# Competent Persons Report for Certain Assets in Offshore Guyana, Offshore Namibia and Offshore South Africa

## Prepared in accordance with the AIM Note for Mining and Oil and Gas Companies

**Effective Date: 20 March 2022**
**Date of this Report: 20 March 2022**

**Prepared for:**

## ECO (Atlantic) Oil & Gas Ltd

**And**

## Strand Hanson, Ltd.

**Prepared By:**


**Letha C. Lencioni**
**Registered Petroleum Engineer**
**State of Colorado #29506**

**5665 Flatiron Parkway, Suite 250**
**Boulder, CO 80301**

# 1. EXECUTIVE SUMMARY

This report addresses the ECO (Atlantic) Oil & Gas Ltd ("ECO Atlantic", "ECO", "The Company") exploratory oil and gas assets in offshore Guyana, offshore Namibia and offshore South Africa. The assets owned by ECO Atlantic are summarized in Table 1-1.

**Table 1-1 Summary of Assets owned by ECO (Atlantic) Oil & Gas Ltd**

| Asset | Country | Operator | Working Interest (%) | Status | Expiry Date | License Area ($km^2$)[1] | Water Depth, meters |
|---|---|---|---|---|---|---|---|
| Orinduik Block | Guyana | Tullow | 15.0 | Exploration | January 2026 | 1,800 | 70 to 1,450 |
| Canje Block | Guyana | Exxon | - | Exploration | | | |
| Block 2012A (Cooper) (PEL97) | Namibia | ECO | 85.0 | Exploration | February 2031 | 5,788 | 100 to 500 |
| Blocks 2111B and 2211A (Guy) (PEL99) | Namibia | ECO | 85.0 | Exploration | February 2031 | 11,457 | 1,500 to 3,000 |
| Blocks 2211Ba and 2311A (Tamar)(PEL100) | Namibia | ECO | 85.0 | Exploration | February 2031 | 5,648 | 2,500 to 3,000 |
| Blocks 2213A & 2213B (west half) (Sharon)(PEL98) | Namibia | ECO | 85.0 | Exploration | February 2031 | 5,700 | 100 to 500 |
| 2B Block | South Africa | ECO | 50.0 | Exploration | 11/16/2022 | 3,062 | 100 to 250 |
| 3B/4B Block | South Africa | Africa Oil Corp | 20.0 | Exploration | March 2022* | 17,581 | 1,700 to 3,500 |

*Note: The increase in Eco's Namibian interests, addition of 6,457 $km^2$ to the Guy Block, and the stated ownership of the South African assets assumes the completion of the acquisition of Azinam Group Holdings ("Completion"). As announced by Eco on 11 March 2022, all conditions required for Completion have occurred save and except for receipt of the final approval of the TSX Venture Exchange (the "Approval"). Such Approval is expected imminently. This report assumes such Approval has been granted and Completion has occurred, including the increased interests in Namibia and South Africa having become effective.*

** Renewal expected.*

[1] Approximate

This report is an update to the reports dated February 1, 2020 (for Orindiuk Block)[2] and October 31, 2016 (for Namibia assets)[3] by Gustavson Associates LLC (note that Gustavson Associates LLC is now a part of WSP USA) and reflects an expected change in ownership, public information from off block wells, and additional blocks in South Africa and their leads. The expected change in ownership percentage and change in size in the offshore Namibia blocks and the addition of offshore blocks in South Africa are a result of the acquisition of the Azinam assets, completion of which is expected imminently. For the assets in Guyana and the Sharon and Cooper Blocks, no new geologic or geophysical data are available, and the Prospective Resource estimates presented in the 2020 and 2016 reports are simply repeated here.

In addition, ECO, through an acquisition of an interest in JHI Associates has acquired an indirect working interest in the Canje Block in offshore Guyana; however, the leads have not been evaluated for this report. The Namibia blocks have new Petroleum Exploration Licenses granted as of 3 February 2021.

WSP has prepared estimates of Prospective Resources based on probabilistic calculations, with reservoir parameters extracted from our review of geological and geophysical interpretations prepared by ECO and/or their various partners. These probabilistic estimates of unrisked Prospective Oil and Gas Resources are presented in Table 1-2 for all of the assets detailed in this report.

Note that these estimates do not include consideration for the risk of failure in exploring for these resources. The results from the drilling of the Jethro 1 and Joe 1 wells on the Orinduik Block indicated the presence of oil and gas; however, the level of testing of these hydrocarbon accumulations was not sufficient to change the category of those resources from Prospective to Contingent.

[2] Gustavson Associates, LLC: "Competent Persons Report for Certain Assets in Offshore Guyana Prepared According to AIM Note for Mining and Oil and Gas Companies," 1 February 2020.
[3] Gustavson Associates, LLC: "Competent Persons Report for Certain Assets in Offshore Namibia and Offshore Guyana," 31 October 2016.

A discovery well, the A-J1, was drilled in the 2B Block in South Africa in 1988.  WSP has not evaluated any resources associated with this well.

Resources associated with the Canje Block in Guyana and Tamar Block in Namibia are still under evaluation and no resource estimation for these blocks have been prepared as part of this report. As such, information relating to these blocks is not presented in this report to the same level of detail as for the other blocks.  Data for this report has been provided by Azinam, Africa Energy, Africa Oil, JHI, and Tullow.  There are numerous additional leads and prospects in several different blocks that are still being evaluated as of the writing of this report.

**Table 1-2 Unrisked Prospective Resource Estimates**

| | | Gross | | | Net attributable to ECO's interests | | | |
|---|---|---|---|---|---|---|---|---|
| **Asset** | **Country** | **Low Estimate** | **Best Estimate** | **High Estimate** | **Low Estimate** | **Best Estimate** | **High Estimate** | **Operator** |
| **Oil & Liquids Prospective Resources (millions of barrels)** | | | | | | | | |
| Lower Risk | | | | | | | | |
| Orinduik | Guyana | 2,315 | 4,537 | 8,179 | 347 | 681 | 1,227 | Tullow |
| Cooper | Namibia | 151 | 245 | 398 | 128 | 209 | 339 | ECO |
| 2B | South Africa | 209 | 491 | 984 | 104 | 246 | 492 | ECO |
| 3B/4B | South Africa | 973 | 3,088 | 7,138 | 195 | 618 | 1,428 | Africa Oil |
| Higher Risk | | | | | | | | |
| Cooper | Namibia | 283 | 507 | 843 | 241 | 431 | 717 | ECO |
| Guy | Namibia | 1,671 | 4,924 | 10,937 | 1,421 | 4,185 | 9,297 | ECO |
| Sharon | Namibia | 702 | 2,212 | 5,518 | 597 | 1,880 | 4,691 | ECO |
| **Total for Oil & Liquids** | | **6,304** | **16,004** | **33,998** | **3,033** | **8,249** | **18,189** | |
| **Gas Prospective Resources (billions of standard cubic feet)** | | | | | | | | |
| Lower Risk | | | | | | | | |
| Orinduik | Guyana | 1,798 | 3,626 | 6,811 | 270 | 544 | 1,022 | Tullow |
| Cooper | Namibia | 141 | 240 | 407 | 120 | 204 | 346 | ECO |
| 2B | South Africa | 31 | 73 | 149 | 15 | 37 | 74 | ECO |
| 3B/4B | South Africa | 426 | 1,360 | 3,136 | 85 | 272 | 627 | Africa Oil |
| Higher Risk | | | | | | | | |
| Cooper | Namibia | 264 | 496 | 868 | 224 | 422 | 738 | ECO |
| Guy | Namibia | 1,625 | 4,812 | 10,869 | 1,381 | 4,090 | 9,239 | ECO |
| Sharon | Namibia | 668 | 2,176 | 5,466 | 568 | 1,849 | 4,646 | ECO |
| **Total for Gas** | | **4,952** | **12,782** | **27,706** | **2,663** | **7,417** | **16,692** | |

*Source: Letha C. Lencioni*
*Note: Assets designated as "Lower Risk" have probability of success (POS) estimated at 16%-81%, while those designated as "Higher Risk" have POS estimated at 2%-3.5%.*
*"Operator" is name of the company that operates the asset*
*"Gross" indicates 100% of the resources estimated for the blocks, while "net" indicates the share attributable to ECO's interests.*
*The increase in Eco's Namibian interests, addition of 6,457 km$^2$ to the Guy Block, and the stated ownership of the South African assets assumes the completion of the acquisition of Azinam Group Holdings ("Completion"). As announced by Eco on 11 March 2022, all conditions required for Completion have occurred save and except for receipt of the final approval of the TSX Venture Exchange (the "Approval"). Such Approval is expected imminently. This report assumes such Approval has been granted and Completion has occurred, including the increased interests in Namibia and South Africa having become effective.*

**Prospective Resources** are defined as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity." [4] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Low Estimate represents the $P_{90}$ values from the probabilistic analysis (in other words, the value is greater than or equal to the $P_{90}$ value 90% of the time), while the Best Estimate represents the $P_{50}$ and the High Estimate represents the $P_{10}$. The totals given are simple arithmetic summations of values and are not themselves $P_{90}$, $P_{50}$, or $P_{10}$ probabilistic values.

[4] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Third Edition,* August 2018, updated October 2019, pg. 13.

# 2. TABLE OF CONTENTS

PAGE

APPENDICES



## LIST OF FIGURES

FIGURE PAGE

# LIST OF TABLES

# 3. INTRODUCTION

## 3.1 AUTHORIZATION

WSP (the Consultant) has been retained by ECO (Atlantic) Oil & Gas Ltd ("ECO Atlantic", "ECO", "The Company", "The Client") to prepare a Competent Persons Report in accordance with the AIM Note for Mining and Oil and Gas Companies. This report covers the assets owned by ECO in petroleum license blocks located in offshore Guyana, offshore Namibia, and offshore South Africa.

## 3.2 INTENDED PURPOSE AND USERS OF REPORT

The purpose of this Report is to update the Client's Prospective Resources on their assets based on new and additional data analysis and future operations.

## 3.3 OWNER CONTACT AND PROPERTY INSPECTION

This Consultant has had frequent contact with the Client. This Consultant has not personally inspected the subject property.

## 3.4 SCOPE OF WORK

This report is intended to describe and quantify the Prospective Resources contained within the Blocks in offshore Guyana, offshore Namibia, and offshore South Africa that are subject to petroleum license agreements with the governments of Guyana, Namibia, and South Africa.

The scope of work involved reviewing data provided by the Client including presentations, seismic data, maps, and interpretations. The interpretations prepared by the Client and/or their partners identified leads and prospects for potential further exploration. This work was reviewed for reasonableness. WSP has not prepared any independent geological and geophysical interpretations or maps. Parameters were extracted from the Client provided data in order to estimate the

Prospective Resources on the Client's assets. Note that new calculations were made as a portion of the work related to this report only for the Guy Block in Namibia, where two new leads were added and the license area containing a portion of another lead was regained, and for the new blocks offshore South Africa. The other resource estimates are reproduced from our 2016 and 2020 reports. The files provided by the Client that were relied upon for our analyses are presented in Section 6, References.

## 3.5 APPLICABLE STANDARDS

This report has been prepared in accordance with the AIM rules for Companies, which includes specifically the Note for Mining and Oil and Gas Companies. The Prospective Resource estimates prepared by WSP are compliant with both Canadian National Instrument 51-101 (Canadian Oil and Gas Evaluation Handbook, or COGEH)[5] and the Petroleum Resources Management System (PRMS).[6] The resource definitions from both these standards essentially the same: PRMS definitions are set out in Appendix A.

## 3.6 ASSUMPTIONS AND LIMITING CONDITIONS

The accuracy of any estimate is a function of available time, data and of geological, engineering, and commercial interpretation and judgment. While the interpretation and estimates presented herein are believed to be reasonable, they should be viewed with the understanding that additional analysis or new data may justify their revision. WSP reserves the right to revise its opinions, if new information is deemed sufficiently credible to do so.

The use of this report is strictly subject to terms and conditions of the agreement between WSP and its client. Unless otherwise agreed by WSP, the issuance or review of this report does not grant rights to any Third Parties. Other than the client, this document may not be utilized or relied

[5] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Third Edition,* August 2018, updated October 2019
[6] https://www.spe.org/en/industry/reserves/

upon for any purpose and WSP shall not be liable for any loss or damage caused by such use or reliance.

In the event that this report is disclosed or distributed to any Third Party, no such Third Party shall be entitled to place reliance upon any information, warranties or representations which may be contained within this document and the Recipients of this document shall indemnify WSP against all and any claims, losses and costs which may be incurred by WSP relating to such Third Parties.

## 3.7 INDEPENDENCE/DISCLAIMER OF INTEREST

WSP has acted independently in the preparation of this Report. The company and its employees have no direct or indirect ownership in the property appraised or the area of study described. Ms. Letha Lencioni is signing off on this Report, which has been prepared by her as a Qualified Reserves and Resource Evaluator, with the assistance of others on WSP's staff. Our fee for this Report and the other services that may be provided is not dependent on the amount of resources estimated.

# 4. DISCLOSURES REGARDING ASSETS

## 4.1 GUYANA

### 4.1.1 Location and Basin Name

The Guyana-Suriname Basin located in the northeastern offshore of South America, with portions of it in the offshore areas of Venezuela, Guyana, Suriname, and French Guiana (Figure 4-1). Within this basin, ECO owns an interest in the Orinduik Block, which is located in offshore waters of Guyana (Figure 4-2).

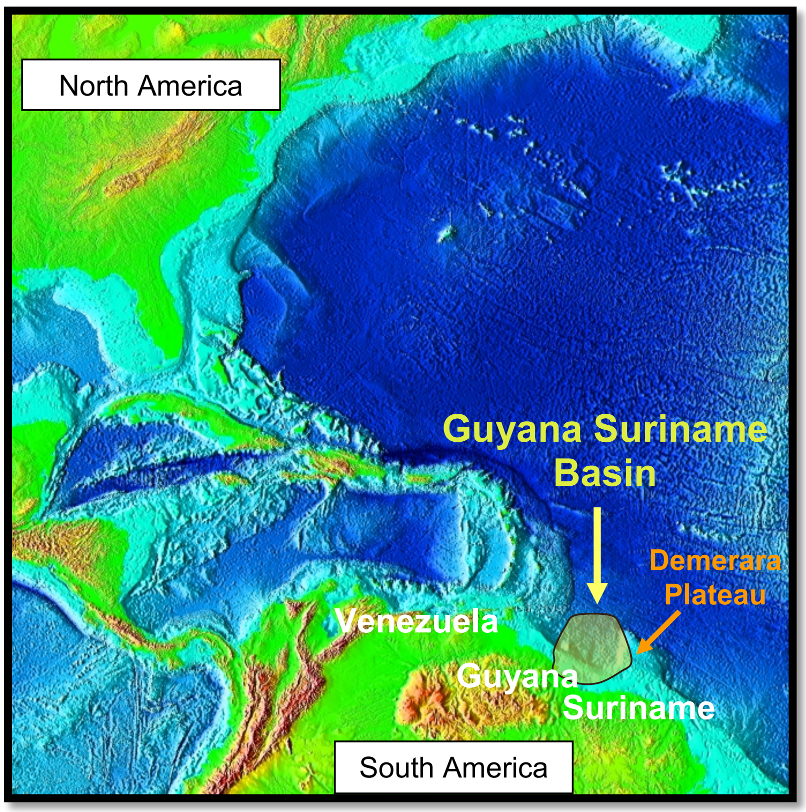



**Figure 4-1 Location Map of the Guyana Suriname Basin (ECO)**

The Guyana-Suriname Basin had been a lightly explored basin with eleven wells drilled between 1967 and 2000. Three additional wells were drilled between mid-2000 and 2012 but in 2015, activity increased dramatically with the Liza oil and gas discovery by ExxonMobil in the Stabroek

Block, which is adjacent to the Orinduik Block. As of the date of this report, ExxonMobil has discovered multiple accumulations of oil and gas including the Hammerhead that is located seven kilometers east of the Orinduik block. In addition, Tullow has drilled two wells in Orinduik Block known as the Jethro 1 and the Joe 1 wells which indicated the presence of hydrocarbons, and Repsol has drilled a successful Cretaceous well, the Carapa 1, to the south. The potential for large conventional accumulations in stratigraphic and subtle structural traps in this area has been proven by recent discoveries on the neighboring Stabroek Block. CGX Energy in the Corentyne block has recently drilled the Kawa 1 well which is reported to be a discovery in the Cretaceous. Apache and Total Energies have drilled several successful wells to the east in the offshore of Suriname. The basin is characterized by moderate to high-risk, high-reward exploration potential in a low-risk, favorable political and economic environment.

4.1.2 Gross and Net Interest in the Property

The Orinduik Block license area is 1,800 square kilometers (444,789 acres) where ECO Guyana Inc., after buying out the minority interest partners, had a 40.0% net working interest (WI) (Figure 4-2). ECO sold a 25.0% working interest on 28 November 2018 to Total E&P Activités Pétrolières SA (Total), a subsidiary of Total Petroleum, for US$ 12.5MM. This transaction reduced ECO's interest to 15.0%. Total has in turn sold 40% of their 25% stake in the block to Qatar Petroleum. Tullow Oil Plc (Tullow) is the designated Operator holding the remaining WI and has carried ECO Guyana Inc. for a portion of the initial exploration program work commitment. ECO Guyana Inc. is owned 100.0% by ECO (Guyana) Barbados Ltd. who in turn is wholly owned by ECO (Atlantic) Oil & Gas Ltd.

ECO owns an indirect working interest in the Canje Block by means of a 10% interest in JHI Associates, a private company with a 17.5% interest in the Canje Block. This results in a 1.75% ECO interest in the Canje Block.

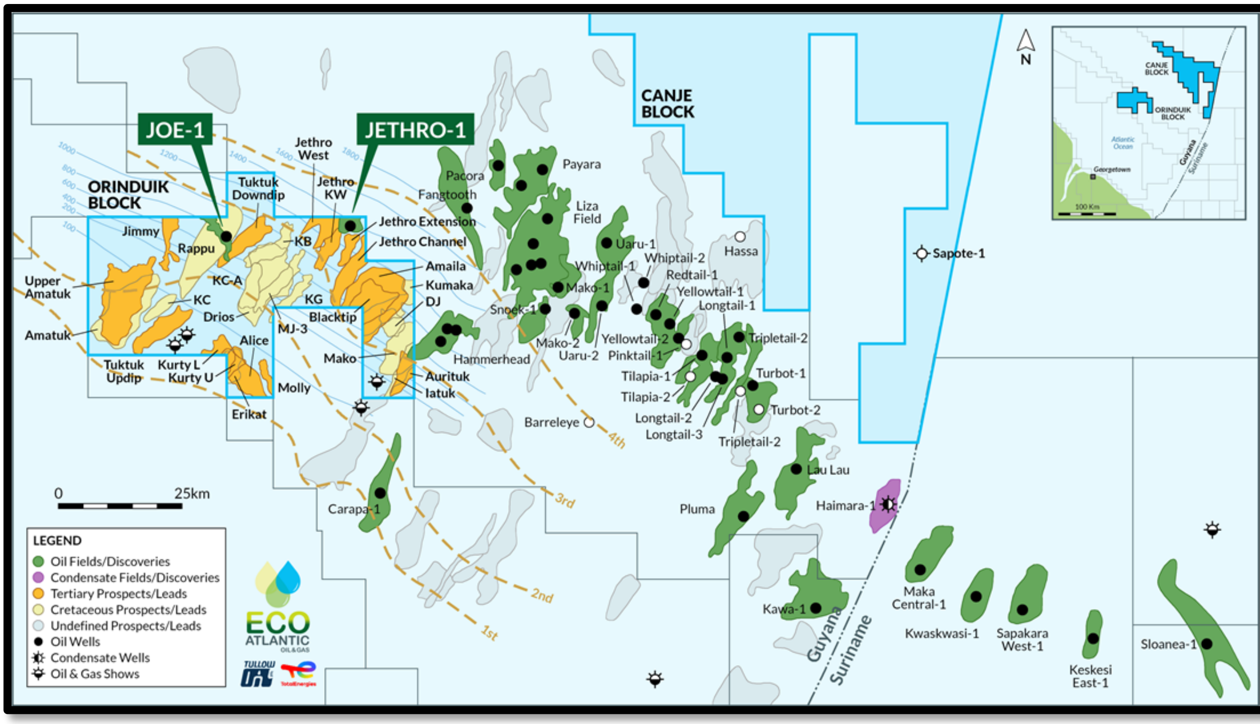



**Figure 4-2 Index Map of Offshore Guyana Orinduik Block (ECO)**

### 4.1.3 Expiry Date of Interest

The Orinduik license was awarded in January 2016 for an initial term of four years in which the work obligations were to review the existing 2D seismic data and by the end of the fourth year acquire and process a 3D seismic survey over the area of interest. The partners, to date, have fulfilled these obligations and in addition have drilled 2 wells. The partners have approved the license entry into the First Three Year Renewal Period on 14 January 2020 that includes an obligation to drill one exploration well, which has been fulfilled with the drilling of the Jethro #1 well and therefore no part of the block has to be relinquished. The Second Three Year Renewal Period that would commence in January 2023 has a 20% Relinquishment requirement.

### 4.1.4 Range of Water Depths

The Orinduik Block has water depths ranging from less than 300 meters to the southwest to 1,450 meters to the northeast (Figure 4-2). The majority of the block is in water depths of less than 500 meters.

### 4.1.5 Description of Target Zones

The Guyana-Suriname Basin is a passive margin basin resulting from the Jurassic aged rifting apart of Africa and South America followed by Cretaceous time drifting of the continents to form the Atlantic Ocean. The basin has received clastic deposits in shelf, slope, and basin depositional environments during the Cretaceous to Recent times. The Guyana basin has more than 7,000 meters of sedimentary fill in certain areas.

The target reservoir rocks for the Orinduik Block are sandstones deposited as shelf margin, channel fill and overbank deposits, slope, and basin turbidite fans as well as carbonates in the form of reefs and shallow water limestones. These rocks are of Cretaceous and younger age and are expected to be similar to the Cretaceous and Tertiary age reservoirs discovered on the neighboring Stabroek Block by ExxonMobil at Liza, Liza Deep, Payara, Pacora, Ranger, Snoek, Longtail, Pluma, Haimara, Hammerhead, Tripletail, Yellowtail, Uaru, Mako, Turbot and several others. These sandstones and limestones are interbedded and capped with shales and marls, which provide seals to these reservoir units. The relative positions of the current discoveries including the Tertiary Hammerhead and the Cretaceous Liza and Carapa fields, the positive results from the Joe and Jethro wells, and certain leads are seen in the cross section in Figure 4-3. The Tertiary sandstones penetrated by the Jethro 1 and Joe 1 wells are made up of high quality well sorted sands.

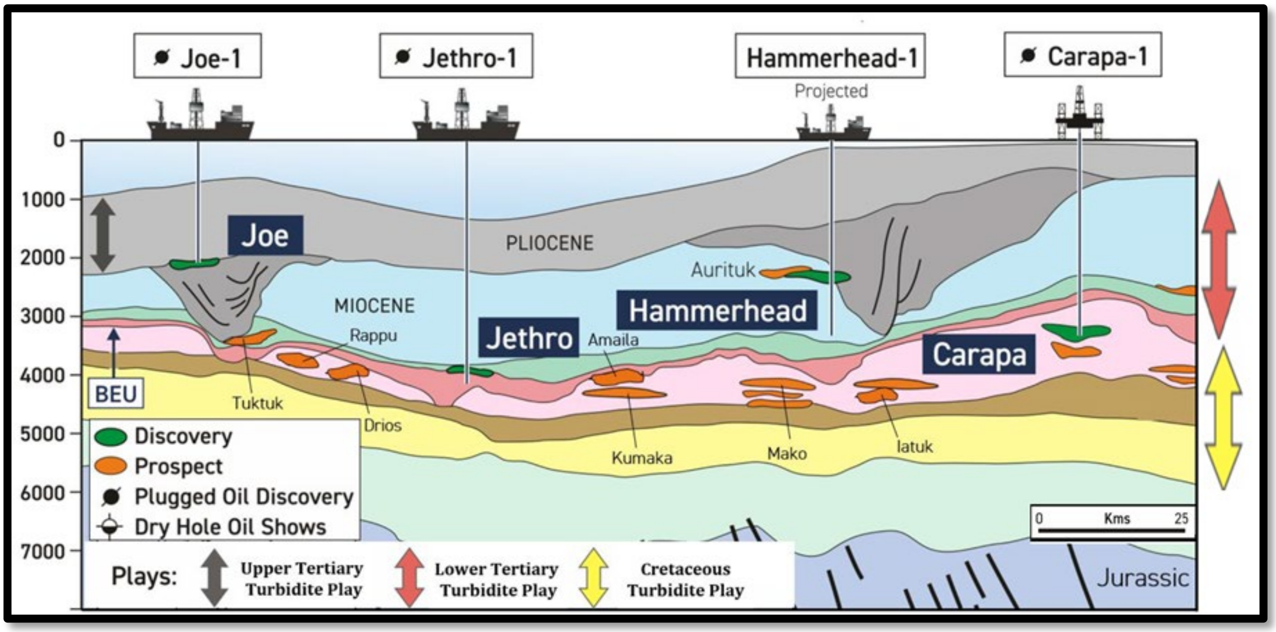



**Figure 4-3 Schematic of Major Discoveries (courtesy of Tullow Oil Plc)**

The Upper Cretaceous section includes Slope Channel Complex deposits, which are dependent on stratigraphic pinchouts as well as well-developed basin floor fan deposystems. Additional targets are characterized as terraced slopes where sand has ‘pooled’ in a flat spot or a gradient change along the slope (Figure 4-4). The Liza sand fan complex analog has been identified as being specifically Maastrichtian in age in the Late Cretaceous. The Hammerhead discovery less than 7 kilometers east of the Orinduik Block boundary has proven that the Tertiary section has commercial accumulations of hydrocarbons in stratigraphic sand traps. Figure 4-5 shows the relative positions of the various Orinduik, Stabroek, and Kanuku Block leads, prospects, and discoveries.

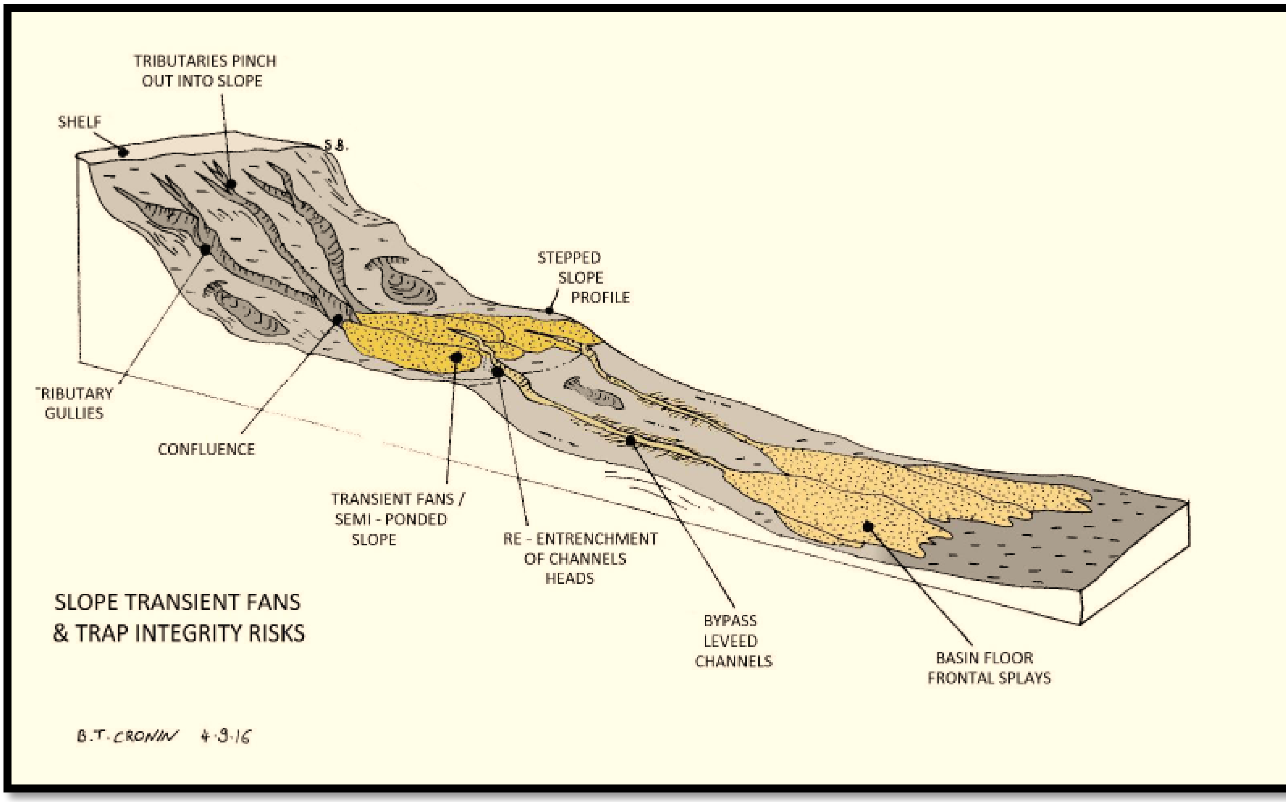



**Figure 4-4 Diagram of Terraced or Stepped Slope Sand Accumulations (courtesy of Tullow Oil Plc)**

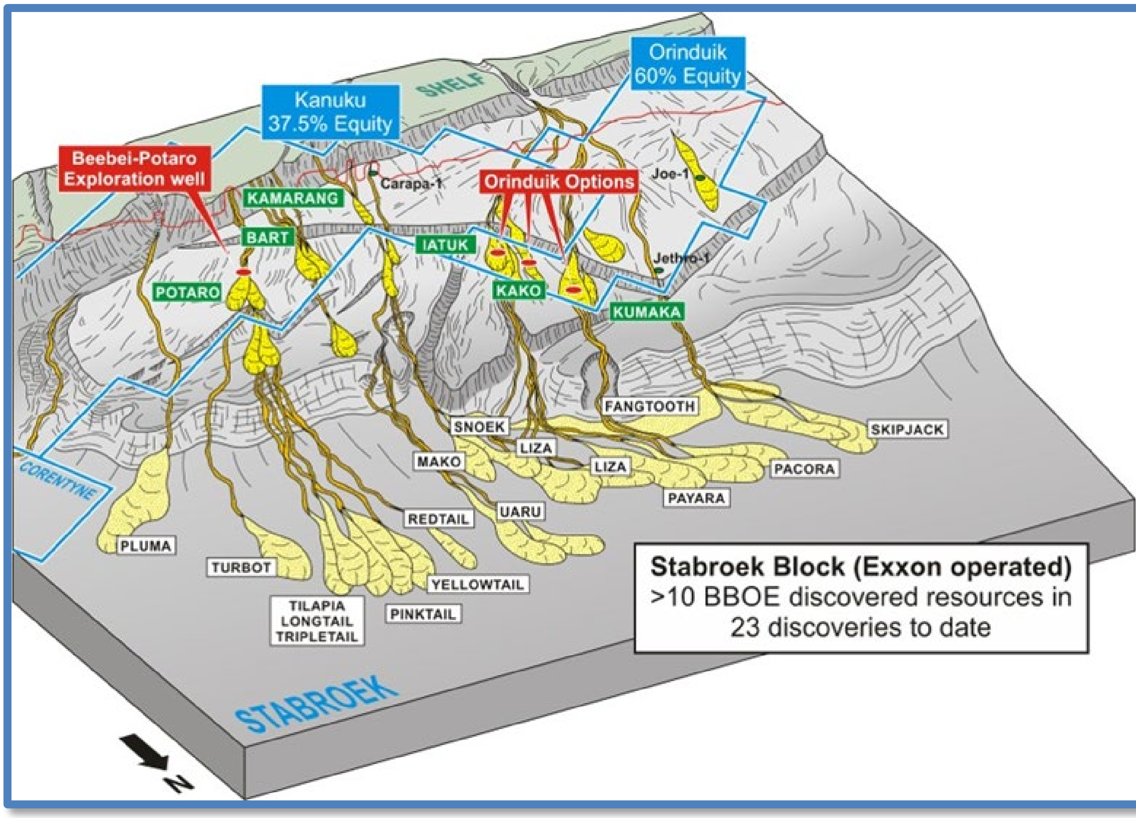



**Figure 4-5 Maps Showing the Orinduik and Other Blocks with Leads and Discoveries (courtesy of Tullow Oil Plc)**

4.1.6 Distance to Nearest Commercial Production

The nearest current hydrocarbon production is located to the north from the Liza Field on ExxonMobil's Stabroek Block and southeast, onshore in Suriname in the Tambaredjo field and the adjacent Calcutta field just to the west. In December 2019, ExxonMobil initiated production in the Liza Field at a rate of 25,000 BOPD, as reported by Hess. The Tambaredjo, Tambaredjo Northwest, and Calcutta fields that are located onshore in Suriname are currently producing 16,000 BOPD from an estimated STOIIP of 1 billion barrels.[7] These fields are more than 300 kilometers southeast of the prospective area.

The map below (Figure 4-6) shows the location of each field discovered on the Stabroek Block at the time of this report. The Hammerhead discovery, which is less than 7 kilometers away from

[7] http://opportunities.staatsolie.com/en/geology-of-the-guyana-suriname-basin

the Orinduik Block boundary, found a significant oil sand in the Tertiary aged section. The Liza Phase 1 development, sanctioned June 2017, is progressing rapidly, with first production started in December 2019. Liza Phase 1 will consist of 17 wells connected to a floating production, storage and offloading (FPSO) vessel designed to produce up to 120,000 barrels of oil per day, currently production is 75,000 barrels per day. The second phase of the Liza development is utilizing a second FPSO with gross production capacity of approximately 220,000 barrels of oil per day, which is already operational. Planning is underway for a third phase of development, which will use a third FPSO designed to produce approximately 180,000 barrels of oil per day, with first production expected as early as 2023. Up to five production units are expected to be online by 2025 with production of 750,000 barrels of oil per day anticipated.

The accumulations penetrated by the Jethro 1 and Joe 1 wells on the Orinduik block are currently being evaluated by the operator for possible future development.

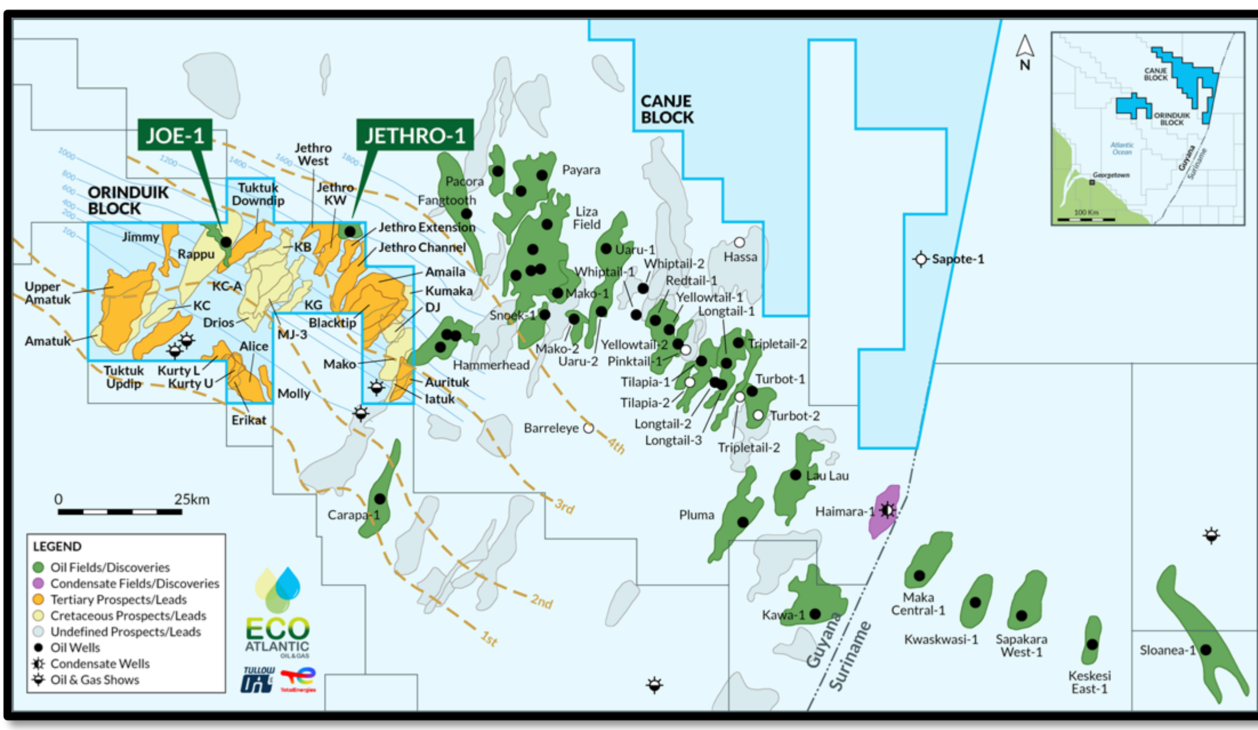



Figure 4-6 Index Map of Orinduik Block Discoveries and ExxonMobil Discoveries (ECO)

4.1.7 Product Types Reasonably Expected

The drilling of the Jethro and Joe wells on the Orinduik Block found oil and associated gas in the Tertiary sections. The oil from these wells is reported by the operator to be similar in gravity to the ExxonMobil Hammerhead oil, in the 12 °to 15 ° API range, although a final PVT analysis has not been provided by the operator at the time of this report. The Repsol Carapa 1 well located less than 40 kilometers southeast of the Hammerhead area and 55 kilometers south of the Jethro well has discovered 27 ° API oil in the Cretaceous. Thus, if discoveries are made on this block, they may be expected to contain heavy oil in the Tertiary and intermediate oil and associated gas in the Cretaceous.

Unconventional oils – mainly heavy oils, extra heavy oils and bitumens – represent a significant share of the total oil world reserves. Oil companies have expressed interest in unconventional oil as alternative resources for the energy supply. These resources are composed usually of viscous oils and, for this reason, their use requires additional efforts to guarantee the viability of the oil recovery from the reservoir and its subsequent transportation from production wells to ports and refineries.[8] The use of diluents such as diesel oil can aid in the producibility and marketing of heavy oils.

4.1.8 Range of Pool or Field Sizes

The Orinduik Block contains seismic leads[9] that were identified based on the interpretation of the time and depth 3D seismic data. The areas of these leads range in size from 0.75 to 95 square kilometers. The Best Estimate Gross Unrisked Prospective Oil Resources for the leads in the Orinduik Block range from 9 to 1,422 MMBbl oil.[10]

[8] AN OVERVIEW OF HEAVY OIL PROPERTIES AND ITS RECOVERY AND TRANSPORTATION METHODS; R. G. Santos, W. Loh, A. C. Bannwart, and O. V. Trevisan
[9] A lead is generally defined as an indication of the possible presence of a hydrocarbon trap which may warrant further exploration
[10] Details on these calculations are discussed in Section 5 of this report.

4.1.9 Depth of the Target Zones

The depth ranges for the target zones for the leads in Orinduik Block described in this report are based on the PSDM 3D seismic data, where available, and estimated by converting time to depth for the leads on the PSTM data. These depths, which are the parameters used in the estimate of Prospective Resources range from 1,425 to 5,150 meters.

4.1.10 Identity and Relevant Experience of the Operator

Tullow Oil Plc is the designated operator of the Orinduik Block. Tullow is an independent international oil and gas company headquartered in London UK. Tullow has over 30 years of experience in the exploration and development to production of offshore and onshore assets around the world. Tullow has had numerous meetings with the partners relative to the ongoing technical work and has provided the seismic data products utilized in the interpretations.

ECO (Atlantic) Oil & Gas Ltd, with a team of highly experienced exploration scientists and technologists has operated its own offshore 2D and 3D seismic surveys on behalf of the Company and its partners.

Exxon, the operator of the Canje Block, has many decades of operational experience.

4.1.11 Future Work Plans and Expenditures

In the Orinduik Block, Tullow has reprocessed and merged the two 3D datasets, The results included a PSDM volume which is currently being used to high grade the location of a new well that would test the Cretaceous on the block. These options will be reviewed by the partners in the first quarter of 2022 and will be subject to the approval of the operating committee.

4.1.12 Market and Infrastructure

Infrastructure for the transport and marketing of hydrocarbons is currently present as of December 2019 in the form of a floating production storage and offloading (FPSO) unit on the large oil discovery known as Liza on the Stabroek Block by ExxonMobil. Additional FPSO facilities are planned by ExxonMobil, and current and future discoveries in Orinduik and Kanuku as well as nearby in Suriname will spur development of more extensive offshore production networks to bring that crude and associated gas to market. Other strategies could have produced oil stored either in a Fixed Storage Platform (FSP) or a guyed or anchored Floating Storage and Offloading (FSO) tanker. Oil would then be transported by tanker from the FPSO, FSO, or FSP to markets in North America, Europe, Asia, or South America.

4.1.13 Petroleum Systems

Oil production from the onshore Tambaredjo, Tambaredjo Northeast and Calcutta fields and that of the newly discovered Liza field indicate that a proven active petroleum system (Magoon, 1988) or systems are present in the Guyana-Suriname Basin.

Two source rock intervals have been identified in the Guyana-Suriname Basin, the Upper Albian to Santonian Canje Formation and an unnamed Jurassic interval. Oils in the Tambaredjo, Tambaredjo Northwest, and Calcutta fields located onshore in Suriname have been sourced from rocks in the Canje Formation.[11] The Canje Formation is presently in the oil window in the offshore Guyana and Suriname area (Schwarzer and Krabbe, 2009) (Figure 4-7). Significant oil generation from this source rock began during the Late Paleocene and continues.

The Canje Formation source rock consists dominantly of organic-rich black mudstones with Total Organic Carbon (TOC) contents ranging from 2% to 5%. Values as high as 20% have been measured in equivalent Cenomanian to Santonian age black mudstones drilled during ODP Leg 207 (Erbacher, 2004) on the Demerara Plateau. Source rocks are dominantly algal Type II marine organic material with increasing terrestrial components in nearshore locations. Equivalent age

[11] http://opportunities.staatsolie.com/en/geology-of-the-guyana-suriname-basin/petroleum-systems/

source rocks of the Guyana Suriname Basin are now within the oil generation window with many 'shows' of oil and gas from several wells indicating the presence of hydrocarbons (Ginger, 1990). In this portion of the Guyana Suriname basin, the top of the oil window may be near 3,500 meters based on a locally higher thermal gradient than other areas in the basin. The mature pod of Cretaceous source rocks is located offshore in an area of the basin along the Guyana and Suriname coast (Figure 4-7). This source rock is up to 550 meters thick. Migration to the producing oil fields onshore has been primarily lateral and updip for 100 to 150 kilometers (Ginger, 1990; Staatsolie.com, 2016).

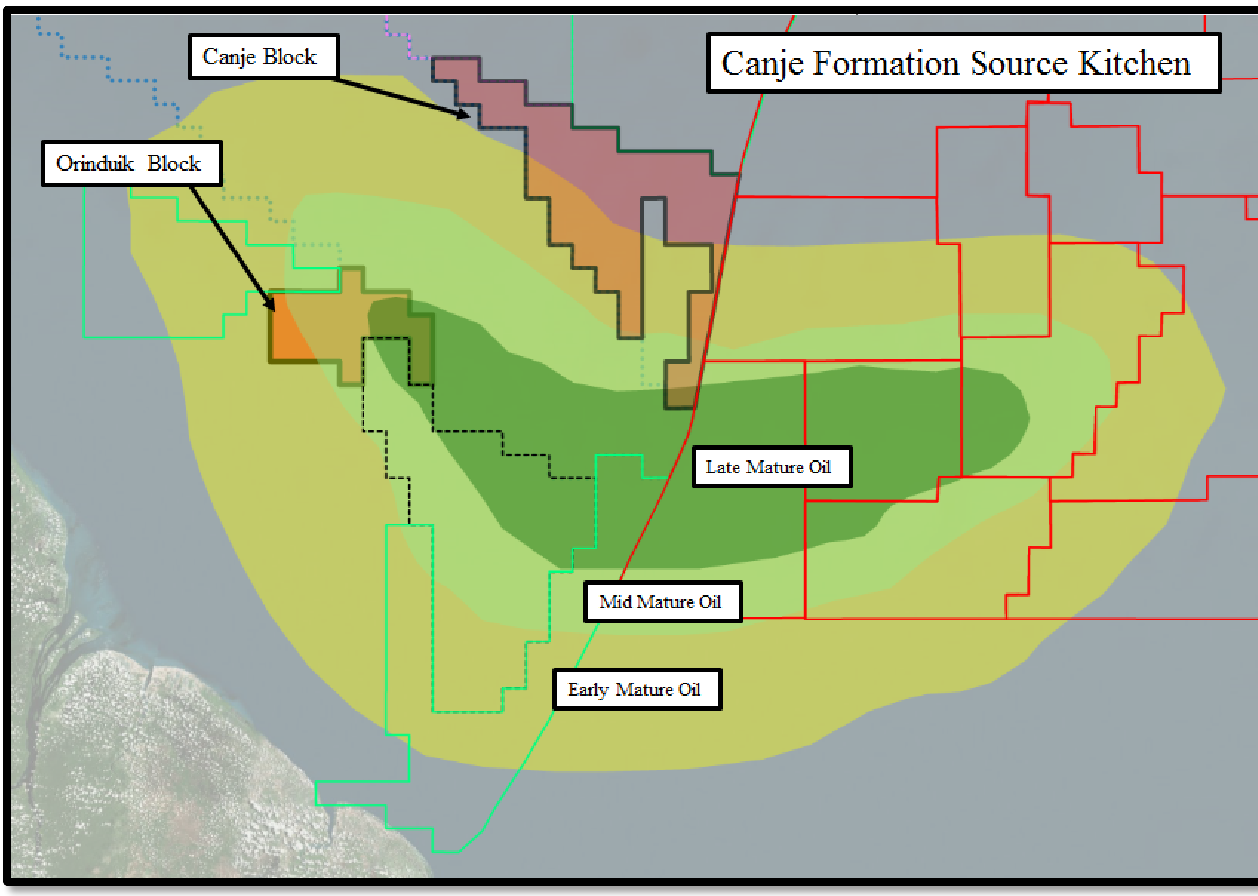



**Figure 4-7 Map of Offshore Suriname Showing Mature Canje Formation Source Rock Maturation Level (Gustavson, after CGX Energy)**

Evidence of Jurassic source rocks in the basin comes from analysis of oil in Suriname that is unlike the Cretaceous sourced oil (Bihariesingh, 2014). These Jurassic source rocks are interpreted to have been deposited in pre-rift and rift depositional environments. These rocks include lacustrine shales with Type I oil-prone organic material. More than one rift half-graben may be present under the basin where lacustrine or restricted marine source rocks are mature and generating oil.

Based on the results to date, it is likely that additional source rocks exist in the Tertiary interval that have not been fully identified. The Hammerhead in Stabroek Block and the Jethro and Joe wells on Orinduik Block have a different type of oil in the Tertiary from that found in the Cretaceous in the Carapa well and the Cretaceous discoveries in Stabroek. The Tertiary section appears to have a low gravity (12 ° to 18 ° API) high sulfur oil where the Cretaceous has a higher gravity (27 ° to 32 ° API) and low sulfur oil as seen in the Carapa well south of Orinduik and Liza north of Orinduik.

### 4.1.14 Analogous Fields

#### 4.1.14.1 Tertiary

Several offshore fields in Brazil with heavy oil have been put on production or are being developed. These include:

- Atlanta Field Brazil – The field is being developed with high (88 degree) angle wells and will utilize ESP's to produce the 14 ° API high viscosity oil. The FPSO selected for the EPS will have a 180,000 Bbl storage capacity and 30,000 BOPD processing capacity. Average expected production rate is 12,000 BOPD per well.
- Marlim Sul Field Brazil in 402 m water Depth; 16 ° to 20 ° API; Reservoir depth 2,808 meters; Peak rate 200,000 BO/D
- Jubarte Field Brazil – 1,500 m WD; 17 ° API;
- Parque de Conchas Brazil – 1,752 m WD; 17 ° API; 886 m reservoir depth
- Peregrino Field Brazil – 100 m WD; 14.5 ° API; 2,250 m reservoir repth; FPSO; horizontal wells with a 2,000 m lateral; over 74,000 b/d peak production started April 2011

A comparable field in the North Sea would be the Mariner Field UK with 110-meter WD, 14 ° API, and 1,492 m reservoir depth.

4.1.14.2 Cretaceous

ExxonMobil has discovered several accumulations of oil and gas in the Cretaceous in the neighboring Stabroek Block. The Liza fields and other discoveries in Stabroek establish the presence of hydrocarbon accumulations in the area with 32.1 ° API low sulfur oil and in the Repsol Carapa well located south of Orinduik which has 27 ° API low sulfur oil, based on preliminary reports.

4.1.15 Exploration History for the Offshore of Guyana

Exploration activity in the offshore of Guyana began in 1958 when the California Oil Company conducted seismic surveys but did not drill a well. The first wells in the Guyana offshore area were drilled by Conoco and Tenneco in 1967. The Guyana Offshore #1 well encountered gas shows while the subsequent Guyana Offshore #2 well was a dry hole. Shell and Conoco drilled the Berbice #1 well in 1971 that had oil and gas shows in the Miocene but was abandoned after a gas kick at 2,171 meters (7,124 feet) in the Eocene. The Berbice #2 well found minor gas shows and oil stains in the Pliocene and Oligocene. Shell drilled the Mahaica #1 and #2 wells in 1974 with no success. In 1975, Shell drilled the Abary #1 well which found oil and gas shows and flowed 37 ° API oil from a turbidite at a depth of 3,990 meters (13,091 feet). Deminex drilled the Essequibo #1 well which had several oil and gas shows in the Miocene and Upper Cretaceous in 1977 but the subsequent well, the Essiquibo #2 drilled nearby had only minor shows of methane in the Upper Cretaceous. The Essiquibo wells and the Berbice wells were located on the extreme southern part of the Orinduik Block. The Arapaima #1 was drilled by Total in 1992 with gas tested in the Lower Cretaceous. In mid-2000, CGX Energy was prepared to drill the Eagle #1 well but the rig had to abandon the location because a Surinamese gunboat threatened to fire on it. The rig was moved to the Horseshoe West #1 location closer to shore which was abandoned as a dry hole.

Drilling activity resumed in 2012, after the 2007 agreement between Guyana and Suriname to resolve the border dispute, with the drilling of the Eagle #1 and Jaguar #1 wells. The Eagle well found reservoir quality sands with shows of hydrocarbons in the Eocene and Upper Cretaceous while the Jaguar well was abandoned due to unexpected high pressures encountered in the well.

ExxonMobil then drilled the Liza #1 well which discovered commercial quantities of oil and gas in 2015 in the Stabroek Block, which is adjacent to the Orinduik Block. This discovery was followed by several additional successes which resulted in an estimated recoverable resource of 4 billion oil-equivalent barrels. ExxonMobil has drilled over 35 wells with 23 to date on the Stabroek Block, including the Hammerhead #1 well and has initiated production from the Liza field as of December 2019 and plans to further develop the discovered fields and continue exploratory drilling.

Tullow Jethro #1 well was drilled in a Water Depth of 1,364 meters to a TD of 4,400 meters. The well was spud on 4 July 2019 using the drillship Stena Carron and took 59 Days including logging, at a total cost of US$51.5 MM. The well discovered an Early Oligocene (Rupelian) aged high quality sand at 4,178.5 meters down to 4,233 meters with 12 ° to 15 ° API high sulfur oil based on preliminary studies by the operator.

Tullow Joe #1 well was drilled in a Water Depth of 776 meters to a TD of 2,175 meters. The well was spud on 25 August 2019 using the drillship Stena Carron and took 27 days including a sidetrack, logging, and abandonment at a total cost of US$21.0 MM. The well discovered Tertiary aged high-quality sand at 2,102 meters along with a silty sand package at 2,085 meters. The oil samples from this well are reported by the operator to be 13 $^{\circ API}$ based on preliminary studies. Note that final PVT analyses are not available as yet.

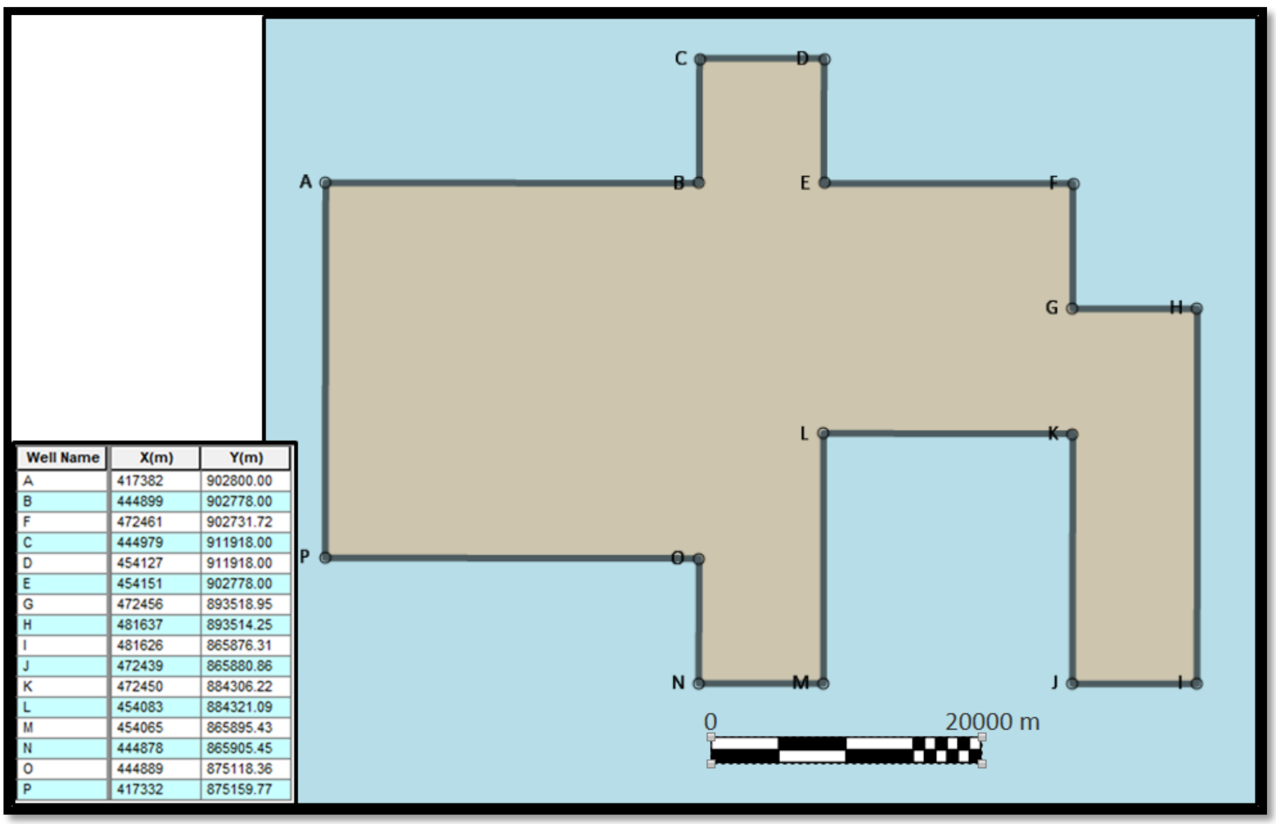
The Repsol Carapa 1 well was drilled in late 2019 to a depth of 3,290 meters in 68 meters of water in Kanuku Block. The well, which is southeast of the Orinduik Block, discovered 4 meters of Upper Cretaceous sand with 27 $^{\circ API}$ oil with less than 1% sulfur.

ExxonMobil drilled three wells into the Cretaceous in the Canje Block which had indications of hydrocarbons but were plugged as dry holes.

The CGX Energy Kawa 1 well is the most recent reported discovery in 2022 nearby with multiple Cretaceous aged oil sands. In addition, several discoveries have been announced in Suriname to the east by Apache, TotalEnergies and others.

4.1.16 Contract Areas

The Orinduik Block license area is 1,800 square kilometers (444,789 acres) where ECO Guyana Inc. has a 15.0% net working interest (WI) (Figure 4-8). Tullow Oil Plc (Tullow) is the designated Operator holding 60.0% WI and Total E&P Activités Pétrolières SA owns 25.0% WI by way of a Farm-In Agreement with ECO. ECO Guyana Inc. is owned 100.0% by ECO (Guyana) Barbados Ltd. who in turn is wholly owned by ECO (Atlantic) Oil & Gas Ltd.




| Well Name | X(m) | Y(m) |
|---|---|---|
| A | 417382 | 902800.00 |
| B | 444899 | 902778.00 |
| F | 472461 | 902731.72 |
| C | 444979 | 911918.00 |
| D | 454127 | 911918.00 |
| E | 454151 | 902778.00 |
| G | 472456 | 893518.95 |
| H | 481637 | 893514.25 |
| I | 481626 | 865876.31 |
| J | 472439 | 865880.86 |
| K | 472450 | 884306.22 |
| L | 454083 | 884321.09 |
| M | 454065 | 865895.43 |
| N | 444878 | 865905.45 |
| O | 444889 | 875118.36 |
| P | 417332 | 875159.77 |

**Figure 4-8 Map of the Orinduik Block License Area (Gustavson)**

4.1.17 Discoveries and Leads

At the time of this report, there were several different 3D seismic data sets with various derivative volumes used as the basis for the interpretations of the various seismic leads. The DJ, KG, KD, and Iatuk-D Leads are based on an early PSDM or depth converted data while the KB, KC, Amatuk, MJ-3, MJ-4 and KC-A are based on the early PSTM or time data and the more recent leads are derived from a new PSTM merged dataset. There are additional lead ideas observed by ECO, Tullow, and TotalEnergies on the seismic data that are not included in this report. The new merged PSDM dataset is still being interpreted by the Partners. Completion of this work may result in new interpretation of the location and size of the leads analyzed in this report. The 22 leads and prospects on the Orinduik Block included in this report are listed in Table 4-1.

