

Chapter 1

introduction

1.1. Sudan's potential:

Sudan has proven oil reserves of 6.4 billion barrels, 32 times more than was estimated in 1981. Both reserves and production cover 0.5% of the world reserves and production. Sudan is Africa's largest country and the tenth largest country in the world. Its only coastline is in North-East, whereas the main hydrocarbon reserves are located in the South. The country is divided into 23 prospective blocks that have all been awarded, with the exception of Blocks 10 and 12B. So far, the oil exploration has been limited to the central and south central regions, but the country may also have commercial reserves in the east and Northwest. Sudan remains largely unexplored. Intensive and comprehensive seismic data have been collected from a few areas only. No exploration commitment has been contractually imposed by the Government and the operating companies have concentrated on the most immediately promising areas, leaving other areas unexplored. On the other hand, the operators of the producing blocks are currently implementing aggressive exploration programs. With the companies wanting to achieve payback as quickly as possible, development of discoveries is likely to be prompt. The average block size is immense: 61,000 km², compared to 5,700 km² for Libya and 1,500 km² for Angola and Nigeria. Block B, for instance, covers 118,000 km², which is about half the UK. The only producing blocks are 1 through 7 of 23 in total. Except for the two off shore blocks in the Red Sea, the remaining blocks look much less promising, even though little or no seismic research has been done. They are all leased by marginal and inexperienced companies. For instance, Zafir Petroleum has a stunning gross acreage of 315,722 km² (Blocks 9 and 11), but has no previous operator experience. Among the non-producing blocks, block B, also in the South, is the most promising. Sudan's oil production will probably peak in 2008, but revenues may be maintained for another ten years at current levels, depending on the development of oil prices and whether the Dar Blend refinery will indeed be a price booster. The only prospective block that remains to be explored, Block B, will not come on stream before 2014 and may then partially compensate for the exhaustion of the fields that are currently producing.

1.2. The geology of Sudan:

Sudan geological study was focused on the surface geology mainly for surface mapping and limited shallow mining activities. With the recent discovery of commercial hydrocarbon, extensive subsurface data has been acquired both offshore and onshore. These data revealed existence of several sedimentary basins offshore in the Red Sea and onshore in the interior Sudan. Main sedimentary Basins are shown in Figure (1.1).

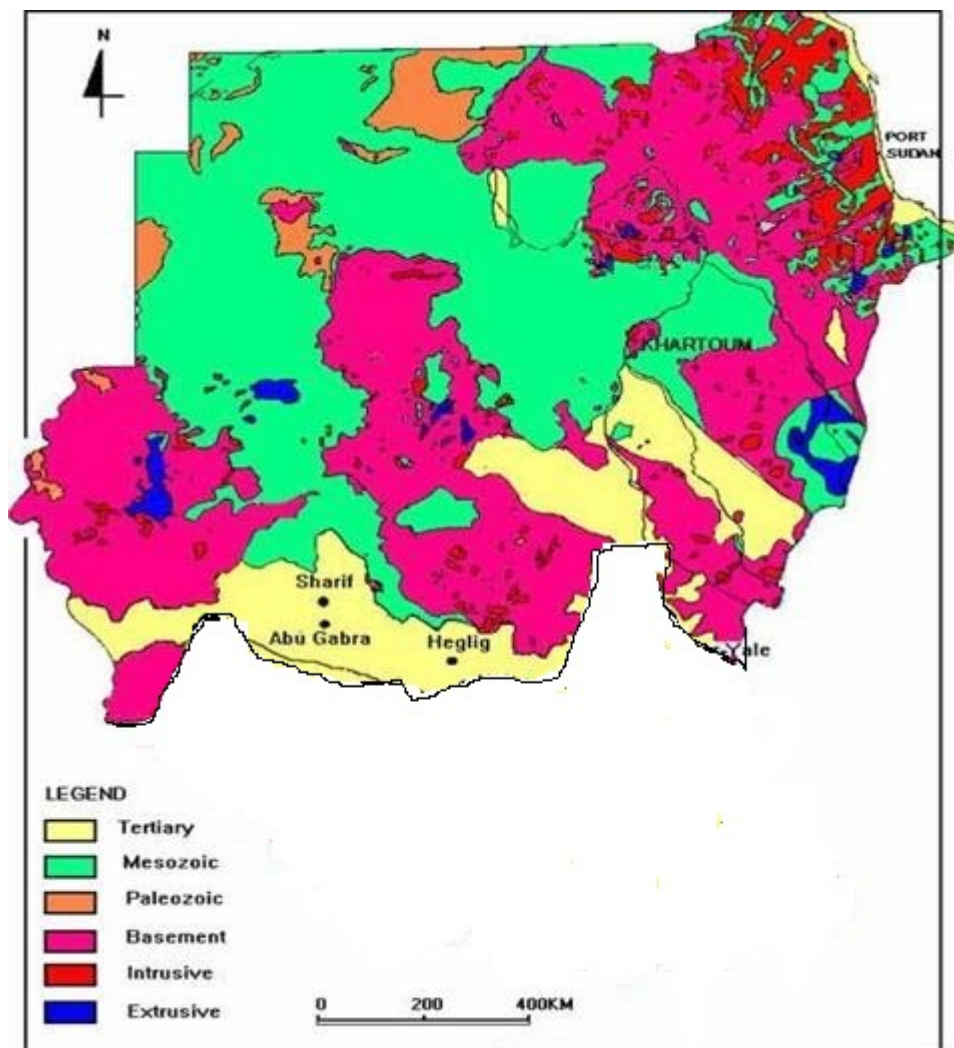


Fig (1.1.) : Geological map of Sudan

These basins are all rift basins, owing their existence to the rifting activities of Western Central and East African Rift Systems. Exploration is still at early stages and the data collected is scarce. Based on the available data and from analogy to other basins it can be concluded that the major conditions for Petroleum accumulations have been met. Hundreds

of meters of rich source rocks have been penetrated in Muglad, Melut, Blue Nile, Red Sea, Khartoum and White Nile Basins.

Excellent and extensive reservoir quality sands have also been drilled. The oldest sedimentary basins encountered so far in Sudan are of Cambro-Ordovician age? These occur within narrow grabens formed by rifting, which preceded consolidation of Pan African structures in north and north-western Sudan shows the distribution of sedimentary basins in Sudan, Much attention has been given to an already explored Mesozoic rift related basin systems, in the south and central Sudan, while the Paleozoic basins in the NW Sudan have not been explored, Data from these basins such as surface geology, regional gravity and magnetic which indicate that the basins are deep and filled by thick Pile of marine and continental sediments during Palaeozoic and Mesozoic times e.g. Murdi basin (4.5 km depth), and South WadiHowar basin(5 – 6 km). The gravity, seismic and drilling data acquired in interior Mesozoic basins in the central and southern Sudan indicated that more than 30000 feet of clastic sediments occur within the deepest central trough of the three major rift basins, which runs along the western flank of the Muglad basin and that of Unity in the Eastern flank, whereas, shows the Stratigraphy of the Melut basin. The sediments are interbedded sandstones, claystones, siltstones, mudstones and shales. Intrusive rocks (Sills) were encountered in some wells such as in Garad-1, Sobat-1, Tabaldi-1 . Changes in lithofacies primarily reflect variation in the subsidence rates of various sub-basins. The lack of significant magmatism during active rifting is attributed the shallow depth of fault detachment at a brittle –ductile transition zone. AbuGabra Formation is the main source rock, consists of dark lacustrine shales containing atypically waxy kerogen and proved to be a reservoir in block#6. Bentiu formation, Darfur group sandstone members, Amal and Tendi formations are the principal reservoirs. Shale, sand, claystones within Darfur Group as well as shale sand claystones within AbuGabra Formation act as seal to underlying oil bearing horizons. None of the wells drilled in the Melut basin, has encountered the source rock show ever, based on the crude oil biomarker distributions and characteristics, it is believed that the source rock in Melut basin is equivalent to the AbuGabra Formation found in the Muglad basin, Yabous Formation is the main reservoir in Melut basin. Time of oil migration is uncertain, but it seem stop during mid to late Tertiary in the Muglad basin and during mid–Cretaceous to Late Cretaceous time in the Melut basin.

1.3 Industry of oil in Sudan:-

Oil was discovered in Sudan in the mid-1970s, but production did not start until 1999. The pioneer companies Chevron and Shell were forced to blow out in 1984, after the outbreak of civil war. They eventually sold their rights in 1990, booking a \$1 billion loss. Mid-1990s, the CNPC and PETRONAS from Malaysia, both fully state controlled, grasped this unique opportunity to invest in an oil rich area that was out of bounds for the oil majors. They continue to dominate the scene. In 2003, when the violent displacement campaign in their areas of operation became public knowledge, their junior western partners, OMV (Austria) and Talisman Energy (Canada), left Sudan, while Lundin Petroleum from Sweden kept its interest in block 5B. ONGC from India stepped in, completing the prevailing position of Asian national oil companies in Sudan's oil industry. CNPC, PETRONAS and ONGC account for over 90% of Sudan's total output. Not only are these companies important to Sudan, Sudan is also important to them. For each of them, Sudan was the largest overseas operation in 2007, substantially so for both PETRONAS and ONGC. And their Sudanese assets are highly profitable. They are not very likely to offer opportunities for newcomers to farm in on their existing assets. They are mostly state-owned and their investment decisions are made at a country level rather than a company level, making them resistant to shareholder activism. While, at a global level, Sudan is a minor oil producing and exporting country, China, India and Malaysia have invested billions of dollars in the country, also outside the oil industry. They consider their relations with the country not only as economic, but also geo-strategic and energy-strategic successes that are worth defending.

