Management Discussion and Analysis

This management discussion and analysis ("MD&A") of the financial condition and results of operations of SierraCol Energy Limited and its subsidiaries ("we", "our", "SCE" or the "Company") should be read in conjunction with the unaudited condensed consolidated financial statements for the period ended 30 September 2023 and 2022 and the notes thereto. Please read the full cautionary statements at the end of the document.

3Q23 performance highlights

Operational

Operational update

- Share Before Royalties ("SBR") production was 41.7 kboed, slightly down 0.2 kboed q/q, mainly due to lower production in Middle Magdalena area.
- Middle Magdalena production was affected by surface equipment failures and maintenance in the water injection and production system. By quarter-end, these issues were resolved, and production levels increased.
- The Caño Limón area is back to normal operations following external events in the second quarter. Production recovery is on track and is expected to continue increasing during 4Q23.
- During the quarter, 2 active rigs drilled and completed 12 new wells: 1 in the Caño Limón area and 11 in Middle Magdalena. The workover campaign included 25 workovers in the Caño Limón area, 2 in Middle Magdalena, and 1 in Central Llanos.
- YTD SBR production averaged 43.2 kboed, within production guidance.
- The Company reiterates its 2023 production guidance as well as the capital and exploration expenditures guidance.
- During the quarter, 80% of the Caño Limón area production was shipped via the Caño Limón-Coveñas ("CLC") pipeline vs 45% in 2Q23. The remaining production was shipped via the alternative evacuation route, the Bicentenario ("OBC") pipeline.

Committed to ESG goals

- Following on from our voluntary Taskforce on Climate-related Financial Disclosures ("TCFD") report issued in 2Q23, after quarter-end, we published our first voluntary report in line with the Taskforce on Nature-related Financial Disclosures ("TNFD").
- SierraCol continues to make progress on the initiatives to reduce its carbon footprint.
- In connection with our goal to eliminate gas flaring by 2025, we implemented a gas-to-liquids project in the Caño Limón area.

Financial

Financial metrics

- Brent price increased $8.2/bbl q/q to $85.9/bbl, and Vasconia differential contracted by $1.9/bbl q/q to $3.6/bbl.
- Average realised price of $81.3/boe vs Brent of $85.9/bbl. Realised price increased more than Brent q/q (16% vs 11%) due to a lower Vasconia differential and increased shipping via the CLC pipeline.
- Net income of $76.8 million, up 36% q/q, mainly as a result of higher realisation.
- Adjusted EBITDAX of $172.4 million ($55.6/boe), up 31% q/q, driven mainly by higher realisation, partially offset by higher lifting cost.
- Lifting costs were higher $16.8 million q/q driven by $6.5 million from increased activity/scope, $5.0 million due to foreign exchange rate, $4.7 million linked to timing effects, and $0.6 million in other increases.
- Last twelve-months ("LTM") Adjusted EBITDAX of $647.0 million.
- Adjusted operating netback of $57.6/boe, up 13% q/q mainly as a result of higher Brent price partially offset by increased lifting cost per barrel.
- Capital and exploration expenditures of $50.8 million, up 14% q/q mainly driven by drilling activities in the Middle Magdalena and higher development and workover activities in the Caño Limón area. Capex for 9M23 stands at $ 124.5 million.
- Free Cash Flow of $(34.2) million, mainly due to tax payments of $117.3 million in the quarter.

Ample liquidity and low net leverage

- Total available liquidity of $199.9 million (cash and cash equivalents of $107.3 million plus $92.6 million in undrawn amounts of committed credit lines).
- During the quarter, the Company paid $25.0 million of the $45.0 million that were drawn from the Revolving Credit Facility ("RCF"). After quarter-end the remaining amount was fully repaid.
- Net debt of $539.5 million with cash and cash equivalents of $107.3 million, and net leverage of 0.8x.
- Considering available liquidity, low net leverage, and meeting business requirements, the Board may decide to distribute dividends to shareholders in December.

Risk management

- On our Brent hedging programme for the next six months, 4Q23-1Q24, we have hedged 47% of our hedgeable production, with a weighted average long put strike price of $64.0/bbl.
- Regarding the currency hedging programme, we currently have hedged approximately 50% of the Company's cash needs in Colombian peso until 2Q24. We are employing zero-cost collars with a weighted average strike price of $4,107/$4,672, and forward contracts with an average forward rate of $4,374.

