Canacol Energy Ltd. Announces 2P Reserves and Deemed Volumes of 607 Bcfe Worth US$2.1B BTAX and 10 Year Reserve Life Index

CALGARY, ALBERTA - (March 21, 2024) - Canacol Energy Ltd. ("Canacol" or the "Corporation") (TSX:CNE; OTCQX:CNNEF; BVC:CNEC) is pleased to report its conventional natural gas, light, medium, and heavy crude oil reserves, and deemed volumes for the fiscal year end December 31, 2023. The Corporation's conventional natural gas reserves are located in the Lower Magdalena Valley basin, Colombia. Canacol has light and medium crude oil reserves located in the Middle Magdalena Valley basin, Colombia and light, medium, and heavy crude oil reserves and deemed volumes in the Llanos basin, Colombia.

Canacol Energy Ltd Gross Conventional Natural Gas, Light/Medium/Heavy Crude Oil Reserves and Deemed Volumes Summary(1)(5)

Product Type		**Proved Developed Producing *("PDP")***	**Proved Developed Not Producing *("PDNP")***	**Proved Undeveloped *("PUD")***	**Total Proved *("1P")***	**Total Proved + Probable *("2P")***	**Total Proved + Probable + Possible *("3P")***
Conventional natural gas and light/medium/heavy crude oil(4)	*Bcfe(2)*	**98.3**	**161.4**	**35.5**	**295.2**	**607.3**	**1,042.9**
Total oil equivalent	*MMBOE(2)*	17.2	28.3	6.2	51.8	106.6	183.0
Before tax NPV-10(3)	*MM US$*	$398.6	$657.0	$60.5	$1,116.1	$2,135.1	$3,200.8
After tax NPV-10(3)	*MM US$*	$398.5	$655.8	$60.5	$1,114.8	$1,763.5	$2,375.7

(1) *All reserves are represented at Canacol's working interest share before royalties.*
(2) *The term "BOE" means a barrel of oil equivalent and the term "cfe" means cubic feet equivalent of natural gas on the basis of 5.7 thousand standard cubic feet ("Mcf") of natural gas to 1 barrel of oil ("bbl") as per Colombian regulatory practice.*
(3) *Net Present Value (NPV) is stated in millions of USD and is discounted at 10 percent.*
(4) *Conventional light/medium/heavy crude oil includes deemed volumes of 100 mbbls PDP, 175 mbbls 1P, 238 mbbls 2P, and 343 mbbls 3P. Deemed volumes are derived from Rancho Hermoso volumes that are operated but not owned by Canacol where Canacol receives a tariff. They are calculated by multiplying the 100% sales volumes by the ratio of the tariff received divided by the sales price of the light/medium/heavy crude oil that Canacol receives a tariff for.*
(5) *The numbers in this table may not add due to rounding.*

Highlights

Conventional Natural Gas and Light/Medium/Heavy Crude Oil Proved + Probable Reserves and Deemed Volumes ("2P"):

- 2P before tax NPV-10 of US$2.1 billion at December 31 ,2023, a 10% increase over the prior year value of US$1.9 billion at December 31, 2022
- 2P after tax NPV-10 of US$1.8 billion at December 31, 2023, a 34% increase over the prior year value of US$1.3 billion at December 31, 2022. The significant increase in after tax 2P values is primarily impacted by the Corporation's restructuring in the fourth quarter of 2022, the results of which are first incorporated in this year's reserve report
- Decreased by 6.9% since December 31, 2022, totaling 607 billion standard cubic feet equivalent ("Bcfe") at December 31, 2023, with a before tax value discounted at 10% of US$2.1 billion, representing both CAD$82.62 per share of reserve value, and CAD$54.63 per share of 2P net asset value (net of US$723.5 million of net debt)
- Reserve replacement of 31% based on calendar 2023 conventional natural gas, light/medium/heavy crude oil reserve, and deemed volume additions of 15.9 Bcf, 0.5 MMBbls, and 0.2 MMBbls, respectively, totaling 20 Bcfe
- 2P Finding and Development Cost ("F&D") of US$3.17 / Mcf e for the three-year period ending December 31, 2023

