NEWS RELEASE

February 19, 2025

WHITECAP RESOURCES INC. ANNOUNCES RECORD ANNUAL PRODUCTION AND STRONG 2024 RESULTS

CALGARY, ALBERTA – Whitecap Resources Inc. ("Whitecap" or the "Company") (TSX: WCP) is pleased to report its operating and audited financial results for the three months and year ended December 31, 2024.

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, 2024 which are available at www.sedarplus.ca and on our website at www.wcap.ca.

	Three Months ended Dec. 31		Year ended Dec. 31	
Financial ($ millions except for share amounts)	2024	2023	2024	2023
Petroleum and natural gas revenues	926.1	914.1	3,665.7	3,551.6
Net income	233.8	298.3	812.3	889.0
Basic ($/share)	0.40	0.49	1.37	1.47
Diluted ($/share)	0.40	0.49	1.36	1.46
Funds flow [1]	412.8	462.3	1,632.2	1,791.4
Basic ($/share) [1]	0.70	0.77	2.74	2.96
Diluted ($/share) [1]	0.70	0.76	2.73	2.94
Dividends declared	107.1	109.6	433.3	372.8
Per share	0.18	0.18	0.73	0.62
Expenditures on property, plant and equipment [2]	261.4	200.5	1,131.1	953.8
Free funds flow [1]	151.4	261.8	501.1	837.6
Net Debt [1]	933.1	1,385.5	933.1	1,385.5
Operating				
Average daily production				
Crude oil (bbls/d)	94,965	88,687	92,449	85,718
NGLs (bbls/d)	20,797	19,241	20,371	17,296
Natural gas (Mcf/d)	365,809	351,757	368,610	320,922
Total (boe/d) [3]	176,730	166,554	174,255	156,501
Average realized Price [1,4]				
Crude oil ($/bbl)	92.46	93.98	94.52	95.05
NGLs ($/bbl)	34.23	37.85	34.47	38.90
Natural gas ($/Mcf)	1.57	2.48	1.56	2.84
Petroleum and natural gas revenues ($/boe) [1]	56.96	59.66	57.48	62.17
Operating Netback ($/boe) [1]				
Petroleum and natural gas revenues[1]	56.96	59.66	57.48	62.17
Tariffs [1]	(0.40)	(0.42)	(0.42)	(0.49)
Processing & other income [1]	0.61	0.80	0.69	0.87
Marketing revenues [1]	4.37	4.57	4.00	4.82
Petroleum and natural gas sales [1]	61.54	64.61	61.75	67.37
Realized gain/(loss) on commodity contracts [1]	0.84	(0.14)	0.61	0.34
Royalties [1]	(9.11)	(10.66)	(9.41)	(10.83)
Operating expenses [1]	(13.70)	(13.41)	(13.71)	(14.10)
Transportation expenses [1]	(2.24)	(2.09)	(2.13)	(2.17)
Marketing expenses [1]	(4.37)	(4.54)	(3.97)	(4.79)
Operating netbacks	32.96	33.77	33.14	35.82
Share information (millions)				
Common shares outstanding, end of period	587.5	598.0	587.5	598.0
Weighted average basic shares outstanding	587.6	603.2	594.9	605.1
Weighted average diluted shares outstanding	591.4	607.3	598.1	608.6

MESSAGE TO SHAREHOLDERS

Over the past three years, Whitecap has increased average production from 112,222 boe/d in 2021 to over 174,000 boe/d in 2024. As we continued to grow our asset base, we have also reduced our common shares outstanding by 28.3 million shares increasing our production per share[5] by 57% over the three year period. At the same time, we have continued to strengthen our balance sheet with net debt now under $1.0 billion, a debt to EBITDA ratio[6] of only 0.34 times and $1.6 billion of undrawn credit capacity.

A key factor in our ongoing success has been our ability to execute on multiple initiatives to achieve our business objectives in 2024. Our achievements below highlight the quality of assets across our portfolio and demonstrate our technical, operational and financial expertise in creating value on those assets.

