Canacol Energy Ltd. Reports a 10% Increase in Realized Contractual Natural Gas Sales Volumes, 24% Increase in Adjusted Funds from Operations and Net Income of $7 million in Q4 2021

CALGARY, ALBERTA - (March 17, 2022) - Canacol Energy Ltd. ("Canacol" or the "Corporation") (TSX:CNE; OTCQX:CNNEF; BVC:CNEC) is pleased to report its financial and operating results for the three months and year ended December 31, 2021, as well as its conventional natural gas reserves for the year ended December 31, 2021. Dollar amounts are expressed in United States dollars, with the exception of Canadian dollar unit prices ("C$") where indicated and otherwise noted.

Highlights for the three months and year ended December 31, 2021

- Realized contractual natural gas sales volumes increased 10% and 6% to 185.9 million standard cubic feet per day ("MMscfpd") and 181.4 MMscfpd for the three months and year ended December 31, 2021, compared to 169.8 MMscfpd and 171.6 MMscfpd for the same periods in 2020, respectively. Average natural gas production volumes increased 9% and 7% to 186.1 MMscfpd and 182.8 MMscfpd for the three months and year ended December 31, 2021, compared to 170.1 MMscfpd and 171.1 MMscfpd for the same periods in 2020, respectively. The increases are mainly due to increased firm contract and spot market sales as a result of less COVID-19 pandemic restrictions.
- Total natural gas revenues, net of royalties and transportation expenses increased 10% and 1% to $67 million and $243.4 million for the three months and year ended December 31, 2021, compared to $60.9 million and $240.3 million for the same periods in 2020, respectively, mainly attributable to an increase in natural gas production.
- Adjusted funds from operations increased 24% and 6% to $43.7 million and $153.8 million for the three months and year ended December 31, 2021, compared to $35.3 million and $145.1 million for the same periods in 2020, respectively. Adjusted funds from operations per basic share increased 25% and 7% to $0.25 per basic share and $0.86 per basic share for the three months and year ended December 31, 2021, compared to $0.20 per basic share and $0.80 per basic share for the same periods in 2020, respectively.
- Adjusted EBITDAX increased 7% and 4% to $49.2 million and $194.4 million for the three months and year ended December 31, 2021, compared to $45.9 million and $187.5 million for the same periods in 2020, respectively.
- The Corporation realized a net income of $7 million and $15.2 million for the three months and year ended December 31, 2021, compared to a net income of $0.9 million and a net loss of $4.7 million for the same periods in 2020, respectively. The net income realized during the three months and year ended December 31, 2021 was mainly due to a lower deferred tax expense of $10.7 million and $37.4 million realized during the three months and year ended December 31, 2021, respectively, which was mainly as a result of the de-recognition of certain deferred tax assets for non-capital losses in Q4 2020. In addition, there were increased revenues, net of transportation expenses in 2021 due to higher sales volumes.
- The Corporation's natural gas operating netback slightly increased to $3.59 per Mcf in the three months ended December 31, 2021, compared to $3.58 per Mcf for the same period in 2020. The increase is mainly due to a decrease in royalties by 8% to $0.67 per Mcf in the three months ended December 31, 2021, compared to $0.73 per Mcf for the same period in 2020. The decrease of royalties was due to lower production at the

Corporation's VIM-5 block, which is subject to a higher royalty rate. The lower royalties were offset by higher operating expenses per Mcf of 9% to $0.35 per Mcf during the three months ended December 31, 2021, compared to $0.32 per Mcf for the same period in 2020, mainly due to an increase in maintenance costs.

