Form 51-101 F1

Decklar Resources Inc.

Statement of Reserves Data

And Other Oil and Gas Information

As of December 31, 2022

May 1, 2023

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LEGAL ADVISORIES

This Statement of Reserves Data contains forward-looking information within the meaning of applicable Canadian securities laws. Forward-looking information relates to future events or future performance and is based upon the Company's current internal expectations, estimates, projections, assumptions and beliefs. All information other than historical fact is forward-looking information. Information relating to "Reserves" is forward-looking as it involves the implied assessment, based on certain estimates and assumptions, that the Reserves exist in the quantities estimated and that they will be commercially viable to produce in the future. Words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words that convey certain events or conditions "may" or "will" occur are intended to identify forward-looking information. In particular, this Statement of Reserves Data contains forward-looking information, including among other places, under the headings "Pricing Assumptions", "Abandonment and Reclamation Costs", "Future Development Costs", "Tax Horizon", "Properties With No Attributed Reserves", "Exploration and Development Activities" and "Production Estimates". This forward-looking information includes but is not limited to, statements regarding: future net revenue; business strategy, plans and priorities; planned drilling, exploration and development activities; the quantity and development of Reserves; and other expectations, beliefs, plans, goals, objectives, assumptions, information and statements about possible future events, conditions, results of operations or performance.

The forward-looking information is based upon assumptions as to future commodity prices, currency exchange rates, inflation rates, well production rates, well drainage areas, success rates for future drilling and availability of labour and services. With respect to estimates of Reserves and resource volumes, a key assumption is the validity of the data used by McDaniel & Associates in their independent reserves evaluation and resource assessment. With respect to estimates of numbers of future wells to be drilled a key assumption is that geological and other technical interpretations performed by the Company's technical staff and consultants, which indicate that commercially economic Reserves can be recovered from the Company's oil and gas assets as a result of drilling such future wells, are valid.

Undue reliance should not be placed on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. As a consequence, actual results may differ materially from those anticipated.

Forward-looking information necessarily involves both known and unknown risks associated with oil and gas exploration, production, transportation and marketing such as uncertainty of geological and technical data, imprecision of Reserves and resources estimates, operational risks, environmental risks, loss of market demand, general economic conditions affecting ability to access sufficient capital, changes in governmental regulation of the oil and gas industry and competition from others for scarce resources.

The foregoing list of risk factors is not exhaustive. Additional information on these and other risk factors that could affect operations or financial results are included in the Company's filing statements and in other reports filed with Canadian securities regulatory authorities. Forward looking information is based on estimates and opinions of management at the time the information is presented. The Company is not under any duty to update the forward-looking information after the date of this Statement of Reserves Data to conform such information to actual results or to changes in the Company's plans or expectations, except as otherwise required by applicable securities laws.

ABBREVIATIONS

bbl	barrel
bopd	barrels of oil per day
Mbbl	thousands of barrels of oil
MMbbls	millions of barrels of oil
Mscf	thousand standard cubic feet
MMscf	million standard cubic feet
NGLs	natural gas liquids
$000	thousand US dollars

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

1 Date of Statement

This statement of Reserves Data is dated May 1st, 2023 and was prepared on April 24, 2023. The effective date of the information provided herein is December 31, 2022.

2 Disclosure of Reserves Data

Decklar Resources Inc., herein after referred to as "Decklar" or the "Company", has as of December 31, 2022 reserves relating entirely to the Company's participating interest in the Oza field and the Asaramatoru field (the "Fields"), its only oil and gas reserves properties, located in Nigeria. Decklar currently has Risk Service Agreements ("RSAs") with the owners of the Fields under which it funds near term development costs and receives a variable participating interest in the Fields.

For stating the Company's oil and gas reserves publicly, the Company retained the services of McDaniel & Associates Consultants Ltd. ("McDaniel"), who are independent qualified reserves evaluators appointed by the Company pursuant to NI 51-101, to conduct independent evaluations of all the Company's oil and gas properties. McDaniel has provided the Company with an evaluation (the "McDaniel Report") prepared in compliance with NI 51-101 in respect of the Company's oil and gas reserves as at December 31,2022.

