Resource Report for Certain Assets in Offshore Namibia and Report for Assets in Offshore Guyana

Prepared According to National Instrument 51-101

Date of this Report: October 31, 2016

Prepared for:

ECO Atlantic (PTY), Ltd

ECO
OIL & GAS LTD.

Prepared By:

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1. EXECUTIVE SUMMARY

The report addresses the ECO Atlantic exploratory oil and gas assets in offshore Namibia and offshore Guyana. The assets owned by ECO Atlantic (Pty) Ltd are summarized in Table 1—1.

Table 1—1 Summary of Assets owned by ECO Atlantic (Pty) Ltd

Asset	Operator	Working Interest (%)	Status	Expiry Date	License Area (km2)[1]	Water Depth, meters
Namibia – Block 2012A (Cooper)	ECO	32.5	Exploration	March 2020	5,000	200 to 500
Namibia – Blocks 2111B and 2211A (east half) (Guy)	Azinam	50.0	Exploration	March 2020	5,000	2,000
Namibia – Blocks 2213A and 2213B (west half) (Sharon)	ECO	60.0	Exploration	March 2020	5,000	200
Namibia – Blocks 2211Ba and 2311A (Tamar)	ECO	72.0	Exploration	March 2020	7,500	2,000
Guyana – Orinduik Block	Tullow	40.0	Exploration	January 2026	1,800	70

Based on probabilistic estimates, the gross unrisked Prospective Resources for Cooper, Guy and Sharon Blocks in Namibia are listed below in Table 1—2, and the Net Unrisked Prospective Resources for Cooper, Guy and Sharon Blocks in Namibia are listed below in Table 1—3. Since the data in the Tamar Block in Namibia and the Orinduik Block of Guyana are still under internal review, Prospective Resources have not been estimated for this report.

This report supersedes all other reports relative to the ECO Atlantic (Pty), Ltd Namibia assets.

[1] Approximate

Table 1—2 Gross Unrisked Prospective Resource Estimates by Block

Block	Oil in Place, MMBbl			Prospective Oil Resources, MMBbl			Prospective Associated Gas Resources, BCF		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Cooper Block	1,896.1	3,166.0	5,036.7	434.3	752.8	1,241.8	404.8	735.8	1,274.9
Guy Block	2,194.9	6,903.0	16,906.8	489.4	1,581.4	4,009.9	478.2	1,545.3	3,932.4
Sharon Block	3,136.4	9,658.5	23,345.3	701.9	2,211.7	5,518.4	668.3	2,175.6	5,465.9
TOTAL	**7,227.3**	**19,727.4**	**45,288.9**	**1,625.6**	**4,546.0**	**10,770.2**	**1,551.2**	**4,456.7**	**10,673.2**

(MMBbl = million barrels of oil; BCF = billion cubic feet)

Table 1—3 Net Unrisked Prospective Resource Estimates by Block

Block	Oil in Place, MMBbl			Prospective Oil Resources, MMBbl			Prospective Associated Gas Resources, BCF		
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Cooper Block	616.2	1,029.0	1,636.9	141.2	244.7	403.6	131.6	239.1	414.3
Guy Block	1,097.4	3,451.5	8,453.4	244.7	790.7	2,005.0	239.1	772.6	1,966.2
Sharon Block	1,881.1	5,795.1	14,007.2	421.2	1,327.0	3,311.0	401.0	1,305.4	3,279.6
TOTAL	**3,595.5**	**10,275.5**	**24,097.6**	**807.0**	**2,362.4**	**5,719.6**	**771.6**	**2,317.1**	**5,660.1**

(MMBbl = million barrels of oil; BCF = billion cubic feet)

Note that these estimates do not include consideration for the risk of failure in exploring for these resources. 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." [2] 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.

[2] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Second Edition*, Volume 1, September 1, 2007, pg 5-7.

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2. INTRODUCTION

2.1 AUTHORIZATION

Gustavson Associates LLC (the Consultant) has been retained by ECO Atlantic (PTY), Ltd (the Client, ECO) to prepare an updated Report under Canada's National Instrument 51-101, *Standards of Disclosure For Oil and Gas Activities*, regarding holdings of ECO in offshore Namibia which include Petroleum Exploration Licenses (PEL) for Block 2012A (Cooper Block), the west half of Blocks 2213A and 2213B (Sharon Block), the east half of Blocks 2111B and 2211A (Guy Block), Blocks 2211Ba and 2311A (Tamar Block) and the Orinduik Block offshore Guyana.

2.2 INTENDED PURPOSE AND USERS OF REPORT

The purpose of this Report is to support the Client's filing with the Toronto Stock Exchange (TSX).

2.3 OWNER CONTACT AND PROPERTY INSPECTION

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

2.4 SCOPE OF WORK

This Report is intended to describe and quantify the Prospective Resources contained within the offshore Blocks that are subject to a petroleum license agreement with the Namibian government and report on the offshore Block that is subject to a petroleum license agreement with the government of Guyana which has not been fully evaluated at the time of this report.

2.5 APPLICABLE STANDARDS

This Report has been prepared in accordance with Canadian National Instrument 51-101. The National Instrument requires disclosure of specific information concerning prospects, as are provided in this Report.

2.6 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. Gustavson Associates reserves the right to revise its opinions, if new information is deemed sufficiently credible to do so.

2.7 INDEPENDENCE/DISCLAIMER OF INTEREST

Gustavson Associates LLC 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 Evaluator, with the assistance of others on Gustavson's staff. Our fee for this Report and the other services that may be provided is not dependent on the amount of resources estimated.

3. DISCLOSURES REGARDING ASSETS

3.1 LOCATION AND BASIN NAME: GUYANA

The Guyana-Suriname Basin is located in the northeastern offshore of South America off the countries of Venezuela, Guyana, Suriname and French Guiana (Figure 3—1). The Orinduik Block is located offshore of the country of Guyana in the Guyana-Suriname Basin (Figure 3—2).

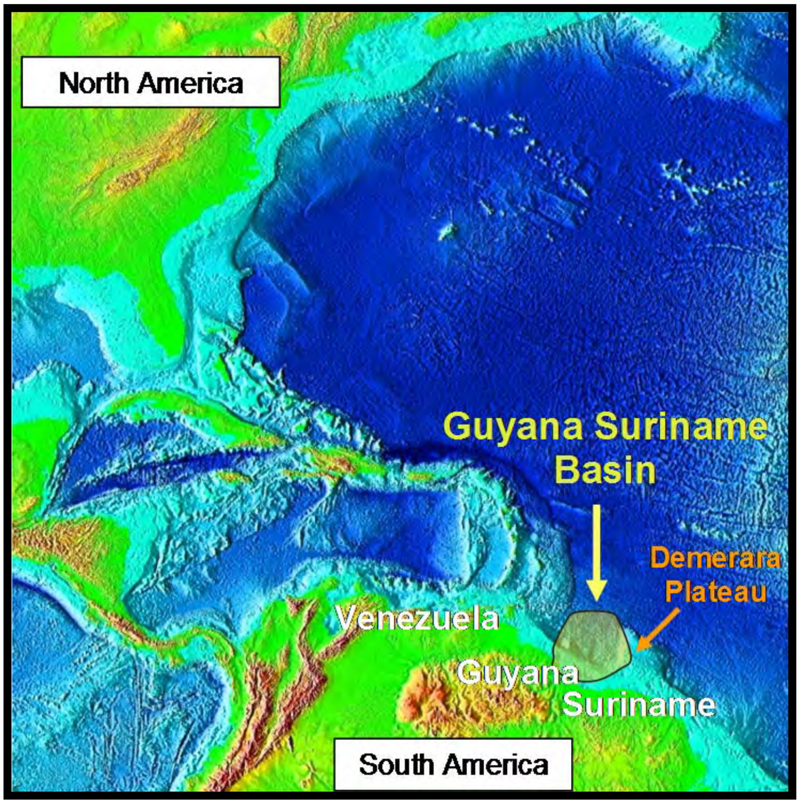

Figure 3—1 Location map of the Guyana Suriname Basin

The Guyana-Suriname Basin is a lightly explored basin. Sixteen wells were drilled between 1970 and 2006 with the deepest reaching a depth of 5,400 meters. There is the potential for large conventional accumulations in stratigraphic traps and subtle structural traps. The basin is characterized by moderate to high-risk, high-reward exploration potential in a low-risk, favorable political and economic environment.

3.1.1 Gross and Net Interest in the Property

The Orinduik Block license area is 1,800 square kilometers (444,789 acres) where ECO has a 40% working interest (WI) (Figure 3—2). Tullow Oil Plc (Tullow) is the designated Operator holding the remaining WI and carries ECO for a portion of the initial exploration program work commitment.

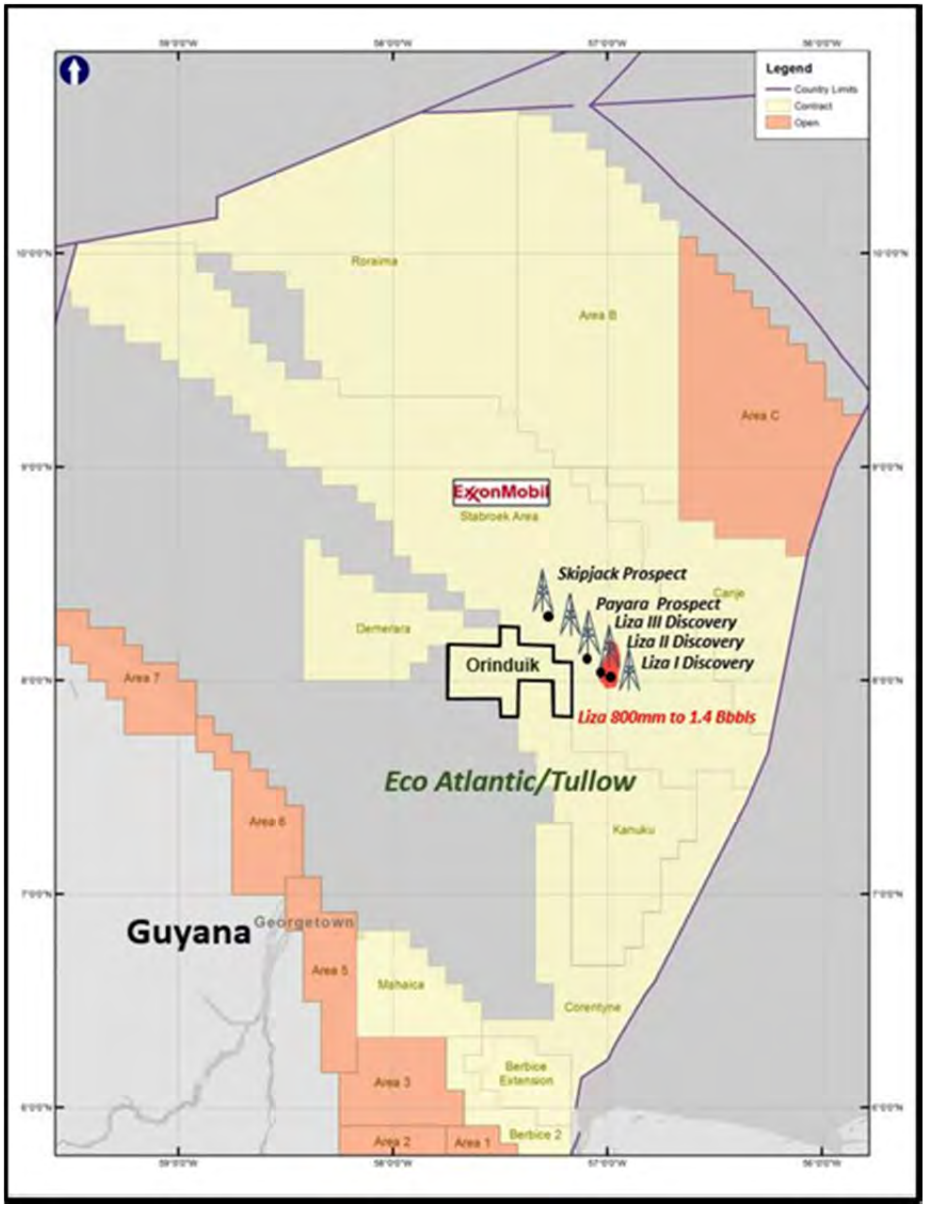

Figure 3—2 Index map of Guyana Offshore

3.1.2 Expiry Date of Interest

The license was awarded in January 2016 for an initial term of four years in which the work obligations are to review the existing 2D seismic data and by the end of the fourth year acquire and process a 3D seismic survey over an area of interest. The current plan by the partners includes the acquisition, processing and interpretation of a 3D seismic survey by the second quarter of 2017 or sooner. The initial term can be extended for six additional years and by year nine a well would need to be drilled on the Block.

3.1.3 Description of Target Zones

The Guyana-Suriname Basin is a passive margin basin resulting from Jurassic rifting apart of Africa and South America followed by Cretaceous drifting of the continents to form the northern Atlantic Ocean.

The basin has received clastic deposits in shelf, slope, and basin depositional environments during the Cretaceous to Recent. The Guyana basin has more than 7,000 meters of sedimentary fill.

The target reservoir rocks for the Orinduik Block are sandstones deposited as shelf margin, slope and basin turbidite fans. These rocks are of Cretaceous and younger age and are expected to be similar to the Cretaceous age reservoir at the ExxonMobil discovery at Liza. These sandstones are interbedded with shales and marls, which provide seal to these reservoir units. A schematic section from Tullow (Figure 3—3) depicts an interpretation that shows the relationship of the Exxon Liza discovery projected into a section line that goes through the updip Amatuk lead that is being evaluated.

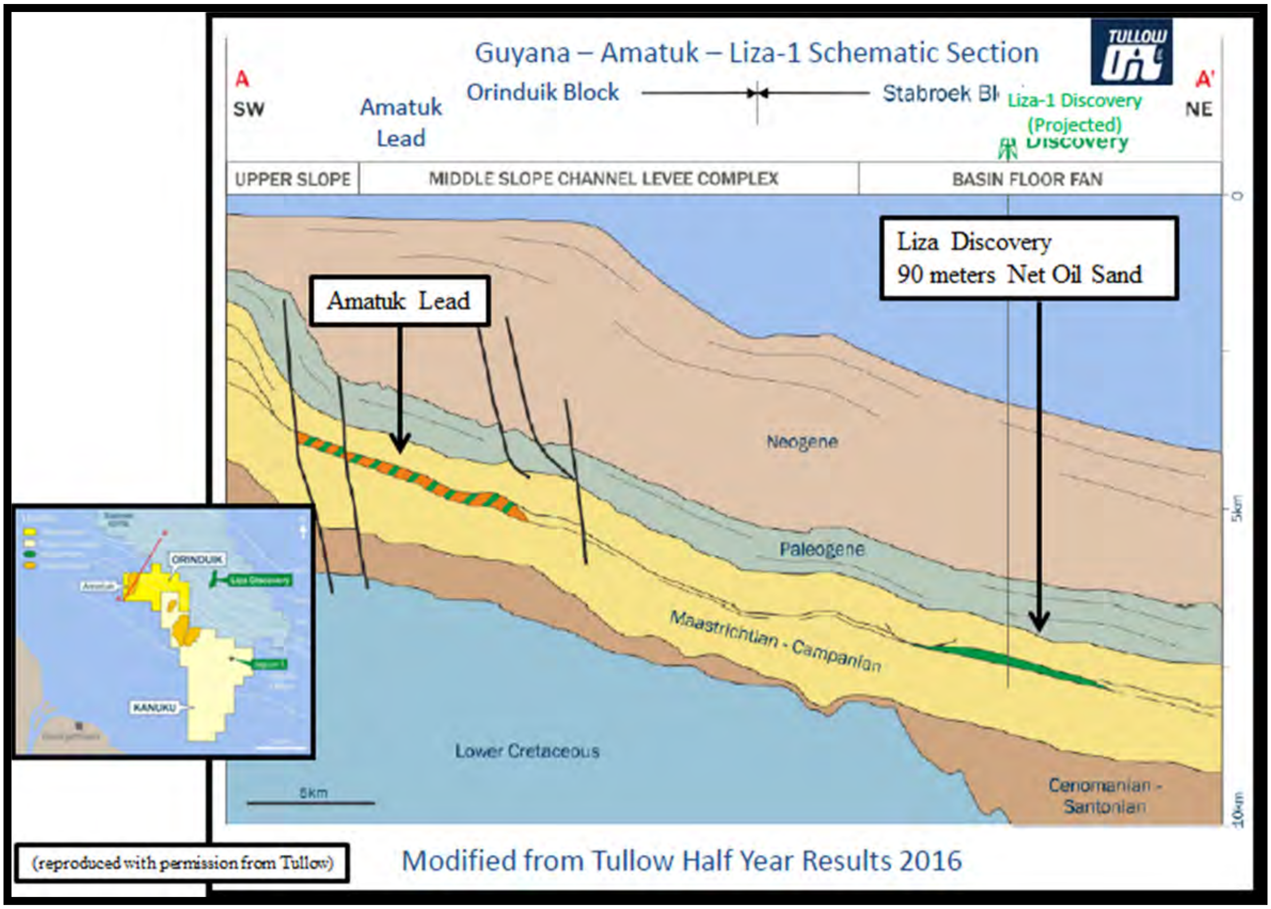

Figure 3—3 Schematic Section from Tullow (courtesy of Tullow Oil Plc)

3.1.4 <u>Distance to Nearest Commercial Production</u>

The nearest hydrocarbon production is located to the southeast, onshore in Suriname in the Tambaredjo field and the adjacent Calcutta field just to the west. 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.[3] These fields are more than 300 kilometers southeast of the prospective area. Venezuela has reported numerous, recent, offshore gas discoveries ranging in size from 0.5 to 7.0 trillion cubic feet. The discoveries in Venezuela are in the process of undergoing commercial development.

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

The discovery by ExxonMobil of Liza-1, Liza-2 and Liza-3 just to the east of the Orinduik Block is reportedly significant with more than 90 meters (295 feet) of oil bearing, Upper Cretaceous sandstone reservoirs in the #1 and #3 wells and 58 meters (190 feet) in the #2 well. The Liza-1 well was drilled to a depth of 5,433 meters (17,825 feet) in 2015 and the Liza-2 to a depth of 5,475 meters (17,963 feet). Recoverable reserves have been estimated to be up to 1.4 billion barrels of oil equivalent (Dunnahoe, 2016).[4] A fourth well, the Skip Jack, was drilled at a location 40 kilometers northwest of the Liza-1 well, on the ExxonMobil Stabroek Block in 2016. This well reportedly did not find commercial oil.[5]

3.1.5 Product Types Reasonably Expected

Oil and associated gas would be expected to be encountered on the Orinduik Block based on the discovery at Liza.

3.1.6 Range of Pool or Field Sizes

Gustavson has not evaluated leads on the Orinduik Block for this report.

3.1.7 Depth of the Target Zone

Gustavson has not evaluated leads on the Orinduik Block for this report.

3.1.8 Identity and Relevant Experience of the Operator

ECO Atlantic Oil and Gas is an Operator of Oil and Gas offshore 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

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[4] http://www.ogj.com/articles/2016/06/exxonmobil-confirms-oil-discovery-in-second-well-offshore-guyana.html 06/30/2016 and http://www.worldoil.com/news/2015/10/22/exxon-mobil-s-deepwater-liza-find-could-put-guyana-suriname-basin-on-the-map

[5] http://www.kaieteurnewsonline.com/2016/09/09/exxonmobil-comes-up-empty-on-third-well/

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 Executives 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.

3.1.9 Risks and Probability of Success

Gustavson has not evaluated leads on the Orinduik Block for this report.

3.1.9.1 Preliminary Assessment

Several Maastrichtian and Campanian aged areas of interest have been identified on the 2D seismic dataset one of which is the Amatuk lead. The Amatuk lead is in the Orinduik Canyon Play Fairway and is located west and updip to the Exxon Liza discovery (Figure 3—4). These areas are still being evaluated and interpreted and, based on the downdip Liza discovery, are expected to contain oil and associated gas at an estimated depth of 3,000 meters. Current plans are to continue the review of the existing 2D seismic data and acquire 2,000 square kilometers of 3D seismic data by the second quarter of 2017. The stacked amplitude event is depicted on the seismic lines in Figure 3—5 courtesy of Tullow Oil Plc.

ECO's partner, Tullow, reports an estimated mean Prospective Resources of 900 MMBO (Figure 3—6) based on their initial evaluation of two lead areas; however, Gustavson has not conducted an independent evaluation of the data at this time and cannot verify this estimate.

