Mnazi Bay Field
Reserves Assessment
as at December 31, 2016

Prepared for:

Maurel et Prom
and
Wentworth Resources Limited

Prepared by:

RPS Energy Canada Ltd.

March 8, 2017

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March 8, 2017

Job No. ECV 16-2206/CC01374

Wentworth Resources Limited
3210, 715 – 5th Avenue SW
Calgary, Alberta Canada T2P 2X6

Attention: Mr. Geoffrey Bury, Managing Director

Dear Mr. Bury,

Re: Mnazi Bay Reserves Assessment, as at December 31, 2016

As requested by Maurel et Prom ("M&P") in the engagement letter dated October, 2016 (the "Agreement"), RPS Energy Consultants Ltd. ("RPS") has completed an independent reserves assessment of Maurel et Prom and Wentworth interests in the Mnazi Bay Licence in Tanzania.

Reserves volumes for the Mnazi Bay Licence were derived from volumetrics based on a 3D geological static model which was constructed utilizing the Maurel et Prom 2014 seismic interpretation, calibrated to the horizon tops as identified in the five wells drilled on the licence. The volumes derived from the Petrel model were combined with petrophysical evaluations and well test data from the five wells and have incorporated a range of gas-down-to and gas-water contact depths. Estimates of ultimate technical recovery were derived from a probabilistic analysis of original gas in place and material balance modeling.

Wentworth owns 31.94% working interest in the production operations and 39.925% working interest in exploration operations.

The reserves and resource volumes are summarized in the following table:

Reserves Summary for Mnazi Bay as at December 31, 2016						
	Field		Wentworth 31.94% WI			
	Gross(1) Reserves		Gross(1) Reserves		Net(2) Reserves	
Reserves Category	Sales Gas (Bscf)	BOE (MMbbl)	Sales Gas (Bscf)	BOE (MMbbl)	Sales Gas (Bscf)	BOE (MMbbl)
PDP	105.1	17.5	33.6	5.6	27.2	4.5
PD	160.1	26.7	51.1	8.5	42.1	7.0
1P	344.6	57.4	110.1	18.3	79.8	13.3
2P	566.6	94.4	181.0	30.2	115.9	19.3
3P	847.6	141.3	270.7	45.1	156.5	26.1

(1) Gross Reserves are Company Working Interest Share of Total Field Reserves

(2) Net Reserves are calculated as the product of Company Gross Reserves and the ratio of Company net revenue to Company WI share of field gross revenue

The Mnazi Bay Licence also contains additional hydrocarbon potential in a number of undrilled locations; however, evaluation of these prospects is outside of the scope of this engagement.

This report is issued by RPS under the appointment by Maurel et Prom and is produced as part of the engagement detailed therein and subject to the terms and conditions of the Agreement. Those terms and conditions contain inter alia restrictions on the use and distribution of information and materials contained in this report.

This report is addressed to Wentworth, a named Third Party as defined in the Agreement and is only capable of being relied on by Maurel et Prom and the Third Parties (including Wentworth) under and pursuant to (and subject to the terms of) the Agreement.

Wentworth may disclose the signed and dated report to third parties as contemplated by the purpose detailed in the Agreement but in making any such disclosure Wentworth shall require the third party (including any Third Parties) to accept it as confidential information only to be used or passed on to other persons as Wentworth is permitted to do under the Agreement.

We appreciate the opportunity to conduct this resource assessment for you. We trust that the attached report meets your requirements.

Yours sincerely,

RPS Energy

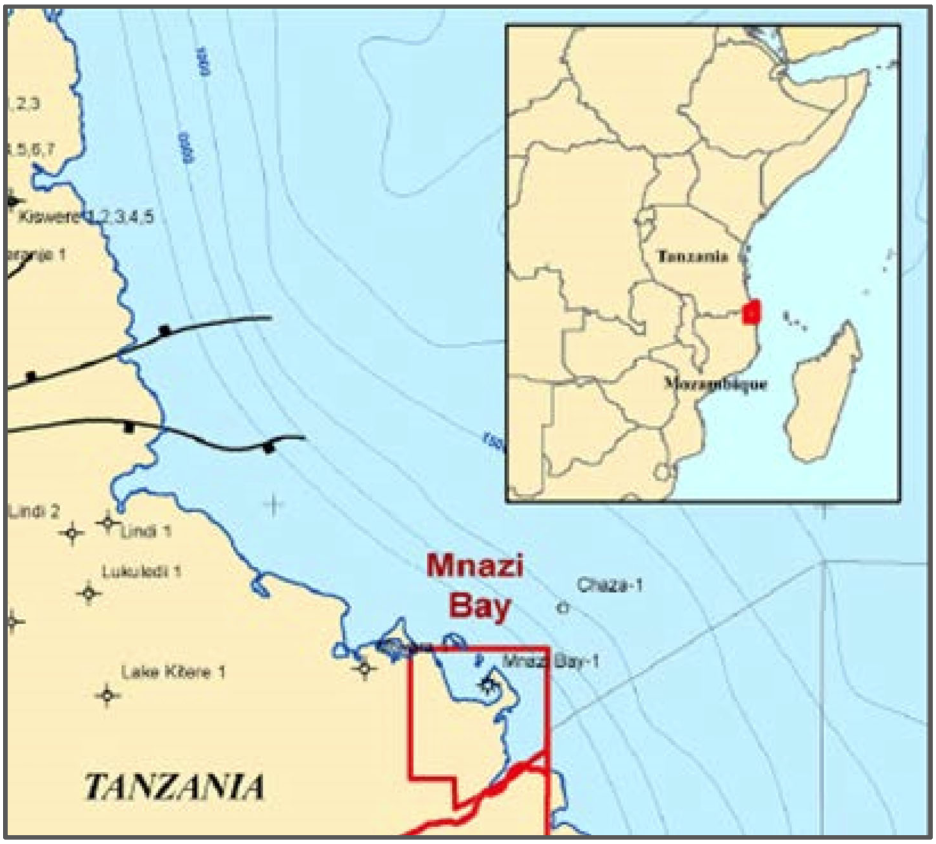
PROFESSIONAL ENGINEER
BRIAN D. WEATHERILL
ALBERTA

PERMIT TO PRACTICE
RPS ENERGY CANADA LTD.
Signature
Date 2017-03-08
PERMIT NUMBER: P4348
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

Brian D. Weatherill, P. Eng.
Reservoir Engineering Specialist
encl.

EXECUTIVE SUMMARY

RPS has reviewed the available data for the Mnazi Bay Concession Area in South-East Tanzania and has evaluated Maurel et Prom's ("M&P") 48.06% (production operations) working interest in the reserves volumes of the 756 km^2 area. The effective date of this report is December 31, 2016.

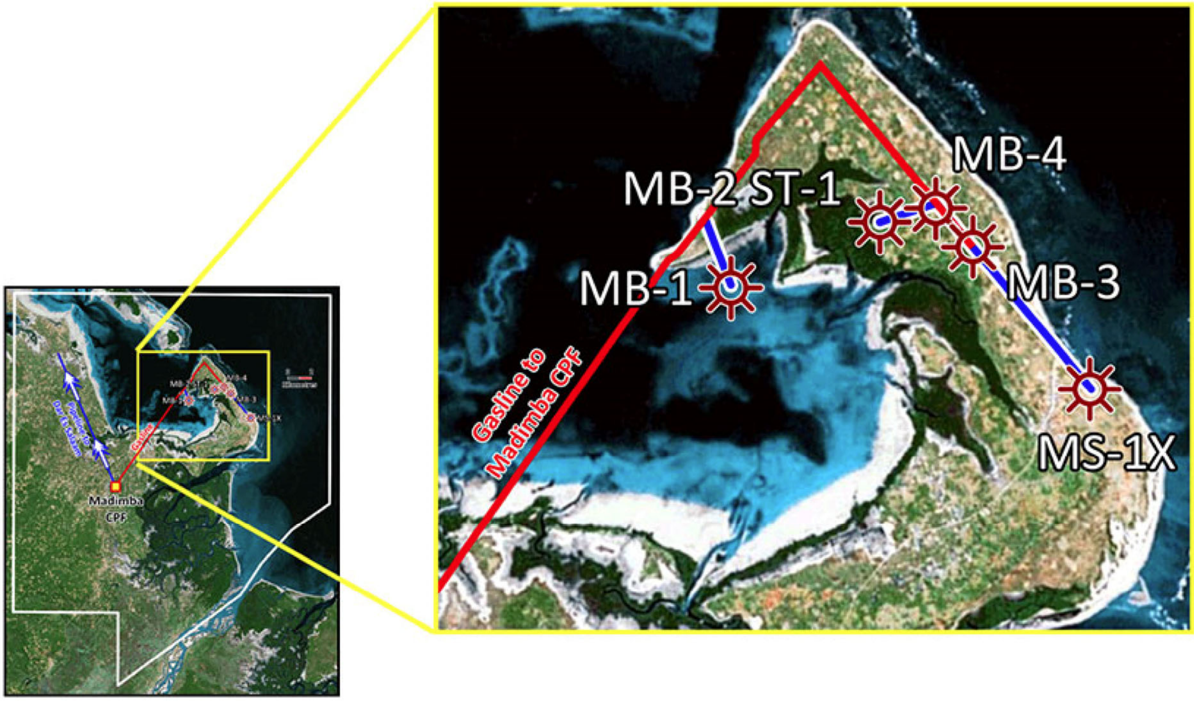


Source: Wentworth

Including well MB-4, completed in 2015, there is a total of five gas wells drilled on the licence, all of which produce. These wells define the Mnazi Bay and Msimbati gas fields.

A Gas Sales Agreement ("GSA") was signed between the partners (M&P, Wentworth Gas Limited, Cyprus Mnazi Bay Limited and Tanzania Petroleum Development Corporation) and the buyer, Tanzania Petroleum Development Corporation ("TPDC") on September 12, 2014 for delivery of raw gas at the outlet of the Mnazi Bay Gas Processing Facilities. Facilities associated with export to the processing plant at Madimba (trans-national pipeline to Dar Es Salaam) were completed in 2016 enabling increased offtake above local requirements for power generation at Mtwara.

The Mnazi Bay concession area (also referred to as the "Mnazi Bay Licence" in this report) is shown below with the Mnazi Bay/Msimbati Field and its five wells highlighted in red. A Development Licence has been issued on the discovery block and eight adjoining blocks comprising the contract area, with an initial term of twenty-five years from October 26, 2006.



Mnazi Bay Licence Area

Source: Base image from Google Earth

As part of an independent resources assessment of this licence for Wentworth Resources in 2013 and a reserve evaluation conducted for year-end 2014, RPS reviewed 1658 km of 2-D seismic data (103 lines) on the Mnazi Bay Licence, with the interpretation focus on drill-ready prospects. Additional data reviewed included offsetting well logs and field production histories, details of new competitor discoveries in Tanzania and geological and reservoir information from publically available sources.

RPS estimates of reserves volumes for the Mnazi Bay Licence, as of December 31, 2016 are summarized for the Wentworth Resources interest in the Table below.

Wentworth Resources Working Interest Reserves for Mnazi Bay as at December 31, 2016 RPS Forecast 2017-01-01								
Reserve Category	Gross Reserves				Net Reserves			
	Oil (MMstb)	Sales Gas (Bscf)	NGL& C5+ (MMbbl)	BOE (MMbbl)	Oil (MMstb)	Sales Gas (Bscf)	NGL& C5+ (MMbbl)	BOE (MMbbl)
PROVED								
Producing	-	*33.6*	-	*5.6*	-	*27.2*	-	*4.5*
Non Producing	-	*17.6*	-	*2.9*	-	*14.8*	-	*2.5*
Undeveloped	-	*58.9*	-	*9.8*	-	*37.7*	-	*6.3*
Total Proved	**-**	**110.1**	**-**	**18.3**	**-**	**79.8**	**-**	**13.3**
Probable	-	*70.9*	-	*11.8*	-	*36.1*	-	*6.0*
PROVED + PROBABLE	**-**	**181.0**	**-**	**30.2**	**-**	**115.9**	**-**	**19.3**
Possible	-	*89.8*	-	*15.0*	-	*40.6*	-	*6.8*
PROVED + PROBABLE + POSSIBLE	**-**	**270.7**	**-**	**45.1**	**-**	**156.5**	**-**	**26.1**

The NPV estimates associated with these reserves volumes, for Wentworth Resources, are:

Wentworth Resources Working Interest Reserves for Mnazi Bay as at December 31, 2016 RPS Forecast 2017-01-01										
Reserve Category	NPV Before Tax Million US$					NPV After Tax Million US$				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
PROVED										
Producing	*86.5*	*79.1*	*72.6*	*67.0*	*62.1*	*85.2*	*78.0*	*71.7*	*66.2*	*61.4*
Non Producing	*26.5*	*22.2*	*18.5*	*15.4*	*12.9*	*23.8*	*20.1*	*16.8*	*14.1*	*11.8*
Undeveloped	*100.4*	*72.3*	*53.2*	*39.9*	*30.4*	*92.7*	*66.8*	*49.1*	*36.8*	*28.0*
Total Proved	**213.4**	**173.7**	**144.4**	**122.3**	**105.4**	**201.7**	**164.9**	**137.7**	**117.1**	**101.2**
Probable	*92.5*	*62.2*	*45.9*	*36.7*	*31.2*	*84.8*	*57.4*	*42.6*	*34.2*	*29.2*
PROVED + PROBABLE	**305.9**	**235.9**	**190.3**	**159.0**	**136.5**	**286.5**	**222.3**	**180.3**	**151.3**	**130.3**
Possible	*131.3*	*70.0*	*40.0*	*24.7*	*16.5*	*120.5*	*64.5*	*37.1*	*23.0*	*15.4*
PROVED + PROBABLE + POSSIBLE	**437.2**	**305.8**	**230.3**	**183.7**	**153.0**	**407.0**	**286.8**	**217.3**	**174.3**	**145.8**

These assessments are made in accordance with the standards defined in the SPE/WPC Petroleum Resources Management System (2007) and the Canadian Oil and Gas Evaluation Handbook ("COGEH").