The definitions of the various categories of reserves are those set out in NI 51-101 and in the Canadian Oil and Gas Evaluation Handbook ("COGEH"). The Company engaged McDaniel to provide an evaluation of the Company's proved, probable and possible reserves. The following are the definitions of proved, probable and possible reserves as set out in the COGEH:

> "**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.
>
> "**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves is the targeted level of certainty.
>
> "**possible reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. At least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves is the targeted level of certainty.

It should not be assumed that the present worth of estimated future net revenue represents the fair market value of the reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Report will be attained and variances could be material. The reserves and revenue estimates set forth below are estimates only and the actual reserves and realized revenue may be greater or less than those calculated.

Unless otherwise stated herein all currency amounts indicated as "$" in this Statement of Reserves Data are expressed in thousands of United States dollars ("USD").

The following table discloses, in the aggregate, the Company's gross and net proved, probable and possible reserves, estimated using forecast prices and costs, by product type.

SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2022
(Forecast Prices & Costs)

	Decklar's Interest in Reserves(1)(2)(3)							
	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMscf)		Natural Gas Liquids (Mbbl)	
	Gross(4)	Net(5)	Gross(4)	Net(5)	Gross(4)	Net(5)	Gross(4)	Net(5)
Nigeria								
Proved developed producing	1,332	1,260	–	–	–	–	–	–
Proved developed non–producing	1,102	1,047	–	–	–	–	–	–
Proved undeveloped	3,113	2,950	–	–	–	–	–	–
Total proved reserves	**5,547**	**5,257**	**–**	**–**	**–**	**–**	**–**	**–**
Probable......................................	4,841	4,574	–	–	–	–	–	–
Total Proved Plus Probable Reserves	**10,388**	**9,832**	**–**	**–**	**–**	**–**	**–**	**–**
Possible..	5,144	4,793	–	–	–	–	–	–
Total Proved Plus Probable Plus Possible Reserves	**15,533**	**14,625**	**–**	**–**	**–**	**–**	**–**	**–**
Total								
Proved developed producing	1,332	1,260	–	–	–	–	–	–
Proved developed non–producing	1,102	1,047	–	–	–	–	–	–
Proved undeveloped	3,113	2,950	–	–	–	–	–	–
Total proved reserves	**5,547**	**5,257**	**–**	**–**	**–**	**–**	**–**	**–**
Probable......................................	4,841	4,574	–	–	–	–	–	–
Total Proved Plus Probable Reserves	**10,388**	**9,832**	**–**	**–**	**–**	**–**	**–**	**–**
Possible..	5,144	4,793	–	–	–	–	–	–
Total Proved Plus Probable Plus Possible Reserves	**15,533**	**14,625**	**–**	**–**	**–**	**–**	**–**	**–**

Notes:

(1) Totals may not add due to rounding.
(2) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101 and COGEH.
(3) Fluid type is classified according to COGEH defined criteria, with 100% of reserves in the Fields being Light and Medium Oil
(4) "Gross" reserves refer to Decklar's participating interest share of the property gross reserves before deducting royalties owed to the government or third parties and before deducting income taxes or their equivalent.
(5) "Net" reserves refer to Decklar's participating interest share of the property gross reserves after deducting royalties owed to the government or third parties but before deducting income taxes or their equivalent.

The following table discloses, by country and in the aggregate, the net present value of the Decklar's future net revenue attributable to the reserves categories in the previous table, estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

NET PRESENT VALUE OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2022
(Forecast Prices & Costs)

