NEWS RELEASE

February 3, 2025

WHITECAP RESOURCES INC. ANNOUNCES STRONG 2024 RESERVES METRICS AND PROVIDES AN OPERATIONS UPDATE

CALGARY, ALBERTA – Whitecap Resources Inc. ("Whitecap" or the "Company") (TSX: WCP) is pleased to provide the results of our 2024 year end reserves evaluation as prepared by McDaniel & Associates Consultants Ltd. ("McDaniel").

2024 was a strong operational and financial year for Whitecap, driven by the successful execution of our organic drilling program. Our annual production of 174,255 boe/d[1] (65% liquids) was significantly above our initial expectations for the year, with the outperformance primarily driven by initial production results from our key assets including the Montney at Musreau, Duvernay at Kaybob, Glauconite in Central Alberta and Frobisher in East Saskatchewan. Our base production also outperformed our expectations through lower declines, production optimization and additional egress capacity.

Across all three reserves categories, proved developed producing ("PDP"), total proven ("TP") and total proven plus probable ("TPP"), we replaced over 110% of production[2], achieved debt-adjusted reserves per share growth[3] of 12% – 13% and generated strong recycle ratios[4], all of which demonstrate the predictability and profitability of our asset base. Our long-dated premium drilling inventory of 6,270 (5,461 net) locations[5] provides shareholders with sustainable and profitable long-term growth in production, funds flow and free funds flow. At our current drilling pace, our total inventory represents almost 30 years of development on our asset base.

We highlight the following 2024 year end reserves report results:

- **Reserves Growth[3].** Strong reserves per share growth of 4% on PDP reserves, 4% on TP reserves and 5% on TPP reserves. On a debt-adjusted basis, reserves per share growth is 12% on PDP reserves, 12% on TP reserves and 13% on TPP reserves.

- **Strong Recycle Ratios.** Low Finding, Development & Acquisition ("FD&A") costs[4] of $8.82/boe on PDP reserves, $12.46/boe on TP reserves and $10.02/boe on TPP reserves results in recycle ratios of 3.8 times, 2.7 times and 3.3 times, respectively. The strong recycle ratios reflect our high-quality asset base that generate attractive and resilient netbacks through commodity price cycles.

- **Long-Dated Inventory.** Our booked locations within TPP reserves represent only 32% of our 6,270 (5,461 net) identified locations in inventory. Our future growth will favour development of our unconventional Montney and Duvernay assets, with only 16% of 2,447 (2,198 net) identified unconventional locations being booked within our TPP reserves.

OPERATIONS UPDATE & OUTLOOK

Our 2025 drilling program is off to a strong start, with fourteen rigs currently running across our asset base to spud 83 (75.5 net) conventional wells and 12 (12.0 net) unconventional Montney and Duvernay wells in the first half of the year while planning to spend approximately 55% of our $1.1 – $1.2 billion annual capital budget.

At Kaybob, our 11-14B pad, which was our pilot drilled with vertical benching in a wine rack style development, has achieved IP(90) rates of 1,237 boe/d (40% liquids) including 379 bbl/d of condensate per well. Adjusted for lateral length (approximately 2,900 metre average compared to our type curve at 3,200 metres), production results from this pad are in line with our type curve expectations, while currently observed reservoir performance is notably stronger than that of analogue offset wells. These strong reservoir performance measures have provided us the confidence to progress this pilot with a follow-up pad, a five (5.0 net) well pad at 08-05A, which is currently being completed and expected to be on production late March this year.

The 11-14B pad is bounded by a number of offset wells and continued production performance will lead to an improvement in our long-term development plans through additional locations and/or higher recoveries per well. Our ability to apply this potential development style across our Duvernay assets at Kaybob is enabled by the relative thickness of net pay we have observed at upwards of 50 – 70 metres. We have not yet incorporated improvements to our inventory stemming from vertical benching into our Duvernay inventory at this time but are encouraged by the initial results.

