BLUELAKE ENERGY

Commentary on Gulf of Guinea Energy

Presented to

Actis

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Summary and Conclusion

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Summary

- This report has been prepared exclusively for Actis as guide to the assets of Gulf of Guinea Exploration (GoGE) in Nigeria.
- GoGE has a 40% equity interest in a Farm-in Agreement (FOA) to the Uquo License in the Niger Delta.
- The FOA entitles GoGE to a 52% working interest in the oil and 45% working interest in the potential gas of the Uquo license, after certain taxes and royalties have been paid to the Nigerian Government and the seller of the FOA – Shell.
- The gross oil reserves in the Uquo field are as follows:
  - 1P 6MMbbl from 3 wells
  - 2P 47.6MMbbl from 11 wells
  - 3P 82.8MMbbl from 18 wells
- There are 3 separate accumulations- Area A/B/C of hydrocarbons on twin faulted anticlinal structures but only the oil in one of these structures is classified as Proven + Probable (2P) reserves.
- Some additional oil and all the gas is classified as a 'Resource', partly for technical reasons – but mostly (in the case of the gas) – because there is no current market/infrastructure for the gas.
- We have tested the assumptions made by the Competent Persons Report (CPR), prepared by TRACS to verify that the stated reserves and resources are reasonable.
- We have done this by checking the assumed data in the following areas:
  - static reservoir and fluid data defining hydrocarbons in place.
  - Dynamic data from well testing defining potential production.
  - static and dynamic data defining likely recovery factors
  - financial benchmarking of the cost of future operations
  - overall independent valuation of 2P reserves
  - analog field analysis of nearby fields in the Niger Delta.
- We have not looked at the gas reserves or upside resources in any detail as we think this would be premature and if our findings on the TRACS 2P data are sound then it follows that most of the other data from TRACS should be reliable.

Conclusion

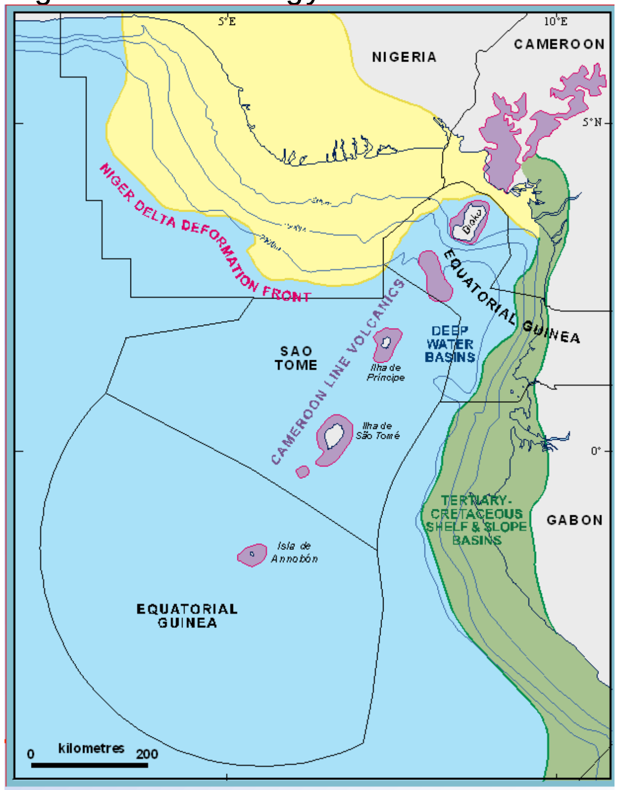
- The Niger Delta is well known as one of the most prolific hydrocarbon basins in the world and needs no further glorification.
- **The point about the Uquo field is that it sits in a non-prolific area on the eastern flank of the basin where hydrocarbon classification between gas and liquid is an uncertainty.**
- **The other uncertainty is how far down the oil goes until water is found (the oil water contact-OWC), this is a positive uncertainty in a way.**
- We can be fairly certain about oil in Area A and gas in Area B but additional oil in Area C is an uncertainty and this is more likely to be gas/condensate, based on inconclusive testing and our overall view of the area.
- Furthermore, Nigeria has been notorious (it is changing) for flaring gas as the infrastructure for transmission and use is relatively undeveloped compared to oil.
- The core value of the Uquo field therefore resides in the proven plus probable oil reserves of the Area A where one of four wells drilled was the only one flow tested.
- Overall, we think the techniques employed by TRACS to determine oil reserves have been fairly (and rightly) conservative; but to put some perspective on the upside oil let us quote some gross data (GoGE about 60% of this):
  - 2P oil in place is 135MMbbl and recovery of 30%-50% (40MMbbl-67MMbbl) is likely
  - 3P oil in place is 220MMbbl assuming the OWC is deeper (66mmbbl-10MMbbl)

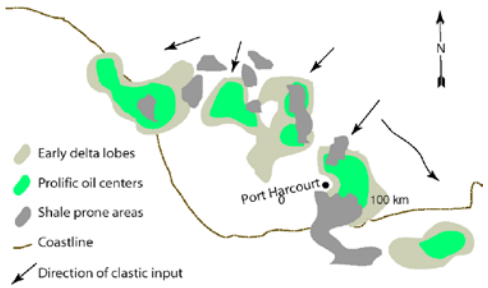
  So fairly quickly the gross reserve of 47.6MMbbl could double by being a little less conservative.
- Contingent Resources assigned by TRACS reflect the uncertainty of hydrocarbon type, mainly in Area C and although we have not examined this in detail in this report (the focus has been on 2P) – an additional 27MMbbl-41MMbbl oil or 1226bcf-1738bcf (pretty large), appears likely.
- Gas developments always need a lot of gas to make the economics work – but 1000bcf plus are enough – this is a future evaluation exercise in our view and current value should focus on the 2P oil.
- We have run our own valuation model to compare to TRACS and our analysis is fairly close across the range of oil prices and discount rates.
- **In our opinion, a reasonable valuation for GoGE net entitlement interest in the 47.6MMbbl 2P reserve is about 30MMbbl and this is worth between $133-$168MM based on a 12% discount rate and long term $40-$50/bbl oil prices (nominal 2.5%) and this could easily grow to 50MMbbl on the same $/bbl value.**

Regional Overview

Niger Delta Region

Niger Delta Geology





Commentary

- The diagram on the left shows how the geology of the Niger delta spreads out into the Atlantic.
- The Tertiary section of the Niger Delta is divided into three formations, representing prograding depositional facies, distinguished on the basis of sand-shale ratios.
- The 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 amounts of clay and silt.
- Deposition of the overlying Agbada Formation, the major petroleum-bearing unit, began in the Eocene and continues into the Recent.
- In the lower Agbada Formation, shale and sandstone beds were deposited in equal proportions, however, the upper portion is mostly sand with only minor shale interbeds.
- Petroleum occurs throughout the Agbada Formation of the Niger Delta and several directional trends form an "oil-rich belt" having the largest field and lowest gas: oil ratio as shown in the diagram lower left.
- Outside of the "oil-rich belt" the gas: oil ratios (GOR) are high and this is what has been found in Uquo.
- Causes for the distribution of GOR's are thought to include
  - remigration induced by tilting during the latter history of deposition.
  - flushing of accumulations by gas generated at higher maturity.

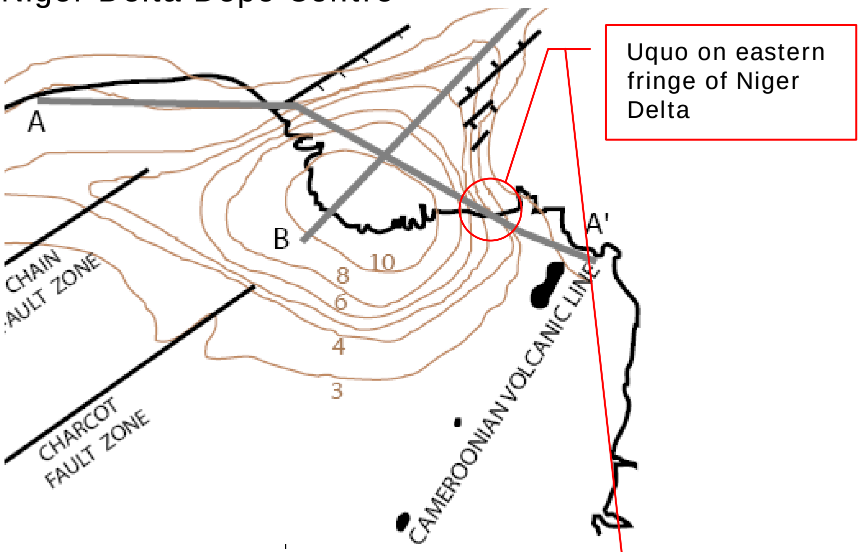
  We cover these points in more detail on the following page.
- The associated gas in the Niger Delta is thermal in origin, e.g. deeper, with low CO_2 and N_2 concentrations. Hydrogen sulfide is not a problem.

Conclusion

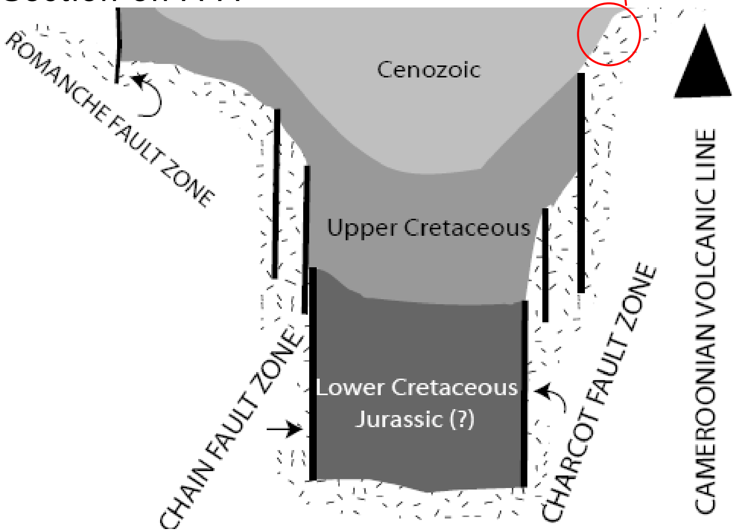
- The Agbada sands have been shown to exist in the Uquo well and we would expect to see similar deposition as described for the Niger Delta area.
- We would expect to see more gas and condensate than oil.
- The Uquo well encountered gas condensate in the lower formations as well as most of Area B and this is in-line with the 'thermal' descriptions above.
- **Therefore good chance of gas/condensate or very light oil discoveries.**

Niger Delta Gas/liquid Determinants

Niger Delta Depo Centre



Section on A-A



Source: USGS

Commentary

- The following quotation from the US Geological survey on the Niger Delta summarises the uncertainty of gas v oil v condensate on the fringes of the Niger Delta-

  'Outside of the "oil-rich belt" (central, easternmost, and northernmost parts of the delta), the gas:oil ratios (GOR) are high. ***The GOR within each depobelt increases seaward and along strike away from depositional centers.*** *Causes for the distribution of GOR's are speculative and include remigration induced by tilting during the latter history of deposition within the downdip portion of the depobelt, updip flushing of accumulations by gas generated at higher maturity, and/or heterogeneity of source rock type (Doust and Omatsola, 1990).'*
  - The Niger Delta Petroleum System, USGS 1999.

- Scott Pickford suggest in their report on certain Cameroon fields to the east, that they are overpressured and we therefore see similarities with conclusions drawn by the US Geological survey on certain areas of the Niger Delta as follows:-

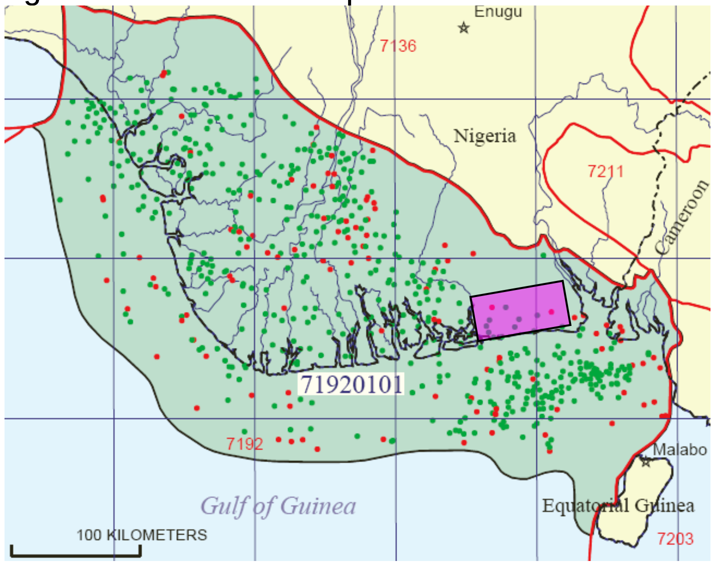
  'in rapidly sinking basins, such as the Gulf of Mexico, the fracturing/resealing cycle occur in intervals of thousands of years. This type cyclic expulsion is certainly plausible in the Niger Delta basin where the Akata Formation is over-pressured. ***Beta and Oti (1995) predict a bias towards lighter hydrocarbons (gas and condensate) from the over-pressured shale*** *as a result of down-slope dilution of organic matter as well as differentiation associated with expulsion from over-pressured sources.'*

- What does this mean for Uquo – hydrocarbons are more likely to be condensate and gas than oil

We conclude that third party data points towards the Uquo area (e.g. Niger Delta fringes) being a gas/condensate prone area.

