enerPLUS

TSX & NYSE: ERF

Peters & Co. Limited Energy Conference

September 14, 2022

Forward looking information and statements

This presentation contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this presentation contains forward-looking information pertaining to the following: updated 2022 production and capital spending guidance; expected capital spending levels in 2022; expectations regarding 2022 and future shareholder returns, including payment of dividends and Enerplus' share repurchase program, the timing and amounts thereof and funding dividends and the share repurchase program from free cash flow; expectations regarding free cash flow generation and capital spending reinvestment rates; expected operating strategy in 2022 and expectations regarding our drilling program and well costs; 2022 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the expected effectiveness of such hedges in protecting our cash flow from operating activities and adjusted funds flow; oil and natural gas prices and differentials and expectations regarding the market environment and our commodity risk management program in 2022; updated and existing 2022 Bakken and Marcellus differential guidance; expectations regarding realized oil and natural gas prices; expected operating, transportation and cash G&A expenses and production taxes and updated 2022 guidance with respect thereto; expectations regarding net debt and debt reduction; expectations regarding increases to dividends and timing thereof; and expectations regarding renewal of our normal course issuer bid, including timing and size thereof.

The forward-looking information contained in this presentation reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; the continued operation of the Dakota Access Pipeline; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current and anticipated commodity prices, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, the impact of inflation, weather conditions, storage fundamentals and expectations regarding the duration and overall impact of COVID-19; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the ability to fund increased dividend payments and the share purchase program from free cash flow as expected and discussed in this presentation; our ability to comply with our debt covenants; the availability of third party services; expected transportation expenses; the extent of our liabilities; and the availability of technology and process to achieve environmental targets. In addition, our 2022 guidance described in this presentation is based on: a WTI price of US$90.00/bbl, a NYMEX price of US$6.50/Mcf, a Bakken crude oil price of $+1.00/bbl above WTI, a Marcellus natural gas price differential of $(0.75)/Mcf below NYMEX and a CDN/USD exchange rate of 0.78. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.

The forward-looking information included in this presentation is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued instability, or further deterioration, in global economic and market environment, including from COVID-19, inflation and/or the Ukraine/Russia conflict and heightened geopolitical risks; decreases in commodity prices or volatility in commodity prices; changes in realized prices of Enerplus' products from those currently anticipated; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; legal proceedings or other events inhibiting or preventing operation of the Dakota Access Pipeline; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facilities and/or outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; changes in law or government programs or policies in Canada or the United States; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our 2022 interim MD&As, our annual information form for the year ended December 31, 2021, our 2021 annual MD&A and Form 40-F as at December 31, 2021).

The forward-looking information contained in this presentation speaks only as of the date of this presentation. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

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Enerplus – differentiated Bakken platform

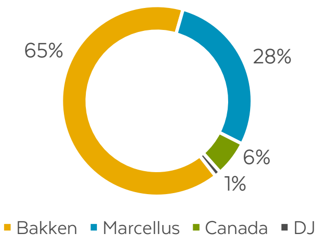
Key updates from Q2 2022:

1 STRONG OPERATING RESULTS DROVE PRODUCTION INCREASE

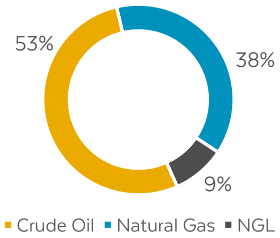
2 ON TRACK TO DELIVER RECORD ANNUAL FREE CASH FLOW

3 INCREASING RETURN OF CAPITAL TO SHAREHOLDERS

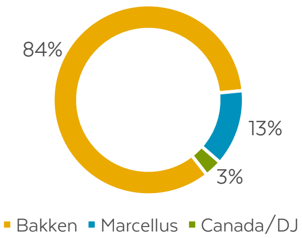
Production by area[1]