- Recycle ratio of 0.4x for the year ended December 31, 2023 (calculated based on the natural gas netback of US$4.11 / Mcf for the year ended December 31, 2023)
- Recycle ratio of 1.2x for the three-year period ending December 31, 2023 (calculated based on the weighted average natural gas netback of US$3.73 / Mcf for the years ended December 31, 2023, 2022 and 2021)
- Reserves life index ("RLI") of 9.9 years based on annualized fourth quarter 2023 conventional natural gas production of 168,127 thousand standard cubic feet per day ("Mscfpd") or 29,496 barrels of oil equivalent per day ("BOEPD")
- RLI of 9.4 years based on conventional natural gas production guidance of 177,000 Mcfpd for calendar 2024 (high end 2024 production guidance as announced February 5, 2024)

Conventional Natural Gas and Light/Medium/Heavy Crude Oil Total Proved Reserves and Deemed Volumes ("1P"):

- Decreased by 13.0% since December 31, 2022, totaling 295 Bcfe at December 31, 2023, with a before tax value discounted at 10% of US$1.1 billion, representing both CAD$43.19 per share of reserve value, and CAD$15.19 per share of 1P net asset value (net of US$723.5 million of net debt)
- Reserve replacement of 32% based on calendar 2023 conventional natural gas, light/medium/heavy crude oil reserve, and deemed volume additions of 18.2 Bcf, 0.3 MMBbls, and 0.2 MMBbls, respectively, totaling 21 Bcfe
- 1P F&D of US$4.70 / Mcfe for the three-year period ending December 31, 2023
- RLI of 4.8 years based on annualized fourth quarter 2023 conventional natural gas production of 168,127 Mcfpd or 29,496 BOEPD
- RLI of 4.6 years based on conventional natural gas production guidance of 177,000 Mcfpd for calendar 2024 (high end 2024 production guidance as announced February 5, 2024)

Conventional Natural Gas and Light/Medium/Heavy Crude Oil Total Proved + Probable + Possible Reserves and Deemed Volumes ("3P"):

- Decreased by 4.2% since December 31, 2022, totaling 1,043 Bcfe at December 31, 2023, with a before tax value discounted at 10% of US$3.2 billion, representing both CAD$123.86 per share of reserve value, and CAD$95.86 per share of 3P net asset value (net of US$723.5 million of net debt)
- Reserve replacement of 31% based on calendar 2023 conventional natural gas, light/medium/heavy crude oil reserve, and deemed volume additions of 13.3 Bcf and 0.8 MMBbls, and 0.3 MMBbls, respectively, totaling 20 Bcfe
- 3P F&D of US$1.83 / Mcf for the three-year period ending December 31, 2023
- RLI of 17.0 years based on annualized fourth quarter 2023 conventional natural gas production of 168,127 Mcfpd or 29,496 BOEPD
- RLI of 16.1 years based on conventional natural gas production guidance of 177,000 Mcfpd for calendar 2024 (high end 2024 production guidance as announced February 5, 2024)

Ravi Sharma, COO said, "In 2023 we added 20 Bcfe of 2P reserves and deemed volumes, an increase of 3%, and added 21 Bcfe to the 1P reserve and deemed volumes for an increase of 6%. Our core fields, Clarinete, Nelson, Aguas Vivas and Pandereta continue to perform well and saw increases in 1P reserves. Our 2P increases were limited due to lack of exploration success at the near field Cereza and Piña Norte prospects, and our inability to get the Natilla exploration well drilled to the target interval due to technical difficulties drilling the well and the sidetrack. As our producing fields mature we are executing development programs to increase PDP reserves by converting PDNP and PUD reserves to PDP to maintain our productive capacity and production. Our recent 3D surveys have delineated and confirmed further prospectivity in VIM 5 and SSJN-7 that we will drill in 2024, 2025 and beyond to potentially add new production clusters and add to the over 900 BCF of 2P natural gas reserves the company has discovered since inception."