**Table 4-1 List of Leads on Orinduik Block**

| Lead | Play type | Age | Average Depth, m | Low Estimate ($P_{90}$) Area, km$^2$ | High Estimate ($P_{10}$) Area, km$^2$ |
|---|---|---|---|---|---|
| Jethro | Strat Trap | Tertiary | 4,232 | 8 | 21 |
| Joe | Strat Trap | Tertiary | 2,025 | 5 | 27 |
| Jethro Ext | Strat Trap | Tertiary | 4,100 | 2 | 7 |
| Hammerhead | Strat Trap | Tertiary | 3,550 | 0.75 | 1.5 |
| Rappu | Strat Trap | U. Cret | 3,650 | 35 | 95 |
| KB | Strat Trap | Tertiary | 3,700 | 17 | 43 |
| DJ | Strat Trap | U. Cret | 4,160 | 14 | 30 |
| KG | Strat Trap | U. Cret | 3,900 | 17 | 34 |
| Amaila/Kumaka | Strat Trap | U. Cret | 4,250 | 32 | 77 |
| Iatuk-D | Strat Trap | U. Cret | 4,850 | 37 | 73 |
| KC | Strat Trap | U. Cret | 2,460 | 6 | 15 |
| Amatuk | Channel Fill | U. Cret | 2,415 | 35 | 90 |
| MJ-3 | Strat Trap | U. Cret | 3,700 | 18 | 37 |
| Jimmy | Strat Trap | U. Cret | 2,120 | 6 | 18 |
| KC-A | Strat Trap | U. Cret | 3,225 | 7 | 12 |
| Jethro Chan | Strat Trap | Tertiary | 4,350 | 8 | 16 |
| Alice | Strat Trap | Tertiary | 1,465 | 8 | 47 |
| Kurty U | Strat Trap | Tertiary | 2,678 | 2 | 10 |
| Kurty L | Strat Trap | Tertiary | 2,777 | 3 | 15 |
| EriKat | Strat Trap | U. Cret | 3,118 | 6 | 15 |
| Jethro KW | Strat Trap | Tertiary | 4,131 | 8 | 19 |
| Jethro West | Strat Trap | Tertiary | 4,212 | 12 | 20 |

4.1.18 Risks and Probability of Success

The recent drilling activity has confirmed the presence of hydrocarbons in the Tertiary section in the Orinduik Block, and data from the Cretaceous discoveries on Stabroek and Kanuku blocks, limited to publicly available information, is indicative of the presence of hydrocarbons in the Cretaceous. The discovery of oil in the Cretaceous section in the Carapa #1 well in the Kanuku

Block updip to the Orinduik Block mitigates some of the risk in the subject Cretaceous leads; however, they still have a relatively higher level of risk compared to the Tertiary because of the results from the Jethro and Joe wells with indications of hydrocarbons on Orinduik. The available database is limited to several 3D seismic data sets and derivatives, the incomplete data from the new wells and the information from the few 'legacy' wells drilled in the area and public information. The lead sections, Upper to Lower Cretaceous and Tertiary, have been evaluated in several wells drilled in the area with oil shows and reservoir quality rock present. The wells drilled by ExxonMobil have reportedly found hydrocarbons in the Upper Cretaceous and Tertiary and confirmed by Tullow; and commercial production by ExxonMobil is expected to commence in the immediate area as of the date of this report. The three wells drilled by ExxonMobil in the Canje Block were all dry holes. The quantification of geologic risk or the chance of finding commercial quantities of hydrocarbons in any single lead for the plays in this area can be characterized with the following variables:

<u>Trap</u>: defined as the presence of a structural or stratigraphic feature that could act as a trap for hydrocarbons;
<u>Seal</u>: defined as an impermeable barrier that would prevent hydrocarbons from leaking out of the structure;
<u>Reservoir</u>: defined as the rock that is in a structurally favorable position having sufficient void space present whether it be matrix porosity or fracture porosity to accumulate hydrocarbons in sufficient quantities to be commercial; and
<u>Source</u>: defined as the occurrence of hydrocarbon source rocks that could have generated hydrocarbons during a time that was favorable for accumulation in the structure.

The Probability of Success (POS) or favorability that the above defined variables would occur and the Overall POS for any single Lead is the product of all four variables.

Due to the stratigraphic nature of the traps, the predominant risks in the subject block relate to the presence of intact seals both vertical and lateral, and the quality of the reservoir rock for the creation of commercial accumulations of oil and gas. This range of risk values is typical of leads for wildcat exploratory prospects where data is scarce but commercial hydrocarbons have been discovered in the same environmental system nearby. The variations in POS numbers are generally based on the type of seismic data that support the Leads and Prospect. There is higher confidence in the leads interpreted and modeled on the various data that was calibrated to the Hammerhead discovery.

Table 4-2 shows the Orinduik Leads and the resulting geologic Probability or Chance of Success in percent based on the risk variables.[12]

**Table 4-2 Probability of Success, Orinduik Block**

| Lead | Trap | Seal | Reservoir | Source | Overall |
|---|---|---|---|---|---|
| Alice (Tert) | 80% | 60% | 90% | 100% | 43.2% |
| Amaila/Kumaka (U Cret) | 80% | 50% | 70% | 100% | 28.0% |
| Amatuk (U Cret) | 80% | 50% | 60% | 100% | 24.0% |
| DJ (U Cret) | 70% | 50% | 75% | 100% | 26.3% |
| EriKat (U Cret) | 90% | 60% | 60% | 100% | 32.4% |
| Hammerhead (Tert) | 90% | 90% | 100% | 100% | 81.0% |
| Iatuk-D (U Cret) | 80% | 50% | 70% | 100% | 28.0% |
| Jethro (Tert) | 90% | 90% | 100% | 100% | 81.0% |
| Jethro Ch (Tert) | 70% | 90% | 70% | 100% | 44.1% |
| Jethro Ext (Tert) | 90% | 60% | 80% | 100% | 43.2% |
| Jethro KW (Tert) | 60% | 50% | 60% | 90% | 16.2% |
| Jethro W (Tert) | 60% | 50% | 65% | 90% | 17.6% |
| Jimmy (Tert) | 95% | 85% | 80% | 100% | 64.6% |
| Joe (Tert) | 90% | 90% | 100% | 100% | 81.0% |
| KB (Cret) | 70% | 50% | 80% | 100% | 28.0% |
| KC (U Cret) | 80% | 50% | 60% | 100% | 24.0% |
| KC-A (U Cret) | 80% | 50% | 60% | 100% | 24.0% |
| KG (U Cret) | 80% | 50% | 70% | 100% | 28.0% |
| Kurty L (Tert) | 90% | 80% | 60% | 100% | 43.2% |
| Kurty U (Tert) | 90% | 80% | 60% | 100% | 43.2% |
| MJ-3 (U Cret) | 80% | 50% | 60% | 100% | 24.0% |
| Rappu (U Cret) | 70% | 60% | 60% | 100% | 25.2% |

Several additional leads have been identified by ECO and their partners, which have not been evaluated at the time of this report.

[12] Note: Jethro and Joe POS factors have been reduced from the 2020 report for consistency with Prospective Resource definitions.

## 4.2 NAMIBIA

### 4.2.1 Location and Basin Name

The subject area is located in the Walvis Basin in the offshore of Namibia. Namibia is located on the west coast of southern Africa situated south of Angola, north of South Africa, and west of Botswana (Figure 4-9). ECO (Atlantic) Oil & Gas Ltd, through its wholly owned subsidiary ECO (Namibia) Barbados Ltd., which in turn wholly owns ECO Namibia (Pty) Ltd. and Pan African Oil Namibia Holdings (Pty) Ltd, holds interests in four Petroleum Exploration License (PEL) Blocks totaling approximately 28,593 square kilometers. Note that due to the reissue of the Petroleum Exploration Licenses, the PEL numbers have changed.


**Figure 4-9 Map of the Country of Namibia (Trek, 2008)**

These four Blocks are the Cooper Block (Block 2012A) (PEL30) PEL97, Guy Block (Blocks 2111B & 2211A) (PEL34) PEL99, Sharon Block (west half of Blocks 2213A & B) (PEL33) PEL98, and Tamar Block (Blocks 2211Ba & 2311A) (PEL50) PEL100 (Figure 4-10). Note that as stated previously, the increase in Eco's Namibian interests and addition of 6,457 km2 to the Guy Block assumes the completion of the acquisition of Azinam Group Holdings ("Completion"). As announced by Eco on 11 March 2022, all conditions required for Completion have occurred save and except for receipt of the final approval of the TSX Venture Exchange (the "Approval"). Such Approval is expected imminently. This report assumes such Approval has been granted and Completion has occurred, including the increased interests in Namibia having become effective.

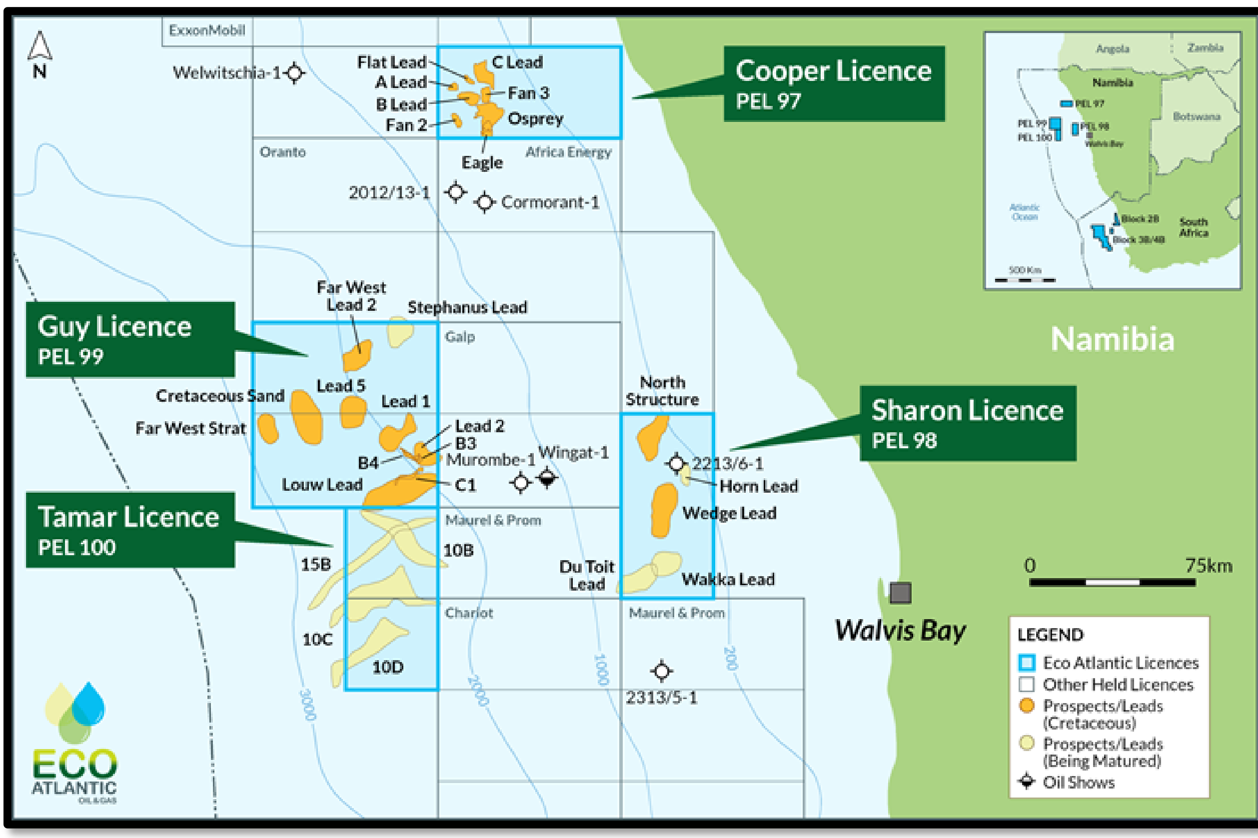



**Figure 4-10 Index map Offshore Namibia with ECO Block locations (ECO)**

As of the writing of this report, ECO's four license blocks in Namibia are exploratory. Based on work performed by the Client, Azinam and Gustavson various leads and one prospect were identified on the subject license blocks. This work was reviewed for reasonableness and incorporated into the estimate of prospective resources.

4.2.2 Gross and Net Interest in the Property

The Cooper Block License (PEL97) covers an area of approximately 5,788 square kilometers (1,430,246 acres). ECO (Atlantic) Oil & Gas Ltd, through its wholly owned subsidiary ECO Namibia (Pty) Ltd, holds a 85.0% working interest (WI) and is designated as the Operator. The Cooper Block is located in an area where the water depth ranges from less than 100 meters to over 500 meters. All of the Cooper lead and prospect areas are within the 200 to 500 meter water depth range.

The Sharon Block License (PEL98) covers an area of approximately 5,700 square kilometers (1,408,500 acres). ECO holds an 85%WI and is designated as the Operator. The water depth at the Sharon Block ranges from 100 meters to 500 meters.

The Guy Block License (PEL99) covers an area of approximately 11,457 square kilometers (2,831,086 acres). ECO holds a 85% WI and is designated as the Operator. The water depth ranges from 1,500 to 3,000 meters.

The Tamar Block License (PEL100) covers an area of approximately 5,648 square kilometers (1,395,651 acres). ECO holds an 85% WI and is designated as the Operator. The water depth ranges from 2,500 to more than 3,000 meters. ECO has 100% of the commitment costs.

ECO is obligated to carry a local company for 5% and Namcor's 10% through the drilling of a well on each block.

4.2.3 Expiry Date of Interest

The Cooper, Sharon and Guy Blocks were initially licensed to a subsidiary of ECO (Atlantic) Oil & Gas Ltd, ECO Atlantic (Pty) Ltd, in March 2011 for an initial four-year term which had been extended for one year to March 2016. The Tamar Block was acquired more recently through a business transaction. Subsequently, the Namibian government has issued new Petroleum

Exploration Licenses to ECO for all four blocks as of 3 February 2021 for ten years. Therefore, the PEL's will continue to February 2031.

### 4.2.4 Description of Target Zones

There are multiple target horizons and trap types over the four Blocks as depicted in Figure 4-11 including channel and turbidite sands and carbonate reefs in structural and stratigraphic trap settings. Typical trap types vary by Block as indicated by the range of the green bars above the diagram.

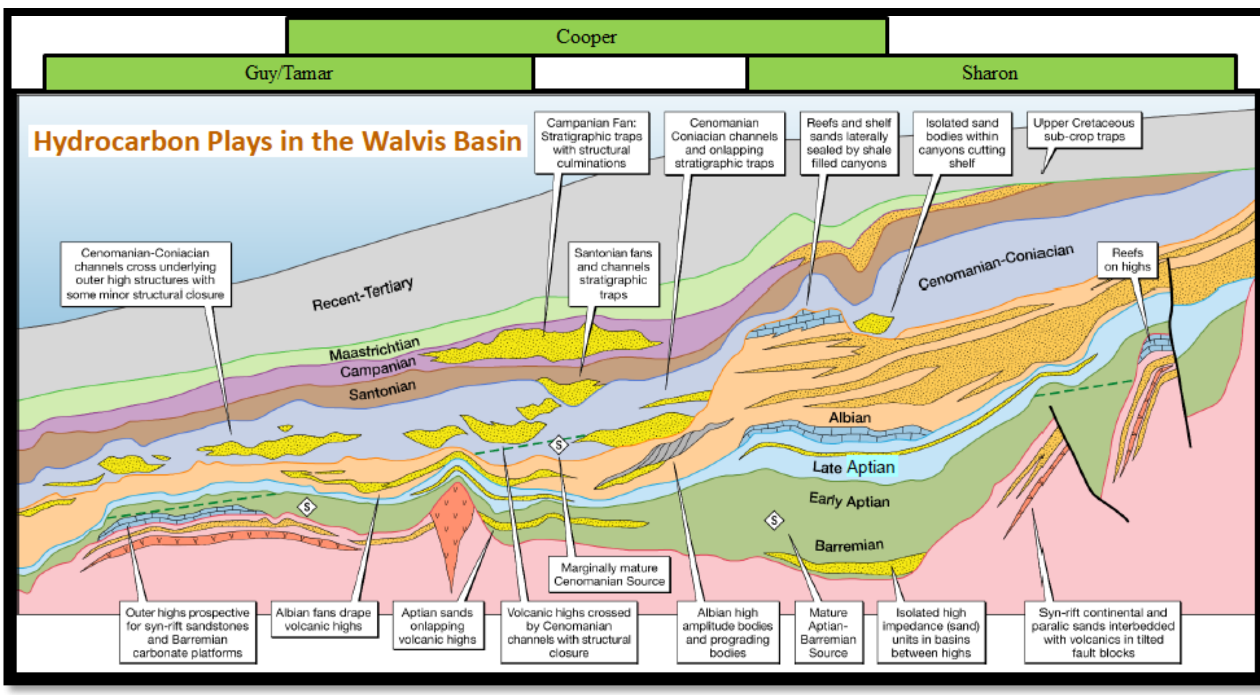



**Figure 4-11 Play Types in the Offshore of Namibia for the ECO Blocks (Gustavson, after Azinam)**

### 4.2.5 Distance to the Nearest Commercial Production

Oil is being produced in the offshore of Angola, approximately 600 kilometers to the north, from multiple fields, and gas has been produced from the Kudu Field approximately 900 kilometers to the south of the ECO Atlantic Blocks in the offshore of Namibia.

4.2.6 Product Types Reasonably Expected

Oil of 30 to 40 degrees API with associated gas is the expected hydrocarbon type to be found if there are successful discoveries in these exploratory leads.

4.2.7 Range of Pool or Field Sizes

The ten leads and one prospect evaluated for this report have minimum to maximum areas of closure ranging from 3 to 125 square kilometers with gross thicknesses ranging from 60 to 280 meters. The Best Estimate Gross Unrisked Prospective Oil Resources for the leads in Namibia range from 26 to 5,518 MMBbl oil.[13]

4.2.8 Depth of the Target Zone

These leads are estimated to occur at a depth range of 2,650 to 4,300 meters with a normal pressure and temperature gradient. This is based on a time-depth relationship from the Block 1911/10-1 well which had a check-shot included in the data provided and the tie to the Sasol 2012/13-1 well.

4.2.9 Identity and Relevant Experience of the Operator

ECO (Atlantic) Oil & Gas Ltd. is an Operator of Oil and Gas exploration projects in deep and shallow water offshore. The Company has been evaluated, prequalified, and approved as Operator by Governments in Namibia, Ghana, and Guyana. The company has completed detailed onshore and offshore exploration and interpretation of existing well data, geology and seismic data and has operated its own offshore 2D and 3D seismic surveys on behalf of the Company and its partners. A team of highly experienced explorationists in the resource sector, the Executive team understand, manage and direct the exploration in its offshore interests. The management team is knowledgeable and interactive in negotiating operating contracts, managing joint interest financial accounts, reporting to partners and representing partners to host government through managing its joint operating agreements, petroleum agreements, permitting and license commitments.

[13] Details on these calculations are discussed in Section 5 of this report.

4.2.10 Future Work Plans and Expenditures

The Namibian Blocks are considered to be a unit, which means that work done on one Block can be used to fulfill the commitment on all Blocks. The Company is currently assessing the option to complete additional 2D seismic in select areas of the Blocks. The Company is continuing interpretation of the completed 3D work and will define its drilling plans accordingly on the Blocks within the next the next four years. ECO is responsible for the carry of local Namibian companies which own 5% in each block and the 10% Namcor share through the drilling of a well on each block.

Namibia Cooper Block – All seismic acquisition and processing is complete, and interpretation has been completed. No significant additional capital commitments are required in advance of drilling. ECO is responsible for its working interest share of overheads, license fees and general operating costs which are minimal and shared between all working interests.

Namibia Sharon Block – The Company is currently evaluating where to conduct additional 2D seismic acquisition on the Sharon Block to determine where to shoot additional 3D seismic based on the interpretation of its other 3D seismic programs. The Company will decide if additional 2D or 3D is warranted in late 2022. Current estimated net cost to ECO for approximately 1,000 square kilometers, inclusive of processing; to complete and interpret is +/- US$1.5 Million. No other significant additional capital commitments are required in advance of drilling. ECO will pay its net share on the well; the Company anticipates it will further farm down in advance of drilling. The Company currently estimates Gross cost for drilling the well would be approximately US$25 Million. ECO is responsible for its working interest share of overheads, license fees and general operating costs which are minimal and shared between all working interests.

Namibia Guy Block – A 3D seismic survey has been completed and interpretation is being completed. No significant capital commitments are required in advance of drilling. ECO is responsible for its net Working Interest. ECO will pay its net share on the well; the Company anticipates it will further farm down in advance of drilling. The Company currently estimates

Gross cost for drilling the well to be approximately US$35 Million. ECO is responsible for its working interest share of overheads, license fees and general operating costs which are minimal and shared between all working interests.

Namibia Tamar Block – A 3D seismic survey acquisition is anticipated for 2024, if the internal interpretation of the 2D seismic defines a regional target. Current estimated net cost to ECO for approximately 500 square kilometers, inclusive of processing; to complete and interpret is +/- US$1.5 Million. No other significant additional capital commitments are required in advance of drilling. If a drilling target is established by or before the end of 2024, ECO intends to agree to an appropriate farm out agreement to reduce its net share on the well. The Company will not proceed with drilling under its current net interest based on the current known interpretations. A farm down is anticipated. Budgeted well cost is approximately US$35 Million Gross. ECO is responsible for its working interest share of overheads, license fees and general operating costs which are minimal and shared between all working interests.

#### 4.2.11 Market and Infrastructure

Oil is being produced in the offshore of Angola to the north from multiple fields and gas has been produced from the Kudu Field to the south in the offshore of Namibia. The market and infrastructure near the license area will have to be developed as exploration continues.

#### 4.2.12 Geology

##### 4.2.12.1 Structure

During the Triassic Period, Africa and South America were connected as a part of Gondwana. Gondwana began to rift or spread apart during the Jurassic Period and the South Atlantic margin started to open. The Namibian offshore basins were formed in this passive margin during the opening of the South Atlantic and the continental break up. The basins were further developed while the continents continued to drift apart from each other during the Cretaceous Period until Recent time. The opening and the rift to drift configuration of the South Atlantic margin is depicted in Figure 4-12 from Adams (2010). The yellow circle highlights Namibia, which was near the Santos Basin in Brazil at this time and which is considered an analogous play area. The Santos Basin has had a number of commercial hydrocarbon discoveries recently and could be considered the mirror image of the Walvis Basin in Namibia.

Cretaceous to Tertiary sediments were deposited over early Cretaceous rift sediments to form the basin system that extends along offshore Namibia. The rift zone is characterized by tilted blocks bounded mostly by landward dipping normal faults. This series of tilted blocks runs the entire length of the margin. The sedimentary basins in offshore Namibia are illustrated in Figure 4-13 where the area of interest is within the Walvis Basin.

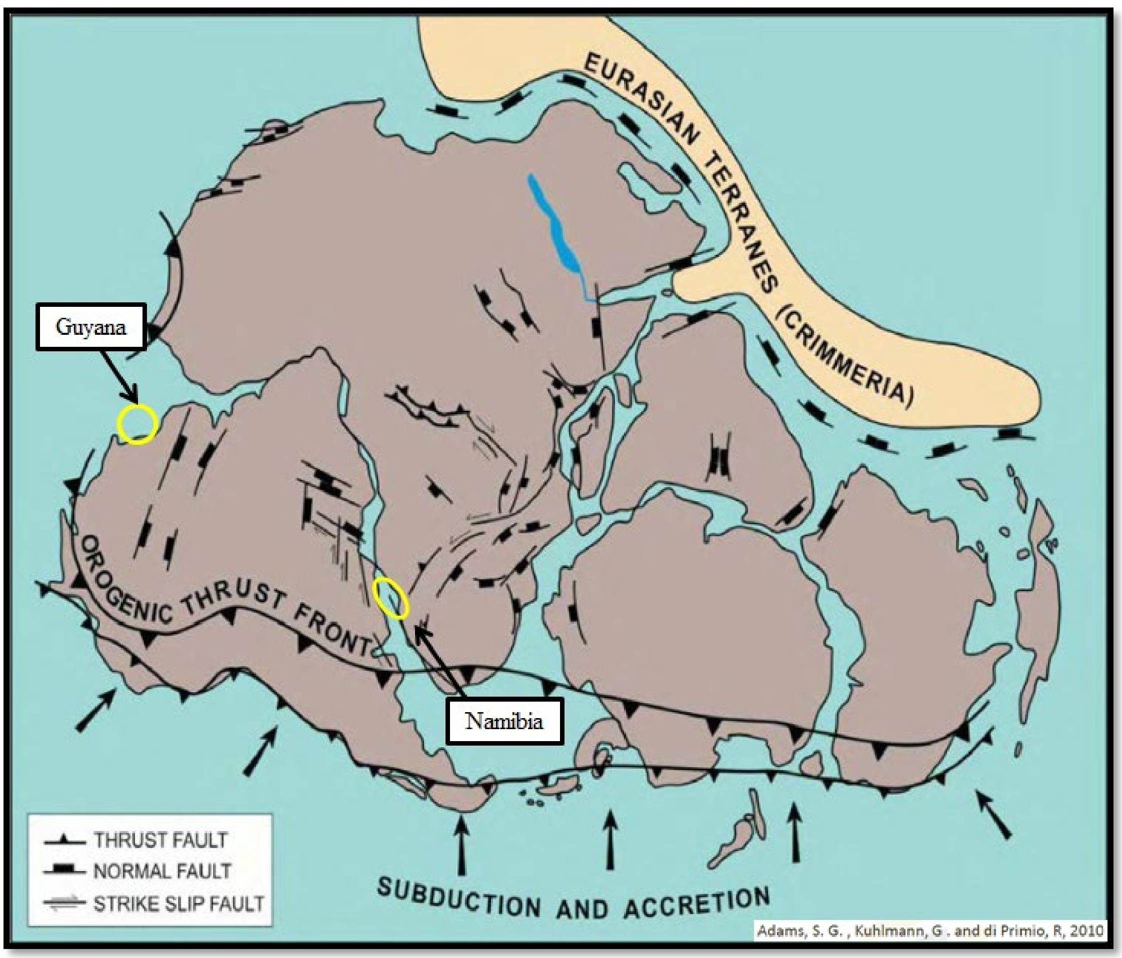



**Figure 4-12 Paleogeographic Map of the Opening of the South Atlantic Margin**

(Adams et al, 2010) Highlighted are Namibia and Guyana

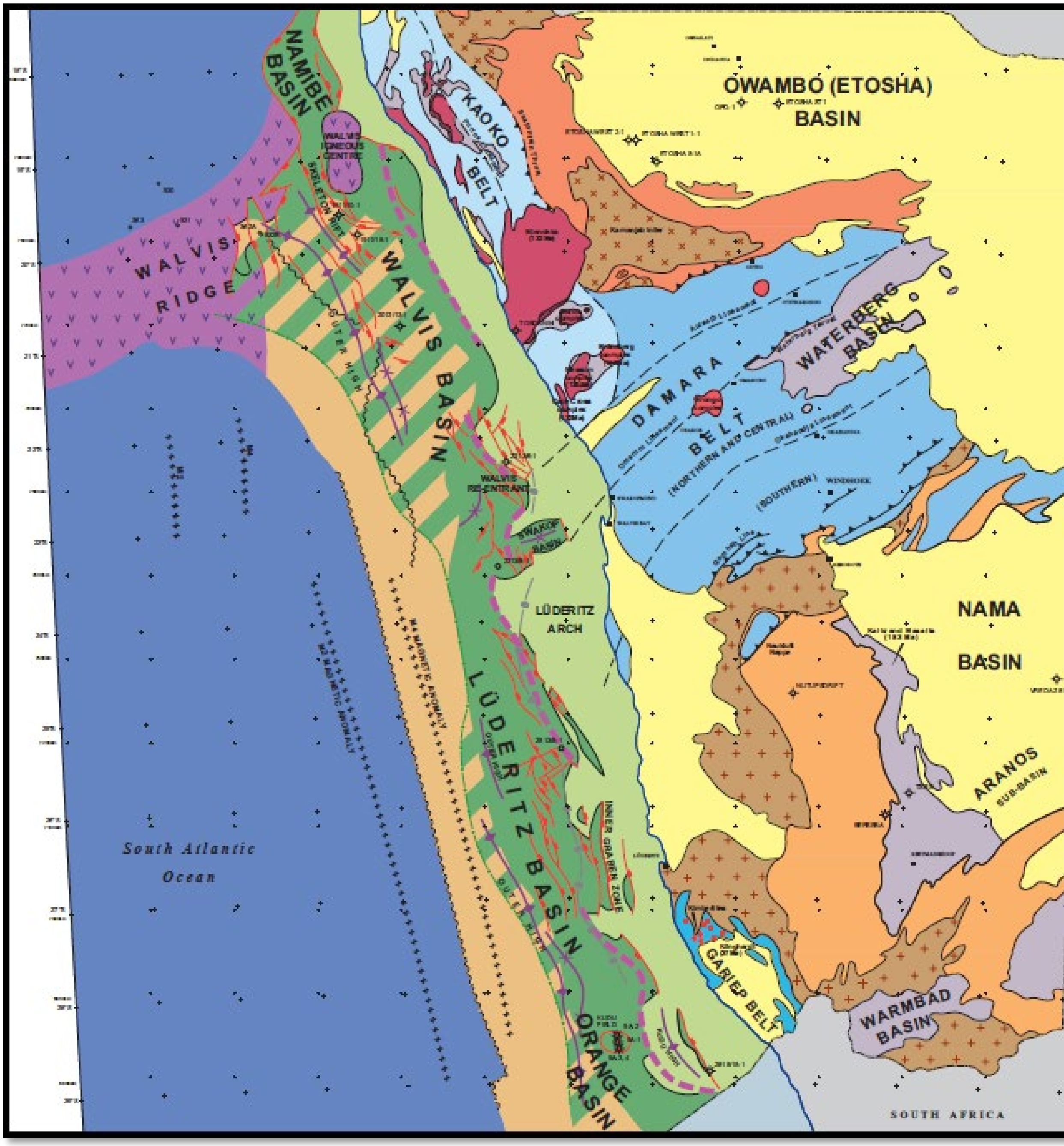



**Figure 4-13 Sedimentary Basins in Offshore Namibia**

(Bray, Lawrence, Swart, 1998)

4.2.12.2 Stratigraphy

The basin system in offshore Namibia is depicted Figure 4-14 which is a generalized stratigraphic chart of the area showing age, rift stage, stratigraphy, oil and gas shows, and potential source rock intervals in the Early and Late Cretaceous.

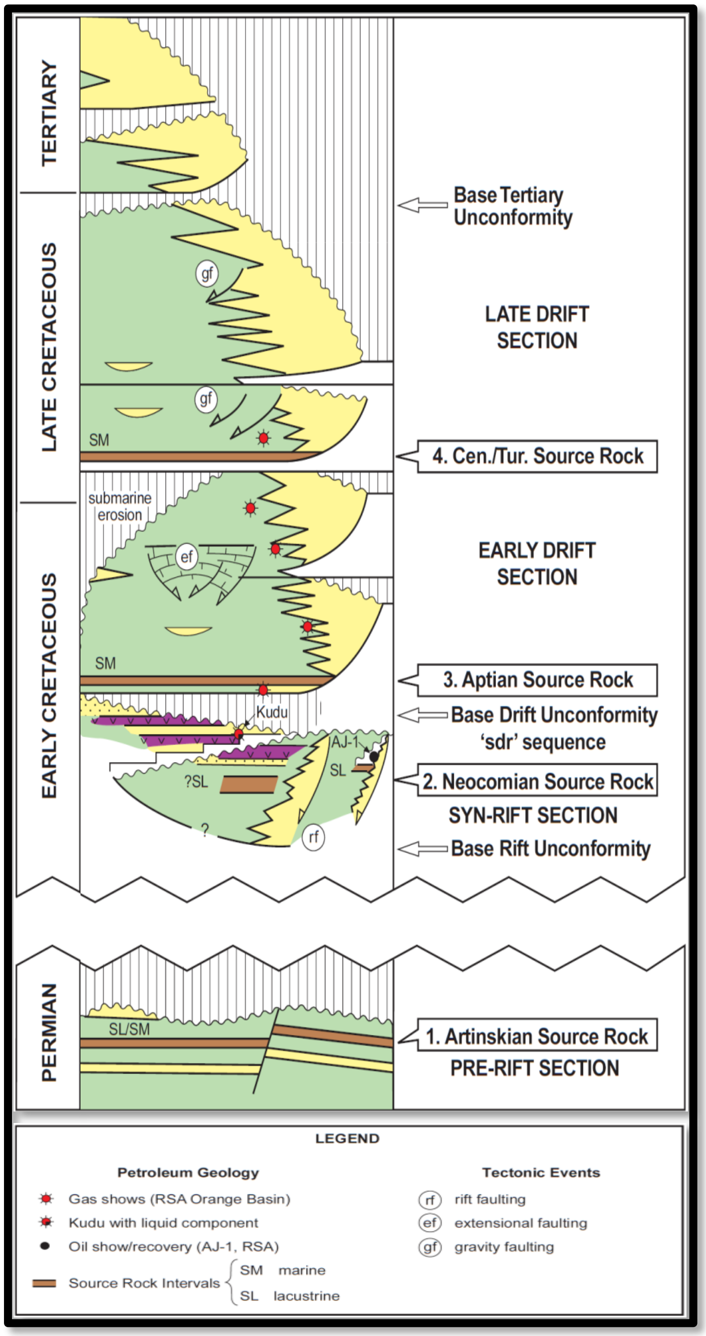



**Figure 4-14 Generalized Stratigraphic Chart of Offshore Namibia**

(Bray, Lawrence, Swart, 1998)

#### 4.2.12.3 Petroleum System

In a frontier exploration area, any information on the petroleum system is applied or modeled to the extent possible. However, there is usually very limited data of this sort in sparsely explored areas and consequently, petroleum companies primarily target anticlines and fault traps for exploratory drilling.

Petroleum systems (Magoon, 1988) are based on the factors affecting hydrocarbon accumulations including

1. trap (a structure or limit to the quality of the reservoir rock that is capable of holding hydrocarbons).
2. reservoir rock (one or more rock layers that has sufficient porosity and permeability to store hydrocarbons) – the Upper Oligocene strata are expected to be sand and shale with sufficient porosity and permeability to store hydrocarbons.
3. source rock (a rock layer in the region that has sufficient organic content to provide for hydrocarbons) – the Cenomanian – Turonian source rock was noted by Shell to be an excellent source rock.
4. maturation (the burial of the source rock sufficient to generate hydrocarbons from the organic material within the source rock) – the Cenomanian–Turonian source rock should be in the early oil window at this time.
5. migration (the path of movement of the generated hydrocarbons from the source rock to a trap), seal (a layer that is impermeable to hydrocarbon and prevents the hydrocarbon from escaping the trap) – faults that would act as migration pathways have been identified on the seismic data. These faults extend from the Cenomanian–Turonian source rock up into the lead structures.
6. timing (the events must occur in the correct order to create and preserve a hydrocarbon accumulation) – the generation of hydrocarbons would have occurred recently, most likely after the structures were formed.

4.2.12.4 Source Rocks

Shell, in the Block 2313/5-1 well proposal report, noted that 270 meters of good to excellent oil prone source rock was logged in the Block 1911/ 10-1 well drilled by Norsk Hydro in 1995. These included Turonian shales (W4 Group) seen at a depth of 3,334 to 3,646 meters and Cenomanian shales (W3 Group) encountered at a depth of 3,646-3,856 meters. The deposition of these sediments coincided with the mid-Cretaceous 'oceanic anoxic event'.

Early Aptian source rock[14] was deposited when restricted marine conditions prevailed. The Aptian section in the Kudu wells contains a marine oil prone source rock approximately 140 meters thick. This same source is located on Cooper Block, Figure 4-15, down-dip to the leads. The HRT Wingat well, drilled approximately 210 kilometers (130 miles) south of the Cooper Block, also identified a well-developed Aptian source rock, which was reported to be in the oil generating window. The oil from this well was described as light oil at 41 degrees API with a GOR of 1,193 scf/bbl. Oil of 40 degrees API with associated gas is the expected hydrocarbon type to be found in these leads due to the Turonian–Cenomanian aged source rock and the Aptian source rock being just within the hydrocarbon generating window. A preliminary study by PGS based on geothermal gradients derived from the existing well information indicates that the Turonian–Cenomanian aged source rock could be in the oil window in the western part of the Cooper Block and the Aptian aged source rock could be within the oil window throughout most of the Block. The Sasol well identified source rocks in the Upper Cretaceous Santonian to Cenomanian interval from 3,285 to 3,657 meters and in the Turonian – Cenomanian section a very good oil-prone source rock occurred from 3,500 to 3,650 meters. Additional potential source rock intervals have been identified from early rifting, lacustrine environments that were capable of preserving organic-rich, oil-prone claystones. Hauterivian (Neocomian) aged lacustrine source rocks are present just south of the area of interest in the Orange Basin. Permian aged (Artinskian) marine source rocks, such as the Whitehill Formation (although not reached in the existing wells) are also believed to be present in the offshore of Namibia.[15]

[14] Oil & Gas Journal – August 1998 – R. Bray, S. Lawrence, R. Swart
[15] Bray, Lawrence, and Swart, "Source Rock, maturity data indicate potential off Namibia", Oil and Gas Journal, August 1998.

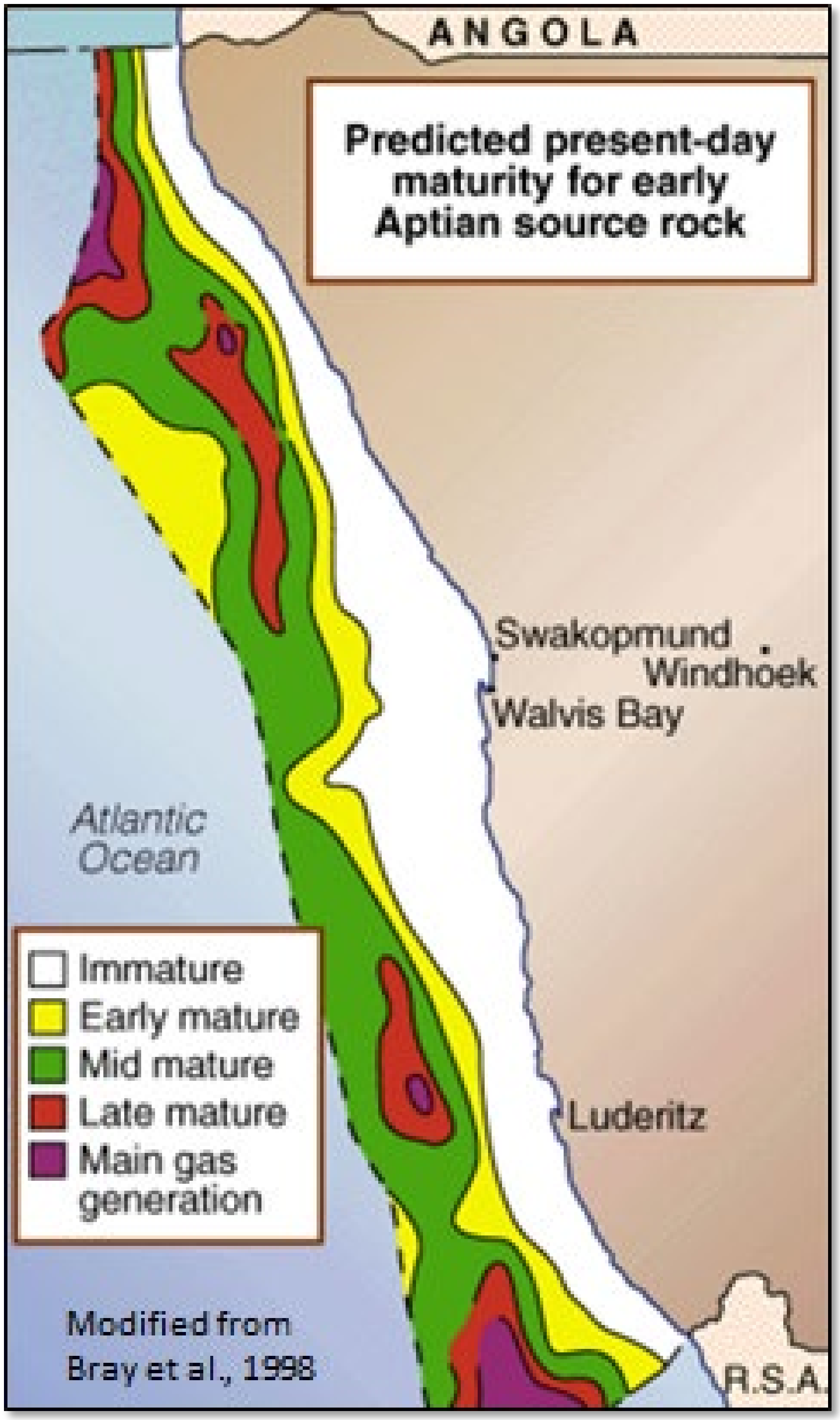



**Figure 4-15 Extent of Albian-Aptian Source Rock (Azinam after Bray)**

#### 4.2.12.5 Generation and Migration

Oil would be generated from the Turonian, Cenomanian and Aptian shales below and downdip of the lead traps and would migrate along faults that intersect both the source rock at depth and the lead section. Structural and fault traps as well as stratigraphic traps with shale layers as a seal form the leads identified on the seismic data. These seals have not been observed in the few wells drilled in the area and the structures are based on seismic time maps.

#### 4.2.12.6 Reservoir Rocks

The reservoirs consist of sandstones deposited in marine, channel-fan complexes on the slope and in the basin for Cooper, Guy, and Tamar Blocks and sandstones deposited in near shore marine shelf settings for Sharon Block. Carbonate reservoirs may also be present at Sharon Block however the well drilled on the Sharon Block did not encounter carbonates.

##### 4.2.12.6.1 Cooper Block

Reservoir rocks expected to be targets on Cooper Block would be similar in age and characteristics as those found in the Sasol 2012/13-1 well, the HRT Wingat-1 well, the Norsk Hydro well, and the Murombe-1 well (Figure 4-17). These nearby wells encountered Cretaceous age reservoir sandstones with good reservoir properties.

The Sasol 2012/13-1 well, drilled to the south of Cooper Block, found sands identified as deep-water turbidites in the Maastrichtian to Campanian (Cretaceous) section. This interval occurred from 2,660 to 2,994 meters and was 334 meters in gross thickness. Analysis of sidewall core samples from the well indicated an estimated porosity of 21%.

The Norsk Hydro 1911/15-1 well, drilled to the north of Cooper Block, encountered thick Tertiary to Late Cretaceous age reservoir rock with good reservoir properties. The reported average porosity was 24.3% and the lower portion of the Cretaceous section was described as predominately fine-grained rocks and limestone/dolomite.

The HRT Wingat-1 well penetrated several thin-bedded oil-saturated sands. Analysis of this oil indicated 41 degree API oil with a 1,193 GOR within the Cretaceous section.

The Murombe-1 well encountered 36 meters of net sand. The reported average estimated porosity was 19% and up to 28% in the Baobab sand.

4.2.12.6.2 Sharon Block

Reservoir rocks expected to be targeted on Sharon Block would be sandstones deposited in shelf and carbonates deposited in shelf-edge depositional environments. The Ranger 2213/6/1 well, which was drilled on 2213 in 1995, encountered thick sandstone reservoirs of Cretaceous age and a very thick interval of Tertiary age sandstone. There were no shows. Other examples of potential reservoir rocks would be found in the Wingat-1, which had oil shows, and HRT Murombe-1 wells are just to the west and down dip from Sharon Block and were discussed in the Cooper Block section.

4.2.12.6.3 Guy Block and Tamar Block

The Guy and Tamar Blocks are along trend and adjacent to each other and would have similar targets with similar reservoir rocks. These reservoirs would be sandstones deposited in turbidite fan-channel complexes in slope and basin depositional settings.

Examples of the reservoirs that would be expected at both Guy and Tamar can be found in the HRT Wingat-1 and HRT Murombe-1 wells, which are just to the east and updip from Guy Block and discussed in the Cooper Block section. There were oil shows in sandstones with good reservoir properties in the Wingat-1 well. Potential reservoir sandstone was encountered in the Murombe-1 well with good reservoir properties.

4.2.12.7 Traps and Seals

Structural and fault traps as well as stratigraphic traps with shale layers as a seal form the leads.

#### 4.2.12.8 Analogous Field

##### 4.2.12.8.1 Santos Basin

The Tupi Oil Field in the Santos Basin, discovered in 2006 in the offshore of Brazil, is estimated to contain up to 8 billion barrels of recoverable oil (Fessler, 2011).The Santos Basin in Brazil consists of drift and rift sections that are of similar age as those found in offshore Namibia and may be considered the conjugate basin for offshore Namibia. Volcanism was present during the formation of the basin, much like the early Cretaceous syn-rift section in Namibia. Albian and Aptian carbonates are also present in the Santos Basin similar to the early drift section in Namibia (UFRJ and Gustavson, 1999).

#### 4.2.12.9 Exploration History

The offshore of Namibia is an underexplored area with only 20 shallow shelf wells drilled in an area of more than 500,000 square kilometers. A graphical view of the wells and a map view of the wells in the Walvis Basin are depicted in Figure 4-16 and Figure 4-17 respectively. Five of these wells are located in the southern part of the offshore area in Kudu Field which was drilled in 1974 and is the only discovery so far. Offshore leases were first offered in 1968 and 1972 and by 1975 approximately 33,000 line-kilometers of 2-D seismic data had been shot, but only one well was drilled.[16] A United Nations mandate in 1976 voided all concessions granted to foreign companies by the government of South Africa, which had control over the Namibian area, and for the next 10 years there was virtually no oil or gas activity until in 1987 and 1988. At that time, two more wells in Kudu were drilled for Namcor. In 1989 Intera, ECL, and Halliburton Geophysical Services Inc. shot a 10,600 line-kilometer regional speculative seismic survey off Namibia. This was followed up with an infill survey of some 3,500 line-kilometers and additional speculative surveys shot in early to mid-1990 by TGS and Western. The 1911/15-1 well was drilled in early 1994 and the 1911/10-1 well was drilled in early 1995 by Norsk Hydro Namibia. The Ranger Oil Namibia Ltd

[16] NAMIBIA, PRACTICALLY UNEXPLORED, MAY HAVE LAND, OFFSHORE POTENTIAL; Apr 8, 1991; M.P.R. Light, H. Shimutwikeni

2213/6-1 was drilled in early 1995; the Sasol 2012/13-1 well located to the south of Cooper Block was drilled in early 1997.

In 2012, Chariot drilled the Tapir South-1 well to a depth of 4,879 meters north of the Walvis Ridge and found wet Upper Cretaceous sandstones. Chariot also drilled a well to the south of Cooper and between Guy and Sharon in Block 2714A and encountered source rocks in the Cretaceous section.

In 2013, HRT drilled 2 wells in Block 2212A the Wingat-1 and the Murombe-1. The Wingat well had oil shows and found source rocks reportedly in the oil window. In Block 2713 northwest of Kudu field, HRT drilled the Moosehead-1 which encountered 100 meters of carbonates and 'wet' gas shows were seen along with a well-developed Aptian age source rock. Oil seeps have been observed in the offshore area near the Cooper Block.

In 2014, Repsol and Tower Resources drilled the Welwitschia-1 well in License PEL0010 (Blocks 1910A, 1911, and 2011A). Repsol was operator. This well drilled to a total measured depth of 2,454 meters. The Paleocene, Maastrichtian and upper Campanian reservoirs were found to be poorly developed and no hydrocarbons were encountered. The license was not renewed and expired in 2015.

In early 2022, in the Orange Basin located south of the Walvis basin in the offshore of Namibia and South Africa, both the Shell Graff #1 and the TotalEnergies Venus #1 wells have been reported by various sources as discoveries.

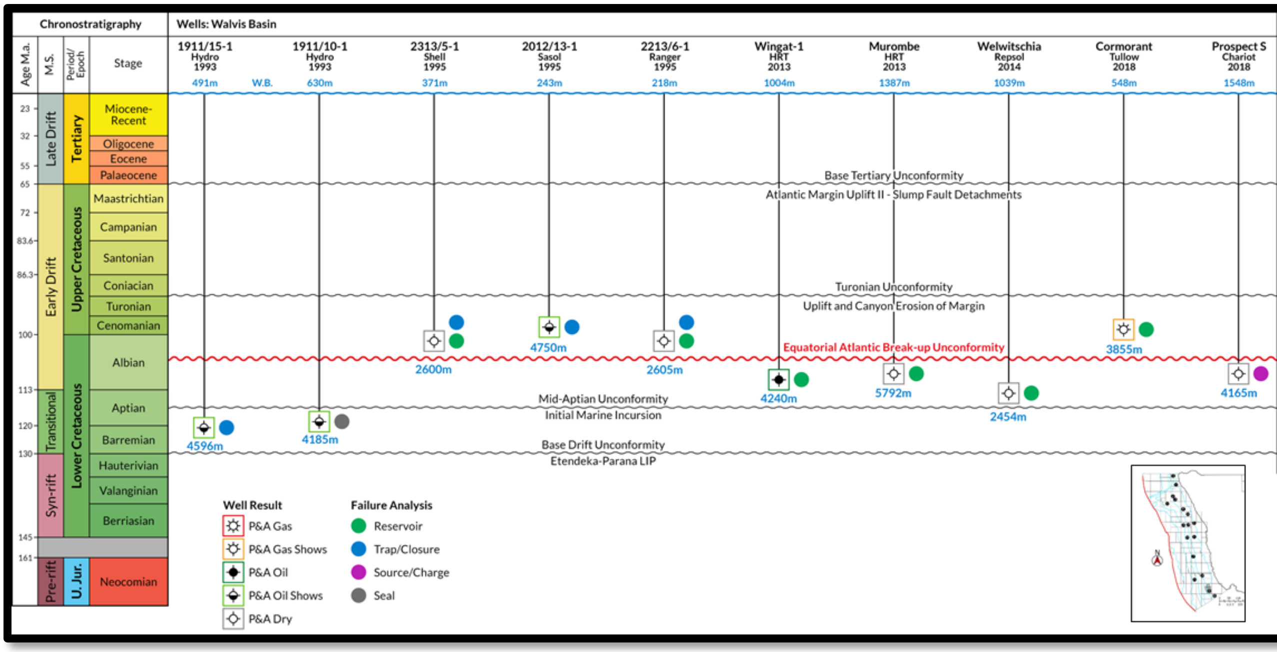



**Figure 4-16 Walvis Basin Exploration History**

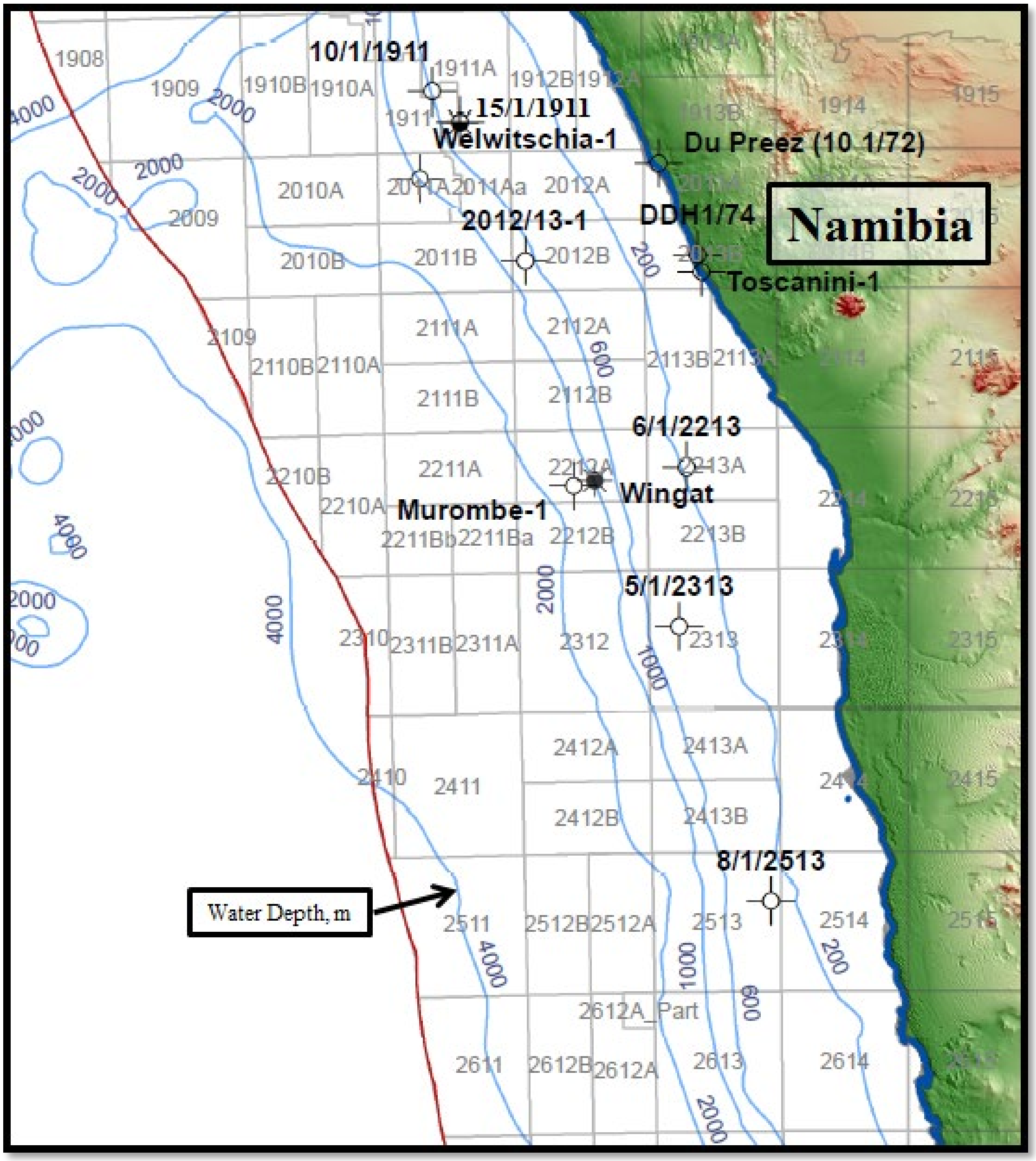



**Figure 4-17 Map of Northern Offshore Namibia Showing Wells (Gustavson)**

4.2.12.10 Namibia Leads

The index map (Figure 4-18) of the four ECO Namibia blocks shows the identified leads on the blocks. Note that some of the leads have not been evaluated for this report.

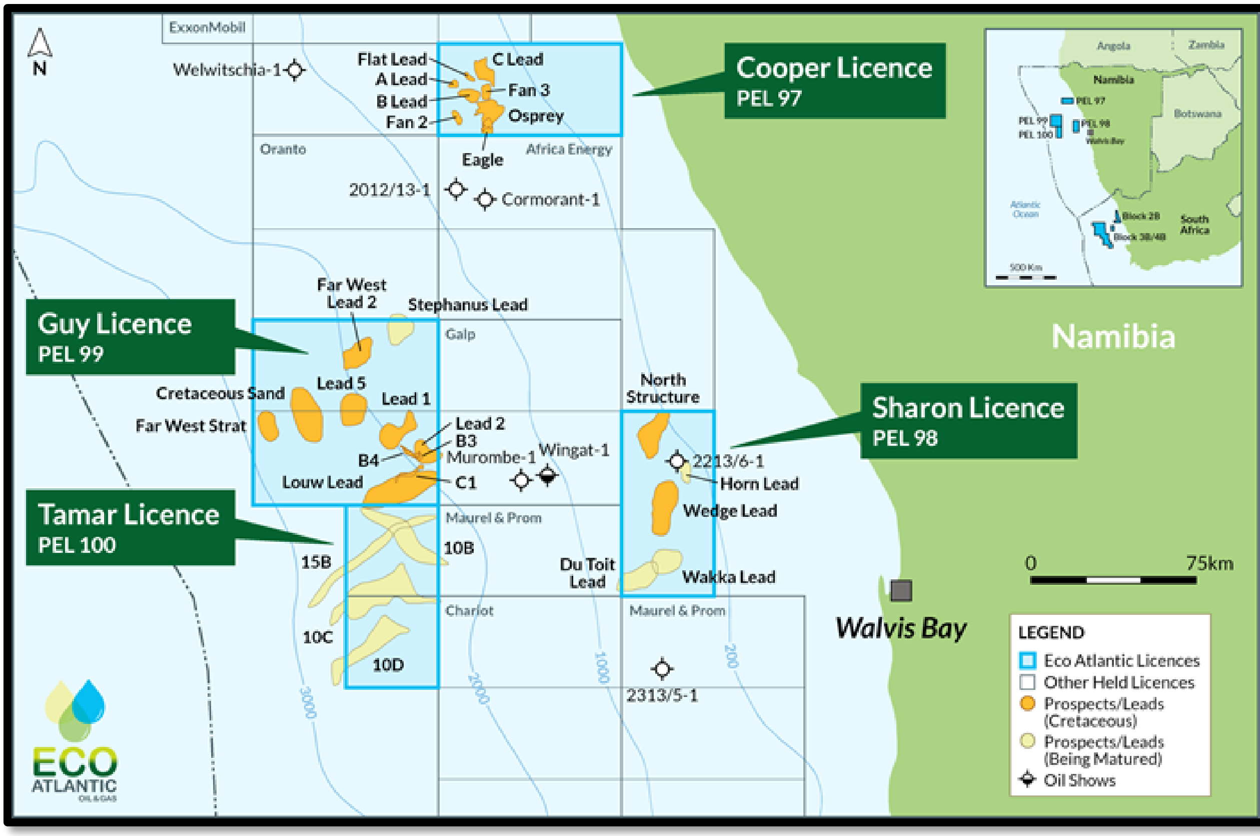



**Figure 4-18 Index Map of the Offshore Namibia Leads (ECO)**

Note that not all the Leads on this map are included in the resource estimates for this report.

4.2.12.10.1 Cooper Block PEL97

The Cooper Block is located off the coast of Namibia (Figure 4-18) in less than 100 meters to over 500 meters of water. The play types expected based on Figure 4-11 include deeper water sediments in the west and south parts of the Block such as Albian age sand fans in both structural and stratigraphic trap settings; Aptian sands pinching out against volcanic highs; stratigraphically trapped Santonian fans and channels; Cenomanian channels; Campanian fans as well as shallower water features to the east such as isolated sand filled channels.

The 2D seismic data and a 1,108 square kilometer 3D seismic survey over Cooper Block show excellent Eocene, Upper Cretaceous Maastrichtian, and Lower Cretaceous age Albian/Aptian reflectors that can be tied back to the SASOL 2012/13-001 well. These reflectors have been mapped in the local area and form the basis for geologic horizon identification. The Leads identified as A, B, C, and Flat (Figure 4-19) are based on 2D seismic data and appear to be fault bounded, and have structural closures of 20 to over 75 meters in the Late Cretaceous section. The faults in the structural leads are interpreted to extend down into the Turonian aged source rock. These structures persist down through the Early Cretaceous in most cases but these intervals, which have similar closures, were not included in the evaluation. The zones of interest are defined as the Early through Late Cretaceous in age.

In addition to the 2D seismic leads, the Osprey prospect, which is interpreted to be of Albian age, is interpreted on the new 3D seismic data to be a stratigraphic trap in the Late and Early Cretaceous section. The image from the Cooper 3D seismic data set (Figure 4-20) shows the Osprey amplitude in a 3D sense and how it pinches out at the base of the slope forming a stratigraphic trap. The warmer colors indicate the sand portion of the amplitude event while the cooler colors indicate shales. A post depositional shale filled channel apparently cut the Osprey sand body. Other potential turbidite deposits are located to the north of Osprey. The Osprey prospect on the Cooper Block is estimated to occur at a depth range of 2,650 to 2,850 meters with a normal pressure and temperature gradient. A seismic line from the 3D (Figure 4-21) that goes through the Osprey prospect shows that the amplitude response is readily apparent.