RESERVE DEFINITIONS

The following definitions have been used by RPS Energy Canada Ltd. (RPS) in evaluating reserves. These definitions meet the requirements of the Canadian National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities" and its companion policy. These definitions are based on the following references:

1. **Society of Petroleum Evaluation Engineers (Calgary Chapter) and Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) -** "Canadian Oil and Gas Evaluation Handbook, Volume 1, Second Edition", September 1, 2007.
2. **Society of Petroleum Evaluation Engineers (Calgary Chapter) and Canadian Institution of Mining, Metallurgy and Petroleum -** "Canadian Oil and Gas Evaluation Handbook, Volume 2, First Edition", November 1, 2005.
3. **Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers -** "Petroleum Resource Management System (SPE – PRMS)", 2007.

Reserves

Reserves are volumes of hydrocarbons and associated substances estimated to be commercially recoverable from known accumulations from a given date forward by established technology under specified economic conditions and government regulations. Specified economic conditions may be current economic conditions in the case of constant price and uninflated cost forecasts (as required by many financial regulatory authorities) or they may be reasonably anticipated economic conditions in the case of escalated price and inflated cost forecasts.

The abbreviations utilized for these reserve categories are shown parenthetically.

Proved Reserves (P)

Proved reserves are those reserves that can be estimated with a high degree of certainty on the basis of an analysis of drilling, geological, geophysical and engineering data. A high degree of certainty generally means, for the purposes of reserve classification, that it is likely that the actual remaining quantities recovered will exceed the estimated proved reserves and there is a 90% confidence that at least these reserves will be produced, i.e. there is only a 10% probability that less than these reserves will be recovered. In general reserves are considered proved only if supported by actual production or formation testing. In certain instances proved reserves may be assigned on the basis of log and/or core analysis if analogous reservoirs are known to be economically productive. Proved reserves are also assigned for enhanced recovery processes which have been demonstrated to be economically and technically successful in the reservoir either by pilot testing or by analogy to installed projects in analogous reservoirs.

Proved Developed Reserves (PD)

Proved developed reserves are those proved reserves that are expected to be recovered from existing wells and installed facilities, or, if facilities have not be installed, that would involve a low expenditure (compared to drilling a well) to put the reserves on production. Proved developed reserves are categorized into producing and non-producing.

Proved Developed Producing Reserves (PDP)

Proved developed producing reserves are those reserves expected to be recovered from completion intervals open at the time of estimate. They may be actually on production or, if temporarily shut in, the date of resumption of production known with a reasonable certainty.

Proved Developed Non-Producing Reserves (PDNP)

Proved developed non-producing reserves include shut in and behind pipe reserves. Shut in reserves are expected to be recovered from existing completions that are shut in for marketing constraints or require minor capital expenditures (such as tie ins) and the date of production is uncertain. Behind pipe reserves are expected to be recovered from zones behind casing in existing wells and require minor capital expenditures (such as perforating) for completion prior to production at a date that is uncertain.

Proved Undeveloped Reserves (PUD)

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant capital expenditure (compared to the cost of drilling a well) is required to render them capable of production. These reserves may be assigned to new wells, major recompletions or major facility expenditures.

Probable Reserves (PROB)

Probable reserves (also called **Probable Additional** reserves) are quantities of recoverable hydrocarbons estimated on the basis of engineering and geological data that are similar to those used for proved reserves but that lack, for various reasons, the certainty required to classify the reserves are proved. Probable reserves are less certain to be recovered than proved reserves; which means, for purposes of reserves classification, that there is 50% probability that more than the Proved plus Probable Additional reserves will actually be recovered. These include reserves that would be recoverable if a more efficient recovery mechanism develops than was assumed in estimating proved reserves; reserves that depend on successful workover or mechanical changes for recovery; reserves that require infill drilling and reserves from an enhanced recovery process which has yet to be established and pilot tested but appears to have favourable conditions for successful application.

Possible Reserves

Possible reserves are quantities of recoverable hydrocarbons estimated on the basis of engineering and geological data that are less complete and less conclusive than the data used in estimates of probable reserves. Possible reserves are less certain to be recovered than proved or probable reserves which means for purposes of reserves classification there is a 10% probability that more than these reserves will be recovered, i.e. there is a 90% probability that less than these reserves will be recovered. This category includes those reserves that may be recovered by an enhanced recovery scheme that is not in operation and where there is reasonable doubt as to its chance of success. RPS only determines possible reserves when specifically requested to do so.

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LEGAL NOTICE

This report is issued by RPS under the appointment by Maurel et Prom in the engagement letter dated October, 2016 (the “Agreement”), and is produced as part of the engagement detailed therein and subject to the terms and conditions of the Agreement.

This report is addressed to Wentworth Resources Limited, a named Third Party as defined in the Agreement and is only capable of being relied on by Maurel et Prom and the Third Parties under and pursuant to (and subject to the terms of) the Agreement.

Maurel et Prom may disclose the signed and dated report to third parties as contemplated by the purpose detailed in the Agreement but in making any such disclosure Maurel et Prom shall require the third party (including any Third Parties, which include Wentworth Resources Ltd) to accept it as confidential information only to be used or passed on to other persons as Maurel et Prom is permitted to do under the Agreement.

This document was prepared by RPS Energy Canada Ltd. (operating as RPS) solely for the benefit of Maurel et Prom and the Third Parties (including Wentworth) named in the Agreement.

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Project Title	**Mnazi Bay Field Reserves Assessment as at December 31, 2016**		
Project Number	CC01246		
	AUTHORS:	Project Manager	Date of Issue
	Brian D. Weatherill	Brian D. Weatherill	March 8, 2017
	Jerry Hadwin		
File Location:	RPS Energy Canada Suite 700, 555 – 4th Avenue SW Calgary, Alberta T2P 3E7 Tel:1(403) 265-7226 Fax:1(403) 269-3175 Email: rpscal@rpsgroup.com		

CERTIFICATE OF QUALIFICATION
B.D. Weatherill

I, Brian D. Weatherill, a Professional Engineer at RPS Energy Canada Ltd., and co-author of a property evaluation (the "Evaluation") dated March 8, 2017 prepared for Maurel et Prom and Wentworth Resources Limited, do hereby certify that:

- I am a Petroleum Engineer employed by RPS Energy Canada Ltd., which prepared a Resource Assessment of the Mnazi Bay, Tanzania assets, the Rovuma Onshore Block in Mozambique and an opinion as to the potential of the Mozambique Rovuma Offshore Area 1 Block assets of Maurel et Prom and Wentworth Resources Limited, as of December 31, 2016.
- I attended the University of British Columbia and that I graduated with a Bachelor of Applied Science Degree Geological Engineering in 1973; that I am a registered Professional Engineer in the Province of Alberta (APEGA); and that I have in excess of 35 years' experience in Petroleum Engineering relating to Canadian and international oil and gas properties.
- I and my employer are independent of Wentworth and our remuneration is not related in any way to Maurel et Prom, nor Wentworth's value or any Maurel et Prom or Wentworth financing or capital funding activities.
- I have not, directly or indirectly, received an interest, and I do not expect to receive an interest, direct or indirect, in Maurel et Prom or Wentworth Resources Limited or any associate or affiliate of those companies.
- The evaluation was prepared based upon information supplied by Maurel et Prom and Wentworth Resources Limited as well as other public data sources.
- As of the date of this certificate, I am not aware of any material change since the effective date of the Evaluation and, to the best of my knowledge, information and belief the sections of this report for which I am responsible contain all scientific information that is required to be disclosed to make this report not misleading.

B.D. Weatherill, P. Eng.

INDEPENDENT PETROLEUM CONSULTANT'S CONSENT AND WAIVER OF LIABILITY

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada knows that it is named as having prepared an independent report of the gas reserves of the Tanzanian property owned by Maurel et Prom and Wentworth Resources and it hereby gives consent to the use of its name and to the said report. The effective date of the report is December 31, 2016.

In the course of the assessment, Maurel et Prom and Wentworth Resources provided RPS Energy personnel with basic information which included petroleum and licensing agreements, geologic, geophysical and production information, cost estimates, contractual terms and studies made by other parties. Any other engineering or economic data required to conduct the assessment upon which the original and addendum reports are based, was obtained from public literature, and from RPS Energy non-confidential client files and previous technical resource assessment reports on the subject property. The extent and character of ownership and accuracy of all factual data supplied for this assessment, from all sources, has been accepted as represented. RPS Energy reserves the right to review all calculations referred to or included in the said reports and, if considered necessary, to revise the estimates in light of erroneous data supplied or information existing but not made available at the effective date, which becomes known subsequent to the effective date of the reports.

There is considerable uncertainty in attempting to interpret and extrapolate field and well data and no guarantee can be given, or is implied, that the projections made in this report will be achieved. The report and production potential estimates represent the consultant's best efforts to predict field performance within the scope, time frame and budget agreed with the client. Moreover, the material presented is based on data provided by Maurel et Prom and Wentworth Resources Limited. RPS Energy cannot be held responsible for decisions that are made based on this data or reports. The use of this material and reports is, therefore, at the user's own discretion and risk. The report is presented in its entirety and may not be made available or used without the complete content of the reports. RPS Energy liability shall be limited to the correction of any computational errors contained herein.

RPS Energy Group

1.0 INTRODUCTION

1.1 Background and Historical Description

Maurel et Prom ("M&P") and Wentworth Resources Limited ("Wentworth") own working interests in the Mnazi Bay Development Licence in Tanzania (Figure 1-1). M&P, the Operator of the concession, owns its interests through its local subsidiary, M&P Exploration and Production Tanzania Ltd and a share of Cyprus Mnazi Bay Limited ("CMBL"). Similarly, Wentworth owns a non-operating working interest in the Tanzanian legal entity Wentworth Gas Limited and a share of CMBL. The other working interest owner in the Licence is the national oil company, the Tanzania Petroleum Development Corporation ("TPDC").

