NEWS RELEASE

October 23, 2024

WHITECAP RESOURCES INC. EXCEEDS 2024 PRODUCTION GUIDANCE AND ANNOUNCES 2025 BUDGET

CALGARY, ALBERTA – Whitecap Resources Inc. ("Whitecap" or the "Company") (TSX: WCP) is pleased to report its operating and unaudited financial results for the three and nine months ended September 30, 2024.

Selected financial and operating information is outlined below and should be read with Whitecap's unaudited interim consolidated financial statements and related management's discussion and analysis for the three and nine months ended September 30, 2024 which are available at www.sedarplus.ca and on our website at www.wcap.ca.

	Three Months ended Sep. 30		Nine Months ended Sep. 30	
Financial ($ millions except for share amounts)	2024	2023	2024	2023
Petroleum and natural gas revenues	890.9	955.9	2,739.6	2,637.5
Net income	274.2	152.7	578.5	590.7
Basic ($/share)	0.46	0.25	0.97	0.98
Diluted ($/share)	0.46	0.25	0.96	0.97
Funds flow [1]	409.0	466.0	1,219.4	1,329.1
Basic ($/share) [1]	0.69	0.77	2.04	2.19
Diluted ($/share) [1]	0.68	0.76	2.03	2.18
Dividends declared	107.9	87.8	326.2	263.2
Per share	0.18	0.15	0.55	0.43
Expenditures on property, plant and equipment [2]	272.7	281.9	869.7	753.3
Free funds flow [1]	136.3	184.1	349.7	575.8
Net Debt [1]	1,361.8	1,260.2	1,361.8	1,260.2
Operating				
Average daily production				
Crude oil (bbls/d)	92,335	85,238	91,604	84,717
NGLs (bbls/d)	20,578	17,804	20,228	16,640
Natural gas (Mcf/d)	362,332	323,903	369,551	310,531
Total (boe/d) [3]	173,302	157,026	173,424	153,112
Average realized Price [1,4]				
Crude oil ($/bbl)	94.29	103.72	95.23	95.43
NGLs ($/bbl)	34.02	36.75	34.55	39.32
Natural gas ($/Mcf)	0.76	2.76	1.56	2.97
Petroleum and natural gas revenues ($/boe) [1]	55.88	66.17	57.65	63.10
Operating Netback ($/boe) [1]				
Petroleum and natural gas revenues[1]	55.88	66.17	57.65	63.10
Tariffs [1]	(0.43)	(0.50)	(0.43)	(0.51)
Processing & other income [1]	0.67	0.79	0.72	0.90
Marketing revenues [1]	3.79	5.04	3.87	4.91
Petroleum and natural gas sales [1]	59.91	71.50	61.81	68.40
Realized gain on commodity contracts [1]	0.93	0.04	0.53	0.52
Royalties [1]	(9.01)	(11.53)	(9.51)	(10.90)
Operating expenses [1]	(13.38)	(13.97)	(13.71)	(14.35)
Transportation expenses [1]	(2.10)	(2.22)	(2.09)	(2.19)
Marketing expenses [1]	(3.76)	(4.99)	(3.84)	(4.89)
Operating netbacks	32.59	38.83	33.19	36.59
Share information (millions)				
Common shares outstanding, end of period	588.0	606.2	588.0	606.2
Weighted average basic shares outstanding	595.2	606.0	597.3	605.8
Weighted average diluted shares outstanding	599.2	610.0	600.7	609.5

MESSAGE TO SHAREHOLDERS

Whitecap continued its strong operational momentum in the third quarter with production exceeding expectations on both a total basis and on liquids production. Production in the quarter averaged 173,302 boe/d (112,913 bbl/d of total liquids and 362,332 mcf/d of natural gas) compared to our forecast of 167,500 boe/d (107,500 bbl/d of total liquids and 360,000 mcf/d of natural gas). As a result of the year to date outperformance, we now forecast our full year production to average 172,500 boe/d which is above the high end of our previously increased production guidance of 167,000 – 172,000 boe/d. This is our third production guidance increase for 2024.