1.4. Sudan's oil reserves:

This estimate is based on expected production using existing technology. It deals with proven reserves only and does not take into account probability of new finds, for instance in the huge underexplored blocks 5B and B. Some believe that the Melut Basin may in fact hold 1.3 billion recoverable barrels. British Petrol's (BP) estimate of 6.4 billion barrels proved recoverable reserves seems high. GNPOC's production in Blocks 1, 2 and 4 reached its peak production of 328,000 bbl/d in 2005. Reportedly, GNPOC's policy to pump as much as possible as quickly as possible, has led to a loss of production potential. Unity and Heglig fields are in decline with produced water ratios exceeding 65%. On the other hand, the Neem field in block 4 that came on stream in July 2006 has offset most of the decline in production from the Unity and Heglig fields and, together with other, smaller new fields, will allow GNPOC to remain Sudan's main oil producing company for a few more years. Exploration

outside Upper Nile and Abyei (South-Kordofan) has been disappointing. Chevron's two dry wells in Block C were matched by five dry wells that Advanced Petroleum Company (APCO) drilled in 2005-6, leading to the withdrawal of Cliveden Ltd. Parts of Block 6 (Chinese National Petroleum Company/Sudapet - CNPCIS) were relinquished in 2005 for lack of prospects to form the new Block 17. SUDAPAK1 failed to find oil in Blocks 11 and 14, while WNPOC-3 in Block 8 did thus far not beat Chevron's 1982 small find of Dinder 1. The Suakin gas condensate structure in Block 15, discovered by Chevron in 1976, was then estimated to have potential reserves of 10 - 49 bcf of natural gas and 100 - 500 million barrels of condensate. However, recent re-appraisals indicate a less extensive pay zone. Blocks 12A and 14 are not highly prospective. The fact that the remaining open Blocks 10 and 12B, offer moderate prospects at best, concludes the modest outlook for the Northern part of the country. Among the non-explored blocks, 5B (WNPOC-2) and B (Total-led consortium) potentially contain important commercial quantities. On the other hand, results in the Southern part of Block 7 (PDOC) and in the adjacent Ethiopian province Gambella have been disappointing, possibly backing up the suspicions of some geologists that the further South, the smaller the hydrocarbon (oil and gas) reservoirs

EXPLORATION CYCLE IN A SEDIMENTARY BASIN

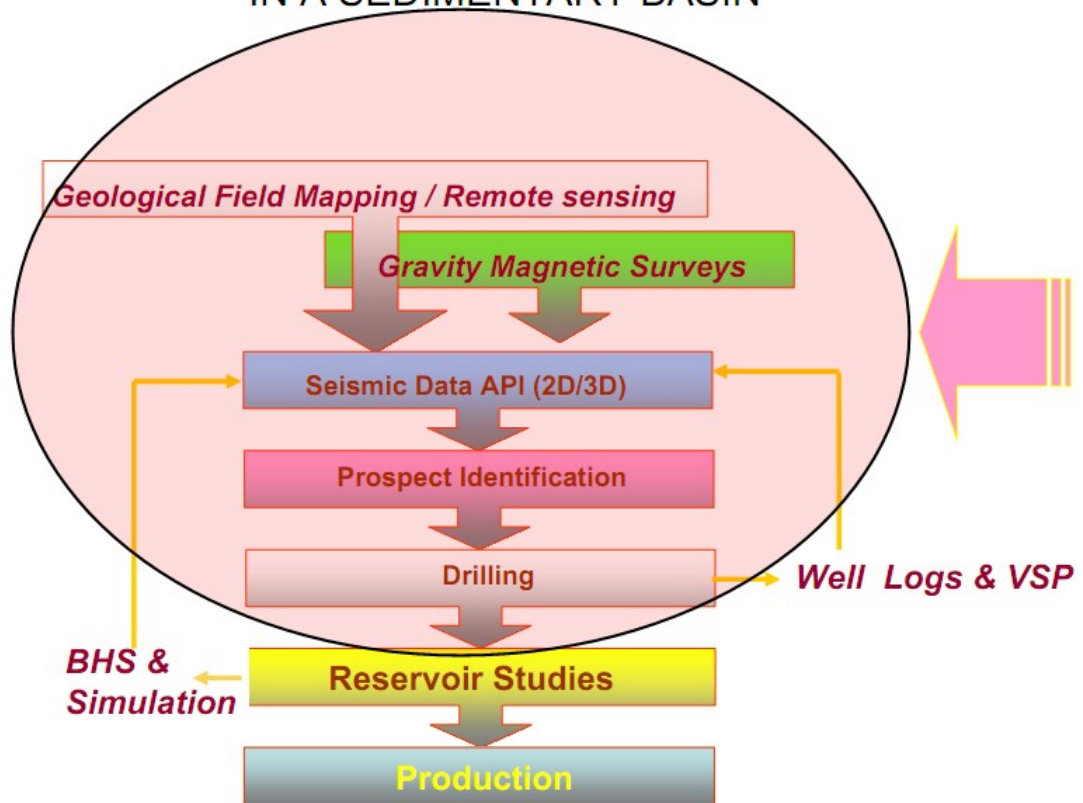


Figure (1.2.) Exploration cycle in a sedimentary basin.

Chapter 2

Geological and Stratigraphy study

2.1. Blue Nile Basin:

The Blue Nile Basin is a major geological formation in the north-western Ethiopian Plateau formed in the Mesozoic Era during a period of crustal extension associated with the break-up of Gondwana, and filled with sedimentary deposits. The modern Blue Nile River cuts across part of the sedimentary basin.

2.1.1. Strata:

The Blue Nile basin originated in an area of Neoproterozoic rocks aged about 750 Ma that had become a pen plain, possibly during the Paleozoic era (540 Ma^[fn 1] - 250 Ma). The basin was formed due to rifting during the Mesozoic era (250 Ma - 66 Ma). Between the Triassic and early Jurassic, about 300 m of fluvial sediments were deposited by rivers and streams. During the Jurassic (200 Ma - 145 Ma) the basin was twice covered by an arm of the Indian Ocean for extended periods, creating a lower limestone sediment 450 m thick and an upper limestone sediment 400 m thick. In the late Jurassic and early Cretaceous periods the basin

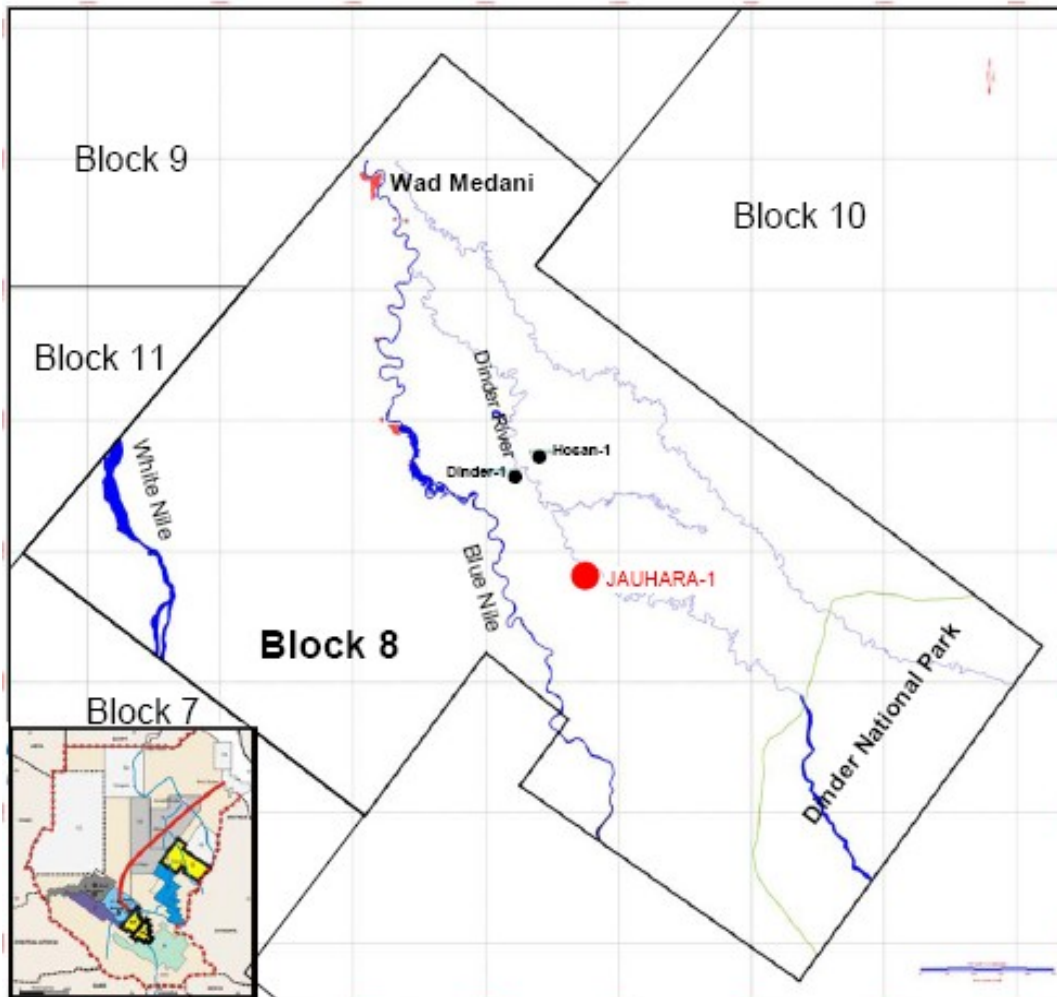
rose, and the 280 m upper sandstone sediments, both Alluvial or flu-vial, were deposited. In total, about 1.4 km of sediment was deposited over the basement rocks in this period. Later, the Afar mantle plume caused volcanic eruptions in the early and late Oligocene (34 - 23 Ma), depositing volcanic rocks between 500 m and 2000 m thick, with further eruptions in the Quaternary depositing another 300 m of rock. These layers have been exposed where the Blue Nile River has cut through the strata, creating a 1,600 m gorge where the rocks of different periods can be studied. However, the architecture of the basin is not well known in other areas due to the thick upper layer of comparatively recent volcanic rock.