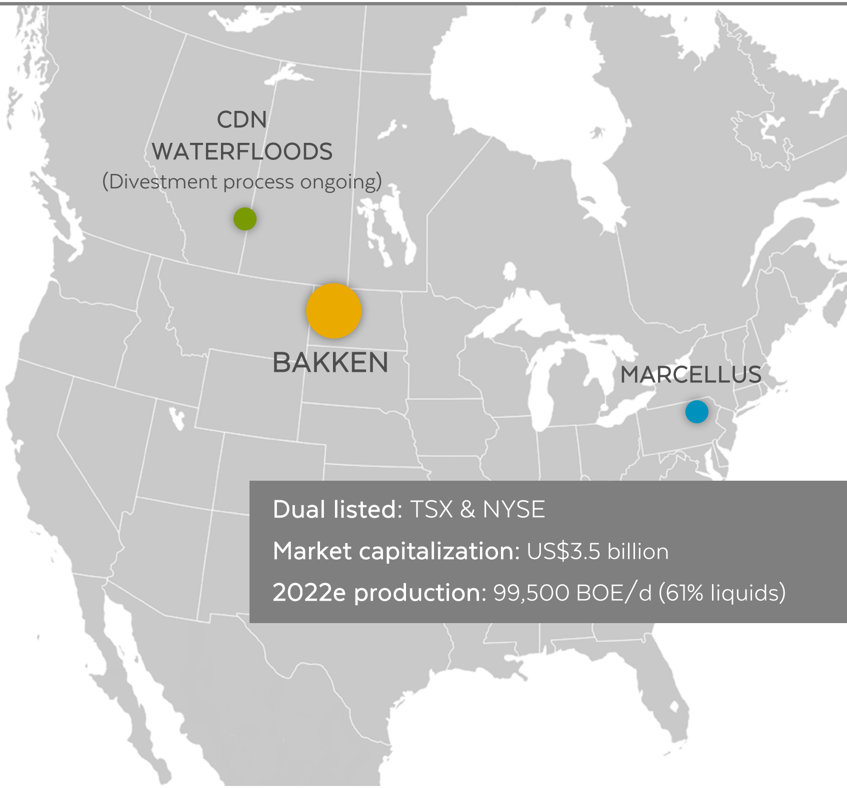


Production by product[1]



Capital allocation[1]





Dual listed: TSX & NYSE

Market capitalization: US$3.5 billion

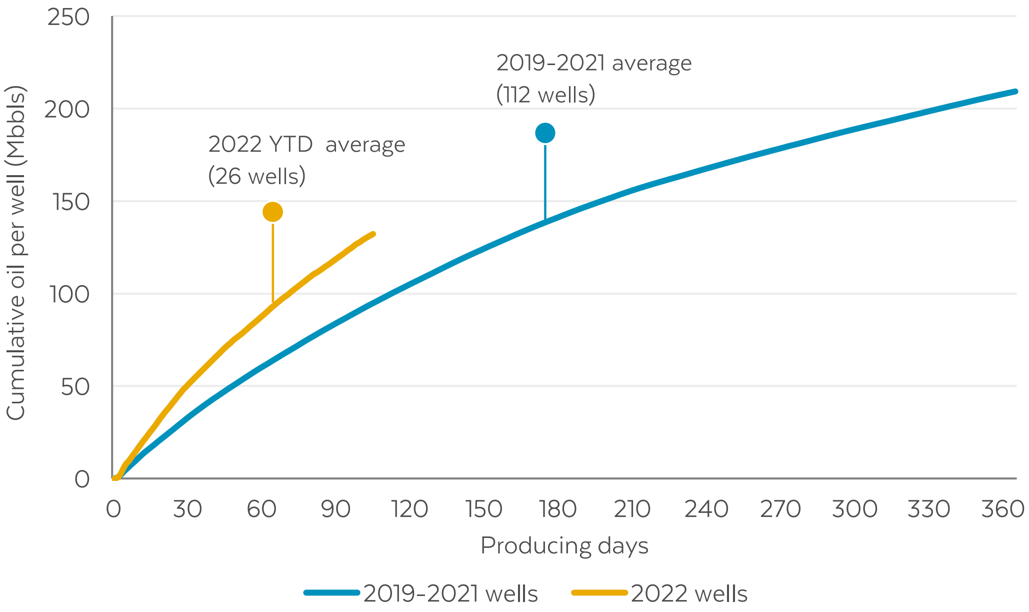
2022e production: 99,500 BOE/d (61% liquids)

