” and “sapropelic” kerogens?

5. At which stage, diagenesis, catagenesis or metagenesis, is petroleum formed?

6. Why are most oil fields found in younger sediments?

7. What is vitrinite reflectance and how is it used in determining the oil window?

8. When conducting Rock-Eval pyrolysis, what is Tmax?

9. What are the two main limitations of vitrinite reflectance?

10. What are the three basic geochemical screening methods for source rock analysis?

    a.

    b.

    c.

11. How does the “soluble organic matter extraction” chromatogram differ from the “canned cuttings gas” chromatogram?

12. What are the preferred sampling intervals for geochemical information?

    a. Pyrolysis -

    b. Vitrinite Reflectance -

13. What is the difference between “positive” and “negative” geochemical sample preparation?

14. Name four charts or graphs that can be useful in interpreting geochemical information?

    a.

    b.

    c.

    d.

15. What are two general guidelines for those reviewing geochemical logs?

    a.

    b.

•Notes•

Introduction To Well Testing

Upon completion of this section, you should be able to:

- Explain the differences between a DST and a Wireline Formation Test
- Discuss the procedures used when running a DST
- Read a typical DST chart
- Calculate the amount of water cushion required for a DST test
- Explain the procedures for running a wireline formation test
- Understand “pressure build-up theory” and explain what can be obtained from the calculations
- Collect the relevant data that is to included on the “Test Report” for attachment to the Formation Evaluation Log

Additional Review/Reading Material

IHRDC Video Tape PE 404 - *Drillstem Testing*

Lee, John, *Well Testing*, SPE Textbook Series

Atlas Wireline Service, *Formation Multi-Tester, Principles, Theory and Interpretation*, Western Atlas International,1987

Johnston-Macco, *Review of Basic Formation Evaluation*, Schlumbeger, 1976

•Notes•

Introduction To Well Testing

The various methods of formation evaluation have advanced considerably in recent years, but regardless of the evaluation method, the commercial potential of any formation cannot be accurately determined until that formation is allowed to produce. A Drill Stem Test or a Wireline Formation Test is essentially a temporary well completion conducted for the purposes of sampling formation fluids, and establishing the probability of commercial production.

Before the development of a method for testing the productivity of a formation, it was necessary to set a string of casing and merely allow the oil, water or gas to flow into the borehole, after removing the drilling fluid.

Apart from being potentially very dangerous, this technique was also time consuming and expensive (having to set casing), particularly if the test was negative and drilling was resumed. In many cases, because of this deeper drilling was restricted because of the smaller hole size. The development of a safe, simple and inexpensive testing technique was therefore a major advance, and was successfully introduced to the oil industry in 1926. The process of opening isolated sections of the borehole to atmospheric pressure made it possible to test formations without unnecessary hazards.

Test results may be obtained in the open hole, or through perforated sections of casing, to determine the productivity of the formation and secure samples of the formation fluids for laboratory analysis.

The Drill Stem Test (DST) was first introduced by Halliburton. It was designed to temporarily relieved the hydrostatic pressure of the drilling fluid from the formation by the use of down hole tools. This was done by setting a cone packer on the shoulder of a smaller ID hole which had been drilled into a potential oil bearing formation. A gear operated valve provided the opening and closing operations of the test.

A pressure recording device was later incorporated to verify the correct operation of the tool, and was at this stage rather insensitive. However, with the recognition of the potential value from interpretation of DST pressure curves, the development and use of accurate pressure recorders quickly followed.

Today, the DST is made by lowering a valve, packer and length of perforated tail pipe on the end of drillpipe to the level of the formation. The packer is set against the wall of the borehole so that it seals off the test interval from the mud column above. The valve is then opened which effectively reduces the pressure opposite the borehole to atmospheric pressure causing formation fluids to flow into the hole and be produced through the drillpipe.

In addition to the DST, wireline formation testers (FIT, RFT) are often used to provide a safe, fast and economical method of testing. They may be run at the end of a logging suite and are particularly useful for testing zones indicated by wellsite log analysis to be productive before incurring the expense of completion.

A wireline tester consists of a sampling chamber or chambers connected to an opening in a pad that is forced against the wall of the borehole, to produce a seal. A tube or shaped charge is forced into the formation, allowing formation fluids to enter the tool. A pressure transducer measures both shut-in and flowing pressures.

The major difference between this and the conventional DST is the amount of fluid sample obtained from the test. Wireline tests usually collect up to 6 gallons per chamber. Also the fluid flow in a wireline test is through a single perforation.

By using two sample chambers, fluid from different zones can be produced and recovered and a whole series of pressure tests conducted, whereas the DST can only sample one zone at a time.

The overall aim of these tools is to provide a sample of formation fluids and to enable the following evaluations to be made.

1. Fluid Identification
    - oil gravity determination
    - gas analysis
    - gas/oil ratio
    - water cut
2. Pressure Determination
    - flowing pressure
    - formation shut-in pressure
    - hydrostatic pressure
3. Permeability Determinations
    - rough estimates from examination of pressure curve
    - pressure build-up theory
4. Estimations of daily oil/gas production

Drillstem Tests

As mentioned above, the DST operates by isolating the zone to be tested by means of a packer or series of packers. A tester, containing control valves is situated above the packer and the valves are opened after the packer has been seated. The expanded packer prevents drilling fluid in the annulus from entering the section to be tested, so that only fluids from that section can enter the drillpipe.

A continuous record of the pressures is made and recorded, describing flowing and shut-in periods as well as running in and pulling out of the hole.

When the test period is completed, the drillpipe is raised which performs a number of functions. Firstly, it closes the valves of the tester, trapping any fluids inside. Secondly, it opens a by-pass valve which allows the pressures on either side of the packer to equalize. Finally, it extends and reduces the packer to normal size so that it may be unseated and the test-string retrieved.