Discussion of Year Ended December 31, 2023 Reserves Report

During the year ended December 31, 2023, the Corporation recorded increases in certain reserve categories due to discoveries at Lulo on the VIM21 block, Piña Norte on the Esperanza block, and Pistacho on the VIM5 block. All aforementioned additions are in the Lower Magdalena Valley. Positive technical revisions were associated primarily with Clarinete, Pandereta, and Claxon on the VIM5 block, Chinu on the SSJN7 block due to a working interest consolidation to 100% from 50%, and Rancho Hermoso in the Llanos basin. Negative technical revisions were associated primarily with Fresa on the VIM21 block.

The following tables summarize information from the independent reserves report prepared by Boury Global Energy Consultants Ltd. ("BGEC") effective December 31, 2023 (the "BGEC 2023 report"). The BGEC 2023 report covers 100% of the Corporation's conventional natural gas and light/medium/heavy oil reserves and deemed volumes.

The BGEC 2023 report was prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument NI 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserve information as required under NI 51-101 is included in the Corporation's Annual Information Form, which will be filed on SEDAR by March 31, 2024.

Canacol Gross Natural Gas, Light/Medium/Heavy Crude Oil Reserves and Deemed Volumes for the Year Ended December 31, 2023[1]

Reserve Category[2]	31-Dec-22 (MMcfe)	31-Dec-23 (MMcfe)	Difference (%)
Total Proved (1P)	339,243	295,171	-13.0%
Total Proved + Probable (2P)	**652,466**	**607,343**	**-6.9%**
Total Proved + Probable + Possible (3P)	1,088,172	1,042,940	-4.2%

(1) *The numbers in this table may not add due to rounding.*
(2) *All reserves are Canacol working interest before royalties.*

5-Year Gas and Oil Price Forecasts – BGEC Report December 31, 2023[1]

		Reserve Report Date	2024	2025	2026	2027	2028
Volume weighted Total Proved + Probable (2P) average gas price[2]	*US$/Mcf*	31-Dec-23	6.86	6.47	6.56	7.90	7.69
Chimela Realized Oil Price- net of quality offset and transportation[3]	*US$/bbl*	31-Dec-23	61.82	63.82	64.82	66.32	69.32
Rancho Realized Oil Price- net of quality offset and transportation[4]	*US$/bbl*	31-Dec-23	72.50	74.50	76.50	78.50	80.50

(1) *The numbers in this table may not add due to rounding.*
(2) *The gas price forecast is based on existing long term contracts net of transportation (if applicable) and adjusted for inflation, along with interruptible gas sales pricing based on forecasts from S&P.*
(3) *The Chimela oil price forecast is based on BGEC's Brent forecast less US$16.18/bbl for quality offset and transportation costs.*
(4) *The Rancho Hermoso non-tariff oil price forecast is based on BGEC's WTI forecast less US$0.50/bbl for quality offset and transportation costs. Additionally, Canacol receives tariffs of $17.36/bbl for Mirador production (currently producing at RH10), $17.36/bbl escalated with inflation for RH11 and RH16 production ($20.32/bbl in January 2024), and a tariff between $14.50/bbl and $26.00/bbl that fluctuates with Brent pricing ($20.42/bbl in January 2024).*

Conventional Natural Gas, Light/Medium/Heavy Crude Oil Reserves, and Deemed Volumes Net Present Value Before & After Tax Summary(1)

	Before tax				After tax			
Reserve Category		**31-Dec-23 *(M US$)*[2]**		**Net Asset Value 31-Dec-23 *(C$/share)*[3]**		**31-Dec-23 *(M US$)*[2]**		**Net Asset Value 31-Dec-23 *(C$/share)*[3]**
Total Proved (1P)	$	1,116,092	$	15.19	$	1,114,821	$	15.14
Total Proved + Probable (2P)	**$**	**2,135,121**	**$**	**54.63**	**$**	**1,763,454**	**$**	**40.24**
Total Proved + Probable + Possible (3P)	$	3,200,751	$	95.86	$	2,375,662	$	63.94

(1) *The numbers in this table may not add due to rounding.*
(2) *Net present value is stated in thousands of USD and is discounted at 10 percent. The forecast prices used in the calculation of the present value of future net revenue are based on the price deck described above. The BGEC forecast for conventional natural gas, light/medium/heavy crude oil, and deemed volume prices at December 31, 2023 are included in the Corporation's Annual Information Form.*
(3) *Net asset value ("NAV") is calculated as at December 31, 2023 NPV10 less estimated net debt of US$723.5 million (being US$713.4 million of total debt plus working capital deficit of US$10 million) divided by 34.1 million basic shares outstanding as at December 31, 2023. NAV calculations are converted to $CAD at December 31, 2023 effective rate of USD:CAD =1.32.*

