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 June 2023 and 2022 and the notes thereto. Please read the full cautionary statements at the end of the document.

2Q23 performance highlights

Operational

Resilient operations

- Share Before Royalties ("SBR") production was 41.9 kboed, down 6% q/q, mainly due to operational and external events in the Caño Limón area, partially offset by increased production in Central Llanos. Production in Middle Magdalena remained essentially flat.
- The above mentioned events in the Caño Limón area relate to delays in activity execution, well failures, disruptions to the pipeline system, electrical events and floods. These events are now largely resolved.
- During the quarter, 1 active rig drilled 2 new wells in Central Llanos. The workover campaigns included 9 jobs in the Caño Limón area, 3 in Middle Magdalena and 2 in Central Llanos.
- Revised production guidance to 42 – 44 kboed, from 43 – 45 kboed, in connection with events affecting production in the Caño Limón area. Guidance on capital and exploration expenditures remains unchanged at $190 - $210 million.
- 45% of the Caño Limón area production was shipped via the Caño Limón-Coveñas ("CLC") pipeline. The remaining production was shipped via the alternative evacuation route, the Bicentenario ("OBC") pipeline.
- After quarter-end, a new development well drilled in the REX NE field in the Caño Limón area confirmed the opportunity to develop a new reservoir area. Evaluation of potential reserves addition is ongoing.

Committed to ESG goals

- After-quarter end, we published our second Task Force on Climate-related Financial Disclosures ("TCFD") report for 2022, demonstrating our ongoing commitment to improve our ESG performance and disclosure.
- SierraCol continues to make progress on the initiatives to reduce our carbon footprint.
- We continued with the installation of permanent magnet motors in the Caño Limón area, replacing to date over 50% of the motors planned for 2023.
- Regarding fugitive methane emissions, during the second quarter mitigation actions were completed in the Caño Limón area. In Central Llanos, we started measurements to establish the baseline.

Credit ratings

- Fitch and Moody's (after quarter-end) affirmed credit ratings at B+ and B1, respectively, both with stable outlook.

Financial

Financial metrics

- Brent price dropped $4.4/bbl q/q to $77.7/bbl, while Vasconia differential contracted by $2.3/bbl q/q to $5.5/bbl.
- Average realised price of $70.4/boe vs Brent of $77.7/bbl. This reflects 55% of Caño Limón's production was shipped via the OBC pipeline ($1.2/boe).
- Revenue from crude oil sales was $199.7 million, down 12% q/q mainly due to lower realised price ($10.9 million) and lower volumes sold ($16.1 million).
- Adjusted EBITDAX of $131.4 million ($46.1/boe), down 24% q/q, impacted mainly by lower Brent price and higher lifting cost (mostly driven by higher well work activity and foreign exchange impact).
- Last twelve-months ("LTM") Adjusted EBITDAX of $680.4 million, down 11% q/q mainly due to a lower Brent price.
- Adjusted operating netback of $50.9/boe, down 13% q/q mainly as a result of lower Brent price and increased lifting cost per barrel (mostly driven by increased well work activity and lower volumes sold).
- Capital and exploration expenditures of $44.5 million, up 52% q/q due to increased development activity, focused in more complex drilling areas.
- Free Cash Flow of $9.2 million, down 85% q/q mainly due to a lower Adjusted EBITDAX, higher tax payments and increased capital expenses.

Ample liquidity and low net leverage

- Net debt of $497.8 million with cash and cash equivalents of $173.2 million, given a portion of the income tax payment was postponed for 3Q23[1].
- Net leverage of 0.7x.
- Total available liquidity of $239.9 million (cash and cash equivalents of $173.2 million plus $66.7 million in undrawn amounts of committed credit lines).
- In June, $45.0 million was drawn from the Revolving Credit Facility ("RCF") to support working capital requirements[1].
- Dividend payments during the quarter of $1.3 million to non-controlling interest.

Risk management

- For the period 2H23, we have hedged 50% of our hedgeable production, with a weighted average long put strike price of $65.0/bbl, partially financed by selling puts for 29% of our hedgeable production, with a weighted average short put strike price of $46.4/bbl.

