STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

1. DATE OF STATEMENT

This Statement of Reserves Data and Other Oil and Gas Information (the "Statement") of Reconnaissance Energy Africa Ltd. ("ReconAfrica" or the "Company") is dated July 31, 2023. The effective date of the information provided in this Statement is March 31, 2023, unless otherwise indicated. The information contained herein was prepared on July 28, 2023.

Cautionary Note Regarding Forward-Looking Statements

This Statement contains "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation in Canada, the United States and any other applicable jurisdiction (collectively, "forward-looking statements"). Forward-looking statements are provided as of the date of this Statement and the Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable securities laws.

Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "believe", "could", "estimate", "expect", "forecast", "guidance", "intend", "may", "plan", "predict", "project", "should", "target", "will", or similar words suggesting future outcomes or language suggesting an outlook. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Company, future production and grades, the economic limit or viability of assets, projections for sales growth, estimated revenues, resources, targets for cost savings, general economic conditions, the construction cost of new projects, the timing and outcome of exploration projects and drilling programs, projected capital expenditures, transportation costs, the timing of new projects, the outcome of legal proceedings, general public perception of the Company, the integration of acquisitions, future debt levels, fiscal regimes, the outlook for the prices of hydrocarbons, the outlook for economic recovery and trends in the trading environment, statements about strategies, cost synergies, revenue benefits or integration costs and production capacity of the Company and the industry and countries in which the Company operates. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties that may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Operating conditions can have a significant effect on the timing of events. Accordingly, investors are cautioned that events or circumstances could cause results to differ materially from those predicted. Management of the Company believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Statement should not be unduly relied upon.

In particular, this Statement contains forward-looking statements pertaining to, among others, the following:

- expectations regarding the ongoing exploration process for the newly identified Kavango sedimentary basin in Northeast Namibia and Northwest Botswana (the "Kavango Basin"), including the Company's 2022 stratigraphic test well drilling program and the next phase of the Company's 2-D seismic acquisition, processing and interpretation program;
- expectations regarding future expenditures to be incurred or spent on the Company's assets;
- expectations regarding the Company's interpretation of data and models relating to its assets;
- operating results and future performance of the Company;
- information in respect of, or relating to, risked and un-risked prospective resources, including third party assessments, including those contained in the NSAI Report (as defined herein);
- the size, characteristics and features of the Company's oil and/or gas opportunities, future potential oil, natural gas and natural gas liquids, resources and the ability to commercially exploit them;
- the Company's proposed exploration, drilling and exploitation activities and timelines;
- expectations, given exploration success, regarding the future development of the Company's assets and the by-products of such development;
- the potential returns for undiscovered oil and/or gas deposits in the Kavango Basin;

- the Company seeking potential partnering opportunities to assist in its exploration and development of hydrocarbons in the Kavango Basin;
- the Company's acquisition of half of the 10% carried participating interest in the Namibia Licence held by NAMCOR;
- projections of market prices, including market prices for oil and natural gas, and costs; and
- expectations regarding the infrastructure and transportation facilities that will be available to the Company for the storage and shipment of any products it may produce.

Statements relating to "reserves" and "resources" (including prospective resources, as such terms are defined in this Statement) are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future.

Forward-looking statements are based on the Company's current beliefs as well as assumptions made by, and information currently available to, the Company concerning future oil and natural gas production levels, future commodity prices, the ability to add oil and natural gas reserves through farm-in, acquisition and/or drilling at competitive prices, future exchange rates, the cost and availability of equipment and services in the field, the impact of increasing competition and the ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and discussed more extensively in the Company's annual information form for the year ended December 31, 2021 under the heading "Risk Factors":

- risks related to the nature of the business of the Company;
- exploration and production risks inherent in the oil and natural gas industry;
- risks related to permits, licences, approvals and authorizations;
- ongoing capital requirements;
- weaknesses and volatility in the oil and gas industry;
- inflation;
- interest rates;
- negative operating cash flow;
- possible failure to realize anticipated benefits of acquisitions;
- commitments and contingencies;
- economic dependence;
- reliance on key individuals;
- marketability of crude oil and natural gas;
- project related risks;
- climate change;
- risks of foreign operations;
- risks of operating through foreign subsidiaries;
- risks related to fraud, bribery and corruption in Namibia, Botswana and Mexico;
- changes in government policy;
- royalty regimes;
- "resources" vs "reserves";
- estimates of resources;
- reserves estimates and reserve replacement risk;
- status and stage of development;
- availability of equipment and access restrictions;
- nature of reserves and additional funding requirements;
- third party credit risks;
- operating hazards and other uncertainties;
- competition;
- alternatives to and changing demand for petroleum products;
- global financial conditions;

- macro-economic risks;
- the ongoing invasion of Ukraine by Russia;
- geo-political change;
- ongoing or future pandemics;
- sufficiency of insurance coverage;
- joint property ownership;
- joint venture risks;
- cyber attacks or terrorism;
- non-governmental organizations and eco-terrorism risks;
- infrastructure, energy and water supplies;
- disclosure controls and procedures;
- environmental regulations;
- market access constraints and oil and gas transportation risks;
- conflicts of interest;
- risks related to operating in African countries;
- tax regimes;
- foreign currency exchange risks;
- risks related to changes to national and local governmental laws and regulations;
- regulatory risks;
- management of growth;
- claims and legal proceedings;
- risks related to disclosure around Canada's extractive sector transparency measures act;
- any potential failure comply with anti-bribery and anti-corruption laws;
- reputation risks;
- environmental, pollution, occupational health and safety risks;
- discretion regarding potential use of proceeds;
- volatility in the trading price of the Company's common shares;
- liquidity of the Company's common shares;
- dilution and further sales of the Company's common shares; and
- dividends.

With respect to forward-looking statements contained in this Statement, ReconAfrica has also made assumptions regarding, among other things, the willingness of operators to conduct operations on certain properties in foreign jurisdictions; the future oil and/or gas prices or cost of products sold; the ability to obtain required capital to finance exploration, development and operations; the ability to maintain sufficient funds to continue the operations of the Company; the timely receipt of any required regulatory approvals; the ability to obtain drilling success consistent with expectations; the ability of the Company to secure adequate product transportation; no material variations in the current tax and regulatory environments; and the ability to obtain equipment, services, supplies and personnel in a timely manner to carry out its activities. Forward-looking statements and other information contained herein concerning the oil and/or gas industry and ReconAfrica's general expectations concerning this industry are based on estimates prepared by management of ReconAfrica with help from NSAI and other third-party contractors using data from publicly available industry sources, as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of the industry. Although this data is generally indicative of relative market positions, market shares and performance characteristics, it is inherently imprecise. While ReconAfrica is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

The above summary of major risks and assumptions related to forward-looking statements included or incorporated by reference in this Statement has been provided for readers to gain a more complete perspective on the Company's future operations. However, readers should be cautioned that the above list of factors is not exhaustive and that this information may not be appropriate for other purposes. Forward-looking statements included in this Statement are valid only as at the date hereof and the Company does not intend to update or revise these forward-looking statements except as required by applicable securities laws. The forward-looking statements contained in this Statement are expressly qualified by this cautionary note.

Abbreviations

2U	best estimate scenario of prospective resources
acre-ft	acre-feet
bbl	barrels
Bcf	billions of cubic feet
BOE	barrels of oil equivalent
COGEH	Canadian Oil and Gas Evaluation Handbook
COGEH Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information included in the COGEH
km2	square kilometers
KS	Cretácico Superior
KM	Cretácico Medio
m	meters
Mbbl	thousands of barrels
Mcf	thousands of cubic feet
MD	measured depth
mD	millidarcies
MMbtu	millions of British thermal units
MMbbl	millions of barrels
MMcf	millions of cubic feet
NSAI	Netherland, Sewell & Associates, Inc.
OGIP	original gas-in-place
OOIP	original oil-in-place
P05	5 percent confidence level
P50	50 percent confidence level
P95	95 percent confidence level
P_d	chance of development
PEL	petroleum exploration licence
P_g	probability of geologic success
PHIE	effective porosity
rb/stb	reservoir barrels per stock tank barrel
scf/rcf	standard cubic feet per reservoir cubic foot
STARSS	Southern Trans-African rift and shear system
S_w	water saturation
SWE	effective water saturation
TVDSS	true vertical depth subsea
US$	United States dollars
USM$	thousands of United States dollars
USMM$	millions of United States dollars shale volume
VSP	vertical seismic profile

2. DISCLOSURE OF RESERVES DATA

ReconAfrica engaged Netherland, Sewell & Associates, Inc. (“NSAI”), an independent qualified reserves evaluator, to prepare a report relating to the Company’s reserves as of March 31, 2023. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated. The Company’s licences located in Northeast Namibia and Northwest Botswana are set out in the Appendix to this Statement including a summary of the estimation of prospective resources of the Company as of March 31, 2023.