Type of Packer Arrangement

There are three main types of packer arrangements, shown in Figure 8-1, they are:

1. The Open Hole Single Packer DST

   this tool can test one zone or series of zones at the same time beneath a single packer situated in the open hole and with the drillstem resting on bottom of the borehole.

2. The Straddle Packer DST

   this tool is used to isolate formations above and below the zone to be tested. An anchor assembly is required.

3. The Hook-Wall Packer DST

   this tool has the packer set inside casing and supported by a set of slips. It is used to test through perforations in the casing or in the open hole beneath the casing, as well as for water shut off after cementing. This type of test is useful when a multi-zone completion is anticipated.

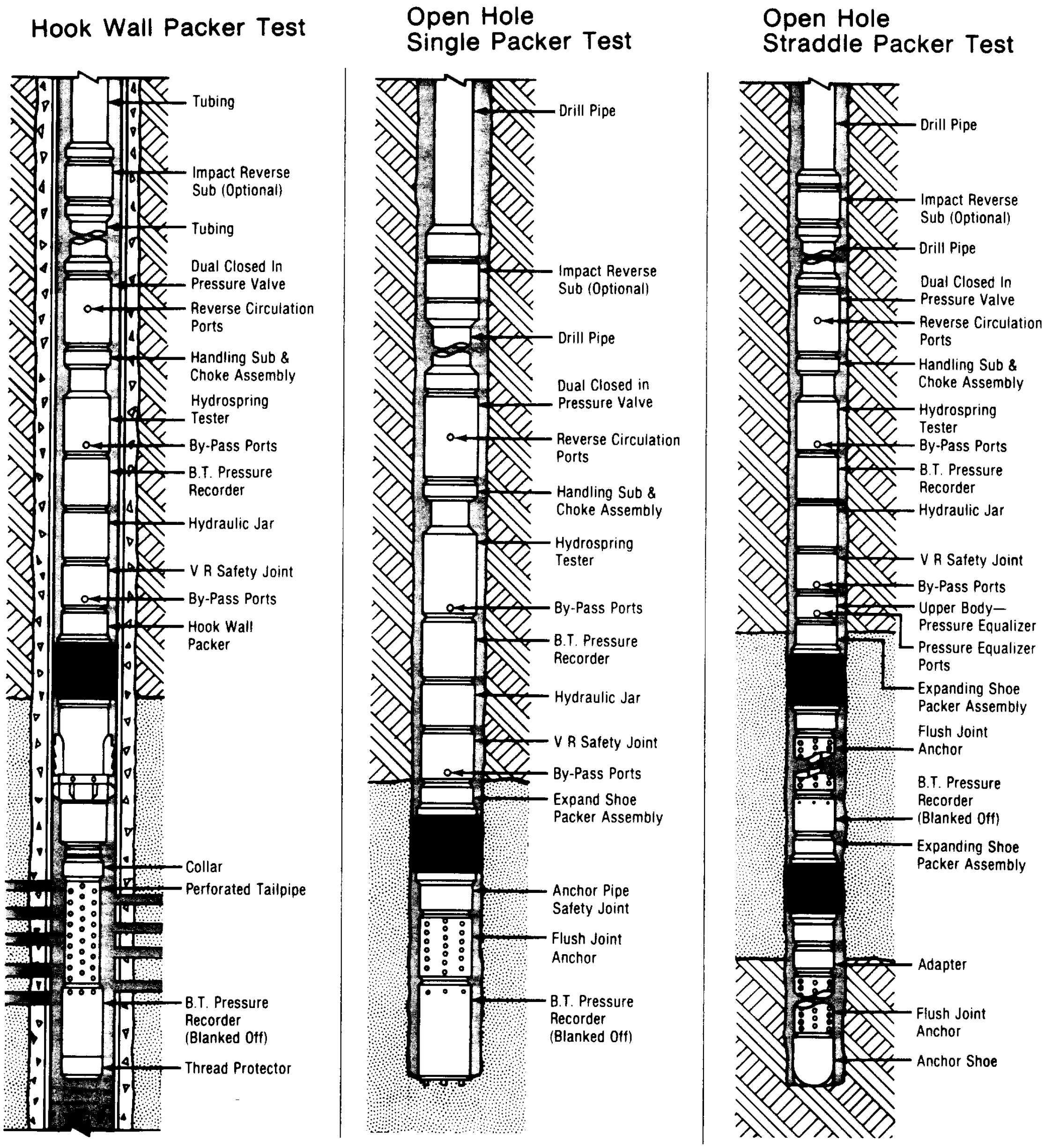


Figure 8-1 Three Basic DST Assemblies (from Halliburton Services)

Pre-Test Procedures and Precautions

1. Conditioning the Mud System - The drilling fluid must be properly conditioned before the test can take place. In particular the following parameters should be checked:

    a. Mud Weight - This should be sufficient to control the well throughout the entire testing procedure.

    b. Viscosity - Must be high enough to remove all the cuttings from the hole, yet the mud must be fluid enough to reduce gas cutting to a minimum.

    c. Water Loss - Must be low to prevent fluid migration, and the filter cake must be thin to prevent sticking of the test string, particularly the packer.

The actual mud type, whether it be oil or water based does not alter the testing procedure.

4. All foreign material must be removed from the hole using a full gauge bit and casing scraper.
5. In open hole testing the section in which the packer is to be set must be chosen carefully. The caliper log can be an invaluable tool in this respect.
6. Checks must be made for leaks in the drill string when running into the hole, and all joints should be pressure tested.
7. The borehole must be full of fluid before the tester valves are opened. If the fluid level drops after the valves are opened, the packer may not be seated correctly.

Pressure Recording Devices

Recording devices provide a continuous record of the various pressures which occur during the test. In fact it records pressure at all times, whether it's caused by the mud, oil, water or gas. The record appears on a chart placed in the testing assembly and recordings are made on a black coated brass drum by a steel, diamond or sapphire stylus. The stylus is attached to the end of a helical Bourdon-type tube.