1) *Charts reflect 2022e production and capital allocation.*

Strong well performance & execution driving higher production forecast

Enerplus average North Dakota well performance[(1)]

Average cumulative oil production per well



2022 PRODUCTION GUIDANCE

+1,500 BOE/d (vs initial guidance)[(2)]

- Increased guidance despite storm impacts and announced Canadian divestment which have impacted production by ~2,000 BOE/d

Q3 LIQUIDS PRODUCTION GROWTH

+15% (vs Q2)

- Expecting robust second half 2022 volumes driven by an active development program and continued well outperformance

1) *Includes all Enerplus operated wells since 2019.*
2) *Based on guidance midpoint.*

Return of capital to shareholders

2022 RETURN OF CAPITAL PLAN

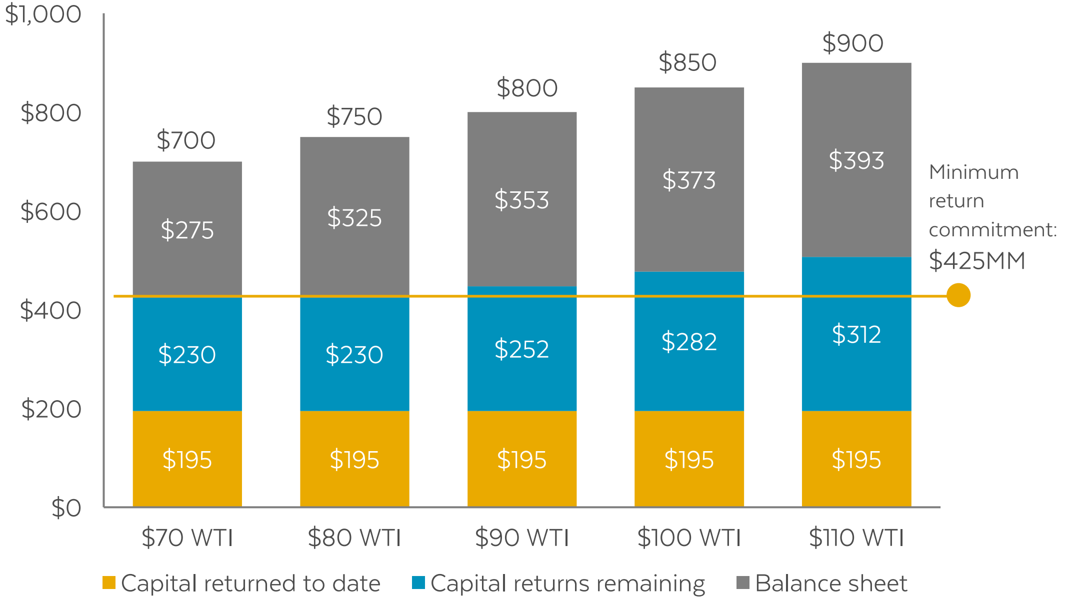
- Increased return of capital to at least 60% of free cash flow commencing in 2H 22 (from 50% previously)
- Increased minimum 2022 return of capital commitment to $425 million (from $350 million)
- Returns to be delivered through dividends and share repurchases
- Quarterly dividend increased by 16% to $0.05/share
- Minimum of $230 million in remaining cash returns in 2022 (Sep-Dec)

2023 RETURN OF CAPITAL PLAN

- At least 60% of free cash flow

2022 free cash flow allocation oil price sensitivity (rest of year prices)(1)