We also plan to bring on production our first triple bench Montney three (1.5 net) well pad at North Kakwa in April of this year, with completion operations commencing after the 08-05A Duvernay pad is complete. We are looking forward to production results later this year as it will inform future development opportunities in an area that has not been actively drilled since we acquired it in 2021.

Our most active conventional areas of development in the first half of the year are the Viking with 33 (33.0 net) wells, the Glauconite with 12 (11.2 net) wells, the Frobisher with 11 (11.0 net) wells and southwest Saskatchewan with 11 (9.7 net) wells.

Our conventional program is focused on high confidence and efficient development opportunities as well as advancing our key inventory enhancement initiatives such as extended reach horizontals, monobore drilling design, adding additional lateral legs (including open hole multi-lateral development), and production and egress optimizations. We have only booked 43% of our 3,823 (3,263 net) total locations in our conventional inventory and our total inventory now includes 110 (88.3 net) State A Frobisher locations. Our conventional inventory is characterized by high netback, light oil weighted assets that generate strong economics through commodity price cycles.

2024 RESERVES REVIEW

Our 2024 year end reserves were evaluated by independent reserves evaluator McDaniel in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") as of December 31, 2024. The reserves evaluation was based on the average forecast pricing of McDaniel, GLJ Ltd. and Sproule Associates Limited and foreign exchange rates at January 1, 2025 which is available on McDaniel's website at www.mcdan.com.

Reserves included are Company share (gross) reserves which are the Company's total working interest reserves before the deduction of any royalties and without including any royalty interests payable to the Company. Additional reserves information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR+ at www.sedarplus.ca. The numbers in the tables below may not add due to rounding.

Summary of Reserves

Reserves as at December 31, 2024

	Company Share (Gross) Reserves		
Description	Light & Medium Crude Oil (Mbbl)	Tight Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)
Proved developed producing	191,107	620	339,901
Proved developed non-producing	2,377	-	5,092
Proved undeveloped	100,277	9,185	161,391
Total proved	293,761	9,805	506,384
Probable	100,605	6,200	197,985
Total proved plus probable	394,366	16,005	704,369

Description	Shale Gas (MMcf)	Natural Gas Liquids (Mbbl)	Total (Mboe)
Proved developed producing	338,367	62,358	367,131
Proved developed non-producing	44,901	4,427	15,136
Proved undeveloped	1,012,874	118,664	423,836
Total proved	1,396,141	185,449	806,103
Probable	916,748	104,520	397,114
Total proved plus probable	2,312,889	289,969	1,203,216

Net Present Values of Future Net Revenue

Summary of Before Tax Net Present Values of Future Net Revenue (Forecast Pricing)
As at December 31, 2024

	Before Tax Net Present Value ($ millions) (1)				
	Discount Rate				
Reserves Category	0%	5%	10%	15%	20%
Proved Developed Producing	7,388	6,455	5,439	4,711	4,186
Proved developed non-producing	390	305	253	218	192
Proved undeveloped	7,560	4,969	3,417	2,425	1,756
Total Proved	15,337	11,729	9,109	7,354	6,133
Total Probable	10,800	6,024	3,967	2,877	2,217
Total Proved + Probable	26,138	17,752	13,076	10,230	8,351

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

Future Development Costs ("FDC")

FDC reflects the best estimate of the capital cost to develop and produce reserves. FDC associated with our TP reserves at year end 2024 is $7.0 billion undiscounted ($5.1 billion discounted at 10%).

Also included in FDC are 1,763 (1,496.7 net) proved booked drilling locations and 253 (219.4 net) probable booked drilling locations.

