Zacks Small-Cap Research

September 12, 2014

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Taipan Resources Inc. (V.TPN-TSX-V)

V.TPN: Initiating coverage of Taipan Resources with Outperform rating

Current Recommendation	**Outperform**
Prior Recommendation	N/A
Date of Last Change	09/10/2014
Current Price (09/11/14)	$0.39
Six- Month Target Price	**$0.87**

OUTLOOK

Taipan Resources is an oil & gas exploration company which holds material working interests in two onshore blocks (Block 1 and Block 2B) in Kenya. Block 2B has a NI 51-101 estimate of Gross Mean Un-risked Prospective Resources of 1,593 MMBOE and an NI 51-101-compliant estimate on Block 1 is expected in the near future. Exploratory wells on both properties are expected to spud in the next 12 months, for which Taipan is fully funded. With Taipan Resources offering exposure to the potential opening of a new major oil play in East Africa, coverage is initiated with an Outperform rating with a price target of $0.87.

SUMMARY DATA

52-Week High	**$0.66**
52-Week Low	**$0.23**
One-Year Return (%)	**34.48**
Beta	**N/A**
Average Daily Volume (shrs.)	**277,100**
Shares Outstanding (million)	**106.8**
Market Capitalization ($mil.)	**$41.7**
Short Interest Ratio (days)	**N/A**
Institutional Ownership (%)	**12.0**
Insider Ownership (%)	**11.0**
Annual Cash Dividend	**$0.00**
Dividend Yield (%)	**0.00**
5-Yr. Historical Growth Rates	
Sales (%)	**N/A**
Earnings Per Share (%)	**N/A**
Dividend (%)	**N/A**
P/E using TTM EPS	**N/M**
P/E using 2014 Estimate	**N/M**
P/E using 2015 Estimate	**N/M**
Zacks Rank	**N/A**

Risk Level	**Above Average**
Type of Stock	**Small-Value**
Industry	**Oil-C$ E&P**
Zacks Rank in Industry	**N/A**

ZACKS ESTIMATES

Revenue
(in millions of $CDN)

	Q1 (Jan)	Q2 (Apr)	Q3 (Jul)	Q4 (Oct)	Year (Oct)
2012	0.0 A	0.0 A	0.0 A	0.0 A	0.0 A
2013	0.0 A	0.0 A	0.0 A	0.0 A	0.0 A
2014	0.0 A	0.0 A	0.0 E	0.0 E	0.0 E
2015					0.0 E

Earnings per Share
(EPS is operating earnings before non recurring items)

	Q1 (Jan)	Q2 (Apr)	Q3 (Jul)	Q4 (Oct)	Year (Oct)
2012	-$0.00 A	-$0.00 A	-$0.03 A	-$0.02 A	-$0.05 A
2013	-$0.04 A	-$0.09 A	-$0.02 A	-$0.05 A	-$0.19 E
2014	-$0.00 A	-$0.00 A	-$0.01 E	-$0.02 E	-$0.04 E
2015					-$0.08 E

Zacks Projected EPS Growth Rate - Next 5 Years % **N/A**

Quarterly EPS may not equal annual EPS total due to rounding.

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KEY POINTS

- Taipan Resources offers exposure to the potential opening of a new major oil play in East Africa.
- Taipan is an oil & gas exploration company which holds working interests in two onshore blocks (Block 1 and Block 2B) in Kenya.
- Management is focusing on prospective Tertiary and Cretaceous hydrocarbon plays in onshore Kenya that have similar geological settings to those in East Africa that have yielded oil and/or gas discoveries in Uganda, Sudan, Ethiopia and Kenya.
- **Block 2B**
  - A NI 51-101-compliant report on **Block 2B** was completed in February 2014, which increased the estimates of the **Gross Mean Un-risked Prospective Resources by 288% to 1,593 MMBOE**.
  - Though Block 2B is considered a potential Cretaceous play since the Anza Basin is on trend with the analogous producing systems in Sudan, management firmly believes the thick Tertiary sand beds will prove analogous to recent oil discoveries in commercial quantities at the "*String of Pearls*" in the Lokichar Tertiary Basin. Block 2B has similar structures and is expected to have similar oil-prone source and sealing rocks to the Lokichar.
  - The spudding of an exploration well at the **Badada Prospect** in Block 2B is planned for the end of 2014 or early 2015. The well will target a structural lead at the basin's edge and test the prospective Tertiary and Cretaceous formations.
  - On June 24, 2014, Africa Oil announced that its 3,030-meter Sala-1 well on Block 9 in the Anza Basin encountered three zones of interest. The upper gas-bearing interval tested dry gas at a maximum rate of 6 MMCFPD from a 25-meter net pay interval and the lower interval tested at lower rates of dry gas from a 50-meter potential net pay interval. The Sala-1 well is located approximately 83 km northwest of **Taipan's** Badada Prospect.
- **Block 1**
  - Taipan has begun the process of **commissioning a NI 51-101-compliant report** on Block 1. The report is expected to be released during the fourth quarter of 2014.
  - An exploration well on either the **El Wak** or **Khorof Prospect** is planned for spudding in the second half of 2015.
- Recent Financings
  - In June 2014, Taipan received $4.5 million from the farm-out of 15% participating interest in Block 2B to Tower Resources.
  - A private placement of Units completed in April 2014 provided net proceeds of $6.11 million.
- Taipan Resources is **fully funded** through the drilling of the first exploratory wells on Block 1 and Block 2B.
  - The private placement of Units completed in April 2014 provided sufficient funds to resolve any perceived encumbrance on its rights and entitlements to a 20% participating interest in Block 1 and also to fund its participating interest share of costs in drilling the first exploration well.
  - Through a farm-out agreement on Block 2B, Premier Oil is paying Taipan's working interest share for drilling the first exploratory well (Badada-1) in the block.
- The drilling of exploratory wells in Kenya by Tullow Oil, Africa Oil, Marathon, etc. has created much interest and speculation in the oil plays of East Africa.
- News concerning exploration wells drilled in the Anza Basin will most likely also have a meaningful impact on Taipan's stock.
- In May 2014, Taipan's stock was up-listed to the OTCQX, the OTC market's highest tier.
- Coverage is initiated on Taipan Resources with an Outperform rating.

OVERVIEW

With its head office in Nairobi Kenya and records office in Vancouver Canada, Taipan Resources Inc. (TPN: TSX-V and TAIPF: OTCQX) is an oil & gas exploration company with interests in two onshore

blocks in Kenya. Taipan holds a **30% participating interest in Block 2B** and a **20% participating interest in Block 1**. Both blocks are highly prospective oil & gas exploration properties that are held through Production Sharing Contract (PSC) agreements with the Government of Kenya through the company's wholly owned subsidiary, Lion Petroleum Corp.

Taipan Resources is participating in the under-explored frontier area of the nascent oil province of Kenya, which has the potential to become a major world-class oil play. The first major oil discovery in Kenya was the Ngamia-1 well drilled by the Tullow Oil (TLW: LSE) in the East Africa Rift system during March 2012. Since then, Tullow has drilled an additional six successful wells based on the "*String of Pearls*" concept. Every successful discovery well (or even a well with significant oil shows) to some extent de-risks East Africa's oil & gas potential.

Holding material positions in two blocks, Taipan Resources is positioned to participate in the opening of Kenya as part of the East Africa oil province. With technical understanding of the complex East African basins still evolving, Taipan is among the vanguard of exploration companies in pursuit of new oil & gas plays with potentially very high upside.

Though no reserves have been assessed for these blocks, **Prospective Petroleum Resources** from yet undiscovered accumulations have been estimated. In February 2014, Taipan Resources announced details of Sproule International's independent assessment of the prospective resources on Block 2B exploration property with an effective date of December 31, 2013. Based on 19 exploration leads, the total estimated **Mean Gross Unrisked Prospective Resources** on **Block 2B increased 288%** from 410.4 MMBOE to **1,593 MMBOE** from the prior estimation. This most recent NI 51-101-compliant Prospective Resource Estimate incorporated the interpretation of 439 km of 2D seismic data acquired in early-2013 and the interpretation of reprocessed vintage seismic data.

Taipan Resources

Summary of Licenses and Prospective Oil Resources

Country	License	Taipan's Working Interest (%)	Operator	Operator Working Interest (%)	Other Farm-in Partners	Partner Working Interest (%)	Gross Area (km2)	Gross Unrisked Prospective Est. (Mean) (MMBOE)	Net Unrisked Prospective Est. (Mean) (MMBOE)	51-101 Estimate Effective Date
Kenya	Block 1	**20%**	EAX (Afren plc)	80%	none	N/A	22,564	2,422	484	N/A
Kenya	Block 2B	**30%**	Taipan Resources	30%	Tower Resources Premier Oil	55% 15%	5,464	1,593	478	31-Dec-2013

A NI 51-101-compliant Prospective Resource Assessment has not yet been completed on Block 1, but one is expected which will utilize the 1,900 km of 2D seismic data acquired during 2012, along with the 10,696 km airborne high resolution gravity and magnetic survey conducted in 2011. However, Afren has provided an in-house estimate of **2,422 MMBOE** for **Gross Mean Unrisked Prospective Resources** on **Block 1**.[i]

The management of Taipan Resources anticipates the **completion of two exploration wells in the next 12 months**: one at the **Badada Prospect** in Block 2B and the other at either the **El Wak** or **Khorof Prospect** in Block 1. **Taipan Resources is fully funded through the drilling of both exploratory wells**. In Block 2B, the company's 30% working interest share of the costs of drilling and testing the Badada prospect are being paid by Premier Oil plc (PMO: LSE) as part of the farm-out agreement[ii]. In Block 1, Taipan's costs have been funded both by a portion of the net proceeds from the recent private placement of 18,002,777 Units and by $4.5 million cash payment from the farm-out of the 15% participating interest in Block 2B to Tower Resources (TRP: LSE).

Having traded on the TSX Venture Exchange (TSXV) with the symbol TPN since the company's IPO in February 2007, Taipan Resources began trading on the OTCQX in May 2014 under the symbol TAIPF.

Merger with Lion Petroleum Corp.

In July 2012, Taipan Resources closed the amalgamation with Lion Petroleum Corp. Shareholders and convertible bridge loan holders of Lion Petroleum received 20,124,817 shares of Taipan Resources, which post-merger represented 39.1% of surviving company. As part of the amalgamation, Taipan Resources provided irrevocable bank guarantees to fund the required work program on Block 2B, along with other commitments on Block 1.

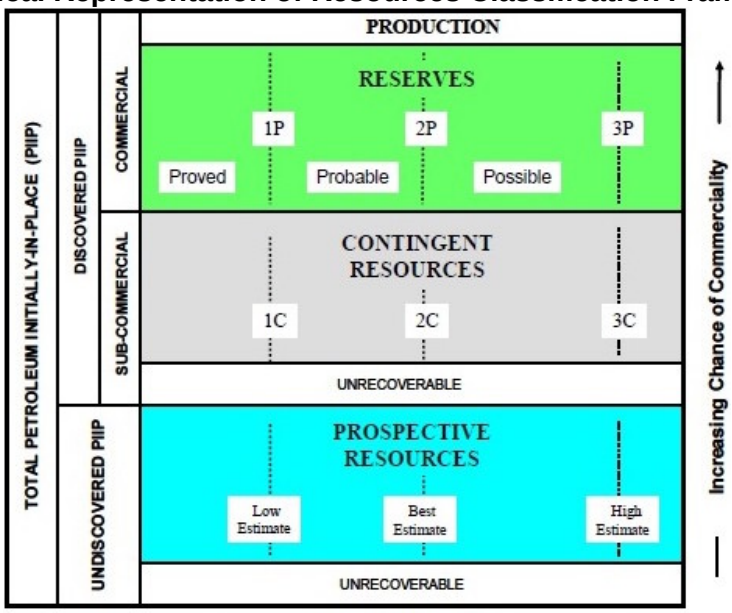
Lion Petroleum had been granted Production Sharing Contract (PSC) agreements by the Ministry of Energy, Republic of Kenya for 100% participating interest in Block 1 (initially comprised of 31,781 km2) in November 2007 and for 100% participating interest in Block 2B (7,807 km2) in September 2008. [N.B. Subsequently, Taipan Resources farmed out 80% interest in Block 1 and 70% interest in Block 2B. In addition, mandated relinquishments reduced the area of both blocks by 30%]

When merged with Lion Petroleum in 2012, total Net Unrisked Prospective Resources on the blocks were **528 MMBOE** based upon the NI 51-101 report prepared by Sproule Associates Limited for Block 2B (387 MMBOE) and by the management of Afren Plc for Block 1 (141 MMBOE).

PROSPECTIVE RESOURCE PRIMER

For those unfamiliar with NI 51-101 prospective resource terminology, "**prospective resources** are those quantities of oil and gas estimated on a given date to be potentially recoverable from undiscovered accumulations"[iii] by application of future development projects. "Prospective resources have both an associated chance of discovery and a chance of development,"[iv] Furthermore, prospective resources are referred to as "the recoverable portion of undiscovered petroleum initially-in-place."[v] **The key elements of prospective resources** are that **they are undiscovered, yet deemed potentially recoverable since they are considered to be "technically viable and economic to recover"**[vi] under existing economic conditions, operating methods and government regulations. However, "prospective resources are estimates of volumes that are recoverable or potentially recoverable and, as such, cannot be described as being 'in-place.' Terms such as 'potential reserves,' 'undiscovered reserves,' 'reserves in place,' 'in-place reserves' or similar terms must not be used because they are incorrect and misleading."[vii]

Graphical Representation of Resources Classification Framework



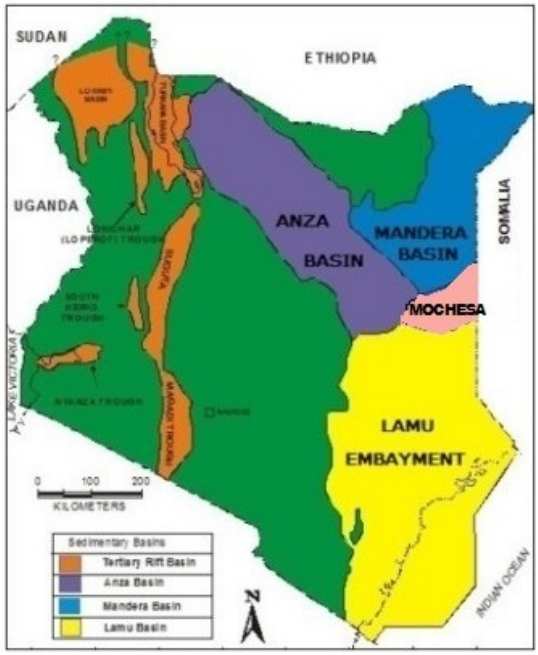
Courtesy of SPE-PRMS

The term "**unrisked**" refers to the fact that the resource estimate has not been risked for two risk components: 1) the probability that any portion of the prospective resources will be discovered and 2) the chance of development. The probability of discovery is based on the geological chance of success. The chance of development incorporates economic, regulatory, market, facility, corporate commitment and political risks. Also, the chance of development would include the degree of certainty as to the commercial viability and the timing of the resource's development.

Gross estimates are determined without consideration of working interests, royalties and other encumbrances. **Net estimates** of resources incorporate the working interest structure of the project, but do not consider royalties. Net estimates of the value of resources do not consider development and future production costs, future abandonment costs and non-property-related expenses, such as general and administrative expenses (G&A), debt service costs and future income tax expense, along with the financial effect of Depreciation, Depletion and Amortization (DD&A) expense. Also, pricing assumptions may or may not be used.