The Company’s crude oil and natural gas reserves are located in Chiapas, Mexico, and were acquired via the acquisition of Renaissance Oil Corp. (“Renaissance”) on July 27, 2021. Set out below is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Company as at March 31, 2023 as evaluated by NSAI in its report dated July 28, 2023 (the "NSAI Report"). The NSAI Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the NSAI Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the NSAI Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

Summary of Oil & Gas Reserves
As of March 31, 2023
Forecast Prices and Costs

Reserves Category	Crude Oil		Conventional Natural Gas				Total BOE	
	Light and Medium Crude Oil Combined(1)		Solution Gas		Non-Associated Gas			
	Gross (Mstb)	Net (Mstb)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MBOE)	Net (MBOE)
Proved Developed Producing	312	68	1,140	446	5,632	890	1,441	291
Proved Undeveloped	-	-	-	-	-	-	-	-
Total Proved	**312**	**68**	**1,140**	**446**	**5,632**	**890**	**1,441**	**291**
Probable	117	22	309	120	1,957	300	494	92
Total Proved Plus Probable	**429**	**90**	**1,449**	**566**	**7,589**	**1,190**	**1,935**	**382**
Possible	144	24	302	116	2,258	343	570	100
Total Proved Plus Probable Plus Possible	**573**	**113**	**1,751**	**682**	**9,846**	**1,533**	**2,506**	**483**

(1) Includes condesate reserves

Summary of Net Present Values of Future Net Revenue
As of March 31, 2023
Forecast Prices and Costs

Reserves Category	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (%/Year)					Unit Value Before Income Tax Discounted at 10%/Year
	0 (M$US)	5 (M$US)	10 (M$US)	15 (M$US)	20 (M$US)	0 (M$US)	5 (M$US)	10 (M$US)	15 (M$US)	20 (M$US)	($US/BOE)
Proved											
Developed Producing	5,240	4,784	4,400	4,072	3,791	3,778	3,423	3,128	2,879	2,667	15.13
Undeveloped	-	-	-	-	-	-	-	-	-	-	
Total Proved	**5,240**	**4,784**	**4,400**	**4,072**	**3,791**	**3,778**	**3,423**	**3,128**	**2,879**	**2,667**	**15.13**
Probable	1,838	1,491	1,224	1,018	856	1,278	1,046	865	722	609	13.38
Total Proved Plus Probable	**7,079**	**6,275**	**5,624**	**5,090**	**4,647**	**5,056**	**4,469**	**3,992**	**3,601**	**3,276**	**14.71**
Possible	2,244	1,704	1,321	1,044	840	1,577	1,209	945	752	608	13.17
Total Proved Plus Probable Plus Possible	**9,323**	**7,979**	**6,945**	**6,134**	**5,487**	**6,633**	**5,678**	**4,937**	**4,352**	**3,884**	**14.39**

Notes:

NPV of FNR includes all resource income:
- Sale of oil, gas, by-product reserves
- Processing third party reserves
- Other income

Income Taxes
- Includes all resource income
- Applies appropriate income tax calculations
- Includes prior tax pools

Unit Values are based on net reserve volumes

BOE Equivalent: 6 Mcf = 1 BOE

Total Future Net Revenue (undiscounted)
As of March 31, 2023
Forecast Prices and Costs

Reserves Category	Revenue (M$US)	Royalties (1) (M$US)	Operating Costs (M$US)	Development Costs (M$US)	Abandonment & Reclamation Costs (M$US)	Future Net Revenue Before Income Taxes (M$US)	Income Taxes (M$US)	Future Net Revenue After Income Taxes (M$US)
Proved	53,050	2,172	2,845	-	638	5,240	1,619	3,621
Proved Plus Probable	73,412	2,967	3,965	-	638	7,079	2,180	4,898
Proved Plus Probable Plus Possible	98,176	3,784	5,169	-	638	9,323	2,848	6,475

(1) Includes Royalties plus Exploration & Production Activities Tax

Future Net Revenue by Production Type
As of March 31, 2023
Forecast Prices and Costs

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10%/Year (M$US)	Unit Value Before Income Taxes Discounted at 10%/Year ($US/BOE)
Proved	Light and Medium Crude Oil Combined (1)	2,677	5.39
	Conventional Natural Gas (2)	1,884	2.08
	Topen Abandonment	-162	0.00
	TOTAL	**4,400**	**3.13**
Proved Plus Probable	Light and Medium Crude Oil Combined (1)	3,338	5.30
	Conventional Natural Gas (2)	2,447	2.01
	Topen Abandonment	-162	0.00
	TOTAL	**5,624**	**3.05**
Proved Plus Probable Plus Possible	Light and Medium Crude Oil Combined (1)	3,944	5.19
	Conventional Natural Gas (2)	3,163	2.02
	Topen Abandonment	-162	0.00
	TOTAL	**6,945**	**2.98**

Notes:
Unit Values are based on net reserve volumes
(1) Net oil revenue includes revenue from solution gas and associated by-products.
(2) Net gas revenue includes revenue from associated by-products (condensate).
BOE Equivalent 6 Mcf = 1 BOE

3. PRICING ASSUMPTIONS

The pricing assumptions used in the NSAI Report with respect to net present values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. NSAI is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

Summary of Pricing Assumptions
As of March 31, 2023

Period	Benchmark Oil/Condensate Price ($US/bbl)	Oil/Condensate Differential[1]	Average Received Oil/Condensate Price ($US/bbl)	Benchmark Gas Price ($US/MMBtu)	Gas Price Differential[2]	Average Received Gas Price ($US/Mcf)
Historical[3]						
04/01/22 - 03/31/23	91.38[4]	-7.29	84.09	5.955[5]	0.565	6.520
Forecast[6]						
04/01/23 - 12/31/23	76.38	-7.29	69.09	3.100	0.565	3.665
01/01/24 - 12/31/24	76.54	-7.29	69.25	3.741	0.565	4.306
01/01/25 - 12/31/25	75.45	-7.29	68.16	4.283	0.565	4.848
01/01/26 - 12/31/26	76.96	-7.29	69.67	4.370	0.565	4.935
01/01/27 - 12/31/27	78.50	-7.29	71.21	4.460	0.565	5.025
01/01/28 - 12/31/28	80.07	-7.29	72.78	4.552	0.565	5.117
01/01/29 - 12/31/29	81.67	-7.29	74.38	4.644	0.565	5.209
01/01/30 - 12/31/30	83.30	-7.29	76.01	4.737	0.565	5.302
01/01/31 - 12/31/31	84.96	-7.29	77.67	4.831	0.565	5.396
01/01/32 - 12/31/32	86.68	-7.29	79.39	4.928	0.565	5.493
01/01/33 - 12/31/33	88.40	-7.29	81.11	5.035	0.565	5.600
Thereafter, an escalation rate of 2.0% percent per year applied to Benchmark prices for inflation						

(1) Oil/Condensate differential is based on the historical accounting records of ReconAfrica and is inclusive of adjustments for quality and market differentials

(2) Gas differential is based on the historical accounting records of ReconAfrica and is inclusive of adjustments for energy content and market differentials

(3) Prices used in Constant Case

(4) 12-month unweighted arithmetic average of the first-day-of-the-month West Texas Intermediate spot price for each month in the period April 2022 through March 2023

(5) 12-month unweighted arithmetic average of the first-day-of-the-month Henry Hub spot price for each price for each month in the period April 2022 through March 2023

(6) Forecast Benchmark prices are an average of four March 31, 2023, forecasts prepared by Canadian independent consultants. Oil/Condensate prices are based on NYMEX West Texas Intermediate near-month prices; Gas prices are based on NYMEX Henry Hub near-month prices.

4. RECONCILIATION OF CHANGES IN RESERVES

Reconciliation of Company Gross[1] Reserves by Product Type
As of March 31, 2023
Forecast Prices and Costs

Factors	Light and Medium Crude Oil Combined[2]					Conventional Natural Gas					BOE				
	Gross Proved (Mstb)	Gross Probable (Mstb)	Gross Proved Plus Probable (Mstb)	Gross Possible (Mstb)	Gross Proved Plus Probable Plus Possible (Mstb)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Possible (MMcf)	Gross Proved Plus Probable Plus Possible (MMcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)	Gross Possible (Mboe)	Gross Proved Plus Probable Plus Possible (Mboe)
December 31, 2021	**786.8**	**259.2**	**1,046.0**	**286.0**	**1,332.0**	**11,568.5**	**4,545.1**	**16,113.6**	**5,146.2**	**21,259.7**	**2,714.9**	**1,016.7**	**3,731.6**	**1,143.6**	**4,875.3**
Extensions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	(338.5)	(6.7)	(481.1)	(6.3)	(623.3)	(2,605.6)	(87.6)	(4,884.4)	(395.7)	(7,471.3)	(772.8)	(21.3)	(1,295.2)	(72.3)	(1,868.6)
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	(135.9)	(135.9)	(135.9)	(135.9)	(135.9)	(2,191.2)	(2,191.2)	(2,191.2)	(2,191.2)	(2,191.2)	(501.1)	(501.1)	(501.1)	(501.1)	(501.1)
March 31, 2023	**312.4**	**116.6**	**429.0**	**143.7**	**572.8**	**6,771.6**	**2,266.4**	**9,038.0**	**2,559.2**	**11,597.2**	**1,441.0**	**494.4**	**1,935.4**	**570.3**	**2,505.6**

(1) Company Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

(2) Includes condensate reserves.

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5. ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

As of March 31, 2023, there are no proved developed non-producing or proved undeveloped reserves for the Chiapas properties. Volumes associated with the Malva Location 1 have been reclassified as contingent resources. No values have been included that can be attributed to interests in undeveloped acreage beyond these tracts for which undeveloped reserves have been estimated.

Funding for the Company's Mexican assets are derived from internally generated cash flow and, to the extent that the asset does not generate sufficient cash flow to support a new development project, it would be deferred, potentially beyond two years. It would also be deferred if the Company changed its strategic capital allocation program for the asset. As disclosed in the Form 51-101F1 for the year ended December 31, 2021, the Malva 1 well was scheduled to be drilled in November of 2022, however, this has not yet occurred.

Future Development Costs

Regarding the Form 51-101F1 for the year ended December 31, 2021, the capital cost associated with (a) proved reserves were expected to be $4.3 million to be spent by December 2022 in the Malva Field (not spent to date), and (b) proved plus probable reserves were expected to be $4.3 million to be spent by December 2022 in the Malva Field (not spent to date). At this time, the Company has no intention of developing these assets or incurring future development costs on these assets. However, in the past, funding for these assets have been derived from internally generated cash flow and, to the extent that the asset did not generate sufficient cash flow to support a new development project, it would be deferred. The Company does not anticipate that current operation of the property will be uneconomic for the Company as it does not anticipate incurring any development costs at this time.

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance. While these factors can be considered and potentially anticipated, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly. For a discussion of risk factors and uncertainties affecting reserves data, see Risk Management & Risk Factors – Reserve Estimates and Reserve Replacement Risks in the annual information form dated June 20, 2023, available on the Company's profile on SEDAR at www.sedar.com.

6. OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

Mundo Nuevo

The Mundo Nuevo block is located onshore 42 km southwest of the city of Villahermosa, Tabasco with an areal extent of 27.7 km^2 (6,845 acres). The Mundo Nuevo field, a middle Cretaceous fractured carbonate reservoir, was discovered in 1977 and includes 14 drilled (non-producing) wells and one producing well. This field was developed by Mexico's state-owned oil and gas company, Pemex, through the drilling of 14 wells, reaching peak production of over 15,000 barrels per day (bbls/day) of light crude oil, in the early 1980s, with an average reservoir depth of 3,580 meters. The Mundo Nuevo field is currently producing light crude oil and natural gas from one well which is transported from the field in a pipeline for sale. Renaissance was awarded the Mundo Nuevo block with an additional royalty amount of 80.69%.

Malva

The Malva block is located onshore 61 km southwest of the city of Villahermosa, Tabasco with an areal extent of 21.2 km^2 (5,239 acres) The Malva field, an upper Cretaceous limestone reservoir, was discovered in 2003 and includes four drilled (non-producing) wells and one producing well. This field was developed by Pemex through the drilling of the 4 wells, reaching peak production of over 2,000 barrels bbls/day of light crude oil, in the late 2000s, with an average reservoir depth of 2,680 meters. The Malva field is currently producing light crude oil and natural gas from one well which is transported from the field in a pipeline for sale. Renaissance was awarded the Malva block with an additional royalty amount of 57.39%.

Properties with No Attributed Reserves

Mundo Nuevo

The Mundo Nuevo block is described in the previous section above. Work program commitments include the drilling of one new well and other evaluation costs totaling approximately US$7.8 million. At this time, the Company has no intention of developing this block or incurring future development costs on this block.

Malva

The Malva block is described in the previous section above. Work program commitments include the drilling of two new wells, the workover of the producing Malva 85 well and other evaluation costs totaling approximately US$13.8 million. At this time, the Company has no intention of developing this block or incurring future development costs on this block.

Topén

The Topén block is located onshore 45 km southwest of the city of Villahermosa, Tabasco with an areal extent of 25.3 km^2 (6,251 acres). The Topén field, an upper Cretaceous fractured carbonate reservoir, was discovered in 1978. This field was developed by Pemex through the drilling of 5 wells, reaching peak production of over 1,500 barrels bbls/day of medium crude oil, in the mid 1980s, with an average reservoir depth of 3,300 meters. Renaissance was awarded the Topén block with an additional royalty amount of 78.79%. Work program commitments include the drilling of one new well, workovers on three wells and other evaluation costs totaling approximately US$9.4 million. At this time, the Company has no intention of developing this block or incurring future development costs on this block.

Pontón

The Pontón block is located onshore 25 km southeast of Panuco city, Veracruz, with an areal extent of 12 km^2 (2,965 acres). The Pontón field was discovered and put into production in 1971 in the Upper Jurassic San Andres formation. In May 1991, production commenced in the Lower Cretaceous Tamaulipas Inferior formation. This field was developed by Pemex, through the drilling of 14 wells in the 1970s. Although not currently producing, Pontón has cumulatively produced approximately 800,000 barrels of light oil (34° API). The Upper Jurassic San Andres formation has an average reservoir depth of 1,266 meters and the Lower Cretaceous Tamaulipas Inferior formation has an average reservoir depth of 925 meters. On July 13, 2017, Renaissance was awarded its request for force majeure for the Pontón block, allowing for a temporary suspension of development operations to facilitate the remediation by the previous operator of certain areas of the Pontón block that incurred surface contamination from previous oil field activities. Under the terms of the licences for all of Renaissance's operated blocks in Mexico, previous operators are responsible for the remediation of all pre-existing damages identified and documented by Renaissance. Renaissance was awarded the Pontón block with an additional royalty amount of 21.39%.

Namibia

ReconAfrica holds a 90% interest in a petroleum exploration licence in northeast Namibia which covers the entire Kavango sedimentary basin (the "Namibia Licence" or "PEL 73"). The National Petroleum Company of Namibia ("NAMCOR"), a Namibian state-owned entity, holds the remaining 10% interest in the Namibia Licence on a carried interest basis. The Namibia Licence, which is governed by the terms of a petroleum agreement between the Company and the Namibia Ministry of Mines and Energy (the "MME") dated January 26, 2015 (the "Petroleum Agreement"), provides the Company with the exclusive right to conduct exploration activities on certain licenced property covering an area of approximately 25,341.33 km^2 (6.3 million acres, 5.6 million net acres) and, based on commercial success, it entitles ReconAfrica to obtain a 25-year production licence.

The Petroleum Agreement describes an eight-year exploration work program and accompanying minimum expenditures on the Namibia Licence related thereto. Such exploration program consists of the following three phases:

- Initial Exploration Period (4 years): minimum expenditure of US$5,000,000 including a requirement to spend US$50,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibians, of which US$35,000 is to be paid to the Namibian Petroleum Training and Educational Fund and US$15,000 is to be paid in connection with the in-house training of Namibian citizens in the field of oil and/or gas exploration.
- First Renewal Exploration Period (2 years): minimum expenditure of US$10,000,000 including a requirement to spend US$50,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibians, of which US$35,000 is to be paid to the Namibian Petroleum Training and Educational Fund and US$15,000 is to be paid in connection with the in-house training of Namibian citizens in the field of oil and/or gas exploration.
- Second Renewal Exploration Period (2 years): minimum expenditure of US$10,000,000 including a requirement to spend US$50,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibians, of which US$35,000 is to be paid to the Namibian Petroleum Training and Educational Fund and US$15,000 is to be paid in connection with the in-house training of Namibian citizens in the field of oil and/or gas exploration.

On October 22, 2018, the MME granted a one-year extension to the Initial Exploration Period of the Namibia Licence.

Pursuant to an adjustment letter dated February 25, 2019, the MME agreed to adjust the work commitment, minimum expenditure requirement, and timing of relinquishment under the Petroleum Agreement and the Namibia Licence such that the Company's work and expenditure commitments under the Initial Exploration Period would be deemed to have been satisfied provided that, by January 29, 2020, the Company drill one stratigraphic test well, rather than two. The drilling of one stratigraphic test well would fulfil the Company's work and expenditure obligation to the end of the Initial Exploration Period.

Pursuant to such adjustment letter, ReconAfrica's obligation to drill the second stratigraphic test well was deferred to and became a part of the work commitments that must be satisfied during the First Renewal Exploration Period. Further, the relinquishment obligation which was to arise at the end of the Initial Exploration Period was deferred until the First Renewal Exploration Period.

On December 24, 2019, the Company announced that Namibia's Minister of Mines and Energy had confirmed that the Namibia Licence had been approved for its First Renewal Exploration Period, and accordingly the exploration phase of the Namibia Licence was renewed and continued until January 25, 2022. The MME's approval included recognition that the proposed work program for the First Renewal Exploration Period included the drilling of two stratigraphic test wells. On September 10, 2021, Namibia's Minister of Mines and Energy granted approval of a one-year extension on the First Renewal Exploration Period, extending such period to January 29, 2023 due to the impacts of the COVID-19 pandemic on the Company's operations. On September 5, 2022, Namibia's Minister of Mines and Energy granted approval of a further one-year extension on the First Renewal Exploration Period, extending such period to January 29, 2024. The work requirements for both 2D seismic and aggregate expenditure of US$10,000,000 have been satisfied.

In addition to the aforementioned minimum exploration expenditure, the Company is required to pay to the Government of Namibia an annual licensing fee ranging from NAD$60 to NAD$150 per square kilometer of PEL 73, depending on the applicable stage of exploration. Should the Namibian Minister of Mines and Energy grant a production licence over any part of the Namibia Licensed Property (as further described below), the annual licensing fee will increase to NAD$1,500 per square kilometer to which such production licence relates.

In accordance with the Petroleum Agreement, as adjusted by the February 25, 2019 adjustment letter, the Company must relinquish at least 50% of the exploration area covered by the Namibia Licence no later than either (i) 60 days following the completion of the drilling of the second stratigraphic test well; or (ii) at the end of the First Renewal Exploration Period, to be agreed upon between the MME and the Company.

A further 25% of the exploration area covered by the Namibia Licence must also be relinquished by the Company no later than 30 days before the end of the First Renewal Exploration Period following the grant of the Namibia Licence. In determining the relinquished area, any areas of the Namibia Licensed Property that have been identified as potentially productive are excluded from the relinquishment requirements. In a letter dated October 4, 2021, the Namibia Ministry of Mines and Energy agreed that the first relinquishment will occur at the end of the First Renewal Exploration Period, and that the second relinquishment is waived.

In the event the exploration work at the Namibia Licensed Property leads to the discovery of an economically viable petroleum reservoir, the Company may, pursuant to the terms of the Petroleum Agreement, make an application for a production licence. Within six months after making such application, subject to the provisions of the Petroleum Act (Namibia), the Namibian Minister of Mines and Energy may grant to the Company a 25-year production licence. The Company is required to pay, to the benefit of the Government of Namibia on a quarterly basis, a 5% production royalty based on the market value, as determined in accordance with the provisions of the Petroleum Agreement, of any natural gas or crude oil produced under a production licence granted pursuant to the Petroleum Agreement. An incremental three-tiered Additional Profits Tax ("APT") is charged on the after-tax net cash flow from petroleum operations in the Namibia Licensed Property. Exploration, development and operating expenditures, as well as royalty and corporate income tax, are all fully deductible in the year they are paid in the computation of the APT net cash flow for the year. APT will only be paid if the petroleum operations in the Namibia Licensed Property earn an after-tax real (i.e. inflation-adjusted) rate of return of 15%. The second and third tiers of APT become payable once the profitability level exceeds 20% and 25% respectively. The first-tier rate of APT is established in the legislation (through a formula) at 25%. The incremental second and third tier APT rates are determined in the Petroleum Agreement, and in the case of the Company, are 28% and 29% respectively.

On September 22, 2022, the Company announced that it had entered into a definitive purchase and sale agreement with its partner, NAMCOR, to acquire half of its 10% carried participating interest in the approximate 6.3 million acres petroleum exploration license in the Kavango basin. The consideration for the 5% interest comprises of (a) 5,000,000 common shares of the Company having an aggregate value of $31,750,000 with a deemed price per share of $6.35 and (b) US$2,000,000 in cash. As of the date of this 51-101F1, the transaction with NAMCOR has not yet been completed and discussions are ongoing.