	Net Present Values of Future Net Revenue[1][2][3][4][5][6]										Unit Value[7] before Income Tax Discounted at
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)					
Reserves Category	0	5	10	15	20	0	5	10	15	20	10%/year
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$/bbl
Nigeria											
Proved developed producing .	45,384	40,477	36,551	33,352	30,706	45,384	40,477	36,551	33,352	30,706	29.01
Proved developed non-producing	21,265	18,038	15,539	13,564	11,976	21,265	18,038	15,539	13,564	11,976	14.84
Proved undeveloped	61,880	46,315	35,195	27,031	20,894	61,880	46,315	35,195	27,031	20,894	11.93
Total Proved Reserves	**128,529**	**104,830**	**87,284**	**73,948**	**63,576**	**128,529**	**104,830**	**87,284**	**73,948**	**63,576**	**16.60**
Probable	91,844	65,281	48,342	36,903	28,830	91,844	65,281	48,342	36,903	28,830	10.57
Total Proved Plus Probable Reserves	**220,373**	**170,111**	**135,626**	**110,851**	**92,406**	**220,373**	**170,111**	**135,626**	**110,851**	**92,406**	**13.79**
Possible..................................	105,240	71,299	51,695	39,530	31,501	105,240	71,299	51,695	39,530	31,501	10.78
Total Proved Plus Probable Plus Possible Reserves	**325,613**	**241,410**	**187,321**	**150,381**	**123,907**	**325,613**	**241,410**	**187,321**	**150,381**	**123,907**	**12.81**
Total											
Proved developed producing	45,384	40,477	36,551	33,352	30,706	45,384	40,477	36,551	33,352	30,706	29.01
Proved developed non-producing	21,265	18,038	15,539	13,564	11,976	21,265	18,038	15,539	13,564	11,976	14.84
Proved undeveloped	61,880	46,315	35,195	27,031	20,894	61,880	46,315	35,195	27,031	20,894	11.93
Total Proved Reserves	**128,529**	**104,830**	**87,284**	**73,948**	**63,576**	**128,529**	**104,830**	**87,284**	**73,948**	**63,576**	**16.60**
Probable	91,844	65,281	48,342	36,903	28,830	91,844	65,281	48,342	36,903	28,830	10.57
Total Proved Plus Probable Reserves	**220,373**	**170,111**	**135,626**	**110,851**	**92,406**	**220,373**	**170,111**	**135,626**	**110,851**	**92,406**	**13.79**
Possible..................................	105,240	71,299	51,695	39,530	31,501	105,240	71,299	51,695	39,530	31,501	10.78
Total Proved Plus Probable Plus Possible Reserves	**325,613**	**241,410**	**187,321**	**150,381**	**123,907**	**325,613**	**241,410**	**187,321**	**150,381**	**123,907**	**12.81**

Notes:

(1) Totals may not add due to rounding.
(2) The definitions of the various categories of reserves and expenditures are those set out in NI 51-101.
(3) Based on forecast prices and costs at January 1, 2023.
(4) Interest expenses and corporate overhead, etc. were not included.
(5) The net present values may not necessarily represent the fair market value of the reserves.
(6) The field operator pays income taxes on behalf of the joint venture prior to Decklar's participating interest allocation of net revenue, therefore the before and after-tax values are identical.
(7) Unit values are calculated using estimated net present value of future net revenue before income taxes using a discount rate of 10% and the Company net reserves.

The following table discloses, by country and in the aggregate, certain elements of the Company's future net revenue attributable to proved reserves, proved plus probable reserves and proved plus probable plus possible reserves, estimated using forecast prices and costs, and calculated without discount.

TOTAL FUTURE NET REVENUE
AS OF DECEMBER 31, 2022
(Undiscounted)

Reserves Category	Revenue[1]	Royalties[2]	Other Expenses[3]	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes[4]	Income Taxes	Future Net Revenue after Income Taxes
	$000	$000	$000	$000	$000	$000	$000	$000	$000
Nigeria									
Total Proved Reserves	541,213	34,824	15,343	215,222	143,550	3,745	128,529	-	128,529
Total Proved Plus Probable Reserves	930,117	67,883	27,035	376,323	234,427	4,077	220,373	-	220,373
Total Proved Plus Probable Plus Possible Reserves	1,314,994	113,470	40,614	575,776	255,443	4,077	325,613	-	325,613
Total									
Total Proved Reserves	541,213	34,824	15,343	215,222	143,550	3,745	128,529	-	128,529
Total Proved Plus Probable Reserves	930,117	67,883	27,035	376,323	234,427	4,077	220,373	-	220,373
Total Proved Plus Probable Plus Possible Reserves	1,314,994	113,470	40,614	575,776	255,443	4,077	325,613	-	325,613

Notes:

(1) Totals may not add or subtract due to rounding.