($ millions)	Total Proved	Total Proved plus Probable
2025	1,110	1,133
2026	1,219	1,261
2027	1,309	1,374
2028	1,419	1,492
2029	1,016	1,303
Remainder	940	2,185
Total FDC, Undiscounted	7,014	8,748
Total FDC, Discounted at 10%	5,111	6,102

Performance Measures (Including FDC)

The following table highlights finding and development ("F&D")[3] and FD&A costs and associated recycle ratios, including FDC, based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

	2024	**2023**	**2022**	**Three Year Weighted Average**
Proved Developed Producing				
F&D costs per boe (1)	$16.01	$14.69	$13.25	$14.64
F&D recycle ratio (2)	2.1x	2.4x	3.5x	2.7x
FD&A costs per boe (3)	$8.82	$17.24	$24.05	$16.76
FD&A recycle ratio (2)	3.8x	2.1x	2.0x	2.6x
Total Proved				
F&D costs per boe (1)	$19.24	$17.63	$16.95	$17.94
F&D recycle ratio (2)	1.7x	2.0x	2.8x	2.2x
FD&A costs per boe (3)	$12.46	$22.55	$14.98	$16.63
FD&A recycle ratio (2)	2.7x	1.6x	3.1x	2.5x
Total Proved Plus Probable				
F&D costs per boe (1)	$15.46	$20.53	$19.61	$18.52
F&D recycle ratio (2)	2.1x	1.7x	2.4x	2.1x
FD&A costs per boe (3) (4)	$10.02	nm	$11.55	nm
FD&A recycle ratio (2) (4)	3.3x	nm	4.1x	nm

(1) F&D costs are non-GAAP ratios and are calculated as the sum of development capital of $1.1 billion (excluding corporate and capitalized general and administrative expenses ("G&A")) plus the change in FDC for the period of $22 million (PDP), $372 million (TP) and $378 million (TPP), divided by the change in reserves volumes that are characterized as development for the period. See "Oil and Gas Metrics" and "Specified Financial Measures".

(2) Recycle ratio is a non-GAAP ratio and is calculated as operating netback[4] divided by F&D or FD&A costs. Our operating netback in 2024 was $33.14/boe[4]. See "Oil and Gas Metrics" and "Specified Financial Measures".

(3) FD&A costs are non-GAAP ratios and are calculated as the sum of development capital of $1.1 billion (excluding corporate and capitalized G&A) plus acquisition capital of -$505 million plus the change in FDC for the period of $22 million (PDP), $372 million (TP) and $378 million (TPP), divided by the change in total reserves volumes, other than from production, for the period. See "Oil and Gas Metrics" and "Specified Financial Measures".

(4) The impact of net dispositions in 2023 results in a very low denominator value and therefore the 2023 FD&A cost of $85.40 per boe is deemed not material ("nm") to our reserves performance measures.

Production Replacement Ratio and Reserve Life Index

The following table highlights our production replacement ratio and reserve life index[2] ("RLI") based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel:

In 2024, we replaced 112% of production on a PDP reserves basis, 123% of production on a TP reserves basis and 154% of production on a TPP reserves basis.

	2024	2023	2022	Three Year Weighted Average
Proved Developed Producing				
Production replacement (1)	112%	71%	208%	131%
RLI (years) (2)	5.7	5.9	6.2	5.9
Total Proved				
Production replacement (1)	123%	81%	588%	265%
RLI (years) (2)	12.5	13.0	13.2	12.9
Total Proved Plus Probable				
Production replacement (1)	154%	16%	952%	380%
RLI (years) (2)	18.7	19.2	20.0	19.3

(1) Production replacement ratio is calculated as total reserves additions (including acquisitions net of dispositions) divided by annual production. Whitecap's production averaged 174,255 boe/d in 2024.

(2) RLI is calculated as total Company share (gross) reserves divided by the annualized fourth quarter actual production of 176,730 boe/d.

On behalf of our employees, management team and Board of Directors, we would like to thank our shareholders for their support and look forward to an exciting 2025 and beyond.

NOTES

1 Disclosure of production on a per boe basis in this press release consists of the constituent product types and their respective quantities disclosed herein. Refer to Barrel of Oil Equivalency and Production, Initial Production Rates and Product Type Information in this press release for additional disclosure.

2 See "Production Replacement Ratio and Reserve Life Index".

3 "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 (-$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.