$ millions



Capital returns = Dividends + Share repurchases

1) *Capital returned to date is inclusive of dividends and share repurchases through August 2022. Sensitivity uses $6.50/Mcf NYMEX. Allocation to balance sheet includes annual ARO spending.*

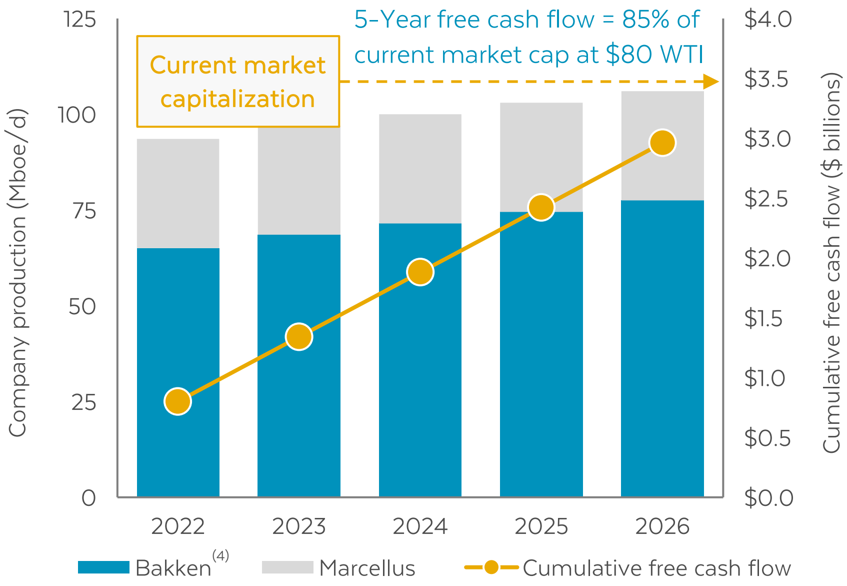
Bakken focused five-year outlook

- Bakken focused five-year outlook expected to generate ~$3bn of free cash flow[(1)] at $80/bbl WTI[(1)]
- Annual liquids production growth rate of 3-5%[(3)]
  - Maintains sustainable base production decline rate
  - Outlook excludes remaining Canadian assets due to ongoing divestment process

Five-year outlook based on $80/bbl WTI, $4.00/Mcf NYMEX[(1)]

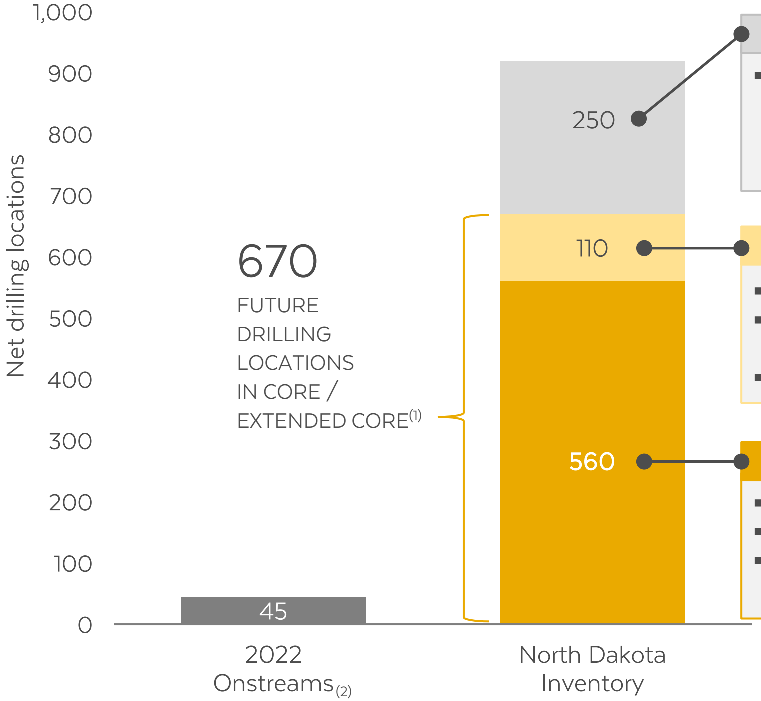
Annual capital spending[(2)]	Annual liquids production growth[(3)]
~$500 million	3-5%
Average reinvestment rate	**Cumulative free cash flow[(1)]**
<50%	~$3 billion

