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SHALES: A REVIEW OF THEIR CLASSIFICATIONS, PROPERTIES AND IMPORTANCE TO THE PETROLEUM INDUSTRY

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ABSTRACT

Shales are fine-grained, laminated or fissile clastic sedimentary rocks with predominance of clay and silt as the detrital components. They may be classified as clayey, silty or sandy shales on the basis of texture. Other criteria used in the classification of shales include mineralogical composition, cementing materials, organic matter content, depositional environment and strength. Generally, shales have moderate to high clay content (average, 57%), low strength (range, 5-30MPa), low permeability(range, 1 x 10^{-6} - 10^{-12} m/s) and are water sensitive(susceptible to hydration and swelling when in contact with water).

Shales are important to the petroleum industry because of their usefulness as source rocks in petroleum generation, seals in petroleum traps and reservoirs. Problems associated with drilling oil/gas wells in shale formations include slow rate of penetration and wellbore instability. These problems are generally caused by pressure gradients between the oil/gas wells and shale formations, and shale hydration due to drilling fluid/shale interactions. The problems can be prevented or controlled by adequate monitoring of the drilling fluid density and use of potassium-base drilling fluid that is insensitive to shale hydration. In the Niger Delta petroleum province, the source rocks and seal rocks are the marine/deltaic, plastic and over-pressured shales of Akata and Agbada Formations.

KEY WORDS: Shales, Classification, Strength, Composition, Petroleum Industry, Niger Delta.

INTRODUCTION

Shales are fine-grained laminated or fissile clastic sedimentary rocks with predominance of silt and clay as the detrital components (Krumbein and Sloss, 1963). They are formed from silts and clays that have been deposited and compacted or hardened into rocks. On the basis of texture therefore, the most common types of shales are silty shale (silt dominant) and clay shale (clay dominant). These two types of shales are also called argillaceous shales. Occasionally, shales may also contain appreciable amounts of sands in which case they may be called sandy shale (arenaceous shale). Black shales with high proportion of organic matter content are called carbonaceous or bituminous shale. Shales that contain high amount of lime are known as calcareous shale.

Shales are the most abundant of all sedimentary rocks (constituting about 60%), and are distributed in wide range of geologic ages from Paleozoic to Cenozoic (Boggs, 1995; Greensmith, 1975). Their colours may range from white through green to grey and black depending on their composition and environment of deposition.It is obvious from the above that shales are highly varied in nature and composition.

In this paper, the composition, classification, properties and uses of shales are reviewed with emphasis on their importance to the petroleum industry. The Niger Delta petroleum province is discussed as a case history to illustrate the importance of this rock class.

ORIGIN AND COMPOSITION OF SHALES

Shales may form in any environmental condition in which sediment is abundant and water energy sufficiently low to allow settling of suspended fine silt and clay. They are particularly characteristic of marine environments adjacent to major continents where the sea floor lies below the storm wave but they can also form in lakes (lacustrine/continental) and deltaic (transitional/marginal) environments (Porter et al, 1980). Well-known examples of thick deposits of shales include the Eocene Green River Shale (Oil shale) of Colorado (USA), Cretaceous Mancos Shale of Western North America (stretching from New Mexico to Saaskatchewan and Alberta in Canada) and Paleocene Akata Shale of Niger Delta (Nigeria).

Silts and clays when newly deposited from suspension in water undergo compaction due to continuous accumulation of other sediments above them. The compaction causes the reduction of the porosity from initial value of about 70 to 90% to final value of about 7 to 30%. At the same time the clay minerals and micas would change from a random arrangement to a parallel arrangement, which gives the shale its laminated structure. According to Porter et al (1980), laminars in shales should have thickness of 10mm or less while beds in other rocks should have thickness greater than 10mm. Increasing depth of burial and associated increasing temperature are always related to the maturity/degree of induration of shales. The diagenetic reactions in clay that accompany depth of burial/increasing temperature include mineral changes such as smectite-illite transformation and precipitation of cementing minerals (Singer and Muller, 1983; Franklin and Dusseault, 1989). These processes generally lead to reduction in porosity and increase in bulk density of shale with depth (Fleming et al, 1970; Greensmith, 1975; Fertl, 1977). Figures 1 and 2 show the progressive decrease in porosity and increase in bulk density of shales with depth, respectively.

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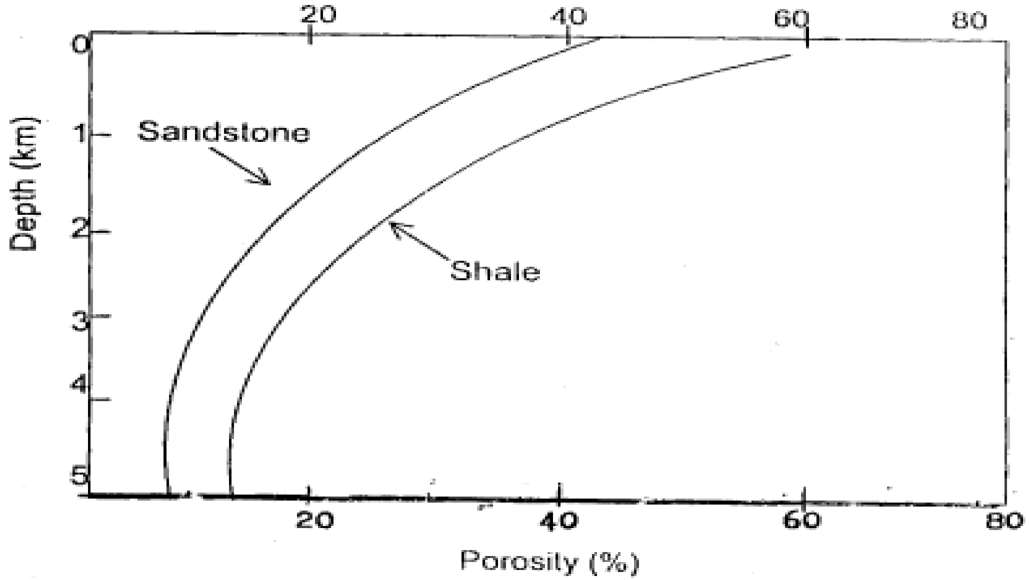

Fig. 1. Curves showing changes in porosity of shale and sandstone as functions of burial depth/compaction (After Boggs, 1995).

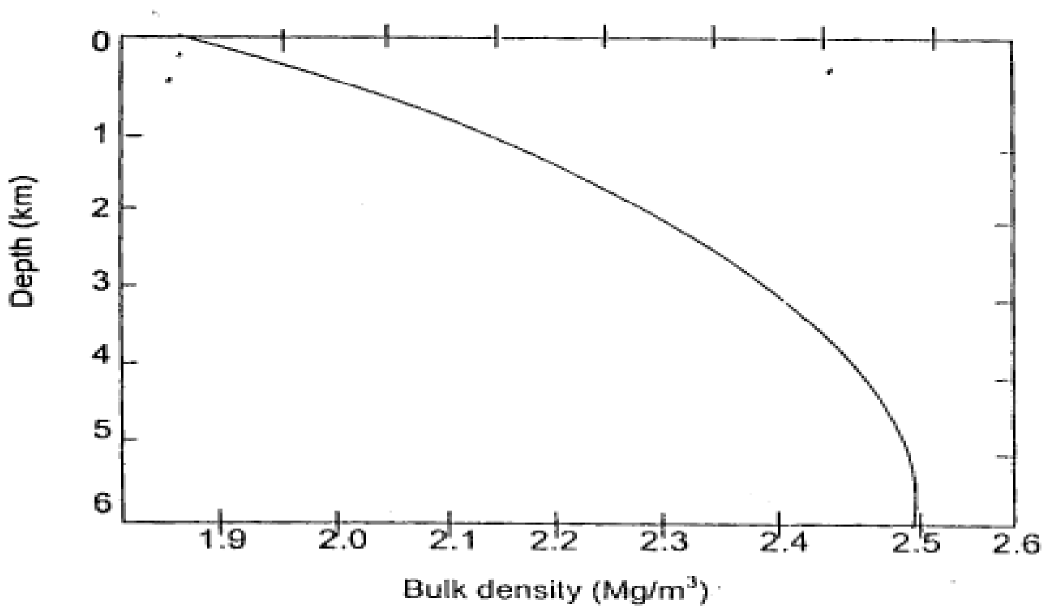

Fig. 2. Shale bulk density variations with depth (After Boggs, 1995).