Well pressures are transmitted through a rubber diaphragm to a fluid inside the tube. The pressure increases cause the tube to uncoil, moving the stylus away from the baseline on the chart. The chart travels past the stylus at a constant rate and is controlled by a spring driven clock designed to withstand shocks and high bottomhole temperatures. Clocks can vary from 3-180 hours and the pressure recorders can handle 500-25,000 psi.

The tool also incorporates a maximum temperature recording thermometer as bottom hole temperatures in excess of 200°F can affect the calibration of the tool. Calibration should be done regularly using a dead weight tester.

Standard, Single Packer Drillstem Test Procedure

The exact arrangement of the various valves, testers, packers and pressure recording devices will be determined by a number of factors, the most important being the condition of the well and the purpose of the test as well as particular operating companies' procedures. With this in mind, a very generalized arrangement is outlined below:

1. Disc Valves - situated on top of the assembly
2. Shut-in Pressure Valve - situated above the equalizing valve
3. Main Valve - above the equalizing valve to stop flow into the pipe
4. Equalizing Valve - situated directly above the packer
5. Packer
6. Anchor - with perforations to allow fluid entry
7. Pressure Recording Devices
8. Safety Devices
    a. Jars - situated as close to the packer as possible.
    b. Safety joint - allows recovery of equipment and the test record.
    c. Reverse Circulating tools

Procedure

1. The testing assembly (Figure 8-2) is lowered into the hole on drillpipe, with the test valve closed to prevent fluid flowing into the drillpipe. Usually a portion of the drillpipe is filled with a cushion of water, oil or drilling fluid to prevent the collapse of the drill string, particularly at greater depths. It also helps reduce the shock with the sudden and complete release of pressure when the test valve is opened.
2. With the anchor resting on bottom, part of the weight of the drillstring is applied to expand the packer. With the tester valves opened, the packer is completely expanded due to the hydrostatic pressure of the drilling fluid acting on the exposed end of the packer.

   Sealing is completed as the packer conforms to the exact shape of the hole. The perforated anchor pipe supports the packer from below. The anchor pipe should be set in a firm formation which has not been washed out.

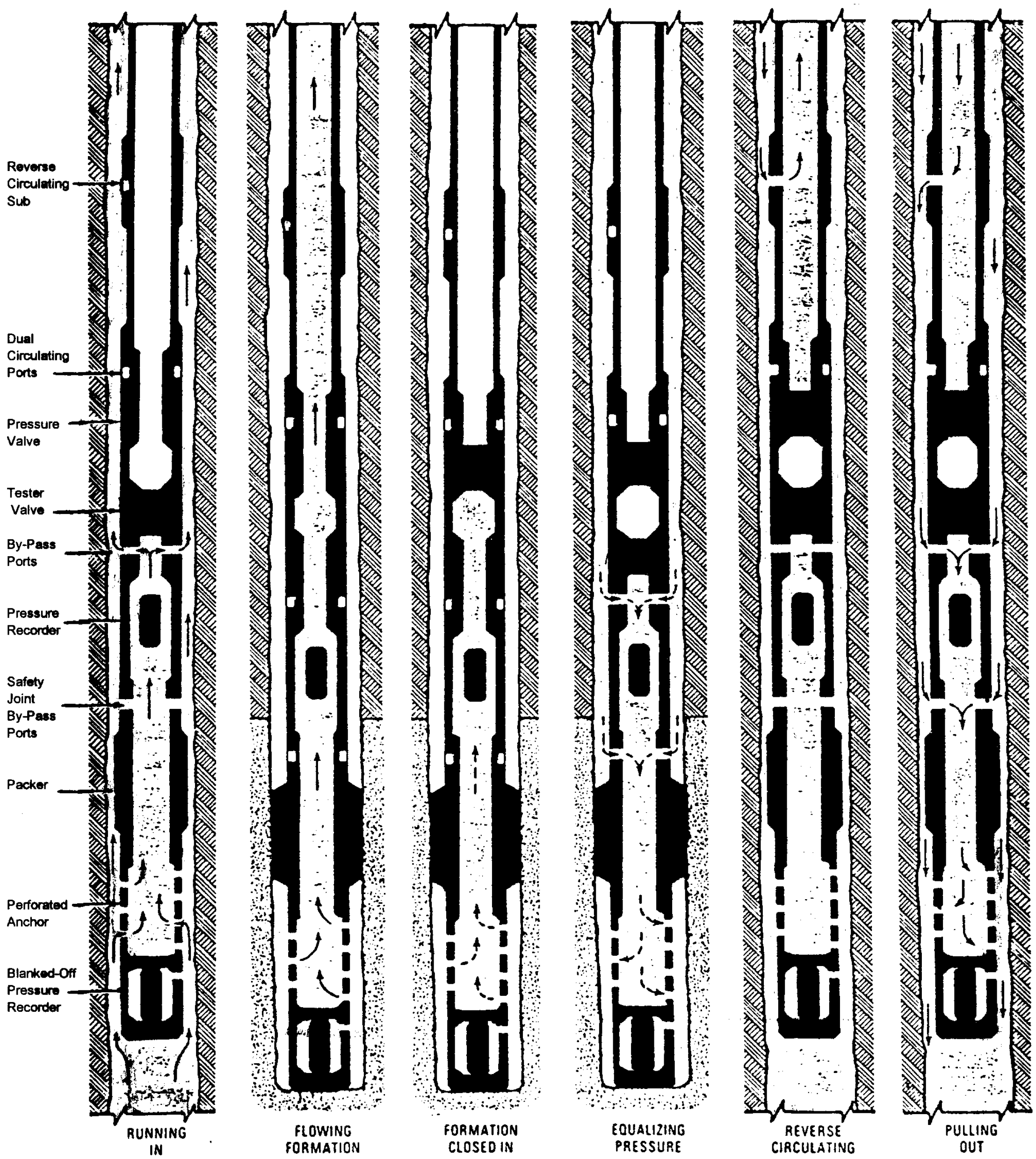


Figure 8-2 TESTING - Fluid Passage Diagram (from Halliburton Services)

3. The packer supports the hydrostatic pressure load of the well fluid and the formation below the packer is relieved of pressure and exposed to near atmospheric conditions. The formation fluids can then flow into the hole and be produced through the drillpipe (Figure 8-3).