2.1.2. Rifting:

The NW trending rift basin originated when the basement rocks were extended between the Triassic and early Cretaceous periods through forces related to the rifting of Gondwana. As the Blue Nile basin formed, it was filled with clastic and marine sediments. In the late Miocene further rifting occurred in a NW-SE extension associated with the Main Ethiopian rift, which formed NE-trending faults. In the Quaternary (2.5 Ma - present) the region was subject to further stresses as the Main Ethiopian rift opened obliquely, creating N, ESE and NW trending extensions within the basin. Other rift basins with the same orientation formed in the region at the same time. The Blue Nile rift, Melut Basin and Muglad Basin all terminate on the line of the Central African Shear Zone, a major strike-slip shear zone. It is now known that the Muglad and Melut connect in the south east, and then connect to the Anza trough in Kenya. It is possible that the Blue Nile basin may be a south eastern extension of the Blue Nile rift in the Sudan, and may also extend south east of the Main Ethiopian rift, connecting to the Ogaden Basin in south east Ethiopia



Figure(2.1):Blue Nile rift location



Figure(2.2.): Block 8 Location:

2.2. Formation Description:

Sample description start from 25m MDRTE, just below the conductor pipe in the recent deposits. A summary of the samples description is provided in the Composite Well Log (Attachment 1) and also in the Daily Geological Reports. The formation tops are best defined based on wire line logs. Generally, the samples quality is fair to good. Recent deposits penetrated in the upper section of the borehole from surface to top of Damazin formation. They comprises loose sandstone and vary colored clay stone. The sandstone is medium to coarse in grain size and occasionally very coarse. It is moderately sorted, sub angular to sub rounded with trace argillaceous matrix. The clay stone is predominantly light to medium grey in color. It is firm to hard, silty and slightly calcareous. This section overlies Damazin formation and about 204 meters thick. No hydrocarbon shows observed. Damazin Formation

(204m MDRTE to 508m MDRTE): Coniacian – Santonian Damazin Formation comprises sandstone with minor interbedded clay stone throughout the entire section. The sandstone is commonly coarse to very coarse in grain size, occasionally medium, disaggregated and rarely argillaceous. Locally kaolinite cementing material is observed. The interbedded clay stone is generally firm to hard, silt and varicolored, pale yellowish brown to greenish grey. Trace pellets are observed within the cuttings. No hydrocarbon shows are observed. The thickness of this sequence about 304 meters.

2.2.1. Dinder I formation (508 m MDRTE to 1147 m MDRTE): Barremian

Top Dinder I formation is demarcated at 508m MDRTE from E logs. This formation consists mainly sandstone. The sandstone is generally fine to medium grained. Locally it is Very fine in grain size grading to silt stones. Coarse grained are observed in this section as well. It is moderately to poorly sorted. It is disaggregated while sometimes is poorly calcareous cemented. It is rounded to sub rounded, with argillaceous matrix. The clay stone is soft to firm, silty and sandy, varicolored, commonly reddish-brown to greenish grey and yellowish white. The base of this formation which lies uncomfortably with the top of Dinder II formation is picked at 1147m MDRTE. This section is about 639 meters thick. No hydrocarbon shows are observed in the cuttings.

2.2.2. Dinder II Formation (1147m MDRTE to 1872m MDRTE): Neomian - Barremian:

Dinder II formation top is derived at 1147m MDRTE based on E logs. This formation comprises intercalated sand stone, clay stone and thin layers of siltstone. There is cycling in sandstone deposition indicating high and low current environment and repeating of depositional periods. Starts with low current depositional environment at the base of the formation, where sand is very fine to fine in grain size. Thin stringers of siltstone are encountered through this section. A high current depositional environment seems clear in the middle section of the formation, where the sandstone is grading from coarse to very coarse in grain size. A third cycle is noticed at upper formation depositing where very fine to fine grained sandstone and rare medium to coarse sand is also observed. These sands are generally disaggregated, even though poor calcareous cementing is observed. Rare pyrite is observed in the cutting samples. The clay stone is oxidized below the unconformity of the formation top. It is predominantly reddish brown in colour, minor is light to medium grey while becoming dark with depth towards the base of the formation. It is also silty, and in part sandy. No oil

stain is observed in the cuttings. A high peak of total gas (143,048 ppm, 14.3%) is recorded in Lower Dinder II formation at 1827.5m MDRTE consist of all components from C1 to C5. The sequence thickness is about 725 meters.

2.2.3. Dinder III Formation (1872m MDRTE to 2680m MDRTE): Alenian-Cammeridgian

The top of Dinder III is defined at 1872m MDRTE based on E logs. This sequence is dominated by inter bedded sandstone and clay stone with minor siltstone. The sandstone is commonly fine to very fine in grain size. it is poorly calcareous cemented. Thin stringers of siltstone less than two meters in thickness are also observed. The siltstone is off white grey to greenish grey in colour, poorly calcareous cemented and firm to moderately hard. The clay stone is predominantly reddish brown in colour while minor are light to medium grey. It is silty and sandy and moderately hard. Rare pyrite is also observed in the cuttings. Poor oil shows are recorded throughout this section in the sand and thin stringers of siltstone. No oil stain no primary fluorescence is observed, while only very slow milky white streaming cut fluorescence with no residual ring is observed. Gas recorded throughout the interval ranges from C1 to C5. Dinder III thickness is about 808 meters.

2.2.4. Blue Nile Formation (2680m MDRTE to 2978m MDRTE): Middle Jurassic

Blue Nile formation comprises mainly clay stone and minor sandstone inter beds. The clay stone is commonly medium to dark grey in colour. It is silty and sandy, hard to moderately hard. The sandstone is very fine to fine grained. It is poorly calcareous cemented with common argillaceous matrix. Gas recorded throughout the interval ranges from C1 to C5. The sequence is about 298 meters thick.

Geographic Location				Deviated Well				Targets		Logging Program	Coring	
System	Series	Formation	TWT msec	TVD mSRD 400	TVD mRTE 443.4	MD mRTE 443.4	Lithology	Primary	Secondary			
T-Q	Upper Cretaceous	Santonian	130	105	148.4	147.4	[Yellow Lithology]				20" CSG @ 18m.	12-1/4" Pilot Hole for E-log. Open-up to 17-1/2" Hole.
		Coniacian	470	495	538.4	537.4						
Lower Cretaceous	Barremian	Dirdir 1					[Yellow Lithology]				13-3/8" CSG @ 550m.	PEX-HALS-BHC-GR
		Dirdir 2	640	745	788.4	787.4						
	Neomian	Dirdir 2					[Green Lithology]					12-1/4" Hole.
		Dirdir 3	890	1145	1188	1189.5						
Jurassic	Aalenian-Kimmeridgian	Dirdir 3					[Yellow Lithology]				9-5/8" CSG @ 2042mMD	PEX-HALS-GR FMI-DSI (Optional) MDT-GR-SC (Optional) CST-GR
			1145	1585	1628	1678.6						
	Middle Jurassic?	Blue Nile					[Yellow Lithology]				7" LINER @ TD for DSTs in 8-1/2" SECTION.	8-1/2" Hole.
		Blue Nile	1520	2245	2200	2467.4						
		Proposed TD	1780	2710	2753	3024						

Figure (2.3.): lithology table.

Chapter 3

Geophysical surveys

3.1. Introduction

In this block Chevron was performed some limited magnetic survey and new air bone gravity is completed (2006).

3.2. Seismic survey

3.2.1. Stratigraphy of Blue Nile basin from seismic data:

By joining the seismic data and well data we can identify five reflector there are:

Damazin formation:

The average two way time equal 0.125 sec, the formation comprise sandstone with minor inter bedded clay stone the thickness of this formation is about 304 m.

