NEWS RELEASE

February 21, 2024

WHITECAP RESOURCES INC. ANNOUNCES 2023 RESULTS AND RESERVES, OPERATIONS UPDATE AND UPDATED 2024 GUIDANCE

CALGARY, ALBERTA – Whitecap Resources Inc. ("Whitecap" or the "Company") (TSX: WCP) is pleased to report its operating and audited financial results for the three and twelve months ended December 31, 2023.

Selected financial and operating information is outlined below and should be read with Whitecap's audited annual consolidated financial statements and related management's discussion and analysis for the three months and year ended December 31, 2023 which are available at www.sedarplus.ca and on our website at www.wcap.ca.

Financial ($ millions except for share amounts and percentages)	Three months ended Dec. 31 2023	2022	Year ended Dec. 31 2023	2022
Petroleum and natural gas revenues	914.1	1,116.5	3,551.6	4,452.9
Net income	298.3	318.7	889.0	1,676.1
Basic ($/share)	0.49	0.52	1.47	2.72
Diluted ($/share)	0.49	0.52	1.46	2.70
Funds flow [1]	462.3	593.6	1,791.4	2,322.8
Basic ($/share) [1]	0.77	0.97	2.96	3.77
Diluted ($/share) [1]	0.76	0.97	2.94	3.74
Dividends declared	109.6	67.2	372.8	237.2
Per share	0.18	0.11	0.62	0.39
Expenditures on property, plant and equipment [2]	200.5	179.0	953.8	686.5
Free funds flow [1]	261.8	414.6	837.6	1,636.3
Net Debt [1]	1,385.5	1,913.1	1,385.5	1,913.1
Operating				
Average daily production				
Crude oil (bbls/d)	88,687	91,812	85,718	86,417
NGLs (bbls/d)	19,241	17,473	17,296	15,521
Natural gas (Mcf/d)	351,757	342,640	320,922	254,708
Total (boe/d) [3]	166,554	166,392	156,501	144,389
Average realized Price [1,4]				
Crude oil ($/bbl)	93.98	102.50	95.05	114.68
NGLs ($/bbl)	37.85	46.84	38.90	55.30
Natural gas ($/Mcf)	2.48	5.56	2.84	5.62
Petroleum and natural gas revenues ($/boe) [1]	59.66	72.94	62.17	84.49
Operating Netback ($/boe) [1]				
Petroleum and natural gas revenues[1]	59.66	72.94	62.17	84.49
Tariffs [1]	(0.42)	(0.49)	(0.49)	(0.46)
Processing & other income [1]	0.80	0.77	0.87	0.68
Marketing revenues [1]	4.57	5.93	4.82	5.99
Petroleum and natural gas sales [1]	64.61	79.15	67.37	90.70
Realized gain/(loss) on commodity contracts [1]	(0.14)	(1.43)	0.34	(4.66)
Royalties [1]	(10.66)	(13.34)	(10.83)	(16.35)
Operating expenses [1]	(13.41)	(14.13)	(14.10)	(14.54)
Transportation expenses [1]	(2.09)	(2.12)	(2.17)	(2.18)
Marketing expenses [1]	(4.54)	(5.87)	(4.79)	(5.94)
Operating netbacks	33.77	42.26	35.82	47.03
Share information (millions)				
Common shares outstanding, end of period	598.0	608.7	598.0	608.7
Weighted average basic shares outstanding	603.2	610.8	605.1	616.5
Weighted average diluted shares outstanding	607.3	613.8	608.6	621.1

MESSAGE TO SHAREHOLDERS

2023 was a strong year for Whitecap both operationally and financially, highlighted by 11% production per share growth[5] and the achievement of our second of two net debt milestones, prompting a 26% increase to our base dividend. The ongoing development of our high-quality drilling inventory has yielded exceptional results, with our team constantly evaluating options to further improve capital efficiencies and netbacks for increased profitability.

Average 2023 production of 156,501 boe/d, including 103,014 bbls/d of light oil and liquids and 320,922 mcf/d of natural gas, generated funds flow of $1.8 billion ($2.94 per share) and after capital expenditures of $954 million, resulted in free funds flow of $838 million ($1.38 per share[1]). Dividends declared of $373 million ($0.62 per share) along with $123 million of share repurchases on our normal course issuer bid ("NCIB") resulted in shareholder returns of approximately $500 million ($0.81 per share). We are committed to strong return of capital to shareholders with a current base monthly dividend of $0.0608 per share ($0.73 per share annually) which will be supplemented with share repurchases on our NCIB.

We are also pleased to report exceptional 2023 reserve values highlighted by per share organic growth across all three reserve categories. These organic growth additions resulted in proved developed producing ("PDP") and total proven ("TP") production replacement[1] of 107% and 141%, respectively, and reflect our strong 2023 drilling program. Three-year average finding and development ("F&D") recycle ratios[1] between 2.6 times and 3.3 times highlight the robust profitability of our asset base through commodity price cycles.

Our balance sheet remains a priority for us and is in excellent condition with less than $1.4 billion of net debt (0.7 times debt to EBITDA ratio[6]) at year end and approximately $1.7 billion of available capacity on $3.1 billion of total debt capacity. As we continue to allocate a portion of our free funds flow towards debt reduction, this will further strengthen our balance sheet for both downside protection and value enhancing opportunities in the future.

Near the end of the fourth quarter, we completed a tuck-in acquisition of light oil Viking assets in one of our core areas in Western Saskatchewan for cash proceeds of $154 million, prior to closing adjustments. The acquisition consolidates an active area of our Viking drilling program, was completed at attractive acquisition metrics, and was highly accretive to funds flow per share and free funds flow per share. Our team is now actively executing on production optimization opportunities on this 100% light oil asset base.

We provide the following fourth quarter and full year 2023 financial and operating highlights:

- **Funds Flow.** Full year and fourth quarter funds flow netbacks[1] of $31.36 per boe and $30.16 per boe, respectively, were strong despite average 2023 WTI crude oil prices being 18% lower and natural gas prices being 50% lower than in 2022. Operating costs of $14.10 per boe were down 3% from 2022, despite inflationary pressures persisting through the year. Full year funds flow of $1.8 billion equates to $2.94 per share, while fourth quarter funds flow of $462 million equates to $0.76 per share.

- **Drilling Program.** We were the fourth most active driller in Western Canada in 2023, drilling 215 (189.0 net) wells, including 181 (158.2 net) wells in our East Division and 34 (30.8 net) wells in our West Division. Of the $954 million of capital expenditures incurred in 2023, 80% was allocated to drilling and completions, while 17% was directed to facilities spending, including initial work on our Musreau battery to support Montney production additions in 2024 as well as an expansion to our 3-27 facility supporting regional Montney and Charlie Lake development in the Peace River Arch.