Shales have definite mineralogical and chemical composition. These characteristics are controlled by the properties of the parent rock and the depositional environment. The chemical composition may reflect the composition of the parent rock only but the mineralogical composition is influenced by both the parent rock and the depositional environment. The average mineralogical composition of shales is given in Table 1 (Attewell and Farmer, 1976; Fertl, 1977; Boggs, 1995) which shows that the clay minerals are the dominant minerals (about 57%). The main clay minerals are smectites (montmorillonite), illite, kaolinite and chlorite.

Generally, the smectites are expansive and characteristic of low-energy marine alkaline environment. The other clay minerals are not expansive and occur in high-energy (where rate of leaching is high) and non-marine (continental or transitional) neutral/acidic environments. The average clay mineral content of shales may be constant but there is steady conversion or transformation of smectite to illite as the depth of burial/geologic age increases due to increasing temperature and pressure (Fig. 3). Generally, smectites seem to be destroyed and absent if the sediments containing the mineral have been buried at depths greater than 3,500m or exposed to temperatures above 200°C (Franklin and Dusseault, 1989). According to these authors, sedimentary rocks older than Jurassic usually contain little or no smectite.

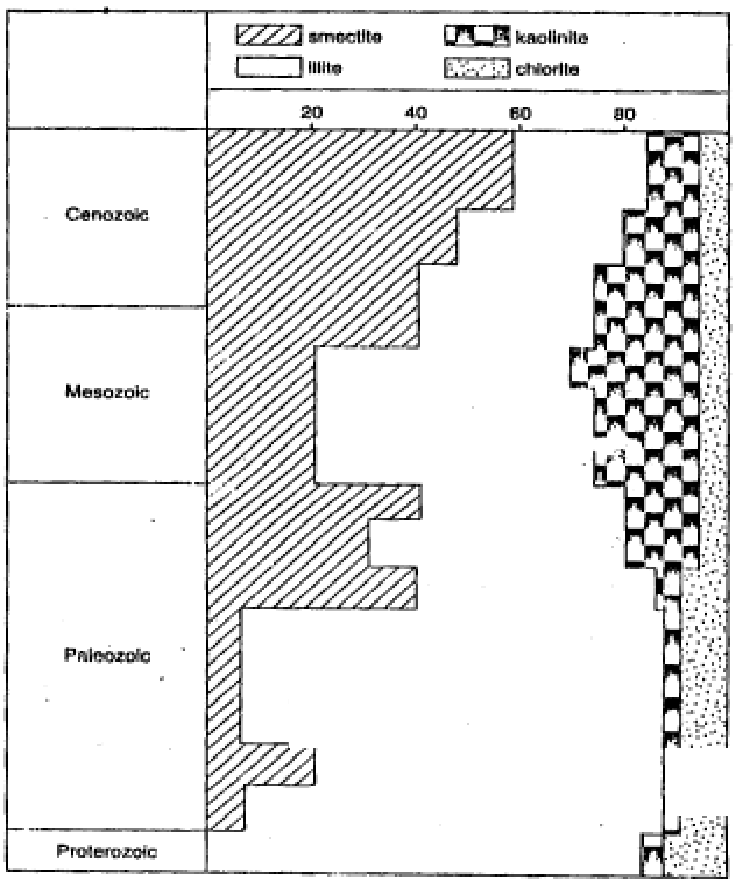

Fig.3. Systematic changes in abundance of major clay minerals as a function of geologic age (After Singer and Muller, 1983).

The clay minerals composition of shales and other argillaceous rocks have been used in the interpretation of their depositional environments. According to Grim (1953), clay minerals do not alter during transportation in fluviatile environment but become susceptible to change once they reach open bodies of water such as lakes, seas and oceans. In other words, a clay mineral once formed may be converted to another form of clay mineral depending on the drainage condition and/or depth of burial. Smectite is easily converted to illite and chlorite under these varying conditions. The formation of kaolinite is favoured in areas of intense rainfall and leaching to maintain high Al: Si ratio (acidic condition; pH $\leq$ 7.0). Smectite formation is favoured by poor rainfall and leaching conditions to maintain a low Al: Si ratio (alkaline condition; pH: 8.5-10.0). Nonacid potassium-rich condition with intermediate rainfall and leaching favour formation of illite and chlorite (near neutral condition; pH > 7 and < 8.5). Smectites and kaolinites are easily converted to illite and chlorite as the depositional environment/depth of burial changes (Shaw, 1980).

Shales contain a wide range of major oxides including S_iO_2, Al_2O_3, T_iO_2, M_nO, MgO, CaO, Na_2O, K_2O and P_2O_5 (Table 2). They also generally contain higher amounts of metal elements than other sedimentary rocks as Table 3 shows. The metal concentration of limestone and sandstone are included in Table 3 for comparison. Black shales contain Mo, V and other organic compounds in addition due to planktonic organisms (Dunham, 1961). Presence of CO_2 and H_2S in black shales is evidence of oxygen deficiency in the water immediately overlying the sea floor where the black shales occur. Black shales cannot therefore contain benthonic organisms (benthos) but may contain planktonic organisms that may have died and been carried to the bed of the ocean or sea floor.

Table 1: Average mineralogical composition of shales (Attewell and Farmer, 1976; Boggs, 1995; Fertl, 1977)

Mineral	Composition (%)
Clay minerals	57
Quartz and chert	25
Feldspar	8
Calcite/dolomite	3
Pyrite/mica	3
Iron oxides	2
Organic carbon	1
Others (heavy minerals, etc)	1
Total	**100%**

Table 2: Average chemical composition of shales Greensmith, 1975)

Major oxides	Concentration (%)
S_i0_2	60.9
Al_20_3	18.5
Fe_20_3	7.2
T_i0_2	0.9
Mn0	0.1
Mg0	2.9
Ca0	2.4
Na_20	1.8
K_20	4.0
P_20_5	0.2
Total	**98.90%**

Table 3: Average metal contents of different rock types (Alloway, 1990)

Metals	Rock type / Content (ppm)		
	Shales	Limestone	Sandstone
As	13	1	1
Be	3	N.R	N.R
Co	19	N.R	1
Cr	90	11	35
Cu	39	6	30
Mg	3	1	1
Ni	68	7	9
Pb	23	5.7	10
Se	1	0.03	N.R
Sn	6	1	1
Th	12	N.R	2
U	4	02	1
Zn	120	20	30

CLASSIFICATION OF SHALES

Shales are fissile clastic sedimentary rocks formed from transportation, deposition and compaction of detrital materials of silt and clay. Fissility of the clay is its main distinguishing characteristic from other sedimentary rocks. Fissility is defined as the property of a rock to split easily along thin closely spaced (< 10mm approximately) parallel layers (Ingram, 1953). This fissility factor is highlighted in Table 4 that shows classification of sediments and sedimentary rocks based on sizes of fragments.

Table 4: Classification of shales and other sedimentary rocks based on sizes of fragments (Compton, 1977; Porter et al, 1980)

Grain-size	Sediment name		Rock name	
> 2.00mm	Gravel		Conglomerate (Brecia if grains are angular)	
2.00 –0.06mm	Sand		Sandstone	
0.06 – 0.002mm	Silt	Mud	Siltstone (33% of clay fraction)	Shale when laminated
			Mudstone (33-66% of clay fra.)	
<0.002mm	Clay		Claystone (>66% of clay fra.)	

The classification of shales like other sedimentary rocks should reflect the observable features and environment of deposition. Accordingly, shales are classified on the basis of texture, mineralogical composition, type of cementation/cementing materials, depositional environment, organic matter content and strength (Krumbein and Sloss, 1963; Boggs, 1995). Details of the classifications are discussed below.