Operational Achievements

- Upward revisions to guidance four times throughout the year, achieving average production of 174,255 boe/d (65% liquids) compared to our budget of 165,000 boe/d (63% liquids), an increase of 6%.
- Our oil and natural gas liquids weighting at 65% outperformed our expectation of 63% primarily driven by higher than forecast crude oil and condensate volumes from the Montney at Musreau, the Duvernay at Kaybob as well as from the Glauconite in Central Alberta and the Frobisher in East Saskatchewan.
- Strong reserves per share growth[7] of 4% on proved developed producing ("PDP") reserves, 4% on total proven ("TP") reserves and 5% on total proven plus probable ("TPP") reserves. On a debt-adjusted basis[7], reserves per share growth was 12% on PDP reserves, 12% on TP reserves and 13% on TPP reserves.
- Low Finding, Development & Acquisition ("FD&A") costs[1] of $8.82/boe on PDP reserves, $12.46/boe on TP reserves and $10.02/boe on TPP reserves resulting in recycle ratios[1] of 3.8 times, 2.7 times and 3.3 times, respectively.
- Entered into a strategic partnership with Pembina Gas Infrastructure ("PGI") to fund 100% of phase 1 of the Lator Infrastructure to unlock 35,000 – 40,000 boe/d of Montney production in Whitecap's highly economic Lator area, with the potential to increase to 85,000 boe/d with our Lator phase 2 development. Whitecap will design, construct and operate the facility.

Financial Achievements

- Generated fourth quarter funds flow of $413 million ($0.70 per share) and full year 2024 funds flow of $1.6 billion ($2.73 per share). After capital expenditures of $261 million and $1.1 billion, free funds flow was $151 million ($0.26 per share[1]) in the fourth quarter and $501 million ($0.84 per share) for the full year, respectively.
- Monetized a 50% working interest in our Musreau Facility and Kaybob Complex for proceeds of $520 million representing an attractive EBITDA disposition multiple of 14 times. Whitecap retained a 50% working interest and operatorship in both facilities.
- Secured additional infrastructure access, enhanced contract terms and highly competitive fees on processing, transportation, fractionation and marketing on our current and future Montney development with a net present value of $190 million that will enhance our future funds flow netback.
- Successful inaugural investment grade issuance of 5-year senior notes for gross proceeds of $400 million at an attractive fixed interest rate of 4.382% per annum.
- Reduced net debt by $452 million resulting in year end net debt of $933 million, a Debt to EBITDA ratio of 0.34 times, an EBITDA to interest expense ratio[6] of 25.91 times and a debt to capitalization ratio[6] of 0.11 times.

Return of Capital to Shareholders

- Provided a sustainable base dividend of $0.73 per share equating to $433.3 million returned to shareholders and bringing our total dividends paid since 2013 to $2.2 billion.
- Continued to enhance our capital structure by repurchasing 12.7 million common shares for $130 million.
- Our business is resilient down to US$50/bbl WTI and $2.00/GJ AECO whereby we have sufficient funds flow to support the dividend and maintain our current production at 174,000 boe/d.
- Longer term, our objective is to increase our dividend commensurate with our targeted 3% – 8% production per share growth[5] and supported by increasing funds flow.

OPERATIONS REVIEW

During 2024, we invested $1.1 billion to drill 246 (225.2 net) wells, including 38 (36.5 net) wells across our unconventional portfolio and 208 (188.6 net) wells across our conventional portfolio. Our 2024 capital program was split approximately even between our unconventional and our conventional assets, with strong operational results from each of our core areas.

Unconventional

Musreau Montney

2024 was an important year for us at Musreau as we completed the commissioning and start-up of our owned and operated Musreau 05-09 battery. The battery was completed two weeks ahead of schedule and 10% below budget. The commissioning of the battery allowed us to increase what was nominal production in the area to approximately 17,500 boe/d. We brought on production 16 (16.0 net) wells during 2024 with performance exceeding our expectations on both a total and a condensate production basis.