- **Increasing Return of Capital.** We increased our dividend for the seventh time in three years to $0.73 per share annually in October 2023. We have been focused on delivering a strong return of capital to shareholders since paying our first dividend at the start of 2013, returning a total of $1.8 billion in dividends over the past eleven years. These returns have been further enhanced by repurchasing over 76 million shares for $612 million since 2017. Total return to shareholders of approximately $500 million in 2023 demonstrates a continuation of this strategy.

- **Balance Sheet Strength.** Year end net debt of $1.4 billion equated to a debt to EBITDA ratio of 0.7 times and an EBITDA to interest expense ratio[6] of 27.0 times, both well within our debt covenants of not greater than 4.0 times and not less than 3.5 times, respectively. We have significant financial flexibility with over $1.7 billion of available capacity on $3.1 billion of total credit capacity.

OPERATIONS UPDATE

West Division

We continue to advance operations in our West Division including a buildout of new facilities and infrastructure to handle our production growth into the future. We are looking forward to our next stage of Montney development at

Musreau with the completion of our battery in the second quarter of this year. Our 2023 West Division drilling program has achieved excellent results thus far with average well results performing above type curve expectations, while we also continue to expand our technical knowledge of our asset base.

At Kakwa, we are encouraged by strong initial results on our two most recent Montney pads, where we have optimized our development strategy for dynamic reservoir and fluid properties in this localized area. Our 3-well (3.0 net) 02-26 (B) pad was brought on production in September and has achieved an average IP(120) rate of 1,889 boe/d (32% liquids) per well which is 26% above our expectations. The 3-well (3.0 net) 03-21 (B) pad that was drilled in the fourth quarter was tied into permanent facilities in early February, with test results showing similar characteristics as the 02-26 (B) pad.

Although early, we are encouraged by the initial results of these two pads and application of this well design and spacing strategy may be transferable to other areas of future Montney and Duvernay development. While we ultimately believe that individual pad design will be tailored to the various geological and reservoir characteristics across our asset base, successful application of this well design and spacing strategy across a broader area has the potential to meaningfully improve the overall economics of our unconventional drilling inventory well into the future.

We also spud our first two 4-well pads (8.0 net wells) at Musreau in the fourth quarter, which are expected to be completed and ready to be brought on production upon completion of our 20,000 boe/d battery. The ramp up of production into this facility will occur during the second quarter, and we target facility capacity being reached as our third and fourth 4-well pads (8.0 net wells) are brought on production at Musreau later this year.

At Lator, we recently drilled a 2-well (2.0 net) pad as part of our validation and delineation efforts of this future area of Montney growth. The wells have achieved IP(60) rates of 1,655 boe/d (45% liquids) per well which are approximately 15% above our expectations. Strong return characteristics along with a significant land position will make Lator an area of meaningful growth for the West Division in the coming years. We plan to drill an additional two (2.0 net) Montney wells at Lator in 2024. Engineering and commercial work is underway to establish the optimal development and infrastructure strategy for this area.

With respect to our Duvernay asset at Kaybob, our results continue to outperform our expectations as our first seven (7.0 net) wells (4-well and 3-well pads) achieved an average IP(90) rate of approximately 1,600 boe/d (36% liquids) per well, which is 24% above our expectations. We plan to bring eight (8.0 net) wells on during 2024 as we continue to increase production towards our target of 90% capacity of our 100% owned 15-07 gas processing facility by the end of 2025. The first 3 wells of our 2024 program are currently being drilled to a 4,200-metre lateral length, approximately 750 metres longer than our initial seven Duvernay wells.

As part of the execution of our 2024 capital spending program and long-range planning scenarios, we have an active water management strategy to mitigate impacts of potential drought conditions in Alberta. We have a combination of term and temporary licenses along with established water infrastructure to support our 2024 program.

East Division

2023 was a very strong operational year for our East Division with outperformance across all four regions. We drilled 181 (158.2 net) wells during the year, which included 151 (134.9 net) light oil wells into the Cardium, Frobisher, Glauconite, and Viking formations that are characterized by quick payouts and high netbacks. With over 50,000 boe/d of production under secondary and tertiary recovery, we also spent a total of $110 million on these assets in 2023. Approximately 60% of this capital was directed towards drilling producing wells in areas under secondary and tertiary recovery while the remaining 40% was directed towards injector drills and conversions along with base volume maintenance activities, to preserve our low decline rate of 20% for the Division.

In Eastern Saskatchewan, we drilled 46 (41.0 net) wells, primarily focused on the Frobisher formation. We have been utilizing open hole multi-lateral technology, drilling dual and triple leg laterals consistently since early 2021, and have incorporated longer laterals and additional lateral legs where viable. As a result, our average total lateral length increased by 45% (700 metres per well) as compared to 2022. After providing for the impact of longer laterals, our 2023 program has been very successful, generating average IP(90) results that are 13% above expectations. We have an active 2024 program underway with three rigs currently running in Eastern Saskatchewan with plans to drill 23 (21.1 net) wells in the first quarter.

Our Western Saskatchewan region includes both low decline waterflood assets along with quick payout, high netback Viking light oil assets. On average, our 2023 Western Saskatchewan well results exceeded our expectations by 9% on an IP(180) basis, which includes our Viking drilling program that averaged a capital payout[7] of six months in 2023. The integration of the acquisition completed in late December is ongoing with combined production in the Elrose area now at 6,500 bbls/d which represents over 40% of our total high netback, Viking light oil production. Our secondary/tertiary recovery enhancements and greater use of extended reach horizontal wells are some of the many inventory enhancement initiatives that our technical team has undertaken in Western Saskatchewan over the past several years.

The profitability of our Weyburn asset is a function of an extremely low decline rate of 3% and a 100% oil and NGLs production base with 35% of rollout areas still to be converted for CO_2 injection. We drilled 4 (3.4 net) producing wells and 4 (3.7 net) injection wells in 2023, with our 2024 program increasing to 9 (6.3 net) producing wells and 8 (5.2 net) injection wells. Net operating income[8] from this asset has paid out the purchase price of $940 million 1.2 times since we acquired it in December 2017. The property continues to produce 14,500 boe/d net to Whitecap at this time.

We have also recently started CO_2 injection at a pilot CO_2 flood into the Frobisher formation underlying the Weyburn Midale unit. We drilled two (2.0 net) producer wells and three (3.0 net) injection wells in 2023 and initiated CO_2 injection in late 2023. Early results are encouraging with a notable production response coming through approximately one month after injection, increasing oil rates on the two producer wells from approximately 40 bbls/d to over 200 bbls/d, per well. Further technical analysis to determine commerciality and large-scale development is ongoing, and we will provide updates as next steps are determined.