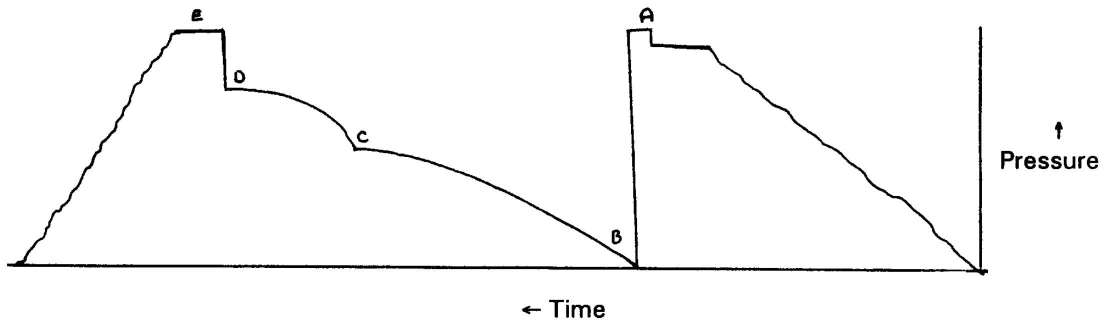


Figure 8-3 A Typical DST Chart

From right to left, the chart shows the build up to hydrostatic pressure as the tool is run into the hole. At the test depth, the pressure of the mud column is recorded at point A.

Setting the packer causes compression of the mud in the annulus in the test interval shown by a small rise.

With the packer set and the test tool open, the pressure drops to the initial flowing pressure at point B, which should be close to atmospheric pressure.

The flowing pressure then rises to a maximum at point C, as the fluid moves from the formation through the perforated anchor and into the drill pipe.

After the well has been flowing for the desired length of time, the shut-in valve is closed by rotating the pipe to the right. The pressure builds up and the final shut-in pressure is recorded at point D.

When the shut-in period is completed, the equalizing valves are opened allowing the pressure to equalize on both sides of the packer which can then be unseated. The pressure then increases to hydrostatic pressure at point E. As the test string is removed from the hole the pressure gradually reduces to atmospheric. Before pulling out of the hole, any fluids in the Drillstring can be reverse-circulated out, and either collected or disposed.

Calculating the Water Cushion for Drill Stem Test Tools

A general “rule of thumb” states that a drill stem test run below 10,000 feet should seldom encounter a differential pressure over 4500 psi, rarely exceeding 5000 psi. To maintain an 80 percent success ratio, the differential pressure should remain between 4000 to 4500 psi, provided hole conditions are reasonable.

To maintain the proper differential pressure, a “cushion” is placed in the drillpipe. Water is generally used, nitrogen is another cushion. Though nitrogen can be used, it is much more expensive and the drillpipe must be in good condition.

Calculations are performed to determine the length of the water cushion in order to ensure the correct differential pressure. For example:

Packer Depth:	10,000 feet
Mud Density:	9.8 lb/gal
Pressure on Packer:	10,000 x 9.8 x 0.0519 = 5086 psi
Recommended Differential:	4200 psi

Water cushion required to reduce 5086 psi to 4200 psi, or 886 psi (5086 -4200)

Length of water cushion = 2046 feet (886 ÷ 0.433)

Example Table for Fresh Water Cushions

1000 ft of cushion = 1000 x 0.433 = 433 psi
2000 ft of cushion = 2000 x 0.433 = 866 psi
3000 ft of cushion = 3000 x 0.433 = 1299 psi
4000 ft of cushion = 4000 x 0.433 = 1732 psi

Variations On The 'standard' Test

Double Packer Test

1. If the depth, pressure or formations are such that additional support and fluid seal are needed so two open hole packers may be used in tandem. The lower packer must be set in a formation which will give sufficient support to allow the upper packer to set and expand.
2. A double packer test is also used to isolate and test one of a group of perforated sections in a given well. Generally the perforated zones must be separated by 50-100', or less if there is a good casing cement job between them. If this casing is not properly cemented, or if the formation has considerable vertical permeability, then this may allow fluids to travel from one set of perforations to another.

Hook Wall or Casing Packer Test

The hook wall packer is expanded with a set of slips, so that it may be set, released and reset at any depth without changing the arrangement of the test tools or coming out of the hole.

It is usually used to test through perforations in the casing, or liner, but is also run as the lower packer in a double packer test in order to support and expand the upper packer. When testing inside the casing, perforations may either be made by wireline before running in with the test string or by attaching a gun to the bottom of the string. If both operations are performed on a single run, then it has the advantage that the measurements used are the operator's actual pipe tally, and also that the perforations are exposed for the minimum amount of time before testing takes place.

Double Shut-in Pressure Tests

Today, double shut-in pressure tests (Figure 8-4) are more commonly used than single shut in tests. In this situation, flow period is usually between 5 and 10 minutes and the initial shut-in pressure is around 30 minutes.

It measures the quick return to equilibrium conditions in the flushed zone. Because the initial flow period is limited, pressure disturbance in the formation is reduced, so that during the initial shut-in time there will be a very rapid rise in borehole pressure, such that estimates of reservoir pressure may be obtained quite quickly. By using this method, the operator can have at least one shut-in pressure, even if the tool later malfunctions.

After the first test period, the well should have returned to its initial state, and the second flow period can last from 30 minutes to more that 2 hours. The final shut-in period is usually at least as long or longer than the final flowing time.

Comparisons of the initial and final shut-in pressures can give the operator valuable information of the permeability of the formation and an indication of formation damage which could have reduced fluid recovery during the drillstem test.