Through the application of our unconventional development workflow, we have updated the well configuration and completion design, which now favours multi-bench development. This approach, which vertically offsets wells within the Montney, enhances reservoir coverage while mitigating inter-wellbore interference. This strategic shift has delivered stronger well results, with multi-bench wells tracking long-term outperformance to expectations of approximately 20%. We are actively monitoring these results and evaluating their implications for future development within Musreau and on analogous lands.

Lator Montney

At Lator we continued to assess the deliverability and liquids content across this asset with two (2.0 net) delineation wells drilled on the eastern and southern portions of our Lator acreage. The first well has now been on production for more than 120 days and has achieved an IP(120)[3] rate of 1,265 boe/d (41% liquids, including 442 bbl/d of condensate). The second well, with over 80 days of production, is tracking a projected IP(90)[3] rate of approximately 1,600 boe/d (24% liquids, including 250 bbl/d of condensate).

In 2024, we also entered into a strategic partnership with PGI to fund 100% of phase 1 of the Lator Infrastructure allowing us to move forward with completion of our detailed engineering and design work and obtaining the required regulatory approvals. Engineering and procurement efforts are advancing as planned, with permitting in progress and approximately three quarters of critical long-lead items now ordered. Additionally, design and acquisition are underway for field facilities and gathering infrastructure. The 4-13 Phase 1 facility is on track to be completed in late 2026/early 2027.

Kakwa Montney

In Kakwa, we drilled our first triple bench pad in 2024 which was designed to evaluate the potential of the D2, D3, and Lower Middle Montney formations with completions currently underway.

In addition, the production results from our wider six wells per section spacing initiative, compared to previously eight wells per section spacing, have proven successful with improved per section economic return profiles. We are currently drilling a four-well pad (4.0 net) in southeast Kakwa, marking our third pad with wider inter-well spacing in the area.

Kaybob Duvernay

In 2024 we spud 23 (23.0 net) wells and brought 8 (8.0 net) wells on production at Kaybob, including three wells with 4,200 metre lateral lengths, our longest Duvernay laterals to date. Our development at Kaybob continues to exceed expectations with production in the area totaling approximately 24,000 boe/d in the fourth quarter of 2024.

We also tested a wine rack design within the Duvernay formation with our 11-14B pad. Initial indications upon completion, flowback, and the first 90 days of production are all favourable and we recently completed fracturing operations on our second wine-racked pad at 08-05A.

Beyond wine rack trials, we are also advancing capital efficiency improvements through extended laterals, leveraging our land base and subsurface characteristics. Our next three development pads will feature 2.5-mile laterals, enhancing resource recovery and operational efficiency.

Conventional

Central Alberta

Our 2024 Glauconite program included 17 (16.7 net) wells and was very successful as we advanced from a monobore drilling trial to full implementation, drilling our last five (5.0 net) wells as monobore's to end the year. We have taken a staged approach to applying monobore drilling in the Glauconite due to technical risks, which our team has done an exceptional job navigating through and ultimately validating an opportunity for enhancement. Given these results, we have now built in a 10% reduction in well costs in the Glauconite across our internal inventory, improving the already robust economics of this asset.

East Saskatchewan

We drilled 37 (34.4 net) dual and triple leg Frobisher wells in 2024, with results forecasted to generate an average payout[8] in nine months, with average IP(90) results tracking 30% above our expectations. Increasing reservoir contact through longer laterals as well as increasing the number of horizontal legs has been the primary enhancement opportunity since we acquired these assets in 2021. Consolidation across our land base over the last few years has also provided the opportunity to drill longer laterals across a greater portion of our assets, leading to improved capital efficiencies.

We also implemented an eight-leg open hole multi-lateral ("OHML") pilot in 2024 that targeted a tighter flow unit within the upper Frobisher known as the State A. Through 150 days of production[3], our State A OHML pilot well has achieved an average production rate of 191 boe/d (70% liquids), resulting in strong economics and the addition of three years of drilling inventory.