- The Corporation's natural gas operating netback decreased 5% to $3.40 per Mcf in the year ended December 31, 2021, compared to $3.57 per Mcf for the same period in 2020. The decrease is mainly due to the lower average realized prices, net of transportation expense due to lower priced fixed contracts for the 2021 contract year, compared to the 2020 contract year. In addition, the Corporation's operating expenses per Mcf increased 4% to $0.28 per Mcf in the year ended December 31, 2021, compared to $0.27 per Mcf for the same period in 2020.
- Net capital expenditures for the three months and year ended December 31, 2021 were $21.6 million and $99.9 million, respectively. Net capital expenditures included non-cash adjustments related mainly to decommissioning obligations and right-of-use leased assets of $1.5 million and $2.9 million for the three months and year ended December 31, 2021, respectively.
- On June 17, 2021, the Corporation entered into a three year term credit agreement with Banco Davivienda ("Colombia Bank Debt") for a principal amount of $12.9 million denominated in COP, which is subject to an annual interest rate of IBR plus 2.5% (IBR was 1.86% at the agreement date). The Colombia Bank Debt was used to repay the Corporation's litigation settlement liability, which was subject to an 8.74% annual interest rate. The principal is scheduled to mature three years from the agreement date.
- On November 24, 2021, the Corporation completed a private offering of senior unsecured notes in the aggregate principal amount of $500 million ("2028 Senior Notes"). The 2028 Senior Notes will pay interest semi-annually at a rate of 5.75% per annum, and will mature in 2028, unless earlier redeemed or repurchased in accordance with their terms. In connection with the 2028 Senior Notes offering, the Corporation entered into a tender offer with Credit Suisse Securities (USA) LLC ("Purchaser") to purchase any and all of the outstanding $320 million Senior Notes due in 2025 ("Tender Offer"), which were subject to a 7.25% interest rate ("2025 Senior Notes"). The Corporation used the $500 million proceeds to repay its Credit Suisse Bank Debt of $30 million and refinance its 2025 Senior Notes of $320 million.
- As at December 31, 2021, the Corporation had $138.5 million in cash and cash equivalents and $148.1 million in working capital surplus. The increase in cash and cash equivalents was mainly due to the refinancing of the Corporation's Senior Notes with an incremental principal amount of $180 million. The Senior Notes interest rate was reduced from 7.25% to 5.75% per annum.

Sustainability

Canacol continues to be committed to strengthening its environmental, social and governance ("ESG") strategy. Canacol enthusiastically supports global goals to meet the Paris Agreement targets as well as Colombia's commitment to a 51% reduction in emissions by 2030, of which natural gas will play a crucial role in a fair and equitable energy transition. The Corporation's purpose with regards ESG matters is to improve the quality of life of millions of people through the exploration, production and supply of conventional natural gas in Colombia. Alongside this, the Corporation's objective is to generate value for its stakeholders in a sustainable, collaborative, co-responsible, respectful and transparent way. With the Corporation's transition to natural gas, it now has an environmentally friendly value proposition that contributes to the reduction of CO2 emissions in Colombia and provides for a more efficient use of resources.

The Corporation continues to support its communities in essential social projects such as access to water and utilities, productive projects, construction and improvement of public and community infrastructure, technical and university scholarships amongst others.

The Corporation has strong corporate governance standards and procedures, which are aligned with best global practices and trends, and uses control mechanisms that protect shareholder's interests, respect and promote human rights, guarantee ethical behavior and integrity and ensure regulatory compliance.

In 2021, the Corporation made substantial improvements not only in the many ESG aspects related to its business but also in the way it manages and reports sustainability to its stakeholders. For 2022 and beyond, the Corporation is committed to continue developing and maintaining a robust ESG strategy and, as such, is implementing a six-year plan with the following four priorities:

1. A cleaner energy future - deliver natural gas under the highest environmental and operational efficiency standards.
2. A safe and committed team - maintain best-in-class health and safety practices and promote a diverse and inclusive culture.
3. A transparent and ethical business - adopt the best practices, encourage respect for human rights and ensure ethics and integrity in everything Canacol does.
4. A society guided by sustainable development - promote and maintain close and transparent relationships that guarantee communities' growth and quality of life.