[1] Subsequent to the disbursement of the $45.0 million from the RCF, a portion of the income tax payment was postponed for 3Q23, in connection with a special resolution passed by the Colombian Government for companies that received approval to participate in the Works for Taxes program.

Financial and operational results

Key figures

	2Q23	1Q23	2Q22(1)	Δ q/q	Δ y/y	6M23	6M22(1)	Δ y/y
Production & sales (kboed)								
Gross production	77.9	83.2	78.4	-6%	-1%	80.5	82.1	-2%
SBR production(2)	41.9	44.6	42.8	-6%	-2%	43.3	44.7	-3%
Net production	33.2	34.9	31.2	-5%	7%	34.1	33.2	3%
Net sales	31.3	34.0	30.9	-8%	1%	32.7	33.0	-1%
Operating netback per barrel of net sales ($/boe)								
Brent price	77.7	82.1	112.0	-5%	-31%	79.9	104.9	-24%
Realised price	70.4	74.2	103.8	-5%	-32%	72.4	96.9	-25%
Lifting cost	(18.9)	(14.8)	(13.9)	28%	36%	(16.8)	(13.3)	26%
Transport cost	(0.6)	(0.7)	(0.9)	-23%	-37%	(0.7)	(0.9)	-28%
Adjusted operating netback per boe(2)	50.9	58.6	89.0	-13%	-43%	54.9	82.7	-34%
Administrative expenses	(3.0)	(3.3)	(3.3)	-8%	-8%	(3.2)	(3.3)	-4%
Realised loss on oil derivatives	(0.5)	(0.4)	(10.0)	16%	-95%	(0.4)	(7.7)	-94%
Other(3)	(1.3)	1.4	2.0	nm	nm	0.1	1.7	-94%
Operating netback(2)	46.1	56.4	77.7	-18%	-41%	51.5	73.4	-30%
Adjusted EBITDAX ($ million)								
Total revenue	200.5	227.3	291.8	-12%	-31%	427.8	577.8	-26%
Lifting cost	(53.9)	(45.4)	(38.9)	19%	39%	(99.3)	(79.3)	25%
Transport cost	(1.6)	(2.2)	(2.6)	-28%	-39%	(3.8)	(5.3)	-27%
Adjusted operating netback(2)	144.9	179.7	250.3	-19%	-42%	324.6	493.2	-34%
Administrative expenses	(8.6)	(10.1)	(9.2)	-15%	-7%	(18.7)	(19.5)	-4%
Realised loss on oil derivatives	(1.3)	(1.2)	(28.2)	8%	-95%	(2.6)	(45.8)	-94%
Other(3)	(3.6)	4.4	5.6	nm	nm	0.8	9.9	-92%
Adjusted EBITDAX(2)	131.4	172.8	218.5	-24%	-40%	304.2	437.8	-31%
Key financial results ($ million)								
Net income	56.6	75.8	85.6	-25%	-34%	132.4	172.2	-23%
Capex and exploration expenditures(2)	44.5	29.2	32.8	52%	36%	73.7	71.1	4%
Free Cash Flow(2)	9.2	62.8	27.5	-85%	-67%	72.0	157.4	-54%
Cash & cash equivalents	173.2	115.2	189.8	50%	-9%	173.2	189.8	-9%
Net debt(2)	497.8	490.8	414.4	1%	20%	497.8	414.4	20%

(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 has revised its 2023 SBR production guidance to 42 – 44 kboed, from 43 – 45 kboed, in connection with events affecting production in the Caño Limón area. The capital and exploration expenditures guidance remains unchanged.