Higher than forecast liquids production from our oil weighted and condensate rich assets contributed to funds flow of $409 million ($0.68 per share). WTI averaged above $100/bbl Canadian in the third quarter, resulting in a strong operating netback of $32.59/boe. After capital expenditures of $273 million, free funds flow was $136 million in the quarter and was $350 million for the nine months ended September 30, 2024.

We have a robust return of capital framework in place where for the nine months ended September 30, 2024, we have repurchased $119 million of shares under our normal course issuer bid ("NCIB") and paid $326 million of dividends to shareholders.

Net debt at the end of the third quarter was $1.4 billion (0.6 times Debt to EBITDA[5]) on total credit capacity of $2.2 billion. On closing of the Pembina Gas Infrastructure ("PGI") transaction (details press released on July 2, 2024), net debt is expected to be approximately $1 billion (0.5 times Debt to EBITDA) which provides us with low leverage and ample liquidity. The closing of the PGI transaction is pending final regulatory approval.

We also recently released our investment grade credit rating of BBB (low), with a stable trend, by DBRS, Inc. Whitecap can now, and intends to, access the investment grade bond market to diversify our debt structure into a deeper market that provides for longer tenors and a lower cost of funding.

We provide the following third quarter and year to date 2024 financial and operating highlights:

- **Production Growth.** Production momentum and continued operational execution resulted in 12% production per share growth[6] compared to the third quarter of 2023. Crude oil and condensate production from our unconventional Montney and Duvernay and Southeast Saskatchewan Frobisher assets contributed to our overall liquids production outperforming expectations.

- **Funds Flow.** Third quarter funds flow of $409 million ($0.68 per share) benefitted from strength in crude oil and condensate prices along with continued focus on reducing operating costs. Natural gas revenue was less than 3% of petroleum and natural gas revenue in the third quarter as AECO natural gas prices averaged $0.65/GJ.

- **Capital Program.** Third quarter capital expenditures of $273 million included the drilling of a total of 67 (63.8 net) wells including 2 (2.0 net) Montney, 5 (5.0 net) Duvernay and 60 (56.8 net) conventional wells. We brought 4 (4.0 net) Montney wells at Musreau on production during the third quarter.

- **Return of Capital.** For the nine months ended September 30, 2024, we have returned $445 million to shareholders ($0.74 per share) through $326 million of base dividends and $119 million of share repurchases under our NCIB.

- **Balance Sheet Strength.** Quarter end net debt of $1.4 billion equated to a Debt to EBITDA ratio of 0.6 times, an EBITDA to interest expense ratio[5] of 25.3 times, and a debt to capitalization ratio[5] of 0.17 times, all well within our debt covenants of not greater than 4.0 times, not less than 3.5 times and not greater than 0.6 times, respectively. During the third quarter, we entered into a new $2 billion unsecured covenant-based credit facility which replaced our previous secured credit and term loan facilities.

2025 BUDGET

Our Board of Directors has approved a 2025 capital budget of $1.1 – $1.2 billion which is forecast to achieve average production of 176,000 – 180,000 boe/d (63% liquids). This is expected to deliver organic production per share growth of 4% – 6% and generate funds flow of approximately $1.6 – $1.7 billion at US$70/bbl WTI and $2.50/GJ AECO.

Whitecap has an enviable portfolio of highly economic drilling inventory in both our conventional light oil plays as well as the unconventional liquids rich Montney and Duvernay plays providing decades of sustainable production and funds flow growth.

Unconventional

Building off our operational success in 2024, we plan to allocate approximately 50% of our capital budget ($550 – $600 million) to our Montney and Duvernay assets which includes drilling 30 (30.0 net) wells in 2025. With 34 (32.5 net) wells coming on stream in 2025, including wells drilled in 2024, these assets are expected to deliver production growth of 10% on an annual basis and 20% exit to exit.