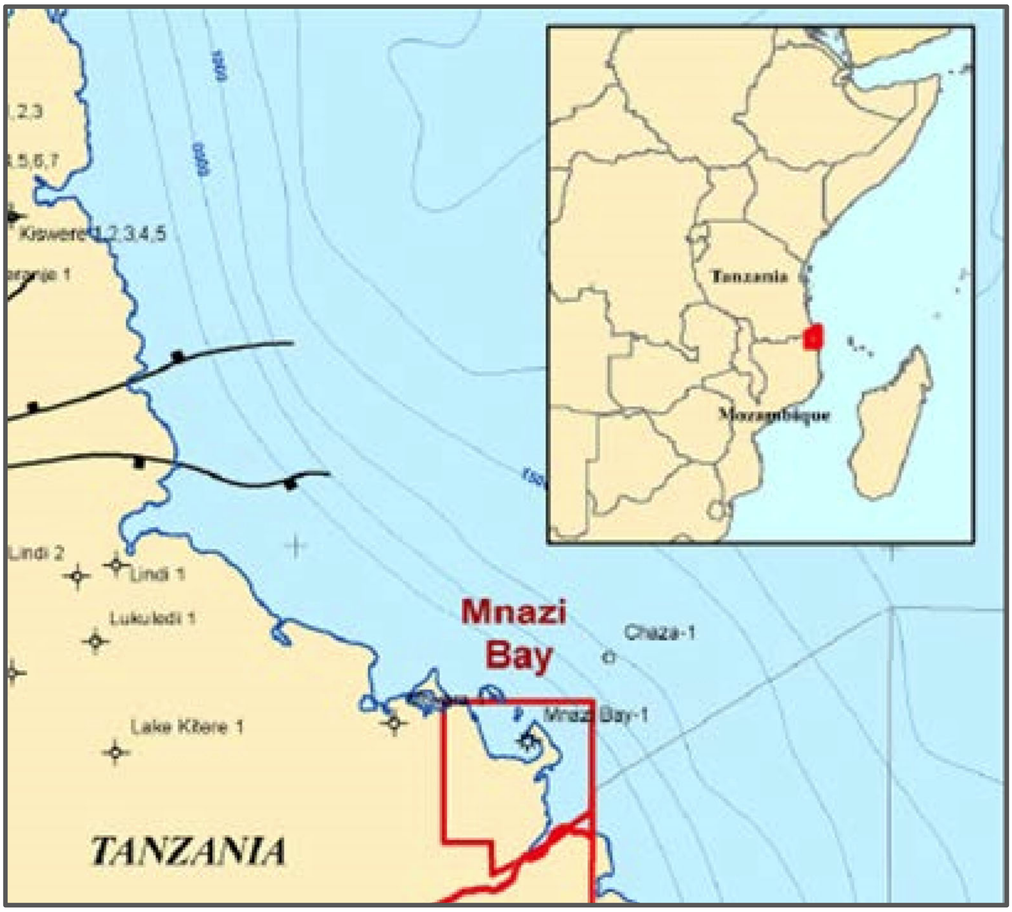

Figure 1-1: Location Map of Mnazi Bay Licence

Source: Wentworth

Asset	Working Interest	Status	Licence Expiry Date	Licence Area	Comments
Mnazi Bay PSA and Development Licence, Tanzania	**Maurel et Prom** 48.060% production 60.075% exploration **Wentworth Resources Ltd** 31.940% production 39.925% exploration	Production, Development and Exploration	October 26, 2031	756 km^2	Field development currently on production. Additional exploration and development potential

Table 1-1: Summary Table of Assets

The Mnazi Bay Concession is located at approximately 10° 19' South and 40° 23' East, on the south-eastern coast of Tanzania, just north of the border with Mozambique. (Figure 1-2)

In 1982, a gas field (Mnazi Bay) was discovered on the concession by AGIP, who drilled the discovery well Mnazi Bay #1 ("MB-1") on a seismically-defined structure. The objective of the well was to identify the stratigraphic column and focus on a Lower Cretaceous oil target. The well was evaluated as having oil and gas in several potential reservoir zones and was drill stem tested over two Miocene aged zones; the "D" zone producing over 13 MMscf/d of sweet dry gas, and then the "D" & "E" zones combined, flowing at about 12.5 MMscf/d of dry gas. These tests demonstrated the commercial potential of the discovery. After testing, the well was suspended by AGIP, due to lack of gas markets at the time. The concession was subsequently relinquished by AGIP.

In 2003, Artumas Group Inc. (now Wentworth)[1] held discussions with the Government of Tanzania with the objective of implementing a gas-to-power ("GTP") project as a means of exploiting the potential gas resources. The GTP project was conceptualized as comprising several components; development of the gas reservoir, by drilling and tie-in of sufficient production wells, a gas pipeline, a gas fired-power plant and an upgraded power transmission system for local power distribution.

In August 2003 an agreement of intent was struck between the Government of Tanzania, the Tanzanian Petroleum Development Corporation ("TPDC") and Artumas to proceed with the GTP project. In mid-2004, a Production Sharing Agreement ("PSA") on the acreage was executed between the Government of Tanzania, TPDC and Artumas Group & Partners (Gas) Limited ("AG&P"), a wholly owned subsidiary of Artumas, clearing the way for implementation of the project. The agreement concession was comprised of a 756.8 km2 (75,680 hectare) exploration area, both onshore and offshore (Figure 1-2). The concession PSA is also supported by the Agreement of Intent and several other related agreements with the Government of Tanzania to

[1] In September 2010, Artumas Group Inc. changed its name to Wentworth Resources Limited, as a result of a business combination transaction between the two companies. In this report, RPS uses the name Artumas, where appropriate, in discussion of historical company activities which pre-date the corporate name change.

implement the other aspects of the GTP project. On October 26, 2006 the Tanzanian Ministry of Energy and Minerals granted a Development Licence to TPDC covering one discovery block and eight adjoining blocks, which comprise the Mnazi Bay Contract Area covering the same area as the original PSA Exploration Licence. The Development Licence has an initial twenty-five year term to 2031), and may be extended under certain conditions.

Figure 1-2: Mnazi Bay Licence Area

In 2005 Artumas initiated a program of field development and appraisal, activities. This consisted of:

- Reprocessing and reinterpretation of the original 2 D seismic data;
- MB-1 well was re-entered, and re-tested over the D & E sands;
- MB-2 was drilled, logged and tested over the C, D, F, G and I sands;
- MB-3 was drilled, logged and tested over the C, D, F and G sands;
- MS-1X was drilled, logged and tested over the Mnazi Bay F sands, and the Msimbati K1, K2 and K3 sands The acquisition and interpretation of an additional 453 km of marine and transition zone 2D seismic, which led to the identification of numerous leads and prospects.

In concert with field appraisal activities, Artumas constructed field production facilities and a 27 km, 8" gas pipeline, northwest, to Mtwara. The production facilities and pipeline are tied in to an associated 18-megawatt electric power generation facility located at Mtwara. The power facility generated first electricity on December 24, 2006, fuelled by gas production from the Mnazi Bay Field. Commissioning of the Mnazi Bay gas processing facility and tie-in connection to the Mtwara area power generating facility was completed on March 5, 2007. Production increased, from approximately 0.5 MMscf/d initially, to over 2 MMscf/d in 2015. In August 2015 with the development of an export route to Madimba, gas deliveries to the Tanzanian transnational pipeline commenced, delivering gas to a power plant at Dar Es Salaam and production rates ramped up to a peak production of over 71 MMscf/d in 2016.

In November 2009, Artumas completed a sale of a portion of its interest in the Mnazi Bay Licence to Maurel et Prom S.A. and Cove Energy Tanzania Mnazi Bay Ltd., and on December 1, 2009, Maurel et Prom assumed operatorship. In September 2010 Artumas completed the process of changing its name to Wentworth Resources Limited, and then in July 2012, the Cove Energy interest in the licence were purchased by Maurel et Prom and Wentworth, resulting in the share ownerships in place at the effective date of this report.

1.2 Scope

This evaluation covers the gas reserves within the Tertiary formations within the Mnazi Bay licence, Tanzania

1.3 Data Sources

RPS has based this reserves assessment on publicly-available basin data, data supplied by both Maurel & Prom and Wentworth and work previously carried out by RPS and its predecessor company, APA Petroleum Engineering Inc.

Key data and reports which form the basis of RPS' estimates are as follows:

- Maurel et Prom proprietary 2D & 3D seismic data
- Mnazi Bay and Msimbati field - well and production data (five wells).
- Previous RPS and APA studies and resource reports

In addition, RPS has relied upon, and accepted without independent verification, land and concession term data and information supplied by Maurel et Prom and Wentworth.

No site visit was conducted as a part of this evaluation; however, RPS has conducted site visits to the Mnazi Bay property during 2007 and 2008.

1.4 Prior Assessments

RPS and its predecessor company APA petroleum engineering have prepared various previous resource assessments on the Mnazi Bay Licence for Wentworth and its predecessor company Artumas. Some basic data from these prior assessments, and where applicable, some analyses have been utilized and incorporated into this evaluation. The prior works are listed in the list of References to this document.

1.5 Reserve Definitions

Reserves detailed in this report have been assessed using the Resource definitions as published by COGEH, the Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers[1].

2.0 CONCESSION AREAS

2.1 Mnazi Bay Licence, Tanzania

The Mnazi Bay Concession Area is located in south-eastern Tanzania in the Ruvuma (alternately-spelled Rovuma) Basin. The concession area is a 756 square kilometre block that holds Tertiary, Cretaceous and Jurassic hydrocarbon potential (Figure 2-1). The discovered Tertiary-aged Mnazi Bay and Msimbati fields and extensions are defined by relatively sparse and variable quality 2D seismic data and by good quality 3D data over the offshore portion of the licence. Six wells have been drilled on the concession to date; five in the Mnazi Bay field (MB-1, MB-2, MB-3, MB-4 and MS-1X) and one exploration well, Ziwani-1, which was non-commercial. Additionally, several exploration prospects have been identified on the licence, however, these prospects are outside of the scope of this reserve evaluation.

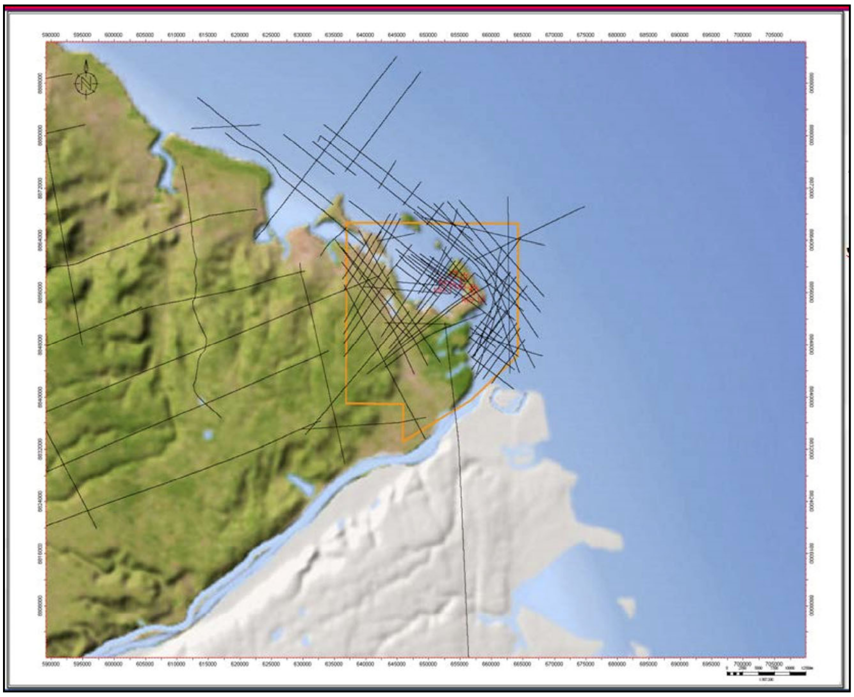

Figure 2-1: Mnazi Bay Concession, Tanzania

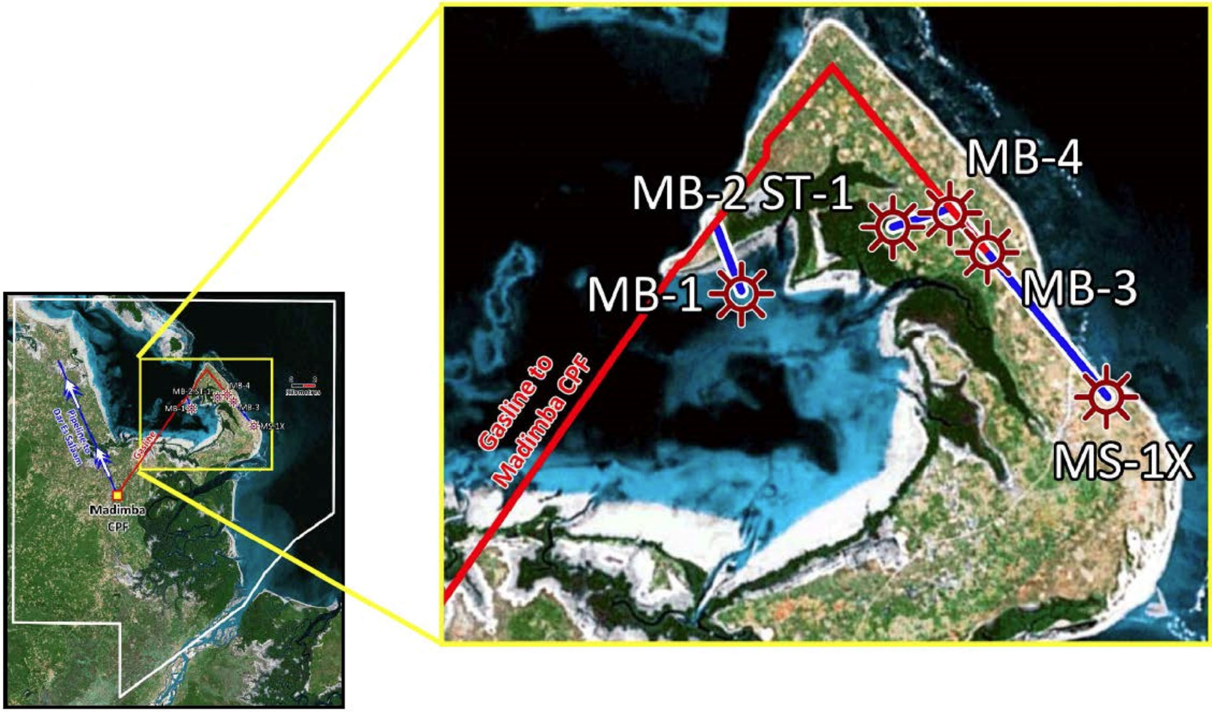

Figure 2-2: Mnazi Bay showing Mnazi Bay/Msimbati Field

2.1.1 Interests and Burdens

2.1.1.1 Maurel et Prom

Maurel et Prom owns a 48.06% operating working interest in petroleum operations other than exploration on the Mnazi Bay Licence block together with partner Wentworth Resources 31.94% and TPDC 20.00%.