Classification based on texture

Shales characteristically contain fine-grained silt and clay particles (< 0.063mm). They are therefore classified as silty shale or clay shale, depending on whether silts or clays dominate in the constituents of the rock. Silty shale and clay shale may collectively be called argillaceous shales. Occasionally, shales may also contain appreciable amounts of sands, in which case they may be called sandy shale or arenaceous shale.

Classification based on mineralogical composition

Shales may be classified as quartzose, feldspathic or micaceous shale depending on the predominance of the minerals quartz, feldspar or mica, respectively, in the rock after appropriate XRD analysis (Pettijohn, 1957).

Classification based on type of cementation/cementing materials.

Shales like other sedimentary rocks are cemented by some minerals or elements after deposition and compaction. The dominant type of cementing material may be used in the classification of the shale since this may affect the properties or performance of the shale when used as an engineering material. The common cementing materials are silica, iron oxide and calcite or lime. Accordingly, shales may be classified as siliceous, ferruginous or calcareous (sometimes also called limy), respectively.

Classification based on depositional environment

The sedimentary environment of any sedimentary rock (including shale) is a natural geographical entity in which sediments are accumulated and later changed to rock (Reineck and Singh, 1980). Three depositional sedimentary environments are recognized, namely, continental, transitional or marginal and marine. Each depositional environment has various subdivisions. Shales are generally deposited in lacustrine (continental), deltaic (transitional) and marine depositional environments and may correspondingly be classified as such; that is, lacustrine, deltaic and marine shales (Compton, 1977; Boggs, 1995). Lacustrine deposits are characterized by mixture of clay, silt and sands; inorganic carbonate precipitates; and various fresh water invertebrate organisms including bivalves, ostracods, gastropods, diatoms and various plant deposits. Most lake deposits are less than 10m thick. Deltaic deposits are generally paralic (consisting of orderly sequences of shales and sandstones formed as a result of alternating marine transgressions and regressions). They are also characterized by shallow depth and concentration of kaolinite/illite/montmorillonite clay minerals. Deposits of marine environment are characterized by homogenous rock sequences (non-paralic), great depth, oxygen deficiency, and concentration of illite/montmorillonite clay minerals. Shales of marine depositional environment are generally darker in colour and richer in marine planktonic fossils than shales deposited in lacustrine and deltaic environments.

Classification based on organic matter content

Shales may be classified as carbonaceous or bituminous on the basis of their organic matter content (Krumbein and Sloss, 1963). The organic matter content of carbonaceous and bituminous shales are generally above 10%. The organic matter induces black or grey colour to the shales. The black colour of some shales may also be due to presence of iron sulphide. When the dominant organic matter content is from plant fragments such as pollen grains, stems and leaves, the shale is classified as carbonaceous, and the depositional environment is usually continental (lacustrine) or transitional (deltaic or lagoon). When the dominant organic matter content in the shale is from animal fragments such as fossils, the shale is classified as bituminous and its depositional environment is usually deltaic or marine. Both carbonaceous and bituminous shales are important source rocks for generation of petroleum oil and gas depending on their amount / type of kerogen content (Stocker et al, 1975). Kerogen is that part of organic matter in sediments (such as shales) which when mature can generate petroleum oil and gas naturally (Tissot and Welte, 1984).

Classification based on strength

The slake-durability index of a weak rock such as shale is a measure of the resistance of the rock to cycles of wetting and drying. It is obtained from the slake durability test (Franklin, 1983) usually used to evaluate the usefulness of rocks in engineering projects such as foundations, slopes and embankments. Shales with slake-durability index of less than 80% are classified as soil-like while those with slake durability index of more than 80% are classified as rock-like. Soil-like shales are subjected to Atterberg Limits test to determine they plasticity index while rock-like shales are subjected to point load strength test to determine their strength (Franklin and Dusseault, 1989). A plot of the three index properties of shale, namely, slake-durability index, plasticity index and point load strength index in one graph (Fig. 4; Franklin, 1983) gives a shale rating system which is used in assessing the quality of the shale as an engineering material. Underwood (1967) and Fleming et al (1970) have also classified shale as soil-like or rock-like on the basis of their texture, organic matter content and cementing materials (Table 5).

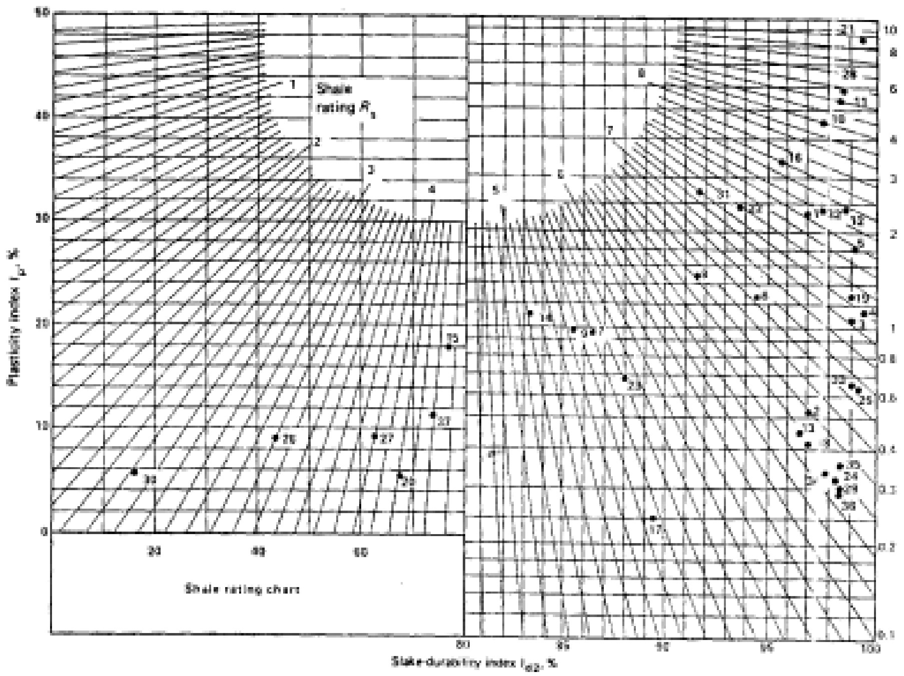

Fig 4: Shale rating system (After Franklin, 1983)

Strength characterization of shales can also be derived from stress/strain curves. This is because when rocks are loaded, they generally show different stress-strain curves before failure. This behaviour is related to the elastic properties of the rock including Youngs Modulus of Elasticity (E), Poisson's ratio (v) and the Uniaxial Compressive Strength (UCS). Figure 5 shows the stress-strain behaviour of shale/rock-salt and sandstone/granite Generally soft rocks with low strength exhibit ductile or plastic behaviour/failure when loaded, while hard rocks with high strength exhibit brittle behaviour/failure when loaded. Table 8 is a summary of shale classifications

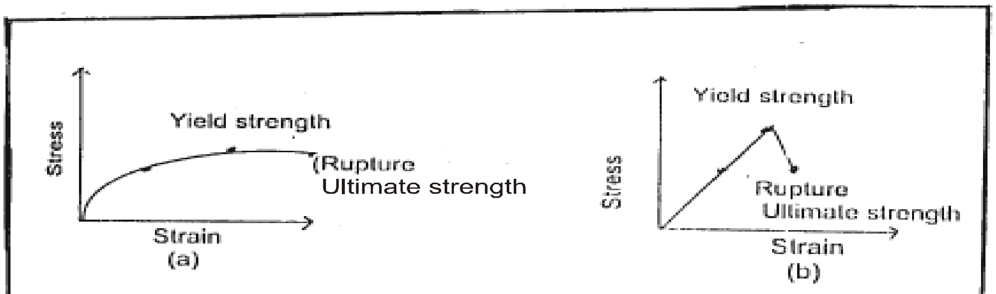

Fig. 5 Stress-strain behaviour of shale (a) and sandstone (b)
(After Roberts, 1977)

Table 5: A geological classification of shale Underwood, 1967; Fleming et al, 1970)