Figure 8-4 Double Shut-in Pressure Record

Recent developments include testing tools which can be opened and closed any number of times without disturbing the packer. These can give even more help in substantiating reservoir depletion.

Modern Techniques

RTTS Packer

The RTTS or Retrievable Test Treat - Squeeze packer is used on many testing jobs today, particularly on floating rigs where the majority of tests are carried out inside the casing.

The RTTS Hook-Wall packer is similar to the standard RTTS packer except that it does not have hydraulic hold-down slips.

One of the main advantages is that if necessary, the packer can be set and the drillstring easily backed off, so that it can be left in place and retrieved later on.

Hydraulic Test

The hydraulic tester was designed to provide a combination tool to take the place of three of the valves normally used in the testing assembly. It also has a number of other advantages in that rotation of the drillpipe is not required to open and close the valves, but by a simple up and down movement. The mechanism also tends to retard the opening of the valves, so that weight can be set for a time to allow the packer to expand before the tool opens. This time delay also helps prevent premature opening, due to bridges or tight spots.

At the end of the time interval however, which is determined by the amount of applied weight, the tester valve opens rapidly giving a definite indication at the surface by a slight movement of the drillpipe and the weight indicator needle.

The main advantage though, is in combining three valves into a single tool. As the main valve and the equalizing valve are usually in opposite positions (one open, one closed) it is easy to combine the points for these onto the same mandrel.

Side Wall Anchor

The side wall anchor is used below a straddle packer in the open hole. It eliminates the need for anchor pipe extending to the bottom of the hole by providing support for the weight required to expand the packer. The tool has six large mechanical slips mounted on a wedge shaped body which are set by rotating the string to the right and applying weight.

Permanently Installed Surface Recording Instruments

There are a number of devices manufactured today to allow bottom hole pressure instruments to be permanently installed in the test tool and for the pressures to be recorded at the surface.

The Maihak type gauge is basically a Bourdon Tube whose displacement is telemetered to the surface via a single conductor cable. It uses the pulsed-vibration frequency of a diaphragm actuated taut wire for telemetry.

In the Ball Bros type gauge, the deflection of the tube is measured by the downhole rotation of a code wheel, and data is telemetered to the surface in a code form.

All of these devices consist basically of a downhole transmitter attached to the recording device and a surface receiver. Usually with computational equipment, there are a number of far more sophisticated devices now available to take advantage of micro-processing technology.

Floating Vessel Equipment & Techniques

Well testing from a floating vessel requires special equipment to compensate for vessel motion and sub-sea tools to allow the well to be shut-in if the rig has to disconnect from the wellhead. The additional equipment and redundancy complicate the test string and the operation leading to increased problems with equipment and data interpretation.

There are certain precautions that should be taken when testing from a floating rig. These include:

1. Set the packer, and perform the test in a liner or casing string.
2. Use a test tree in the BOP stack
3. Immediately stop testing if:
    a. The pressure rating of the equipment is approached.
    b. Gases reach explosive levels or poison gas is produced.
    c. Vessel motion is becoming unsafe.

There are various types of specialized testing equipment used from floating rigs, and also special procedures. The multiple flow testers described earlier are used in preference to the two flow period test tools, since they may have to be opened and closed more often because of the extra precautions required. There are two main types of test tools currently used:

1. Annulus Pressure Tool

    These are quite new and operate by pressure alone, and do not require drillstring manipulation. The valves are activated by applying 1000 - 1500 psi to the annulus. This pressure allows the valve to close, and by pressuring up further to 2000 - 2500 psi they will close and lock, trapping a sample of reservoir fluid after the final flow period. It also acts as a safety device for shutting in the well if the tubing parts and casing pressures increases above 2500 psi.

2. Reciprocating Test Tools

    These tools are operated by reciprocation and require a full cycle for operation. When the tool is first set down on the packer, the test valve will open after a 3 or 5 minute delay. Picking up and setting down will close the valve and each alternative cycle will then open or close the valve as often as necessary.

Sub-Sea Shut-in Procedure

Special sub-sea trees are designed to land in the wellhead and BOP's to shut in the tubing at the sea floor. They use redundant, hydraulically operated valves, and the pipe to the surface can be released if it is necessary to disconnect the riser from the wellhead. In most current systems, they are designed to fit beneath the rams so that these may be closed.

Hang-off shoulders are provided to support the tree and a fluted hang-off point that will not pass the wellhead is included.

The tree is usually designed to fit into a particular stack and during the test, the rams are closed around the test tree and the casing pressure monitored through a kill/choke line.

Wireline Formation Tests

Formation test tools are used extensively in modern drilling operations and they provide a fast, safe and economical method of testing. Pressures can be recorded at the surface, and formation fluids can be recovered by using one or two chambers. Depth control is obtained by correlation with the SP log or with the GR log in cased holes.

The main advantages in using wireline formation testers are:

1. The well is under complete control.
2. An average test can be completed under 4 hours.
3. Selection of zones to test can be made after logs have been analyzed.
4. The complete cycle of tool operation is recorded on film at the surface.

Figure 8-5 illustrates the pad-type probe. Figure 8-6 is a schematic of the sampling system.

The tool basically comprises, a surface controlled actuating mechanism, the hydraulic system formation seal pad and backup shoe with the snorkel tube, and the sample chamber. The sample chamber capacity is usually 3 or 6 gallons. For the Repeat Formation Tester, or RFT, two sample chambers can be attached for recovering fluids from different zones, and any number of pressure readings can be taken.

For unconsolidated sands the formation seal pad is fitted with a snorkel tube, but for tighter formations where the tube may become clogged or bent, the snorkel screen is used. For testing consolidated formations and cased holes, the seal pad can be fitted with a dual gun block, which fires two shaped charges into the formation.

Procedure

1. The pad expanding valve is opened, allowing drilling fluid to enter the tool. The buildup of hydrostatic pressure forces both the seal pad and the back-up plate against the walls of the borehole. The hydrostatic pressure can then be measured and recorded, and this indicates that the tool is properly set.

