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 Combined Financial Statements and the Condensed Consolidated Financial Statements for the year ended 31 December 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 single 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

FY21 & 4Q21 Performance Highlights

Operational

- **Strong performance overall**
  - FY21 gross production of 83.1 kboed, net production of 34.6 kboed, within guidance[1]. Exit rate of 36.1 kboed.
  - Net production of 34.3 kboed in 4Q21, up 8% compared with 3Q21, due to recovery from the events in 3Q21. Down 7% vs 4Q20 mainly as a result of a lower share in production caused by high-price clauses.
  - Operational activity increased in 4Q21 with 15 wells drilled and 22 workovers. In FY21, we drilled 28 wells: 4 wells in the Caño Limón area, 21 wells in La Cira Infantas and 3 wells in Central Llanos. In addition, 111 workovers were completed during 2021.
  - The Caño Limón-Coveñas ("CLC") pipeline resumed normal operations on 28 November. No batches through Bicentenario ("OBC") pipeline in December.
  - Certified 2P reserves of 116 million boe, with an R/P ratio of 9.7 years and a reserves replacement ratio of 104%.
- **Delivering on ESG**
  - During 2021 we set ambitious goals related to energy efficiency and transition programmes, with an aspiration to be carbon neutral by 2030.
  - In 2021 we reduced our emissions by 18% vs 2020. Our emissions intensity factor improved from 33 to 28 kg CO_2e/boe. We remain on track to deliver a 50% reduction in emissions by 2023 (vs 2020 baseline).
  - 2021 TRIR of 0.89 with 15% reduction vs 2020 and the lowest in the last three years.
  - In 2021 we replaced a total of 37 MW of crude-based power generation with energy from the national grid.
  - The Environmental and Social Action Plan (ESAP) was developed, and the relevant 2021 actions have been implemented. 2022 actions are ongoing.
  - Inaugural sustainability report for the year 2020 was issued in November 2021.

Financial

- **Strong financial results**
  - Oil sales revenue in FY21 of $786.2 million, up 47% vs FY20 as a result of higher realisations ($314.4 million) partly offset by lower volumes ($63.8 million).
  - Average realised price of $64.9/boe during FY21 vs Brent of $70.9/bbl.
  - Industry-leading netbacks with Adjusted operating netback of $50.3/boe and Operating netback of $47.4/boe in FY21.
  - Adjusted EBITDAX of $576.3 million in FY21.
  - Free Cash Flow of $268.5 million in FY21 and total capex & exploration activities of $166.8 million. Including COG for the whole year the total is $170.7 million[1], in line with guidance.
- **Robust cash position and low net leverage**
  - Net debt of $480.7 million with cash and cash equivalents of $119.3 million.
  - Net leverage is 0.8x for year-end 2021.
  - Total available liquidity is $181.1 million as a result of cash and cash equivalents plus $61.8 million unused RCF.
  - First coupon payment of $18.0 million and a dividend payment of $250.0 million in December 2021.
- **Risk management**
  - We are actively managing a Brent price hedging programme.
  - For the 1Q22-4Q22 period, 53% of our volumes are hedged with a weighted average long put strike price of $54/bbl and a and net premium of $1.07/bbl.
  - Weighted average call strike price of $83/bbl over 36% of hedgeable volumes, winding down throughout the year.
  - For the 2Q22-1Q23 and 3Q22-2Q23 periods we have hedged 43% and 35% of our production, with an average long put strike price of $56/bbl and $59/bbl, respectively.