Financial and operational results

Key figures

	3Q23	2Q23	3Q22[1]	Δ q/q	Δ y/y	9M23	9M22[1]	Δ y/y
Production & sales (kboed)								
Gross production	77.1	77.9	80.1	-1%	-4%	79.4	81.4	-2%
SBR production[2]	41.7	41.9	43.5	-1%	-4%	42.7	44.3	-4%
Net production	33.4	33.2	32.0	1%	5%	33.9	32.8	3%
Net sales	33.7	31.3	30.3	8%	11%	33.0	32.1	3%
Operating netback per barrel of net sales ($/boe)								
Brent price	85.9	77.7	97.7	11%	-12%	81.9	102.5	-20%
Realised price	81.3	70.4	92.6	16%	-12%	75.5	95.5	-21%
Lifting cost	(22.8)	(18.9)	(16.8)	20%	36%	(18.9)	(14.4)	31%
Transport cost	(1.0)	(0.6)	(0.9)	77%	11%	(0.8)	(0.9)	-14%
Adjusted operating netback per boe[2]	57.6	50.9	74.9	13%	-23%	55.8	80.2	-30%
Administrative expenses	(2.8)	(3.0)	(1.9)	-9%	45%	(3.0)	(2.8)	8%
Realised loss on oil derivatives	(0.5)	(0.5)	(1.0)	1%	-53%	(0.4)	(5.6)	-92%
Other[3]	1.2	(1.3)	1.9	nm	-37%	0.5	1.8	-72%
Operating netback[2]	55.6	46.1	73.9	20%	-25%	52.9	73.6	-28%
Adjusted EBITDAX ($ million)								
Total revenue	252.5	200.5	258.2	26%	-2%	680.3	836.0	-19%
Lifting cost	(70.7)	(53.9)	(46.8)	31%	51%	(170.0)	(126.1)	35%
Transport cost	(3.1)	(1.6)	(2.5)	93%	25%	(6.9)	(7.8)	-10%
Adjusted operating netback[2]	178.7	144.9	208.9	23%	-14%	503.3	702.1	-28%
Administrative expenses	(8.5)	(8.6)	(5.3)	-1%	62%	(27.2)	(24.8)	10%
Realised loss on oil derivatives	(1.5)	(1.3)	(2.8)	11%	-48%	(4.0)	(48.6)	-92%
Other[3]	3.7	(3.6)	5.0	nm	-25%	4.5	14.9	-70%
Adjusted EBITDAX[2]	172.4	131.4	205.8	31%	-16%	476.6	643.6	-26%
Key financial results ($ million)								
Net income	76.8	56.6	80.9	36%	-5%	209.2	253.1	-17%
Capex and exploration expenditures[2]	50.8	44.5	55.3	14%	-8%	124.5	126.4	-2%
Free Cash Flow[2]	(34.2)	9.2	130.0	nm	nm	37.8	287.4	-87%
Cash & cash equivalents	107.3	173.2	302.5	-38%	-65%	107.3	302.5	-65%
Net debt[2]	539.5	497.8	300.7	8%	79%	539.5	300.7	79%

[1] The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | [2] See "Non-IFRS Measures" section. | [3] Other includes prepaid expenses, other income/expenses (net), realised foreign exchange gain (loss), fair value remeasurements and non-recurring costs.

2023 Guidance

The company reiterates its 2023 production guidance as well as the capital and exploration expenditures guidance .

	2023 guidance
SBR production (kboed)	42 - 44
Capital and exploration expenditures ($m)[1]	$190 – $210

Production

kboed	3Q23	2Q23	3Q22	Δ q/q	Δ y/y	9M23	9M22	Δ y/y
Gross production	77.1	77.9	80.1	-1%	-4%	79.4	81.4	-2%
SBR production								
Caño Limón area	24.9	24.6	27.6	1%	-10%	25.8	28.1	-8%
Middle Magdalena	13.1	13.8	13.7	-5%	-4%	13.7	13.6	–%
Central Llanos	3.7	3.5	2.3	3%	59%	3.3	2.6	26%
SBR production	41.7	41.9	43.5	-1%	-4%	42.7	44.3	-4%
Light and medium oil	40.9	41.2	43.0	-1%	-5%	42.0	43.8	-4%
Heavy oil	0.5	0.4	0.4	10%	23%	0.4	0.4	16%
Gas	0.2	0.3	0.2	-13%	57%	0.3	0.2	52%
Royalties in kind	3.4	3.5	3.3	-3%	4%	3.6	3.5	3%
Price-related effects	4.8	5.1	8.3	-7%	-42%	5.3	8.0	-34%
Net production	33.4	33.2	32.0	1%	5%	33.9	32.8	3%

SBR production for 3Q23 was 41.7 kboed, slightly lower than 2Q23 by 0.2 kboed. Production was down 0.7 kboed in the Middle Magdalena area, partially offset by an increase in the Caño Limón area of 0.3 kboed and in Central Llanos of 0.1 kboed.