Dinder I formation:

(508m to 1147m MDRTE) Barremian .the average of two time to this formation 0.29 sec, this formation consist mainly sandstone .the thickness of sequence about 639 m.

Dinder II formation:

(1147m to 1872m MDRTE) Neomian Barremian. The average two time is 0.7 sec .This formation comprises intercalated sandstone, clay stone and thin layers of siltstone the thickness of this sequence is about 725m.

Dinder III formation:

(1872m to 2680m MDRTE) Alenian Cammeridgian. The average TWT to this formation is 1.3 sec. This sequence is dominated by interbedded sandstone .The thickness of this sequence is about 808 m.

Blue Nile formation:

(2680m to 2978m MDRTE) middle Jurassic .The average TWT 2.15 sec .The Blue Nile formation comprises mainly clay stone and minor sandstone inter beds. The thickness is about 298 m.

3.2.2. Main structure and faults network

We getting information from the seismic sections and contour maps, and we divided the basin into three zone there are: northern sub-basin, southern sub-basin and central sub-basin.

Northern sub-basin :

We found many types of fault there are: master faults, graben, synthetic, antithetic, and half graben.

The main graben in the northern east of the basin. The faults pattern is irregular and there no fault in the further north of basin .And we found many anticline and syncline.

The central sub-basin :

We found many types of faults there are: master normal faults, graben, synthetic, antithetic, thrust fault and roll over fault.

The faults pattern is irregular and in the nether central the faults directional in east west direction .And we found many anticlines and synclines.

Southern sub-basin :

We found many types of there are: Master Normal faults, graben, synthetic, anticline, horest listric normal faults the fault pattern is irregular. And we found many anticlines and syncline. The ddpest point in the top Blue Nile second salt depth map is 5500m and shallowest point is 450m .The location of Jauhara due the seismic data is drilled over fault.

Seismic interpretation of the sections at the area of JAUHARA-1:-

3.2.3. Seismic dip line:

In this section we see three major faults, this faults can classified as normal faults, and more than sixteen small faults.

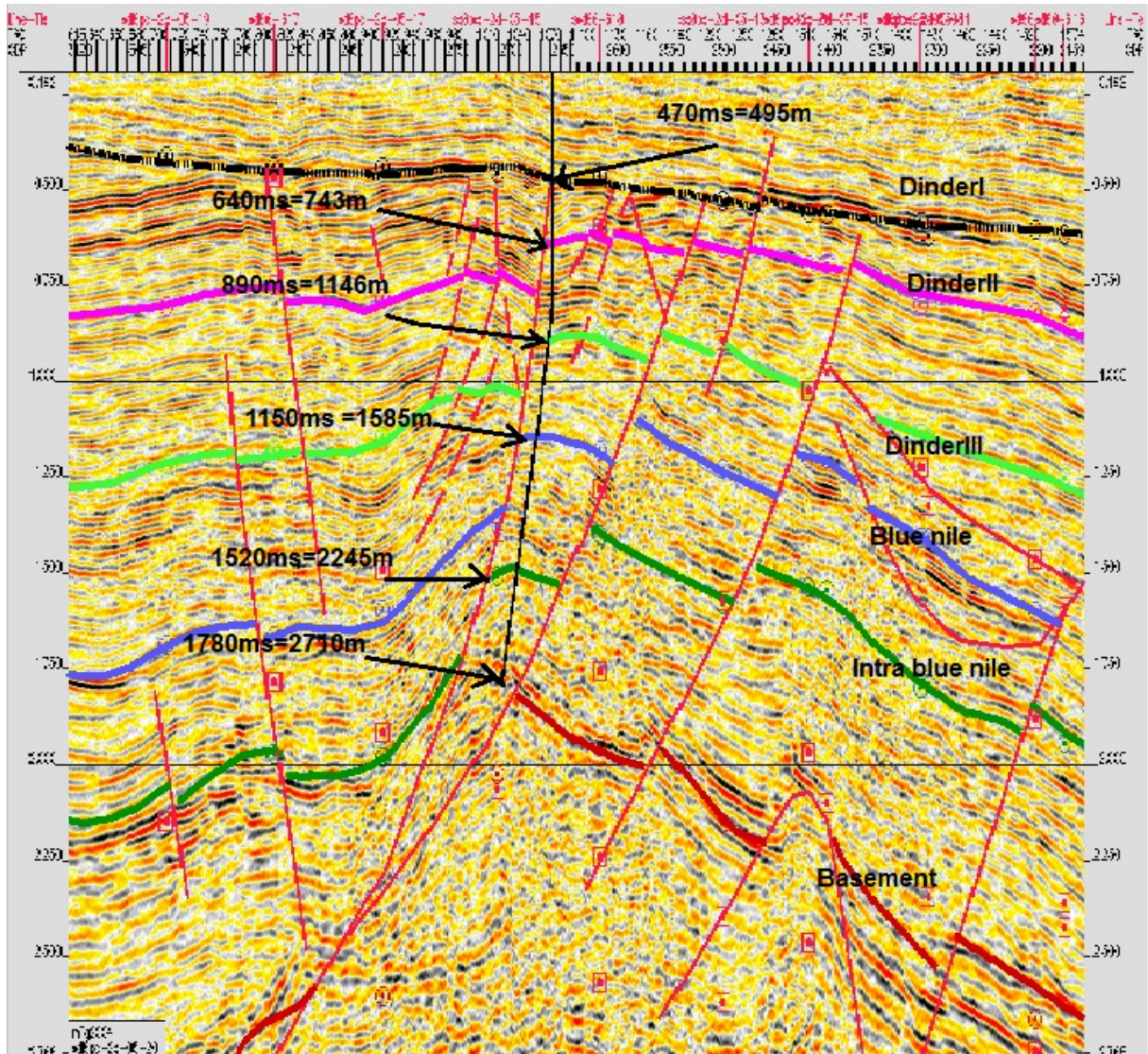
At the left side of the well there are three small faults that we can classified it as antithetic faults.

Also at the same side we can detect four small faults that we can classified it as synthetic faults.

There are two graben between the layers Dinder and Dinder III one at the right side of the well and the second at the left side.

At the right side of the well there are three small faults that we can classified it as synthetic faults.

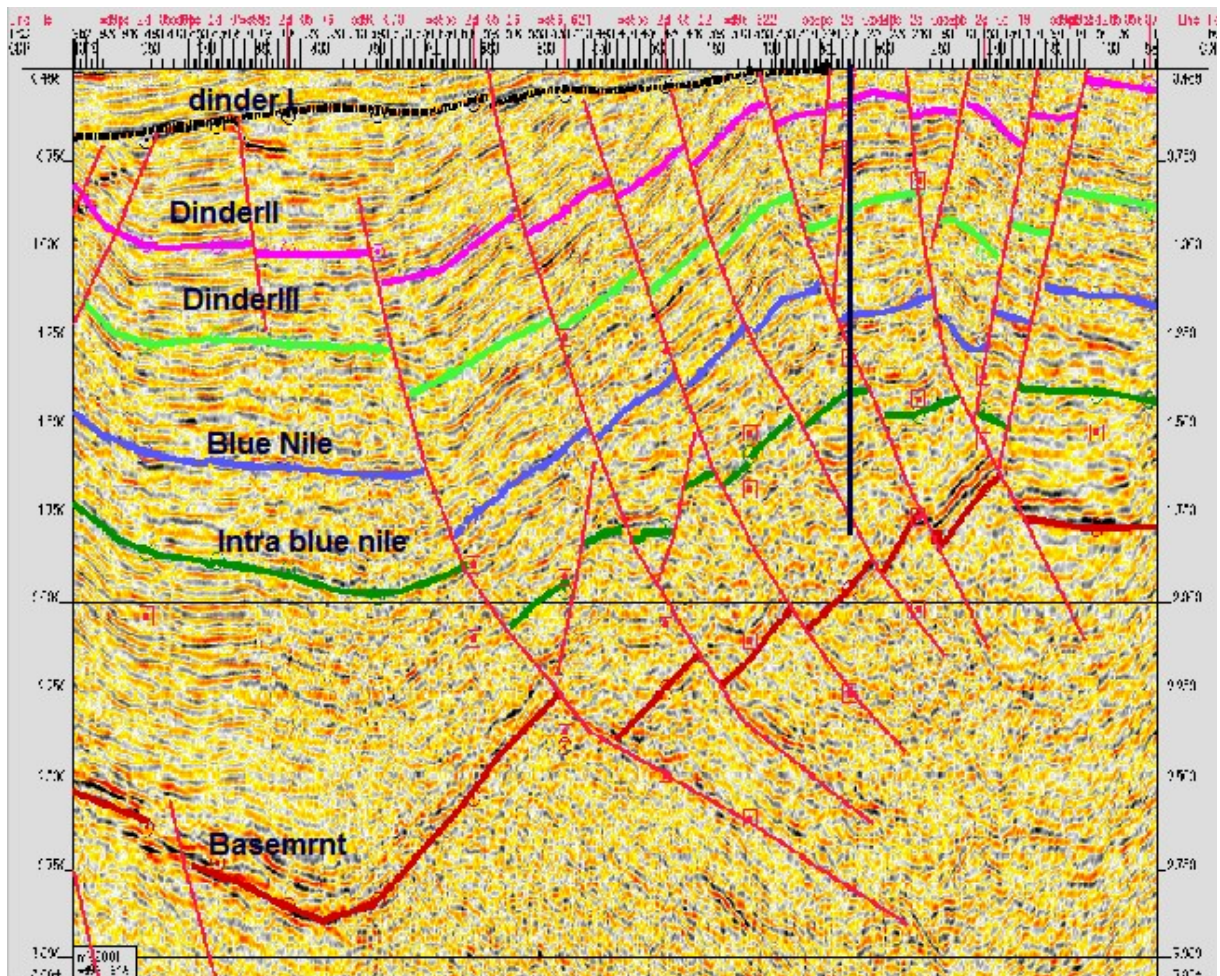
At the far right of the section there are two listric normal faults at the layers Dinder III and Blue Nile. At the basement layer we found the rash of volcanic lava.