SYNOPSIS OF PROJECTS





Block 2B (northeast Kenya)

Taipan Resources holds **30% equity interest** of the Production Sharing Contract (PSC) on the 1,348,700-acre Block 2B in northeast Kenya. Taipan initially acquired a 100% interest in Block 2B through the merger with Lion Petroleum in July 2012. Subsequently, Premier Oil earned 55% interest through a farm-out agreement in December 2013, and Tower Resources earned 15% through another separate farm-out agreement in June 2014. A partial relinquishment on October 8, 2013 (the PSC's third anniversary) reduced the area by 30% from 7,807 km2 to 5,465 km2 (current net of 1,639 km2 to Taipan Resources).

The 2013 farm-out agreement designates Taipan Resources as the operator during the exploration phase; however, Premier Oil has the right to assume operatorship during the development phase. Taipan Resources is fully funded through the drilling of the first exploratory well (Badada -1) on Block 2B. To date, exploration has been focused on western portion of Block 2B associated with the southwestern extension of the Anza Basin.

Based on gravity, magnetic and seismic data, management believes that Block 2B is the "sweet spot" of the **Anza Basin** with the Badada well having the potential not only to be the Basin's opening well, but also to unlock significant prospective resource value.

Block 1 (northeast Kenya)

Taipan Resources holds a 20% working interest in Block 1, which the company also acquired through the merger with Lion Petroleum. EAX, a wholly-owned subsidiary of Afren plc, holds the remaining 80% working interest and is the operator of the project. Situated in the Mandera-Lugh Basin, Block 1 currently encompasses 22,246 km2 (net 4,449 km2), having undergone a partial relinquishment that reduced Block 1 from its original area of 31,781 km2.

PROSPECTIVITY OF EAST AFRICA

There is a concerted effort to discover oil resources in sedimentary formations in the **rift basins of East Africa**. Fueled by a series of impressive oil discoveries, notably in the **Ogaden Basin** of Ethiopia (1973), **Muglad Basin** of Sudan (1982), **Melut Rift Basin** of Sudan (2002) and **East Africa Rift Basin** [the last of which includes the **Albertine Rift Basin** of Uganda (in 2005) in the Western Branch and the **Lokichar Basin** of Kenya (2012) in the Eastern Branch], East Africa has emerged as an exciting, prospective oil province.

Despite the comparatively limited seismic data and exploratory drilling results, there is strong evidence that petroleum systems exist in the East African Rift System (Ngamia-1 discovery), Ogaden Basin (Calub Field) the Cretaceous Central African Rift Basin in the southern Sudan (Unity 1, Unity 2, Heglig and Great Palogue fields) and the Eastern African Margin (gas production in Tanzania and Mozambique). All these East Africa basins share many characteristics, including source rocks, reservoirs, seals and structure with other similar rift basins that produce significant volumes of oil and gas, including the North Sea with its reserves of 60 BBO and 2,400+ exploration wells. Taipan's Block 2B overlies the Anza Basin on trend with the Cretaceous Rift Basin while Block 1 extends over the Mandera-Lugh Basin on trend with the Ogaden Basin.

Due to the complex nature of the East African basins, the search for oil resources has not yet evolved to the level of conventional analysis common for mature oil fields. Rather, in this frontier area, the analysis and interpretation of the spatial and temporal evolution of rift development, volcanics and sediment deposition guides the strategic search for prospective resources. Thereafter, seismic survey data is acquired to provide a rudimentary configuration of geologic units. Recently, the key to discovering hydrocarbon deposits in East African Rift System has been the utilization of basin development, depositional analogues and correlation of equivalent strata. Ultimately, it appears that the integration of regional tectonics and a more comprehensive stratigraphic database derived from well data will be the keys to unlocking the true hydrocarbon potential of East Africa. Due to the nature of frontier drilling, the discussion on the elements (source, reservoir and seal rocks) and dynamic processes (trap formation, etc.) of the prospective petroleum systems is still rudimentary.

BLOCK 2B (KENYA)

Overview

Taipan Resources currently holds a **30% equity interest** of the Production Sharing Contract (PSC) on Block 2B. Taipan initially acquired a 100% interest in Block 2B through the merger with Lion Petroleum in July 2012. Subsequently, through farm-out agreements, Taipan granted Premier Oil the ability to earn a

55% of the PSC (and become operator of the project) and Tower Resources to earn 15%. Taipan Resources is the operator during the exploration phase of Block 2B; however, Premier Oil has the right to assume operatorship during the development phase.

Originally, when the Production Sharing Contract (PSC) with the Government of Kenya became effective on December 16, 2008, Block 2B encompassed an area of 7,806.53 km2. A partial relinquishment of 30% occurred on June 1, 2013, the end of the Initial Exploration Period, which reduced the area to 5,464.57 km2. The company opted to surrender the eastern 30% of the block. An additional partial 30% relinquishment is scheduled to transpire before the end of the First Additional Exploration Period, namely before June 1, 2015. **Currently, Block 2B encompasses 5,464.57 km2** (or 1,639.37 to Taipan Resources).

The most recent NI 51-101-compliant report (with an effective date of December 31, 2013) estimates that the **Gross Mean Unrisked Prospective Resources** is **1,593 MMBOE** within the 19 exploration leads. With a 30% working interest, the **Net Mean** Unrisked Prospective Resources of Taipan Resources is **478 MMBOE.**

Taipan Resources is fully funded through the drilling of the first well (Badada-1) and the acquisition of 25 km2 of 3D seismic data on Block 2B under the farm-out agreement with Premier Oil up to $13.265 million.

Location

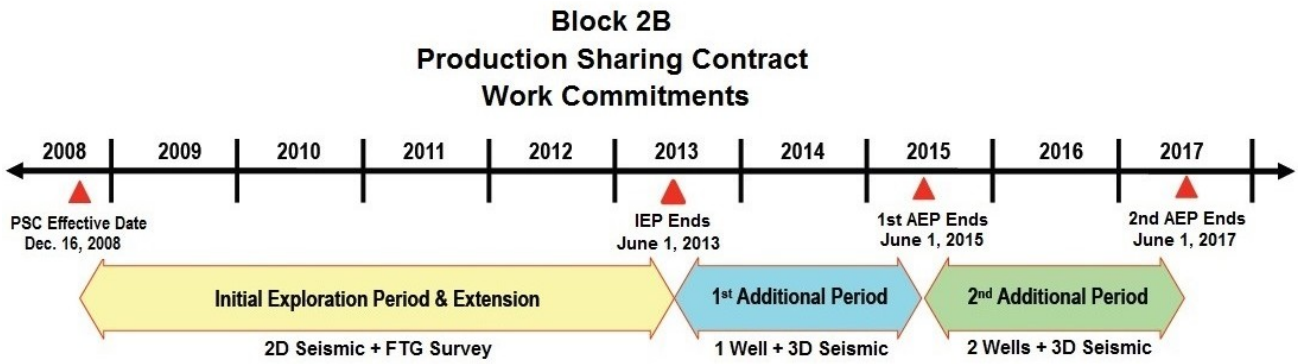
Block 2B is located in northeast Kenya and occupies the area of confluence of the Anza, Mochesa and Mandera-Lugh Basins.

To date, exploration has been focused on western portion of Block 2B that is associated with the southwestern extension of the **Anza Basin** (aka Anza graben[viii]), which management believes has prospectivity similar to **Tertiary Period plays** that are analogous to discoveries located in the Lokichar Basin of the Eastern Branch of the East Africa Rift and to **Cretaceous Period plays** in the Muglad and Melut Basins of southern Sudan.

Ownership

Lion Petroleum was awarded a **Production Sharing Contract** by Government of Kenya for an undivided 100% participating interest in Block 2B on September 17, 2008 with an effective date of December 16, 2008. At the time, Block 2B encompassed 7,806.53 km2. The Production Sharing Contract originally called for a seven-year exploration period consisting of three terms. However, Lion Petroleum negotiated that a study period be established prior to the initiation of the Initial Exploration Period. As a result, the first three-year **Initial Exploration Period** (IEP) began on June 1, 2010 effectively extending the termination date of the IEP to June 1, 2013. The two-year second term, known as the **First Additional Exploration Period**, expires on June 1, 2015, and a third two-year term, known as the **Second Additional Exploration Period** is scheduled to end on June 1, 2017. Upon the declaration of a commercial discovery, the resulting production period will extend up to 25 years.

During the three-year Initial Exploration Period, originally the PSC holder (Lion Petroleum) was obligated to incur $11.75 million in exploration expenditures, including $6.0 million on a contingent well. However, as a result of extending the Initial Exploration Period to June 1, 2013, Lion Petroleum paid a $4.0 million extension fee to the Ministry of Energy and agreed to an amended minimum expenditure obligation of $6.5 million ($4.5 million for a 439 km 2D seismic program and $2.0 million for a block-wide FTG survey). The two-year First Additional Exploration Period requires a minimum expenditure obligation of $13.0 million with the work program to include a 100 km 2D seismic program[ix] and a 3,000-meter exploratory well. During the two-year Second Additional Exploration Period, the PSC holder is obliged to drill two additional exploratory wells, each to a minimum depth of 3,000 meters, along with further seismic work all the while expending a minimum of $19.0 million.



Taipan Resources initially acquired a 100% interest in Block 2B through the merger with Lion Petroleum in July 2012. On October 3, 2013, **Premier Oil** Investments Limited, a wholly-owned subsidiary of Premier Oil plc (PMO: LSE), became a **farm-in partner** and acquired a **55% participating interest** in Block 2B (with an effective date of June 1, 2013) by 1) reimbursing Taipan for $1.0 million in back costs, and 2) guaranteeing the payment of at least $13.275 million for Taipan's working interest share in minimum work requirements and expenditure obligations ($4.50 million) and the cost of drilling and testing the first exploratory well ($8.775 million) during the First Additional Exploration Period, along with potentially additional future costs[x]. Premier Oil's estimated gross investment, including its working interest share of expenditures and reimbursement of back costs to Taipan, is $30.5 million. The farm-out agreement with Premier Oil not only carries Taipan's costs through the exploration work program, but also brings Premier's technical expertise to the project. According to the farm-out agreement, Taipan Resources remains the operator during the exploration phase.

On June 2, 2014, Tower Resources (Kenya) Limited, a subsidiary of AIM-listed **Tower Resources** Inc. (TRP: LSE) **acquired a 15% participating interest** in Block 2B in total consideration of $4.5 million, 9.0 million Ordinary Shares in Tower Resources (payable in two equal over three months and worth approximately $500,000 on the date of the announcement) and a contingent payment of $1.0 million on the spudding of a second well in Block 2B. Tower's estimated gross investment through the drilling of the first well, including its working interest share of expenditures (estimated to be $4.425 million), is $9.425 million. Taipan Resources retains a participating 30% interest and remains the operator during the exploration phase of Block 2B.

The Government of Kenya retains the option to acquire a working interest of up to 18% in the development area. If acquired, the Government of Kenya assumes its proportional share of costs, expenses and obligations. If and when oil is produced from Block 1, the Government of Kenya receives a share of **profit oil**[xi] (see table below), along with any share arising from the Government's exercise of its option to secure additional participating interests.

Daily Production	**Government Share**
First 0 - 20,000 BOPD	55%
Next 20,001 - 30,000 BOPD	60%
Next 30,001 - 50,000 BOPD	63%
Next 50,001 - 100,000 BOPD	68%
Over 100,000 BOPD	78%

Muglad and Melut Basins (Sudanese Prospectivity Reference)

The **Muglad and Melut Rift Basins** are predominately situated in South Sudan with a small portion located in Sudan, the former having gained independence from the latter in July 2011. According to the BP Statistical Review of World Energy 2013, proven reserves of the Muglad and Melut Basins in South Sudan were **3.5 billion barrels of oil**. In Sudan, proven reserves are 1.5 billion barrels, which are

located in Muglad, Melut and the Blue Nile Rift Basins. Also, the estimate of natural gas reserves in the Muglad and Melut Basins is 3 trillion cubic feet (TCF), but the natural gas associated with oil production is mostly flared or re-injected since the infrastructure for gas development is lacking. As of the beginning of 2014, at least 900 operative oil wells were located in South Sudan alone.

The major oil fields in the **Muglad Basin** are **Unity** and **Heglig fields**, both of which were discovered by Chevron in 1982. Though at the time the estimated reserves were 593 million barrels (MMBO), Chevron suspended operations in 1984, near the beginning of the Second Sudanese Civil War which lasted until 2005. Production from the Muglad and Melut Basins resumed in 2006[xii], and the next year, the estimate of proven oil reserves was increased to 5.0 billion barrels. Some other discoveries in the Muglad Basin include the Thar Jath (250 MMBO) and Mala (44 MMBO) fields both in Block 5A (South Sudan), the Fula field (discovered in 2001) in Block 6 (Sudan), the Toma and Munga fields in Block 1 (Sudan) and the Bamboo oil field in Block 2 (Sudan).

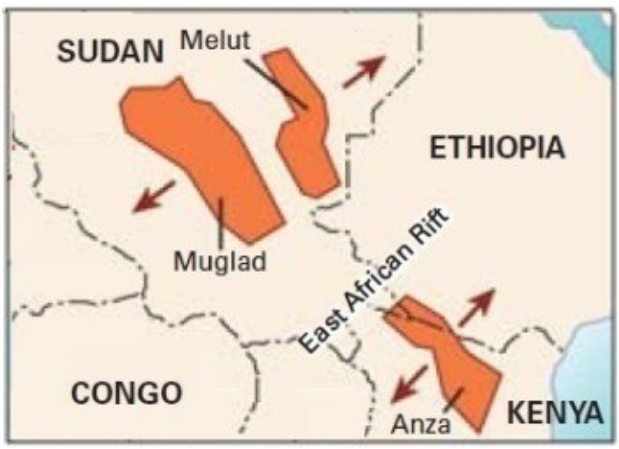
Oil Fields of South Sudan and Sudan

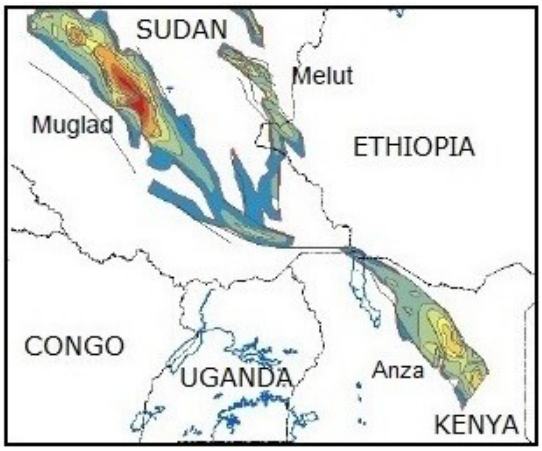
Country	License	Basin	Main Oil Fields	Blend
South Sudan	Block 1	Muglad	Unity, Toma & Munga	Nile
South Sudan	Block 3	Melut	Adar-Yale & Agordeed	N/A
South Sudan	Block 5A	Muglad	Thar Jath, Mala & Jarayan	Nile
South Sudan	Block 7	Melut	Great Palogue, Teng-Mishmish & Fal	Dar
Sudan	Block 2	Muglad	Heglig & Bamboo	Nile
Sudan	Block 4	Muglad	Diffra, Neem, Kaikang & Shelungo	Nile
Sudan	Block 6	Muglad	Fula & Hadida	Fula
Sudan	Block 17	Muglad	al-Barasaya	N/A

The major oil field in the **Melut Basin** is the **Great Palogue Oil field**, which was discovered in 2002 with the drilling of the Palogue-1 well. It is located in Block 7E of South Sudan, along with the Fal field.