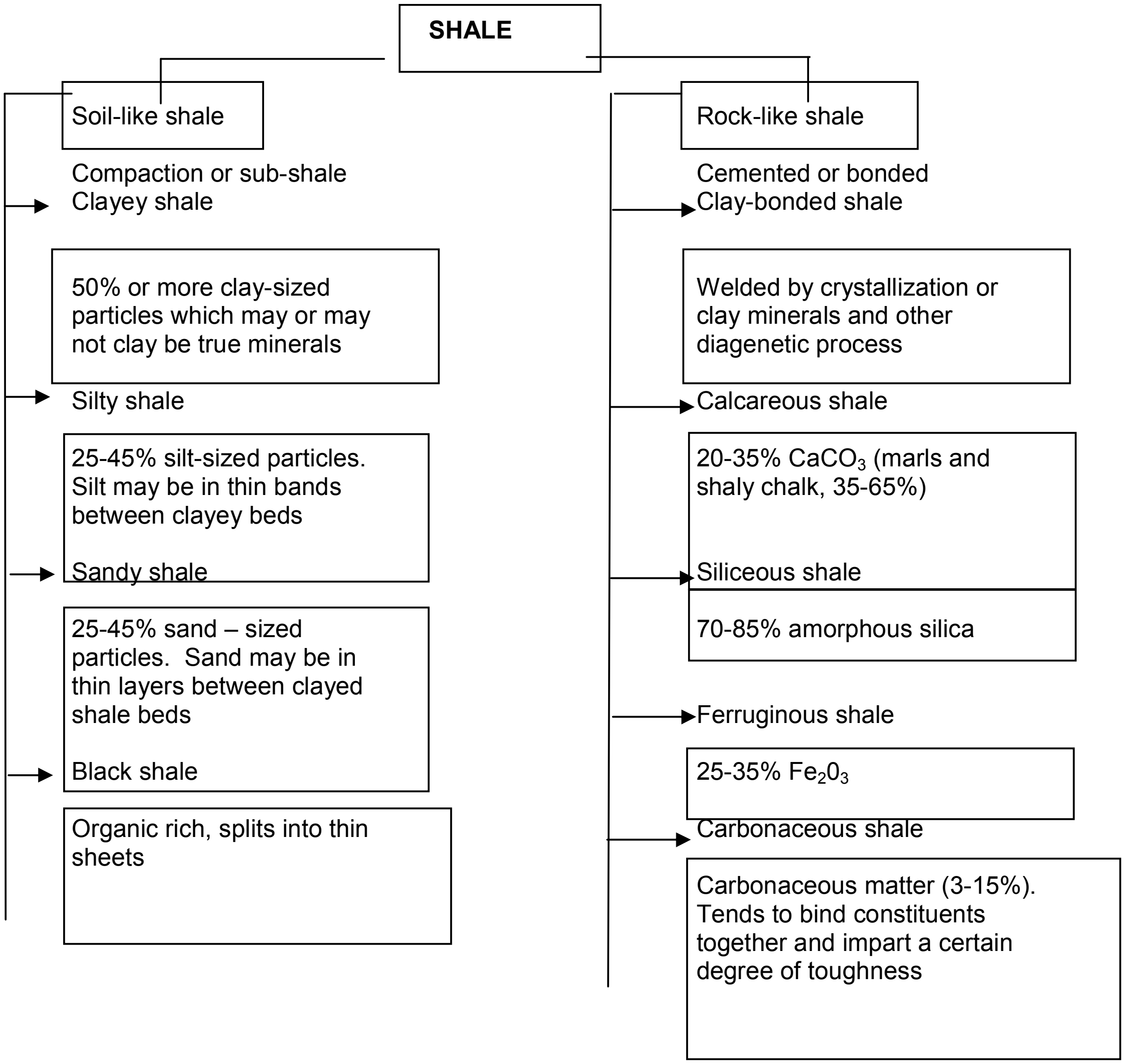

Table 6 shows different methods of describing uniaxial compressive strength (UCS) of rocks (IAEG, 1979; ISRM, 1981), while Table 7 shows description of point load strength (Franklin and Dusseault, 1989).

The terms soft rock and hard rock have also been used to distinguish rocks of different compressive strength. According to Canadian Geotechnical Society (1985), rocks with UCS (ISRM Classification) values less than 20 MPa are classified as soft, while those with values of over 20 MPa are described as strong. Soft/weak rocks generally break with one blow of geological hammar while strong/hard rocks need several blows of the hammar to break.

Table 6: Description of grades of unconfined compressive strength (UCS)

IAEG (1979)		ISRM (1981)	
Description	Strength (MPa)	Description	Strength (MPa)
Weak	Below 15	Very low	Less than 6
Moderately weak	15 – 50	Low	6 – 20
Strong	50 – 120	Moderate	20 – 60
Very strong	120 –230	High	60 – 200
Extremely strong	Above 230	Very high	Over 200

Table 7: Description of Point Load Strength Index (Franklin and Dusseault, 1989)

Description	Point Load Strength Index (MPa)	UCS equivalent (MPa)
Extremely low	Less than 0.03	Less than 0.5
Low	0.03 – 0.1	0.5 – 1. 6
Medium	0.0 – 1	5 – 16
High	1 – 3	15 – 60
Very high	3 – 10	50 – 160
Extremely	Over 10	Over 160

PROPERTIES OF SHALES

Because of the varied nature of shales, there are also varied properties. Most of these properties can be grouped into petrophysical and geomechanical. The petrophysical properties include density, porosity, permeability and clay content, while the geomechanical properties include plasticity index, slake-durability index, swelling potential, hardness, point-load strength(tensile), uniaxial compressive strength (compressive), in-situ stress and Modulus of Elasticity (Young's modulus). Most of these properties are used in the engineering evaluation of shales (Table 9). As already said, these properties are varied. For example, clay shales usually have permeability of the order of $1x10^{-9}$-10^{-12} m/s, while sandy and silty shales and closely jointed clay shales may have permeability as high as 1×10^{-6} m/s. Table 10 gives ranges and average values of some of these properties while Table 11 shows the significance of some of these properties to the petroleum industry. Figure 6 shows the relationship between hydrostatic/formation pressure, overpressure, bulk density and depth in shales (Fertl, 1977; Darley and Gray, 1988).

Table 8: Summary of shale classifications

SHALES	Texture	. Silty shale . Clay shale . Sandy shale
	Mineralogical Composition	. Feldspathic shale . Quartzose shale . Micaceous shale
	Cementing Materials	. Calcareous shale . Ferruginous shale . Siliceous shale
	Organic Matter Content	. Carbonaceous shale . Bituminous shale
	Depositional Environment	. Lacustrine . Deltaic . Marine
	Strength	. Soil-like or rock-like . Weak or strong . Low strength or high strength . Low modulus ratio or high modulus ratio . Soft/plastic or hard/brittle

Table 9: An engineering evaluation of shale (Underwood, 1967; Fleming et al, 1970)

Laboratory less and in-situ observations	Average range of values		Probable in-situ behaviour					
	Unfavourable	Favourable	High porepre-ssure	Low bearing capacity	Slope stability problem	Rapid slaking	Rapid erosion	Tunnel support problem
Compressive strength (Mpa)	0.34 – 2.07	2.07–34.50	√	√				√
Modulus of Elasticity (Mpa)	140 –1400	1400 -1400		√				√
Cohesive strength (Kpa)	35 – 700	700 > 10,500			√			√
Angle of internal friction (deg)	10 – 20	20 – 65			√			√
Dry density (Mg/m^3)	1.12 –1.78	1.78 –2.56	√				√	
Natural moisture content (%)	20 – 34	5 – 20	√		√			
Potential swell (%)	3 –15	1 –3			√		√	√
Coefficient of permeability (m/s)	$10^{-7} - 10^{-12}$	$>10^{-7}$	√		√	√		
Predom. Clay mineral	Illite/mont.	Kaolinite/ chlorite	√		√			
Activity	0.75 > 2.0	0.35 – 0.75			√			
Spacing of rock joints	Closely spaced	Widely spaced		√	√			√
Wetting and drying cycles	Reduces grain sizes	Reduces to flakes				√	√	
State of stress	Greater than existing overburden	About equal to existing overburden			√		√	√

Table 10: Summary of some petrophysical and geomechanical properties of shales (Attewell and Farmer, 1976; Franklin and Dusseault, 1989; Waltham, 1994).