[1] Guidance: FY21 production includes twelve months of production from the COG assets, and twelve months execution of capex & exploration activities. The consolidated financial statements for the period ended 31 December 2021 will, however, only include the results of COG from the date of acquisition, 4 May 2021

Financial and Operational Results

Key Figures from the Combined Financial Statements

$ million (unless stated)	4Q20	3Q21	4Q21	Δ q/q	Δ y/y	FY20	FY21	Δ y/y
Production & Sales								
Gross production (kboed)	84.4	78.8	83.6	6%	-1%	87.7	82.3	-6%
Net production (kboed)	36.9	31.6	34.3	8%	-7%	37.3	33.9	-9%
Net sales (kboed)	37.0	30.3	34.8	15%	-6%	37.5	33.3	-11%
Adjusted operating netback[2]								
Realised price ($/boe)	42.7	64.0	70.2	10%	64%	39.1	64.9	66%
Lifting cost ($/boe)	(13.0)	(15.6)	(13.3)	-15%	2%	(9.8)	(14.0)	43%
Transport cost ($/boe)	(0.8)	(0.2)	(0.6)	254%	-21%	(0.7)	(0.5)	-21%
Adj. operating netback ($/boe)	28.9	48.3	56.4	17%	95%	28.6	50.3	76%
Financial Results								
Revenue	145.4	178.3	224.9	26%	55%	536.7	789.0	47%
Lifting cost	44.3	43.4	42.5	-2%	-4%	134.2	170.1	27%
Transport cost	2.6	0.5	1.9	307%	-26%	9.5	6.7	-30%
Adjusted operating netback	98.5	134.5	180.4	34%	83%	393.0	612.2	56%
Administrative expenses	10.3	5.0	15.0	198%	46%	38.8	35.4	-9%
Income tax expense / (income)	55.6	52.3	38.7	-26%	-31%	36.6	175.3	380%
Net income	(66.0)	31.3	83.1	165%	nm	37.2	226.3	508%
Capex & exploration activities	6.5	42.9	64.0	49%	885%	48.0	166.8	248%

Key Figures from the Consolidated Financial Statements

$ million (unless stated)	FY21
Adjusted EBITDAX[2]	576.3
Operating netback ($/boe)[2]	47.4
Pro Forma Adjusted EBITDAX[2]	582.6
Free Cash Flow[2]	268.5
Net debt[2]	480.7
Net leverage[2] (x)	0.8x

[2] See "Non-IFRS Measures" section on page 9

2022 Guidance

	2022E
Net production (kboed)	32 – 34
Capital and exploration expenditures[3] ($m)	185 – 205

This guidance assumes $85/bbl Brent price for the full year of 2022.

2021 Audited Reserves

The following is a summary of the results of our annual independent reserves assessment, certified by DeGolyer and MacNaughton (D&M)[4]. Reserves are presented as the Company's working interest after royalties:

million boe, unless stated	PDP	1P	2P	3P
Reserves at 31 December 2020	57.7	88.1	115.6	142.6
Production[5]	(12.0)	(12.0)	(12.0)	(12.0)
Additions	10.4	4.6	12.6	18.5
Reserves at 31 December 2021	56.0	80.7	116.2	149.0
R/P (years)	4.7	6.7	9.7	12.4
Reserves replacement ratio ("RRR")	86%	38%	104%	153%

At year-end 2021, our 2P reserves were 116.2 million boe, with an RRR of 104%. Our 2P reserves-to-production ratio was 9.7 years, up from 8.5 years at the end of 2020.

Figures and Analysis from Combined Statements

Production

Kboed	4Q20	3Q21	4Q21	Δ q/q	Δ y/y	FY20	FY21	Δ y/y
Gross production	84.4	78.8	83.6	6%	-1%	87.7	82.3	-6%
Net production								
Caño Limón area	23.8	18.5	21.1	14%	-11%	23.2	20.8	-11%
Middle Magdalena	13.2	10.7	10.2	-5%	-23%	14.1	11.4	-19%
Central Llanos	0.0	2.4	3.0	24%	100%	0.0	1.8	100%
Net production	36.9	31.6	34.3	8%	-7%	37.3	33.9	-9%
Oil	36.9	31.4	34.1	9%	-7%	37.2	33.7	-10%
Gas	0.1	0.3	0.2	-34%	93%	0.1	0.2	242%

[3] The guidance includes development and exploration capex plus exploration expenses

[4] Reserves assessment of the Bolivar block was carried out by Beicip-Franlab, accounting for 3% of certified 2P reserves

[5] For reserves reporting production numbers are net sales entitlement volumes

Net production increased 8% q/q mainly as a result of a recovery in output in the Caño Limón area after the events in 3Q21 (weather-related events in the Caño Limón area and a labour strike at La Cira Infantas), strong performance of workovers in Central Llanos and production from the Pumara-2 well.