(2) Royalties include government and overriding royalties

(3) Other Expenses include oil levies such as Niger Delta Development Fund and Education Tax

(4) The field operator pays income taxes on behalf of the joint venture prior to Decklar's participating interest allocation of net revenue, therefore the before and after-tax values are identical.

The following table discloses, by production group, the net present value and the unit value of the Company's future net revenue attributable to its proved reserves, its proved plus probable reserves and its proved plus probable plus possible reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

NET PRESENT VALUE OF FUTURE NET REVENUE

Reserves Category	Production Group	Future Net Revenue before Income Taxes (Discounted at 10%/Year)	Unit Value[1]
		$000	($/bbl)
Proved Reserves...	Light and Medium Crude Oil	87,284.3	16.60
	Heavy Oil	-	-
	Conventional Natural Gas	-	-
	Natural Gas Liquids	-	-
	Total	**87,284.3**	**16.60**
Proved Plus Probable Reserves........................	Light and Medium Crude Oil	135,626.0	13.79
	Heavy Oil	-	-
	Conventional Natural Gas	-	-
	Natural Gas Liquids	-	-
	Total	**135,626.0**	**13.79**
Proved Plus Probable Plus Possible Reserves..	Light and Medium Crude Oil	187,321.5	12.81
	Heavy Oil	-	-
	Conventional Natural Gas	-	-
	Natural Gas Liquids	-	-
	Total	**187,321.5**	**12.81**

Notes:

(1) Unit values are calculated using estimated net present value of future net revenue before income taxes using a discount rate of 10% and the Company net reserves. Unit values are presented on a $/bbl basis for crude oil reserves.

3 Pricing Assumptions

The following table sets forth the benchmark reference prices as at December 31, 2022, provided by McDaniel which were McDaniel's then current forecast prices at the effective date of the McDaniel Report. Crude sales to a local refinery onshore Nigeria were at an effective fixed price of $70/bbl[1], however the buyer also covered the costs of logistics for delivery. Crude sales to local refineries are ongoing and assumed to be renewed annually for the purposes of the reserves valuations and projections at 230 Mbbl per annum. 86% of these local refinery deliveries are assumed to be at the fixed price of US$70/bbl, and the balance be at the Sales Oil Price in the table below. These terms are consistent with Decklar's existing contracts. Crude sales above the local deliveries at 230 Mbbl will be sold internationally at the Sales Oil Price. There is no obligation on Decklar's part to renew the local contracts, nor is there a domestic supply obligation for crude oil production in Nigeria.

Year	Brent Crude Oil Price(1)	Price differential(2) (Nigeria)	Sales Oil Price(2) (Nigeria)	Inflation Rates
	($/bbl)	($/bbl)	($/bbl)	(%/Year)
2023	84.00	1.00	83.00	2.00
2024	80.58	1.00	79.58	2.00
2025	79.59	1.00	78.59	2.00
2026	78.53	1.00	77.53	2.00
2027	80.10	1.00	79.10	2.00
2028	81.70	1.00	80.70	2.00
2029	83.34	1.00	82.34	2.00
2030	85.00	1.00	84.00	2.00
2031	86.70	1.00	85.70	2.00
Inflation after 2032	2%	2%	2%	2.00

Notes:

(1) Brent price forecast based on the McDaniel January 1, 2023 price forecast.

(2) The price differential adjusts for quality differential, and marketing fees.

[1] A certain proportion of local refinery deliveries are paid for in Naira. These have been converted for reporting purposes at 450 Naira/USD.

4 Reconciliations of Changes in Reserves

The following table provides a reconciliation of Decklar's gross reserves between December 31, 2021 to December 31, 2022 based on forecast prices and costs.