A copy of the Petroleum Agreement is available on SEDAR+ under ReconAfrica's profile at www.sedarplus.com. See "*Material Contracts*" in the Company's annual information form for the year ended December 31, 2021.

<u>Botswana</u>

In June 2020, the Company was granted a petroleum licence in northwestern Botswana ("PEL 001") for approximately 2.45 million acres (9,921 km^2) (later reduced to approximately 2.22 million acres or 8,900 km^2 by amendment dated December 24, 2020 and further reduced to approximately 1.88 million acres (7,592 km^2) by amendment dated April 13, 2023). Terms of the licence are as follows:

- 100% working interest in all petroleum rights from surface to basement
- An initial 4-year exploration period, with renewals up to an additional 10 years, in accordance with the Botswana Petroleum (Exploration and Production) Act
- Upon declaration of commercial production, the operator holds the right to enter into a 25-year production licence with a 20-year renewal period, in accordance with the Botswana *Petroleum (Exploration and Production) Act*
- Royalties associated with the production licence will be subject to negotiation, in accordance with the Botswana *Petroleum (Exploration and Production) Act*
- The Company has committed to a minimum work program of US$432,000 over the first 4-year exploration period

On January 11, 2021, the Company and the Government of Botswana announced an amendment to the PEL 001 to exclude the Tsodilo Hills, a UNESCO World Heritage Site, from ReconAfrica's entire Core and Buffer areas. Beginning in 2022, the Company made clear to the Government of Botswana that they would not be doing any work in the designated RAMSAR area and for it to be excluded. After the Government of Botswana went through its internal review process, this area was removed from PEL 001 on April 13, 2023.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

For information on significant factors or uncertainties relevant to properties with no attributed reserves, please refer to the Company's consolidated financial statements for the 15 months ended March 31, 2023 and related management's discussion and analysis.

Abandonment and Reclamation Costs

Abandonment and reclamation costs based on the Company's estimates were included in the NSAI Report at the property level for existing wells with reserves assigned and existing material, dedicated facilities. For leases that are projected to be active on or after March 31, 2023, net abandonment and reclamation costs are scheduled to be incurred at the end of the economic life of the lease. For leases that are projected to be no longer active as of March 31, 2023, net abandonment and reclamation costs are scheduled to be incurred over the next 3 years. Capital costs and abandonment and reclamation costs are not escalated for inflation.

The total abandonment cost in respect of proved reserves using forecast prices is $638,220 (undiscounted). 100% of such amounts were deducted as abandonment costs in estimating the Company's future net revenue as disclosed above.

Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

Forward Contracts

Currently there are no material forward contracts or commitments.

Tax Horizon

The Company does not anticipate having taxes payable for the 15 months ended March 31, 2023. Based on current estimates of the Company's future taxable income and levels of tax-deductible expenditures including royalties, management believes that the Company will not be required to pay cash income taxes for the life of the Total Proved Reserves.

The Company's Namibia and Botswana projects are in the exploration and evaluation stage of development and capitalized costs to date will be available for deduction for income tax purposes. The Company does not expect to be taxable in the foreseeable future.

Costs Incurred

For the Chiapas blocks, no property acquisition, exploration or development expenditures were incurred other than field maintenance and evaluation expenditure during the 15 months ended March 31, 2023. For information on exploration and development costs please refer to Note 6 of the Company's consolidated financial statements for the 15 months ended March 31, 2023 and related management's discussion and analysis.

Exploration and Development Activities

Namibia

During the 15 months ended March 31, 2023, the Company drilled the Well 1819/8-2 ("8-2") in Namibia and completed a seismic program and enhanced full tensor gradiometer ("eFTG") surveys. The 8-2 well, located in the Kavango East region, 6.5 kilometres west of Kawe 6-2, began drilling on June 25, 2022 and finished at total depth on August 15, 2022. The well encountered intervals rich with gas (Methane) and hydrocarbon gas liquids ("HGLs"), specifically, Ethane, Butane and Propane as well as smaller quantities of heavier hydrocarbons. Hydrocarbon gas/HGLs were sampled in Isotubes during drilling and analysed by GeoMark Research (Houston, TX), revealing the presence of thermogenic hydrocarbons, which were generated from organic matter under high temperatures. Between the depths of 1,300 and 1,335 meters below surface, a significant proportion of these samples were HGLs. Additionally, hydrocarbon gases were recorded in various intervals between 838m and 1,807m, and between 1,990m and 2,058m, the total depth of the well. Although geologically a successful well, economic accumulations of hydrocarbons were not encountered.

The well produced additional valuable geological information intersecting the predicted Karoo stratigraphy and pre-Karoo stratigraphy, which included promising source, seal and reservoir rock lithologies. Cuttings samples were collected at 5m intervals and 38 sidewall cores were brought to surface. Sample analysis and other analytical work is ongoing. Geochemical analysis of samples rich in organic matter is currently being conducted by Geomark Research to establish the extent of source rock potential. Petrophysical logs will be calibrated with core analyses to determine the thickness and quality of potential reservoir intervals.

The Vertical Seismic Profile ("VSP") for the 8-2 well, which is critical for carrying out an improved time to depth conversion of the seismic data, was completed in latter 2022 and integrated into the seismic interpretation. The apparent lack of closure and potential oil source-maturation issues at this location highlight the need for multiple seismic line confirmation and/or eFTG to support all new drilling decisions. ReconAfrica extended its seismic acquisition program to acquire a cumulative total of over 2,000 kilometres which has just been completed.

The Company built the access road and drilling pad and moved the rig to the next rift basin well, the Wisdom 5-1 ("5-1") in the fourth quarter of 2022. With the goal of maximizing the chance of success for the 5-1 and other potential locations, including the Damara fold belt, the Company determined it was best to use all available and expected data, including the additional 2D seismic and eFTG before commencing with drilling. This acquisition has been completed and interpretation and analysis of the data are ongoing. After data interpretation and analysis is complete, the decision will be made on the next drilling location.

The Company has now conducted seismic operations in three phases over three years, from 2021 to 2023. The operations have been conducted using low impact methods: small footprint sources, state of the art receiver wireless technologies, cloud computing, and sensitivity and awareness in all operational activities. A total of 2,767 line kilometres of seismic have been acquired over these three years, comprising of 497 kilometres in Phase 1, 761 kilometres in Phase 2 and 1,509 kilometres in Phase 2 Extension.

Seismic data acquired in the Phase 1 and Phase 2 campaigns, conducted in 2021 and the first half of 2022, have been processed and interpreted. Similarly, a large proportion of Phase 2 Extension lines, acquired from November 2022 to May 2023, have been processed and interpreted. Processing and interpretation of the remaining lines is being finalized.

Over the duration of the seismic operations, the Company, the seismic contractor (Polaris Natural Resources Ltd.), and its subcontractors employed over 630,000 man-hours and drove over two million kilometres without any significant health, safety, or environmental incidents; there were no lost time incidents in the two years of operations - Polaris first commenced work in Namibia in July 2021. Our two entities have worked hand-in-hand to achieve our exploration goals in 2D seismic data acquisition and to impact the local communities positively through employment, acquisition of services and procurement of goods in the Kavango East and Kavango West regions.

As the Company has stated before, the first two phases identified a number of leads and considerably expanded the Company's portfolio of opportunities. The latest seismic program was designed to better define these leads, de-risk potential drilling targets, and add new leads. The program is also designed to confirm the lateral extension of the Karoo Rift Basin to the south-east, potentially to the edge of PEL 73, and to delineate a new play fairway identified in Phase 1; the Damara fold belt.

The Damara fold belt is an area of extensive folding and associated faulting to the south and west of the Karoo Rift Basin, which has been identified as a result of the seismic data and drilling results. This compressional geological province is of Pre-Karoo Late Proterozoic age and is a large area of synclines and anticlines. One of the expectations of the latest seismic acquisition, besides defining Karoo Rift structures, is to delineate four-way dip closures across these anticlinal structures. Mapping the extent of these anticlines and defining the four-way dip closures could result in materially large structures, possibly hundreds of square kilometres in aerial extent.

Combining the seismic sub-surface data, the surface geological maps, and outcrop data should further enhance prospect definition. It is significant that the Proterozoic rocks have been penetrated in each of the previous three wells, notably the Kawe 6-2 well which contained two intervals with significant oil shows and reservoir porosity. The good quality of seismic imaging of the Damara fold belt, especially when not overlain by the Karoo Rift Graben, should make it easier to define and target four-way anticlinal dip closures. However, the lateral continuity and interpolation of these structures between widely separated 2D seismic lines requires additional sub-surface information, hence the Company's decision to collect eFTG data.

ReconAfrica engaged a leading airborne geophysical survey provider, Metatek Group Limited, to conduct an eFTG survey over an area of 2,184 square kilometres (540,000 acres) over PEL 73. This program was subsequently extended by 2,814 km2 (695,000 acres) in two contiguous areas, and the complete program is nearly 5,000 square kilometres. The data were acquired in April and May 2023.

The eFTG is an advanced three-component high resolution airborne gravity survey which specifically allows earth scientists to identify changes in sub-surface rock density with the goal of delineating hydrocarbon traps. Unlike traditional gravity instruments, which measures vertical responses, the eFTG (gravimetry) measures changes in the gravity response using multi-component airborne instruments. Simultaneously, high resolution magnetic and light detection and ranging ("LiDAR") data is also acquired, to correct and supplement the gravimetric data. When calibrated with existing 2D seismic data, the eFTG imaging can greatly enhance the geoscientists' ability to identify structures and extrapolate their geometries in three dimensions.

The processing, inversion and interpretation of these data is underway, including seismic calibration. It is expected that this information, combined with the 2D seismic and well data, will considerably enhance the Company's ability to image and understand the sub-surface. It will make a significant contribution to building a risk weighted prospect portfolio and define the Company's future drilling campaign.