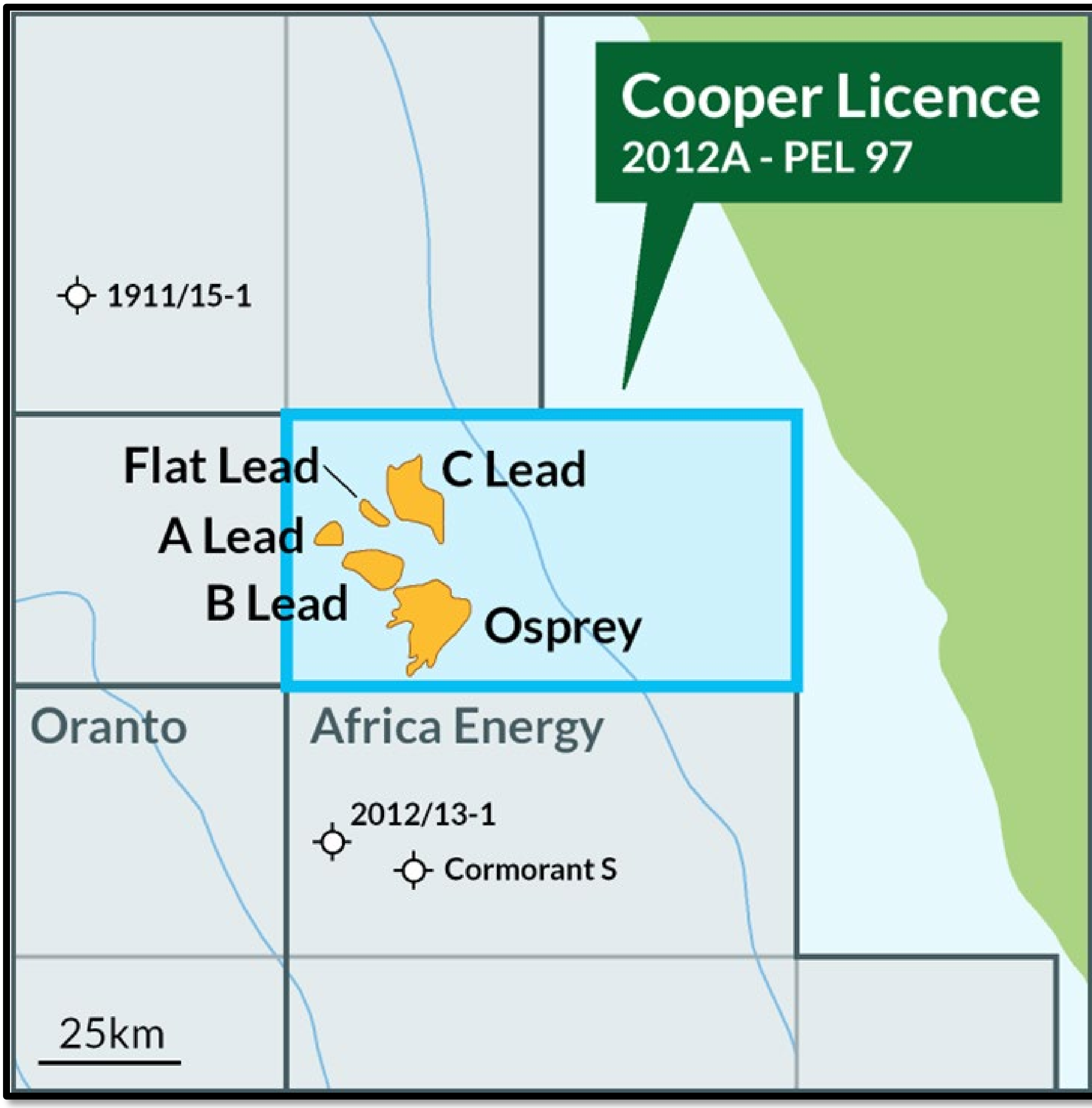



**Figure 4-19 Cooper Block with Lead and Prospect Area Outlines (ECO)**

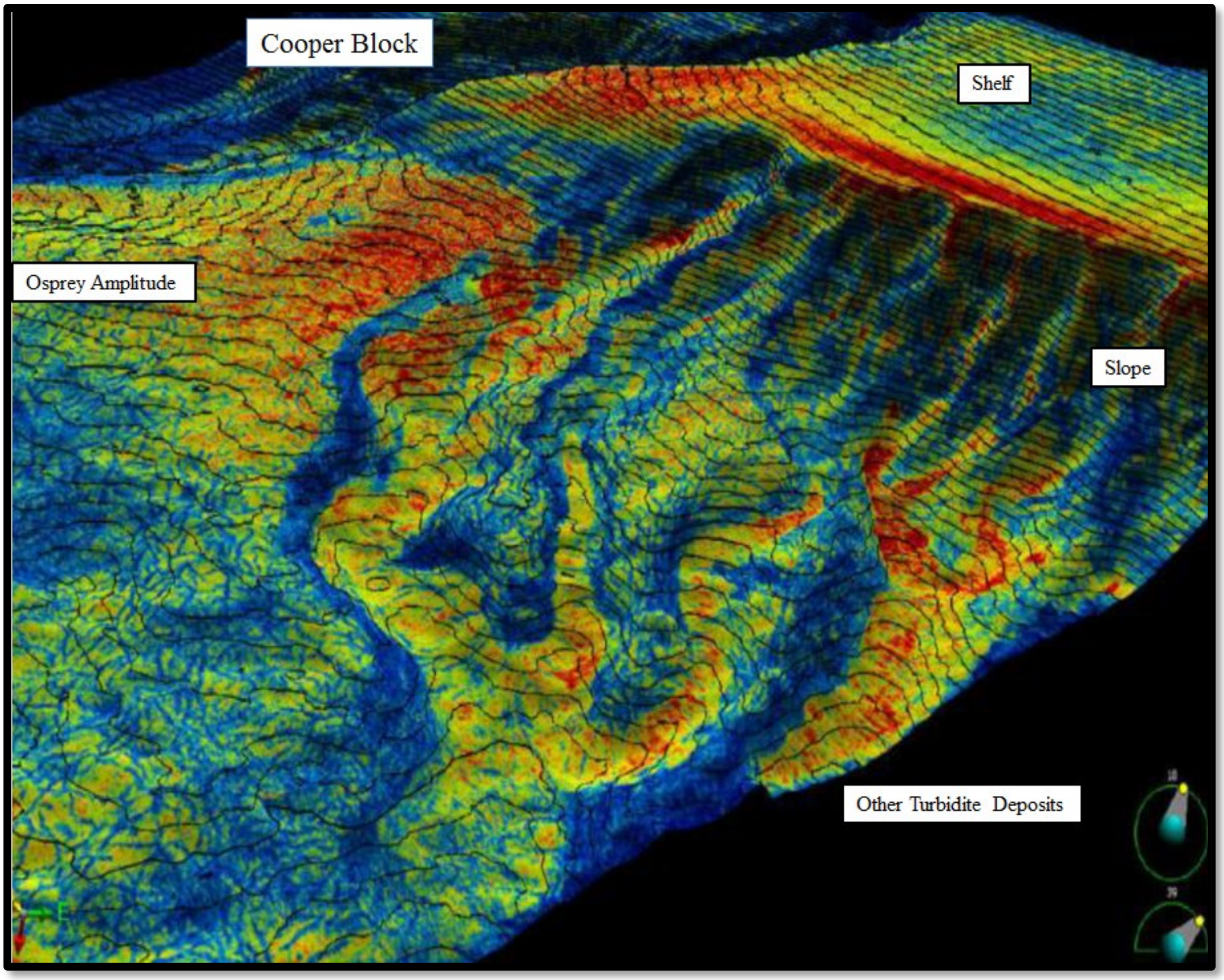



**Figure 4-20 Image from Cooper 3D Seismic Data Set (ECO)**

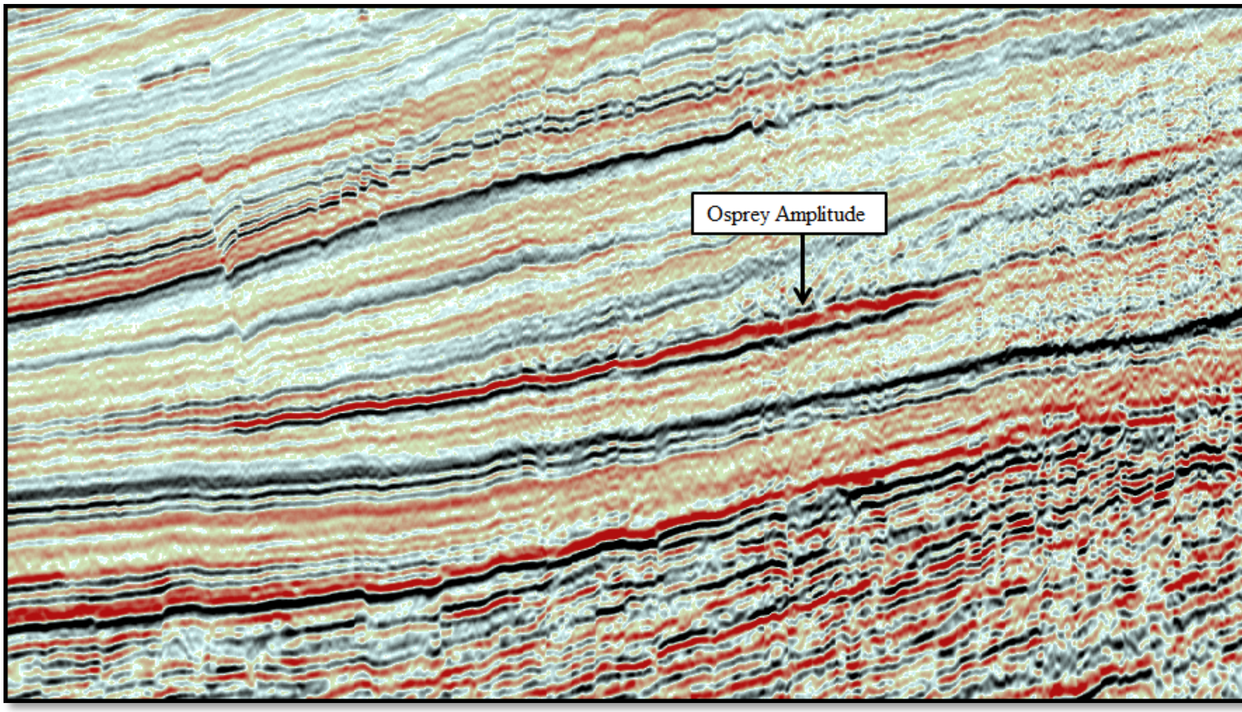



**Figure 4-21 Seismic Line from Cooper 3D showing the Osprey Amplitude (Gustavson)**

The Osprey prospect amplitude map overlain with time structure contours, with downdip being to the southwest, is depicted in Figure 4-22. The yellow outline polygon is the area used for the maximum (P10) case in the Prospective Resource estimate. The amplitude is interpreted by ECO and partners to be a sand body in a similar basinal position as a sand identified as the Ondongo sand found in the Murombe well 220 kilometers to the south.

The Osprey Prospect having been delineated by a 3D seismic data set would have an estimated Probability of Success (POS) of 17.9%[17]. Several additional leads have been identified by ECO and their partners which have not been evaluated at the time of this report.

[17] Section 3.2.4 Risk Assessment

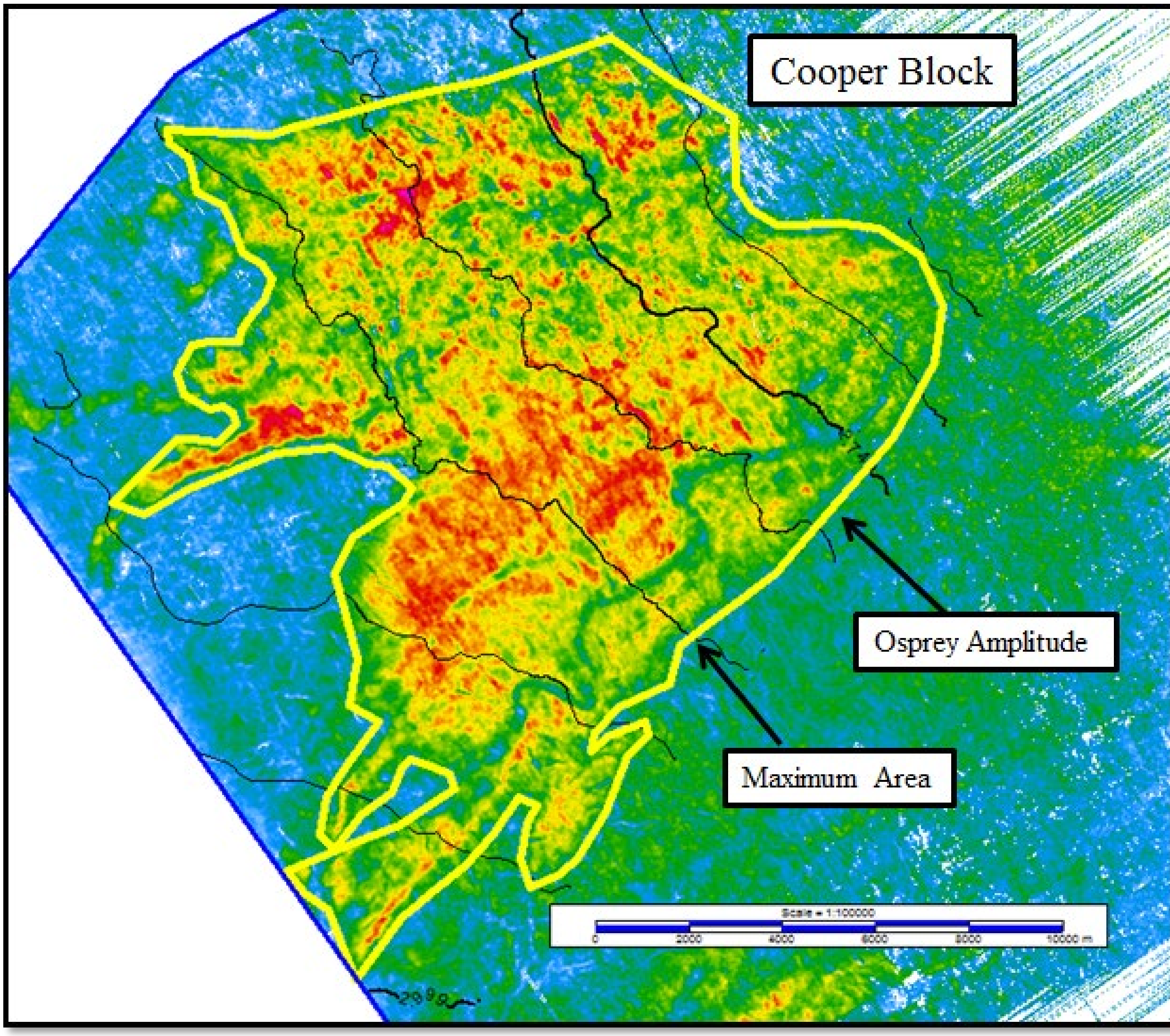



**Figure 4-22 Amplitude with Time Structure Map of Osprey Prospect (Gustavson)**

4.2.12.10.2 Sharon Block PEL98

The Sharon Block consists of the western halves of Blocks 2213A and 2213B (Figure 4-23). The interpretation of over 606 line-kilometers of widely spaced (14 to 22 kilometers) 2D seismic data over Sharon Block, have shown excellent Lower Cretaceous reflectors that are tied back to the Ranger 2213/6-001 well located in the north half of the Block. An additional 3,086 line-kilometers of close spaced (2 kilometers), which was purchased recently, is being evaluated for additional lead areas. Play types anticipated (Figure 4-11) include deep structures and isolated fluvial and nearshore shallower marine stratigraphic sand bodies. Two Leads seen on the original six 2D seismic lines are included in this report identified as North Structure and Wedge (Figure 4-24). The North Structure lead is based on the original 2D seismic data while the Wedge Lead is based on the original and the newer data.

The 2213/6-1 Ranger Oil well, which was a dry hole in the north half of the license area, was used as a reference for the seismic data. The leads on the Sharon Block are estimated to occur at a depth range of 2,540 to 2,700 meters with a normal pressure and temperature gradient. This is based on a time-depth relationship utilized by Shell Oil since no check shot information or VSP data was available at the time of interpretation.

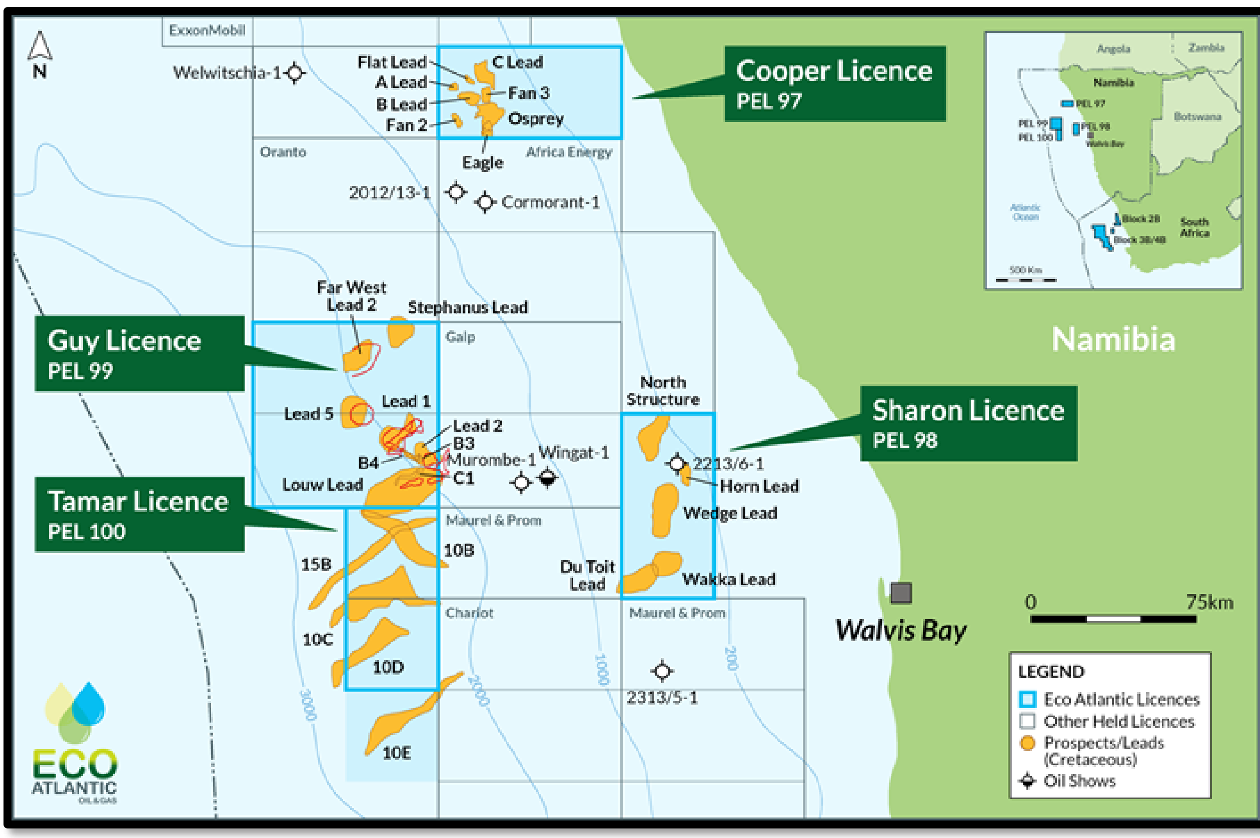



**Figure 4-23 Location of Sharon Block (ECO)**

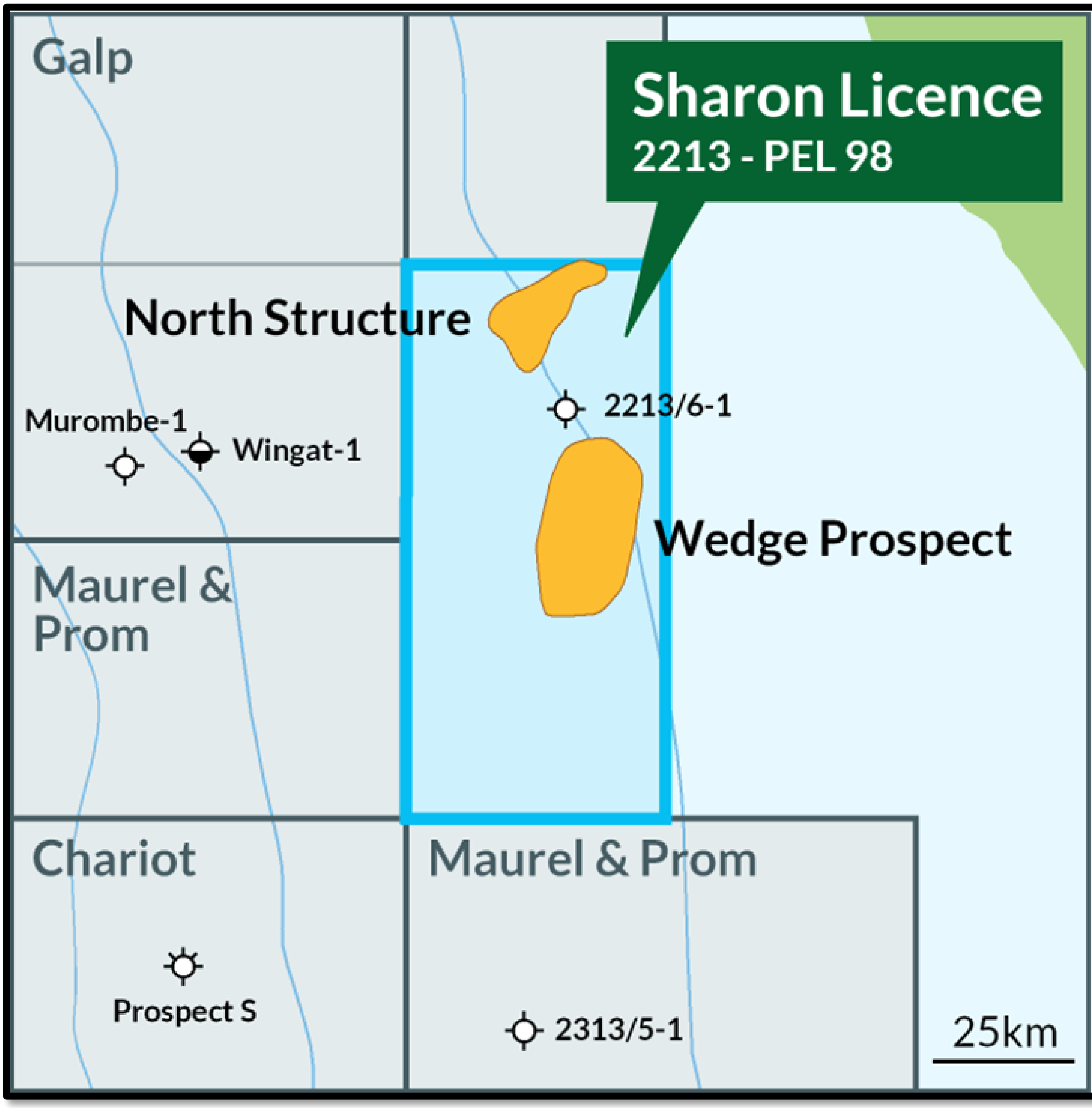



**Figure 4-24 Location of Leads in Sharon Block Namibia (ECO)**

4.2.12.10.3 Guy Block PEL99

The Guy Block is comprised of Blocks 2111B and 2211A (Figure 4-25). The play types anticipated (Figure 4-11) are stratigraphic traps comprising deep water Albian to Cenomanian aged fan and channel deposits in stratigraphic traps among others.

The interpretation of the 675 line-kilometers of 2D seismic data available prior to 2014 over Guy Block has shown excellent Cretaceous to Tertiary reflectors. These reflectors have been mapped throughout the available data and form the basis for geologic horizon identification. Four Cretaceous leads are identified in this report, two of which are structural in nature and fault bounded and two that are stratigraphic. The leads of the Guy Block are estimated to occur at a depth range of approximately 3,460 to 4,300 meters with a normal pressure and temperature gradient. This is based on a time-depth relationship utilized by Shell Oil in Block 2213 located to the east of Guy Block because no check shot information or VSP data was available at the time of interpretation.

At the end of 2014, ECO purchased 473 kilometers of existing data and acquired 1,012 kilometers of new 2D seismic data. The new seismic data was used to tie into the Murombe-1 well located to the east of Guy Block in Block 2212A. The Murombe well drilled through channel sands that are identified as the Baobab sands which have been interpreted by the operator as extending into the southeastern part of Guy. Seismic line NWG98-408 (Figure 4-32) shows several potential sand bodies in the southeast of Guy Block. These potential leads were not evaluated for this report. An 864 square kilometer 3D seismic survey (Figure 4-25) was acquired at the end of 2015 in order to better image the potential traps associated with the Baobab sand channels seen on the 2D data. These data are still being interpreted.

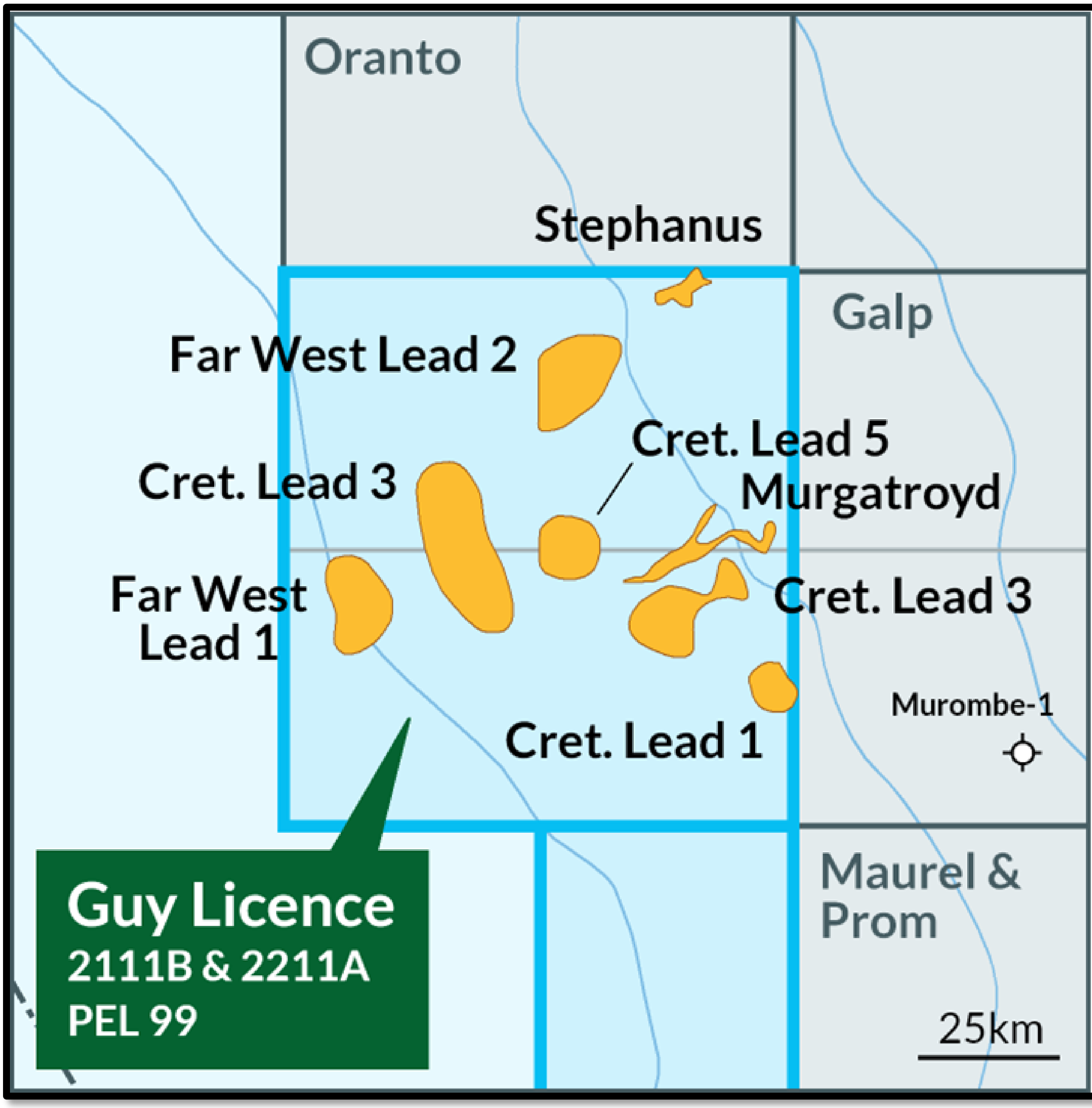



**Figure 4-25 Location of Leads in Guy Block Namibia (ECO)**

The leads are interpreted as structures with associated faults and stratigraphic traps. These faults are interpreted to extend down into the Lower Permian aged source rock.

The Guy block was an asset that was owned by ECO and partially relinquished as of the previous report by Gustavson Associates. The western half that was relinquished recently was added back and the previously reported leads on the block were based on Gustavsons work. The Murgatroyd and Stephanus leads that were added to the Guy block in this report were presented by Azinam who was Operator at the time of the last report, were reviewed by ECO and independently reviewed by Gustavson. ECO had just completed the 3D acquisition and the evaluation was not complete at the time of the last report. The evaluation was subsequently completed by Azinam. The new leads were accepted as reasonable with the downward adjustment of the porosity and saturation parameters.

The estimated reservoir parameters of the leads are discussed in Section 5.

The Far West Lead #1, Figure 4-26, is a structural lead in the northwest portion of License Area 2211A and is observed on only one line of data. It is situated in an estimated 3,150 meters of water, covers 255 square kilometers (98 square miles), has 60+ meters of structural closure in the anticipated Base Tertiary pay zone, and is estimated to be at a subsea depth of -4,100 meters. Other possible pay zones range in age from Synrift through Paleocene.

Far West Lead #2, Figure 4-27, is located in the north central portion of License Area 2111B and is observed on several lines in the northern portion of the Guy Block. This lead is in an estimated 2,325 meters of water, covers 331 square kilometers (128 square miles), and has over 100 meters of structural closure in the anticipated Base Tertiary pay zone at an estimated depth of -3,525 meters subsea. Other possible pay zones range in age from Synrift through Eocene. This feature could possibly be a smaller closure at the southern end of a much larger structure extending from the south part of License Area 2111B and continue for many tens of kilometers to the north and off License 2111B.

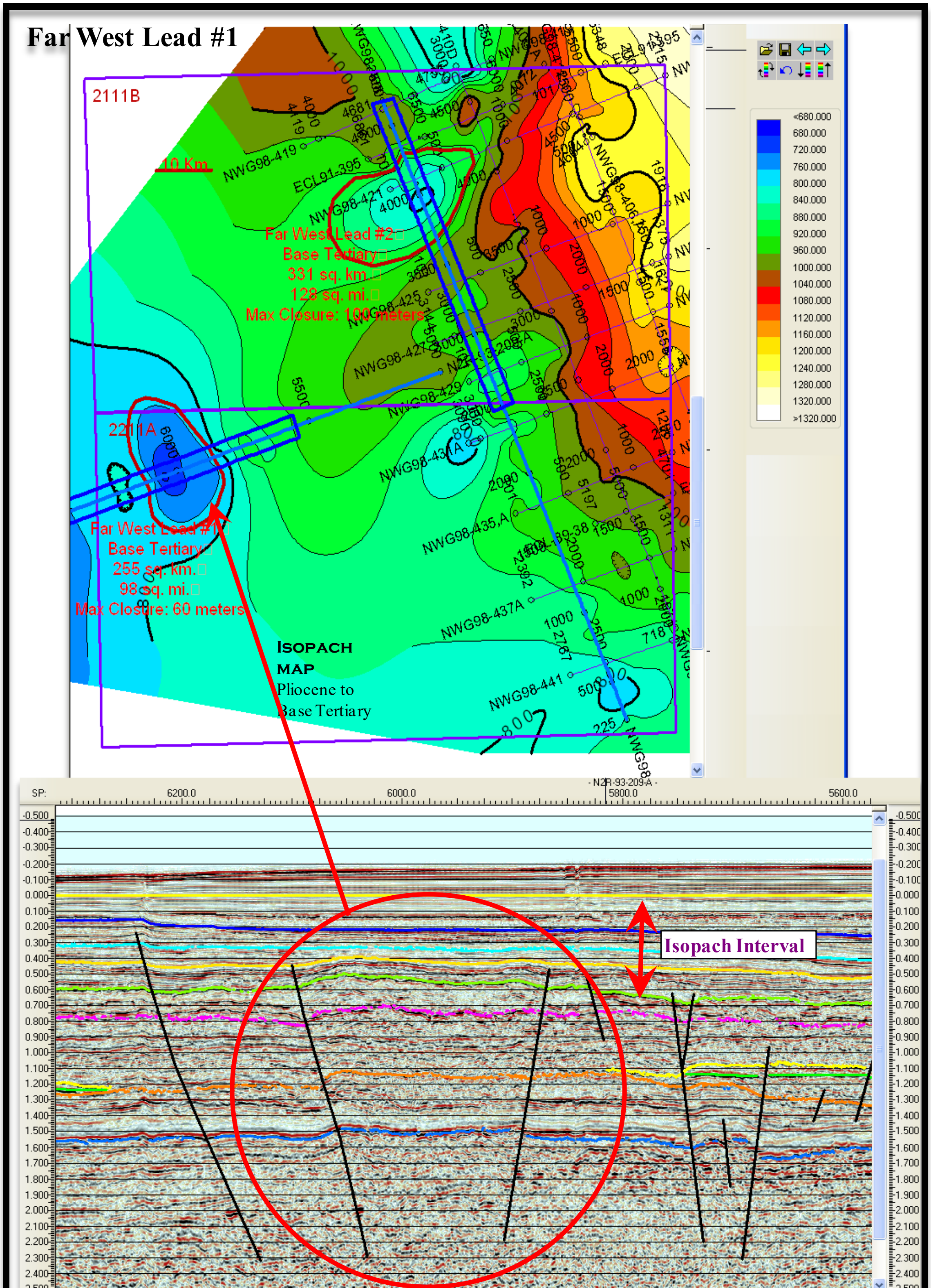



Figure 4-26 Map and Seismic Line of Far West Lead #1 (Gustavson)

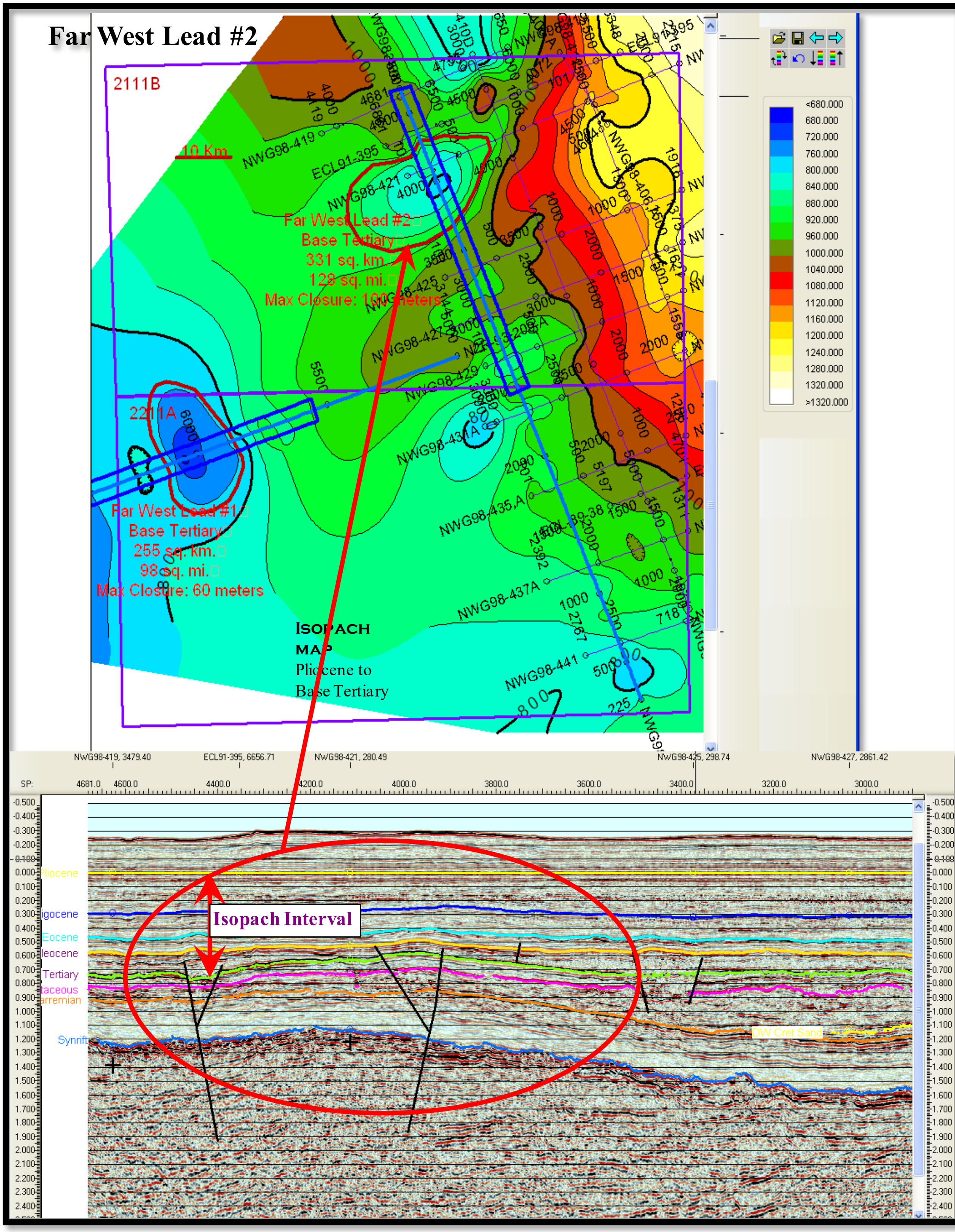



**Figure 4-27 Map and Seismic Line of Far West Lead #2 (Gustavson)**

The Cretaceous Sand Lead #1, Figure 4-28, is in the northeast portion of License Area 2211A and is interpreted to be a thick lower Cretaceous turbidite sand. Situated in 2,400 meters of water, this lead covers 201 square kilometers (77.7 square miles) and may have 120 meters of sand pay thickness with an estimated subsea top of -4,000 meters.

The Cretaceous Sand Lead #2, Figure 4-29, is in the extreme eastern part of block 2211A and is also interpreted to be a thick lower Cretaceous turbidite sand. Situated in 2,250 meters of water, this lead covers 68 square kilometers (26 square miles) but may have only 50 meters of sand pay thickness. This lead is estimated to be at a subsea depth of -4,050 meters.

The Cretaceous Sand Lead #3, Figure 4-30, is situated almost equally in both License Areas 2111B and 2211A and close to the western boundary. This lead is observed on only one line and is also thought to be thick lower Cretaceous turbidite sands. Additionally, this lead is situated in the low area between the structurally controlled Far West Leads #1 & #2 and contains an interpreted flat seismic reflector throughout the sand body, possibly indicative of an oil-gas/water contact. Located in 2,750 meters of water, this lead could be as large as 417 square kilometers (161 square miles), have over 150 meters of pay sand (average pay thickness of 80 meters) and has an approximate subsea depth of -4,350 meters.

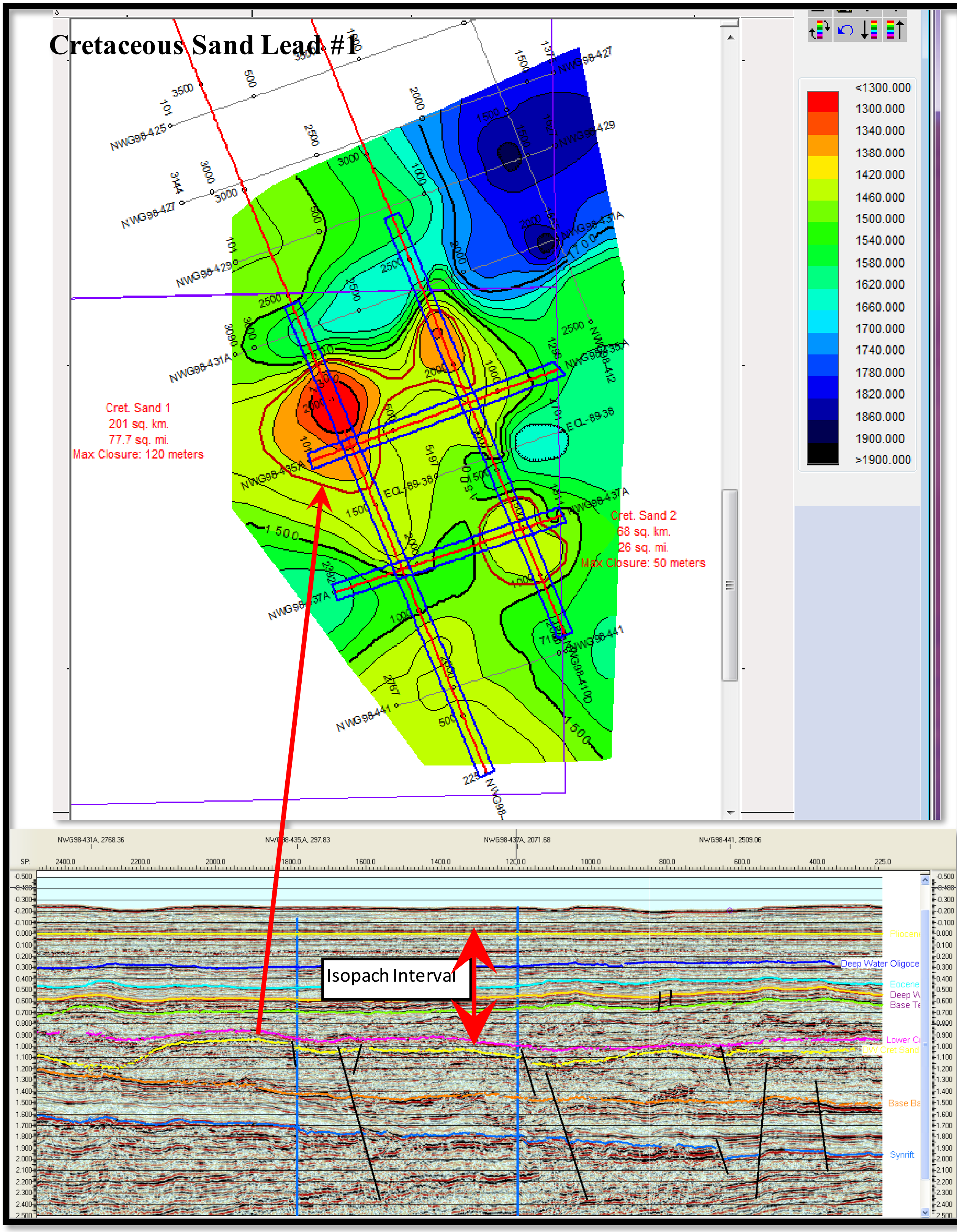



**Figure 4-28 Map and Seismic Line of Cretaceous Sand Lead #1 (Gustavson)**

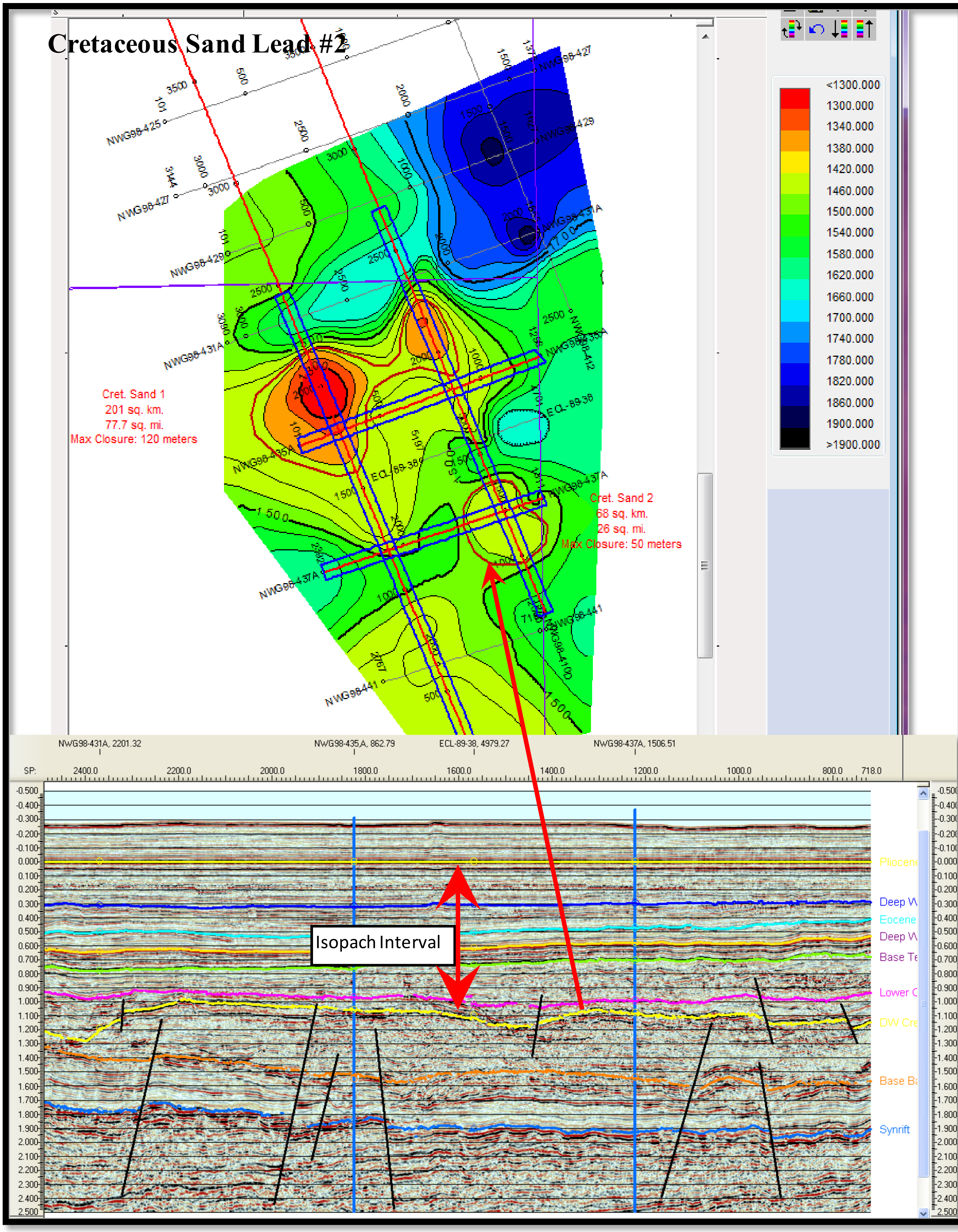



Figure 4-29  Map and Seismic Line of Cretaceous Sand Lead #2 (Gustavson)

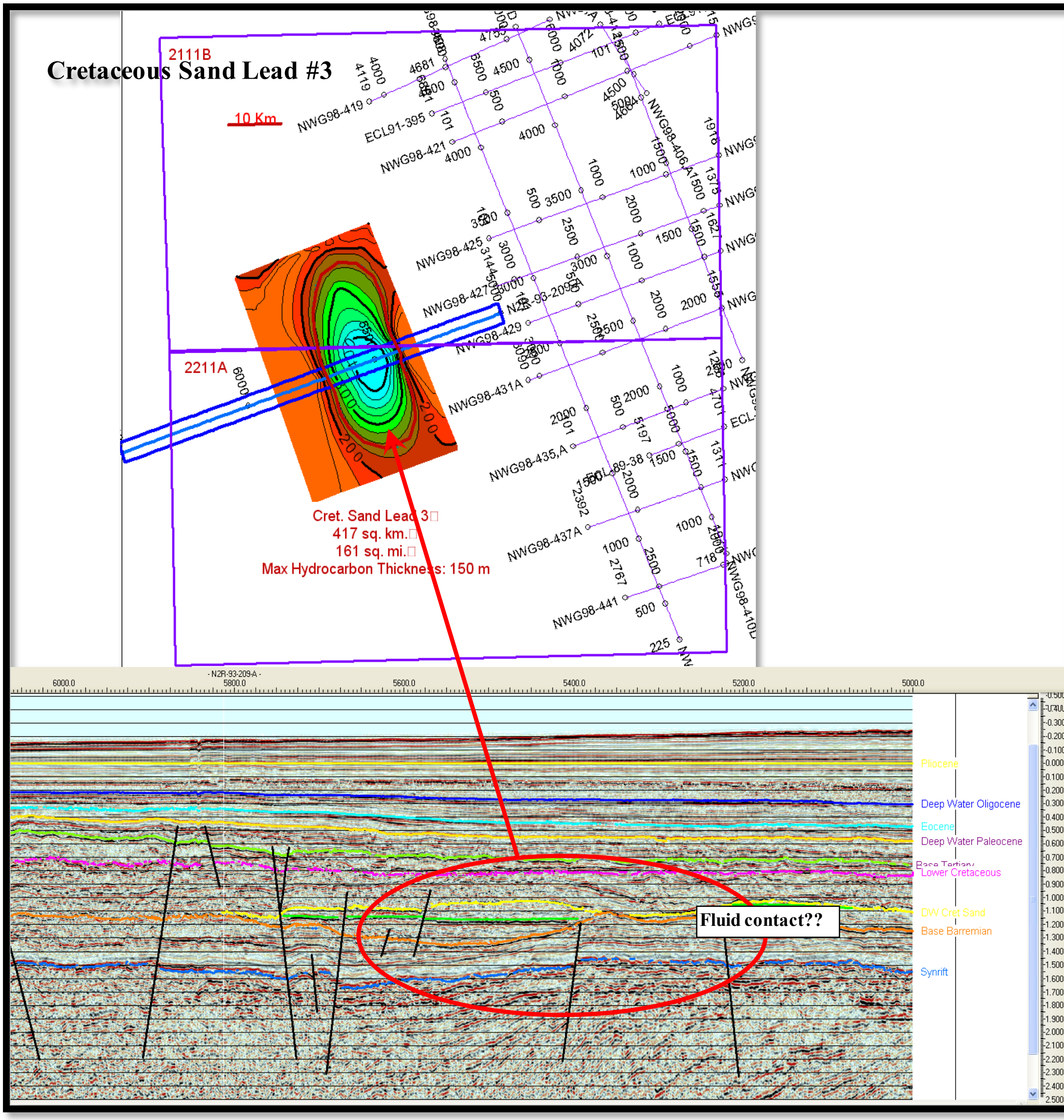



**Figure 4-30 Map and Seismic Line of Cretaceous Sand Lead #3 (Gustavson)**

The Cretaceous Sand Lead #5, Figure 4-31, is located almost exactly in the middle of the Guy Project Area. The lead is also thought to be in lower Cretaceous turbidite sands with an interpreted oil-gas/water contact reflector, one that however is not as obvious as that observed on Cretaceous Sand Lead #3. Located in 2,600 meters of water, this lead covers possibly 138 square kilometers

(53 square miles) but may have only 25 meters or less of sand pay thickness and at an estimated subsea depth of -4,300 meters.

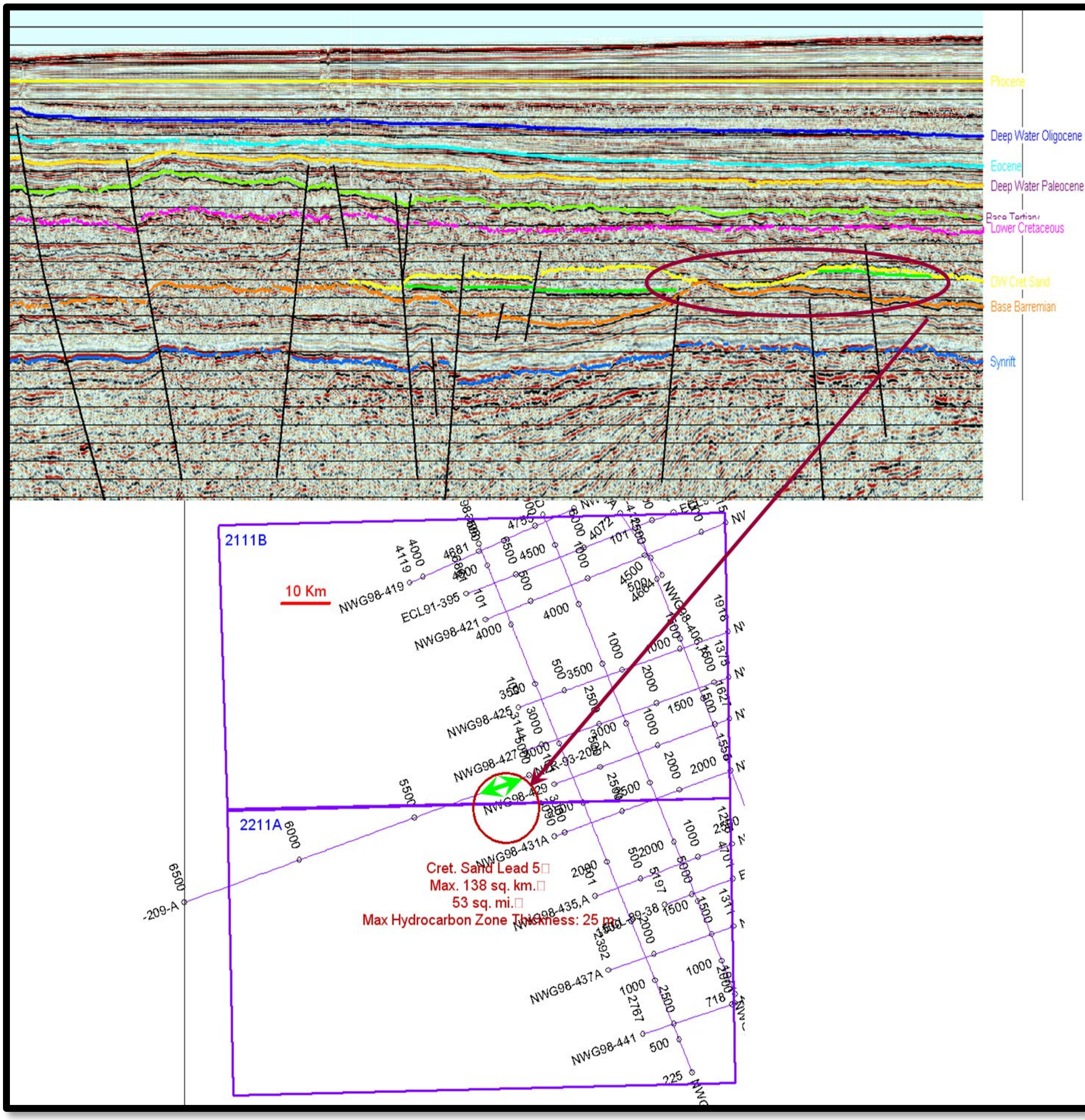



**Figure 4-31 Map and Seismic Line of Cretaceous Sand Lead #5 (Gustavson)**

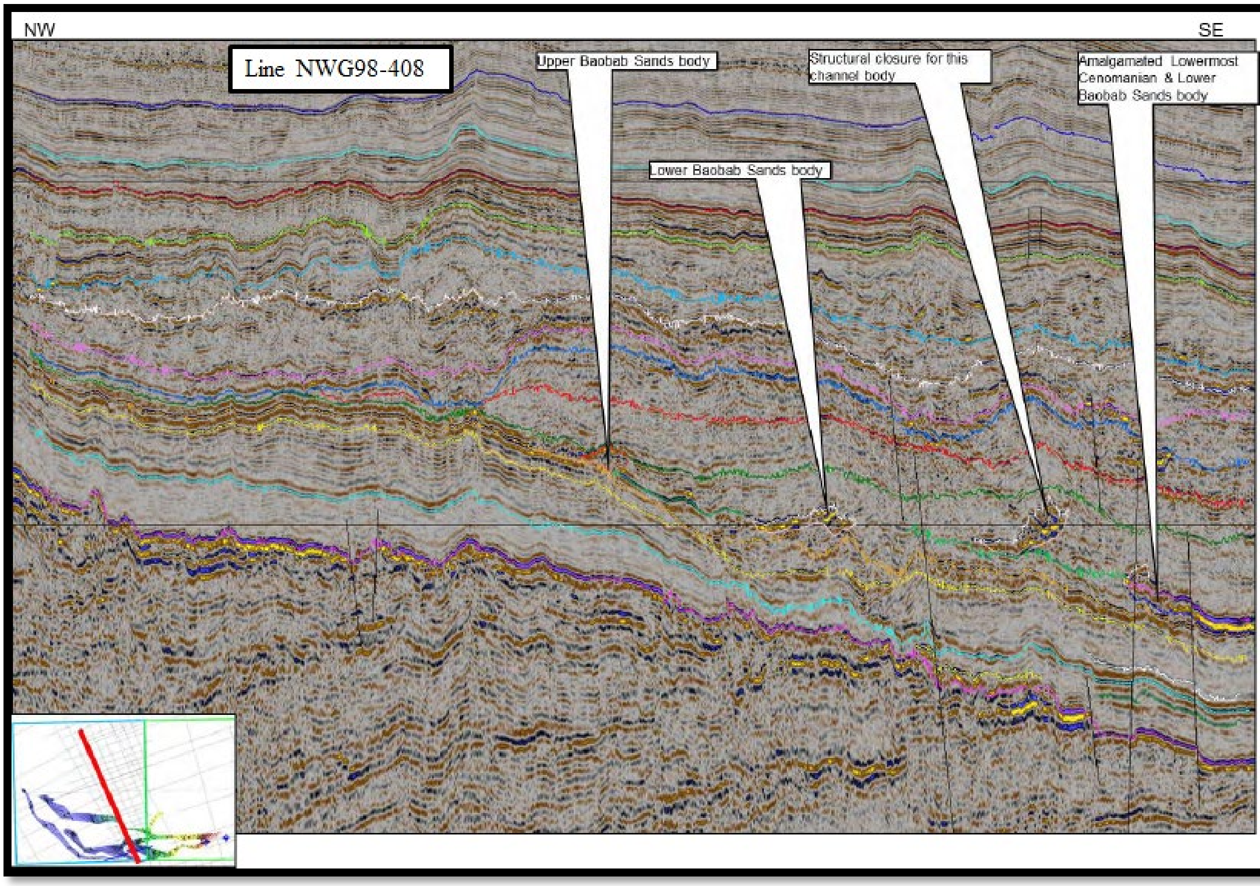



**Figure 4-32 Guy Block Line NWG098-048 (Azinam)**

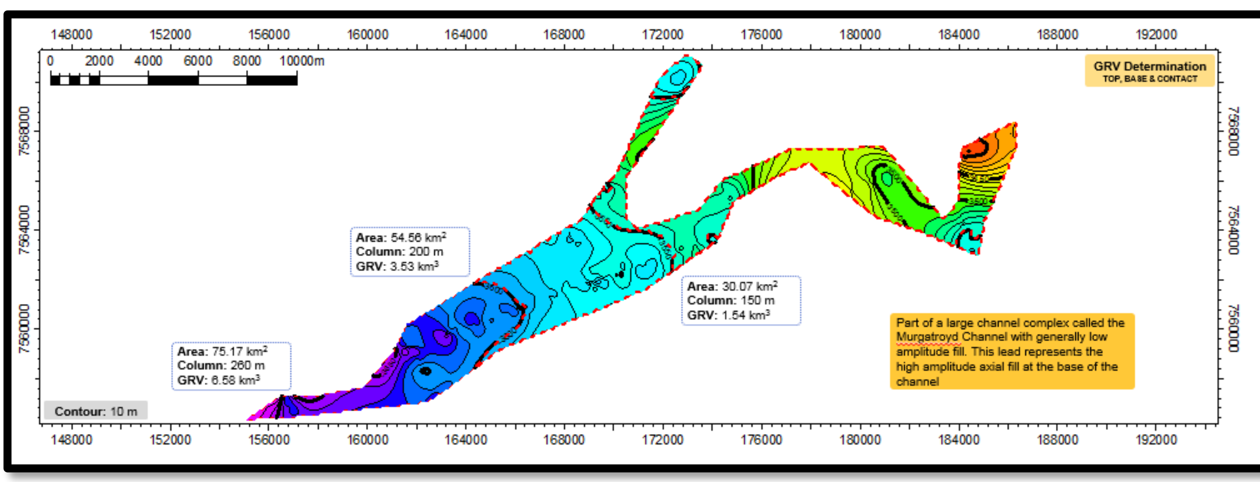



**Figure 4-33 Murgatroyd Channel Lead (Azinam)**

The Murgatroyd Channel Lead, Figure 4-33, is located in the southeast part of the Guy Project Area. The lead is also thought to be in lower Cretaceous channel sands. Located in 2,012 meters of water, this lead covers possibly 75 square kilometers (29 square miles) and may have 260 meters or less of gross sand thickness and at an estimated subsea depth of -3,600 meters.