West Saskatchewan

We drilled 81 (78.7 net) Viking wells in 2024 focusing solely on extended reach horizontals of 1 mile to 1.5 miles, relative to historical standard-length development wells of 0.5 miles. Our extended reach wells have reduced per unit operating costs, surface footprint, and infrastructure spending resulting in improved economics. We plan to continue to expand extended reach horizontal well utilization in 2025, including at Elrose, where recent consolidation has enabled the use of longer laterals and a more efficient program in the area.

Weyburn

At Weyburn, we drilled 22 (14.8 net) wells in 2024, including 11 (7.6 net) producers and 11 (7.2 net) injector wells. The Weyburn asset generated over $160 million of net operating income[9] (after capital expenditures) in 2024 as its low base decline rate of approximately 5% and light oil weighted netback provides long-term sustainable cash flow to the Company.

OUTLOOK

2024 was a strong year for Whitecap and the operational and financial success achieved during the year will have a meaningful impact beyond 2024 as the concepts, processes and pilots undertaken will enhance our already robust 6,270 (5,461 net) future inventory locations[10] providing us with decades of sustainable production, funds flow and free funds flow growth.

2025 is off to a strong start as we look to continue the operational momentum from 2024 through a very active first quarter and into the remainder of the year. Our unchanged 2025 guidance is for average production of 176,000 – 180,000 boe/d (63% liquids) and a capital budget of $1.1 – $1.2 billion. At US$70/bbl WTI and $2.00/GJ AECO[11], we are forecast to generate $1.7 billion of funds flow and $550 million of free funds flow in 2025. With net debt of under $1 billion, our balance sheet is in excellent condition, and we will continue to focus on share repurchases under our normal course issuer bid to enhance our returns to shareholders, over and above our base dividend of $0.73 per share annually.

Canadian energy of all forms are vital parts of the Canadian economy and critical for both Canadian and North American energy security. The potential for tariffs on oil and gas exported to the United States brings into focus our lack of market diversification and concentrated reliance on one trading partner. We are beginning to understand the positive impact of the Trans Mountain Expansion since it came online last year and we also expect to see the positive impact of the LNG Canada ramp up later this year, but we need more projects as these will bring further market diversification and are overwhelmingly beneficial to all Canadians across our country.

Our business has never been stronger and more resilient. Not only have we managed through extreme volatility over the last several years, but more importantly, our team has been able to execute on development opportunities as well as capture incremental opportunities during periods of market dislocation to make our company stronger.

On behalf of our employees, management team and Board of Directors, we would like to thank our shareholders for their continued support.

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 ($/boe), free funds flow diluted ($/share), FD&A costs and recycle ratio are non-GAAP ratios. Refer to the Specified Financial Measures section and Oil and Gas Metrics section in this press release for additional disclosure and assumptions.

[2] Also referred to herein as "capital expenditures" and "capital budget".

[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 & 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, EBITDA to interest expense ratio and debt to capitalization ratio are specified financial measures that are calculated in accordance with the financial covenants in our credit agreement, adjusted for cash of $362 million at December 31, 2024.

[7] Reserves per share is the Company's total crude oil, NGL and natural gas reserves volumes for the applicable period divided by the weighted average number of diluted shares outstanding for the applicable period. "Reserves per share growth" is determined in comparison to the applicable comparative period. "Debt-adjusted reserves per share" is calculated as year end reserves divided by year end fully diluted shares (approximately 595 million) plus the annual change in net debt (approximately -$452 million) divided by the average annual share price for 2024 ($9.99). Debt-adjusted reserves per share growth is determined in comparison to the year end reserves divided by year end fully diluted shares from the applicable comparative period.

[8] Also referred to as "capital payout". Refer to Oil and Gas Metrics in this press release for additional disclosure.

[9] "Operating income" is also referred to herein as "operating netback". Refer to the Specified Financial Measures section in this press release for additional disclosure. Net operating income is operating income minus the capital expenditures for the specified area.

[10] 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.