Duvernay

We drilled our first Duvernay pad in mid-2023 and have now drilled and brought on production 10 (10.0 net) Duvernay wells at Kaybob. Results to date have exceeded our initial expectations that were set upon completion of an extensive technical analysis that we undertook after acquiring the asset in the third quarter of 2022.

We plan to drill 20 (20.0 net) Duvernay wells in 2025 which will have our 15-07 gas processing facility operating at capacity in the second half of 2025. Our recently drilled 11-14B five well pad (5.0 net) will be tied into permanent facilities by the end of October this year. This is our first pad that incorporated a benching trial as the thickness in this area of the Duvernay lends itself to vertical inter-well spacing to access greater portions of the reservoir. Given the thickness of the Duvernay across our land base, results from this pad will inform future well designs to optimize capital efficiency as we develop our expansive drilling inventory.

Montney

At Musreau, our 05-09 battery has been operating at condensate capacity with our most recent four well pad producing at restricted rates due to continued strong condensate production from our previous two pads. We have completed the drilling of our last four well pad (4.0 net) in 2024 and this is expected to be on production prior to year end. In 2025, we have one four well pad (4.0 net) planned for the second half of the year to maintain production at the battery.

In Kakwa, we are currently drilling our first triple bench pad, testing the potential of each of the D2, D3 and Lower Middle Montney zones. In 2025, we have one four well pad (4.0 net) at southeast Kakwa planned which will be our third pad with wider inter-well spacing, building on the success of our previous pads in the Kakwa area.

At Lator, we are progressing our technical analysis as well as development planning for the area to coincide with the completion of our planned 04-13 battery in late 2026/early 2027. The two (2.0 net) wells drilled in 2024 will be on production prior to year end and we will follow up with two (2.0 net) additional wells in 2025. Results from this targeted development will inform development plans as we progress from phase one to phase two over the next several years. The focus for Lator in 2025 will be on technical due diligence, development planning, completion of the detailed engineering and design work for the 04-13 battery, and obtaining the required regulatory approvals for the commencement of the development program in 2026.

Conventional

We plan to invest $550 – $600 million to drill 190 (171.8 net) conventional wells in Alberta and Saskatchewan in 2025 which will deliver modest growth while generating 70% of Whitecap's free cash flow.

The very active capital programs across our conventional assets lead to stronger capital efficiencies and greater opportunities for inventory enhancement by using the same rigs, crews and service providers across our base programs. As a result, we are able to quickly implement new well designs and/or development plans to improve the already robust economics and further extend the inventory duration of this asset base.

In Central Alberta, we plan to drill 30 (23.7 net) wells in 2025 with a focus on the Glauconite in southwestern Alberta and the Cardium at West Pembina. Our operational momentum in the Glauconite has continued with the successful drilling of three monobores, resulting in 10% cost savings per well and we are currently drilling our fourth monobore. We plan to utilize a monobore drilling design for the majority of our Glauconite program in 2025. With continued success, the 10% cost savings per well provide a line of sight to over 90% of our inventory being identified as top tier locations.

Western Saskatchewan will be our most active area of development, with plans to drill 100 (98.8 net) wells of which 79 (79.0 net) will be targeting light oil in the Viking. In our Elrose Viking area, we have transitioned the drilling program to extended reach horizontal development to improve on the historic results. At US$70/bbl WTI, our 2025 Viking program is expected to have an average per well payout[7] of only eleven months.

In Eastern Saskatchewan, we plan to drill 39 (35.3 net) wells in 2025 of which 31 (12.7 net) will be targeting the Frobisher formation. The economics of our light oil Frobisher assets are extremely robust and recent wells are forecasted to achieve capital payout[8] three times in the first three years of production. Early time results from our State A (Frobisher) open hole multi-lateral pilot well are encouraging and further success will extend the inventory duration of this highly economic asset.

At Weyburn, we plan to drill 21 (14.2 net) wells in 2025, which will be a mix of new phase rollouts and infill wells on existing phases. We have achieved strong production results relative to our expectations on our rollout programs over the past four years, further validating the success of the CO_2 flood and our forecasts for ultimate recovery.