Nigeria (and Total)	Light and Medium Oil (Mbbl)			Heavy Oil (Mbbl)			Conventional Natural Gas (MMscf)		
	Gross Proved	Gross Probable	Total Gross Proved plus Probable	Gross Proved	Gross Probable	Total Gross Proved plus Probable	Gross Proved	Gross Probable	Total Gross Proved plus Probable
Opening balance[(1)(2)] December 31, 2021	4,794	9,069	14,477	-	-	-	-	-	-
Plus:									
Extensions & Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	768	1,334	1,070	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Less:									
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Production	(14)	(14)	(14)	-	-	-	-	-	-
Ending balance – December 31, 2022	5,548	10,389	15,533	-	-	-	-	-	-

Notes:
(1) Gross reserves are based on the Company’s participating interest.
(2) Reserves reconciliation for year ended December 31, 2022 was based on forecast prices and costs.

5 Additional Information Relating to Reserves Data

5.1 Undeveloped Reserves

The following table summarizes the volumes of Decklar's proved undeveloped reserves and probable undeveloped reserves that were first attributed in each of Decklar's most recent three financial years and before that time, in the aggregate.

SUMMARY OF COMPANY UNDEVELOPED RESERVES
(Forecast Prices & Costs)

	Light/Medium Oil		Heavy Oil		Conventional Natural Gas	
Proved Undeveloped	First Attributed (Mbbl)	Booked (Mbbl)	First Attributed (Mbbl)	Booked (Mbbl)	First Attributed (MMscf)	Booked (MMscf)
Prior to 2017	–	–	–	–	–	–
2018	–	–	–	–	–	–
2019	–	–	–	–	–	–
2020	483	483	–	–	–	–
2021	1,832	2,315	–	–	–	–
2022	–	3,113	–	–	–	–

Probable Undeveloped	First Attributed (Mbbl)	Booked (Mbbl)	First Attributed (Mbbl)	Booked (Mbbl)	First Attributed (MMscf)	Booked (MMscf)
Prior to 2017	–	–	–	–	–	–
2018	–	–	–	–	–	–
2019	–	–	–	–	–	–
2020	294	294	–	–	–	–
2021	1,770	2,064	–	–	–	–
2022	–	2,717	–	–	–	–

The following discussion generally describes the basis on which Decklar attributes proved and probable undeveloped reserves and its future plans for developing such reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations and meeting the confidence criteria for the Proved Reserves category, where a significant capital expenditure (such as the cost of drilling a well) is required to render them capable of production.

Probable Undeveloped Reserves

Probable undeveloped reserves are those additional reserves (not included in the Proved category) expected to be recovered from known accumulations and meeting the confidence criteria for the Probable Reserves category, where a significant capital expenditure (such as the cost of drilling a well) is required to render them capable of production.

The Company expects that all the undeveloped Proved and Probable reserves will be developed within a four-year timeframe, consistent with the development program represented in the McDaniel Report.

5.2 Significant Factors or Uncertainties

McDaniel conducted its independent reserves evaluation on Decklar's reserves as at December 31, 2022. The process of establishing reserves requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

As circumstances change and additional data become available, reserves estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserves estimates are accurate, reserves estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserves estimates can arise from changes in year-end oil and gas prices, and reservoir performance.

The reserve estimates of Decklar's oil, NGL and natural gas reserves provided in this Statement of Reserves Data and Other Oil and Gas Information are estimates only and there is no assurance or guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than the estimates provided herein and such variances could be material.

5.3 Future Development Costs

The following table provides information regarding the development costs deducted in the estimation of future net revenue attributable to the Decklar's reserves.

FUTURE DEVELOPMENT COSTS (UNDISCOUNTED)(1)

	Proved Reserves	Proved Plus Probable Reserves	Proved Plus Probable Plus Possible Reserves
	$'000s	$'000s	$'000s
Nigeria (and Total)			
2023	53,300.0	53,300.0	53,300.0
2024	76,704.0	97,104.0	97,104.0
2025	12,484.8	71,267.4	81,671.4
2026	1,061.2	11,673.3	22,285.4
2027	-	1,082.4	1,082.4
Thereafter	-	-	-
Total Future Development Costs	**143,550.0**	**234,427.1**	**255,443.2**

Note:

(1) Future Development Costs shown are associated with booked reserves in the McDaniel Report and do not necessarily represent the Company's full exploration and development budget.