During the first half of 2022, the Corporation plans to announce its short- and medium-term carbon emission reduction targets, together with a projected timeline for achieving net-zero emissions. In the meantime, the Corporation strives to achieve scope 1 and 2 GHG emissions intensities that are at least 40% lower on average than gas focused peers (and 90% lower on average than oil focused peers) in North and South America.

Outlook

For the remainder of 2022, the Corporation is focused on the following objectives: 1) drilling of up to twelve exploration and development wells in a continuous program targeting a 2P reserves replacement ratio of more than 200% and a 2P RLI of 9.3 years; 2) acquisition of 470 square kilometers of 3D seismic on the Corporation's VIM-5 block to expand the its exploration prospect inventory; 3) purchase of rental facilities equipment and the installation of gas compression to lower operating expenses and increase recovery factors, respectively; 4) selection of a contractor for the new gas pipeline from Jobo to Medellin which will add 100 MMscfpd (with expansion potential up to 200 MMscfpd) of new gas sales to the interior in late 2024, resulting in Canacol being responsible for 30% (up to 40%) of Colombia's domestic gas supply; 5) continuing the return of capital to shareholders in the form of dividends and common share buybacks; and 6) continue with the Corporation's commitment to its ESG strategy and achievement of scope 1 and 2 GHG emissions intensities that are at least 40% lower on average than its gas focused peers (and 90% lower on average than oil focused peers) in North and South America.

FINANCIAL & OPERATING HIGHLIGHTS

(in United States dollars (tabular amounts in thousands) except as otherwise noted)

Financial	Three months ended December 31,			Year ended December 31,		
	2021	2020	Change	**2021**	2020	Change
Total natural gas, LNG and crude oil revenues, net of royalties and transportation expense	**77,073**	63,976	20%	**275,662**	246,804	12%
Adjusted Funds from operations[1][2]	**43,691**	35,251	24%	**153,847**	145,122	6%
Per share – basic ($)[1]	**0.25**	0.20	25%	**0.86**	0.80	7%
Per share – diluted ($)[1]	**0.25**	0.20	25%	**0.86**	0.80	7%
Net income (loss) and comprehensive income (loss)	**7,024**	921	662%	**15,177**	(4,743)	n/a
Per share – basic ($)	**0.04**	0.01	300%	**0.09**	(0.03)	n/a
Per share – diluted ($)	**0.04**	0.01	300%	**0.09**	(0.03)	n/a
Cash flow provided by operating activities	**28,881**	26,477	9%	**123,814**	152,325	(19%)
Per share – basic ($)	**0.16**	0.15	7%	**0.70**	0.84	(17%)
Per share – diluted ($)	**0.16**	0.15	7%	**0.70**	0.84	(17%)
Adjusted EBITDAX[1]	**49,198**	45,941	7%	**194,390**	187,528	4%
Weighted average shares outstanding – basic	**176,558**	179,764	(2%)	**178,141**	180,646	(1%)
Capital expenditures, net of dispositions	**21,556**	29,366	(27%)	**99,940**	83,964	19%
				Dec 31, 2021	Dec 31, 2020	Change
Cash and cash equivalents				**138,523**	68,280	103%
Working capital surplus				**148,124**	73,404	102%
Total debt				**557,709**	415,209	34%
Total assets				**843,760**	749,792	13%
Common shares, end of period (000's)				**176,167**	179,515	(2%)

