RECONNAISSANCE ENERGY AFRICA LTD.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

As of December 31, 2024

1. DATE OF STATEMENT

This statement of reserves data and other oil and gas information (this "**Statement**") of Reconnaissance Energy Africa Ltd. ("**ReconAfrica**" or the "**Company**") is dated April 29, 2025. The effective date of the information provided in this Statement is December 31, 2024. Unless otherwise noted, references to dollar amounts are in Canadian dollars.

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:

- the Company's business strategy, strength and focus;
- expectations to add reserves through acquisitions and development of the Company's existing assets;
- the Company's aim to prove a potential reserve that could lead to economic stimulus, funding local and regional jobs and other socio-economic benefits such as increased infrastructure, potable water access and investments in environmental and wildlife conservation;
- expectations regarding the ongoing exploration process for the newly identified Kavango sedimentary basin in Northeast Namibia and Northwest Botswana (the "**Kavango Basin**");
- expectations related to the work program at PEL 73 (as defined herein) following the Company's receipt of the Second Renewal Exploration Period covering the period January 30, 2024 to January 29, 2026;
- proven working conventional petroleum system with oil in stratigraphic wells and gas seeps in the Kavango Basin;
- expectations regarding the strategic joint venture transaction with BW Energy (as defined herein) pursuant to the BW Energy Farm Down Agreement (as defined herein), including the timing and amount of cash payments relating to the joint venture transaction, the timing and amount of any bonus payments, and the timing and amount of production milestone payments;
- 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;
- 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 byproducts of such development;
- the potential returns for undiscovered oil and/or gas deposits in the Kavango Basin;
- ongoing activities by major industry competitors in Namibia and Botswana;
- the continuing competitiveness of the fiscal regimes in the jurisdictions in which the Company operates;
- the NAMCOR Transaction (as defined herein), being the Company's acquisition of half of the 10% carried participating interest in the Namibia Licence (as defined herein) held by NAMCOR (as defined herein);
- projections of market prices, including market prices for oil and natural gas, and costs;
- supply and demand for oil and natural gas;
- 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;
- the Company's intention in respect of maintaining sufficient insurance;
- updates of the Company's ongoing relationships with the Namibian and Botswanan governments and key ministries therein;
- expectations regarding the development of environmental laws and regulations, including as a result of the implementation of the Paris Agreement on climate change by various countries, the future costs to the Company associated with compliance with such laws and regulations and any potential changes to public perception following ongoing changes to climate laws; and
- the Company's dividend policy.

Statements relating to "reserves" and "resources" (including prospective resources, as such terms are defined in the Form 51-101F1) 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. See "*Other Oil and Gas Information*".

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 annual information form for the nine months ended December 31, 2025 under "*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 substantial capital requirements;
- weaknesses and volatility in the oil and gas industry;
- adverse economic conditions;
- geopolitical instability and the escalation and expansion of conflict globally;
- inflation, cost management and rising interest rates;
- political uncertainty in Namibia, Botswana and Canada;
- access restrictions and tariff risks;
- 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 and Botswana;
- 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 risk;
- operating hazards and other uncertainties;
- competition;
- alternatives to and changing demand for petroleum products;
- global financial conditions;
- macro-economic risk;
- international conflicts;
- 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 risk;
- 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*;
- failure to comply with anti-bribery and anti-corruption laws;
- reputation risk;
- environmental, pollution, occupational health and safety risks;
- discretion regarding potential use of proceeds;
- volatility in the trading price of the Common Shares of the Company (“Common Shares”);
- liquidity of Common Shares and realization of investment in Common Shares;
- dilution and further sales of 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 (as defined herein) 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 or incorporated by reference in this Statement are valid only as at the date of this Statement, 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 statement.

ABBREVIATIONS

2U	best estimate scenario of prospective resources
Bcf	billions of cubic feet
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
Damara	Damara Fold and Thrust Belt
FMI	formation microimager
km	kilometers
m	meters
Ma	mega annum
MD	measured depth
MMbbl	millions of barrels
ms	milliseconds
NI 51-101	Canadian National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities
NSAI	Netherland, Sewell & Associates, Inc.
nT	nanotesla
NTG	net-to-gross ratio
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 License
P_g	probability of geologic success
PHIE	effective porosity
rb/stb	reservoir barrels per stock tank barrel
ReconAfrica	Reconnaissance Energy Africa Ltd.
scf/rcf	standard cubic feet per reservoir cubic foot
STARSS	Southern Trans-African Rift and Shear System
SWE	effective water saturation
TVDSS	true vertical depth subsea
V_{sh}	shale volume

2. DISCLOSURE OF RESERVES DATA

The Company does not have any reserves (as such term is defined by National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**")).

On October 25, 2023, ReconAfrica disposed of its assets and operations in Mexico via the sale of Renaissance Oil Corp. ("**Renaissance**"), a wholly-owned subsidiary of the Company, which the Company did not consider to be material in the context of its business strategy, and therefore no longer has any reserves.

See the Appendix to this Statement for the Company's disclosure of the estimated prospective resources in certain prospects and leads located in the Damara Fold and Thrust Belt play area and the Karoo Rift play area of PEL 73 in the Kavango Basin, northeastern Namibia.

3. PRICING ASSUMPTIONS

No pricing assumptions have been made due to the sale of all the Company's reserves as noted above.

4. RECONCILIATION OF CHANGES IN RESERVES

As of March 31, 2024 and December 31, 2024, the Company had no reserves.

5. ADDITIONAL INFORMATION RELATING TO RESERVES DATA

As of December 31, 2024, the Company had no reserves.

6. OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

ReconAfrica is a Canadian-based oil and gas company working collaboratively with national governments to explore the potential for oil and gas resources in northeast Namibia on Petroleum Exploration Licence 073 ("**PEL 73**" or the "**Namibia Licence**") and northwest Botswana on Petroleum Exploration Licence 001 ("**PEL 001**" or the "**Botswana Licence**").

As of the date hereof, ReconAfrica holds a 70% working interest in PEL 73 (with BW Energy Limited ("**BW Energy**") holding a 20% working interest and the National Petroleum Corporation of Namibia ("**NAMCOR**") holding a 10% carried participating interest). PEL 73 covers two major play types in the Kavango Basin, the Damara Fold and Thrust Belt play area and the Karoo Rift play area. ReconAfrica holds a 100% interest in PEL 001. The exploration licences cover a contiguous area of 25,341 km2 (6.3 million gross acres and 4.41 million net acres) in Namibia and 7,592 km2 (1.9 million gross and net acres) in Botswana.

For a general description of the Company's important properties, including any statutory or other mandatory relinquishments, surrenders, back-ins or changes in ownership, see "*Disclosure of Reserves Data — Other Oil and Gas Information — Properties with No Attributed Reserves*", below.

PEL 73 and PEL 001 (each as defined below) are located onshore in Namibia and Botswana, respectively.

The Company has drilled four gross (2.8 net) non-producing wells located in PEL 73. The Company does not have any producing oil wells or gas wells.

Properties with No Attributed Reserves

NAMIBIA

<u>General</u>

Namibia, a former colony of Germany and then administered by South Africa pursuant to the Treaty of Versailles, gained independence from South Africa in 1990. Namibia has a highly developed infrastructure by regional standards, including well paved highways and a modern telecommunications system. As of the date of this Statement, major industry competitors such as ExxonMobil Corporation, Royal Dutch Shell plc, Total S.A. and Galp Energia, SGPS, S.A. all have active operations in Namibia.

Summer is from October to April and temperatures range from 20º C to 34º C during these months. Average winter temperatures range between 18°C and 22°C. The average annual rainfall varies from 350mm in the central interior and 700mm in the Caprivi Strip. The rainy season is from October until April. Paved and gravel roads exist on the Namibia Licensed Property (as defined below) and paved roads are present from the Namibia Licensed Property to the capital Windhoek and to the port at Walvis Bay. It is 225 kilometres from the Namibia Licensed Property to the railhead at Grootfontein, which connects to Walvis Bay. There is an airport on the Namibia Licensed Property with connections to the other Namibia airports including Windhoek.

<u>*Petroleum Agreement and Namibia License (PEL 073)*</u>

In Namibia, all rights in relation to the exploration for, the production and disposal of, and the control over petroleum vest in the state. The *Petroleum (Exploration and Production) Act 2 of 1991* (Namibia), together with the *Petroleum (Taxation) Act 3 of 1991* (Namibia) are the principal laws regulating the granting and transfer of petroleum licences to explore for and produce petroleum within the Republic of Namibia. Prior to a petroleum licence being granted, the *Petroleum (Exploration and Production) Act 2 of 1991* (Namibia) requires that the Namibian Minister of Mines and Energy enter into a petroleum agreement with the licence applicant containing the terms and conditions applicable to such licence and possible future licences, including production licences.