[11] Based on the following commodity pricing and exchange rate assumptions for the remainder of 2025: US$70/bbl WTI, $2.00/GJ AECO and USD/CAD of $1.43.

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 20, 2025.

The conference call dial-in number is: 1-888-510-2154 or (403) 910-0389 or (437) 900-0527

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: our belief that phase 1 of the Lator infrastructure will unlock 35,000 – 40,000 boe/d of Montney production; our belief that the Lator area is highly economic and we have the potential to increase production to 85,000 boe/d with our Lator phase 2 development and our plan to design, construct and operate the facility; our forecast for the EBITDA disposition multiple of 14 times for the partial sale of the Musreau Facility and Kaybob Complex; our belief that securing additional infrastructure access, enhanced contract terms and highly competitive fees on processing, transportation, fractionation and marketing on our current and future Montney development results in a net present value of $190 million, that will enhance our future funds flow netback; our belief that our business is resilient down to US$50/bbl WTI and $2.00/GJ AECO whereby we will have sufficient funds flow to support the dividend and maintain our current production at 174,000 boe/d; that our longer term objective is to increase our dividend commensurate with our targeted 3% – 8% production per share growth and that such objective is supported by increasing funds flow; our forecast for the second well at Lator, and the calculation of the projected IP(90) rate of approximately 1,600 boe/d (24% liquids, including 250 bbl/d of condensate); that the 4-13 Phase 1 facility at Lator is on track to be completed in late 2026/early 2027; that wider six wells per section spacing initiative has improved per section economic return profiles; our belief that we will achieve capital efficiency improvements through extended laterals at Kaybob; our belief that 2.5 mile laterals at Kaybob will enhance resource recovery and operational efficiency; our belief that a 10% reduction in well costs in the Glauconite will improve the already robust economics of this asset; our forecast that the dual and triple leg Frobisher wells drilled in 2024 will generate an average payout in nine months; that drilling longer laterals in East Saskatchewan will lead to improved capital efficiencies; that we plan to continue to expand extended reach horizontal well utilization in 2025 in the Viking, including at Elrose, where recent consolidation has enabled the use of longer laterals and a more efficient program in the area; our belief that Weyburn's low base decline rate of approximately 5% and light oil weighted netback provides long term sustainable cash flow to the Company; our belief that the operational and financial success achieved during 2024 will have a meaningful impact beyond 2024; our belief that the concepts, processes and pilots undertaken will enhance our already robust 6,270 (5,461 net) future inventory locations providing us with decades of sustainable production, funds flow and free funds flow growth; our belief that we will continue operational momentum from 2024 through a very active first quarter and into the remainder of 2025; our forecast for 2025 average production (including by product type) and 2025 capital expenditures; our forecast to generate $1.7 billion of funds flow and $550 million of free funds flow in 2025 at US$70/bbl WTI and $2.00/GJ AECO for the remainder of 2025; our belief that our balance sheet is in excellent condition and that we will continue to focus on share repurchases under our normal course issuer bid to enhance our returns to shareholders, over and above our base dividend of $0.73 per share annually; our belief that Canadian energy of all forms are vital parts of the Canadian economy and critical for both Canadian and North American energy security; our belief that the potential for tariffs on oil and gas exported to the United States brings into focus our lack of market diversification and concentrated reliance on one trading partner; our belief that we are beginning to understand the positive impact of the Trans Mountain Expansion since it came online last year and we also expect to see the positive impact of the LNG Canada ramp up later this year and our belief that we need more projects as these will bring further market diversification and are overwhelmingly beneficial to all Canadians across our country; our belief that our business has never been stronger and more resilient; and our belief that our company is stronger after having been able to execute on organic development opportunities as well as capture incremental opportunities during periods of market dislocation;.