Five-year production and free cash flow outlook



1) See Non-GAAP & Other Financial Measures in "Advisories". 2022 is based on rest of year prices of $90/bbl WTI and $6.50 /Mcf NYMEX. Years 2023-2026 are based on $80/bbl WTI and $4.00/Mcf NYMEX.
2) 2022 capital spending guidance is $400-$440MM. 2023-2026 projected at approximately $500MM.
3) 3-5% annual production growth is from 2023-2026 and is divestment adjusted for Canadian assets. 2022e growth is 8% based on the guidance midpoint.
4) Bakken production on chart includes volumes from the DJ Basin.

Deep drilling inventory supports sustainable outlook



Inventory upsides

- Lower return locations that offer upside through stimulation advances, well cost improvements, sustained high oil prices

Extended Core

- Periphery of established core
- Lower returns than Core, but exceeds returns threshold at midcycle prices
- Primarily southern Dunn

Core

- Established economic core of play
- Well defined & de-risked
- FBIR, northern Dunn, eastern Williams

>Decade

of Core drilling inventory

(at development pace assumed in 5-year plan)

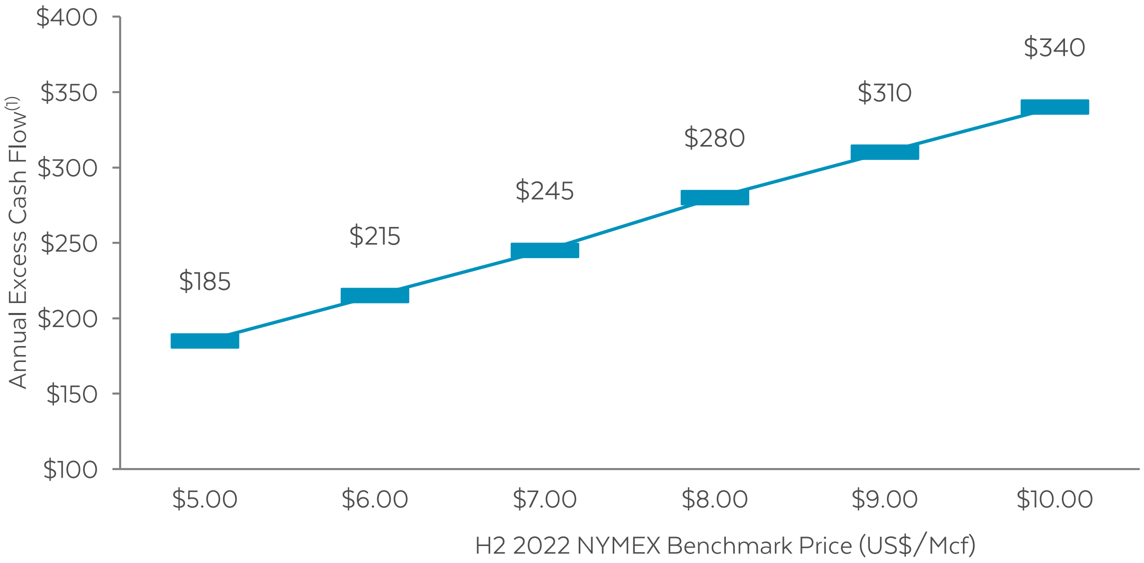
Additional drilling inventory in the Extended Core + Upside locations