Middle Magdalena production was affected by surface equipment failures and maintenance in the water injection and production system. However, by quarter-end, these issues were resolved, and production levels increased. Currently, activities are being carried out to ramp up production during 4Q23.

Regarding our Llanos basin operations, production increased in Caño Limón and Central Llanos area mainly due to good production results in development activities and recovery from 2Q23 events in the Caño Limón area.

Compared to 3Q22, SBR production decreased 1.9 kboed as a result of: i) a decrease of 2.7 kboed due to lower production in the Caño Limón area in connection with deferred production from downhole failures at the end of 2Q23 and delays in execution of activity, and ii) an impact of 0.5 kboed in the Middle Magdalena area for the reasons explained above. The lower production was partially offset by an increase in Central Llanos of 1.4 kboed mainly driven by strong results in development wells.

2 active rigs during the quarter drilled and completed 12 new wells: 1 in the Caño Limón area and 11 in Middle Magdalena. The workover campaign included 25 jobs in the Caño Limón area, 2 in Middle Magdalena and 1 in Central Llanos.

SBR production of 42.7 kboed for 9M23, 4% down compared to 9M22 mainly driven by an impact of 2.3 kboed in the Caño Limón area, as a result of delayed drilling activity in connection with 2Q23 events, partially offset by an increased production of 0.7 kboed in Central Llanos.

[1] Guidance includes development, green and exploration capex plus exploration expenses.

Revenue

	3Q23	2Q23	3Q22	Δ q/q	Δ y/y	9M23	9M22	Δ y/y
Revenue ($ million)								
Oil sales	251.7	199.7	258.0	26%	-2%	678.1	834.5	-19%
Natural gas sales	0.5	0.6	0.3	-14%	69%	1.6	1.0	59%
Services	0.3	0.2	0.0	56%	nm	0.6	0.5	5%
Total revenue	252.5	200.5	258.2	26%	-2%	680.3	836.0	-19%
Net sales (million boe)								
Oil sales	3.1	2.8	2.8	9%	11%	9.0	8.7	3%
Natural gas sales	0.02	0.02	0.01	-11%	75%	0.06	0.04	62%
Net sales	3.1	2.8	2.8	9%	11%	9.0	8.8	3%
Prices								
Brent ($/bbl)	85.9	77.7	97.7	11%	-12%	81.9	102.5	-20%
Vasconia differential ($/bbl)	3.6	5.5	3.8	-35%	-5%	5.7	4.2	36%
Average realised price ($/boe)	81.3	70.4	92.6	16%	-12%	75.5	95.5	-21%

Revenue from oil sales increased 26% q/q, $52.0 million, mainly due to a higher average realised price of $81.3/bbl vs $70.4/bbl (a benefit of $33.7 million) and $18.3 million from an increase in sales volume of 9% q/q.

Average realised price increased 16% q/q, mainly due to an increase in Brent of 11% and smaller Vasconia differential by $1.9/bbl. Average realised price is also benefited by an increased shipping via the CLC pipeline during the quarter. 20% of Caño Limón production during 3Q23 was sold near wellhead to be shipped via the OBC pipeline vs 55% in 2Q23.

Compared to 3Q22 revenue from oil sales remained essentially flat.

Compared to 9M22, revenue from oil sales decreased 19%, mainly due to a lower average realised price driven by a decrease in commodity prices ($173.1 million), the net impact of the OBC pipeline usage of $0.7/boe[2] ($6.2million), partially offset by an increase in volumes sold ($23.0 million).

