Management Discussion and Analysis

The following management discussion and analysis ("MD&A") of SierraCol Energy Limited and its subsidiaries ("the Company") financial condition and results of operations should be read in conjunction with the Unaudited Interim Combined Financial Statements and the Condensed Consolidated Financial Statements for the nine months ended 30 September 2021 and the notes thereto. The primary differences between the Consolidated Financial Statements and the Combined Financial Statements for each period presented herein relate primarily to certain cash, capital structure, management loans, guarantees of certain obligations of other group entities, transaction costs and compensation expenses, miscellaneous administrative costs and hedging activities conducted by Swissco. 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 one accounting period. The quantities of over-and under-lifted production entitlement are not considered material to the overall production figures in any period. 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.

3Q21 Performance Highlights

Operational

- **Resilient operations**
  - Net production of 31.6 kboepd in 3Q21, down 9% compared with 2Q21, due to weather-related events (floodings in Arauca and failure of the national power grid) in the Caño Limón area, a labour strike at La Cira Infantas, and the impact of high-price clauses on net production
  - Production has since been restored from 78.8 kboepd gross (3Q21) to 82.8 kboepd gross (November 2021)
  - The Caño Limón Coveñas ("CLC") pipeline was shut-in between 4 August and 28 November as a result of major landslides caused by heavy rain. The alternative route of Bicentenario pipeline ("OBC") was used during this period to evacuate crude from the Caño Limón area, but the CLC pipeline resumed normal operations on 28 November
  - Operational activity increased in 3Q with 3 active rigs which drilled 9 wells in La Cira Infantas, 1 well in the Caño Limón area and 1 well in Central Llanos. In addition 10 workovers were completed during 3Q21
  - The Pumara-2 well discovery in Central Llanos found oil in the Guadalupe, Gacheta and Mirador formations. Evaluations continue
- **Delivering on ESG**
  - We are on track for achieving a significant reduction in our carbon footprint by the end of 2021 and further reductions in coming years
  - Completed phase two of the crude oil power plant shutdown (37MW) in the Caño Limón operations (migrating to the national grid) on 9 September
  - Approved contract for construction of a 40 MW solar park in the Caño Limón area. The contractor is working on detailed engineering and project socialization in the area. Expected to be fully operational by 2H22
  - Continued progress against the Environmental and Social Action Plan (ESAP) objectives
  - Inaugural sustainability report for the year 2020 was issued in November 2021

Financial

- **Strong financial results**
  - Revenue for oil sales in 9M21 was $561.8 million, up 44% vs same period last year as a result of higher realisations ($225.0 million) partly offset by lower volumes ($53.9 million)
  - Average realised price of $62.9/boe during 9M21 vs Brent of $67.8/bbl
  - Adjusted Operating netback of $48.2/boe and Operating netback of $46.5/boe in 9M21, remaining best-in-class
  - Adjusted EBITDAX of $416.7 million in 9M21. Including COG for the full period[1] would yield a Pro Forma Adjusted EBITDAX of $423.0 million
  - Free Cash Flow of $132.2 million in 9M21 and Adjusted Capex of $92.5 million[2]
- **Robust cash position and low net leverage**
  - Net debt of $338.9 million with cash and cash equivalents of $261.1 million
  - Net leverage is 0.6x
  - Total available liquidity in 9M21 is $327.7 million as a result of cash and cash equivalents plus $66.6 million still undrawn from our RCF
  - First coupon payment of $18 million on 15 Dec/21
  - In light of our cash generation and available liquidity, we will make a dividend payment of $250.0 million on 16 Dec/21, maintaining a prudent leverage below 1.0x
- **Risk management**
  - We continue to protect our oil price downside risk through hedging, while avoiding speculative positions and leaving room for upside potential
  - As of the date of this document, we had hedged 55% of our production for the 4Q21-3Q22 and 35% of our production for 1Q22-4Q22, using three-way hedging structures with an average long put strike price of $50.8/bbl and $50.7/bbl, respectively.
  - We expect to be back towards our indicative level of 50% for the next twelve months as we move through next year, and will continue to use our judgement to evaluate the market.