6 Other Oil and Gas Information

The following is a summary of Decklar's participating interest in Nigerian properties with proved, probable and possible reserves as at the most recently completed financial year.

6.1 Oil and Gas Properties and Wells

6.1.1 Oza Field

The Oza Field is an onshore conventional oil field, on dry terrain, in the northwestern part of Oil Mining Lease ("OML") 11, approximately 30 kilometres southwest of Port Harcourt which is part of the Abia State in Nigeria. The field was formerly operated by Shell Petroleum Development Company of Nigeria Ltd. ("Shell"), the local subsidiary of Royal Dutch Shell PLC.

The Oza Field's 20 square kilometre concession was carved out of OML 11 in 2003 as part of the Government's Marginal Field Development Program and was awarded to Millenium Oil and Gas Company Limited ("Millenium") having won the bid during the 2003 Marginal Fields Licensing Round. Millenium is the operator and now holds 60% of the Oza Field license, having farmed down 20% to Hardy Oil Nigeria Limited and 20% to Emerald Energy Resources Limited. Decklar is developing the field through a Risk Service Agreement ("RSA") with Millenium on behalf of the Oza Field Joint Venture ("JV") which was entered into in 2019. Under the RSA, Decklar provides technical and financial support to the JV and receives 80% of the Oza Field's gross production before payout, and after payout receives a sliding scale share of the field's gross production starting at 80% and reducing over several intermediate tiers to 40% after 10 million barrels of cumulative crude oil sales from the Oza Field since the RSA came into effect.

The Oza Field has three wells and one side track drilled by Shell between 1959 and 1974. During the period when Shell was the operator, there were two periods of extended production testing from the Oza-1, -2 & -4 wells. Well tests on two wells estimated 2,000 boe/d at 35°-43° API gravity crude oil. The oil-bearing sandstone reservoirs in the Oza Field are of the Agbada formation, consistent with regional oilfields in the Niger Delta. A 140 square kilometre 3D seismic survey covers the full area of the Oza Field and forms the basis for subsurface interpretation and field development planning.

Since Millenium's acquisition of the Oza Field, infrastructure has been installed including (i) an export pipeline to tie the Oza Field into the Trans Niger Pipeline ("TNP") operated by Shell which goes to the Bonny Export Terminal, (ii) a 6,000 bopd Early Production System ("EPF") suitable to process the oil water and gas from the Oza Field, (iii) a lease automatic custody transfer ("LACT") unit fiscal metering system, and (iv) infield flow-lines and manifolds. Millenium also conducted several flow tests of the existing wells which had produced between 500 - 1,200 boe/d on test.

The Oza-1 well was re-entered in 2021, with existing perforations cemented off and the shallower zones L2.2, L2.4, L2.6 perforated and tested. The L2.6 zone was set up for first production from the sliding sleeve completion, which had tested up to 2,463 bopd on 32/64 choke setting. Following the completion and clean-up of the zone, which resulted in 22,000 bbls of crude oil in storage at the field location pending export, the well was suspended. The well was tested over two intervals in 2022, producing an additional 14 Mbbls of crude oil.

Decklar intends to continue the initial development on the Oza Field by drilling up to 10 additional development wells These activities are anticipated to be carried out during 2023-2026.

6.1.1 Asaramatoru Field

On November 5, 2021, Decklar closed the Share Purchase Agreement ("SPA") to acquire all of the issued and outstanding ordinary shares in Purion Energy Limited (now renamed to Decklar Asaramatoru Resources Limited), a Nigerian entity that had entered into an RSA with Prime, the operator of the Asaramatoru Field. Through this acquisition, Decklar participates in the continued development of the oil resources in the Field.