Operating expenses

$ million (unless otherwise stated)	3Q23	2Q23	3Q22	Δ q/q	Δ y/y	9M23	9M22	Δ y/y
Lifting cost	70.7	53.9	46.8	31%	51%	170.0	126.1	35%
Transportation cost	3.1	1.6	2.5	93%	25%	6.9	7.8	-10%
Operating expenses	73.8	55.5	49.3	33%	50%	177.0	133.9	32%
Per barrel of net sales ($/boe)	23.8	19.5	17.7	22%	34%	19.6	15.3	28%

Lifting cost increased by $16.8 million q/q primarily driven by: i) $6.5 million in connection with increased activity/ scope (related to well work and maintenance), ii) an increase of $5.0 million due to foreign exchange rate resulting

[2] The net impact relating to the production shipped via the OBC pipeline recognises the transport cost SierraCol would have had to incur if 100% of the Caño Limón area production had been shipped via the CLC pipeline.

from the Colombian peso revaluation, iii) $4.7 million linked to timing effects associated with retroactive adjustments corresponding to the first half of the year, and iv) $0.6 million from other increases.

Compared to 3Q22 lifting cost was $23.9 million higher. This is mainly as a result of: i) $7.5 million due to increased activity/scope (related to well work and maintenance), ii) $4.8 million in connection with foreign exchange rate given a revaluation of the Colombian peso of 8% ($4,042 USD/COP in 3Q23 vs $4,414 in 3Q22) iii) $4.7 million linked to timing effect associated with retroactive adjustments during the first half of the year, iv) $3.6 million from cost inflation over services and materials, and v) $ 3.3 million from other increases.

Compared to 9M22 lifting cost increased $43.9 million. This is mainly driven by $27.0 million in connection with increased activity/scope (related to well work and maintenance), $23.0 million from cost inflation over services and materials, and $3.9 million from other increases, partially offset by $10.0 million of 7% Colombian peso devaluation ($4,372 USD/COP in 9M23 vs $4,081 in 9M22).

Transport cost increased $1.5 million q/q and $0.6 million vs 3Q22 due to higher evacuation through the CLC pipeline.

Absolute operating expenses increased 33% vs 2Q23 while the cost per barrel increased by 22%.

Absolute operating expenses vs 3Q22 and 9M22 increased 50% and 32%, while the cost per barrel increased 34%, and 28%, respectively.

Adjusted operating netback per boe

$/boe of net sales	3Q23	2Q23	3Q22	Δ q/q	Δ y/y	9M23	9M22	Δ y/y
Realised price	81.3	70.4	92.6	16%	-12%	75.5	95.5	-21%
Lifting cost	(22.8)	(18.9)	(16.8)	20%	36%	(18.9)	(14.4)	31%
Transport cost	(1.0)	(0.6)	(0.9)	77%	11%	(0.8)	(0.9)	-14%
Adj. operating netback per boe	57.6	50.9	74.9	13%	-23%	55.8	80.2	-30%

Adjusted operating netback increased 13% q/q, as a result of the higher realised price partly offset by a 20% increase in operating expenses explained in the previous section.

Compared to 3Q22 and 9M22, Adjusted operating netback per boe decreased 23% and 30%, respectively, as a result of lower realised prices and an increase in operating expenses.

Administrative expenses

$ million	3Q23	2Q23	3Q22	Δ q/q	Δ y/y	9M23	9M22	Δ y/y
Administrative expenses	8.5	8.6	5.3	-1%	62%	27.2	24.8	10%

Administrative expenses remained essentially flat q/q.

Compared to 3Q22 administrative expenses increased $3.3 million mainly due to lower personnel expenses related to a one-off adjustment in 3Q22 and foreign exchange rate resulting from the 9% Colombian peso revaluation ($4,042 USD/COP in 3Q23 vs $4,414 in 3Q22).

Compared to 9M22 administrative expenses increased $2.5 million mainly due to: i) higher personnel expenses ii) lower overhead recoveries from partners, partially offset by foreign exchange benefit ($4,372 USD/COP in 9M23 vs $4,081 in 9M22).

Capital expenditures

$ million	3Q23	2Q23	3Q22[1]	Δ q/q	Δ y/y	9M23	9M22[1]	Δ y/y
Caño Limón area	28.9	22.3	13.6	30%	112%	60.6	40.4	50%
Middle Magdalena	16.6	6.0	28.4	175%	-41%	29.3	49.4	-41%
Central Llanos	3.8	14.5	4.8	-74%	-20%	29.2	8.0	263%
Development capex	49.4	42.8	46.8	15%	6%	119.2	97.9	22%
Exploratory drilling	0.4	0.8	7.6	-47%	-94%	1.4	26.0	-95%
Total capex	49.8	43.7	54.3	14%	-8%	120.6	123.9	-3%
Exploration expenses[2]	1.0	0.8	1.0	20%	1%	3.8	2.5	53%
Capex and exploration expenditures	50.8	44.5	55.3	14%	-8%	124.5	126.4	-2%

[1] The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | [2] Exploratory expenses are presented net of dry hole costs and impairments.