[1] COG only included in actual results from May 2021

[2] Including COG for the full period and all exploration activities, total capex and exploration expenses is $106.7 million

Financial and Operational Results

Key Figures from the Combined Financial Statements

$ million (unless otherwise stated)	3Q20	2Q21	3Q21	Δ q/q	Δ y/y	9M20	9M21	Δ y/y
Production & Sales								
Gross production (kboepd)	84.8	84.3	78.8	-7%	-7%	88.8	81.9	-8%
Net production (kboepd)	37.9	34.7	31.6	-9%	-17%	37.4	33.8	-10%
Net sales (kboepd)	42.3	36.7	30.3	-17%	-28%	37.7	32.8	-13%
Adjusted Operating netback[3]								
Realised price ($/boe)	40.3	65.0	64.0	-2%	59%	37.9	62.9	66%
Lifting cost ($/boe)	(8.7)	(12.4)	(15.6)	25%	79%	(8.7)	(14.2)	63%
Transport cost ($/boe)	(0.6)	(0.6)	(0.2)	-70%	-72%	(0.7)	(0.5)	-21%
Adjusted Operating netback ($/boe)	31.0	52.0	48.3	-7%	56%	28.5	48.2	69%
Financial Results								
Revenue	157.0	217.0	178.3	-18%	14%	391.3	564.1	44%
Lifting cost	33.9	41.5	43.4	5%	28%	90.0	127.6	42%
Transport cost	2.4	1.9	0.5	-75%	-80%	6.9	4.7	-31%
Adjusted Operating netback	120.8	173.6	134.5	-23%	11%	294.4	431.7	47%
Administrative expenses	7.1	4.9	5.0	4%	-29%	28.5	20.4	-29%
Income tax expense / (income)	(29.3)	34.9	52.3	50%	278%	(19.1)	136.7	816%
Net income	61.0	86.0	31.3	-64%	-49%	103.2	143.2	39%
Adjusted Capex	1.3	37.6	39.4	5%	2,932%	42.9	92.5	116%

Key Figures from the Consolidated Financial Statements

$ million (unless otherwise stated)	9M21
Adjusted EBITDAX[3]	416.7
Operating netback ($/boe)[3]	46.5
Pro Forma Adjusted EBITDAX[3]	423.0
Free Cash Flow[3]	132.2
Net debt	338.9
Net leverage[4] (x)	0.6x

[3] See “Non-IFRS Measures” section on page 9
[4] Calculated as net debt divided by annualized Adjusted EBITDAX

4Q21 Outlook

- We expect a further ramp up in activity during 4Q21 with a second drilling rig in the Caño Limón area and a second drilling rig in La Cira Infantas to accelerate development campaigns in 4Q21, for a total of 5 drilling rigs in 4Q21
- Additional workover and well service activities are also planned
- Waterflood strategy to recover injection process efficiency continues in La Cira Infantas
- Batea exploration well in La Cira Infantas has been drilled and evaluations are ongoing
- Civil works and other preparations for the Caño Caranal well are expected before year-end
- On 28 November 2021 the CLC pipeline resumed normal operations
- First coupon payment of $18 million on 15 December 2021
- In light of our cash generation and available liquidity of $327.7 million, we will make a dividend payment of $250.0 million on 16 December 2021, maintaining a prudent leverage below 1.0x

2021 Guidance

	2021E[5]
Net production (kboepd)	34 – 36
Capital and exploration expenditures[6] ($m)	170 – 190

We expect FY21 net production and capital and exploration expenditures results to be within the stated guidance range.

Figures and Analysis from Combined Statements

Production

kboepd	3Q20	2Q21	3Q21	Δ q/q	Δ y/y	9M20	9M21	Δ y/y
Gross production	84.8	84.3	78.8	-7%	-7%	88.8	81.9	-8%
Net production								
Caño Limón area	24.4	21.2	18.5	-13%	-24%	23.1	20.6	-10%
Middle Magdalena	13.5	11.8	10.7	-10%	-21%	14.4	11.8	-18%
Central Llanos	0.0	1.6	2.4	47%	100%	0.0	1.4	100%
Net production	37.9	34.7	31.6	-9%	-17%	37.4	33.8	-10%
Oil	37.9	34.3	31.4	-8%	-17%	37.4	33.5	-10%
Gas	0.0	0.4	0.3	-31%	428%	0.1	0.3	309%