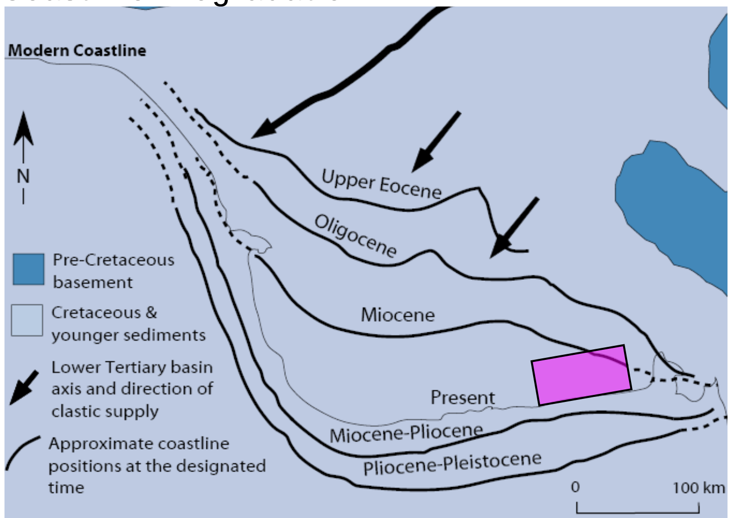
Niger Delta Close up

Agbada Reservoir map



Source: USGS

Coastline Progradation

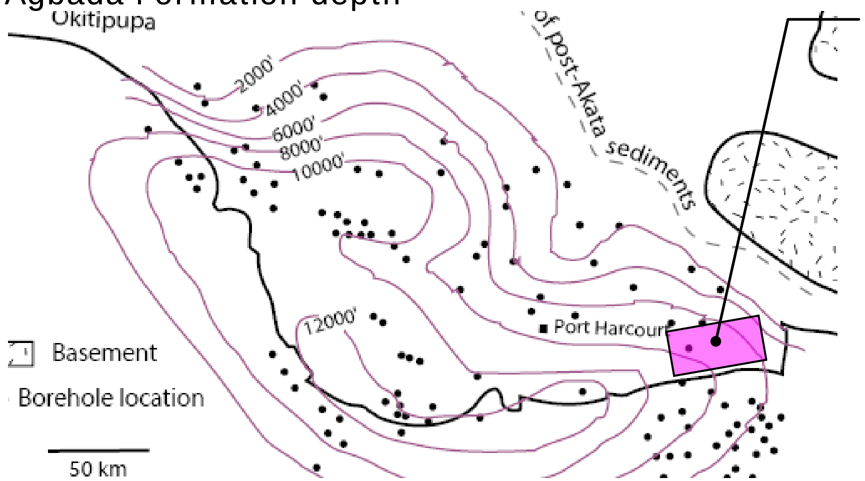


Source: USGS

Tertiary Niger Delta

- **ASSESSMENT UNIT:** Agbada Reservoirs
- **DESCRIPTION:** Sandstone reservoirs in the Agbada Formation of the Niger Delta.
- **SOURCE ROCKS:** Marine shale's of the Agbada and Akata Formations; low, possible deeper Cretaceous source. Most oils are paraffinic, but some shallow oils are biodegraded and naphtenic. Gravities range from about 16° to 50° API, averaging about 35°.
- **MATURATION:** Probably starting about Late Eocene and continuing to the present.
- **MIGRATION:** Either directly from adjacent source rocks or up growth faults from deeper sources.
- **RESERVOIR ROCKS:** Paralic sandstones in the Agbada Formation, especially point bars of distributary channels and coastal barrier bars. Many of the reservoirs sandstones are nearly unconsolidated. Typical sandstones have porosities of 40 percent and permeabilities of 2 Darcy (very high).
  Reservoir depth of Agbada 6000ft in the area of Uquo
- **TRAPS AND SEALS:** Structural traps related to rollovers and growth faults, some stratigraphic traps; seals are interbedded shale's within the Agbada Formation.

Agbada Formation depth

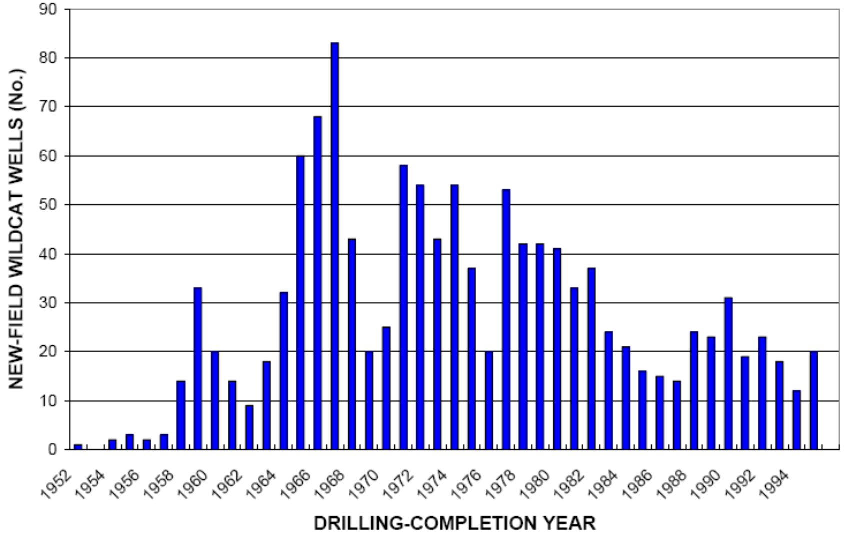


Source: USGS

- Shows the Agbada formation contours of 6000ft crossing top of block.
- So what? – this shallow depth may give more association with gas?

Field Discovery History

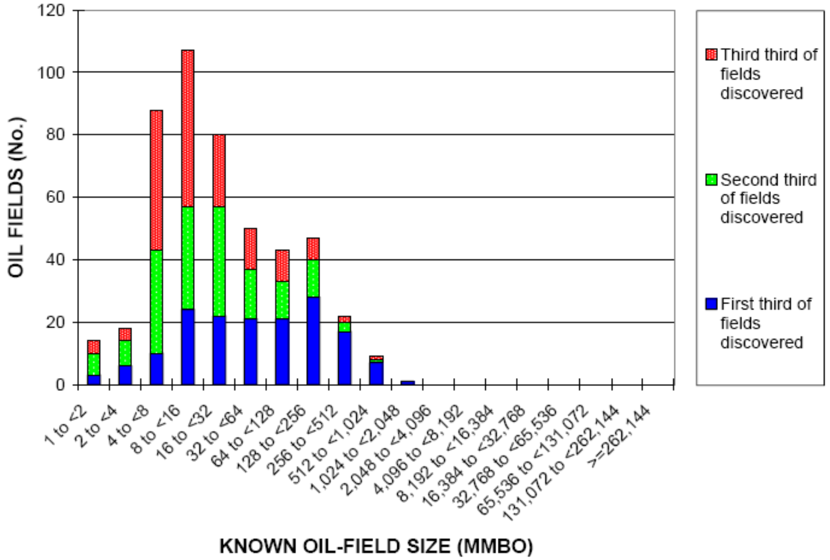
Agbada Reservoir Discoveries



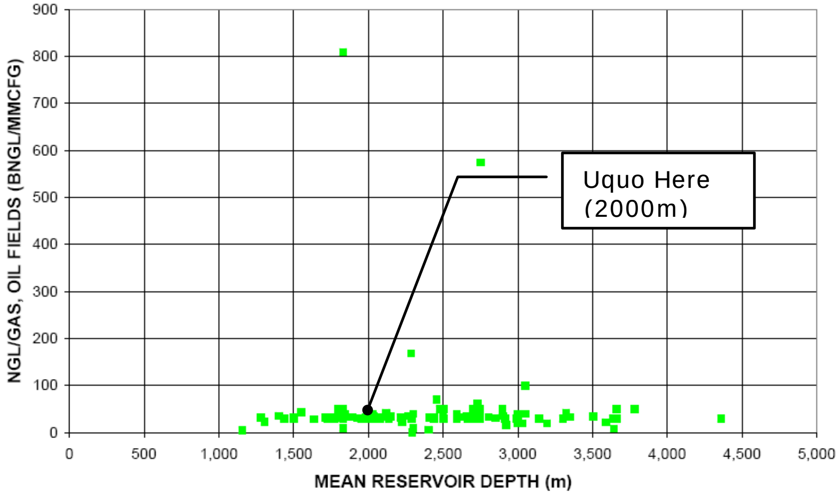
Commentary

- The onshore Niger Delta oil was discovered and developed in the 1960-1980.
- Most of the fields discovered were in the range of 10MMbbl-100MMbbl.
- The mean discovered field sizes were:
  - 71MMbbl oil
  - 343 bcf gas
- About 480 oil fields and 93 gas fields were discovered in the 1952-1999 period.
- The mean specific gravity of oil in the Agbada Niger delta is 35API, light sweet crude.
- The mean reservoir depth of discoveries has been between 1500m-3000m.

Agbada Reservoir size

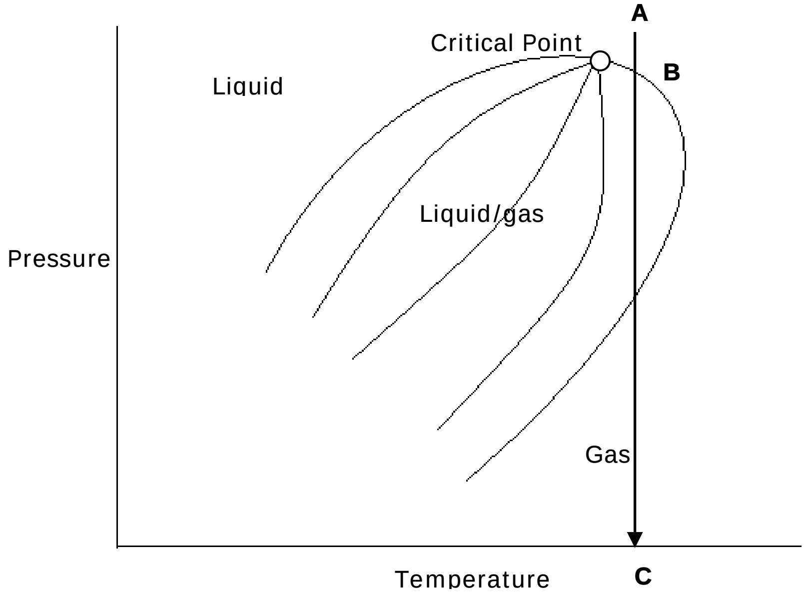


Mean Reservoir Depth



Uquo Reserves Uncertainty

Hydrocarbon Phase Diagram



Source: Bluelake

Commentary

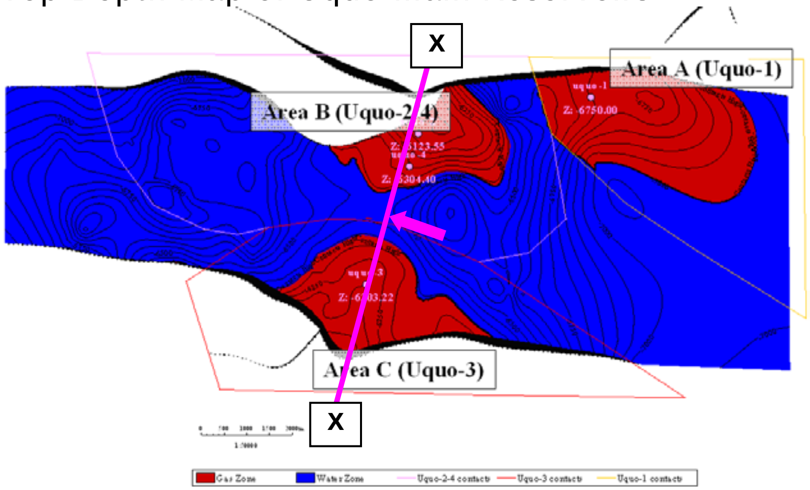
- We have to describe a simple reservoir engineering concept to describe the uncertainty on the gas/liquid/condensate content of the Uquo discovery.
- Pure hydrocarbons (C_2H_6-Ethane) for example, can be turned from gas to liquid by increasing pressure (this would be the top edge of the curve shown left).
- But mixtures of hydrocarbons (multiphase) exhibit a full range of liquid to gas properties as shown left.
- The reservoir is assumed to be at constant depth (and therefore temperature).
- So if pressure in the reservoir is reduced (from A-C), the reservoir fluids will change phase from completely liquid to completely gas or a mixture of the two.
- At high temperatures as shown by our line A-B-C, past the critical point, liquids condense out of the gas in the reservoir at point B and this leaves condensate trapped in the reservoir.
- Because the complete fluid samples were not recovered in the Uquo discovery, or at least we have not seen the analysis - pressure and temperature data appears incomplete, a precise estimate of the liquids v gas recovered is not yet possible.
- In addition, if pressure support can be maintained from an active aquifer then the additional liquids may be extracted but aquifer activity is also unknown.
- This is why TRACS has applied varying recovery factors (condensate yield) depending on these conditions.