The Asaramatoru Field, operated and owned 51% by Prime and owned 49% by Suffolk Petroleum Limited ("Suffolk"), is situated onshore in the southern swamp section of OML 11 in the Eastern Niger Delta area, which is one of the largest onshore oil producing blocks spanning the coastal swampy section in the south to dry land in the north. The Asaramatoru Field is situated in the vicinity of Andoni Local Government Area in mangrove forested terrain and is approximately 45 km S/SE of the oil city of Port Harcourt in Rivers State and approximately 40 km south of the Oza Field. The Bonny Oil Export Terminal and Bonny LNG plant are located approximately 15 km south of the Asaramatoru field.

The Asaramatoru Field was formerly operated by Shell Petroleum Development Company of Nigeria Limited ("SPDC"). SPDC discovered the oil field in 1973 with the drilling of the AST-1 well, which discovered 10 hydrocarbon bearing reservoirs. The AST-2 well was drilled by SPDC in 1989 and discovered additional oil reservoirs in a separate fault block. SPDC never placed the two wells on production and suspended both wells after the drilling and completion activities. Data available includes the wireline well logs, additional test data, and a 3D seismic survey conducted in 1996.

The Asaramatoru Field was awarded to Prime and Suffolk by the Federal Government of Nigeria in 2004 as part of the first Marginal Field Program. A subsidiary of Prime was appointed operator of the field.

Prime and Suffolk re-entered the existing two wells and commenced initial production testing activities in 2014. The wells produced an average of 2,700 barrels oil per day during intermittent production over three years, with the crude production being barged to an offshore facility for storage and export. The two wells have been shut in since late 2018 due to lower oil prices and logistics connected with barging and export activities, and limited storage facilities at the well locations.

Decklar next planned stages for development of the Asaramatoru Field include re-entering the existing wells in the field (AST-1 and AST-2) to reinstate production. It is then anticipated that up to 5 additional development wells will be drilled for full field development, and that production facilities, flow lines, and export facilities will be installed in phases as the field development progresses. The re-entry activities are anticipated to be completed in 2023, with further development drilling in 2024-2025.

SUMMARY OF PRODUCING AND NON-PRODUCING WELLS

	Light/Medium Oil (wells)	Heavy Oil (wells)	Conventional Natural Gas (wells)	Total
Nigeria (and Total)				
Gross Wells[1]				
Producing[3]	2.0	–	–	2.0
Non-producing[4]	3.0	–	–	3.0
Total Gross Wells	**5.0**	**–**	**–**	**5.0**
Net Wells[2]				
Producing[3]	1.6	–	–	1.6
Non-producing[4]	2.4	–	–	2.4
Total Net Wells	**4.0**	**–**	**–**	**4.0**

Notes:

(1) "Gross Wells" represent the number of wells in which the Company has a working-interest.

(2) "Net Wells" represent the number of wells obtained by aggregating the Company's working-interests in each of its Gross Wells.

(3) "Producing" includes wells presently producing and contributing revenue or wells presently producing that are expected to contribute revenue in the foreseeable future through the sale of presently produced oil.

(4) "Non-Producing" includes wells that are presently non-producing or wells presently producing but are not expected to contribute revenue in the foreseeable future through the sale of presently produced oil.

6.2 Properties With No Attributed Reserves

The only property with no attributable reserves is Decklar's interest in the Emohua Field, which has identified Contingent Resources. On June 6, 2022, the Company announced the acquisition of Westfield Exploration and Production Limited, which has since been renamed Decklar Emohua Resources Limited. Further details on the Emohua Field and Decklar's interest are available on the Company's website.

6.3 Forward Contracts

The Company has not entered into any forward contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

	Abandonment and Reclamation Costs	
Properties	Undiscounted $000	Discounted @ 10% $000
Oza Field	2,404	1,331
Asaramatoru Field	1,673	1,121
Total Properties	**4,077**	**2,452**

The table above shows the Company's participating interest share at December 31, 2022 of the estimated well and facilities abandonment and reclamation costs (not including any "credits" for equipment salvage). These estimates include costs associated with future development and facilities. Abandonment and reclamation costs have been estimated using industry practice and are in line with estimates in the operator's development plans.

6.5 Tax Horizon

The Company has no foreseeable material tax liabilities associated with its oil and gas operations.