Net production decreased 9% q/q mainly as a result of weather-related events in the Caño Limón area and a labour strike at La Cira Infantas. In July, the Arauca Department was severely impacted by floods and a failure in the national power grid. These events affected the Caño Limón area operations by 2.0

[5] The guidance was constructed assuming a $70/bbl Brent price for 2H and COG for the whole period
[6] The guidance includes development and exploration capex plus exploration expenses

kboepd. In September, a strike delayed the drilling campaign in La Cira Infantas by a month, affecting production by an additional 0.6 kboepd.

Production optimization options are being implemented across all assets to mitigate the impact, including base production optimization and acceleration of drilling programs. The Caño Limón area and La Cira Infantas each had an additional rig ready to drill in October. Additional workovers and redesigns are being executed in the Caño Limón area. The strike at La Cira Infantas has been lifted and operations have resumed.

Net production was also affected by 1.4 kboepd as a result of the Price Premium Adjustments ("PPA") from the high-price clauses in the Cravo Norte and La Cira Infantas contracts, which led to a lower share of production. The Caño Limón area and La Cira Infantas had an impact of 0.7 kboepd each.

Compared to 3Q20 and 9M20 production decreased by 17% and 10% respectively, due mainly to: i) a lower share in production and ii) and lower production performance in La Cira Infantas.

Revenue

	3Q20	2Q21	3Q21	Δ q/q	Δ y/y	9M20	9M21	Δ y/y
Revenue ($ million)								
Oil sales	156.7	215.8	177.6	-18%	13%	390.7	561.8	44%
Natural gas sales	0.1	0.9	0.6	-32%	432%	0.4	1.8	371%
Services	0.2	0.3	0.2	-53%	-31%	0.2	0.5	118%
Revenue	157.0	217.0	178.3	-18%	14%	391.3	564.1	44%
Net sales								
Oil sales (mbbl)	3.9	3.3	2.8	-16%	-29%	10.3	8.9	-14%
Natural gas sales (mboe)	0.0	0.0	0.0	-31%	428%	0.0	0.1	308%
Net sales (mboe)	3.9	3.3	2.8	-17%	-28%	10.3	9.0	-13%
Prices								
Brent ($/bbl)	43.4	69.0	73.2	6%	69%	42.5	67.8	59%
Vasconia differential ($/bbl)	3.0	2.9	4.0	39%	33%	4.9	3.1	-37%
Average realised price ($/boe)	40.3	65.0	64.0	-2%	59%	37.9	62.9	66%

Revenue from oil sales decreased 18% q/q, $38.2 million, mainly due to lower sales as a result of the decrease in net production. This decrease is primarily explained by lower production from the mentioned 3Q21 events, with an impact of $35.4 million, 24% of which is caused by PPA clauses. The remaining $2.8 million are due to the decrease in realised oil price.

In early August, we started evacuating our oil through the OBC pipeline as an alternative route to the CLC pipeline, due to damages the latter sustained caused by landslides created by heavy rains. This has temporarily affected our realised price, with a $3.2/bbl impact for the quarter[7]. The Vasconia differential increased 39% q/q, which further affects our realised price.

[7] OBC pipeline costs are accounted for in the realised price as an offset to Brent

Compared to 3Q20 and 9M20 revenue from oil sales increased by 13% and 44% respectively, due mainly to rising commodity prices ($66.2 million and $225.0 million, respectively), partially offset by lower production volumes (-$45.4 million and -$53.9 million, respectively).

Operating Expenses

$ million (unless otherwise stated)	3Q20	2Q21	3Q21	Δ q/q	Δ y/y	9M20	9M21	Δ y/y
Lifting cost	33.9	41.5	43.4	5%	28%	90.0	127.6	42%
Transportation cost	2.4	1.9	0.5	-75%	-80%	6.9	4.7	-31%
Operating expenses[8]	36.2	43.4	43.9	1%	21%	96.8	132.4	37%
Per unit ($/boe)	9.3	13.0	15.7	21%	69%	9.4	14.8	57%

Lifting cost increased 5% q/q mainly due to higher costs caused by the flooding and electrical contingency in the Caño Limón area and higher maintenance activity. Transporation costs decreased 75% q/q due to reduced evacuation through the CLC pipeline. The impact of the use of the OBC pipeline is reflected in the lower realisation price of the quarter.