Operating	Three months ended December 31,			Year ended December 31,		
	2021	2020	Change	**2021**	2020	Change
Production[1]						
Natural gas and LNG (MMscfpd)	**186,145**	170,087	9%	**182,829**	171,126	7%
Colombia oil (bopd)	**244**	287	(15%)	**289**	291	(1%)
Total (boepd)	**32,901**	30,127	9%	**32,364**	30,313	7%
Realized contractual sales[1]						
Natural gas and LNG (MMscfpd)	**185,896**	169,763	10%	**181,434**	171,600	6%
Colombia oil (bopd)	**490**	300	63%	**294**	286	3%
Total (boepd)	**33,103**	30,083	10%	**32,124**	30,392	6%
Operating netbacks[1]						
Natural gas and LNG ($/Mcf)	**3.59**	3.58	—	**3.40**	3.57	(5%)
Colombia oil ($/bopd)	**21.93**	23.04	(5%)	**28.39**	18.57	53%
Corporate ($/boe)	**20.51**	20.44	—	**19.48**	20.34	(4%)

(1) Non-IFRS measures – see "Non-IFRS Measures" section within the MD&A.

(2) Adjusted funds from operations represents cash flow provided by operating activities before certain adjustments related to i) changes in non-cash working capital of $16.9 million and ii) the payment of the remaining outstanding balance of the Corporation's litigation settlement liability of $13.1 million.

2021 Reserves Information

The Corporation's conventional natural gas reserves are located in the Lower Magdalena Valley basin, Colombia.

Canacol Energy Ltd Gross Conventional Natural Gas Reserves Summary

Product Type		Proved Developed Producing *("PDP")*	Total Proved *("1P")*	Total Proved + Probable *("2P")*	Total Proved + Probable + Possible *("3P")*
Conventional natural gas	***Bcf***	**236.0**	**368.4**	**606.9**	**952.3**
Total oil equivalent(3)	*MMBOE*	41.4	64.6	106.5	167.1
Before tax NPV-10(4)	*MM US$*	$665.7	$1,015.3	$1,708.8	$2,753.3
After tax NPV-10(4)	*MM US$*	$569.5	$792.2	$1,229.2	$1,893.7

(1) *All reserves are represented at Canacol's working interest share before royalties.*
(2) *The term "BOE" means a barrel of oil equivalent 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.*

Highlights

Conventional Natural Gas Proved + Probable Reserves ("2P"):

- Decreased by 4.8% since December 31, 2020, totaling 607 billion standard cubic feet ("Bcf") at December 31, 2021, with a before tax value discounted at 10% of US$ 1.7 billion, representing both CAD$ 12.32 per share of reserve value, and CAD$ 9.37 per share of 2P net asset value (net of US$409.6 million of net debt)
- Reserve replacement of 54% based on calendar 2021 gross conventional natural gas reserve additions of 36 Bcf
- 2P Finding and Development Cost ("F&D") of US$ 1.20 / Mcf for the three-year period ending December 31, 2021
- Recycle ratio of 1.8x for the year ended December 31, 2021 (calculated based on the natural gas netback of US$ 3.40 / Mcf for the year ended December 31, 2021)
- Recycle ratio of 3.0x for the three-year period ending December 31, 2021 (calculated based on the weighted average natural gas netback of US$ 3.58 / Mcf for the years ended December 31, 2021, 2020 and 2019)
- Reserves life index ("RLI") of 8.9 years based on annualized fourth quarter 2021 conventional natural gas production of 186,145 thousand standard cubic feet per day ("Mscfpd") or 32,657 barrels of oil equivalent per day ("BOEPD")
- RLI of 8.3 years based on conventional natural gas production guidance of 200,000 Mcfpd for calendar 2022 (high end 2022 production guidance as announced December 15, 2021)

Conventional Natural Gas Proved Developed Producing Reserves ("PDP"):

- Decreased by 14.8% since December 31, 2020, totaling 236 Bcf at December 31, 2021
- Reserve replacement of 39% based on calendar 2021 gross conventional natural gas reserve additions of 26 Bcf

Conventional Natural Gas Total Proved Reserves ("1P"):