	2023E original guidance	2023E revised guidance
SBR production (kboed)	43 – 45	42 – 44
Capital and exploration expenditures ($m)[2]	$190 – $210	$190 – $210

Production

kboed	2Q23	1Q23	2Q22	Δ q/q	Δ y/y	6M23	6M22	Δ y/y
Gross production	77.9	83.2	78.4	-6%	-1%	80.5	82.1	-2%
SBR production								
Caño Limón area	24.6	28.0	27.3	-12%	-10%	26.2	28.4	-7%
Middle Magdalena	13.8	14.0	12.8	-2%	8%	13.9	13.6	2%
Central Llanos	3.5	2.6	2.7	33%	31%	3.1	2.8	12%
SBR production	41.9	44.6	42.8	-6%	-2%	43.3	44.7	-3%
Light and medium oil	41.2	43.9	42.3	-6%	-3%	42.5	44.2	-4%
Heavy oil	0.4	0.4	0.3	5%	28%	0.4	0.4	12%
Gas	0.3	0.3	0.2	-8%	73%	0.3	0.2	49%
Royalties in kind	3.5	3.8	3.3	-6%	6%	3.6	3.6	2%
Price-related effects	5.1	6.0	8.3	-15%	-38%	5.6	7.9	-29%
Net production	33.2	34.9	31.2	-5%	7%	34.1	33.2	3%

SBR production for 2Q23 was 41.9 kboed, 2.7 kboed lower than 1Q23. Production was down 3.4 kboed in the Caño Limón area and 0.2 kboed in the Middle Magdalena area, partly offset by an increase in Central Llanos of 0.9 kboed.

Production in the Caño Limón area was impacted by delays in execution of activity (1.5 kboed), downhole failure in two wells (0.9 kboed), disruptions to the pipeline system (0.6 kboed), and minor electrical events and heavy rains causing flooding (0.4 kboed).

Compared to 2Q22, SBR production decreased 0.9 kboed as a result of the impact in the Caño Limón area for reasons explained above (2.7 kboed y/y), which were partially offset by an increase in the Middle Magdalena of 1.0 kboed and in Central Llanos of 0.8 kboed.

1 active rig during the quarter drilled 2 new wells in the Central Llanos area. The workover campaigns included 9 jobs in the Caño Limón area, 3 in Middle Magdalena and 2 in Central Llanos .

SBR production of 43.3 kboed for 6M23, 3% lower compared to 6M22 mainly driven by 2.1 kboed in Caño Limón area, as a result of the events previously described, partially offset by increased production of 0.6 kboed in Central Llanos and in Middle Magdalena area.

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

Revenue

	2Q23	1Q23	2Q22	Δ q/q	Δ y/y	6M23	6M22	Δ y/y
Revenue ($ million)								
Oil sales	199.7	226.7	291.4	-12%	-31%	426.4	576.5	-26%
Natural gas sales	0.6	0.5	0.3	2%	100%	1.1	0.7	55%
Services	0.2	0.1	0.2	205%	6%	0.3	0.6	-54%
Total revenue	200.5	227.3	291.8	-12%	-31%	427.8	577.8	-26%
Net sales (mboe)								
Oil sales	2.8	3.0	2.8	-7%	1%	5.9	5.9	-1%
Natural gas sales	0.02	0.02	0.01	-2%	90%	0.04	0.03	57%
Net sales	2.8	3.1	2.8	-7%	1%	5.9	6.0	-1%
Prices								
Brent ($/bbl)	77.7	82.1	112.0	-5%	-31%	79.9	104.9	-24%
Vasconia differential ($/bbl)	5.5	7.9	5.1	-30%	9%	6.7	4.4	54%
Average realised price ($/boe)	70.4	74.2	103.8	-5%	-32%	72.4	96.9	-25%

Revenue from oil sales decreased 12% q/q, $27.0 million, mainly due to a lower average realised price of $70.4/boe vs $74.2/boe (an impact of $10.9 million) and $16.1 million from a decrease in sales volume of 7% q/q due to pipeline system restrictions.

Average realised price decreased 5% q/q, mainly due to a decrease in Brent price. Average realised price was also impacted considering 55% of Caño Limón production during 2Q23 was sold near well head to be shipped via the OBC pipeline, the alternative route. As a result, those volumes incurred in lower transportation costs, but were sold at a relatively higher commercial discount to account for transportation costs ($1.2/boe[3] or $3.5 million). The Vasconia differential decreased by $2.3/bbl q/q, increasing price realisation and offsetting price impact by $6.6 million.