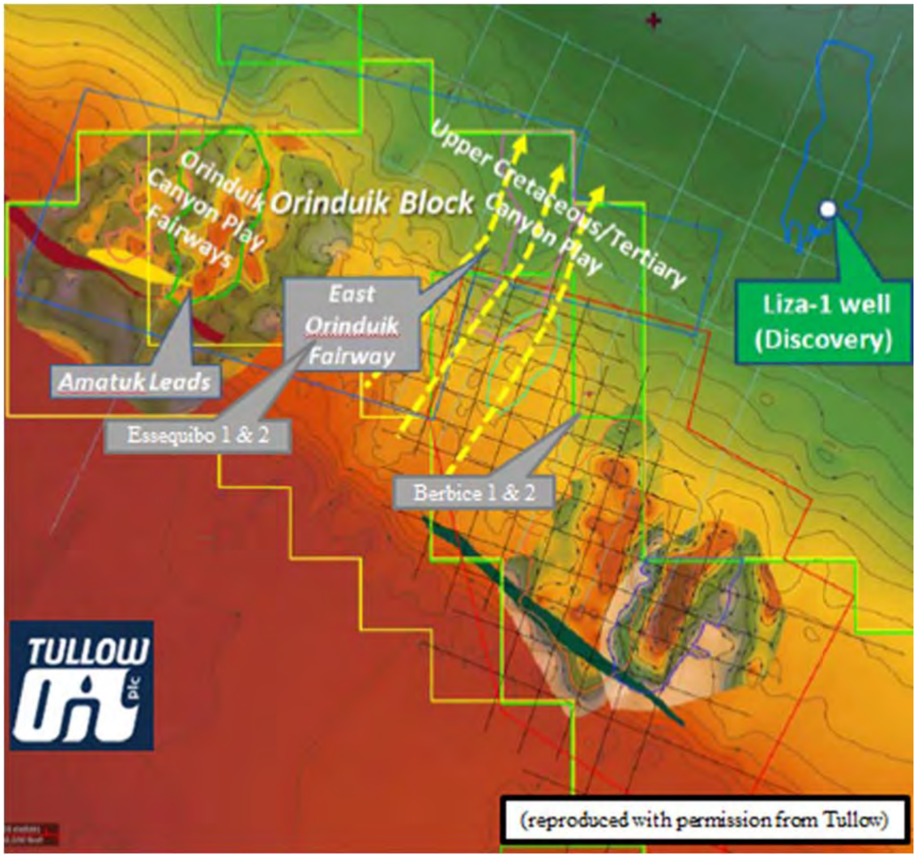


Figure 3—4 Play map from Tullow Interpretation (courtesy of Tullow Oil Plc)

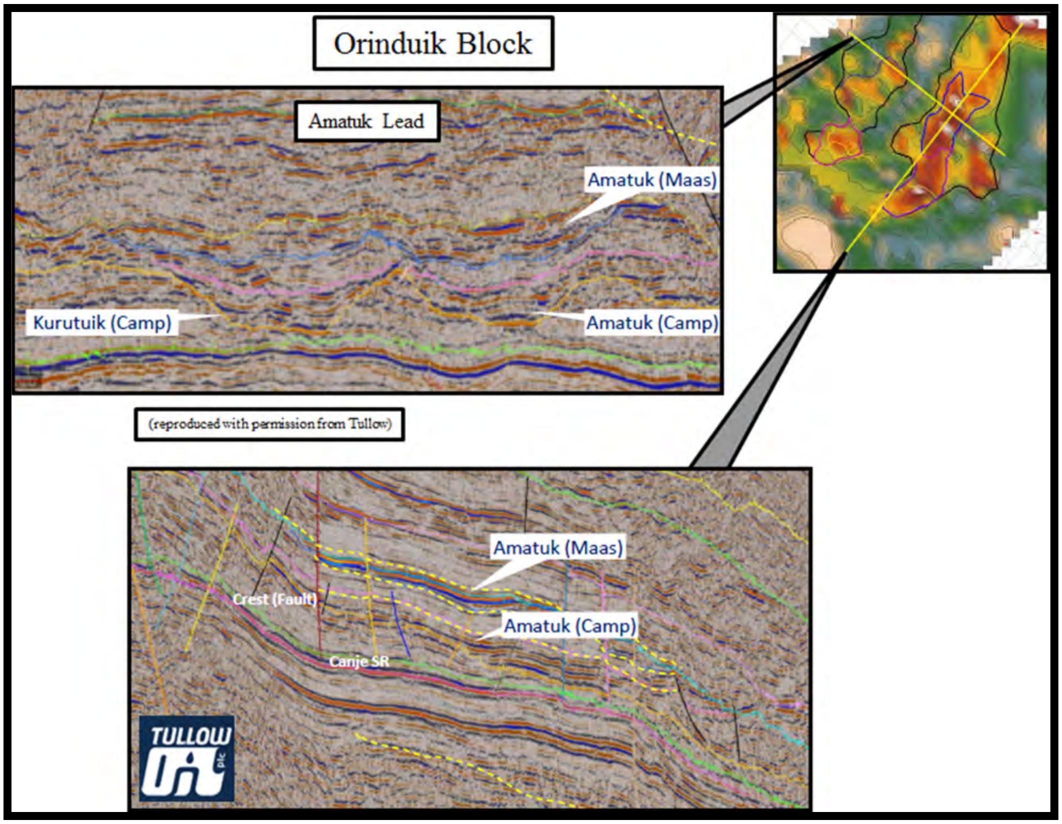
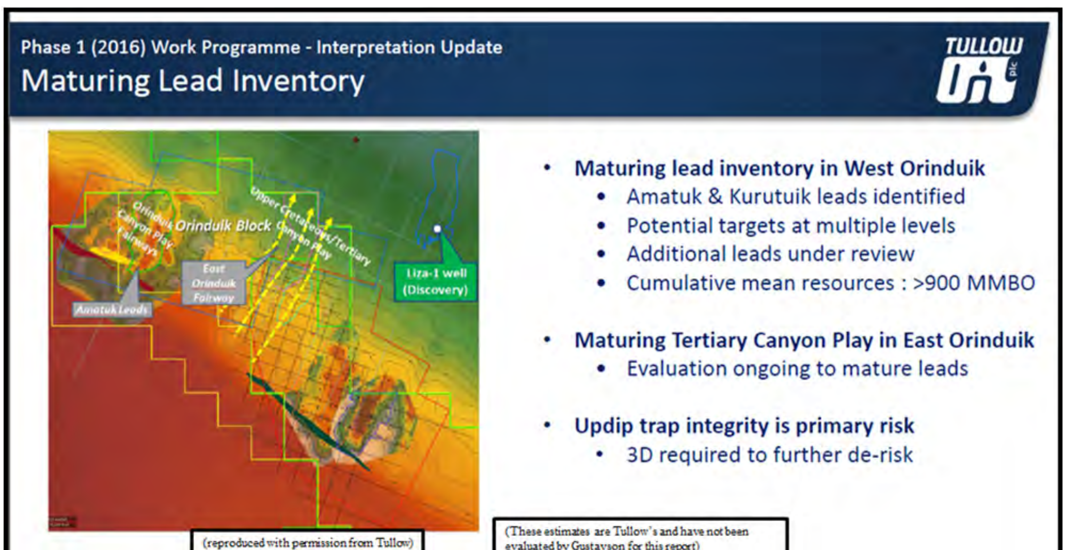


Figure 3—5 Orinduik 2D Seismic lines with Leads (courtesy of Tullow Oil Plc)



Lead	Water Depth (m)	Overburden (m)	Area (Mean) (Km2)	Pg %	Mean Resource (MMBO)	Potential AVO Uplift
Amatuk	70	~2830	60	15	~700	Up to 15%
Kurutuik	70	~2930	25	15	>~200	Up to 15%

Figure 3—6 Tullow Oil Plc Preliminary Estimate of Resources

3.1.10 Future Work Plans and Expenditures

The current plan by the partners includes the acquisition, processing and interpretation of a 3D seismic survey by the second quarter of 2017 or sooner. ECO will be carried by Tullow for the 3D Seismic anticipated for Q2 or Q3 2017. The company is not obligated to complete 3D until 2020, however has moved up its schedule, at its option, due to recent regional discoveries adjacent to the Orinduik Block. ECO is carried through the minimum 1,000 square kilometer 3D program by Tullow who is Operator (Net 60%) on the Block. All 2D seismic is acquired and interpretation is being completed. After 3D, no significant additional capital commitments are required in advance of drilling which is not committed until 2021. Net cost to ECO (40% WI) is approximately $15 Million based on the anticipated well depth and 70 meter water depth. 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.

3.1.11 Market and Infrastructure

Infrastructure for the transport and marketing of hydrocarbons is currently not present in the offshore shelf areas of Guyana and Suriname. The large oil discovery at Liza will spur development of an offshore production network to bring that crude and associated gas to market. Produced oil could be stored either in a Fixed Storage Platform (FSP) or a guyed or anchored Floating Storage and Offloading (FSO) tanker. Oil could then be transported by tanker from the FSO or FSP to markets in North America, Europe, Asia, or South America. The refinery operated by Staatsolie in Suriname does not have the capacity to process large amounts of oil and the existing markets in Guyana and Suriname are small.

3.1.12 Geology

The Guyana-Suriname Basin is a passive margin basin formed by Triassic to Jurassic rifting and separation of South America from Africa (Figure 3—7).

This basin is primarily offshore and is bounded to the south by crystalline basement and to the east by the Demerara High, a remnant of continental crust from the separation, (Schwarzer and Krabbe, 2009).

The basin fill includes clastic deposits from the South American continent, which formed deltas along a passive margin shelf and slope (Figure 3—8). Carbonate depositional settings were located on the shelf edge. Miocene uplift changed the drainage of the continent and reduced the clastic sedimentation from the continent replacing the coarse-grained clastics and shelf edge carbonates with fine-grained clastics.

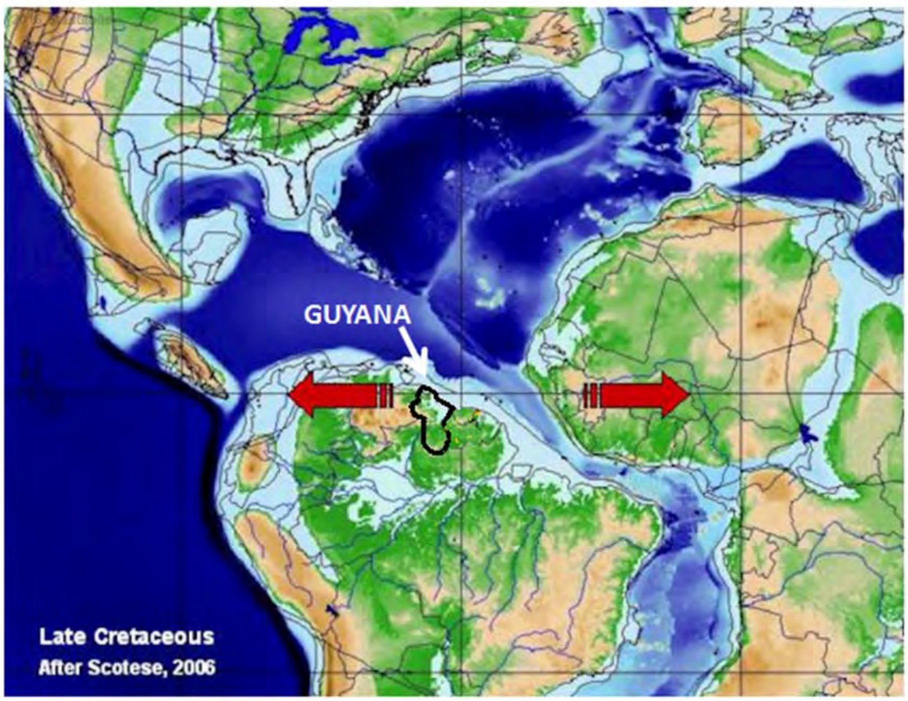
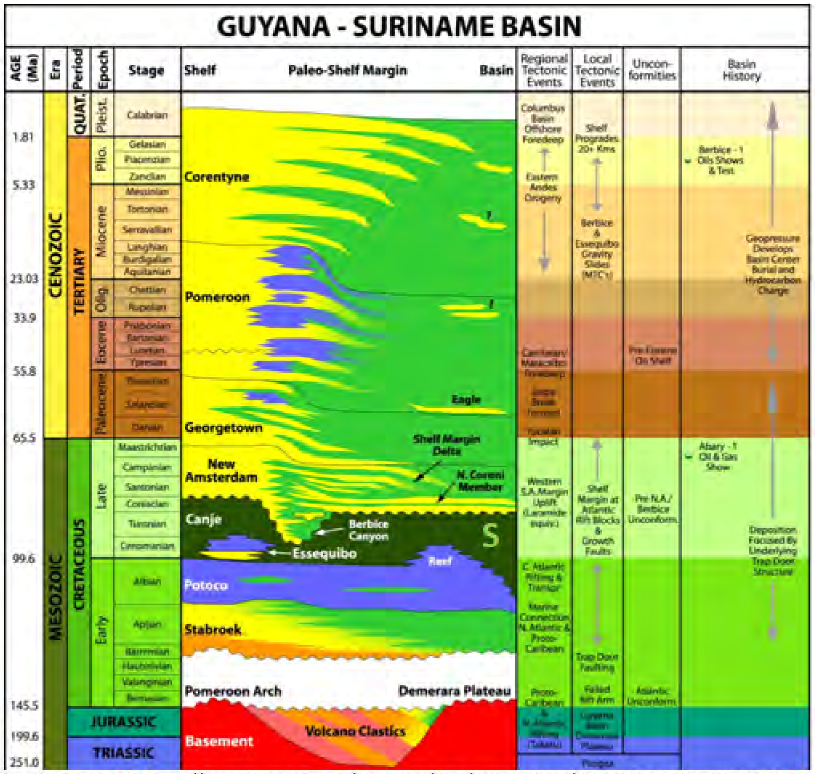


Figure 3—7 Paleotectonic Map Showing the Location of Guyana and Plate Tectonics in the Late Cretaceous



After Workman, 2007, http://www.cgxenergy.com/cmsAssets/docs/presentations/GuyanaMiningAbstract-Jul31-07.pdf

Figure 3—8 Stratigraphic Column for the Guyana Suriname Basin

3.1.13 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 (Figure 3—8). Oils in the Tambaredjo, Tambaredjo Northwest, and Calcutta fields located onshore in Suriname have been sourced from rocks in the Canje Formation.[6] The Canje Formation is presently in the oil window offshore Guyana and Suriname (Schwarzer and Krabbe, 2009) (Figure 3—9). Significant oil generation from this source rock began during the Late Paleocene and continues.

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

The Canje Formation source rock (Figure 3—8) 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 component in nearshore locations. Equivalent age 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 3—9). 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).

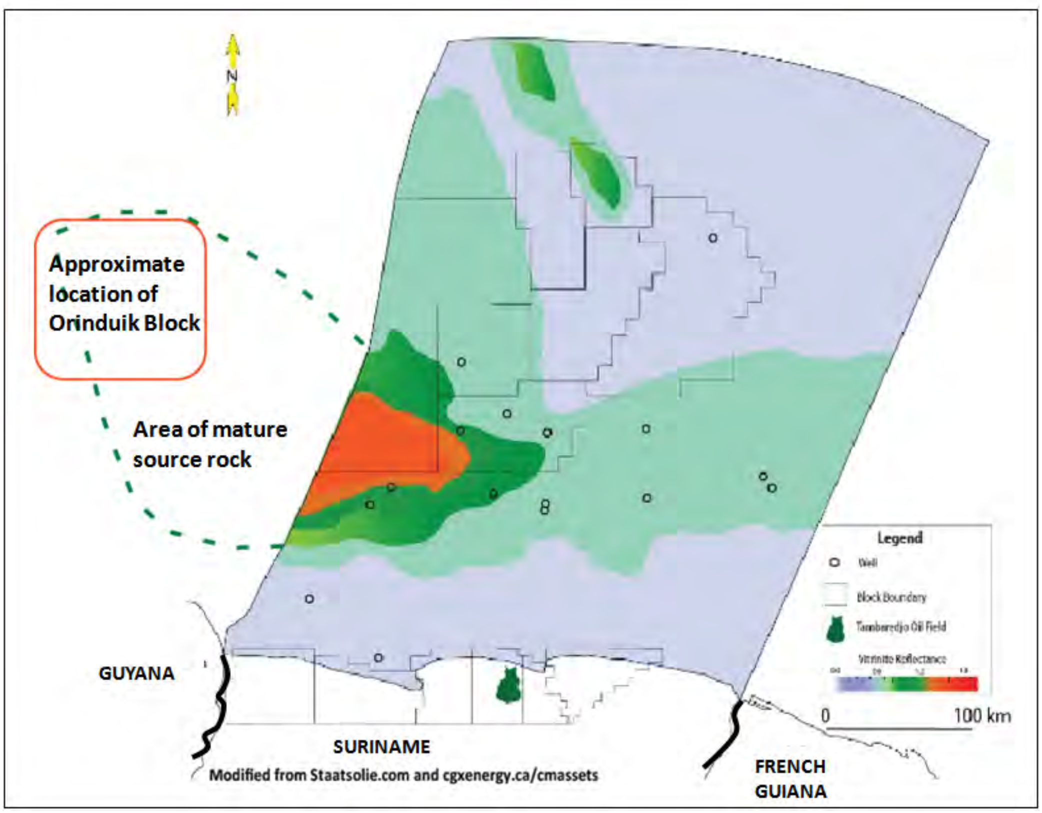


Figure 3—9 Map of Offshore Suriname Showing Mature Canje Formation Source Rock Maturation Level

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.

3.2 LOCATION AND BASIN NAME: NAMIBIA

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 3—10). ECO holds interests in four Petroleum Exploration License (PEL) Blocks totaling approximately 22,500 square kilometers.

Figure 3—10 Map of the country of Namibia (Trek, 2008)

These four Blocks are the Cooper Block (Block 2012A) PEL 30, Guy Block (east half of Blocks 2111B & 2211A) PEL 34, Sharon Block (west half of Blocks 2213A & B) PEL 33, and Tamar Block (Blocks 2211Ba & 2311A) PEL 50 (Figure 3—11).

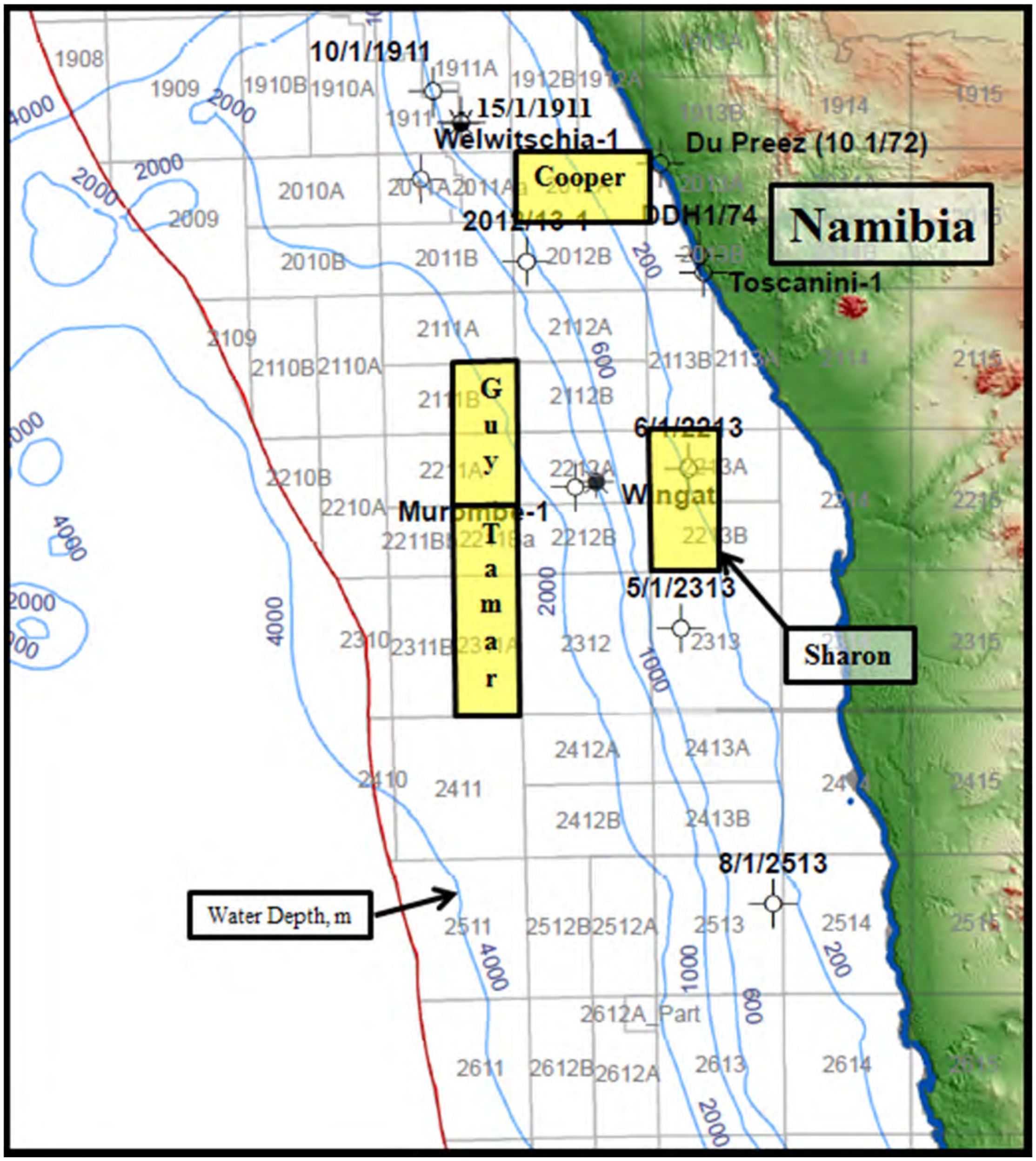


Figure 3—11 Index map Offshore Namibia with ECO Block locations

3.2.1 Gross and Net Interest in the Property

The Cooper Block License (PEL 30) covers an area of approximately 5,000 square kilometers (1,235,000 acres). ECO holds a 32.5% 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. If Tullow chooses to exercise its option over another 15% interest in the license and drills a well ECO would be 100% carried through the drilling of the well.