<u>Mexico</u>

During the 15 months ended March 31, 2023, Renaissance incurred $1.3 million in resource property evaluation expenditures for its licences in Chiapas, Mexico. None of these costs were capitalized in exploration and evaluation assets in the statement of financial position as at March 31, 2023. No drilling of new wells or workovers to existing wells were completed during the year.

Production Estimates

The following table sets forth the volume of working interest production, before royalties, estimated for 2023 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of gross proved and probable reserves:

Reserves Category[1]	Crude Oil Combined[2] (Mstb)	Conventional Natural Gas (MMcf)	Total BOE (MBOE)
Proved Developed Producing	89.9	1,492.3	338.7
Proved Undeveloped	0.0	0.0	0.0
Total Proved	**89.9**	**1,492.3**	**338.7**
Probable	3.2	15.7	5.8
Total Proved Plus Probable	**93.1**	**1,508.0**	**344.4**

(1) Located in Chiapas, Mexico.

(2) Includes condensate volumes

Notes:

- 43% of crude oil (38.8 Mstb) produced from the Malva field, 57% (51.2 Mstb) from Mundo Nuev
- 17% of gas (253.2 MMcf) produced from the Malva field, 83% (1239.1 MMcf) from Mundo Nuev

Production History

On May 10, 2016, Renaissance recorded first revenue from oil and gas operations after executing license contracts for the Mundo Nuevo, Topén and Malva blocks, located in Chiapas, Mexico. ReconAfrica acquired Renaissance on July 27, 2021, at which point it recorded first revenue from oil and gas operations.

Recent production history as follows:

	Fifteen months ended March 31, 2023		
	Oil (Bbl/d)	Natural Gas (Mcf/d)	Total (Boe/d)
Mundo Nuevo	166	3,928	821
Malva	128	920	282
	294	4,847	1,102

Average Production by Product	Three months ended March 31, 2023	Three months ended December 31, 2021	Fifteen months ended March 31, 2023	July 27 to December 31, 2021
Crude oil (Bbl/d)	289	318	294	318
Natural gas (Mcf/d)	4,773	5,037	4,847	5,034
Total (Boe/d)	1,085	1,157	1,102	1,157

Revenue From Product Sales	Three months ended March 31, 2023	Three months ended December 31, 2021	Fifteen months ended March 31, 2023	July 27 to December 31, 2021
Crude oil	$ 2,285,600	$ 2,626,048	$ 14,736,802	$ 4,288,175
Natural gas	2,604,675	3,932,676	17,900,416	6,121,538
Total	$ 4,890,275	$ 6,558,724	$ 32,637,218	$ 10,409,713

Average Prices	Three months ended March 31, 2023	Three months ended December 31, 2021	Fifteen months ended March 31, 2023	July 27 to December 31, 2021
Crude oil ($/bbl)	87.81	89.88	110.00	85.97
Natural gas ($/mcf)	6.06	8.49	8.12	7.75

Royalties	Three months ended March 31, 2023	Three months ended December 31, 2021	Fifteen months ended March 31, 2023	July 27 to December 31, 2021
Charge for the period	$ 3,898,273	$ 5,128,074	$ 26,429,369	$ 8,217,849
Percentage of revenue	79.7%	78.2%	81.0%	78.9%
Per Boe	$ 39.93	$ 48.18	$ 52.69	$ 45.25

Production Costs	Three months ended March 31, 2023	Three months ended December 31, 2021	Fifteen months ended March 31, 2023	July 27 to December 31, 2021
Charge for the period	$ 280,581	$ 484,534	$ 1,657,634	$ 669,983
Percentage of revenue	5.7%	7.4%	5.1%	6.4%
Per Boe	$ 2.87	$ 4.55	$ 3.30	$ 3.69

Operating Netback	Three months ended March 31, 2023	Three months ended December 31, 2021	Fifteen months ended March 31, 2023	July 27 to December 31, 2021
Revenue From Product Sales	$ 4,890,275	$ 6,558,724	$ 32,637,218	$ 10,409,713
Royalties	(3,898,273)	$ (5,128,074)	(26,429,369)	(8,217,849)
Production costs	(280,581)	$ (484,534)	(1,657,634)	(669,983)
Operating Netback	711,421	946,116	4,550,215	1,521,881
Per Boe	$ 7.29	$ 8.89	$ 9.07	$ 8.38

APPENDIX

OPTIONAL DISCLOSURE OF PROSPECTIVE RESOURCES DATA

The following is a summary of the estimation of prospective resources of the Company as of March 31, 2023 as set out in the NSAI Report. The NSAI Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil & Gas Evaluation Handbook prepared jointly by the Society of Petroleum and Engineers (Calgary Chapter) (the “COGE Handbook”) and in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”).

Summary of Prospective Oil and Gas Resources

The Company has not yet established reserves on any of its Namibia or Botswana properties due to the fact that its oil and/or gas activities are currently in the preliminary stages. The following information on the Namibia Licensed Property is derived from the NSAI Report.

The prospective resources herein are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by applying future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further categorized according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity. The prospective resources included in the NSAI Report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these leads, as discussed in subsequent paragraphs. The NSAI Report does not include economic analysis for these leads. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in the NSAI Report have a reasonable chance of being economically viable. There is no certainty that any portion of the prospective resources will be discovered. If they are discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

Totals of unrisked prospective resources beyond the lead level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect and lead, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

Summary of Unrisked Best Estimate Prospective Oil and Gas Resources
As of March 31, 2023

Subclass	Gross (100 Percent)		Company Gross		Net	
	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)
Prospects	484.5	20,188.9	436.1	18,170.0	414.3	17,261.5
Leads	1,602.5	909.6	1,442.3	818.6	1,370.2	777.7

Summary of Risked(2) Best Estimate Prospective Oil and Gas Resources
As of March 31, 2023

Subclass	Gross (100 Percent)		Company Gross		Net	
	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)
Prospects	25.2	1,024.1	22.7	921.7	21.6	875.6
Leads	37.8	22.1	34.0	19.9	32.3	18.9

Note: Prospective resources are the arithmetic sum of multiple probability distributions.
(1) Net prospective resources are after royalty deductions.

(2) These estimates are based on unrisked prospective resources that have been risked for chance of discovery and chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

Oil and condensate volumes are expressed in millions of barrels (MMbbl); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (Bcf) at standard temperature and pressure bases.

The prospective resources shown in the NSAI Report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. Low estimate and high estimate prospective resources have not been included in the NSAI Report. For the purposes of the NSAI Report, the volumes and parameters associated with the best estimate scenario of prospective resources are referred to as 2U. The 2U prospective resources have been aggregated beyond the prospect and lead level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation. Statistical principles indicate that the arithmetic sums of multiple estimates may be misleading as to the volumes that may actually be recovered.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. The prospective resources included in the NSAI Report represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made; prospective resources have both an associated chance of discovery and a chance of development, which together define the chance of commerciality.

Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation.

Development risking addresses the probability of development given geologic success; this risk analysis is conducted based on the associated economic and development related factors (development plan, production forecasts, markets, facilities, capital and operating costs, product prices, approvals, etc.). For the purposes of this assessment of development risk, NSAI has considered the primary elements to be (1) financial considerations, (2) access to sales markets, (3) development plan approval, and (4) government and regulatory approvals.

Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in the NSAI Report is a discussion of the primary geologic risk elements for each prospect and lead.

Each prospect and lead was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect or lead drilling outcomes. If petroleum discoveries are made, smaller-volume prospects and leads may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in the NSAI Report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects and leads.

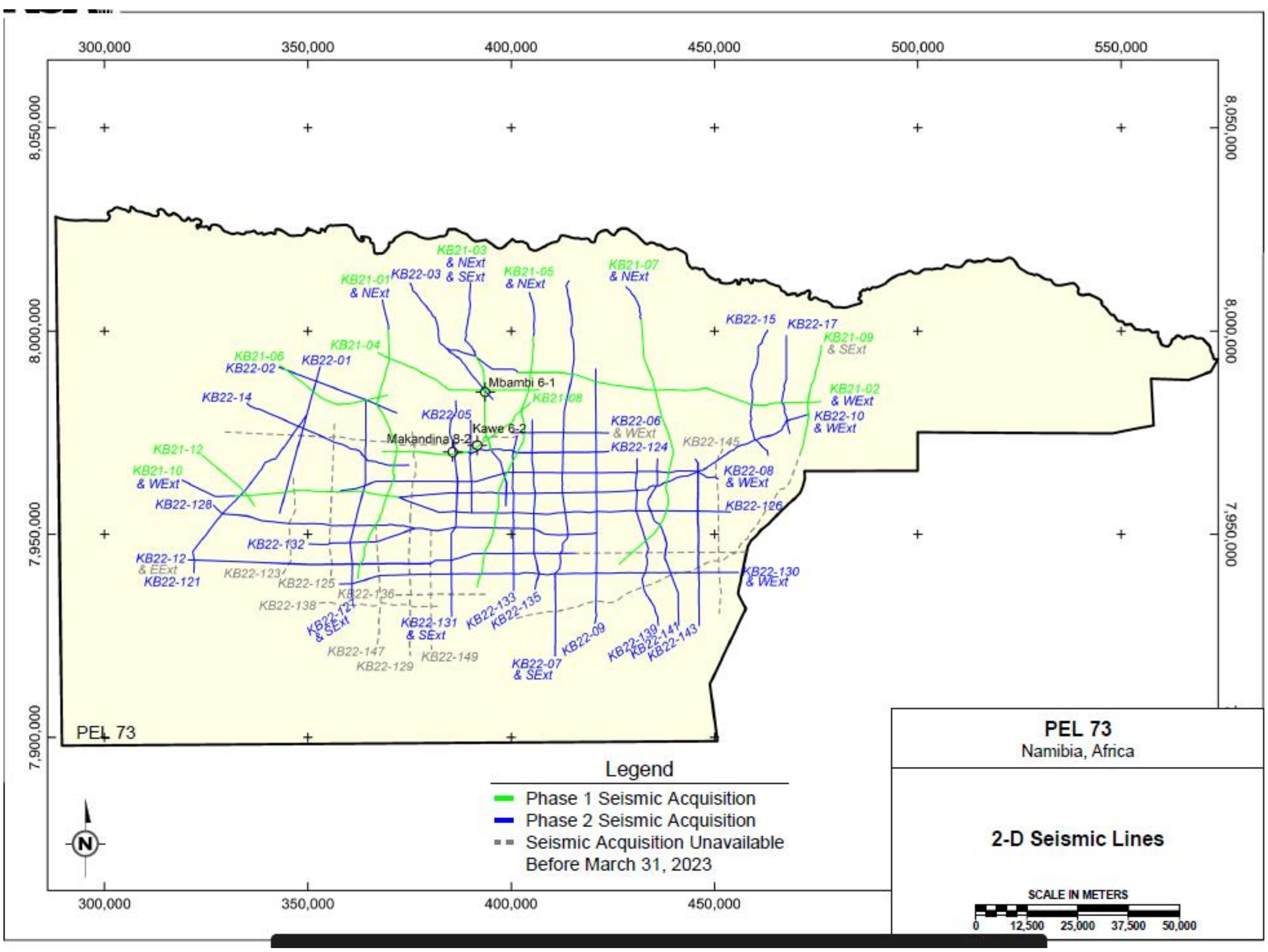
With respect to the Company's Namibian assets, as the Damara Fold Belt is a prospective resource and the first potential production in the basin, an evaluation of commercialization will await a successful discovery well to provide critical production test data, including rates and pressures. Based on reservoir studies, including samples, core and well log analysis, the production is expected to be gas with some potential gas liquids, and the reservoir is expected to be a conventional reservoir system, not requiring any special technology for production.