Compared to 2Q22, revenue from oil sales decreased 31%, mainly due to a lower average realised price driven by decreasing commodity prices ($94.4 million), partially offset by $2.7 million from an increase in volumes sold.

Compared to 6M22, revenue from oil sales decreased 26%, mainly due to a lower average realised price driven by decreasing commodity prices ($138.7 million), the net impact of the OBC pipeline usage of $0.8/boe[3] ($4.7 million) and a decrease in volumes sold ($6.7 million).

Operating expenses

$ million (unless otherwise stated)	2Q23	1Q23	2Q22	Δ q/q	Δ y/y	6M23	6M22	Δ y/y
Lifting cost	53.9	45.4	38.9	19%	39%	99.3	79.3	25%
Transport cost	1.6	2.2	2.6	-28%	-39%	3.8	5.3	-27%
Operating expenses	55.5	47.6	41.6	17%	34%	103.2	84.6	22%
Per barrel of net sales ($/boe)	19.5	15.6	14.8	25%	32%	17.5	14.2	23%

[3] 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

Lifting cost increased by 19% q/q mainly due to: i) higher number of well works during the second quarter, ii) maintenance to pipes and facilities equipments, and iii) foreign exchange rate impact given the Colombian peso revaluation.

Compared to 2Q22 and 6M22, lifting cost was 39% and 25% higher, respectively. This is mainly as a result of: i) an increase in purchased energy in the Caño Limón area given the replacement of crude-based power generation with electricity from the national grid, which is more than offset by the sale of barrels previously used for self-consumption, along with an increase in energy tariffs, ii) higher activity in well interventions across all assets, and iii) higher equipment maintenance activities in Central Llanos and La Cira Infantas. These increases were partially offset by foreign exchange benefit ($3,915 USD/COP in 2Q22 vs $4,432 USD/COP in 2Q23; $3,914 USD/COP in 6M22 vs $4,595 USD/COP in 6M23).

Transport cost decreased $0.6 million vs 1Q23 and $1.0 million vs 2Q22 due to reduced evacuation via the CLC pipeline due to pipeline system restrictions.

Absolute operating expenses increased 17% vs 1Q23 while the cost per barrel increased by 25%, as net sales decreased 7% q/q.

Absolute operating expenses vs 2Q22 and 6M22 increased 34% and 22%, while the cost per barrel increased 32% and 23%, respectively.

Adjusted operating netback per boe

$/boe of net sales	2Q23	1Q23	2Q22	Δ q/q	Δ y/y	6M23	6M22	Δ y/y
Realised price	70.4	74.2	103.8	-5%	-32%	72.4	96.9	-25%
Lifting cost	(18.9)	(14.8)	(13.9)	28%	36%	(16.8)	(13.3)	26%
Transport cost	(0.6)	(0.7)	(0.9)	-23%	-37%	(0.7)	(0.9)	-28%
Adj. operating netback per boe	50.9	58.6	89.0	-13%	-43%	54.9	82.7	-34%

Adjusted operating netback per boe was $50.9/boe, down 13% q/q, as a result of the lower realised price and a 25% increase in operating expenses explained in the previous section.

Compared to 2Q22 and 6M22, Adjusted operating netback per boe decreased 43% and 34%, respectively.

Administrative expenses

$ million	2Q23	1Q23	2Q22	Δ q/q	Δ y/y	6M23	6M22	Δ y/y
Administrative expenses	8.6	10.1	9.2	-15%	-7%	18.7	19.5	-4%

Administrative expenses decreased 15% q/q as a result of higher recovery of costs from partners during 2Q23 partially offset by adverse foreign exchange impact.

Compared to 2Q22 and 6M22 administrative expenses decreased by $0.6 million and $0.8 million, respectively.