Reserve Life Index ("RLI")[1][2]

Reserve Category	31-Dec-22 (yrs)[3]	31-Dec-23 (yrs)[4]
Total Proved (1P)	5.2	4.8
Total Proved + Probable (2P)	**10.0**	**9.9**
Total Proved + Probable + Possible (3P)	16.8	17.0

(1) *The numbers in this table may not add due to rounding.*
(2) *"RLI" Reserve Life Index is calculated by dividing the applicable reserves category by the annualized fourth quarter production.*
(3) *Calculated using average 3 month ending December 31, 2022 natural gas production of 177,985 Mcfpd or 31,225 BOEpd annualized.*
(4) *Calculated using average 3 month ending December 31, 2023 natural gas production of 168,127 Mcfpd or 29,496 BOEpd annualized.*

Year Ended December 31, 2023 Canacol Gross Reserves and Deemed Volumes Reconciliation [1]

PROVED DEVELOPED PRODUCING	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2022)	-	-	-	161,633	-	28,357
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[2]	594	457	137	(7,193)	-	(668)
Discoveries[4]	-	-	-	5,646	-	991
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(12)	(12)	-	(65,089)	-	(11,407)
Closing Balance (December 31, 2023)	583	445	137	94,997	-	17,249

TOTAL PROVED	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2022)	1,023	1,023	-	333,412	-	59,516
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[3]	512	300	212	11,934	-	2,606
Discoveries[4]	-	-	-	6,232	-	1,093
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(12)	(12)	-	(65,089)	-	(11,431)
Closing Balance (December 31, 2023)	1,523	1,311	-	286,489	-	51,784

TOTAL PROVED + PROBABLE	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2022)	5,725	5,725	-	619,833	-	114,467
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions(3)	725	443	282	1,304	-	954
Discoveries(4)	-	-	-	14,598	-	2,561
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(12)	(12)	-	(65,089)	-	(11,431)
Closing Balance (December 31, 2023)	6,438	6,156	282	570,645	-	106,552

TOTAL PROVED + PROBABLE + POSSIBLE	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE
Opening Balance (December 31, 2022)	13,613	13,613	-	1,010,578	-	190,908
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions(3)	1,164	769	394	(12,955)	-	(1,109)
Discoveries(4)	-	-	-	26,243	-	4,604
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(12)	(12)	-	(65,089)	-	(11,431)
Closing Balance (December 31, 2023)	14,766	14,371	-	958,777	-	182,972

(1) *The numbers in this table may not add due to rounding.*
(2) *PDP technical revisions due to transfers to PDNP as certain wells in Nelson, Clarinete, and Alboka that were producing at December 31, 2022 were not producing and awaiting workovers to restart production at December 31, 2023.*
(3) *Conventional natural gas technical revisions in 1P through to 3P are associated primarily with Clarinete, Pandereta, Siku, San Marcos, Aguas Vivas, Chirimia, and Toronja.*
(4) *Conventional natural gas discoveries are associated with Lulo, Aguas Vivas, and Cornamusa on the VIM21 block, Piña Norte and San Marcos on the Esperanza block, and Pistacho and Pandereta on the VIM5 block.*

1P Reserves Metrics Reconciliation – Canacol Working Interest before Royalty[(1)(2)]

		Calendar 2023		Three-Year Ending December 31, 2023
Net Capital Expenditures (M$ US)[(3)]	$	202,923	$	446,614
Capital Expenditures - Change in FDC (M$ US)[(4)]	$	2,288	$	16,959
Total F&D (M$ US)[(5)]	$	205,211	$	463,573
Net Acquisitions (M$ US)		-		-
Total FD&A (M$ US)[(6)(7)]	$	205,211	$	463,573
Reserve Additions (MMcfe)		21,084		98,623
Reserve Additions – Net Acquisitions		-		-
Reserve Additions Including Net Acquisitions (MMcfe)		21,084		98,623
1P F&D per Mcfe (US$/Mcfe)[(5)]	**$**	**9.73**	**$**	**4.70**
1P FD&A per Mcfe (US$/Mcfe)[(6)(7)]	**$**	**9.73**	**$**	**4.70**