The Sharon Block License (PEL 33) covers an area of approximately 5,000 square kilometers (1,235,000 acres). ECO holds a 60%WI and is designated as the Operator. The water depth at the Sharon Block ranges from 100 meters to 500 meters. ECO will be carried for 20% of their share of the 3D seismic acquisition costs.

The Guy Block License (PEL 34) covers an area of approximately 5,000 square kilometers (1,235,000 acres). ECO holds a 50% WI and Azinam is the Operator. The water depth ranges from 1,500 to 3,000 meters. ECO is being carried through the 3D interpretation costs.

The Tamar Block License (PEL 50) covers an area of approximately 7,500 square kilometers (1,853,290 acres). ECO holds a 72% 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.

3.2.2 Expiry Date of Interest

The Cooper, Sharon and Guy Blocks were licensed to ECO in March 2011 for an initial four year term which had been extended for one year to March 2016. Since the work commitment has been met, the three Blocks have been renewed for an additional two year period and can be renewed for an additional two years until March 2020. The Tamar Block was obtained from Pan African who had obtained the license in March 2012. The commitments have all been met to date and the Block will be renewed by ECO for the next two years in which the commitment is to acquire a 500 square kilometer 3D survey in Fall of 2018.

3.2.3 Description of Target Zones

There are multiple target horizons and trap types over the four Blocks as depicted in Figure 3—12 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.

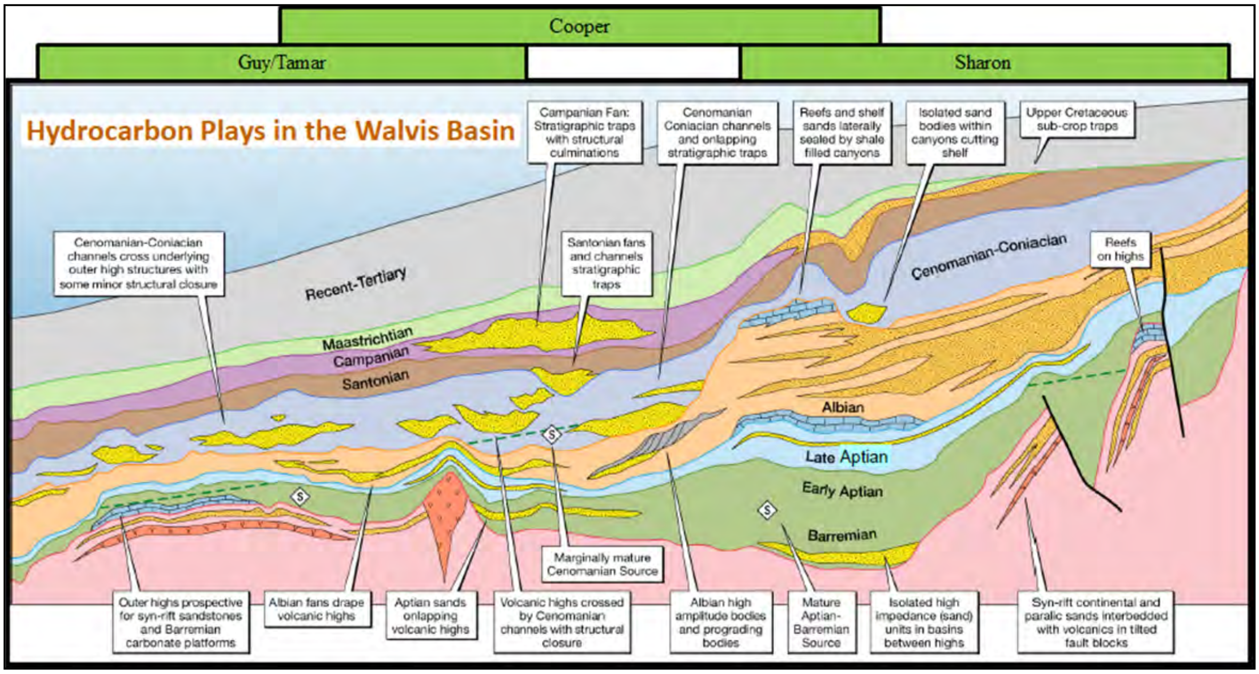


Figure 3—12 Play types in the Offshore of Namibia with the ECO Blocks

3.2.4 <u>Distance to the Nearest Commercial Production</u>

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 Blocks in the offshore of Namibia.

3.2.5 <u>Product Types Reasonably Expected</u>

Oil of 30 to 40 degrees API with associated gas is the expected hydrocarbon type to be found in these leads.

3.2.6 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 52.3 to 1,302.3 MMBbl.

3.2.7 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.

3.2.8 Identity and Relevant Experience of the Operator

ECO Atlantic Oil and Gas is an Operator of Oil and Gas offshore 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.

3.2.9 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

Presence of Hydrocarbons: 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 3—1 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 3—1 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
Presence of HC	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 of this Report as Table 3—2, Table 3—3, and Table 3—4. The variations in COS numbers are generally based on the amount and type of seismic data that support the Leads and Prospect.

3.2.10 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 on the Sharon Block. 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.

Namibia Cooper Block – All seismic is complete and interpretation is being completed. No significant additional capital commitments are required in advance of drilling. Drilling is anticipated by or before the end of March 2020. ECO is fully carried on the well by Tullow. 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 2018 for drilling a well by March 2020. Current estimated net cost to ECO for approximately 1000 Km^2, inclusive of processing; to complete and interpret is +/- $1.5 Million. No other significant additional capital commitments are required in advance of drilling. Drilling is anticipated by or before March 2020. 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 Net cost for drilling the well to be approximately $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 – 3D is complete and interpretation is being completed. No significant capital commitments are required in advance of drilling. Drilling is anticipated on or before March 2020. 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. Company currently estimates Net cost for drilling the well to be approximately $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 –3D seismic acquisition is anticipated for Fall 2018 if the internal interpretation of the 2D seismic defines a regional target. Current estimated net cost to ECO for approximately 500 Km^2, inclusive of processing; to complete and interpret is +/- $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 2019. ECO intends to agree to an appropriate farm out agreement to reduce its net share on the well in order to drill it. 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 $70 Million Gross, ECO's Net cost, should it chose to proceed, will be approximately 25% of the gross based on its current risking philosophy. 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.

3.2.11 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.

3.2.12 Geology

3.2.12.1 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 3—13, 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 3—14 where the area of interest is within the Walvis Basin.

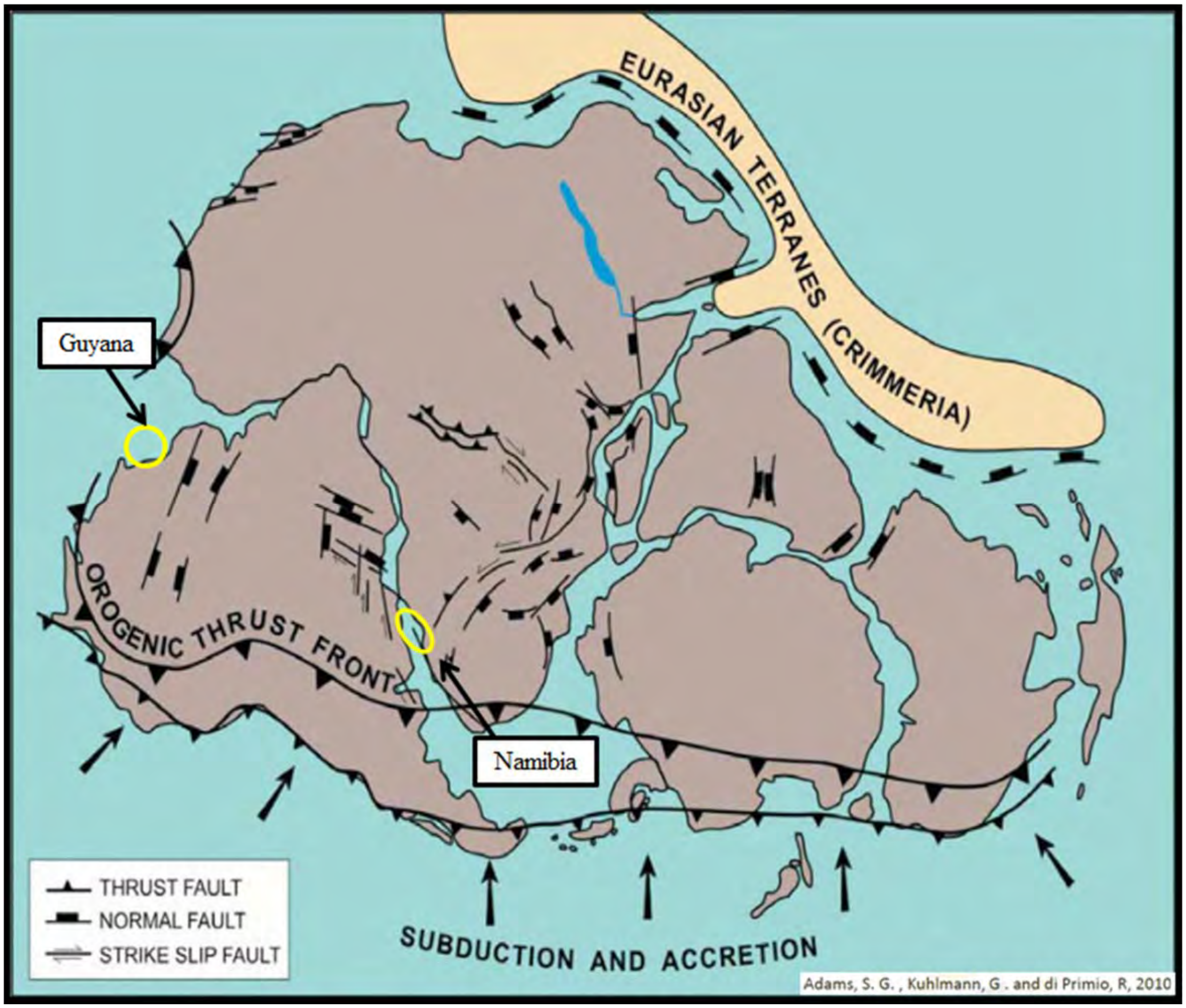


Figure 3—13 Paleogeographic Map of the Opening of the South Atlantic Margin

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

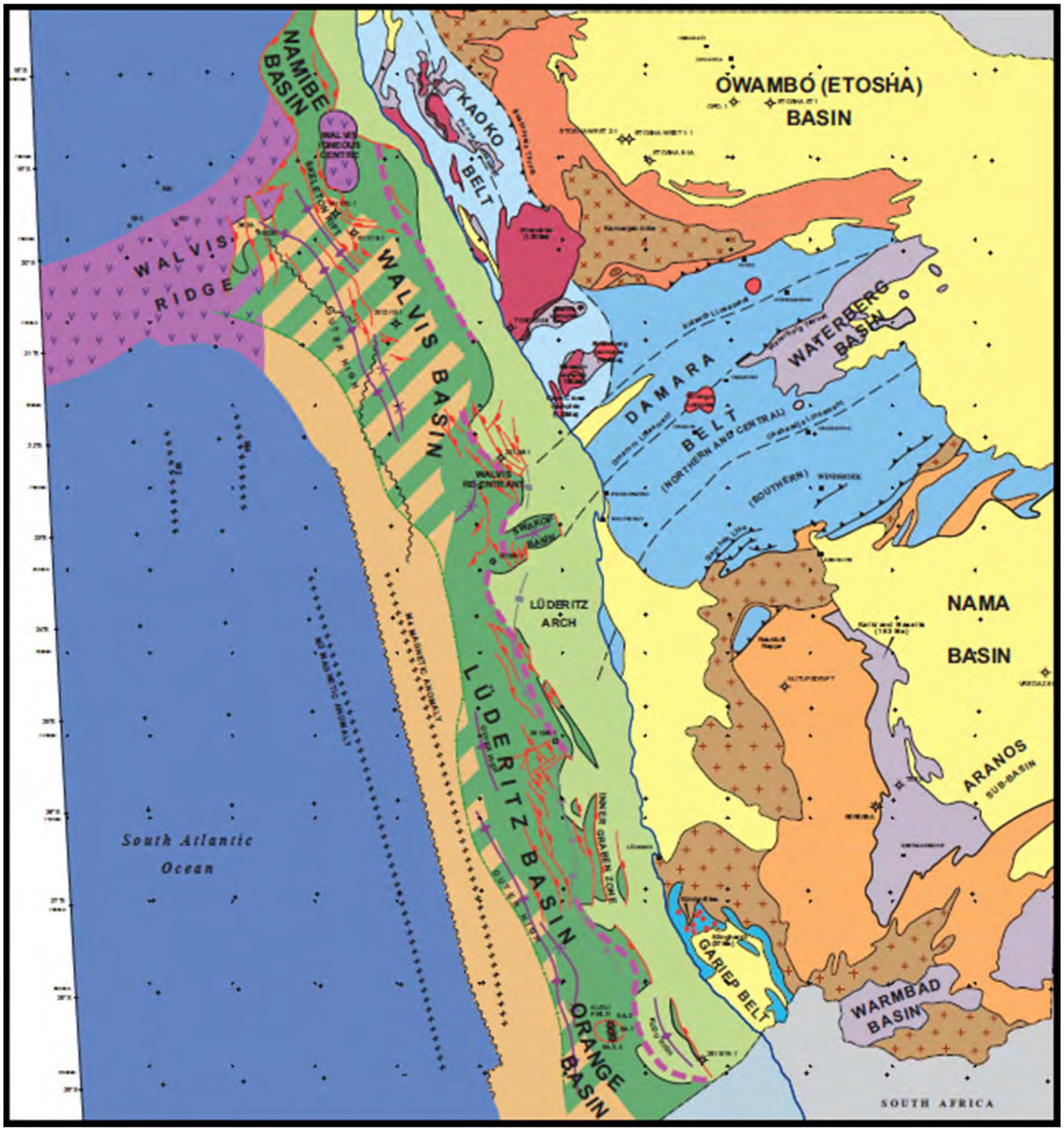


Figure 3—14 Sedimentary Basins in Offshore Namibia
(Bray, Lawrence, Swart, 1998)

3.2.12.2 Stratigraphy

The basin system in offshore Namibia is depicted in Figure 3—15, 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.

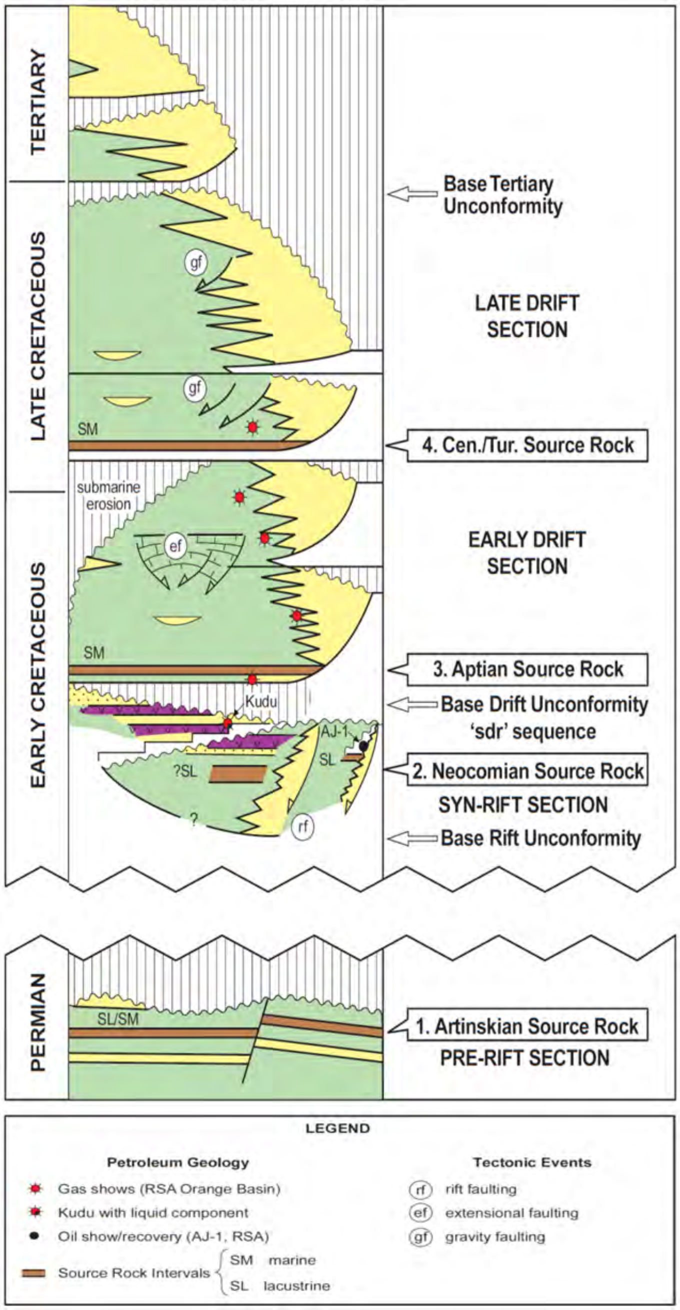


Figure 3—15 Generalized Stratigraphic Chart of Offshore Namibia
(Bray, Lawrence, Swart, 1998)

3.2.12.3 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.

3.2.12.4 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[7] 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 3—16, 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.[8]

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[7] Oil & Gas Journal – August 1998 – R. Bray, S. Lawrence, R. Swart

[8] Bray, Lawrence, and Swart, “Source Rock, maturity data indicate potential off Namibia”, Oil and Gas Journal, August 1998.

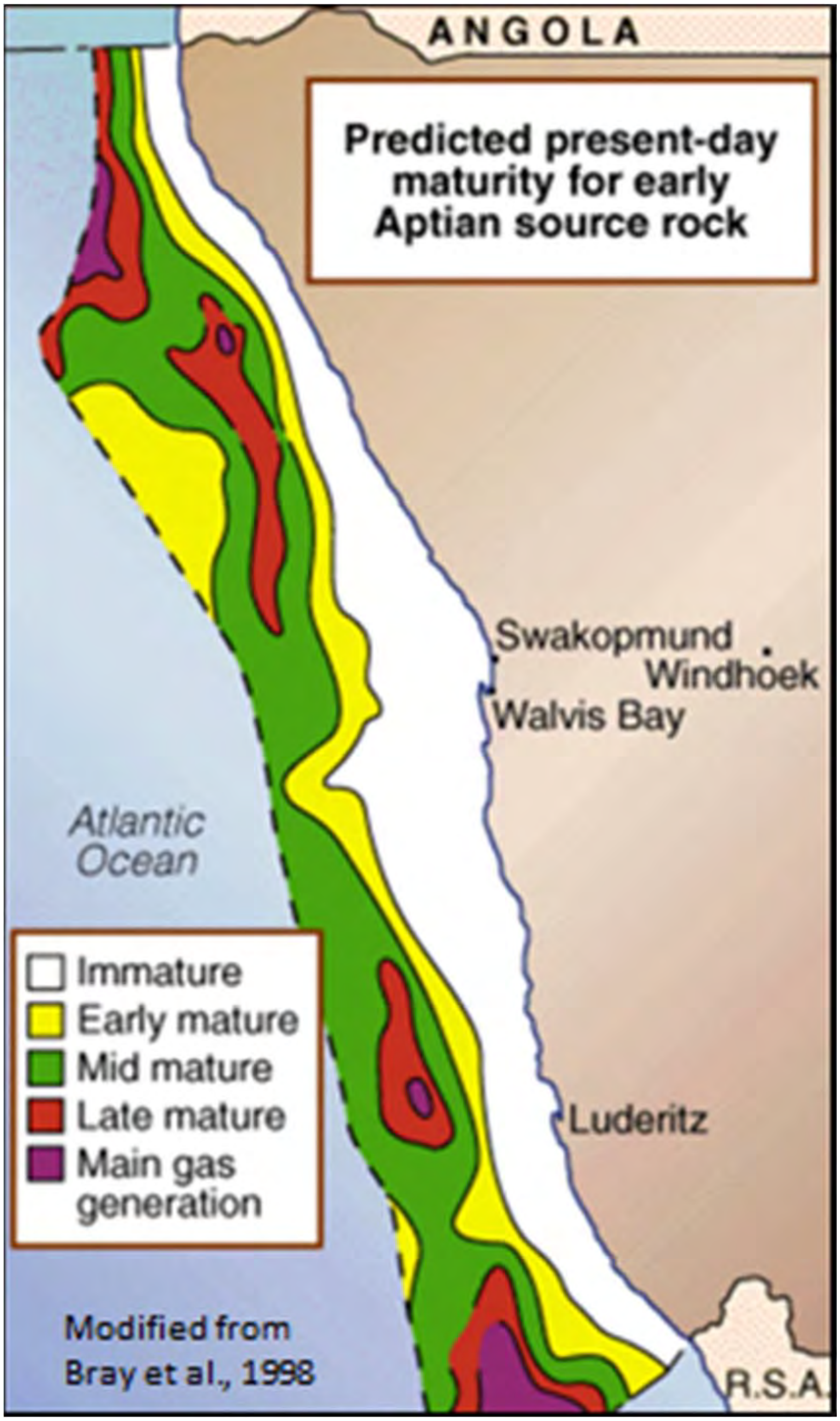

Figure 3—16 Extent of Albian-Aptian Source Rock

3.2.12.5 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.