Development capex increased 15% q/q, mainly driven by resumed drilling activities in the Middle Magdalena and increased workover activity in the Caño Limón area. 12 wells drilled and completed and 28 workover jobs were executed during 3Q23 vs 2 wells drilled and completed and 15 workover jobs during 2Q23.

Compared to 3Q22 development capex increased 6%, mainly due to a focus on more complex drilling areas in Caño Limón partially offset by a decrease in activity in Middle Magdalena and Central Llanos.

Compared to 9M22, development capex increased 22%, as a result of higher drilling and workover activity in Caño Limón (focused in more complex drilling areas) and Central Llanos, partially offset by a decrease in drilling activity in Middle Magdalena.

Exploratory drilling in 9M23 decreased 95% vs 9M22 given no exploration wells were drilled during this period.

Capital and exploration expenditures totalled $124.5 million in 9M23.

Adjusted EBITDAX and Free Cash Flow

$ million	3Q23	2Q23	3Q22(1)	Δ q/q	Δ y/y	9M23	9M22(1)	Δ y/y
Net income for the period	76.8	56.6	80.9	36%	-5%	209.2	253.1	-17%
Financial income and financial expenses	7.7	6.7	9.2	16%	-17%	23.2	26.9	-14%
Depreciation, depletion and amortisation	32.2	31.7	22.9	2%	41%	95.8	82.3	17%
Income tax expense	37.4	37.6	71.1	–%	-47%	123.2	211.0	-42%
Exploration expenses and dry hole cost	0.6	1.0	31.1	-43%	-98%	4.1	59.0	-93%
Foreign exchange (income) / loss	0.9	(2.6)	(3.7)	nm	nm	5.3	(0.8)	nm
Accretion of decommissioning liability	1.1	1.1	1.8	3%	-39%	3.2	4.5	-30%
Prepaid expenses and bond cost amortisation	5.4	2.1	3.2	158%	68%	10.7	9.5	12%
Unrealised fair value gain on derivatives	1.3	(0.2)	(11.5)	nm	nm	0.7	(6.7)	nm
Inventory fluctuation	6.7	(2.8)	0.5	nm	>1000%	(1.4)	1.0	nm
Fair value remeasurements	–	–	–	–%	–%	–	3.9	-100%
Other non-cash items	2.3	0.2	0.2	959%	>1000%	2.5	–	>1000%
Adjusted EBITDAX	172.4	131.4	205.8	31%	-16%	476.6	643.6	-26%
Exploration drilling(2)	(0.4)	(0.8)	(8.2)	-47%	-95%	(1.4)	(26.6)	-95%
Exploration and seismic expense	(1.0)	(0.8)	(0.8)	20%	20%	(3.8)	(2.4)	63%
Tax payments	(117.3)	(61.6)	–	91%	–%	(197.1)	(132.1)	49%
Capital expenditures(2)	(52.7)	(42.8)	(47.9)	23%	10%	(122.5)	(99.0)	24%
Acquisition of PUT-36	–	–	–	–%	–%	–	(10.0)	-100%
Inventory of capitalizable parts/	–	–	–	–%	–%	–	(2.8)	-100%
Decommissioning funding	–	–	–	–%	–%	–	–	–%
Change in working capital(3)	(40.0)	(24.2)	(18.1)	65%	121%	(130.7)	(79.4)	65%
Non-recurring costs	–	–	–	–%	–%	–	–	–%
Realised FX rate gain (loss)	4.9	8.5	–	-43%	>1000%	17.9	(0.9)	nm
Lease payments	(0.1)	(0.4)	(0.9)	-66%	-85%	(1.1)	(3.2)	-65%
Free Cash Flow	(34.2)	9.2	130.0	nm	nm	37.8	287.4	-87%

(1) The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | (2) Figures including capital and exploration drilling accruals | (3) Figures excluding capital and exploration drilling accruals.