2. The snorkel tube, snorkel tube screen or shaped charges are forced into the formation, allowing fluid to flow into the tool. This initial shut-in pressure can then be recorded.

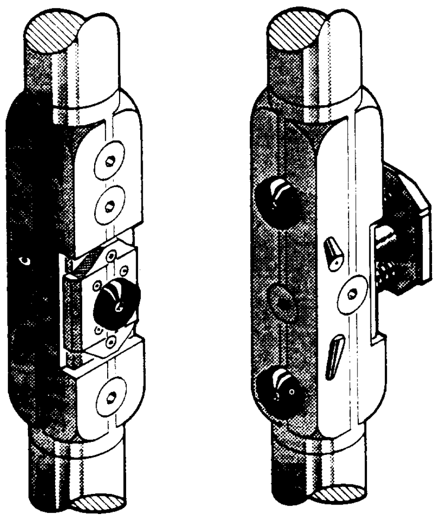


Figure 8-5 RFT Pad

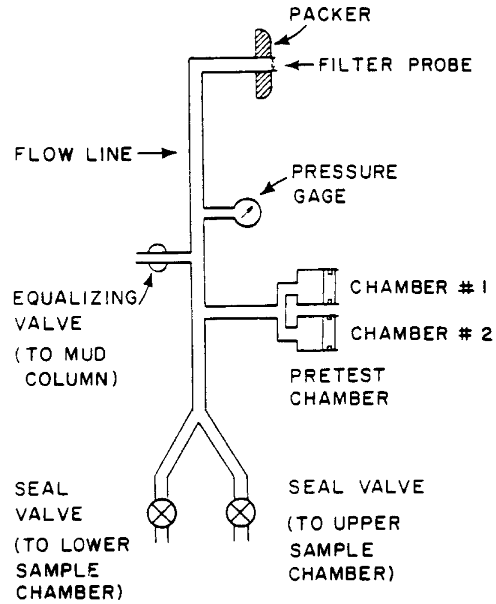


Figure 8-6 RFT Pad Sampling System

3. The sample chamber seal valve is then opened, allowing the fluids to flow into the sample chamber. The flowing pressure can also be recorded. The sample chamber contains water in the upper part and air at atmospheric pressure in the lower, separated by a series of one or more chokes, with a floating piston on top of the water cushion. As formation pressure builds up, so the water cushion is displaced into the lower chamber, and the upper chamber becomes filled with formation fluids (Figure 8-7:).

4. Once the sample has been taken, the sample chamber seal valve is closed hydraulically, trapping the fluids in the chamber. At this point the final shut-in pressure can also be recorded.

5. Shots are fired to release the pads from the face of the formation, which are then closed completely by hydrostatic pressure.

6. With the tool at the surface, gas may be bled from the sample chamber through the separator and measured by a gas meter. Other fluids can be drawn off through a valve out the bottom of the separator and the volume of oil, water and distillate can be measured.

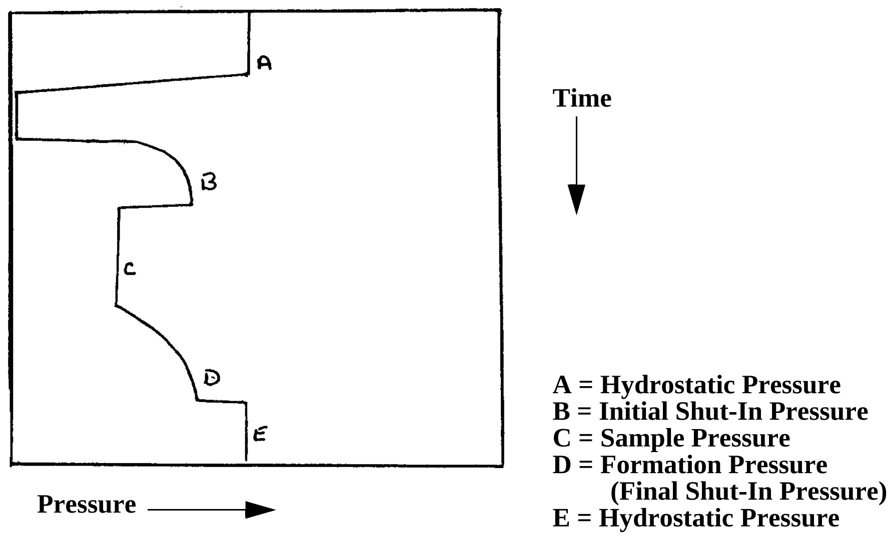
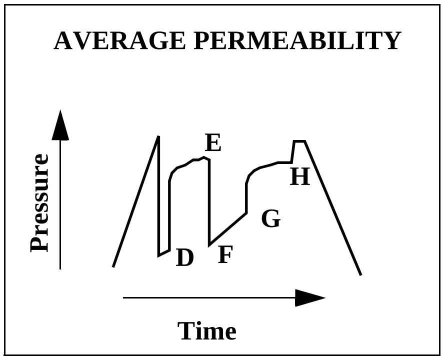


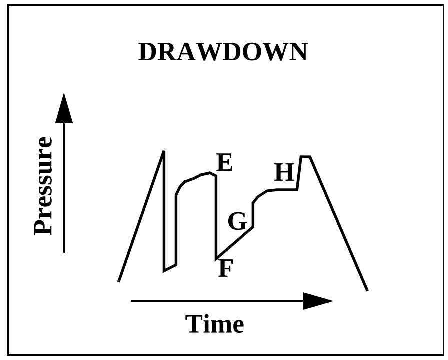
Figure 8-7: Typical Medium Permeability Pressure Record.