In Central Alberta, our focus is in the Cardium and Glauconite formations, drilling 16 (10.4 net) wells into the Cardium and 14 (12.8 net) wells into the Glauconite in 2023. Our West Pembina Cardium program achieved strong results with average IP(90) rates exceeding expectations by 10%. Our Glauconite continues to achieve strong results, with average production rates in line with our expectations and liquids rates outperforming by 5% on an IP(90) basis. Our consolidated land position has allowed us to continually test increasing lateral lengths. We plan to drill 5 (4.9 net) Glauconite wells with an average lateral length of 2,700 metres and 8 (5.8 net) Cardium wells in the first quarter.

2023 RESERVES

Operational success and a deep set of highly economic inventory has resulted in strong year end reserve values. We continue to see the benefits of our consolidation strategy that began in late-2020 as greater scale and asset optimization opportunities have yielded consistent per share growth and increasing net present values.

One of the benefits of consolidating acreage has been an ability to drill longer laterals in areas that were previously restricted by ownership boundaries. In addition, we are consistently expanding the applicability of increased lateral lengths to greater portions of our asset base, giving potential for improved capital efficiencies and, therefore, increased profitability. At year end, we have identified 6,400 drilling locations[9] in inventory which provides for over 25 years of sustainable and profitable growth.

We highlight the following 2023 year end reserve report results:

- **Per Share Focus.** Debt-adjusted reserves per share[10] increased 6% on a PDP basis, 10% on a TP basis and 7% on a total proven plus probable ("TPP") basis despite net dispositions decreasing total reserves. Our focus on per share metrics along with strong return on capital execution will maximize long-term profits for our shareholders.

- **Production Replacement.** Prior to the impact of net dispositions, we replaced 107% of production on a PDP basis, 141% of production on a TP basis and 107% of production on a TPP basis. Strong operational execution along with a prolific asset base provide for increased sustainability over the long term.

- **Long-Dated Inventory.** We have significant inventory life across all our assets, with a PDP reserve life index[11] ("RLI") of 6 years, a TP RLI of 13 years, and a TPP RLI of 19 years. These are consistent with the three-year average and are reflective of the expansive opportunity we have to develop these assets over time.

- **Strong Recycle Ratios.** Our PDP F&D[1] cost of $14.68 per boe, our TP F&D cost of $17.62 per boe and our TPP F&D cost of $20.46 per boe resulted in strong recycle ratios of 2.4 times, 2.0 times and 1.8 times, respectively. The three-year average F&D recycle ratios range from 2.6 times to 3.3 times, which emphasizes our strong asset base and our focus on long-term profitability.

OUTLOOK

We have increased our 2024 average production guidance range to 165,000 – 170,000 boe/d (8% production per share growth) to reflect the Viking tuck-in acquisition along with the reduction in capital spending. Our capital budget is now expected to be $900 million to $1.1 billion, which is $100 million lower than originally budgeted, providing another year of strong operational execution underpinned by the technical enhancements undertaken in 2023.

WTI crude oil prices continue to be relatively volatile but have been rangebound between US$70/bbl and US$80/bbl and currently at approximately US$75/bbl for the balance of 2024. This, combined with the weak Canadian dollar, results in a very strong Canadian crude oil price in excess of $100/bbl. We also anticipate light and heavy oil differentials to tighten further throughout the year with the completion of the Trans Mountain Expansion project in the coming months, bringing further pricing upside to Canadian crude oil production.

Natural gas prices are currently challenged with the lack of winter demand resulting in weak AECO prices forecasted through to the end of the summer, and a seasonal increase into next winter is anticipated. While the liquids component of our unconventional assets currently drives the economics, our growth in natural gas volumes is anticipated to coincide with the commissioning of LNG Canada in 2025. Completion of this facility is an important step for Canada, as there will be an ability to deliver natural gas to overseas markets which should reduce gas-on-gas competition within Canada. Further to this, as part of our ongoing efforts to diversify our natural gas volumes, we have joined Rockies LNG Partners to contribute 100,000 mcf/d of natural gas towards the Ksi Lisims LNG project and add exposure to non-North American natural gas prices.

At current strip prices[12], we are forecasting 2024 funds flow of approximately $1.6 billion which results in free funds flow of $600 million, after capital investments. This is more than sufficient to fund our annual dividend obligation of $435 million. We have stress tested our dividend down to US$50/bbl WTI and $2.00/GJ AECO and have further flexibility to reduce our capital program to ensure dividends and capital investments are fully funded by cash flows. Our balance sheet remains in excellent shape with low leverage and ample liquidity to support the business throughout various commodity price cycles.

Our long term organic corporate growth outlook has been updated and increased to 210,000 boe/d by the end of 2028, which represents average organic growth of 5% on an annual basis, driven primarily by our liquids rich Montney and Duvernay assets. At the end of 2028, we will still have over 20 years of drilling inventory remaining, assuming a consistent 5% annual growth rate beyond 2028.

We would like to emphasize that our objective is to provide sustainable and profitable growth to our shareholders, including a disciplined level of debt, while remaining committed to responsible development of our assets. Our strategy includes advancing our emission reduction strategy and utilizing our expertise in carbon sequestration.

On behalf of our employees, management team and Board of Directors, we would like to thank our shareholders for their support and look forward to an exciting 2024 and beyond.

NOTES

1. Funds flow, funds flow basic ($/share), funds flow diluted ($/share) and net debt are capital management measures. Average realized price and per boe disclosure figures are supplementary financial measures. Operating netback and free funds flow are non-GAAP financial measures. Operating netbacks ($/boe), F&D costs, funds flow netbacks ($/boe), free funds flow diluted ($/share) and recycle ratio are non-GAAP ratios. Refer to the Specified Financial Measures section in this press release for additional disclosure and assumptions.
2. Also referred to herein as "capital expenditures", "capital investment" and "capital spending".
3. Disclosure of production on a per boe basis in this press release consists of the constituent product types and their respective quantities disclosed herein. Refer to Barrel of Oil Equivalency and Production, Initial Production Rates and Product Type Information in this press release for additional disclosure.
4. Prior to the impact of risk management activities and tariffs.
5. Production per share is the Company's total crude oil, NGL and natural gas production volumes for the applicable period divided by the weighted average number of diluted shares outstanding for the applicable period. Production per share growth is determined in comparison to the applicable comparative period.
6. Debt to EBITDA ratio and EBITDA to interest expense ratio are specified financial measures that are calculated in accordance with the financial covenants in our credit agreement.
7. Also referred to herein as "half-cycle payout". Refer to Oil and Gas Metrics in this press release for additional disclosure.
8. Also referred to herein as "operating netback".
9. Disclosure of drilling locations in this press release consists of proved, probable, and unbooked locations and their respective quantities on a gross and net basis as disclosed herein. Refer to Drilling Locations in this press release for additional disclosure.
10. "Debt-adjusted reserves per share" is calculated as year end reserves divided by year end fully diluted shares plus the annual change in net debt divided by the average annual share price. Debt-adjusted reserves per share growth is determined in comparison to the yar end reserves divided by year end fully diluted shares from the applicable comparative period.
11. See "Production Replacement Ratio and Reserve Life Index".
12. Based on the following strip commodity pricing and exchange rate assumptions for 2024: US$75/bbl WTI, $1.95/GJ AECO, USD/CAD of $1.35.