Maurel et Prom also owns a 60.075% working interest in exploration operations on the block, together with Wentworth's 39.925% working interest. The exploration interest is subject to a provision of a back-in right, held by TPDC whereby, upon an oil or gas discovery, TPDC may back-in with up to 20% interest. If TPDC should exercise this right, MEP and Wentworth's interest in the discovery would decrease proportionally to the development licence values above. The company working interests represent the interest in field gross recoverable volumes (and cost commitments), not net entitlements after application of royalty or equivalent deductions.

In addition, Maurel et Prom owns a US$9.358 million (as of December 31, 2016) receivable from TPDC, resulting from TPDC's election to participate in the Mnazi Bay and Msimbati gas field discoveries in 2006, and representing TPDC share of past costs plus accumulated interest.

Production operations on the development licence area are governed by the Production Sharing Agreement, executed in 2004. This agreement is a cost recovery form of agreement and contains detailed cost recovery and profit sharing arrangements and production royalty payment obligations.

2.1.1.2 Wentworth

Wentworth owns a 31.94% working interest in petroleum operations other than exploration on the Mnazi Bay Licence block together with operator Maurel et Prom 48.06% and TPDC 20%.

Wentworth also owns a 39.925% working interest in exploration operations on the block, together with Maurel et Prom's 60.075% working interest. The exploration interest is subject to a provision of a back-in right, held by TPDC whereby, upon an oil or gas discovery, TPDC may back-in with a 20% interest. If TPDC should exercise this right, MEP and Wentworth's interest in the discovery would decrease to the development licence values above. The company working interests represent the interest in field gross recoverable volumes (and cost commitments), not net entitlements after application of royalty or equivalent deductions.

In addition, Wentworth owns a US$27.155 million (as of December 31, 2016) receivable from TPDC, resulting from TPDC's election to participate in the Mnazi Bay and Msimbati gas field discoveries in 2006, and representing TPDC share of past costs plus accumulated interest. Wentworth also retains an option to transfer a further 5% working interest per well in exchange for other parties' payment for up to two appraisal wells on the block.

Production operations on the development licence area are governed by the Production Sharing Agreement, executed in 2004. This agreement is a cost recovery form of agreement and contains detailed cost recovery and profit sharing arrangements and production royalty payment obligations.

2.1.2 Mnazi Bay Licence Block Exploration History

The Mnazi Bay gas field was discovered in 1982 by AGIP. The first well Mnazi Bay #1 ("MB-1") tested gas from the Miocene formation at rates of 13 MMcf/d. After testing, the well was suspended by AGIP, due to lack of gas markets at the time. The concession was subsequently relinquished by AGIP. The licence was acquired by Artumas (now Wentworth) in 2004. In 2005, following reprocessing and acquisition of additional 2D seismic data, the MB-1 well was re-entered and three gas discovery wells were drilled, MB-2, MB-3 and MS-1X. Two additional seismic programs were shot in 2007 and 2008 by Artumas (now Wentworth).

Maurel et Prom assumed operatorship of the Mnazi Bay PSA during 2009. A 3D seismic data survey covering the offshore portion of the block was recorded and processed during 2012 / 2013. In 2013 a 328 km^2 3D offshore seismic survey was conducted, and in 2014 an additional 315 km of 2D onshore seismic and 58 km of high resolution onshore seismic data was collected. The MB-4 well was drilled and completed as a gas producer in June 2015.

3.0 REGIONAL GEOLOGY AND PETROLEUM SYSTEM

3.1 Regional Geological Setting

The Mnazi Bay Licence area in Tanzania is located in the northern part of the Ruvuma ("Rovuma" in Mozambique) Basin which straddles the border between Tanzania and Mozambique. It is one of numerous basins along the east coast of Africa, formed when the palaeo-continent of Gondwana rifted apart during the Permian, Triassic and early Jurassic. Regionally, the rifting associated with the formation of the Ruvuma Basin led to the separation of the island of Madagascar from the main body of Africa.

Figure 3-1: Location Map Ruvuma Basin

The basin contains Triassic and Lower-Jurassic, syn-rift sediments overlain by thick drift sequences. The depositional environment is dominantly clastic with the exception of some mid-Jurassic carbonates. Early-Jurassic, restricted-marine deposits and continental sediments along the basin margins are overlain by a transgressive-regressive sequence estimated to be as much as 7-8 km thick at the coast. In response to the early uplift and doming that preceded rifting of the modern-day East African Rift System, the Ruvuma River delta and submarine channel system began to form during the Oligocene. The passive-margin sequence was succeeded by a massive influx of eastward prograding clastic sediments from Mid-Tertiary to Recent. The position of the Ruvuma Delta depo-centre was constrained by fault block rotation and basin subsidence during the Tertiary, with the early centre located towards the northern part of the Ruvuma Basin. These sediments have been subjected to intensive gravity-driven deformation, shale diapirism and slumping. The Ruvuma Delta complex comprises of a thick, eastwardly prograding wedge of rapidly deposited clastic sediments which extends eastward into canyon/channel sediments, forming a complex network of stacked channel sandstones. Resources are contained in this Tertiary interval, primarily in the Miocene and Oligocene.

The stratigraphy in the area is shown on the following chart:

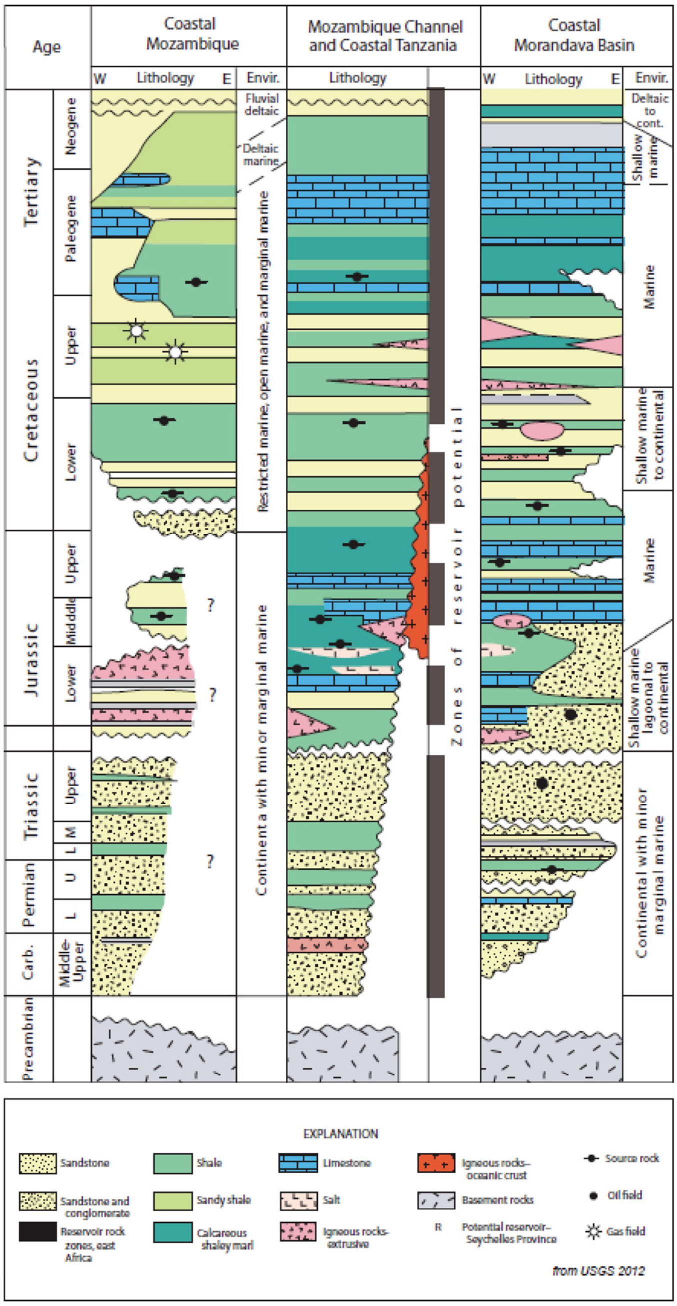

Figure 3-2: Stratigraphic Chart [2]

3.2 Tertiary Depositional Environments

The Tertiary sequence in the Mnazi Bay area is situated within the canyon slope setting (Figure 3-3); these marine canyon-fill gravity deposits contain sandstones, which provide good reservoirs, and shales, which enable stratigraphic traps. Onshore Mozambique Tertiary deposits are fluvial, deltaic deposits and marine shelf deposits (Figure 3-4), which make excellent reservoirs. In Offshore Area 1, Tertiary sediments consist of channel and deepwater fan deposits, which contain excellent quality reservoir sands; hydrocarbons are trapped on toe thrust structures. (Figure 3-3 and Figure 3-4).

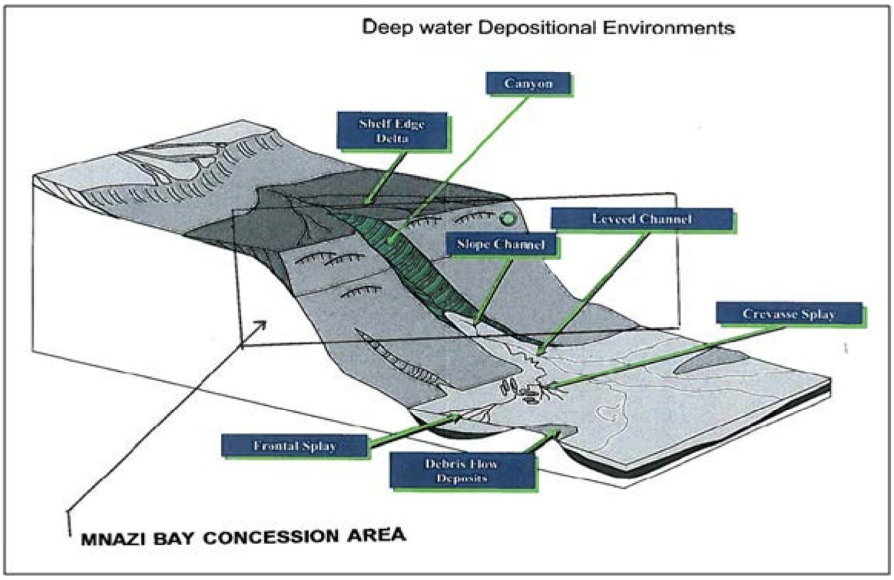

Figure 3-3: Tanzania Tertiary Deposition - Canyon Slope Setting

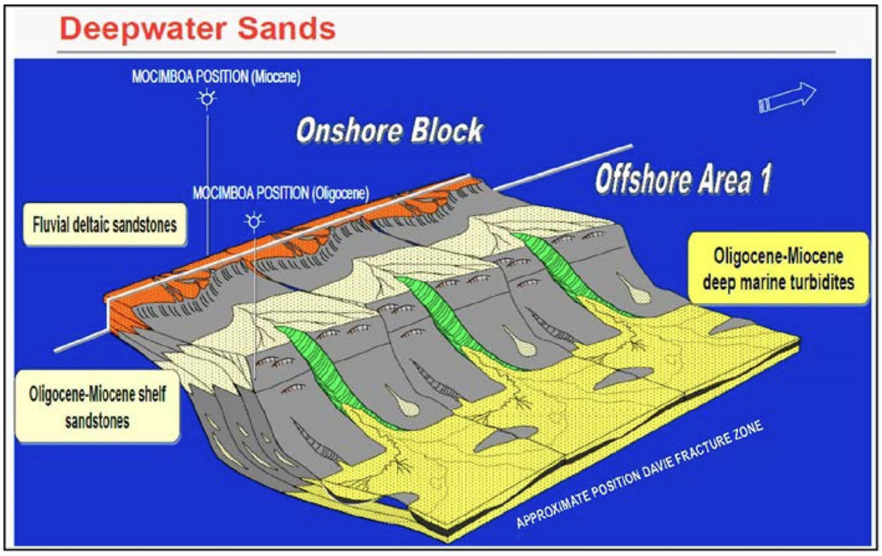

Figure 3-4: Mozambique Tertiary Deposition. Onshore Block: Fluvial-Deltaic and Marine Shelf Sandstone.

Offshore Area 1: Deep Marine Turbidites and Fans

Source: Cove Investor Presentation (May 2011)

Figure 3-5 below shows the correlation between three wells on-shore Tanzania and on-shore Mozambique demonstrating the Upper and Lower Tertiary depositional cycles across the Ruvuma (Rovuma) Basin.