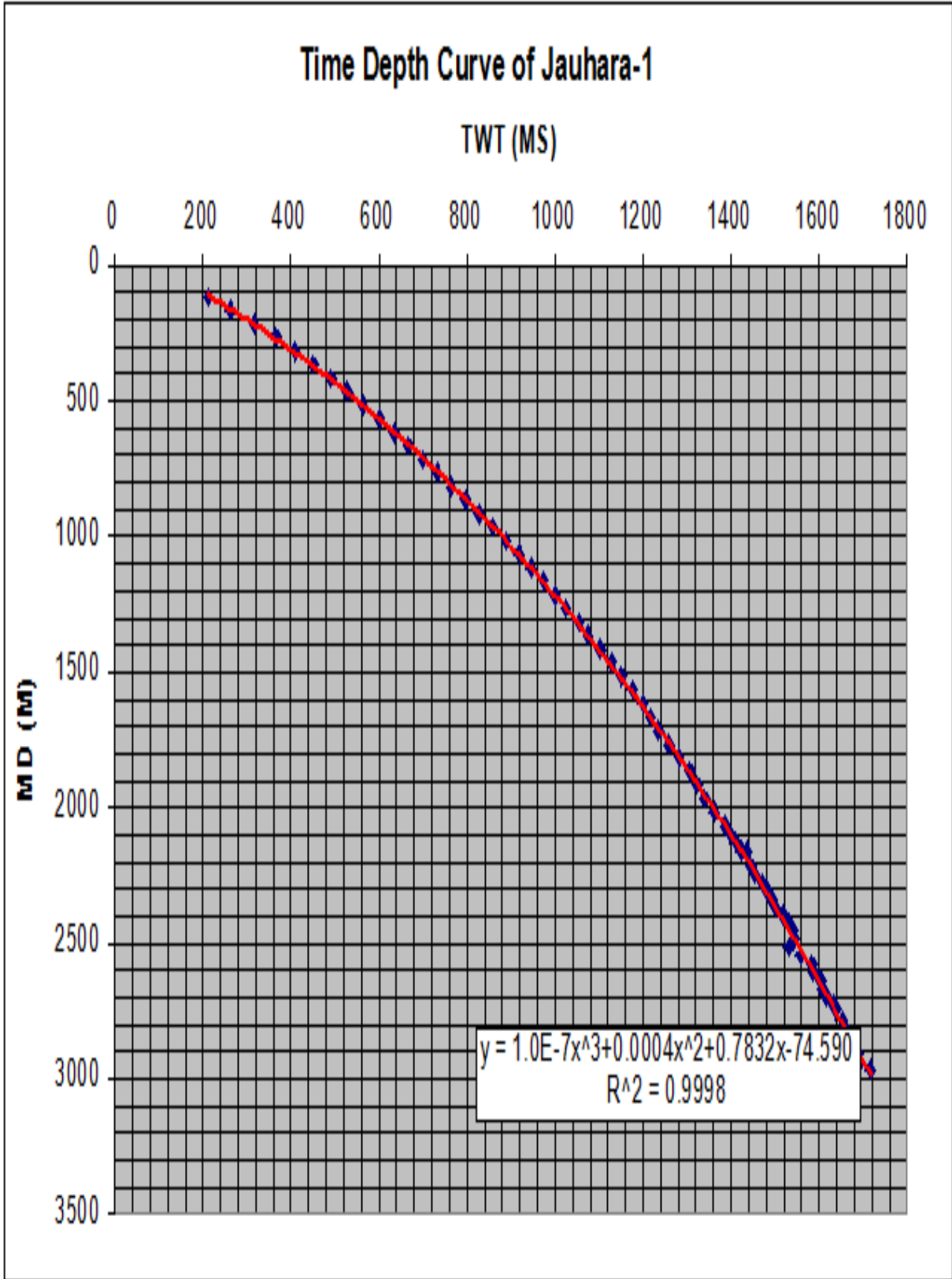
Figure(3.1.) Seismic Dip Line SD8PC-2D-05-20

3.2.4. Seismic cross line

In this section we can see six major faults, this faults can classified as a normal faults and there are ten small faults, At the far left there are two antithetic faults and one synthetic fault, At the middle of the section exactly at the intra Blue Nile layer there are two antithetic faults, and they cause graben, at the right of the section there are five antithetic faults, and they cause graben.



Figure(3.2.): Seismic Cross Line SD86-618



Figure(3.3.):time depth curve of Jauhara-1:

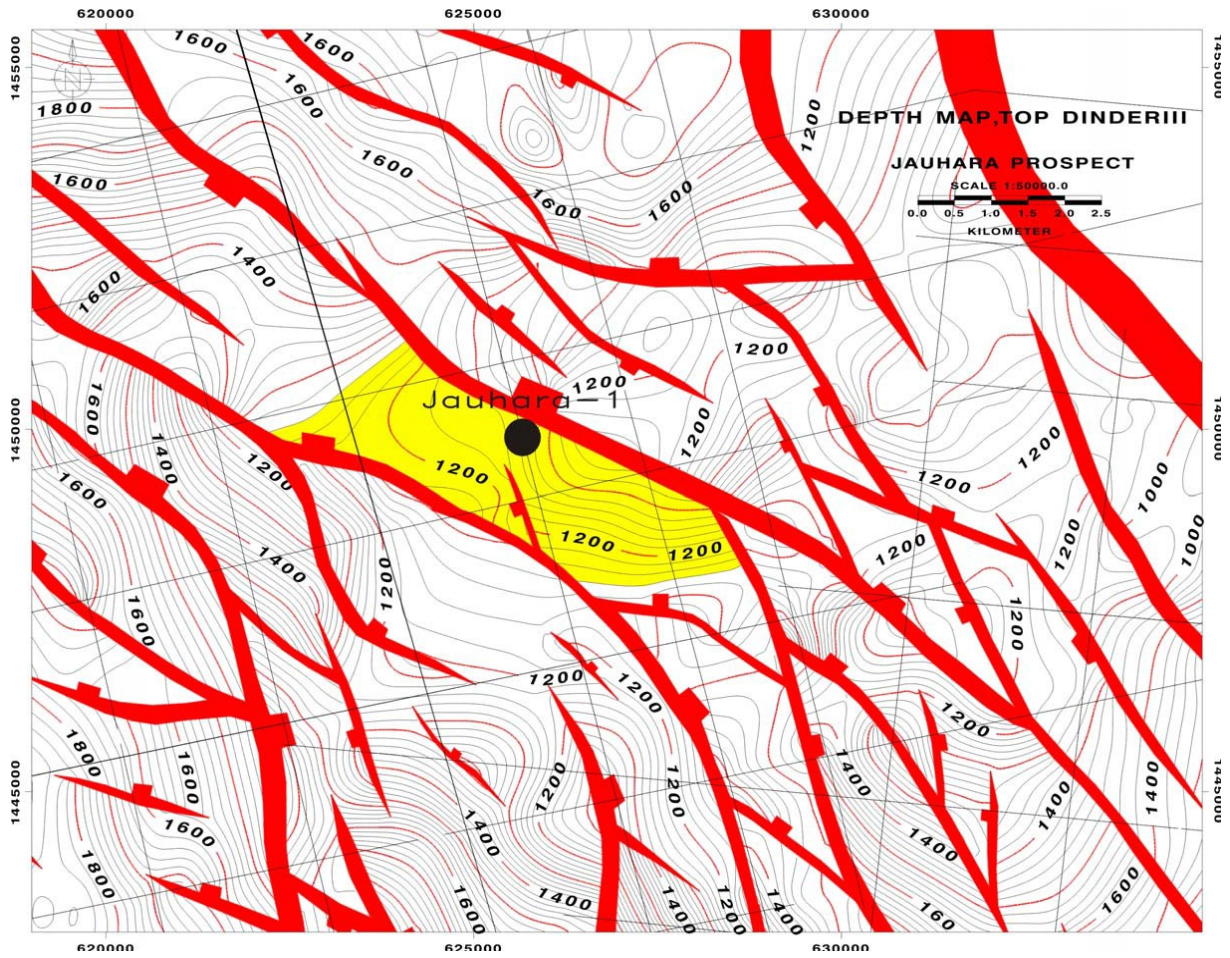
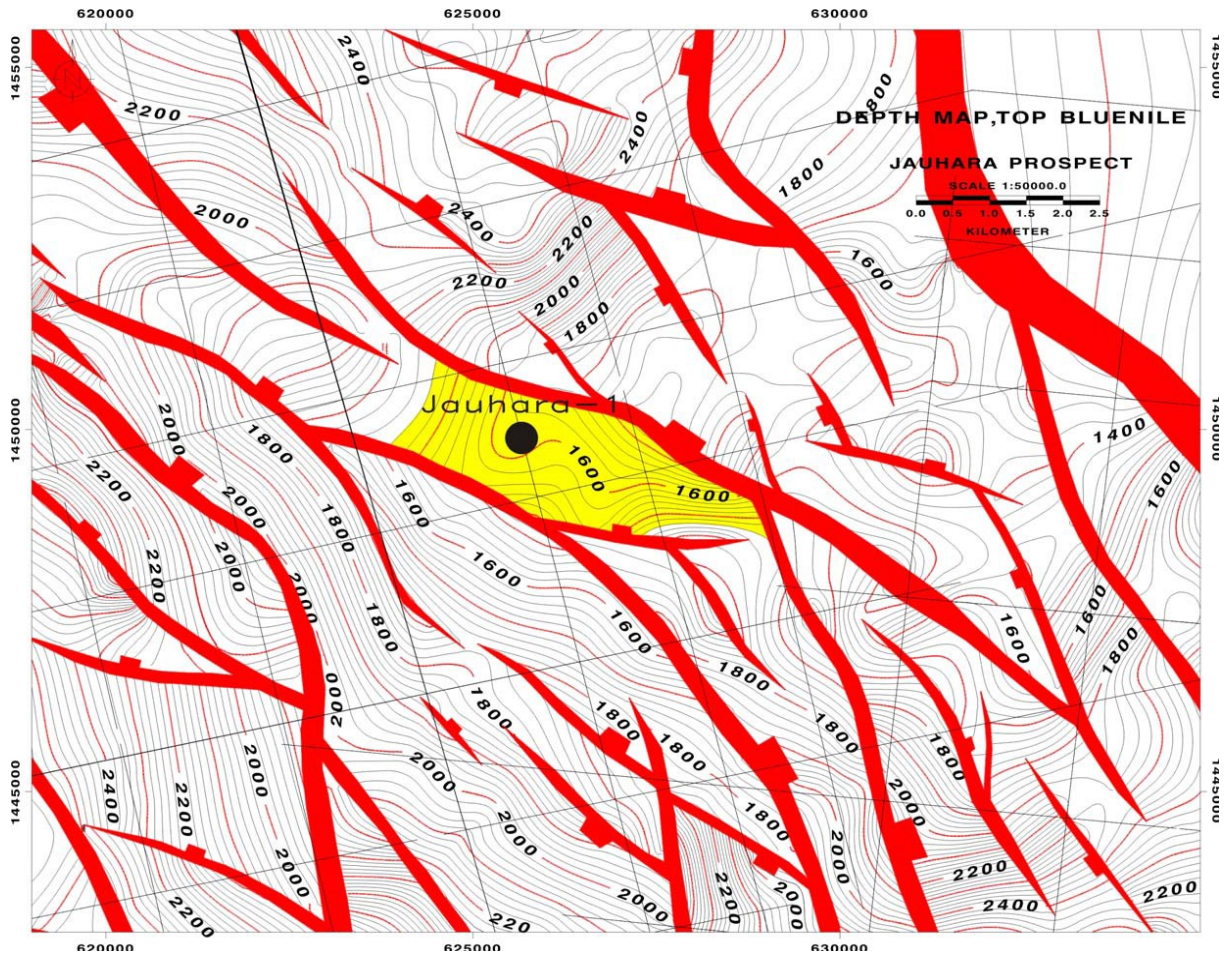