3.2.12.6 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.

3.2.12.6.1 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 3—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.

3.2.12.6.2 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.

3.2.12.6.3 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.

3.2.12.7 Traps and Seals

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

3.2.13 Analogous Field

3.2.13.1 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).

3.2.14 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 (Figure 3—17). 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.[9] 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 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.

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

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.

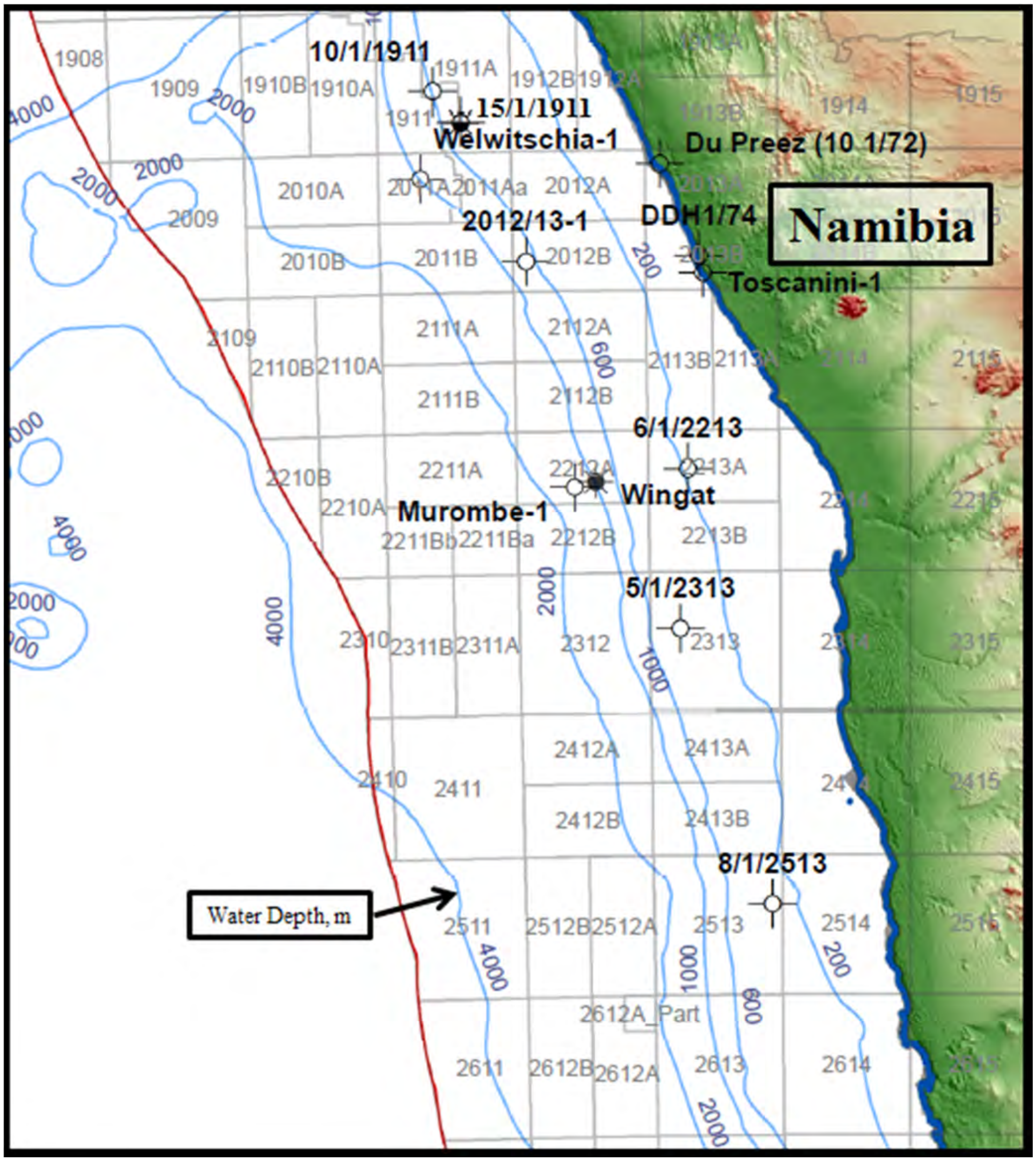

Figure 3—17 Map of Offshore Northern Namibia Showing Wells

3.2.15 <u>Contract Areas</u>

ECO holds interests in four Petroleum Exploration License (PEL) Blocks totaling approximately 22,500 square kilometers. The Cooper Block, Sharon Block, Guy Block, and Tamar Block are located as seen in (Figure 3—11) above. The Cooper, Sharon and Guy Blocks were licensed to

ECO in March 2011 for an initial four year term which had been extended for one year to March 2016. Since the work commitment has been met, the three Blocks have been renewed for an additional two year period and can be renewed for an additional two years until March 2020. The Tamar Block was obtained from Pan African who had obtained the license in March 2012. The commitments have all been met to date and the Block will be renewed by ECO for the next two years in which the commitment is to acquire a 500 square kilometer 3D survey Fall of 2018.

Cooper Block contract area totals approximately 5,000 square kilometers. Exploration License Agreement number 0030 for the Cooper Block is made with the *Republic of Namibia Ministry of Mines and Energy*, dated March 14, 2011.

The Guy Block contract area totals approximately 5,000 square kilometers. Exploration License Agreement number 0034 for the Guy Block is made with the *Republic of Namibia Ministry of Mines and Energy*, dated March 14, 2011.

The contract area for Sharon Block totals approximately 5,000 square kilometers. Exploration License Agreement number 0033 for the Sharon Block is made with the *Republic of Namibia Ministry of Mines and Energy*, dated March 14, 2011

3.2.16 Leads

3.2.16.1 Cooper Block PEL 30

The Cooper Block is located off the coast of Namibia (Figure 3—18) in less than 100 meters to over 500 meters of water. The play types expected based on Figure 3—12 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 3—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.

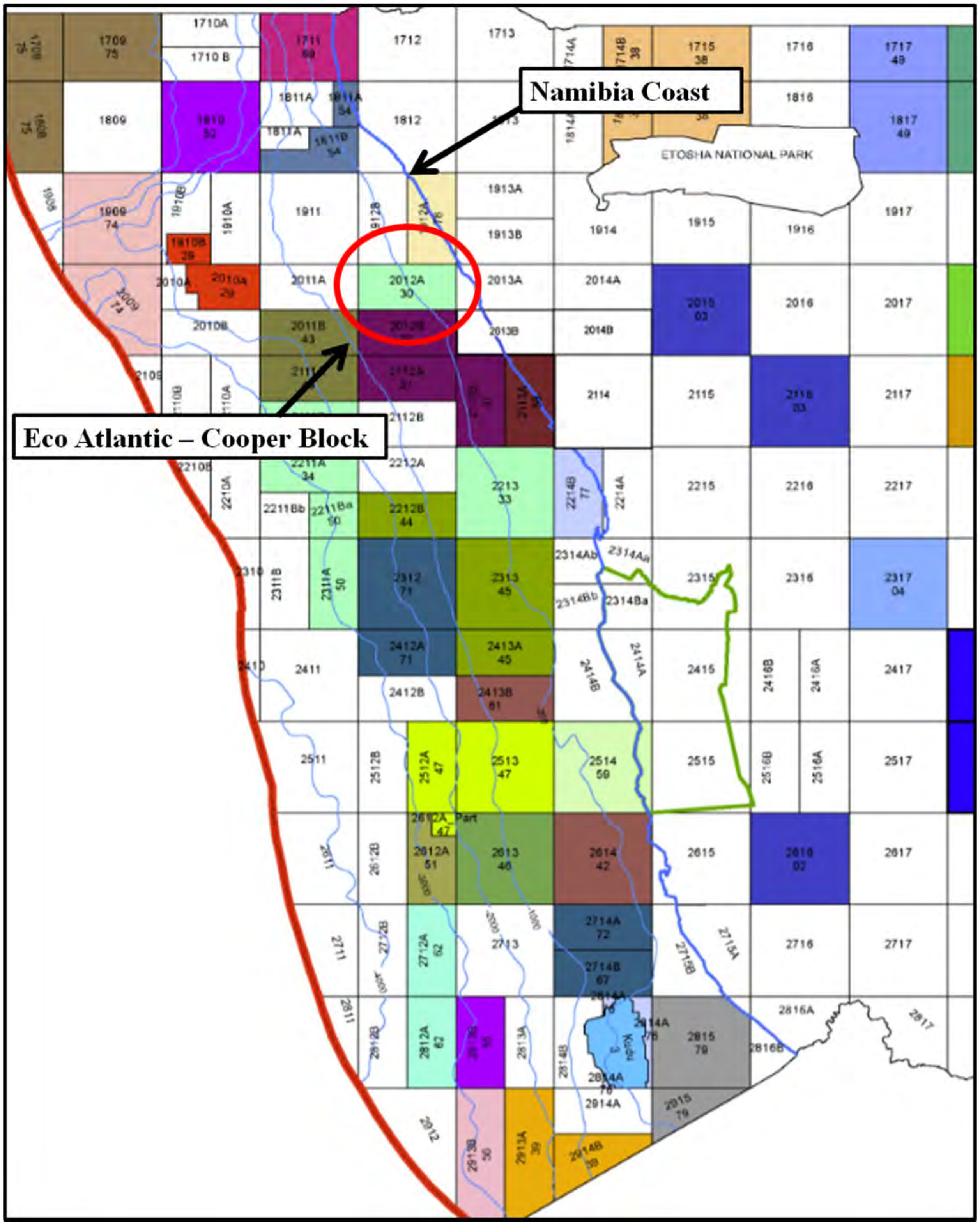

Figure 3—18 Location of Cooper Block

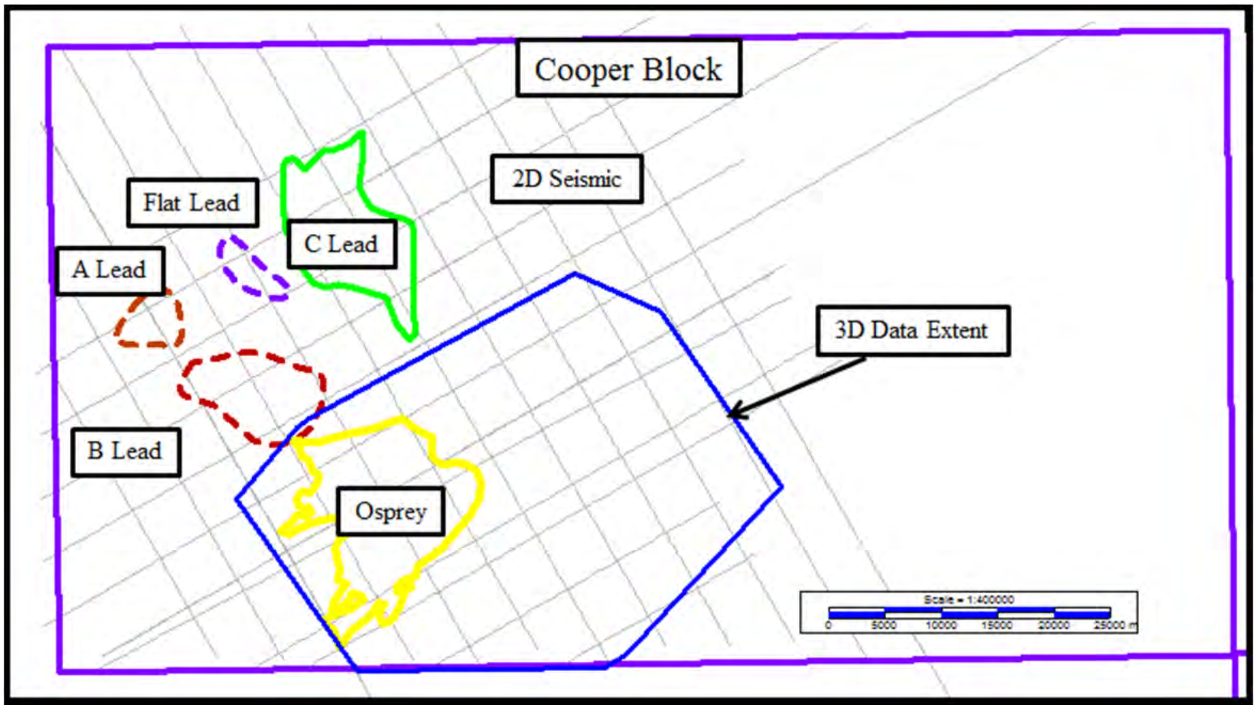

Figure 3—19 Cooper Block with Lead and Prospect Area Outlines

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 3—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 3—21) that goes through the Osprey prospect shows that the amplitude response is readily apparent.

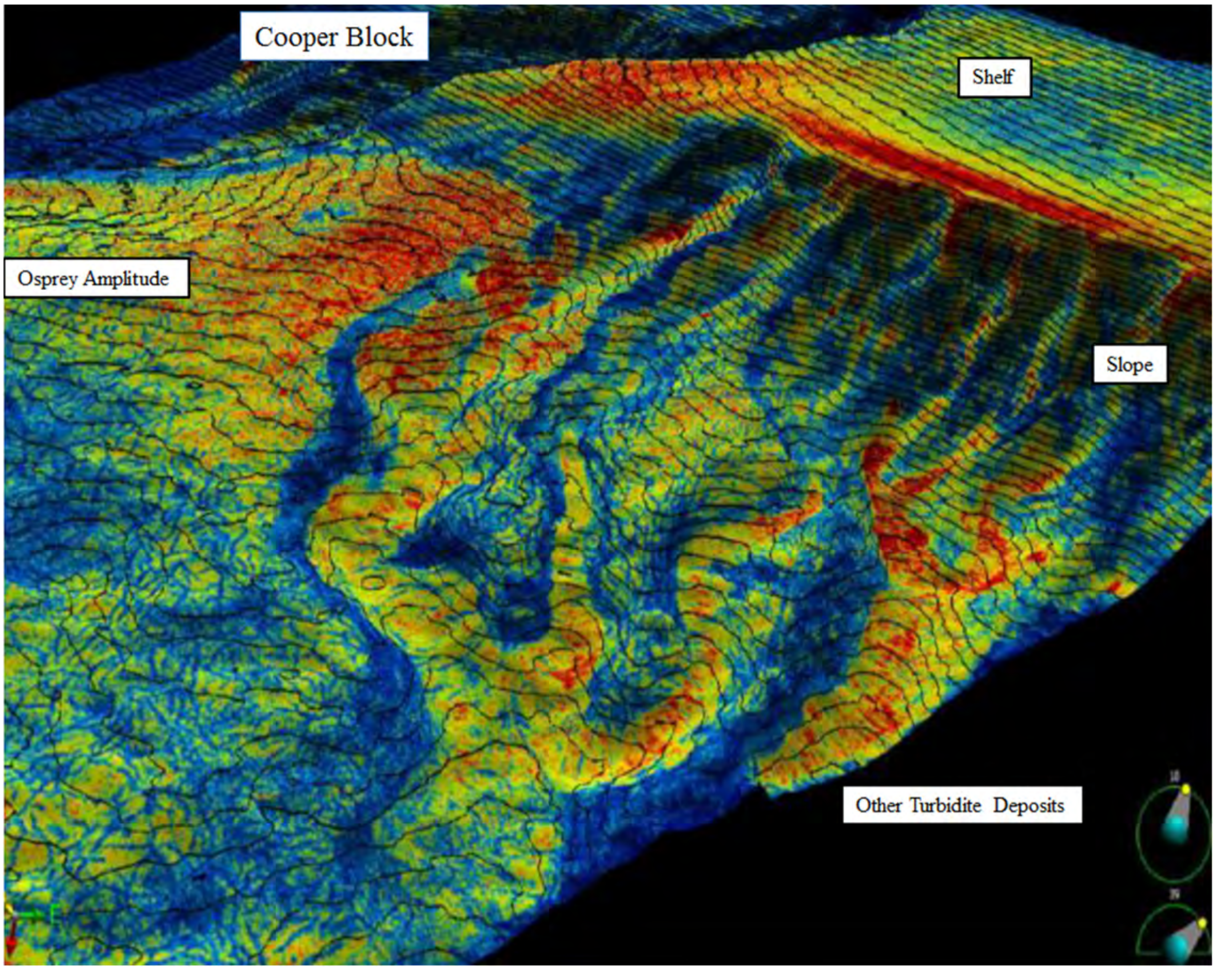

Figure 3—20 Image from Cooper 3D seismic data set

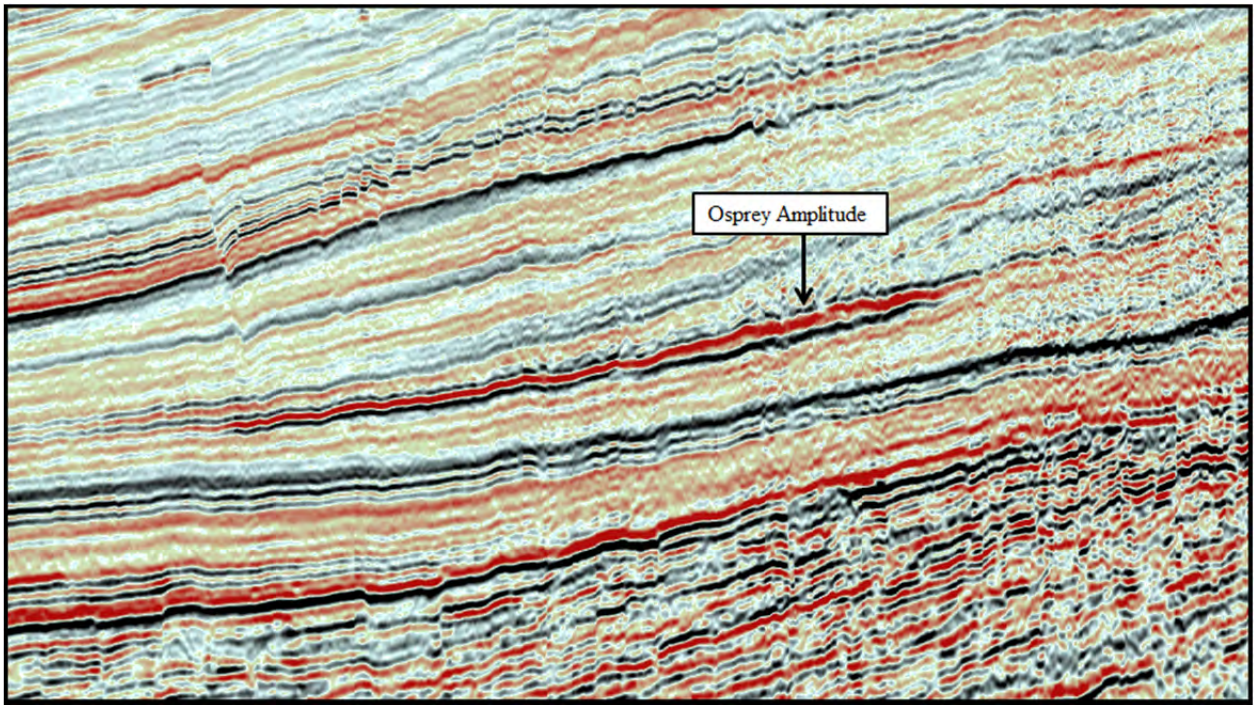

Figure 3—21 Seismic Line from Cooper 3D showing the Osprey Amplitude

The Osprey prospect amplitude map overlain with time structure contours, with downdip being to the southwest, is depicted in Figure 3—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 areas in square kilometers and acres used in the Probabilistic Prospective Resource estimates are compiled in Table 3—2.

The Osprey Prospect having been delineated by a 3D seismic data set would have an estimated Chance of Success (COS) of 17.9%[10]. Several additional leads have been identified by ECO and their partners which have not been evaluated at the time of this report.