OUTLOOK

Our operational execution to date has been exceptional and we expect this to continue for the rest of the year and into 2025. We believe that crude oil prices will remain volatile but on balance robust, especially considering the weak Canadian dollar, and are expected to average US$65/bbl to US$75/bbl (C$90/bbl to C$103/bbl) in 2025. AECO prices are anticipated to remain weak, although incremental egress with LNG Canada 1 & 2, Cedar, Woodfibre and Ksi Lisims will be supportive of higher natural gas prices longer term.

We have taken a prudent approach to our 2025 capital budget to ensure it is defensible at lower commodity prices but also provides us optionality should commodity prices be higher than we anticipate. We expect to deliver organic production per share growth of approximately 5% and similar to 2024, we will look for opportunities to enhance our per share metrics in 2025.

Our balance sheet remains in excellent shape with low leverage and ample liquidity and will be further strengthened with our free funds flow in 2025.

We are excited about the opportunities within our vast portfolio of over 6,400 drilling locations[8] including the enhanced oil recovery projects that underpin the sustainability of our dividend and growth model, and we look forward to updating our shareholders on our progress for the rest of the year, in 2025, and beyond.

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) is a non-GAAP ratio. Refer to the Specified Financial Measures 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 and Product Type Information in this press release for additional disclosure.
4 Prior to the impact of risk management activities and tariffs.
5 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.
6 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.
7 Also referred to herein as "capital payout". Refer to Oil and Gas Metrics in this press release for additional disclosure.
8 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.

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 Wednesday, October 23, 2024.

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 forecasts for average daily production (including by product type and the proportional liquids production) and capital expenditures for 2024 and 2025; our expectation for net debt to be approximately $1 billion on closing of the PGI transaction; our belief net debt of $1 billion provides us with low leverage and ample liquidity; our belief that with an investment grade credit rating we can now access the investment grade bond market to diversify our debt structure into a deeper market that provides for longer tenors and a lower cost of funding; our intention to access the investment grade bond market; our forecast for organic production per share growth of 4% – 6%; our forecast for 2025 funds flow of approximately $1.6 – $1.7 billion at US$70/bbl WTI and $2.50/GJ AECO; our belief that we have an enviable portfolio of highly economic drilling inventory in both our conventional light oil plays as wells the unconventional liquids rich Montney and Duvernay plays providing decades of sustainable production and funds flow growth; our forecasts for the allocation of our 2025 budget to each of our unconventional and conventional assets, including the expected wells drilled in total and by region and the anticipated timing thereof; our forecasts for the number of unconventional wells to come on stream in 2025 and that these assets are expected to deliver production growth of 10% on an annual basis and 20% exit to exit; our plans to drill 20 (20.0 net) Duvernay wells in 2025 which will have our 15-07 gas processing facility operating at capacity in the second half of 2025; the expected timing of our 11-14B five well pad (5.0 net) being tied into permanent facilities and our expectation that results from this pad will inform future well designs to optimize capital efficiency as we develop