2023 RESERVES REVIEW

Our 2023-year end reserves were evaluated by independent reserves evaluator McDaniel & Associates Consultants Ltd. ("McDaniel") in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") as of December 31, 2023. The reserves evaluation was based on the average forecast pricing of McDaniel, GLJ Ltd. and Sproule Associates Limited and foreign exchange rates at January 1, 2024 which is available on McDaniel's website at www.mcdan.com.

Reserves included are Company share (gross) reserves which are the Company's total working interest reserves before the deduction of any royalties and including any royalty interests payable to the Company. Additional reserve information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR+ at www.sedarplus.ca. The numbers in the tables below may not add due to rounding.

Summary of Reserves

Reserves as at December 31, 2023

	Company Share (Gross) Reserves		
Description	Light & Medium Oil (Mbbl)	Tight Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)
Proved developed producing	201,566	737	318,561
Proved developed non-producing	2,313	0	7,271
Proved undeveloped	102,255	8,664	162,792
Total proved	306,134	9,401	488,624
Probable	108,069	8,000	196,423
Total proved plus probable	414,203	17,400	685,046

Description	Shale Gas (MMcf)	Natural Gas Liquids (Mbbl)	Total (Mboe)
Proved developed producing	319,542	51,755	360,409
Proved developed non-producing	30,901	7,553	16,228
Proved undeveloped	997,087	111,426	415,658
Total proved	1,347,530	170,734	792,294
Probable	869,388	84,194	377,897
Total proved plus probable	2,216,918	254,927	1,170,191

Net Present Values of Future Net Revenue

Summary of Before Tax Net Present Values of Future Net Revenue (Forecast Pricing)
As at December 31, 2023

	Before Tax Net Present Value ($ millions) [(1)]				
	Discount Rate				
Reserves Category	0%	5%	10%	15%	20%
Proved Developed Producing	8,052	6,765	5,593	4,779	4,201
Proved developed non-producing	487	386	324	283	252
Proved undeveloped	9,144	6,000	4,168	3,007	2,223
Total Proved	17,683	13,151	10,085	8,068	6,676
Total Probable	11,773	6,611	4,334	3,112	2,373
Total Proved + Probable	29,456	19,762	14,419	11,180	9,049

(1) Includes abandonment and reclamation costs as defined in NI 51-101 for all of our facilities, pipelines and wells including those without reserves assigned.

Future Development Costs ("FDC")

FDC reflects the best estimate of the capital cost to develop and produce reserves. FDC associated with our TP reserves at year end 2023 is $6.6 billion undiscounted ($4.9 billion discounted at 10%).

Also included in FDC are 1,590 (1,374 net) proved booked drilling locations and 323 (271 net) probable booked drilling locations.

($ millions)	Total Proved	Total Proved plus Probable
2024	999	1,024
2025	1,206	1,244
2026	1,218	1,341
2027	1,154	1,269
2028	1,112	1,331
Remainder	954	2,160
Total FDC, Undiscounted	6,641	8,370
Total FDC, Discounted at 10%	4,856	5,857

Performance Measures (Including FDC)

The following table highlights F&D and FD&A costs and associated recycle ratios, including FDC, based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2023	2022	2021	Three Year Weighted Average
Proved Developed Producing				
F&D costs per boe [(1)]	$14.68	$13.20	$16.28	$14.64
F&D recycle ratio [(2)]	2.4x	3.6x	1.8x	2.6x
FD&A costs per boe [(3)]	$17.30	$24.01	$11.75	$18.01
FD&A recycle ratio [(2)]	2.1x	2.0x	2.6x	2.2x
Total Proved				
F&D costs per boe [(1)]	$17.62	$16.90	$5.05	$14.15
F&D recycle ratio [(2)]	2.0x	2.8x	5.9x	3.3x
FD&A costs per boe [(3)]	$22.64	$14.98	$11.48	$16.92
FD&A recycle ratio [(2)]	1.6x	3.1x	2.6x	2.4x
Total Proved Plus Probable				
F&D costs per boe [(1)]	$20.46	$19.53	$4.63	$16.25
F&D recycle ratio [(2)]	1.8x	2.4x	6.4x	3.2x
FD&A costs per boe [(3)(4)]	nm	$11.55	$9.60	nm
FD&A recycle ratio [(2)(4)]	nm	4.1x	3.1x	nm

(1) F&D costs are non-GAAP ratios and are calculated as the sum of development capital of $939.6 million (excluding corporate and capitalized G&A) plus the change in FDC for the period of -$40.7 million (PDP), $479.6 million (TP) and $312.8 million (TPP), divided by the change in reserves volumes that are characterized as development for the period. See "Oil and Gas Metrics" and "Specified Financial Measures".

(2) Recycle ratio is a non-GAAP ratio and is calculated as operating netback divided by F&D or FD&A costs. Our operating netback in 2023 was $35.82/boe. See "Oil and Gas Metrics" and "Specified Financial Measures".

(3) FD&A costs are non-GAAP ratios and are calculated as the sum of development capital of $939.6 million (excluding corporate and capitalized G&A) plus acquisition capital of -$228.9 million plus the change in FDC for the period of -$13.0 million (PDP), $329.2 million (TP) and $62.9 million (TPP), divided by the change in total reserves volumes, other than from production, for the period. See "Oil and Gas Metrics" and "Specified Financial Measures".

(4) The impact of net dispositions in 2023 results in a very low denominator value and therefore the 2023 FD&A cost of $85.74 per boe is deemed not material to our reserve performance measures.

Production Replacement Ratio and Reserve Life Index

The following table highlights our production replacement ratio and reserve life index ("RLI") based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel, including the impact of net dispositions in 2023:

In 2023, prior to the impact of net dispositions, we replaced 107% of production on a PDP reserves basis, 141% of production on a TP reserves basis and 107% of production on a TPP reserves basis.