Regarding infrastructure, this area of northeast Namibia has good overall infrastructure, including transportation, communications and services. There is no oil or gas production infrastructure at this time. There is a very strong market for local power generation for Namibia and for all of southern Africa. Conceptually, Gas-To-Power technologies are expected to be the initial commercialization approach, and the main transmission grid for the region crosses PEL 73. It is premature at this time to estimate total cost and time to achieve commercial production.

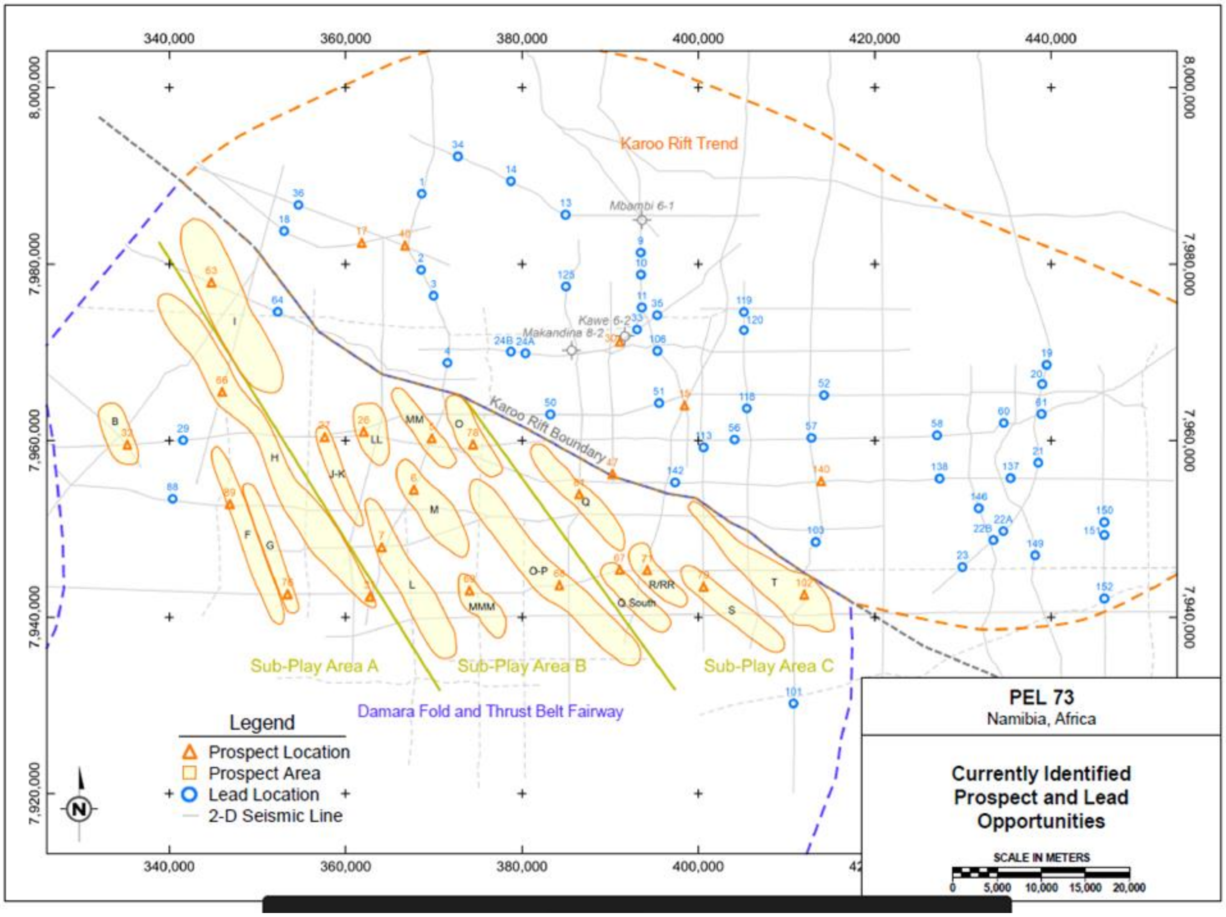
An estimate of risked net present value of future net revenue of prospective resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the required investment. It includes prospective resources that are considered too uncertain with respect to the chance of discovery to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Location of Licenced Area in Namibia (PEL 73)

Well and Seismic Basemap (PEL 73)

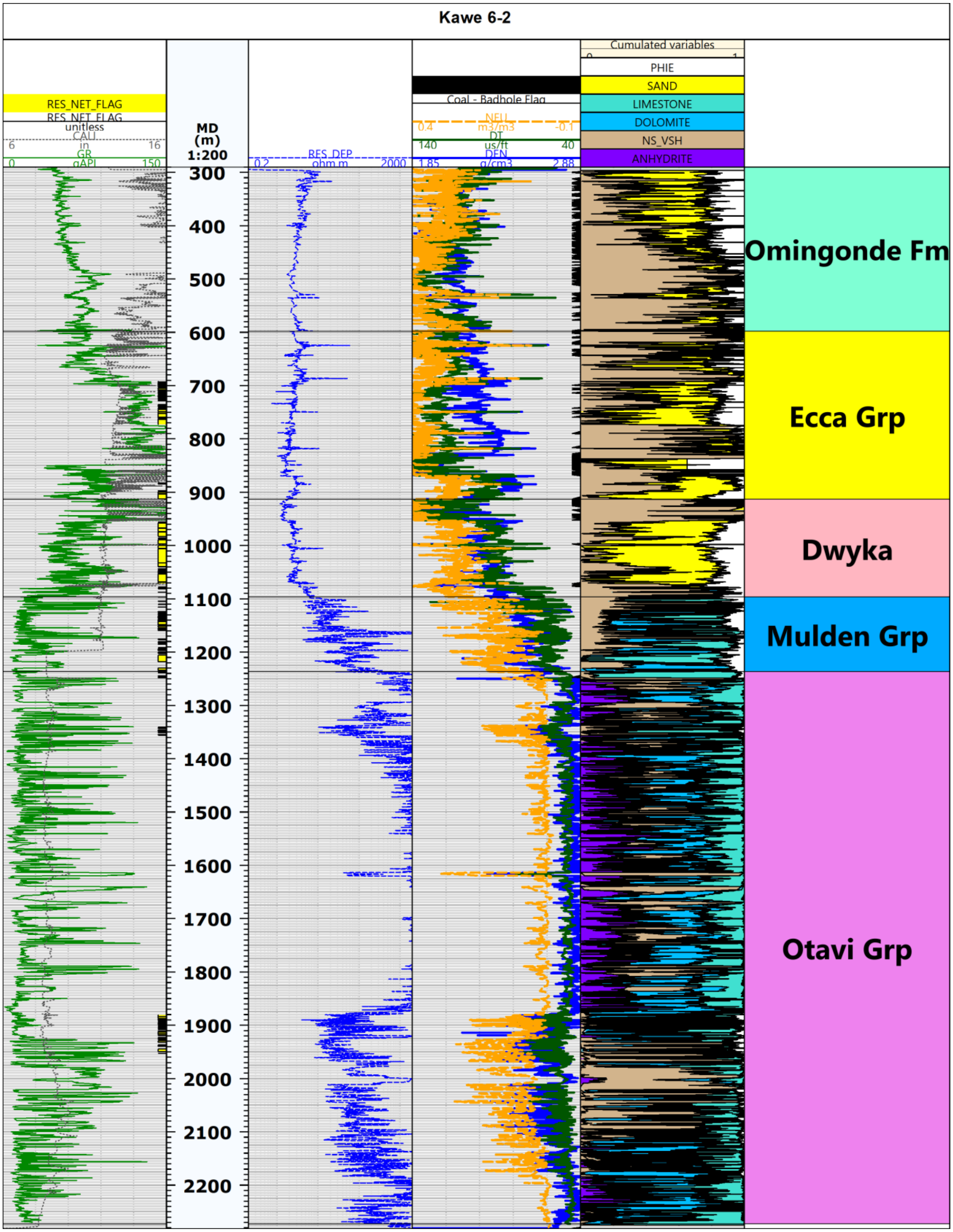


Location of Hydrocarbon Plays, Prospects and Leads



[redacted]

Kawe 6-2 Well Log, Kavango Basin, Onshore Namibia



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Summary of Selected Reservoir Parameters
As of March 31, 2023