6.6 Costs Incurred

The costs included in the following represent the Company's share of the total costs incurred.

Properties in Nigeria	Acquisition Costs[1] CAD $ millions	Exploration Costs CAD $ millions	Development Costs[2] CAD $ millions	Other Costs[3] CAD $ millions
Asaramatoru Field	7.5	-	-	1.2
Oza Field - capex	7.5	-	33.9	-
Emohua Field	17.9	-	-	-
TOTAL	32.9	-	33.9	1.2

Notes:

(1) The acquisition which resulted in Decklar interest in the Emohua Field was funded by the issuance of 6 million Decklar common shares which at the time of the acquisition had a nominated value of CAD $9.0 million, and provision of initial funding of CAD$8.8 million.

(2) Includes those costs of a capital project nature and therefore does not include field operating costs or crude evacuation costs.

(3) Other costs consist of general and administrative expenses of the oil mining license holder.

6.7 Exploration and Development Activities

Oza Field

The Oza-1 well was re-entered in 2021, with three new zones perforated and tested including the L2.2, L2.4, and L2.6 zones. The L2.6 produced at up to 2,463 bopd on 32/64 choke setting and is the first zone to be produced from the sliding sleeve completion. The L2.4 zone produced 10.3 MMscf/d of natural gas at 28/64 choke setting and L2.2 zone produced 1,371 bopd at 28/64 choke setting. The well is completed with a sliding sleeve single string setup, including gas lift mandrels for future artificial lift applications. The Oza-1 well was produced intermittently during 2022, with total crude production of 14 Mbbls during the period.

Asaramatoru Field

No development activities were undertaken in the Asaramatoru field in 2022.

6.8 Production Estimates

The forecast for 2023 is:

SUMMARY OF COMPANY GROSS PRODUCTION ESTIMATES(1)(2)
(Forecast Prices & Costs)

Nigeria (and Total)	Light and Medium Oil (Mbbl) Year 2023	Heavy Oil (Mbbl) Year 2023	Conventional Natural Gas (MMscf) Year 2023
Proved			
Asaramatoru Field	226	-	-
Oza Field	308	-	-
Total	**533**	-	-
Probable Additional		-	-
Asaramatoru Field	7		
Oza Field	27	-	-
Total	34	-	-
Possible Additional			
Asaramatoru Field	24		
Oza Field	23	-	-
Total	**47**	-	-

Notes:
(1) Estimates are calculated based on the McDaniel Report.
(2) Represents estimated production from January 1, 2023 to December 31, 2023

6.9 Production History

Oza Field

The original wells, Oza 1, Oza 2, and Oza 4 (a sidetrack of Oza 3) had originally produced 1 MMbbl of crude oil under the operatorship of Shell. Millenium, during the various extended well tests between 2013-2019, produced an additional 0.3 MMbbl of crude oil. Cumulative oil recovery totals 1.30 MMbbl of crude oil as at December 31, 2020.

During 2021, the Oza-1 well was recompleted and tested. Recovery from testing operations was 22 Mbbls in 2021 and 14 Mbbl in 2022. Production was intermittent during 2022 due to limited availability of field storage capacity and viable export solutions. Evacuation from the field commenced in 2022 with deliveries via trucking and pipeline solutions to the Forcados terminal, along with trucking deliveries to a local refinery in Nigeria.

The Oza Field has never been put on full commercial production, which Decklar plans to achieve during 2023.

Asaramatoru Field

The existing wells of Asaramatoru-1 and Asaramatoru-2 wells were drilled by Shell in 1973 and 1989 respectively. The field was not put on commercial production at that time. Following award to Prime (as operator) and Suffolk as a marginal field, the operator re-entered the existing two wells and commenced initial production testing activities in 2014. The wells produced an average of 2,700 barrels oil per day during intermittent production over three years, with the crude production being barged to an offshore facility for storage and export. The two wells have been shut in since late 2018 due to lower oil prices and logistics connected with barging and export activities, and limited storage facilities at the well locations.

Re-entry of the existing wells is planned for 2023, which will commence commercial production from the field.