Decrease in working capital q/q is mainly attributed to higher accounts receivable, driven primarily by increases in volumes delivered and billed, at a higher realised price, which had not yet been paid by customers by quarter-end[3].

Adjusted EBITDAX increased 31% q/q mainly due to an increase of $8.2/bbl in Brent partially offset by higher operational expenses.

Adjusted EBITDAX for 9M23 was $476.6 million, resulting in an Operating netback of $52.9/boe.

Free Cash Flow totalled $(34.2) million in the quarter mainly driven by higher tax payments, in connection with 2022 results, change in working capital as explained above, and higher capital expenses.

[3] See note 10 of the condensed consolidated financial statements for the period ended 30 September 2023.

Cash flows

The table summarises the classification of our cash flows for 9M23 and 9M22:

$ million	9M23	9M22
Net cash flows from operating activities	151.0	391.9
Net cash flows used in investing activities	(151.0)	(148.0)
Net cash flows from financing activities	0.1	(55.6)
Increase in cash and cash equivalents during the period	0.1	188.3
Cash and cash equivalents at the beginning of the period	106.2	119.3
Effect of foreign exchange on cash and cash equivalents held in foreign currencies	1.0	(5.1)
Cash and cash equivalents at the end of the period	107.3	302.5

As presented in the interim condensed consolidated statement of cash flows within the Financial Statements document:

Cash flows from operating activities for 9M23 of $151.0 million is presented net of cash taxes paid of $197.1 million. Cash flows used in investing activities include cash additions of $110.8 million to property, plant and equipment ("PPE") and $1.4 million to exploration and evaluation assets, a $45.0 million contingent payment to Oxy, and financial income of $6.1 million. Cash flows from financing activities include dividends paid to non-controlling interest of $13.8 million, an outstanding short-term debt of $40.0 million, interest and financial expenses paid of $23.2 million, and lease payments of $1.1 million.

Cash and cash equivalents at quarter-end were $107.3 million.

Liquidity and capital resources

$ million (unless stated)	9M23	9M22
2028 senior notes @ 6.00%	600.0	600.0
Drawdown of short-term debt	40.0	–
Capital lease obligations	6.8	3.2
Total indebtedness	646.8	603.2
(-) Cash & cash equivalents	107.3	302.5
(=) Net debt	539.5	300.7
LTM Adjusted EBITDAX	647.0	813.2
Net leverage (x)	0.8x	0.4x
Cash and cash equivalents	107.3	302.5
Undrawn amounts of committed credit lines[4]	92.6	56.5
Total liquidity	199.9	359.0

We ended 9M23 with an ample liquidity, closing at $199.9 million, and maintaining a low net leverage at 0.8x.

In the second quarter, $45.0 million was drawn down from the RCF to support working capital requirements. During the third quarter, the Company prepaid $25.0 million, and subsequent to the quarter-end, on 31 October, the Company prepaid the remaining amount. Therefore, the current undrawn amount of the RCF is $113.0 million[5], from an aggregate principal amount of commitments provided of $120.0 million.

In the previous quarter, an additional $20.0 million was drawn down from a BTG Pactual short-term credit line.

[4] Includes the RCF undrawn amounts as of 30 September 2023. The available amount of the RCF reflects the COP/USD exchange rate as of that date and $5.0 million used towards letters of credit. The aggregate principal amount of commitments provided under the RCF is $120.0 million.
[5] The current undrawn amount of the RCF reflects the COP/USD exchange rate as of the date of this document and $5.0 million used towards letters of credit.

Summary of quarterly results[1]