We conclude that the because of the uncertainty on reservoir phase composition and aquifer pressure support that lower recovery factors are appropriate for Uquo.

Uquo Block

Uquo Block

Top Depth Map of Uquo main Reservoirs



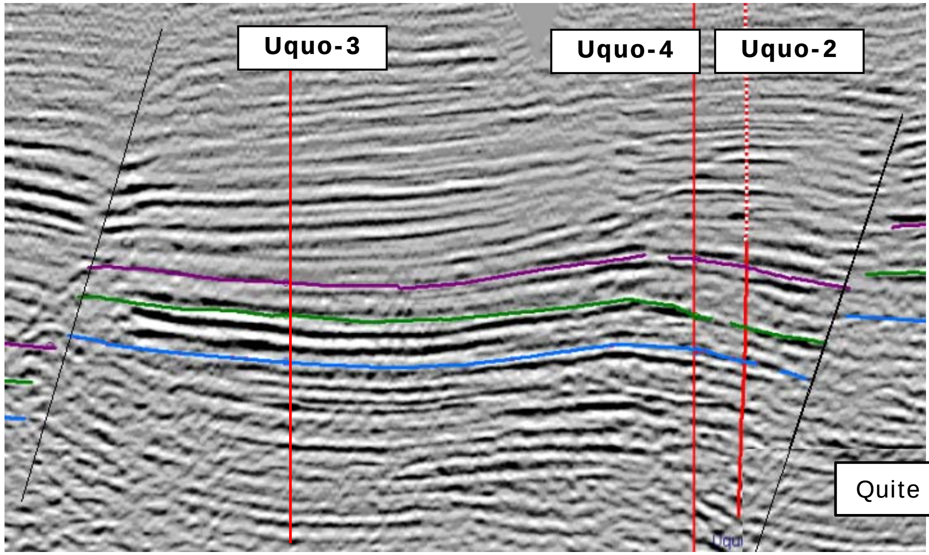
Source: TRACS

Commentary

- Although 4 wells have been drilled in the area only one (Uquo-1) was tested and we cover more of this production data on the following pages.
- In terms of hydrocarbons in the ground (STOIIP and GIIP), the other 3 wells were logged (electric readings taken to determine physical properties of rocks and hydrocarbons).
- From this it was determined that there were 4 main hydrocarbon bearing intervals in the P50 (most likely) scenario:

Area A/C: Oil Formations		**Area B: Gas Formations**	
Uquo-1	**Uquo-3**	**Uquo-2**	**Uquo-4**
		D1.0	D1.0
D1.3	D1.3	D1.3	D1.3
D1.4	D1.4	D1.4	D1.4
D1.5			
D1.6			
		D2.0	D2.0
D5.0	D5.0	D5.0	D5.0

Seismic on X-X



Source: TRACS

Reserves Summary

- Oil in Area A is proven (from flow testing) but oil in Area C has been logged but not tested so there are no reserves, only resources.
- Therefore the Proven + Probable (2P) reserves are based on Area A only and are 48MMbbls Gross (100%).
- We need to check the calculated recovery factors by analogy to other fields.
- We understand the 2P reserves assumed reservoirs that flowed (D1.5 & D5.0), plus half the volumes of D1.3, D1.4 & d1.6.

STOIIP

	P90 (MMbbl)	P50 (MMbbl)	P10 (MMbbl)
Area A	21	135	219
Area C	0	63	86

GIIP

	P90 (bcf)	P50 (bcf)	P10 (bcf)
Area B/C	848	1746	2449

Recovery Factors

Area A	29%	35%	38%
Area C		38%	41%

Recovery Factors

Area B/C	70%	59%	56%

Quite low

Reserves/Resources

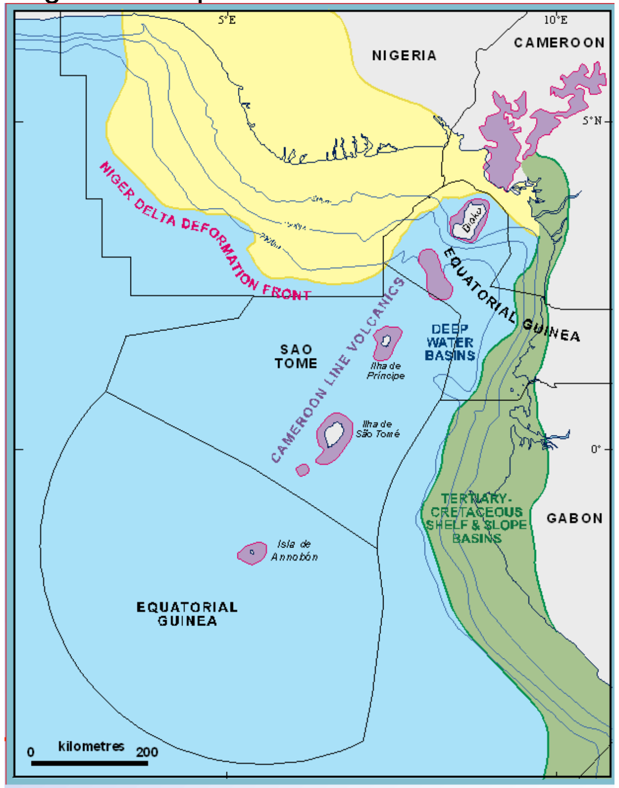
	P90 (MMbbl)	P50 (MMbbl)	P10 (MMbbl)
Area A	6	48	83
Area C	0	24	35

Resources

	P90 (bcf)	P50 (bcf)	P10 (bcf)
Area B/C	594	1031	1362

Recovery Factor Comparisons

Regional Map



Regional Field Comparisons

- The P50 recovery factor assumed by TRACS is 35%.
- How does this compare to other fields along the Gulf of Guinea?:

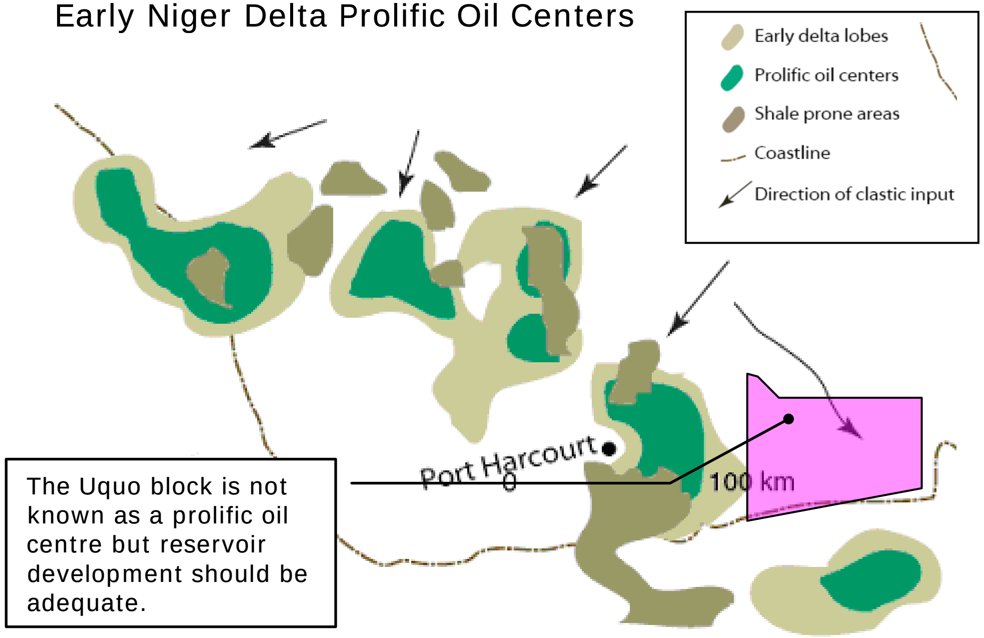
AFRICA		Working Interest (%)	GOR (bbl/MMscf)	Poro (%)	Perm (mD)	N/G (%)	API	Recovery Factor (%)
Nigeria	Uquo	52%	1200	30%	1000	100	46	35%
Equatorial Guinea	Ceiba [4]	100%		25%	1000			28%
	Okume Complex [4]	100%					20-35	32%
Congo	N Kossa [4]	100%						32%
	N Kossa South [4]	100%						42%
	M Boundi [4]	100%					41	22%
	N Soko [4]	100%					37	14%
	Moho/Bilondo [4]	100%					32	21%
Gabon	Kowe [4]	100%					44	34%
	Etame [4]	100%		28%	1000		36	19%
	Limande [4]	100%						16%
	Turnix [4]	100%					27	16%
	Niungo [4]	100%			100-1000			20%
	Echira [4]	100%		25%	300		36.7	14%
Cote D Ivoire	Espoir E [5]	100%		20%		0.6	33	39%
	Espoir W [5]	100%					33	16%/71%
	Acajou	100%		0.2			32	8%

1: Millenium Atlas, Geological Society, 2003
2: DTI Data
3: Salamon Smith Barney, Thames/Murdoch Sales Memorandum, 1999
4: Scott Pickford CPR, Energy Africa takeover
5: Canadian Natural Resources
6: Lasmo

- Although the Niger Delta is fairly unique on the African West Coast it is worth considering a comparison to other fields in the area.
- We have shown a number of fields above where there are known recovery factors.
- Considering the comparable reservoir characteristics we think the 35% assumption for the 2P reserves appears reasonable.

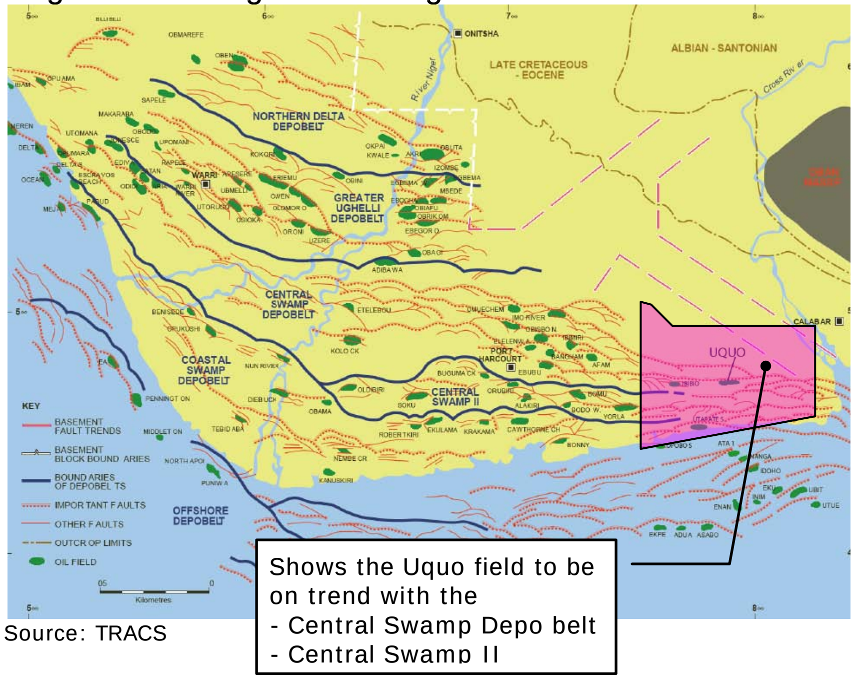
Uquo Field Location

Early Niger Delta Prolific Oil Centers



Source: USGS

Regional Geological Setting



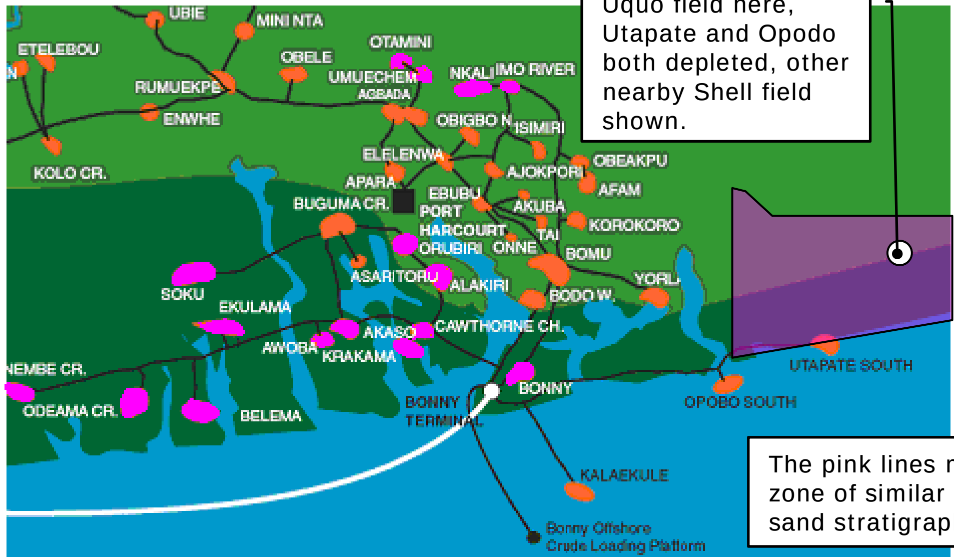
Source: TRACS

Commentary

- What is the potential for hydrocarbons on the Uquo Block and what type should we expect – oil/gas or condensate?
- We are interested to see where the Uquo field is positioned relative to the known hydrocarbon centers across the Niger Delta.
- We have shown a map from the US Geological Survey (USGS) top left and this shows the major oil centers.
- The shale centers are the typical 'source' rocks and the 'clastic input' areas where clastics (sand/limestone grains) are found and are usually indicative of reservoir presence.
- The Oil Centers map indicates that the Uquo field is someway North West of the most prolific centers; although this is a relative analysis and does not mean there are no hydrocarbons in the Uquo area as we known this is already proven.
- But the 'Direction of clastic input' arrow indicates that reservoir is likely.
- It may be interesting to compare the fields on trend with Uquo in the Central Swamp Depo belt and Swamp II