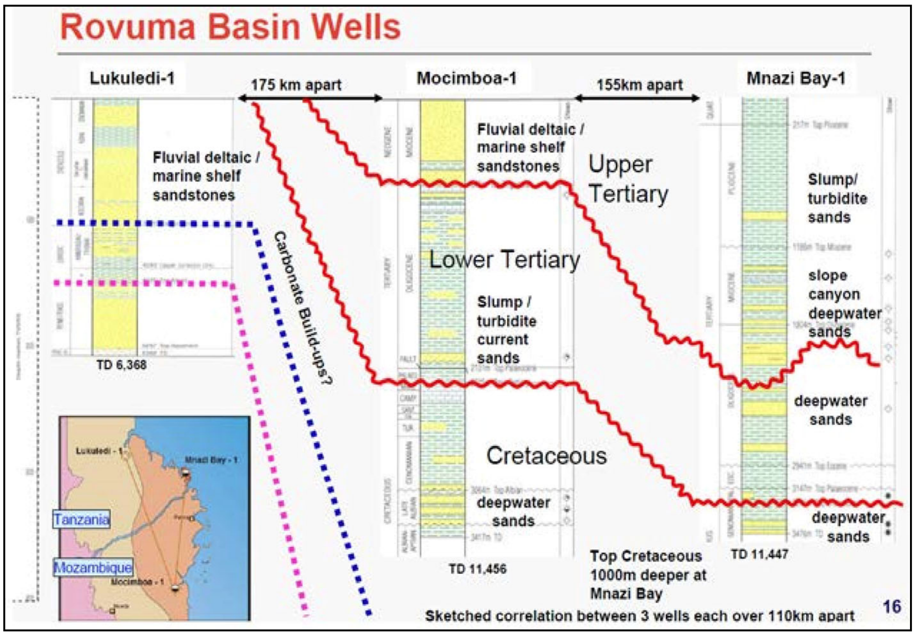

Figure 3-5: Cross Section across On-Shore Tanzania and Mozambique Showing Upper and Lower Tertiary Environments and Reservoir/Seal Pairs

Source: Cove Investor Presentation (May 2011)

3.3 Tertiary Stratigraphy

The new prospects on the Mnazi Bay licence and the Mnazi Bay and Msimbati fields lie at the northern end of the Ruvuma Basin. The Ruvuma basin contains a shallow deltaic through deep slope and deep water fan succession. Reliable correlations within such successions are difficult, as channelized, laterally-discontinuous reservoir sandstones, deposited in shallow deltaic through to deep slope settings, generally lack unique, correlatable characteristics. The Pliocene, Miocene, Oligocene and Eocene deposits on the Mnazi Bay licence are all thought to be deposited as deep-water continental slope deposits consisting of channels within submarine canyons and turbidite current sediments. The submarine canyons are filled with channel sands and slump deposits (shales).

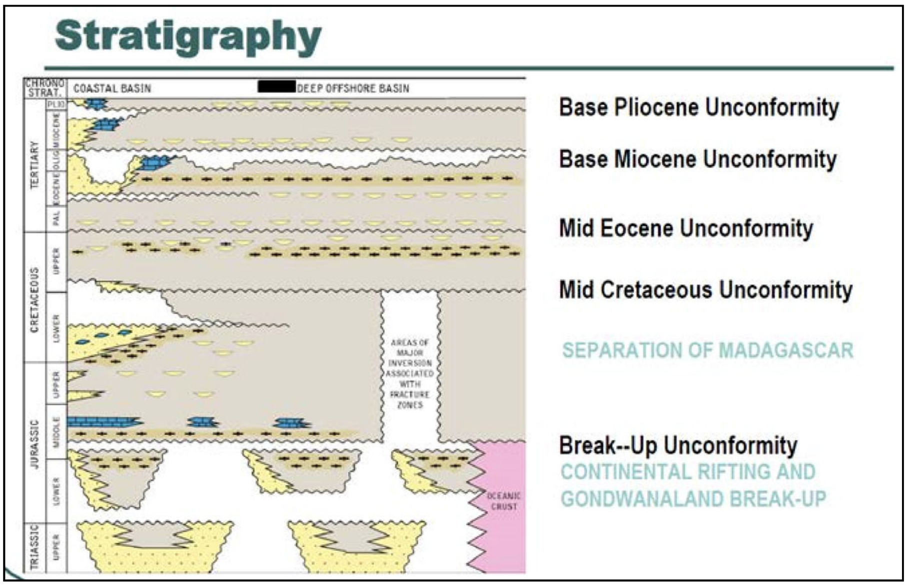

Figure 3-6: Evolution of the Ruvuma Basin with Stratigraphic Units

Source: Artumas Internal Presentation

3.4 Cretaceous Stratigraphy

An Early Cretaceous regression resulted in Lower Cretaceous deposition dominated by continental clastics on the western flank of the basin in the Maconde Formation passing laterally to shallow marine deposits to the east. The Maconde Formation consists of fluvial conglomerates and feldspathic quartz sandstones with associated fine grained interbedded clastic facies.

These terrestrial deposits pass into Aptian-Albian aged shallow marine fluvio-deltaic clastics, intra-slope channels and basin floor submarine fan complexes. Based on modern analogues the stratigraphic architecture in different portions of the submarine fan complex is expected to vary based on position on the slope. In an upslope position the primary facies include mass-transport deposits and sand or mud-filled channels. The mid slope setting is characterized by sand-filled channels and levees passing laterally into fine grained marine mudstones. On the basin floor the facies include sandstone lobes as well as very fine grained interbedded sandstones and siltstones. The most distal and lateral fan positions include thin sandy channels, tabular sandstone beds and laminated mudstone. This distal setting is anticipated to have the lowest net:gross sand ratios.

The Upper Cretaceous is characterized by marine fine grained clastics, micaceous and pyritic shales, fossiliferous lime mudstone and dolomite deposited in a range of restricted and open marine settings. The formational nomenclature given to this post-Albian marine succession is the upper Domo Shales and overlying Grudja Formation in the Mozambique coast and channel area but it is unclear whether this terminology extends into the Ruvuma Basin.

3.5 Ruvuma Basin - Source Rocks, Maturity and Migration Paths

Only a small number of wells have been drilled in the Ruvuma Basin to date, consequently the main potential source rock sequences have yet to be intersected in the subsurface. Data from recent discoveries on the Offshore Area 1 Block are not available. Analogues from other East

African margin basins have been used to describe the source rock potential of the Ruvuma Basin. Known source rocks, along the East African margin, range from Permo-Triassic through Jurassic to possibly Cenozoic age. The source for the Mnazi Bay and Msimbati gas discoveries is thought to be the regionally extensive mature Jurassic source rocks.

Results of 1D basin modeling from across the Ruvuma Basin indicate that peak oil generation for mid-Jurassic source rocks was during early-mid Cretaceous times, while remaining potential source rocks in the Late Jurassic, Cretaceous and younger sections, which saw major hydrocarbon generation and expulsion during the Eocene, Oligocene, and Recent epochs. The latter is triggered by the initiation of the Late-Tertiary to Recent East African Rift Valley system which resulted in subsidence and a major heating phase pulse throughout the Ruvuma Basin.

3.6 Structure

Two episodes of deformation dominate the structural history of the Ruvuma Basin. During rifting, a NNE-SSW trending system of horsts and grabens developed, affecting pre-Upper Jurassic strata. These strata dip regionally eastward due to loading of the passive margin. Gravitational collapse of passive margin sediments has resulted in the development of a linked shelf-extensional and basinward toe-thrust system. Listric normal faults cut Tertiary strata and sole in a decollement near the top of the Cretaceous. The associated toe-thrust system is located offshore to the east of the Mnazi Bay licence in Tanzania and offshore Mozambique.

Figure 3-7 shows the linked extensional system of roll over anticlines associated with normal listric growth faults, as found in Mnazi Bay and onshore Mozambique, and basinward toe thrust systems which create structural traps for Tertiary plays in offshore Mozambique.

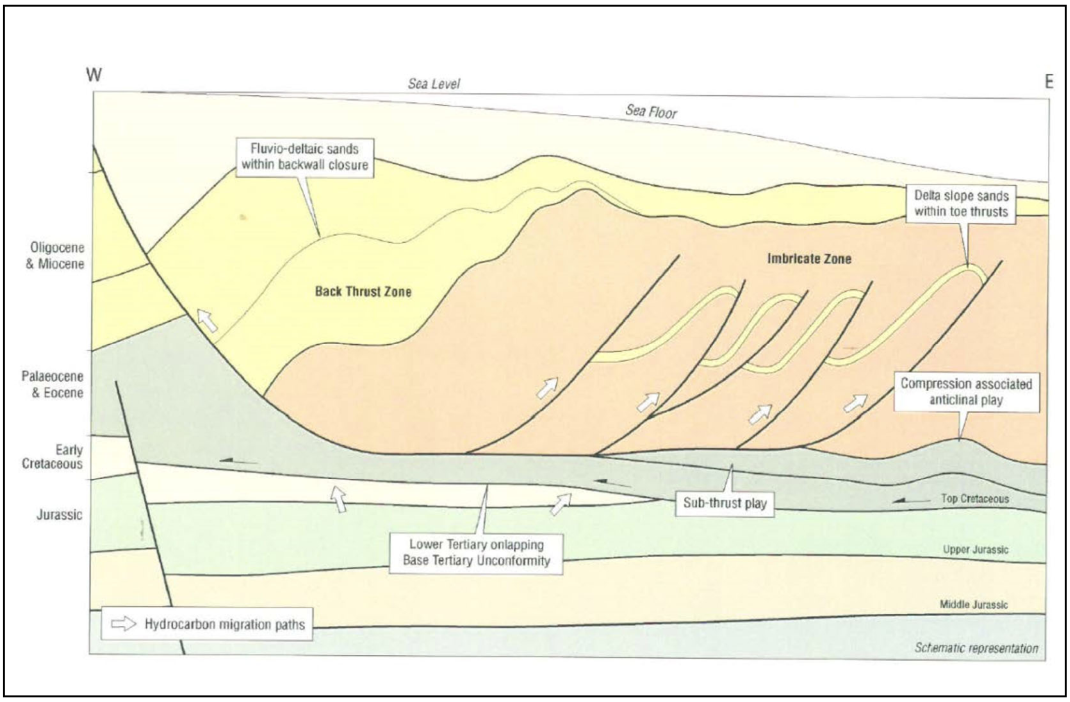

Figure 3-7: Cross Section Showing the Linked Extensional and Basinward Toe Thrust System

Source: Artumas Internal Presentation

4.0 MNAZI BAY FIELD – RESERVES

The Mnazi Bay and Msimbati discoveries together comprise the Mnazi Bay Field and the reservoirs are collectively referred to as comprising the Mnazi Bay Licence. The depositional model for the reservoirs is based on a stratigraphically complex series of stacked channels deposited in a deep-water canyon/slope setting.

4.1 Reservoir Geology

4.1.1 Stratigraphy

Mnazi Bay and Msimbati reservoirs lie at the northern end of the Ruvuma Basin. The Ruvuma Basin contains a succession from shallow deltaic through deep slope. Reliable correlations within such successions are difficult, as channelized, laterally-discontinuous reservoir sandstones, deposited in shallow deltaic through to deep slope settings, generally lack unique, correlatable characteristics.

Within the reservoir section, several correlation schemes can be envisioned between the MB-1, MB-2, MB-3, MB-4 and MS-1X wells. The nature of the seismic anomalies at Mnazi Bay, indicate a deep water channel/canyon setting rather than a near shore deltaic environment. The reservoir sands are interpreted to have been deposited on the deepwater continental slope, as offset stacked channel deposits and have been identified as occurring within four Miocene-aged channel sequences, the Lower Sand and Upper Sand for the Mnazi Bay reservoir section and the Lower K Sand and Upper K Sand for Msimbati Field (Figure 4-1 and Figure 4-2). The sand units were correlated using seismic and well logs and used channel scour, gas-water contacts and thickness and flooding surfaces to identify the channel sequences.

Five wells at Mnazi Bay, MB-1, MB-2, MB-3, MB-4 and MS-1X contain gas in the Miocene.

A composite of the logs from the five wells at Mnazi Bay is shown in Figure 4-1 and Figure 4-2.