Property	Average value/range
Bulk density (Mg/m^3)	2.30
Porosity (%)	15 (7 –30)
Permeability (m/s)	1×10^{-9} ($1 \times 10^{-6} - 10^{-12}$)
UCS (Mpa)	20 (3 – 30)
Young's modulus (Gpa)	5.0
Poisson's ratio	0.22
Resistivity (Ohm-m)	0.5 – 15

Table 11: Significance of some petrophysical and geomechanical properties of shales in the petroleum industry (Levorsen, 1985; Krumbein and Sloss, 1963)

Parameter	Significance
Bulk density	Influences overburden pressure; increases with depth; used in predicting occurrence of overpressure.
Porosity	Measure of the pore space in a rock expressed in Percentage; used in predicting overpressures.
Permeability	Measure of ease of fluid flow through the rock; shales have low permeability, shales are therefore good seal rocks. Naturally fractured shales have high permeability and therefore high reservoir potential
Fluid/formation pressures	Formation pressure differential at depth; influences fluid migration and flow during production; increase pressure at depth contributes to occurrence of overpressures; overpressure create drilling problems

Electrical resistivity Measure of resistance of passage of electric current in rock; depends on nature of sediments and fluid filling it. Shales have low resistivity; used in estimating prosity of rocks and identification of shales

Formation temperature Influences temperature of formation of oil/gas; affects stability of drilling fluid.

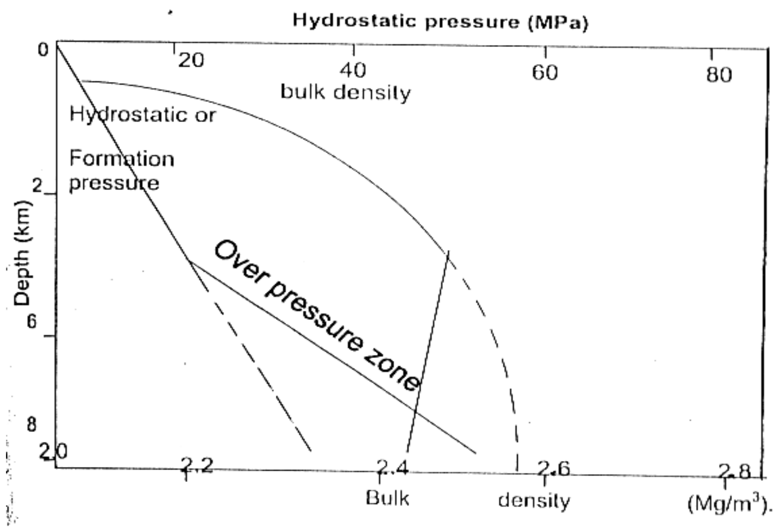

Fig. 6. Relationship between formation pressure and bulk density variations with depth (Modified from Fertl, 1977; Darley and Gray, 1988).

IMPORTANCE OF SHALES TO THE PETROLEUM INDUSTRY

The petroleum industry encompasses exploration, production, transportation, processing and marketing of petroleum oil and gas. The generation and accumulation of petroleum involve three stages, namely, generation in the source rocks, migration through geologic formations and storage in rock reservoirs (Magara, 1977; Tissot and Welte, 1984). Petroleum source rocks are geologic formations that are capable of generating petroleum (Tissot, 1977). Coal, mudstone and shale are the recognized source rocks because of their organic carbon contents. These organic contents, depending on their nature, depositional environment, temperature, pressure, and depth of burial are capable of generating petroleum. Generally, petroleum gas is produced in high temperature/pressure, humic and plant dominant organic sediments such as coal while oil is produced from less humic, fossil dominant and moderate temperature/pressure marine shales (Nwachukwu, 1976; Selley, 1977). The source rocks have very low porosity and permeability, and thus the petroleum once formed is trapped in the rock but may move out due to hydrodynamic pressure conditions into a nearby porous rock from where it continues moving or migrating until it is trapped or stored in a suitable geologic reservoir formation (Magara, 1977; Levorsen, 1985). The petroleum oil or gas trapped in the reservoirs can then be exploited by drilling wells into the reservoirs. Such reservoirs include sandstones, limestones as well as fractured shales. Shales as impermeable rocks are also important seals in stratigraphic and structural traps. Shales are therefore important as source rocks, reservoir, as well as seal rocks. According to Roegiers (1993), about 90% of all formations drilled in the petroleum industry is shales and limestones. It is also known that shales can be problematic in the petroleum industry. Roegiers (1993) has it that about 75% of well drilling/completion problems are related to shale formations. Details of the positive as well as the negative aspects of shale to the petroleum industry are now reviewed.

Positive Aspects

Shale as source rock in petroleum generation

Petroleum source rocks under favourable depositional environment and temperature/pressure conditions generate gas and oil. According to Selley(1977), Mtanju et al (1991) and Obaje et al (2004), the potential of a source rock to generate petroleum depends on the underlisted factors:

(a) Total organic carbon (TOC) >0.5%
(b) Hydrogen index (H1) > 150mg Hc/g TOC
(c) Oxygen index < 160mgC0_2/g org.C
(d) Liptinite content > 15%
(e) Temperature range (Oil window) 100 – 250^{o}C
(f) Vitrinite Reflectance R_o0.5 – 1.2%

Tissot (1977) lists the conditions slightly differently. According to him, the conditions include: sufficient amount and right quality of organic matter, the latter meaning that the chemical composition of the kerogen should be favourable for a high yield of oil and gas upon burial. Tissot also stressed that the thermal history of the source rock must be such that it can produce significant amount of petroleum. The thermal history is tied to the maturation of source rock, which may be expressed by the transformation ratio, that is, the ratio of the petroleum already generated to the genetic potential.

Shale as petroleum trap/seal rock

Petroleum traps may be classified into structural and stratigraphic. Structural traps are folded and/or faulted geologic formations. In each case shale acts as either cap or seal rock (Fig. 7). In the Niger Delta, for example the faults are growth faults which are normal faults formed as a result of differential loading/rapid sedimentation of dense sediments (sands) in overepressured shale. These growth faults are associated with rollover anticlines which are traps for petroleum accumulation (Fig. 8). Stratigraphic traps are brought about by facie changes due to unconformity and occurrence of coral reefs (Fig. 9; Levorsen, 1985). Structural and stratigraphic traps with shale seals are common in the Niger Delta, North Sea and Gulf of Mexico petroleum provinces (Laplante, 1976; Nwachukwu, 1976; Selley, 1977).

Shales are also known to act as seal rocks in the form of shale smears. According to Aydin and Eyal (2002), shale smear occurs along a fault (particularly normal or reverse fault) in a sedimentary rock sequence in which incompetent (low strength and plastic/ductile) shale is sandwiched between competent(high strength and brittle) sandstone or limestone. In the process of faulting, the shale undergoes thinning perpendicular to the fault and stretching parallel to the fault. Internal faulting, jointing and folding may also occur in the smeared shale. Aydin and Eyal (2002) note that these internal faults within the shale are mostly parallel with the bounding faults and do not pose much hazard to the sealing efficiency of the shale smear except when the continuity of the shale sealing rock is breached in the cause of primary faulting or reactivation of the faults. Fig. 10 shows a fault with shale smear at Gulf of Aquaba, Israel.

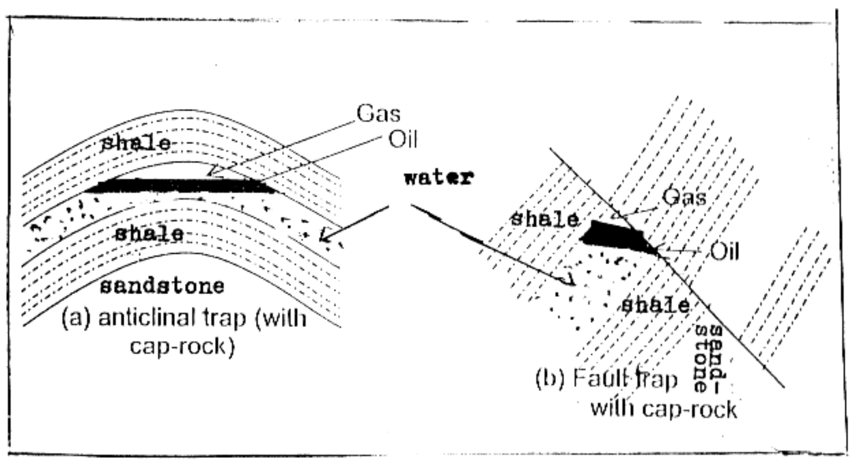

Fig. 7 Types of structural traps (After Levorsen, 1985).