Net production was affected by 0.4 kboed 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 was impacted by 0.2 kboed and La Cira Infantas was impacted by of 0.15 kboed.

Compared to 4Q20 and FY20, production was down 7% and 9% respectively, mainly due to a lower share in production from the PPA (-5.4 kboed and -3.4 kboed, respectively), lower production performance in La Cira Infantas (-0.5 kboed and -1.1 kboed, respectively), better performance in the Caño Limón area in 4Q21 vs 4Q20 but a slightly lower performance in FY21 vs FY20 (0.3 kboed and -0.6 kboed, respectively), partially offset by the COG acquisition (3.0 kboed and 1.8 kboed, respectively).

Revenue

	4Q20	3Q21	4Q21	Δ q/q	Δ y/y	FY20	FY21	Δ y/y
Revenue ($ million)								
Oil sales	144.9	177.6	224.4	26%	55%	535.5	786.2	47%
Natural gas sales	0.2	0.6	0.4	-34%	90%	0.6	2.2	274%
Services	0.3	0.2	0.1	-41%	-71%	0.6	0.6	7%
Revenue	145.4	178.3	224.9	26%	55%	536.7	789.0	47%
Net sales								
Oil sales (million bbl)	3.4	2.8	3.2	15%	-6%	13.7	12.1	-12%
Natural gas sales (million boe)	0.0	0.0	0.0	-34%	93%	0.0	0.1	241%
Net sales (million boe)	3.4	2.8	3.2	15%	-6%	13.7	12.2	-11%
Prices								
Brent ($/bbl)	45.3	73.2	79.7	9%	76%	43.3	70.9	64%
Vasconia differential ($/bbl)	2.6	4.0	4.8	18%	86%	4.3	3.5	-18%
Average realised price ($/boe)	42.7	64.0	70.2	10%	64%	39.1	64.9	66%

Revenue from oil sales increased 26% q/q or $46.8 million, mainly due to higher sales as a result of the increase in net production, with an impact of $27.2 million, of which $30.7 million are due to strong performance in production, partially offset by -$3.4 million due to the impact of high-price clauses in production share. The remaining $19.6 million are mainly due to the increase in realised oil price.

From early August and until 28 November, we evacuated our oil through the OBC pipeline, due to repairs in the CLC pipeline required as a result of landslides created by heavy rains. This temporarily affected our realised price, with a $2.5/bbl impact for the fourth quarter[6]. The Vasconia differential increased 18% q/q, which further affected our realised price. No batches were evacuated through the OBC pipeline in December.

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

Compared to 4Q20 and FY20, revenue from oil sales increased by 55% and 47% respectively, due mainly to rising commodity prices ($88.5 million and $314.4 million, respectively), partially offset by lower production volumes (-$8.9 million and -$63.8 million, respectively).

Operating Expenses

$ million (unless stated)	4Q20	3Q21	4Q21	Δ q/q	Δ y/y	FY20	FY21	Δ y/y
Lifting cost	44.3	43.4	42.5	-2%	-4%	134.2	170.1	27%
Transportation cost	2.6	0.5	1.9	307%	-26%	9.5	6.7	-30%
Operating expenses[7]	46.9	43.9	44.5	1%	-5%	143.7	176.8	23%
Per unit ($/boe)	13.8	15.7	13.9	-12%	1%	10.5	14.5	39%

Lifting cost had a slight decrease q/q, despite an increase in production, which led to a reduction in unit costs of 12%. This was mainly driven by a lower number of well services required in 4Q21, offset by higher energy costs and maintenance activity that had been delayed due to the floodings in Arauca during 3Q21.