Pursuant to the terms of a petroleum agreement among the Government of the Republic of Namibia, the National Petroleum Corporation of Namibia ("**NAMCOR**"), and Reconnaissance Energy Namibia (Pty) Ltd. ("**ReconNamibia**"), a wholly owned subsidiary of ReconAfrica, dated January 26, 2015 and as adjusted on February 25, 2019 (the "**Petroleum Agreement**"), the Company holds a 70% interest (reduced from 90% pursuant to the BW Energy Farm Down Agreement) in PEL 73 in respect of approximately 6.3 million acres

($25,341.33 km^2$) of oil and/or gas exploration properties comprising six licensed blocks, namely 1719, 1720, 1721, 1819, 1820 and 1821 situated in the Kavango Basin of northeast Namibia (the "**Namibia Licensed Property**"), granted by the Government of the Republic of Namibia to ReconNamibia and NAMCOR pursuant to the *Petroleum (Exploration and Production) Act*, *1991* (Namibia) and governed by the Petroleum Agreement (the "**Namibia Licence**"). The Namibia Licence, which entitles ReconAfrica to apply for and receive, subject to Namibian government approval, a 25-year production licence upon successful discovery of an economically viable resource at the Namibia Licensed Property, and the Petroleum Agreement are ReconAfrica's main assets.

The following summary of key terms of the Petroleum Agreement is qualified in its entirety by the full text of the Petroleum Agreement, a copy of which is available on the Company's SEDAR+ profile at www.sedarplus.ca. The Petroleum Agreement describes an eight-year exploration work program and accompanying minimum expenditures on the Namibia Licensed Property related thereto. Such exploration program consists of the following three phases:

Initial Exploration Period (4 years, subject to possible one-year extension)

- Collection of existing surface and subsurface exploration data including, without limitation potential fields, remote sensing, satellite imagery, geomorphological, geochemical, radiometric and well data.
- Reprocessing and reinterpretation of all geological and geophysical data.
- Geochemical soil sampling and analysis.
- Initial integral assessment of the hydrocarbon potential of the area.
- Environmental impact assessment for both drilling and seismic acquisition activities.
- A minimum 500 kilometres of 2D seismic data for assessment of geology and basin structural configuration (with an option to replace the seismic program with two stratigraphic test wells to the base of the Karoo Super group sequences with total depth at the top of Damara belt related sequences).
- Full integral assessment of the hydrocarbon potential of the area and gross resources estimates.
- Planning for drilling two stratigraphic tests or exploration wells.

Minimum expenditures for the initial exploration phase, as prescribed by the Petroleum Agreement, total US$5,000,000. Additionally, the Company is required 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 Namibian Ministry of Mines and Energy granted a one-year extension to the Initial Exploration Period of the Namibia Licence.

Pursuant to an adjustment letter dated February 25, 2019, the Namibian Ministry of Mines and Energy 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 will be deemed to have been satisfied provided that, by January 29, 2020, the Company drills one stratigraphic test well, rather than two. The drilling of one stratigraphic test well will 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 has been deferred to and becomes a part of the work commitments that must be satisfied during the First Renewal Exploration Period (Namibia). Further, the relinquishment obligation which arises at the end of the Initial Exploration Period has been deferred into the First Renewal Exploration Period (Namibia).

On December 18, 2019, Namibia's Minister of Mines and Energy confirmed that the Namibia Licence had been approved for its First Renewal Exploration Period(Namibia), and accordingly the exploration phase of the Namibia Licence was renewed and continued until January 25, 2022. Such approval included recognition that the proposed work program for the First Renewal Exploration Period (Namibia) included the drilling of two stratigraphic test wells.

First Renewal Exploration Period (Namibia) (2 Years, subject to possible one-year extension)

- Acquire 250 kilometres of 2D seismic data.
- Drill and evaluate two stratigraphic and/or exploration wells.
- Design and plan 3D seismic acquisition program for continued exploration and drilling program.

Minimum expenditures for the First Renewal Exploration Period, as prescribed by the Petroleum Agreement, total US$10,000,000 plus an additional 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. The work requirements for 2D seismic, well drilling and aggregate expenditure have been satisfied.

On September 10, 2021, Namibia's Minister of Mines and Energy granted approval of a one-year extension on the First Renewal Exploration Period (Namibia), 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 (Namibia), extending such period to January 29, 2024.

On September 22, 2022, the Company announced that it had entered into a definitive purchase and sale agreement with NAMCOR dated September 21, 2022, to acquire half of NAMCOR's 10% carried participating interest in PEL 73 (the "**NAMCOR Transaction**"). The NAMCOR Transaction has not yet been completed as previously anticipated and discussions are ongoing between the Company and NAMCOR. The Company has agreed to issue 5,000,000 Common Shares to NAMCOR, subject to certain contractual restrictions on transfer, and pay US$2 million in cash for the acquisition of half of NAMCOR's 10% carried participating interest in the Namibia Licence. Completion of the NAMCOR Transaction is expected to follow fulfilment of various conditions precedent, including approval of the Namibian Ministry of Mines and Energy, the approval or waiver of Namibia's competition authority and the acceptance by the TSXV. There can be no assurance that the NAMCOR Transaction will be completed on these terms or at all.

On October 30, 2023, Namibia's Minister of Mines and Energy confirmed that the Namibia Licence had been approved for its Second Renewal Exploration Period covering the period from January 30, 2024 to January 29, 2026, under revised terms as detailed in the following section.

Second Renewal Exploration Period (2 Years, subject to possible one-year extension)

- Either
  - acquire 500 kilometres of 2D seismic data, or
  - acquire 1,200 square kilometres of eFTG data, or
  - some combination of (i) or (ii) which is reasonable and achieves a significant increase in the data acquired by the Company during the Second Renewal Exploration Period.
- Design an exploration or stratigraphic test well and then drill such well.

Minimum expenditures for the Second Renewal Exploration Period, as prescribed by the Petroleum Agreement, total US$10,000,000 plus an additional 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. However, as the Company's exploration expenditures in the First Renewal Exploration Period exceeded the minimum US$10,000,000, this excess of over US$60,000,000 may be applied to reduce the minimum exploration expenditure commitment in the Second Renewal Exploration Period (Namibia). This treatment has been confirmed by the Namibia Ministry of Mines and Energy and accordingly there is no minimum exploration expenditure for the Second Renewal Exploration Period. This does not alter the Company's obligation to conduct the seismic and drilling exploration work described above. ReconAfrica has satisfied the drilling obligation through the drilling of the Naingopo well, with the 3D seismic program estimated to begin in the second half of 2025.

Other Material Provisions

The Company is required to pay to the Government of Namibia an annual licensing fee ranging from NAD$60 to NAD$150 per square kilometre of the Namibia Licensed Property, 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 kilometre to which such production licence relates.

In accordance with the Petroleum Agreement, as adjusted by the February 25, 2019 and October 4, 2021 adjustment letters, the Company must relinquish at least 50% of the exploration area covered by the Namibia Licence at the end of the First Renewal Exploration Period (Namibia) (January 29, 2024). 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.

As part of the approval for the Second Renewal Exploration Period by the Namibian Ministry of Mines and Energy, the Company requested and on November 27, 2023 was granted, a relinquishment exemption based on the provisions of Section 37 (5) of the Petroleum Act of 1991. The request was based on the Company's belief following the evaluation of acquired subsurface data over the past three years that a significant portion of PEL 73 will be prospective for the exploration of oil and gas. As a result, the Company does not have to relinquish any of the acreage and retains access to the entire Namibia Licence.

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.

A copy of the Petroleum Agreement is available on SEDAR+ under ReconAfrica's profile at www.sedarplus.ca.

BW Energy Farm Down

On July 16, 2024, the Company entered into a memorandum of understanding ("**MOU**") for the BW Energy Farm Down (as defined below) of PEL 73.

On July 30, 2024, the Company announced that, further to the MOU, it entered into a definitive farm down agreement (the "**BW Energy Farm Down Agreement**") with BW Energy for a strategic farm down (the "**BW Energy Farm Down**") of a 20% working interest in PEL 73. On July 30, 2024, the Company announced that, further to the MOU, it entered into the BW Energy Farm Down Agreement for the BW Energy Farm Down. On January 29, 2025, the Company announced that the BW Energy Farm Down had closed upon receipt of the approvals of Namibian Ministry of Mines and Energy and NAMCOR. Upon closing, the working interests in PEL 073 became: ReconAfrica, operator, 70% working interest; BW Energy 20% working interest; and NAMCOR 10% carried participating interest .

Pursuant to the BW Energy Farm Down Agreement, BW Energy agreed to participate in two Damara Fold Belt exploration wells and a 3D seismic program, with an option to participate in two Rift Basin exploration wells over a two-year period.

The Company's total potential consideration under the BW Energy Farm Down Agreement is US$141 million ($203 million), including a $22 million (US$16 million) equity investment pursuant to the bought-deal financing completed by the Company in July 2024. An additional US$45 million ($65 million) bonus will be earned at declaration of commerciality (FID). These commerciality bonus payments will be paid in two installments, one at FID and the second payment one year after production. In the event of development of discoveries, production bonuses based on certain cash flow milestones achieved by BW Energy could total an additional US$80 million ($115 million). Three separate production bonus payments of US$25 million ($36 million), are made after BW Energy reaches certain free cash flow milestones. An additional first production payment of US$5 million ($7 million), is paid sixty days after the start of commercial production. All values converted using the USD exchange rate as at December 31, 2024.