- Decreased by 6.7% since December 31, 2020, totaling 368 Bcf at December 31, 2021
- Reserve replacement of 60% based on calendar 2021 gross conventional natural gas reserve additions of 40 Bcf
- 1P F&D of US$ 1.56 / Mcf for the three-year period ending December 31, 2021
- Recycle ratio of 2.3x for the year ended December 31, 2021 (calculated based on the natural gas netback of US$ 3.40 / Mcf for the year ended December 31, 2021)

- Recycle ratio of 2.3x for the three-year period ending December 31, 2021 (calculated based on the weighted average natural gas netback of US$ 3.58 / Mcf for the years ended December 31, 2021, 2020 and 2019)
- RLI of 5.4 years based on annualized fourth quarter 2021 conventional natural gas production of 186,145 Mcfpd or 32,657 BOEPD
- RLI of 5.0 years based on conventional natural gas production guidance of 200,000 Mcfpd for calendar 2022 (high end 2022 production guidance as announced December 15, 2021)

Conventional Natural Gas Total Proved + Probable + Possible Reserves ("3P"):

- Increased by 0.1% since December 31, 2020, totaling 952 Bcf at December 31, 2021, with a before tax value discounted at 10% of US$ 2.8 billion
- Reserve replacement of 102% based on calendar 2021 gross conventional natural gas reserve additions of 68 Bcf
- 3P F&D of US$ 0.70 / Mcf for the three-year period ending December 31, 2021
- Recycle ratio of 3.5x for the year ended December 31, 2021 (calculated based on the natural gas netback of US$ 3.40 / Mcf for the year ended December 31, 2021)
- Recycle ratio of 5.1x for the three-year period ending December 31, 2021 (calculated based on the weighted average natural gas netback of US$ 3.58 / Mcf for the years ended December 31, 2021, 2020 and 2019)
- RLI of 14.0 years based on annualized fourth quarter 2021 conventional natural gas production of 186,145 Mcfpd or 32,657 BOEPD
- RLI of 13.0 years based on conventional natural gas production guidance of 200,000 Mcfpd for calendar 2022 (high end 2022 production guidance as announced December 15, 2021)

Discussion of Year Ended December 31, 2021 Reserves Report

During the year ended December 31, 2021, the Corporation recorded increases in certain reserve categories as a result of the drilling and completion of locations at Aguas Vivas on the VIM-21 natural gas block, San Marcos-1 on the Esperanza natural gas block, and Siku-1 on the VIM-5 natural gas block, all in the Lower Magdalena Valley basin, Colombia. Technical revisions were associated primarily with (i) the Cañahuate field on the Esperanza block and (ii) the Oboe field on the VIM-5 block.

The following tables summarize information from the independent reserves report prepared by Boury Global Energy Consultants Ltd. ("BGEC") effective December 31, 2021 (the "BGEC 2021 report"). The BGEC 2021 report covers 100% of the Corporation's conventional natural gas reserves.

The BGEC 2021 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, 2022.

Canacol Gross Natural Gas Reserves for the Year Ended December 31, 2021

Reserve Category(1)	31-Dec-20 (MMcf)	31-Dec-21 (MMcf)	Difference (%)
Proved Developed Producing (PDP)	276,869	236,023	-14.8%
Total Proved (1P)	394,792	368,366	-6.7%
Total Proved + Probable (2P)	637,249	606,855	-4.8%
Total Proved + Probable + Possible (3P)	951,069	952,292	+0.1%

(1) *All reserves are Canacol working interest before royalties.*

5-Year Gas Price Forecast – BGEC Report December 31, 2021

		Reserve Report Date	2022	2023	2024	2025	2026
Volume weighted Total Proved + Probable (2P) average gas price	*US$/Mcf*	31-Dec-21	4.99	5.14	5.21	5.38	5.49

(1) *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 La Unidad de Planeación Minero Energética ("UPME"), a special administrative unit of the Colombian Ministry of Mines and Energy.*

Natural Gas Reserves Net Present Value Before & After Tax Summary (1)