Lifting cost was slightly lower in 4Q21 vs 4Q20 and unit costs remained flat.

FY21 lifting costs were 27% higher than FY20 as a result of higher workover and well services activities as activity was significantly reduced during 2020 due to Covid 19.

Transportation cost FY21 was lower compared to FY20 mainly as a result of lower utilisation of the CLC pipeline in 2021 (69%) due to repairs, vs 100% in 2020.

Adjusted Operating Netback

$/boe	4Q20	3Q21	4Q21	Δ q/q	Δ y/y	FY20	FY21	Δ y/y
Realised price	42.7	64.0	70.2	10%	64%	39.1	64.9	66%
Operating expenses	(13.8)	(15.7)	(13.9)	-12%	1%	(10.5)	(14.5)	39%
Adjusted operating netback	28.9	48.3	56.4	17%	95%	28.6	50.3	76%

Adjusted operating netback increased 17% q/q due to: i) a higher realised price caused by a higher Brent, partially offset by the impact on realised price caused by the use of OBC pipeline; ii) the decrease in operating expenses per barrel as a result of the increase in production.

4Q21 vs 4Q20 Adjusted operating netback per barrel increased 95%, mainly as a result of higher realised prices and operating expenses that remained at the same level.

FY21 vs FY20 Adjusted operating netback increased by 76% as a result of higher realised prices, partly offset by higher operating expenses driven by increased workover and well services activity.

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

Administrative Expenses

$ million	4Q20	3Q21	4Q21	Δ q/q	Δ y/y	FY20	FY21	Δ y/y
Administrative expenses	10.3	5.0	15.0	198%	46%	38.8	35.4	-9%

Administrative expenses in 4Q21 increased 198% q/q, mainly due to one-off expenses related to the separation from Oxy.

Compared to 4Q20, administrative expenses increased 46% also as a result of one-off expenses associated with the separation.

Compared to FY20, these expenses decreased 9% as a result of higher recharges to partners driven by higher activity.

Capital Expenditures

$ million	4Q20	3Q21	4Q21	Δ q/q	Δ y/y	FY20	FY21	Δ y/y
Caño Limón area	0.2	20.5	27.5	34%	>1000%	28.0	83.3	198%
Middle Magdalena	6.9	11.6	17.4	50%	151%	22.0	44.9	104%
Central Llanos	0.0	7.5	7.0	-7%	100%	0.0	16.6	100%
Development capex	7.1	39.6	51.9	31%	630%	49.9	144.8	190%
Less: Teca	(1.2)	(0.2)	2.1	nm	nm	(4.5)	1.9	nm
Adjusted Capex	5.9	39.4	54.0	37%	814%	45.4	146.7	223%
of which development activities	0.7	29.6	40.5	37%	>1000%	31.9	107.5	237%
of which maintenance activities	5.2	9.8	13.5	38%	160%	13.5	39.3	191%
Exploratory drilling	0.1	2.4	8.4	242%	>1000%	0.4	11.4	>1000%
Total capex	6.0	41.8	62.4	49%	947%	45.8	158.2	246%
Exploration expenses	0.5	1.1	1.6	42%	193%	2.2	8.6	288%
Capex & exploration activities	6.5	42.9	64.0	49%	885%	48.0	166.8	248%

Adjusted Capex increased 37% q/q, mainly due to the ramp up in activity from the production optimization activities implemented across all assets to mitigate the impact of the surface events from the previous quarter, and the execution of the activity that was delayed due to those events. The Caño Limón area and La Cira Infantas each had an additional rig ready to drill in October.

Central Llanos had a slight decrease of 7% q/q as most of Pumara-2 drilling took place in 3Q21, although the well was completed and online in 4Q21.