The Muglad and Melut Basins are part of a huge **Cretaceous rift system** that extends across central Africa and includes the Anza Basin. Block 2B in Kenya is on trend with these NW-SE trending Sudanese basins and their commercial producing oil fields.

One of the factors contributing to the discovery of the Unity, Heglig and Great Palogue fields was the belief that both source rocks and reservoir rocks were present in the Central Africa and East Africa rift systems. Therefore, explorationists postulated that prospective sedimentary horizons should exist.





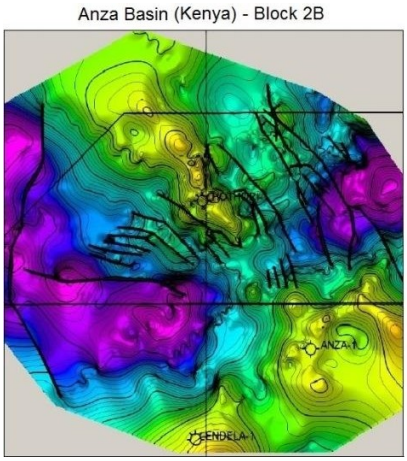
In 2011, the USGS defined the Cretaceous-Cenozoic Composite Total Petroleum System (TPS) known as the **Central African Rifts Assessment Unit** (AU). This AU includes parts of the Central African Republic, Chad, Ethiopia, Kenya (Anza Basin), Sudan (Muglad and Melut Basins) and Tanzania. The assessment is based on geology-based data on source rocks, reservoir rocks and traps for hydrocarbon accumulation. By analyzing the geologic elements of a total petroleum system, the USGS defined that this TPS included Cretaceous-Paleogene lacustrine (lake) and marine (sea) source rocks, Cretaceous-Paleogene reservoirs, shale seals and traps, along faulting that is typically associated with hydrocarbon deposits.[xiii]

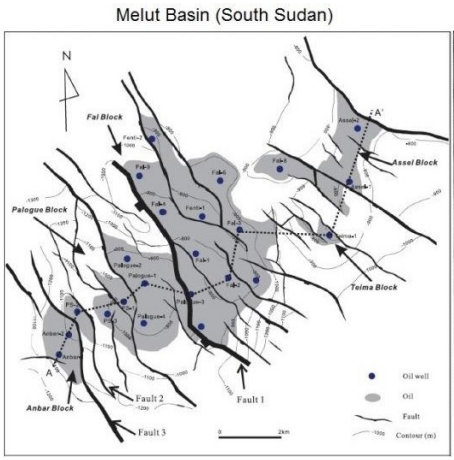
With the discovery of commercially-viable oil fields, i**nevitably the supporting infrastructure will be constructed**.

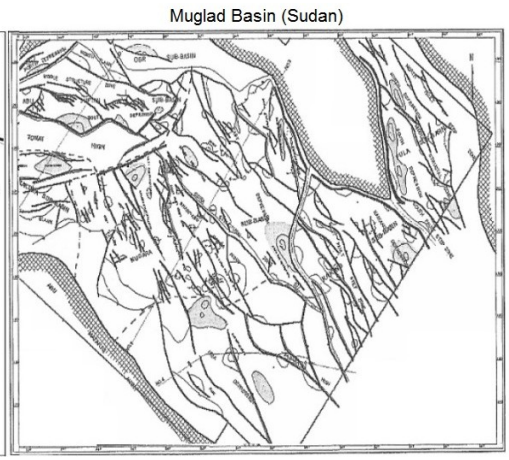


In the case of Sudan, the 1,542 km, 28-inch Greater Nile Oil Pipeline (GNOP) was completed in July 1999. It connects the Heglig processing facility, which serves the Unity Field, to the Marine Terminal just south of Port Sudan on the Red Sea. In mid-2006, the 1,380 km Petrodar pipeline came on stream in order to transport Dar Blend (heavy sweet crude) from the Great Palogue field (Blocks 3 and 7) in the Melut Basin to Port Sudan. Also, along with many other processing facilities serving other oil fields, two other major feeder pipelines were constructed: one 100 km pipeline to transport Nile crude from the Thar Jath field in Block 5A to the GNOP (172 km) and the other 720 km pipeline to carry Fula crude to the Khartoum refinery.

Similar Structures

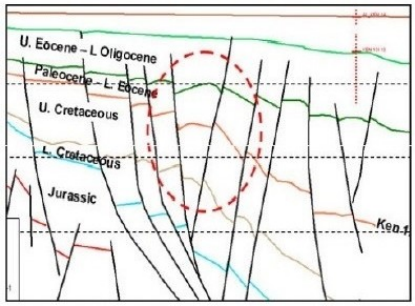




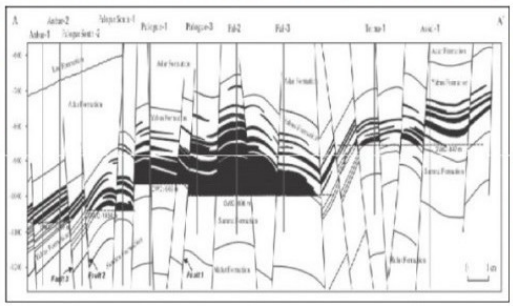


The Cretaceous source rocks of the Melut, Muglad and Anza Basins are controlled by the regional series of fault trends and analogous fracture zones. The structural systems of all three basins are dominated by **NW-SE trending faults** that are **parallel** to the basin axis. The basins are fault bounded structures.

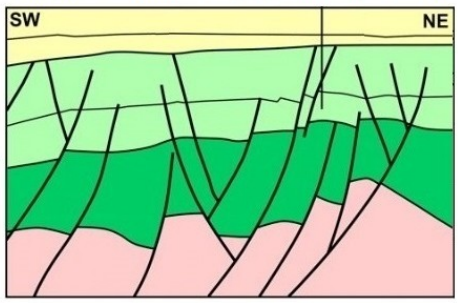
South Anza Basin (Kenya)



Melut Basin - Palogue Field (South Sudan)



Muglad Basin - Heglig Field (Sudan)



In addition, the faulted patterns within the anticline structures are similar with the basins being characterized by the presence of numerous tilted fault blocks. The assemblage of faults exhibit different patterns (such as Y-shaped, fan-shaped, flower-shaped, cabbage-like, parallel stepwise, etc.) that can generate favorable, oil-trapping, reservoir–cap combinations (see representative cross sections below).

Similar Stratigraphy

In general, the Lower and Upper Cretaceous sandstone formations constitute the migration pathway from the source rocks to the traps. One of the features of these rifted sedimentary basins is the presence of organic-rich source rocks deposited during the Lower Cretaceous Period. Using sequence stratigraphic principles, similar marker horizons with comparable sediment stacking patterns form the basis for stratigraphic correlation across these Cretaceous basins.

The geological elements of the Sudanese petroleum systems could provide insights concerning the Anza Basin. The identification of reservoir rocks, source rocks, cap rocks and trap types, along with the reservoir formation processes, provide leads for the stratigraphic interpretation of well bores and seismic surveys. Of particular interest is that the Tertiary formations in the Melut Basin are quite productive.

At least 11 litho-stratigraphic units have been established in the **Muglad Basin**, of which two Lower Cretaceous formations (**Abu Gabra** and **Bentiu**) are the main oil-bearing reservoir horizons. The lower sandstone interval of the **Aradeiba** Formation in the Darfur Group is a secondary reservoir target. The deeper Lower Cretaceous **Sharaf** Formation and shales in **Abu Gabra** are the source rocks.

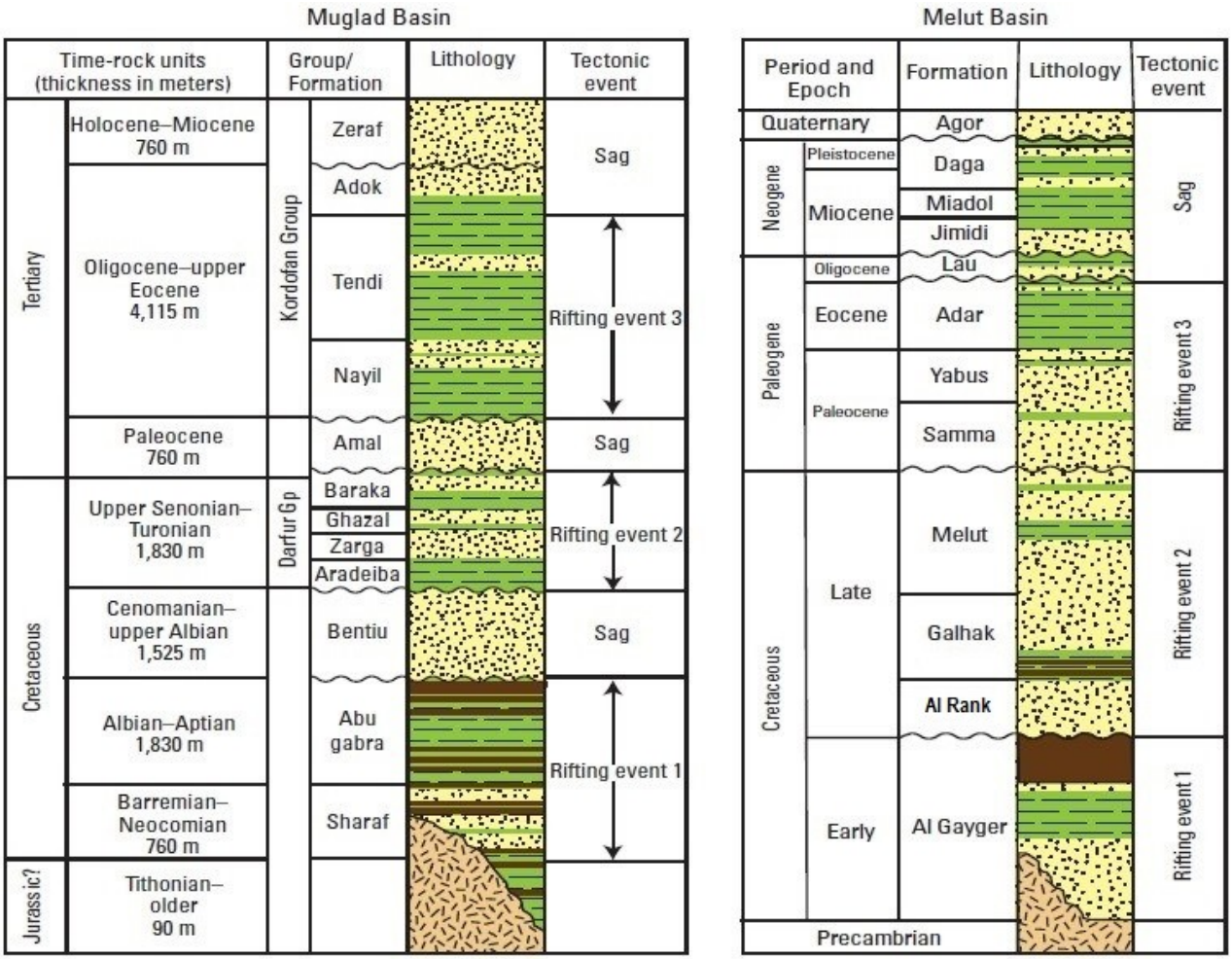
The Abu Gabra is predominately claystones with intervals of shales, sandstones and siltstones. The overlying Bentiu is characterized by thick sandstone sequences. Intervals of mudstone and shales in the Upper Cretaceous Darfur Group act as seals.

In the northern portion of the **Muglad Basin** (Block 6), reservoirs have been discovered in the Lower Cretaceous **Abu Gabra** Formation. In the southern part (Blocks 1, 2 & 4), the pay zone is the Lower Cretaceous **Bentiu** Formation, which contains a massive oil pool. The Fula field in Block 6, which is closer to the Central African Fault Zone, the shales of Lower Cretaceous Abu Gabra are source rocks while the **Abu Gabra** Formation's sandstones, along with the **Bentiu** Formation act as reservoir beds. Certain sequences in the Upper Cretaceous Darfur Group are the cap rocks. In the Heglig field (Block 2), the Sharaf and Abu Gabra Formations are source rocks. In Block 4, the Shelungo field's main reservoir rocks are the **Aradeiba** and **Bentiu** sandstone Formations. The lacustrine shale of the Abu Gabra Formation appears to be a primary hydrocarbon source rock.

In the **Melut Basin**, the primary pay zones of the Great Palogue and Agordeed fields are the Tertiary (Paleogene) **Samma** and **Yabus** Formations, which are composed of sandstones and mudstones. The Upper Cretaceous **Melut** Formation is a secondary contributor. The source rocks are the Lower Cretaceous shales of the Al Renk and Galhak Formations, which are believed to be equivalent to the Sharaf and Abu Gabra Formations found in the Muglad Basin. The Upper Cretaceous Melut Formation consists predominantly of sandstones, which are considered to be the migration pathway from the source rocks to the traps. Shales are found throughout the stratigraphic sequences providing seals over the

reservoirs. Moreover, the Adar Formation is especially considered the seal for the underlying Yabus and Samma reservoirs.

Stratigraphy of Muglad and Melut Basins



The wildcat Palogue-1 well spudded in 2002 encountered 72.3 meters of net oil pay in Tertiary (Paleogene) Samma and Yabus Formations and 9.9 meters in the Cretaceous Melut Formation. An indication of the relative reserves is that the Paleogene sandstones tested at an initial rate of 5,100 BOPD while the deeper pay zone Cretaceous sandstones tested at 300 BOPD. After drilling additional wells, the discovery was proven to be the 500+ MMBBO Great Palogue Oil field.[xiv]

The dominant structural styles in the Melut Basin are the large-scale, gentle-sloping anticlines in each sub-basin. Pay zones are found in favorable areas for petroleum accumulation, particularly at fault block traps.

Another example in the Melut Basin is the Adar-Yale field in Block 3. Initially discovered in 1981 by Chevron, the average pay zone situated in the Paleogene sandstone formation only averaged only 2.9 meters. The field was not considered commercial despite a resource estimate of 168 MMBO. However, later in March 1997, under Gulf Petroleum the field began producing 5,000 BOPD. In 2001, several other small oil pools were discovered raising the reserve to 405 MMBO.

The study of petroleum systems in the Melut and Muglad Basins lead to two exploratory insights. First, certain reservoir and source sequences appear to exist in both basins, confirming some level of continuity of Melut and Muglad Basins. Second, the dichotomy between the Upper Cretaceous main pay zones of the Muglad Basin and the shallower Paleogene strata in the Melut Basin may be a function of Upper Cretaceous Darfur Group and Adar Formation cap rocks, respectively.

The Anza Basin is considered the extension of the Cretaceous rift system, and therefore, could exhibit analogous structural and stratigraphic hydrocarbon aspects of the Muglad and Melut Basins of the South Sudan and Sudan with similar fault trends, tilted fault blocks and the presence of prospective Cretaceous and Tertiary strata. Using Muglad and Melut Basin analogues, the regional geological model for identifying the presence of potential source rocks, reservoirs and seals will help interpret the seismic surveys of Block 2B and aid in recognizing favorable geological conditions and potential reservoir horizons.