Analog Field Analysis

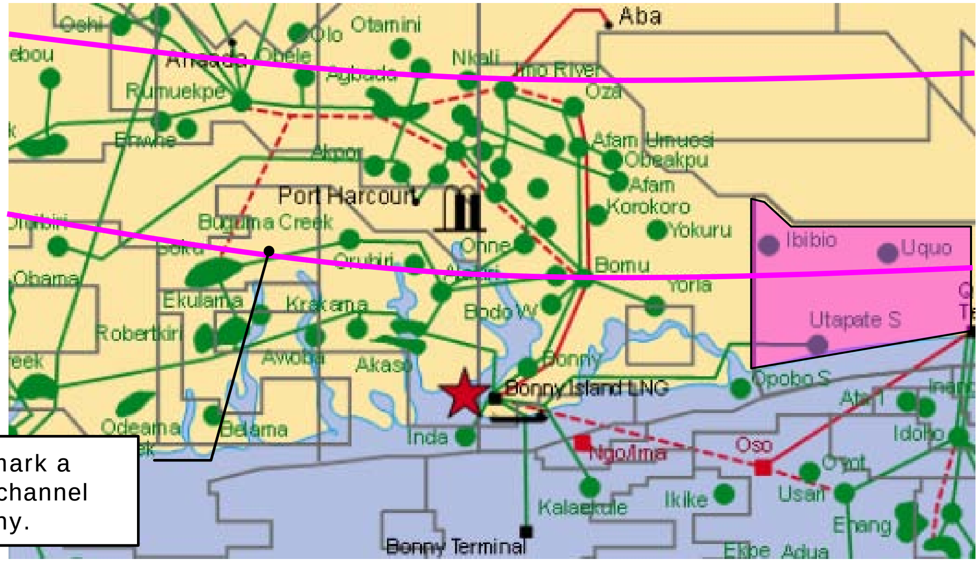
Shell Fields



Uquo field here, Utapate and Opodo both depleted, other nearby Shell field shown.

Source: Shell Nigeria

All Fields



The pink lines mark a zone of similar channel sand stratigraphy.

Source: TRACS, Bluelake

Shell Fields Production Data – 2Q 2006

Shell Wells	No Wells	Location	Oil 2Q06 Production (MMbbl)	Gas 2Q06 Production (MMscf)	Oil Per Well Prod (b/d)	Gas Per Well Prod (MMscf/d)	API	GOR
Akaso	9	Swamp	1.64	2553	18,179	28.4	39.48	278
Alakiri	6	Dry	0.27	2057	3,005	22.9	39.86	1354
Awoba	7	Swamp	2.77	2691	30,733	29.9	43.72	173.26
Belema	11	Swamp	2.74	1907	30,477	21.2	31.31	124
Bonny	9	Swamp	0.34	36241	3,731	402.7	29.15	19223
Cawthorne	22	Swamp	3.60	5471	40,033	60.8	39.01	270
Ekulama	16	Swamp	1.67	1157	18,507	12.9	28.4	124
Imo River	35	Dry	2.28	1433	25,344	15.9	31.53	112
Krakama	5	Swamp	0.38	306	4,246	3.4	30.58	143
Nembe Creek	38	Swamp	3.73	3484	41,389	38.7	37.35	1191
Nkali	4	Dry	0.15	886	1,700	9.8	40.18	1028
Odeama Creek	4	Swamp	0.67	634	7,441	7.0	32.37	169
Orubiri	1	Dry	0.10	53	1,059	0.6	25.03	99
Otamini	2	Dry	0.40	332	4,456	3.7	22.15	147
Soku	28	Swamp	1.52	40659	16,889	451.8	42.44	4764
Umuechem	4	Dry	0.15	164	1,667	1.8	36.24	195
Total/Average Data			**22.40**	**100028**	**15,553**	**69**	**34**	**1837**

Source: Nigerian National Petroleum Corp, 2006

Commentary

- We have taken recent production data from nearby Shell fields for comparison purposes on relative productivity.
- The Uquo field is in the transition between swamp and dry land as shown in the diagrams above.
- The Central Swamp Depo Belt fields are shown highlighted in yellow and indicate average flow rates of about 8,000b/d per well.
- There is no real pattern associated with Gas Oil Ratio (GOR) from geographical location, this is more likely to be depth associated.
- But overall the average productivity of wells in the area is very high:
  - oil wells 15,500b/d
  - gas wells 70MMcfd
- Bearing in mind that many of these fields will be late life production – the initial rates of the Uquo can be expected to be relatively high on the basis of nearby analog fields
  - 2600b/d+ oil and 5MMcfd for gas

Uquo Capex / Opex

Uquo Opex and Capex

Gross Capex projections

GROSS

Area A

Oil	**WI**	**Totals**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
1P	100%	67	19.7	32.4	15.0				
2P	**100%**	**143**	**18.6**	**58.2**	**47.6**	**18.2**			
3P	100%	217	18.6	60.4	58.6	45.0	34.1		

Area C

Oil	100%	Total	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
1P	100%								
2P	100%	58	0.0	25.8	21.6	10.7			
3P	100%	69	0.0	25.8	41.7	12.5	-11.0		

Capex Observations

- Gross capex for P50 case is $143MM.
- This assumes
  - $7MM per development well
  - $3MM per water injector
  - $47MM production facilities
  - $8MM 17km oil pipeline to Eket
- Gross equity P50 reserve is 47.6MMbbl
- Unit capex therefore $3.00/bbl
- Relatively conservative in our opinion.

Comparable Capex/Opex

GROSS		**Type**	**Capex & aband ($MM)**	**Aband ($MM)**	**Opex (excl tarif) ($MM)**	**Unit Capex ($/boe)**	**Unit opex ($/boe)**
Nigeria	**Uqoa**	**Onshore**	**142.7**		**353.2**	**3.0**	**7.4**
Equatorial Guinea	Ceiba [4]	Offshore	260.2	40.0	856.8	3.0	9.9
Congo	N Kossa [4]	Offshore				0.0	0.0
	N Kossa South [4]	Offshore				0.0	0.0
	M Boundi [4]	**Onshore**	**459.3**		**520.2**	**2.5**	**2.9**
Gabon	Kowe [4]	Offshore	10.5	0.0	335.2	0.3	8.2
	Etame [4]	Offshore	21.0	7.5	214.4	0.9	8.9
	Limande [4]	Offshore	7.5	10.0	36.3	2.4	11.8
	Turnix [4]	Offshore	2.5		97.2	0.2	8.9
	Niungo [4]	**Onshore**	**10.9**	**5.0**	**56.8**	**0.6**	**3.0**
	Echira [4]	**Onshore**	**2.5**	**5.0**	**46.3**	**0.5**	**8.6**
Cote D Ivoire	Espoir E	Offshore	70.5	27.0	564.5	1.3	10.1
Equatorial Guinea	Okume Complex [4]	Offshore	1074.8	114.8	629.3	5.5	3.2
Congo	N Soko [4]	Offshore				0.0	0.0
	Moho/Bilondo [4]	Offshore				0.0	0.0
Cote D Ivoire	Espoir W	Offshore	210.1	27.0	71.2	5.1	1.7
	Acajou	Offshore				0.0	0.0

Opex Observations

- Overall Gross Opex also $353MM (real not inflated).
- Opex data based on
  - $10MM per annum fixed cost
  - $4/bbl variable cost
- Equates to $7.40/bbl.
- Relatively high compared to other African onshore projects.
- We would not usually expect onshore costs to be as high as other offshore projects shown.
- We are not aware that any security costs are built into the operating costs but this is a minor point as opex is already high.

Uquo Production

Production Profile checks

Production Profiles

GROSS

Area A

Oil	WI	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
1P	100%		1673	2863	2324	1887	1534	1248	1016	827	674	549	448	366	298	244	199	163	133	6
2P	**100%**		**5191**	**15838**	**16111**	**13978**	**12144**	**10565**	**9204**	**8029**	**7013**	**6134**	**5371**	**4709**	**4133**	**3631**	**3194**	**2812**	**2479**	**48**
3P	100%		5220	18126	26369	26092	22734	19840	17339	15176	13300	11672	10256	9023	7948	7008	6186	5466	4834	83

Area C

Oil	100%	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
1P	100%																			0
2P	100%		1262	8002	7368	6540	5812	5172	4608	4110	3668	3278	2931	2622	2348	2103	1885	1690	1516	24
3P	100%		1485	10700	11103	9877	8798	7844	7001	6254	5591	5002	4477	4010	3594	3222	2890	2593	2327	35

NET

Area A

Oil	WI	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
1P	52%		870	1489	1208	981	798	649	528	430	350	285	233	190	155	127	103	85	69	3
2P	52%		2699	8236	8378	7269	6315	5494	4786	4175	3647	3190	2793	2448	2149	1888	1661	1462	1289	25
3P	52%		2715	9426	13712	13568	11822	10317	9016	7892	6916	6069	5333	4692	4133	3644	3217	2842	2514	43

Area C

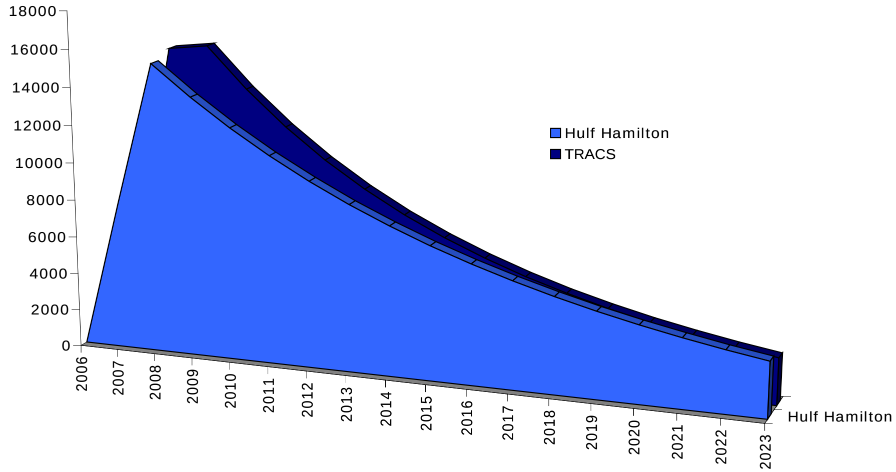
Oil		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
1P	45%																			0
2P	45%		568	3601	3316	2943	2615	2327	2074	1850	1651	1475	1319	1180	1057	946	848	761	682	11
3P	45%		668	4815	4996	4445	3959	3530	3150	2814	2516	2251	2015	1805	1617	1450	1301	1167	1047	16

2P Profile Check		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
D 1.3/1.4 Initial rate:		2702																	
D 1.5/1.6 Initial rate:		1319																	
D5.0 Initial rate:		379																	
Decline factor:		0.1101																	
D1.3/1.4			3																
D1.5/1.6			3	2															
D5				3															
D1.3/1.4			3893	8105	7260	6503	5825	5218	4674	4187	3751	3360	3009	2696	2415	2163	1938	1736	1555
D1.5/1.6			3958	3545	3176	2845	2548	2282	2045	1831	1641	1470	1316	1179	1056	946	848	759	680
D1.5/1.6				2638	2363	2117	1896	1699	1522	1363	1221	1094	980	878	786	704	631	565	506
D5				1138	1019	913	818	732	656	588	526	472	422	378	339	304	272	244	218
HH	**47.60**		**7850**	**15425**	**13818**	**12377**	**11087**	**9932**	**8896**	**7969**	**7139**	**6394**	**5728**	**5131**	**4596**	**4117**	**3688**	**3304**	**2959**
TRACS	**47.65**		**5191**	**15838**	**16111**	**13978**	**12144**	**10565**	**9204**	**8029**	**7013**	**6134**	**5371**	**4709**	**4133**	**3631**	**3194**	**2812**	**2479**

P50 profile assumes 11 production wells.

Source: TRACS, Bluelake

Production Profile Comparisons



Commentary

- We have projected out the TRACS projected production profiles for each of the P90/P50/P10 profiles above but our focus is the P50 data.
- For comparison purposes we have constructed our own production profile based on approximate initial well rate assumptions as follows:
  - Formations D1.3 & 1.4: 2700b/d
  - Formations D1.5 & D1.6: 1300b/d
  - Formations D5.0: 380b/d.
- We then assumed that each well would decline with an exponential coefficient of 11%.
- Our resulting profile is not dissimilar from the TRACS profile as shown left.