Comparing FY20 to FY21 Adjusted Capex increased 223% due to the ramp up in drilling and workover programs across the assets for a total of 28 wells and 111 workovers in 2021 vs 8 wells and 63 workovers during 2020. In Central Llanos, investments are primarily explained by the Danés-2 and Pumara-2 wells. We have also conducted IT one-off investments due to the separation from Oxy.

We have low maintenance capex requirements of only 27% of Adjusted Capex for FY21. 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	**FY21**
Net income for the period	**162.3**
Financial income and financial expenses	24.3
Depreciation, depletion and amortization	97.7
Income tax expense	186.1
Exploration and seismic expenses and dry hole cost	8.6
Foreign exchange (income) / loss	(9.6)
Accretion of decommissioning liability	7.8
Non-recurring costs	11.6
Prepayment and bond cost amortization	12.1
Property, plant and equipment retirement	11.9
Inventory impairment	1.6
Unrealized fair value gain on derivatives	9.0
Fair value remeasurement net pension liability	(2.7)
Fair value remeasurement MIP	1.9
Fair value remeasurement contingent consideration	57.6
Teca	(4.0)
Adjusted EBITDAX	**576.3**
Exploration drilling[8]	(11.4)
Exploration and seismic expense	(8.6)
Tax payments	(56.3)
Cash capital expenditures[8]	(144.9)
Decommissioning funding	(2.8)
Change in working capital[8]	(72.1)
Non-recurring costs	(11.6)
Realised foreign exchange rate	5.5
Lease payments (principal + interest)	(5.6)
Free Cash Flow	**268.5**

Adjusted EBITDAX for FY21 was $576.3 million, resulting in an Operating netback of $47.4/boe, and generating $268.5 million of Free Cash Flow. Pro Forma Adjusted EBITDAX for FY21 was $582.6 million.

[8] Figures before accruals adjustments

Cash Flows

The following table presents our primary sources and uses of cash and cash equivalents for FY21:

$ million	**FY21**
Net cash flows from operating activities	393.8
Net cash flows used in investing activities	(109.6)
Net cash flows from financing activities	(273.7)
Increase in cash and cash equivalents during the period	**10.6**
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	(0.8)
Cash and cash equivalents at the end of the period	**119.3**

Cash flows from operating activities are presented net of cash taxes paid of $56.3 million. Cash flows used in investing activities include additions to PPE of $109.8 million and additions to exploration and evaluation assets of $5.9 million, partially offset by cash acquired from COG for $6.0 million. Cash flows from financing activities include the issuance of the long term notes for $600 million, partially offset by the RBL repayment of $195.0 million, dividends paid of $635.0 million, interest paid of $23.2 million and notes issuance costs of $19.6 million.

Cash and cash equivalents as of year end FY21 were $119.3 million increasing 9% from the beginning of the period.

Liquidity and Capital Resources

$ million (unless stated)	**FY21**
2028 senior notes @ 6%	600.0
Net debt	480.7
Adjusted EBITDAX	575.6
Net leverage (x)	0.8x
Cash and cash equivalents	119.3
RCF (available amount)	61.8
Total liquidity	181.1

For FY2021 we maintained a healthy level of liquidity, closing at $181.1 million, and a prudent leverage of 0.8x.

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.

For the 1Q22-4Q22 period, 53% of our volumes are hedged. The weighted average long put strike price is $54/bbl and net premium of $1.07/bbl. The weighted average short call strike price of $83/bbl over 36% of hedgeable volumes, winding down throughout the year.

For the 2Q22-1Q23 and 3Q22-2Q23 periods we have hedged 43% and 35% of our production, with an average long put strike price of $56/bbl and $59/bbl, respectively. We expect to be back towards our indicative level of 50% of our production hedged for the next twelve months as we move through the year, applying our judgement in evaluating 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.

Net debt: calculated as total debt minus cash and cash equivalents.

Net leverage: calculated as net debt divided by last twelve months(‘’LTM”) Adjusted EBITDAX.

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.