South Lokichar Basin (East Africa Rift System Prospectivity Reference)

Management postulates that thick Tertiary sediments overlying Cretaceous horizons in the Anza Basin are also highly prospective citing the recent discoveries in the Lokichar Basin of the East African Rift System. It should be added that the oil reservoirs in the Melut Basin in South Sudan are located in the Tertiary (Paleogene) formations. In Block 2B, the primary drilling prospect is a Tertiary prospect adjacent to the main basin-bounding fault.

The **East African Rift system** is composed of a series of discrete yet tectonically interconnected rift basins characterized by **two main branches**: the Eastern Rift Branch and the Western Rift Branch. The fundamental units of each branch are the rift basins, of which the South **Lokichar Basin** is one.

Successful exploration wells drilled on other blocks in Kenya continue to de-risk East African basin plays. Tullow Oil has been successfully utilizing the "**S*tring of Pearls***" concept as an exploration strategy in this Tertiary Rift Basin. The "S*tring of Pearls*" approach presumes oil discoveries along one rift should provide evidence that resource potential exists along the same rift and also along other rift valleys with similar geologies.

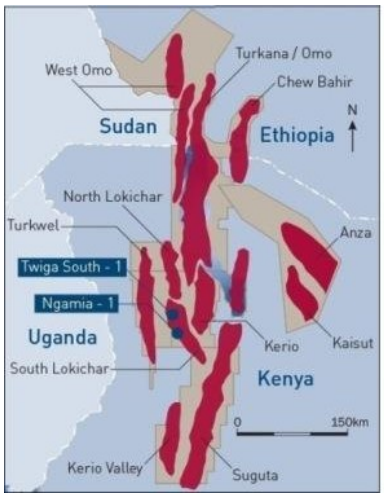
In the South Lokichar Basin, situated in the **Eastern Branch** of the East Africa Rift (EAR), many non-commercial exploratory wells were completed with marginal discoveries or oil shows prior to the commercial discovery in 2012. Each exploratory well added to the knowledge base; for example, Loperot-1 drilled by Amoco in 1992 to a depth of 2,950 meters demonstrated the presence of thick organic-rich shales and the potential for reservoirs in the Auwerwer and Lokhone sandstone intervals. Building upon the database of these exploratory wells, Tullow Oil made the first major oil discovery in Kenya with the **Ngamia-1 well** in Block 10BB during **March 2012**.

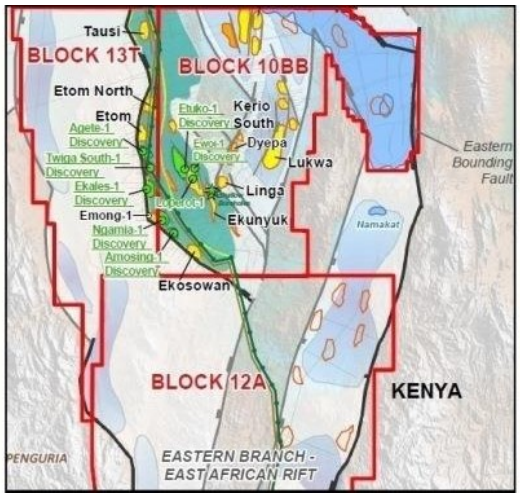
In total, Tullow Oil announced seven oil discoveries in the South Lokichar Basin through January 2014. The basin-opening wells are Ngamia-1, Twiga South-1, Etuko-1, Ekales-1, Agete-1, Amosing-1, and Ewoi-1. Five of the wells were drilled along the trend of the western basin bounding fault while two (Etuko-1 and Ewoi-1) tested the rift flank play on the eastern side of the basin. The latest updated estimate of discovered resources in the Lokichar Basin by Tullow (as of May 2014) is roughly 600 MMBOE.

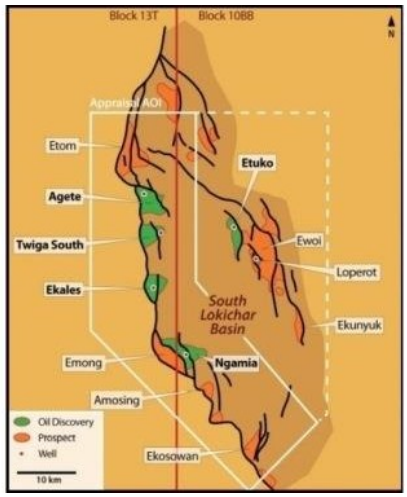
Discoveries

License	Well	Date Completed	Depth (meters)	Basin	Oil Play	Primary Formation	Net Pay (meters)	Secondary Formation	Net Pay (meters)	Flow Rate (BOPD)
East African Rift System (Kenya)										
Successful wells by Tullow Oil (operator) - Africa Oil										
Block 10BB	Ngamia -1	Mar-12	2,340	Lokichar	Tertiary	Auwerwer	200	Lower Lokhone	43	3,200
Block 13T	Twiga South-1	Nov-12	3,250	Lokichar	Tertiary	Auwerwer	30	Lower Lokhone	N/A	2,812
Block 10BB	Etuko-1 & 2	Jul-13	3,100	Lokichar	Tertiary	Auwerwer	200	Lower Lokhone	50	550
Block 13T	Ekales-1	Sep-13	2,554	Lokichar	Tertiary	Auwerwer	41	Lower Lokhone	N/A	1,000
Block 13T	Agete-1	Nov-13	1,930	Lokichar	Tertiary	Auwerwer	100	Lower Lokhone	100	500
Block 10BB	Amosing	Jan-14	2,351	Lokichar	Tertiary	Auwerwer	180	Lokhone	180	TBA
Block 13T	Ewoi -1	Jan-14	1,911	Lokichar	Tertiary	Lokhone	50	-	50	TBA

Tullow Oil continues to conduct an exploration and appraisal program in order to better understand the potential scale of the south Lokichar Basin in northern Kenya. Ultimately, a comprehensive reservoir model for the Lokichar Basin will be developed.



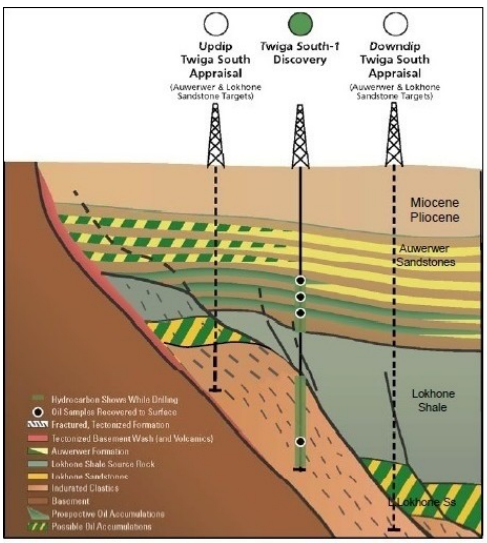


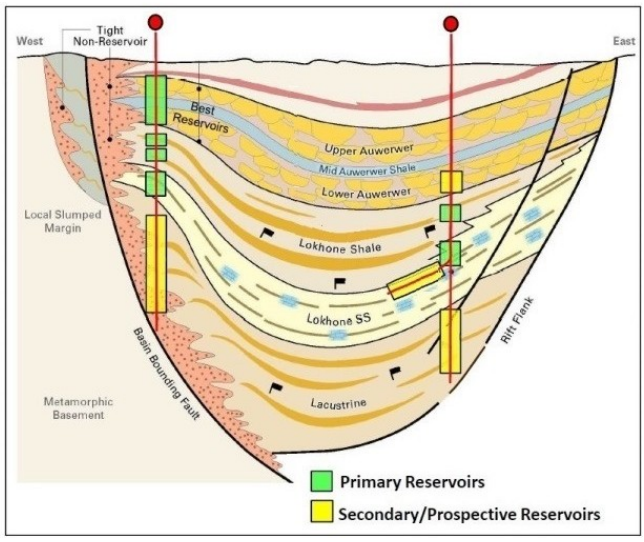


Stratigraphy of South Lokichar Basin

The most productive reservoirs in the South Lokichar Basin are the Tertiary **Auwerwer** sandstone formations. The Tertiary (Miocene) **Upper and Lower Lokhone** sandstones also are pay zones. The Lokhone Shale and the deeper Loperot Shale intervals of the Lokhone Formation are potential source members.

The seven "*String of Pearls*" discoveries by Tullow Oil- Africa Oil partnership in the South Lokichar Basin provide **three levels of prospectivity** toward Taipan's Block 2B in the Anza Basin. First, the potentially commercially oil flow in the South Lokichar Basin was discovered in **Tertiary sandstone formations**, which are prolific in the Anza Basin. Second, the **average sediment thickness in the Anza Basin is 10,000 meters**, which is 2.5 times the average 4,000 meters in the East Africa Tertiary Rift. And third, the **structural play** of the "*String of Pearls*" along the rift flank play on the eastern side of the South Lokichar Basin is structurally similar to the tilted fault block play of the Badada prospect.





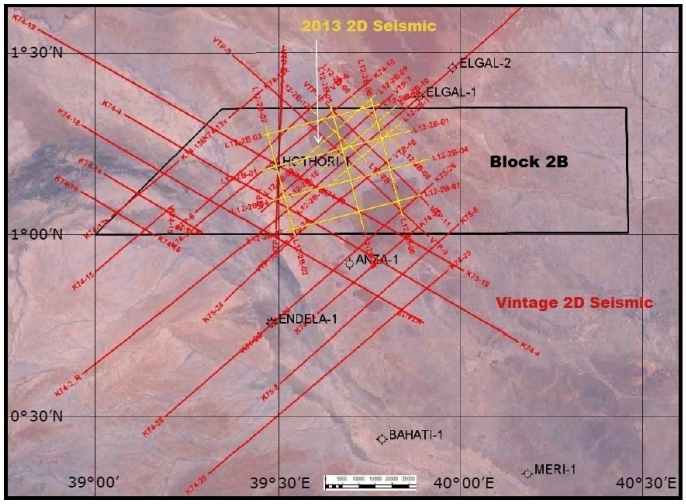
It should be noted that not all of Tullow Oil's appraisal wells are commercially viable; however, incremental knowledge about the basin was gleaned from the drilling results*.* The Etuko-2 well was drilled to test the Upper Auwerwer sands near the Etuko-1 discovery on the eastern flank play. The well

penetrated a potential oil column, but only water flowed during the drill stem test. Also, the 1,802-meter Ekunyuk -1 well was drilled on the eastern flank play on trend with the Etuko-1 and Ewoi-1 discoveries; however, it only encountered 5 meters of oil pay.

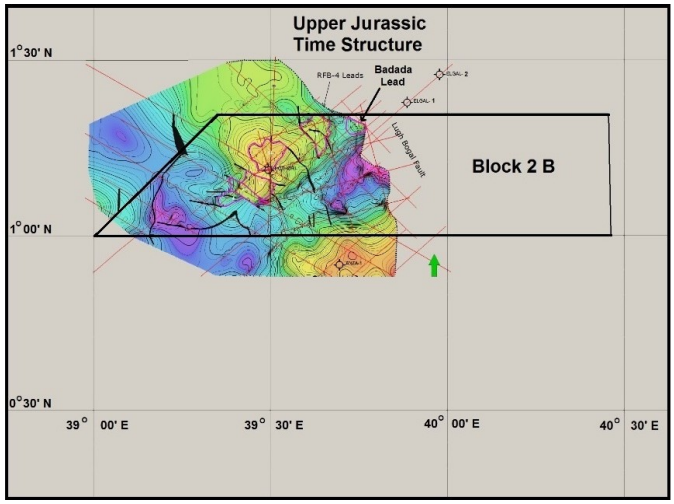
Developmental Work Programs

In 1974 and 1975, Chevron and Esso conducted an extensive seismic program in the southern Anza Basin, including the area now delineated as Block 2B. All told, approximately 1,850 km of vintage seismic data was acquired prior to Lion Petroleum's involvement with Block 2B.

Block 2B – Seismic



Upper Jurassic (Ken 8) Time Structure



After completing an in-depth technical review of Block 2B during the first two years of the Initial Exploration Period, Taipan Resources acquired **439 km of 540-fold 2D seismic data** between January and March 2013 (yellow lines in diagram) complementing the vintage seismic data (red lines). In March and April 2013, a **12,173 km Full Tensor Gradiometry** (FTG) survey was recorded by ArkeX Ltd. The interpretation of the processed seismic survey and its integration into a NI 51-101-compliant resource assessment resulted in **a 75% increase in the mean un-risked prospective resources**. The total cost of the programs was $6.5 million, of which $1.0 million was recouped through the terms of the farm-out agreement with Premier Oil.

A further **196.2 km of 540-fold 2D seismic** data was acquired in the first calendar quarter of 2014 in order to better identify the planned drilling location. All told, almost 2,500 km of 2D seismic data has been shot over Block 2B, of which 635 km has been acquired by Taipan Resources with its partner, Premier Oil.

Taipan's Exploratory Well – Badada Prospect (formerly known as Pearl Prospect)

The gravity anomalies interpreted from the data collected from the FTG survey are being used in tandem with the 2D seismic results to determine the optimal location for the initial exploration well. The decision process includes the identification of both potential structural traps formed against the basin-bounding fault and probable reservoir zones in the prospective Tertiary and Cretaceous formations. The data from the recently acquired 2D seismic survey was used to finalize the drilling location of Badada-1.

The location of the prospective Badada-1 well is in the southeastern extension of the Anza Basin, near its juncture with the Mandera-Lugh and Mochesa Basins. The primary target is a Tertiary prospect at the basin's edge, which is situated in a geological "*String of Pearls*"-type setting similar to the recent discoveries by Tullow Oil (TLW: LSE) in the rift flank play on the eastern side of the Lokichar Basin. In pursuing the structural lead at the basin's edge, the bore will also test a deeper lead, the prospective

Cretaceous formations that geological, geophysical, geochemical studies of the Anza Basin indicate the existence of oil-prone source rocks and prospective sandstone reservoirs.

Management anticipates that the exploratory well will be spudded at the Badada Prospect at the end of 2014 or early 2015. The well will target the prospect lead that Sproule International estimates (in the NI 51-101 Technical Report dated December 31, 2013) to contain a Mean Gross Unrisked Prospective Resource of 251 MMBOE (see table from Technical Report below).

Funding of Badada Prospect

The estimated gross costs to be incurred during the First Additional Exploration Period of in Block 2B, including the drilling and testing of the Badada-1 well, is **$29.5 million**. **Premier Oil is obligated to pay up to $29.5 million** according to its farm-out agreement, which was negotiated prior to farm-out of an additional 15% to **Tower Resources**, **which is now responsible for paying** its participating interest share of costs, which is estimated to be **$4.425 million**.

Prospective Resource Estimate

Three NI-51-101-compliant Prospective Resource Estimates have been filed on Block 2B, all completed by Sproule Associates. The **initial estimate** of Gross Mean Unrisked Prospective Resources was **387 MMBOE**, which reinterpreted approximately 1,860 km of historic 2D seismic data. Sproule mapped 17 separate leads on three principle stratigraphic horizons (Upper Jurassic, Cretaceous and Lower Tertiary) in the report effective June 1, 2012 and just prior to Taipan's merger with Lion Petroleum. Taipan re-commissioned the report in which the mean of the outcomes from the various leads were arithmetically summed instead of statistically aggregated. As a result, the Gross Mean Unrisked Prospective Resources increased 5.9% to **410 MMBOE** in the updated assessment with an effective date of October 31, 2012.