The forward-looking information is based on certain key expectations and assumptions made by our management, including: that the tariffs that have been publicly announced by the U.S. and Canadian governments (but which are not yet in effect) do not come into effect, but that if such tariffs do come into effect, the potential impact of such tariffs, and that other than the tariffs that have been announced, neither the U.S. nor Canada (i) increases the rate of scope of such tariffs, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; 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 current and forecast inflation rates and/or 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; reserves 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; 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 2025 and beyond referred to 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 2025 forecast (including for commodity prices and exchange rates); the risk that (i) negotiations between the U.S. and Canadian governments are not successful and one or both of such governments implements announced tariffs, increases the rate or scope of announced tariffs, or imposes new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company; 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 elevated inflation rates, elevated 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, tariffs, import or export restrictions or prohibitions, production curtailment, royalties and environmental (including emissions and "greenwashing") 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 for net present value of enhanced contract terms and highly competitive fees on processing, transportation, fractionation and marketing on our current and future Montney development; our forecast for the EBITDA disposition multiple of 14 times for the partial sale of the Musreau Facility and Kaybob Complex; our forecast that we still have sufficient funds flow to support the dividend and maintain our current production at 174,000 boe/d down to US$50/bbl WTI and $2.00/GJ AECO; our objective to increase the dividend commensurate with our targeted production per share growth; our forecast that the dual and triple leg Frobisher wells drilled in 2024 will generate an average payout in nine months; our forecast for 2025 capital budget, funds flow and free funds flow; and our forecast for commodity prices in 2025; 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

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"**, "**capital payout**" or "**payout per well**", **"development capital"**, **"FD&A costs"**, and **"recycle ratio"**. 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 and dispositions, acquisition capital is the net purchase price 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)	**2024**	**2023**	**2022**
Property acquisitions	4.7	165.5	7.9
Corporate acquisitions	-	-	2,001.6
Less: Property dispositions	509.4	394.4	24.4
Acquisition Capital	(504.7)	(228.9)	1,985.1

"**Capital payout**" or "**payout per well**", 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 capital payout and payout per well as a measure of capital efficiency of a well to make capital allocation decisions.

"Development 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 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)	**2024**	**2023**	**2022**
Expenditures on property, plant and equipment	1,131.1	953.8	686.5
Less: expenditures on corporate and capitalized general and administrative expenses	18.8	14.2	16.6
Development Capital	1,112.3	939.6	669.9

"FD&A costs" are calculated as the sum of development capital plus acquisition capital plus the change in future development costs (being the best estimate of the capital cost to develop and produce reserves) 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.

"Recycle ratio" is calculated by dividing operating netback per boe by 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 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.

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, 2024 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 6,270 (5,461 net) drilling locations identified herein, 1,763 (1,497 net) are proved locations, 253 (219 net) are probable locations, and 4,254 (3,745 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(90), IP(120), IP(150)) 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 months and year ended December 31, 2024 and 2023, the year ended December 31, 2021, the forecast average daily production for 2024 and 2025 (midpoint), the forecast average daily production for our Lator Phase 1 (midpoint) and 2 facilities, the average daily production rate for the Musreau production increase, the fourth quarter of 2024 at Kaybob and for (1) the first Lator well (IP(120)), (2) the second Lator well projected IP(90), and (3) the State A OHML (IP(150)) 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	Q4/2024	Q4/2023	2024	2023
Light and medium oil (bbls/d)	74,105	76,519	75,171	74,913
Tight oil (bbls/d)	20,860	12,168	17,278	10,805
Crude oil (bbls/d)	94,965	88,687	92,449	85,718
NGLs (bbls/d)	20,797	19,241	20,371	17,296
Shale gas (Mcf/d)	218,860	210,026	220,567	185,791
Conventional natural gas (Mcf/d)	146,949	141,731	148,043	135,131
Natural gas (Mcf/d)	365,809	351,757	368,610	320,922
Total (boe/d)	176,730	166,554	174,255	156,501

Whitecap Corporate	2021	2024 Budget (Mid-Point)	2025 Guidance (Mid-Point)
Light and medium oil (bbls/d)	73,458	71,500	73,000
Tight oil (bbls/d)	1,929	14,500	19,000
Crude oil (bbls/d)	75,387	86,000	92,000
NGLs (bbls/d)	10,418	18,000	20,000
Shale gas (Mcf/d)	20,402	220,000	241,000
Conventional natural gas (Mcf/d)	138,099	146,000	155,000
Natural gas (Mcf/d)	158,501	366,000	396,000
Total (boe/d)	112,222	165,000	178,000