Valuation

Oil Price Comparisons

2005 Nigeria vs. Global Oil Prices (Average spot price)

CRUDE STREAM / MONTH	OPEC Basket	Brent	WTI	Isthmus	Bonny Light	Minas	Saharan Blend	Arabian Light	Dubai	Tia Juana Light	Iran Heavy	Kuwait Export	Basrah Light
JANUARY	40.2400	44.0100	46.6400	38.8900	44.0100	42.5500	44.3900	38.2600	37.7800	35.7500	0.0000	0.0000	0.0000
FEBRUARY	41.6800	44.8700	47.6900	40.0800	45.4300	44.5600	45.4400	40.1000	39.3500	36.7700	0.0000	0.0000	0.0000
MARCH	49.0700	52.6000	54.0900	47.5200	53.1500	54.3000	52.5900	46.8500	45.6000	43.5000	0.0000	0.0000	0.0000
APRIL	49.6300	51.8700	53.0900	47.1300	53.1800	55.9600	51.9800	48.6800	47.2400	43.2700	0.0000	0.0000	0.0000
MAY	46.9600	48.9000	50.2500	45.0500	50.2300	50.3400	48.6900	47.0900	45.6800	41.6700	43.2500	46.3600	44.5700
JUNE	52.0400	54.7300	56.6000	51.4800	55.9300	55.0200	54.4100	52.4700	51.3700	48.1900	49.6000	51.1500	50.5900
JULY	53.1300	57.4700	58.6600	53.8500	58.4000	56.1700	57.3000	53.4600	52.7800	49.1000	51.0700	51.3100	52.2400
AUGUST	57.8200	64.0600	64.9600	59.6600	65.4900	61.0700	63.6700	58.2400	56.5500	54.2200	55.6900	55.1800	57.1000
SEPTEMBER	57.8800	62.7500	65.2800	59.9200	65.6000	60.2700	63.3000	57.6300	56.4100	53.8700	55.1000	54.6000	55.6800
OCTOBER	54.6300	58.7500	62.6700	55.6400	60.7400	58.6400	59.4800	54.6500	54.2000	51.4800	51.7300	51.7600	51.3900
NOVEMBER	51.2900	58.4200	55.4100	51.5700	58.1800	53.8700	56.1500	51.5500	51.6300	48.7700	49.2800	49.1900	48.0700
DECEMBER	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
AVERAGE	46.1975	49.8692	51.2783	45.8992	50.8617	49.3958	49.7833	45.7483	44.8825	42.2158	29.6433	29.9625	29.9700

2005 Nigerian Domestic Prices

CRUDE STREAM / MONTH	Forcados Blend	Bonny Light	Brass Blend	Escravos Light	Pennington Light	Antan Blend	Amenam Blend	Qua- Iboe Light	Oso Condensate	Obe	Okono	Yoho Light	EA Light	ABO Blend	Ukpokiti
JANUARY	43.7338	45.0173	44.7939	44.1960	43.1185	40.0864	43.9608	45.0451	0.0000	45.1970	44.7635	45.1370	44.1926	44.9980	45.3640
FEBRUARY	45.2137	45.6382	45.0223	46.1831	43.8815	44.2653	45.2920	45.4955	47.4725	43.5780	46.7833	45.9293	46.2940	46.6100	0.0000
MARCH	53.6539	53.6894	54.3834	53.3493	53.1830	50.3073	53.1973	52.6179	53.7535	54.6380	52.8030	52.9600	52.7286	0.0000	0.0000
APRIL	51.3629	51.0744	50.4895	51.8415	50.0737	47.7380	49.1670	51.1311	0.0000	50.5210	50.6795	0.0000	50.5707	52.6475	49.4870
MAY	48.9496	48.9105	49.6197	48.8780	49.0470	45.4748	49.2065	49.2893	49.7593	49.4730	49.0055	48.5615	48.5700	47.2510	0.0000
JUNE	54.5933	55.2775	56.1410	55.4674	52.4100	50.5893	55.5100	55.6849	54.2245	51.8190	56.1530	54.9105	54.8673	0.0000	0.0000
JULY	59.3045	58.9247	58.9479	58.3959	59.4785	54.9029	58.3725	58.4009	60.7620	0.0000	58.4625	58.7793	59.6264	57.6505	0.0000
AUGUST	66.4414	67.4019	68.0898	66.1674	65.2885	61.3350	66.2700	66.3391	65.0540	67.1510	65.6020	65.4068	64.8708	0.0000	65.8800
SEPTEMBER	64.6602	64.4415	65.7833	65.0907	64.3320	58.1227	63.4850	64.0892	63.1635	0.0000	62.3105	65.0330	64.6967	65.9550	0.0000
OCTOBER	60.2902	59.9750	59.9402	59.9460	59.7120	55.8525	59.8057	60.0086	58.5210	58.8570	60.0765	60.3910	59.3335	59.4320	0.0000
NOVEMBER	55.7710	55.3674	55.0254	55.7848	57.0295	50.8217	55.2857	55.4510	58.9540	0.0000	55.2627	55.4573	56.0294	55.6650	54.3940
DECEMBER	58.0385	57.5230	57.4406	57.1844	59.2725	53.7700	57.4558	58.0229	59.2325	57.1590	59.6210	57.9860	57.7437	58.3800	0.0000
AVERAGE	55.1677	55.2701	55.4731	55.2070	54.7356	51.1055	54.7507	55.1313	57.0897	53.1548	55.1269	55.5047	54.9603	54.2877	53.7813

Source: Nigerian National Petroleum Corp, 2006

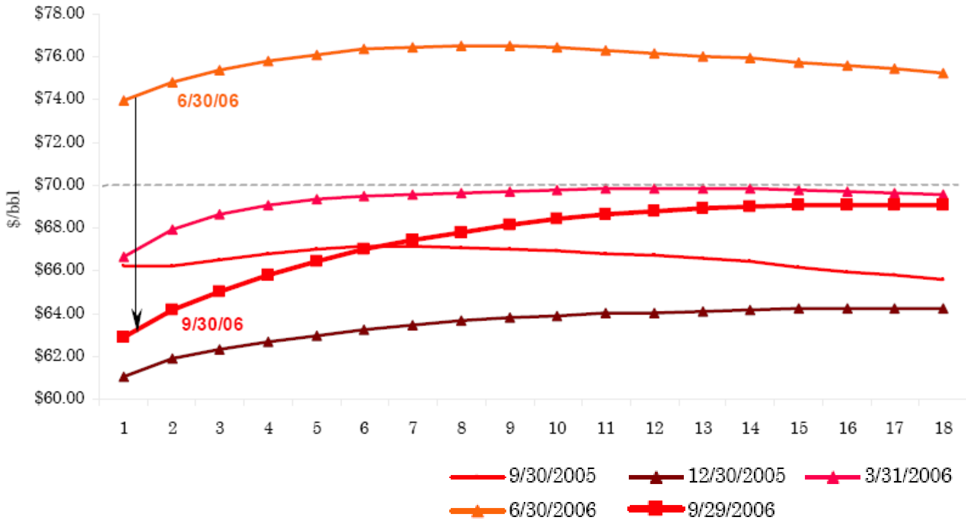
Oil Price Assumptions

- TRACS use the NYMEX forward curve from 9th May 2006 – 2011:

2007	2008	2009	2010	2011	2012	2013	2014	2015
$73.21	$71.43	$69.30	$67.61	$66.19	$64.87	$63.57	$62.30	$61.06

- As the diagram below shows from 29 September 2006, Nymex crude futures have fallen about $10/bbl for an 18 month option.
- This indicates to us that the NYMEX Oil Price Deck used by TRACS in their report is possibly optimistic.
- It is important therefore to focus on the long term $40/bbl and $50/bbl cases.
- But also we need to consider that Bonny Light (the predominant Niger Delta crude) trades at a premium to Brent ($1.00/bbl) and discount to WTI (-$0.41/bbl) in 2005.
- In our opinion a long term oil price assumption of $40/bbl-$50/bbl would be prudent.
- We will tabulate our valuation compared to TRACS for each of the different crude cases on the following pages.

NYMEX 2006 WTI Crude Futures



Source: JS Herold

Valuation

Fiscal Regime

- Gulf of Guinea Energy (GoGE) holds a 52% economic interest in the Uquo oil license and 45% in the gas license.
- Our valuation and analysis focuses on the oil portion only.
- GoGE Partner Frontier holds the remaining stake.
- The Fiscal terms work in 3 stages
  1) The Uquo (100%) license pays 55% tax + 2.5%-18.5% royalty (production dependent) to the Nigerian Gov.
     a 5% education and other taxes are also payable and capital allowances are set against tax at 20%
  2) The Uquo (100%) license also pays a royalty to Shell, the previous owner, between 2.5%-12.5%, also production dependent.
  3) A 'mini PSA' operates between GoGE and Frontier where GoGE pays all costs and recovers 100% of costs from upto 90% of revenues.
     The remaining 'profit oil' is split 52%/48% according to the respective equity shares.
- We calculate the overall effect of this is to increase GoGE interest in net P50 reserves interest from 52% of 47.6MMbbl = 24.8MMbbl to 29.5MMbbl
- We call this 29MMbbl the 'entitlement reserve' and this is a particularly attractive part of the contract as 'entitlement oil' is usually less than 'cost oil'.
- So overall we calculate that the Nigerian Government takes roughly a 40% of GoGE share of oil and this is not bad.

Oil Price Inputs

- We have used the same assumptions as 4 cases proposed by TRACS:
- Prices (as well as costs) are inflated at 2.5%:
- The data shown below is un-inflated.

2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Futures	73.2	71.4	69.3	69.3	69.3	69.3	69.3	69.3	69.3
$40/bbl	73.2	71.4	40.0	40.0	40.0	40.0	40.0	40.0	40.0
$50/bbl	73.2	71.4	50.0	50.0	50.0	50.0	50.0	50.0	50.0
$60/bbl	73.2	71.4	60.0	60.0	60.0	60.0	60.0	60.0	60.0

Valuation Output

- We have shown the output from our model compared to the TRACS data for varying discount rates and oil prices for the P50 case:

HH

Uquo-1	**P50**	**(Futures)**	**($40/bbl)**	**($50/bbl)**	**($60/bbl)**
NPV 10		**247**	153	192	232
NPV 12		217	133	168	202
NPV 15		185	110	138	166

TRACS

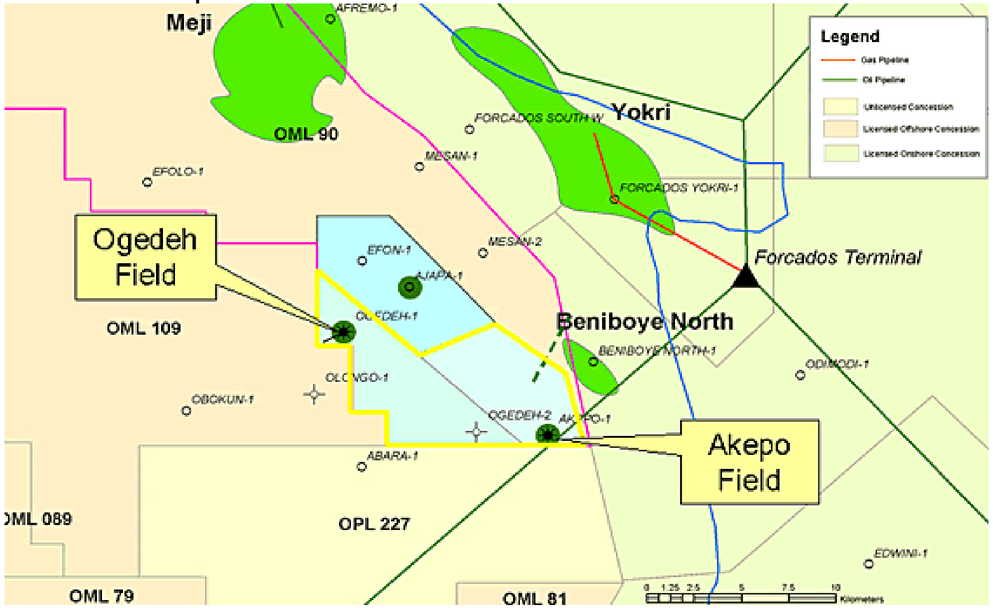
Uquo-1	**P50**	**(Futures)**	**($40/bbl)**	**($50/bbl)**	**($60/bbl)**
NPV 10	**32.507**	**233**	164	209	255
NPV 12	**32.507**	211	146	187	228
NPV 15	**32.507**	183	108	167	137

- We conclude that the TRACS valuation model appears reasonable in terms of the output data.
- We concede that our valuation model is probably less sophisticated than the TRACS model and this should be borne in mind when considering our data.
- In our opinion the valuation should be pitched somewhere between $40/bbl-$50/bbl at 12%, e.g. **$133MM-$168MM** or $146MM-$187MM by the TRACS estimates.