	Before tax				After tax			
Reserve Category		31-Dec-21 *(M US$)(1)*		Net Asset Value 31-Dec-21 *(C$/share)(2)*		31-Dec-21 *(M US$)(1)*		Net Asset Value 31-Dec-21 *(C$/share)(2)*
Proved Developed Producing (PDP)	$	665,658	$	1.85	$	569,506	$	1.15
Total Proved (1P)	$	1,015,266	$	4.37	$	792,215	$	2.76
Total Proved + Probable (2P)	**$**	**1,708,767**	**$**	**9.37**	**$**	**1,229,217**	**$**	**5.91**
Total Proved + Probable + Possible (3P)	$	2,753,336	$	16.90	$	1,893,721	$	10.70

(1) *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 gas prices at December 31, 2021 are included in the Corporation's Annual Information Form.*

(2) *Net asset value ("NAV") is calculated as at December 31, 2021 NPV10 less estimated net debt of US$409.6 million (being $557.7 million of total debt less estimated working capital of $148.1 million) divided by 176.2 million basic shares outstanding as at December 31, 2021. NAV calculations are converted to $CAD at December 31, 2021 effective rate of USD:CAD =1.27.*

Reserve Life Index ("RLI")(3)

Reserve Category	31-Dec-20 (yrs)(1)	31-Dec-21 (yrs)(2)
Proved Developed Producing (PDP)	4.5	3.5
Total Proved (1P)	6.4	5.4
Total Proved + Probable (2P)	**10.3**	**8.9**
Total Proved + Probable + Possible (3P)	15.3	14.0

(1) *Calculated using average 3 month ending December 31, 2020 natural gas production of 170,087 Mcfpd or 29,840 BOEpd annualized .*
(2) *Calculated using average 3 month ending December 31, 2021 natural gas production of 186,145 Mcfpd or 32,657 BOEpd annualized.*
(3) *"RLI" Reserve Life Index is calculated by dividing the applicable reserves category by the annualized fourth quarter production.*

Year Ended December 31, 2021 Canacol Gross Reserves 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[(5)]
Opening Balance (December 31, 2020)	-	-	-	276,869	-	48,574
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[(2)]	-	-	-	9,399	-	1,649
Discoveries[(3)]	-	-	-	16,361	-	2,870
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,605)	-	11,685
Closing Balance (December 31, 2021)	-	-	-	236,023	-	41,408

TOTAL PROVED	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE[(5)]
Opening Balance (December 31, 2020)	-	-	-	394,792	-	69,262
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[(2)]	-	-	-	3,025	-	531
Discoveries[(3)]	-	-	-	37,154	-	6,518
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,605)	-	(11,685)
Closing Balance (December 31, 2021)	-	-	-	368,366	-	64,626

TOTAL PROVED + PROBABLE	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE[(5)]
Opening Balance (December 31, 2020)	-	-	-	637,249	-	111,798
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[(2)]	-	-	-	(33,975)	-	(5,960)
Discoveries[(3)]	-	-	-	70,185	-	12,313
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,605)	-	(11,685)
Closing Balance (December 31, 2021)	-	-	-	606,855	-	106,466

TOTAL PROVED + PROBABLE + POSSIBLE	Total Oil (MBBL)	Light/Med Crude Oil (MBBL)	Heavy Crude Oil (MBBL)	Conventional Natural Gas (MMCF)	NGL (MBBL)	TOTAL MBOE[5]
Opening Balance (December 31, 2020)	-	-	-	951,069	-	166,854
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[2]	-	-	-	(58,245)	-	(10,218)
Discoveries[3]	-	-	-	126,073	-	22,118
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(66,605)	-	(11,685)
Closing Balance (December 31, 2021)	-	-	-	952,292	-	167,069