Exploration

The Company's core operating objectives are to identify and develop oil and/or gas assets through exploration conducted pursuant to the Namibia Licence, which was obtained by ReconNambia, now a wholly owned subsidiary of the Company following the reverse takeover transaction completed in 2019. During 2015, Reconnaissance Oil & Gas Corp. acquired a high-resolution geomagnetic survey of the Namibia Licensed Property and conducted a detailed analysis of the resulting data and other available data related to the Namibia Licensed Property, including reprocessing and reinterpretation of all existing geological and geophysical data. This led to the identification on the Namibia Licensed Property of the Kavango Basin, as a sub-basin of the Greater Owambo Basin in northeastern Namibia.

Prior to the Company's acquisition of the Namibia Licence, the Namibia Licensed Property had seen no historical drilling or 2D seismic acquisition, with the closest subsurface well control 385 km to the west. This critical control point, Stratigraphic Test #1, was drilled to a depth of 1878 metres by Etosha Petroleum Co. in 1964, and encountered Kalahari Sequence, Karoo Supergroup – lower Karoo and Damara Sequence – Otavi and Mulden Groups.

The Company's geologic team has defined a beneficial structural framework and depositional basin configuration utilizing a high-resolution aero-magnetic database. The Company has developed a fully integrated structural inversion model for the entirety of the Namibia Licensed Property defining a pull-apart basin with targetable half grabens capable of housing substantial thickness of Karoo-Aged sediments and underlying Lower Paleozoic Units. Regional geologic investigations of Permian Karoo deposition, including Main Karoo Basin, Botswana Kalahari Basin and Namibian basins Kavango, Karasburg, Nama, Waterberg, Huab and Owambo support potential for adequate thickness of resource-prone sediments. Preliminary analyses indicate basin depths supportive of oil and/or gas thermal maturation levels.

ReconAfrica hired an in-country environmental assessment firm who initiated an environmental impact assessment in the fourth quarter of 2018 for the purpose of obtaining the necessary governmental permits and approvals to allow drilling operations to occur. The Company identified a number of possible drilling locations for stratigraphic test wells, the drilling of which would provide critical and useful information about the stratigraphy of the Namibia Licensed Property and whether hydrocarbons exist on the Namibia Licensed Property. The Environmental Compliance Certificate was obtained on October 7, 2019 and the Company commenced drilling operations on the Namibia Licensed Property in January 2021.

The Company has received ECC no. 2300571, from the Environmental Commissioner, Ministry of the Environment, Forestry and Tourism, covering PEL 73, for the drilling of 12 exploration and appraisal wells from July 4, 2023 to July 4, 2026, including six in the Damara Fold Belt and six in the Rift Basin. The Company has applied for an amendment to ECC no. 2300571 to move the location of three of the original drill locations and to add a further five drill locations with three in the Damara Fold Belt and two in the Rift Basin.

The Company has applied for a renewal and amendment to ECC no. 001491 covering a 2D seismic survey. The renewal and amendment include two test lines to complete an analysis of previously obtained results and additional 2D or 3D seismic survey coverage.

Seismic Operations and Technical Studies

In Namibia, the Company conducted seismic operations in three phases (phase 1, phase 2 and the phase 2 extension) over three years, from 2021 to 2023. The operations were conducted using low impact methods: small footprint sources, state of the art wireless receiver technologies, cloud computing, and sensitivity and awareness in all operational activities. A total of 2,767 kilometres of seismic have been acquired over these three years, comprising 497 kilometres in Phase 1, 761 kilometres in Phase 2 and 1,509 kilometres in the Phase 2 Extension. The seismic data acquisition program has been completed and processed, providing a good regional 2D seismic data set over the most prospective areas of PEL 73.

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.

The first two phases identified a number of leads and considerably expanded the Company's portfolio of opportunities. The phase 2 extension was designed to better define these leads, de-risk potential drilling targets, and add new leads. The program was 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 Company has further progressed its technical assessment of the Damara Fold Belt with the integration of new studies, basin modelling and all available geochemical data. The Company now anticipates potentially having oil in the shallower Mulden reservoir intervals, while the deeper Otavi target is expected to have natural gas with liquid/oil potential. Due to the coarse seismic grid over the Rift basin, the Company is evaluating options to acquire a 3D program to further delineate the identified leads prior to any drilling in the Rift. Seismic acquisition is anticipated to occur in the second half of 2025.

Enhanced Full Tensor Gravity ("eFTG") Survey

ReconAfrica engaged an airborne geophysical survey provider, Metatek Group Limited, to conduct an eFTG survey over an area of 2,184 square kilometres (540,000 acres) over the Company's exploration licence in Northeastern Namibia. 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 was 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 measure 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 and inversion of this data was completed and integrated with the seismic data to evaluate the Company's exploration inventory. This information, combined with the 2D seismic and well data, has enhanced the Company's ability to image and understand the sub-surface, significantly contributing to building a risk weighted prospect portfolio and defining the Company's future drilling program.

Drilling Program

The Company's initial drilling program, which commenced at the beginning of 2021, was designed to test organic rich source rocks, evidence of migrated hydrocarbons and conventional traps. ReconAfrica completed two wells in the third quarter of 2021 which achieved the stated purpose of the initial drilling program, the establishment of a working conventional petroleum system in the Kavango Basin. Well 1819/8-2 ("**8-2**"), 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 hydrocarbon shows with gas (methane) and gas liquids. Hydrocarbon shows with gases were identified between 838m and 1,807m, and between 1,990m and 2,058m; although geologically a successful well, economic accumulations of hydrocarbons were not encountered. The apparent lack of structural closure and potential oil source-maturation issues at this location highlighted the need for multiple seismic line confirmation and eFTG to support all new drilling decisions. The data gathered from the well program, seismic operations and eFTG has led to the identification of a new play, the Damara Fold Belt.

The ReconAfrica technical team anticipates drilling multiple wells in the Damara Fold Belt, beginning with the Naingopo (Prospect L) well, which spud on July 7, 2024, and reached a total depth of 4,184 metres or 13,724 feet in November 2024. The well encountered 52 metres of net reservoir in the Otavi Group, with the Mulden reservoirs being tighter than expected. The acquisition and processing of the vertical seismic profile of the well has allowed us to correlate the well results to the Otavi seismic event, derisking the Otavi presence in future Damara Fold Belt prospects. Additionally, the indication of oil via rock fluorescence was pervasive within the Otavi Group. This interval of fluorescence was associated with oil being recovered at surface in the drilling mud system. Side wall cores, isotubes, cuttings and fluid samples are currently with third party service providers for further analysis. Delays in drilling were encountered due to slower drilling rates in the Mulden formation, tight hole conditions while setting casing, and drilling past planned total depth. The well was temporarily abandoned in December and in January 2025 the rig was rigged down after conducting rig maintenance.

After analysis of the logs at Naingopo and re-interpretation of the seismic in the area around Naingopo and Prospect P ("**Kambundu**"), it was determined the best location to drill the next Damara Fold Belt well is Prospect I. Permits for the land access/use and water have been submitted and construction activities for the road and drill site are underway. The spud of Prospect I is anticipated in Q2 of 2025.

BOTSWANA

General

Botswana, a former colony of the United Kingdom and sovereign nation since 1966, is Africa's longest standing democracy.

Summer is from October to April and temperatures range from 20º C to 34º C during these months. Average winter temperatures range between 18°C and 22°C. The average annual rainfall varies from 350mm in the central interior and 700mm in the Caprivi Strip. The rainy season is from October until April. Paved and gravel roads exist on the Botswana Licensed Property (as defined below). Road access to the Botswana Licensed Property is by paved road from the Namibia Licensed Property in the Caprivi Strip, or by paved and gravel roads from Gaborone, the capital of Botswana.

Botswana Licence (PEL 001)

On June 9, 2020, the Company, through its wholly owned subsidiary, Reconnaissance Energy Botswana (Pty) Ltd. ("**ReconBotswana**"), was granted 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) (the "**Botswana Licensed Property**"). The lands subject to the Botswana Licence are contiguous to the Namibia Licensed Property.

The terms of the Botswana 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*, and generally range from 3 to 10% of gross revenue from production;
- the Company has committed to a minimum work program of 5,000,000 Botswana Pula (BWP) (approximately $515,000) over the first 4-year exploration period; and

- the corporate tax rate of Botswana is 22%.

The Company is at an early stage and in the process of completing desktop studies. ReconAfrica has completed a hydrogeology including groundwater feasibility study prepared by a Botswana third-party service company. The Botswana Licensed Property excludes National Parks, the Tsodilo Hills, RAMSAR area, and the Okavango Delta. The Company also self-imposes additional buffer zones to avoid environmentally sensitive areas.

In March 2024, the Company applied for a six-month extension of the Botswana Licence while it continued to negotiate a petroleum agreement with the government of Botswana. The Company has also applied for a renewal of the licence should the extension not be approved. Under the terms of the Botswana Petroleum Act the Botswana Licence was deemed to continue in force until the Minister decided on the licence extension and renewal.