Taipan Resources

History of Prospective Oil Resources for BLOCK 2B

Country	License	Operator	Taipan's Working Interest (%)	Gross Area (km2)	Leads (#)	Gross Unrisked Mean Prospective Estimate (MMBOE)	Net Unrisked Mean Prospective Estimate (MMBOE)	Gross Risked Mean Prospective Estimate (MMBOE)	Net Risked Mean Prospective Estimate (MMBOE)	51-101 Estimate Effective Date
Kenya	Block 2B	Taipan Resources	100%	7,807	17	387	387	127	127	1-Jun-2012
Kenya	Block 2B	Taipan Resources	100%	7,807	17	410	410	127	127	31-Oct-2012
Kenya	Block 2B	Taipan Resources	45%	5,458	19	1,593	717	137	62	31-Dec-2013
Kenya	Block 2B	Taipan Resources	30%	5,458	19	1,593	478	137	41	31-Dec-2013

The 439 km of 2D seismic data acquired by Taipan in early-2013 significantly improved the dataset. The vintage seismic data were reprocessed and compiled with the newly acquired and processed data. Consequently, the number of prospect leads expanded from 17 to 19 and each lead was evaluated to determine ranges of undiscovered initially-in-place, risked prospective and unrisked prospective resources. Also, the number of representative seismic horizons expanded to five: Jurassic (Ken 8), Lower Cretaceous (Ken 10), Upper Cretaceous (Ken 12), Lower Tertiary (Ken 13) and Upper Tertiary (Ken 14).

The most recent NI 51-101-compliant report (with an effective date of December 31, 2013) estimates that the **Gross Mean Unrisked Prospective Resources** is **1,593 MMBOE** within the 19 exploration leads. With a 30% working interest, the **Net Mean** Unrisked Prospective Resources of Taipan Resources is **478 MMBOE.**

Property Gross and Company Gross Unrisked Prospective Resources[1,5] for Exploration Leads, Anza Basin, Block 2B, Kenya As of December 31, 2013					
	Property Gross				Company Gross
Prospect	Low[2] Estimate (P90) (MMBOE)[6]	Best[3] Estimate (P50) (MMBOE)[6]	High[4] Estimate (P10) (MMBOE)[6]	Mean Estimate Property Gross (MMBOE)[6]	Mean Estimate WI=45% (MMBOE)[6]
Lead 1 (Pearl)	70	178	498	251	113
Lead 2	65	158	427	219	98.6
Lead 3	20	67	233	109	49.0
Lead 4	44	102	274	141	63.5
Lead 5	35	90	247	125	56.3
Lead 6	10	30	91	44	19.8
Lead 7	13	47	196	88	39.6
Lead 8	32	85	231	115	51.8
Lead 9	22	60	180	88	39.6
Lead 10	15	48	161	77	34.7
Lead 11	17	48	140	70	31.5
Lead 12	13	43	137	65	29.3
Lead 13	13	40	128	61	27.5
Lead 14	11	30	92	45	20.3
Lead 15	2.4	10.6	46.3	19.9	9.0
Lead 16	3	13.5	64	27.2	12.2
Lead 17	3	13.5	63.4	27	12.2
Lead 18	0.9	4.9	25.4	10.9	4.9
Lead 19	2.1	6.7	21.3	10.2	4.6
Total[7]				1593	717

Expected Milestones and Related Events:

- Further evaluation of Sala-1 exploratory well, which was drilled by Africa Oil (AOI: TSXV) on Block 9 in the Anza Basin (northwest and contiguous to Taipan's Block 2B on the same tilted fault play)
- Results from the Sala-2 appraisal well, which spudded in late July and is designed to test the up-dip extent of the upper and lower gas bearing sandstone intervals encountered by Sala-1.
- The drilling of an exploratory well on the Badada prospect of Block 2B, which management anticipates occurring in late 2014 through early 2015

BLOCK 1 (KENYA)

Overview

Taipan Resources currently holds a **20% working interest** in Block 1, which was acquired through the merger with Lion Petroleum. East Africa Exploration Ltd (aka EAX), a wholly-owned subsidiary of **Afren plc**, holds the remaining 80% working interest and is the **operator of the project**.

When the Production Sharing Contract (PSC) with the Government of Kenya became effective on October 8, 2007, Block 1 encompassed an area of 31,781.68 km2. In accordance with the PSC, a 30% relinquishment of the Block 1 occurred in October 2012. The company opted to surrender area located on the west of the block. An additional partial 30% relinquishment is scheduled to transpire before the end of the First Additional Exploration Period, namely before October 8, 2014. The third two-year term, known as the Second Additional Exploration Period is scheduled to end on October 8, 2016. **Currently, Block 1 encompasses 22,246.48 km2** (or 4,449.30 net to Taipan Resources).

Block 1 appears to be a highly prospective property signified by the presence of multiple oil seeps in and around the block, along with gas discoveries in the contiguous Ogaden Basin. With 10,696 km airborne gravity and magnetic data, 850 km of historic 2D seismic data and 1,900 km of relatively recent 2D seismic data having been acquired and interpreted, the Block's partners (Afren plc and Taipan Resources) are **planning on drilling** their first **exploratory well in Block 1** with primary targets being either the El Wak or Khorof leads, both being distinguished by a four-way dip-closure structural trap associated with an oil seep. The recent private placement has enabled **Taipan Resources to fully fund** the drilling of the first exploratory well in Block 1.

Location

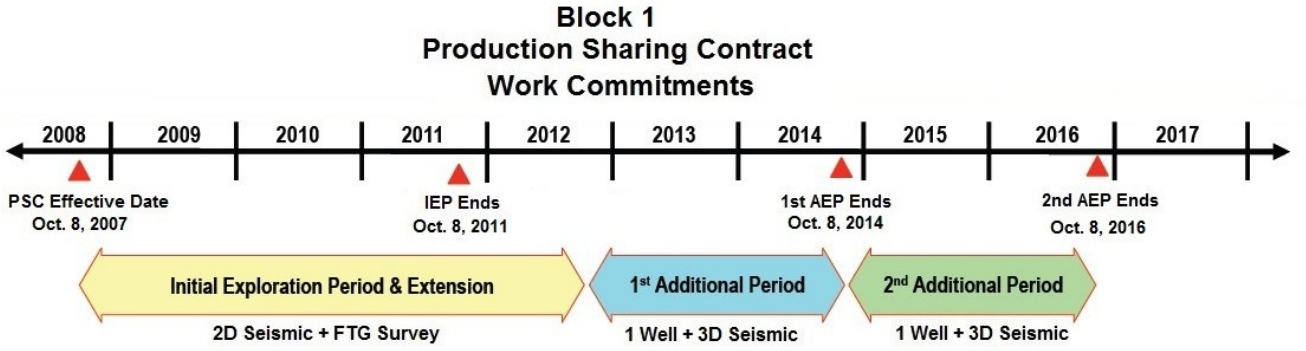
Block 1 is situated in northeast Kenya and overlies the western margin of the Mandera-Lugh Basin (aka the Mandera Basin), an under-explored basin that many geologists consider to be the southern extension of the Ogaden Basin in Ethiopia. The Calub and Hilala Gas Fields in the Ogaden Basin are estimated to contain reserves of approximately 4.0 TCF (trillion cubic feet).

Ownership

Lion Petroleum was awarded a **Production Sharing Contract** for an undivided 100% participating interest in Block 1 on November 19, 2007 with an effective date of February 19, 2008. At the time, Block 1 encompassed 31,780.68 km2. The Production Sharing Contract originally called for a seven-year exploration period consisting of three terms. However, the commencement date of the first three-year **Initial Exploration Period** was extended by about 6 months to October 8, 2008, and later the termination date was extended by one year such that the Initial Exploration Period ended on October 8, 2012. The second two-year term, known as the **First Additional Exploration Period**, expires on October 8, 2014, and a third two-year term, known as the **Second Additional Exploration Period** ends on October 8, 2016. Upon the declaration of a commercial discovery, the resulting production period will extend up to 25 years.

During the three-year Initial Exploration Period, the PSC holder (Lion Petroleum) is obligated to incur $9.55 million in exploration expenditures and another $6.0 million during the subsequent two-year First Additional Exploration Period. During the Second Additional Exploration Period, the PSC holder is required to drill one exploratory well to a minimum depth of 3,000 meters expending a minimum of $6.0 million and acquire 25 km2 of 3D seismic data.

In January 2009, East African Exploration (Kenya) Ltd (EAX), a wholly-owned subsidiary of Afren plc (AFR: LSE), became a farm-in partner, acquiring a 50% interest in Block 1 by assuming $6.5 million of expenditure obligations and other costs during the initial exploration period. Subsequent expenditures were to be split equally. However, on April 5, 2012, Afren plc exercised its option to increase its participating interest on Block 1 from 50% to 80% by incurring an incremental $6.0 in exploration expenditures, which carried Lion Petroleum through most of the cost of 2D seismic program. Thereafter, in July 2012, Taipan Resources merged with Lion Petroleum Corp. and thus acquired a 20% working interest in Block 1.



The Government of Kenya retains the option to acquire a working interest of up to 18% in the development area. If acquired, the Government of Kenya assumes its proportional share of costs, expenses and obligations. If and when oil is produced from Block 1, the Government of Kenya receives a share of **profit oil**[xv] (see table below), along with any share arising from the Government's exercise of its option to secure additional participating interests.

Daily Production	Government Share
First 0 - 20,000 BOPD	55%
Next 20,001 - 30,000 BOPD	60%
Next 30,001 - 50,000 BOPD	63%
Next 50,001 - 100,000 BOPD	68%
Over 100,000 BOPD	78%

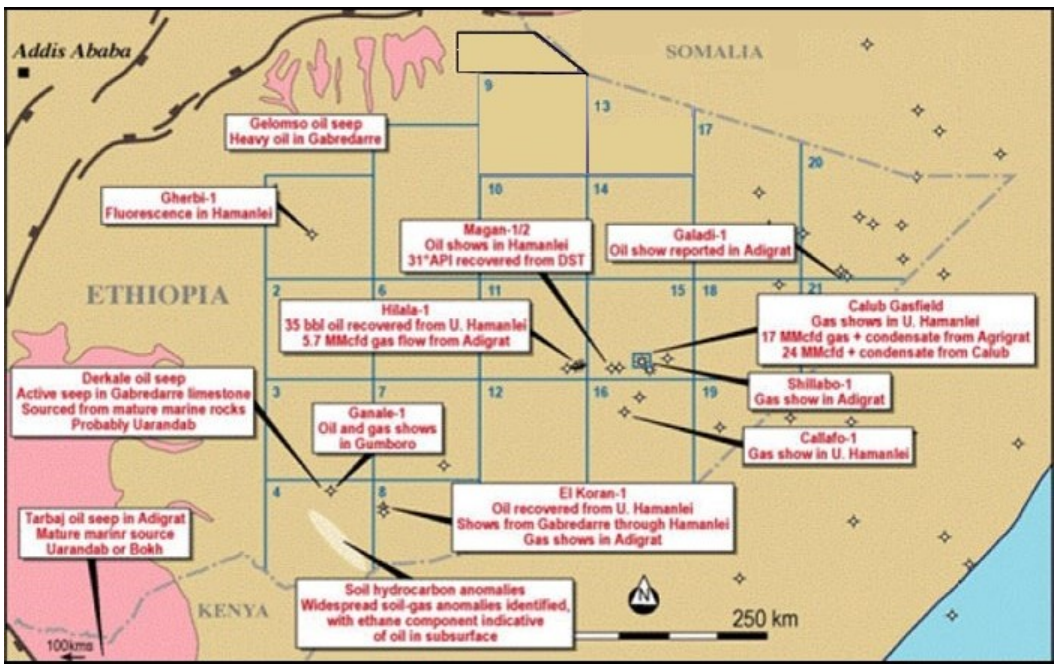
Prospectivity

Block 1 is situated on the western margin of the **Mandera-Lugh Basin** in north-eastern Kenya on the borders with both Ethiopia and Somalia. The Mandera-Lugh Basin is continuous with the Ogaden Basin's Calub, Hilala, El Kuran and Genale hydrocarbon occurrences which emanate from **Karoo-aged formations** (which includes units originating in the early Carboniferous, Permian, Triassic and early Jurassic Periods) of the Ogaden Basin. Multiple oil seeps in the Mandera-Lugh Basin confirm the presence of hydrocarbons and indicate the presence of potential petroleum systems. Two plunging structural features have been identified, both of which could exhibit fault-dependent closures. Adding confidence to the area's prospectivity, the Mandera-Lugh Basin is considered to be the southern extension of the Ogaden Basin, which shares many analogous formations with the Mandera-Lugh and has estimated reserves of over 4.0 TCF according to the Ministry of Mines and Energy of Ethiopia.

Oil Seeps

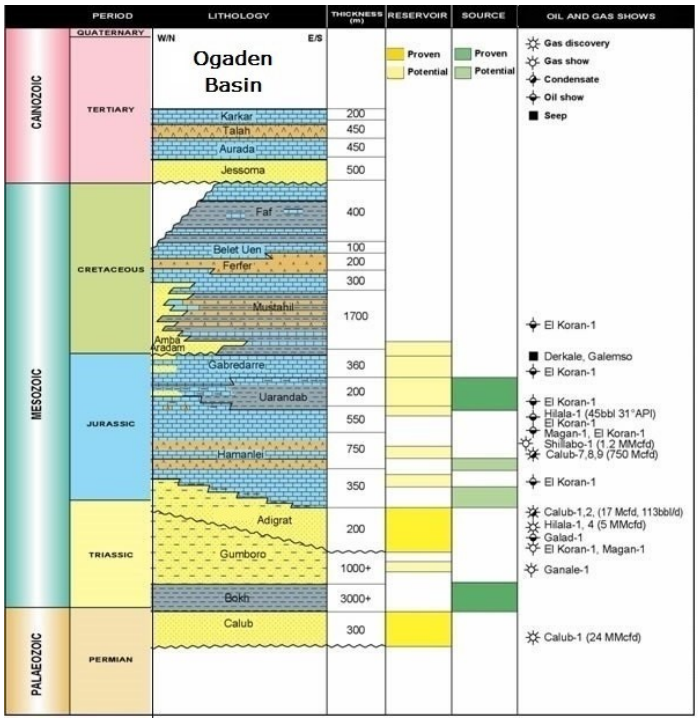
The occurrences of oil seeps **at Tarbaj** (Kenya) in the southwest portion of Block 1, **at Genale** (Ethiopia) northeast of Block 1 **and two other locations within Block 1** confirm that the block is oil prone and strongly suggest the presence of a petroleum system in the Mandera-Lugh Basin.

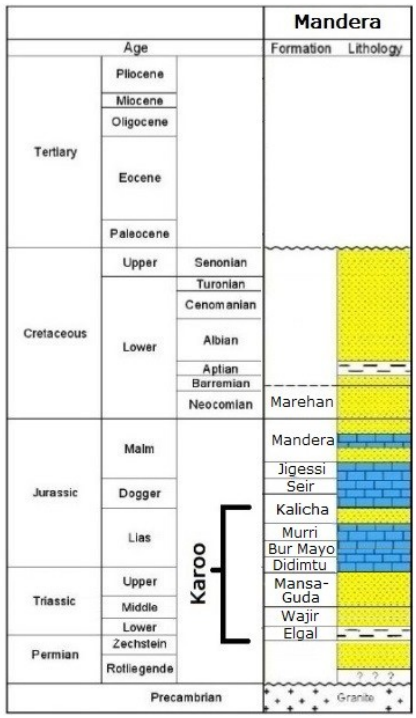
Hydrocarbon Discoveries, Shows and Seeps in the Ogaden and Mandera-Lugh Basins



At Tarbaj, the oil seep appears in a shallow water-well drilled by the Government of Kenya and seems to be migrating along an up-dip in the Mandera-Lugh Basin. In 1987, a 54-meter stratigraphic well (Tarbaj-1) was drilled by Total to evaluate the geological stratigraphy attendant with the seep. Oil shows (asphalt and tar staining) were evident in the core obtained in the 25-to-54 meter interval, interpreted to correspond with Upper Triassic to Lower Jurassic rock strata, with good tar staining in the 40.5-43.5 meter interval, interpreted as Karoo-aged sandstones of the **Mansa-Guda Formation**.