1) *See "Advisories – Drilling Inventory" for a reconciliation of undrilled locations between those associated with reserves and those not associated with any reserves. As at 1 Jan 2022. Includes operated and non-operated locations.*
2) *2022 onstreams includes operated and non-operated wells.*

Marcellus – robust excess cash flow generation

Enerplus' Marcellus 2022 excess cash flow generation[1]

Unhedged net operating income less capital spending sensitivity using flat H2 2022 NYMEX prices



Natural gas commodity hedging contracts

NYMEX

	Jul 1, '22 – Oct 31, '22	Nov 1, '22 – Mar 31, '23	Apr 1, '23 – Oct 31, '23
Swaps			
Swaps	40,000	-	-
Vol. (Mcf/d)	$3.40	-	-
Collars			
Vol. (Mcf/d)	60,000	120,000	50,000
Puts	$3.77	$6.27	$4.05
Calls	$4.50	$18.17	$7.00

Enerplus Q2 2022 Marcellus production was 168 MMcf/d (net)

1) *Excess cash flow is equal to net operating income less capital spending. Marcellus net operating income and capital spending in H1 2022 were $139 million and $31 million respectively. Marcellus capital spending in H2 2022 is estimated at approx. $25 million. Excludes impact of hedges.*

Why invest in Enerplus

- **THE BAKKEN IS AN ADVANTAGED BASIN**
  - 10,000 drilling locations at or below $60/bbl WTI; 5,000 at or below $50/bbl WTI
  - Supportive regulatory environment
  - Significant egress: Bakken oil prices currently at a premium to WTI
- **ENERPLUS IS A DIFFERENTIATED BAKKEN PLATFORM**
  - Over a decade of core inventory based on 3-5% growth rate assumed in 5-year outlook
  - Among the best drilling & completions execution and safety performance in the basin
- **EXPOSURE TO STRONG NATURAL GAS PRICES THROUGH THE MARCELLUS**
  - Strong free cash flow generation; attractive hedging in 2023
- **DISCIPLINED CAPITAL ALLOCATION**
  - Reinvestment rate of ~35% in 2022, <50% in 2023-2026 assuming $80 WTI
  - Forecasting ~$800MM of free cash flow in 2022 (>20% FCF yield) based on $90 WTI
  - Meaningful cash returns to shareholders ($425MM min. in 2022, 60% of FCF min. in 2023)
  - Profitable and sustainable organic liquids production growth of 3-5%
  - Low financial leverage with potential to be net debt free in 2023

Advisories

Assumptions

All amounts in this presentation are stated in U.S. dollars unless otherwise specified. All financial information in this presentation has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent and Cubic Feet of Gas Equivalent

This presentation contains references to "BOE" (barrels of oil equivalent), "MBOE" (one thousand barrels of oil equivalent), and "MMBOE" (one million barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Non-GAAP & Other Financial Measures

This presentation includes references to certain non-GAAP financial measures and non-GAAP ratios used by the Company to evaluate its financial performance, financial position or cash flow. Non-GAAP financial measures are financial measures disclosed by a company that (a) depict historical or expected future financial performance, financial position or cash flow of a company, (b) with respect to their composition, exclude amounts that are included in, or include amounts that are excluded from, the composition of the most directly comparable financial measure disclosed in the primary financial statements of the company, (c) are not disclosed in the financial statements of the company and (d) are not a ratio, fraction, percentage or similar representation. Non-GAAP ratios are financial measures disclosed by a company that are in the form of a ratio, fraction, percentage or similar representation that has a non-GAAP financial measure as one or more of its components, and that are not disclosed in the financial statements of the company. These non-GAAP financial measures and non-GAAP ratios do not have standardized meanings or definitions as prescribed by U.S. GAAP and may not be comparable with the calculation of similar financial measures by other entities. Please see Management's Discussion & Analysis for the composition of each non-GAAP measure, the identified GAAP equivalency to the extent one exists, a reconciliation of the measure to the mostly directly comparable GAAP financial measure and details on the usefulness of the measure for the reader. These non-GAAP financial measures and non-GAAP ratios should not be considered as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP. Please see "Non-GAAP Measures" in the latest MD&A for more detail.