Figure (3.4.): Top DinderIII depth map:



Figure(3.5): Top of Blue Nile depth map:

Chapter 4

exploration

4.1. Introduction

Jauhara -1 is a wildcat well proposed to test the hydrocarbon potential in Blue Nile basin, Block 8.

The primary targets are Dinder III and Lower Dinder II sands, whilst the secondary target is Blue Nile sands.

4.2. Jauhara -1

Jauhara -1 is located 36.5 km south of Hosan -1 and 32.3 km southeast of Dinder -1.

Surface Coordinates:

Latitude: 13 deg 06' 45.82" N

Longitude: 34 deg 09' 33.43" E

UTM Easting: 625665 mE

UTM Northing: 1449890.40 mN

Ellipsoid: WGS 84

Seismic Reference:

SP1330, Line No. sd8pc-2d-05-20

Subsurface Location:

Jauhara -1 is a deviated hole. A 100 meter bottom hole Radius of uncertainty is allowed. Single shot, no directional deviation surveys conducted at depths as preprogram indicate that maximum horizontal uncertainty at 932.14m MDRTE is less than 27m. See table 1 below.

Table (4.1.): Well Subsurface Location :

Survey Depth (m MDRTE)	Section Length (m)	Deviation (degrees)	Maximum Section Offset (m)	Maximum Radius of Uncertainty (m)
874.370	874.37	1.590	24.26	24.26
901.760	27.39	1.600	0.76	25.02
932.140	30.38	2.930	1.55	26.57

Basic Well Data:-

Name: Jauhara-1
 Field: Jauhara
 Classification: Exploration
 Type: Onshore Vertical Oil Well from surface to 920m and a deviated well trajectory from 920m MDRTE to 2978m MDRTE (TD).
 Status: Suspended
 Operator: WNPOC
 Partners: PETRONAS Carigali Overseas Sdn. Bhd. (77.0%) Sudapet Ltd. (15.0%)
 Hi Tech Group Co. Ltd. (8.0%)
 Mud logging: Data Log
 Wire line Logging: Schlumberger
 Coring Services: No coring this well
 Well site Geologist: El-Tahir Abdalaziz/ Mohanad Ali/ Adil Ali
 Primary Reservoir: Dinder III at 1796.85m TVDRTE (1872m MDRTE) and Lower Dinder II at 1144.98m TVDRTE (1147m MDRTE)
 Secondary Reservoir: Blue Nile sands at 2491.46m TVDRTE (2680m MDRTE)
 Surface Coordinates: Latitude: 13o 06' 45.82" N
 Longitude: 34o 09' 33.43" E
 UTM Easting: 625665 mE
 UTM Northing: 1449890.40 mN
 Ellipsoid: WGS 84
 Seismic Reference: SP1330, Line No. sd8pc-2d-05-20
 Subsurface Location: Less than 26.57 meters horizontal displacement
 Ground Elevation: 435.9m AMSL
 Drill Pad Elevation: 436.6m AMSL
 RTE Elevation: 444.1m AMSL (6.9 m AGL)
 Total Depth: 2978m MDRTE
 Spud Date: 15 October 2005, 10:00 hours
 TD Reached: 19 December 5, 17:10 hours
 Rig Release: 27 December 2005, 15:00 hours
 Total Days: 73.46
 Borehole Design: 17 ½" hole section from 25.5 to 555m MDRT

	12 ¼” hole section from 25.5 to 2042m MDRTE
	8 ½” hole section from 2042 to 2978m MDRTE
Casing Design:	20” casing pre-set at 25.5m MDRTE
	13 3/8” casing shoe at 553.5m MDRTE
	9 5/8” casing shoe at 2042m MDRTE
Mud System:	KCL polymer in 17 ½”, 12 ¼” and 8 ½” hole sections
Lost Circulation:	None
H2S:	None
Cuttings Sampling:	12 ½” pilot hole down to 555m every 10 meters.
	12 ¼” hole section down to from 555 – 2042 every 10 meters.
	8 ½” Hole section 2042-2978m – every 5 meters
	3 sets wet, 3 sets washed & dried
	1 set Palynological every 30m from surface to TD,
	1 set Geochem every 10m from 2042m to TD.
Temperature:	118 deg F at 545m Corrected BHA 160 deg F at 1686m MDRTE
(MDT)	
	175.9 deg F at 2083m (RFT)
	210 deg F at 2974m MDRTE Corrected BHT
Pressure:	Normal pressure regime.
Completion:	Jauhara -1 has been temporarily suspended.