Stratigraphy of Ogaden and Mandera Basins





Sandstone sediments of the Karoo Supergroup outcrop along the western rim of the Mandera-Lugh Basin in northeastern Kenya. The outcrops have aided in the construction of stratigraphic cross-sections of geological formations. An outcrop east of Tarbaj displays oil-filled fractures in the **Jurassic Murri Formation**, suggesting Karoo-equivalent reservoirs in the Mandera-Lugh Basin. Also, the Jurassic **Didimtu limestone** could be a potential reservoir formation. Shale formations (that might provide seals for reservoirs or provide a migration route for the seeps) are also present in the outcrop. Potential source rocks include the shale intervals of the **Elgal Formation** (at the Permian-Triassic boundary), which is considered the source for the gas and condensate in Ethiopia's Gas Calub Field in the Ogaden Basin (see below).

Ogaden Basin (Ethiopian Prospectivity Reference)

Encompassing approximately 350,000 km2, the Ogaden Basin is the largest proven hydrocarbon bearing sedimentary basin in Ethiopia with the sedimentary thickness reaching up to 10,000 meters. Despite the basin's checkered developmental history, exploratory results in the Ogaden Basin have been encouraging.

In 1969 Tenneco was granted an exploration license in the Ogaden Basin. Tenneco's third well, Calub-1, discovered the **Calub Gas Field** in 1973 and the **Hilala Gas Field** in 1974; however, Tenneco relinquished the concession in 1975 when the former socialist government of Ethiopia (the Derg) expelled all western companies. Subsequently between 1979 and 1992, the Soviet Petroleum Exploration Expedition (SPEE) collected various geological data and drilled exploratory wells, nine at Calub and three at Hilala.

As a result of the exploratory work completed by Tenneco which was confirmed by SPEE, the **Calub gas-condensate field** has an **estimated reserve of 2.7 TCF** and the **Hilala gas-condensate field** an **estimated reserve of 1.3 TCF**, according to the Ministry of Mines and Energy of Ethiopia. The main gas and condensate reservoir unit at both fields is the **Adigrat Sandstone Formation**. The other major reservoir of the Calub Gas Field is the **Calub Sandstone Formation**. Situated in **Block 11 and Block 15** of Ethiopia, the Calub and Hilala Gas Fields are considered commercially viable.

After the fall of the Derg in 1987, SPEE withdrew from Ethiopia. Subsequently, the Ministry of Mines has attempted to develop the gas fields with the Chinese company Zhoungyan Petroleum Exploration Bureau (between 1998 and 2001), Malaysia-based Petronas Carigali (between 2007 and 2010) and Hong Kong-based PetroTrans (July 2011 - June 2012).

Most recently, the partnership of New Age African Global Energy Ltd, Africa Oil and Afren plc in **Block 8 of Ethiopia** completed drilling the **El Kuran-3** 3,528-meter appraisal well, which encountered numerous oil and gas shows in several intervals, but especially a gas-condensate zone in the Hamanlei Formation. Previously, the **El-Kuran-1** and **El Kuran-2** wells encountered hydrocarbons: gas shows in the Adigrat Formation and oil shows in the Hamanlei Formation. The mission of the El Kuran-3 appraisal well was to test the reservoir potential of the sediment members of the Permian **Calub Formation** and the Triassic **Adigrat Formation**, along with the Jurassic carbonate rocks in the **Hamanlei Formation**, and also to evaluate the deeper Gumboro zone. That partnership is currently analyzing the well's data, assessing the economic viability of the discoveries and attempting to secure an extension to the Initial Exploration Period from the Government of Ethiopia.

There are two non-commercial discoveries of note. In 2009 Petronas drilled an exploratory well near the Genale oil seep in the 24,420 km2 **Genale block** (Block 4) and discovered a **gas reserve estimated at 0.7 TCF**. Also, a crude oil reserve was discovered near the Hilala gas field; however, it was deemed non-commercial with the interval being only one meter in thickness.

Analogous Stratigraphy with Ogden Basin in Ethiopia

Both the Mandera-Lugh Basin and Ogaden Basin share many characteristics, including similarly-aged formations that display remarkable stratigraphic equivalency. Afren plc has specifically identified the Upper Triassic and Jurassic formations of the Mandera-Lugh Basin to be the primary zones of oil prospectivity. The Jurassic **Bur Mayo**, **Kalicha** and **Seir Formations** appear analogous to the Jurassic Lower and Upper Hamanlei Formations in the Ogaden Basin. In addition, the gas and condensate reservoirs discoveries of gas and condensate in the in the Calub and Hilala Gas Fields are the Triassic Adigrat sandstone and Permian Calub sandstone formations, with the source being the Permian-Triassic Bokh Shale Formation, all of which are comparable to the Triassic **Mansa-Guda** sandstone and a yet-to-be-named Permian KEN 3 mega-sequence sandstone formation, with the source being the Triassic **Elgal** Shale Formation, respectively.

Developmental Work Programs

Historically, gravity and seismic surveys were conducted by Burmah Oil[xvi] during the 1970's, and in the 1980's Amoco[xvii] and Total (TOT: NYSE) acquired a combined 850 km of 2D seismic data. Under the current Production Sharing Contract, the partners acquired 10,696 km of high resolution **airborne gravity and magnetic** data during the first half of 2011, which was used to target the subsequent seismic program.

Having mapped out several major structures, **1,900 km of** 60-fold[xviii] **2D seismic data** was acquired by Afren over two parts of Block 1 during 2012, which more than fulfilled the exploration expenditure obligation (1,200 km of seismic data) of the Initial Exploration Period and allowed for the exercise of the option to continue into the First Additional Exploration Period. The processed seismic images of the sub-surface geologic structures were delivered in mid-2013. During the interpretation phase, **six leads and**

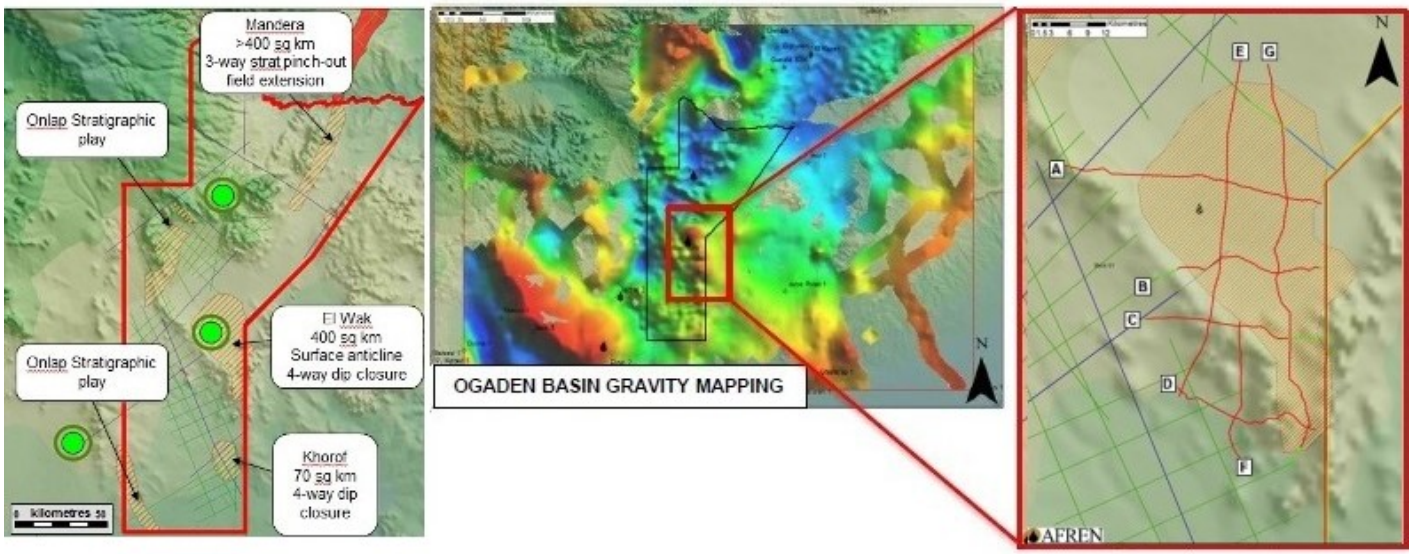
prospects were identified from the seismic data set, along with a number of new play concepts. Many of the prospects that were identified from the interpretation of the 1,900 km 2D seismic program have analogues in Ethiopia's Ogaden Basin.

In the second half of 2014, **an additional 290 km of 2D seismic is expected to be acquired** with processing and interpretation of the data to follow. The operator of Block 1, Afren, is expected to drill an exploration well in the next 12 months.

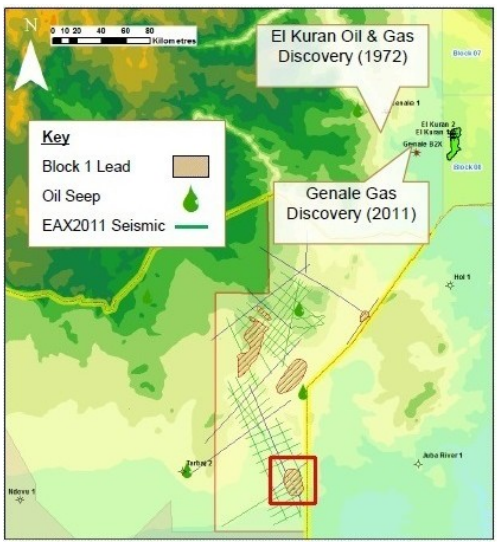
Taipan's Exploratory Wells – El Wak and Khorof Prospects

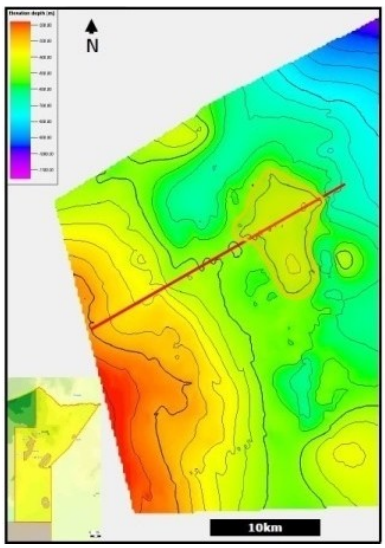
Management expects an exploratory well to be drilled on either the **El Wak** or **Khorof prospect** in Block 1 in the next 12 months. Both prospects exhibit a **four-way dip-closure** structural trap associated with an oil seep. This geological formation is an imperfect stratigraphic trap identified by an anticline (a fold that is convex up) that is faulted on one side and possibly covered by an impermeable rock layer, indicating a potential oil or gas reservoir. (See the interpreted seismic profiles below).

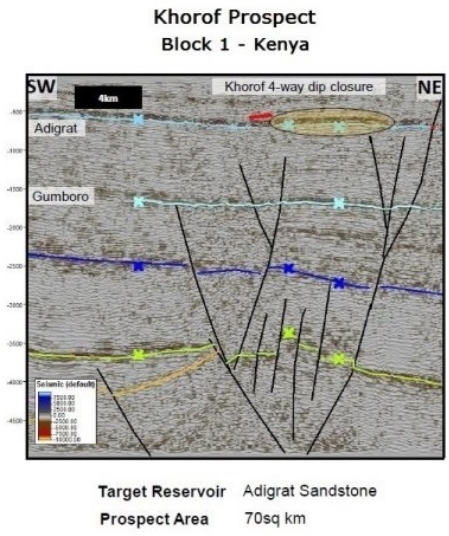
El Wak Prospect



Khorof Prospect







Prospective Resource Estimate

A NI 51-101-compliant Prospective Resource Assessment has not yet been completed on Block 1. However, the managements of both Afren plc and Taipan Resources have periodically proffered estimates.

Today, the gross mean prospective resource estimate by the management of Afren is **2,422 MMBOE** (or 484 MMBOE net to Taipan).[xix] However, Taipan's management more conservatively estimates that the gross unrisked prospective resource is 1,300 MMBOE (or 260 MMBOE net to Taipan).[xx] Incidentally, the management of Afren estimates that the Gross Unrisked Prospective Resource of the Khorof prospect is 270 MMBOE (which would imply 54 MMBOE net to Taipan).[xxi]

When Taipan Resources was in the process of acquiring Lion Petroleum in mid-2012**,** the total net unrisked prospective resources on the both blocks was 528 MMBOE, which was based upon the NI 51-101 report prepared by Sproule Associates for Block 2B and an estimate by Afren's management for Block 1. Since the gross unrisked prospective resources of Block 2B was 410 MMBOE at the time, it implies that the net unrisked prospective resources on Block1 was **118 MMBOE** to Taipan in mid-2012.

With recent access to Afren's processed 2D seismic data, Taipan initiated the process of commissioning a NI 51-101-compliant report on Block 1, which should be available sometime in the second half of 2014.

Default in Block 1 Resolved

During the first quarter of fiscal 2013, Taipan Resources and the operator of Block 1 (East Africa Exploration Ltd aka EAX) entered into a dispute over noncompliance with the terms of the farm-out agreement, the deed of assignment and the joint operating agreement. As a result, declined to pay its share of cash calls and EAX retaliated by issuing a Notice of Default. Subsequently, in May 2014, the situation was resolved, and Taipan Resources earned back its 20% participating interest by paying the cash calls plus accrued interest (which totaled $3,566,377) to Afren.

Funding

As a result of the private placement of Units completed in April 2014, Taipan Resources was able to resolve any encumbrance of its 20% participating interest in Block 1 due to the Notice of Default and is **fully funded through the drilling of the first exploratory well** by Afren.

Expected Milestones and Related Events:

- Acquisition and processing of 290 km of 2D seismic in late-2014
- Evaluation of El Kuran-3 well located in the Ogaden Basin close to the border with Block 1
- The completion of an initial NI 51-101-compliant Prospective Resource Assessment on Block 1
- Drilling of an exploratory well at either the El Wak or Khorof prospect of Block 1 within the next 12 months

RECENT NEWS

Block 2B

On June 24, 2014, Africa Oil (AOI: TO) announced that its 3,030-meter **Sala-1 well on Block 9** in the Anza Basin encountered three zones of interest over a 1,000 meter gross interval. The upper gas-bearing interval tested dry gas from a 25-meter net pay interval (maximum rate of 6 MMCF/D) and the 50-meter lower interval of potential net pay tested at low rates of dry gas. The discovery confirms the

potential for the accumulation of hydrocarbons as a gas deposit in the structural trapping associated with the bounding Lagh-Bhogal Fault along the Anza Basin. The Sala-1 well is located approximately 83 km northwest of **Taipan's** Badada Prospect.

On June 2, 2014, the Taipan's **farm-out agreement with Tower Resources closed**, by which Tower Resources acquired a 15% participating interest in Kenya's Block 2B. **Taipan Resources received $4.5 million in cash** and **4.5 million Ordinary Shares in Tower Resources** (TRP: LSE). An additional 4.5 million shares will be received in early September. As a partner, Tower Resources is obligated to pay its participating interest share of costs going forward.