The fiscal regimes of both Namibia and Botswana are both globally competitive. In the “African Investment Index” published in 2018 by Quantum Global Research Lab, the independent research arm of the Quantum Global Group, a group of companies operating in the areas of investment management, private equity, active management and research with a focus on Africa, Quantum Global Research Lab ranked Botswana as the fourth most attractive investment destination in Africa.

In October 2024, the Company was granted approval for the First Renewal Exploration Period (Botswana) which covers the period from October 1, 2024, to September 30, 2028. Under the terms of the First Renewal Exploration Period (Botswana) the Company will be required to undertake various geotechnical evaluations, vegetation mapping, a water study report, methane seep detection activities, an environmental impact study and provide funding for Botswana Petroleum Exploration and Training. Minimum expenditures during this period total 5,000,000 Botswana Pula (BWP) (approximately $515,000).

First Renewal Exploration Period (Botswana) (4 Years)

- Year One
    - Updated access report
    - Remote stressed vegetation mapping
    - Provide funding for Botswana Petroleum Exploration and Training (US$25,000)
- Year Two
    - Conduct water study report
    - Methane seep detection environmental permitting requirements
    - Provide funding for Botswana Petroleum Exploration and Training (US$25,000)
- Year Three
    - Carryout environmental impact study
    - Methane seep detection
    - Provide funding for Botswana Petroleum Exploration and Training (US$25,000)
- Year Four
    - Carry out soil geochemical sampling
    - Carry out geophysical exploration
    - Provide funding for Botswana Petroleum Exploration and Training (US$25,000)

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 (i) the Appendix to this Statement under the heading “Summary of Prospective Oil and Gas Resources”; (ii) the Company’s consolidated financial statements for the nine months ended December 31, 2024 and related management discussion and analysis as available on the Company’s profile on SEDAR+

at www.sedarplus.ca; and (iii) the risk factors and uncertainties described under the heading "Risk Factors" in the Company's the Annual Information Form for the nine months ended December 31, 2024 as available on the Company's profile on SEDAR+ at www.sedarplus.ca.

Forward Contracts

Currently there are no material forward contracts or commitments.

Tax Horizon

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

During the nine months ended December 31, 2024, the Company incurred costs of $33.0 million, mainly related to the drilling the Naingopo (Prospect L) well, which spud on July 7, 2024, and preparation costs for the Kambundu well location and a Vibroseis seismic parameter test to establish the best Vibrator sweep parameters and number of Vibrators in a fleet, and to investigate field data processed results for future seismic projects on block PEL 73.

The following table summarizes certain expenditures for the Company during the nine months ended December 31, 2024.

	Property Acquisition Costs			
	Proved Properties	**Unproved Properties**	**Exploration Costs**	**Development Costs**
2024	-	-	$33.0 million	-

"**Development Costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(ii) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(iv) provide improved recovery systems.

"**Exploration Costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(ii) costs of carrying and retiring unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(iii) dry hole contributions and bottom hole contributions;

(iv) costs of drilling and equipping exploratory wells; and

(v) costs of drilling exploratory type stratigraphic test wells.

"**Property Acquisition Costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(i) costs of lease bonuses and options to purchase or lease a property;

(ii) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(iii) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

Exploration and Development Activities

During the nine months ended December 31, 2024, ReconAfrica drilled one gross (0.7 net) exploratory well in PEL 73 and no commercial discovery was made.

For a general description of ReconAfrica's most important current and likely exploration and development activities, by country, see "*Disclosure of Reserves Data — Other Oil and Gas Information — Properties with No Attributed Reserves — Namibia*" and "*Disclosure of Reserves Data — Other Oil and Gas Information — Properties with No Attributed Reserves — Botswana*", above.

Production Estimates

The Company does not have any production estimates.

Production History

For the nine-months ended December 31, 2024, the Company had no production.

APPENDIX

OPTIONAL DISCLOSURE OF PROSPECTIVE RESOURCES DATA

ReconAfrica engaged Netherland, Sewell & Associates, Inc. ("**NSAI**"), an independent qualified reserves evaluator, to provide an updated prospective resource report dated March 26, 2025 (with an effective date of December 31, 2024) relating to the Company's prospective resources (the "**Updated Report**"). The Updated Report focused solely on the Company's interest in certain prospects and leads located in the Damara Fold and Thrust Belt (Damara) play area and the Karoo Rift play area of PEL 73 in the Kavango Basin, northeastern Namibia. The preparation date of the Updated Report is January 1, 2025; NSAI did not consider any geological, engineering, or financial data for its evaluation after that date. The Updated Report is available on the Company's profile on SEDAR+ at www.sedarplus.ca.

The estimates in the Updated Report have been prepared in accordance with the definitions and guidelines set forth in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook (COGEH) maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

As of December 31, 2024, ReconAfrica owned a 90% working interest in PEL 73. As of the date hereof, ReconAfrica holds a 70% working interest in PEL 73 (with BW Energy holding a 20% working interest and NAMCOR holding a 10% carried participating interest).

Summary of Prospective Oil and Gas Resources

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

Exploration opportunities are subclassified as prospects or leads depending upon the available data and degree of interpretation. A prospect is considered to have enough data and interpretation such that it is currently ready to drill. A lead has insufficient data or interpretation to adequately identify a drillable structural closure and/or petroleum system at the current time. As of the date of the Updated Report, 25 prospects and 49 leads were identified and evaluated.

Prospective resources 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 Updated 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 prospects and leads, as discussed in subsequent paragraphs. The Updated Report does not include economic analysis for these prospects and leads. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in the Updated 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 develop and produce any portion of the prospective resources.

Totals of unrisked prospective resources beyond the prospect and lead levels 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 these levels can be defined only by summing risked prospective resources. Such risk is often significant.

The Updated Report estimates the unrisked and risked gross (100 percent) best estimate (2U) prospective light and medium crude oil resources and the unrisked and risked company gross and net 2U prospective oil resources to the Company interest in these prospects and leads, as of December 31, 2024, to be:

Best Estimate (2U) Prospective Light & Medium Crude Oil Resources (MMbbl)

Play Area/Subclass	Unrisked Gross (100%)	Unrisked Company Gross	Unrisked Net(2)	Risked(1) Gross (100%)	Risked(1) Company Gross	Risked(1) Net(2)
Damara						
Prospects	2,566.1	2,309.5	2,194.0	156.5	140.9	133.8
Leads	123.2	110.9	105.3	4.1	3.7	3.5
Karoo Rift						
Prospects	484.5	436.1	414.3	25.2	22.7	21.6
Leads	1.602.5	1,442.3	1,370.2	37.8	34.0	32.3
Total PEL 73						
Prospects	3,050.6	2,745.6	2,608.3	181.7	163.6	155.4
Leads	1,725.7	1,553.1	1,475.5	42.0	37.8	35.9

Notes: Prospective resources are the arithmetic sum of multiple probability distributions.

(1) 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.

(2) Net prospective resources are after a 5-percent deduction for royalties.

(3) Totals may not add because of rounding.

There is no certainty that any portion of the resources outlined below will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Oil volumes in the tables above are expressed in millions of barrels (MMbbl); a barrel is equivalent to 42 United States gallons.

For a description of the significant positive and negative factors relevant to the estimate see (i) the risk factors and uncertainties described under the heading "Risk Factors" in the Company's the Annual Information Form for the nine months ended December 31, 2024 as available on the Company's profile on SEDAR+ at www.sedarplus.ca; and (ii) "*Disclosure of Reserves Data — Other Oil and Gas Information — Properties with No Attributed Reserves — Namibia*" and "*Disclosure of Reserves Data — Other Oil and Gas Information — Properties with No Attributed Reserves — Botswana*", above

Given the nature and stage of the Company's exploration for the potential for oil and gas resources in PEL 73 and PEL 001, the Company does not have sufficient information to support any reasonable estimates regarding the total cost required to achieve commercial production, the general timeline for the project, including estimated date of first commercial production, the recovery technology, or the type of project.

The prospective resources shown in the Updated 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 Updated Report.

For the purposes of the Updated 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 levels 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 estimates for risked resources are derived directly from the estimates for unrisked resources, incorporating a geologic risk assessment for each prospect; such risked resources also incorporate a development risk assessment. The prospective resources included in the Updated 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 considered the primary elements to be (1) financial considerations, (2) access to sales markets, (3) development plan approval, and (4) government and regulatory approvals.