	2023	2022	2021	Three Year Weighted Average
Proved Developed Producing				
Production replacement [(1)]	71%	208%	372%	211%
RLI (years) [(2)]	5.9	6.2	7.3	6.4
Total Proved				
Production replacement [(1)]	80%	589%	545%	389%
RLI (years) [(2)]	13.0	13.2	12.5	12.9
Total Proved Plus Probable				
Production replacement [(1)]	16%	952%	737%	553%
RLI (years) [(2)]	19.1	20.1	17.6	19.1

(1) Production replacement ratio is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production. Whitecap's production averaged 156,501 boe/d in 2023.

(2) RLI is calculated as total Company share reserves divided by the annualized fourth quarter actual production of 166,554 boe/d.

CONFERENCE CALL AND WEBCAST

Whitecap has scheduled a conference call and webcast to begin promptly at 9:00 am MT (11:00 am ET) on Thursday, February 22, 2024.

The conference call dial-in number is: 1-888-390-0605 or (587) 880-2175 or (416) 764-8609

A live webcast of the conference call will be accessible on Whitecap's website at www.wcap.ca by selecting *"Investors"*, then *"Presentations & Events"*. Shortly after the live webcast, an archived version will be available for approximately 14 days.

For further information:

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NOTE REGARDING FORWARD-LOOKING STATEMENTS

This press release contains forward-looking statements and forward-looking information (collectively "forward-looking information") within the meaning of applicable securities laws relating to the Company's plans and other aspects of our anticipated future operations, management focus, strategies, financial, operating and production results and business opportunities. Forward-looking information typically uses words such as "anticipate", "believe", "continue", "trend", "sustain", "project", "expect", "forecast", "budget", "goal", "guidance", "plan", "objective", "strategy", "target", "intend", "estimate", "potential", or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future, including statements about our strategy, plans, focus, objectives, priorities and position.

In particular, and without limiting the generality of the foregoing, this press release contains forward-looking information with respect to: that we will supplement our base dividend with share repurchases on our NCIB; that our balance sheet will further strengthen for both downside protection and value enhancing opportunities in the future as we allocate a portion of our free funds flow towards debt reduction; that the Musreau battery will support Montney production additions in 2024; our belief that we have significant financial flexibility with over $1.7 billion of available capacity; the buildout of new facilities and infrastructure in our West Division to handle production growth in the future, including our belief that the Musreau battery will be completed in the second quarter of this year; our belief that application of our well design and spacing strategy from our two recent Montney pads may be transferable to other areas of future Montney and Duvernay development; that successful application of this well design and spacing strategy across a broader area has the potential to meaningfully improve the overall economics of our unconventional drilling inventory well into the future; our expectation that our first two 4-well pads at Musreau will be completed and ready to be brought on production upon completion of our battery; our belief that the ramp up in production into our Musreau battery will occur in the second quarter; our belief that we will reach our target facility capacity as our third and fourth 4-well pads are brought on production at Musreau later this year; our belief that strong return characteristics and a significant land position will make Lator an area of meaningful growth for the West Division in the coming years; our plans to drill an additional two Montney wells at Lator in 2024; our belief that engineering and commercial work will establish the optimal development and infrastructure strategy at Lator; our plans to bring on eight Duvernay wells during 2024; that Duvernay production will continue to increase towards our target of 90% facility capacity by the end of 2025; our belief that our water management strategy will mitigate the impact of potential drought conditions in Alberta; our belief that wells drilled into the Cardium, Frobisher, Glauconite and Viking formations are characterized by quick payouts and high netbacks; our plans to drill 23 wells in the first quarter in Eastern Saskatchewan; our belief that the profitability of our Weyburn asset is a function of an extremely low decline rate of 3% and a 100% oil and NGLs production base; that 35% of rollout areas are still to be converted for CO_2 injection at our Weyburn asset; our plan to drill 9 producing and 8 injection wells at Weyburn in 2024; our plans to drill 5 Glauconite wells with an average lateral length of 2,700 metres and 8 Cardium wells in the first quarter of 2024; our belief that consistently expanding the application of increased lateral lengths will provide the potential for improved capital efficiencies and therefore improved profitability; our belief that we have 6,400 drilling locations in inventory, which provides for over 25 years of sustainable and profitable growth; our belief that focusing on per share metrics along with strong return on capital execution will maximize long-term profits for our shareholders; our belief that strong operational execution along with a prolific asset base provide for increased sustainability over the long term; our belief that our inventory, as measured by reserve life index, is reflective of the expansive opportunity we have to develop our assets over time; our belief that F&D recycle ratios emphasize our strong asset base and our focus on long term profitability; our expected capital budget for 2024 and that it will provide for strong operational execution underpinned by the technical enhancements undertaken in 2023; that we anticipate light and heavy oil differentials to tighten further throughout the year with the completion of the Trans Mountain Expansion project in the coming months, bringing further pricing upside to Canadian crude oil production; our anticipation for a seasonal increase in natural gas prices into next winter; our anticipation that growth in our natural gas volumes will coincide with the commissioning of LNG Canada in 2025, and that completion of this facility will expand market access which should reduce gas-on-gas competition within Canada; our belief that by joining Rockies LNG Partners we will contribute 100,000 mcf/d towards the Ksi Lisims LNG project and add exposure to non-North American natural gas markets; our forecasted 2024 funds flow of $1.6 billion at current strip prices, resulting in free funds flow of $600 million after capital investments; that we have flexibility to reduce our capital program to ensure dividends and capital investments are fully funded by cash flows at US$50/bbl WTI and $2.00/GJ AECO; our belief that our balance sheet remains in excellent shape and we have ample liquidity to support the business throughout various commodity price cycles; our long term organic corporate growth outlook for production of 210,000 boe/d by the end of 2028 and that our Montney and Duvernay assets will drive the growth; our belief that at the end of 2028 we will still have over 20 years of inventory remaining; that our objective is to provide sustainable and profitable growth to our shareholders, including a disciplined level of debt, while remaining committed to responsible development of our assets; that our strategy includes advancing our emission reduction strategy and utilizes our expertise in carbon sequestration; and, future development costs. Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking information is based on certain key expectations and assumptions made by our management, including: that we will continue to conduct our operations in a manner consistent with past operations except as specifically noted herein (and for greater certainty, the forward-looking information contained herein excludes the potential impact of any acquisitions or dispositions that we may complete in the future); the general continuance or improvement in current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; expectations and assumptions concerning prevailing and forecast commodity prices, exchange rates, interest rates, inflation rates, applicable royalty rates and tax laws, including the assumptions specifically set forth herein; the ability of OPEC+ nations and other major producers of crude oil to adjust crude oil production levels and thereby manage world crude oil prices; the impact (and the duration thereof) of the ongoing military actions in the Middle East and between Russia and Ukraine and related sanctions on crude oil, NGLs and natural gas prices; the impact of rising and/or sustained high inflation rates and interest rates on the North American and world economies and the corresponding impact on our costs, our profitability, and on crude oil, NGLs and natural gas prices; future production rates and estimates of operating costs and development capital, including as specifically set forth herein; performance of existing and future wells; reserve volumes and net present values thereof; anticipated timing and results of capital expenditures/development capital, including as specifically set forth herein; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the timing and costs of pipeline, storage and facility construction and expansion; the state of the economy and the exploration and production business; results of operations; performance; business prospects and opportunities; the availability and cost of financing, labour and services; future dividend levels and share repurchase levels; the impact of increasing competition; ability to efficiently integrate assets and employees acquired through acquisitions or asset exchange transactions; ability to market oil and natural gas successfully; our ability to access capital and the cost and terms thereof; that we will not be forced to shut-in production due to weather events such as wildfires, floods, droughts or extreme hot or cold temperatures; the commodity pricing and exchange rate forecasts for 2024 specifically set forth herein; and that we will be successful in defending against previously disclosed and ongoing reassessments received from the Canada Revenue Agency and assessments received from the Alberta Tax and Revenue Administration.