Capital expenditures

$ million	2Q23	1Q23	2Q22[1]	Δ q/q	Δ y/y	6M23	6M22[1]	Δ y/y
Caño Limón area	22.3	9.4	12.7	138%	76%	31.7	26.8	18%
Middle Magdalena	6.0	6.7	8.2	-10%	-26%	12.7	21.1	-40%
Central Llanos	14.5	10.9	2.3	32%	530%	25.4	3.3	676%
Development capex	42.8	27.0	23.2	59%	85%	69.9	51.1	37%
Exploratory drilling	0.8	0.1	8.8	488%	-90%	1.0	18.4	-95%
Total capex	43.7	27.1	32.0	61%	36%	70.8	69.6	2%
Exploration expenses[2]	0.8	2.1	0.8	-61%	4%	2.9	1.6	85%
Capex and exploration expenditures	44.5	29.2	32.8	52%	36%	73.7	71.1	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] Exploratory expenses are presented net of dry hole costs and impairments.

Development capex increased 59% q/q, as a result of higher drilling, workover and maintenance activity across all assets, focused in more complex drilling areas in Caño Limón and Central Llanos. 2 wells were drilled and completed and 15 workover jobs were executed in 2Q23 vs 9 wells drilled and completed and 8 workover jobs during 1Q23.

Compared to 2Q22 and 6M22, development capex increased 85% and 37% respectively, mainly due to the continuity of the Central Llanos drilling campaign (which started in 4Q22) and higher drilling activity in the Caño Limón area.

Exploratory drilling in 6M23 decreased 95% vs 6M22 given no exploration wells were drilled during the first half of 2023.

Capital and exploration expenditures totalled $73.7 million in 6M23 vs $71.1 million y/y, a 4% increase.

Adjusted EBITDAX and Free Cash Flow

$ million	2Q23	1Q23	2Q22[1]	Δ q/q	Δ y/y	6M23	6M22[1]	Δ y/y
Net income for the period	56.6	75.8	85.6	-25%	-34%	132.4	172.2	-23%
Financial income and financial expenses	6.7	8.8	8.9	-24%	-25%	15.5	17.7	-12%
Depreciation, depletion and amortisation	31.7	32.0	29.8	-1%	6%	63.7	59.4	7%
Income tax expense	37.6	48.2	93.6	-22%	-60%	85.8	139.8	-39%
Exploration expenses and dry hole cost	1.0	2.5	9.0	-58%	-88%	3.5	27.9	-87%
Foreign exchange (income) / loss	(2.6)	6.9	(3.2)	nm	-21%	4.4	2.8	53%
Accretion of decommissioning liability	1.1	1.0	1.1	3%	-7%	2.1	2.8	-25%
Prepaid expenses and bond cost amortisation	2.1	3.3	3.3	-36%	-37%	5.3	6.3	-16%
Unrealised fair value gain on derivatives	(0.2)	(0.4)	(11.4)	-55%	-98%	(0.6)	4.8	nm
Inventory fluctuation	(2.8)	(5.2)	1.8	-46%	nm	(8.0)	0.5	nm
Fair value remeasurements	–	–	–	–%	–%	–	3.9	-100%
Other non-cash items	0.2	–	–	–%	nm	0.2	(0.2)	nm
Adjusted EBITDAX	131.4	172.8	218.5	-24%	-40%	304.2	437.8	-31%
Exploration drilling[2]	(0.8)	(0.1)	(8.8)	487%	-90%	(1.0)	(18.4)	-95%
Exploration and seismic expense	(0.8)	(2.1)	(0.8)	-61%	4%	(2.9)	(1.6)	85%
Tax payments	(61.6)	(18.2)	(112.7)	238%	-45%	(79.8)	(132.1)	-40%
Capital expenditures[2]	(42.8)	(27.0)	(23.2)	59%	85%	(69.8)	(51.1)	37%
Acquisition of PUT-36	–	–	(10.0)	–%	-100%	–	(10.0)	-100%
Inventory of capitalizable parts/	–	–	(2.8)	–%	-100%	–	(2.8)	-100%
Change in working capital[3]	(24.2)	(66.5)	(30.1)	-64%	-20%	(90.7)	(61.3)	48%
Realised FX rate gain (loss)	8.5	4.5	(1.7)	88%	nm	13.0	(1.0)	nm
Lease payments	(0.4)	(0.6)	(0.9)	-27%	-57%	(1.0)	(2.2)	-57%
Free Cash Flow	9.2	62.8	27.5	-85%	-67%	72.0	157.4	-54%

[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.