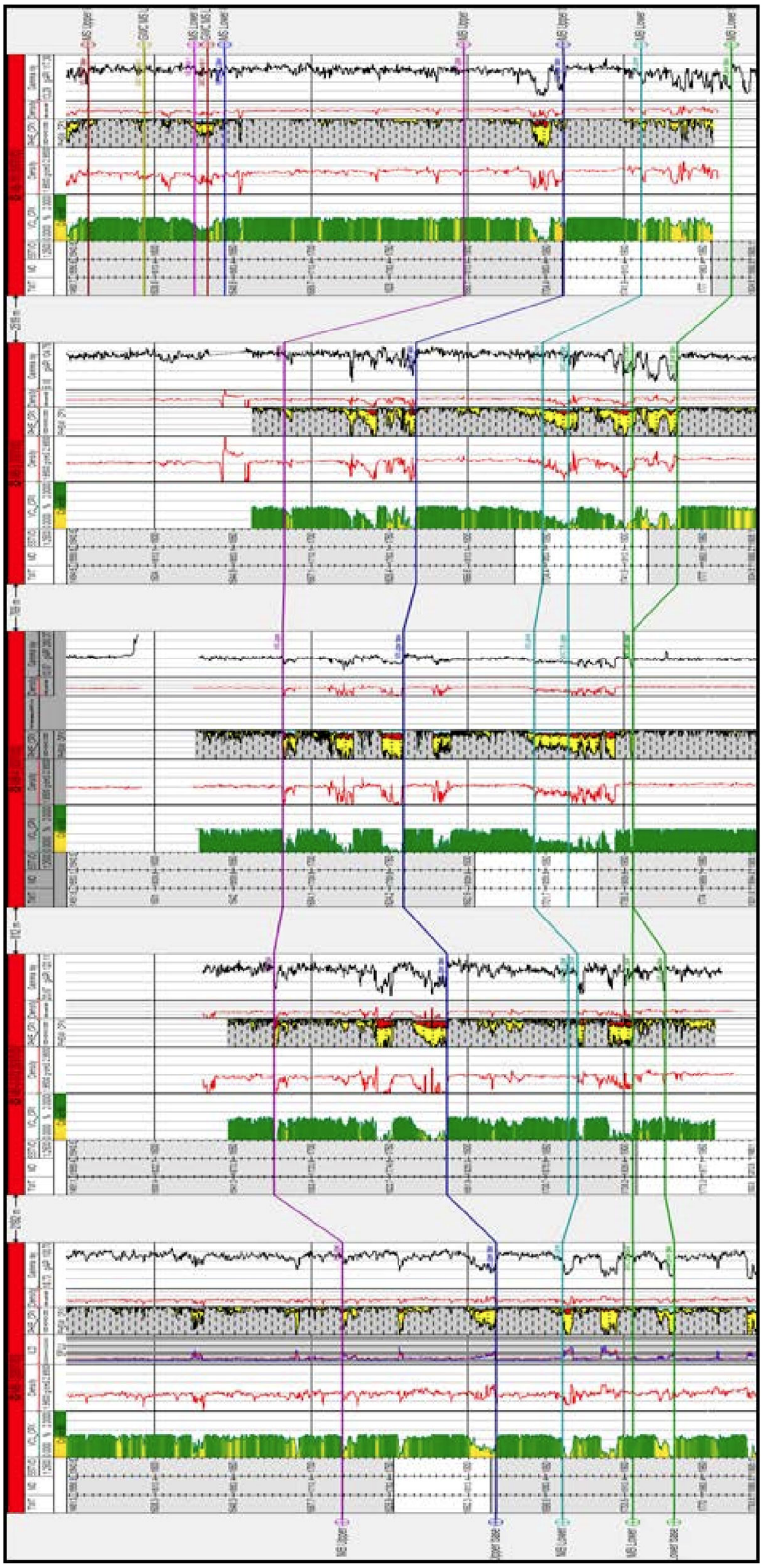

Figure 4-1: Mnazi Bay Stratigraphic Section

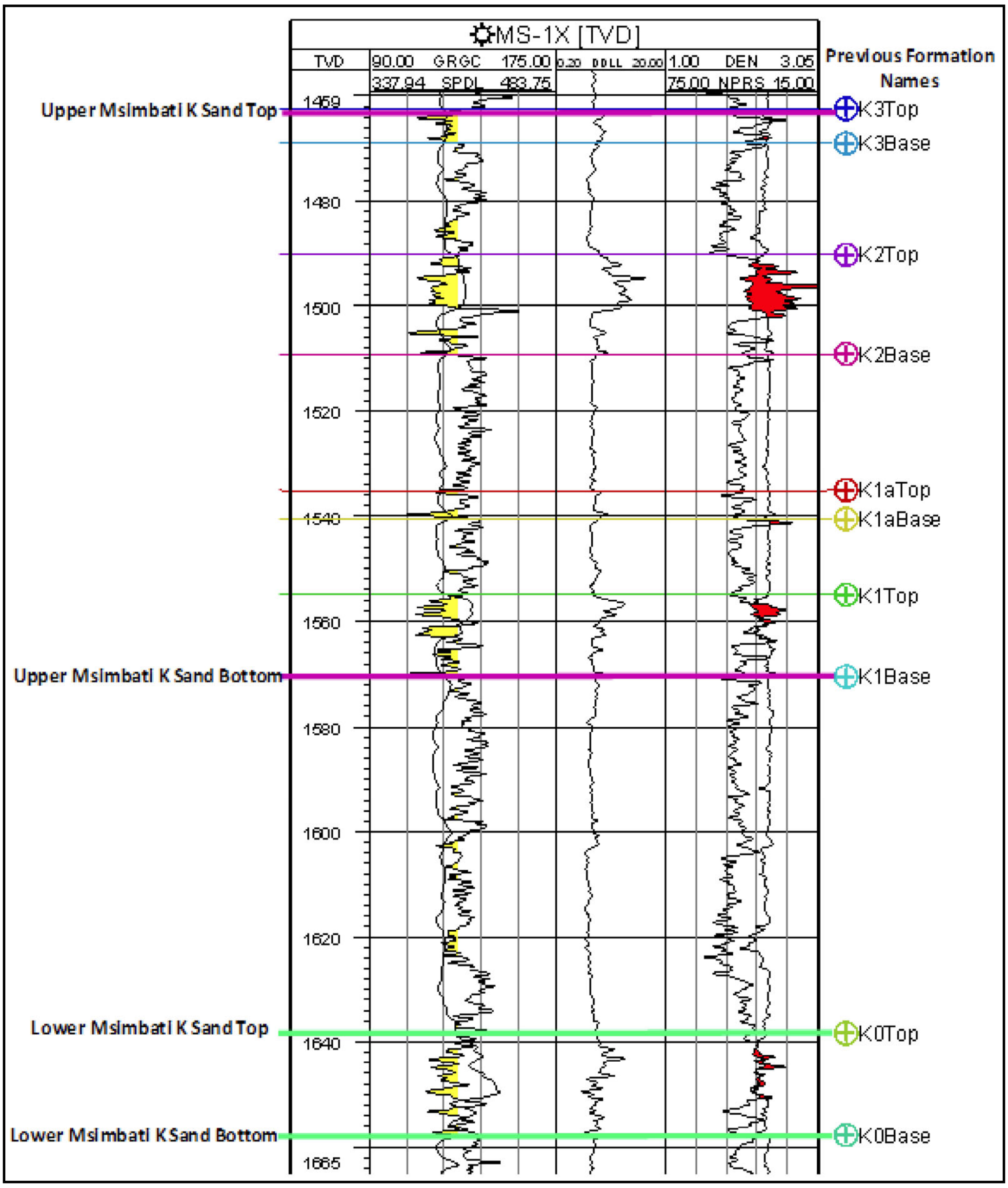

Figure 4-2: Msimbati Field MS-1X K Sands – Stratigraphic Section

4.1.2 Structural Geology

The Mnazi Bay structure lies along the crest of a major roll-over anticline associated with an extensional normal listric growth fault. The channel complex cuts into the anticline and is parallel to the fault trend.

A pre-Tertiary unconformity high, as shown in Figure 4-3, at Mnazi Bay/Msimbati may have influenced preferential fairways for the intense channelized slope system during the Oligocene and Miocene.

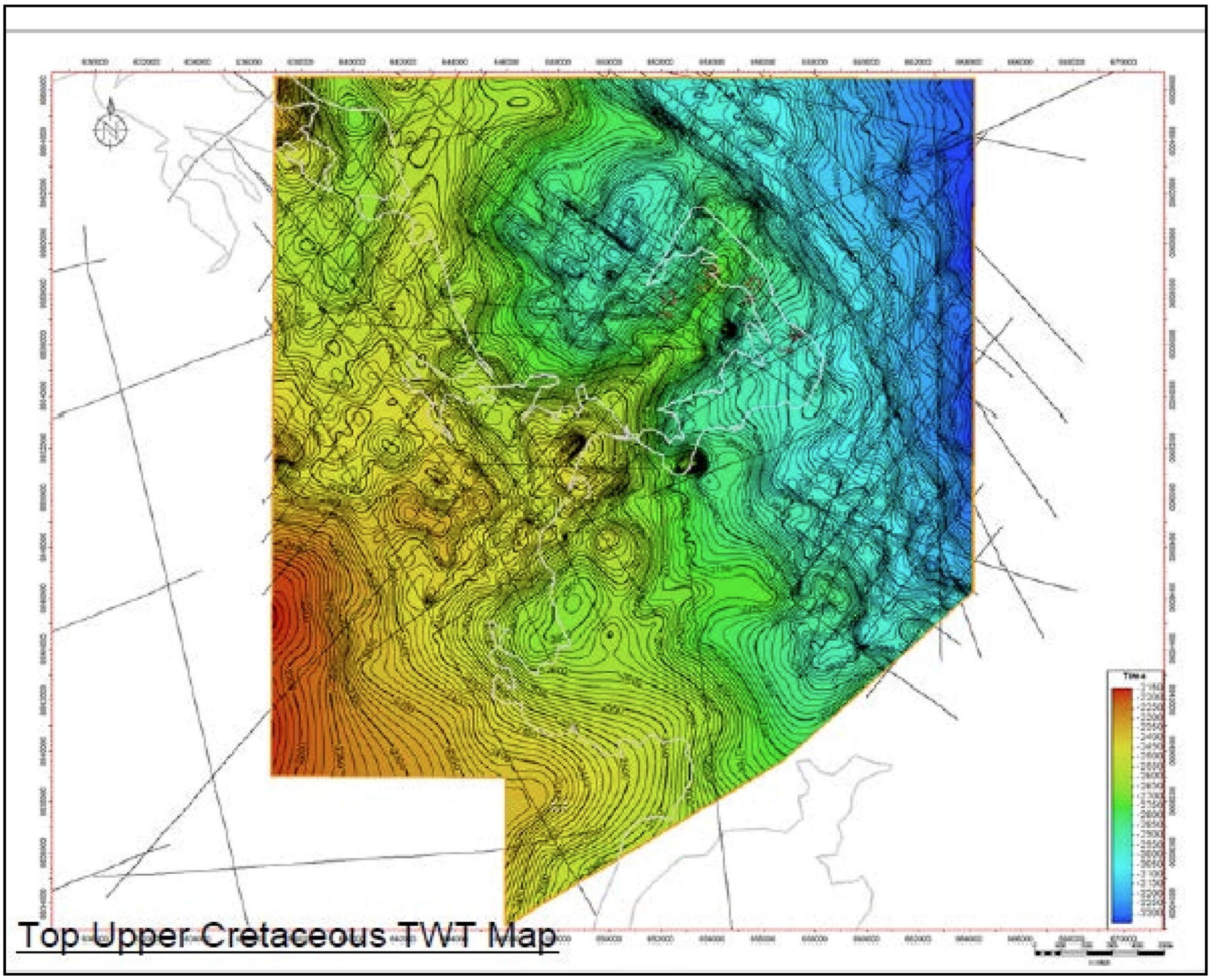

Figure 4-3: Pre-Tertiary Unconformity Surface (Top Upper Cretaceous)

4.1.3 Seismic Interpretation

Mnazi Bay Field

Four horizons have been picked within the Mnazi Bay channel structure; the Upper K and Lower K sands and the MB Upper and MB Lower Sands. The MB Lower Sand package contain sands which have previously been described as the C, D and E sands, while the MB Upper Sand package contains sands previously described as the F, G, H and I sands, all of Mio-Oligocene age. There is a shale interval between the two sand packages.

Figure 4-4 shows the Mnazi Bay channel feature with the upper sand package tops identified in yellow, the bases in red.