(1) *The numbers in this table may not add due to rounding.*
(2) *All values in this table are stated on a 1P (Total Proved) basis.*
(3) *The Corporation excludes investments on the Medellin pipeline from the F&D calculations. 2023, 2022 and 2021 capital expenditures exclude US$9 million, US$9.9 million and US$3.2 million related to expenditures on the Medellin pipeline, respectively. The Corporation also excludes expenditures on corporate assets from the F&D calculations. 2023, 2022 and 2021 capital expenditures exclude US$3.3 million, US$5 million and US$3 million related to expenditures on corporate assets.*
(4) *"Capital Expenditures – change in FDC" is rounded. FDC is the 1P (Total Proved) future development capital.*
(5) *1P F&D – Finding and Development Costs on a 1P (Total Proved) basis.*
(6) *1P FD&A - Finding, Development and Acquisition Costs on a 1P (Total Proved) basis.*
(7) *With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.*

2P Reserves Metrics Reconciliation – Canacol Working Interest before Royalty[(1)(2)]

		Calendar 2023		Three-Year Ending December 31, 2023
Net Capital Expenditures (M$ US)[(3)]	$	202,923	$	446,614
Capital Expenditures - Change in FDC (M$ US)[(4)]	$	10,828	$	86,508
Total F&D (M$ US)[(5)]	$	213,751	$	533,122
Net Acquisitions (M$ US)		-		-
Total FD&A (M$ US)[(6)(7)]	$	213,751	$	533,122
Reserve Additions (MMcfe)		20,035		168,340
Reserve Additions – Net Acquisitions		-		-
Reserve Additions Including Net Acquisitions (MMcfe)		20,035		168,340
2P F&D per Mcf (US$/Mcfe)[(5)]	**$**	**10.67**	**$**	**3.17**
2P FD&A per Mcf (US$/Mcfe)[(6)(7)]	**$**	**10.67**	**$**	**3.17**

(1) *The numbers in this table may not add due to rounding.*
(2) *All values in this table are stated on a 2P (Total Proved + Probable) basis.*
(3) *The Corporation excludes investments on the Medellin pipeline from the F&D calculations. 2023, 2022 and 2021 capital expenditures exclude US$9 million, US$9.9 million and US$3.2 million related to expenditures on the Medellin pipeline, respectively. The Corporation also excludes expenditures on corporate assets from the F&D calculations. 2023, 2022 and 2021 capital expenditures exclude US$3.3 million, US$5 million and US$3 million related to expenditures on corporate assets.*
(4) *"Capital Expenditures – change in FDC" is rounded. FDC is the 2P (Total Proved + Probable) future development capital.*
(5) *2P F&D – Finding and Development Costs on a 2P (Total Proved + Probable) basis.*
(6) *2P FD&A - Finding, Development and Acquisition Costs on a 2P (Total Proved + Probable) basis.*
(7) *With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.*

3P Natural Gas Reserves Metrics Reconciliation – Canacol Working Interest before Royalty[(1)(2)]

		Calendar 2023		Three-Year Ending December 31, 2023
Net Capital Expenditures (M$ US)[(3)]	$	202,923	$	446,614
Capital Expenditures - Change in FDC (M$ US)[(4)]	$	11,313	$	84,208
Total F&D (M$ US)[(5)]	$	214,236	$	530,822
Net Acquisitions (M$ US)		-		-
Total FD&A (M$ US)[(6)(7)]	$	214,236	$	530,822
Reserve Additions (MMcfe)		19,923		290,114
Reserve Additions – Net Acquisitions		-		-
Reserve Additions Including Net Acquisitions (MMcfe)		19,923		290,114
3P F&D per Mcf (US$/Mcfe)[(5)]	**$**	**10.75**	**$**	**1.83**
3P FD&A per Mcf (US$/Mcfe)[(6)(7)]	**$**	**10.75**	**$**	**1.83**