Whitecap Facility/Region	Lator Phase 1 (Mid-Point)	Musreau Production	Kaybob Q4/2024 Production
Light and medium oil (bbls/d)	-	-	-
Tight oil (bbls/d)	12,500	11,100	5,000
Crude oil (bbls/d)	12,500	11,100	5,000
NGLs (bbls/d)	4,167	1,100	2,600
Shale gas (Mcf/d)	125,000	31,800	98,400
Conventional natural gas (Mcf/d)	-	-	-
Natural gas (Mcf/d)	125,000	31,800	98,400
Total (boe/d)	37,500	17,500	24,000

Whitecap Initial Production Rates	Lator IP(120)	Lator Projected IP(90)	State A IP(150)
Light and medium oil (bbls/d)	-	-	103
Tight oil (bbls/d)	442	250	-
Crude oil (bbls/d)	442	250	103
NGLs (bbls/d)	77	134	31
Shale gas (Mcf/d)	4,478	7,296	-
Conventional natural gas (Mcf/d)	-	-	342
Natural gas (Mcf/d)	4,478	7,296	342
Total (boe/d)	1,265	1,600	191

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 Accounting Standards" 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 **"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 15 "Revenue" to the Company's audited annual consolidated financial statements for the year ended December 31, 2024, 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 Accounting Standards 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 Free Funds Flow" section of our management's discussion and analysis for the three months and year ended December 31, 2024 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, except per share amounts)	**2024**	**2023**	**2024**	**2023**
Cash flow from operating activities	419.8	476.2	1,833.5	1,742.5
Net change in non-cash working capital items	(7.0)	(13.9)	(201.3)	48.9
Funds flow	412.8	462.3	1,632.2	1,791.4
Expenditures on PP&E	261.4	200.5	1,131.1	953.8
Free funds flow	151.4	261.8	501.1	837.6
Funds flow per share, basic	0.70	0.77	2.74	2.96
Funds flow per share, diluted	0.70	0.76	2.73	2.94

**"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).

"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, 2024 for additional disclosures.

"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, 2024 for additional disclosures. The following table reconciles the Company's long-term debt to net debt:

Net Debt ($ millions)	**Dec. 31, 2024**	**Dec. 31, 2023**
Long-term debt	1,023.8	1,356.1
Cash	(362.3)	-
Accounts receivable	(422.2)	(400.2)
Deposits and prepaid expenses	(22.4)	(32.9)
Non-current deposits	(86.6)	(82.9)
Accounts payable and accrued liabilities	767.1	509.0
Dividends payable	35.7	36.4
Net Debt	933.1	1,385.5

"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 Accounting Standards 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 three months and year ended December 31, 2024, 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)	**2024**	**2023**	**2024**	**2023**
Petroleum and natural gas revenues	926.1	914.1	3,665.7	3,551.6
Tariffs	(6.5)	(6.4)	(26.9)	(27.9)
Processing & other income	9.9	12.2	44.1	49.8
Marketing revenues	71.0	70.1	255.0	275.4
Petroleum and natural gas sales	1,000.5	990.0	3,937.9	3,848.9
Realized gain/(loss) on commodity contracts	13.6	(2.1)	38.6	19.5
Royalties	(148.1)	(163.4)	(600.1)	(618.9)
Operating expenses	(222.7)	(205.5)	(874.1)	(805.4)
Transportation expenses	(36.4)	(32.1)	(135.9)	(123.8)
Marketing expenses	(71.0)	(69.6)	(253.3)	(273.9)
Operating netbacks	535.9	517.3	2,113.1	2,046.4

"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 Accounting Standards 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.

"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.

"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 15 "Revenue" to the Company's audited annual consolidated financial statements for the year ended December 31, 2024, 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, 2024, 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.