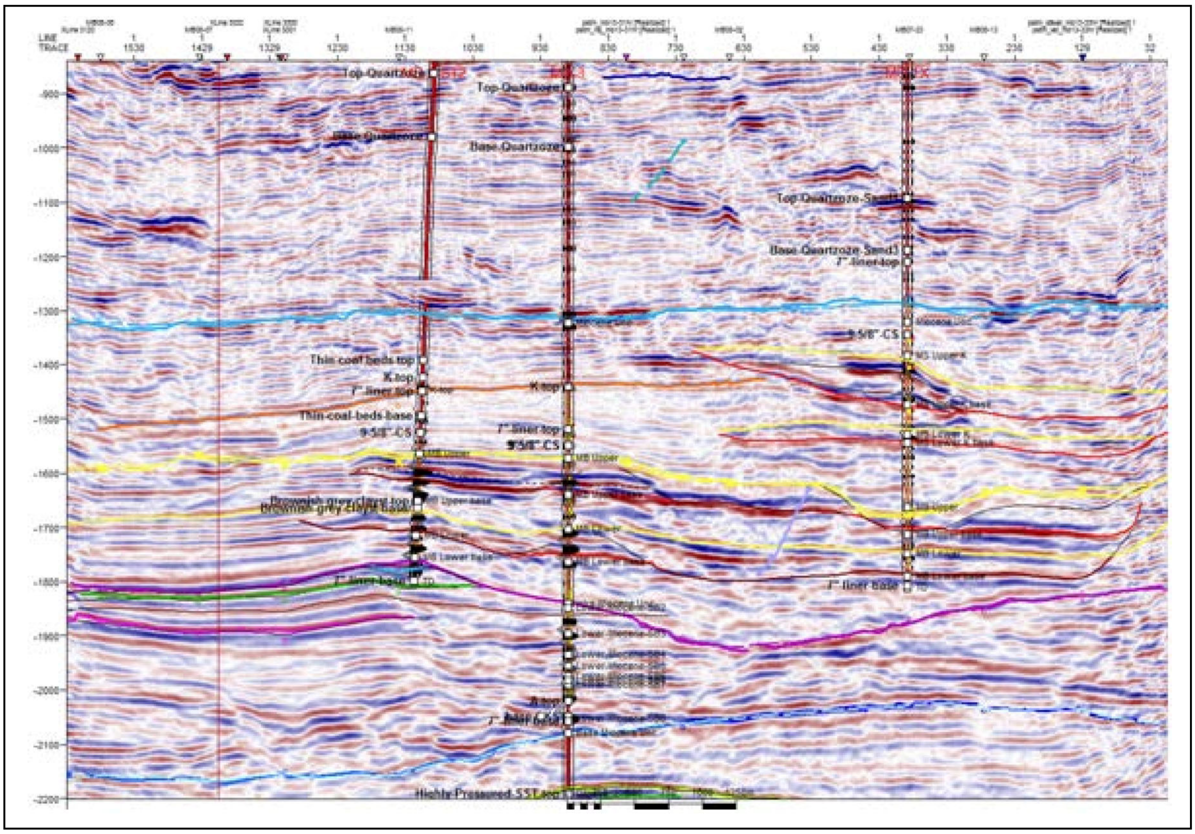

Figure 4-4: Line MB13-29 Showing the Mnazi Bay Channel

4.1.4 Geological Model – Gross Rock Volume

Mnazi Bay

A simple geological/geophysical structural model was constructed using depth grids created by seismic mapping and log data from the five wells; MB-1, MB-2, MB-3, MB-4 and MS-1X. Gross rock volumes were calculated using depth grids created from the seismic mapping from the top and bottom of the mapped sand packages above gas-water contacts. In order to create the depth grids, the depths from the well control were used in conjunction with the time structures to create a velocity field within the channels.

The following maps were produced:

- MB Upper Sand Top Structure Map
- MB Upper Sand Base Structure Map
- MB Lower Sand Top Structure Map
- MB Lower Sand Base Structure Map

- Upper K Sand Top Structure Map
- Upper K Sand Base Structure Map
- Lower K Sand Top Structure Map
- Lower K Sand Base Structure Map

- MB Upper Sand Isopach
- MB Lower Sand Isopach
- Gross Thickness above gas-water contact ("GWC")
- Upper K Sand Isopach
- Lower K Sand Isopach

Figure 4-5 and Figure 4-6 are examples of these maps. All the maps are included in Appendix 2.

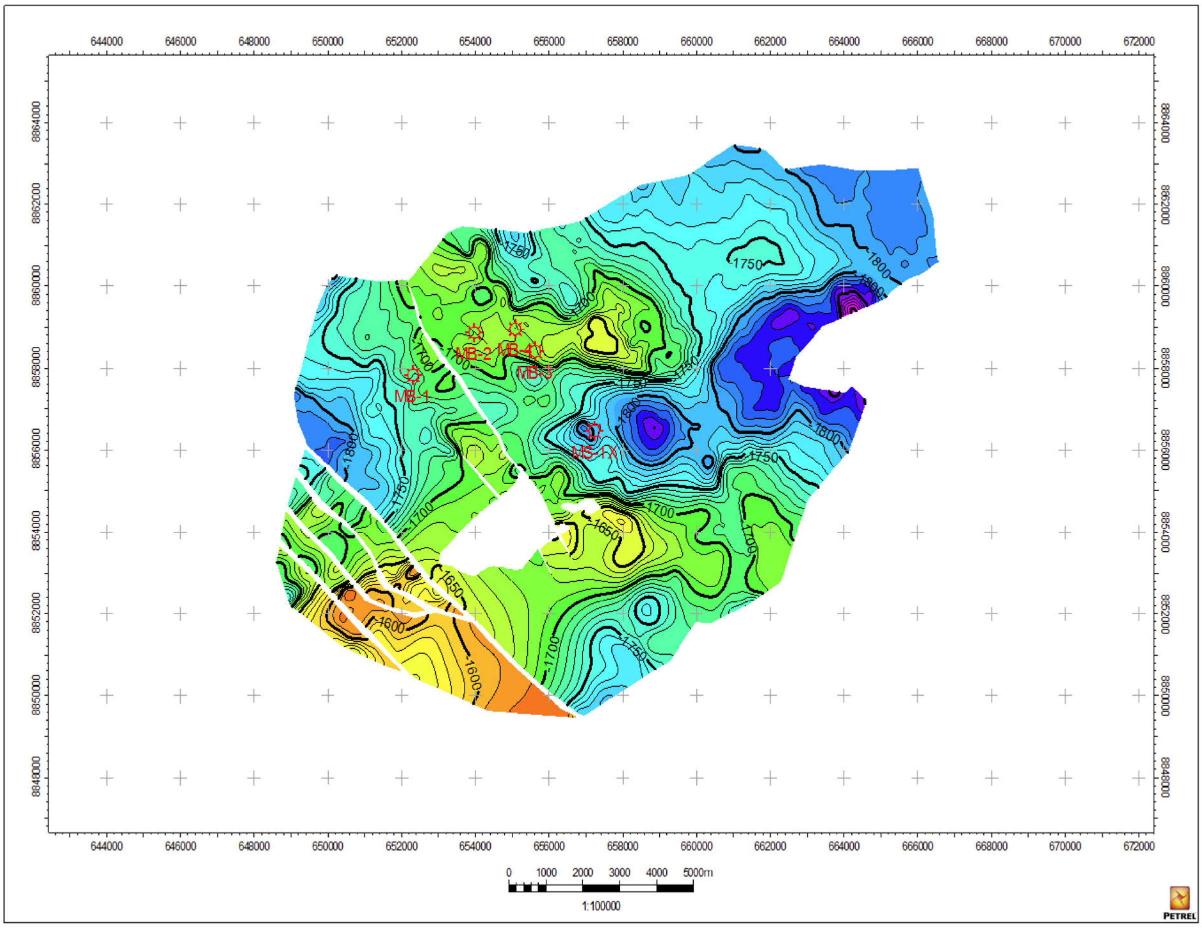

Figure 4-5: Mnazi Bay - Upper Sand Top Structure Map

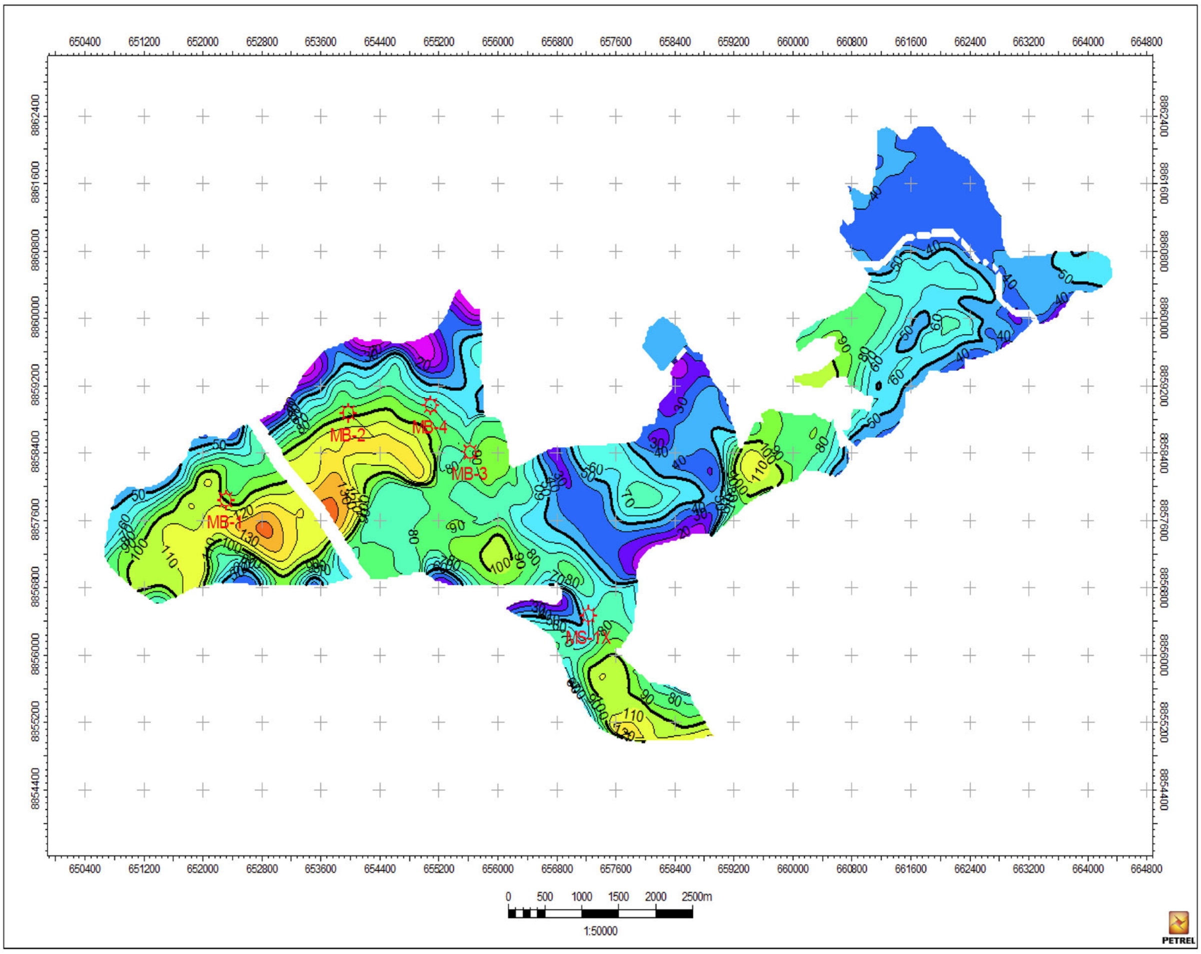

Figure 4-6: Mnazi Bay - Upper Sand Isopach above GWC

4.1.5 Petrophysical Analysis

The Mnazi Bay reservoirs have been penetrated by five wells:

- Mnazi Bay #1(“MB-1”) drilled by AGIP in 1982;
- Mnazi Bay #2 (“MB-2”); drilled by Artumas in 2006;
- Mnazi Bay #3 (“MB-3”); drilled by Artumas in 2006
- Msimbati #1 (“MS-1X”), drilled by Artumas in 2007
- Mnazi Bay #4 (“MB-4”); drilled by Maurel et Prom in 2015

Full suites of open-hole logs were run in all wells, including resistivity devices, neutron-density, and borehole-compensated sonic. No core has been acquired; side-wall core samples were obtained from the latest well, MB-4, but not used in the analysis.

Logs from MB-1, MB-2, MB-3 and MS-1X have been previously evaluated to identify potentially productive intervals, and establish reservoir parameters[3 4 5 6]. The CPIs and values from these wells, provided by Maurel et Prom for the 2014 reserves analysis, remain valid and show close agreement with the values established previously. To derive net reservoir thicknesses and petrophysical parameters for the MS Upper Sand, MS Lower Sand, MB Upper Sand and MB Lower Sand gas-prone intervals the following cut-offs were used:

- Vsh < 0.50,
- Φe > 0.08, and
- Sw < 0.60

RPS was provided with the raw log and interpreted data for the most recent well, MB-4, and conducted a quick-look analysis which confirmed the evaluation conducted by Maurel et Prom.

On this basis, RPS considers the formation tops, logs, CPIs and petrophysical parameter values provided by Maurel et Prom to be reliable.

A composite of the logs from the four wells is shown in Figure 4-1 and Figure 4-2 of Section 4.1. The input values used to define the distributions for the probabilistic volumetric assessment are summarized in Table 4-1.