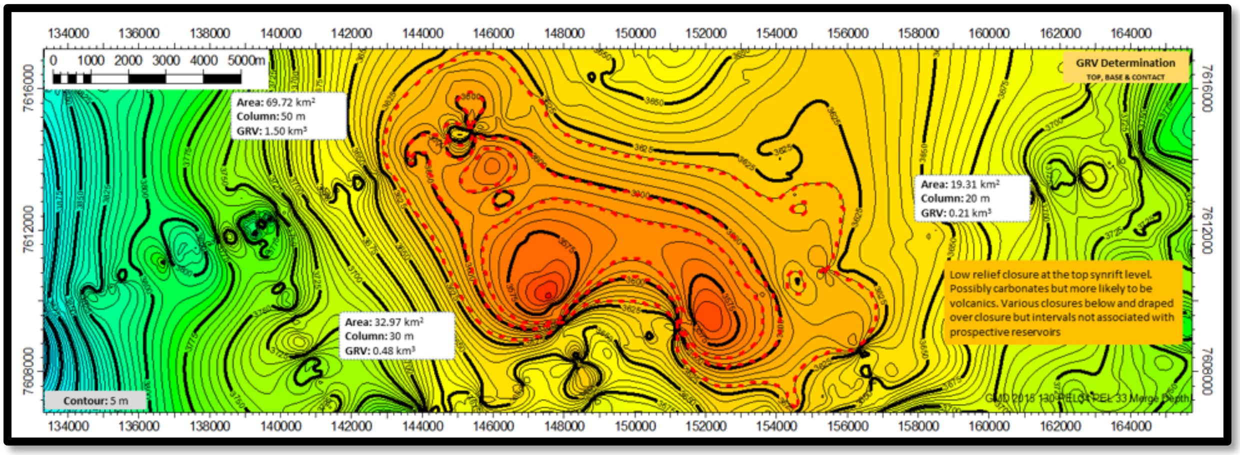



**Figure 4-34 Stephanus Lead (Azinam)**

The Stephanus Lead, Figure 4-34 and Figure 4-35 is located in the northeast of the Guy Project Area. The lead is also thought to be in lower Cretaceous turbidite sands. Located in 2,132 meters of water, this lead covers possibly 70 square kilometers (27 square miles) and may have 50 meters or less of gross sand thickness and at an estimated subsea depth of -3,600 meters.

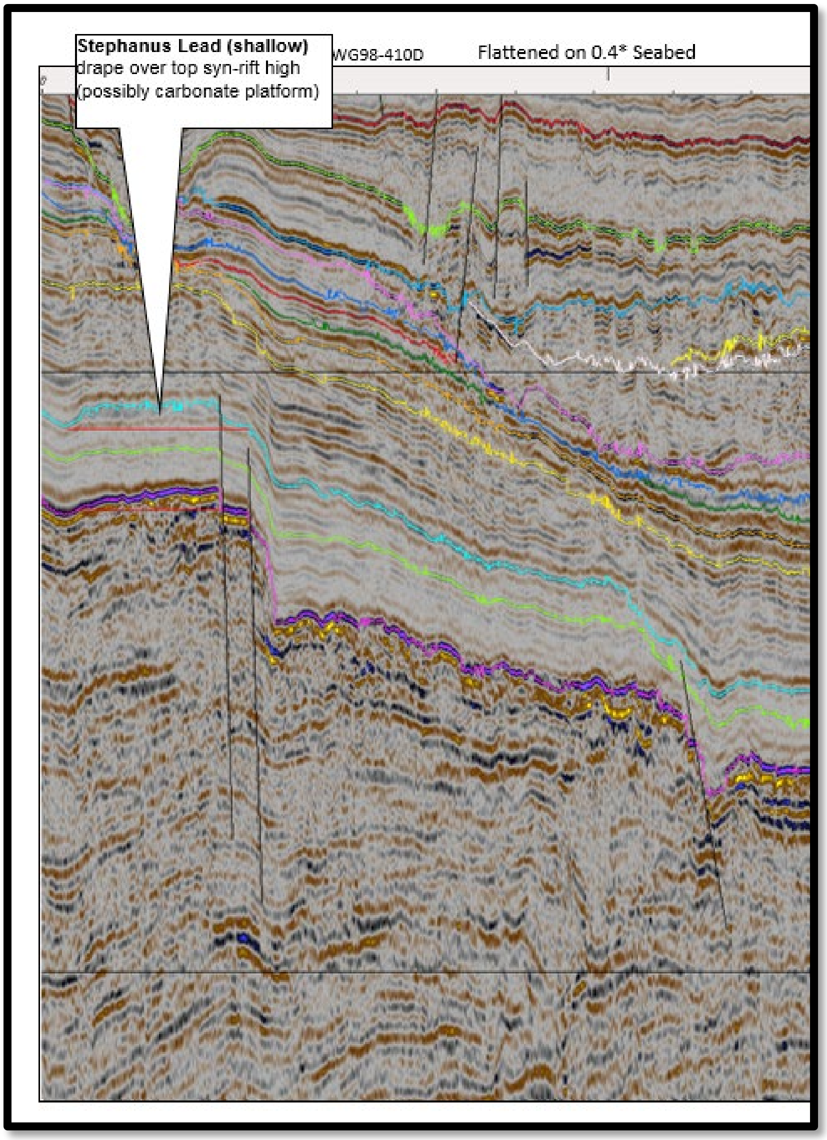



**Figure 4-35 2D Seismic Line over the Stephanus Lead (Azinam)**

Several additional leads have been identified by ECO and their partners which have not been evaluated at the time of this report.

4.2.12.10.4 Tamar Block PEL 50

The Tamar Block, PEL 50, consists of Block 2211Ba and 2311A (Figure 4-36). The approximately 1,000 line-kilometers of the Tamar Block 2D seismic data) is currently being reviewed. There are promising seismic events that appear to be channel-fan complexes. The play types anticipated to be found here Figure 4-36 are similar to Guy Block deep water deposits of Albian to Cenomanian aged fan and channel deposits in stratigraphic traps among others.  The potential leads, which have not been fully delineated at this time and will need to be high-graded and evaluated in detail.

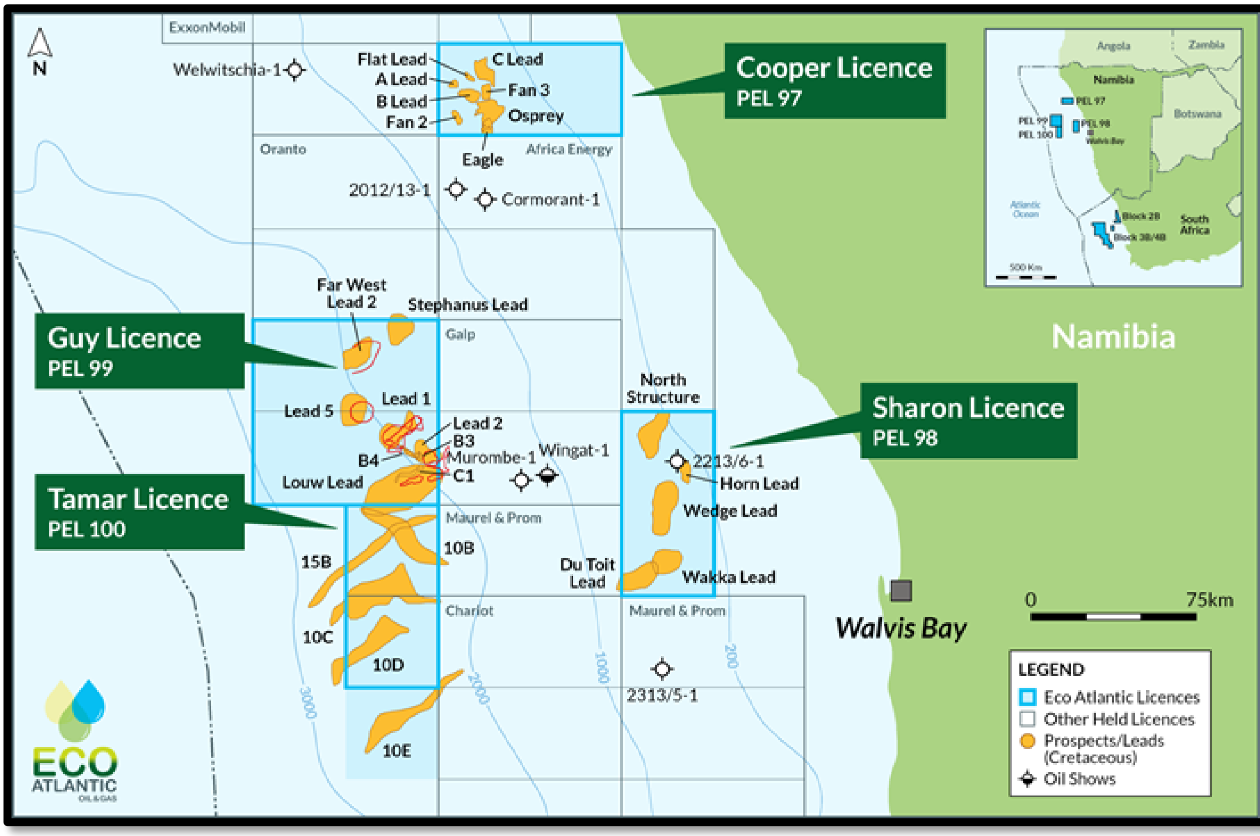



**Figure 4-36  Location of Tamar Block (ECO)**

4.2.13 Risks and Probability of Success

Due to the paucity of available data, the subject leads and prospect have a high level of risk.  The database is limited in seismic data coverage and few wells have been drilled in the area.  The lead section, Upper to Lower Cretaceous, has been evaluated in several wells drilled in the area with oil shows and reservoir quality rock present; however, no commercial production has been established in the immediate area.  The quantification of risk or the chance of finding commercial quantities of hydrocarbons in any single lead for the plays in this area can be characterized with the following variables:

Trap: defined as the presence of a structural or stratigraphic feature that could act as a trap for hydrocarbons;

Seal: defined as an impermeable barrier that would prevent hydrocarbons from leaking out of the structure;

Reservoir: defined as the rock that is in a structurally favorable position having sufficient void space present whether it be matrix porosity or fracture porosity to accumulate hydrocarbons in sufficient quantities to be commercial; and

Source: defined as the occurrence of hydrocarbon source rocks that could have generated hydrocarbons during a time that was favorable for accumulation in the structure.

Table 4-3 shows the range of the Probability of Success (POS) or favorability that the above defined variables would occur. The range of the Overall POS for any single Lead or Prospect is the product of all four variables.

**Table 4-3 Range of the Probability of Success (POS)**

| Probability of Success (POS) | Range % Min | Max | Comments |
|---|---|---|---|
| Trap | 50 | 80 | Seismic data indicates the presence of structures and stratigraphic traps |
| Seal | 25 | 40 | Typical shale layers |
| Reservoir | 30 | 70 | Reservoir quality sands encountered in local wells |
| Source | 50 | 80 | Production in Angola, Brazil, seeps, oil shows in local wells |
| **Overall** | **1.9** | **17.9** | The product of the above factors |

The predominant risks relate to the presence of an intact seal, the timing of source maturation, and hydrocarbon migration sufficient for the creation of commercial accumulations of oil and gas. This range of risk values is typical of leads for wildcat exploratory prospects where data is scarce. The estimated Probability of Success for each Lead or Prospect is contained in Section 4.2.12 of this Report as Table 4-4, Table 4-5, and Table 4-6. The variations in POS numbers are generally based on the amount and type of seismic data that support the Leads and Prospect.

**Table 4-4 Probability of Success, Cooper Block Leads and Prospects**

| Lead/Prospect | Trap | Seal | Reservoir | Source | Risk POS% |
|---|---|---|---|---|---|
| Lead A | 80% | 40% | 70% | 80% | 17.9% |
| Lead B | 40% | 40% | 40% | 50% | 3.2% |
| Lead C | 44% | 40% | 40% | 50% | 3.5% |
| Lead Flat | 44% | 40% | 40% | 50% | 3.5% |
| Osprey | 38% | 40% | 40% | 50% | 3.0% |

**Table 4-5 Probability of Success, Sharon Block Leads**

| Lead/Prospect | Trap | Seal | Reservoir | Source | Risk POS% |
|---|---|---|---|---|---|
| North Structure | 45% | 30% | 40% | 35% | 1.9% |
| Wedge | 50% | 45% | 45% | 35% | 3.5% |

**Table 4-6 Probability of Success, Guy Block Leads**

| Lead/Prospect | Trap | Seal | Reservoir | Source | Risk POS% |
|---|---|---|---|---|---|
| Cretaceous 1 | 42% | 30% | 35% | 50% | 2.2% |
| Cretaceous 2 | 45% | 32% | 35% | 50% | 2.5% |
| Cretaceous 3 | 45% | 32% | 35% | 50% | 2.5% |
| Cretaceous 4 | 45% | 30% | 35% | 45% | 2.1% |
| Cretaceous 5 | 45% | 30% | 35% | 45% | 2.1% |
| Far West 1 | 42% | 30% | 35% | 45% | 2.0% |
| Far West 2 | 42% | 30% | 35% | 45% | 2.0% |
| Stephanus | 45% | 30% | 30% | 50% | 2.0% |
| Murgatroyd | 30% | 35% | 45% | 45% | 2.1% |

4.2.14 Database

There are several wells drilled near the ECO Blocks. 2D seismic is available and has been interpreted, and 3D seismic has been acquired and interpreted in some areas.

4.2.14.1.1 Seismic Data

The Cooper Block (Block 2012A) PEL97 (Figure 4-19) is covered by an original 840 line-kilometers of widely spaced (5 to 15 kilometers) 2D seismic data, an additional 610 line-kilometers of infill 2D data which improved the spacing to 5 kilometers and partially covered by a new 1,108 square kilometer 3D seismic survey.

The Guy Block (east half of Blocks 2111B & 2211A) PEL99 is covered by 675 line-kilometers of widely spaced (7 to 19 kilometers) vintage 2D seismic as well as a recently acquired 1,000 line-kilometers of new 2D seismic data with a more dense coverage. ECO has acquired an 870 square kilometer 3D seismic survey which is being interpreted at this time.

The Sharon Block (west half of Blocks 2213 A & B) PEL98 is covered by an original 606 line-kilometers of widely spaced (14 to 22 kilometers) 2D seismic data and an additional 3,086 line-kilometers of close spaced (2 kilometers) 2D seismic data.

Tamar Block (Blocks 2211Ba & 2311A) PEL100 has been recently added to the license areas in offshore Namibia through an acquisition. The existing grid of 2D seismic data is currently being reviewed.

4.2.14.1.2 Well Data

Wells drilled in the vicinity of Cooper Block include the 1911/10-1 well drilled by Norsk Hydro Namibia in early 1995 to a depth of 4,185 meters in a water depth of 631 meters and the 1911/15-1 well drilled by Norsk Hydro Namibia in early 1994 to a depth of 4,586 meters in a water depth of 521 meters. The Sasol 2012/13-1 well located to the south of Cooper Block was drilled in early 1997 to a depth of 3,714 meters in a water depth of 688 meters. The Ranger Oil Namibia Ltd 2213/6-1 located in the north of Sharon Block was drilled in early 1995 to a depth of 2,627 meters in a water depth of 218 meters.

Reports on several wells were made available by ECO. These reports are largely biostratigraphic studies and core reports of cores taken in the deeper Campanian and Albian sections as well as electric well log data from six wells in the area. However, the petrophysical characteristics relied upon for the Cretaceous section was obtained from reported values from information provided by ECO. These values were assumed to be correct and appear to be similar to sand and shale accumulations in other parts of the world. The 2D seismic data over Sharon Block has shown excellent Lower Cretaceous reflectors that are tied back to the Ranger 2213/6-001 well.

The HRT Wingat-1 well was drilled in Block 2212A to a depth of 5,000 meters and found two source rocks in the oil window. Several thin bedded oil saturated sands were encountered in this well with 41 degree API oil and a 1,193 GOR. The Murombe-1 well, also located in Block 2212A, was drilled to a depth of 5,729 meters. This well found a 242 meter interval containing 36 meters of net sand (assumed to be Upper Cretaceous age) with an average porosity of 19%, which was wet. This well also found the same well-developed marine source rock as the Wingat-1.

The Moosehead-1 well was drilled in Block 2713 northwest of Kudu field to 4,170 meters with wet gas shows and found two potential source rocks including the Aptian.

Repsol drilled the Welwitschia -1 in 2014 just west of the Cooper Block. This well reportedly encountered poorly developed Cretaceous reservoirs and had no shows. No data is available from this well at this time.

## 4.3 SOUTH AFRICA ORANGE BASIN

### 4.3.1 Location and Basin Name

The 2B and 3B/4B blocks are located off the western coast (Figure 4-37) south of the Namibian border. These blocks are in the southern extent of the Orange Basin which extends northward into Namibia where the Kudu gas field and the recent oil discoveries by TotalEnergies in the Venus well and Shell in the Graff well are located. The A-J1 well in the 2B Block and the Ibhubesi discovery have established a petroleum system in the local area. The leads included in this report are based on interpretations done by Azinam, Africa Energy Corp and Africa Oil Corp and were reviewed by WSP and the Clients personnel. The lead parameters were accepted as reasonable with a downward adjustment on recovery factors.

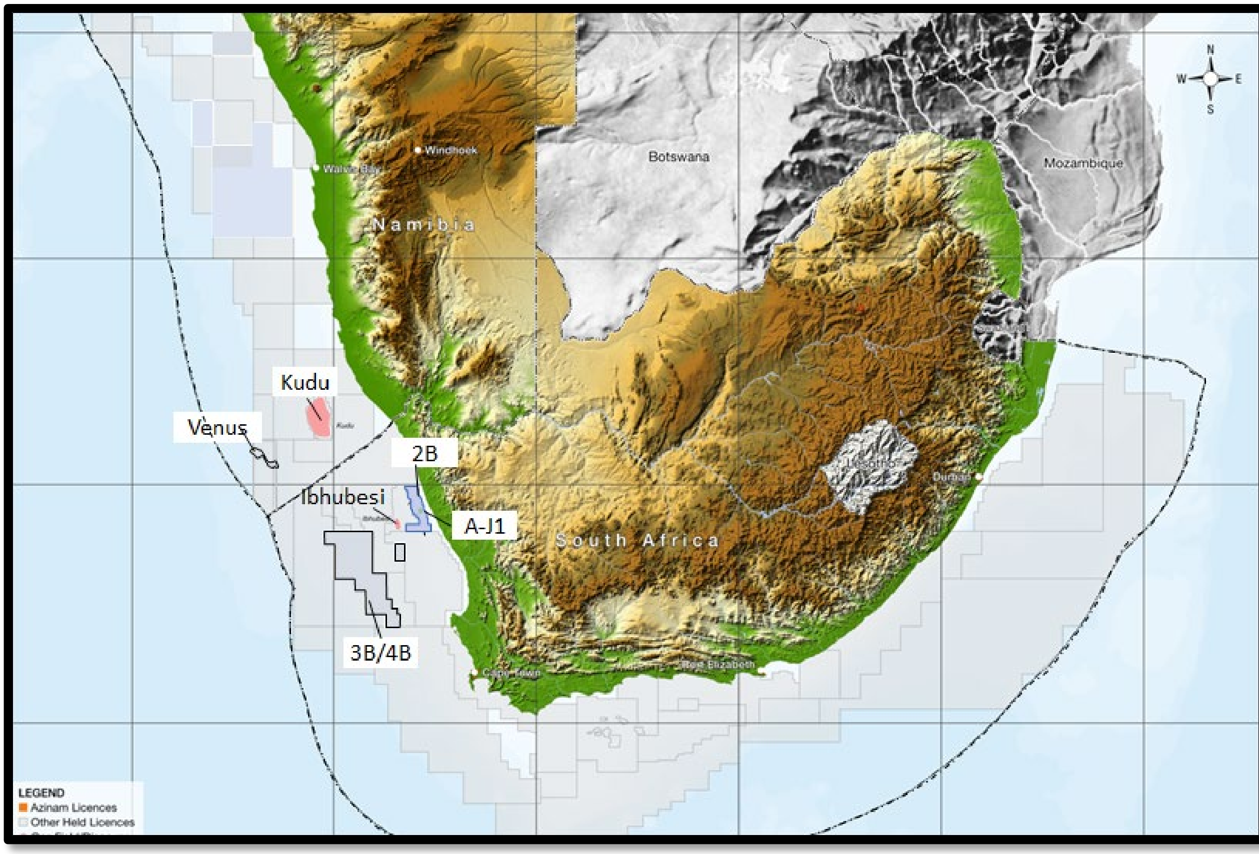



**Figure 4-37 Location Map of South Africa (Azinam)**

4.3.2 <u>2B Block</u>

4.3.2.1 Gross and Net Interest in the Property 2B Block

Block 2B (Figure 4-38) is located in the Orange River Basin, shallow water area, lying between the Ibhubesi gas field and the Namaqualand coast. The Block covers an area of 3,062 km2 (Figure 4-39) and water depth ranges from 0 m to 250 m. ECO by way of the Azinam transaction has a 50.0% working interest in the block and has been designated the Operator. Note that as stated previously, the stated ownership of the South African assets assumes the completion of the acquisition of Azinam Group Holdings ("Completion"). As announced by Eco on 11 March 2022, all conditions required for Completion have occurred save and except for receipt of the final approval of the TSX Venture Exchange (the "Approval"). Such Approval is expected imminently.

This report assumes such Approval has been granted and Completion has occurred, including the increased interests in South Africa having become effective.

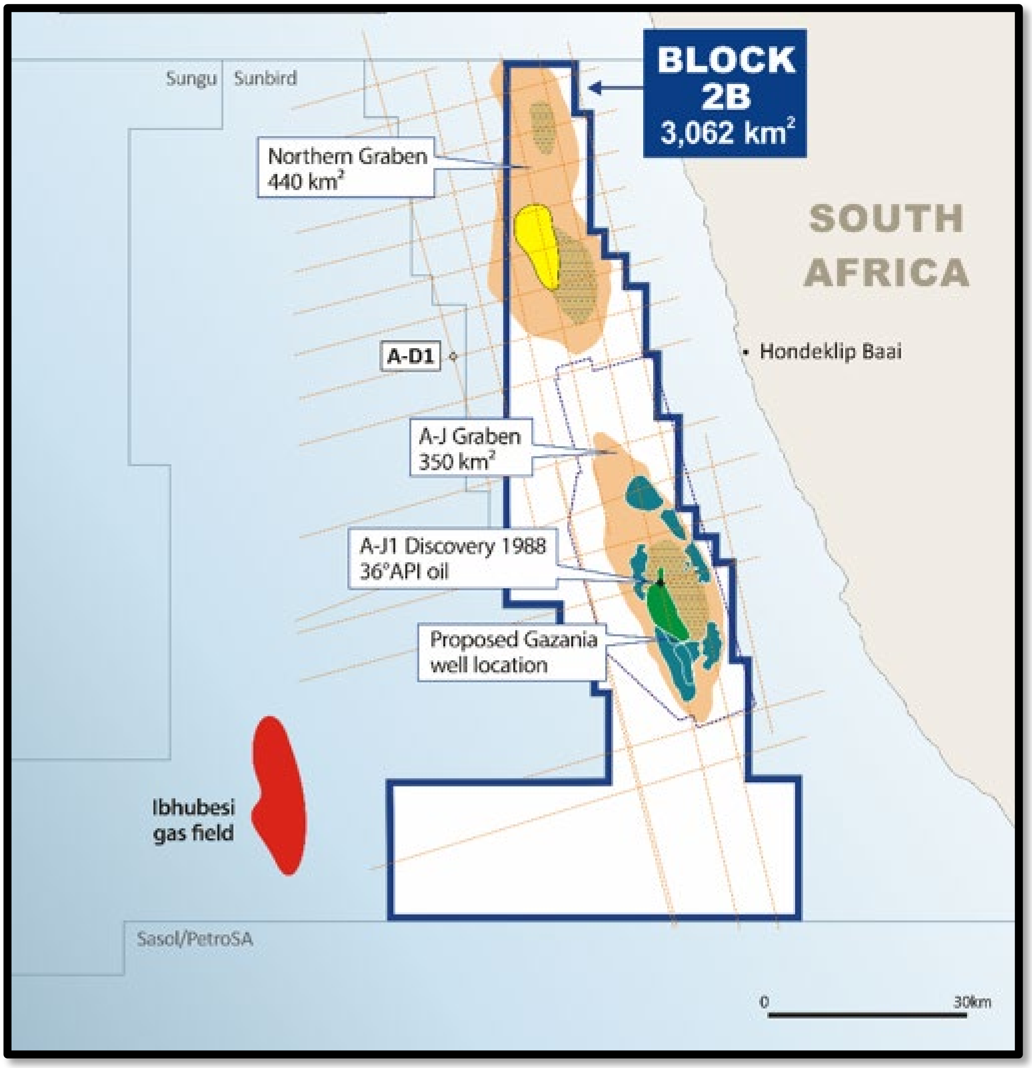
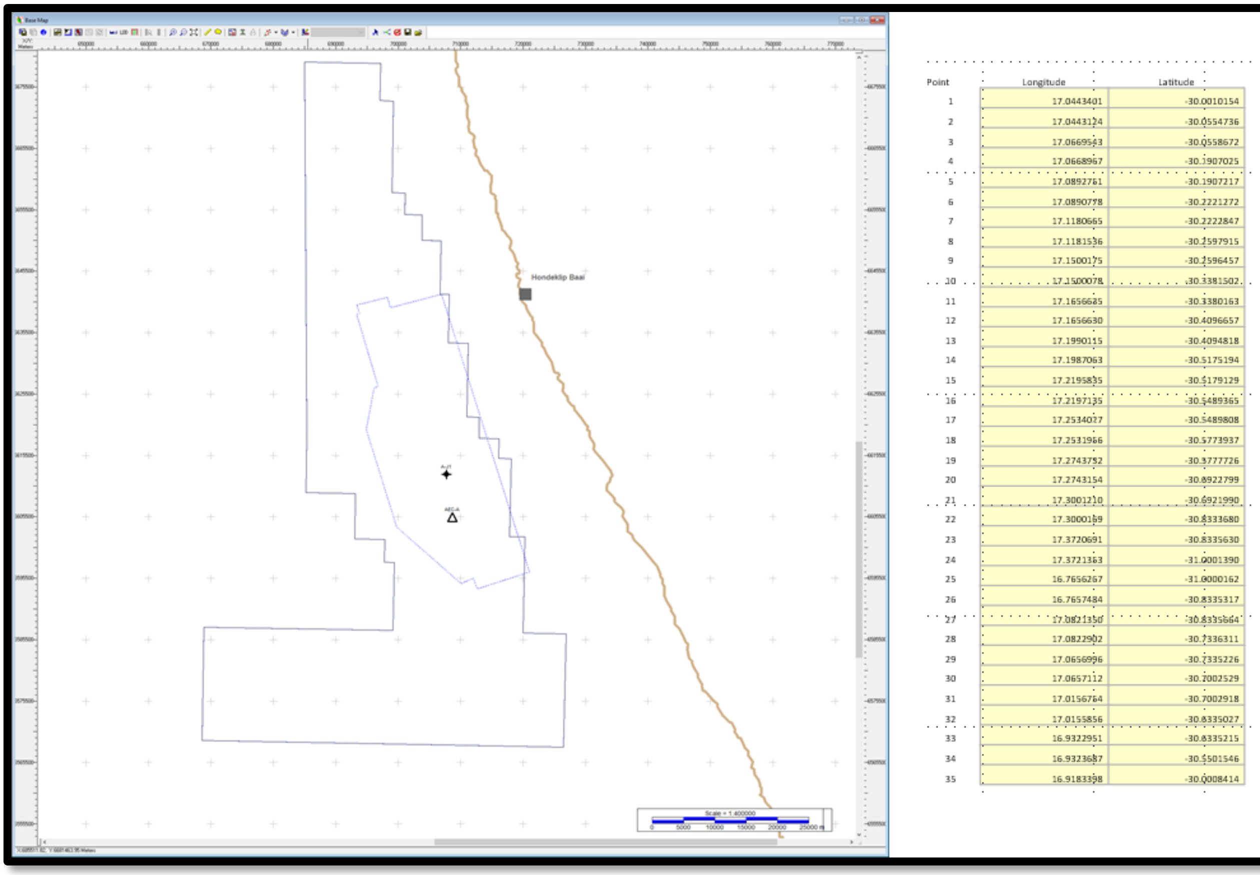



**Figure 4-38 Block 2B Map (Azinam)**




| Point | Longitude | Latitude |
|---|---|---|
| 1 | 17.0443401 | -30.0010154 |
| 2 | 17.0443124 | -30.0554736 |
| 3 | 17.0669543 | -30.0558672 |
| 4 | 17.0668967 | -30.1907025 |
| 5 | 17.0892761 | -30.1907217 |
| 6 | 17.0890778 | -30.2221272 |
| 7 | 17.1180665 | -30.2222847 |
| 8 | 17.1181536 | -30.2597915 |
| 9 | 17.1500175 | -30.2596457 |
| 10 | 17.1500078 | -30.3381502 |
| 11 | 17.1656685 | -30.3380163 |
| 12 | 17.1656630 | -30.4096657 |
| 13 | 17.1990115 | -30.4094818 |
| 14 | 17.1987063 | -30.5175194 |
| 15 | 17.2195835 | -30.5179129 |
| 16 | 17.2197135 | -30.5489365 |
| 17 | 17.2534027 | -30.5489808 |
| 18 | 17.2531966 | -30.5773937 |
| 19 | 17.2743752 | -30.3777726 |
| 20 | 17.2743154 | -30.8922799 |
| 21 | 17.3001210 | -30.6921990 |
| 22 | 17.3000169 | -30.8333680 |
| 23 | 17.3720691 | -30.8335630 |
| 24 | 17.3721363 | -31.0001390 |
| 25 | 16.7656267 | -31.0000162 |
| 26 | 16.7657484 | -30.8335317 |
| 27 | 17.0821350 | -30.8335664 |
| 28 | 17.0822902 | -30.7336311 |
| 29 | 17.0656996 | -30.7335226 |
| 30 | 17.0657112 | -30.7002529 |
| 31 | 17.0156764 | -30.7002918 |
| 32 | 17.0155856 | -30.8335027 |
| 33 | 16.9322951 | -30.8335215 |
| 34 | 16.9323687 | -30.5501546 |
| 35 | 16.9183398 | -30.0008414 |

**Figure 4-39 Block 2B Map with Point Locations (Azinam)**

4.3.2.2 Expiry Date of Interest 2B Block

The South African fiscal regime, revised in February 2009, is one of the most beneficial in the world from the contractor perspective. It is a simple tax/royalty system, with a maximum royalty of 5% and CT of 29%. A state company (PetroSA) equity of 10% is carried through exploration and generous uplifts are available on both exploration and development capital expenditures.
The 2B Block is located offshore Republic of South Africa (Figure 4-40). The area under license is currently 3,062 km2 after two rounds of relinquishments. Water depth varies from 100m to around 250m over the block.

In October 2016 Africa Energy corporation obtained governmental and regulatory approval of its acquisition of operatorship and 90% participating interest in the block. 10% will be retained by Crown Petroleum. The Exploration Right was awarded on 13th April 2011 for an initial three year period. An application to renew this Exploration Right was approved by the Petroleum Agency of South Africa, and signed in March 2015 for the First Renewal Period, which has a two year duration.

The work commitment for the First Renewal Period involved geological and geophysical studies with the purpose of identifying one or more well locations to appraise the Well A-J1 discovery. Two further renewal periods are possible, each with a duration of two years, and each requiring a 15% relinquishment. Africa Energy Corporation has recently submitted documentation to the South African licensing authority (PASA) applying for permission to enter the Second Renewal Period for a duration of two years during which one well will be drilled. Should commerciality in the block be declared, and the Exploration Right converted to a Production Right, the Republic of South Africa has the right to back into the block with up to 20% paying equity. Under additional terms of the Exploration Right, a further 10% interest must be transferred to a suitably qualified BEE (Black Economic Empowerment) enterprise at mutually acceptable commercial rates. Figure 4-39 shows the block boundary points and their locations.

Currently the block is in the third renewal period and the scheduled expiry date for the Block is 16 November 2022. However, the operator can apply for a Production License based on the Contingent Resources found in the A-J1 well. This process would take up to a year to be approved and would then result in a 30-year license for the block.

#### 4.3.2.3 Description of Target Zones

Contingent oil resources are associated with Well A-J1, drilled in Block 2B in 1988. The well found and tested stratigraphically trapped oil within a sedimentary section of Lower Cretaceous age, known as the Lacustrine Sequence. One drill-stem test in the lower part of the Lacustrine Sequence flowed 36 ° API gravity oil at an average rate of 190 stb/d over a 36 hour duration flow period. There is significant uncertainty in the thickness, quality, connectivity and areal extent of the Lacustrine Sequence away from Well A-J1. This discovery is referred to as Gazania by Africa Energy.

The main reservoir objectives are the fluvial and lacustrine sands of the AJ Graben of Lower Cretaceous age (Figure 4-40). These occur in three sequences, penetrated by the A-J1 well, the lowest of which was oil bearing. The upper sequences (with shows) are interpreted to rise updip to the graben margins, where they form pinchout and hanging wall traps beneath the pronounced end Rift unconformity. Further, more speculative prospectivity has been identified as a fractured basement play (analogous to Yemen), which could form a secondary target, adjacent to the AJ Graben. The 2D seismic data has also revealed the presence of a further (undrilled) Rift Graben, lying on-trend to the north of the AJ Graben. It is expected that this would become the focus of additional exploration, once commercial success had been established in the AJ Graben.

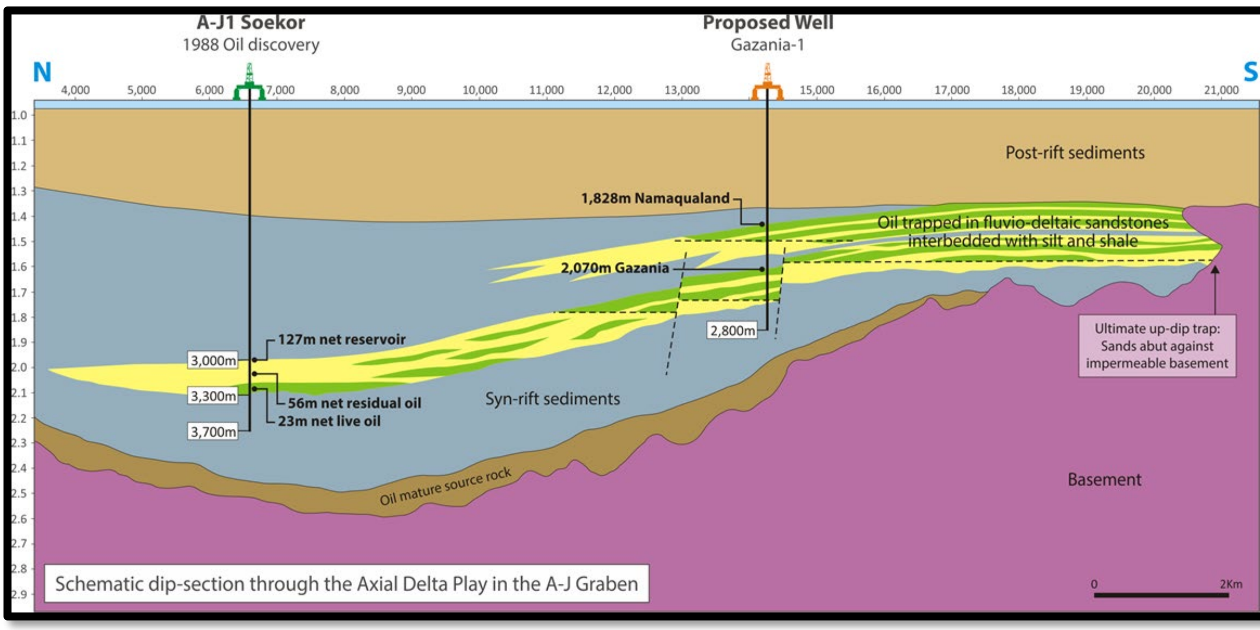



**Figure 4-40 Block 2B Schematic with A-J1 Well and Proposed Well (Azinam)**

4.3.2.4 Distance to the Nearest Commercial Production

Oil is being produced in the offshore of Angola, approximately 1,800 kilometers to the north, from multiple fields, and gas has been produced from the Kudu Field approximately 200 kilometers to the north of the 2B Block in the offshore of Namibia.

#### 4.3.2.5 Product Types Reasonably Expected

Light oil and gas are expected in this area based on the A-J1 well tests.

#### 4.3.2.6 Range of Pool or Field Sizes

The three leads evaluated for this report have minimum to maximum areas of closure ranging from 5 to 17 square kilometers with gross thicknesses ranging from 54 to 392 meters. The Best Estimate Gross Unrisked Prospective Oil Resources for the leads in South Africa Block 2B range from 92 to 208 MMBbl oil.[18]

#### 4.3.2.7 Depth of the Target Zones

These leads are estimated to occur at a depth range of 1,524 to 2,130 meters with a normal pressure and temperature gradient.

#### 4.3.2.8 Identity and Relevant Experience of the Operator

In the 2B Block, ECO (Atlantic) Oil & Gas Ltd. is an Operator of Oil and Gas exploration projects in deep and shallow water offshore. The Company has been evaluated, prequalified and been approved as Operator by Governments in Namibia, Ghana and Guyana. The company has completed detailed onshore and offshore exploration and interpretation of existing well data, geology and seismic data and has operated its own offshore 2D and 3D seismic surveys on behalf of the Company and its partners. A team of highly experienced explorationists in the resource sector, the Executive team understand, manage and direct the exploration in its offshore interests. The management team is knowledgeable and interactive in negotiating operating contracts, managing joint interest financial accounts, reporting to partners and representing partners to host Government through managing its Joint Operating Agreements, Petroleum Agreements, Permitting and License commitments.

[18] Details on these calculations are discussed in Section 5 of this report.

#### 4.3.2.9 Future Work Plans and Expenditures

The future plan for the 2B Block is for the Gazania #1 well to be drilled in the fourth quarter of 2022. The well will test the Gazania and Namaqualand prospects updip to the A-J1 discovery well. The well is estimated to cost US$31.4 MM and is planned to take 20 days to drill. ECO will pay for 75% of the well cost up to US$30 MM where the ECO's share reduces to 50%.

#### 4.3.2.10 Market and Infrastructure

The TotalEnergies Venus discovery and the Shell Graff discovery in Namibia just north of the subject blocks, if commercial, will change the market dynamics significantly. South Africa would benefit substantially from additional discoveries in South Africa and the initiation of commercial production.

#### 4.3.2.11 Geology

The Orange Basin, similar to the Walvis Basin, formed during the rifting and separation of the South American and African plates, has all the features typical of a passive margin. The basin fill comprises largely clastic material of Cretaceous age, transported into the basin by the westward flowing Orange and proto-Orange River systems as a passive margin wedge, which exceeds 7,000m in the depocenter. This wedge is underlain by rifted continental crust below a Hauterivian unconformity, which a system of isolated truncated half-grabens parallel to the coast. These grabens are generally faulted down to the west. Block 2B overlies the A-J Graben in an area not affected by a major transverse fracture. From regional considerations, sediments may be as old as Jurassic, although the oldest dated sediments are of Hauterivian age (Mid-Lower Cretaceous). These are continental fluvial and lacustrine deposits, in places interbedded with volcanics. Termination of active rifting and the onset of thermal subsidence are marked by the strong Hauterivian unconformity. The early transitional. drift interval between this unconformity and an Aptian unconformity, was laid down in conditions between true continental and true open marine. Therefore, sediments consist of both shallow marine and continental deposits (occasionally with interbedded basalts). A major drowning of the margin above this Aptian unconformity marks the onset of open marine conditions and the start of the true drift wedge, with strong prograding intervals punctuated by erosional sequence boundaries. The Cretaceous sediments are siliciclastic ranging from near shore and coarser in the east to deep marine and finer grained in the west. Following a period of post-Cretaceous (Cenomanian) major uplift, westward tilting and erosion, the thin Tertiary succession is mainly composed of calcareous oozes and carbonates. This thick wedge of sediment underwent repeated deformation on the paleo-slope caused by sediment loading and slope instability, especially during the Upper Cretaceous. These sedimentary tectonic features typically comprise gravity faults and folds, with detachment glide planes in mobile over-pressured shale in the east and compressional toe-thrust faults and folds in the west. The underlying paleo-shelf is tectonically unaffected. Figure 4-41 below, adapted from van der Spuy's work, shows the full stratigraphic sequence and main tectonic events. It also identifies the main unconformities / maximum flooding surfaces, which create sequence boundaries. The main zone of interest in Block 2B is the syn-rift sediments of the A-J Graben. The Ibubhesi Gas Field reservoirs are younger being of Upper Albian to Cenomanian age. The main zones of interest in the 3B/4B block are marine basin floor fan turbidite sequences of Cretaceous age.

4.3.2.11.1 Structure

Figure 4-41 depicts the various play types and structural features in the southern part of the Orange Basin. In the 2B Block area there are half-grabens formed during the rifting phase with lacustrine accumulations of reservoir quality sediments as well as source rocks. In the 3B/4B area to the southwest, basin floor fan turbidites are found.

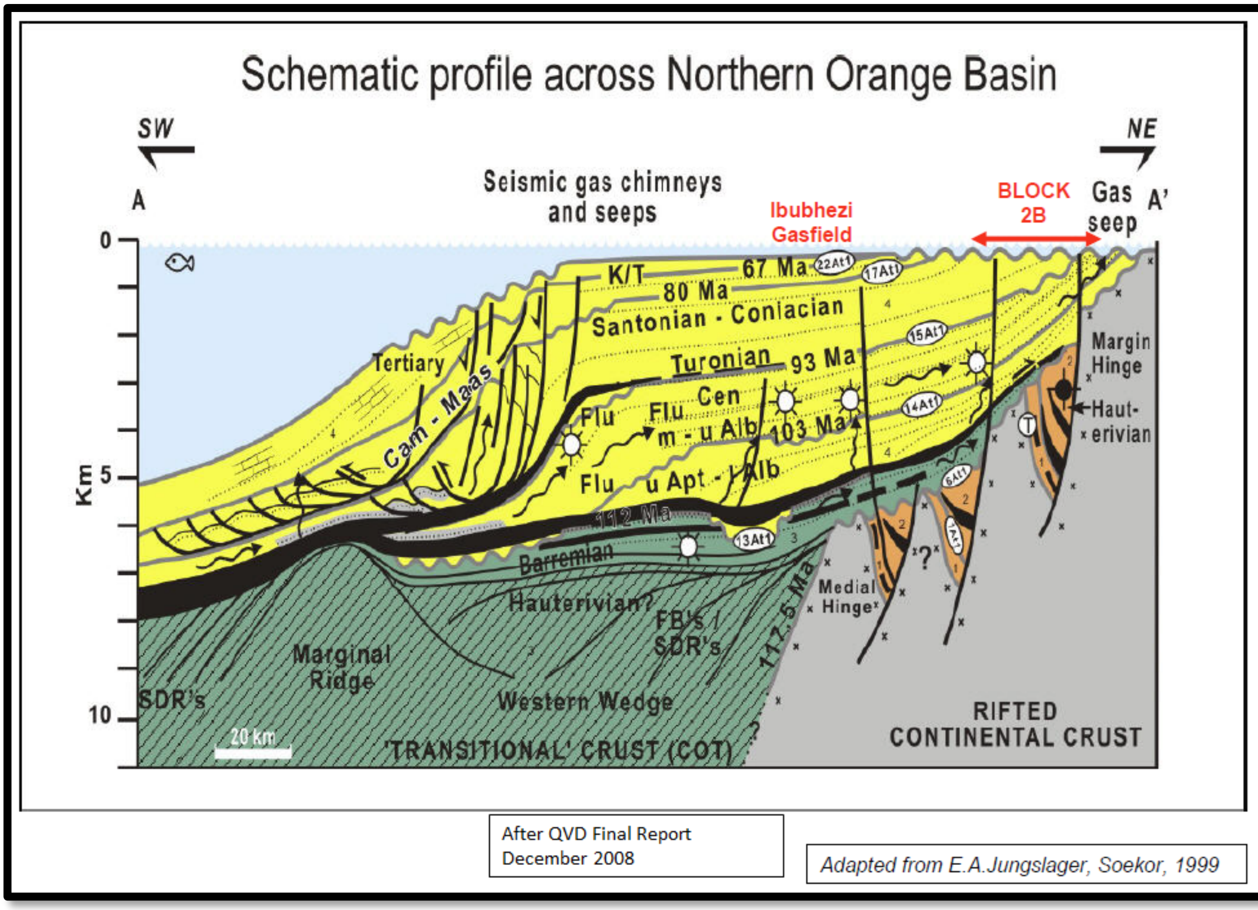



**Figure 4-41 Schematic of Play Types in the Orange Basin (Africa Energy)**

4.3.2.11.2 Stratigraphy

Figure 4-42 shows the general stratigraphic column in the Orange Basin with the major events that occurred in the basin.

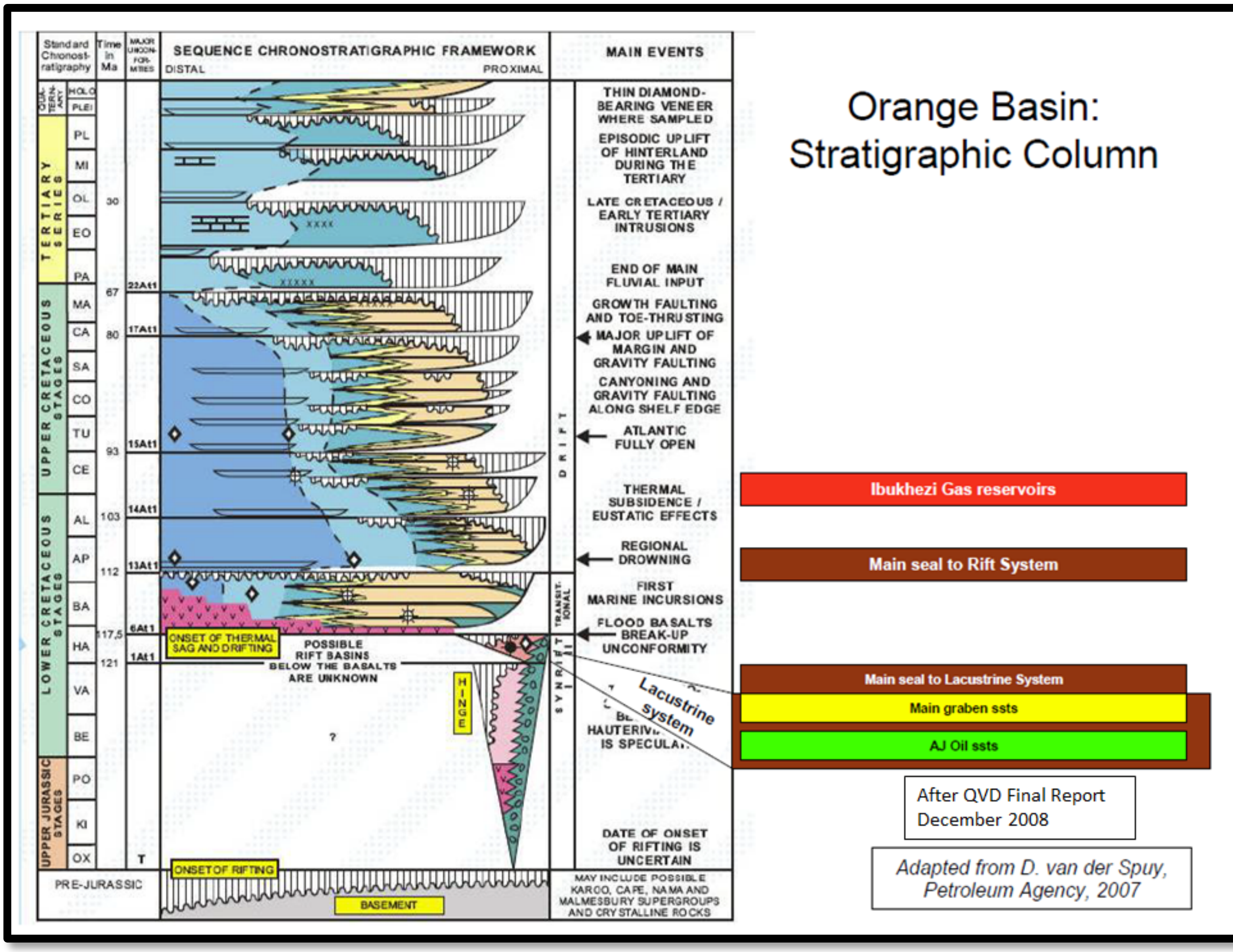



**Figure 4-42 Orange Basin Stratigraphic Column (Africa Energy)**

4.3.2.11.3 Petroleum System

4.3.2.11.3.1Reservoirs

The A-J1 well drilled through a 340m thick lacustrine interval (3000-3340m) of which 120m of net sandstone reservoirs were discovered. These sandstones have porosities between 8 - 15% and permeabilities between 1 - 435mD. They are buried beneath 3km of overburden at A-J1. The seismic inversion and normal compaction curves suggest that improved porosity and permeability can be expected up-dip of A-J1 in the Gazania Prospect where the overburden is only 2,500m, and the depositional environment more proximal.

#### 4.3.2.11.3.2 Trap

A combination of stratigraphic and fault-related mechanisms are trapping oil in the Lacustrine Axial Delta Play. Seismic mapping suggests that A-J1 could have intersected such a trap in a downdip location with significant up-dip potential. Other traps, such as 3-way dip closures against the master fault, and sub-crop traps have also been mapped in the basin.

#### 4.3.2.11.3.3 Seal

The interbedded lacustrine shales are the main seal for the Lacustrine Axial Delta Play. The core, log and seismic data interpretation suggests that blanketing shales were regularly deposited during transgressive lake high-stands during times of rapid subsidence and/or sediment starvation.

#### 4.3.2.11.3.4 Timing and Migration

Basin modelling studies suggest that migration started in the mid Tertiary (even earlier for a deeper source rock) and continues into the present. Reservoirs of the Lacustrine Axial Delta Play are ideally located stratigraphically and structurally for efficient oil migration.

#### 4.3.2.11.3.5 Source

Algal rich lacustrine source rocks were intersected at A-J1 over a 350m interval (Figure 4-43). Average TOCs are ~3% (max 5.5%) in the Lacustrine interval. Oxygen Index values are low, suggesting that the Kerogen is Type I. Hydrogen Index values suggest that oil generation has occurred. Tmax values indicate that the section is marginally mature to mature. The DST oil has a more mature signature, suggesting that the oil is probably charged from a thicker, more mature lateral equivalent in the center of the paleo-lake. Fluid inclusion studies could support the presence of another, deeper source rock, beneath the TD of A-J1.

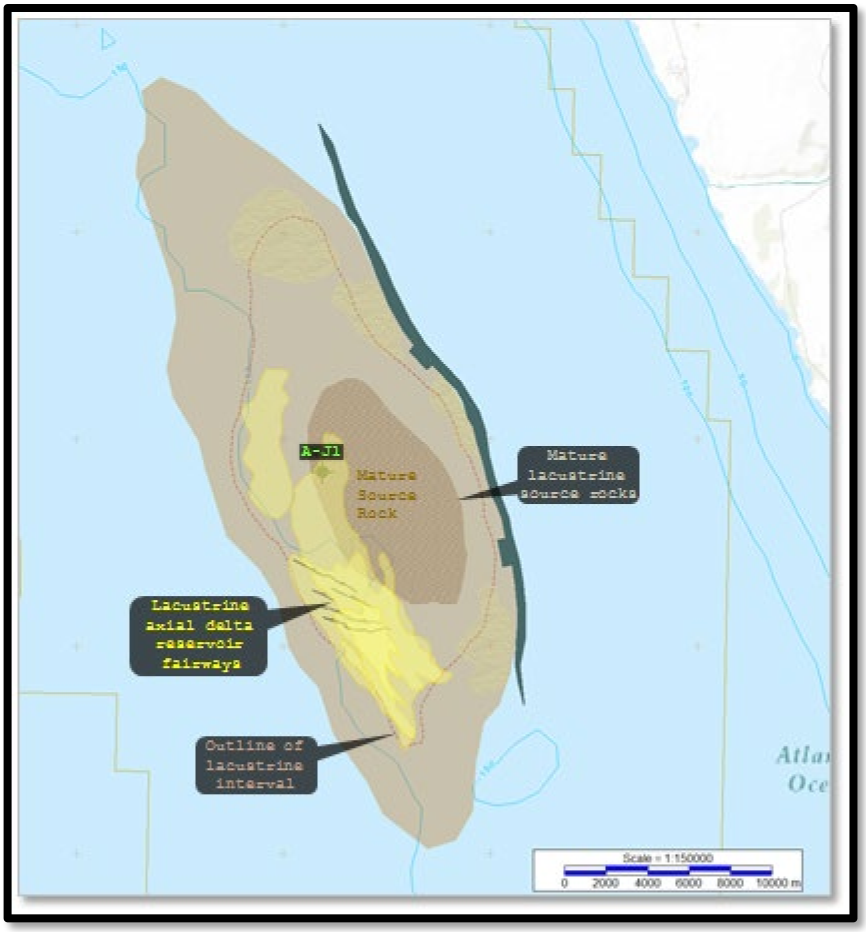



**Figure 4-43 Source Rock Location Map in the 2B Block (Azinam)**

The A-J1 oil was generated from an *algal-rich, lacustrine source rock deposited under arid, saline, possibly carbonate-rich conditions.* The oil is *nonbiodegraded* and has achieved the *peak oil-generative stage.* The A-J1 oil does not appear to be related to Paleozoic lacustrine, hypersaline oil from Namibia or Lower Cretaceous lacustrine Bucomazi-sourced oil from Angola. The oil is probably derived from lateral equivalents of marginally mature to mature, Hauterivian lacustrine oil shales in the range 2900-3400 m in the A-J1 well. (Chevron Overseas Petroleum Inc 1992)

A 3D seismic dataset is available over Block 2B, including derivative products such as a relative acoustic impedance inversion (RAI). In addition, the results of Well A-J1 and its sidetrack A-J1Z were available for our analysis, including wireline log data. Some formation pressure data and drill-stem test data were also available.

Well A-J1 was drilled by Soekor in 1988 as a stratigraphic test of the A-J Graben in what is now Block 2B, offshore RSA. The well found 36 ° API oil in the lacustrine sediments of Hauterivian (Lower Cretaceous) age (Figure 4-2, Figure 4-8). The original hole suffered mud losses when drilling the Lacustrine Sequence, and was eventually side-tracked due to a stuck drill-pipe. The side-track was cored and drill-stem tested at a rate of 191 bopd from an 8.5m interval at a depth of 3,250 m MD.

#### 4.3.2.11.3.6 Exploration History

Relatively few wells have been drilled in the Orange Basin. In 1974 Chevron (Figure 4-44) discovered the Kudu gas field and the majority of the wells in this area were drilled into that accumulation. In 1988, Soekor drilled the AJ-1 oil discovery near shore in a lacustrine environment.

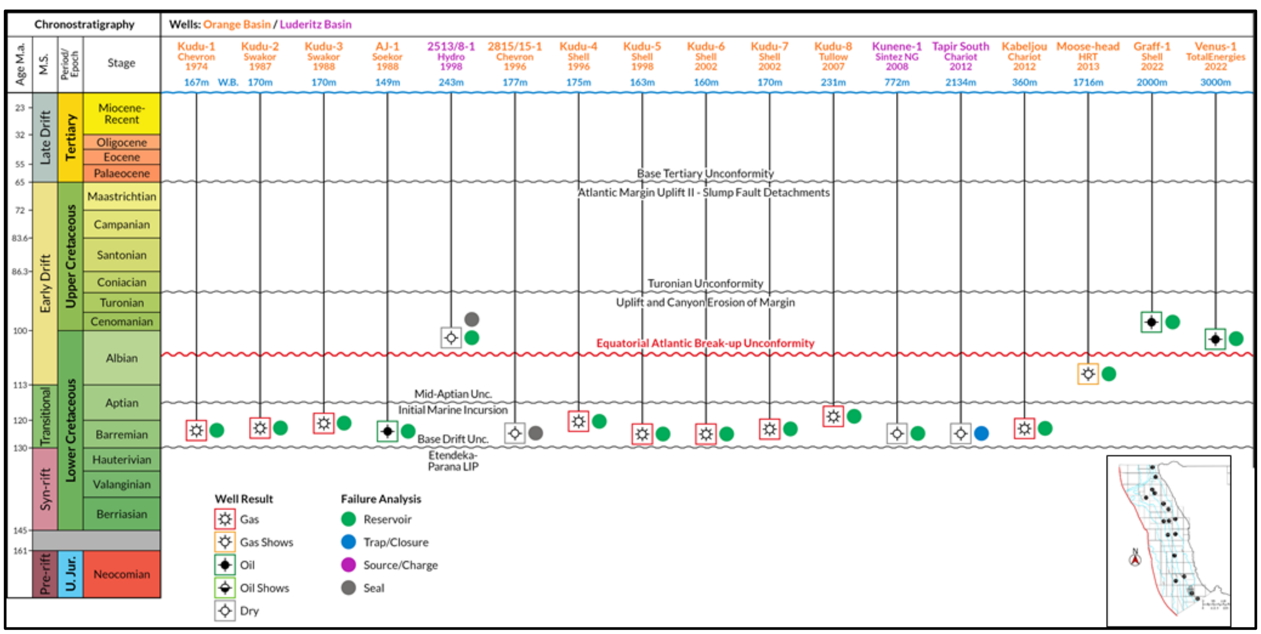



**Figure 4-44 Exploration History in the Orange and Luderitz Basins**

In early 2022, in the Orange Basin located south of the Walvis basin in the offshore of Namibia and South Africa, both the Shell Graff #1 and the TotalEnergies Venus #1 wells have been reported by various sources as discoveries.

4.3.2.11.4 Leads

4.3.2.11.4.1 Namaqualand

The schematic (Figure 4-45) shows the relationship between the A-J1 discovery well, the Gazania and Namaqualand prospects.