Other financial measures include supplementary financial measures and capital management measures. Supplementary financial measures are disclosed by a company that (a) are, or are intended to be, disclosed on a periodic basis to depict the historical or expected future financial performance, financial position or cash flow of a company, (b) are not disclosed in the financial statements of the company, (c) are not non-GAAP financial measures, and (d) are not non-GAAP ratios. Capital management measures are financial measures disclosed by a company that (a) are intended to enable an individual to evaluate a company's objectives, policies and processes for managing the company's capital, (b) are not a component of a line item disclosed in the primary financial statements of the company, (c) are disclosed in the notes to the financial statements of the company, and (d) are not disclosed in the primary financial statements of the company. Please see "Other Financial Measures" in the latest MD&A

Presentation of Production and Reserves Information

All production volumes presented in this presentation are reported on a "net" basis (the Company's working interest share after deduction of royalty obligations, plus the Company's royalty interests), unless expressly indicated that it is being presented on a "gross" basis. Previously, the Company presented production volumes on a "company interest" basis, which was calculated as its working interest share before deduction of royalties plus the Company's royalty interests. With these changes, production volumes presented by the Company on a "net" basis are expected to be lower than those presented historically. All reserves information presented herein are reported in accordance with Canadian reserve evaluation standards under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("Canadian NI 51-101 Standards"), except certain reserves information effective December 31, 2021 in accordance with the provisions of the Financial Accounting Standards Board's ASC Topic 932 Extractive Activities – Oil and Gas, which generally utilize definitions and estimations of proved reserves that are consistent with Rule 4-10 of Regulation S-X promulgated by the U.S. Securities and Exchange Commission (collectively, the "U.S. Rules"), but does not necessarily include all of the disclosure required by the SEC disclosure standards set forth in Subpart 1200 of Regulation S-K (the "U.S. Standards"). The practice of preparing production and reserves data under the Canadian NI 51-101 Standards differs from the U.S. Rules and the presentation of production and reserves data under the Canadian Standards differs from presentation under the U.S. Standards. Please refer to our 2021 reserves news release for further information. All references to "liquids" in this presentation include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and NGLs on a combined basis. All references to "natural gas" in this presentation include conventional natural gas and shale gas on a combined basis. Enerplus' oil and gas reserves statement for the year ended December 31, 2021, which will include complete disclosure of our oil and gas reserves and other oil and gas information prepared under the Canadian NI 51-101 Standards and also certain information about our oil and gas reserves prepared in accordance with the U.S. Rules, is contained within our Annual Information Form (AIF) for the year ended December 31, 2021 which is available on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this presentation for more complete disclosure on our operations.

Drilling Inventory and Expected Well Performance

Drilling locations associated with proved plus probable undeveloped reserves have been evaluated or reviewed by Enerplus' independent qualified reserves evaluators in accordance with the COGE Handbook. Drilling locations associated with unrisked "best estimate" economic contingent resources in "development pending" project maturity sub-class have been evaluated by Enerplus' independent qualified reserves evaluators, McDaniel & Associates Ltd in the case of North Dakota in accordance with the COGE Handbook. Unbooked future drilling locations are not associated with any reserves or contingent resources of Enerplus and have been identified by Enerplus and have not been audited by Enerplus' independent qualified reserves evaluators. Existing Enerplus net locations in North Dakota as at 1 Jan 2022 are 920 and comprise 316 2P undeveloped reserves locations, 284 best estimate contingent resources locations and 320 unbooked future locations. The Enerplus expected well performance comes from analyzing historical well productivity within the geographic area outlined in the locator box on the maps on the respective slides. The data set analyzed excludes wells completed before 2016 and the Enerplus expected well is an average of our future planned inventory. Payout times and NPVs are calculated assuming a $6.5MM capital well cost.

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