Applications & Interpretations

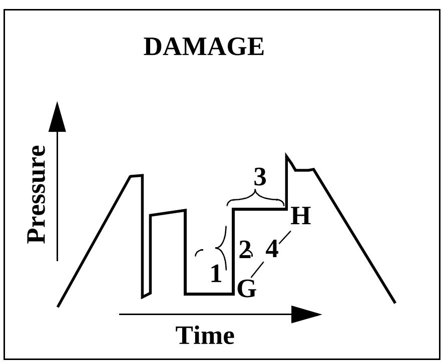
The first stage in test interpretation, whether from wireline or DST data, is to examine the pressure recording charts to verify both correct tool operation and that the pressures were measured accurately. Figure 8-8a: and Figure 8-8b: illustrate examples of reservoir permeability, reservoir drawdown and reservoir damage.



On this chart, the shape of the two shut-in curves (DE and GH), the rate of shut-in pressure buildup, and the indicated influx of fluid during the final flow (line GF) suggests a zone of average permeability.

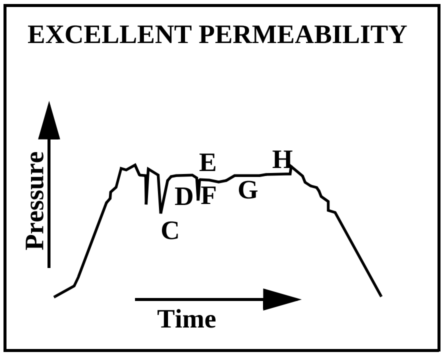


Because the final shut-in pressure (H) is much lower than the initial shut-in pressure (E), this chart indicates that the reservoir tested was "drawn down" considerably (line FG) and may be limited in size.

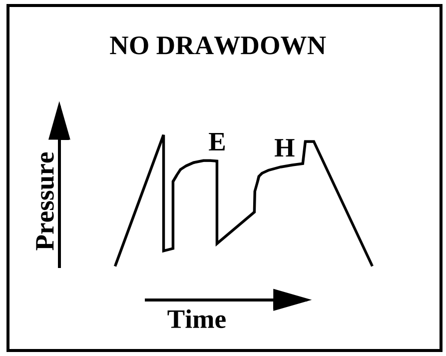


With some exceptions, a damaged zone will be indicated by the configuration of the shut-in curve (GH). Specific indicators are a very sharp rise after the final flow (1), a short curve radius (2), a reasonably flat slope (3), and a high differential pressure between the final flow and final shut-in (4).

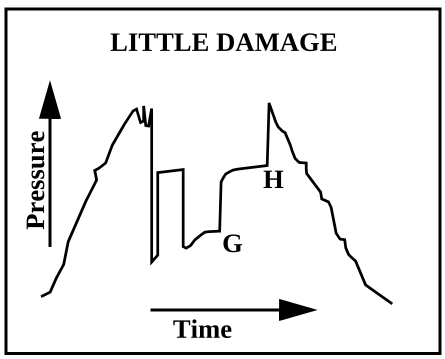
Figure 8-8a: DST Examples of Average Permeability, Reservoir Drawdown and Reservoir



This chart, on the other hand, suggests a zone with high permeability. The shut-in curves (DE and GH) were developed faster, and the flow curves (CD and FG) indicate a high rate of fluid entry to the test tool.



However, where the difference between the initial shut-in pressure (E) and the final shut-in pressure (H) is less than two percent, as it is here, the chart would suggest not only high permeability but also a potentially commercial reservoir.



By comparison, this chart shows relatively little damage to the reservoir. The radius of curve GH is longer with a slope and the differential pressure is not as great between final flow (G) and final shut-in (H).

Figure 8-8b: DST Examples of Excellent Permeability, No Drawdown and Little Reservoir Damage

Fluid Analysis

One of the most important results of any formation test is the analysis of the amount and composition of the recovered fluids. The API gravity of any recovered oil can be easily measured with a hydrometer and corrected to 60°F (15.5°C).

The gas/oil ratio can be determined from wireline tests from the quantity of gas and oil recovered in the sample chamber. This is given in the equation below:

$$\mathrm{GOR} = \frac{\text{cubic feet of gas}}{\text{cubic centimeters of oil}} \times 159000$$

From the wireline test, it is also possible to predict whether hydrocarbons or water will be produced. When the sample chamber is brought to the surface, gas is liberated from the fluids by use of a separator and also because of the reduction in temperature and pressure. If the amount of formation gas measured at the gas meter is greater than the amount of gas which is soluble in water at formation temperature and pressure, then the zone tested will produce hydrocarbons.

The recovery and analysis of formation water is also important in order to estimate the amount of water that will be produced with the oil or gas. Mud filtrate and recovered water can be titrated and converted to resistivities. With knowledge of the resistivity of formation water, Rw, the percentage of formation water recovered on the test can be calculated.

Pressure Build-up Theory

Because of the relatively short duration of a formation test, the build up of the bottom hole pressure during the shut-in periods will not normally reach static conditions and give a record of true bottom hole pressure. It is necessary therefore to extrapolate this build up of pressure to static conditions. The build up curves can be read in discreet time segments and can be plotted against pressure,

$$\log\frac{(\Delta t + T)}{\Delta t}$$

where: Δt = the shut-in time (minutes)
T = the flow time (minutes)

Static reservoir pressure is that value where log $(\Delta t + T)/\Delta t$ is equal to zero. Theoretically, this extends the build up curve to infinity.

Theory and methods for analyzing pressure buildup in wells have been presented by many people, but the one produced by Horner is probably the most widely used. The basic assumptions are those of radial flow, infinite reservoir and a single compressible fluid, and these are fairly well suited to DST conditions.