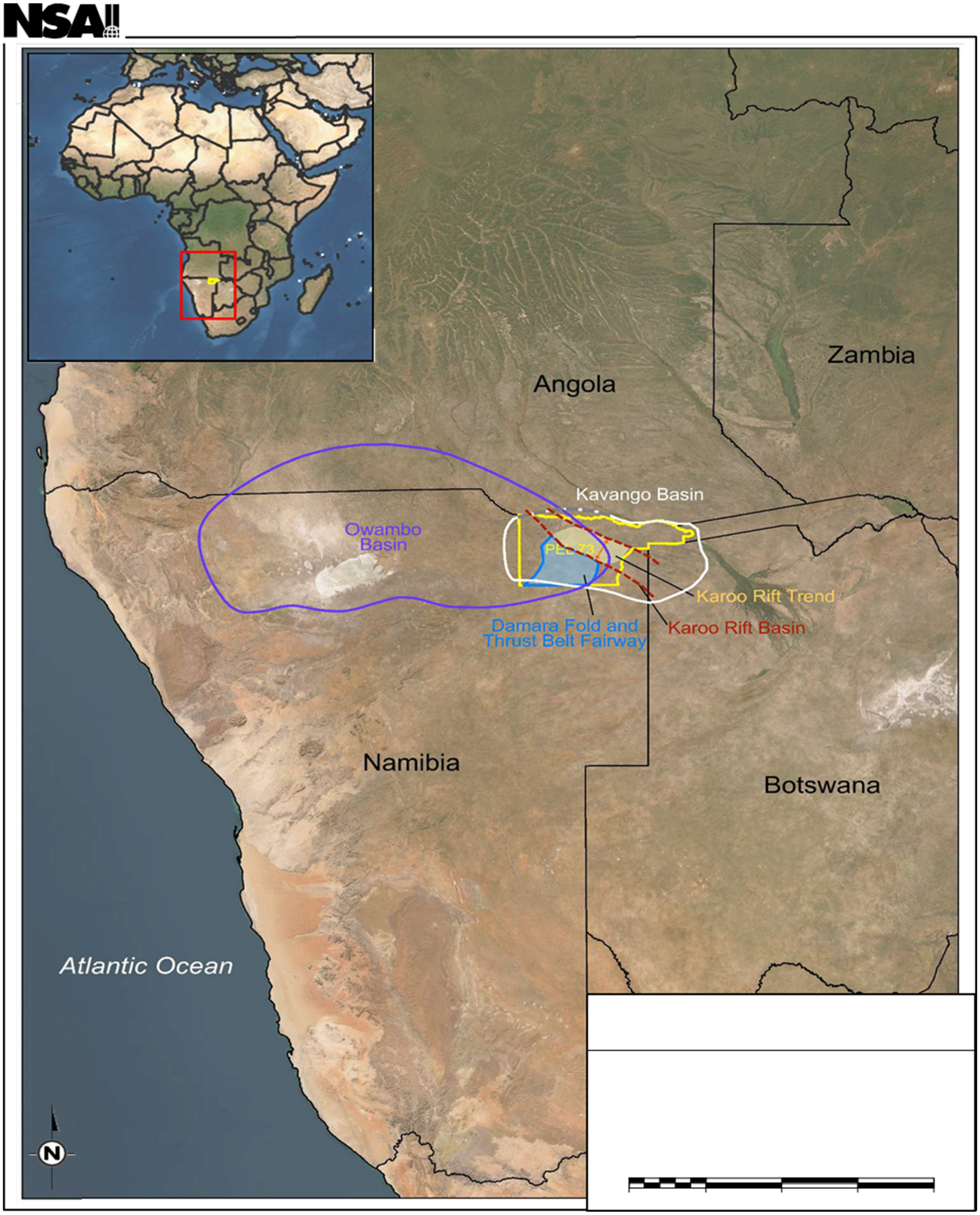
Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements for each prospect and lead.

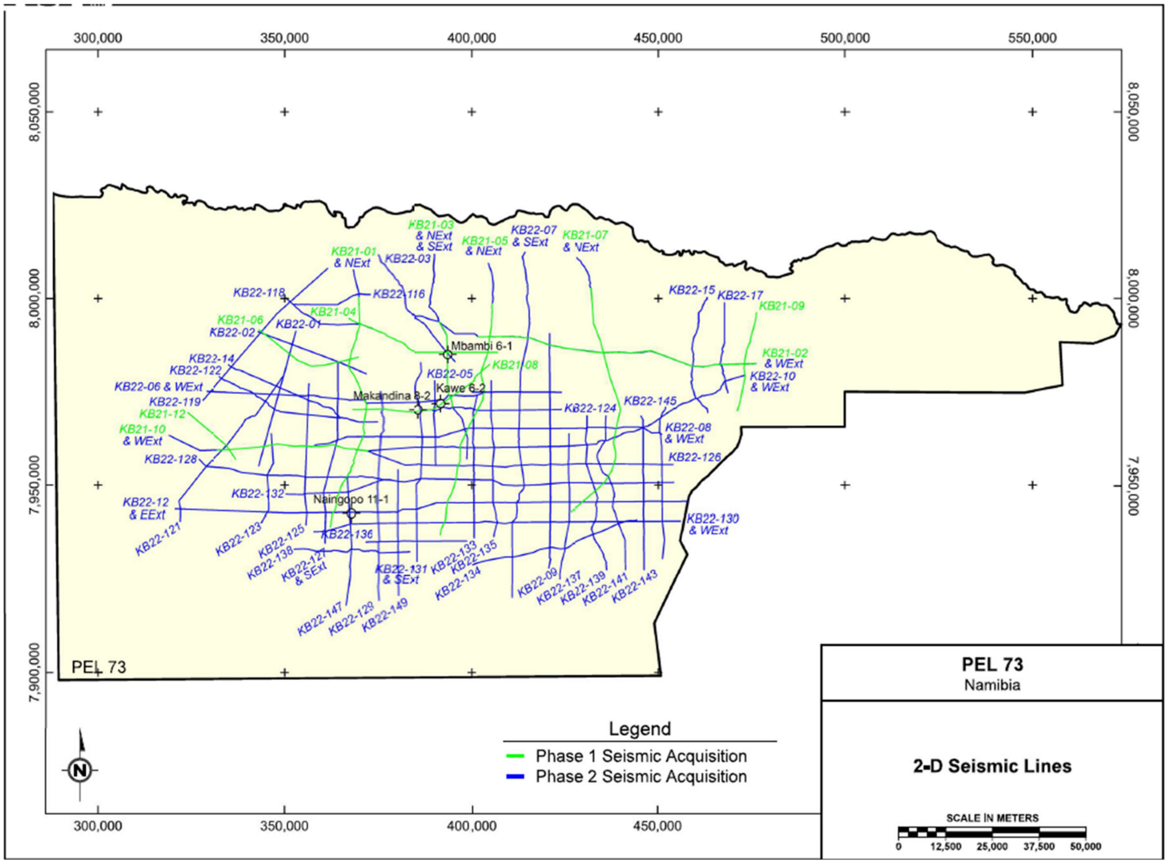
Each prospect and lead was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect or lead drilling outcomes. If petroleum discoveries are made, smaller-volume prospects and leads may not be commercial to 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. Opportunities in the Damara play area were also evaluated based on available geologic and geochemical data to determine the likely hydrocarbon fluid type, whether oil or gas, in the event of a discovery. For the Updated Report, prospective resources volumes for the Damara play area within the Otavi and Mulden Groups are summarized as potential oil discoveries because of recent reassessment of available data. However, prospective resources volumes for the Damara play area are also summarized as potential gas discoveries in the appendix of the Updated Report.

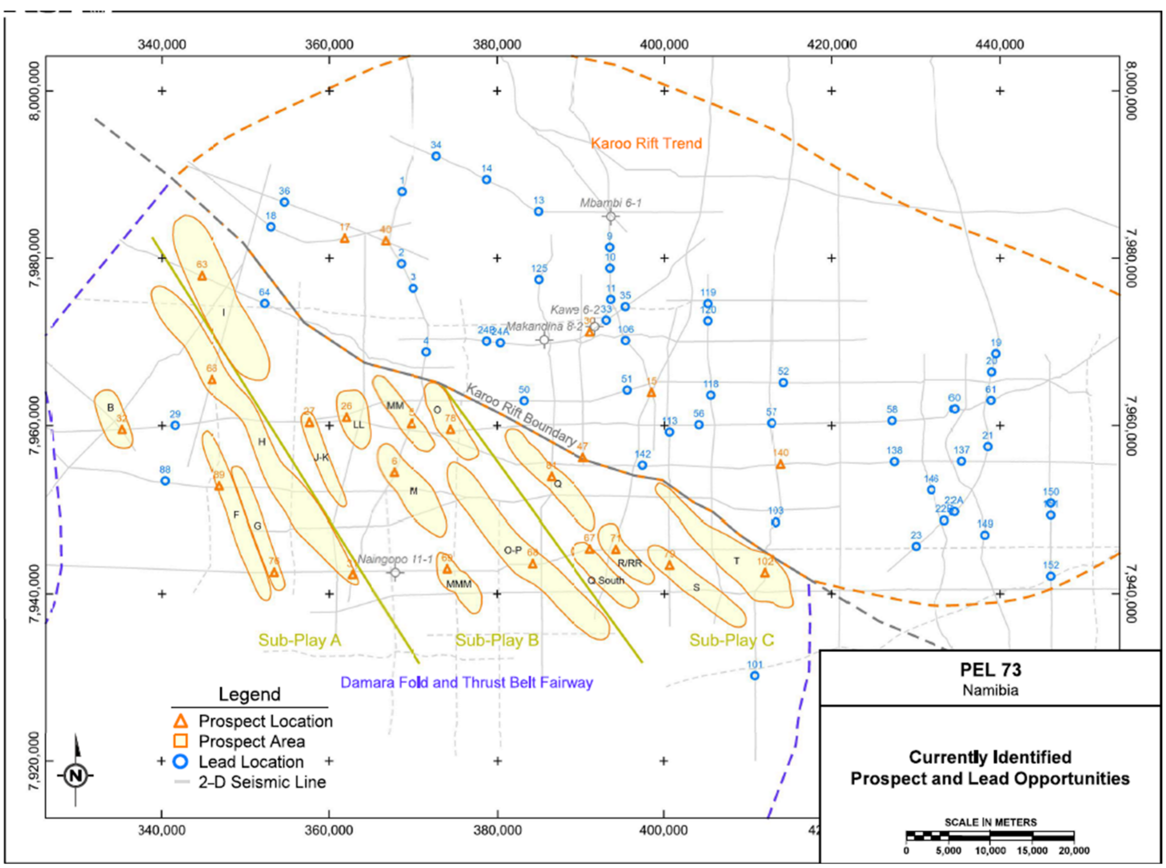
It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this document and the Updated 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.