[10] Section 3.2.4 Risk Assessment

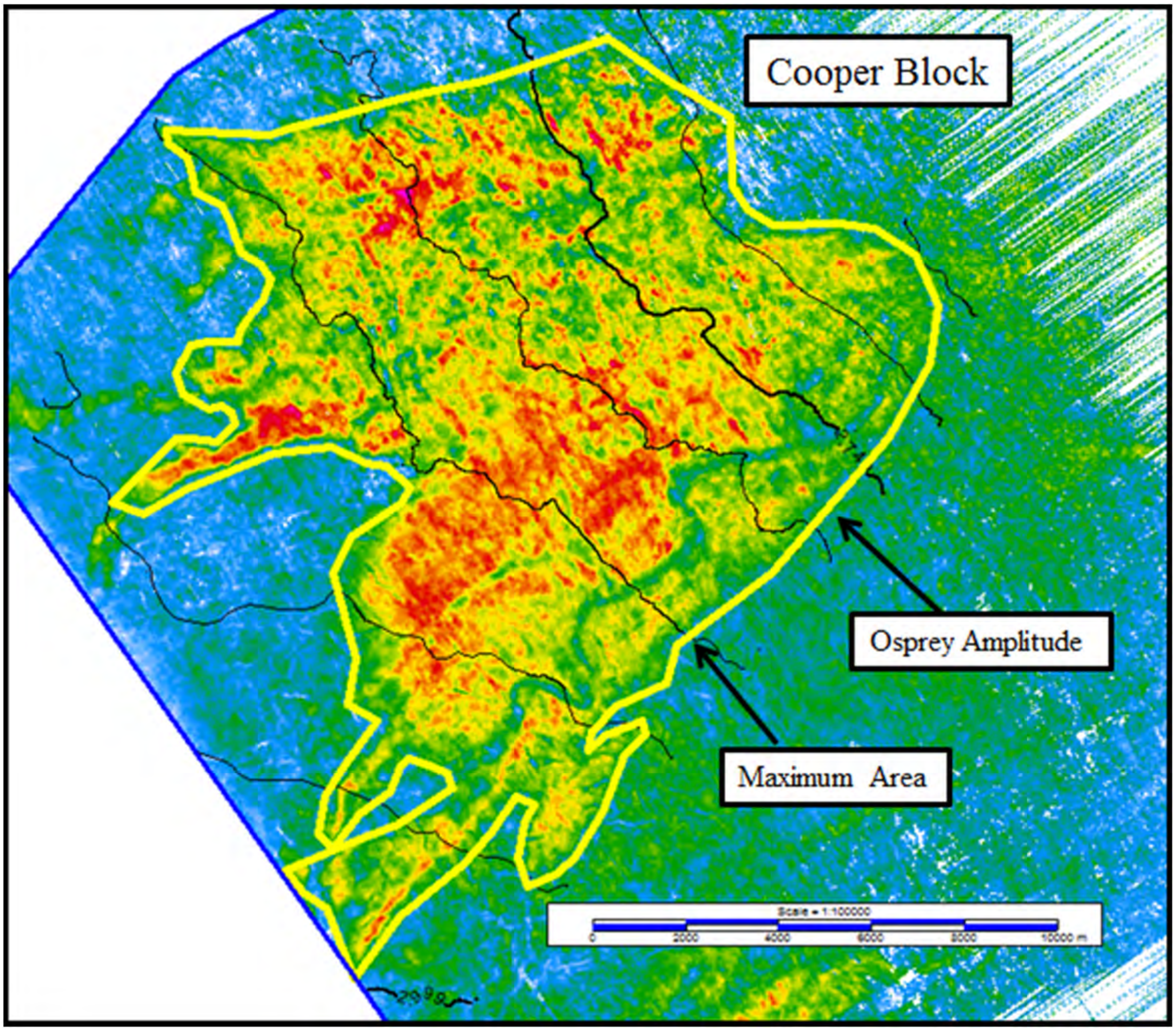

Figure 3—22 Amplitude with Time Structure Map of Osprey Prospect

Table 3—2 Cooper Block Lead and Prospect Areas and P50 Gross Prospective Resources with COS

Lead/Prospect	Minimum (P10) km^2 / Acres	Most Likely (P50) km^2 / Acres	Maximum (P90) km^2 / Acres	Gross Prospective Oil Resources (P50) Most Likely MMBO	Risk COS%
Lead A	4.4 / 1,087	11.0 / 2,718	14.1 / 3,494	70.5	3.2
Lead B	14.1 / 3,494	35.3 / 8,735	70.7 / 17,470	205.3	3.5
Lead C	22.8 / 5,634	57.0 / 14,085	114.0 / 28,170	179.3	3.5
Lead Flat	3.2 / 791	8.0 / 1,977	16.0 / 3,954	52.3	3.0
Osprey	49.8 / 12,300	89.8 / 22,200	175.0 / 43,250	245.5	17.9

3.2.16.2 Sharon Block PEL 33

The Sharon Block consists of the western halves of Blocks 2213A and 2213B (Figure 3—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 3—12) 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 3—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.

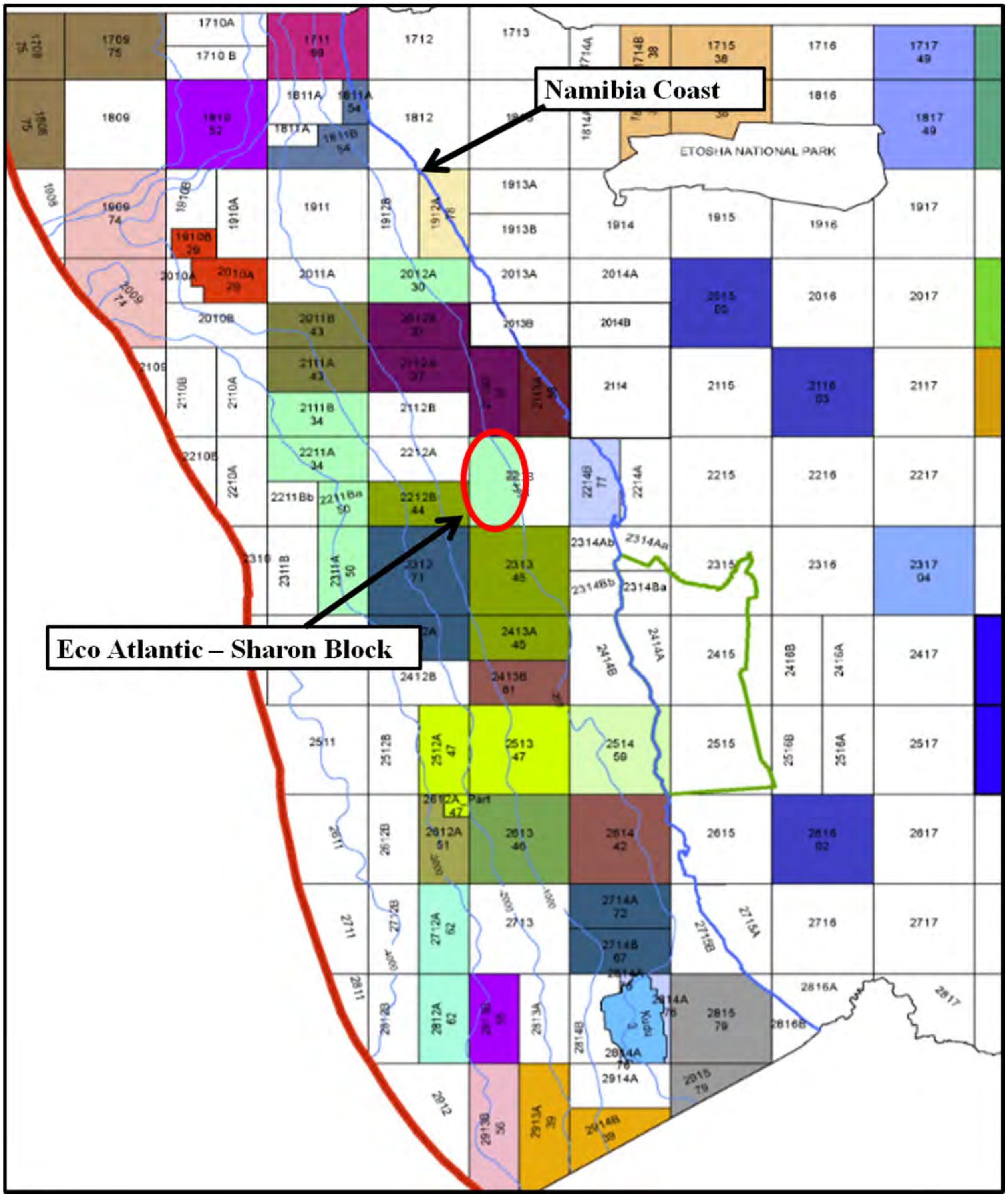

Figure 3—23 Location of Sharon Block

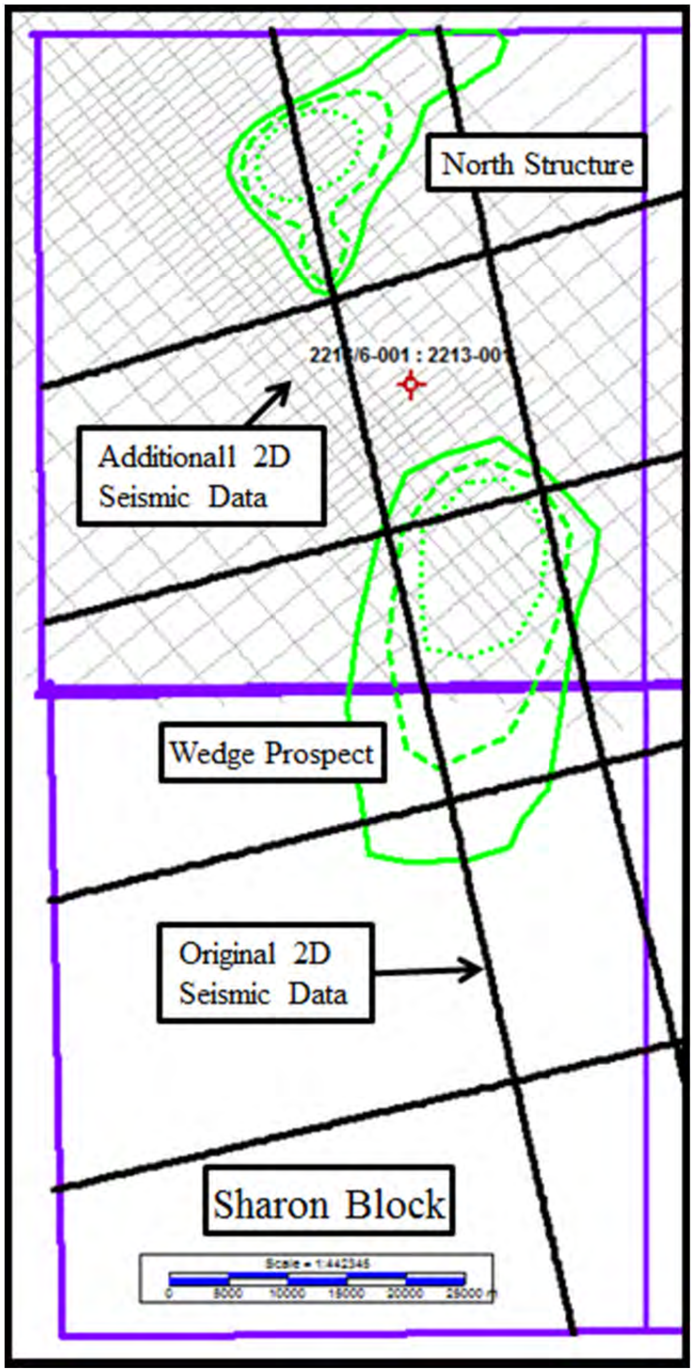

Figure 3—24 Location of Leads and current 2D seismic data in Sharon Block Namibia

The areas in square kilometers and acres used in the Probabilistic Prospective Resource estimates are compiled in Table 3—3 below.

Table 3—3 Sharon Block Lead Areas and P50 Gross Prospective Resources with COS

Lead	Minimum (P10) km^2 / Acres	Most Likely (P50) km^2 / Acres	Maximum (P90) km^2 / Acres	Gross Prospective Oil Resources (P50) Most Likely MMBO	Risk COS%
North Structure	47.5 / 11,737	112.7 / 27,849	230.0 / 56,834	909.4	1.9
Wedge	125.0 / 30,890	294.0 / 72,650	564.9 / 139,600	1,302.3	3.5

3.2.16.3 Guy Block PEL 34

The Guy Block consists of the east halves of Blocks 2111B and 2211A (Figure 3—25). The play types anticipated (Figure 3—12) 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 (Figure 3—26) 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. The extent of the numerous Cenomanian channel sands that have been tied to the Baobab sand in the Murombe well is depicted in Figure 3—27. Seismic line NWG98-408 (Figure 3—28) 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 3—26) 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.

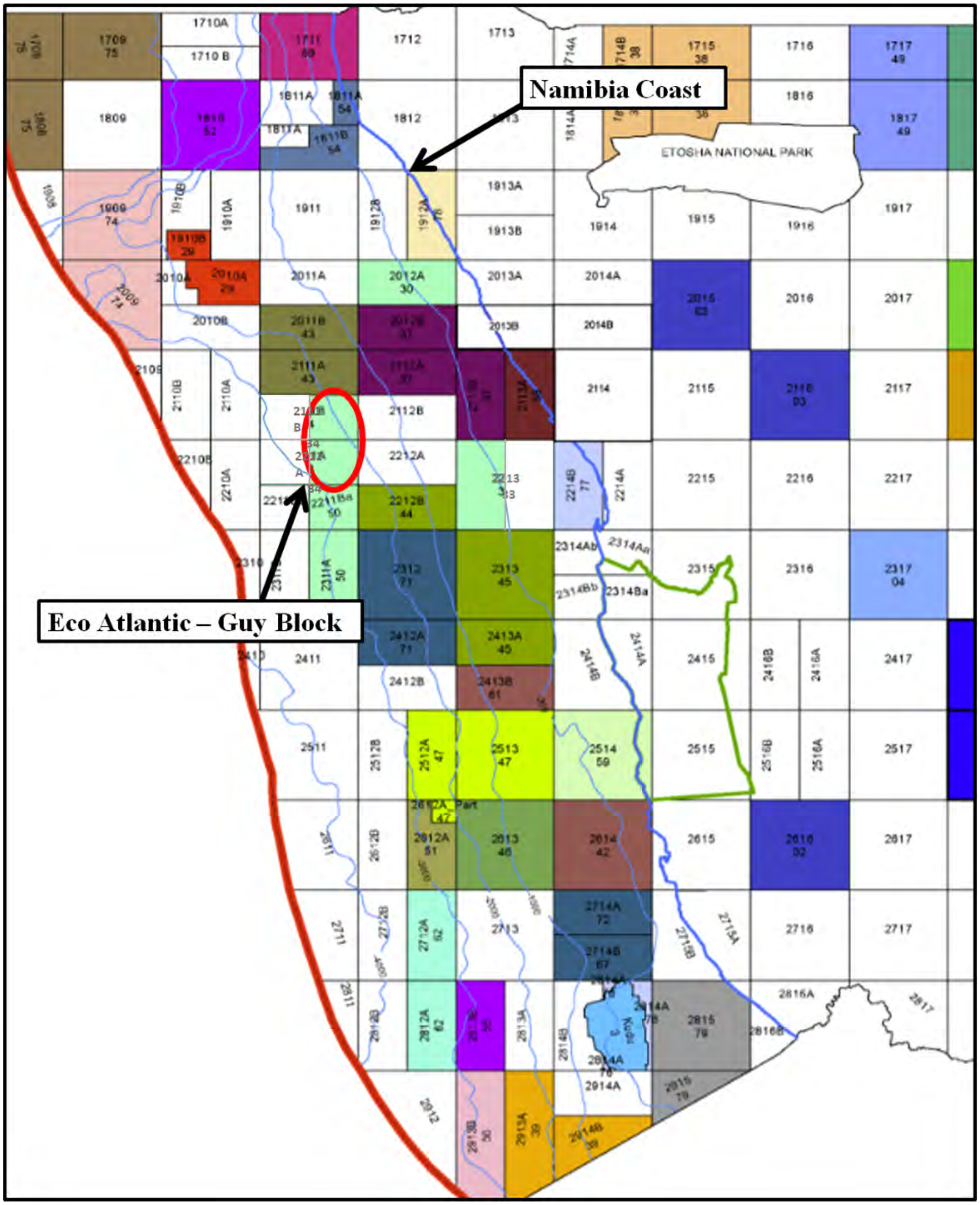

Figure 3—25 Location of Guy Block

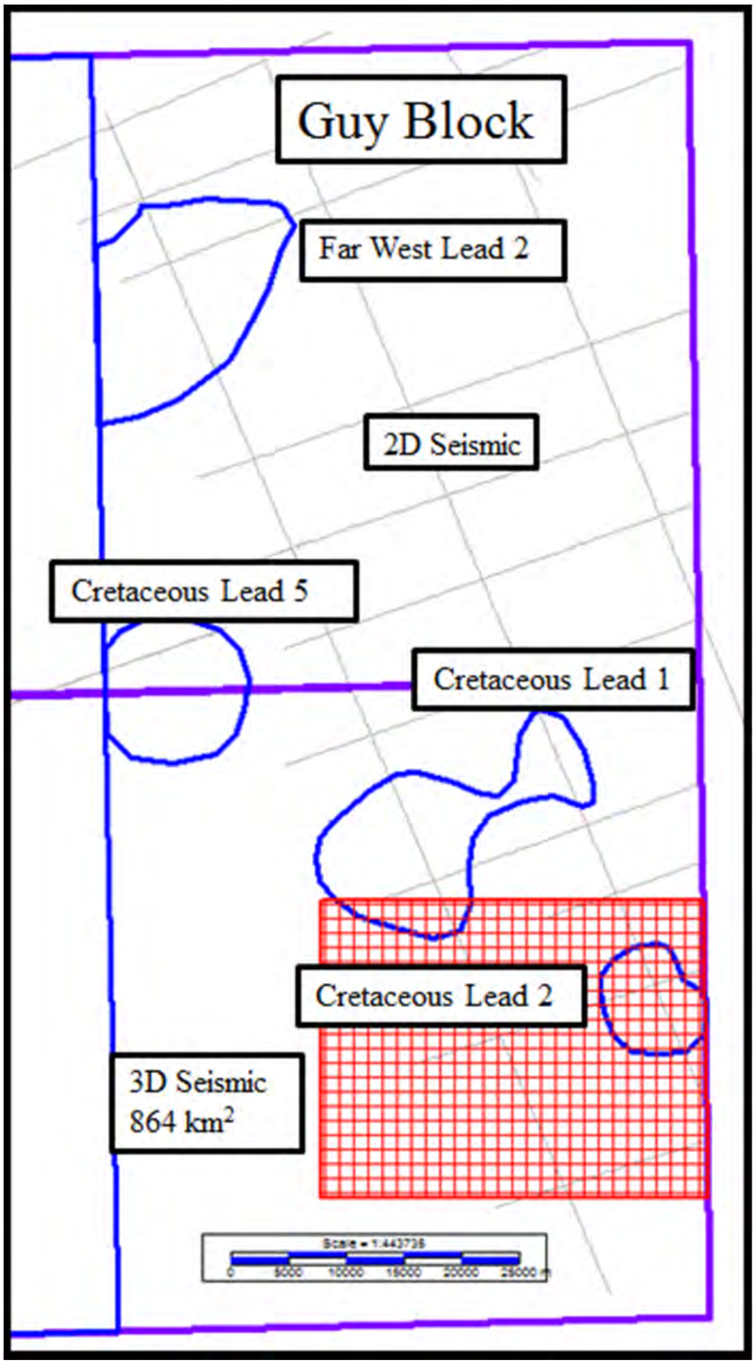

Figure 3—26 Location of Leads in Guy Block Namibia

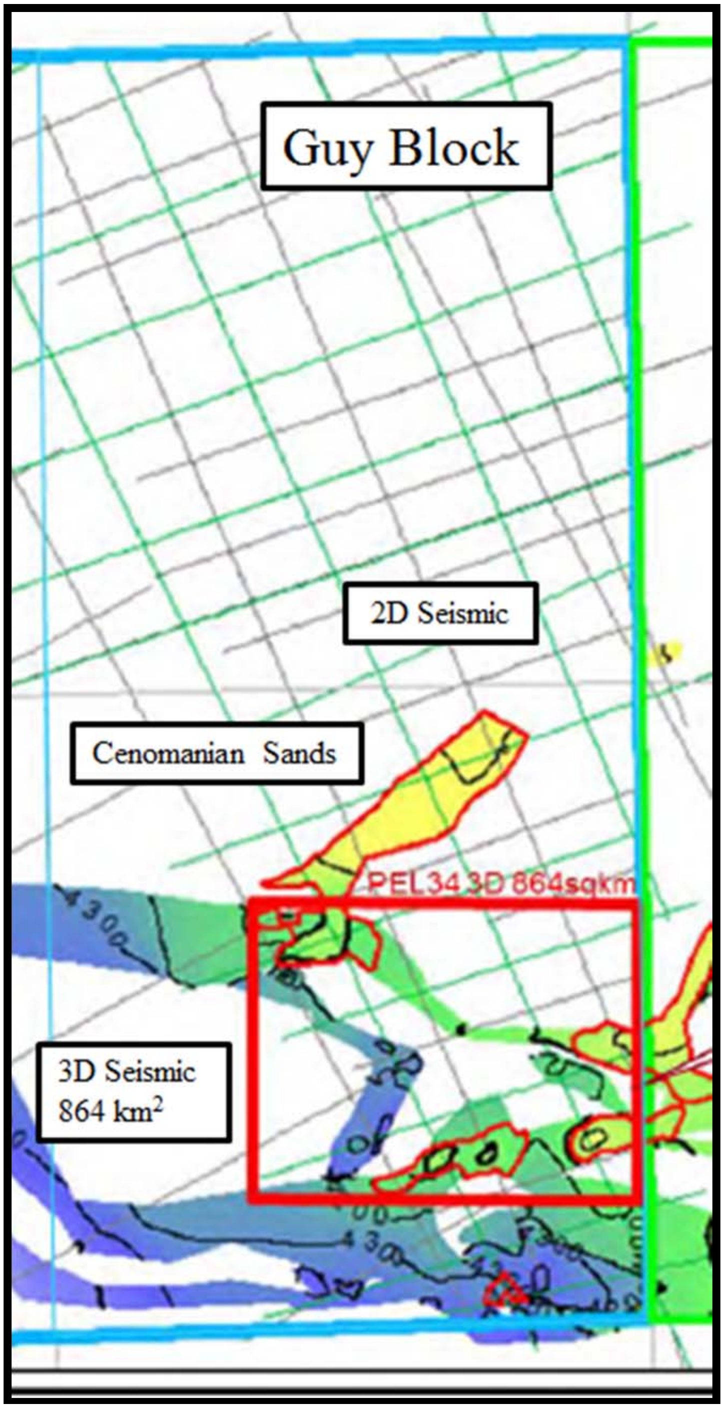

Figure 3—27 Guy Block with Cenomanian Sand Channels including the Baobab (Azinam)