Increase in working capital in 2Q23 vs 1Q23 of $42.3 million is mainly due to an increase in accounts payable as a result of increased activity in the second quarter.

Adjusted EBITDAX was $131.4 for 2Q23 and $304.2 million for 6M23, resulting in an Operating netback of $46.1/boe and $51.5/boe, respectively. Adjusted EBITDAX decreased 24% q/q and 31% y/y mainly due to a decrease in Brent price (of $4.4/bbl and $25.0/bbl, respectively) and the higher lifting cost of the current period. Free Cash Flow totalled $9.2 million during the quarter and $72.0 million for 6M23.

Cash flows

The table summarises the classification of our cash flows for 6M23 and 6M22:

$ million	6M23	6M22[(1)]
Net cash flows from operating activities	126.8	220.6
Net cash flows used in investing activities	(92.6)	(107.0)
Net cash flows from financing activities	32.1	(41.4)
Increase in cash and cash equivalents during the period	66.3	72.2
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	0.7	(1.7)
Cash and cash equivalents at the end of the period	173.2	189.8

(1) Contingent payments of $55.0 million have been reclassified from the line item 'Change in trade and other payables' in the 'Changes in assets and liabilities' section, as presented in the 2Q22 interim financial statements, to 'Contingent consideration' line item within 'Net cash flows used in investing activities', to provide consistency with the presentation in the 2022 UK Annual Report. This reclass did not result in changes to net income for the period, net increase in cash and cash equivalents or the net balance sheet.

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

Cash flows from operating activities for 6M23 of $126.8 million is presented net of cash taxes paid of $79.8 million. Cash flows used in investing activities include cash additions of $53.1 million to property, plan and equipment ("PPE") and $0.7 million to exploration and evaluation assets, $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 $10.0 million, a total drawdown of short-term debt of $65.0 million (including $45.0 million from the RCF), interest and financial expenses paid of $20.1 million and lease payments of $1.0 million.

Cash and cash equivalents at quarter-end were $173.2 million, as a result of slippage of some income tax payments from 2Q23 to 3Q23[5].

Liquidity and capital resources

$ million (unless stated)	6M23	6M22
2028 senior notes @ 6%	600.0	600.0
Drawdown of short-term debt	65.0	–
Capital lease obligations	6.0	4.1
Total indebtedness	671.0	604.1
(-) Cash & cash equivalents	173.2	189.8
(=) Net debt	497.8	414.4
LTM Adjusted EBITDAX	680.4	729.8
Net leverage (x)	0.7x	0.6x
Cash and cash equivalents	173.2	189.8
Undrawn amounts of committed credit lines[4]	66.7	61.8
Total liquidity	239.9	251.6

We ended 6M23 with an ample liquidity, closing at $239.9 million, considering a portion of the income tax payment was postponed for 3Q23[5]. We maintain a low net leverage at 0.7x.

During the quarter, $20.0 million was drawn down from a short-term credit line and $45.0 million was drawn down from the RCF to support working capital requirements[5]. Current undrawn amount of the RCF is $66.7 million[4], from an aggregate principal amount of commitments provided of $120.0 million.

[4] RCF undrawn amount as of 30 June 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.

[5] Subsequent to the disbursement of the $45.0 million from the RCF, a portion of the income tax payment was postponed for 3Q23, in connection with a special resolution passed by the Colombian Government for companies that received approval to participate in the Works for Taxes program.