(1) *The numbers in this table may not add due to rounding.*
(2) *Conventional natural gas technical revisions in 1P through to 3P are associated primarily with (i) the Cañahuate field on the Esperanza block and (ii) the Oboe field on the VIM-5 block.*
(3) *Conventional natural gas discoveries are associated with Aguas Vivas on the VIM-21 block, San Marcos-1 on the Esperanza block, and Siku-1 on the VIM-5 block, all in the Lower Magdalena Valley basin, Colombia.*
(4) *The term "BOE" means a barrel of oil equivalent on the basis of 5.7 Mcf of natural gas to 1 barrel of oil ("bbl") as per Colombian regulatory practice.*

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

		Calendar 2021 Conventional Natural Gas	Three-Year Ending December 31, 2021 Conventional Natural Gas
Net Natural Gas Capital Expenditures (M$ US) [2]	$	92,248	244,834
Capital Expenditures - Change in FDC (M$ US) [4]		(32,913)	19,487
Total F&D (M$ US)	$	59,335	264,321
Net Acquisitions (M$ US)		-	-
Total FD&A (M$ US) [6][7][8]	$	59,335	264,321
Reserve Additions (MMCF)		40,179	169,132
Reserve Additions – Net Acquisitions		-	-
Reserve Additions Including Net Acquisitions (MMCF)		40,179	40,179
1P F&D per Mcf (US$/MCF) [5][8]	**$**	**1.48**	**1.56**
1P FD&A per Mcf (US$/MCF) [6][7][8]	**$**	**1.48**	**1.56**

(1) *The numbers in this table may not add due to rounding.*
(2) *The Company excludes midstream investments from the F&D calculations, as these capital investments represent long life midstream assets that have multi decade operating life potential, coupled with residual value. 2021 and 2020 capital expenditures exclude US$ 3.2 million and US$ 2 million related to expenditures on the Medellin pipeline, respectively. 2019 capital expenditures exclude US$ 14.5 million related to the third Jobo Station expansion, which was completed in 2019.*
(3) *All values in this table are stated on a 1P (Total Proved) basis.*
(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.*
(8) *2021 1-year 1P reserves addition is comprised of 37.2 Bcf of discoveries and 3 Bcf of technical revisions. As such, the 1-year 1P F&D of $1.48/Mcf is calculated on the total reserves addition of 40.2 Bcf. 1-year 1P F&D related only to the 37.2 Bcf of discoveries is $1.60/Mcf.*

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

		Calendar 2021	Three-Year Ending December 31, 2021
		Conventional Natural Gas	Conventional Natural Gas
Net Natural Gas Capital Expenditures (M$ US) (2)	$	92,248	244,834
Capital Expenditures - Change in FDC (M$ US) (4)		(22,355)	30,552
Total F&D (M$ US)	$	69,893	275,386
Net Acquisitions (M$ US)		-	-
Total FD&A (M$ US) (6)(7)(8)	$	69,893	275,386
Reserve Additions (MMCF)		36,211	228,889
Reserve Additions – Net Acquisitions		-	-
Reserve Additions Including Net Acquisitions (MMCF)		36,211	228,889
2P F&D per Mcf (US$/MCF) (5)(8)	**$**	**1.93**	**1.20**
2P FD&A per Mcf (US$/MCF) (6)(7)(8)	**$**	**1.93**	**1.20**

(1) *The numbers in this table may not add due to rounding.*
(2) *The Company excludes midstream investments from the F&D calculations, as these capital investments represent long life midstream assets that have multi decade operating life potential, coupled with residual value. 2021 and 2020 capital expenditures exclude US$ 3.2 million and US$ 2 million related to expenditures on the Medellin pipeline, respectively. 2019 capital expenditures exclude US$ 14.5 million related to the third Jobo Station expansion, which was completed in 2019.*
(3) *All values in this table are stated on a 2P (Total Proved + Probable) basis.*
(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.*
(8) *2021 1-year 2P reserves addition is comprised of 70.2 Bcf of discoveries, offset by 34 Bcf of technical revisions. As such, the 1-year 2P F&D of $1.93/Mcf is calculated on the net reserves addition of 36.2 Bcf. 1-year 2P F&D related only to the 70.2 Bcf of discoveries is $1.00/Mcf.*