As stated previously, the use of double or multiple shut-in procedures allows some estimation of reservoir depletion to be made. Dolan et al, have also shown that, as long as the difference in the initial and final production rates is not extreme, then the average production rate can be used as an approximation in pressure build up analysis. The average rate of production is determined by dividing the fluid recovery by the flowing period. The basic pressure build up equation according to Horner is:

$$Pf = Po \times \frac{162.6 \times Q \times \mu \times B}{k \times h} \times \log\left(\frac{\Delta t + T}{\Delta t}\right)$$

Where:

Pf	=	Formation Pressure During Build-up (psi)
Po	=	Maximum Reservoir Pressure (psi)
Q	=	Production Rate (stock-tank bbls/day)
μ	=	Viscosity of produced fluid at reservoir conditions (centipoise)
B	=	Formation Volume Factor (vol formation/vol stock tank)
k	=	Average effective permeability (millidarcies)
h	=	Reservoir thickness (feet)
T	=	Flowing time (minutes)
Δt	=	time of shut-in (minutes)
162.6	=	Conversion factor

To calculate “Kh” of the formation, which is the effective permeability of the reservoir to the produced fluid multiplied by the thickness of the reservoir, the log $(\Delta t + T)/\Delta t$ is plotted against pressure (Horner Method) and the slope of the build up plot is utilized in the following equation:

$$Kh = \frac{162.6 \times Q \times \mu \times B}{m}$$

Where m = slope of build up plot (psi/cycle). The B and μ values can be determined from engineering tables, using information on the oil gravity and gas flow.

Safety Precautions When Testing

One of the first precautions, when drill stem testing, is to measure and caliper the complete test tool. After the tool is made up, insist that an accurate caliper is made on all the OD changes on the tool. This can save considerable time and money when selecting an over-shot or washover pipe, should a fishing job be necessary. Many testing companies have diagrams showing the OD and length of all components in the testing string.

After starting into the hole, make sure the hole is not taking mud, while the test string is being lowered. Most packers are about one inch less than the diameter of the borehole (i.e. 7 in. packer in a 8-1/2 in. hole). This can sometimes cause surge pressures while lowering the string or swab pressures while hoisting the string.

If H_2S is expected, all personnel should be forewarned. The pertinent safety equipment should be on-hand and ready for use. Before the tool is opened, be sure every person on location is alerted to the danger of H_2S and has a thorough knowledge of the testing procedures and safety precautions. Before opening the tool, be sure all open fires are extinguished and that the “No Smoking” rule is understood by all personnel.

Be sure all valves, steel hoses and all pieces of high-pressure floor equipment are functional. Have all flow lines to pits, gas risers, separators and tanks securely tied/staked down. Have gas measuring devices on hand if gas is anticipated.

If high-volume gas is expected, watch the wind direction closely. Flare the gas if possible or lay flow lines so that the gas will not blow back towards the rig or accommodations.

Do not shut down the mud pump for repairs (unless absolutely necessary) while drill stem tests are in progress.

Watch the mud in the annulus at the surface at all times when the test tool is open. Be especially alert when high-pressure formations have been drilled.

Packer seats can fail at any time while the test tool is open. The mud in the annulus will immediately drop if the seat fails. If a hole washes out in the drillpipe or the drillpipe collapses, the annular mud level will drop. If the mud does drop in the annulus, immediately pick up the pipe and start filling the hole with the mud pumps. If the mud level drops and no action is taken, a blowout can result from lowering the hydrostatic pressure on high-pressure, high-volume formations. Since it is impossible to see the mud in the hole with a wiper rubber on the pipe, while hoisting the tool insist on stopping frequently and starting the mud pump to check that the hole is full. Watch the flow line closely to make sure that the mud is not flowing with the pumps off; if this happens then the packers are swabbing the well.

On wells that produce live, gaseous oil in the pipe, the oil should be reversed out or wet plugs used while hoisting the drillpipe.

Reporting Systems

The following is a list of the more important data and samples that should be obtained from a well test:

1. Gas production in MMSCF/D (million standard cubic feet per day). This requires records of separator gas temperatures and pressures, and measurements of gas gravities in addition to normal orifice meter charts.
2. Oil or condensate production rate in barrels per day. This requires measurement of production under separator conditions and a correction factor (from a shrinkage meter to stock tank barrels).
3. BS&W (bottom sediment and water) percentage of the crude. Obtained by centrifuge samples.
4. Water production rate in barrels.
5. Gravities of the oil, gas and water.
6. Salinity of water, and if possible a further compositional analysis.
7. Viscosity of the condensate or crude.
8. Pour-point of the condensate or crude, determined from fresh wellhead samples.
9. Rough wellhead composition of produced gas, including H_2S, CO_2, CO and N_2 content.
10. Bottom Hole Pressures, Build-ups and Drawdowns.
11. Bottom Hole Temperature.
12. Accurate recording of surface pressures, temperatures and flow data versus time.
13. Choke size, in inches.
14. Separator gas samples, under pressure.
15. Separator oil samples, under pressure.
16. Drums or cans for atmospheric samples of condensate or crude oil.
17. Bottom Hole PVT (pressure-volume-temperature) samples.

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Self-Check Exercises: Introduction To Well Testing

1. What are the overall aims of well testing?

   a.

   b.

   c.

   d.

2. What are the three main types of packer arrangements for Drill Stem Testing?

   a.

   b.

   c.

3. How are pressures recorded during a Drill Stem Test?

4. How much water cushion will be required if a DST is to take place at 12,500 ft, with an 11.1 lb/gal mud and a recommended pressure differential of 4500 psi?

5. What are the four main advantages of a wireline formation test?

   a.

   b.

   c.

   d.

6. What is the normal fluid capacity of the wireline test sample chambers?

7. What three results are required from well test fluid analysis?

   a.

   b.

   c.

8. Why is it necessary to extrapolate build-up pressure to static bottom hole pressure?

9. What assumptions are made in the Horner Method of pressure build-up analysis?

10. How is the average rate of production determined from a DST test?

11. In DST analysis, what is “Kh”?

12. Why is it necessary to measure and caliper the DST tool before it is tripped into the hole?

13. What problem can be expected during the tripping in of a DST tool?

14. Why is packer-seat failure so dangerous?

15. What problem can be expected during the trip-out of a DST tool?

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