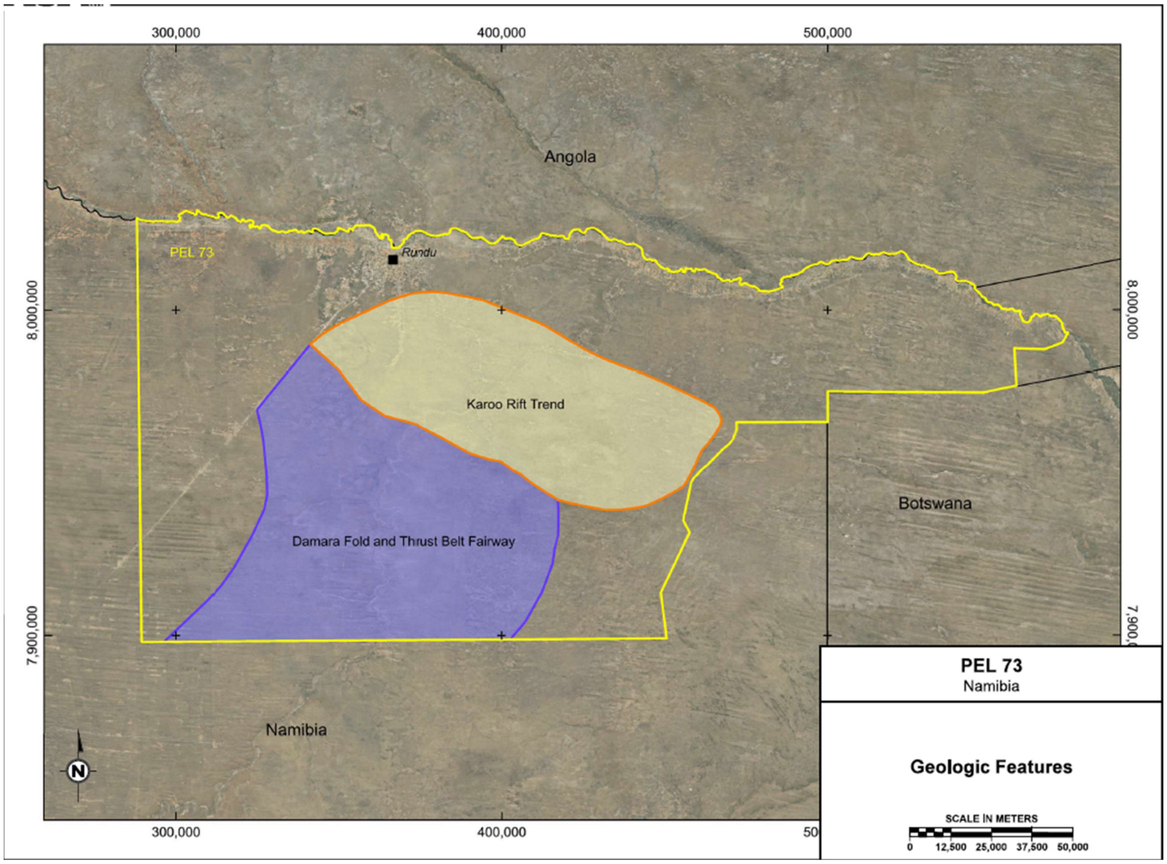
The Updated Report includes a discussion, certificates of qualification, Form 51-101F2 – *Report on Prospective Resources Data by Independent Qualified Reserves Evaluator or Auditor*, a location map, pertinent figures, a summary of reservoir parameters, summaries of prospective resources, and a bibliography. Also included is an alternate assessment of the estimates of in-place and recoverable petroleum for the Damara play area assuming all exploration opportunities included in this report result in gas discoveries instead of oil discoveries. The following pages include further information and descriptions; however, the reader is strongly encouraged to review the Updated Report available on SEDAR+ at www.sedarplus.ca.

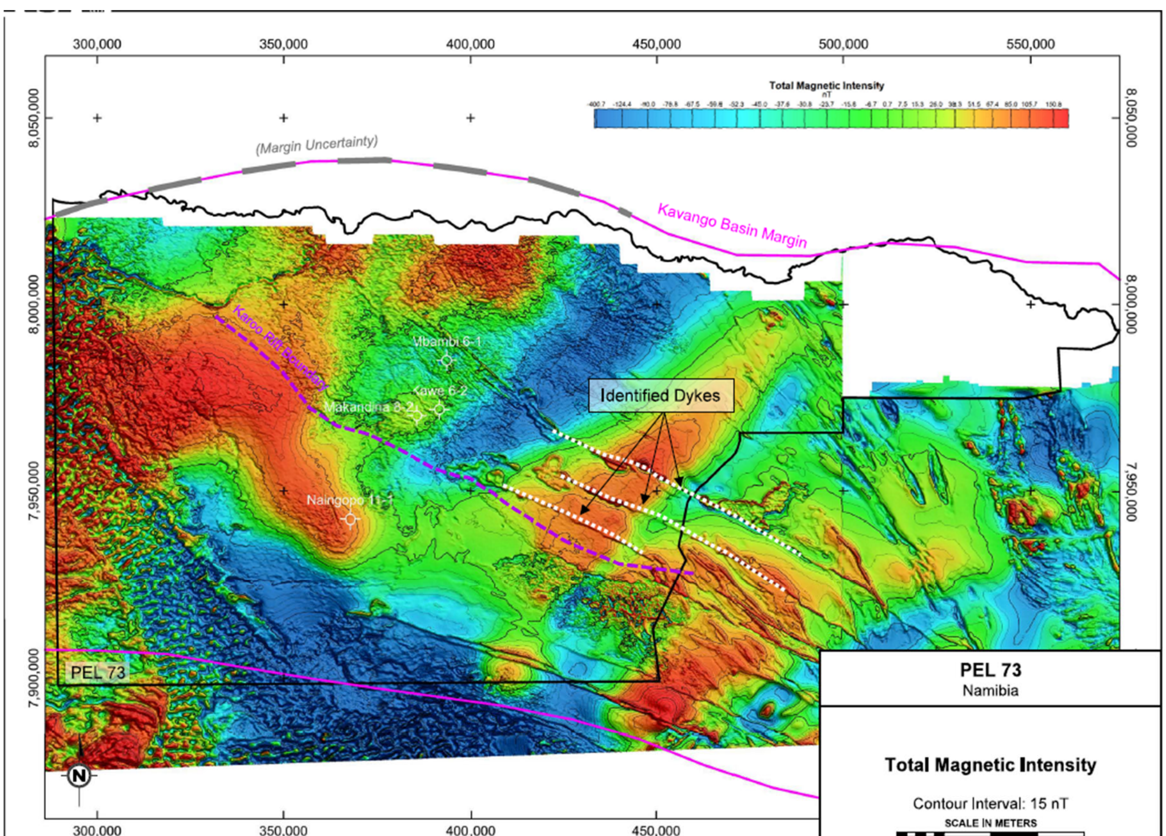
Location of Licenced Area in Namibia (PEL 73)




PEL 73
Namibia
2-D Seismic Lines
Legend
Phase 1 Seismic Acquisition
Phase 2 Seismic Acquisition
SCALE IN METERS
Mbambi 6-1
Kawe 6-2
Makandina 8-2
Naingopo 11-1


PEL 73
Namibia
Currently Identified
Prospect and Lead Opportunities
Legend
Prospect Location
Prospect Area
Lead Location
2-D Seismic Line
SCALE IN METERS
Karoo Rift Trend
Karoo Rift Boundary
Sub-Play A
Sub-Play B
Sub-Play C
Damara Fold and Thrust Belt Fairway





Adapted from a figure provided by Earthfield Technology, LLC.