MS UPPER	P90	P50	P10	Mean	Distrib.	MS LOWER	P90	P50	P10	Mean	Distrib.
N/G	0.06	0.13	0.20	0.13	Normal	N/G	0.20	0.35	0.50	0.35	Normal
Porosity	0.20	0.25	0.30	0.25	Normal	Porosity	0.15	0.185	0.22	0.185	Normal
Sw	0.35	0.45	0.55	0.45	Normal	Sw	0.41	0.51	0.61	0.51	Normal
MB UPPER	**P90**	**P50**	**P10**	**Mean**	**Distrib.**	**MB LOWER**	**P90**	**P50**	**P10**	**Mean**	**Distrib.**
N/G	0.20	0.27	0.34	0.27	Normal	N/G	0.35	0.49	0.63	0.49	Normal
Porosity	0.16	0.23	0.30	0.23	Normal	Porosity	0.18	0.21	0.24	0.21	Normal
Sw	0.30	0.39	0.48	0.39	Normal	Sw	0.28	0.37	0.46	0.37	Normal

Table 4-1: Petrophysical Input Ranges to Volumetric Calculations

4.2 Reservoir Fluids

4.2.1 Pressure vs. Depth Relationships

In all five wells, reservoir pressure has been measured and interpreted at various sand depth levels. Initial reservoir pressures in the gas bearing sands generally range from 2900 to 2990 psia in the Mnazi Bay Sands and 2500 to 2580 psia in the Msimbati Sands. Pressure data from the latest well, MB-4, drilled after eight years of production, show depletion. The pressure in the intermediate sands is broadly aligned with the Lower Mnazi Bay reservoir, indicating communication with these sands (though it is not inconceivable that these sands are not connected and representative of a separate, slightly shallower, GWC). Depletion in the Lower Mnazi Bay varies between 15 and 23 psi. Depletion at the top of the Upper Mnazi Bay amounts to 8 to 9 psia and in the main part of the Upper Mnazi 25 to 32 psi.

The total pressure data set is comprised of RFT (Repeat Formation Test), MDT (Modular Formation Dynamics Tester) and DST (Drill Stem Test) test data. These data allow determination of the in-situ pressure gradients in various sands, both gas bearing and water bearing. Pressure-versus-depth plots for each of the wells are shown in Figure 4-7 to Figure 4-10. A composite pressure vs. depth plot for the initial four wells drilled (prior to depletion) is shown in Figure 4-12. On each plot the range of pressure gradient derived gas-water contact ("GWC") depths is shown.

The composite DST, MDT, RFT pressure data suggest that multiple GWC depths are likely prevalent throughout the fields and are probably both structurally and stratigraphically-controlled.

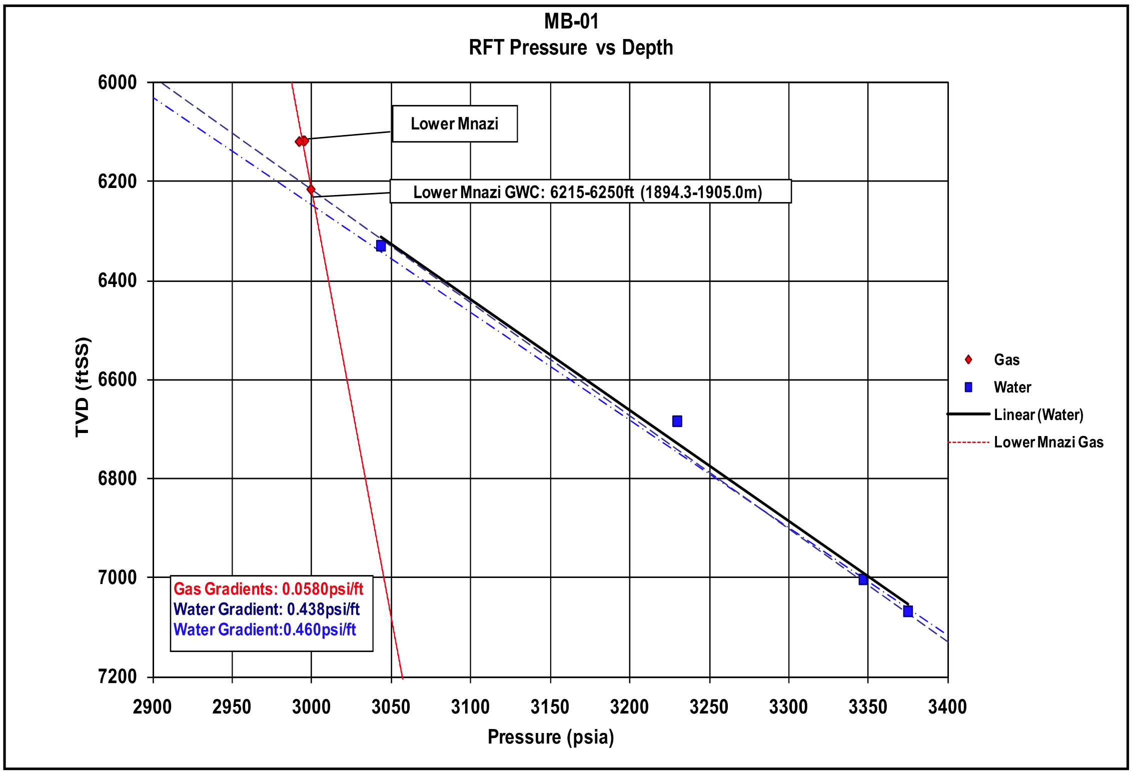

Figure 4-7: MB-01 RFT Pressure vs. Depth

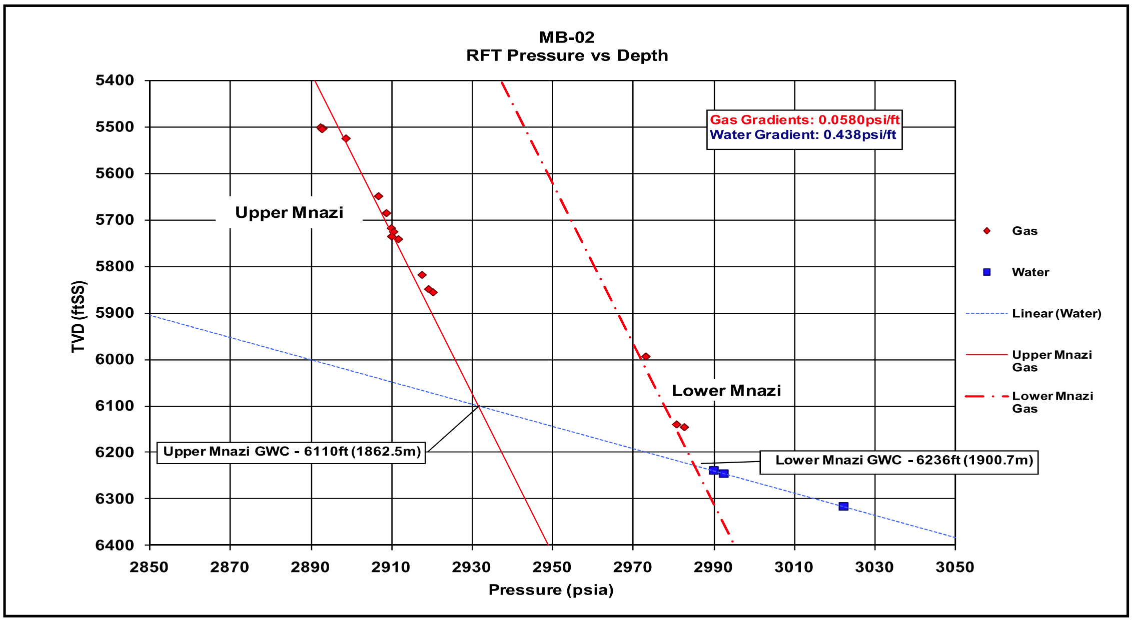

Figure 4-8: MB-02 Pressure vs. Depth

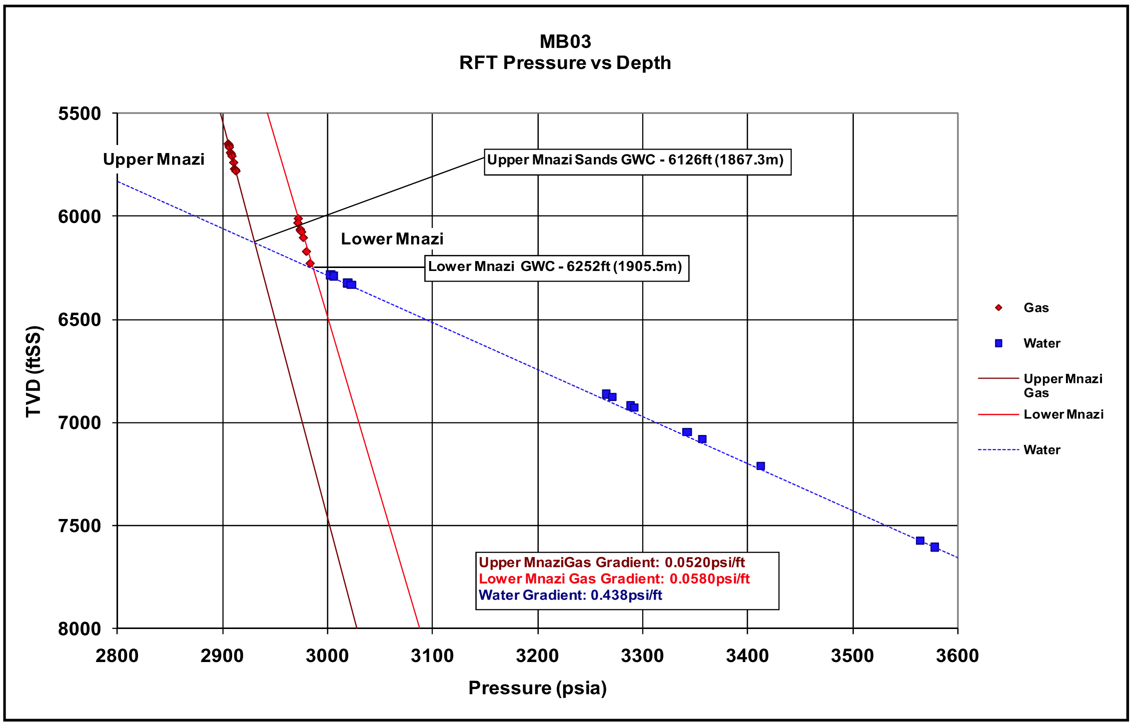

Figure 4-9: MB-03 RFT Pressure vs Depth

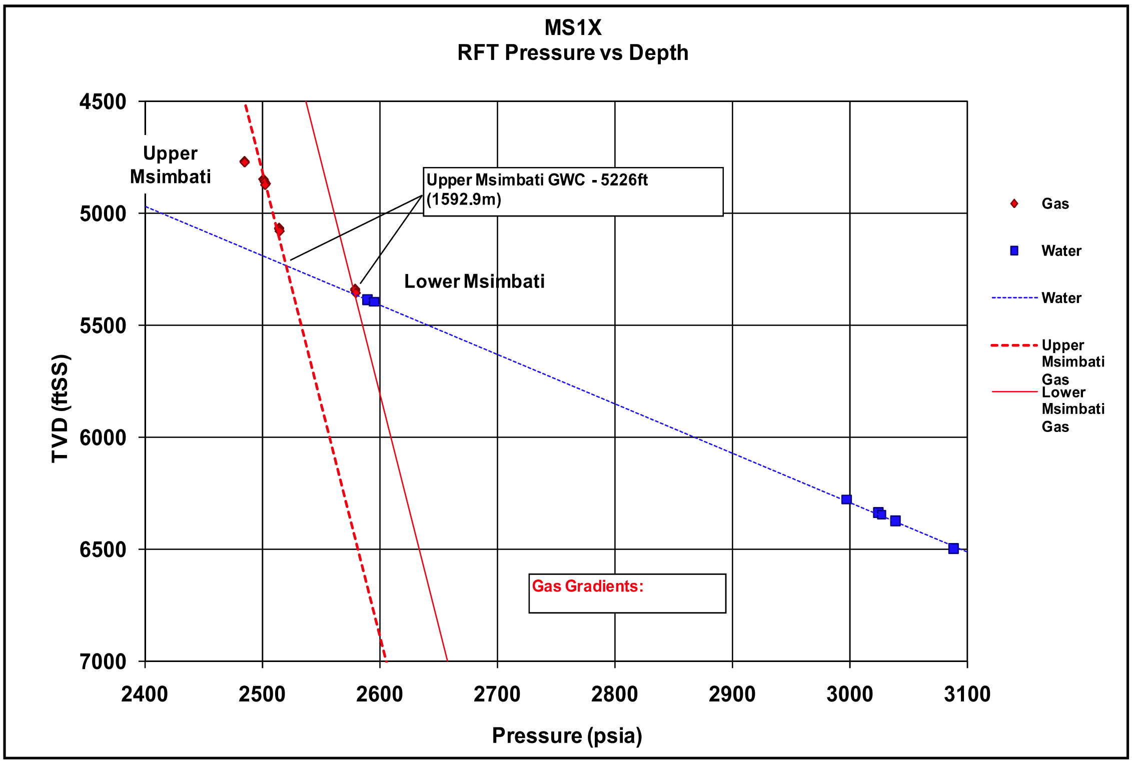

Figure 4-10: MX-1 RFT Pressure vs. Depth