On March 6, 2014, Taipan Resources announced that **BGP completed 196.2 km 2D seismic survey on Block 2B**. The newly-acquired seismic data confirms a robust closure at the Badada Prospect, and the interpretation of the processed data will aid in finalizing the drilling location.

Block 1

On May 21, 2014**,** Taipan Resources announced the **favorable resolution of the default position on Block 1**. The company allocated a portion of the net proceeds from recently-completed private placement (see below) to pay $3,566,377 to Afren plc, thereby resolving the default and restoring the rights and entitlements to Taipan Resources for its 20% participating interest in Block 1. As a result, Taipan received the technical data on the block from Afren, and management began the process of commissioning an initial NI 51-101 Technical Report on the block.

Taipan Resources Begins Trading on OTCQX

On May 23, 2014, Taipan Resources began trading on the OTCQX, the OTC market's highest tier.

Financing

On April 8, 2014, Taipan Resources closed the second and final tranche of a private placement. Both tranches raised total **net proceeds of approximately $6.11 million** through the issuance of 18,003,256 Units at a price of $0.36 per Unit. Each Unit consists of one common share and one four-year warrant exercisable into an additional common share at $0.50.

On February 13, 2013, Taipan completed a non-brokered private placement of 8,878,425 Units at $0.35 per Unit. Gross proceeds were approximately $3,107,450. Each Unit consists of one common share and one five-year warrant exercisable into a common share at $0.50. The management of Taipan subscribed for approximately 20% of the offering.

VALUATION

East Africa (and Kenya in particular) is widely regarded as a frontier area for oil & gas exploration and is generating considerable interest. Though there were some discoveries in the 1970s and 1980s, relatively recent exploration prospects have stimulated sizable investor interest, especially ever since the series of impressive oil discoveries by Heritage Oil (HOIL: LSE) and Tullow Oil (TLW: LSE) starting in November 2006 through mid-2007 in Uganda's Albertine Basin and particularly in Kenya's South Lokichar Basin by Tullow Oil and Africa Oil (AOI: TSXV) beginning in March 2012. In addition, heightened attention in the passive margin and rift plays has motivated some major oil companies (ExxonMobil, Total, Marathon and Statoil to name a few) to acquire interests in certain blocks, indicating a high level of prospectivity from experienced professional buyers. This corporate interest is also evident from many farm-in agreements

by junior producers over the last few years. As a frontier exploration play in the emerging petroleum province of East Africa, Taipan Resources has significant upside potential.

Valuation analysis of exploration companies with Prospective Resources in frontier areas is a challenging exercise. Not only are the resource estimates tentative, but also the uncertainties of discovery and economic development are large. However, the utilization of **comparative analysis** of other junior exploration companies with Prospective Resources appears to be a reasonable methodology to ascertain valuation parameters to estimate a target price. Also, through **scenario analysis**, the stock's price potential can be assessed under various scenarios of developmental success and failure.

Comparative Analysis

Comparable valuation data points for peer frontier companies are fairly limited. Companies similar to Taipan Resources (exploration companies with prospective resources and not generating revenues) often, but not always, provide prospective resource data, and in some cases contingent resource information. The resource information is fraught with concerns of consistency as management's tend to selectively release information and prospective resource data, which may or may not be NI 51-101-compliant. Nevertheless, peer valuation multiples of frontier oil & gas exploration companies with Net Risked Contingent Resources are generally valued between $4.50 and $2.50 per barrel while **Net Risked Prospective Resources are valued between $0.25 and $2.50 per barrel**.

COMPARABLE COMPANIES

Company	Type	Primary Resource Location	Ticker	Currency	7/31/14 Price	TTM High Price	TTM Low Price	Mkt Cap ($MM)	Net Risked Contingent Resources (MMBOE) Best	Net Risked Prospective Resource (MMBOE) Best	Net Unrisked Prospective Resources (MMBOE Best	Current Mkt Cap/ Net Risked Resources ($/BOE)	High Mkt Cap/ Net Risked Resources ($/BOE)	Low Mkt Cap/ Net Risked Resources ($/BOE)
PRIMARILY CONTINGENT RESOURCES														
Ophir Energy	Deep water	Africa	OPHR.L	GBp	215.50	393.90	211.20	2,158	801	125	585	2.33	4.26	2.28
PRIMARILY PROSPECTIVE RESOURCES														
Jacka Resources Ltd	Onshore	Africa	JKA.AX	AUD	0.05	0.16	0.04	17	4	8	54	1.39	4.84	1.21
Africa Oil	Onshore	Africa	AOI.V	CDN	6.68	10.61	6.65	1,914	231	1,369	3,301	1.20	1.90	1.19
Tangiers Petroleum	Off shore	Africa	TPT.AX	AUD	0.13	0.33	0.10	24	0	33	217	0.74	1.87	0.57
Pancontinental	On & off shore	Africa	PCL.AX	AUD	0.02	0.09	0.02	25	0	38	751	0.66	2.56	0.57
Taipan Resources	Onshore	Africa	TPN.V	CDN	0.40	0.66	0.23	39	0	83	962	0.47	0.77	0.27
Simba Energy	Onshore	Africa	SMB.V	CDN	0.06	0.09	0.05	12	0	27	445	0.46	0.70	0.39
Azonto Petroleum	Off shore	Africa	AZO.L	GBp	1.00	2.90	0.68	20	9	39	182	0.41	1.18	0.28
FAR Ltd	On & off shore	Africa	FAR.AX	AUD	0.04	0.06	0.03	91	35	235	5,400	0.34	0.52	0.26
											Average	**0.71**	**1.79**	**0.59**

The relative wide range of valuation multiples can also be attributed to the inconsistency of various metrics among the comparative companies, including the potential size of prospects and the probability of success. For example, prior to 2000, the global average frontier exploration success rate was approximately 10%; however, over the last decade, the success rate has risen to around 20%, primarily from advances in technology, especially concerning the processing and interpretation techniques of seismic data. Also, macro-economic-driven and political event-driven multiple expansion and compression have affected the valuation range of oil & gas stocks over time. In addition, the high valuations can be caused by events that act as catalysts for increased investor interest e.g. a successful discovery well.

Our **primary valuation methodology** for junior exploration companies with prospective resources in frontier areas is **based risked NAV (Net Asset Value)**, which utilizes an appropriate price per BOE multiple on the risked value of prospective resource potential. The price per BOE multiple is derived from the historical multiple ranges from comparative oil & gas exploration companies with prospective resources.

Taipan Resources has minority interests in two properties in Kenya, one with a 51-101-compliant estimate of Prospective Resources and other with an estimate based on Afren's management. The most recent 51-101-compliant Competent Person's Report on Block 2B of Prospective Resources (as of December 31, 2013) estimates a net mean risked prospective resource of 41.0 MMBOE based on 19

leads.[xxii] On Block 1, the gross unrisked estimate by Afren's management implies 41.6 MMBOE to Taipan Resources for **total Net Mean Risked Prospective Resources of 82.6 MMBOE on both blocks**. Currently, the valuation of the entire comparable Prospective Resource group is depressed. Therefore, we are using a reversion-to-the mean multiple in our target assessment. **The average multiple in the last 12 months has been 1.00 per BOE** (removing Jacka Resources which has a high proportion of Contingent Resources). This Prospective Resource valuation methodology results in a **NAV-based target of CDN $0.87**. No discount to the target price is necessary given Taipan's cash balance and fully funded drilling programs.

M&A Analysis

Another valuation methodology involves Merger and Acquisition (M&A) valuation. Majors, mid-tiers and juniors are seeking to enter, complement and diversify by acquiring prospective acreage in East Africa. Transactions from 2006 to the present have averaged $2.30 per BOE, which would imply a **transaction-based target of CDN $1.98**.

Scenario analysis

Scenario analysis offers insight into the potential impact of transformational exploration catalysts. Over the next 12 months, two high impact exploration wells aim to de-risk the 837 MMBLS of gross unrisked prospective resources related to the Badada and Khorof/El Wok prospects.

A significant discovery would boost Taipan's valuation dramatically. A positive evaluation of one or both of these two wells would affect the opportunity value of the remaining prospective resources in Block 2B and Block 1. A commercial-sized discovery would not only open another basin, but also improve the chance of commerciality, thereby converting a larger percentage of the unrisked prospective resources into risked prospective resources and most likely upgrading and increasing the overall resource estimate.

When successful wells are drilled by major oil companies, such as ExxonMobil (NYSE: XOM) or Royal Dutch Shell (NYSE: RDS.B), the impact on share prices is negligible in comparison to discoveries announced by junior exploration companies. Even among juniors, new major discoveries can result in varying degrees of share price movement.

A recent notable example was the announcement on March 26, 2012 that the Ngamia-1 well (the first oil discovery that opened the Lokichar Basin in Kenya) hit 100 meters of net play. Africa Oil (AOI: TSXV) rallied 43% the next day from $2.34 to $3.35. Within 10 weeks, Africa Oil's stock peaked at $11.35 on May 28th, during which time Africa Oil's stock traded from a valuation of 0.43 per BOE on Net Risked Prospective Resources to 2.09 per BOE. At the same time, the ADR of Africa Oil's more diversified partner, Tullow Oil (TUWOY: OTC Pink) hovered in the $11.50-to-$12.50 range (roughly 1,450-to-1,550 GBp TLW: LSE). Since both Africa Oil and Tullow Oil hold a 50% working interest in Block 10BB where the Ngamia-1 well is located, the discrepancy in the price action can be attributed to Africa Oil's aggressive exploration strategy with no production revenues versus Tullow's diversified portfolio of oil & gas projects with producing, exploration and appraisal properties. If one of Taipan's exploratory wells is as successful as Ngamia-1, a commensurate multiple expansion would imply a **commercial well discovery target of CDN $1.80.**

Further evaluation of the recently completed Sala-1 well and results from Sala-2 (both in Block 9) by Africa Oil should also shed more light on the prospectivity of the Anza Basin and could further stimulate investor interest, since a particular play type is de-risked within the region once it has been proven. Similarly, other events could potentially de-risk Taipan's prospects, such as other oil & gas exploration companies announcing oil and/or gas discoveries in Kenya or elsewhere in East Africa. In addition, a seismic campaign that increases the geological chance of success and/or expands the resource estimate in a technical study could serve as a positive near-term catalyst.

Risk Analysis

Whether called frontier investing or elephant hunting, the attendant risks are likewise high when the potential payoff is large. Unquestionably, the exploratory wells to be drilled on Taipan's blocks not only have huge potential, but also carry more risk. For example, on November 26, 2012, shares of Africa Oil declined precipitously after the announcement that its Twiga South-1 exploration well located in Block 13T encountered 30 meters of net oil pay, which was a disappointment after the 100-200 meters of net pay encountered at Ngamia-1 earlier that year. Africa Oil's stock plummeted 43.5% from $10.62 to $6.00 over three weeks before stabilizing in the $6.50-$7.25 range. A few months later, on March 1, 2013, Africa Oil's stock again declined significantly after the announcement that the Paipai-1 exploration well in Kenya's in Block 10A was temporarily suspended for "ongoing evaluation." Over the ensuing seven weeks, Africa Oil's stock declined 23.0% from $7.16 to $5.51 before recovering.

Other risks to valuation include delays of the drilling program, higher than expected expenditures, political/military factors and dilution from share offerings and/or additional farm-outs.

Conclusion

In summary, our valuation approach utilizes risk-adjusted net prospective resource estimates of the delineated exploration prospects. **Our risked NAV valuation of Taipan Resources is CDN $0.87** with upside potential of up to CDN $1.80 on the discovery of a commercial well and a transaction-based target of CDN $1.98. Taipan Resources offers exposure to potential transformational exploration play openers in the Anza and Mandera-Lugh Basins. Significant news flow is expected in 2015 as results from the drilling at the Badada and Khorof Prospects are announced. These impact well updates will serve as catalysts to share price movement. Positive results from the two exploration wells would aid in de-risking the resource estimates with the probable expansion of estimated prospective resources and the conversion of some prospective resources to contingent reserves.

RISKS

- The exploration for hydrocarbons is a high-risk venture with many uncertainties, but especially the risks associated with discovery and economic recoverability. The frontier status of the East African region elevates the risks associated with the exploration for oil & gas.
- Both Block 2B and Block 1 are in the exploration stage and contain no reserves or contingent resources. The NI 51-101-compliant report on Block 2B provides estimates on Prospective Resources (see Prospective Resources Primer section).
- Kenya's nascent petroleum industry has not yet established the infrastructure required to fully exploit the country's petroleum resources.

BALANCE SHEET & PROJECTED INCOME STATEMENT

TAIPAN RESOURCES INC.

(in $ Canadian)	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	2Q FY2014
Fiscal Years ending October 31st	10/31/2007	10/31/2008	10/31/2009	10/31/2010	10/31/2011	10/31/2012	10/31/2013	04/30/2014
ASSETS								
Cash and cash equivalents	322,957	258,354	395,597	1,599,063	1,492,971	2,690,299	271,931	4,001,669
Deposits and prepaid expense	1,067	1,667	3,150	6,110	4,596	52,748	104,735	162,689
GST receivable	306	504	3,697	-	-	-	-	-
Receivables	-	-	-	29,192	31,137	37,513	10,858	11,410
Restricted cash	-	-	-	-	-	3,250,000	-	-
Total current assets	**324,330**	**260,525**	**402,444**	**1,634,365**	**1,528,704**	**6,030,560**	**387,524**	**4,175,768**
Property and equipment - net								
Mineral property (Lucky Joe Property)	-	-	25,000	-	-	-	-	-
Exploration and evaluation assets (Kenya)						15,912,061	15,912,061	15,912,061
Total assets	**324,330**	**260,525**	**427,444**	**1,634,365**	**1,528,704**	**21,942,621**	**16,299,585**	**20,087,829**
LIABILITIES AND SHAREHOLDERS' EQUITY (DEFICIT)								
Accounts payable & accrued liabilities	10,115	8,508	55,010	10,908	11,195	1,567,434	6,705,158	4,392,852
Due to directors	-	627	-	-	-	-	-	-
Total current liabilities	**10,115**	**9,135**	**55,010**	**10,908**	**11,195**	**1,567,434**	**6,705,158**	**4,392,852**
Long-term liabilities	-	-	-	-	-	-	-	-
Total liabilities	**10,115**	**9,135**	**55,010**	**10,908**	**11,195**	**1,567,434**	**6,705,158**	**4,392,852**
Common stock	349,672	350,482	350,482	2,332,221	2,332,221	23,009,842	26,188,849	32,324,940
Share subscriptions	-	-	259,800	-	-	-	-	(133,200)
Additional paid-in-capital	51,204	66,044	66,044	66,044	66,044	383,449	2,231,189	2,775,227
Accumulated deficit	(86,661)	(165,136)	(303,892)	(774,808)	(880,756)	(3,018,104)	(18,825,611)	(19,271,990)
Total shareholders' equity (deficit)	314,215	251,390	372,434	1,623,457	1,517,509	20,375,187	9,594,427	15,694,977
Total equity (deficit)	314,215	251,390	372,434	1,623,457	1,517,509	20,375,187	9,594,427	15,694,977
Total liabilities and shareholders' equity	**324,330**	**260,525**	**427,444**	**1,634,365**	**1,528,704**	**21,942,621**	**16,299,585**	**20,087,829**
Shares outstanding	6,009,950	6,014,450	6,014,450	31,374,450	31,374,450	74,789,667	85,299,363	103,302,619

TAIPAN RESOURCES INC.