our expansive drilling inventory; the expected timing that our last four well pad (4.0 net) in 2024 at Musreau will be on production and our plans for one four well pad (4.0 net) in the second half of 2025 to maintain production at the battery; our 2025 plans for one four well pad (4.0 net) at southeast Kakwa; our expectation that our technical analysis as well as development planning for Lator will coincide with the completion of our planned 04-13 battery in late 2026/early 2027; the expected timing of our two (2.0 net) Lator wells drilled in 2024 to be on production; that we will follow-up with two (2.0 net) additional wells in 2025 and our belief that such targeted development will inform development plans as we progress from phase one to phase two over the next several years; our anticipated focus for Lator in 2025 being on technical due diligence, development planning, completion of the detailed engineering and design work for the 04-13 battery, and obtaining the required regulatory approvals for the commencement of the development program in 2026; our plan to invest $550 – $600 million to drill 190 (171.8 net) conventional wells in Alberta and Saskatchewan in 2025 and that such our conventional program will deliver modest growth while generating 70% of Whitecap's free cash flow; our belief that the very active capital programs across our conventional assets lead to stronger capital efficiencies and greater opportunities for inventory enhancement by using the same rigs, crews and service providers across our base programs and our belief that as a result we will be able to quickly implement new well designs and/or development plans to improve the already robust economics and further extend the inventory duration of our conventional asset base; our plans for Central Alberta, including our plan to drill 30 (23.7 net) wells in 2025 with a focus on the Glauconite in southwestern Alberta and the Cardium at West Pembina; our plans to utilize a monobore drilling design for the majority of our Glauconite program in 2025 and the anticipated benefits to be derived therefrom; our expectation that Western Saskatchewan will be our most active area of development in 2025 and that we will drill 100 (98.8 net) wells in the area, of which 79 (79.0 net) will be targeting light oil in the Viking; our belief that extended reach horizontal development will improve on the historic results at Elrose; our expectation for our 2025 Viking program to have an average payout per well of only eleven months; our plans for Eastern Saskatchewan, including our plan to drill 39 (35.3 net) wells in 2025 of which 31 (12.7 net) will be targeting the Frobisher formation; our forecast for recent Frobisher wells to achieve capital payout three times in the first three years on production; our belief that further success with our State A (Frobisher) open hole multi-lateral project will extend the inventory duration of this highly economic asset; our plans for Weyburn, including our plan to drill 21 (14.2 net) wells in 2025, which will be a mix of new phase rollouts and infill wells on existing phases; our expectation that our exceptional operational execution will continue for the rest of the year and into 2025; our belief that crude oil prices will remain volatile but on balance robust; our expectation that crude oil prices will average US$65/bbl to US$75/bbl (C$90/bbl to C$103/bbl) in 2025; our belief that AECO prices will remain weak and that incremental egress with LNG Canada 1 & 2, Cedar, Woodfibre and Ksi Lisims will be supportive of higher natural gas prices longer term; our expectation to deliver organic production per share growth of approximately 5%; that we will look for opportunities to enhance our per share metrics in 2025; and, our belief that our pro forma balance sheet is in excellent shape with low leverage and ample liquidity and will be further strengthened with our free funds flow in 2025.