Play Type	Target	Sub-play	Reservoir Type	Trap Style	Product	Area (ac-ft) P95	Area (ac-ft) P50	Area (ac-ft) P05	Geometric Factor (Decimal) Minimum	Geometric Factor (Decimal) Most Likely	Geometric Factor (Decimal) Maximum	Net Pay (m) Most Likely
1	Ecca	A	Clastic	Structural	Oil	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	50
1	Ecca	A	Clastic	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	50
1	Dwyka	A	Clastic	Structural	Oil	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	75
1	Dwyka	A	Clastic	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	40
1	Ecca	B	Clastic	Structural	Oil	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	50
1	Ecca	B	Clastic	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	50
1	Dwyka	B	Clastic	Structural	Oil	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	75
1	Dwyka	B	Clastic	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	40
2	UpperMulden	A	Clastic	Structural	Oil	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20
2	LowerMulden	A	Carbonate	Structural	Oil	48 - 606	95 - 1213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	30
2	UpperMulden	A	Clastic	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	20
2	LowerMulden	A	Carbonate	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	30
2	Otavi	A	Carbonate	Structural	Oil	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	30
2	Otavi	A	Carbonate	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	30
2	UpperMulden	B	Clastic	Structural	Oil	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20
2	LowerMulden	B	Carbonate	Structural	Oil	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	30
2	UpperMulden	B	Clastic	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	20
2	LowerMulden	B	Carbonate	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	30
2	Otavi	B	Carbonate	Structural	Oil	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	30
2	Otavi	B	Carbonate	Stratigraphic	Oil	500	1,000	2,000	0.50	0.70	0.90	30
3	UpperMulden	A	Carbonate	Structural	Gas	500 - 3,000	1,000 - 3,960	2,000 - 6,000	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	75
3	LowerMulden	A	Carbonate	Structural	Gas	500 - 3,000	1,000 - 3,960	2,000 - 6,000	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	30
3	Otavi	A	Carbonate	Structural	Gas	500 - 3,000	1,000 - 3,960	2,000 - 6,000	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	50
3	UpperMulden	B	Carbonate	Structural	Gas	873 - 4,250	1,747 - 5,610	3,493 - 8,500	0.40 - 0.50	0.60 - 0.65	0.80	25
3	LowerMulden	B	Carbonate	Structural	Gas	873 - 4,250	1,747 - 5,610	3,493 - 8,500	0.40 - 0.50	0.60 - 0.65	0.80	50
3	Otavi	B	Carbonate	Structural	Gas	873 - 4,250	1,747 - 5,610	3,493 - 8,500	0.40 - 0.50	0.60 - 0.65	0.80	50
3	LowerMulden	C	Carbonate	Structural	Gas	873 - 8,000	1,747 - 10,560	3,493 - 16,000	0.40 - 0.50	0.60	0.70 - 0.80	30
3	Otavi	C	Carbonate	Structural	Gas	873 - 8,000	1,747 - 10,560	3,493 - 16,000	0.40 - 0.50	0.60	0.70 - 0.80	50

Play Type	Target	Sub-play	Reservoir Type	Trap Style	Product	Porosity (Decimal) Minimum	Porosity (Decimal) Most Likely	Porosity (Decimal) Maximum	Water Saturation (Decimal) Minimum	Water Saturation (Decimal) Most Likely	Water Saturation (Decimal) Maximum
1	Ecca	A	Clastic	Structural	Oil	0.12	0.17	0.25	0.15	0.30	0.45
1	Ecca	A	Clastic	Stratigraphic	Oil	0.12	0.17	0.25	0.15	0.30	0.45
1	Dwyka	A	Clastic	Structural	Oil	0.13	0.18	0.25	0.15	0.30	0.45
1	Dwyka	A	Clastic	Stratigraphic	Oil	0.13	0.18	0.25	0.15	0.30	0.45
1	Ecca	B	Clastic	Structural	Oil	0.10	0.15	0.20	0.15	0.30	0.45
1	Ecca	B	Clastic	Stratigraphic	Oil	0.10	0.15	0.20	0.15	0.30	0.45
1	Dwyka	B	Clastic	Structural	Oil	0.11	0.16	0.20	0.15	0.30	0.45
1	Dwyka	B	Clastic	Stratigraphic	Oil	0.11	0.16	0.20	0.15	0.30	0.45
2	UpperMulden	A	Clastic	Structural	Oil	0.06	0.12	0.18	0.25	0.35	0.50
2	LowerMulden	A	Carbonate	Structural	Oil	0.06	0.08	0.12	0.25	0.35	0.50
2	UpperMulden	A	Clastic	Stratigraphic	Oil	0.06	0.12	0.18	0.25	0.35	0.50
2	LowerMulden	A	Carbonate	Stratigraphic	Oil	0.06	0.08	0.12	0.25	0.35	0.50
2	Otavi	A	Carbonate	Structural	Oil	0.05	0.08	0.12	0.25	0.35	0.50
2	Otavi	A	Carbonate	Stratigraphic	Oil	0.05	0.08	0.12	0.25	0.35	0.50
2	UpperMulden	B	Clastic	Structural	Oil	0.06	0.12	0.18	0.25	0.35	0.50
2	LowerMulden	B	Carbonate	Structural	Oil	0.06	0.08	0.12	0.25	0.35	0.50
2	UpperMulden	B	Clastic	Stratigraphic	Oil	0.06	0.12	0.18	0.25	0.35	0.50
2	LowerMulden	B	Carbonate	Stratigraphic	Oil	0.06	0.08	0.12	0.25	0.35	0.50
2	Otavi	B	Carbonate	Structural	Oil	0.05	0.08	0.12	0.25	0.35	0.50
2	Otavi	B	Carbonate	Stratigraphic	Oil	0.05	0.08	0.12	0.25	0.35	0.50
3	UpperMulden	A	Carbonate	Structural	Gas	0.06	0.12	0.18	0.10	0.30	0.50
3	LowerMulden	A	Carbonate	Structural	Gas	0.05	0.08	0.12	0.10	0.30	0.50
3	Otavi	A	Carbonate	Structural	Gas	0.05	0.08	0.12	0.10	0.30	0.50
3	UpperMulden	B	Carbonate	Structural	Gas	0.06	0.12	0.18	0.10	0.30	0.50
3	LowerMulden	B	Carbonate	Structural	Gas	0.05	0.08	0.12	0.10	0.30	0.50
3	Otavi	B	Carbonate	Structural	Gas	0.05	0.08	0.12	0.10	0.30	0.50
3	LowerMulden	C	Carbonate	Structural	Gas	0.05	0.08	0.12	0.10	0.30	0.50
3	Otavi	C	Carbonate	Structural	Gas	0.05	0.08	0.12	0.10	0.30	0.50

Play Type	Target	Sub-play	Reservoir Type	Trap Style	Product	Formation Volume Factor Minimum	Formation Volume Factor Most Likely	Formation Volume Factor Maximum	Units	Recovery Factor (Decimal) Minimum	Recovery Factor (Decimal) Most Likely	Recovery Factor (Decimal) Maximum	Pg (Decimal)
1	Ecca	A	Clastic	Structural	Oil	0.71	0.77	0.83	rb/stb	0.15	0.20	0.35	0.06 - 0.10
1	Ecca	A	Clastic	Stratigraphic	Oil	0.71	0.77	0.83	rb/stb	0.10	0.15	0.25	0.03
1	Dwyka	A	Clastic	Structural	Oil	0.71	0.77	0.83	rb/stb	0.15	0.20	0.35	0.06 - 0.10
1	Dwyka	A	Clastic	Stratigraphic	Oil	0.71	0.77	0.83	rb/stb	0.10	0.15	0.25	0.03
1	Ecca	B	Clastic	Structural	Oil	0.71	0.77	0.83	rb/stb	0.15	0.20	0.35	0.06 - 0.10
1	Ecca	B	Clastic	Stratigraphic	Oil	0.71	0.77	0.83	rb/stb	0.10	0.15	0.25	0.03
1	Dwyka	B	Clastic	Structural	Oil	0.71	0.77	0.83	rb/stb	0.15	0.20	0.35	0.06 - 0.10
1	Dwyka	B	Clastic	Stratigraphic	Oil	0.71	0.77	0.83	rb/stb	0.10	0.15	0.25	0.03
2	UpperMulden	A	Clastic	Structural	Oil	0.67	0.71	0.77	rb/stb	0.15	0.20	0.35	0.05 - 0.08
2	LowerMulden	A	Carbonate	Structural	Oil	0.67	0.71	0.77	rb/stb	0.15	0.20	0.35	0.05 - 0.08
2	UpperMulden	A	Clastic	Stratigraphic	Oil	0.67	0.71	0.77	rb/stb	0.10	0.15	0.25	0.03
2	LowerMulden	A	Carbonate	Stratigraphic	Oil	0.67	0.71	0.77	rb/stb	0.10	0.15	0.25	0.03
2	Otavi	A	Carbonate	Structural	Oil	0.67	0.71	0.77	rb/stb	0.15	0.20	0.35	0.05 - 0.08
2	Otavi	A	Carbonate	Stratigraphic	Oil	0.67	0.71	0.77	rb/stb	0.10	0.15	0.25	0.03
2	UpperMulden	B	Clastic	Structural	Oil	0.67	0.71	0.77	rb/stb	0.15	0.20	0.35	0.05 - 0.08
2	LowerMulden	B	Carbonate	Structural	Oil	0.67	0.71	0.77	rb/stb	0.15	0.20	0.35	0.05 - 0.08
2	UpperMulden	B	Clastic	Stratigraphic	Oil	0.67	0.71	0.77	rb/stb	0.10	0.15	0.25	0.03
2	LowerMulden	B	Carbonate	Stratigraphic	Oil	0.67	0.71	0.77	rb/stb	0.10	0.15	0.25	0.03
2	Otavi	B	Carbonate	Structural	Oil	0.67	0.71	0.77	rb/stb	0.15	0.20	0.35	0.05 - 0.08
2	Otavi	B	Carbonate	Stratigraphic	Oil	0.67	0.71	0.77	rb/stb	0.10	0.15	0.25	0.03
3	UpperMulden	A	Carbonate	Structural	Gas	175	225	275	scf/rcf	0.55	0.65	0.75	0.07 - 0.09
3	LowerMulden	A	Carbonate	Structural	Gas	175	225	275	scf/rcf	0.55	0.65	0.75	0.07 - 0.09
3	Otavi	A	Carbonate	Structural	Gas	200	250	300	scf/rcf	0.55	0.65	0.75	0.07 - 0.09
3	UpperMulden	B	Carbonate	Structural	Gas	175	225	275	scf/rcf	0.55	0.65	0.75	0.07 - 0.10
3	LowerMulden	B	Carbonate	Structural	Gas	175	225	275	scf/rcf	0.55	0.65	0.75	0.07 - 0.10
3	Otavi	B	Carbonate	Structural	Gas	200	250	300	scf/rcf	0.55	0.65	0.75	0.07 - 0.10
3	LowerMulden	C	Carbonate	Structural	Gas	175	225	275	scf/rcf	0.55	0.65	0.75	0.07 - 0.08
3	Otavi	C	Carbonate	Structural	Gas	200	250	300	scf/rcf	0.55	0.65	0.75	0.07 - 0.08

(1) ɔserved in the identified opportunities, which were assessed individually.
(2) ːct the variety observed in the identified opportunities, which were assessed individually.
(3) the identified opportunities, which were assessed individually.