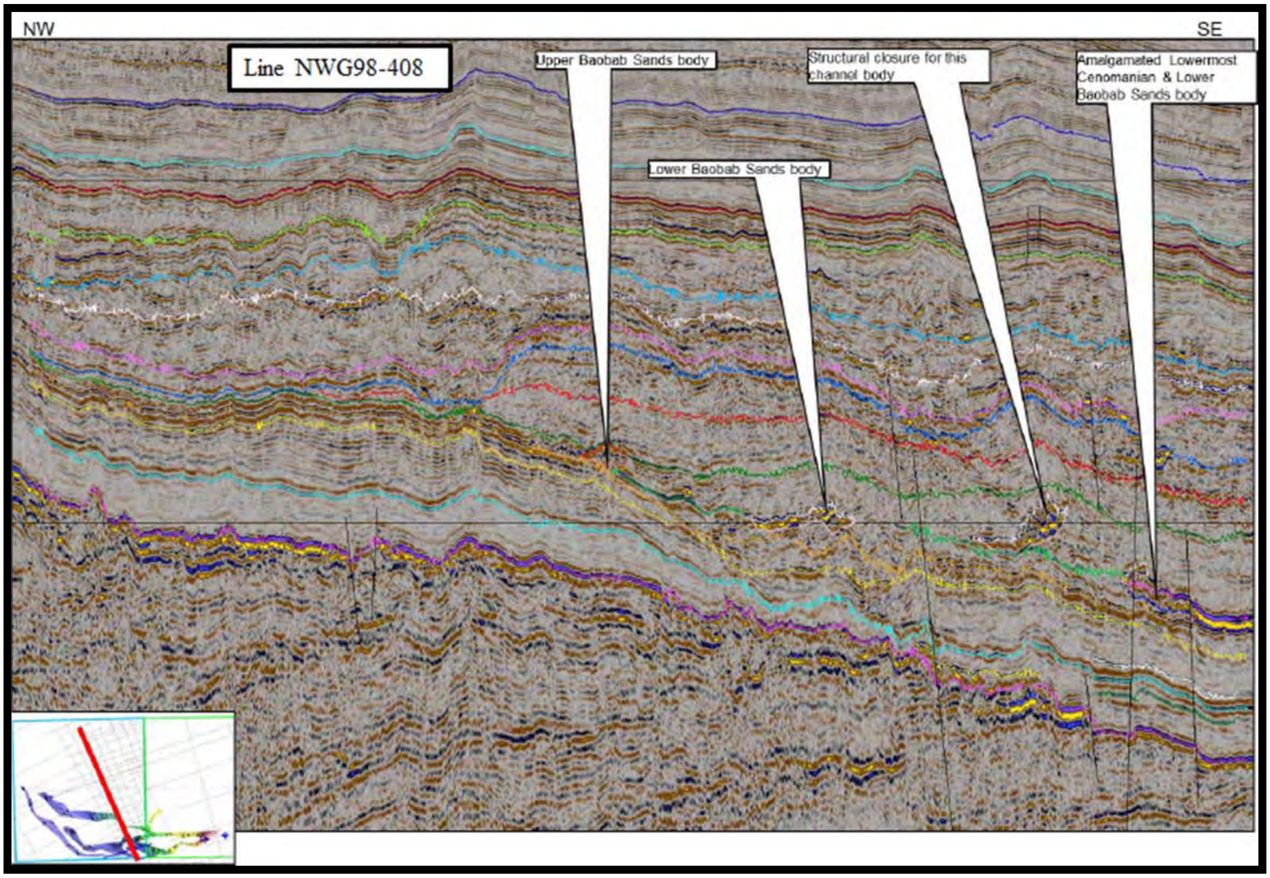

Figure 3—28 Guy Block Line NWG098-048 (Azinam)

The areas in square kilometers and acres used in the Probabilistic Prospective Resource estimates are compiled in Table 3—4 below.

Table 3—4 Guy Block Leads and Areas and P50 Gross Prospective Resources with COS

Lead	Minimum (P10) km² / Acres	Most Likely (P50) km² / Acres	Maximum (P90) km² / Acres	Gross Prospective Oil Resources (P50) Most Likely MMBO	Risk COS%
Far West 2	60.7 / 15,000	157.8 / 39,000	232.3 / 57,400	744.3	2.0
Cretaceous 1	37.0 / 9,143	100.0 / 24,711	201.0 / 49,668	640.4	2.2
Cretaceous 2	17.0 / 4,201	38.0 / 9,390	68.0 / 16,803	100.9	2.5
Cretaceous 5	40.0 / 9,884	67.0 / 16,556	130.0 / 32,100	95.9	2.0

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

3.2.16.4 Tamar Block PEL 50

The Tamar Block, PEL 50, consists of Block 2211Ba and 2311A (Figure 3—29). 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 3—12) 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.

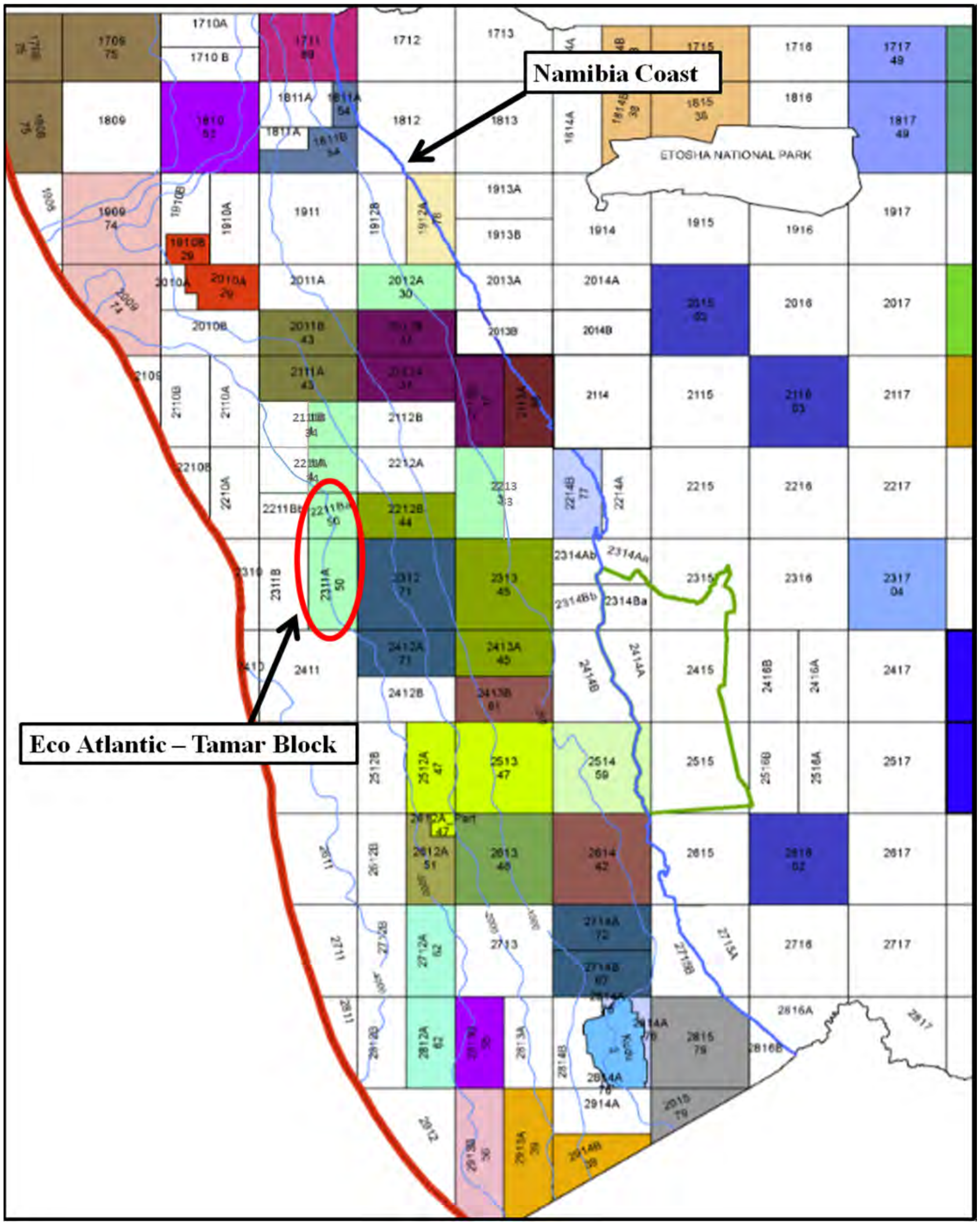

Figure 3—29 Location of Tamar Block

3.2.17 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.

3.2.17.1 Seismic Data

The Cooper Block (Block 2012A) PEL 30 (Figure 3—11) 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) PEL 34 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) PEL 33 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) PEL 50 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.

3.2.17.2 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. PROBABILISTIC RESOURCE ANALYSIS

4.1 GENERAL

A probabilistic resource analysis is most applicable for projects such as evaluating the potential resources of an exploratory area like the Cooper 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 only calculated for Cooper, Guy and Sharon Blocks in Namibia.

4.2 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.

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. A summary of input parameters is shown in Table 4—1.

Table 4—1 Input Parameters for All Leads and Osprey Prospect

	Lead A (Campanian)			Lead B (Mid Albian)			Lead C (Campanian)		
	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
Oil Gravity	30	35	40	30	35	40	30	35	40
Gas-Oil Ratio	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
press gradient	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	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 2		
	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
Oil Gravity	30	35	40	30	35	40	30	35	40
Gas-Oil Ratio	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
press gradient	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	11,366	11,566	11,766
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	15,000	39,000	57,400
Gross Thickness, ft	140	170	250	70	85	100	131	230	328
Net/Gross	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
	Cretaceous Sand Lead 1			Cretaceous Sand Lead 2			Cretaceous Sand Lead 5		
	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
Oil Gravity	30	35	40	30	35	40	30	35	40
Gas-Oil Ratio	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
press gradient	0.44	0.45	0.48	0.44	0.45	0.48	0.44	0.45	0.48
Depth, ft	12,724	12,924	13,124	12,888	13,088	13,288	13,708	13,908	14,108
Porosity	10	21	30	10	21	30	10	21	30
Water Sat.	20	30	40	20	30	40	20	30	40
Drainage area, acres	9,143	24,711	49,668	4,201	9,390	16,803	9,884	16,556	32,100
Gross Thickness, ft	131	262	394	66	115	164	33	59	82
Net/Gross	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
	North Structure			Wedge					
	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum			
Oil Gravity	30	35	40	30	35	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			
press gradient	0.44	0.45	0.48	0.44	0.45	0.48			
Depth, ft	8,331	8,531	8,731	8,331	8,531	8,731			
Porosity	15	20	25	15	20	25			
Water Sat.	20	30	40	20	30	40			
Drainage area, acres	11,737	27,849	56,834	30,890	72,650	139,600			
Gross Thickness, ft	164	328	492	82	164	328			
Net/Gross	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			

In a probabilistic analysis, dependent relationships can be established between parameters if appropriate. For example, portions of a reservoir with the lowest effective porosity generally may be expected to have the highest connate water saturation, whereas higher porosity sections have lower water saturation. In such a case, it is appropriate to establish an inverse relationship between porosity and water saturation, such that if a high porosity is randomly estimated in a given iteration, corresponding low water saturation is estimated. The degree of such a correlation can be controlled to be very strong or weak. This type of dependency, with a medium strength of -0.7, was used in this study for porosity with water saturation and with net/gross ratio. Similarly, 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 0.7 was assigned to gross thickness and productive area.

4.3 PROBABILISTIC SIMULATION

Probabilistic resource analysis was performed using the Monte Carlo simulation software called "@ Risk". This software allows for input of a variety of probability distributions for any parameter. Then the program performs a large number of iterations, either a large number specified by the user, or until a specified level of stability is achieved in the output. The results include a probability distribution 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 until stable statistics (mean and standard deviation) result from the resulting output distribution. This occurred after 5,000 iterations.

4.4 RESULTS

The output distributions were then used to characterize the Prospective Resources. The Gross 100% Results are summarized in Table 4—2. Note that these estimates do not include consideration for the risk of failure in exploring for these resources. The Net to ECO Interest Prospective Unrisked Resource Estimates by Lead are represented in Table 4—3.

Table 4—2 Gross Prospective Unrisked Resource Estimates by Lead and Prospect

Gross (100%)	Oil in Place, MMBbl			Prospective Oil Resources, MMBbl			Prospective Associated Gas Resources, BCF		
Block/Lead	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Cooper Block									
A (Campanian)	173.4	293.7	480.7	40.0	70.5	117.4	36.5	68.9	120.9
B (Albian)	496.2	864.1	1,401.2	113.0	205.3	345.9	105.7	199.5	352.8
C (Campanian)	438.8	753.7	1,187.2	100.9	179.3	292.1	94.4	175.9	303.9
Flat (Campanian)	127.2	219.6	356.7	29.5	52.3	88.0	27.4	51.6	90.2
Osprey	660.5	1,035.0	1,610.8	150.9	245.5	398.5	140.7	239.9	407.1
Cooper Total	**1,896.1**	**3,166.0**	**5,036.7**	**434.3**	**752.8**	**1,241.8**	**404.8**	**735.8**	**1,274.9**
Guy Block									
Far West Lead 2	1,113.4	3,221.9	7,394.9	246.5	744.3	1,762.1	241.5	727.5	1,721.2
Cretaceous Sand Lead 1	778.8	2,819.8	7,437.0	174.4	640.4	1,756.3	171.1	625.7	1,725.8
Cretaceous Sand Lead 2	153.7	439.0	1,056.8	34.6	100.9	247.8	33.1	97.8	246.6
Cretaceous Sand Lead 5	149.0	422.3	1,018.1	33.8	95.9	243.8	32.5	94.2	238.7
Guy Total	**2,194.9**	**6,903.0**	**16,906.8**	**489.4**	**1,581.4**	**4,009.9**	**478.2**	**1,545.3**	**3,932.4**
Sharon Block									
North Structure	1,307.5	3,955.5	9,193.2	293.6	909.4	2,175.8	280.2	887.1	2,172.6
Wedge	1,828.9	5,702.9	14,152.1	408.3	1,302.3	3,342.7	388.0	1,288.6	3,293.3
Sharon Total	**3,136.4**	**9,658.5**	**23,345.3**	**701.9**	**2,211.7**	**5,518.4**	**668.3**	**2,175.6**	**5,465.9**
TOTAL	**7,227.3**	**19,727.4**	**45,288.9**	**1,625.6**	**4,546.0**	**10,770.2**	**1,551.2**	**4,456.7**	**10,673.2**

Table 4—3 Net To ECO Interest Unrisked Prospective Resource Estimates by Lead and Prospect

Net to ECO	Oil in Place, MMBbl			Prospective Oil Resources, MMBbl			Prospective Associated Gas Resources, BCF		
Block/Lead	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Cooper Block									
A (Campanian)	56.4	95.4	156.2	13.0	22.9	38.1	11.9	22.4	39.3
B (Albian)	161.3	280.8	455.4	36.7	66.7	112.4	34.4	64.8	114.7
C (Campanian)	142.6	244.9	385.9	32.8	58.3	94.9	30.7	57.2	98.8
Flat (Campanian)	41.3	71.4	115.9	9.6	17.0	28.6	8.9	16.8	29.3
Osprey	214.7	336.4	523.5	49.0	79.8	129.5	45.7	78.0	132.3
Cooper Total	**616.2**	**1,029.0**	**1,636.9**	**141.2**	**244.7**	**403.6**	**131.6**	**239.1**	**414.3**
Guy Block									
Far West Lead 2	556.7	1,610.9	3,697.5	123.2	372.1	881.1	120.7	363.8	860.6
Cretaceous Sand Lead 1	389.4	1,409.9	3,718.5	87.2	320.2	878.1	85.5	312.9	862.9
Cretaceous Sand Lead 2	76.8	219.5	528.4	17.3	50.4	123.9	16.6	48.9	123.3
Cretaceous Sand Lead 5	74.5	211.1	509.0	16.9	48.0	121.9	16.2	47.1	119.4
Guy Total	**1,097.4**	**3,451.5**	**8,453.4**	**244.7**	**790.7**	**2,005.0**	**239.1**	**772.6**	**1,966.2**
Sharon Block									
North Structure	784.5	2,373.3	5,515.9	176.2	545.6	1,305.5	168.1	532.2	1,303.6
Wedge	1,097.4	3,421.8	8,491.3	245.0	781.4	2,005.6	232.8	773.1	1,976.0
Sharon Total	**1,881.8**	**5,795.1**	**14,007.2**	**421.2**	**1,327.0**	**3,311.0**	**401.0**	**1,305.4**	**3,279.6**
TOTAL	**3,595.5**	**10,275.5**	**24,097.6**	**807.0**	**2,362.4**	**5,719.6**	**771.6**	**2,317.1**	**5,660.1**

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."[11] 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

[11] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Second Edition*, Volume 1, September 1, 2007, pg 5-7.

P_{90} value 90% of the time), while the Best Estimate represents the P_{50} and the High Estimate represents the P_{10}.[12]

Note that a deterministic calculation with any set of the input parameters will not necessarily be close to any of the results shown in Table 4—2. 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 are 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.

The distribution graphs for the resource estimates can be found in Figure 4—1 through Figure 4—11. It should be noted that the shape of the probability distributions all result in 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.

[12] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Second Edition,* Volume 1, September 1, 2007, pg 5-7.