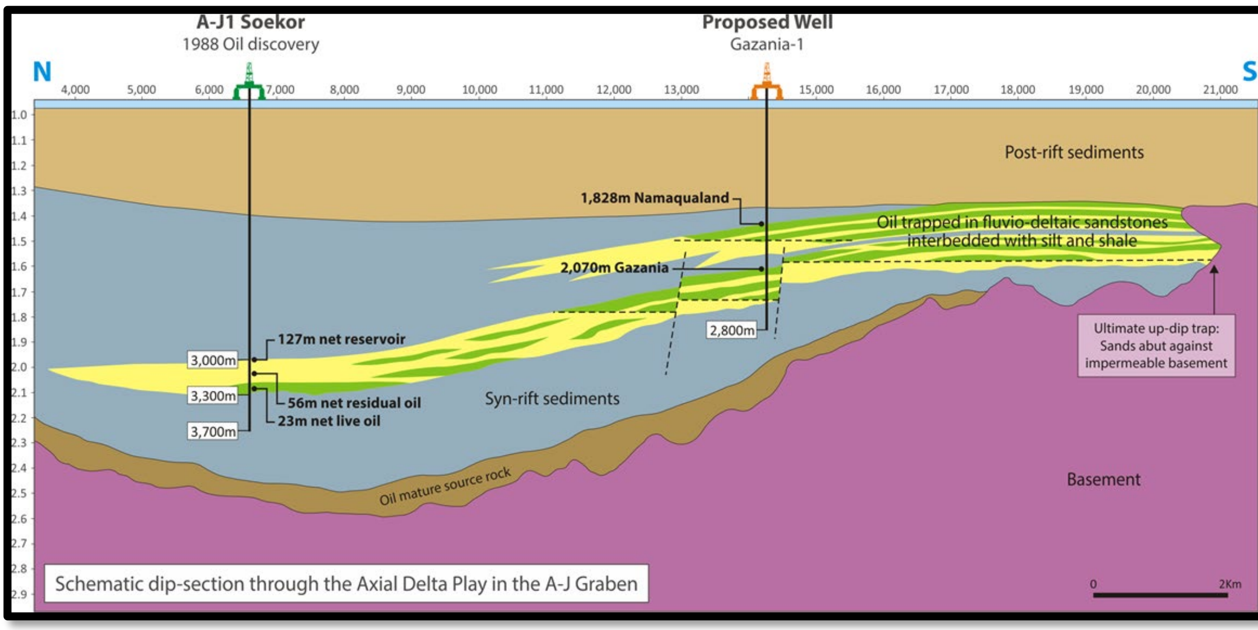



**Figure 4-45 Schematic Section Showing the Gazania and Namaqualand Prospects (Azinam)**

The Namaqualand Prospect is a series of fluvio-deltaic sands interbedded with silt and shales. The 3D seismic data shows a positive AVO response in these events. The Namaqualand Troughs are associated with AVO Type II / III anomalies. The amplitude signatures of the multiple layers have a structural component to their extent. The downdip edge of the Namaqualand prospect should be tested with the current Gazania 1 well plan. Based on the seismic signature stacked pay is likely.

Namaqualand (Figure 4-46 and Figure 4-47) is located in the southeast of the Block 2B Project Area above the Gazania and Pelargonium prospects in 150 meters of water. This lead covers possibly 10 square kilometers (4 square miles) and may have 392 meters or less of gross sand thickness and at an estimated subsea depth of -1,770 meters.

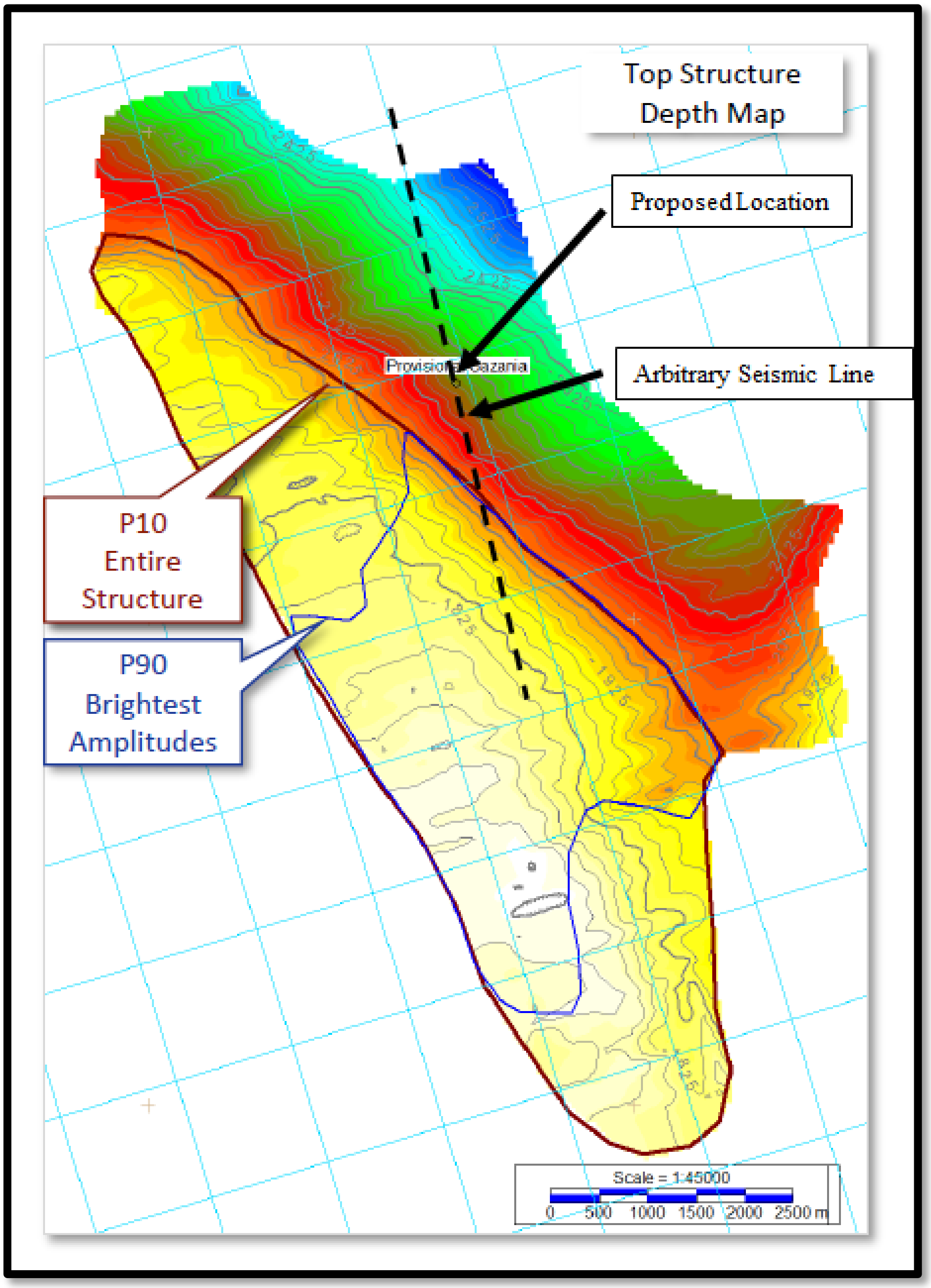



**Figure 4-46 Namaqualand Map in 2B Block (Africa Energy Corp)**

The approximate location of the proposed Gazania 1 well and the seismic line in Figure 4-47 are depicted on the Figure 4-46, Figure 4-48, and Figure 4-49.

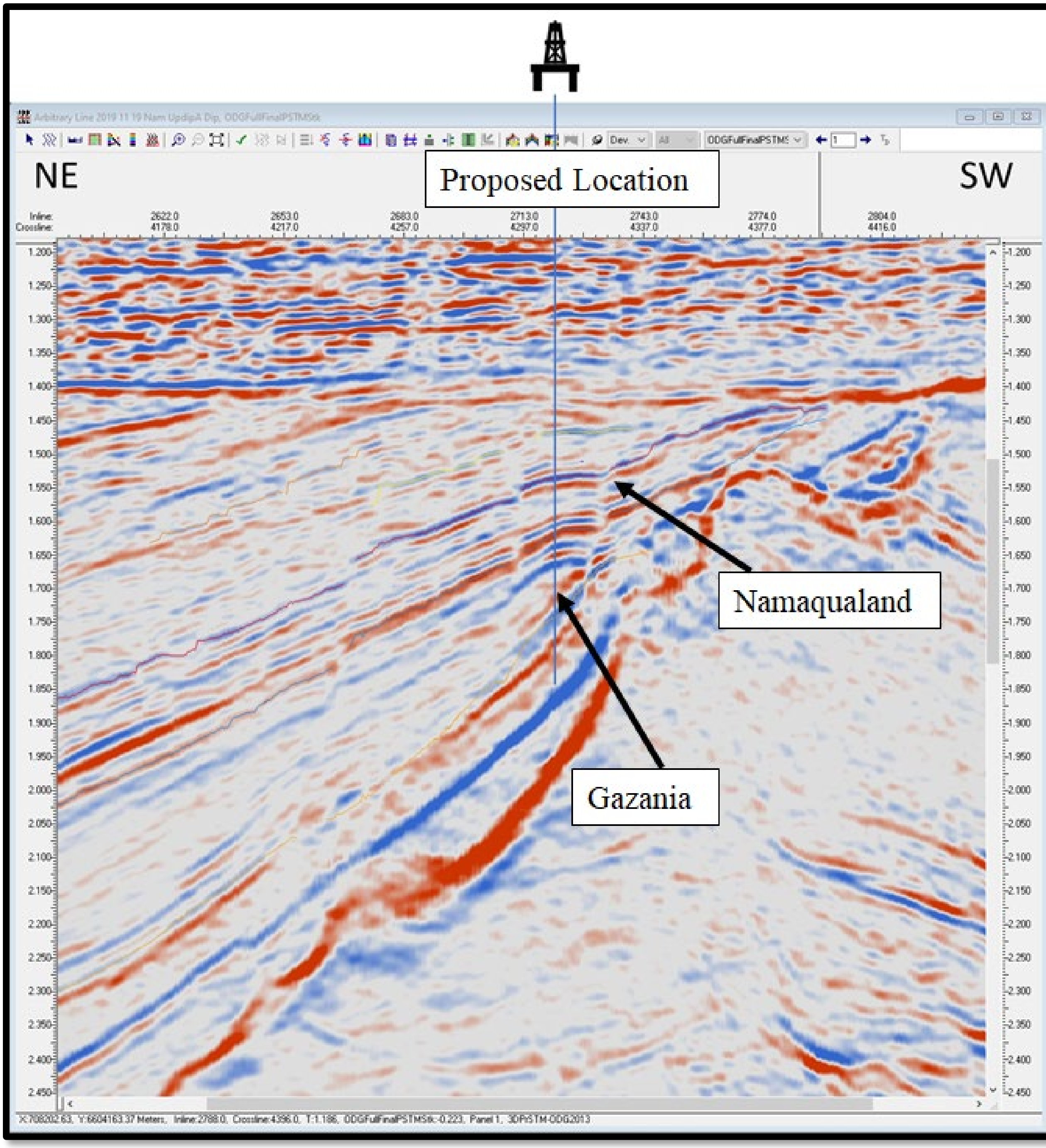



**Figure 4-47 Namaqualand in 2B Block Seismic Section (Africa Energy Corp)**

4.3.2.11.4.2 Gazania Prospect

The Gazania Prospect, Figure 4-48, is located in the southeast of the Block 2B Project Area. The lead is a series of interbedded lacustrine sands and shales updip to the A-J1 discovery. The reservoir quality of the sands is expected to improve updip to the A-J1 well due to lesser overburden. Located in 150 meters of water, this lead covers possibly 16 square kilometers (6 square miles) and may have 392 meters or less of gross sand thickness and at an estimated subsea depth of -2,225 meters.

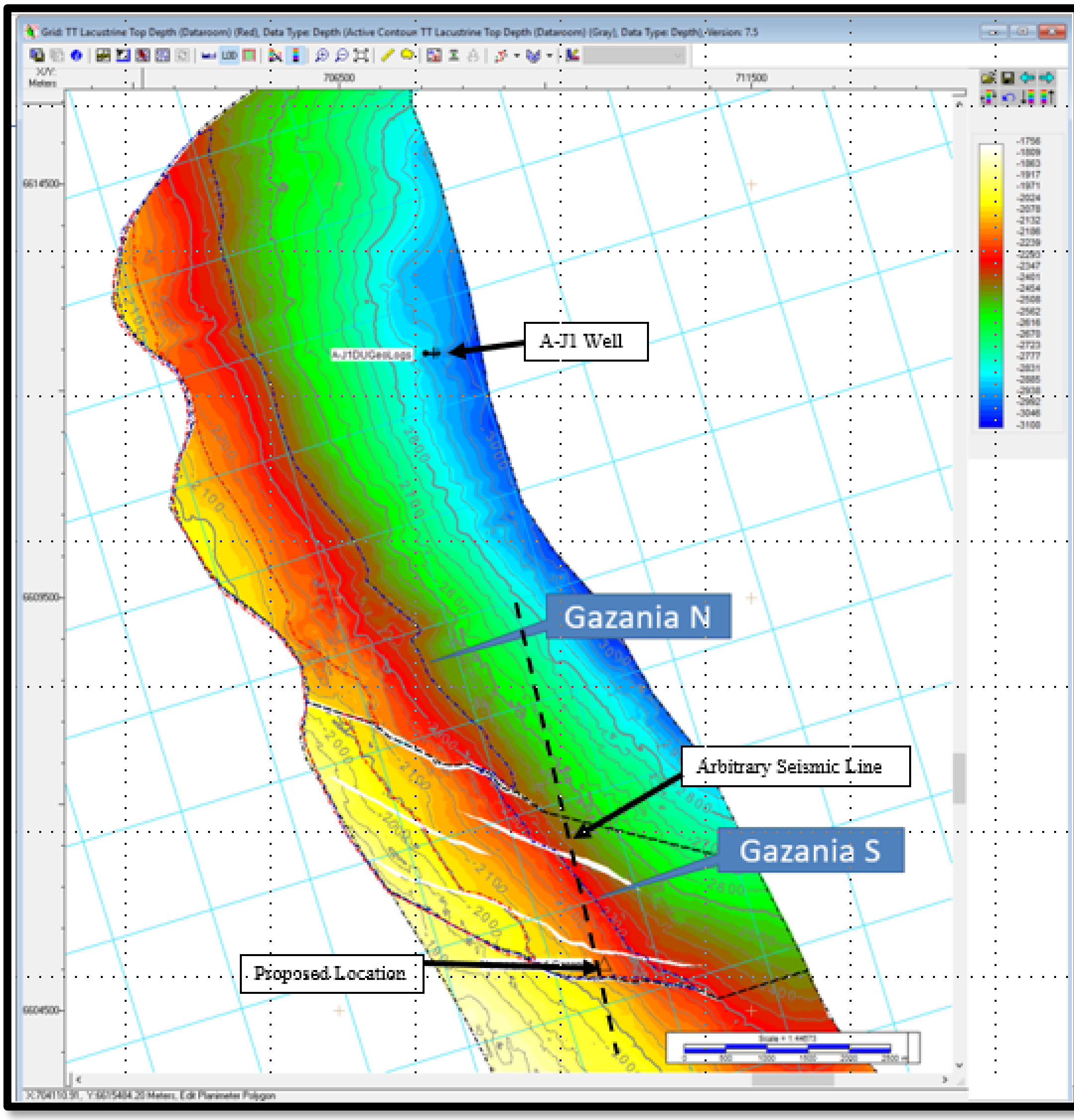



**Figure 4-48 Gazania Prospect in 2B Block (Africa Energy Corp)**

4.3.2.11.4.3Pelargonium (Gazania South) Prospect

The Pelargonium prospect is similar to the Gazania prospect being separated by the NW to SE trending fault (Figure 4-49). Located in the southeast of the Block 2B Project Area southeast of the Gazania prospect in 150 meters of water. This lead covers possibly 17 square kilometers (7 square miles) and may have 140 meters or less of gross sand thickness and at an estimated subsea depth of -2,000 meters.

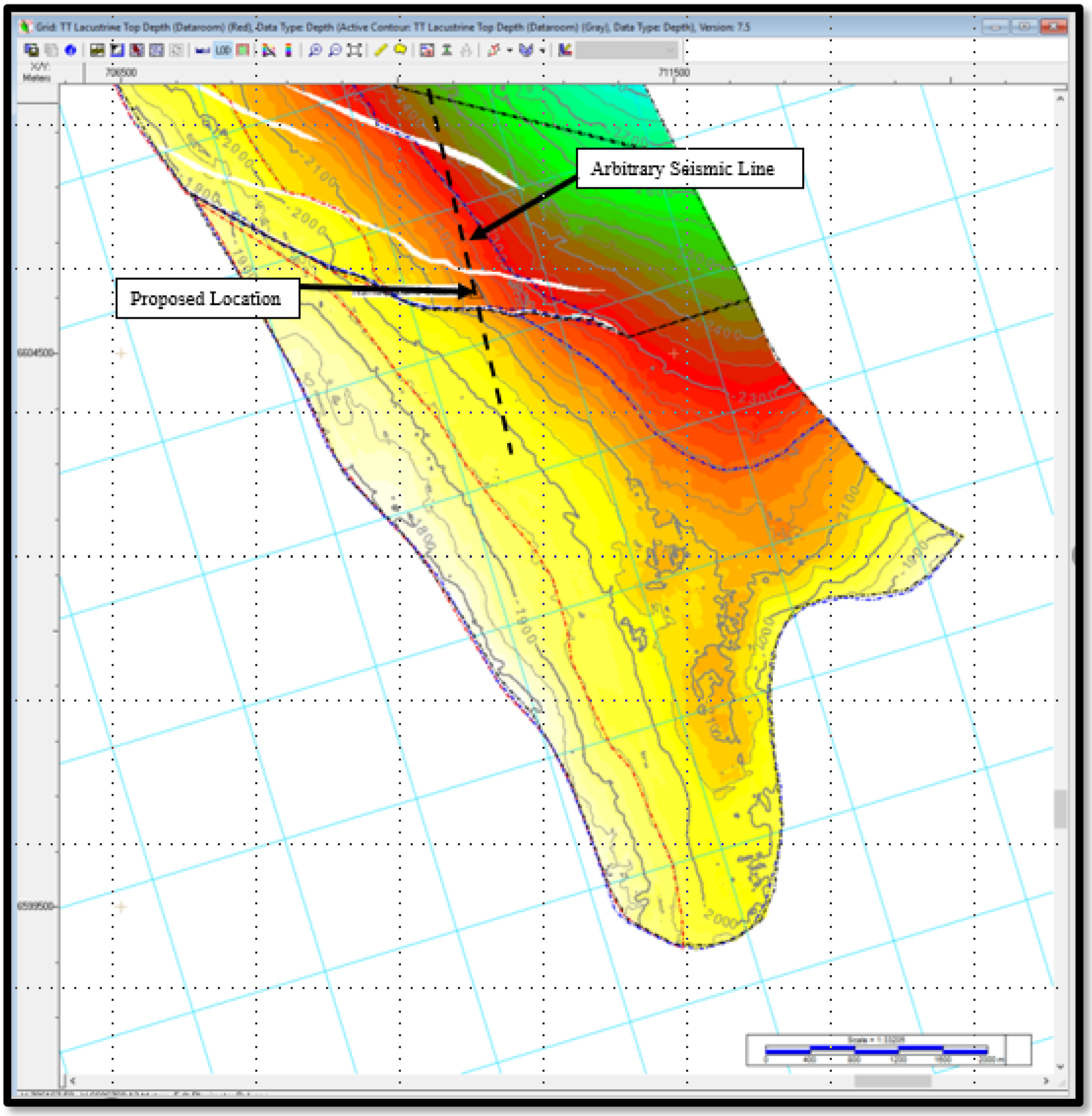



**Figure 4-49 Pelargonium Prospect in 2B Block (Africa Energy Corp)**

4.3.2.12 Risks and Probability of Success

The quantification of risk or the chance of finding commercial quantities of hydrocarbons in any single lead for the plays in this area has been characterized as described in previous sections of this report. The evaluation of risk factors and overall probability of success for the 2B Block are summarized in Table 4-7.

**Table 4-7 Probability of Success, Block 2B Leads**

| Lead | Trap | Seal | Reservoir | Source | Risk POS% |
|---|---|---|---|---|---|
| Pelargonium | 80% | 65% | 65% | 95% | 32.1% |
| Namaqualand | 80% | 65% | 75% | 95% | 37.1% |
| Gazania | 75% | 65% | 75% | 95% | 34.7% |

4.3.3 <u>3B/4B Block</u>

4.3.3.1 Gross and Net Interest in the Property

The 3B/4B Block is 17,581 square kilometers in size situated in the Orange Basin off the coast of the Republic of South Africa, Figure 4-50.

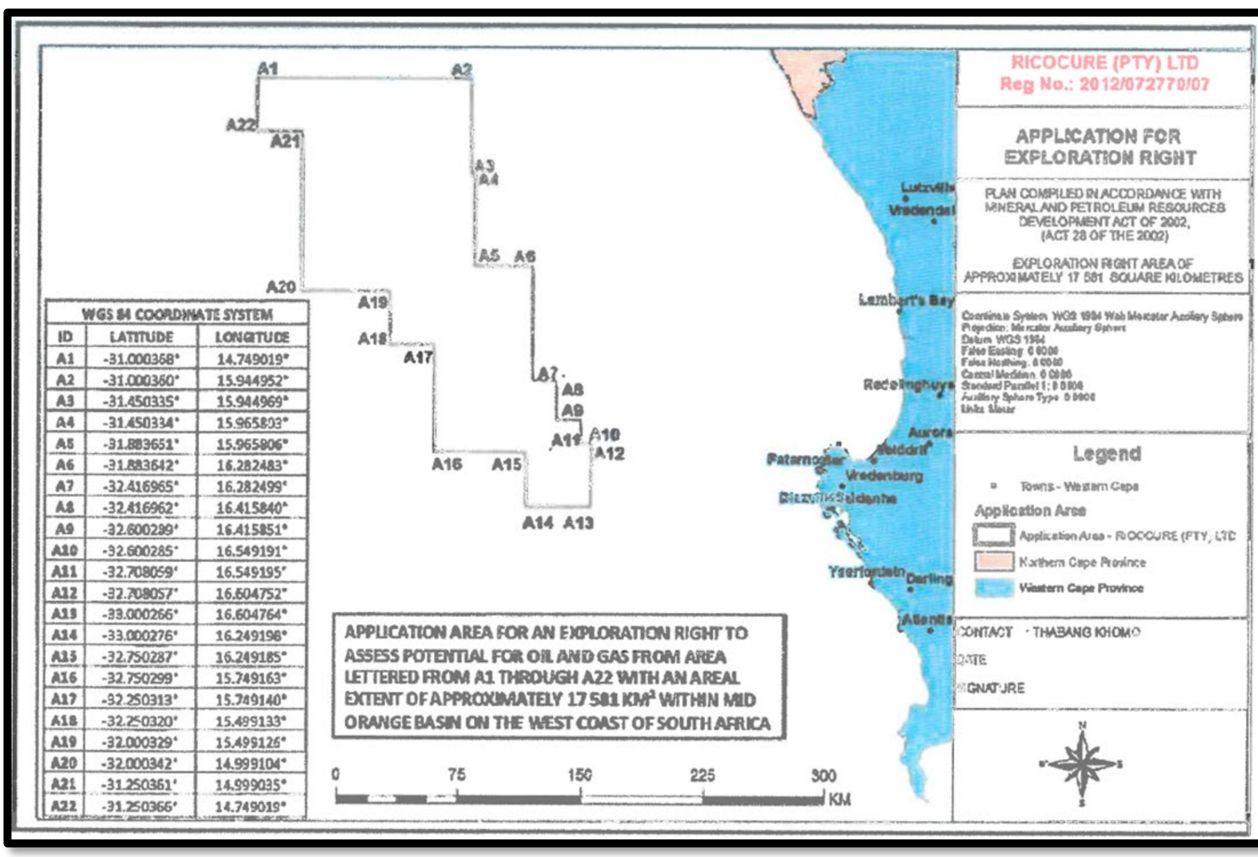



**Figure 4-50 Block Limits for 3B/4B Block (Azinam)**

Note that as stated previously, the stated ownership of the South African assets assumes the completion of the acquisition of Azinam Group Holdings ("Completion"). As announced by Eco on 11 March 2022, all conditions required for Completion have occurred save and except for receipt of the final approval of the TSX Venture Exchange (the "Approval"). Such Approval is expected imminently. This report assumes such Approval has been granted and Completion has occurred, including the increased interests in South Africa having become effective.

#### 4.3.3.2 Expiry Date of Interest

The First renewal period application will be filed in mid-March and is expected to start later in 2022. A 20% relinquishment area which equals 3,516 sq km of contiguous area is required for the first renewal period application. South African Marine Protected Areas (MPA's), which are not firmly established as yet, will play a part in the area of relinquishment decisions.

#### 4.3.3.3 Description of Target Zones

The leads in 3B/4B Block are generally turbidites in a seafloor fan deposit. The traps are generally 3-way closures against a Marginal ridge and stratigraphic closures of slope channels, The seals are provided by deep marine shales.

#### 4.3.3.4 Distance to the Nearest Commercial Production

Oil is being produced in the offshore of Angola, approximately 1,800 kilometers to the north, from multiple fields, and gas has been produced from the Kudu Field approximately 190 kilometers to the north of the 3B/4B Block in the offshore of Namibia.

#### 4.3.3.5 Product Types Reasonably Expected

If discoveries are made on the exploratory leads, then light oil with associated gas is expected based on the reports from the TotalEnergies Venus and Shell Graff discoveries.

#### 4.3.3.6 Range of Pool or Field Sizes

The three leads evaluated for this report have minimum to maximum areas of closure ranging from 18 to 771 square kilometers with gross thicknesses ranging from 15 to 100 meters. The Best Estimate Gross Unrisked Prospective Oil Resources for the leads in South Africa range from 372 to 1,919 MMBbl oil.[19]

#### 4.3.3.7 Depth of the Target Zone

These leads are estimated to occur at a depth range of 3,459 to 4,450 meters with a normal pressure and temperature gradient.

#### 4.3.3.8 Identity and Relevant Experience of the Operator

Africa Oil Corporation is located in Vancouver, British Columbia is an experienced full cycle exploration and production company with operations in onshore Kenya and assets in offshore Nigeria, Guinea-Bissau, Namibia and Africa and offshore Guyana, South America. They have an experienced operations team of Petroleum Engineers and Geologists with significant experience in both onshore and offshore drilling operations.

#### 4.3.3.9 Future Work Plans and Expenditures

The 3B/4B Block plan is to complete the reprocessing and merging of the 3D datasets, initiate an environmental survey in preparation for drilling a well as early as the end of 2022. ECO assumes a 60% carry from Azinam through the seismic processing and will be responsible for 20% of the cost of a well planned to be drilled in early 2023.

#### 4.3.3.10 Market and Infrastructure

[19] Details on these calculations are discussed in Section 5 of this report.

Oil is being produced in the offshore of Angola to the north from multiple fields and gas has been produced from the Kudu Field to the north in the offshore of Namibia. The market and infrastructure near the license area will have to be developed as exploration continues.

#### 4.3.3.11 Source Rocks

Cretaceous Aptian and Barremian shales have been identified as source rocks in the Orange basin. The source is in the oil window and the hydrocarbons are likely oil with wet gas that has been migrating since the late Cretaceous to present day.

#### 4.3.3.12 Leads

##### 4.3.3.12.1 Marula Prospect

A basin floor fan turbidite sequence (Figure 4-51) on a 4-way structure in the Cretaceous Albian aged section. Located in 2,400 meters of water in the middle part of Block 3B/4B. This lead covers possibly 235 square kilometers (91 square miles) and may have 35 meters or less of gross sand thickness and at an estimated subsea depth of -4,400 meters.

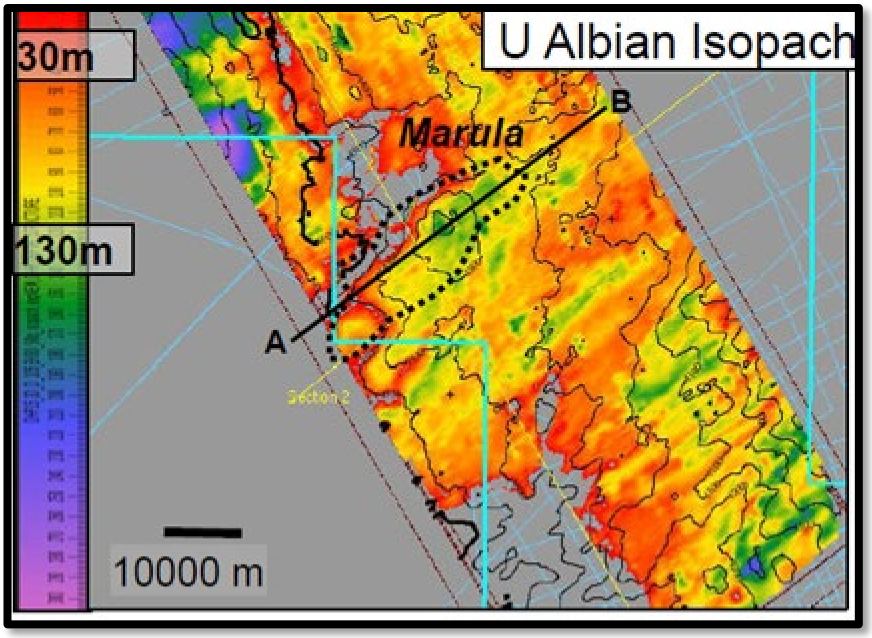



Figure 4-51 Marula Prospect in 3B/4B Block (Azinam)

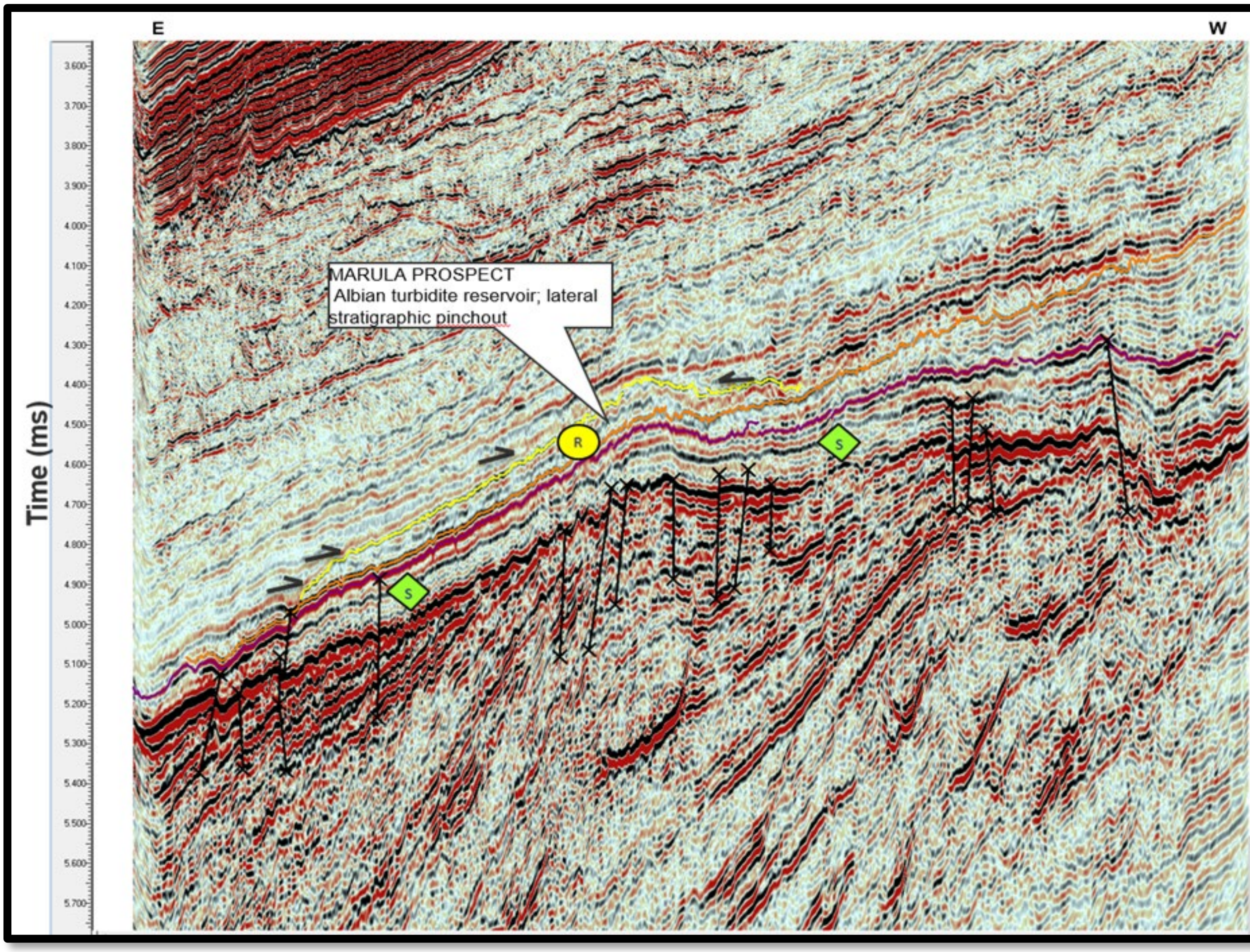



**Figure 4-52 Seismic Section with the Marula Prospect (Azinam)**

4.3.3.12.2 SF-1A Prospect

A stratigraphic trap of a slope fan of Cretaceous aged turbidite sand as seen in the map (Figure 4-53) and the seismic section (Figure 4-54). The target depth is 3,550 meters in 1,600 meters of water. Located in 1,600 meters of water. This lead covers possibly 771 square kilometers (298 square miles) and may have 100 meters or less of gross sand thickness and at an estimated subsea depth of -3,552 meters.

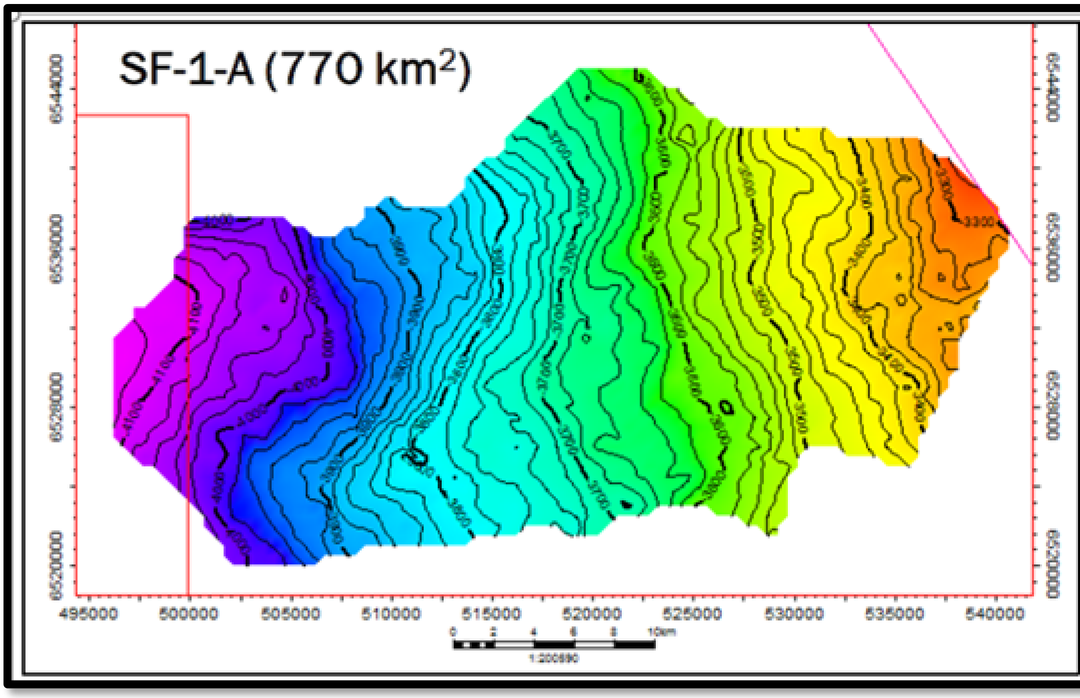



**Figure 4-53 SF-1A Prospect in 3B/4B Block (Azinam)**

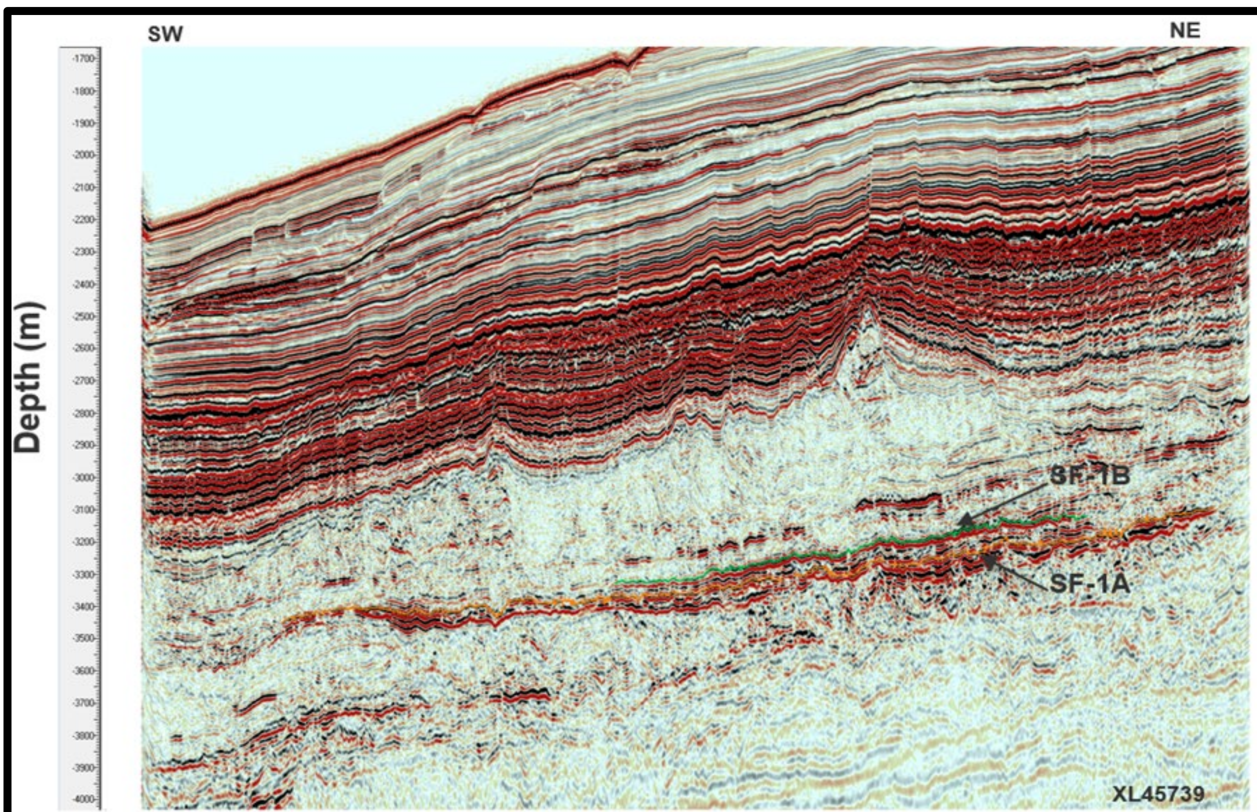



**Figure 4-54 Seismic Section with the SF-1A and SF-1B Prospects in 3B/4B Block (Azinam)**

4.3.3.12.3 SF-1B Prospect

Similar to SF-1A, and stacked above, a stratigraphic trap of a slope fan of Cretaceous aged sand as seen the map (Figure 4-55) and seismic section (Figure 4-54). The target depth is 3,500 meters in 1,600 meters of water.

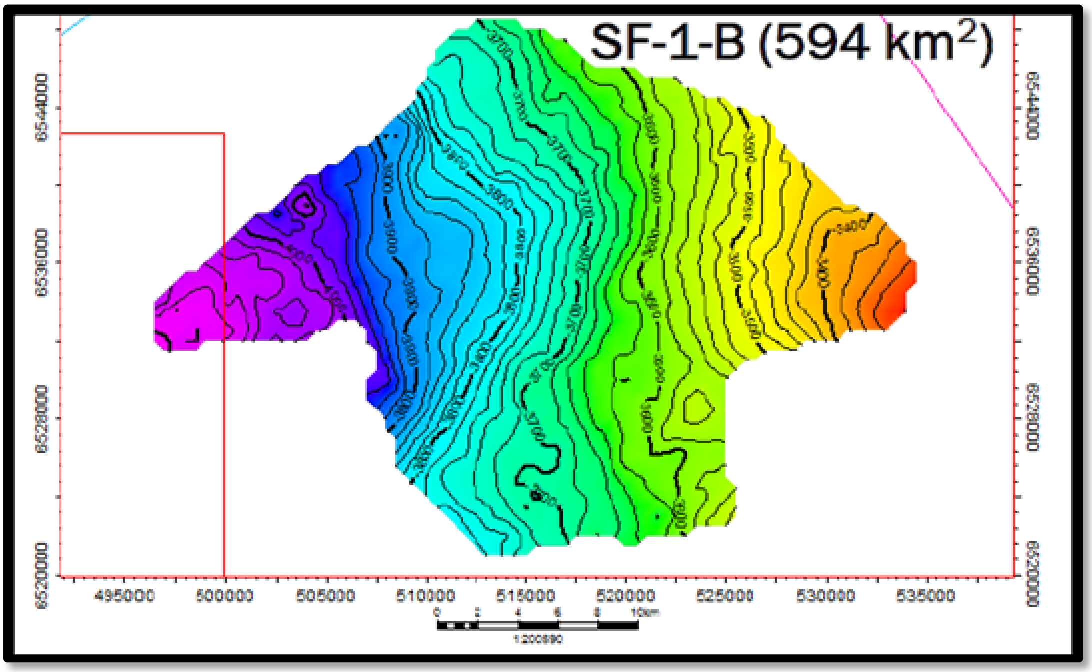



**Figure 4-55 SF-1B Prospect in 3B/4B Block (Azinam)**

Located in 1,600 meters of water. This lead covers possibly 594 square kilometers (229 square miles) and may have 76 meters or less of gross sand thickness and at an estimated subsea depth of -3,500 meters.

4.3.3.13 Risks and Probability of Success

The quantification of risk or the chance of finding commercial quantities of hydrocarbons in any single lead for the plays in this area has been characterized as described in previous sections of this report. The evaluation of risk factors and overall probability of success for the 2B Block are summarized in Table 4-8.

**Table 4-8 Probability of Success, Block 3B/4B Leads**

| Lead | Trap | Seal | Reservoir | Source | Risk POS% |
|---|---|---|---|---|---|
| Marula | 70% | 50% | 70% | 90% | **22.0%** |
| SF-1A | 70% | 50% | 75% | 95% | **24.9%** |
| SF-1B | 75% | 50% | 70% | 95% | **24.9%** |

4.3.3.14 Database 3B/4B

Figure 4-56 shows the 2D seismic dataset over 3B/4B Block and Figure 4-57 shows the 3D seismic data over the block. The northwestern area where the 3D's overlap is currently being reprocessed and merged.

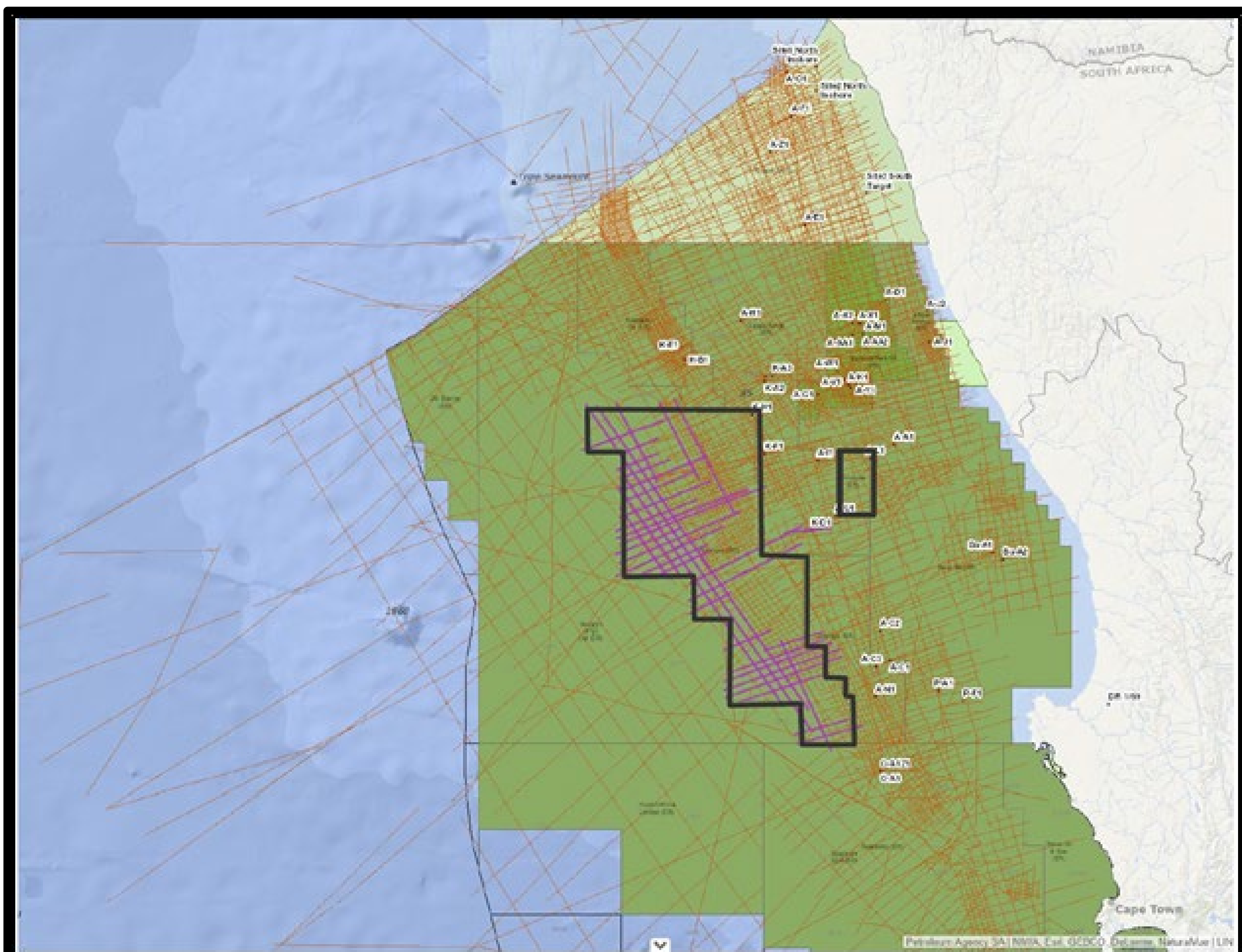



**Figure 4-56 2D Seismic Database in 3B/4B Block (Azinam)**

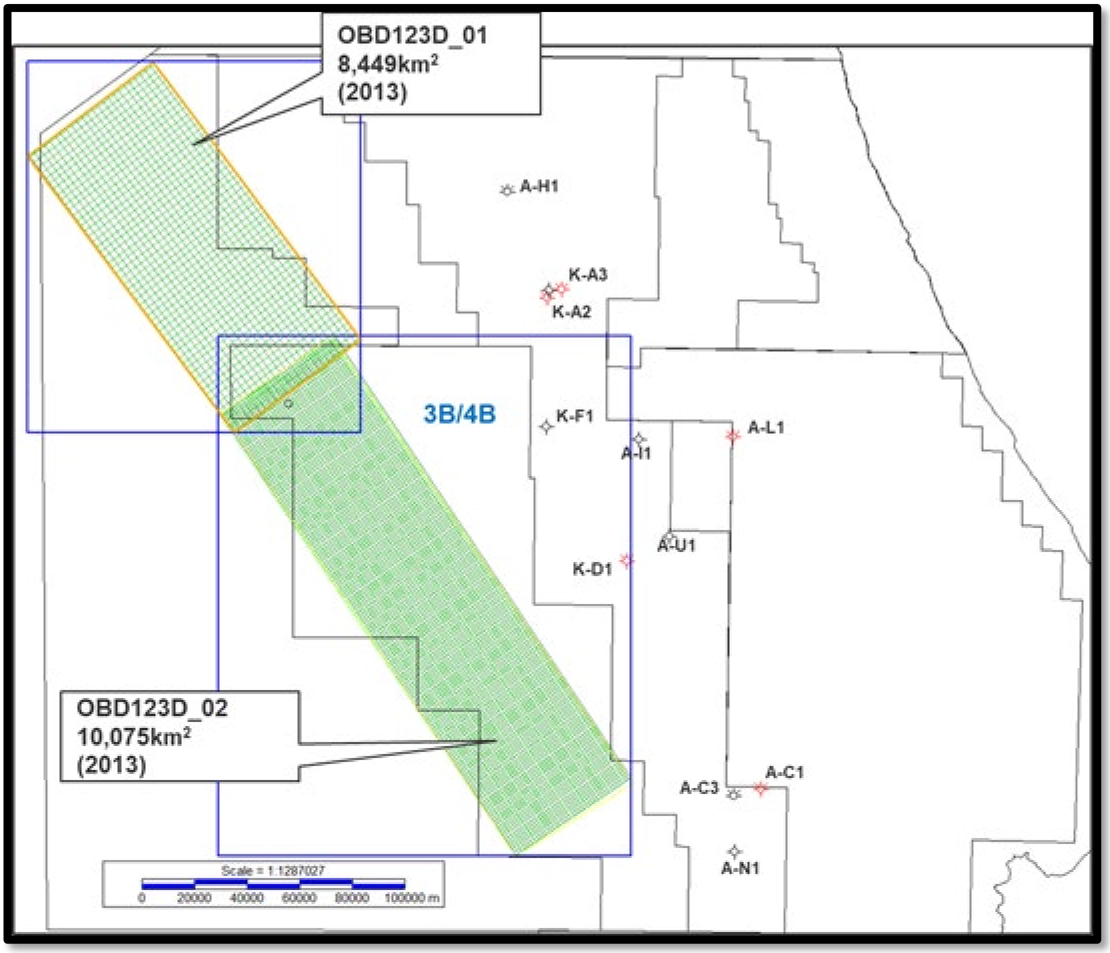



**Figure 4-57 3D Seismic Dataset in 3B/4B Block (Azinam)**

# 5. PROBABILISTIC RESOURCE ANALYSIS

## 5.1 GENERAL

A probabilistic resource analysis is most applicable for projects such as evaluating the potential resources of an exploratory area like the Orinduik Block, where a range of values exists in the reservoir parameters. The range of the expected reservoir data is quantified by probability distributions, and an iterative approach yields an expected probability distribution for potential resources. This approach allows consideration of most likely resources for planning purposes, while gaining an understanding of what volumes of resources may have higher certainty, and what potential upside may exist for the project. The analysis for this project was carried out considering the range of values for all parameters in the volumetric resource equations. Resource estimates were calculated only for the Orinduik Block in Guyana for this report.

## 5.2 INPUT PARAMETERS

This method involves estimating probability distributions for the range of reservoir parameters and performing a statistical risk analysis involving multiple iterations of resource calculations generated by random numbers and the specified distributions of reservoir parameters. To do this, each parameter incorporated in our resource calculation was evaluated for its expected probability distribution. The parameters for porosity, water saturation, pressure, temperature, GOR, and Net/Gross are based on data from similar depositional environments and reservoirs to the subject leads.

Because few data are available about the likely distribution of the reservoir parameters, simple triangular distributions with specification of minimum, most likely or mode, and maximum values were used for most of the parameters. Note that these parameters represent average parameters over the entire lead or prospect. So, for example, the porosity ranges do not represent the range of what porosity might be in a particular well or a particular interval, but rather the reasonable range of the average porosity for the whole lead or prospect. Summaries of input parameters are shown in Table 5-1 through Table 5-5. Note that the parameters for the Guyana leads are all reproduced from our 2020 report. For the Namibia leads, the parameters are reproduced from the 2016 report for all leads which were in that report, except for the Far West Lead #2 in the Guy Block. ECO has re-acquired a license area which was originally part of the Guy Block, but which had been lost at the time of the 2016 report. A portion of the Far West Lead #2 was in this lost and regained license area, as well as three additional leads (Far West Lead #1 and Cretaceous Leads #3 and #4). Two leads on the Guy Block (Stephanus and Murgatroyd) were identified by Azinam, who operated the license area that was lost and regained. These leads were reviewed and analyzed as part of preparation of this report, although they were not included in the 2016 report.