(1) *The numbers in this table may not add due to rounding.*
(2) *All values in this table are stated on a 3P (Total Proved + Probable + Possible) basis.*
(3) *The Corporation excludes investments on the Medellin pipeline from the F&D calculations. 2023, 2022 and 2021 capital expenditures exclude US$9 million, US$9.9 million and US$3.2 million related to expenditures on the Medellin pipeline, respectively. The Corporation also excludes expenditures on corporate assets from the F&D calculations. 2023, 2022 and 2021 capital expenditures exclude US$3.3 million, US$5 million and US$3 million related to expenditures on corporate assets.*
(4) *"Capital Expenditures – change in FDC" is rounded. FDC is the 3P (Total Proved + Probable + Possible) future development capital.*
(5) *3P F&D – Finding and Development Costs on a 3P (Total Proved + Probable + Possible) basis.*
(6) *3P FD&A - Finding, Development and Acquisition Costs on a 3P (Total Proved + Probable + Possible) basis.*
(7) *With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.*

The recovery and reserve and deemed volume estimates of conventional natural gas and light/medium/heavy crude oil are estimates only. There is no guarantee that the estimated reserves and deemed volumes will be recovered, and actual reserves of conventional natural gas and light/medium/heavy crude oil and deemed volumes may prove to be greater than, or less than, the estimates provided.

About Canacol

Canacol is a natural gas and oil exploration and production company with operations focused in Colombia. The Corporation's common stock trades on the Toronto Stock Exchange, the OTCQX in the United States of America, and the Colombia Stock Exchange under ticker symbol CNE, CNNEF, and CNE.C, respectively.

Forward-Looking Information and Statements

This press release contains certain forward-looking statements within the meaning of applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "project", "target", "intend", "believe", "anticipate", "estimate" and other similar words, or statements that certain events or conditions "may" or "will" occur, including without limitation statements relating to estimated production rates from the Corporation's properties and intended work programs and associated timelines. Forward-looking statements are based on the opinions and estimates of management at the date the statements are made and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. The Corporation cannot assure that actual results will be consistent with these forward looking statements. They are made as of the date hereof and are subject to change and the Corporation assumes no obligation to revise or update them to reflect new circumstances, except as required by law. Information and guidance provided herein supersedes and replaces any forward looking information provided in prior disclosures. Prospective investors should not place undue reliance on forward looking statements. These factors include the inherent risks involved in the exploration for and development of crude oil and natural gas properties, the uncertainties involved in interpreting drilling results and other geological and geophysical data, fluctuating energy prices, the possibility of cost overruns or unanticipated costs or delays and other uncertainties associated with the oil and gas industry. Other risk factors could include risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities, and other factors, many of which are beyond the control of the Corporation. Other risks are more fully described in the Corporation's most recent Management Discussion and Analysis ("MD&A") and Annual Information Form, which are incorporated herein by reference and are filed on SEDAR at www.sedar.com. Average production figures for a given period are derived using arithmetic averaging of fluctuating historical production data for the entire period indicated and, accordingly, do not represent a constant rate of production for such period and are not an indicator of future production performance. Detailed information in respect of monthly production in the fields operated by the Corporation in Colombia is provided by the Corporation to the Ministry of Mines and Energy of Colombia and is published by the Ministry on its website; a direct link to this information is provided on the Corporation's website.

***Use of Non-IFRS Financial Measures** - Such supplemental measures should not be considered as an alternative to, or more meaningful than, the measures as determined in accordance with IFRS as an indicator of the Corporation's performance, and such measures may not be comparable to that reported by other companies. This press release also provides information on adjusted funds from operations. Adjusted funds from operations is a measure not defined in IFRS. It represents cash (used) provided by operating activities before changes in non-cash working capital, settlement of a litigation settlement liability and decommissioning obligation expenditures. The Corporation considers funds from operations a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Adjusted funds from operations should not be considered as an alternative to, or more meaningful than, cash (used) provided by operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. The Corporation's determination of adjusted funds from operations may not be comparable to that reported by other companies. For more details on how the Corporation reconciles its cash provided by operating activities to adjusted funds from operations, please refer to the "Non-IFRS Measures" section of the Corporation's MD&A. Additionally, this press release references Adjusted EBITDAX and operating netback measures. Adjusted EBITDAX is defined as consolidated net income adjusted for interest, income taxes, depreciation, depletion, amortization, exploration expenses and other similar non-recurring or non-cash charges. Operating netback is a benchmark common in the oil and gas industry and is calculated as total natural gas, LNG and petroleum sales, net transportation expenses, less royalties and operating expenses, calculated on a per barrel of oil equivalent basis of sales volumes using a conversion. Operating netback is an important measure in evaluating operational performance as it demonstrates field level profitability relative to current commodity prices. Adjusted EBITDAX and operating netback as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.*