4.4.1 Cooper Block

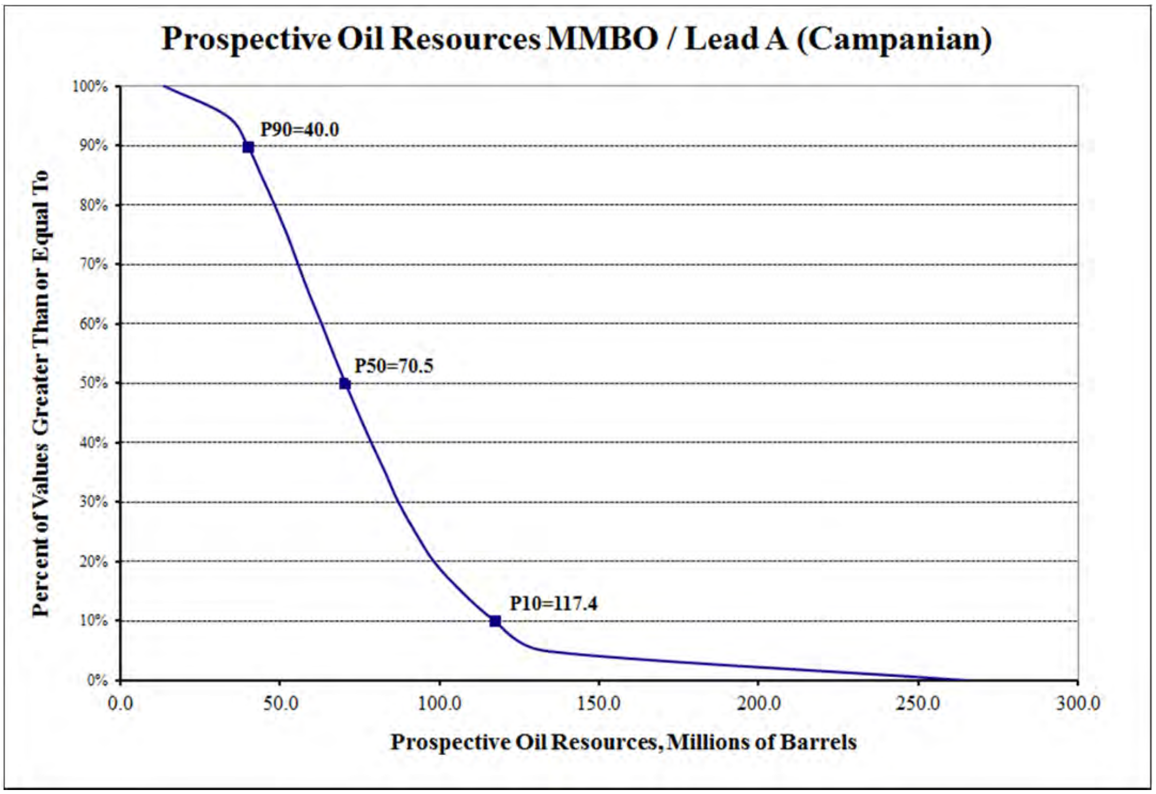

Figure 4—1 Distribution of Prospective Oil Resources, Lead A

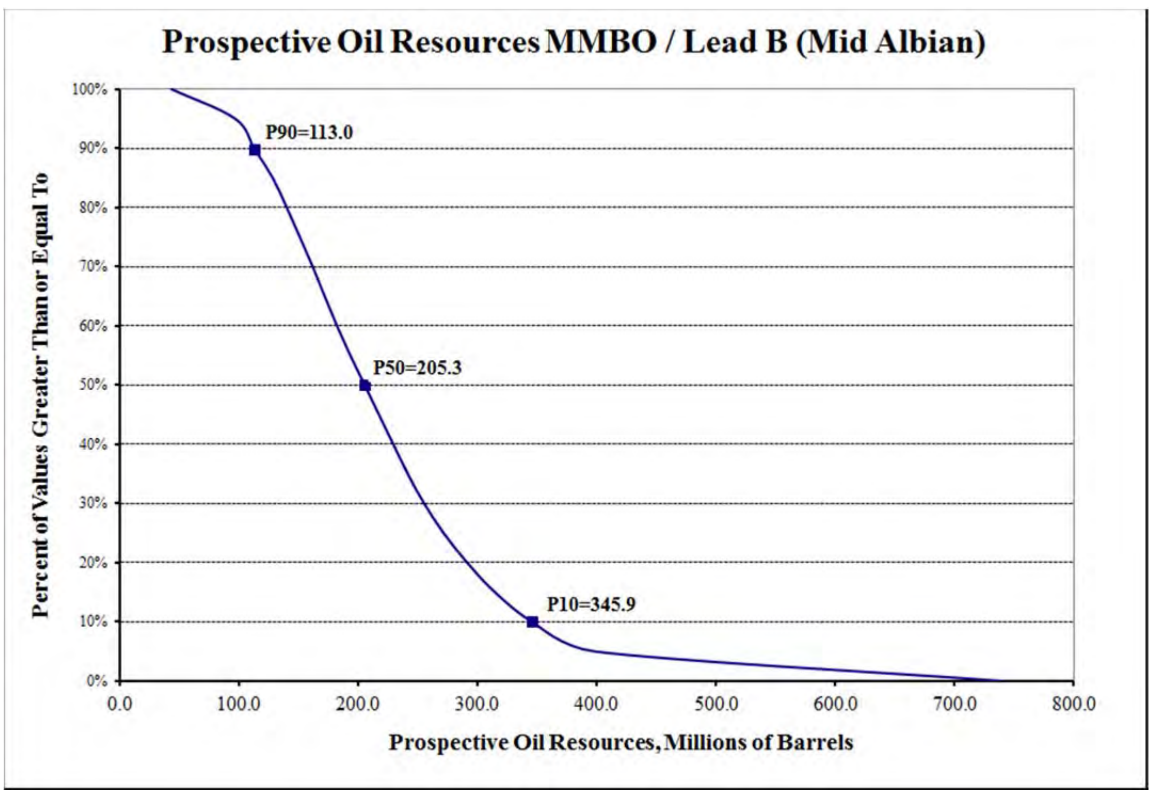

Figure 4—2 Distribution of Prospective Oil Resources, B Lead

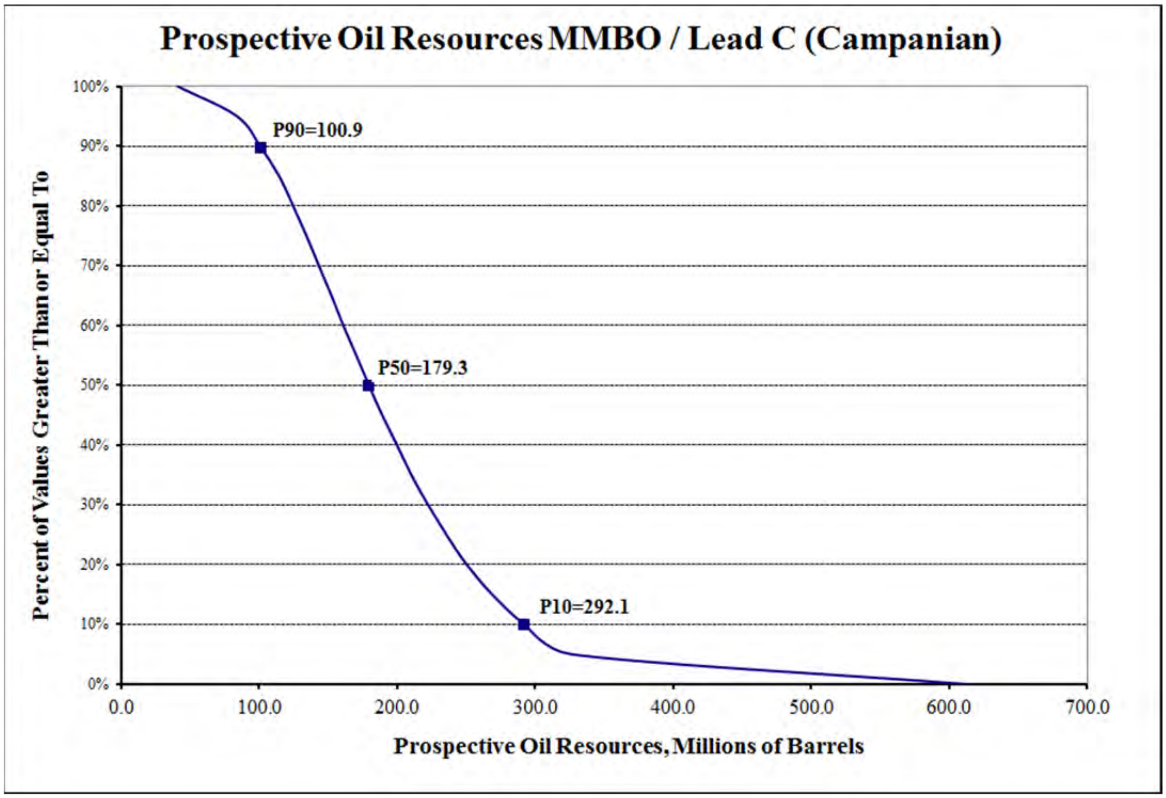

Figure 4—3 Distribution of Prospective Oil Resources, C Lead

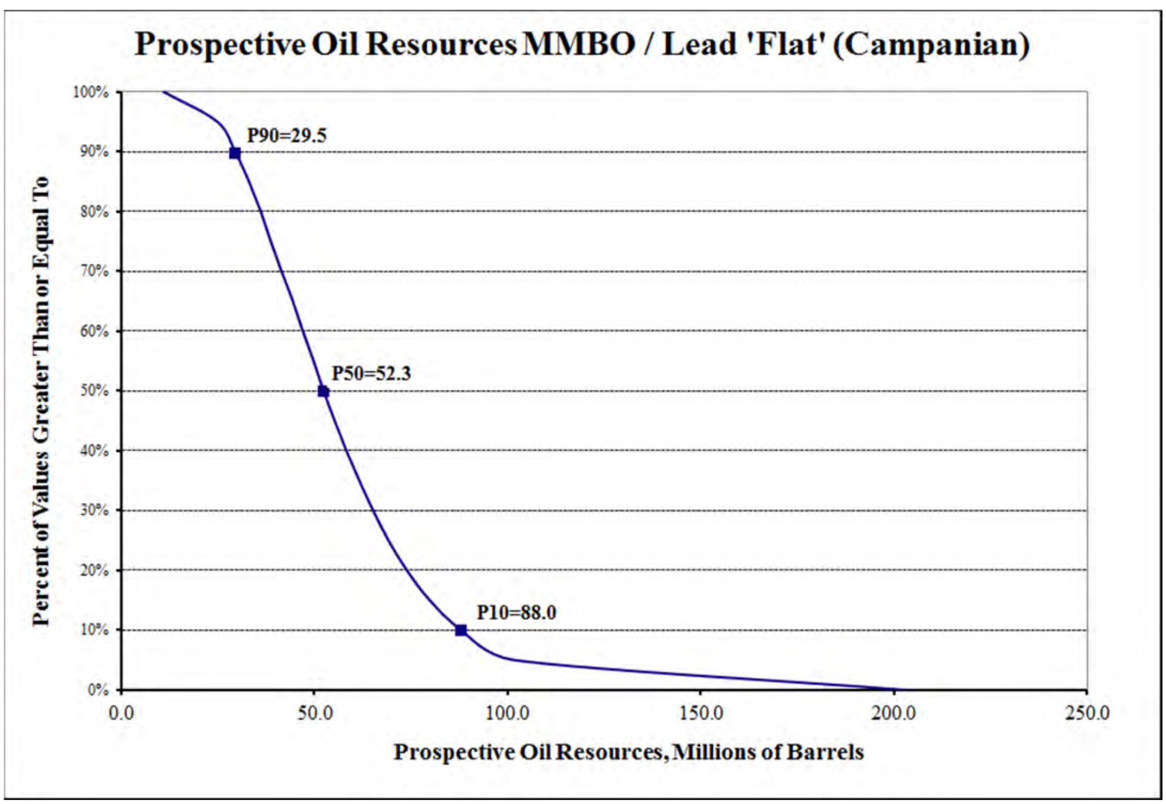

Figure 4—4 Distribution of Prospective Oil Resources, Flat Lead

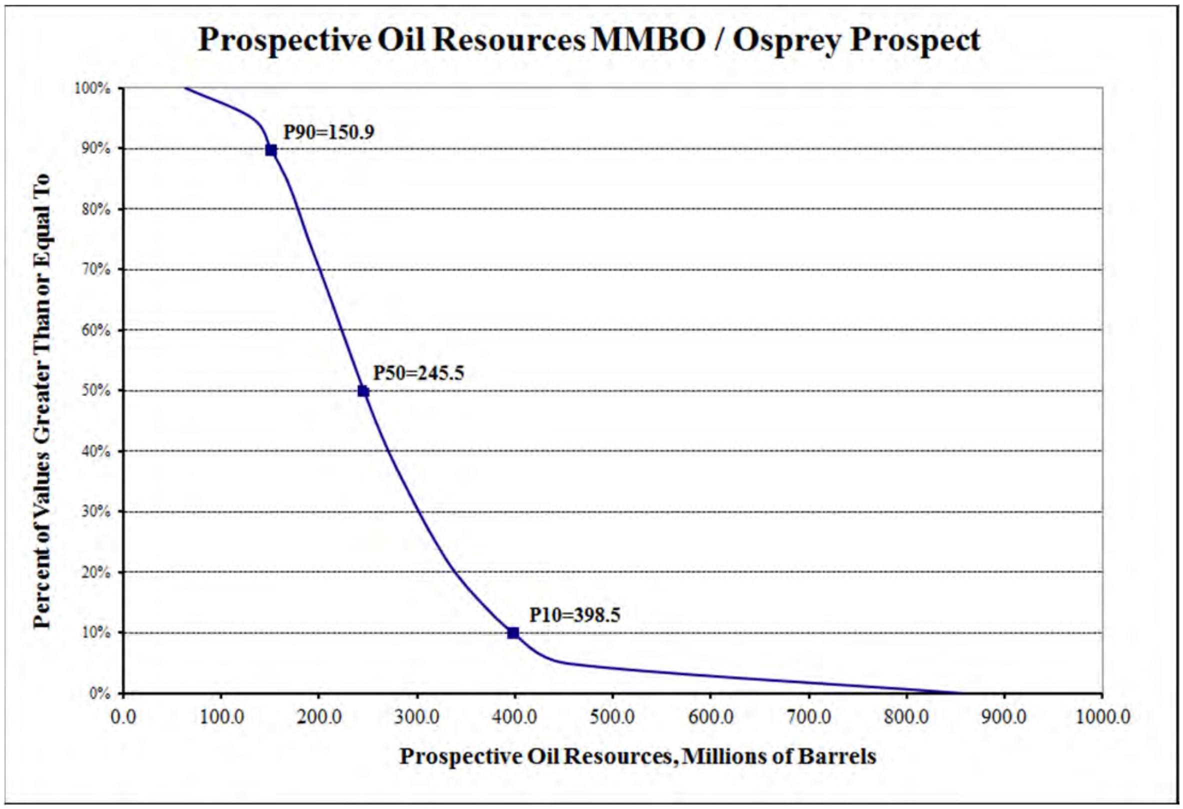

Figure 4—5 Distribution of Prospective Oil Resources, Osprey Prospect

4.4.2 Guy Block

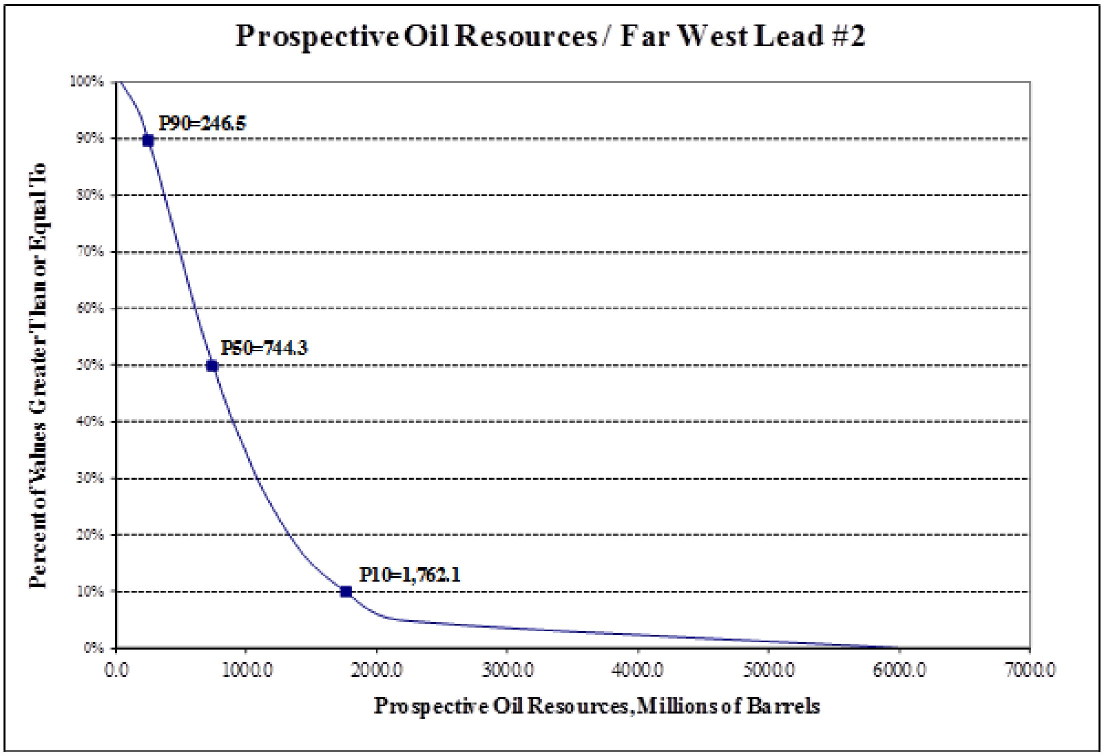

Figure 4—6 Distribution of Prospective Oil Resources, Far West Lead #2

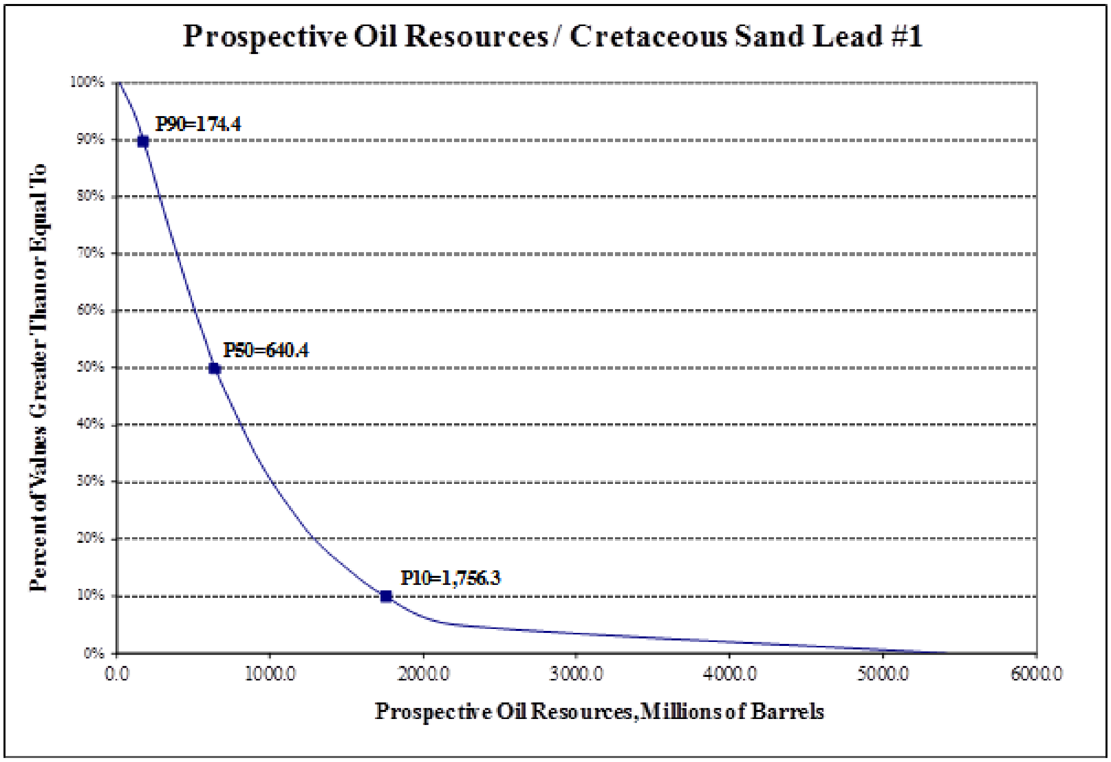

Figure 4—7 Distribution of Prospective Oil Resources Cretaceous Sand Lead #1

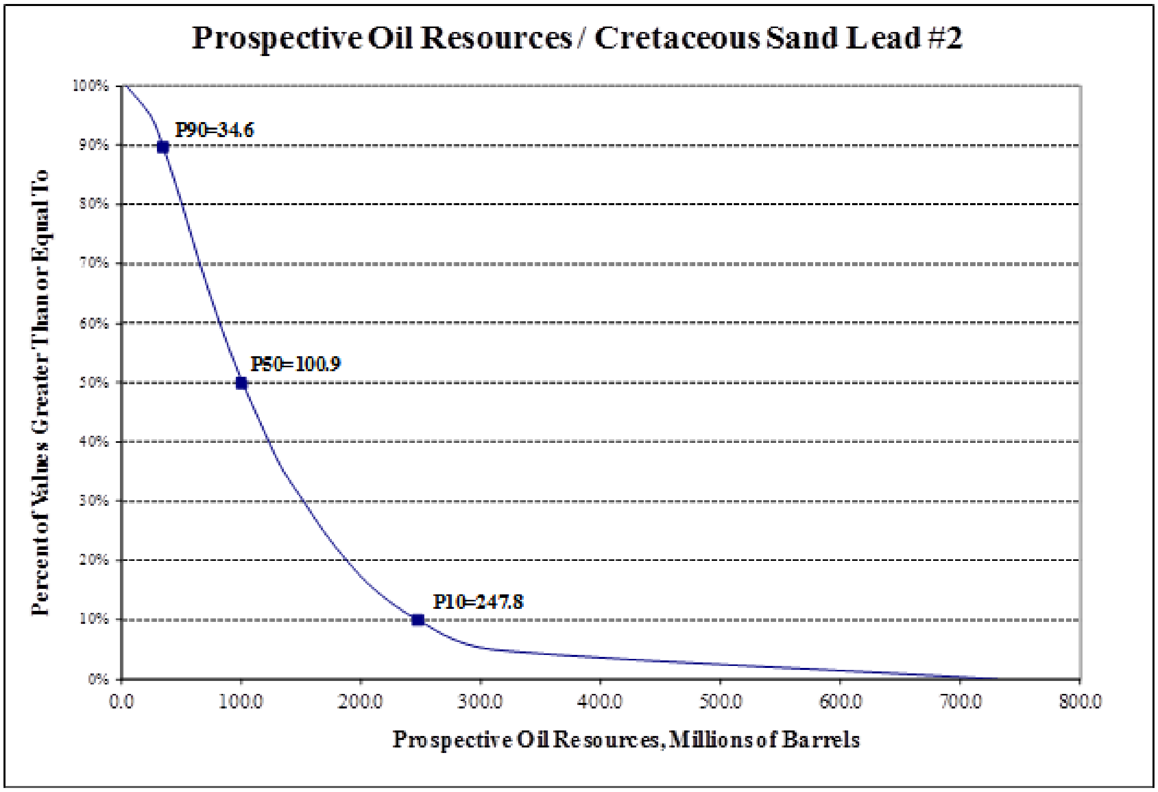

Figure 4—8 Distribution of Prospective Oil Resources, Cretaceous Sand Lead #2

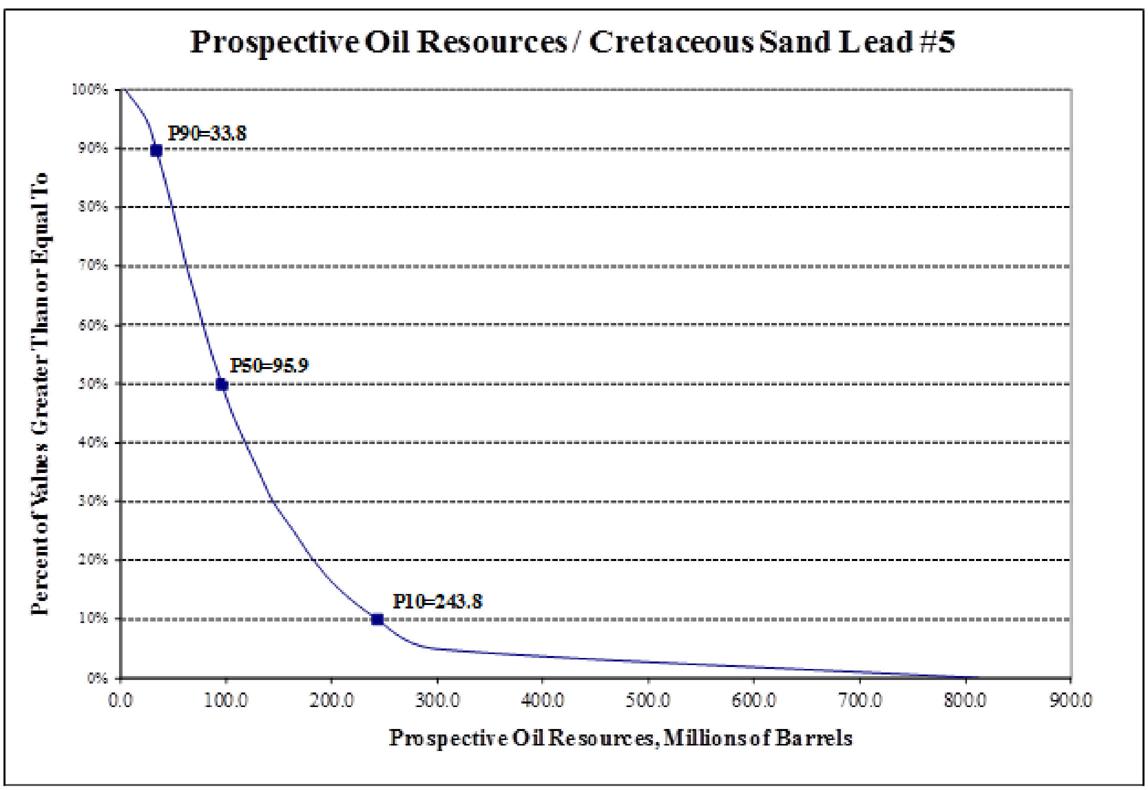

Figure 4—9 Distribution of Prospective Oil Resources, Cretaceous Sand Lead #5

4.4.3 Sharon Block

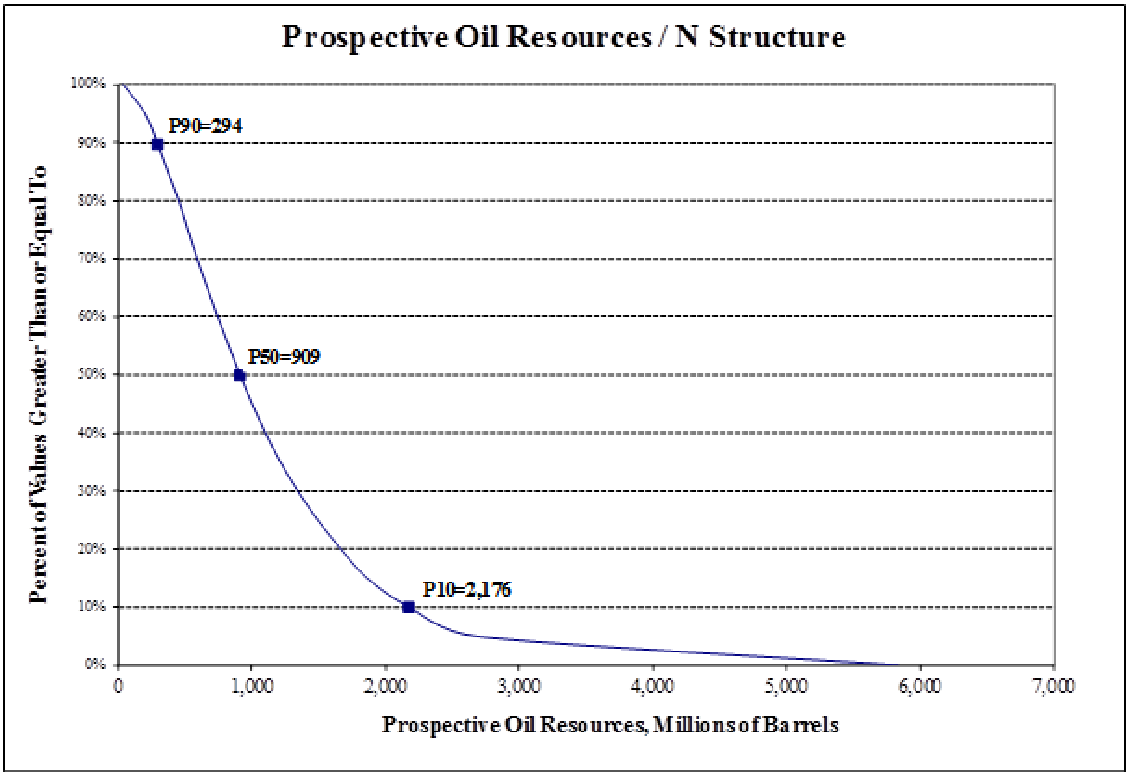

Figure 4—10 Distribution of Prospective Oil Resources N Structure

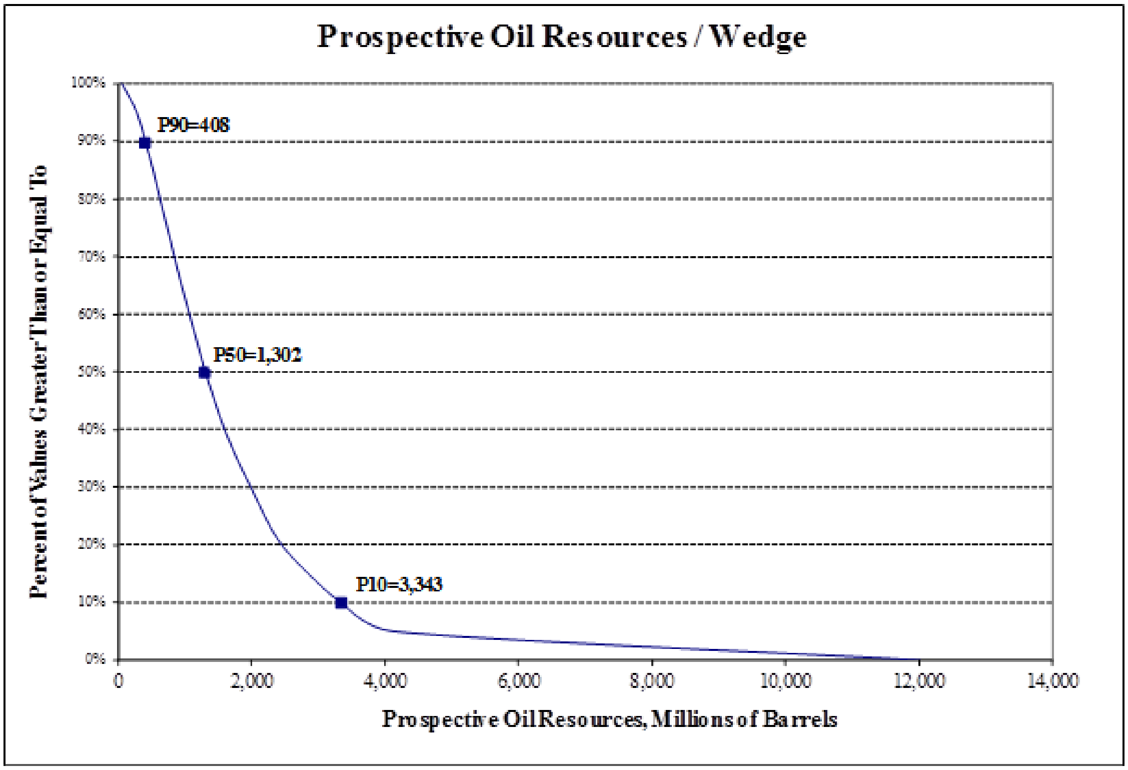

Figure 4—11 Distribution of Prospective Oil Resources Wedge

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6. CONSENT LETTER

Gustavson Associates LLC hereby consents to the use of all or any part of this Lead and Prospect Evaluation Report for the Cooper Block, Sharon Block, Guy Block, and Orinduik Block concessions, as of October 31, 2016, in any document filed with any Canadian Securities Commission by ECO Atlantic (PTY), Ltd.

Letha C. Lencioni
Vice-President, Petroleum Engineering
Gustavson Associates LLC

CERTIFICATE OF QUALIFICATION

I, Letha Chapman Lencioni, Professional Engineer of 5757 Central Avenue, Suite D, Boulder, Colorado, 80301, USA, hereby certify:

1. I am an employee of Gustavson Associates, which prepared a detailed analysis of the oil and gas properties of ECO (Atlantic) (PTY), Ltd. The effective date of this evaluation is October 31, 2016.
2. I do not have, nor do I expect to receive, any direct or indirect interest in the securities of ECO (Atlantic) (PTY), Ltd or their affiliated companies, nor any interest in the subject property.
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 30 years' experience in the conduct of evaluation and engineering studies relating to oil and gas fields.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from public information and records, and the files of ECO (Atlantic) (PTY), Ltd.

COLORADO REGISTERED
LETHA CHAPMAN LENCIONI
29506
PROFESSIONAL ENGINEER

Letha Chapman Lencioni
Chief Reservoir Engineer/
Vice-President, Petroleum Engineering
Gustavson Associates, LLC
Colorado Registered Engineer #29506

I, Jan Joseph Tomanek, Certified Petroleum Geologist of 5757 Central Avenue, Suite D, Boulder, Colorado, 80301, USA, hereby certify:

1. I am an employee of Gustavson Associates, which prepared a detailed analysis of the oil and gas properties of ECO (Atlantic) (PTY), Ltd. The effective date of this evaluation is October 31, 2016.
2. I do not have, nor do I expect to receive, any direct or indirect interest in the securities of ECO (Atlantic) (PTY), Ltd or their affiliated companies, nor any interest in the subject property.
3. I attended the University of Connecticut and I graduated with a Bachelor of Science Degree in Geology in 1975; I am an American Association of Petroleum Geologists Certified Petroleum Geologist and an American Institute of Professional Geologist Certified Professional Geologist, and I have in excess of 35 years' experience in the oil and gas field.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from public information and records, and the files of ECO (Atlantic) (PTY), Ltd.

Jan Joseph Tomanek
Vice-President, Oil and Gas
Gustavson Associates, LLC
AIPG CPG #11566
AAPG CPG # 6239

Additional Professional Personnel who contributed to this Report

<u>Michele G. Bishop</u>

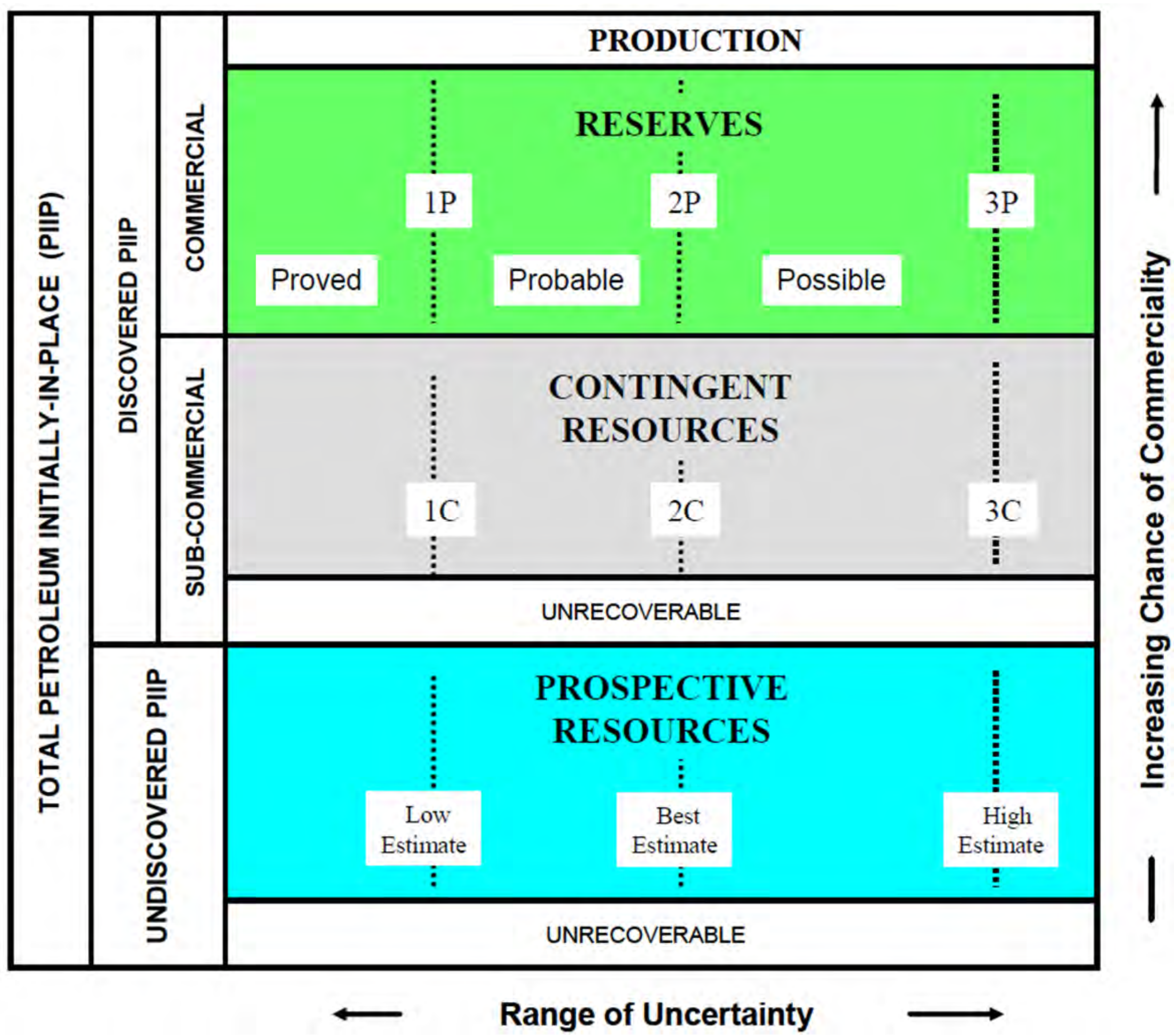
Chief Geologist - Master of Science Degree in Geology from Duke University. Professional Geologist of the State of Wyoming, State of Alaska, and an American Institute of Professional Geologists Certified Professional Geologist with over 30 years of experience in studies relating to oil and gas fields, including estimating quantities of reserves and resources. She is a member in good standing of the following professional organizations: Society for Sedimentary Geology (SEPM), Rocky Mountain Association of Geologists (RMAG), Denver International Petroleum Society (DIPS), The Research Society (Sigma Xi), and the American Institute of Professional Geologists (AIPG).

Credentials include: Wyoming Professional Geologist PG-783, Alaska Certified Professional Geologist CPG-117253 and AIPG Certified Professional Geologist CPG-11291.

Appendix A

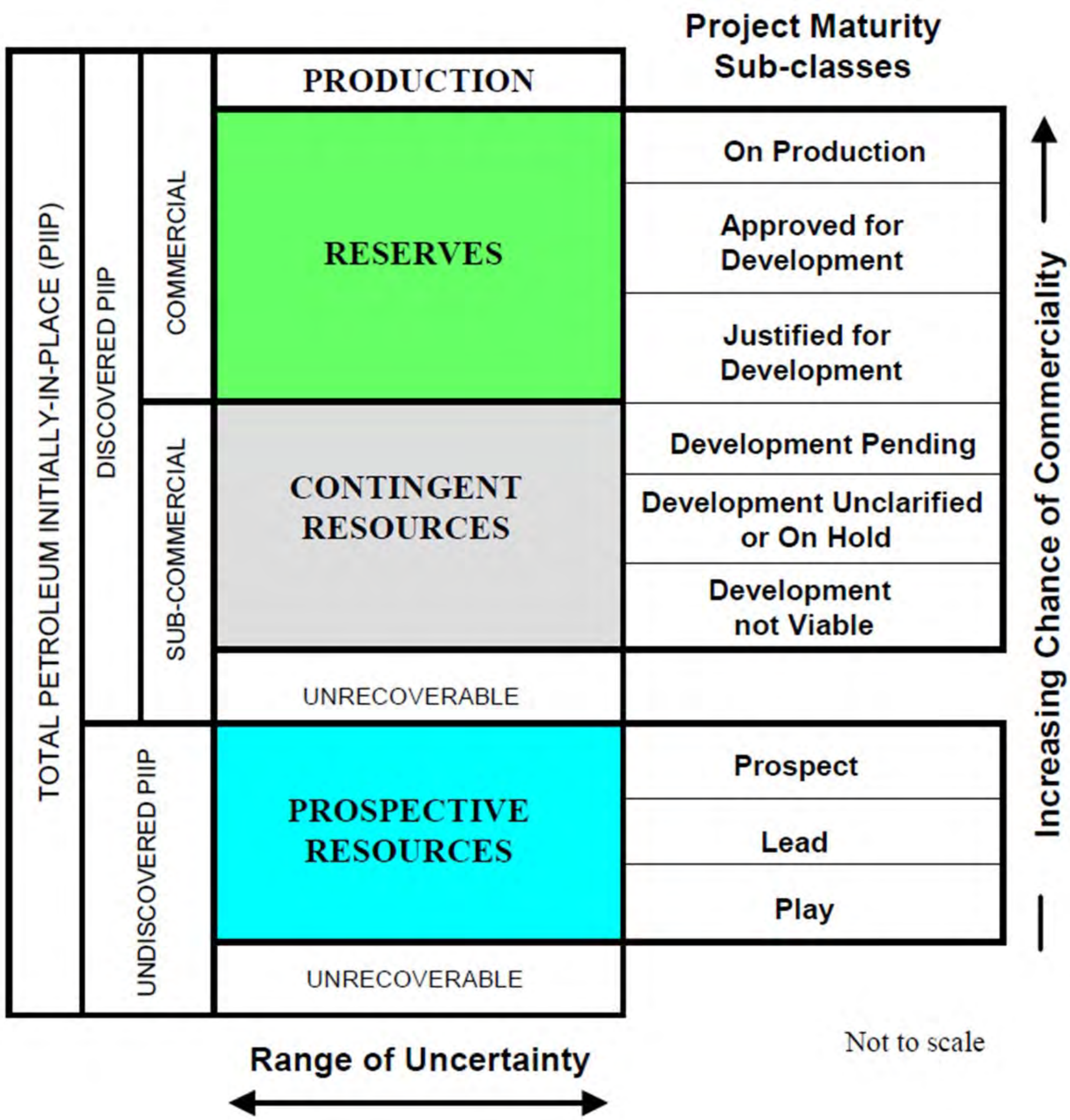
Glossary of Terms and Abbreviations

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, 2007 as shown in the figures below. Note that these figures and definitions are consistent with the figures and definitions provided in the COGEH[13]: the PRMS versions are reproduced here due to their completeness.



Resources Classification Framework

[13] 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 Estimate 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 that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basic-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders). (Also termed "Non-Conventional" Resources and "Continuous Deposits".)

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

The following are abbreviations and definitions for common petroleum terms.

10^3m^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
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