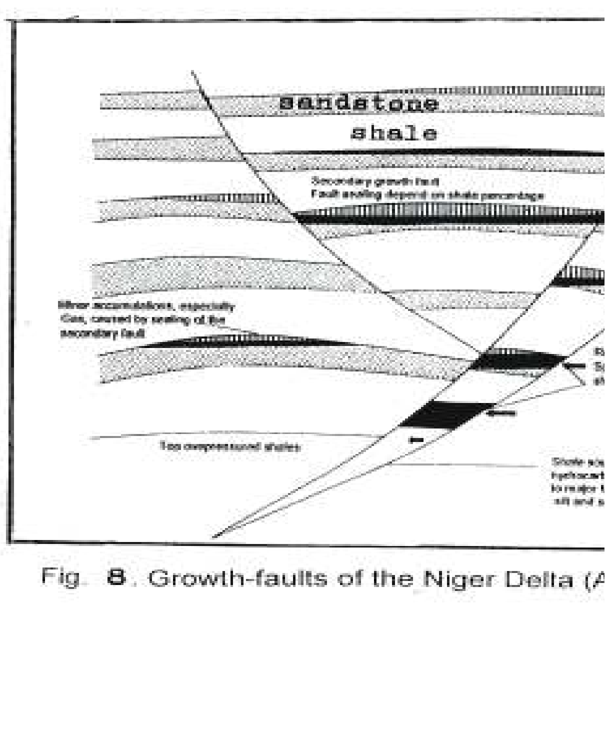

Fig. 8. Growth-faults of the Niger Delta (A

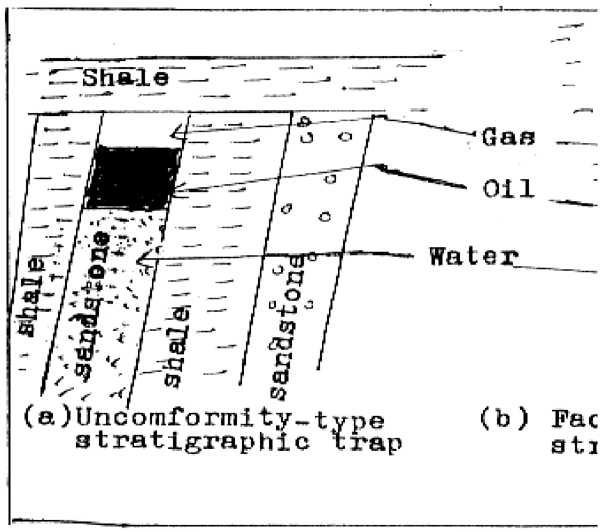

Fig.9 Types of stratigraphic tra

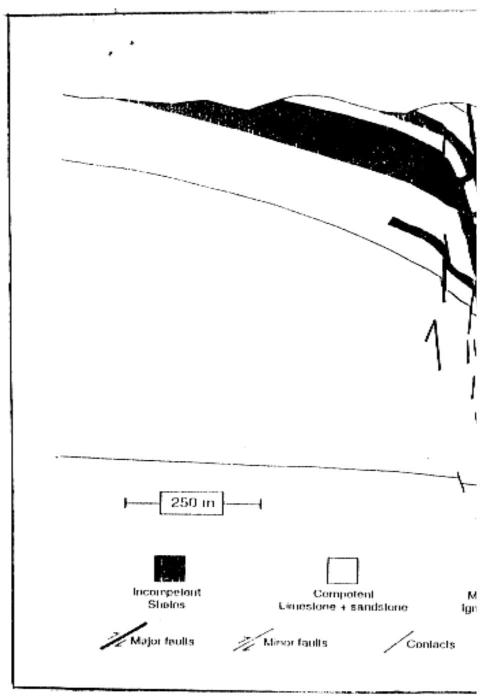

Fig.10. Shale smear in Yehoshafat Fault, Sh
Aquaba-Israel (After Aydin and Eyal,

Shales as oil/gas reservoir

Shales are naturally impermeable and cannot therefore be good reservoir for oil or gas accumulation. But when fractured, either naturally or artificially, the permeability may be increased to an extent that it can accumulate oil/gas and release them at an economic rate. Natural fracturing in shales is common and is caused by volume changes associated with compaction of brittle shales at depth. According to Price (1966), fracturing in shales and other sedimentary rocks at great depth is generally vertical, continuous and without shear displacement. The fractures are therefore joints. Natural fractures in shales are classified as either systematic (occuring in parallel sets and cutting across other joints or discontinuities such as bedding planes) or dip (occuring perpendicular to the bedding planes) joints. Examples of naturally fractured shale gas reservoirs include the Devonian shales of the Appalachian Basin, Michigan Basin and Illinois Basin all in the USA. These shales have continued to produce gas since the mid - 1980s (Explorer, 2001 and 2002). Most producing shale gas wells have long life although production rates are low (20-200 mcfd) and recovery efficiency of the gas in place is low (5-10%). Because fractures in shale gas reservoirs are generally vertical, horizontal wells are always drilled into the shale for better contact with the gas pay zone. Other naturally fractured shales that are oil producing are shown in Table 12. Tables 13 and 14 show US national shale gas reservoirs and their production characteristics (USGS, 1995).

Table12: Examples of oil production from naturally fractured shale reservoirs (Hubbert and Willis, 1955).

Name of Oil Field	Location	Reservoir Rocks
Santa Maria Oil Field	California	75% fractured shale and 25% sands
Spraberry Oil Field	Western Texas	100% fractured shale
Florence Oil Field	Colorado	100% fractured shale

Table 13: United States of America (USA) fractured shale gas (Gas-bearing) resources (USGS, 1995)

Formation	Basin	Basin Area sq.mi (km^2)	Estimated shale gas in-place (Tcf)	Estimated recoverable shale gas (Tcf)
Ohio Shale	Appalachian	160000 (409600)	225 – 258	14.5 – 27.5
Antrim Shale	Michigan	122000 (312320)	35 – 76	11.0 –18.9
New Albany	Illinois	53000 (135680)	86 – 160	1.9 – 19.2
Barnett Shale	Forth Worth	42000 (10,752)	500 – 1000	42.0 – 76.0
Lewis Shale	San Juan	4.2000 (10752)	96 – 101	N. A

Table 14: Some characteristics of producing US shale gas formations/reservoirs (USGS, 1995)

Characteristics	Barnett	Ohio	Antrim	New Albany	Lewis
Depth (ft)	6500-8500	2000-5000	600–2,200	500-200	3000-6000
Bottom-hole temp. (%)	200	100	75	80-05	130-170
TOC (%)	4.5	0.0-4.7	1.20	1.25	0.45-2.5
Total porosity (%)	2.5	2.0	4	5	1.3.5
Water filled porosity (%)	1.9	2.4 –3.0	4	4 - 8	1 – 2
Reservoir pressure (psi)	3000-400	500-2000	400	300-600	1000-1500
Pressure gradient (psi/ft)	0.43 –0.44	0.15 – 0.40	0.35	0.43	0.20-0.25

Oil shales as raw materials for secondary production of oil and gas

Oil shales are fine-grained sedimentary rocks that have a high proportion of organic matter (kerogen), which can be converted to oil or gas by processing (Metz, 1974). Oil shales therefore do not contain liquid petroleum but rather this insoluble organic raw material (kerogen) that matures or generates petroleum. According to De Nevers (1965), the chemical difference between petroleum and kerogen is primarily of molecular geometry. Whereas petroleum molecules are typically composed of linear chains with some attached rings and branches and very little linking between the chains, the chains in kerogen are cross-linked to a significant extent. When kerogen is heated to about 900°F (480°C), the links between chains break and the solid is chemically transformed into an oil (representing about 60% of the kerogen weight), a fuel gas (9%) and a cokelike solid (25%) (De Nevers, 1965). The composition of a typical high-grade oil shale is given in Table 15. Oil shale is one of the most abundant energy resources in the world. Table 16 shows some occurrences.