Table(4.2.):well profile:

Well Profile

Well Profile Table:				Jauhara -1								
Form.	Intervals			Prog.	Casing depth	Bit/TD in/m	Casing		Cement Bond	MW	Highlight	Program
	TVD	M.Depth	thic.				OD/in	Thic./m				
Damazin	390	147.4	390	Conductor	#	24" /25.5	#		To surface	1	*One piece of pup joint will be set at 50m above the top of Bentu and Abugabra formation respectively for future perforating, Exploration department will give final decision for casing program after logging *liner hanger is at 70-150m above the technical casing shoe.	
				Surface hole	#	17 1/2" /555	#		To surface	1.06 --- 1.10		
Dinder-1	537.4	537.4	250	Intermediate hole	0--2042	12 1/4" / 2042	##	11	Tail slurry to 150m above pay zone, lead slurry to surface	1.10 --- 1.15		
Dinder-2	787.1	787.4	402.1									
Dinder-3	1188	1189.5	440									
Blue Nile	#	1678.6	660									
	#	2467.4	465									
Proposed TD	2753	3024										

4.3. Drilling Operation Summary:-

Tiger-2 (Rig 53) was mobilized from China to Jauhara-1 location, rigged up, tested, accepted and was ready to drill on Oct 15, 2005. 20" conductor pipe was pre-set at 20m. 20" TIX drilling spool was nipped up on 20" conductor pipe with 2000psi diverter, tested OK and spudded Jauhara-1 well on 15th Oct-2005 at 10:00 AM. 12 1/4" pilot hole was drilled to 316m, found mud channeling outside of conductor pipe into cellar, trouble shoot and attempted to stop mud channeling, no success, rigged up SLB, mixed and pumped 20 bbls of 15.8 ppg down OEDP and 10 bbls of 15.8 ppg on cellar around conductor pipe. Resumed drilling of 12 1/4" pilot hole to 545m with an average ROP of 13 MPH. Rigged up SLB and logged hole with PEX-HALS-BHC-GR-SP. Resumed drilling and opening pilot hole to 17 1/2" hole to 545m then continued drilling 17 1/2" hole to section TD at 555m. Ran 13 3/8" casing, P110, 68ppf, BTC to 554m cemented with 360 bbls lead of 12.6 ppg cement slurry and 90 bbls tail of 15.8ppg slurry. Remove Drilling spool and perform top job, cut 13 3/8" csg, installed section A well Head, nipped up BOP and tested 12 1/4" steerable BHA was ran to TOC at 522m, drill cement, FC at 529 and FS at 545m. Cleaned rat hole and drilled new formation to 558m, performed FIT to 16ppg EMW with 9.2 ppg mud. Continued drilling 12 1/4" hole vertically to 920m, kicked off and continued rotating, sliding drilling and surveying to 1428mMD, pulled out for MWD change, hole was good, changed out MWD and Motor, ran back and resumed drilling to 1691mMD lost MWD signals, recycled different attempts to regain the signal no success, pulled out with tight section from 1525 to 1270mMD, changed out bit and MWD, ran back to bottom, washed and reamed last 4m and continued rotating/sliding drilling and surveying to 1831mMD with high gas reading of 143,048ppm recorded at 1827mMD, well was static during flow check, resumed drilling to 1862mMD, pulled out bit due to slow ROP of 2.2 MPH while rotary drilling, changed out bit and adjusted motor bent to zero and ran back with rerun able V are 1 PDC to 1841m, washed and reamed to bottom, Continued drilling from 1862 to 1978mMD, ROP was dropped to 1.3 MPH, pulled out and changed bit to Smith PDC, ran back, washed and reamed from 1865 to 1978mMD, drilled with rotary mode to section TD at 2042mMD. Conducted wiper trip to 555m before pull out for log, hole was in good shape. Rigged SLB, ran and logged PEX-HALS-DSI-GR-SP to 553m WLM, RFT-GRSC, took 22 out of 32 points due to seal failure, pulled out and ran back with back up RFT tool, GR failed, pulled out and conducted clean out trip followed by FMIGR log, CST-GR and CSI log.

Rigged up and ran 9 5/8" casing, N-80, 47ppf, BTC to 2042mMD, cemented with 305bbls of 12.6ppg lead 63% excess and 153bbls of 15.8ppg of tail slurry of 35% excess, displaced with 475 bbls mud with final displacement pressure of 950 psi (FC@2018,FS@2042mMD).

Installed casing head spool and tested, nipped up BOP and tested. Ran with 1.15 deg steerable BHA, Drilled cement, float equipment and new formation to 2045mMD, performed FIT test to 16 ppg EMW with 9.6 ppg mud, max. Surface pressure was 2129psi.

Continued drilling to 2347Mmd, ROP slowed down to 2.4 MPH with rotary drilling, pulled out and change BHA, changed out BHA and bit, ran back and resumed rotate/slide drilling to 2475mMD, hole angle was dropped with difficulty to build, pulled out and changed bit and mud motor, ran to bottom and continued drilling to 2624mMD with an avg. ROP of 2.5 rotating and 0.7 MPH while slide drilling, pulled out, changed bit and resumed drilling to 2745mMD with 0.4-0.7 MPH during sliding and 2.3 – 2.7 MPH while rotary drilling, swept hole 40 bbls of hi vis pill, pulled out of hole and ran back with reused PDC bit. Adjusted motor angle to 0.78 deg, continued drilling to 2848mMD with an avg.

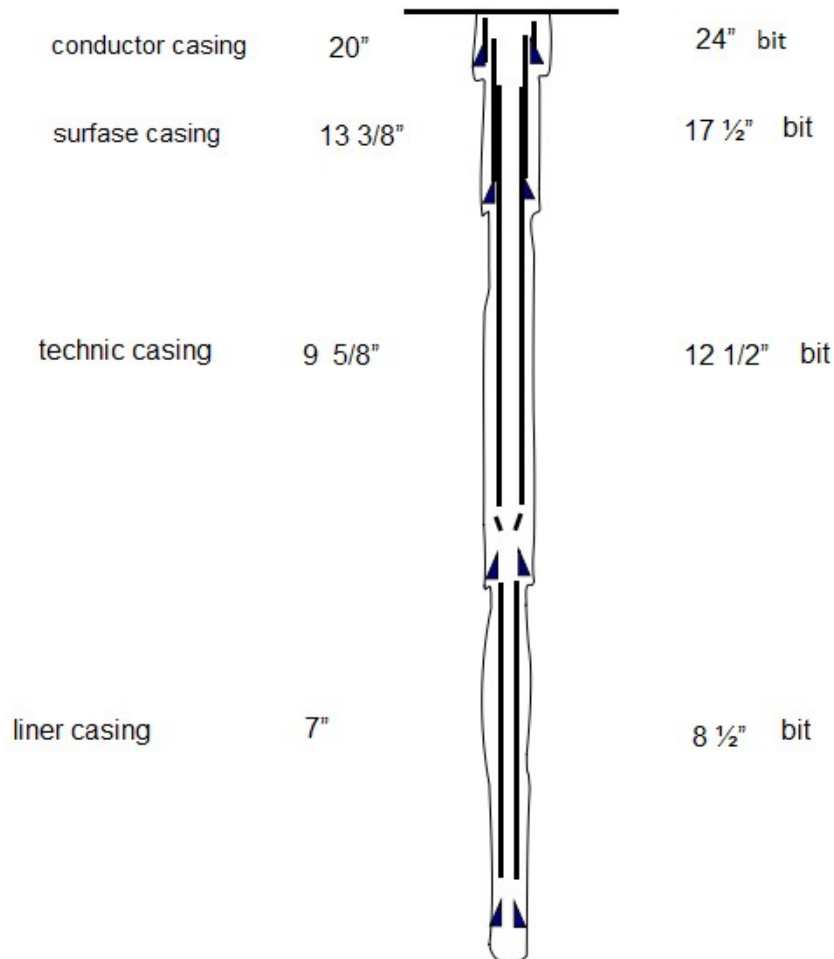
ROP of 1.9 MPH and the lithology was predominantly clay stones with traces of siltstones up to 20%, slugged pipe and pulled out, changed bit to reused HC606 and resumed drilling to final TD 2978mMD (2752MTVD).

Rigged up SLB and ran the following logs : PEX: HALS-MCFL/TLD-HGNS-ECSGR,FMI-DSI-GR, performed clean out trip, hole was tight at 2919,2407 and 2064m with over pull of 50-80klbs, continued e-logging and ran with MDT twice with lost seal result, laid down MDT tool and ran with RFT, pre-tested at three points, no seal, pulled and laid down RFT tool, made check out trip and resumed logging with run no 5 check shot tool, run no 6 CST tool.

Exploration department decided to plug the open hole section, ran with 3 1/2" OPE tubing to 2112m Mix batch and pumped 30 bbls of 15.8 ppg cement slurry, displaced with 4 bbls of water and 105 bbls of 9.6 ppg mud, wait on cement while pulling up to 1234m, ran back and tag top of cement plug at 1994m, pressure tested cement plug and casing to 1500psi.

Pulled of Hole and laid down tubular, nipped down BOP, installed wellhead section B and dry tree, released the rig on Dec 27, 2005 at 2100hrs to move to 3Farasha-1.

4.4. Casing Design:



Figure(4.1.): Casing Design:

4.5. Problem formation:

The following tables show the events which indicates for tolerable comes for both well .this data and event provided by daily drilling reports and daily mud reports.

Table(4.3): Problem formation:

MD (m)	TVD (m)	Formation	Mud weight (ppg)	Remarks
2293	2009.4	Dinder II	9.8	Gas cut mud,mud cut down9.2-9.3ppg
2293	2523	Dinder III	9.8	Mud down 8.8-9.1,risemud weight10.2ppgwhile circulation
2293	2558	Dinder III	9.8	Shut in well ,mud out 8.7-9.1ppg
2293	2593	Dinder III	9.8	Shut in well, gas cut mud to 9.6,cont circulate till mud weight out to10 ppg
2293	2597	Dinder III	9.8	Cut mud to 9.5 ppg
2293	2685	Dinder III	9.8	Mud weight out 8.4ppg,gas cut mud 9.6ppg
2293	2700	Dinder III	9.8	Mud weight out 9.6ppg
2293	2743	Dinder III	9.8	Mud weight out 9.4ppg
2293	2743	Dinder III	9.8	Mud weight out 9.5ppg
2293	2743	Dinder III	9.8	Mud weight out 9.8ppg
2293	2842	Dinder III	9.8	Mud weigh out 9.5ppg

Table (4.4.): Problem formation:

MD(m)	TVD(ppg)	Formation	Mud weight	Remarks
-------	----------	-----------	------------	---------

			(ppg)	
845	845	Dinder I	10.1	Kick
1501	1501	Dinder II	10.6	Increase mud in pit
1644	1644	Dinder II	11	There is gas
1925	1925	Dinder III	12	There is gas

4.6. Drilling problems:

4.6.1. Kick tolerance:

Kick is defined as any entry of formation fluids (gas, oil and water) into the wellbore during drilling.