Operating netback is defined as revenues, net transportation expenses less royalties and operating expenses.

The reserves evaluation, effective December 31, 2023, was conducted by the Corporation's independent reserves evaluator Boury Global Energy Consultants Ltd. ("BGEC") and are in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities. The reserves are provided on a Canacol Gross basis in units of thousands of cubic feet ("MMcf") and thousands of barrels of oil equivalent ("MBOE") using a forecast price deck in US dollars. The estimated values may or may not represent the fair market value of the reserve estimates.

"Gross" in relation to the Corporation's interest in production or reserves is its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

"Net" in relation to the Corporation's interest in production or reserves is its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interest in production or reserves;

"Proved Developed Producing Reserves" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"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;

"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;

"Possible reserves" means 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;

"Deemed Volumes" refer to COGEH Section 3.9.4.8 – Assigning Reserves, and refer to the economic interest method which is used for Risked service contracts where, for volumes produced, the Corporation does not have a direct interest but represents reserves attributable to the Corporation. By definition, these volumes are calculated as the production revenue divided by the tariff price and are considered additive to volumes certified as reserves. Under the terms of this risked Service Agreement, these calculated volumes correspond to actual volumes produced.

BOE and CFE Conversions - "BOE" barrel of oil equivalent or "CFE" cubic feet of gas equivalent is derived by converting natural gas to oil or vice versa in the ratio of 5.7 Mcf of natural gas to one bbl of oil. A BOE or CFE conversion ratio of 5.7 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 5.7:1, utilizing a conversion on a 5.7:1 basis may be misleading as an indication of value. In this news release, the Corporation has expressed BOE using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Ministry of Mines and Energy of Colombia.

"PDP" means Proved Developed Producing
"1P" means Total Proved
"2P" means Total Proved + Probable
"3P" means Total Proved + Probable + Possible

PDP Reserves replacement ratio: Ratio of reserve additions to production, as reported in financial statements during the fiscal year ended December 31, excluding acquisitions and dispositions on a Proved Developed Producing basis.

1P Reserves replacement ratio: Ratio of reserve additions to production, as reported in financial statements during the fiscal year ended December 31, excluding acquisitions and dispositions on a Total Proved basis.

2P Reserves replacement ratio: Ratio of reserve additions to production, as reported in financial statements during the fiscal year ended December 31, excluding acquisitions and dispositions on a Total Proved + Probable basis.

Finding and development costs per thousand cubic feet (Mcf) represent exploration and development costs incurred per Mcf of Total Proved + Probable reserves added during the year. The Corporation, industry analysts, and investors use such metrics to measure a Corporation's ability to establish a long-term trend of adding reserves at a reasonable cost.

Finding, development and acquisition costs per thousand cubic feet (Mcf) represent property acquisition, exploration, and development costs incurred per Mcf of Total Proved + Probable reserves added during the year. The Corporation, industry analysts, and investors use such metrics to measure a Corporation's ability to establish a long-term trend of adding reserves at a reasonable cost.

With the finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Natural gas recycle ratio is calculated by dividing natural gas netback by finding and development costs.

"RLI" Reserve Life Index is calculated by dividing the applicable reserves category by the annualized fourth quarter production.

This press release contains a number of oil and gas metrics, including F&D, FD&A, reserve replacement and RLI, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Corporation's performance; however, such measures are not reliable indicators of the future performance of the Corporation and future performance may not compare to the performance in previous periods.

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