Although we believe that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Whitecap can give no assurance that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature it involves inherent risks and uncertainties. These include, but are not limited to: the risk that the funds that we ultimately return to shareholders through dividends and/or share repurchases is less than currently anticipated and/or is delayed, whether due to the risks identified herein or otherwise; the risk that any of our material assumptions prove to be materially inaccurate, including our 2024 forecast (including for commodity prices and exchange rates); the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, including the risk that weather events such as wildfires, flooding, droughts or extreme hot or cold temperatures forces us to shut-in production or otherwise adversely affects our operations; pandemics and epidemics; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, production, costs and expenses; risks associated with increasing costs, whether due to high inflation rates, high interest rates, supply chain disruptions or other factors; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; inflation rate fluctuations; marketing and transportation risks; loss of markets; environmental risks; competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions; the risk that going forward we may be unable to access sufficient capital from internal and external sources on acceptable terms or at all; failure to obtain required regulatory and other approvals; reliance on third parties and pipeline systems; changes in legislation, including but not limited to tax laws, production curtailment, royalties and environmental (including emissions) regulations; the risk that we do not successfully defend against previously disclosed and ongoing reassessments received from the Canada Revenue Agency and assessments received from the Alberta Tax and Revenue Administration and are required to pay additional taxes, interest and penalties as a result; and the risk that the amount of future cash dividends paid by us and/or shares repurchased for cancellation by us, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, contractual restrictions contained in our debt agreements, and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends and/or the repurchase of shares – depending on these and various other factors as disclosed herein or otherwise, many of which will be beyond our control, our dividend policy and/or share buyback policy and, as a result, future cash dividends and/or share buybacks, could be reduced or suspended entirely. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, the forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits that we will derive therefrom. Management has included the above summary of assumptions and risks related to forward-looking information provided in this press release in order to provide security holders with a more complete perspective on our future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect our operations or financial results are included in reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca).

These forward-looking statements are made as of the date of this press release and we disclaim any intent or obligation to update publicly any forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about our forecast 2024 capital expenditures; our forecast for $1.6 billion of funds flow and $600 million of free funds flow in 2024 after capital expenditures based on current strip prices, and our forecast that this is more than sufficient to fund our annual dividend obligation of $435 million; our forecast that our dividend is fully funded at US$50/bbl WTI and $2.00/GJ AECO and that we have flexibility to reduce our capital program to ensure that dividends and capital investments are fully funded by cash flow, and our forecasts for the future development costs to develop and produce our reserves; all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of Whitecap and the resulting financial results will likely vary from the amounts set forth herein and such variation may be material. Whitecap and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, Whitecap undertakes no obligation to update such FOFI. FOFI contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Whitecap's anticipated future business operations. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein.

OIL AND GAS ADVISORIES

Reserves Volumes and Net Present Values

All reserve references in this press release are "Company share (gross) reserves". Company share reserves are our total working interest reserves before the deduction of any royalties and including any royalty interests payable to the Company.

It should not be assumed that the present worth of estimated future amounts presented in the tables above represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. The recovery and reserve estimates of the crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Barrel of Oil Equivalency

"Boe" means barrel of oil equivalent. All boe conversions in this press release are derived by converting gas to oil at the ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of oil. Boe may be misleading, particularly if used in isolation. A Boe conversion rate of 1 Bbl : 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency ratio of 1 Bbl : 6 Mcf, utilizing a conversion ratio of 1 Bbl : 6 Mcf may be misleading as an indication of value.

Oil and Gas Metrics

This press release contains metrics commonly used in the oil and natural gas industry which have been prepared by management, such as **"acquisition capital"**, **"development capital"**, **"F&D costs"**, **"FD&A costs"**, **"half-cycle payout", "operating netback"**, **"production replacement"**, **"production replacement ratio"**, **"recycle ratio"**, and **"reserve life index"**. These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

"Acquisition capital" is a non-GAAP financial measure used in the determination of FD&A costs, which is a non-GAAP ratio. The most directly comparable GAAP measure to acquisition capital is expenditures on corporate acquisitions, net of cash acquired, and expenditures on property acquisitions. For property acquisitions, acquisition capital is the purchase price, including cash and/or shares of assets acquired (disposed). For corporate acquisitions, it is the purchase price (cash and/or shares plus assumed bank debt, if applicable) including any estimated working capital surplus or deficit rather than the amounts allocated to PP&E for accounting purposes. The following table details the calculation of Acquisition capital for the periods indicated:

		Year ended Dec. 31,	
($ millions)	**2023**	**2022**	**2021**
Property acquisitions	165.5	7.9	154.1
Corporate acquisitions	-	2,001.6	1,432.4
Less: Property dispositions	394.4	24.4	188.2
Acquisition Capital	(228.9)	1,985.1	1,398.4

"Development capital" is a non-GAAP financial measure used in the determination of F&D costs and FD&A costs, which are non-GAAP ratios. The most directly comparable GAAP measure to development capital is expenditures on property, plant, and equipment. Development capital means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development. Development capital excludes corporate and capitalized general and administrative expenses. The following table reconciles expenditures on property, plant and equipment to Development capital for the periods indicated:

		Year ended Dec. 31,	
($ millions)	**2023**	**2022**	**2021**
Expenditures on property, plant and equipment	953.8	686.5	428.5
Less: expenditures on corporate and capitalized general and administrative expenses	14.2	16.6	14.6
Development Capital	939.6	669.9	413.9

"F&D costs" are calculated as the sum of development capital plus the change in FDC for the period when appropriate, divided by the change in reserves that are characterized as development for the period. Development capital is a non-GAAP financial measure used as a component of F&D costs. Management uses F&D costs as a measure of capital efficiency for organic reserves development.