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

		Calendar 2021	Three-Year Ending December 31, 2021
		Conventional Natural Gas	Conventional Natural Gas
Net Natural Gas Capital Expenditures (M$ US) (2)	$	92,248	244,834
Capital Expenditures - Change in FDC (M$ US) (4)		(25,432)	31,094
Total F&D (M$ US)	$	66,816	275,928
Net Acquisitions (M$ US)		-	-
Total FD&A (M$ US) (6)(7)(8)	$	66,816	275,928
Reserve Additions (MMCF)		67,828	393,827
Reserve Additions – Net Acquisitions		-	-
Reserve Additions Including Net Acquisitions (MMCF)		67,828	393,827
3P F&D per Mcf (US$/MCF) (5)(8)	**$**	**0.99**	**0.70**
3P FD&A per Mcf (US$/MCF) (6)(7)(8)	**$**	**0.99**	**0.70**

(1) *The numbers in this table may not add due to rounding.*
(2) *The Company excludes midstream investments from the F&D calculations, as these capital investments represent long life midstream assets that have multi decade operating life potential, coupled with residual value. 2021 and 2020 capital expenditures exclude US$ 3.2 million and US$ 2 million related to expenditures on the Medellin pipeline, respectively. 2019 capital expenditures exclude US$ 14.5 million related to the third Jobo Station expansion, which was completed in 2019.*
(3) *All values in this table are stated on a 3P (Total Proved + Probable + Possible) basis.*
(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.*
(8) *2021 1-year 3P reserves addition is comprised of 126.1 Bcf of discoveries, offset by 58.2 Bcf of technical revisions. As such, the 1-year 3P F&D of $0.99/Mcf is calculated on the net reserves addition of 67.8 Bcf. 1-year 3P F&D related only to the 126.1 Bcf of discoveries is $0.53/Mcf.*

The recovery and reserve estimates of conventional natural gas are estimates only. There is no guarantee that the estimated reserves will be recovered, and actual reserves of conventional natural gas may prove to be greater than, or less than, the estimates provided.

Reserves of conventional natural gas as at December 31, 2021 are evaluated using natural gas pricing 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 La Unidad de Planeación Minero Energética ("UPME"), a special administrative unit of the Colombian Ministry of Mines and Energy. Comparative volumes of conventional natural gas as at December 31, 2020 were evaluated using natural gas pricing based on existing long term contracts net of transportation (if applicable) and adjusted for inflation, along with interruptible gas sales pricing based on UPME at that effective date. Forecast prices used in the reserves reports are included in the Corporation's Annual Information Form, which will be filed on SEDAR by March 31, 2022 under the sections "Forecast Prices Used in Estimates" and "Forward Contracts" in the "Statement of Reserves Data and Other Oil and Gas Information".

This press release should be read in conjunction with the Corporation's audited consolidated financial statements and related Management's Discussion and Analysis ("MD&A"). The Corporation's has filed its audited consolidated financial statements, related MD&A and Annual Information Form as at and for the year ended December 31, 2021 with Canadian securities regulatory authorities. These filings are available for review on SEDAR at www.sedar.com.

About Canacol

Canacol is a natural gas 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.

Realized contractual sales is defined as natural gas and LNG produced and sold plus income received from nominated take-or-pay contracts without the actual delivery of natural gas or LNG and the expiry of the customers' rights to take the deliveries.
The Corporation's LNG sales account for less than one percent of the Corporation's total realized contractual natural gas and LNG sales.

The reserves evaluation, effective December 31, 2021, 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;

BOE Conversion - "BOE" barrel of oil equivalent is derived by converting natural gas to oil in the ratio of 5.7 Mcf of natural gas to one bbl of oil. A BOE 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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