The forward-looking information is based on certain key expectations and assumptions made by our management, including: that the disposition to PGI will occur on the terms and timing anticipated by the Company; that we will continue to conduct our operations in a manner consistent with past operations except as specifically noted herein (and for greater certainty, except with respect to the proposed disposition to PGI, 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 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; 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 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 our disposition to PGI does not close on the terms and/or on the timetable currently anticipated or at all; 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 and 2025 forecasts (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 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 2025 capital expenditures, including the allocation to our unconventional and conventional assets; the portion of our free cash flow that will be generated by our conventional wells in 2025; our forecast for net debt of approximately $1 billion (0.5 times Debt to EBITDA) upon close of the PGI transaction; our forecast for $1.6 – $1.7 billion of funds flow in 2025 at US$70/bbl WTI and $2.50/GJ AECO; that at US$70/bbl WTI our 2025 Viking program is expected to have an average per well payout of only eleven months; that recent wells in the Frobisher formation are forecasted to achieve capital payout three times in the first three years of production; 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.

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 6,442 (5,619 net) drilling locations identified herein, 1,580 (1,374 net) are proved locations, 319 (271 net) are probable locations, and 4,543 (3,974 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 & 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.

The Company's average daily production for the three and nine months ended September 30, 2024 and 2023, and the forecast average daily production for Q3/2024, 2024 and 2025 (midpoint) 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	**9M 2024**	**9M 2023**	**Q3 2024**	**Q3 2023**
Light and medium oil (bbls/d)	75,528	74,372	73,900	74,543
Tight oil (bbls/d)	16,076	10,345	18,435	10,695
Crude oil (bbls/d)	91,604	84,717	92,335	85,238
NGLs (bbls/d)	20,228	16,640	20,578	17,804
Shale gas (Mcf/d)	221,140	177,624	215,309	185,977
Conventional natural gas (Mcf/d)	148,411	132,907	147,023	137,926
Natural gas (Mcf/d)	369,551	310,531	362,332	323,903
Total (boe/d)	173,424	153,112	173,302	157,026

Whitecap Corporate	**2024 Guidance**	**Q3 2024 Forecast**	**2025 Guidance (Mid-Point)**
Light and medium oil (bbls/d)	75,000	72,000	73,000
Tight oil (bbls/d)	16,000	16,000	19,000
Crude oil (bbls/d)	91,000	88,000	92,000
NGLs (bbls/d)	20,200	19,500	20,000
Shale gas (Mcf/d)	220,800	215,000	241,000
Conventional natural gas (Mcf/d)	147,000	145,000	155,000
Natural gas (Mcf/d)	367,800	360,000	396,000
Total (boe/d)	172,500	167,500	178,000

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 "**capital payout**" or "**payout per well**", which 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. 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. 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.

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.

"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 unaudited interim consolidated financial statements for the three and nine months ended September 30, 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 and nine months ended September 30, 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 Sep. 30,		Nine Months ended Sep. 30,	
($ millions, except per share amounts)	**2024**	**2023**	**2024**	**2023**
Cash flow from operating activities	556.2	382.8	1,413.7	1,266.3
Net change in non-cash working capital items	(147.2)	83.2	(194.3)	62.8
Funds flow	409.0	466.0	1,219.4	1,329.1
Expenditures on PP&E	272.7	281.9	869.7	753.3
Free funds flow	136.3	184.1	349.7	575.8
Funds flow per share, basic	0.69	0.77	2.04	2.19
Funds flow per share, diluted	0.68	0.76	2.03	2.18

"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 unaudited interim consolidated financial statements for the three and nine months ended September 30, 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 unaudited interim consolidated financial statements for the three and nine months ended September 30, 2024 for additional disclosures. The following table reconciles the Company's long-term debt to net debt:

Net Debt ($ millions)	**Sep. 30, 2024**	**Sep. 30, 2023**	**Dec. 31, 2023**
Long-term debt	1,095.6	1,177.1	1,356.1
Accounts receivable	(355.4)	(452.3)	(400.2)
Deposits and prepaid expenses	(32.9)	(44.9)	(32.9)
Non-current deposits	(82.9)	(65.3)	(82.9)
Accounts payable and accrued liabilities	701.6	616.4	509.0
Dividends payable	35.8	29.2	36.4
Net Debt	1,361.8	1,260.2	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 and nine months ended September 30, 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:

Operating Netbacks ($ millions)	Three Months ended Sep. 30, 2024	2023	Nine Months ended Sep. 30, 2024	2023
Petroleum and natural gas revenues	890.9	955.9	2,739.6	2,637.5
Tariffs	(6.8)	(7.2)	(20.4)	(21.5)
Processing & other income	10.7	11.4	34.2	37.6
Marketing revenues	60.4	72.8	184.0	205.3
Petroleum and natural gas sales	955.2	1,032.9	2,937.4	2,858.9
Realized gain on commodity contracts	14.9	0.6	25.0	21.6
Royalties	(143.6)	(166.6)	(452.0)	(455.5)
Operating expenses	(213.4)	(201.8)	(651.4)	(599.9)
Transportation expenses	(33.5)	(32.1)	(99.5)	(91.7)
Marketing expenses	(59.9)	(72.1)	(182.3)	(204.3)
Operating netbacks	519.7	560.9	1,577.2	1,529.1

"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 16 "Revenue" to the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2024, by the Company's total production volumes for the period.

"Realized gain on commodity contracts ($/boe)" is a supplementary financial measure calculated by dividing realized gain on commodity contracts, disclosed in Note 5(d) "Financial Instruments and Risk Management – Market Risk" to the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 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.