Table 15: Composition of typical high grade oil shale (25 gallons of oil per ton) (US Dept of Interior, 1973)

Composition	Weight (%)
Organic matter	13.8%
Carbon	(80.5)
Hydrogen	(10.3)
Nitrogen	(1.0)
Suphur	15.8
Oxygen	(100)
Mineral matter	86.2
Carbonnates, mainly dolomites	(48)
Feldspars	(21)
Quartz	(13)
Clays, mainly illite	(13)
Analcite	(4)
Pyrite	(11)
	100

Table 16: World summary of energy resources /oil shales (World Energy Council, 2001**)**

Country	Proven Amount in Place (million tonnes)	Average yield of oil (kg oil per tonne)	Processing method	Production in 1999 (thousands of tonnes of oil)
Morocco	12,000	55	Surface	-
South Africa	73	10	In-situ	-
USA	3,340,000	57	Surface	-
Brazil	9,640	30	Surface	-
Thailand	18,668	50	In-situ	195
Estonia	590	167	Surface	151
Turkey	1,640	36	Surface	-
Ukraine	590	2126	In-situ	-
Israel	15,360	62	Surface	-
Jordan	40,000	100	Surface	-
Australia	32,400	53	In-situ	5

Negative Aspects

Although shales are very positively important to the petroleum industry, they also are known to cause lots of problems to the same industry. Some of the problems associated with shales are slow rate of penetration and wellbore instability. These problems are discussed below.

Slow rate of penetration

In rotary drilling, penetration is achieved by application of torque (force) in a rotating drilling bit with the drilling fluid introduced under pressure from the surface through the drill pipe. The rate of penetration in any rock mass generally declines with depth due to increased differential pressure and in-situ stresses, decreased porosity and decreased rate of drill cutting removal. Rock properties such as compressive strength, abrasiveness and permeability also affect rate of penetration, and so does presence of swelling clays.

Shales, though low strength rocks, have high abrasiveness because of their quartz content which is more than 20% (Sereda and Solovyov, 1977). They also have low porosity and permeability, and significant quantity of clay minerals (about 57% average). The low porosity/permeability and presence of clay minerals contribute to high torque needed to rotate the drill string/bit during drilling; and high abrasiveness affects the rate of bit wear/changes during drilling. These factors are therefore responsible for slow rate of penetration of the drill bit while drilling in shale formations.

Wellbore instability

Wellbore instability is the breakout/caving-in of near-wellbore rocks (well or hole enlargement) and reduction of wellbore size (well or hole tightening) during well drilling/completion operations (Cheatam, 1984). It is common when drilling in shales because shales have characteristically low strength and low permeability. They are also vulnerable to hydration, swelling, strength reduction and failure. Well enlargement and well tightening are caused by the strength reduction of the near-wellbore rocks due to the pressure gradient between the drilling mud in the well and the formation pressure (anisotropic stress distribution at depth, a geomechanical factor). Because the in-situ stress from the formation is always greater than the well pressure, failure occurs either through plastic or brittle deformation. The former leads to a reduction in the size of the well (well tightening) while the latter leads to removal of large chunks of rock fragments from the wall of the wellbore thereby increasing the size of the well (well enlargement) (Roegiers, 1993; Darley, 1969). Well tightening is also caused by adsorption of water by shale

(shale hydration) due to the interaction between the shale exposed on the wall of the wellbore during drilling and the drilling fluid. The swelling experienced by shale due to the hydration may lead to reduction in size of the well. Fig. 11 shows well tightening due to reduction in the size of a wellbore caused by plastic deformation/swelling.

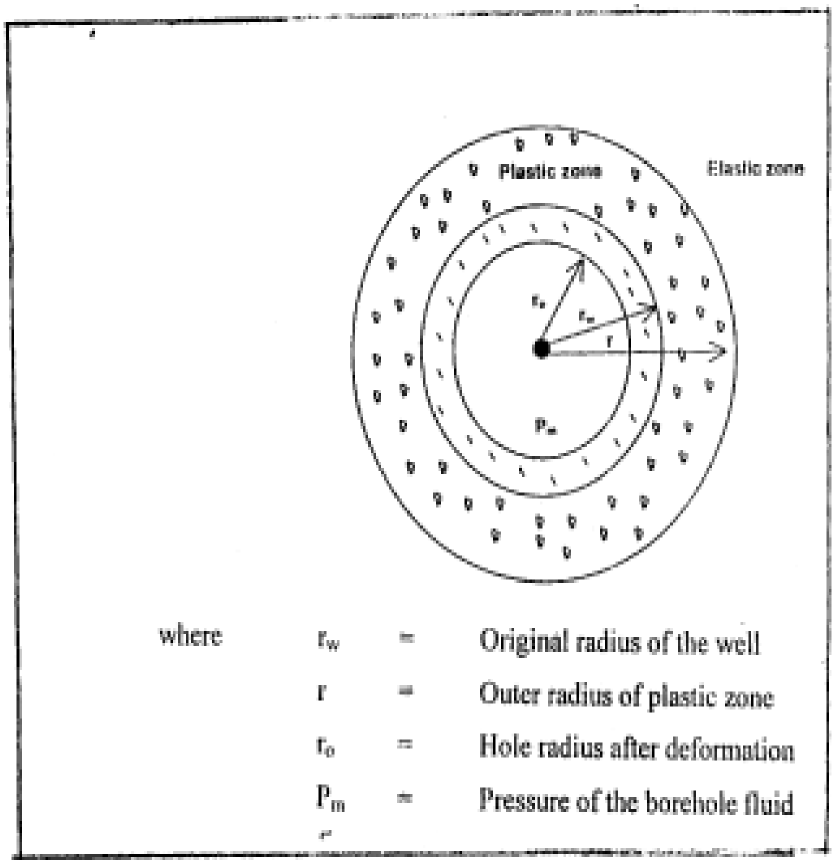

Fig. 11 Plastic deformation of a borehole (After Darley and Gray, 1988).

Well tightening has the effect of reducing the drilling rate when the drag on the rotating pipe is increased because of its contact with the wellbore wall during drilling. It may also cause stuck pipes if the hole size becomes so narrow that it “catches” the drill pipe and prevents it from rotating as designed. According to Adams (1974) and Oudmans (1958) stuck pipes are also called deferential sticking and may be caused by high excessive pressure of the mud column with substantial water loss in different parts of the drill string because of deflection of wellbores (differential pressure).

Well enlargement has the effect of increasing the total amount of rock materials (drill cuttings and wall rocks) to be brought to the surface by the circulating drilling fluid thereby reducing the quality and hence the serviceability of the drilling mud. It increases risk of drill pipe failures because of the deflection and consequently bending stress the pipe may experience in the cavernous (enlarged) zone.

It may also cause blowout or lost circulation (depending on the formation pressure and well pressure). Blowouts are uncontrollable flow of formation fluid (gas, oil and water) into the well and out of the wellhead whenever the formation pressure is greater than the pressure exerted on it by the drilling fluid (Sereda and Solovyov, 1977). Blowouts may cause explosions, fires and destruction of wellhead and drilling equipment. Lost circulation occurs during drilling when the drilling fluid flows continuously from the well into the formation, thus reducing the volume of fluid in circulation. The adverse consequences of lost circulation include increase in the quantity of drilling fluid needed to drill a well, increase in working time used by the drillers to prepare the drilling fluid mixture that will stop lost circulation and overall increase in the cost of drilling the well.