Absolute operating expenses increased only 1% when compared to the previous quarter, but the cost per barrel increased 21% as a result of the lower production.

Compared to 3Q20 and 9M20 operating expenses grew by 21% and 37% respectively, due to higher workover and drilling activity.

Adjusted Operating Netback

$/boe	3Q20	2Q21	3Q21	Δ q/q	Δ y/y	9M20	9M21	Δ y/y
Realised price	40.3	65.0	64.0	-2%	59%	37.9	62.9	66%
Operating expenses	(9.3)	(13.0)	(15.7)	21%	69%	(9.4)	(14.8)	57%
Adjusted Operating netback	31.0	52.0	48.3	-7%	56%	28.5	48.2	69%

Adjusted Operating netback decreased 7% q/q mainly due to the impact on realised price caused by the use of OBC pipeline and the increase in operating expenses per barrel, as a result of lower production. In absolute terms, operating expenses remained at the same level q/q.

Compared to 3Q20 and 9M20 Adjusted Operating netback per barrel increased 56% and 69% respectively, mainly as a result of rising commodity prices, leading to higher realised prices, partially offset by additional operating costs of $6.4/boe and $5.4/boe respectively, as a result of increased workover and well services activity.

[8] Operating expenses does not include inventory fluctuation as it is a non-cash item

Administrative Expenses

$ million	3Q20	2Q21	3Q21	Δ q/q	Δ y/y	9M20	9M21	Δ y/y
Administrative expenses	7.1	4.9	5.0	4%	-29%	28.5	20.4	-29%

Administrative expenses in 3Q21 remained stable q/q. Compared to 3Q20 and 9M20 these expenses decreased 29% in both periods mainly as a result of a reduction in expatriate personnel since SierraCol now operates as a standalone entity, and also higher overhead recovery from the joint venture partners in the Caño Limón area due to higher activity.

Capital Expenditures

$ million	3Q20	2Q21	3Q21	Δ q/q	Δ y/y	9M20	9M21	Δ y/y
Caño Limón area	(0.7)	19.5	18.7	-4%	2,771%	25.1	50.0	99%
Middle Magdalena	2.3	16.4	13.4	-18%	483%	21.0	33.3	59%
Central Llanos	0.0	1.7	7.5	333%	100%	0.0	9.5	100%
Development capex	1.6	37.7	39.6	5%	2,376%	46.1	92.8	101%
Less: Teca	(0.3)	(0.1)	(0.2)	125%	-33%	(3.2)	(0.2)	-92%
Adjusted Capex	1.3	37.6	39.4	5%	2,932%	42.9	92.5	116%
of development activities	(1.3)	24.4	29.5	21%	2,370%	31.3	66.6	113%
of which maintenance activities	2.6	13.2	9.9	-25%	281%	11.6	25.9	124%
Exploratory drilling	0.1	0.3	2.5	605%	2,595%	0.3	3.2	841%
Total capex	1.4	37.9	41.9	10%	2,910%	43.2	95.7	122%

Adjusted Capex increased 116% from 9M20 to 9M21, mainly due to the ramp up in drilling and workover program in the Caño Limón area, lines replacement activity and major tanks maintenance. La Cira Infantas in Middle Magdalena also increased activity from 2020, as all rigs were removed from the area since late March 2020 due to the pandemic. In Central Llanos, increase in investments is primarily explained by the Danés-2 well. We have also conducted IT one-off investments due to the separation from Oxy.

We have low maintenance capex requirements of only 28% of Adjusted Capex for 9M21. This allows us to direct our available funding to growing production and reserves.