Summary of Selected Reservoir Parameters
Damara Fold & Thrust Belt Play Area
As of December 31, 2024

Play Type	Sub-play	Target	Area[1] (acres) P95	Area[1] (acres) P50	Area[1] (acres) P05	Geometric Factor[2] (Decimal) Minimum	Geometric Factor[2] (Decimal) Most Likely	Geometric Factor[2] (Decimal) Maximum	Net Pay (m) Minimum	Net Pay (m) Most Likely	Net Pay (m) Maximum
3	A	Mulden	606 - 8,000	1,213 - 12,500	2,426 - 16,500	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	10	30	100
3	A	Otavi-Huttenberg	606 - 8,000	1,213 - 12,500	2,426 - 16,500	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	30	50	70
3	A	Otavi-Elandshoek	606 - 6,500	1,213 - 9,500	2,426 - 13,000	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	25	50	150
3	B	Mulden	873 - 11,500	1,747 - 17,250	3,493 - 23,000	0.40 - 0.50	0.60 - 0.65	0.80	10	30	100
3	B	Otavi-Huttenberg	873 - 11,500	1,747 - 17,250	3,493 - 23,000	0.40 - 0.50	0.60 - 0.65	0.80	30	50	70
3	B	Otavi-Elandshoek	873 - 9,000	1,747 - 13,500	2,500 - 18,000	0.40 - 0.50	0.60 - 0.65	0.80	25	50	150
3	C	Mulden	2,750	3,630	5,500	0.00	0.50	0.99	10	30	100
3	C	Otavi-Huttenberg	873 - 8,000	1,747 - 10,560	3,493 - 16,000	0.40 - 0.50	0.60	0.70 - 0.80	30	50	70
3	C	Otavi-Elandshoek	873 - 8,000	1,747 - 10,560	3,493 - 16,000	0.40 - 0.50	0.60	0.70 - 0.80	25	50	150

Play Type	Sub-play	Target	Porosity (Decimal) Minimum	Porosity (Decimal) Most Likely	Porosity (Decimal) Maximum	Water Saturation (Decimal) Minimum	Water Saturation (Decimal) Most Likely	Water Saturation (Decimal) Maximum	Formation Volume Factor (rb/stb) Minimum	Formation Volume Factor (rb/stb) Most Likely	Formation Volume Factor (rb/stb) Maximum
3	A	Mulden	0.05	0.07	0.10	0.50	0.30	0.10	1.50	1.40	1.30
3	A	Otavi-Huttenberg	0.07	0.09	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	A	Otavi-Elandshoek	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	B	Mulden	0.05	0.07	0.10	0.50	0.30	0.10	1.50	1.40	1.30
3	B	Otavi-Huttenberg	0.07	0.09	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	B	Otavi-Elandshoek	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	C	Mulden	0.05	0.07	0.10	0.50	0.30	0.10	1.50	1.40	1.30
3	C	Otavi-Huttenberg	0.07	0.09	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	C	Otavi-Elandshoek	0.06	0.08	0.11	0.50	0.30	0.10	1.50	1.40	1.30

Play Type	Sub-play	Target	Recovery Factor (Decimal) Minimum	Recovery Factor (Decimal) Most Likely	Recovery Factor (Decimal) Maximum	P_g[3] (Decimal)
3	A	Mulden	0.15	0.20	0.35	0.07 - 0.13
3	A	Otavi-Huttenberg	0.15	0.20	0.35	0.07 - 0.13
3	A	Otavi-Elandshoek	0.15	0.20	0.35	0.07 - 0.13
3	B	Mulden	0.15	0.20	0.35	0.07 - 0.13
3	B	Otavi-Huttenberg	0.15	0.20	0.35	0.07 - 0.13
3	B	Otavi-Elandshoek	0.15	0.20	0.35	0.07 - 0.13
3	C	Mulden	0.15	0.20	0.35	0.07
3	C	Otavi-Huttenberg	0.15	0.20	0.35	0.07 - 0.11
3	C	Otavi-Elandshoek	0.15	0.20	0.35	0.07 - 0.11

(1) The ranges in P95, P50, and P05 areas reflect the variety observed in the identified opportunities, which were assessed individually.

(2) The ranges in minimum, most likely, and maximum geometric factors reflect the variety observed in the identified opportunities, which were assessed individually.

(3) The ranges in P_g reflect the variety observed in the identified opportunities, which were assessed individually.

Summary of Selected Reservoir Parameters
Karoo Rift Play Area
As of December 31, 2024

Play Type	Sub-play	Target	Area[1] (acres) P95	Area[1] (acres) P50	Area[1] (acres) P05	Geometric Factor[2] (Decimal) Minimum	Geometric Factor[2] (Decimal) Most Likely	Geometric Factor[2] (Decimal) Maximum	Net Pay (m) Minimum	Net Pay (m) Most Likely	Net Pay (m) Maximum
1	A	Ecca	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20	50	100
1	A	Dwyka	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20 - 25	40 - 75	60 - 150
1	B	Ecca	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20	50	100
1	B	Dwyka	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20 - 25	40 - 75	60 - 150
2	A	Upper Mulden	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	5	20	40
2	A	Lower Mulden	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	100
2	A	Otavi	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	60
2	B	Upper Mulden	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	5	20	40
2	B	Lower Mulden	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	100
2	B	Otavi	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	60

Play Type	Sub-play	Target	Porosity (Decimal) Minimum	Porosity (Decimal) Most Likely	Porosity (Decimal) Maximum	Water Saturation (Decimal) Minimum	Water Saturation (Decimal) Most Likely	Water Saturation (Decimal) Maximum	Formation Volume Factor (rb/stb) Minimum	Formation Volume Factor (rb/stb) Most Likely	Formation Volume Factor (rb/stb) Maximum
1	A	Ecca	0.12	0.17	0.25	0.45	0.30	0.15	1.40	1.30	1.20
1	A	Dwyka	0.13	0.18	0.25	0.45	0.30	0.15	1.40	1.30	1.20
1	B	Ecca	0.10	0.15	0.20	0.45	0.30	0.15	1.40	1.30	1.20
1	B	Dwyka	0.11	0.16	0.20	0.45	0.30	0.15	1.40	1.30	1.20
2	A	Upper Mulden	0.06	0.12	0.18	0.50	0.35	0.25	1.50	1.40	1.30
2	A	Lower Mulden	0.06	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30
2	A	Otavi	0.05	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30
2	B	Upper Mulden	0.06	0.12	0.18	0.50	0.35	0.25	1.50	1.40	1.30
2	B	Lower Mulden	0.06	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30
2	B	Otavi	0.05	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30

Play Type	Sub-play	Target	Recovery Factor (Decimal) Minimum	Recovery Factor (Decimal) Most Likely	Recovery Factor (Decimal) Maximum	P_g[3] (Decimal)
1	A	Ecca	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
1	A	Dwyka	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
1	B	Ecca	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
1	B	Dwyka	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
2	A	Upper Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	A	Lower Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	A	Otavi	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	B	Upper Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	B	Lower Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	B	Otavi	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08

(1) The ranges in P95, P50, and P05 areas reflect the variety observed in the identified opportunities, which were assessed individually.
(2) The ranges in minimum, most likely, and maximum geometric factors reflect the variety observed in the identified opportunities, which were assessed individually.
(3) The ranges in P_g reflect the variety observed in the identified opportunities, which were assessed individually.

Summary of Best Estimate Prospective Light/Medium Crude Oil Resource
Damara Fold & Thrust Belt Play Area
As of December 31, 2024