## Table 5-1 Input Parameters for Orinduik Leads, Part 1

| **LEAD** | **Hammerhead (Tert)** | | | **Jethro (Tert)** | | | **Jethro Chan (Tert)** | | | **Jethro Ext (Tert)** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity | 11 | 12 | 18 | 11 | 12 | 18 | 11 | 12 | 18 | 11 | 12 | 18 |
| Gas-Oil Ratio | 100 | 270 | 500 | 100 | 270 | 500 | 100 | 270 | 500 | 100 | 270 | 500 |
| Gas Gravity | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| Pgr, psi | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 |
| Depth, m | 3,200 | 3,550 | 3,700 | 4,178 | 4,232 | 4,300 | 4,210 | 4,350 | 4,550 | 4,000 | 4,100 | 4,200 |
| Porosity | 20 | 28 | 32 | 22 | 27 | 31 | 22 | 27 | 31 | 22 | 27 | 31 |
| Water Sat. | 10 | 20 | 30 | 10 | 20 | 25 | 10 | 20 | 25 | 10 | 20 | 30 |
| Drainage area, km$^2$ | 0.75 | 1 | 1..5 | 8 | 15 | 21 | 8 | 11 | 16 | 2 | 5 | 7 |
| Gross Thickness, m | 45 | 58 | 80 | 45 | 58 | 80 | 45 | 58 | 80 | 45 | 58 | 80 |
| Net/Gross, fraction | 0.85 | 0.90 | 0.95 | 0.85 | 0.90 | 0.95 | 0.70 | 0.75 | 0.80 | 0.70 | 0.75 | 0.80 |
| % Recovery | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 |
| **LEAD** | **Jethro KW (Tert)** | | | **Jethro West (Tert)** | | | **Jimmy (Tert)** | | | **Joe (Tert)** | | |
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity | 11 | 12 | 18 | 11 | 12 | 18 | 12 | 19 | 21 | 12 | 14 | 18 |
| Gas-Oil Ratio | 100 | 270 | 500 | 100 | 270 | 500 | 100 | 270 | 500 | 100 | 270 | 500 |
| Gas Gravity | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| Pgr, psi | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 |
| Depth, m | 3,962 | 4,131 | 4,300 | 4,023 | 4,212 | 4,400 | 2,000 | 2,120 | 2,245 | 1,950 | 2,025 | 2,150 |
| Porosity | 22 | 27 | 31 | 22 | 27 | 31 | 20 | 28 | 32 | 23 | 28 | 32 |
| Water Sat. | 10 | 20 | 30 | 10 | 20 | 30 | 10 | 20 | 30 | 13 | 26 | 35 |
| Drainage area, km$^2$ | 8 | 14 | 19 | 12 | 16 | 20 | 6 | 12 | 18 | 5 | 12 | 27 |
| Gross Thickness, m | 45 | 58 | 80 | 45 | 58 | 80 | 25 | 33 | 50 | 25 | 33 | 50 |
| Net/Gross, fraction | 0.70 | 0.75 | 0.80 | 0.70 | 0.75 | 0.80 | 0.45 | 0.65 | 0.85 | 0.75 | 0.82 | 0.85 |
| % Recovery | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 |
| **LEAD** | **Kurty L (Tert)** | | | **Kurty U (Tert)** | | | **Alice (Tert)** | | | **Amaila/Kumaka (U Cret)** | | |
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity | 12 | 19 | 21 | 12 | 19 | 21 | 12 | 19 | 21 | 25 | 30 | 40 |
| Gas-Oil Ratio | 100 | 270 | 500 | 100 | 270 | 500 | 100 | 270 | 500 | 500 | 1,000 | 1,500 |
| Gas Gravity | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| Pgr, psi | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 | 0.55 | 0.62 | 0.65 | 0.44 | 0.45 | 0.48 |
| Depth, m | 2,670 | 2,777 | 2,884 | 2,570 | 2,678 | 2,785 | 1,425 | 1,465 | 1,485 | 4,000 | 4,250 | 4,550 |
| Porosity | 23 | 28 | 32 | 23 | 28 | 32 | 23 | 28 | 32 | 15 | 25 | 35 |
| Water Sat. | 10 | 20 | 30 | 10 | 20 | 30 | 10 | 20 | 30 | 20 | 30 | 40 |
| Drainage area, km$^2$ | 3 | 8.75 | 14.5 | 1.5 | 5.7 | 9.9 | 8 | 23 | 47 | 32 | 51 | 77 |
| Gross Thickness, m | 25 | 33 | 50 | 25 | 33 | 50 | 25 | 33 | 50 | 100 | 140 | 180 |
| Net/Gross, fraction | 0.25 | 0.45 | 0.65 | 0.75 | 0.82 | 0.85 | 0.75 | 0.82 | 0.85 | 0.25 | 0.45 | 0.65 |
| % Recovery | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 | 12.00 | 20.00 | 30.00 | 19.00 | 28.00 | 35.00 |

# Table 5-2 Input Parameters for Orinduik Leads, Part 2

| LEAD | Amatuk (U Cret) | | | DJ (U Cret) | | | EriKat (U Cret) | | | Iatuk-D (U Cret) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity | 25 | 30 | 40 | 25 | 30 | 40 | 25 | 30 | 40 | 25 | 30 | 40 |
| Gas-Oil Ratio | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| Pgr, psi | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, m | 2,360 | 2,415 | 2,470 | 4,060 | 4,160 | 4,230 | 3,055 | 3,118 | 3,180 | 4,625 | 4,850 | 5,150 |
| Porosity | 15 | 22 | 30 | 15 | 22 | 30 | 15 | 22 | 30 | 15 | 22 | 30 |
| Water Sat. | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 |
| Drainage area, $km^2$ | 35 | 68 | 90 | 14 | 24 | 30 | 6 | 10.5 | 15 | 37 | 50 | 73 |
| Gross Thickness, m | 20 | 40 | 50 | 40 | 50 | 60 | 30 | 40 | 50 | 100 | 125 | 175 |
| Net/Gross, fraction | 0.25 | 0.45 | 0.65 | 0.50 | 0.70 | 0.80 | 0.25 | 0.45 | 0.65 | 0.25 | 0.45 | 0.65 |
| % Recovery | 19.00 | 28.00 | 35.00 | 19.00 | 28.00 | 35.00 | 19.00 | 28.00 | 35.00 | 18.00 | 28.00 | 35.00 |

| LEAD | KC (U Cret) | | | KC-A (U Cret) | | | KG (U Cret) | | | MJ-3 (U Cret) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity | 25 | 30 | 40 | 25 | 30 | 40 | 25 | 30 | 40 | 25 | 30 | 40 |
| Gas-Oil Ratio | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| Pgr, psi | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, m | 2,360 | 2,460 | 2,560 | 2,950 | 3,225 | 3,500 | 3,400 | 3,900 | 4,050 | 2,780 | 3,700 | 4,130 |
| Porosity | 15 | 25 | 35 | 15 | 25 | 35 | 15 | 25 | 35 | 15 | 25 | 35 |
| Water Sat. | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 |
| Drainage area, $km^2$ | 6 | 11 | 15 | 7 | 9 | 12 | 17 | 30 | 34 | 18 | 25 | 37 |
| Gross Thickness, m | 30 | 40 | 50 | 50 | 75 | 100 | 200 | 275 | 325 | 70 | 95 | 120 |
| Net/Gross, fraction | 0.25 | 0.45 | 0.65 | 0.25 | 0.45 | 0.65 | 0.25 | 0.45 | 0.65 | 0.25 | 0.45 | 0.65 |
| % Recovery | 19.00 | 28.00 | 35.00 | 19.00 | 28.00 | 35.00 | 19.00 | 28.00 | 35.00 | 19.00 | 28.00 | 35.00 |

| LEAD | Rappu (U Cret) | | | KB (Cret) | | |
|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity | 25 | 30 | 40 | 25 | 30 | 40 |
| Gas-Oil Ratio | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| Pgr, psi | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, m | 3,400 | 3,650 | 3,850 | 3,660 | 3,700 | 3,740 |
| Porosity | 15 | 25 | 35 | 15 | 25 | 35 |
| Water Sat. | 20 | 30 | 40 | 20 | 30 | 40 |
| Drainage area, $km^2$ | 35 | 65 | 95 | 17 | 27 | 43 |
| Gross Thickness, m | 50 | 75 | 100 | 60 | 70 | 125 |
| Net/Gross, fraction | 0.25 | 0.45 | 0.65 | 0.45 | 0.55 | 0.75 |
| % Recovery | 19.00 | 28.00 | 35.00 | 19.00 | 28.00 | 35.00 |

## Table 5-3 Input Parameters for Namibia Leads, Part 1

| | Lead A (Campanian) | | | Lead B (Mid Albian) | | | Lead C (Campanian) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 30 | 35 | 40 | 30 | 35 | 40 | 30 | 35 | 40 |
| Gas-Oil Ratio, SCF/Bbl | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity, rel. to air | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, ft | 5,741 | 6,069 | 6,397 | 8,986 | 9,186 | 9,386 | 4,101 | 4,511 | 4,921 |
| Porosity, % | 12 | 20 | 25 | 12 | 20 | 25 | 12 | 20 | 25 |
| Water Sat., % | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 |
| Drainage area, acres | 1,087 | 2,718 | 5,436 | 3,494 | 8,735 | 17,470 | 5,634 | 14,085 | 28,170 |
| Gross Thickness, ft | 140 | 170 | 250 | 140 | 170 | 250 | 70 | 85 | 100 |
| Net/Gross, fraction | 0.50 | 0.75 | 0.85 | 0.50 | 0.75 | 0.85 | 0.50 | 0.75 | 0.85 |
| % Recovery | 0.15 | 0.27 | 0.30 | 0.15 | 0.27 | 0.30 | 0.15 | 0.27 | 0.30 |
| | **Lead 'Flat' (Campanian)** | | | **Osprey** | | | **Far West Lead #1** | | |
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 30 | 35 | 40 | 30 | 35 | 40 | 30 | 35 | 40 |
| Gas-Oil Ratio, SCF/Bbl | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity, rel. to air | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, ft | 5,085 | 5,413 | 5,741 | 8,694 | 9,022 | 9,350 | 13,252 | 13,452 | 13,652 |
| Porosity, % | 12 | 20 | 25 | 12 | 20 | 25 | 10 | 21 | 30 |
| Water Sat., % | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 |
| Drainage area, acres | 791 | 1,977 | 3,954 | 12,300 | 22,200 | 43,250 | 16,803 | 37,560 | 63,012 |
| Gross Thickness, ft | 140 | 170 | 250 | 70 | 85 | 100 | 66 | 131 | 197 |
| Net/Gross, fraction | 0.50 | 0.75 | 0.85 | 0.50 | 0.75 | 0.85 | 0.25 | 0.50 | 0.75 |
| % Recovery | 0.15 | 0.27 | 0.30 | 0.15 | 0.27 | 0.30 | 0.15 | 0.20 | 0.35 |
| | **Far West Lead 2** | | | **Cretaceous Sand Lead 1** | | | **Cretaceous Sand Lead 2** | | |
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 30 | 35 | 40 | 30 | 35 | 40 | 30 | 35 | 40 |
| Gas-Oil Ratio, SCF/Bbl | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity, rel. to air | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, ft | 11,366 | 11,566 | 11,766 | 12,924 | 13,124 | 13,324 | 13,088 | 13,288 | 13,488 |
| Porosity, % | 10 | 21 | 30 | 10 | 21 | 30 | 10 | 21 | 30 |
| Water Sat., % | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 |
| Drainage area, acres | 21,498 | 56,093 | 81,792 | 9,143 | 24,711 | 49,668 | 4,201 | 9,390 | 16,803 |
| Gross Thickness, ft | 131 | 230 | 328 | 131 | 262 | 394 | 66 | 115 | 164 |
| Net/Gross, fraction | 0.25 | 0.50 | 0.75 | 0.25 | 0.50 | 0.75 | 0.25 | 0.50 | 0.75 |
| % Recovery | 0.15 | 0.20 | 0.35 | 0.15 | 0.20 | 0.35 | 0.15 | 0.20 | 0.35 |

## Table 5-4 Input Parameters for Namibia Leads, Part 2

| | Cretaceous Sand Lead #3 | | | Cretaceous Sand Lead #4 | | | Cretaceous Sand Lead 5 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 30 | 35 | 40 | 30 | 35 | 40 | 30 | 35 | 40 |
| Gas-Oil Ratio, SCF/Bbl | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity, rel. to air | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, ft | 14,072 | 14,272 | 14,472 | 16,533 | 16,733 | 16,933 | 13,908 | 14,108 | 14,308 |
| Porosity, % | 10 | 21 | 30 | 10 | 21 | 30 | 10 | 21 | 30 |
| Water Sat., % | 20 | 30 | 40 | 20 | 30 | 40 | 20 | 30 | 40 |
| Drainage area, acres | 36,819 | 72,896 | 103,043 | 12,602 | 22,487 | 34,100 | 9,884 | 16,556 | 32,100 |
| Gross Thickness, ft | 164 | 328 | 492 | 49 | 82 | 115 | 33 | 59 | 82 |
| Net/Gross, fraction | 0.25 | 0.50 | 0.75 | 0.25 | 0.50 | 0.75 | 0.25 | 0.50 | 0.75 |
| % Recovery | 15% | 20% | 35% | 15% | 20% | 35% | 15% | 20% | 35% |

| | Stephanus (PEL 34) | | | Mergatroyd (PEL 34) | | | North Structure | | |
|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 30 | 35 | 40 | 30 | 35 | 40 | 30 | 35 | 40 |
| Gas-Oil Ratio, SCF/Bbl | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 | 500 | 1,000 | 1,500 |
| Gas Gravity, rel. to air | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 | 0.65 | 0.70 | 0.75 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, ft | 11,778 | 11,811 | 12,532 | 11,647 | 11,811 | 11,975 | 8,331 | 8,531 | 8,731 |
| Porosity, % | 13 | 15 | 20 | 13 | 20 | 26 | 15 | 20 | 25 |
| Water Sat., % | 25 | 30 | 35 | 25 | 30 | 35 | 20 | 30 | 40 |
| Drainage area, acres | 4,772 | 8,147 | 17,228 | 7,430 | 13,482 | 18,575 | 11,737 | 27,849 | 56,834 |
| Gross Thickness, ft | 66 | 98 | 164 | 492 | 656 | 853 | 164 | 328 | 492 |
| Net/Gross, fraction | 0.50 | 0.60 | 0.70 | 0.60 | 0.70 | 0.80 | 0.25 | 0.50 | 0.75 |
| % Recovery | 15% | 20% | 25% | 15% | 20% | 25% | 15% | 20% | 35% |

| | Wedge | | |
|---|---|---|---|
| | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 30 | 35 | 40 |
| Gas-Oil Ratio, SCF/Bbl | 500 | 1,000 | 1,500 |
| Gas Gravity, rel. to air | 0.65 | 0.70 | 0.75 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 |
| Depth, ft | 8,331 | 8,531 | 8,731 |
| Porosity, % | 15 | 20 | 25 |
| Water Sat., % | 20 | 30 | 40 |
| Drainage area, acres | 30,890 | 72,650 | 139,600 |
| Gross Thickness, ft | 82 | 164 | 328 |
| Net/Gross, fraction | 0.25 | 0.50 | 0.75 |
| % Recovery | 15% | 20% | 35% |

## Table 5-5 Input Parameters for South Africa Leads

| | Marula (3B/4B) | | | SF-1-A (3B/4B) | | | SF-1-B (3B/4B) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 32 | 34 | 36 | 32 | 34 | 36 | 32 | 34 | 36 |
| Gas-Oil Ratio, SCF/Bbl | 390 | 460 | 470 | 390 | 460 | 470 | 390 | 460 | 470 |
| Gas Gravity, rel. to air | 0.60 | 0.63 | 0.65 | 0.60 | 0.63 | 0.65 | 0.60 | 0.63 | 0.65 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, ft | 14,200 | 14,436 | 14,600 | 11,500 | 11,653 | 11,750 | 11,350 | 11,482 | 11,600 |
| Porosity, % | 0.16 | 0.18 | 0.20 | 0.12 | 0.15 | 0.18 | 0.12 | 0.15 | 0.18 |
| Water Sat., % | 0.30 | 0.35 | 0.40 | 0.30 | 0.35 | 0.40 | 0.30 | 0.35 | 0.40 |
| Drainage area, acres | 4,448 | 31,135 | 58,070 | 65,236 | 122,070 | 190,518 | 24,216 | 75,120 | 146,781 |
| Gross Thickness, ft | 66 | 98 | 115 | 98 | 164 | 328 | 49 | 82 | 249 |
| Net/Gross, fraction | 0.65 | 0.70 | 0.75 | 0.50 | 0.55 | 0.60 | 0.50 | 0.55 | 0.60 |
| Recovery Factor | 0.20 | 0.25 | 0.30 | 0.20 | 0.25 | 0.30 | 0.20 | 0.25 | 0.30 |

| | Pelargonium (2B) | | | Namaqualand (2B) | | | Gazania (2B) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum | Minimum | Most Likely | Maximum |
| Oil Gravity, ° API | 34 | 36 | 38 | 34 | 36 | 38 | 34 | 36 | 38 |
| Gas-Oil Ratio, SCF/Bbl | 110 | 140 | 200 | 110 | 140 | 200 | 110 | 140 | 200 |
| Gas Gravity, rel. to air | 0.60 | 0.63 | 0.65 | 0.60 | 0.63 | 0.65 | 0.60 | 0.63 | 0.65 |
| press gradient, psi/ft | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 | 0.44 | 0.45 | 0.48 |
| Depth, ft | 5,906 | 6,562 | 7,217 | 5,000 | 5,807 | 6,500 | 6,890 | 7,300 | 7,710 |
| Porosity, % | 0.15 | 0.19 | 0.25 | 0.15 | 0.21 | 0.30 | 0.15 | 0.19 | 0.25 |
| Water Sat., % | 0.20 | 0.30 | 0.40 | 0.20 | 0.30 | 0.40 | 0.20 | 0.30 | 0.40 |
| Drainage area, acres | 1,236 | 2,719 | 4,201 | 1,483 | 2,033 | 2,460 | 1,186 | 2,570 | 3,954 |
| Gross Thickness, ft | 177 | 262 | 458 | 650 | 755 | 850 | 370 | 533 | 1,285 |
| Net/Gross, fraction | 0.30 | 0.50 | 0.70 | 0.25 | 0.50 | 0.75 | 0.30 | 0.50 | 0.70 |
| Recovery Factor | 0.20 | 0.25 | 0.30 | 0.20 | 0.25 | 0.30 | 0.20 | 0.25 | 0.30 |

In a probabilistic analysis, dependent relationships can be established between parameters if appropriate. For this analysis correlations were set up between gross thickness and drainage area, and between porosity and water saturation. The low end of the gross thickness distributions for this prospective accumulation would generally be expected to occur when the productive area is small; therefore, a positive correlation of 0.95 was assigned to gross thickness and productive area. Higher water saturations are generally associated with lower porosity; therefore, a negative correlation of 0.7 was assigned to porosity and water saturation.

## 5.3 PROBABILISTIC SIMULATION

Probabilistic resource analysis was performed using the Monte Carlo simulation software called @ Risk.[20] This software allows for input of a variety of probability distributions for any parameter. The program performs a large number of iterations, either a number specified by the user, or until a specified level of stability is achieved in the output. The results include a probability distribution

[20] Palisade Corporation

for the output, sampled probability for the inputs, and sensitivity analysis showing which input parameters have the most effect on the uncertainty in each output parameter.

After distributions and relationships between input parameters were defined, a series of simulations were run wherein points from the distributions were randomly selected and used to calculate a single iteration of estimated potential resources. The iterations were repeated for 10,000 iterations so that stable statistics (mean and standard deviation) result from the resulting output distribution.

## 5.4 RESULTS

The output distributions from the Probabilistic simulation were then used to characterize the Prospective Resources. Results for each area are summarized in the following sections. Graphs of resource distributions are included in Appendix B. It should be noted that the probability distributions show a wide spacing between the minimum and maximum expected resources. This is reflective of the high degree of uncertainty associated with any evaluation such as this one prior to actual field discovery, development, and production. Also note that, in general, the high probability resource estimates at the left side of these distributions represents downside risk, while the low probability estimates on the right side of the distributions represent upside potential. These distributions do not include consideration of the probability of success of discovering commercial quantities of oil, but rather represent the likely distribution of oil discoveries, if successfully found.

**Prospective Resources** are defined as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity."[21] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Low Estimate represents the $P_{90}$ values from the

[21] Society of Petroleum Evaluation Engineers, (Calgary Chapter): Canadian Oil and Gas Evaluation Handbook, Third Edition, August 2018, updated October 2019, pg. 13.

probabilistic analysis (in other words, the value is greater than or equal to the $P_{90}$ value 90% of the time), while the Best Estimate represents the $P_{50}$ and the High Estimate represents the $P_{10}$.[22]

Note that a deterministic calculation with any set of the input parameters will not necessarily be close to any of the results shown in these tables. Specifically, the most likely input parameters do not necessarily yield a result very close to the Best Estimate. This is because some of the distributions may be skewed towards the minimum value rather than the maximum value where the minimum to maximum range is large, so that the mean is rather different from the most likely value.

5.4.1 Guyana

The Prospective Resources are summarized in Table 5-6. Note that these estimates do not include consideration for the risk of failure in exploring for these resources.

[22] Ibid.

## Table 5-6 Unrisked Prospective Resource Estimates, Orinduik

| | Gross | | | Net attributable to ECO's interests | | | | |
|---|---|---|---|---|---|---|---|---|
| Lead | Low Estimate | Best Estimate | High Estimate | Low Estimate | Best Estimate | High Estimate | Risk Factor | Operator |
| **Oil & Liquids Prospective Resources (millions of barrels)** | | | | | | | | |
| Alice (Tert) | 65 | 188 | 410 | 10 | 28 | 62 | 43.2% | Tullow |
| Amaila-Kumaka (U Cret) | 340 | 667 | 1,216 | 51 | 100 | 182 | 28.0% | Tullow |
| Amatuk (U Cret) | 101 | 230 | 429 | 15 | 34 | 64 | 24.0% | Tullow |
| DJ (U Cret) | 85 | 150 | 243 | 13 | 22 | 36 | 26.3% | Tullow |
| EriKat (U Cret) | 19 | 39 | 70 | 3 | 6 | 11 | 32.4% | Tullow |
| Hammerhead (Tert) | 8 | 14 | 24 | 1 | 2 | 4 | 81.0% | Tullow |
| Iatuk-D (U Cret) | 346 | 624 | 1,096 | 52 | 94 | 164 | 28.0% | Tullow |
| Jethro (Tert) | 103 | 199 | 345 | 15 | 30 | 52 | 81.0% | Tullow |
| Jethro Chan (Tert) | 77 | 131 | 219 | 12 | 20 | 33 | 44.1% | Tullow |
| Jethro Ext (Tert) | 22 | 51 | 93 | 3 | 8 | 14 | 43.2% | Tullow |
| Jethro KW (Tert) | 82 | 151 | 257 | 12 | 23 | 39 | 16.2% | Tullow |
| Jethro West (Tert) | 110 | 176 | 273 | 17 | 26 | 41 | 17.6% | Tullow |
| Jimmy (Tert) | 30 | 65 | 127 | 4 | 10 | 19 | 64.6% | Tullow |
| Joe (Tert) | 36 | 100 | 222 | 5 | 15 | 33 | 81.0% | Tullow |
| KB (Cret) | 146 | 292 | 572 | 22 | 44 | 86 | 28.0% | Tullow |
| KC (U Cret) | 21 | 41 | 73 | 3 | 6 | 11 | 24.0% | Tullow |
| KC-A (U Cret) | 36 | 63 | 108 | 5 | 10 | 16 | 24.0% | Tullow |
| KG (U Cret) | 340 | 623 | 1,035 | 51 | 94 | 155 | 28.0% | Tullow |
| Kurty L (Tert) | 12 | 34 | 73 | 2 | 5 | 11 | 43.2% | Tullow |
| Kurty U (Tert) | 13 | 41 | 87 | 2 | 6 | 13 | 43.2% | Tullow |
| MJ-3 (U Cret) | 124 | 227 | 397 | 19 | 34 | 59 | 24.0% | Tullow |
| Rappu (U Cret) | 200 | 430 | 810 | 30 | 65 | 121 | 25.2% | Tullow |
| **Total for Oil & Liquids** | **2,315** | **4,537** | **8,179** | **347** | **681** | **1,227** | | |
| **Gas Prospective Resources (billions of standard cubic feet)** | | | | | | | | |
| Alice (Tert) | 17 | 52 | 122 | 3 | 8 | 18 | 43.2% | Tullow |
| Amaila-Kumaka (U Cret) | 320 | 652 | 1,235 | 48 | 98 | 185 | 28.0% | Tullow |
| Amatuk (U Cret) | 95 | 225 | 443 | 14 | 34 | 66 | 24.0% | Tullow |
| DJ (U Cret) | 79 | 146 | 248 | 12 | 22 | 37 | 26.3% | Tullow |
| EriKat (U Cret) | 18 | 38 | 73 | 3 | 6 | 11 | 32.4% | Tullow |
| Hammerhead (Tert) | 2 | 4 | 7 | 0 | 1 | 1 | 81.0% | Tullow |
| Iatuk-D (U Cret) | 329 | 610 | 1,111 | 49 | 91 | 167 | 28.0% | Tullow |
| Jethro (Tert) | 26 | 55 | 105 | 4 | 8 | 16 | 81.0% | Tullow |
| Jethro Chan (Tert) | 19 | 37 | 67 | 3 | 6 | 10 | 44.1% | Tullow |
| Jethro Ext (Tert) | 6 | 14 | 28 | 1 | 2 | 4 | 43.2% | Tullow |
| Jethro KW (Tert) | 21 | 42 | 79 | 3 | 6 | 12 | 16.2% | Tullow |
| Jethro West (Tert) | 27 | 49 | 84 | 4 | 7 | 13 | 17.6% | Tullow |
| Jimmy (Tert) | 8 | 18 | 38 | 1 | 3 | 6 | 64.6% | Tullow |
| Joe (Tert) | 9 | 28 | 66 | 1 | 4 | 10 | 81.0% | Tullow |
| KB (Cret) | 138 | 286 | 578 | 21 | 43 | 87 | 28.0% | Tullow |
| KC (U Cret) | 19 | 40 | 75 | 3 | 6 | 11 | 24.0% | Tullow |
| KC-A (U Cret) | 33 | 62 | 112 | 5 | 9 | 17 | 24.0% | Tullow |
| KG (U Cret) | 320 | 608 | 1,061 | 48 | 91 | 159 | 28.0% | Tullow |
| Kurty L (Tert) | 3 | 9 | 22 | 0 | 1 | 3 | 43.2% | Tullow |
| Kurty U (Tert) | 3 | 11 | 26 | 1 | 2 | 4 | 43.2% | Tullow |
| MJ-3 (U Cret) | 117 | 221 | 405 | 17 | 33 | 61 | 24.0% | Tullow |
| Rappu (U Cret) | 188 | 420 | 825 | 28 | 63 | 124 | 25.2% | Tullow |
| **Total for Gas** | **1,798** | **3,626** | **6,811** | **270** | **544** | **1,022** | | |

*Source: Letha C. Lencioni*
*Note: "Risk Factor" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource*
*"Operator" is name of the company that operates the asset*
*"Gross" indicates 100% of the resources estimated for the blocks, while "net" indicates the share attributable to ECO's interests.*

## 5.4.2 Namibia

Unrisked Prospective Resources for the Namibia blocks are shown in Table 5-7.

### Table 5-7 Unrisked Prospective Resources, Namibia

| | | Gross | | | Net attributable to ECO's interests | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Block** | **Lead/Prospect** | **Low Estimate** | **Best Estimate** | **High Estimate** | **Low Estimate** | **Best Estimate** | **High Estimate** | **Risk Factor** | **Operator** |
| **Oil & Liquids Prospective Resources (millions of barrels)** | | | | | | | | | |
| Cooper | A (Campanian) | 40 | 70 | 117 | 34 | 60 | 100 | 3.2% | ECO |
| Cooper | B (Albian) | 113 | 205 | 346 | 96 | 174 | 294 | 3.5% | ECO |
| Cooper | C (Campanian) | 101 | 179 | 292 | 86 | 152 | 248 | 3.5% | ECO |
| Cooper | Flat (Campanian) | 30 | 52 | 88 | 25 | 44 | 75 | 3.0% | ECO |
| Cooper | Osprey | 151 | 245 | 398 | 128 | 209 | 339 | 17.9% | ECO |
| **Subtotal Oil and Liquids, Cooper** | | **434** | **753** | **1,242** | **369** | **640** | **1,056** | | |
| Guy | Stephanus | 26 | 72 | 160 | 22 | 61 | 136 | 2.0% | ECO |
| Guy | Mergatroyd | 383 | 815 | 1,434 | 326 | 693 | 1,219 | 2.1% | ECO |
| Guy | Far West Lead #1 | 117 | 398 | 949 | 100 | 338 | 807 | 2.0% | ECO |
| Guy | Far West Lead #2 | 279 | 940 | 2,164 | 237 | 799 | 1,839 | 2.0% | ECO |
| Guy | Cretaceous Sand Lead #1 | 139 | 573 | 1,503 | 118 | 487 | 1,277 | 2.2% | ECO |
| Guy | Cretaceous Sand Lead #2 | 27 | 91 | 217 | 23 | 77 | 184 | 2.5% | ECO |
| Guy | Cretaceous Sand Lead #3 | 614 | 1,796 | 3,972 | 522 | 1,527 | 3,377 | 2.5% | ECO |
| Guy | Cretaceous Sand Lead #4 | 56 | 147 | 317 | 48 | 125 | 269 | 2.1% | ECO |
| Guy | Cretaceous Sand Lead #5 | 31 | 92 | 222 | 26 | 78 | 188 | 2.1% | ECO |
| **Subtotal Oil and Liquids, Guy** | | **1,671** | **4,924** | **10,937** | **1,421** | **4,185** | **9,297** | | |
| Sharon | North Structure | 294 | 909 | 2,176 | 250 | 773 | 1,849 | 1.9% | ECO |
| Sharon | Wedge | 408 | 1,302 | 3,343 | 347 | 1,107 | 2,841 | 3.5% | ECO |
| **Subtotal Oil and Liquids, Sharon** | | **702** | **2,212** | **5,518** | **597** | **1,880** | **4,691** | | |
| **Total for Oil & Liquids** | | **2,808** | **7,888** | **17,697** | **2,386** | **6,705** | **15,043** | | |
| **Gas Prospective Resources (billions of standard cubic feet)** | | | | | | | | | |
| Cooper | A (Campanian) | 36 | 69 | 121 | 31 | 59 | 103 | 3.2% | ECO |
| Cooper | B (Albian) | 106 | 199 | 353 | 90 | 170 | 300 | 3.5% | ECO |
| Cooper | C (Campanian) | 94 | 176 | 304 | 80 | 150 | 258 | 3.5% | ECO |
| Cooper | Flat (Campanian) | 27 | 52 | 90 | 23 | 44 | 77 | 3.0% | ECO |
| Cooper | Osprey | 141 | 240 | 407 | 120 | 204 | 346 | 17.9% | ECO |
| **Subtotal Gas, Cooper** | | **405** | **736** | **1,275** | **344** | **625** | **1,084** | | |
| Guy | Stephanus | 25 | 69 | 160 | 21 | 59 | 136 | 2.0% | ECO |
| Guy | Mergatroyd | 369 | 794 | 1,444 | 313 | 675 | 1,228 | 2.1% | ECO |
| Guy | Far West Lead #1 | 113 | 386 | 935 | 96 | 328 | 794 | 2.0% | ECO |
| Guy | Far West Lead #2 | 267 | 920 | 2,128 | 227 | 782 | 1,809 | 2.0% | ECO |
| Guy | Cretaceous Sand Lead #1 | 134 | 559 | 1,488 | 114 | 475 | 1,265 | 2.2% | ECO |
| Guy | Cretaceous Sand Lead #2 | 26 | 88 | 213 | 22 | 75 | 181 | 2.5% | ECO |
| Guy | Cretaceous Sand Lead #3 | 607 | 1,761 | 3,964 | 516 | 1,497 | 3,369 | 2.5% | ECO |
| Guy | Cretaceous Sand Lead #4 | 54 | 144 | 314 | 46 | 123 | 267 | 2.1% | ECO |
| Guy | Cretaceous Sand Lead #5 | 30 | 90 | 224 | 26 | 76 | 190 | 2.1% | ECO |
| **Subtotal Gas, Guy** | | **1,625** | **4,812** | **10,869** | **1,381** | **4,090** | **9,239** | | |
| Sharon | North Structure | 280 | 887 | 2,173 | 238 | 754 | 1,847 | 1.9% | ECO |
| Sharon | Wedge | 388 | 1,289 | 3,293 | 330 | 1,095 | 2,799 | 3.5% | ECO |
| **Subtotal Gas, Sharon** | | **668** | **2,176** | **5,466** | **568** | **1,849** | **4,646** | | |
| **Total for Gas** | | **2,698** | **7,724** | **17,610** | **2,293** | **6,565** | **14,969** | | |

*Source: Letha C. Lencioni*
*Note: "Risk Factor" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource*
*"Operator" is name of the company that operates the asset*
*"Gross" indicates 100% of the resources estimated for the blocks, while "net" indicates the share attributable to ECO's interests.*

## 5.4.3 South Africa

Unrisked Prospective Resources for the South Africa blocks are shown in Table 5-8.

### Table 5-8 Unrisked Prospective Resources, South Africa

| | | Gross | | | Net attributable to ECO's interests | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Block** | **Lead** | **Low Estimate** | **Best Estimate** | **High Estimate** | **Low Estimate** | **Best Estimate** | **High Estimate** | **Risk Factor** | **Operator** |
| **Oil & Liquids Prospective Resources (millions of barrels)** | | | | | | | | | |
| 2B | Pelargonium | 31 | 92 | 196 | 15 | 46 | 98 | 32.1% | ECO |
| 2B | Namaqualand | 114 | 191 | 306 | 57 | 96 | 153 | 37.1% | ECO |
| 2B | Gazania | 64 | 208 | 482 | 32 | 104 | 241 | 34.7% | ECO |
| **Subtotal Oil and Liquids, 2B** | | **209** | **491** | **984** | **104** | **246** | **492** | | |
| 3B/4B | Marula | 94 | 372 | 758 | 19 | 74 | 152 | 22.1% | Africa Oil |
| 3B/4B | SF-1-A | 706 | 1,919 | 4,120 | 141 | 384 | 824 | 24.9% | Africa Oil |
| 3B/4B | SF-1-B | 173 | 797 | 2,260 | 35 | 159 | 452 | 24.9% | Africa Oil |
| **Subtotal Oil and Liquids, 3B/4B** | | **973** | **3,088** | **7,138** | **195** | **618** | **1,428** | | |
| **Total for Oil & Liquids** | | **1,182** | **3,579** | **8,121** | **299** | **863** | **1,919** | | |
| **Gas Prospective Resources (billions of standard cubic feet)** | | | | | | | | | |
| 2B | Pelargonium | 5 | 14 | 30 | 2 | 7 | 15 | 32.1% | ECO |
| 2B | Namaqualand | 17 | 28 | 46 | 8 | 14 | 23 | 37.1% | ECO |
| 2B | Gazania | 10 | 31 | 73 | 5 | 15 | 36 | 34.7% | ECO |
| **Subtotal Gas, 2B** | | **31** | **73** | **149** | **15** | **37** | **74** | | |
| 3B/4B | Marula | 41 | 163 | 334 | 8 | 33 | 67 | 22.1% | Africa Oil |
| 3B/4B | SF-1-A | 309 | 846 | 1,808 | 62 | 169 | 362 | 24.9% | Africa Oil |
| 3B/4B | SF-1-B | 75 | 351 | 995 | 15 | 70 | 199 | 24.9% | Africa Oil |
| **Subtotal Gas, 3B/4B** | | **426** | **1,360** | **3,136** | **85** | **272** | **627** | | |
| **Total for Gas** | | **457** | **1,433** | **3,285** | **101** | **308** | **702** | | |

*Source: Letha C. Lencioni*
*Note: "Risk Factor" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource*
*"Operator" is name of the company that operates the asset*
*"Gross" indicates 100% of the resources estimated for the blocks, while "net" indicates the share attributable to ECO's interests.*

# 6. REFERENCES

## 6.1 FILES RELIED UPON FOR THIS REPORT

| | |
|---|---|
| Word | 2016 51-101 report Final 18Jan2017 |
| PDF | 2021-04-block2b-presentation |
| PDF | Africa Energy Corp. Form NI 51-101 Statement of reserves data filed 03.05.2021 |
| PDF | Africa Energy CPR final-client-release |
| Word | AIM2016 CP report Final 18Jan2017 |
| Excel | Azinam Parameters |
| Excel | Azinam Risk Summary |
| PowerPoint | AZINAM-Namibia Regional Syn-Rift Project |
| PowerPoint | Graphics |
| Word | Guy Block Lead Report 051412WOKsd4 |
| Excel | Guy Block Leads Parameters |
| PowerPoint | Namibia Blocks w Polys |
| Excel | namibiaBlocksSummary2022 |
| PowerPoint | Report Graphics South Africa Azinam |
| PowerPoint | Report Graphics |
| PowerPoint | Report Graphics1 |
| Excel | S Africa Risk |
| **Folder 2B4B** | |
| JPG | 3B4B Central Area |
| PDF | 3b4b Exploration Right |
| PDF | 2022 02 OCM preread |
| PDF | AEC Azinam FOA and Exhibits Feb 24 2020 |
| PDF | AziNam 3B4B Overview |
| PowerPoint | Azinam 3B34B TAC 20 May 2020v2 |
| PDF | Block 3B-4B OCM Notice Feb.2022 |
| PDF | Block 3B-4B OCM PreRead_2021.12.2 |
| JPG | Central Area AVO Summary |
| JPG | Central Area name Changes |
| Excel | SA-3B4B -Marula-Oct 2019 |
| Excel | SA-3B4B -SF-1A-Oct 2019 |
| Excel | SA-3B4B -SF-1B-Oct 2019 |
| Excel | SA-3B4B -Wolf-Oct 2019 |
| Excel | Sa-3b4b-marula-Nov19 |
| Excel | Sa-3b4b-SF1A-Nov19 |
| Excel | Sa-3b4b-SF1B-Nov19 |
| Excel | Sa-3b4b-wolf-Nov19 |
| JPG | Seismic Line |

| | |
|---|---|
| **ECO - 3B 4B 2B Slides** | |
| PDF | 2022 02 OCM preread |
| PowerPoint | Block 2B ECO Intro Jan 18 |
| PowerPoint | Block 3B-4B ECO Intro |
| **PEL 30** | |
| Excel | nam-cooper-Campanian Fan-apr16 |
| Excel | nam-cooper-Fan2-sept18 |
| Excel | nam-cooper-Fan3-sept18 |
| Excel | nam-cooper-Osprey-sept18 |
| Excel | nam-cooper-Santonian Fan-apr16 |
| **PEL33** | |
| Excel | nam-PEL33-111-Albian-Wedge-apr16 |
| Excel | nam-PEL33-nstructure-apr14 |
| **PEL 34** | |
| Excel | nam-PEL34-A1-Jun17 |
| Excel | nam-PEL34-A2-Jun17 |
| Excel | nam-PEL34-Aptian-Wedge-Jun17 |
| Excel | nam-PEL34-B1-Jun17 |
| Excel | nam-PEL34-B2-Jun17 |
| Excel | nam-PEL34-B3-Jun17 |
| Excel | nam-PEL34-B4-Jun17 |
| Excel | nam-PEL34-C2-Jun17 |
| Excel | nam-PEL34-Carbonate-Platform-apr16 |
| Excel | nam-PEL34-D1-Jun17 |
| Excel | nam-PEL34-D2-Jun17 |
| Excel | nam-PEL34-E1-Jun17 |
| Excel | nam-PEL34-Louw-Leads Nov14 |
| Excel | nam-PEL34-Mugatroyd-Channel-apr16 |
| Excel | nam-PEL34-Prospect C1-Sept18 |
| Excel | nam-PEL34-Stepanus-Deep-apr16 |
| Excel | nam-PEL34-Stephanus-Shallow Nov14 |
| **SA Block 2B** | |
| **Folder 2B4B** | **Operator documents AJ-1** |
| PDF | 02 AJ1 Complog |
| JPG | 02 AJ1 CPI |
| PDF | 02 AJ1 Cutting Gas Analysis |
| PDF | 02 AJ1 DST Analysis (1) |
| PDF | 02 AJ1 DST Analysis |
| PDF | 02 AJ1 EOW Report |
| PDF | 02 AJ1 Fluid Inclusion Study |

| Folder REPORTS PRESENTATIONS | BASIN MODELING GEOCHEM |
|---|---|
| TIF | 1988 AJ-1 CUTTINGS GAS ANALYSIS |
| TIF | 1988 AJ1 SOURCE ROCK SUMMAR |
| PDF | 1991 AJ1 FLUID INCLUSION STUDY AMOCO |
| PDF | 1994 AJ1 GEOCHEM SOEKOR |
| PowerPoint | 2008 AJ1 EXPLUSION MODEL |
| PowerPoint | 2015 Maturity Profile TOTAL |
| PowerPoint | 2015 Optical Study TOTAL |
| PDF | A-J1 GEOCHEMICAL DATA (Chevron)POF10200 |
| | **RESERVOIR** |
| PowerPoint | 2014 RESERVOIR STUDY AFREN |
| PowerPoint | 2018 AJ GRABEN Sedimentary fairways mapping |
| | **TECHNICAL EVALUATIONS** |
| **FOLDER** | **2008 TCP Final Report** |
| PDF | 2008 Block 2B Final Technical Report |
| PDF | 2008 Block 2B Final Technical Report-Appendix 1 |
| PDF | 2008 Block 2B Final Technical Report-Appendix 2 |
| PDF | 2008 FINAL TECHNICAL REPORT OF TCP |
| PDF | Thombo - Simco Summary, Block 2B |
| | **INDIVIDUAL FILES UNDER TECHNICAL EVALUATIONS** |
| PDF | Block 2B Exploration Right, Initial Period Results, 2011-2014 |
| PDF | BURDEN_New Ideas applied to A-J Rift Graben |

## 6.2 OTHER REFERENCES


Bihariesingh, Vinita, 2014, Is the Cretaceous an Effective Petroleum system Offshore Suriname? : AAPG Search and Discovery Article #30355, 19 p.

Dennison, Newell M., 2017, A Brief Account of Features Typical of the Offshore Guyana & Takutu Basins: http://www.goga.gy/sites/default/files/Petroleum%20Geology%20Offshore%20Guyana%20-%20Newell%20Dennison.pdf

Dunnahoe, Tayvis, 2016, ExxonMobil confirms oil discovery in sector well offshore Guyana: http://www.ogj.com/articles/2016/06/exxonmobil-confirms-oil-discovery-in-second-well-offshore-guyana.html

ECO Oil & Gas LTD., http://www.ecooilandgas.com/ As of February 18, 2018.

Erbacher, J., Mosher, D.C., Malone, M.J., et al., 2004, Proceedings of the Ocean Drilling Program, Initial Reports Volume 207

Fessler, David, 2011, Three Ways to Profit from the Oil Market's 'New World Order': Peak Energy Strategist, February 18, 2011, http://peakenergystrategist.com/archives/tag/santos-basin/, Accessed June 15, 2011.

Ginger, D., Burial and Thermal Geohistory Modeling of the Offshore Guyana Basin, Lasmo International Limited, Western Division, 67 p., 1990.

Magoon, L.B., 1988, The Petroleum System: A Classification Scheme for Research 1 Exploration and Resource Assessment, *in* L. B. Magoon , ed., Petroleum Systems of the United States: U.S. Geological Survey Bulletin 1870, pages 2-15.

Marsili, M. D. et al.; May 2015, Atlanta Field: Developing Heavy and Viscous Oil in a Challenging Environment

Schwarzer, Danny, and Helle Krabbe, 2009, Source Rock Geochemistry and Petroleum System Modeling in the Guyana Basin, offshore Suriname: AAPG Search and Discovery *Article #90091* .http://www.searchanddiscovery.com/abstracts/html/2009/hedberg/abstracts/extended/schwarzer/schwarzer.htm

R. G. Santos1*, W. Loh2, A. C. Bannwart3 and O. V. Trevisan3, *May 2, 2013, AN OVERVIEW OF HEAVY OIL PROPERTIES AND ITS RECOVERY AND TRANSPORTATION METHODS, Brazilian Journal of Chemical Engineering, Vol. 31, No. 03, pp. 571 - 590, July - September, 2014*

World Oil, 2015, ExxonMobil's deepwater Liza find could put Guyana-Suriname basin on the map: http://www.worldoil.com/news/2015/10/22/exxon-mobil-s-deepwater-liza-find-could-put-guyana-suriname-basin-on-the-map

Bihariesingh, Vinita, 2014, Is the Cretaceous an Effective Petroleum system Offshore Suriname? : AAPG Search and Discovery Article #30355, 19 p.

Bray, Richard, Steve Lawrence, and Roger Swart, 1998, Source Rock, Maturity Date Indicate Potential off Namibia: Oil and Gas Journal, August 1998.

Dunnahoe, Tayvis, 2016, ExxonMobil confirms oil discovery in sector well offshore Guyana: http://www.ogj.com/articles/2016/06/exxonmobil-confirms-oil-discovery-in-second-well-offshore-guyana.html

ECO Oil & Gas, LTD., http://www.ecooilandgas.com/ As of February 18, 2014.

Erbacher, J., Mosher, D.C., Malone, M.J., et al., 2004, Proceedings of the Ocean Drilling Program, Initial Reports Volume 207

Fessler, David, 2011, Three Ways to Profit from the Oil Market's 'New World Order': Peak Energy Strategist, February 18, 2011, http://peakenergystrategist.com/archives/tag/santos-basin/, Accessed June 15, 2011.

Ginger, D., Burial and Thermal Geohistory Modeling of the Offshore Guyana Basin, Lasmo International Limited, Western Division, 67 p., 1990.

Magoon, L.B., 1988, The Petroleum System: A Classification Scheme for Research 1 Exploration and Resource Assessment, *in* L. B. Magoon , ed., Petroleum Systems of the United States: U.S. Geological Survey Bulletin 1870, pages 2-15.

Norsk Hydro, 1995, Conventional Core Analysis Well: 1911/10-1 Field: Norsk Hydro 1911/10, August 1995

Norsk Hydro Namibia, 1994, Well: 1911/15-1 Conventional Core Analysis: Norsk Hydro Namibia AS Conventional Core Analysis February 1994.

Norsk Hydro Namibia, 1995, Final Well Report Well 1911/10-1: 1911 10-1 Norsk Hydro as Final Well Report, Well PL001 Namibia December 1995.

Norsk Hydro Namibia, Final Well Report Well 1911/15-1: FINAL WELL REPORT, LICENSE 001, NAMIBIA.

Petroleum Geo-Services (PGS), 2013; Cooper Block 2012A (Offshore Namibia) Prospectivity Study: PGS, November 2013

Petroleum Agreement Between The Government of the Republic of Namibia and ECO Oil & Gas Namibia (PTY) LTD, February 2011, DEN-23066-2-Petroleum 2012A.

Republic of Namibia, Ministry of Mines, 2011, Petroleum Exploration Licence, Licence No. 0030, 14 March 2011, 2012 A COOPER LIC.

Sasol Petroleum Namibia, 1996, Final Well Report Well 2012/13-1: Sasol Petroleum, July 1996

Schwarzer, Danny, and Helle Krabbe, 2009, Source Rock Geochemistry and Petroleum System Modeling in the Guyana Basin, offshore Suriname: AAPG Search and Discovery *Article #90091* .http://www.searchanddiscovery.com/abstracts/html/2009/hedberg/abstracts/extended/schwarzer/schwarzer.htm

Shell, 1997, Licence 007, Areas 2313A&B: 2313/5-1 (Shark) Well Proposal: Shell Namibia Exploration B.V., November 1997.

Swart, Roger, 2006, Namibia – Current Developments: NAMCOR Ltd., Oil Africa 2006, Cape Town, March 23, 2006.

Trek International Safaris, Inc., 2008, http://www.treksafaris.com/namibia,category.asp, Accessed June 20, 2011.

UFRJ and Gustavson Associates, 1999, Santos Basin Report for Brazil Round 1:

World Oil, 2015, Exxon Mobil's deepwater Liza find could put Guyana-Suriname basin on the map: http://www.worldoil.com/news/2015/10/22/exxon-mobil-s-deepwater-liza-find-could-put-guyana-suriname-basin-on-the-map

## 7. CERTIFICATE OF QUALIFICATION

I, Letha Lencioni, Professional Engineer of 5665 Flatiron Pkwy, Suite 250, Boulder, Colorado, 80301, USA, hereby certify:

1. I am an employee of WSP USA Inc., and am not a sole practioner
2. I do not have, nor do I expect to receive, any direct or indirect interest in the securities of ECO (Atlantic) Oil & Gas Ltd. or their affiliated companies, nor any interest in the subject property. I am not being compensated by any fee linked to admission or value of the applicant.
3. I attended the University of Tulsa and I graduated with a Bachelor of Science Degree in Petroleum Engineering in 1980; I am a Registered Professional Engineer in the State of Colorado, and I have in excess of 40 years' experience in the estimation, assessment, and evaluation of discovered and undiscovered oil and gas fields.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary because all material information was available from public information and records, and the files of ECO (Atlantic) Oil & Gas Ltd.
5. I have reviewed the information contained in the Competent Persons Report for Certain Assets in Offshore Guyana, Offshore Namibia, and Offshore South Africa with the effective date of 20 March 2022.

**Prepared By:**

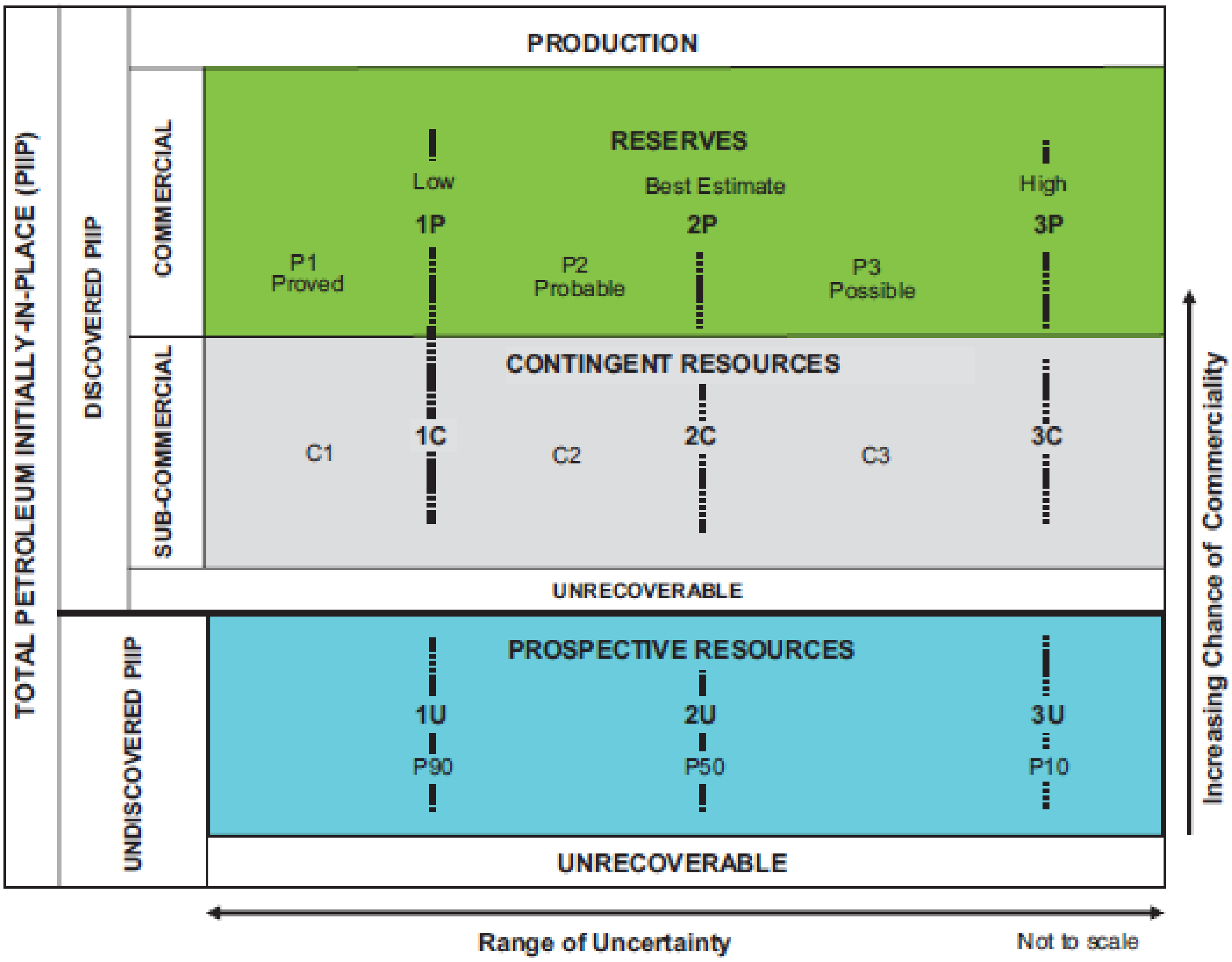
COLORADO REGISTERED LETHA CHAPMAN LENCIONI 29506 PROFESSIONAL ENGINEER

**Letha C. Lencioni**
**Registered Petroleum Engineer**
**Colorado Registered Engineer #29506**

# Appendix A

# Glossary of Terms and Abbreviations

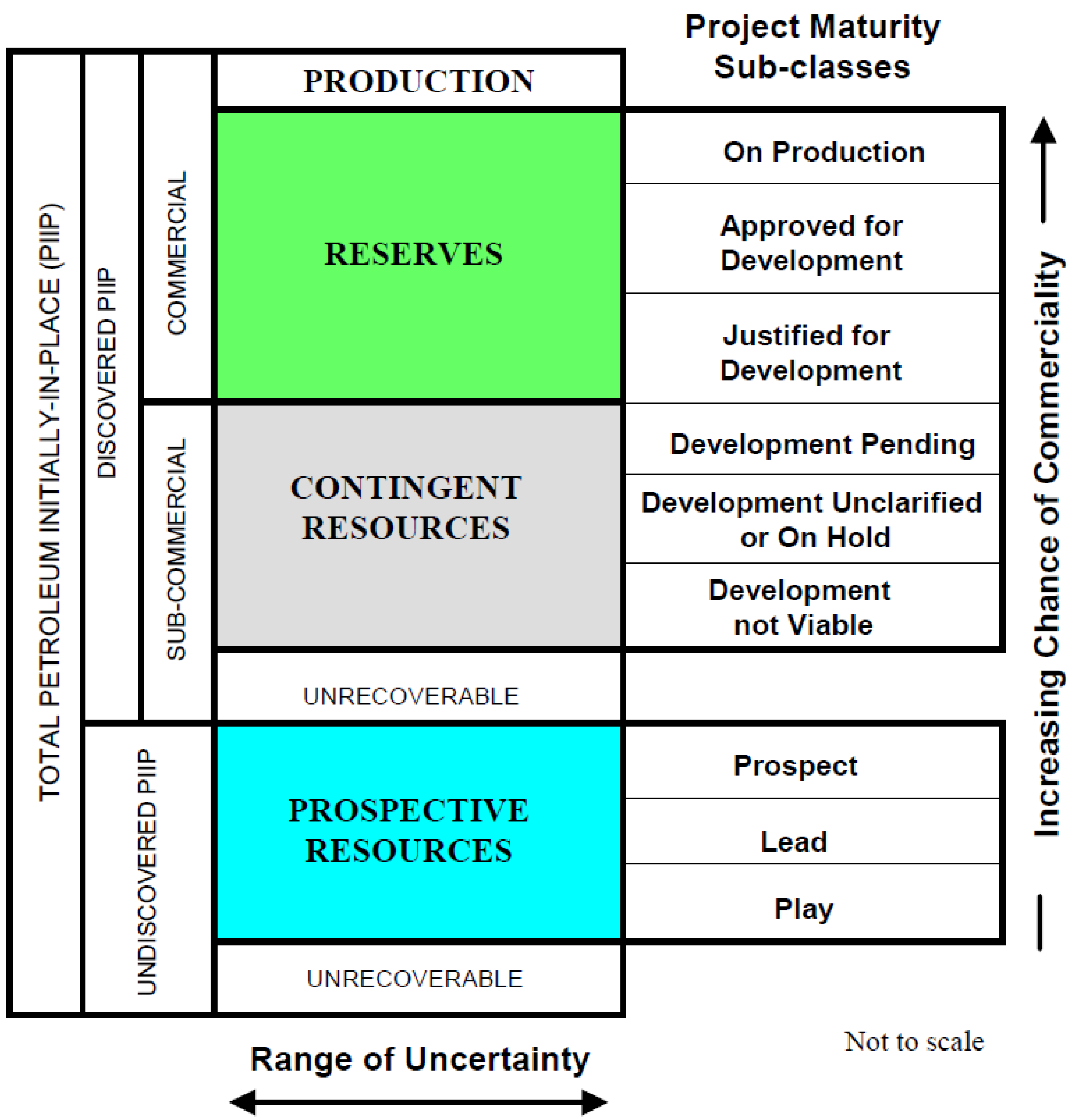
The following are select terms or phrases as defined by Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), and Society of Petroleum Evaluation Engineers (SPEE) in Petroleum Resources Management System, revised 2018, see figures below. Note that these figures and definitions are consistent with the figures and definitions provided in the COGEH[23]: the PRMS versions are reproduced here due to their completeness.




**Resources Classification Framework**

---

[23] Canadian Oil and Gas Evaluation Handbook as referenced earlier in this report.




**Sub-Classes based on Project Maturity**

An **Accumulation** is an individual body of naturally occurring petroleum in a reservoir.

**Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

**Conventional Resources** exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.

**Developed Reserves** are expected quantities to be recovered from existing wells and facilities.

**Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of estimate.

**Developed Non-Producing Reserves** include shut-in and behind-pipe Reserves.

**Estimated Ultimate Recovery (EUR)** are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

A **Lead** is a project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

**Low/Best/High Estimates** are the range of uncertainty that reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project.

A **Play** is a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

A **Pool** is an individual and separate accumulation of petroleum in a reservoir.