Figures and Analysis from Consolidated Statements

Adjusted EBITDAX and Free Cash Flow

The following table shows the reconciliation of net income to Adjusted EBITDAX to Free Cash Flow:

$ million	9M21
Net income for the period	**90.9**
Financial income and financial expenses	15.8
Depreciation, depletion and amortization	68.9
Income tax expense	135.6
Exploration and seismic expenses and dry hole cost	7.1
Foreign exchange (income) / loss	4.1
Accretion of decommissioning liability	6.0
Non-recurring costs	8.5
Unrealized fair value gain on derivates	15.2
Amortization of prepaid expenses	7.8
Property, plant and equipment retirement	0.1
Fair value remeasurement contingent consideration	57.6
Teca	(1.0)
Adjusted EBITDAX	**416.7**
Exploration drilling	(3.1)
Exploration expense	(7.1)
Tax payments	(56.3)
Cash capital expenditures	(92.3)
Decommissioning funding	0.0
Change in working capital	(112.8)
Non-recurring costs	(8.5)
Realized foreign exchange rate	(0.1)
Lease payments	(4.3)
Free Cash Flow	**132.2**

The change in working capital of $112.8 million for the 9M21 period was mainly due to higher accounts receivable, driven primarily by increases in volumes billed but not yet paid by customers ($42.9 million), and tax receivables ($28.0 million); trade receivables have since been collected. There was also an impact on accounts payable, driven by higher payments due to increased workover and drilling activity.

Adjusted EBITDAX for 9M21 was $416.7 million, resulting in an Operating netback of $46.5/boe, and generating $132.2 million of Free Cash Flow. Pro Forma Adjusted EBITDAX for 9M21 was $423.0 million.

Cash Flows

The following table presents our primary sources and uses of cash and cash equivalents for 9M21:

$ million	9M21
Net cash flows from operating activities	232.9
Net cash flows used in investing activities	(89.1)
Net cash flows from financing activities	8.2
Increase in cash and cash equivalents during the period	**151.9**
Cash and cash equivalents at the beginning of the period	109.5
Effect of foreign exchange on cash and cash equivalents held in foreign currencies	(0.3)
Cash and cash equivalents at the end of the period	**261.1**

Cash flows from operating activities is presented net of cash taxes paid of $56.3 million. Cash flows used in investing activities include additions to PPE of $95.4 million partially offset by cash acquired from COG for $6.0 million. Cash flows from financing activities include the issuance of the 2028 senior notes for $600 million, partially offset by the RBL repayment of $195.0 million and dividends paid for $372.7 million.

Cash and cash equivalents for 9M21 were $261.1 million increasing 138% from the beginning of the period.

Liquidity and Capital Resources

$ million (unless otherwise stated)	9M21
2028 senior notes @ 6%	600.0
Net debt	338.9
Annualized Adjusted EBITDAX	555.5
Net leverage (x)	0.6x
Cash and cash equivalents	261.1
RCF (available amount)	66.6
Total liquidity	327.7

For 9M21 we are currently maintaining our strong financial position because of ample liquidity, low leverage, and long-dated debt maturities.

In light of our cash generation and available liquidity of $327.7 million, we will make a dividend payment of $250.0 million on 16 December 2021, maintaining a prudent leverage below 1.0x.

Risk Management Contracts

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, we had hedged 55% of our production for the 4Q21-3Q22 and 35%[9] of our production for 1Q22-4Q22, using three-way hedging structures with an average long put strike price of $50.8/bbl and $50.7/bbl, respectively. We expect to be back towards our indicative level of 50% for the

[9] In each case excluding production attributable to the minority interest held by Repsol in SierraCol Arauca

next twelve months as we move through next year, and will continue to use our judgement to evaluate the market.

Non-IFRS Measures

This MD&A contains non-IFRS financial measures and ratios, including Adjusted EBITDAX, Pro Forma Adjusted EBITDAX, Free Cash Flow and Adjusted Capex 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 amortization, 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 including 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.

Pro Forma Adjusted EBITDAX: consists of Adjusted EBITDAX including the contribution of COG for the full period of 2021.

Adjusted Operating netback: calculated as average realised price minus operating expenses per barrel

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

Adjusted Capex: consists of net cash used in investing activities adjusted to remove the impact of exploration drilling and dry hole expenses and certain other items, and excluding the contribution from the Teca license to net cash used in investing activities.

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