	3Q23	2Q23	1Q23	4Q22	3Q22	2Q22	1Q22	4Q21
Production & sales (kboed)								
Gross production	77.1	77.9	83.2	81.4	80.1	78.4	85.8	83.6
SBR production[2]	41.7	41.9	44.6	44.2	43.5	42.8	46.7	45.1
Net production	33.4	33.2	34.9	33.0	32.0	31.2	35.3	34.3
Net sales	33.7	31.3	34.0	32.1	30.3	30.9	35.0	34.8
Operating netback per barrel of net sales ($/boe)								
Brent price	85.9	77.7	82.1	88.6	97.7	112.0	97.9	79.7
Realised price	81.3	70.4	74.2	81.3	92.6	103.8	90.7	70.2
Lifting cost	(22.8)	(18.9)	(14.8)	(16.5)	(16.8)	(13.9)	(12.8)	(14.0)
Transport cost	(1.0)	(0.6)	(0.7)	(0.8)	(0.9)	(0.9)	(0.8)	(0.4)
Adjusted operating netback per boe[2]	57.6	50.9	58.6	64.0	74.9	89.0	77.1	55.8
Administrative expenses	(2.8)	(3.0)	(3.3)	(4.4)	(1.9)	(3.3)	(3.3)	(3.8)
Realised loss on oil derivatives	(0.5)	(0.5)	(0.4)	(0.3)	(1.0)	(10.0)	(5.6)	(2.4)
Other[3]	1.2	(1.3)	1.4	(1.6)	1.9	2.0	1.4	3.4
Operating netback[2]	55.6	46.1	56.4	57.7	73.9	77.7	69.6	53.0
Adjusted EBITDAX ($ million)								
Total revenue	252.5	200.5	227.3	240.2	258.2	291.8	286.0	224.7
Lifting cost	(70.7)	(53.9)	(45.4)	(48.7)	(46.8)	(38.9)	(40.4)	(45.0)
Transport cost	(3.1)	(1.6)	(2.2)	(2.5)	(2.5)	(2.6)	(2.6)	(1.4)
Adjusted operating netback[2]	178.7	144.9	179.7	189.0	208.9	250.3	242.9	178.3
Administrative expenses	(8.5)	(8.6)	(10.1)	(12.9)	(5.3)	(9.2)	(10.2)	(12.1)
Realised loss on oil derivatives	(1.5)	(1.3)	(1.2)	(1.0)	(2.8)	(28.2)	(17.5)	(7.8)
Other[3]	3.7	(3.6)	4.4	(4.7)	5.0	5.6	4.2	11.1
Adjusted EBITDAX[2]	172.4	131.4	172.8	170.5	205.8	218.5	219.4	169.6
Key financial results ($ million)								
Net income	76.8	56.6	75.8	45.6	80.9	85.6	86.6	84.9
Capex and exploration expenditures[2]	50.8	44.5	29.2	78.5	55.3	32.8	38.3	61.8
Free Cash Flow[2]	(34.2)	9.2	62.8	113.8	130.0	27.5	129.9	139.3
Cash & cash equivalents	107.3	173.2	115.2	106.2	302.5	189.8	178.4	119.3
Net debt[2]	539.5	497.8	490.8	494.8	300.7	414.4	426.7	488.4

[1] The Final Offering Memorandum for the Senior Notes defined that results from the Teca-Cocorna Collaboration Agreement ("Teca") would be removed from our presentation of Adjusted EBITDAX, as its operations were limited to care and maintenance. According to the updated perspective for the asset, from 1Q23 onwards we present the Teca result within Adjusted EBITDAX, Free Cash Flow, and capex and exploration expenditures. Prior quarters have been updated to reflect this view. | [2] See "Non-IFRS Measures" section. | [3] Other includes prepaid expenses, other income/expenses (net), realised foreign exchange gain (loss), fair value remeasurements and non-recurring costs.

Risk management contracts

Brent hedging

Our commodity hedging programme seeks to protect the oil price downside risk on a significant portion of our underlying cash flows, while avoiding speculative positions and leaving room for potential upside. The Company's target is to hedge between 40% to 60% of its expected hedgeable production, six to twelve months ahead.

The table below provides a summary of the current commodity hedging positions as of the date of this document:

				Avg. strike prices ($/bbl)	
Type of Instrument	**Term**	**Benchmark**	**Volume (bbl)**	**Long Put**	**Short Put**
Put Spread	Oct-23	Brent	130,694	65.0	45.0
Put	Oct-23	Brent	130,694	65.0	
Put	Nov-23 to Feb-24	Brent	1,364,144	65.0	
Put	Mar-24	Brent	420,684	60.0	

For the next six months, we have hedged 47% of our hedgeable production, with a weighted average long put strike price of $64.0/bbl.

We will continue to monitor the market and exercise our judgement to enter into new hedging positions when we consider appropriate.

Currency hedging

We have currently open currency hedging positions to manage volatility in the foreign exchange rate of Colombian peso to US dollar, hedging approximately 50% of the Company's cash needs in Colombian peso.