THE NIGER DELTA PETROLEUM PROVINCE AS A CASE EXAMPLE OF THE IMPORTANCE OF SHALES

Location and General Characteristics

The Niger Delta is situated in the Gulf of Guinea (Fig. 12). It has an area of about 300000 km^2, a sediment volume of 500000 km^3 and a sediment thickness of over 12000m (12km) in the basin depocentre(Hospers, 1965; Kulke, 1995),

The deposition of Niger Delta sediments started in the Paleocene with major transgression that led to deposition of Imo Shale in the Anambra Basin to the northeast and Akata Shale in the Niger Delta Basin area to the southwest (Reijers et al, 1997). According to Short and Stauble (1967) and Avbovbo (1978), Akata Formation at the base of the delta is of marine origin, and is composed of thick shale sequences (potential source rock), turbidite sand (potential reservoirs in deep water) and minor amount of clay and silt. The Akata Formation has been estimated to be up to 7000 metres thick (Doust and Omatsola, 1990) (Fig 13).

Deposition of the overlying Agbada Formation (the major petroleum bearing unit) began in the Eocene and continues into the Recent. The formation consists of paralic shale and sandstone sequences of over 3,700 metres thick and represents the actual deltaic portion of the basin. The overlying Benin Formation is about 2000 metres thick (Avbovbo, 1978). The Formation is a continental Eocene to Recent deposit of alluvial and coastal plain sands.

Evamy et al (1978), and Ekweozor and Okoye (1980) have on the basis of organic matter content (>1.4%) and geochemical maturity indicators (including vitrinite reflectance data) shown that marine shales of Akata Formation and Lower Agbada Formation are the source rocks of the Niger Delta oils and gases. Ejadewe et al (1984) used maturation index to arrive at the same result.

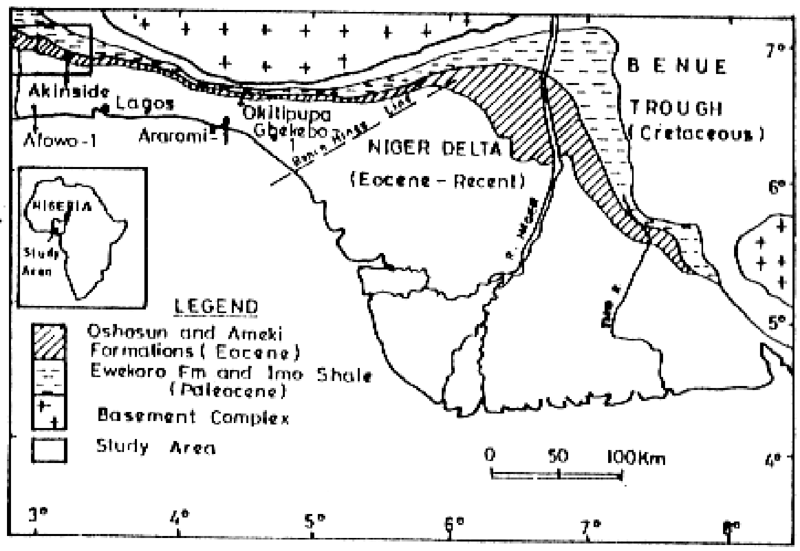

Fig. 12. Location map of the Niger Delta (After Short and Stauble,

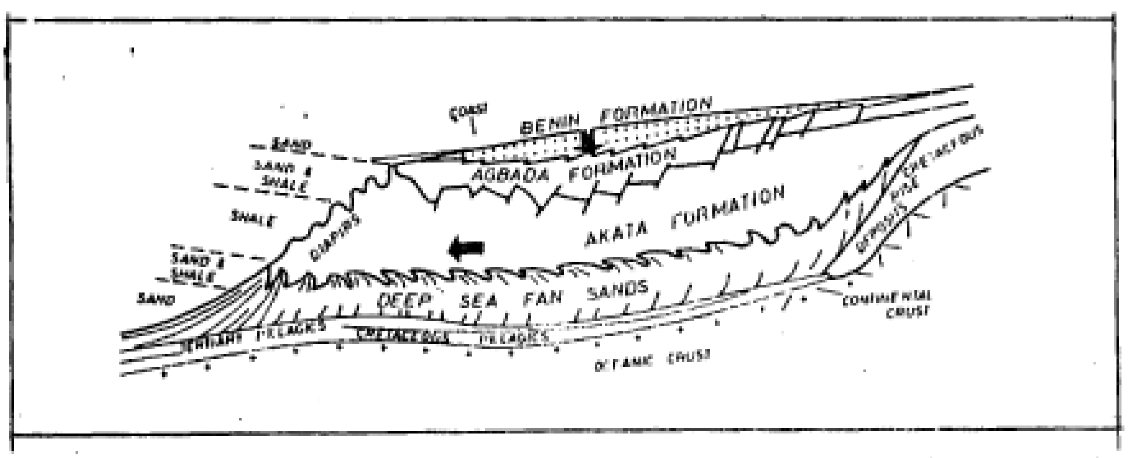

Fig.14. Structure of the Niger Delta (After Burke, 1972).

Traps and seals

Structural traps are dominant in the Niger Delta, although there are few stratigraphic traps. The structural traps were developed during synsedimentary deposition of the paralic Agbada Sequence (Evamy et al, 1978; Stacher, 1995). According to Doust and Omatsola (1990) and Xiao and Suppe (1992), these traps are structures associated with multiple growth faults, roll-over anticlines and clay-filled channels, and they increase in complexity from the north (earlier formed depobelts) to the south (later formed depobelts) in response to increasing instability of the under-compacted and over-pressured shale. Fig. 8 shows Niger Delta growth faults. Stratigraphic traps are common at the flanks of the delta and the deep-sea section where pockets of sandstone (at the flanks) and turbidite sands (at the deep-sea section) occur between diapiric shale and deep-seated Akata Formation.

The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. The shale provides three types of seals, namely: clay/shale smears along faults, interbedded sealing units against which reservoir rocks are juxtaposed due to faulting, and vertical seals (cap-rocks). On the flanks of the delta and deep-sea front, major erosional events of Early to Middle Miocene age formed canyons that are now clay-filled. These clays formed the top seals for some important offshore fields (stratigraphic traps) (Doust and Omatsola, 1990).

Shale-related drilling problems in the Niger Delta

The dominant rocks in the Niger Delta are the over-pressured shales of the Akata and Agbada Formations, the former of which constitute the source rocks and the latter, the reservoir rocks. According to Ichara and Avbovbo (1985), and Obah (1989), drilling problems and hazards encountered in the Delta are often associated with the overpressures, which can result to blowouts and wellbore instability. The abnormal pressures (over-pressures) were brought about in the low permeability shales when fluid contained in them could not be easily dispersed during compaction of the sediments. The excess pore fluid thus remains in the shales and constitutes the overpressures (Bradley, 1975; Bolas et al, 2004).

SUMMARY

Shales are fine-grained laminated or fissile clastic sedimentary rocks with predominance of silt and clay as the detrital particles. Other major constituents include organic matter and cementing materials. The minerals contained in shales are distributed in the silts, clays, cementing materials and organic matter. The common minerals include, clay minerals, feldspars , calcite, mica, quartz, pyrites, iron oxides and organic carbon. Clays and quartz are the main minerals constituting about 57% and 25% by weight, respectively of the rock. Various criteria including texture, mineralogical composition, cementing materials, organic matter content, depositional environment and strength are used in the classification of shales. Shales vary in colour ranging from white through red and green to grey and black depending on mineralogical composition and depositional environment. They are characteristically water sensitive (susceptible to hydration and swelling when in contact with water), with low strength and low permeability.

The importance of shales to the petroleum industry may be either positive (useful) or negative (problematic). The positive aspects include their roles as source rocks in petroleum generation; seal rocks in both structural and stratigraphic traps; reservoirs as in fractured shales and secondary production of oil and gas as in oil shales. The negative aspects are the problems associated with drilling oil/gas wells in shale formations. These problems include slow rate of penetration and wellbore instability. These problems generally increase cost of drilling a well, time of completing the well and sometimes may lead to loss of human life (as in blowouts).

Shales have unique structure and chemical/mineralogical composition compared with other sedimentary rocks: they are fissile, radioactive and contain relatively high proportion of clay minerals and organic matter. They are the only rocks that can occur or be found as source rocks, seal rocks and reservoir rocks in the petroleum industry.

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