"FD&A costs" are calculated as the sum of development capital plus acquisition capital plus the change in FDC for the period when appropriate, divided by the change in total reserves, other than from production, for the period. Development capital and acquisition capital are non-GAAP financial measures used as components of FD&A costs. Management uses FD&A costs as a measure of capital efficiency for organic and acquired reserves development.

"Half-cycle payout" is the time period for the operating netback of a well to equate to the individual cost of drilling, completing and equipping the well. Management uses half-cycle payout as a measure of capital efficiency of a well to make capital allocation decisions.

"Production replacement ratio" or **"production replacement"** is calculated as total reserve additions (including acquisitions net of dispositions) divided by annual production.

"Recycle ratio" is calculated by dividing operating netback per boe by F&D costs or FD&A costs for the year. Operating netback per boe is a non-GAAP ratio that uses operating netback, a non-GAAP financial measure, as a component. Development capital, a non-GAAP financial measure, is used as a component of F&D costs. Development capital and acquisition capital, both non-GAAP financial measures, are used as components of FD&A costs. Management uses recycle ratio to relate the cost of adding reserves to the expected cash flows to be generated.

"Reserve life index" or **"RLI"** is calculated as total Company share reserves divided by annualized fourth quarter actual production.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare our operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

Drilling Locations

This press release discloses drilling inventory in two categories: (i) booked locations (proved and probable); and (ii) unbooked locations. Booked locations represent the summation of proved and probable locations, which are derived from McDaniel & Associates Consultants Ltd.'s reserves evaluation effective December 31, 2023 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources.

- Of the 6,400 (5,600 net) drilling locations identified herein, 1,590 (1,374 net) are proved locations, 323 (271 net) are probable locations, and 4,487 (3,955 net) are unbooked locations.

Unbooked locations consist of drilling locations that have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we will drill all of these drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Production, Initial Production Rates & Product Type Information

References to petroleum, crude oil, natural gas liquids ("NGLs"), natural gas and average daily production in this press release refer to the light and medium crude oil, tight crude oil, conventional natural gas, shale gas and NGLs product types, as applicable, as defined in National Instrument 51-101 ("NI 51-101"), except as noted below.

NI 51-101 includes condensate within the NGLs product type. The Company has disclosed condensate as combined with crude oil and separately from other NGLs since the price of condensate as compared to other NGLs is currently significantly higher and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom. Crude oil therefore refers to light oil, medium oil, tight oil and condensate. NGLs refers to ethane, propane, butane and pentane combined. Natural gas refers to conventional natural gas and shale gas combined.

Any reference in this news release to initial production rates (IP(60), IP(90), IP(120)) are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Whitecap.

The Company's average daily production for the three and twelve months ended December 31, 2023 and 2022, the forecast average daily production for 2024 (midpoint), and the average daily production rate per well for (1) our 3 (3.0 net) 02-26 (B) Montney pad at Kakwa (IP(120)), (2) the 2 (2.0 net) Montney wells at Lator (IP(60)), and (3) the 7 (7.0 net) Duvernay wells at Kaybob (IP(90)) disclosed in this press release consists of the following product types, as defined in NI 51-101 (other than as noted above with respect to condensate) and using a conversion ratio of 1 Bbl : 6 Mcf where applicable:

Whitecap Corporate	Q4/2023	Q4/2022	2023	2022
Light and medium oil (bbls/d)	76,942	80,776	75,432	80,441
Tight oil (bbls/d)	11,745	11,036	10,286	5,976
Crude oil (bbls/d)	88,687	91,812	85,718	86,417
NGLs (bbls/d)	19,241	17,473	17,296	15,521
Shale gas (Mcf/d)	196,540	181,478	171,178	97,299
Conventional natural gas (Mcf/d)	155,217	161,162	149,744	157,409
Natural gas (Mcf/d)	351,757	342,640	320,922	254,708
Total (boe/d)	166,554	166,392	156,501	144,389

Whitecap Corporate / Initial Production Rates	2024 Guidance (Mid-Point)	Kakwa (IP(120))	Lator (IP(60))	Kaybob (IP(90))
Light and medium oil (bbls/d)	75,000	-	-	-
Tight oil (bbls/d)	14,200	394	683	407
Crude oil (bbls/d)	89,200	394	683	407
NGLs (bbls/d)	17,800	216	57	162
Shale gas (Mcf/d)	217,000	7,674	5,490	6,186
Conventional natural gas (Mcf/d)	146,000	-	-	-
Natural gas (Mcf/d)	366,000	7,674	5,490	6,186
Total (boe/d)	167,500	1,889	1,655	1,600

	Weyburn
Light and medium oil (bbls/d)	14,000
Tight oil (bbls/d)	-
Crude oil (bbls/d)	14,000
NGLs (bbls/d)	500
Shale gas (Mcf/d)	-
Conventional natural gas (Mcf/d)	-
Natural gas (Mcf/d)	-
Total (boe/d)	14,500

SPECIFIED FINANCIAL MEASURES

This press release includes various specified financial measures, including non-GAAP financial measures, non-GAAP ratios, capital management measures and supplementary financial measures as further described herein. These financial measures are not standardized financial measures under International Financial Reporting Standards ("IFRS" or, alternatively, "GAAP") and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other companies.

"Acquisition Capital" and **"Development Capital"** are non-GAAP financial measures and**, "F&D Costs", "FD&A Costs"** and **"recycle ratio"** are non-GAAP ratios. See "Oil and Gas Metrics".

"Average realized prices" for crude oil, NGLs and natural gas are supplementary financial measures calculated by dividing each of these components of petroleum and natural gas revenues, disclosed in Note 16 "Revenue" to the Company's audited annual consolidated financial statements for the year ended December 31, 2023, by their respective production volumes for the period.