4 Operating netback is non-GAAP financial measure. Operating netbacks ($/boe), F&D costs, FD&A costs and recycle ratio are non-GAAP ratios. Net debt is a capital management measure. Per boe disclosure figures are supplementary financial measures. Refer to the Specified Financial Measures section in this press release for additional disclosure and assumptions.

5 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.

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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 our over 110% of production replacement, 4% - 5% reserves per share growth and strong recycle ratios all demonstrate the predictability and profitability of our asset base; our belief that our long-dated premium drilling inventory provides shareholders with sustainable and profitable long-term growth in production, funds flow and free funds flow; our belief that at our current drilling pace, our total inventory represents almost 30 years of development on our asset base; our belief that strong recycle ratios reflect our high-quality asset base that generates attractive and resilient netbacks through commodity price cycles; our belief that our future growth will favour development of our unconventional Montney and Duvernay assets; our plans to spud 83 (75.5 net) conventional wells and 12 (12.0 net) unconventional Montney and Duvernay wells in the first half of the year while planning to spend approximately 55% of our $1.1 – $1.2 billion annual capital budget; our beliefs regarding our 11-14B pad's strong reservoir performance measures; the timing of bringing on production our 08-05A pad; our belief that continued production performance of the 11-14B pad will lead to an improvement in our long-term development plans through additional locations and/or higher recoveries per well; our interpretation of relative thickness of net pay at Kaybob and our belief that our ability to apply a certain potential development style across our Duvernay assets at Kaybob is enabled by the relative thickness of net pay; our plans to bring our first triple bench Montney three (1.5 net) well pad at North Kakwa on production in April and our belief that 2025 production results will inform future development opportunities for the area; our plans for conventional areas of development in the first half of the year; and, our belief that our conventional inventory is characterized by high netback, light oil weighted assets that generate strong economics through commodity price cycles. Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking information is based on certain key expectations and assumptions made by our management, including: the impact of the tariffs that were recently announced by the federal governments of the U.S. and Canada, and that neither country imposes new tariffs or other taxes on one another, or imposes restrictions or prohibitions on the export or import of goods between one another; 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 the governments of the U.S. and/or Canada amend existing tariffs or impose new tariffs on one another's goods, including crude oil and natural gas, and that such amended or new tariffs adversely affect the demand and/or market price for the Company's products and/or otherwise adversely affect 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 plan to spend approximately 55% of our $1.1 – $1.2 billion 2025 annual capital budget in the first half of the year; and our forecasts for the future development costs to develop and produce our reserves; all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of Whitecap and the resulting financial results will likely vary from the amounts set forth herein and such variation may be material. Whitecap and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, Whitecap undertakes no obligation to update such FOFI. FOFI contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Whitecap's anticipated future business operations. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein.

OIL AND GAS ADVISORIES

Reserves Volumes and Net Present Values

All reserve references in this press release are "Company share (gross) reserves". Company share reserves are our total working interest reserves before the deduction of any royalties and without including any royalty interests payable to the Company.

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

Barrel of Oil Equivalency

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

Oil and Gas Metrics

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

"Acquisition capital" is a non-GAAP financial measure used in the determination of FD&A costs, which is a non-GAAP ratio. The most directly comparable GAAP measure to acquisition capital is expenditures on corporate acquisitions, net of cash acquired, and expenditures on property acquisitions. For property acquisitions 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

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

		Year ended Dec. 31,	
($ millions)	**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

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

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

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

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

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

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

Drilling Locations

This press release discloses drilling inventory in two categories: (i) booked locations (proved and probable); and (ii) unbooked locations. Booked locations represent the summation of proved and probable locations, which are derived from McDaniel’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.

- Of the 2,447 (2,198 net) unconventional drilling locations identified herein, 280 (241 net) are proved locations, 104 (95 net) are probable locations, and 2,063 (1,862 net) are unbooked locations.

- Of the 3,823 (3,263 net) conventional drilling locations identified herein, 1,483 (1,255 net) are proved locations, 149 (125 net) are probable locations, and 2,191 (1,883 net) are unbooked locations.