The table below provides a summary of the current currency hedging positions as of the date of this document:

Type of Instrument	Term	Benchmark	Volume ($ million)	Avg. Put / Call	Avg. Forward rate
Zero-cost collar	Oct-23 to Dec-23	COP / USD	$15.0	4,000 / 4,500	
Zero-cost collar	Jan-24 to Mar-24	COP / USD	$45.0	4,067 / 4,623	
Zero-cost collar	Apr-24 to Jun-24	COP / USD	$45.0	4,183 / 4,778	
	4Q23 - 2Q24	COP / USD	$105.0	4,107 / 4,672	
Forward	Feb-24	COP / USD	$16.2		4,306
Forward	Apr-24	COP / USD	$51.5		4,360
Forward	Jun-24	COP / USD	$51.0		4,410
	1Q24 - 2Q24	COP / USD	$118.7		4,374

We will continue to actively monitor market conditions and we may continue to hedge local currency to manage volatility in the foreign exchange rate of the Colombian peso to US dollar.

Non-IFRS Measures

This MD&A contains non-IFRS financial measures and ratios, including Adjusted EBITDAX and Free Cash Flow that are not required by, or presented in accordance with, IFRS. Management uses these measures to evaluate operating performance of the Company and as a basis for strategic planning and forecasting, as well as monitoring certain aspects of our cash flow and liquidity. We also believe they provide useful information to investors, securities analysts and other interested parties as supplemental measures of performance.

These non-IFRS measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS.

Adjusted EBITDAX: calculated as comprehensive income or loss adjusted for financial income and financial expenses, depreciation, depletion and amortisation, impairment of property, plant and equipment and inventory, income tax expense, exploration and seismic expenses and dry hole cost, foreign exchange income or loss and other non-cash items excluding other comprehensive income and other adjustments relating to differences in the recognition of revenues and costs which are excluded in order to represent the earnings on a cash basis.

Adjusted operating netback: calculated as total revenue less lifting and transportation costs.

Adjusted operating netback per boe: calculated as average realised price less operating expenses per boe of net sales.

Capex and exploration expenditures: calculated as development capex plus exploratory drilling plus exploration expenses (net of dry hole costs and impairments).

Net debt: calculated as total financial indebtedness less cash and cash equivalents. Total financial indebtedness includes the nominal value of the 2028 senior notes plus capital lease obligations.

Net leverage: calculated as net debt divided by last twelve-months (''LTM'') Adjusted EBITDAX.

Free Cash Flow ("FCF"): consists of Adjusted EBITDAX further adjusted for exploration expenses and tax payments, capital expenditures, decommissioning funding, changes in working capital, realised foreign exchange income or loss, lease payments and non-recurring costs.

Operating netback per boe: calculated as Adjusted EBITDAX divided by net sales.

Share Before Royalties ("SBR") production: Company's working interest production before discounting royalties to government and high-price clause participation royalties (price-related effects).

Vasconia differential: Vasconia FOB Colombia vs Latin America Brent Futures strip (close) reported by Platts, code AAXCB00.

Cautionary Statements

This management discussion and analysis ("MD&A") of the financial condition and results of operations of SierraCol Energy Limited and its subsidiaries ("we," "our", "SCE" or the "Company") should be read in conjunction with the unaudited condensed consolidated financial statements for the period ended 31 March 2023 and the notes thereto. This MD&A includes statements regarding industry outlook, our expectations regarding the performance of our business and other forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to numerous risks and uncertainties, many of which are beyond our control. Our actual results may differ materially from those contained in or implied by any forward-looking statements.

Sales volumes can differ from our net entitlement to production of saleable hydrocarbons due to over- or under-lifting of our production entitlement in any single accounting period. The quantities of over- and under-lifted production entitlement are not considered material to the overall production figures in any period. Where gross amounts are indicated, they are presented on a total basis—i.e., the actual interest of the relevant license holder in the relevant fields and license areas without deduction for the economic interest of commercial partners, government production shares, taxes or royalty interests or other deductions. Our legal interest and effective working interest in the relevant fields and license areas are disclosed separately. Unless otherwise indicated, our production, reserves and resources figures are presented on a basis including our ownership share of volumes of companies that we account for under the equity accounting method.

Certain amounts and percentages included in this document have been rounded for ease of presentation. Accordingly, figures shown as totals or percentage changes between periods may not be the arithmetic result of their inputs as presented in this document.

The best-in-class netback statement is based on our own calculations employing information from Company filings for peers. "Peers" are Latin American oil and gas companies that are focused on Colombia and are listed and/or rated by credit rating agencies.

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