"Free funds flow" is a non-GAAP financial measure calculated as funds flow less expenditures on property, plant and equipment ("PP&E"). Management believes that free funds flow provides a useful measure of Whitecap's ability to increase returns to shareholders and to grow the Company's business. Free funds flow is not a standardized financial measure under IFRS and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other entities. The most directly comparable financial measure to free funds flow disclosed in the Company's primary financial statements is cash flow from operating activities. Refer to the "Cash Flow from Operating Activities, Funds Flow and Payout Ratios" section of our management's discussion and analysis for the year ended December 31, 2023 which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca. In addition, see the following table which reconciles cash flow from operating activities to funds flow and free funds flow:

	Three months ended Dec. 31,		Year ended Dec. 31,	
($ millions)	**2023**	**2022**	**2023**	**2022**
Cash flow from operating activities	476.2	555.8	1,742.5	2,183.1
Net change in non-cash working capital items	(13.9)	37.8	48.9	139.7
Funds flow	462.3	593.6	1,791.4	2,322.8
Expenditures on PP&E	200.5	179.0	953.8	686.5
Free funds flow	261.8	414.6	837.6	1,636.3
Funds flow per share, basic	0.77	0.97	2.96	3.77
Funds flow per share, diluted	0.76	0.97	2.94	3.74

**"Free funds flow diluted ($/share)"** is a non-GAAP ratio calculated by dividing free funds flow by the weighted average number of diluted shares outstanding for the relevant period. Free funds flow is a non-GAAP financial measure component of free funds flow diluted ($/share). Free funds flow diluted ($/share) is not a standardized financial measure under IFRS and therefore may not be comparable with the calculation of similar financial measures disclosed by other entities.

"Funds flow", **"funds flow basic ($/share)" and "funds flow diluted ($/share)"** are capital management measures and are key measures of operating performance as they demonstrate Whitecap's ability to generate the cash necessary to pay dividends, repay debt, make capital investments, and/or to repurchase common shares under the Company's normal course issuer bid. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow, funds flow basic ($/share) and funds flow diluted ($/share) provide useful measures of Whitecap's ability to generate cash that are not subject to short-term movements in non-cash operating working capital. Whitecap reports funds flow in total and on a per share basis (basic and diluted), which is calculated by dividing funds flow by the weighted average number of basic shares and weighted average number of diluted shares outstanding for the relevant period. See Note 5(e)(ii) "Capital Management – Funds Flow" in the Company's audited annual consolidated financial statements for the year ended December 31, 2023 for additional disclosures.

"Funds flow netback ($/boe)" is a non-GAAP ratio calculated by dividing funds flow by the total production for the period. Funds flow netback per boe is not a standardized financial measure under IFRS and, therefore may not be comparable with the calculation of similar financial measures disclosed by other entities. Presenting funds flow netback on a per boe basis allows management to better analyze performance against prior periods on a comparable basis.

"Net Debt" is a capital management measure that management considers to be key to assessing the Company's liquidity. See Note 5(e)(i) "Capital Management – Net Debt and Total Capitalization" in the Company's audited annual consolidated financial statements for the year ended December 31, 2023 for additional disclosures. The following table reconciles the Company's long-term debt to net debt:

Net Debt ($ millions)	**Dec. 31, 2023**	**Dec. 31, 2022**
Long-term debt	1,356.1	1,844.6
Accounts receivable	(400.2)	(480.2)
Deposits and prepaid expenses	(32.9)	(22.7)
Non-current deposits	(82.9)	-
Accounts payable and accrued liabilities	509.0	549.1
Dividends payable	36.4	22.3
Net Debt	1,385.5	1,913.1

"Operating netback" is a non-GAAP financial measure determined by adding marketing revenues and processing & other income, deducting realized losses on commodity risk management contracts or adding realized gains on commodity risk management contracts and deducting tariffs, royalties, operating expenses, transportation expenses and marketing expenses from petroleum and natural gas revenues. The most directly comparable financial measure to operating netback disclosed in the Company's primary financial statements is petroleum and natural gas sales. Operating netback is a measure used in operational and capital allocation decisions. Operating netback is not a standardized financial measure under IFRS and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other entities. For further information, refer to the "Operating Netbacks" section of our management's discussion and analysis for the year ended December 31, 2023, which is incorporated herein by reference, and available on SEDAR+ at www.sedarplus.ca. A reconciliation of operating netbacks to petroleum and natural gas revenues is set out below:

	Three months ended Dec. 31,		Year ended Dec. 31,	
Operating Netbacks ($ millions)	**2023**	**2022**	**2023**	**2022**
Petroleum and natural gas revenues	914.1	1,116.5	3,551.6	4,452.9
Tariffs	(6.4)	(7.5)	(27.9)	(24.1)
Processing & other income	12.2	11.8	49.8	35.9
Marketing revenues	70.1	90.8	275.4	315.7
Petroleum and natural gas sales	990.0	1,211.6	3,848.9	4,780.4
Realized gain (loss) on commodity contracts	(2.1)	(21.9)	19.5	(245.5)
Royalties	(163.4)	(204.2)	(618.9)	(861.8)
Operating expenses	(205.5)	(216.3)	(805.4)	(766.3)
Transportation expenses	(32.1)	(32.5)	(123.8)	(114.8)
Marketing expenses	(69.6)	(89.8)	(273.9)	(313.0)
Operating netbacks	517.3	646.9	2,046.4	2,479.0

"Operating netback ($/boe)" is a non-GAAP ratio calculated by dividing operating netbacks by the total production for the period. Operating netback is a non-GAAP financial measure component of operating netback per boe. Operating netback per boe is not a standardized financial measure under IFRS and, therefore may not be comparable with the calculation of similar financial measures disclosed by other entities. Presenting operating netback on a per boe basis allows management to better analyze performance against prior periods on a comparable basis.

"Petroleum and natural gas revenues ($/boe)", "Tariffs ($/boe)", "Processing and other income ($/boe)" and "Marketing revenues ($/boe)" are supplementary financial measures calculated by dividing each of these components of petroleum and natural gas sales, disclosed in Note 16 "Revenue" to the Company's audited annual consolidated financial statements for the year ended December 31, 2023, by the Company's total production volumes for the period.

"Per boe" or "($/boe)" disclosures for petroleum and natural gas sales, royalties, operating expenses, transportation expenses and marketing expenses are supplementary financial measures that are calculated by dividing each of these respective GAAP measures by the Company's total production volumes for the period.

"Realized gain (loss) on commodity contracts ($/boe)" is a supplementary financial measure calculated by dividing realized gain (loss) on commodity contracts, disclosed in Note 5(d) "Financial Instruments and Risk Management – Market Risk" to the Company's audited annual consolidated financial statements for the year ended December 31, 2023, by the Company's total production volumes for the period.

Per Share Amounts

Per share amounts noted in this press release are based on fully diluted shares outstanding unless noted otherwise.