**Possible Reserves** are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable that Probable Reserves.

**Probable Reserves** are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

**Probabilistic Method** is the method of estimation used when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.

A **Prospect** is a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

**Prospective Resources** are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

**Proved Reserves** are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

**Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

**Unconventional Resources** exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called "continuous-type deposits"). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility. Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

**Undeveloped Reserves** are quantities expected to be recovered through future investments.

The following are abbreviations and definitions for common petroleum terms.

| | |
|---|---|
| $10^3 m^3$ | thousands of cubic meters |
| AVO | amplitude versus offset |
| Bbl, Bbls | barrel, barrels |
| BCF | billions of cubic feet |
| BCM | billions of cubic meters |
| $B_g$ | gas formation volume factor |
| BHT | bottom hole temperature |
| BHP | bottom hole pressure |
| $B_o$ | oil formation volume factor |
| BOE | barrels of oil equivalent |
| BOPD | barrels of oil per day |
| BPD | barrels per day |
| Btu | British thermal units |
| BV | bulk volume |
| CNG | compressed natural gas |
| $CO_2$ | carbon dioxide |
| DHI | direct hydrocarbon indicators |
| DHC | dry hole cost |
| DST | drill-stem test |
| E & P | exploration and production |
| EOR | enhanced oil recovery |
| EUR | estimated ultimate recovery |
| ft | feet |
| $ft^2$ | square feet |
| FVF | formation volume factor |
| G & A | general and administrative |
| G & G | geological and geophysical |
| $g/cm^3$ | grams per cubic centimeter |
| Ga | billion ($10^9$) years |
| GIIP | gas initially in place |
| GOC | gas-oil contact |
| GOR | gas-oil ratio |
| GR | gamma ray (log) |
| GRV | gross rock volume |
| GWC | gas-water contact |
| ha | hectare |
| Hz | hertz |
| IDC | intangible drilling cost |
| IOR | improved oil recovery |
| IRR | internal rate of return |
| J & A | junked and abandoned |
| km | kilometers |
| $km^2$ | square kilometers |
| LoF | life of field |

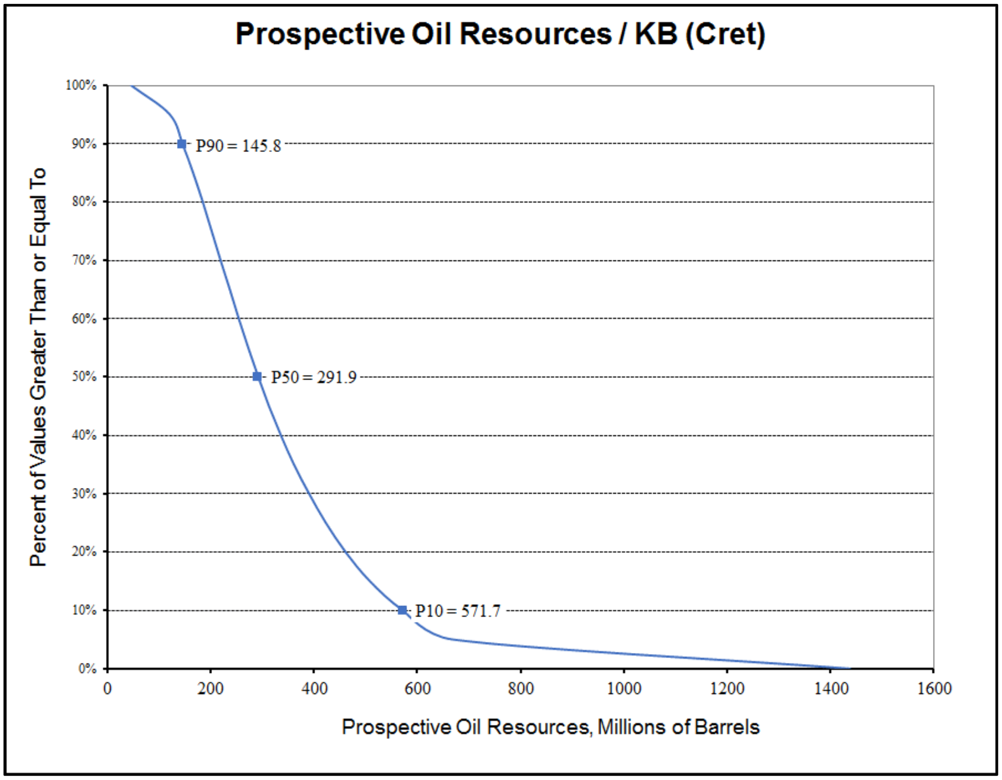
| | |
|---|---|
| M & A | mergers and acquisitions |
| m | meters |
| M | thousands |
| MM | million |
| $m^3$/day | cubic meters per day |
| Ma | million years (before present) |
| max | maximum |
| MBOPD | thousand barrels of oil per day |
| MCFD | thousand cubic feet per day |
| MCFGD | thousand cubic feet of gas per day |
| MD | measured depth |
| mD | millidarcies |
| MDSS | measured depth subsea |
| min | minimum |
| ML | most likely |
| MMBO | million barrels of oil |
| MMBOE | million barrels of oil equivalent |
| MMBOPD | million barrels of oil per day |
| MMCFGD | million cubic feet of gas per day |
| MMTOE | million tons of oil equivalent |
| mSS | meters subsea |
| NGL | natural gas liquids |
| NPV | net present value |
| NTG | net-to-gross ratio |
| OGIP | original gas in place |
| OOIP | original oil in place |
| OWC | oil-water contact |
| P10 | high estimate |
| P50 | best estimate |
| P90 | low estimate |
| P & A | plugged and abandoned |
| ppm | parts per million |
| PRMS | Petroleum Resources Management System |
| PSDM | Pre-Stack Depth Migrated Seismic Data |
| PSTM | Pre-Stack Time Migrated Seismic Data |
| psi | pounds per square inch |
| RB | reservoir barrels |
| RCF | reservoir cubic feet |
| RF | recovery factor |
| ROI | return on investment |
| ROP | rate of penetration |
| SCF | standard cubic feet |
| SS | subsea |
| STB | stock tank barrel |
| STOIIP | stock tank oil initially in place |
| $S_g$ | gas saturation |

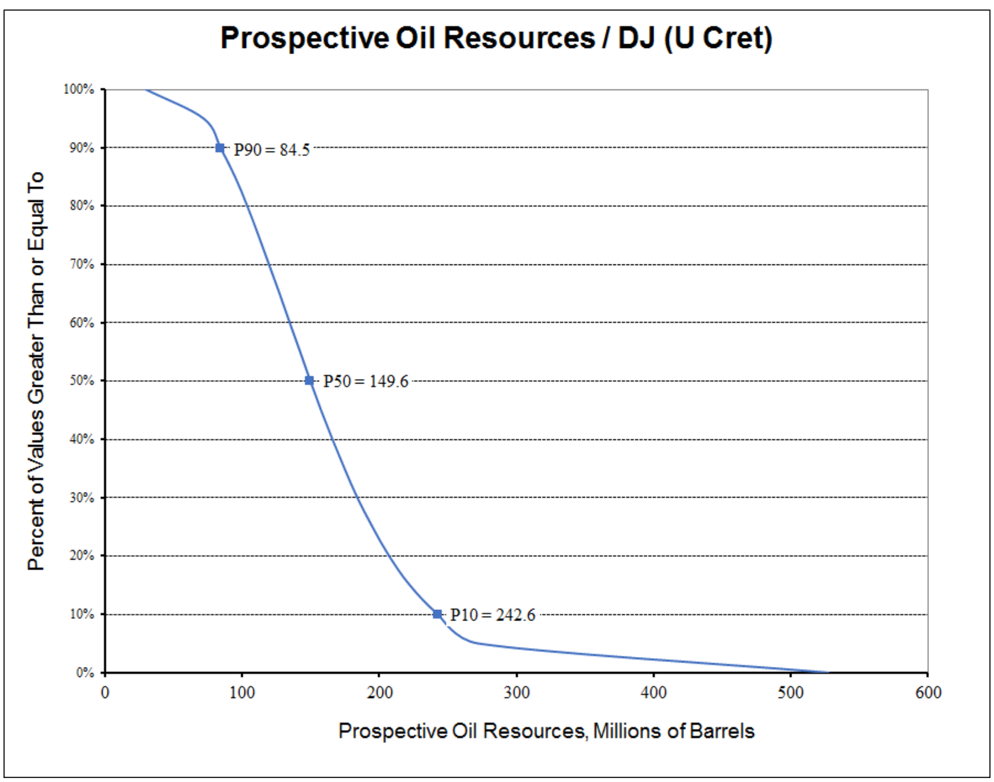
| | |
|---|---|
| $S_o$ | oil saturation |
| $S_w$ | water saturation |
| TCF | trillion cubic feet |
| TD | total depth |
| TDC | tangible drilling cost |
| TVD | true vertical depth |
| TVDSS | true vertical depth subsea |
| TWT | two-way time |
| US$ | US dollar |

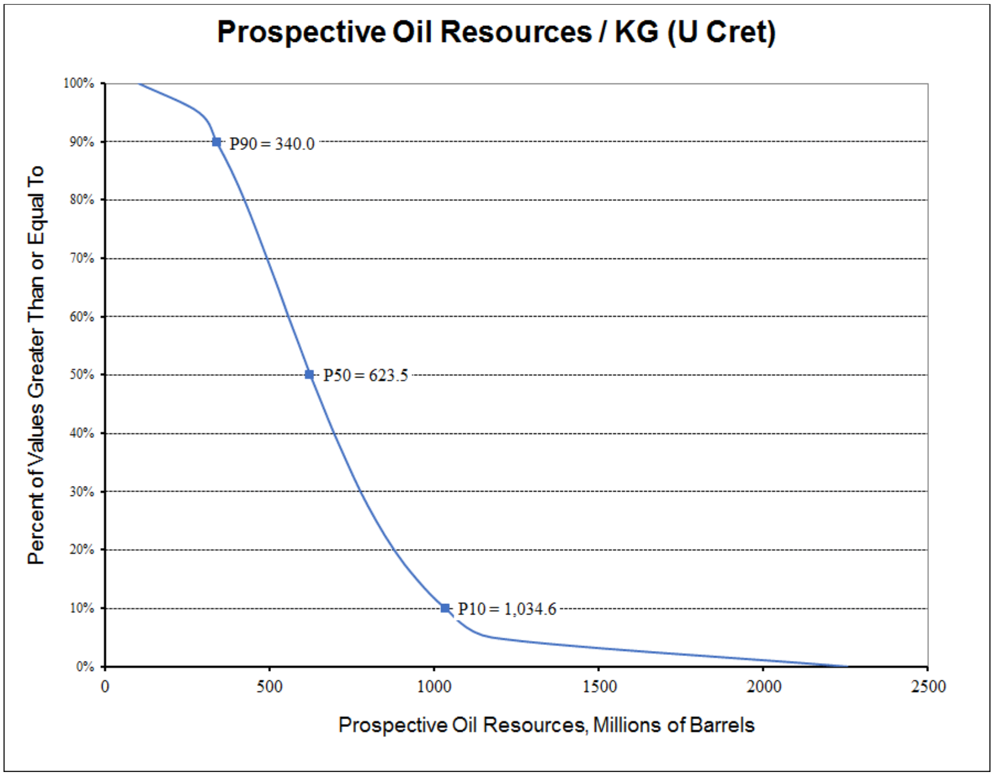
# Appendix B

# Resource Distribution Graphs

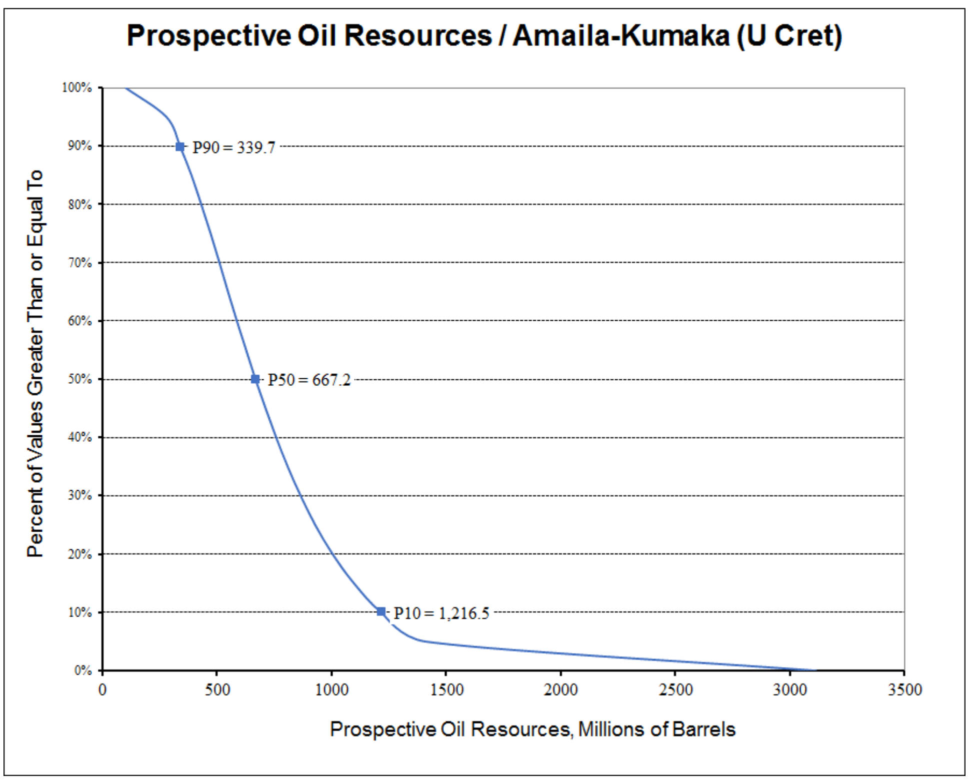
# Orinduik Block



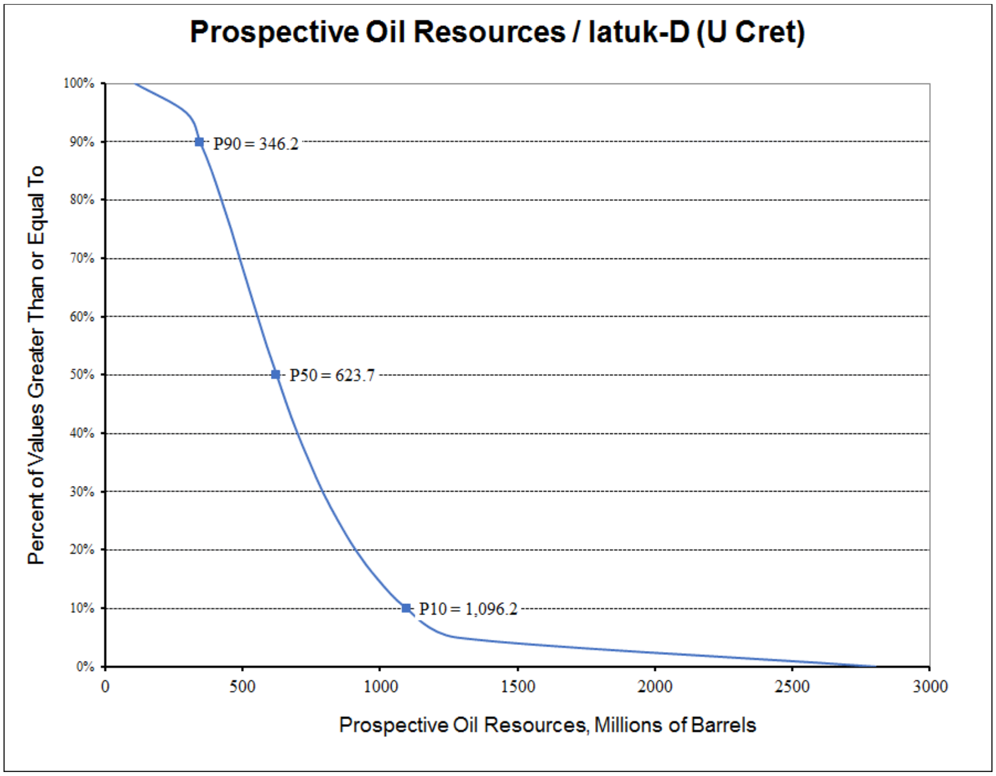



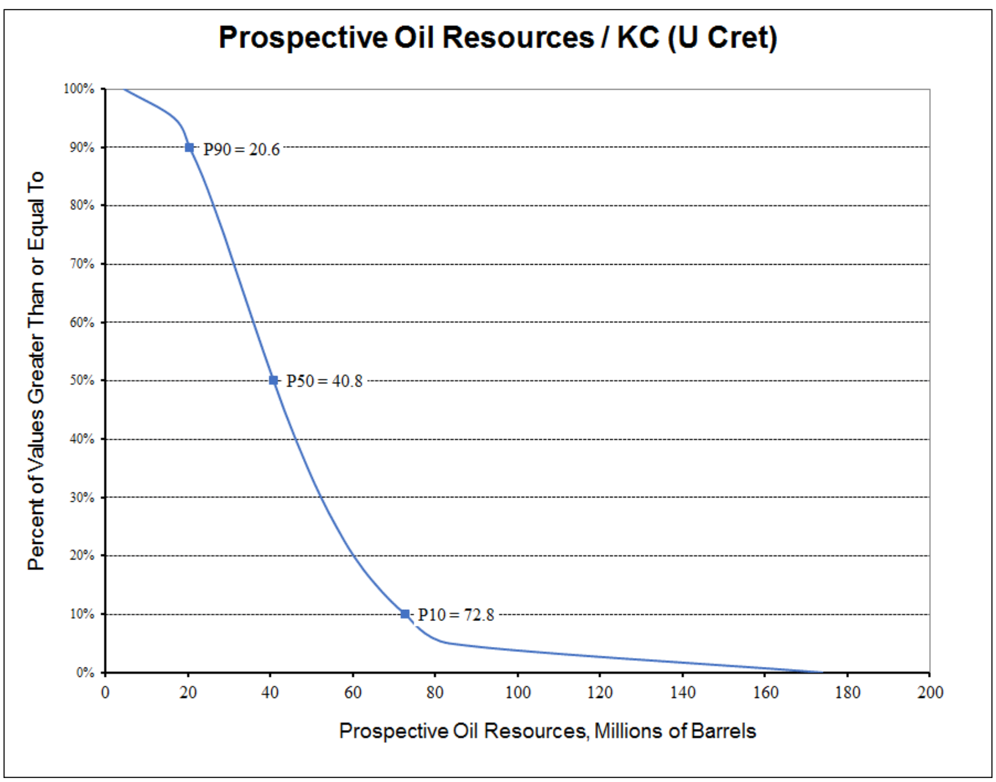


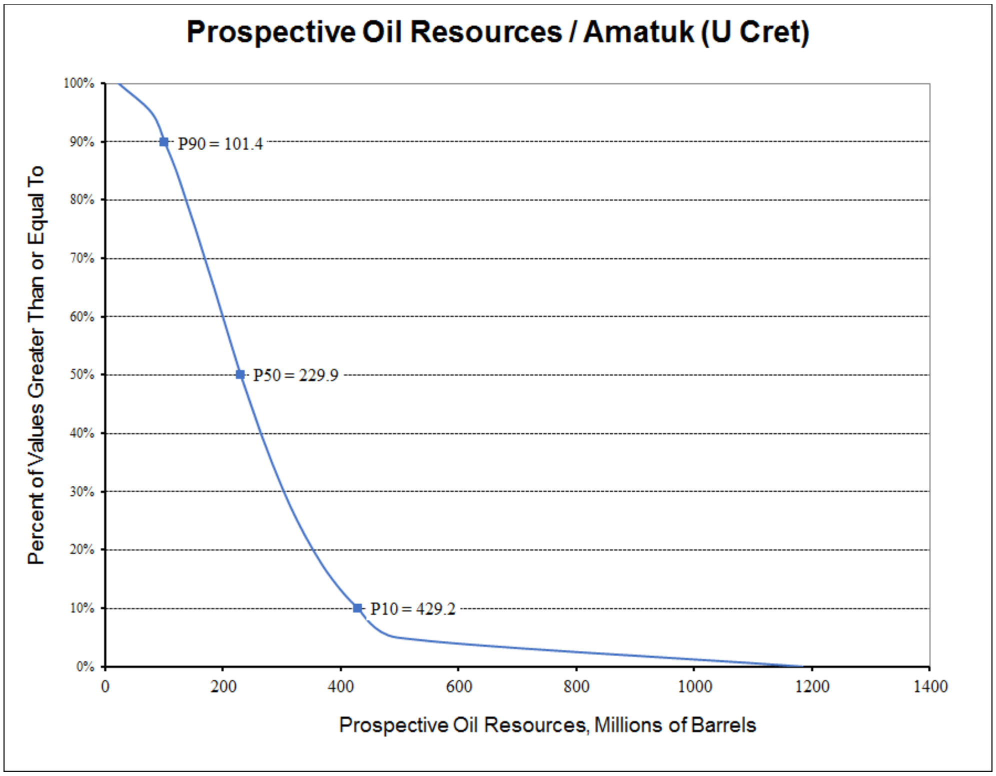
Prospective Oil Resources / KG (U Cret)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 340.0
P50 = 623.5
P10 = 1,034.6
0
500
1000
1500
2000
2500
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels

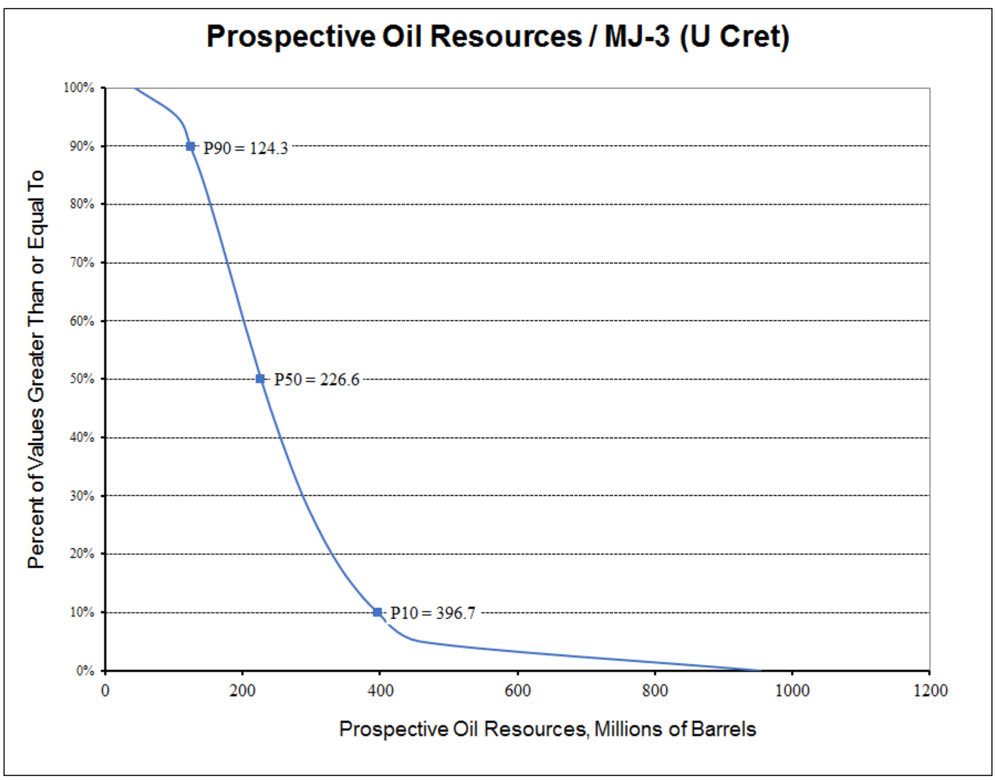



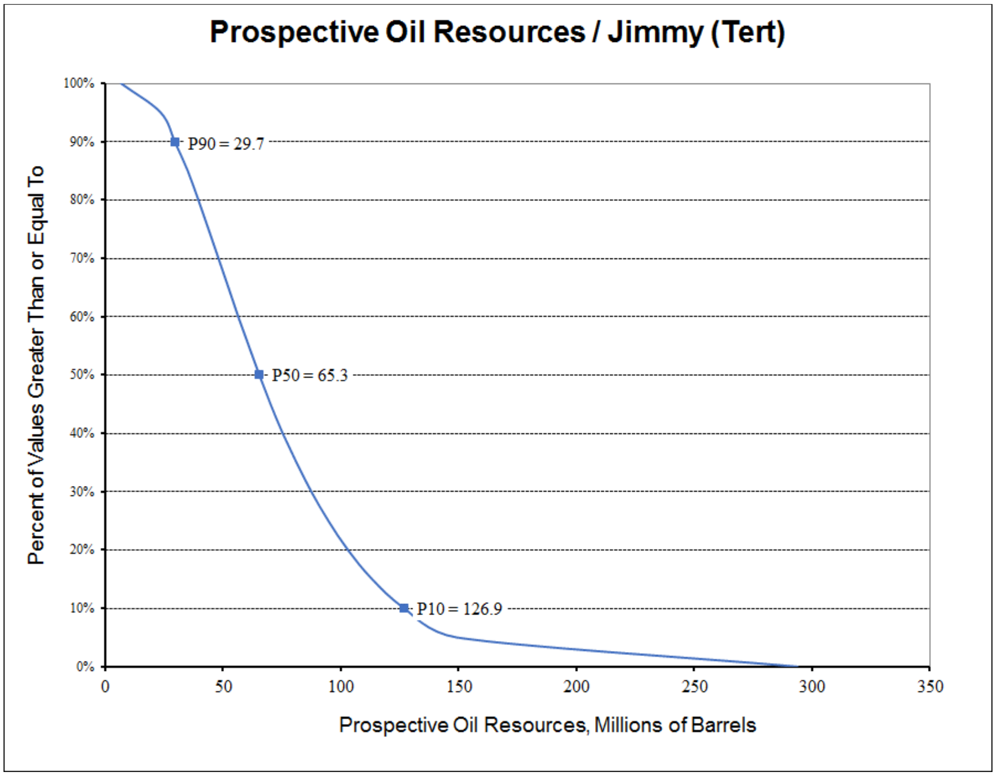
Prospective Oil Resources / Amaila-Kumaka (U Cret)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 339.7
P50 = 667.2
P10 = 1,216.5
0
500
1000
1500
2000
2500
3000
3500
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels

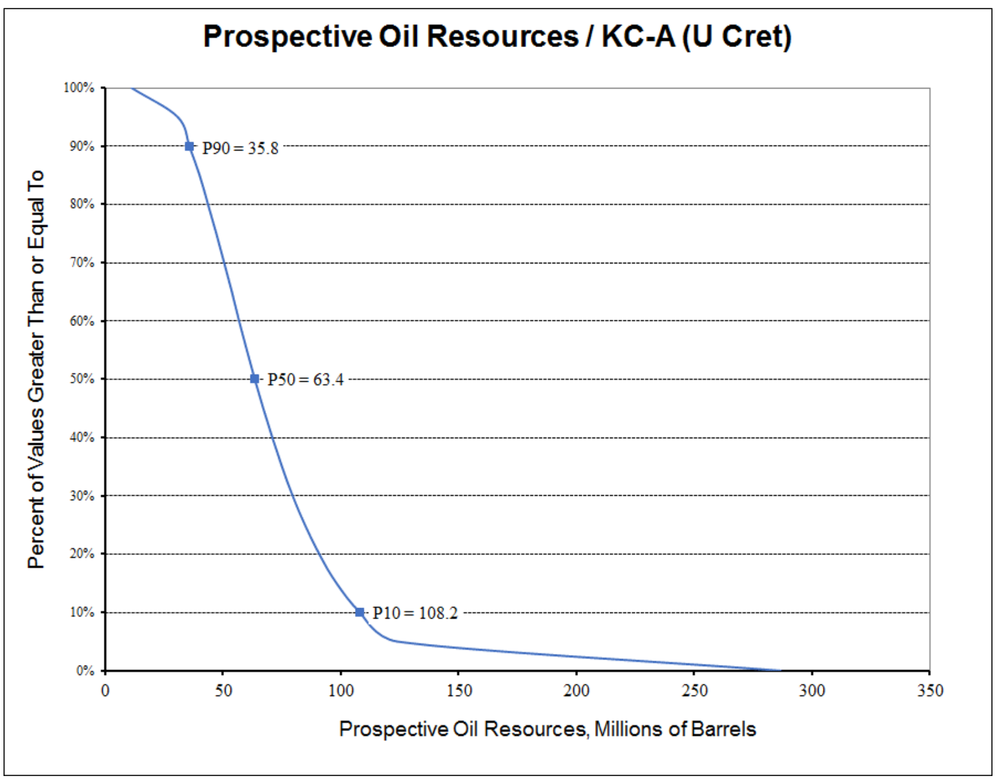

Prospective Oil Resources / Iatuk-D (U Cret)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 346.2
P50 = 623.7
P10 = 1,096.2
0
500
1000
1500
2000
2500
3000
Prospective Oil Resources, Millions of Barrels

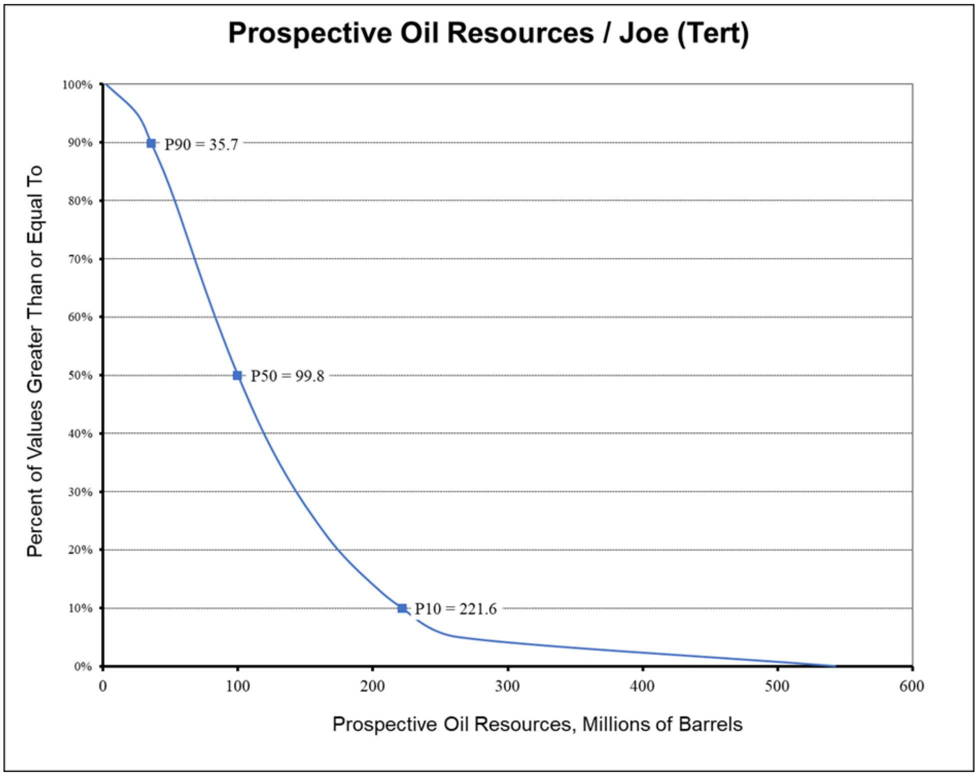

Prospective Oil Resources / KC (U Cret)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 20.6
P50 = 40.8
P10 = 72.8
0
20
40
60
80
100
120
140
160
180
200
Prospective Oil Resources, Millions of Barrels

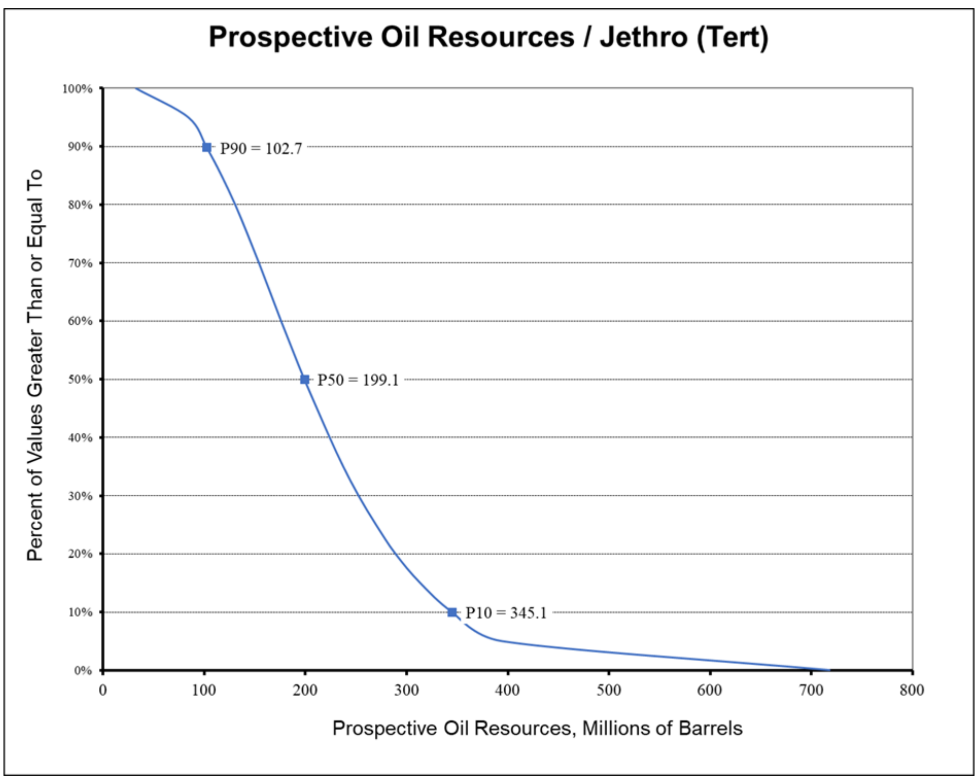

Prospective Oil Resources / Amatuk (U Cret)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 101.4
P50 = 229.9
P10 = 429.2
0
200
400
600
800
1000
1200
1400
Prospective Oil Resources, Millions of Barrels

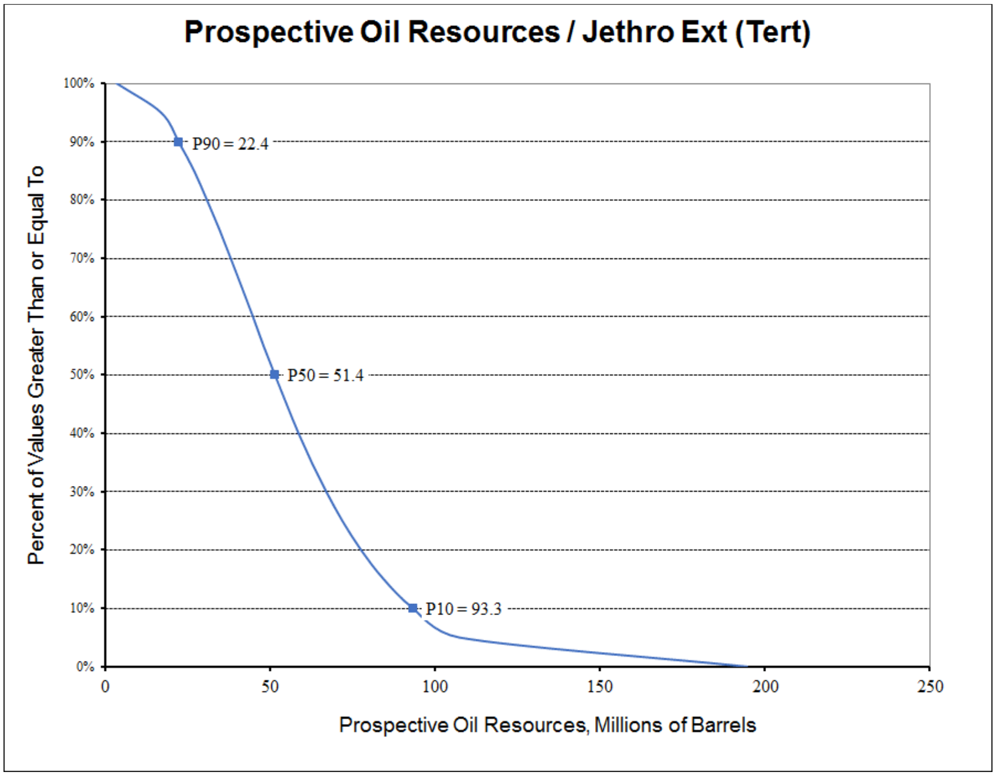

Prospective Oil Resources / MJ-3 (U Cret)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 124.3
P50 = 226.6
P10 = 396.7
0
200
400
600
800
1000
1200
Prospective Oil Resources, Millions of Barrels

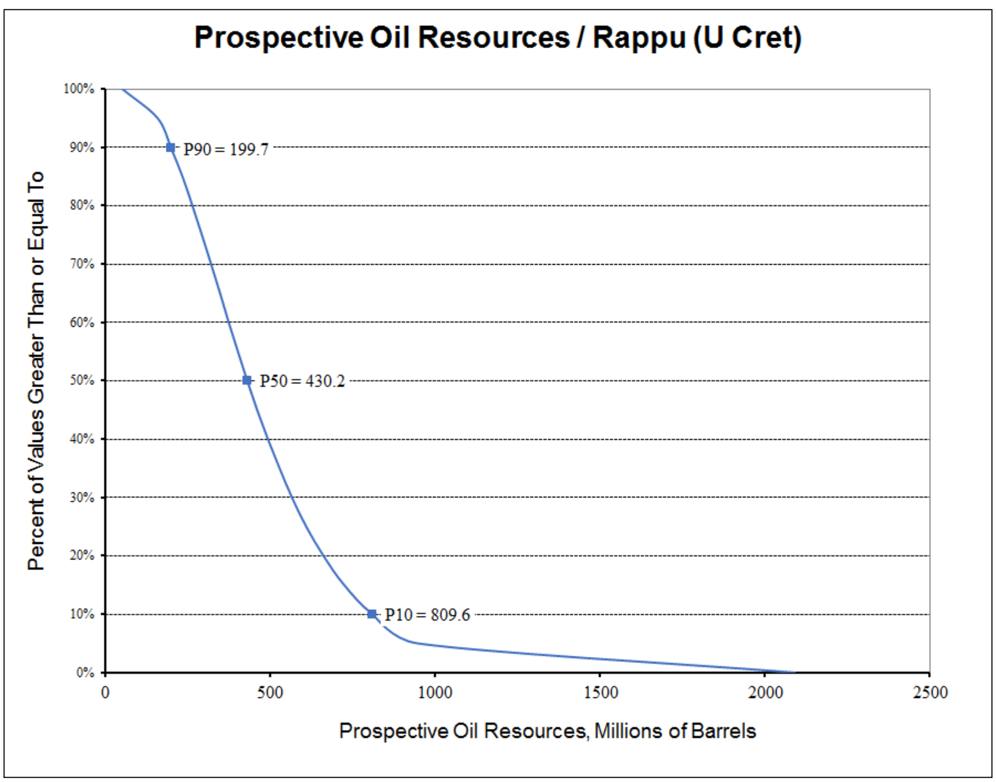

Prospective Oil Resources / Jimmy (Tert)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 29.7
P50 = 65.3
P10 = 126.9
0
50
100
150
200
250
300
350
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels

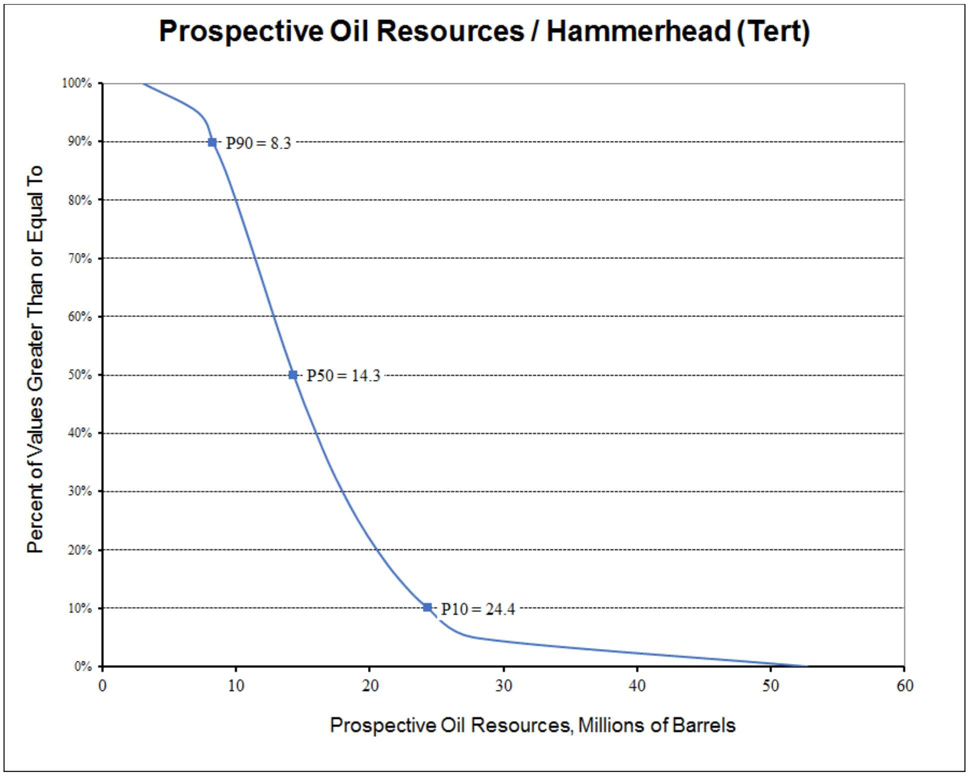

Prospective Oil Resources / KC-A (U Cret)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 35.8
P50 = 63.4
P10 = 108.2
0
50
100
150
200
250
300
350
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels


Prospective Oil Resources / Joe (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 35.7
P50 = 99.8
P10 = 221.6
0
100
200
300
400
500
600
Prospective Oil Resources, Millions of Barrels

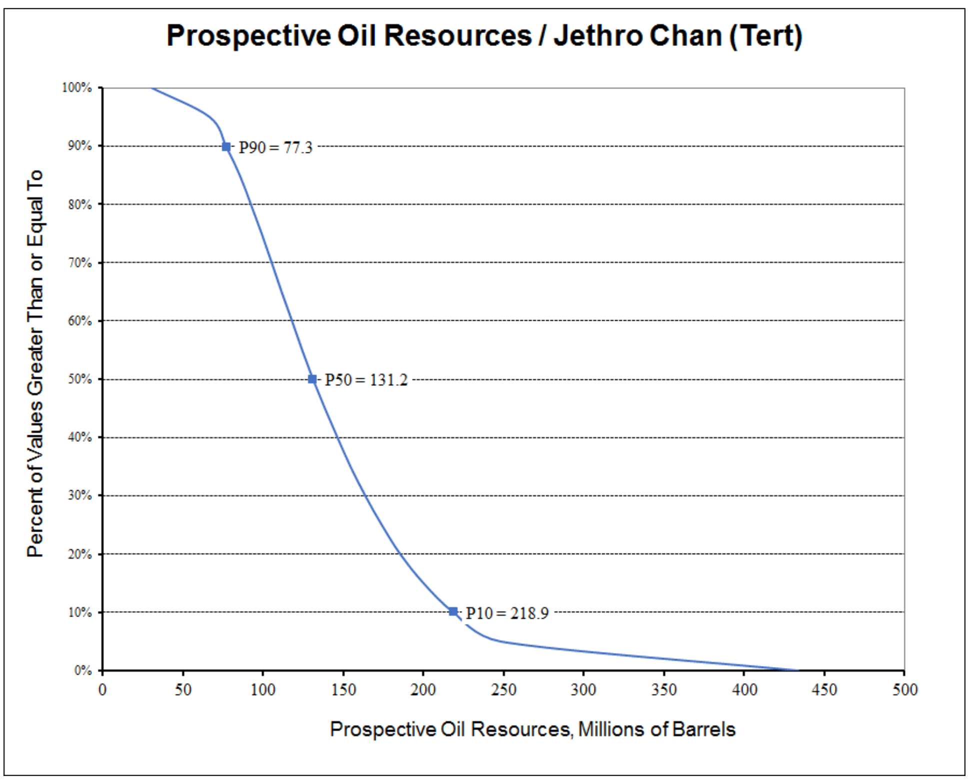

Prospective Oil Resources / Jethro (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 102.7
P50 = 199.1
P10 = 345.1
0
100
200
300
400
500
600
700
800
Prospective Oil Resources, Millions of Barrels


Prospective Oil Resources / Jethro Ext (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 22.4
P50 = 51.4
P10 = 93.3
0
50
100
150
200
250
Prospective Oil Resources, Millions of Barrels

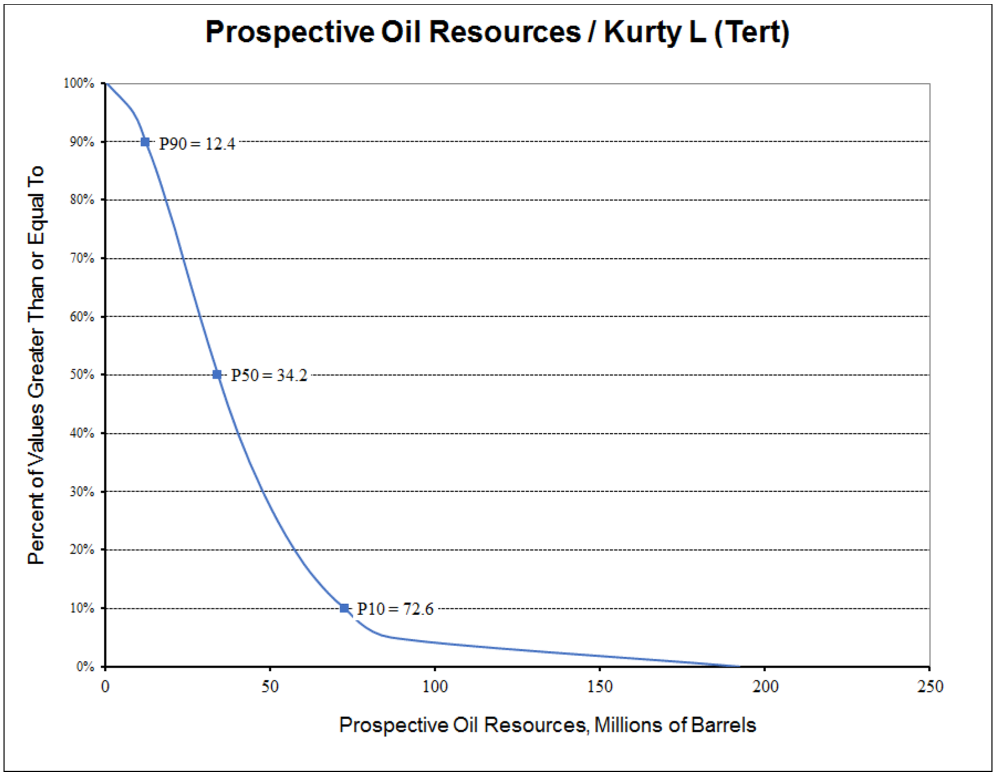

Prospective Oil Resources / Rappu (U Cret)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 199.7
P50 = 430.2
P10 = 809.6
0
500
1000
1500
2000
2500
Prospective Oil Resources, Millions of Barrels

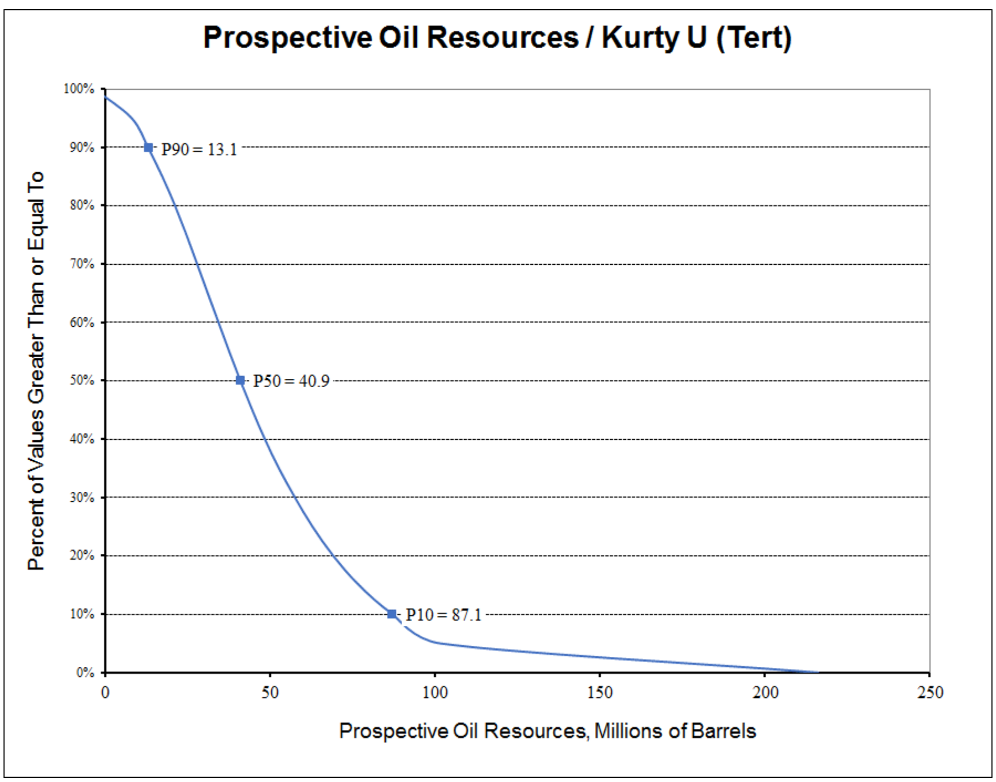


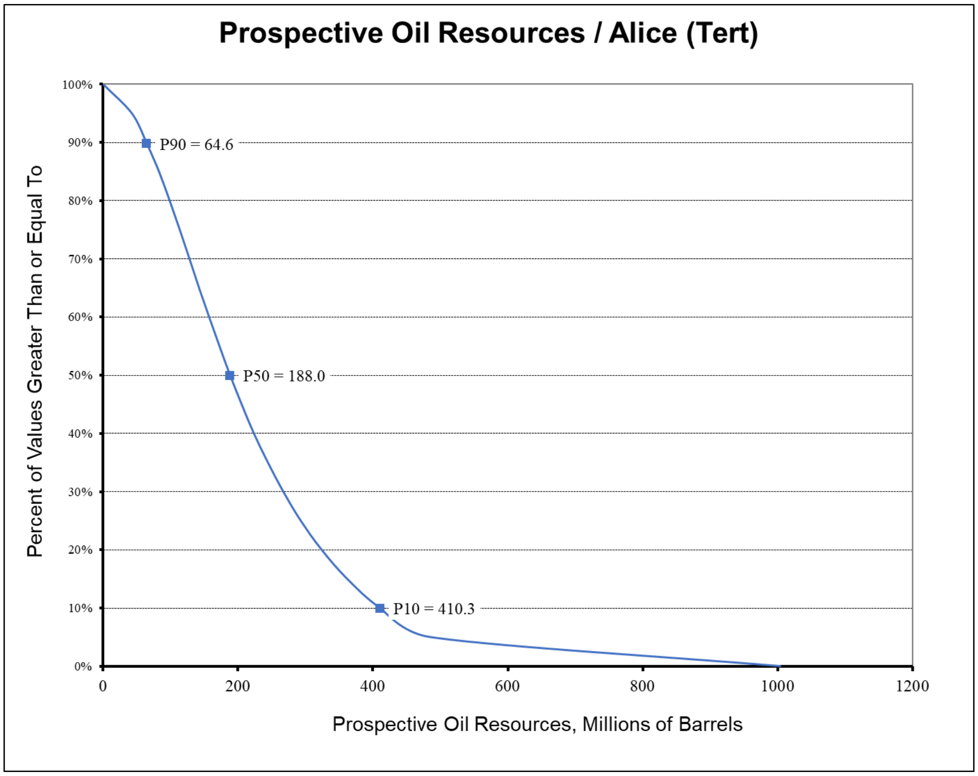
Prospective Oil Resources / Hammerhead (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 8.3
P50 = 14.3
P10 = 24.4
0
10
20
30
40
50
60
Prospective Oil Resources, Millions of Barrels

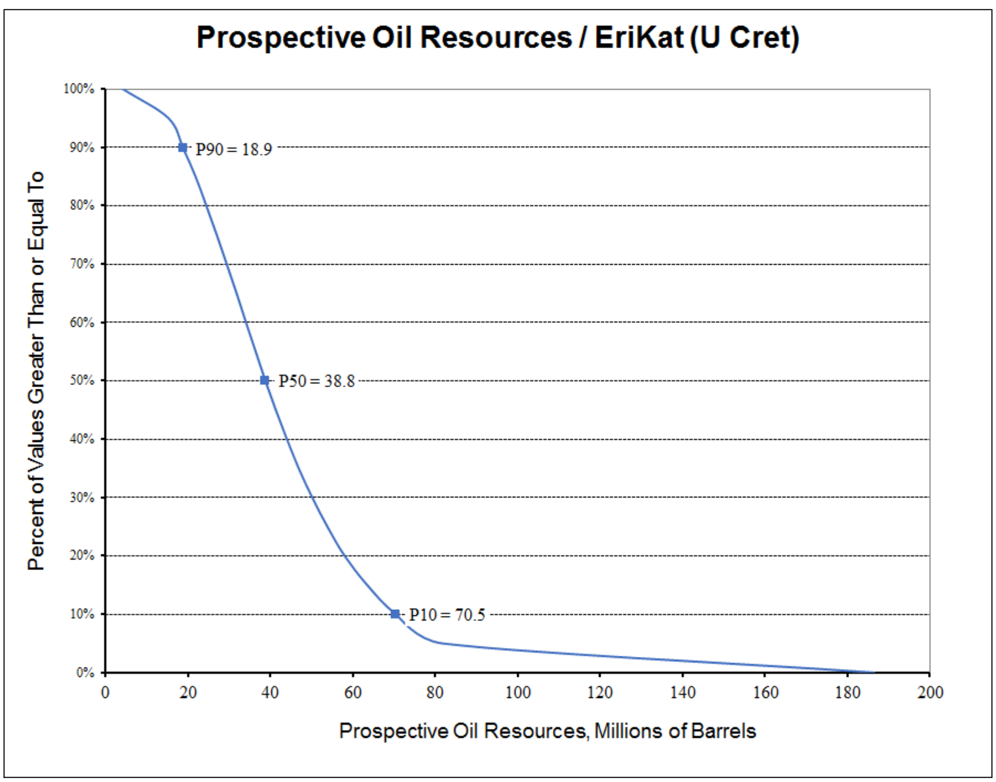
Prospective Oil Resources / Jethro Chan (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 77.3
P50 = 131.2
P10 = 218.9
0
50
100
150
200
250
300
350
400
450
500
Prospective Oil Resources, Millions of Barrels


Prospective Oil Resources / Kurty L (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 12.4
P50 = 34.2
P10 = 72.6
0
50
100
150
200
250
Prospective Oil Resources, Millions of Barrels

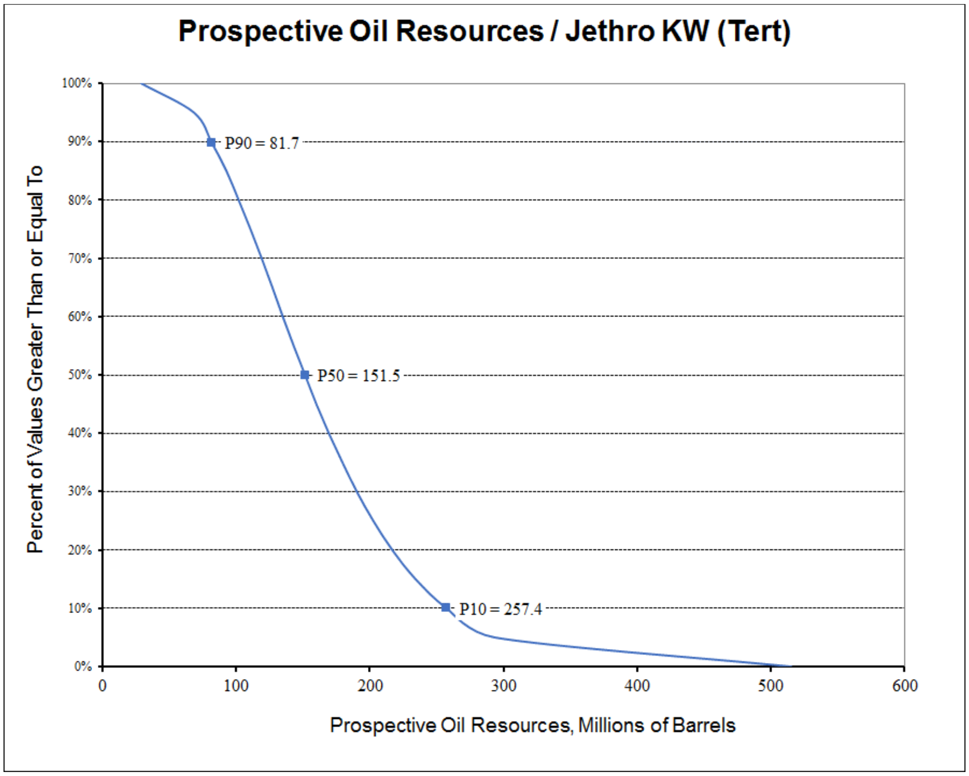

Prospective Oil Resources / Kurty U (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 13.1
P50 = 40.9
P10 = 87.1
0
50
100
150
200
250
Prospective Oil Resources, Millions of Barrels



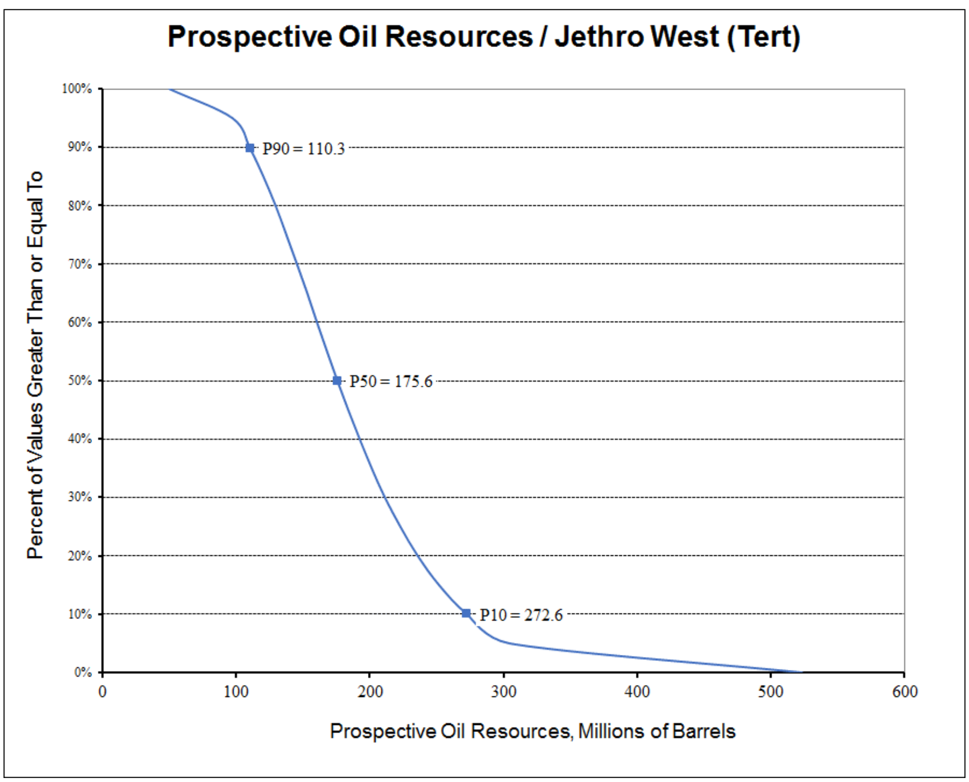
Prospective Oil Resources / Alice (Tert)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 64.6
P50 = 188.0
P10 = 410.3
0
200
400
600
800
1000
1200
Prospective Oil Resources, Millions of Barrels

Prospective Oil Resources / EriKat (U Cret)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90 = 18.9
P50 = 38.8
P10 = 70.5
0
20
40
60
80
100
120
140
160
180
200
Prospective Oil Resources, Millions of Barrels

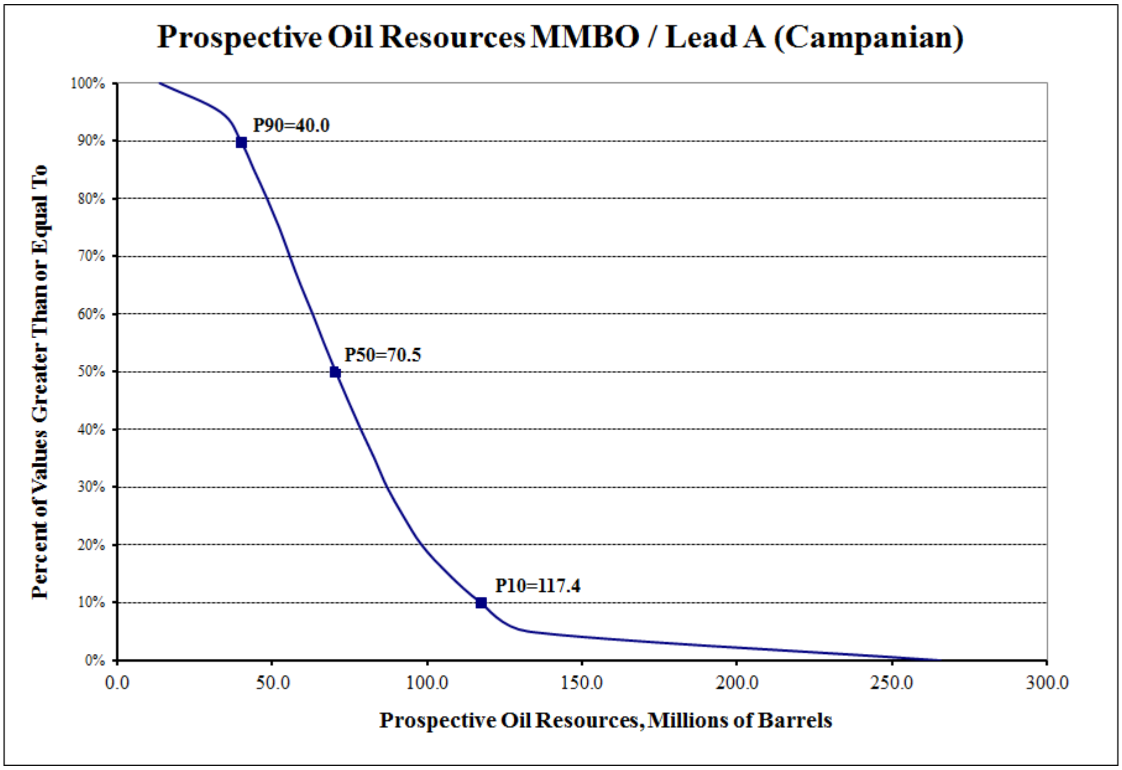


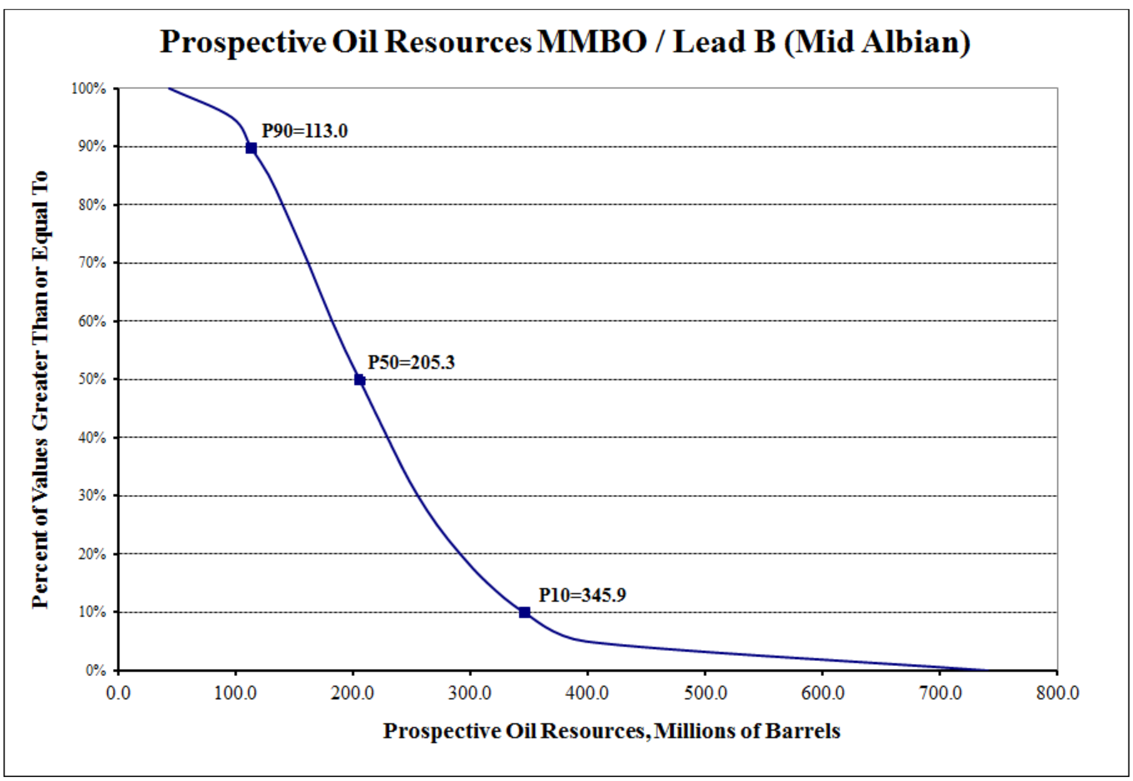
Prospective Oil Resources / Jethro KW (Tert)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90 = 81.7
P50 = 151.5
P10 = 257.4
0
100
200
300
400
500
600
Prospective Oil Resources, Millions of Barrels