Case Studies

Ogedeh and Akepo (Nigeria)

Location Map



Source: Afren

Commentary

The Nigerian licenses were acquired in 2005 by Afren and are OML's – (Oil Mining Licenses) – traditionally allocated to local Nigerian businesses for development with foreign partners in the coastal areas of the country. Many still remain undeveloped and provide potential upside for if Afren can negotiate more deals

Ogedeh

- Eastern Niger delta, 10-25MMbbl discovery just off the coast of Nigeria in relatively shallow 40ft water.
- Discovered in 1993 but untested so there are uncertainties over productivity.
- Afren has a 50% interest in the PSA and will pay 100% of the development costs but take 120% cost oil from first production to repay the investment.
- The other 50% Nigerian partner is Bicta Energy.
- The PSA is quite generous and Afren/Bicta take 100% of profit oil and split it in half.
- The government take comes through royalties (assumed 5%) and a whopping 55% profit tax.
- The Ogedeh field will probably be co developed with the Akepo field with a modest platform and 3 development wells (total 6) on each field, with possible water injection later. – our total capex for each development is $4.49/bbl

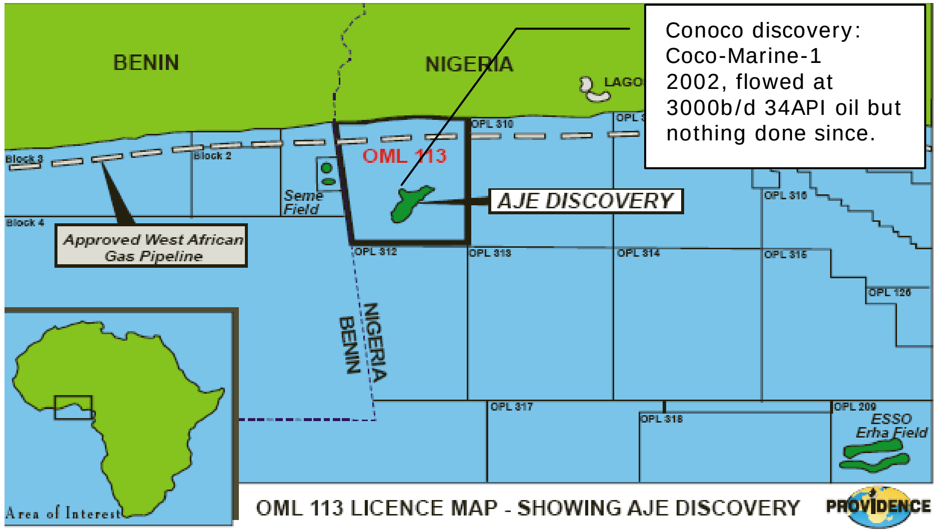
Akepo

- A similar 10-25MMbbl discovery just off the coast in shallow water.
- We know 107ft of net oil pay was logged in the discovery well in 1993.
- Virtually identical development with 3 wells – we assume a 2 year plateau at 7000b/d gross then decline out to 2020 – reservoir and oil quality are good in Nigeria.
- Similar PSA terms – Afren pays development costs and gets back cost oil – this time 100% and not 120%.
- Profit oil split 60/40 not 50/50.
- We assume first oil from both projects in 2007.
- Operating costs $4-$6/bbl between developments.

Conclusion: Decent core production potential from 2 – 16MMbbl (our assumption) oil fields. We may see more of these on the Afren books.

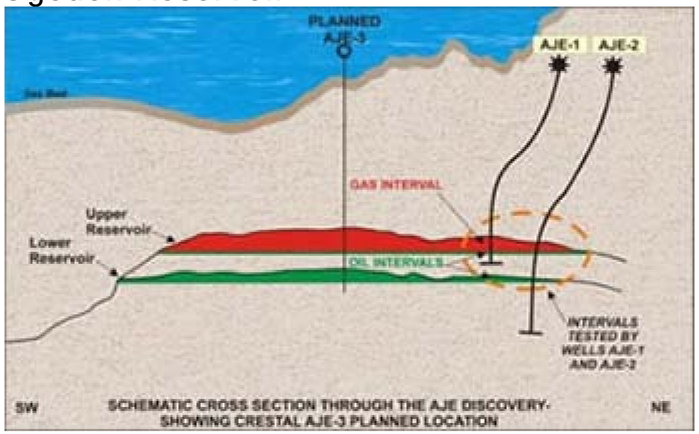
AJE (Nigeria)

Providence Resources Block



Source: Bluelake

Ogedeh Reservoir



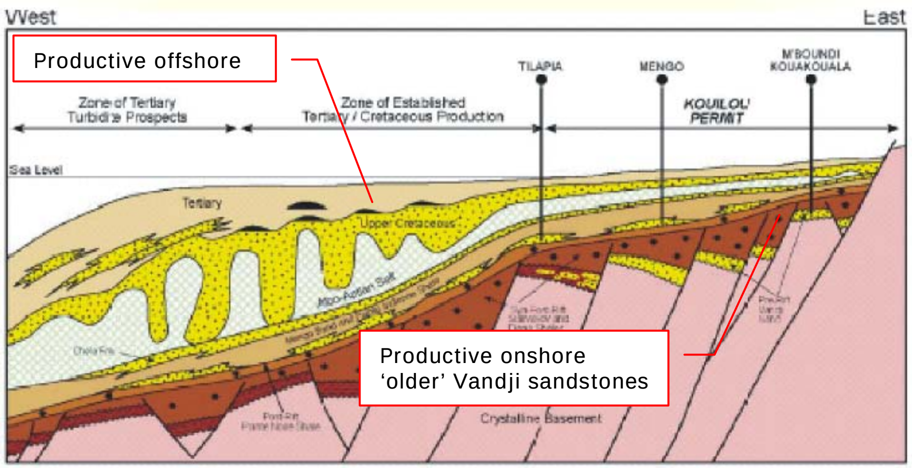
Source: Providence Resources

Commentary

- The AJE field is in the Eastern Niger delta.
- The field is situated in Oil Mining Lease (OML) 113 in water depths of c. 3,000 feet and is 15 miles offshore being some 40 miles southwest of Lagos.
- The discovery well, Aje-1, which was drilled in 1996 encountered oil and gas in reservoirs of Cretaceous age, and flowed at an aggregate rate of 42 MMSCFGD and **2,262 BOPD** over three zones.
- An appraisal well, Aje-2, which was drilled in 1997 flowed **3,866 BOPD** from a deeper separate additional zone which had not been encountered in the Aje-1.
- The Aje field is thought to contain proven plus probable plus possible (1P + 2P + 3P)) un-risked recoverable reserves of ~350 million barrels of oil and ~1.5 trillion standard cubic feet of natural gas. In addition it is thought that Aje holds potential for a further 150 million barrels of condensate oil and natural gas liquids.
- Under the participation agreement (announced on 13 January 2005) entered into by the members of the consortium, Providence is entitled to 6.328% of net revenues from any developments within OML 113 which includes Aje.
- Providence's strong fellow participants in OML 113 include Lundin Petroleum (Technical Advisor), Challenger Minerals (part of the GlobalSantaFe Corporation), Palace Exploration Company, Howard Energy, Syntroleum Corporation and Yinka Folawiyo Petroleum. The participants have also entered into an Area of Mutual Interest agreement covering areas adjoining OML 113.
- Challenger Minerals may be a potential partner for GoGE in other Nigerian developments.

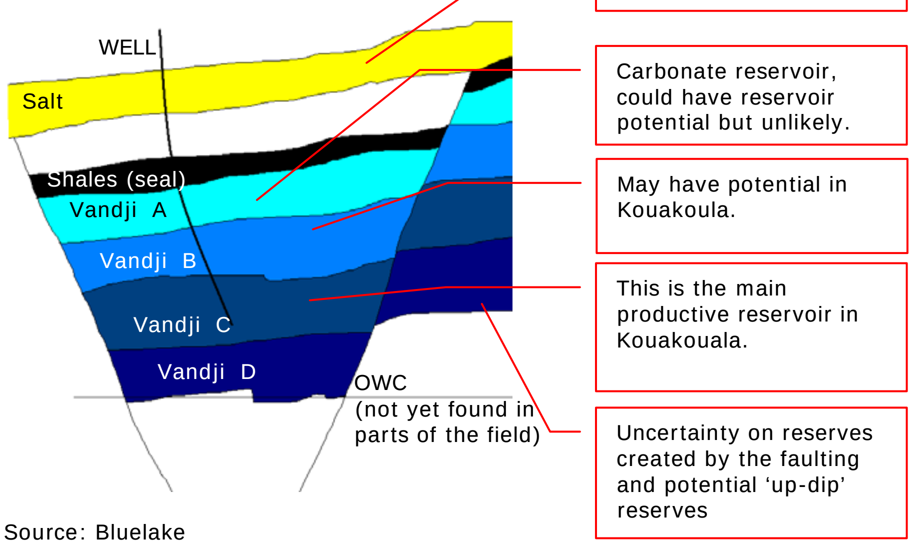
Kouakouala (Congo)

Geological cross section



Source: Burren Energy

Vandji Reservoir cross section



Source: Bluelake

Commentary

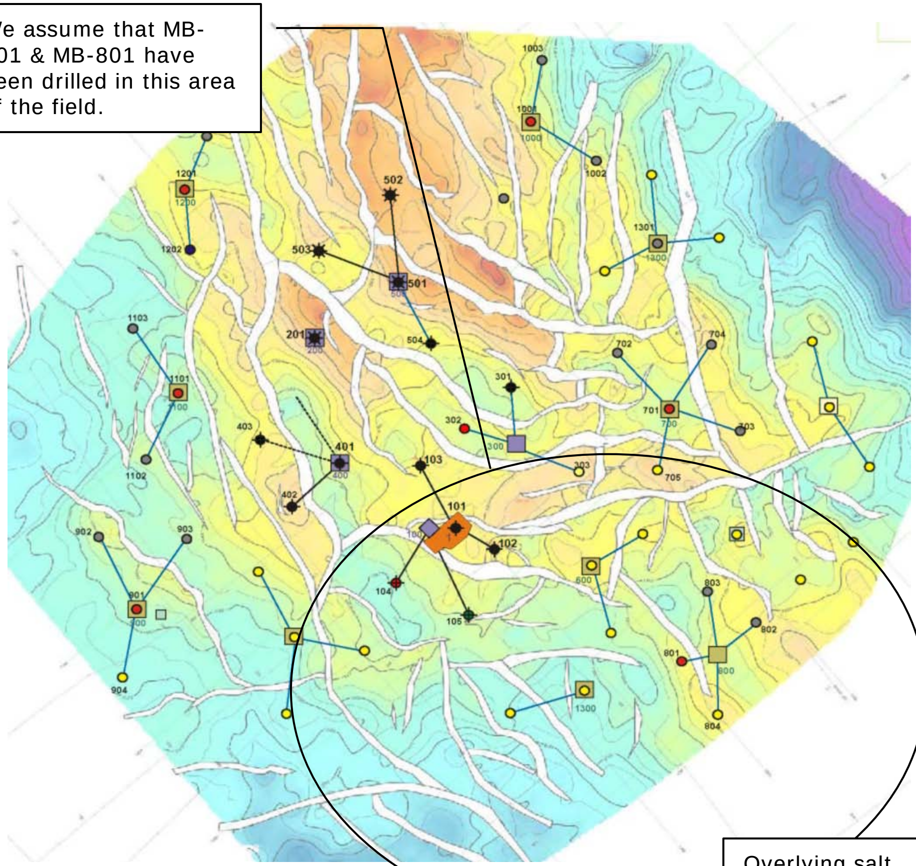
- The Kouakouala Field is productive from sub-salt Aptian age reservoirs comprised of the Vandji sandstones and conglomerates. These reservoirs were deposited on top of granitic and metamorphic basement during the early phase of rifting (see cross section left).
- The Vandji formations are relatively new (although geologically older) as oil bearing discoveries in this part of Africa as compared to the existing Tertiary horizons offshore.
- The potential for Vandji sandstones appears to be improving judging by the results achieved by Burren and M&P on the nearby M'Boundi field.
- Other sub-salt reservoirs include the Djeno sandstones and conglomerates, the Mengo sandstones (productive at the Mengo Field), and the Pointe Noire sandstones (oil-bearing at Kouakouala Field).
- The Kouakouala traps are sealed by the Sialivakou shales.
- The Vandji Formation is made up of four Zones as shown below left.
- The Kouakouala Field structure is further segmented by two synthetic faults also trending northwest-southeast and two northeast-southwest trending faults downthrowing to the northwest and southeast respectively.
- For evaluation purposes, the structure is segmented into 3 areas comprised of the Kouakouala-A Central proved area (where the three producing wells are located), Kouakouala-B Northeast Probable area, and Kouakouala-C Southwest possible area.
- Reservoir rock properties for the Kouakouala Field are as follows: porosity ranged from 16%-19% (good), and permeability ranged from **1 md to 50 md (poor).**
- Total net pay thicknesses per reservoir ranged from 35 to 138 feet. The area is characterized by a normal geothermal gradient giving a formation temperature of around 76°C at 5,000 ft.
- The reservoirs are normally pressured based upon initial reservoir pressures exhibiting a geopressure gradient of 0.46 psi/ft. The field produces a crude averaging 39 degree API gravity (very good quality).
- The reservoirs will ultimately produce through solution gas drive and partial water drive mechanisms.

Conclusion – Vanji sandstone play low risk with generally good upside.

M'Boundi Field (Congo)

M'Boundi top surface map

We assume that MB-701 & MB-801 have been drilled in this area of the field.