- Of the 110 (88.3 net) State A Frobisher drilling locations identified herein, 3 (3.0 net) are proved locations, and 107 (85.3 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)) are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Whitecap.

The Company's average daily production for the three and twelve months ended December 31, 2024 and the average daily production rate per well for our 5 (5.0 net) 11-14B Duvernay pad at Kaybob (IP(90)) disclosed in this press release consists of the following product types, as defined in NI 51-101 (other than as noted above with respect to condensate) and using a conversion ratio of 1 Bbl : 6 Mcf where applicable:

Whitecap Corporate/ Initial Production Rates	**Q4/2024**	**2024**	**Kaybob (IP(90))**
Light and medium oil (bbls/d)	74,105	75,171	-
Tight oil (bbls/d)	20,860	17,278	379
Crude oil (bbls/d)	94,965	92,449	379
NGLs (bbls/d)	20,797	20,371	115
Shale gas (Mcf/d)	218,860	220,567	4,456
Conventional natural gas (Mcf/d)	146,949	148,043	-
Natural gas (Mcf/d)	365,809	368,610	4,456
Total (boe/d)	176,730	174,255	1,237

SPECIFIED FINANCIAL MEASURES

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

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

"**Net Debt**" is a capital management measure and is key to assessing the Company's liquidity. The following table reconciles the Company's long-term debt to net debt:

Net Debt ($ millions)	**Dec. 31, 2024 (unaudited)**	**Dec. 31, 2023**
Long-term debt	661.5	1,356.1
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 and, therefore, may not be comparable with the calculation of similar financial measures disclosed by other entities. A reconciliation of operating netbacks to petroleum and natural gas revenues is set out below:

	Year ended Dec. 31,	
Operating Netbacks ($ millions)	**2024 (unaudited)**	**2023**
Petroleum and natural gas revenues	3,665.7	3,551.6
Tariffs	(26.9)	(27.9)
Processing & other income	44.1	49.8
Marketing revenues	255.0	275.4
Petroleum and natural gas sales	3,937.9	3,848.9
Realized gain (loss) on commodity contracts	38.6	19.5
Royalties	(600.1)	(618.9)
Operating expenses	(874.1)	(805.4)
Transportation expenses	(135.9)	(123.8)
Marketing expenses	(253.3)	(273.9)
Operating netbacks	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 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. The components of operating netbacks per boe are shown below:

	Year ended Dec. 31,	
Operating Netbacks ($ per boe)	**2024 (unaudited)**	**2023**
Petroleum and natural gas revenues(1)	57.48	62.17
Tariffs(1)	(0.42)	(0.49)
Processing & other income(1)	0.69	0.87
Marketing revenues(1)	4.00	4.82
Petroleum and natural gas sales(1)	61.75	67.37
Realized gain (loss) on commodity contracts(1)	0.61	0.34
Royalties(1)	(9.41)	(10.83)
Operating expenses(1)	(13.71)	(14.10)
Transportation expenses(1)	(2.13)	(2.17)
Marketing expenses(1)	(3.97)	(4.79)
Operating netbacks	33.14	35.82

[1] Supplementary financial measure.

"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 by the Company's total production volumes for the period.

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

"Realized gain (loss) on commodity contracts ($/boe)" is a supplementary financial measure calculated by dividing realized gain (loss) on commodity contracts by the Company's total production volumes for the period.

Unaudited Financial Information

Certain financial and operating information included in this press release for the year ended December 31, 2024 including, without limitation, development capital, acquisition capital, finding and development costs, finding, development and acquisition costs, recycle ratio, net debt (and the components thereof), change in net debt and operating netbacks (and the components thereof), are based on estimated unaudited financial results for the year then ended, and are subject to the same limitations as discussed under Note Regarding Forward Looking Statements set out in this press release. These estimated amounts may change upon the completion of audited financial statements for the year ended December 31, 2024 and changes could be material.

Per Share Amounts

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