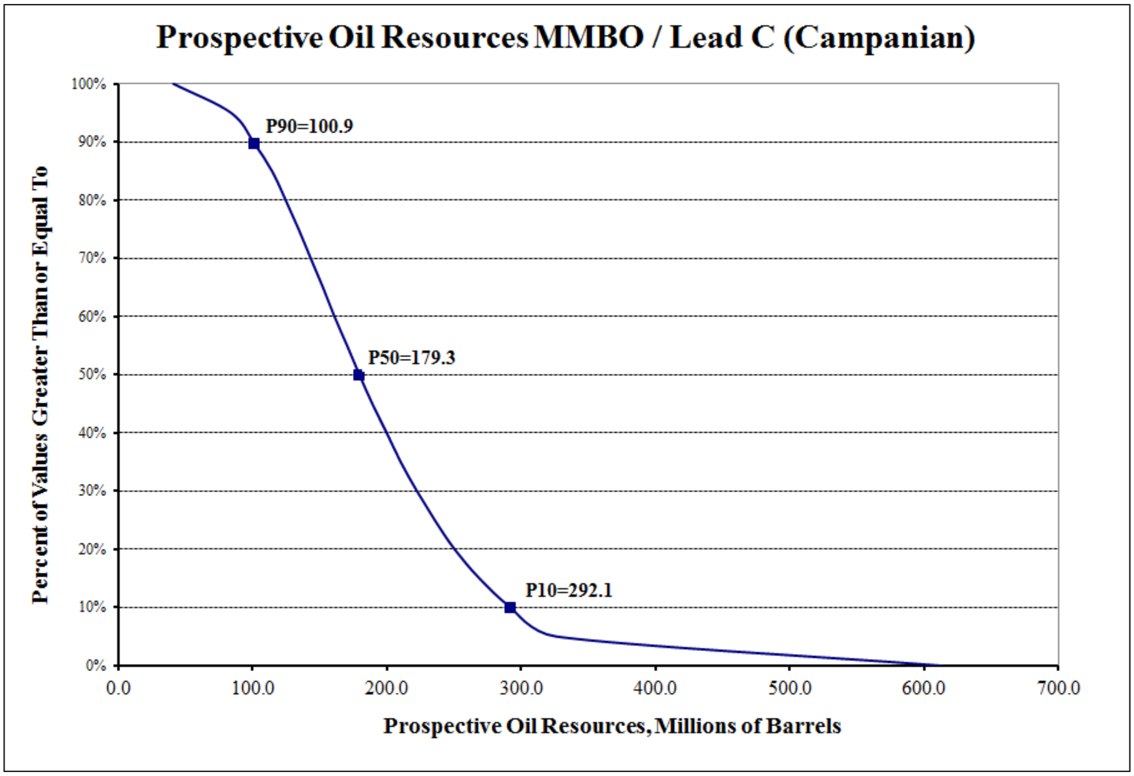



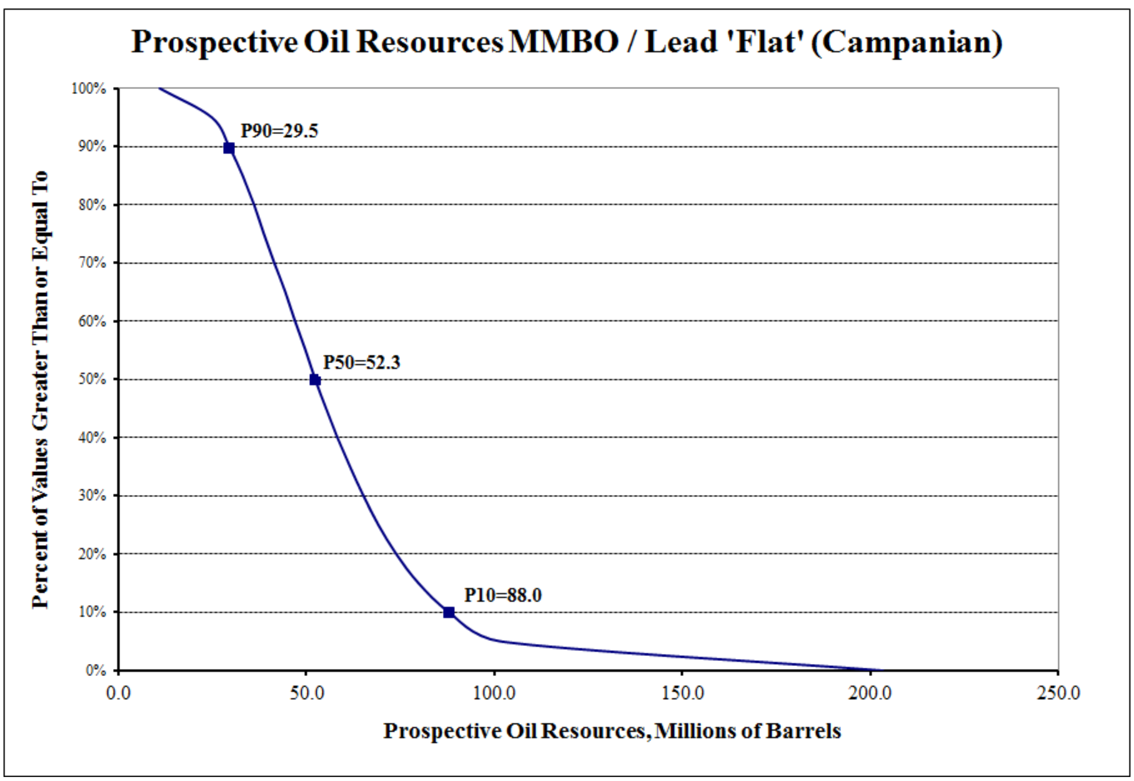
Prospective Oil Resources / Jethro West (Tert)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90 = 110.3
P50 = 175.6
P10 = 272.6
0
100
200
300
400
500
600
Prospective Oil Resources, Millions of Barrels

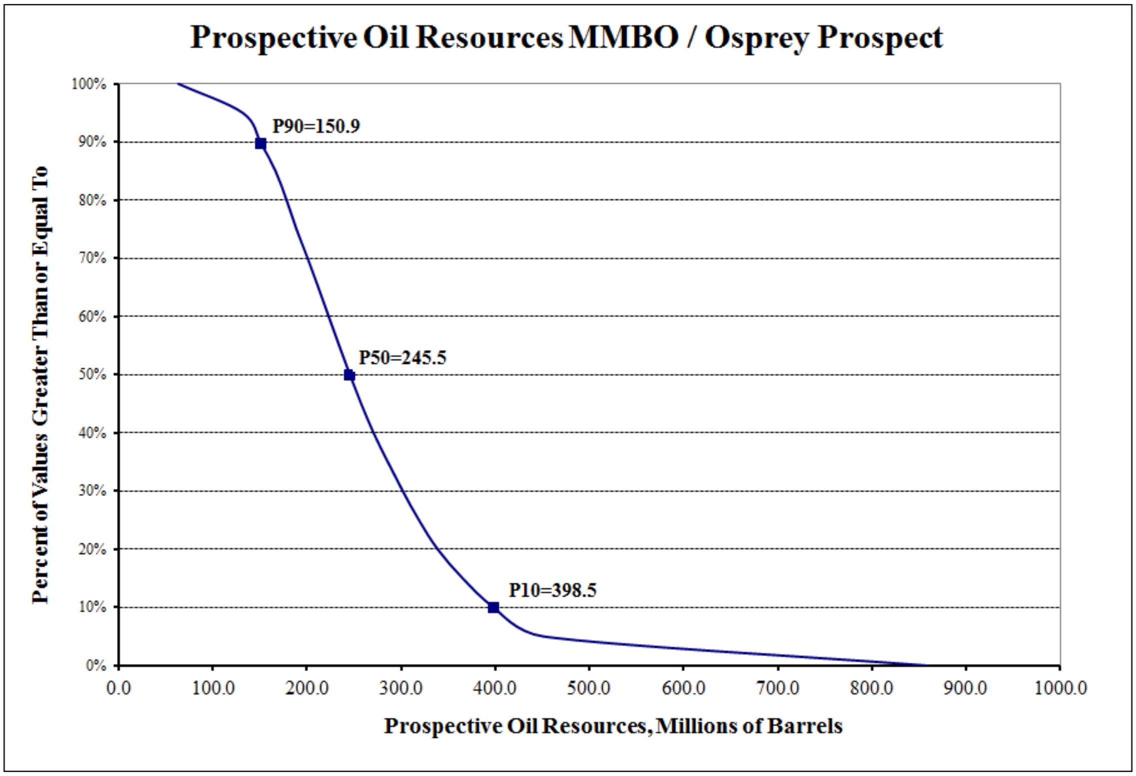
# Cooper Block



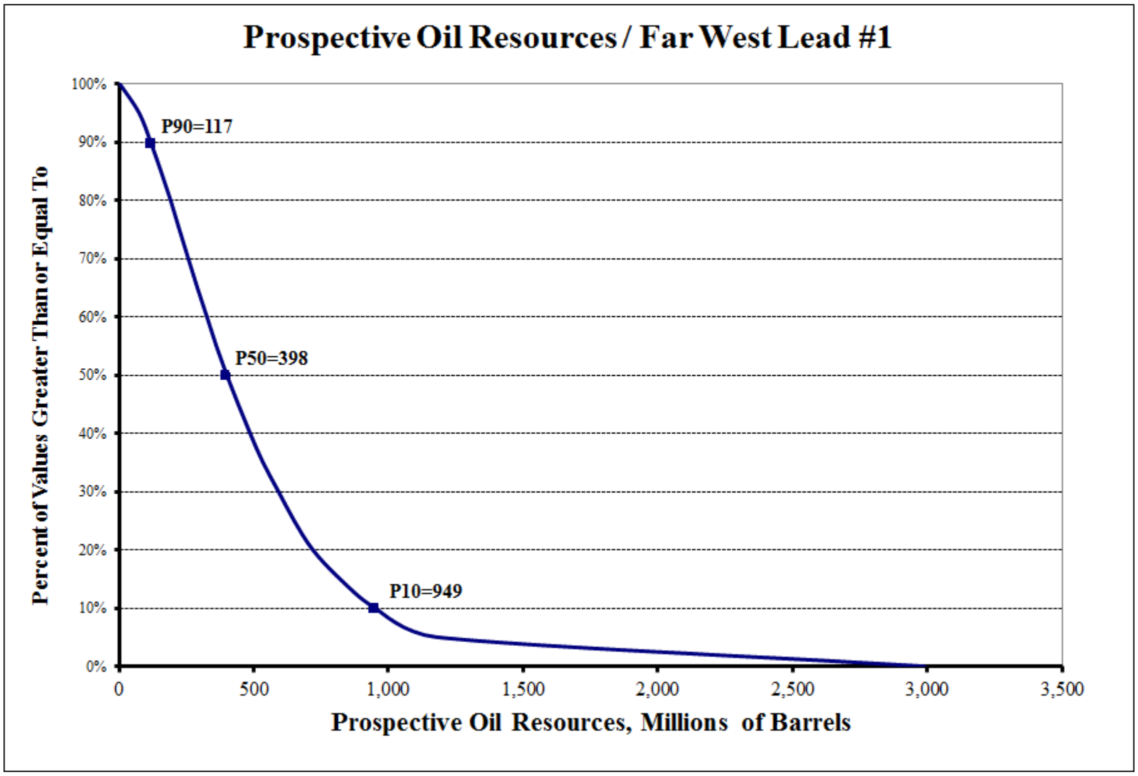

Prospective Oil Resources MMBO / Lead C (Campanian)
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels
P90=100.9
P50=179.3
P10=292.1
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
100.0
200.0
300.0
400.0
500.0
600.0
700.0

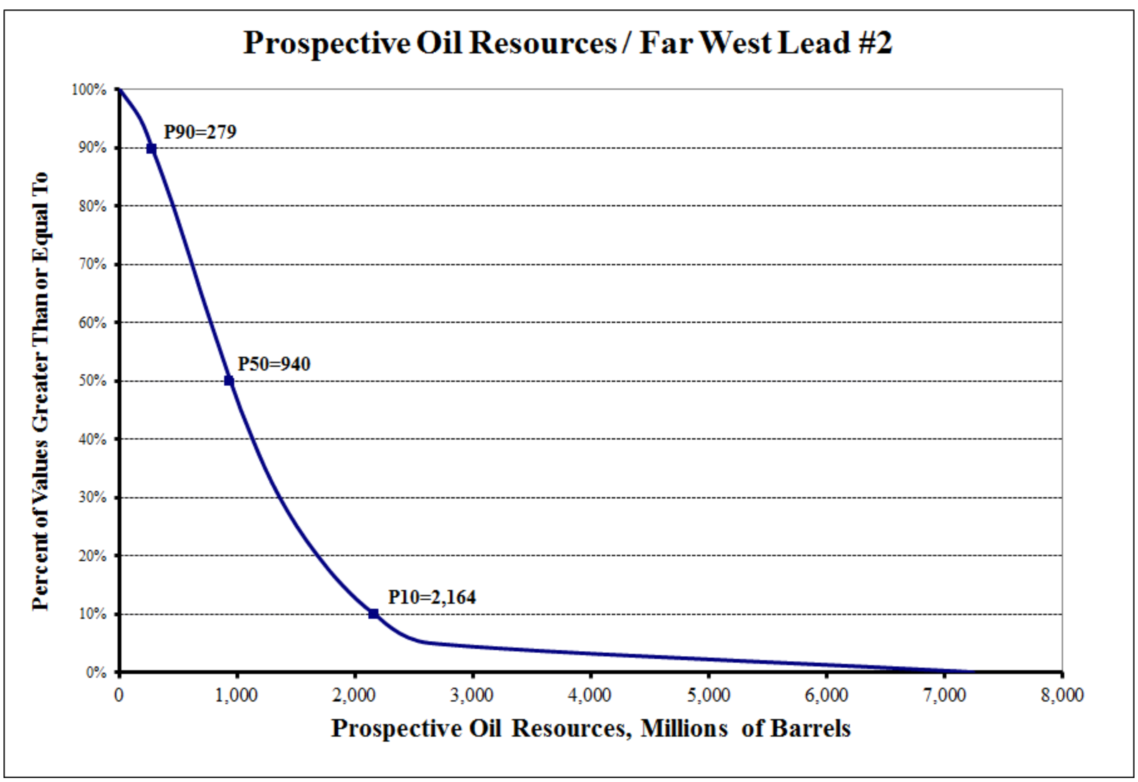

Prospective Oil Resources MMBO / Lead 'Flat' (Campanian)
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels
P90=29.5
P50=52.3
P10=88.0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
50.0
100.0
150.0
200.0
250.0

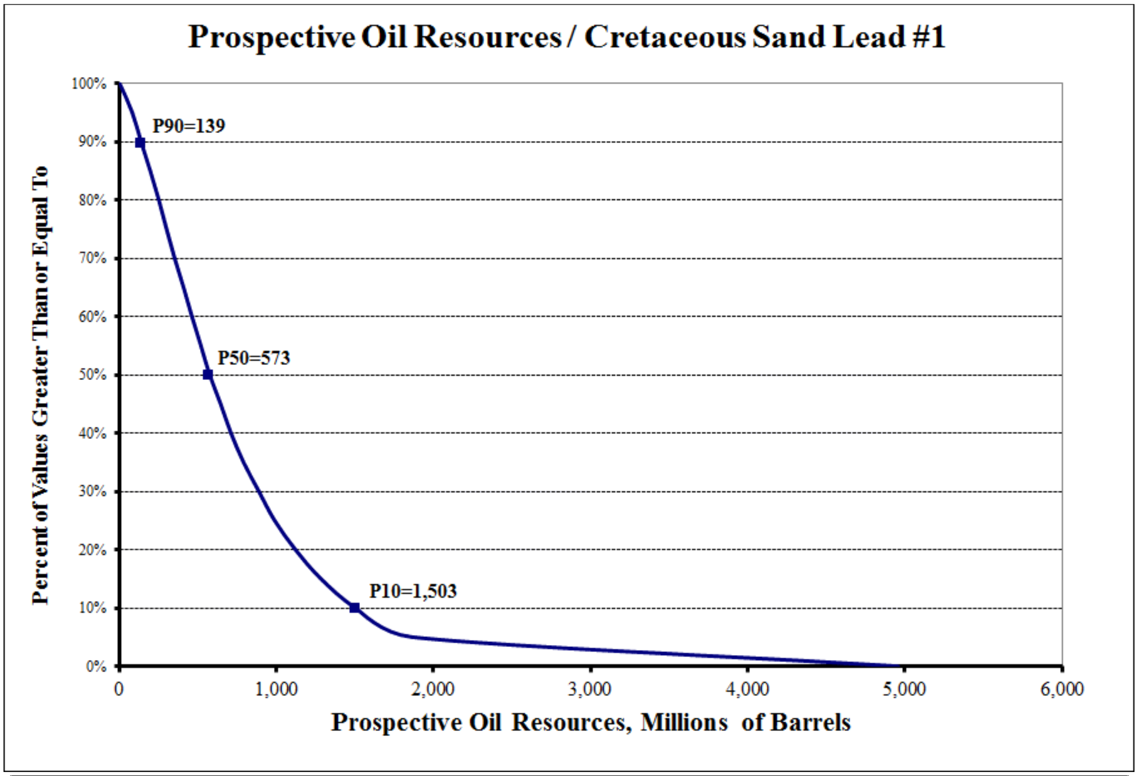


Prospective Oil Resources MMBO / Osprey Prospect
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=150.9
P50=245.5
P10=398.5
0.0
100.0
200.0
300.0
400.0
500.0
600.0
700.0
800.0
900.0
1000.0
Prospective Oil Resources, Millions of Barrels

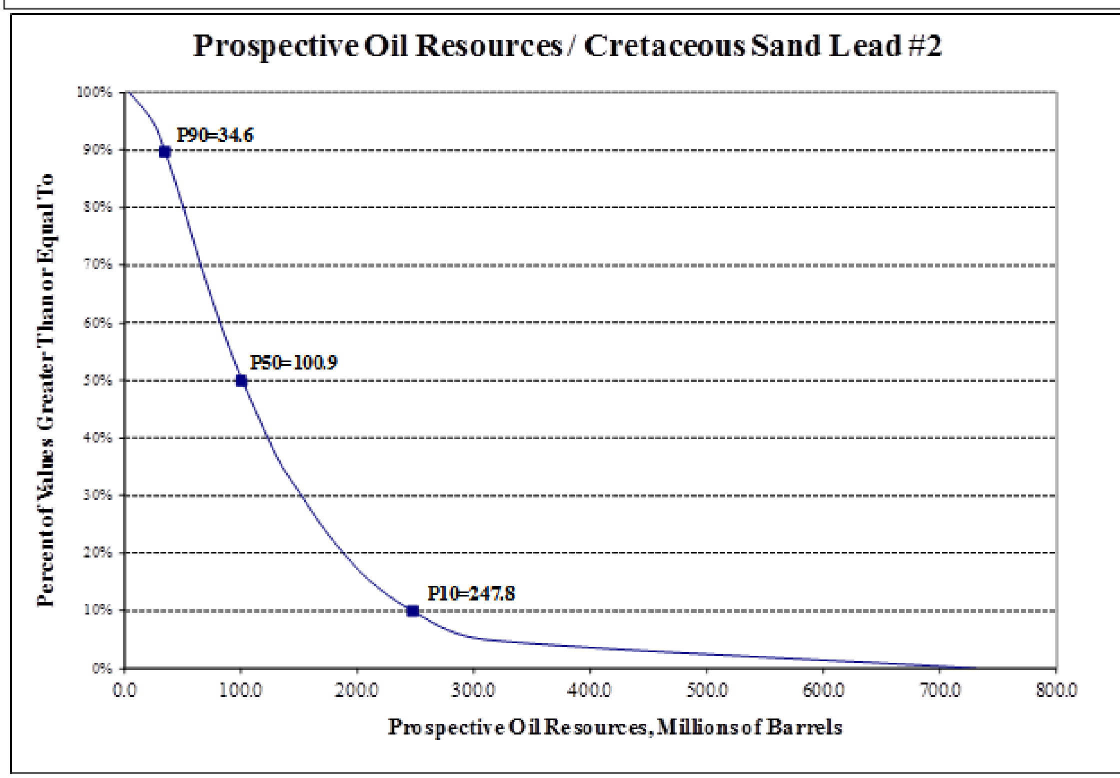
# Guy Block


Prospective Oil Resources / Far West Lead #1
P90=117
P50=398
P10=949
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
500
1,000
1,500
2,000
2,500
3,000
3,500
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels

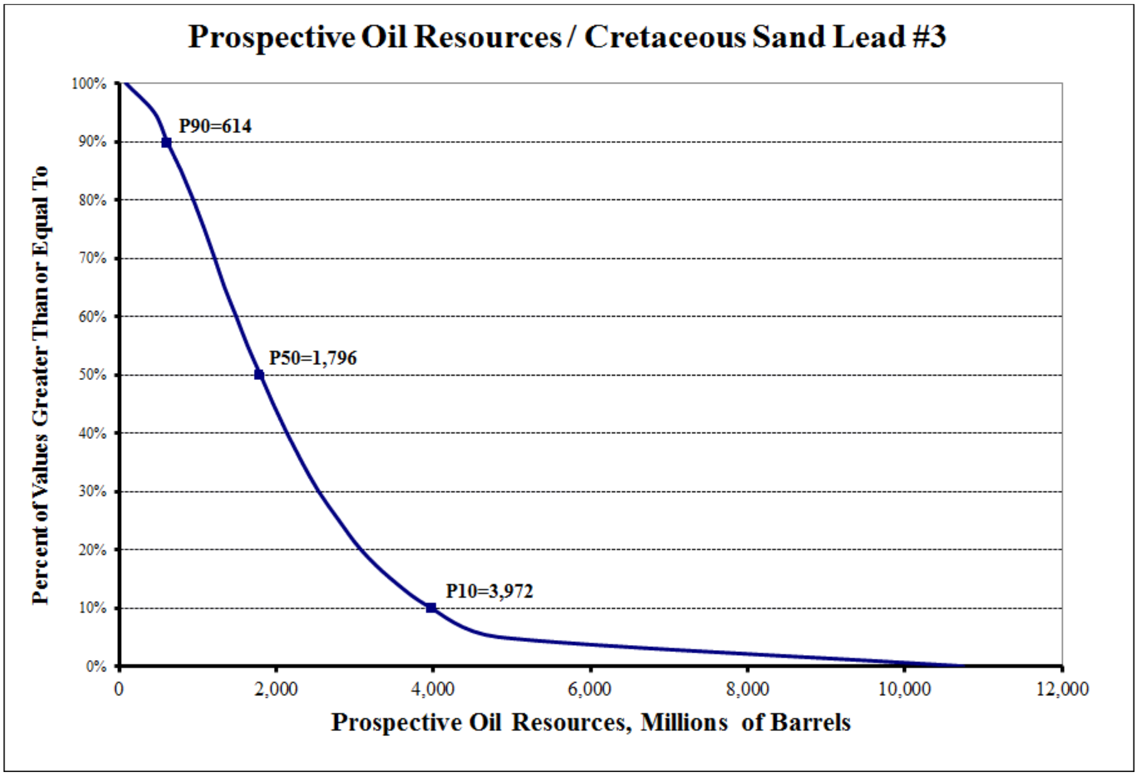

Prospective Oil Resources / Far West Lead #2
P90=279
P50=940
P10=2,164
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels

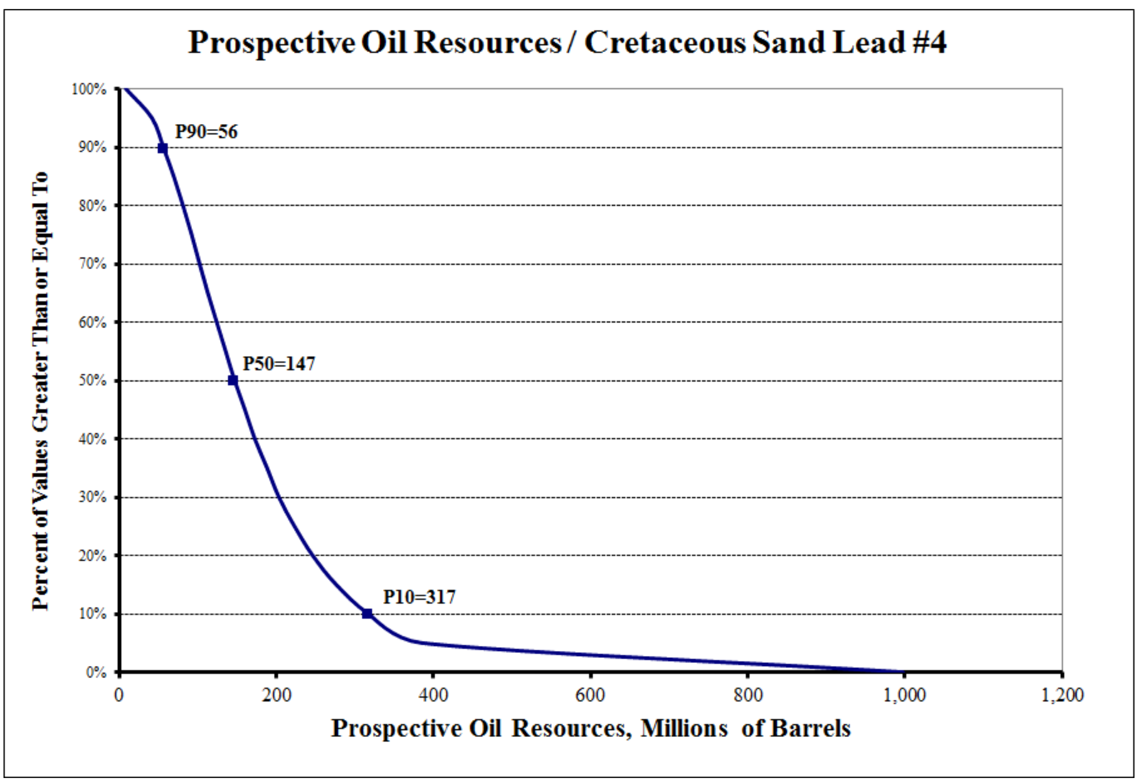


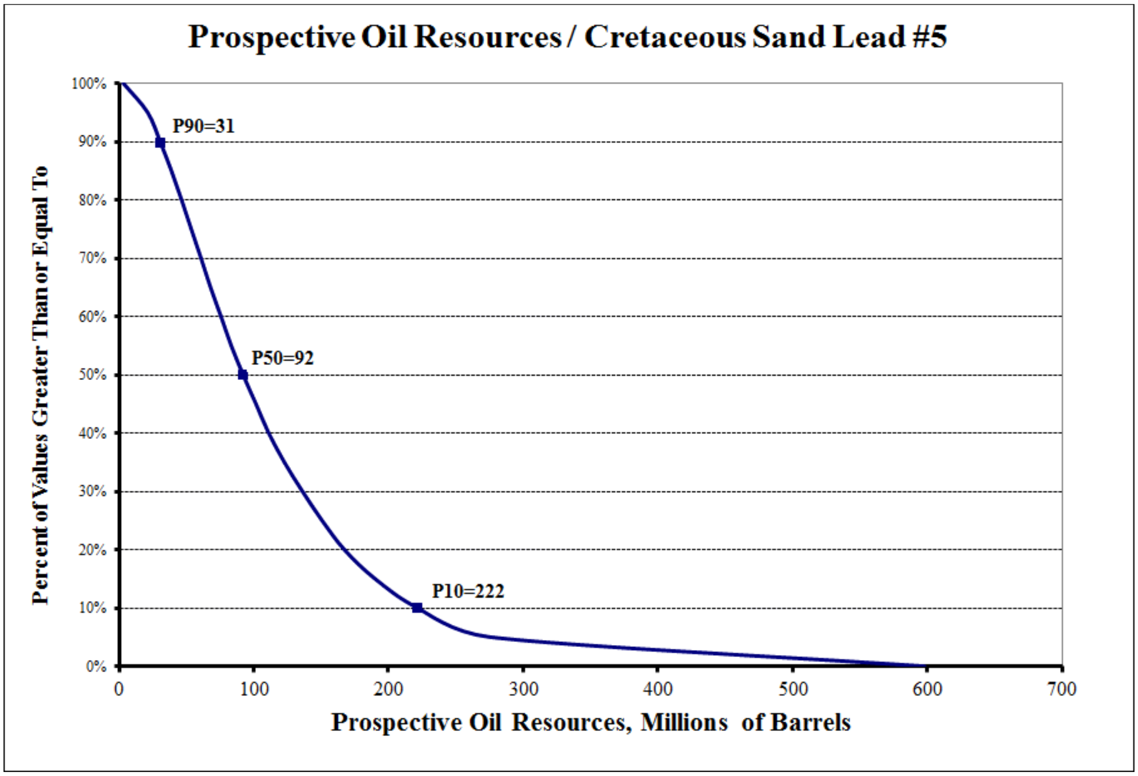
Prospective Oil Resources / Cretaceous Sand Lead #1
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=139
P50=573
P10=1,503
0
1,000
2,000
3,000
4,000
5,000
6,000
Prospective Oil Resources, Millions of Barrels

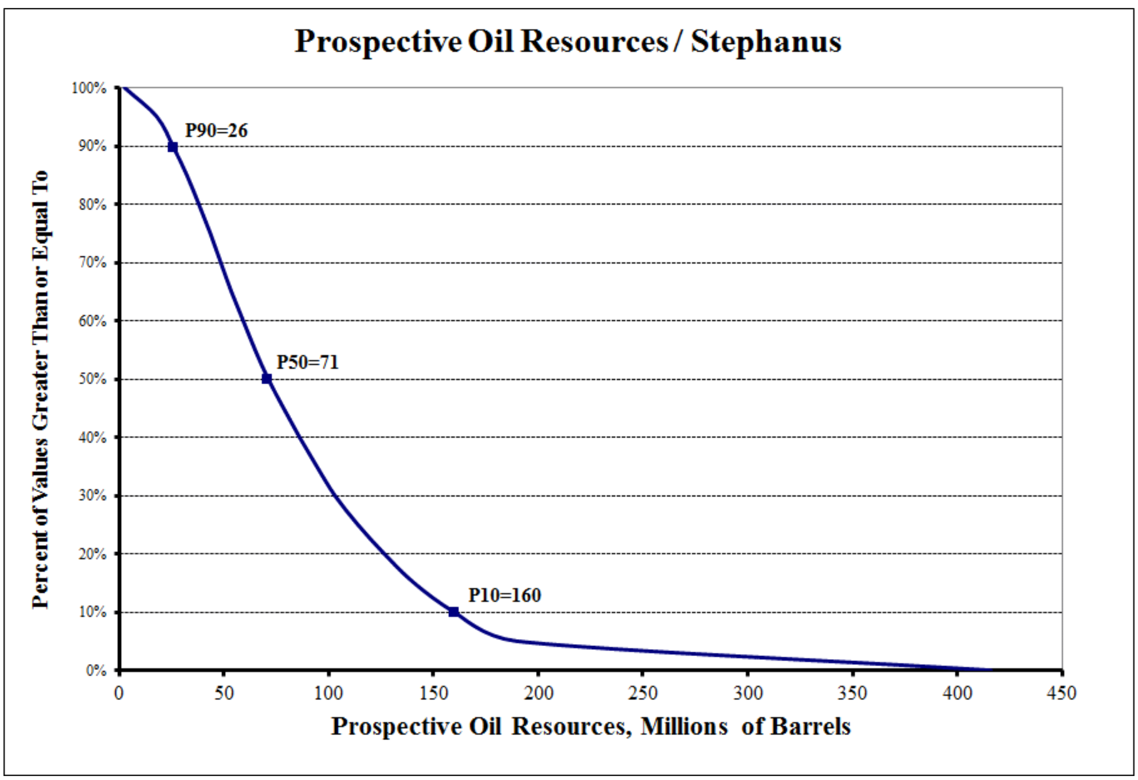



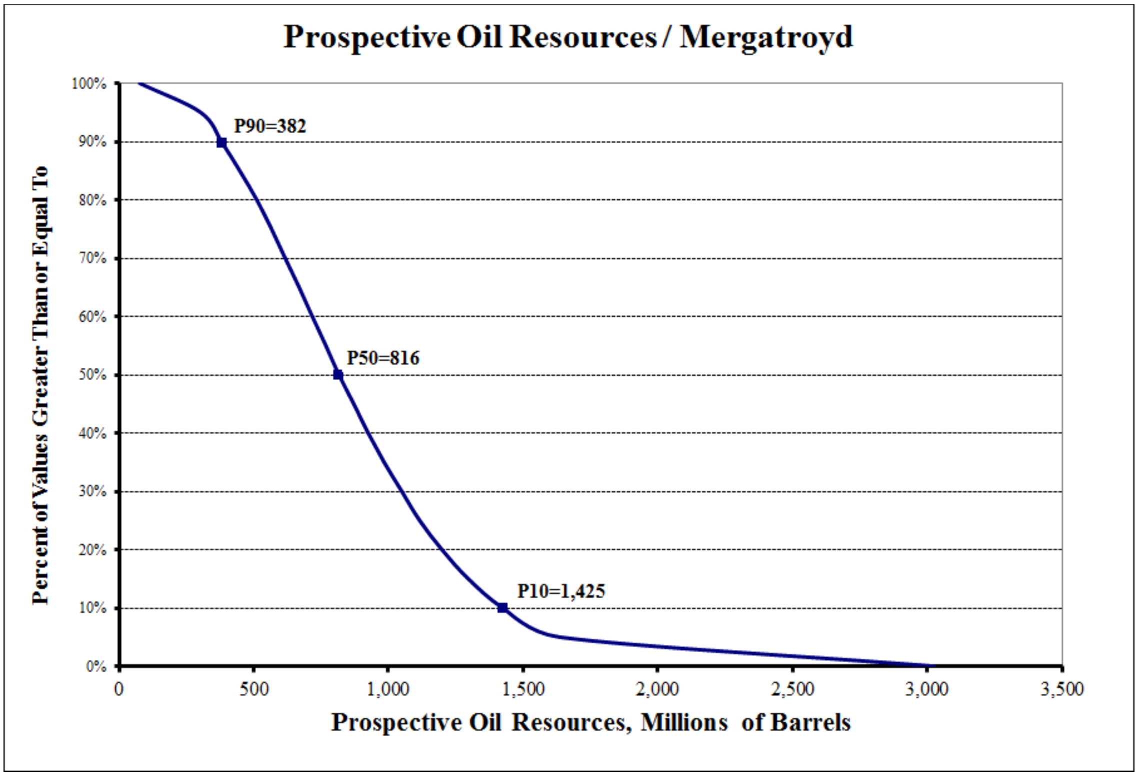
Prospective Oil Resources / Cretaceous Sand Lead #2
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=34.6
P50=100.9
P10=247.8
0.0
100.0
200.0
300.0
400.0
500.0
600.0
700.0
800.0
Prospective Oil Resources, Millions of Barrels


Prospective Oil Resources / Cretaceous Sand Lead #3
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=614
P50=1,796
P10=3,972
0
2,000
4,000
6,000
8,000
10,000
12,000
Prospective Oil Resources, Millions of Barrels

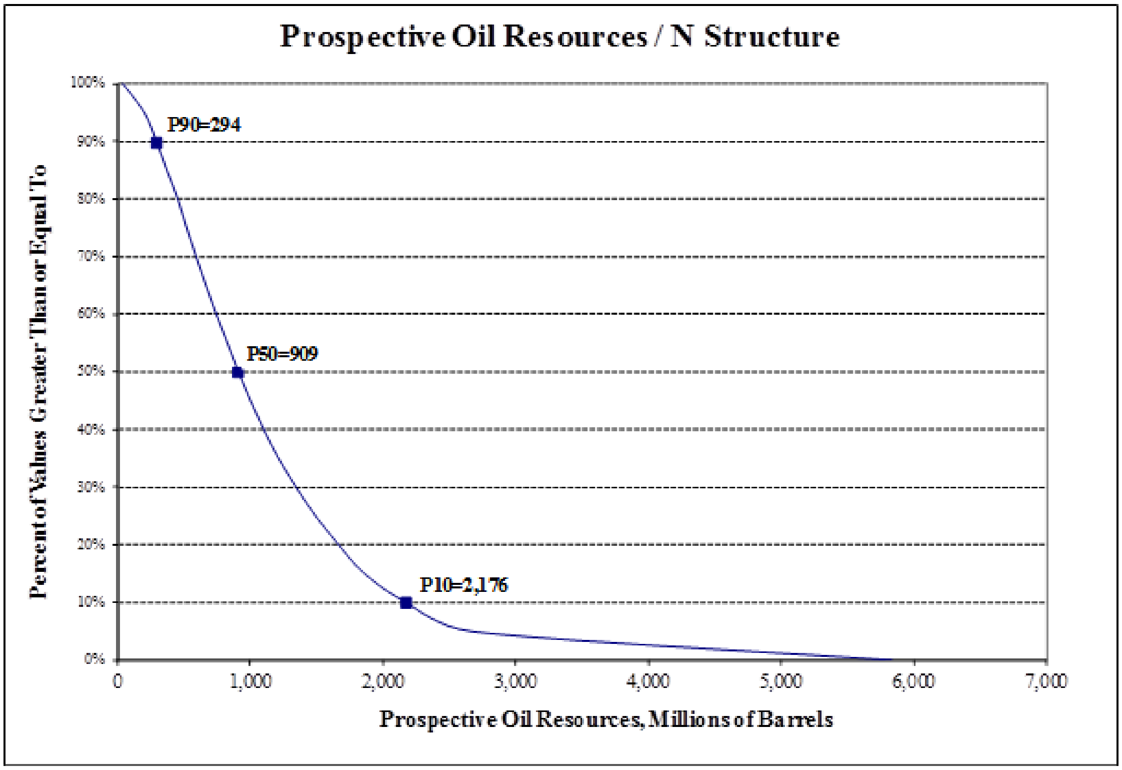

Prospective Oil Resources / Cretaceous Sand Lead #4
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=56
P50=147
P10=317
0
200
400
600
800
1,000
1,200
Prospective Oil Resources, Millions of Barrels

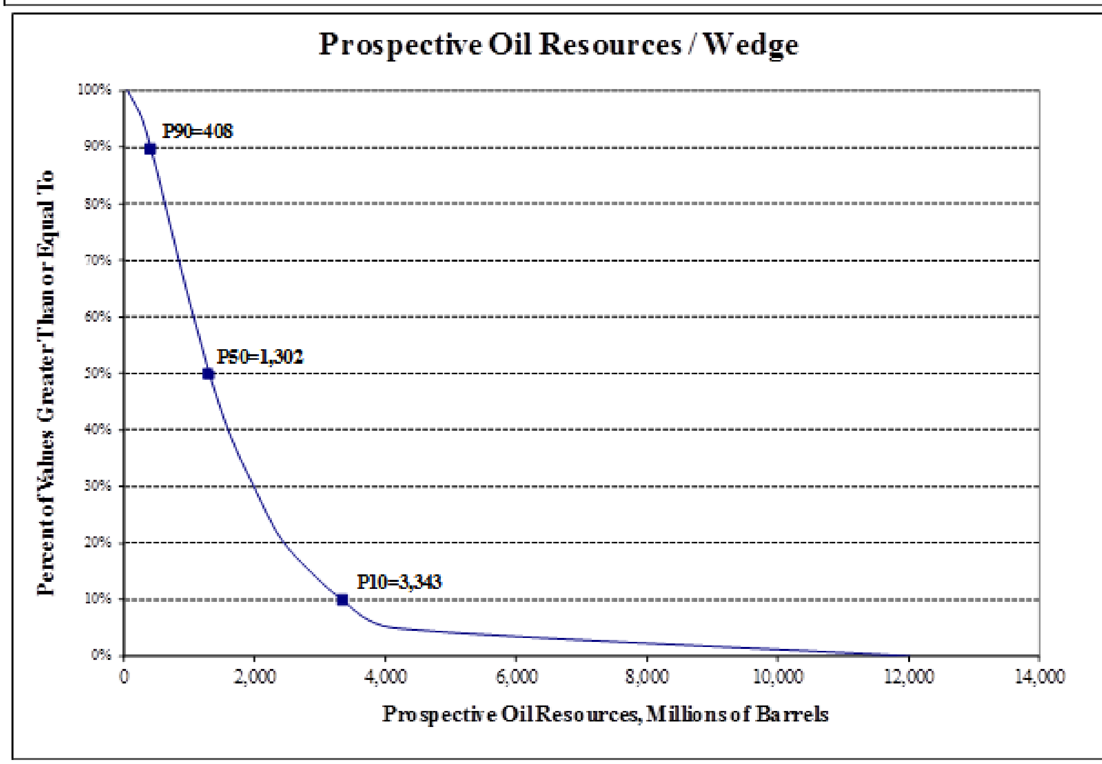

Prospective Oil Resources / Cretaceous Sand Lead #5
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=31
P50=92
P10=222
0
100
200
300
400
500
600
700
Prospective Oil Resources, Millions of Barrels


Prospective Oil Resources / Stephanus
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=26
P50=71
P10=160
0
50
100
150
200
250
300
350
400
450
Prospective Oil Resources, Millions of Barrels

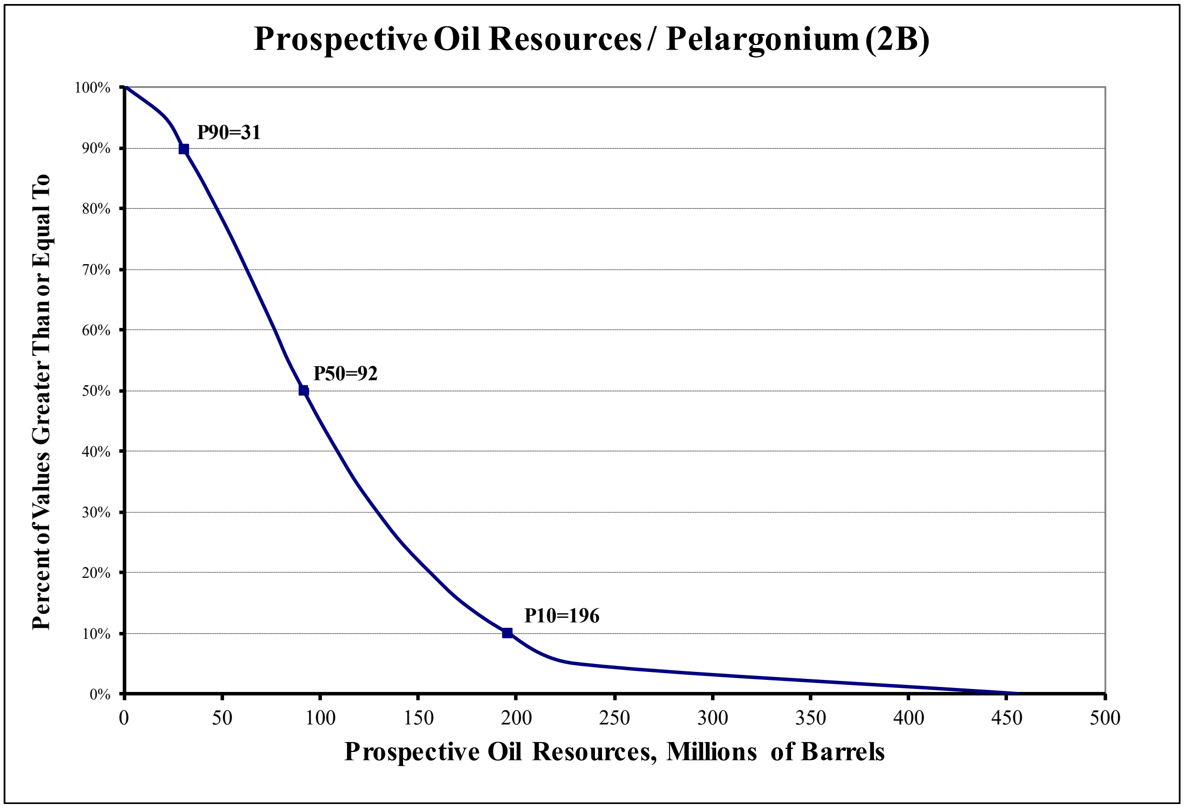

Prospective Oil Resources / Mergatroyd
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=382
P50=816
P10=1,425
0
500
1,000
1,500
2,000
2,500
3,000
3,500
Prospective Oil Resources, Millions of Barrels

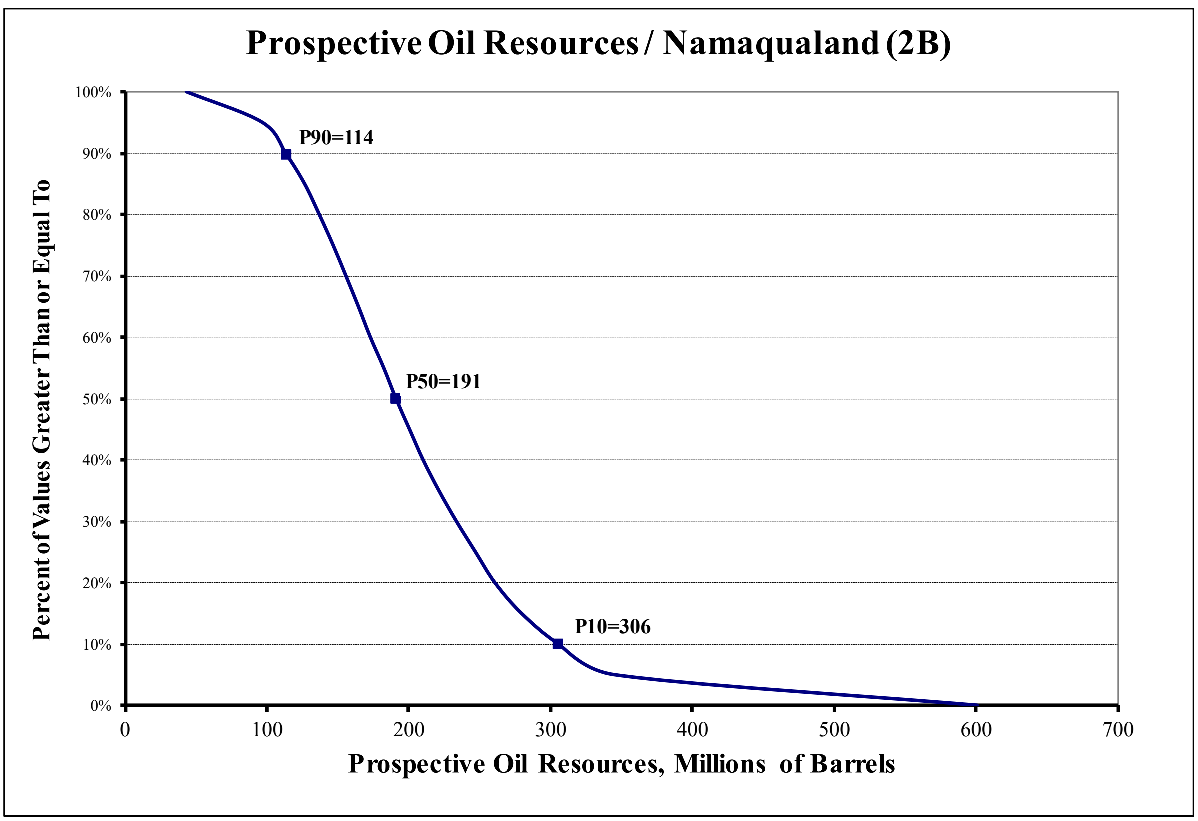
# Sharon Block

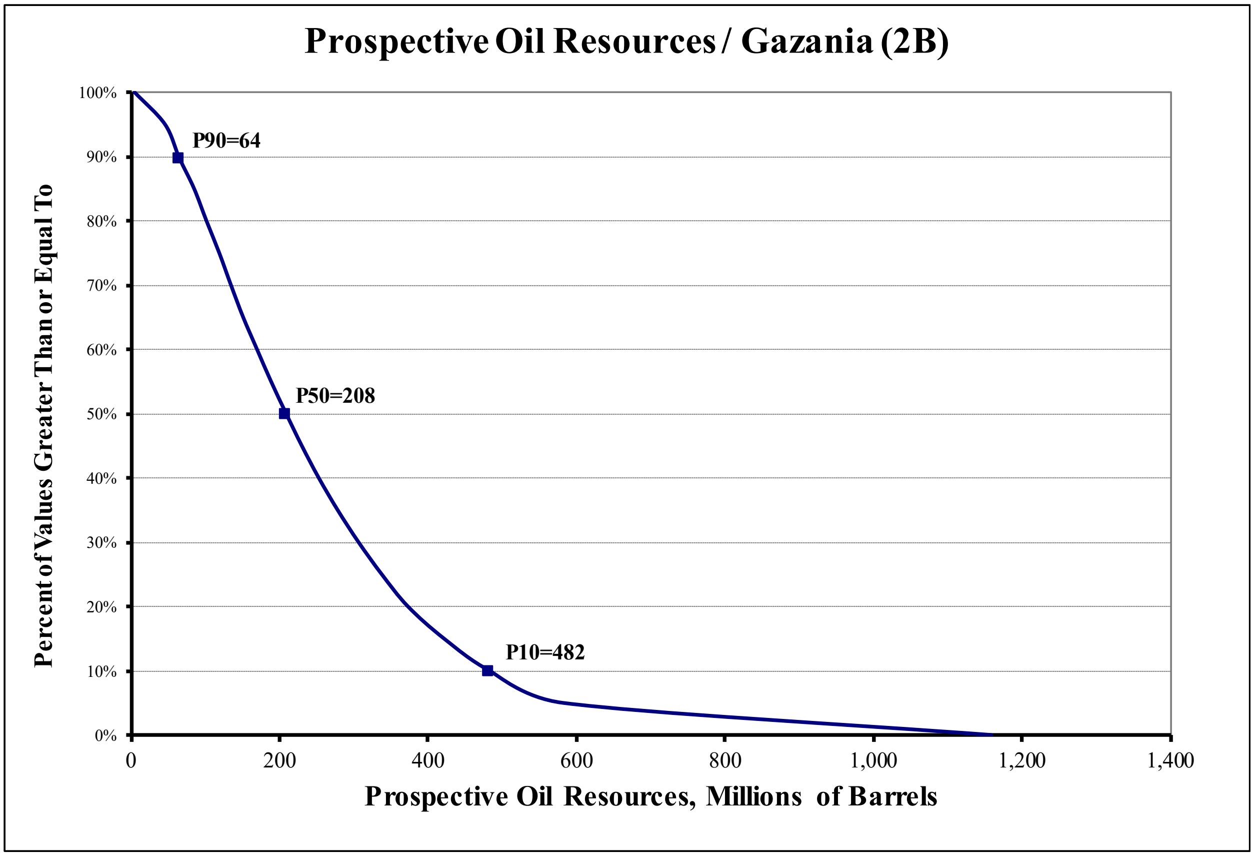


## 2B Block

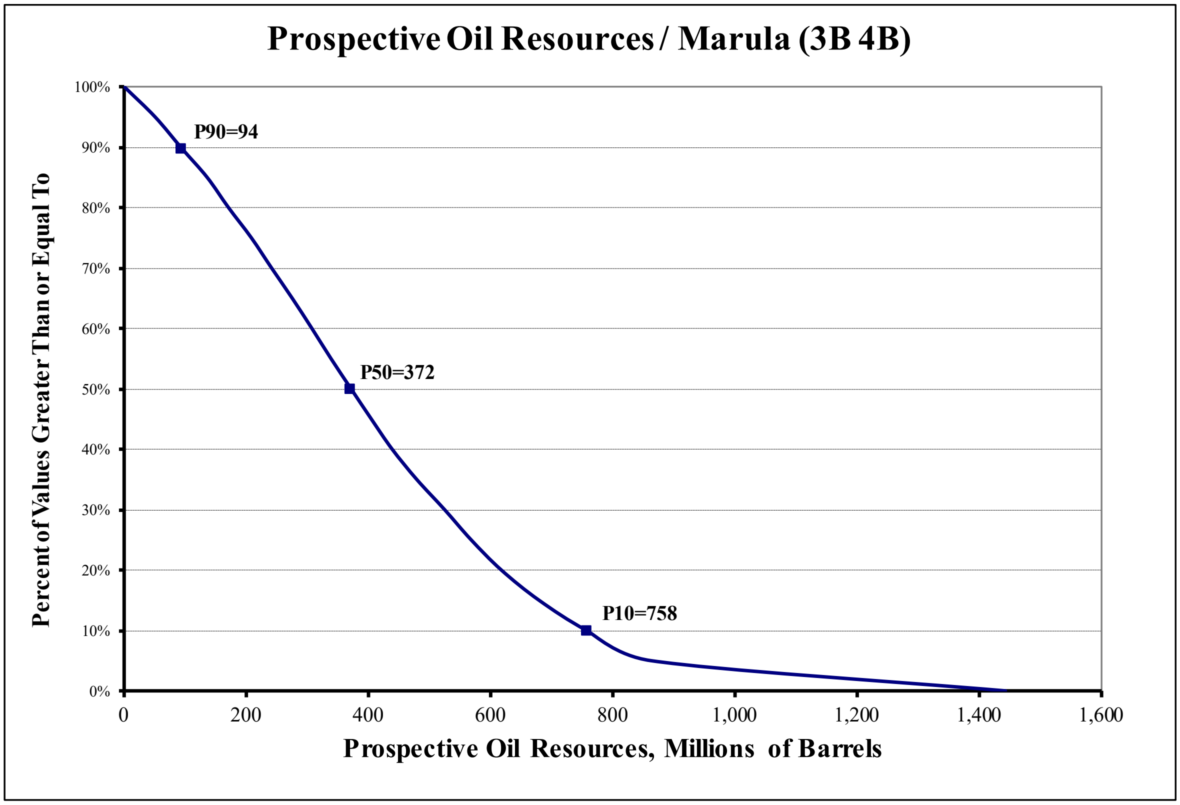

Prospective Oil Resources / Pelargonium (2B)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=31
P50=92
P10=196
0
50
100
150
200
250
300
350
400
450
500
Prospective Oil Resources, Millions of Barrels


Prospective Oil Resources / Namaqualand (2B)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=114
P50=191
P10=306
0
100
200
300
400
500
600
700
Prospective Oil Resources, Millions of Barrels

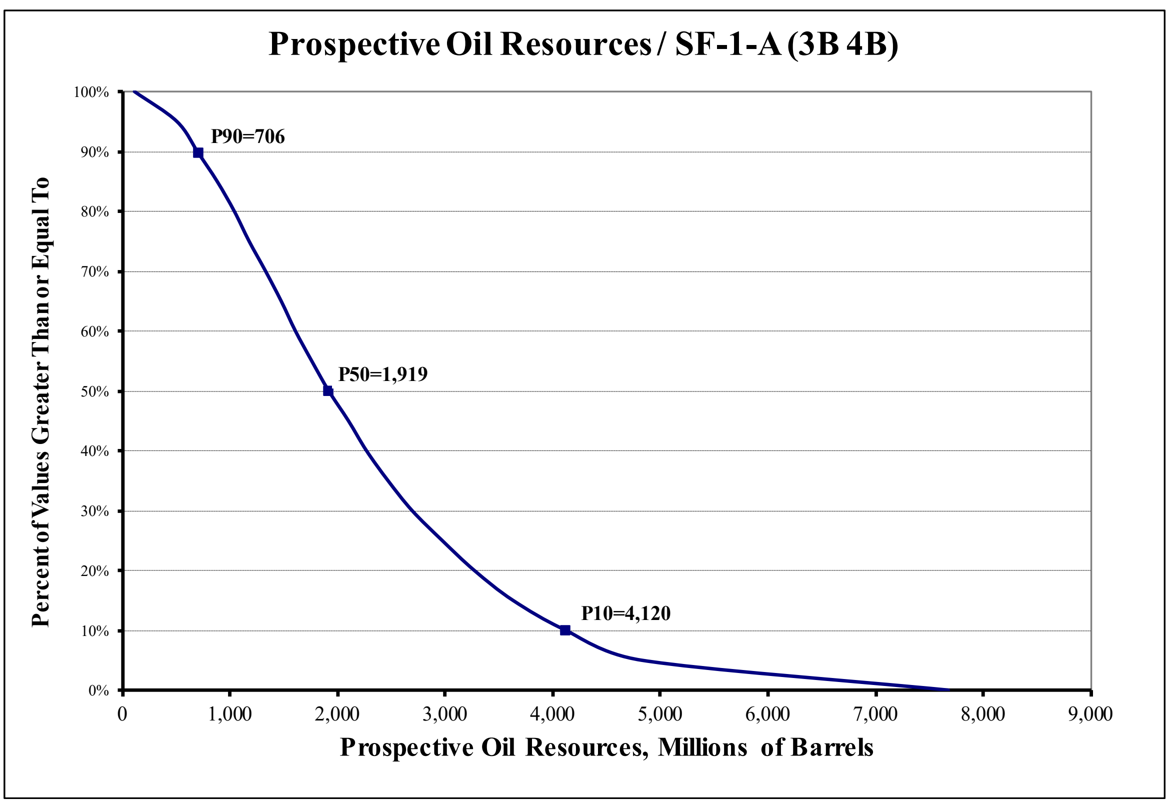


Prospective Oil Resources / Gazania (2B)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=64
P50=208
P10=482
0
200
400
600
800
1,000
1,200
1,400
Prospective Oil Resources, Millions of Barrels

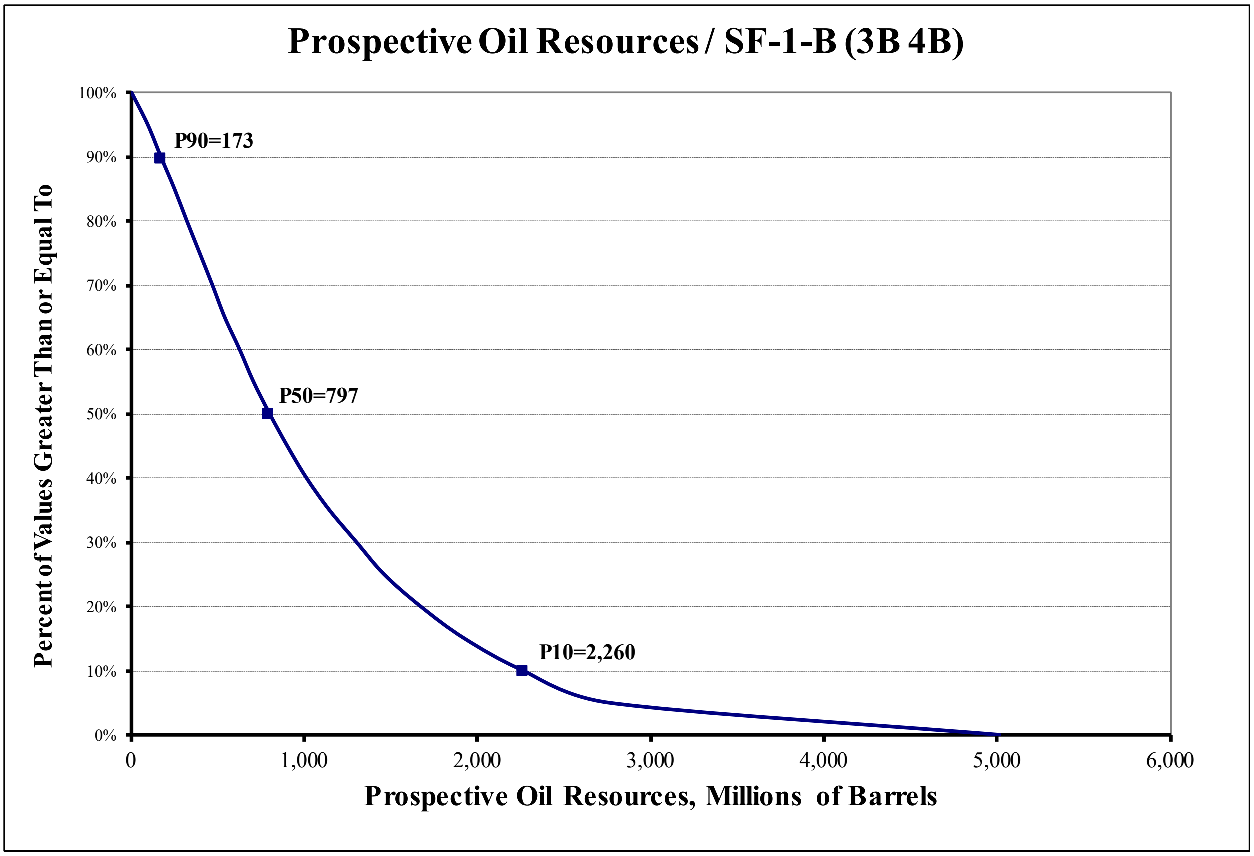
# 3B/4B Block



Prospective Oil Resources / Marula (3B 4B)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=94
P50=372
P10=758
0
200
400
600
800
1,000
1,200
1,400
1,600
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels

Prospective Oil Resources / SF-1-A (3B 4B)
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=706
P50=1,919
P10=4,120
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000
Percent of Values Greater Than or Equal To
Prospective Oil Resources, Millions of Barrels



Prospective Oil Resources / SF-1-B (3B 4B)
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=173
P50=797
P10=2,260
0
1,000
2,000
3,000
4,000
5,000
6,000
Prospective Oil Resources, Millions of Barrels