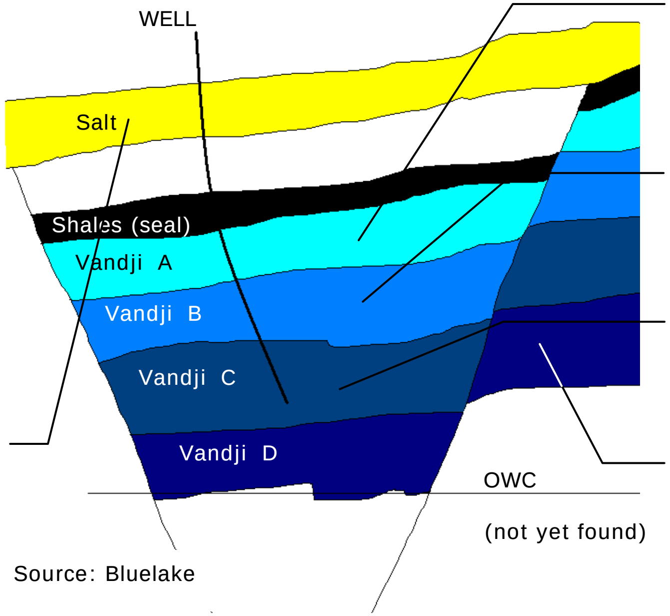


Overlying salt makes seismic interpretation difficult

Source: Burren Energy

Commentary

- It should be clear from the diagram on the left that the M'Boundi field is highly faulted and fractured.
- This makes recovery factors more important than oil in place estimates as the development reached a point where it is sub-economic to extract all the potential reserves.
- There are approximately 14 producing wells on M'Boundi at present and current production is about 15,000b/d from the field.
- Demonstrable productivity from existing wells is therefore about 1,000b/d.
- **On recent testing, MB-801 produced at 1540b/d from a 48m Vandji sandstone section and MB-701 4000b/d from a 77m section.**
- There is evidence therefore that higher productivity (albeit from a larger perforated section) can be obtained from the Vandje-B section.
- 1500b/d may be a reasonable assumption for newly perforated wells.



Carbonate reservoir, could have reservoir potential but unlikely.

Secondary formation tested by MB-801 and MB-701

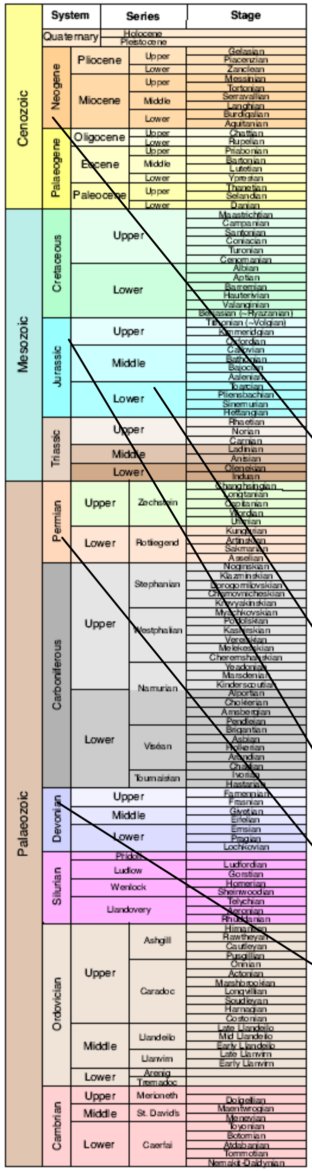
This is the main productive reservoir in the rest of the field

Uncertainty on reserves created by the faultig and potential 'up-dip' reserves

Source: Bluelake

Appendices

Geological Time



Commentary

- Geological time is often used to describe the time at which a depositional basin was being created.
- Since hydrocarbons form from organic material trapped without oxygen (therefore unable to 'rot'), these conditions usually occur under water where massive quantities of particulate material is flowing into a sea or lake.
- The geological time marks when these conditions were present.
- The quality of the present day oil reservoir is enhanced when:
  - coarse grains of sand or limestone compress to form conglomerates with many connected pores.
  - Larger grains of particles form well sorted packages of sand or limestone.
  - The particles are 'clean' e.g. not mixed with layers of clay or mud (although this is required to produce the source and seal material).
- There is no pattern of better hydrocarbon prospectivity with depth/time. Every depositional environment is different.
- Geologists attempt to re model the depositional environment (estuary, lake or river bed) where deposition was taking place to find the best reservoir.
- But reservoir is only on element of the oil equation – we also need source, migration and trap as we have shown on the following pages.

Niger Delta field produce from here.

Prolific in the Northern North Sea with the famous 'Brent' group of sandstones – **B**room-**R**annoch-**E**tive-**N**ansen-**T**arbett

Prolific in Saudi Arabian Upper Jurassic Arab-D formation of the Supergiant Ghawar field.

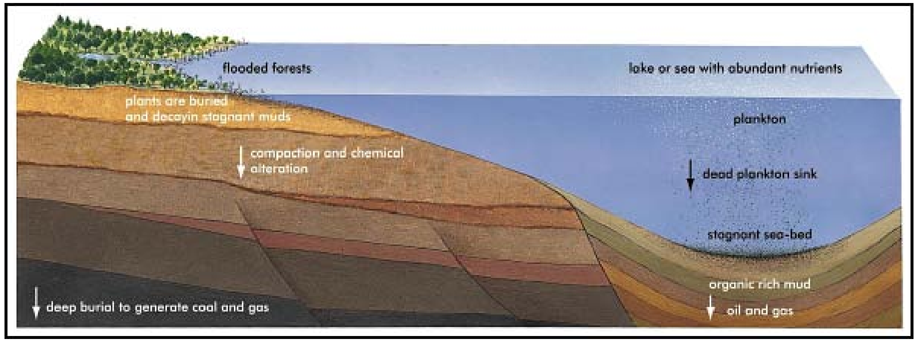
Prolific in the Southern North Sea gas fields.

Devonian plays are prolific in the Timan Pechora basins of Northern Russia.

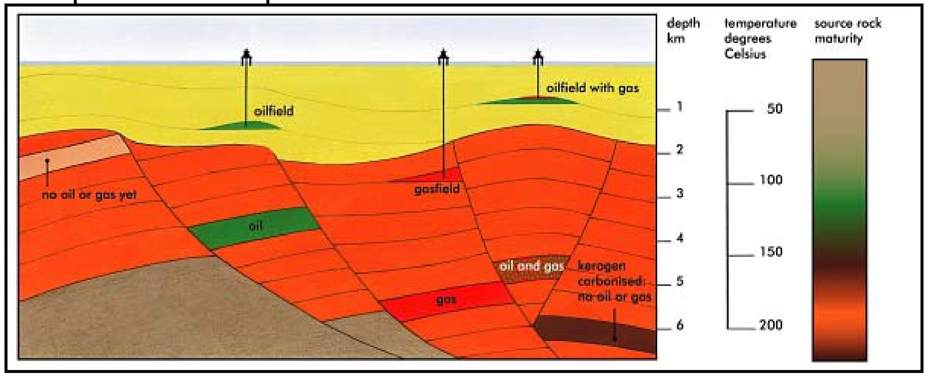
Source: PESGB Millenium Atlas

Source

Oil Source Material



Temperature Dependence

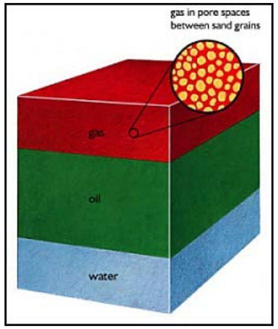


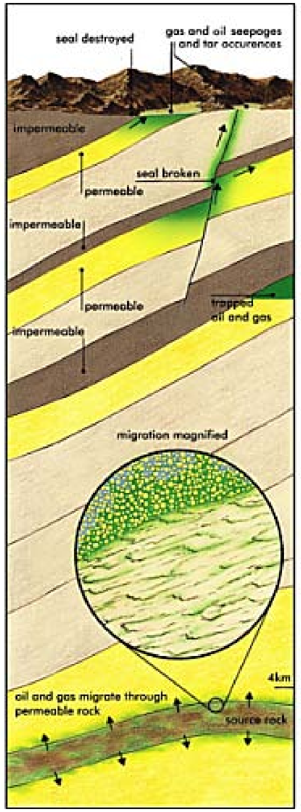
Source Rock Generation

- Oil and gas are derived almost entirely from plankton, decayed plants and bacteria. Energy from the sun has been recycled into useful energy in the form of hydrocarbon compounds.
- Plant and Plankton remains must first be trapped and preserved in sediments (without oxygen), then be buried deeply and slowly 'cooked' to yield oil or gas. Rocks containing sufficient organic substances to generate oil and gas in this way are known as source rocks.
- Dead plants usually are dispersed and decay rapidly, but in areas such as swamps, lakes and poorly oxygenated areas of the seafloor, vast amounts of plant material accumulate. Bacteria breaking down this material may use up all available oxygen, producing a stagnant environment. The plant and bacteria remains become buried and preserved in muds. In swamps the remains may form coals on burial.
- Oil forms from the buried remains of minute aquatic algae and bacteria, but gas forms if these remains are deeply buried. The stems and leaves of buried land plants are altered to coals. Generally these yield no oil, but again produce gas on deep burial.
- Britain's offshore and gas originates from two sources. Gas from beneath the southern North Sea and the Irish Sea formed from coals which were derived from the tropical rain forests that grew in the Carboniferous Period, about 300 million years ago.
- Oil and most gas under the central and northern North Sea and west of the Shetland Islands formed from the remains of planktonic algae and bacteria that flourished in tropical seas of the Jurassic and Cretaceous Periods, about 140 to 130 million years ago. They accumulated in muds, which are now the prolific Kimmeridge Clay source rock.
- On burial the carbohydrates and proteins of the plant remains are destroyed and the remaining organic compounds form kerogen.
- The processes of oil and gas formation resemble those of a kitchen where the rocks are slowly cooked. Temperatures within the Earth's crust increase with depth so that sediments, and kerogen which they contain, warm up as they become buried under thick piles of younger sediments.

Source: UKOOA

Migration





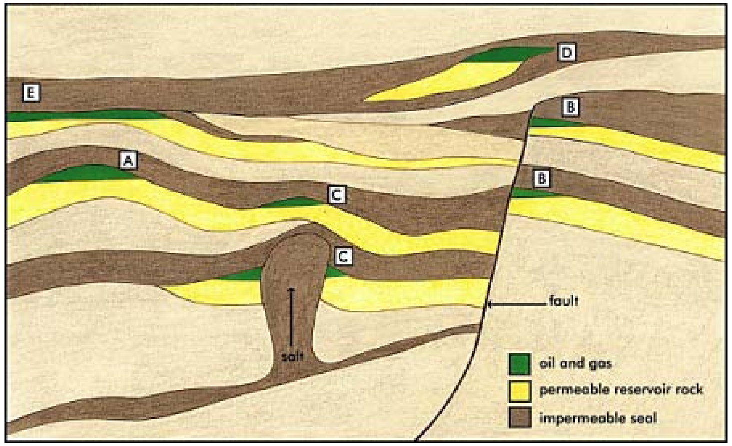
Migration Commentary

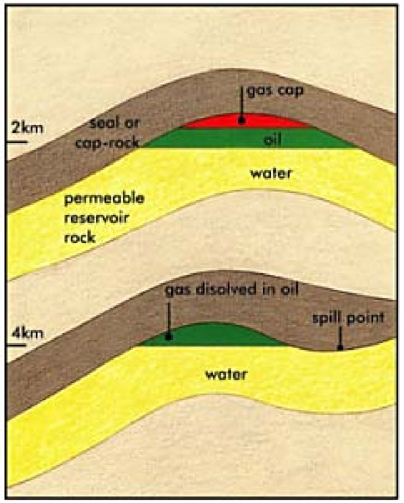
- Oil and gas moves away or migrates from the source rock. Migration is triggered both by natural compaction of the source rock and by the processes of oil and gas formation. Most sediments accumulate as a mixture of mineral particles and water. As they become buried, some water is squeezed out and once oil and gas are formed, these are also expelled. If the water cannot escape fast enough, as is often the case from muddy source rocks, pressure builds up. Also, as the oil and gas separate from the kerogen during generation, they take up more space and create higher pressure in the source rock. The oil and gas move through minute pores and cracks which may have formed in the source rock towards more permeable rocks above or below in which the pressure is lower.
- Oil, gas and water migrate through permeable rocks in which the cracks and pore spaces between the rock particles are interconnected and are large enough to permit fluid movement. Fluids cannot flow through rocks where these spaces are very small or are blocked by mineral growth; such rocks are impermeable. Oil and gas also migrate along some large fractures and faults which may extend for great distances if, or when as a result of movement, these are permeable.
- The industry measure of the ability of oil to flow in rocks is called permeability (k) and the pore volume in rocks is known as porosity (Φ).
- Oil and gas are less dense than the water which fills the pore spaces in rocks so they tend to migrate upwards once out of the source rock. Under the high pressures at depth gas may be dissolved in oil and vice versa so they may migrate as single fluids. These fluids may become dispersed as isolated blobs through large volumes of rock, but larger amounts can become trapped in porous rocks. Having migrated to shallower depths than the source rocks and so to lesser pressures the single fluids may separate into oil and gas with the less dense gas rising above the oil. If this separation does not occur below the surface it takes place when the fluid is brought to the surface. Water is always present below and within the oil and gas layers, but has been omitted from most of the diagrams for clarity.
- Migration is a slow process, with oil and gas traveling between a few kilometers and tens of kilometers over millions of years. But in the course of many millions of years huge amounts have risen naturally to sea floors and land surfaces around the world. Visible liquid oil seepages are comparatively rare, most oil becomes viscous and tarry near the surface as a result of oxidation and bacterial action, but traces of natural oil seepage can often be detected if sought.