Kick Tolerance is defined as the maximum kick volume that can be taken into the well bore and circulated out without fracturing the formation at weak point (shoe), given a difference between pore pressure and mud weight in use.

It is very important to recognize a kick and quick shut-in the well in order to limit Kick volume and to carry out a successful control.

We overcomes kick by Increases in mud weight, Change in casing points and Setting a contingency liner.

At last to prevent the well from kick should be Study of formation

pressures for the safe planning of a well. Values of formation pressures are used to design safe mud weights to overcome fracturing the formation and prevent well kicks.

4.6.2. Pipe sticking:

The pipe cannot pull up, cannot go down, and cannot rotate.

The causes of differential sticking:

- Unnecessary high differential pressures.
- Thick mud cake (continuous high fluid loss to formation).
- Low-lubricity mud cake (high coefficient of friction).
- Excessive embedded pipe length (time delay in operations).

Ways to minimize differential sticking:

- Proper mud characteristics (weight, fluid loss).
- Collar shape (spiral or square collars).
- Keep drilling solids low in the mud.
- Keep rotating the drill string.

4.6.3. Lost circulation:

Is defined as the total or partial loss of drilling fluids or cement slurries into highly permeable zones, cavernous formations, and natural or induced fractures during drilling or cementing operations.

Prevention of lost circulation:

- Maintaining proper mud weight.
- Minimizing annular-friction pressure losses during drilling and tripping in.
- Adequate hole cleaning.
- Avoiding restrictions in the annular space.
- Setting casing to protect upper weaker formations within a transition zone.
- Updating formation pore pressure and fracture gradients for better accuracy with log and drilling data.

Chapter 5

Reserve estimation

5.1. Oil reserves

Oil reserves are the amount of technically and economically recoverable oil. Reserves may be for a well, for a reservoir, for a field, for a nation, or for the world. Different classifications of reserves are related to their degree of certainty. The total estimated amount of oil in an Oil reservoir including both producible and non-producible oil, is called oil in place. However, because of reservoir characteristic and limitations in petroleum extraction technologies, only a fraction of this oil can be brought to the surface, and it is only this producible fraction that is considered to be reserves. The ratio of reserves to the total amount of oil in a particular reservoir is called the recovery factor. Determining a recovery factor for a given field depends on several features of the operation, including method of oil recovery used and technological developments.

5.2. Classification

All reserve estimates involve uncertainty, depending on the amount of reliable geologic and engineering data available and the interpretation of those data. The relative degree of uncertainty can be expressed by dividing reserves into two principal classifications "proven" (or "proved") and "unproven" (or "unproved"). Unproven reserves can further be divided into two subcategories "probable" and "possible" to indicate the relative degree of uncertainty about their existence .

5.2.1. Proven reserves:

Proven reserves are those reserves claimed to have a reasonable certainty (normally at least 90% confidence) of being recoverable under existing economic and political conditions, with existing technology. Industry specialists refer to this as P90 (i.e., having a 90% certainty of being produced). Proven reserves are also known in the industry as 1P.

Proven reserves are further subdivided into "proven developed "(PD) and "proven undeveloped" (PUD).PD reserves are reserves that can be produced with existing wells and perforations, or from additional reservoirs where minimal additional investment (operating expense)is required.PUD reserves require additional capital investment (e.g. drilling new wells) to bring the oil to the surface .

5.2.2. Unproven reserves:

Unproven reserves are based on geological and/or engineering data similar to that used in estimates of proven reserves, but technical, contractual, or regulatory uncertainties preclude such reserves being classified as proven. Unproven reserves may be used internally by oil companies and government agencies for future planning purposes but are not routinely compiled. They are sub-classified as probable and possible .

Probable reserves are attributed to known accumulations and claim a 50% confidence level of recovery. Industry specialists refer to them as "P50" (i.e., having a 50% certainty of being produced). These reserves are also referred to in the industry as "2P" (proven plus probable).

5.3. Estimation techniques

The amount of oil in a subsurface reservoir is called oil in place (OIP). Only a fraction of this oil can be recovered from a reservoir. This fraction is called the recovery factor. The portion that can be recovered is considered to be a reserve. The portion that is not recoverable is not included unless and until methods are implemented to produce it.

1)Volumetric method:

Volumetric methods attempt to determine the amount of oil in place by using the size of the reservoir as well as the physical properties of its rocks and fluids. Then a recovery factor is assumed, using assumptions from fields with similar characteristics. OIP is multiplied by the recovery factor to arrive at a reserve number. Current recovery factors for oil fields around the world typically range between 10 and 60 percent; some are over 80 percent. The wide variance is due largely to the diversity of fluid and reservoir characteristics for different deposits. The method is most useful early in the life of the reservoir, before significant production has occurred.

2)Materials balance method:

The materials balance method for an oil field uses an equation that relates the volume of oil, water and gas that has been produced from a reservoir and the change in reservoir pressure to calculate the remaining oil. It assumes that, as fluids from the reservoir are produced, there will be a change in the reservoir pressure that depends on the remaining volume of oil and gas. The method requires extensive pressure-volume-temperature analysis and an accurate pressure history of the field. It requires some production to occur (typically 5% to 10% of ultimate recovery), unless reliable pressure history can be used from a field with similar rock and fluid characteristics .

3) Production decline curve method:

The decline curve method uses production data to fit a decline curve and estimate future oil production. The three most common forms of decline curves are exponential, hyperbolic, and harmonic. It is assumed that the production will decline on a reasonably smooth curve, and so allowances must be made for wells shut in and production restrictions. The curve can be expressed mathematically or plotted on a graph to estimate future production. It has the advantage of (implicitly) including all reservoir characteristics. It requires a sufficient history to establish a statistically significant trend, ideally when production is not curtailed by regulatory or other artificial conditions .

5.4. Reserve estimation in jauhara-1 location using the volumetric method

Oil in place by the volumetric method is given by:

$$N=7758Ah\phi(1-S_w)/B_{oi}$$

where :

N = original oil in place (OOIP).

7758 = conversion factor from acre-ft to bbls.

A = area of reservoir (acre).

h = height or thickness of pay zone .ft

ϕ = Porosity at, fraction.

S_w = water saturation at, fraction.

B_{oi} = Formation volume factor for oil at initial condition. bbls/STB.

Petrophysical parameter: from log result.

Net pay (h) = 10 m =32.8 ft.

Porosity (ϕ) = 15 %

Water saturation () = 60%

A = 756.2 m² =8139.669 ft²

Assume oil volume factor (B_{oi}) = 1.2 bbls/STB.

Calculation:

$$N=7758*8139.669*32.8*0.15*(1-0.6)/1.2$$

$$N= 103,561,985.447 \text{ STB.}$$

Original oil in place in main reservoir at jauhara-1 is:

$$103,561,985.447 \text{ STB}$$

Chapter 6

Conclusion and Recommendation

6.1. Conclusion

The central African shear zone was formed many rifting in SUDAN such as BAHR EL-ARAB rift, ABU-GABRA rift, Blue Nile rift, ATBARA rift, White Nile rift, MUGLAD rift and this rift formed many basin such as ABU-GABRA basin, Blue Nile basin, MUGLAD basin.

Blue Nile basin is a sedimentary basin in Sudan, the geological and geophysical study show this block may become important block in production oil and gas in Sudan, especially gas, exploratory studies have proven that there is an estimated amount of dry gas.

From the result of the analysis of seismic surveys the Blue Nile basin can be divided into three basin area:

Northern basin are an area a few geological structure so not out of any well drilled, central basin: this region has many of geological structures suitable to be petroleum traps so all wells drilled in this area, and southern basin: in this region we found some geological structures, but is less than the central region of the basin so it does not have drilled wells.

In this block we found many drilling problem such as kick tolerance, pipe sticking, loss of circulation, and then we found there suitable solutions.

Initial gas in between top of the DINDER III and top of Blue Nile formation calculated by the volumetric method and found that initial gas in place is equal to 3,005,416.246 SCF.

6.2. Recommendation

- 1) They found Traces oil shows started from 1639m MDRTE in secondary target sands (Blue Nile Formation) and down to TD. So we recommend that can develop this well.
- 2) They observed Oil shows and associated gas while drilling because that tack care of the dangerous of shallow gas.
- 3) We encountered many problems in this area so we recommend that more studies at this area.
- 4) The formations in Sudan in general are not overpressure so we can solve all the problems are encountered while drilling.

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