			Undiscovered OOIP (MMbbl)		Unrisked Prospective Light/Medium Crude Oil Resources (MMbbl)			Risked Prospective Light/Medium Crude Oil Resources without P_d[1] (MMbbl)			Risked Prospective Light/Medium Crude Oil Resources (MMbbl)		
Subclass	Location	Alternate Name	Gross (100%)	Company Gross[2]	Gross (100%)	Company Gross[2]	P_g (Decimal)	Gross (100%)	Company Gross[2]	Oil P_d[3] (Decimal)	Gross (100%)	Company Gross[2]	Chance of Oil[4]
Prospects													
	5	MM	413.7	372.4	82.7	74.5	0.10	8.3	7.4	0.66	5.5	4.9	Moderate
	6	M	696.8	627.1	139.4	125.4	0.10	13.9	12.5	0.66	9.2	8.3	Moderate
	26	LL	369.7	332.8	73.9	66.6	0.09	6.7	6.1	0.66	4.4	4.0	Moderate
	27	J-K	317.6	285.8	63.5	57.2	0.07	4.3	3.8	0.63	2.7	2.4	Moderate
	31	H South	1,186.0	1,067.4	237.2	213.5	0.07	16.8	15.2	0.69	11.7	10.5	Moderate-High
	32	B	457.8	412.0	91.6	82.4	0.13	11.4	10.3	0.66	7.6	6.8	Moderate
	63	I	1,730.7	1,557.6	346.1	311.5	0.13	43.3	38.9	0.69	30.0	27.0	Moderate
	66	H North	1,514.6	1,363.2	302.9	272.6	0.10	30.3	27.3	0.69	21.0	18.9	Moderate-High
	67	Q South	358.6	322.7	71.7	64.5	0.07	5.1	4.6	0.66	3.4	3.0	Low-Moderate
	68	O-P	1,428.6	1,285.8	285.7	257.2	0.07	20.3	18.3	0.69	14.1	12.7	Moderate
	69	MMM	335.4	301.9	67.1	60.4	0.07	4.8	4.3	0.63	3.0	2.7	Moderate
	71	R/RR	266.5	239.8	53.3	48.0	0.11	5.9	5.3	0.59	3.5	3.2	Low-Moderate
	76	G	547.4	492.6	109.5	98.5	0.07	7.3	6.6	0.66	4.8	4.4	Moderate
	78	O	631.6	568.5	126.3	113.7	0.07	9.0	8.1	0.66	5.9	5.3	Moderate
	79	S	397.6	357.9	79.5	71.6	0.07	5.3	4.8	0.66	3.5	3.2	Low-Moderate
	81	Q	397.8	358.0	79.6	71.6	0.07	5.6	5.1	0.66	3.7	3.4	Low-Moderate
	89	F	936.0	842.4	187.2	168.5	0.08	15.5	14.0	0.69	10.8	9.7	Moderate-High
	102	T	844.0	759.6	168.8	151.9	0.10	16.9	15.2	0.69	11.7	10.5	Low-Moderate
Total Prospects			12,830.6	11,547.5	2,566.1	2,309.5		230.8	207.7		156.5	140.9	
Leads													
	29	-	176.1	158.5	35.2	31.7	0.08	2.9	2.6	0.46	1.4	1.2	Moderate
	64	-	177.5	159.8	35.5	32.0	0.07	2.5	2.2	0.46	1.1	1.0	Moderate
	88	-	123.6	111.2	24.7	22.2	0.07	1.7	1.5	0.33	0.5	0.5	Moderate
	101	-	138.7	124.9	27.7	25.0	0.10	2.8	2.5	0.40	1.1	1.0	Low-Moderate
Total Leads			616.0	554.4	123.2	110.9		9.8	8.9		4.1	3.7	

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 and lead levels are not reflective of volumes that can be expected to be recovered and are shown for convenience only.

(1) Risked prospective resources without P_d do not include risking for Chance of Development (P_d) and only include risking for Chance of Geologic Success (P_g).

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

(3) Oil P_d represents the chance of development assuming oil discovery.

(4) Each prospect has the possibility to discover oil or gas. Chance of oil is based on techincal data available at the time of the evaluation and represents the likelihood that if a discovery is made, the fluid type would be oil. Page A-3 in the appendix summarizes these volumes assuming gas discovery.

Summary of Best Estimate Prospective Light/Medium Crude Oil Resources
Karoo Rift Play Area
As of December 31, 2024

		Undiscovered OOIP (MMbbl)		Unrisked Prospective Light/Medium Crude Oil Resources (MMbbl)			Risked Prospective Light/Medium Crude Oil Resources without P_d[1] (MMbbl)			Risked Prospective Light/Medium Crude Oil Resources (MMbbl)	
Subclass	Location	Gross (100%)	Company Gross[2]	Gross (100%)	Company Gross[2]	Effective P_g (Decimal)	Gross (100%)	Company Gross[2]	P_d (Decimal)	Gross (100%)	Company Gross[2]
Prospects											
	15	1,354.2	1,218.8	270.8	243.8	0.09	25.7	23.1	0.66	17.0	15.3
	17	365.6	329.0	69.2	62.3	0.08	5.8	5.2	0.53	3.1	2.8
	30	152.0	136.8	25.8	23.2	0.06	1.7	1.5	0.56	0.9	0.8
	40	170.3	153.3	27.3	24.6	0.05	1.4	1.2	0.40	0.5	0.5
	47	159.3	143.4	28.0	25.2	0.07	2.0	1.8	0.17	0.3	0.3
	140	316.5	284.9	63.3	57.0	0.10	6.0	5.4	0.56	3.4	3.1
Total Prospects		2,518.0	2,266.2	484.5	436.1		42.5	38.3		25.2	22.7
Leads											
	1	191.5	172.3	38.3	34.5	0.06	2.2	2.0	0.30	0.7	0.6
	2	242.3	218.0	41.6	37.5	0.05	1.9	1.7	0.36	0.7	0.6
	3	205.1	184.6	30.8	27.7	0.04	1.1	1.0	0.33	0.4	0.3
	4	51.6	46.4	10.3	9.3	0.06	0.6	0.5	0.46	0.3	0.2
	9	161.7	145.6	25.6	23.0	0.04	1.1	1.0	0.30	0.3	0.3
	10	158.8	142.9	27.9	25.1	0.05	1.4	1.2	0.40	0.5	0.5
	11	130.2	117.2	22.2	19.9	0.05	1.1	1.0	0.53	0.6	0.5
	13	99.7	89.8	19.9	18.0	0.06	1.2	1.0	0.43	0.5	0.4
	14	196.1	176.5	35.4	31.8	0.05	1.8	1.6	0.20	0.4	0.3
	18	190.7	171.7	31.3	28.2	0.04	1.4	1.2	0.23	0.3	0.3
	19	213.0	191.7	42.6	38.3	0.06	2.5	2.2	0.36	0.9	0.8
	20	158.3	142.5	31.7	28.5	0.06	1.8	1.6	0.17	0.3	0.3
	21	370.6	333.5	74.1	66.7	0.06	4.3	3.8	0.59	2.5	2.3
	22A	869.4	782.4	173.9	156.5	0.06	10.0	9.0	0.66	6.6	5.9
	22B	563.1	506.8	112.6	101.4	0.06	6.5	5.8	0.63	4.1	3.6
	23	232.3	209.0	34.8	31.4	0.04	1.3	1.2	0.33	0.4	0.4
	24A	222.5	200.3	40.7	36.6	0.05	2.1	1.9	0.33	0.7	0.6
	24B	170.4	153.4	30.2	27.2	0.05	1.5	1.4	0.26	0.4	0.4
	33	28.8	25.9	5.8	5.2	0.06	0.3	0.3	0.23	0.1	0.1
	34	222.3	200.0	40.6	36.6	0.05	2.1	1.9	0.30	0.6	0.6
	35	86.4	77.8	17.3	15.6	0.06	1.0	0.9	0.40	0.4	0.4
	36	166.5	149.9	26.5	23.9	0.04	1.1	1.0	0.53	0.6	0.5
	50	148.4	133.5	22.9	20.6	0.04	0.9	0.9	0.46	0.4	0.4
	51	51.9	46.7	10.4	9.3	0.06	0.6	0.5	0.46	0.3	0.2
	52	222.0	199.8	40.6	36.5	0.05	2.1	1.9	0.36	0.8	0.7
	56	113.4	102.1	18.8	17.0	0.05	0.9	0.8	0.43	0.4	0.3
	57	109.6	98.7	18.0	16.2	0.05	0.8	0.7	0.36	0.3	0.3
	58	115.9	104.3	23.2	20.9	0.06	1.3	1.2	0.33	0.4	0.4
	60	116.4	104.8	23.3	21.0	0.06	1.3	1.2	0.33	0.4	0.4
	61	209.1	188.2	41.8	37.6	0.06	2.4	2.2	0.36	0.9	0.8
	103	207.8	187.0	33.5	30.1	0.04	1.4	1.3	0.36	0.5	0.5
	106	147.9	133.1	22.9	20.6	0.04	0.9	0.8	0.56	0.5	0.5
	113	131.8	118.6	22.4	20.2	0.05	1.1	1.0	0.53	0.6	0.5
	118	74.1	66.7	14.8	13.3	0.06	0.8	0.8	0.50	0.4	0.4
	119	128.4	115.5	21.9	19.7	0.05	1.0	0.9	0.53	0.6	0.5
	120	73.6	66.2	14.7	13.2	0.06	0.8	0.8	0.50	0.4	0.4
	125	113.9	102.5	22.8	20.5	0.06	1.3	1.2	0.43	0.6	0.5
	137	205.8	185.2	30.9	27.8	0.04	1.1	1.0	0.23	0.3	0.2
	138	192.6	173.4	31.8	28.6	0.04	1.4	1.3	0.23	0.3	0.3
	142	205.5	185.0	30.8	27.7	0.04	1.1	1.0	0.43	0.5	0.4
	146	705.6	635.0	141.1	127.0	0.06	8.1	7.3	0.66	5.4	4.8
	149	205.3	184.7	30.8	27.7	0.04	1.1	1.0	0.23	0.3	0.2
	150	147.1	132.4	22.7	20.4	0.04	0.9	0.8	0.46	0.4	0.4
	151	147.2	132.5	22.7	20.4	0.04	0.9	0.8	0.53	0.5	0.4
	152	147.1	132.4	25.6	23.0	0.05	1.3	1.1	0.46	0.6	0.5
Total Leads		8,851.7	7,966.5	1,602.5	1,442.3		82.0	73.8		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 and lead levels are not reflective of volumes that can be expected to be recovered and are shown for convienence only.

(1) Risked prospective resources without P_d do not include risking for Chance of Development (P_d) and only include risking for Chance of Geologic Success (P_g).

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