Source: UKOOA

Trapping & Reservoir

Trapping





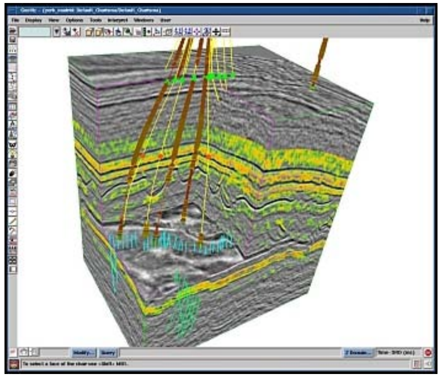
Commentary

- Oilfields and gasfields are areas where hydrocarbons have become trapped in permeable reservoir rocks, such as porous sandstone or fractured limestone. Migration towards the surface is stopped or slowed down by impermeable rocks such as clays, cemented sandstones or salt which act as seals.
- Oil and gas accumulate only where seals occur above and around reservoir rocks so as to stop the upward migration of oil and gas and form traps.
- The migrating hydrocarbons fill the highest part of the reservoir, any excess oil and gas escaping at the spill point where the seal does not stop upward migration. Gas may bubble out of the oil and form a gas cap above it; at greater depths and pressures gas remains dissolved in the oil. Reducing reservoir pressure so that gas comes out of solution is known as a 'blow down'.
- Since few seals are perfect, oil and gas escape slowly from most traps. In many fields' incoming oil and gas balance this loss, as in the Brent and Ekofisk fields in the North Sea. Gas migrates and escapes from traps more readily than oil, but the salt layers beneath the southern North Sea where much gas is trapped have proved a very efficient seal because salt contains no pore spaces, and fractures reseal themselves.
- Structural traps are formed where rocks are folded into suitable shapes (A) or reservoir and sealing rocks are juxtaposed across faults (B). Traps may also form when rocks are domed over rising salt masses (C). Stratigraphic traps originate where a suitable combination of rock types is deposited in a particular environment (D), for example, where a reservoir rock of permeable river sand is sealed by clays accumulated in the swamps which formed to cover the river channel. In reality most traps are formed by more complex sequence of events and cannot be classified so rigidly. For example (E), the reservoir rock was first folded and eroded, then sealed by an impermeable rock which was deposited later over the eroded structure. Where a particular set of circumstances has combined to produce a group of oil or gasfields with similar trap structures or reservoir rock, this is termed a play.
- Reservoir quality is defined by the thickness of the sand/limestone formation and areal extent. The amount of hydrocarbon held in the pores of the rock is a function of the porosity. The rate at which hydrocarbon can be produced is a function of the rock permeability and the drive mechanism.
- Reservoir drive is either:
  - primary: under expansion of the hydrocarbon under pressure
  - secondary: from adjacent gas or water expansion drive
  - tertiary: by man-made CO_2 injection or other chemical/man made means.

Source: UKOOA

Exploration & Production Basics

Field Exploration



Exploration

- Exploration was once the realm of the oil majors as it required highly specialized seismic interpretation techniques that tended to be proprietary.
- With these techniques made available to small and independent E&P's exploration can now be carried out by the smaller companies.
- The advantage a smaller company has is that it can get in early to a new minor province and drill under its own negotiated terms before bringing in major later (Ramco-Caspian, Cairn-India).
- The most prolific exploration basins in deepwater Africa, NW Shelf Australia and the Caspian are still the preserve of the oil majors owing to the attractiveness.
- The exploration process can be summarized:
  - sign exploration concession
  - shoot seismic (usually 2-D)
  - drill exploration 'wild cat'
  - test potential discovery (flow test, formation samples and pressures)
  - Possibly shoot 3-D seismic
  - Appraisal drilling
- If is important to look at the drilling success rate when assessing an oil company and to look at the amount of hydrocarbon reserves added through exploration v purchase.

Development

- In the Development phase a number of producing and possibly injection wells are drilled.
- The injection wells may be used to pump I water/gas to maintain pressure.
- The well 'heads' are tied back to a platform or sub-sea processing facility where oil/gas/water are separated for transportation.
- Oil is easily developed in any remote location as a shuttle tanker can easily ship away the crude.
- Gas usually requires a local market with a direct pipeline.
- However, since the development of global spot gas markets, in large quantities (5tcf+) gas can be liquefied in an LNG plant and transported in the liquid state.
- Since the UK gas reserves are depleting fast new sources of gas to the UK will become an imperative, either by pipeline from the continent or into any of the LNG receiving terminals currently under construction around the UK.
- It is important to monitor the development costs of companies involved in this phase of the business and to look at the amount of hydrocarbon produced for the development investment.
- Currently, many of the E&P's listed in the UK focus on reserves in the ground but few address the issues of developing the hydrocarbon and producing cash flow and hence an investment return.
- We believe that the ability to monetize reserves will become more important in the sector.

Terminology

Anticline:
A fold in layered rocks originating below the surface in the form of an elongated dome. Anticlines make excellent drilling prospects since any oil in the deposit will naturally rise to the highest point of the structure because oil has a lower specific gravity than water.

API
American Petroleum Institute. The primary U.S. oil industry trade association, based in Washington, D.C. API conducts research and sets technical standards for industry equipment and products from wellhead to retail outlet. It also compiles statistics which are regarded as industry benchmarks.

API gravity:
The American Petroleum Institute scale used to express the specific gravity of oils.

Barrel of oil:
Measurements which equal a barrel of oil include 159 liters, 0.159 cubic meters, 35 Imperial gallons, 42 U.S. gallons.

Barrel of oil equivalent (boe):
A term frequently used to measure oil and gas on a comparative basis. In Canada, 10 mcf of natural gas is equivalent to one barrel of oil.

Barrel of oil per day (bpd):
The number of barrels of oil produced from a well over a 24 hour period, normally an average figure from a longer period of time.

Bcf: Billion cubic feet.

B/D: Barrels per Day. Usually used to quantify a refiner's output capacity or an oilfield's rate of flow.

Block:
The subdivision of exploration and production acreage.

Blowouts:
Uncontrolled releases of fluids, solids, or gases.

Book value per share:
Calculated by dividing owners equity by the number of shares outstanding. This accounting calculation is typically considerably lower than the actual share price because accounting principles require the use of historical cost. Book value per share is an estimation of what the company is worth if it were to be liquidated.

British thermal unit (BTU):
The amount of heat required to increase the temperature of a pound of water 1o Fahrenheit. A Btu is used as a common measure of heating value for different fuels. Prices of different fuels and their units of measure (dollars per barrel of crude, dollars per ton of coal, cents per gallon of gasoline, cents per thousand cubic feet of natural gas) can be easily compared when expressed as dollars and cents per million BTUs.

Casing:
The process of lining a drilled hole with steel pipe which is cemented in place to prevent caving in of the hole

Completion:
The procedure by which a successful well is readied for production

Condensate:
Any mixture of relatively light hydrocarbons which remain liquid at normal temperature and pressure. Condensate generally appears when gas is drawn from a well and its temperature and pressure change sufficiently for some of it to become liquid petroleum.

Cubic feet per day (cf/d):
The number of cubic feet of natural gas produced from a well over a 24 hour period, normally an average figure from a longer period of time. Generally expressed as mcf/d = thousand cubic feet per day, mmcf/d = million cubic feet per day, or bcf = billion cubic feet per day.

Drilling mud:
A mixture of clays, water, and chemicals used in drilling operations to lubricate and cool the drill bit, carry drilling wastes to the surface, prevent the walls of the well from collapsing, and to keep the upward flow of oil or gas under control.

Drill string:
Steel pipes roughly 10m long joined together to form a pipe from the drill bit to the drilling platform. It is rotated during drilling and is also the conduit for the drilling mud.

Dry gas:
Gas containing no water vapor, same as lean gas.

Enhanced oil recovery (EOR):
The recovery of oil from a reservoir other than by the use of natural reservoir pressure. This can involve increasing the pressure (secondary recovery) or heating or increasing the pore size of the reservoir (tertiary recovery).

Farm-in:
An outside party paying a land owner all or a percentage of the drilling costs of a well in order to obtain a working interest in the land or well.

Farm-out:
The land owner gives a percentage of his land or a portion of his working interest in a well in order to allow an outside party to drill or explore on his property. This generally reduces risk as capital is provided by the company farming-in.

Fault:
A geological structure consisting of a fracture in the rock along which there has been an observable amount of displacement.

Gas cap:
In a field containing both gas and oil, some gas will often collect at the top of the reservoir in a single deposit known as a gas cap.

Heavy crude:
Oil with a gravity below 28 degrees API. Recovery generally involves an application of heat and steam. Canadian pipelines generally require oil to have a gravity of at least 21:2 degrees API. Heavier crudes must be blended with condensate or NGLs to be shipped by pipeline.

Independent:
Term generally applies to a non-integrated oil or natural gas company, usually active in only one or two sectors of the industry. An independent marketer buys petroleum products from major or independent refiners and resells them under his own brand name or buys natural gas from producers and resells it. There are also independents which are active exclusively either in oil or gas production or refining.

Infill drilling:
Drilling more wells into the same pool so that oil does not have to travel as far through the rock.

Injection well:
A well used for injecting fluids into a formation in an attempt to increase recovery efficiency.

Light crude:
Oil with a gravity of 28 degrees API or higher. High-quality light crude has a gravity of 40 degrees or higher.

Liquefied natural gas (LNG):
Natural gas that has been liquefied for ease of transport by cooling the gas to -162·C. Natural gas has 600 times the volume of LNG.

Liquefied Petroleum Gas (LPG):
Propane, butane, or propane-butane mixtures derived from crude oil refining or natural gas fractionation. For convenience of transportation, these gases are liquefied through pressurization.

Mcf:
Thousand cubic feet.

Natural Gas Liquids (NGL):
A general term for all liquid products separated from natural gas in a gas processing plant. NGLs include propane, butane, ethane, and natural gasoline.

Net Asset Value per Share (NAVPS):
Is the estimated worth of the company based on the current market value of all its assets less liabilities. Calculated by taking the present value of the company's reserves, subtracting long-term debt, and adding working capital. Usually discounted by 10-15%.

Netback:
The amount of money received per barrel of oil equivalent produced after subtracting operating costs, royalties, and general and administrative costs.

Net debt:

Long-term debt plus working capital.

Non-associated Gas:
Natural gas in a reservoir which contains no crude oil.

Oil in place:
The estimation of the real amount of oil in a reservoir.

OPEC:
Organization of Petroleum Exporting Countries.

Operator:
The party responsible for exploration, development, or production projects

Permeability:
The capacity of a reservoir rock to transmit fluids.

Porosity:
The open space within a rock, similar to a sponge.

Possible reserves:
An estimate of possible oil and/or gas reserves based on geological and engineering data from undrilled or untested areas.

Probable reserves:
An estimate of oil and/or gas reserves based on penetrated structures, but needing more advanced confirmation to be classified as proven reserves.

Proven reserves:
The quantity of oil and gas estimated to be recoverable from known fields under existing economic and operating conditions. Determined on the basis of drilling results, production, and historical trends.

Recoverable reserves:
The proportion of hydrocarbons that can be recovered from a reservoir using existing techniques

Reserve life index:
The number of years it would take to deplete proven reserves at the current production rate.

Reserve replacement ratio:
The quantity of added reserves for every barrel of oil equivalent produced.

Reservoir:
Porous permeable rock containing petroleum.

Rich gas:
Gas which is predominately methane but with a relatively high proportion of other hydrocarbons.

Seismic:
Either two-dimensional or three-dimensional, computer assisted processing of sedimentary structures, assist in planning drilling programs.

Solution gas:
Natural gas which is dissolved in the crude oil within the reservoir.

Sour or Sweet Crude:
Industry terms which denote the relative degree of a given crude oil's sulfur content. Sour crude refers to those crudes with a comparatively high sulfur content, 0.5% by weight and above; sweet refers to those crudes with sulfur content of less than 0.5%.

Sour gas:
Contain large amounts of hydrogen sulphide or sulphur. In order to become sweet gas, the sulphur must be removed.

Spot market:
An international market in which oil or oil products are traded for immediate delivery at the current price.

Spud:
The commencement of drilling operations.

Underbalanced drilling:
Occurs when the operator of the site uses specialized mud or gas while drilling to allow for formation fluids to rise to the surface and thus prevent

damage to the prospective formation.

Unitization:
Owners of adjoining properties pool reserves together to form a single producing unit in which each has an interest.

Upstream industry:
Produces petroleum, also referred to as upstream sector; namely, exploration and development companies, seismic ,and drilling contractors, service rig operators, engineering firms, etc.

Viscosity:
The resistance to flow or "stickiness" of a fluid.

Wellhead:
The control equipment fitted to the top of the well consisting of outlets, valves, blowout preventors, etc.

Wet Barrel:
A physical barrel of crude oil or refined product as opposed to a "paper barrel."

Wet Gas:
Natural gas containing condensable hydrocarbons.

Wildcat:
A well drilled in an unexplored area.

Working capital:
Current assets minus current liabilities, shows a company's ability to meet its short-term obligations.

Workovers:
Major repairs or modifications which restore or enhance production from a well.

Source: Canadian Oil & Gas Bulletin