Summary of Best Estimate Prospective Oil Volumes by Location
As of March 31, 2023

Subclass	Location	Undiscovered OOIP (MMbbl) Gross (100%)	Undiscovered OOIP (MMbbl) Company Gross(1)	nrisked Prospective Oil Resources (MMbl Gross (100%)	nrisked Prospective Oil Resources (MMbl Company Gross(1)	Effective P_g (Decimal)	P_d (Decimal)	Risked Prospective Oil Resources (Mbbl) Gross (100%)	Risked Prospective Oil Resources (Mbbl) Company Gross(1)
Prospects									
	15	1,354.2	1,218.8	270.8	243.8	0.095	0.661	17.0	15.3
	17	365.6	329.0	69.2	62.3	0.084	0.529	3.1	2.8
	30	152.0	136.8	25.8	23.2	0.065	0.562	0.9	0.8
	40	170.3	153.3	27.3	24.6	0.050	0.396	0.5	0.5
	47	159.3	143.4	28.0	25.2	0.071	0.165	0.3	0.3
	140	316.5	284.9	63.3	57.0	0.095	0.562	3.4	3.1
Total Prospects		**2,518.0**	**2,266.2**	**484.5**	**436.1**			**25.2**	**22.7**
Leads									
	1	191.5	172.3	38.3	34.5	0.058	0.297	0.7	0.6
	2	242.3	218.0	41.6	37.5	0.045	0.363	0.7	0.6
	3	205.1	184.6	30.8	27.7	0.037	0.330	0.4	0.3
	4	51.6	46.4	10.3	9.3	0.057	0.462	0.3	0.2
	9	161.7	145.6	25.6	23.0	0.042	0.297	0.3	0.3
	10	158.8	142.9	27.9	25.1	0.049	0.396	0.5	0.5
	11	130.2	117.2	22.2	19.9	0.048	0.529	0.6	0.5
	13	99.7	89.8	19.9	18.0	0.058	0.429	0.5	0.4
	14	196.1	176.5	35.4	31.8	0.051	0.198	0.4	0.3
	18	190.7	171.7	31.3	28.2	0.043	0.231	0.3	0.3
	19	213.0	191.7	42.6	38.3	0.058	0.363	0.9	0.8
	20	158.3	142.5	31.7	28.5	0.057	0.165	0.3	0.3
	21	370.6	333.5	74.1	66.7	0.058	0.595	2.5	2.3
	22A	869.4	782.4	173.9	156.5	0.057	0.661	6.6	5.9
	22B	563.1	506.8	112.6	101.4	0.057	0.628	4.1	3.6
	23	232.3	209.0	34.8	31.4	0.037	0.330	0.4	0.4
	24A	222.5	200.3	40.7	36.6	0.052	0.330	0.7	0.6
	24B	170.4	153.4	30.2	27.2	0.050	0.264	0.4	0.4
	33	28.8	25.9	5.8	5.2	0.058	0.231	0.1	0.1
	34	222.3	200.0	40.6	36.6	0.052	0.297	0.6	0.6
	35	86.4	77.8	17.3	15.6	0.057	0.396	0.4	0.4
	36	166.5	149.9	26.5	23.9	0.042	0.529	0.6	0.5
	50	148.4	133.5	22.9	20.6	0.041	0.462	0.4	0.4
	51	51.9	46.7	10.4	9.3	0.057	0.462	0.3	0.2
	52	222.0	199.8	40.6	36.5	0.052	0.363	0.8	0.7
	56	113.4	102.1	18.8	17.0	0.046	0.429	0.4	0.3
	57	109.6	98.7	18.0	16.2	0.046	0.363	0.3	0.3
	58	115.9	104.3	23.2	20.9	0.057	0.330	0.4	0.4
	60	116.4	104.8	23.3	21.0	0.057	0.330	0.4	0.4
	61	209.1	188.2	41.8	37.6	0.057	0.363	0.9	0.8
	103	207.8	187.0	33.5	30.1	0.043	0.363	0.5	0.5
	106	147.9	133.1	22.9	20.6	0.041	0.562	0.5	0.5
	113	131.8	118.6	22.4	20.2	0.048	0.529	0.6	0.5
	118	74.1	66.7	14.8	13.3	0.057	0.496	0.4	0.4
	119	128.4	115.5	21.9	19.7	0.048	0.529	0.6	0.5
	120	73.6	66.2	14.7	13.2	0.057	0.496	0.4	0.4
	125	113.9	102.5	22.8	20.5	0.058	0.429	0.6	0.5
	137	205.8	185.2	30.9	27.8	0.037	0.231	0.3	0.2
	138	192.6	173.4	31.8	28.6	0.044	0.231	0.3	0.3
	142	205.5	185.0	30.8	27.7	0.037	0.429	0.5	0.4
	146	705.6	635.0	141.1	127.0	0.057	0.661	5.4	4.8
	149	205.3	184.7	30.8	27.7	0.037	0.231	0.3	0.2
	150	147.1	132.4	22.7	20.4	0.041	0.462	0.4	0.4
	151	147.2	132.5	22.7	20.4	0.041	0.529	0.5	0.4
	152	147.1	132.4	25.6	23.0	0.049	0.462	0.6	0.5
Total Leads		**8,851.7**	**7,966.5**	**1,602.5**	**1,442.3**			**37.8**	**34.0**

Totals may not add because of rounding.

Notes: In-place volumes are reported at surface conditions. Totals of in-place volumes and unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected t recovered and are shown for convienence only.

(1) Company Gross volumes are ReconAfrica's working interest share of the estimated gross (100%) volumes.

Summary of Best Estimate Prospective Gas Volumes by Location
As of March 31, 2023

Subclass	Location	Undiscovered OGIP (Bcf) Gross (100%)	Undiscovered OGIP (Bcf) Company Gross[(1)]	Unrisked Prospective Gas Resources (Bcf) Gross (100%)	Unrisked Prospective Gas Resources (Bcf) Company Gross[(1)]	Effective P_g (Decimal)	P_d (Decimal)	Risked Prospective Gas Resources (Bcf) Gross (100%)	Risked Prospective Gas Resources (Bcf) Company Gross[(1)]
Prospects									
	5	806.6	725.9	524.3	471.8	0.100	0.525	27.5	24.8
	6	1,970.6	1,773.5	1,280.9	1,152.8	0.111	0.552	78.5	70.7
	7	1,610.7	1,449.6	1,047.0	942.3	0.083	0.552	48.0	43.2
	26	719.9	647.9	467.9	421.2	0.070	0.525	17.2	15.5
	27	919.2	827.3	597.5	537.7	0.071	0.525	22.3	20.0
	31	3,528.5	3,175.6	2,293.5	2,064.2	0.083	0.580	110.4	99.3
	32	1,251.3	1,126.2	813.4	732.0	0.080	0.552	35.9	32.3
	63	3,345.3	3,010.8	2,174.4	1,957.0	0.125	0.580	157.6	141.9
	66	4,285.1	3,856.5	2,785.3	2,506.8	0.100	0.580	161.5	145.4
	67	620.1	558.0	403.0	362.7	0.080	0.469	15.1	13.6
	68	2,816.5	2,534.8	1,830.7	1,647.6	0.071	0.552	71.8	64.6
	69	654.7	589.3	425.6	383.0	0.080	0.497	16.9	15.2
	71	445.9	401.3	289.9	260.9	0.070	0.414	8.4	7.6
	76	1,503.8	1,353.4	977.5	879.7	0.090	0.552	48.6	43.7
	78	1,238.4	1,114.5	804.9	724.4	0.080	0.552	35.6	32.0
	79	638.7	574.9	415.2	373.7	0.067	0.497	13.8	12.4
	81	641.8	577.6	417.2	375.5	0.071	0.497	14.7	13.3
	89	2,626.5	2,363.8	1,707.2	1,536.5	0.100	0.580	99.0	89.1
	102	1,436.4	1,292.8	933.7	840.3	0.080	0.552	41.3	37.1
Total Prospects		**31,059.9**	**27,953.9**	**20,188.9**	**18,170.0**			**1,024.1**	**921.7**
Leads									
	29	481.9	433.7	313.2	281.9	0.070	0.414	9.1	8.2
	64	344.1	309.7	223.6	201.3	0.070	0.331	5.2	4.7
	88	339.9	305.9	220.9	198.8	0.070	0.331	5.1	4.6
	101	233.6	210.2	151.8	136.6	0.080	0.221	2.7	2.4
Total Leads		**1,399.4**	**1,259.5**	**909.6**	**818.6**			**22.1**	**19.9**

Totals may not add because of rounding.

Notes: In-place volumes are reported at surface conditions. Totals of in-place volumes and unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to b recovered and are shown for convienence only.

(1) Company Gross volumes are ReconAfrica's working interest share of the estimated gross (100%) volumes.