Summary of quarterly results[1]

	2Q23	1Q23	4Q22	3Q22	2Q22	1Q22	4Q21	3Q21
Production & sales (kboed)								
Gross production	77.9	83.2	81.4	80.1	78.4	85.8	83.6	78.8
SBR production[2]	41.9	44.6	44.2	43.5	42.8	46.7	45.1	41.6
Net production	33.2	34.9	33.0	32.0	31.2	35.3	34.3	31.6
Net sales	31.3	34.0	32.1	30.3	30.9	35.0	34.8	30.3
Operating netback per barrel of net sales ($/boe)								
Brent price	77.7	82.1	88.6	97.7	112.0	97.9	79.7	73.2
Realised price	70.4	74.2	81.3	92.6	103.8	90.7	70.2	63.9
Lifting cost	(18.9)	(14.8)	(16.5)	(16.8)	(13.9)	(12.8)	(14.0)	(15.1)
Transport cost	(0.6)	(0.7)	(0.8)	(0.9)	(0.9)	(0.8)	(0.4)	(0.4)
Adjusted operating netback per boe[2]	50.9	58.6	64.0	74.9	89.0	77.1	55.8	48.4
Administrative expenses	(3.0)	(3.3)	(4.4)	(1.9)	(3.3)	(3.3)	(3.8)	(2.1)
Realised loss on derivatives	(0.5)	(0.4)	(0.3)	(1.0)	(10.0)	(5.6)	(2.4)	(0.4)
Other[3]	(1.3)	1.4	(1.6)	1.9	2.0	1.4	3.4	(2.0)
Operating netback[2]	46.1	56.4	57.7	73.9	77.7	69.6	53.0	43.9
Adjusted EBITDAX ($ million)								
Total revenue	200.5	227.3	240.2	258.2	291.8	286.0	224.7	178.2
Lifting cost	(53.9)	(45.4)	(48.7)	(46.8)	(38.9)	(40.4)	(45.0)	(42.2)
Transport cost	(1.6)	(2.2)	(2.5)	(2.5)	(2.6)	(2.6)	(1.4)	(1.0)
Adjusted operating netback[2]	144.9	179.7	189.0	208.9	250.3	242.9	178.3	135.0
Administrative expenses	(8.6)	(10.1)	(12.9)	(5.3)	(9.2)	(10.2)	(12.1)	(5.9)
Realised loss on derivatives	(1.3)	(1.2)	(1.0)	(2.8)	(28.2)	(17.5)	(7.8)	(1.0)
Other[3]	(3.6)	4.4	(4.7)	5.0	5.6	4.2	11.1	(5.6)
Adjusted EBITDAX[2]	131.4	172.8	170.5	205.8	218.5	219.4	169.6	122.4
Key financial results ($ million)								
Net income	56.6	75.8	45.6	80.9	85.6	86.6	84.9	45.6
Capex and exploration expenditures[2]	44.5	29.2	78.5	55.3	32.8	38.3	61.8	43.1
Free Cash Flow[2]	9.2	62.8	113.8	130.0	27.5	129.9	139.3	33.6
Cash & cash equivalents	173.2	115.2	106.2	302.5	189.8	178.4	119.3	261.1
Net debt[2]	497.8	490.8	494.8	300.7	414.4	426.7	488.4	347.8

[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 programme

Our commodity hedging program 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.

As of the date of this document, for the period 2H23, we had hedged 50% of our production, with a weighted average long put strike price of $65.0/bbl. The following table shows the percentage of hedged volumes and weighted average long put strike price per quarter:

	3Q23	4Q23	2H23
Hedged volumes in long puts (%)	50%	50%	50%
Weighted average strike ($/bbl)	65.0	65.0	65.0

Some of our long put positions were partially financed by selling puts. The following table shows the percentage of hedged volumes and weighted average short put strike price per quarter:

	3Q23	4Q23	2H23
Hedged volumes in short puts (%)	50%	8%	29%
Weighted average strike ($/bbl)	46.7	45.0	46.4

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

Currency hedging programme

We had currency hedging positions for a total of $148.0 million in 1H23 in connection with tax payments. 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.

As of the date of this document, we have not entered into currency hedge positions for 2H23.

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 30 June 2023 and 2022 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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