Consolidated Statements of Operations and Comprehensive Income

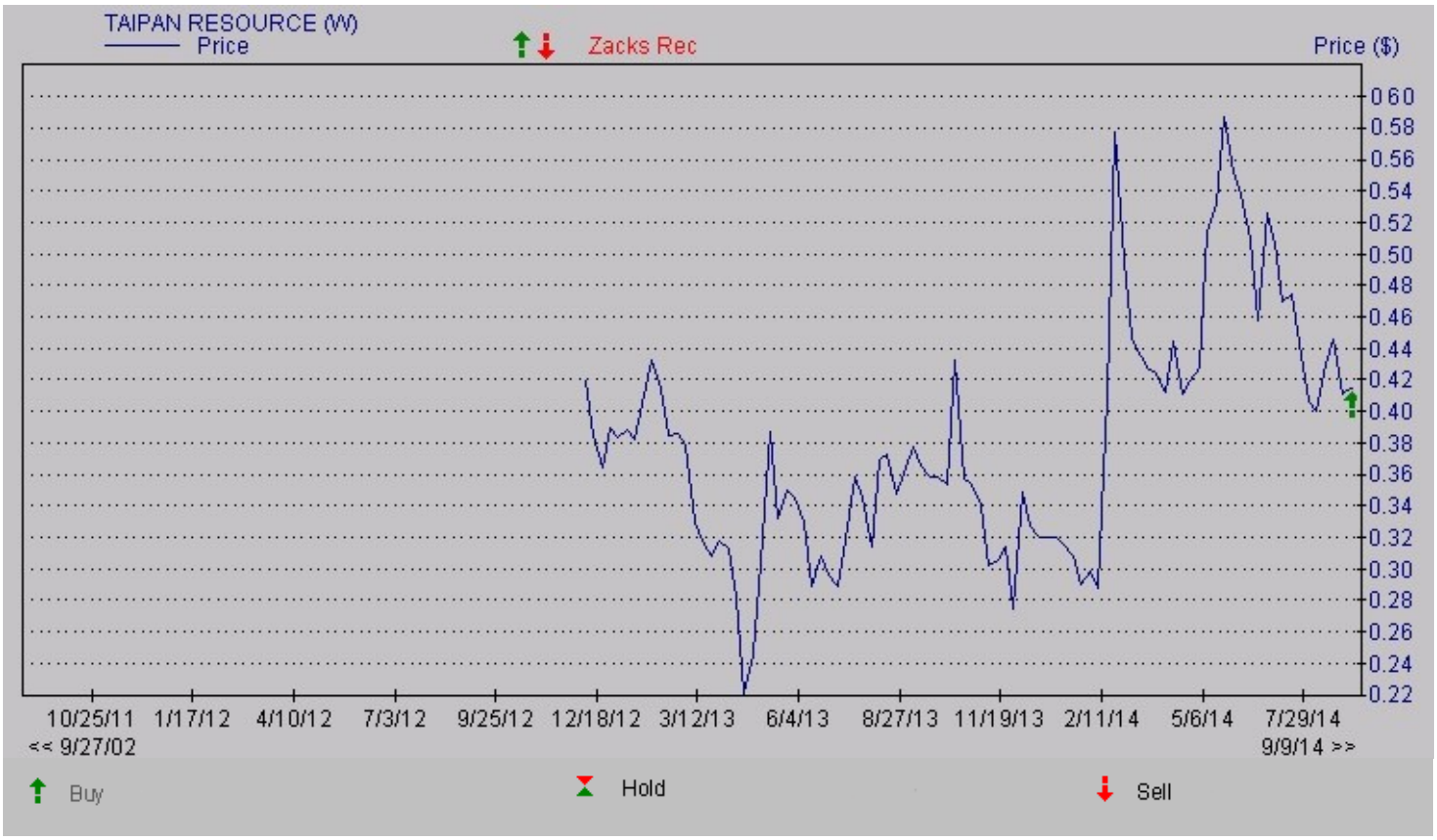
(in $ Canadian) For the years ending October 31	Fiscal Year 2013	FY 2013 NDJ 1Q	FY 2013 FMA 2Q	FY 2013 MJJ 3Q	FY 2013 ASO 4Q	Fiscal Year 2014
Revenue:	**0**	**0**	**0**	**0**	**0**	**0**
Expenses:						
Exploration expenditures (recovery)	1,333,389	917,752	6,814,821	898,687	4,096,839	12,728,099
Filing and regulatory	85,241	14,458	24,495	7,496	2,317	48,766
Management and consulting fees	267,028	191,249	72,971	140,087	(65,440)	338,867
Office, rent and administrative	138,415	109,289	5,107	23,659	43,726	181,781
Accounting & legal fees (professional fees)	173,032	112,748	26,355	40,992	68,325	248,420
Property evaluation expenses	0	0	0	0	0	0
Promotion and shareholder relations	47,262	73,228	69,562	73,419	53,872	270,081
Receivable allowance	0	0	0	0	71,898	71,898
Stock-based compensation	28,532	1,196,875	20,185	313,416	156,716	1,687,192
Travel and accommodations	231,506	55,223	35,445	45,068	60,376	196,112
Operating expenses	**2,304,405**	**2,670,822**	**7,068,941**	**1,542,824**	**4,488,629**	**15,771,216**
Loss from operations	**(2,304,405)**	**(2,670,822)**	**(7,068,941)**	**(1,542,824)**	**(4,488,629)**	**(15,771,216)**
Interest income (expense)	0	0	0	0	0	0
Write-off of mineral property interest	-	-	-	-	-	-
Gain (loss) on settlement of debt	80,239	-	-	-	-	-
Foreign exchange gain (loss)	20,774	(9,505)	(79,468)	89,325	(36,643)	(36,291)
Total other income (expense)	**101,013**	**(9,505)**	**(79,468)**	**89,325**	**(36,643)**	**(36,291)**
Gain (loss) before income taxes	**(2,203,392)**	**(2,680,327)**	**(7,148,409)**	**(1,453,499)**	**(4,525,272)**	**(15,807,507)**
Future income tax (recovery)	0	0	0	0	0	0
Net Gain (Loss)	**(2,203,392)**	**(2,680,327)**	**(7,148,409)**	**(1,453,499)**	**(4,525,272)**	**(15,807,507)**
Total comprehensive loss	**(2,203,392)**	**(2,680,327)**	**(7,148,409)**	**(1,453,499)**	**(4,525,272)**	**(15,807,507)**
Diluted net income per common share	**(0.05)**	**(0.04)**	**(0.09)**	**(0.02)**	**(0.05)**	**(0.19)**
Wgtd avg. com. shares out.- diluted	44,011,330	74,789,667	82,588,563	85,149,363	85,364,059	81,972,913

For the years ending October 31	Fiscal Year 2013	FY 2014 NDJ 1Q	FY 2014 FMA 2Q	FY 2014 MJJ 3Q E	FY 2014 ASO 4Q E	Fiscal Year 2014 E
Revenue:	**0**	**0**	**0**	**0**	**0**	**0**
Expenses:						
Exploration expenditures (recovery)	12,728,099	(424,102)	(1,078,908)	250,000	262,500	(990,510)
Filing and regulatory	48,766	4,244	29,368	16,806	17,646	68,064
Management and consulting fees	338,867	87,814	158,023	122,919	129,064	497,820
Office, rent and administrative	181,781	74,150	130,405	102,278	107,391	414,224
Accounting & legal fees (professional fees)	248,420	74,164	122,799	98,482	103,406	398,850
Property evaluation expenses	0	0	0	0	0	0
Promotion and shareholder relations	270,081	142,867	237,953	190,410	220,000	791,230
Receivable allowance	71,898	0	10,686	0	0	10,686
Stock-based compensation	1,687,192	0	432,078	600,000	700,000	1,732,078
Travel and accommodations	196,112	100,203	126,749	113,476	120,000	460,428
Operating expenses	**15,771,216**	**59,340**	**169,153**	**1,494,370**	**1,660,008**	**3,382,870**
Loss from operations	**(15,771,216)**	**(59,340)**	**(169,153)**	**(1,494,370)**	**(1,660,008)**	**(3,382,870)**
Interest income (expense)	0	0	0	0	0	0
Write-off of mineral property interest	-	-	-	-	-	0
Write-off of AP and acc. liabilities	-	0	55,293	0	0	55,293
Gain (loss) on settlement of debt	-	-	-	-	-	0
Foreign exchange gain (loss)	(36,291)	(259,205)	(13,974)	0	0	(273,179)
Total other income (expense)	**(36,291)**	**(259,205)**	**41,319**	**0**	**0**	**(217,886)**
Gain (loss) before income taxes	**(15,807,507)**	**(318,545)**	**(127,834)**	**(1,494,370)**	**(1,660,008)**	**(3,600,756)**
Future income tax (recovery)	0	0	0	0	0	0
Net Gain (Loss)	**(15,807,507)**	**(318,545)**	**(127,834)**	**(1,494,370)**	**(1,660,008)**	**(3,600,756)**
Total comprehensive loss	**(15,807,507)**	**(318,545)**	**(127,834)**	**(1,494,370)**	**(1,660,008)**	**(3,600,756)**
Diluted net income per common share	**(0.19)**	**(0.00)**	**(0.00)**	**(0.01)**	**(0.02)**	**(0.04)**
Wgtd avg. com. shares out.- diluted	81,972,913	85,299,363	90,498,691	105,037,619	105,037,619	96,468,323

TAIPAN RESOURCES INC.

Consol. Statements of Ops & Comprehensi (in $ Canadian)	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014 E
For the years ending October 31	10/31/2007	10/31/2008	10/31/2009	10/31/2010	10/31/2011	10/31/2012	10/31/2013	10/31/2014
Revenue:	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Expenses:								
Exploration expenditures (recovery)	-	-	-	-	-	1,333,389	12,728,099	(990,510)
Filing and regulatory	13,600	7,171	21,310	23,552	7,895	85,241	48,766	68,064
Management and consulting fees	0	1,610	0	55,000	36,111	267,028	338,867	497,820
Office, rent and administrative	10,275	17,019	26,005	34,588	8,615	138,415	181,781	414,224
Professional fees	8,641	20,607	75,222	50,479	24,708	173,032	248,420	398,850
Property evaluation expenses	3,376	0	0	0	0	0	0	0
Promotion and shareholder relations	8,243	9,033	15,796	14,505	36,965	47,262	270,081	791,230
Receivable allowance	-	-	-	-	-	-	71,898	10,686
Stock-based compensation	32,800	15,200	0	0	0	28,532	1,687,192	1,732,078
Travel and accommodations	5,440	7,632	0	0	0	231,506	196,112	460,428
Operating expenses	**82,375**	**78,272**	**138,333**	**178,124**	**114,294**	**2,304,405**	**15,771,216**	**3,382,870**
Loss from operations	**(82,375)**	**(78,272)**	**(138,333)**	**(178,124)**	**(114,294)**	**(2,304,405)**	**(15,771,216)**	**(3,382,870)**
Interest income (expense)	(265)	(203)	(423)	6,947	8,970	0	0	0
Write-off of mineral property interest	-	-	-	(355,952)	-	-	-	0
Write-off of AP and acc. liabilities	-	-	-	-	-	-	-	55,293
Gain (loss) on settlement of debt	-	-	-	-	-	80,239	-	0
Foreign exchange gain (loss)	-	-	-	-	(624)	20,774	(36,291)	(273,179)
Total other income (expense)	**(265)**	**(203)**	**(423)**	**(349,005)**	**8,346**	**101,013**	**(36,291)**	**(217,886)**
Gain (loss) before income taxes	**(82,640)**	**(78,475)**	**(138,756)**	**(527,129)**	**(105,948)**	**(2,203,392)**	**(15,807,507)**	**(3,600,756)**
Future income tax (recovery)	0	0	0	(56,213)	0	0	0	0
Net Gain (Loss)	**(82,640)**	**(78,475)**	**(138,756)**	**(470,916)**	**(105,948)**	**(2,203,392)**	**(15,807,507)**	**(3,600,756)**
Total comprehensive loss	**(82,640)**	**(78,475)**	**(138,756)**	**(470,916)**	**(105,948)**	**(2,203,392)**	**(15,807,507)**	**(3,600,756)**
Diluted net income per common share	**(0.02)**	**(0.01)**	**(0.02)**	**(0.02)**	**(0.00)**	**(0.05)**	**(0.19)**	**(0.04)**
Wgtd avg. com. shares out.- diluted	5,032,264	6,011,947	6,014,450	22,653,135	31,374,450	44,011,330	81,972,913	96,468,323

HISTORICAL ZACKS RECOMMENDATIONS



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The current distribution is as follows: Buy/Outperform- 16.0%, Hold/Neutral- 77.2%, Sell/Underperform – 5.9%. Data is as of midnight on the business day immediately prior to this publication.

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[i] Afren plc's 2014 Half-yearly Results Presentation, August 29, 2014, page 42.
[ii] Item 6.1 of the Farm-Out Agreement dated October 15, 2013.
[iii] Canadian Oil and Gas Evaluation Handbook (COGEH), Volume 1, Section 5.2.3 a.
[iv] Canadian Securities Staff (CSA) Staff Notice 33 OSCB 11936, December 24, 2010, page 10 and Petroleum Resources Management System Sponsored by Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC) and Society of Petroleum Evaluation Engineers (SPEE) page 3.
[v] CSA Staff Notice 33 OSCB 11936, December 24, 2010, page 12.
[vi] Canadian Oil and Gas Evaluation Handbook (COGEH), Volume 1, Section 5.2.3 a.
[vii] National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI 51-101), Section 5.3 (b) Definitions of Resource Categories.
[viii] A graben is a depressed block of the earth's crust that is bounded on at least two sides by faults, such as a rift valley.
[ix] Initially the PSC required a 25 km2 3D seismic program, which was subsequently negotiated to a 100 km 2D seismic program
[x] Item 6.1 of Farm-Out Agreement states Premier Oil will pay Taipan's working interest share of the cost of drilling and testing the first exploratory well and future costs on Block 2B up to a cost of US$13.275 million.

[xi] Profit oil is that portion of total crude oil produced in excess of cost oil (production used to satisfy recoverable costs, expenses and expenditures).
[xii] Subsequently, issues over oil pipeline fees shut down oil production from South Sudan between January 2012 and April 2013, and again in February 2014.
[xiii] Assessment of Undiscovered Oil and Gas Resources of the Sud Province, North-Central Africa, March 2011.
[xiv] Changing Exploration Focus Paved Way for Success, GEO ExPro, May 2006.
[xv] Profit oil is that portion of total crude oil produced in excess of cost oil (production used to satisfy recoverable costs, expenses and expenditures).
[xvi] Burmah Oil was acquired by British Petroleum (BP plc) in 2000.
[xvii] Formerly known as Standard Oil Company of Indiana, Amoco merged with British Petroleum in 1998.
[xviii] The fold of 2D seismic data is calculated by dividing the number of seismometer groups by twice the number of group intervals between shot points. Typical values of fold for modern seismic data range from 60 to 240 for 2D seismic data.
[xix] Afren plc's 2014 Half-yearly Results Presentation, August 29, 2014, page 42.
[xx] Taipan Resources Investor Presentation, September 2014.
[xxi] Afren plc's 2013 Full Year Results Presentation dated March 27, 2014, page 28.
[xxii] 51-101-compliant Resource Estimate of Block 2B in Kenya (as of December 31, 2013), Table S-2B, page 6