National Bank Financial Energy Tour – Clearwater Focus

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Advisory

In this presentation, we refer to certain specified financial and capital management measures which do not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS"). While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This presentation also contains oil and gas disclosures, various industry terms, and forward-looking statements, including various assumptions on which such forward-looking statements are based and related risk factors. Please see the Company's disclosures located at the end of this presentation for further details regarding these matters.

All slides in this presentation should be read in conjunction with "Forward Looking Statements Advisory", "Specified Financial Measures Advisory", "Capital Management Measures Advisory" and "Advisory Regarding Oil and Gas Information".

This presentation should be read in conjunction with the Company's consolidated interim unaudited financial statements and Management's Discussion and Analysis ("MD&A") for the period ended June 30, 2022.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements. The future oriented financial information and forward-looking statements are made as of September 1, 2022 and Baytex disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

All amounts in this presentation are stated in Canadian dollars unless otherwise specified.

Investment Highlights

High Quality and Diversified Oil Portfolio

- ~ 10 or more years of projected drilling inventory in each of our core areas (Viking, Eagle Ford and Canadian heavy oil)
- Strong capital efficiencies across portfolio

Clearwater Development and Exploration

- > 125 net prospective sections in one of the most profitable plays
- Growing Peavine to 10,000 bbl/d
- Continue appraisal drilling at Peavine and Seal

Meaningful Free Cash Flow Generation

- Exploration and development expenditures ~ 50% of adjusted funds flow at a US$75 WTI price
- Five-year plan (2022-2026) generates ~ $2.8 billion of free cash flow(1)

Shareholder Returns

- 25% of free cash flow to share buybacks commenced May 2022, increasing to 50% upon hitting $800 million net debt target (expected late 2022 / early 2023)
- Repurchased 17.8 million shares through August 2022, 3.1% of float

Environmental Stewardship

- Delivered 52% reduction in GHG emissions intensity through 2021, relative to 2018 baseline; targeting 65% reduction by 2025
- Committed to reducing 2020 end of life well inventory of ~4,500 wells to zero by 2040

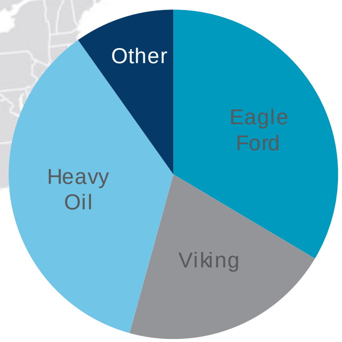
(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See “Specified Financial Measures” in the Q2/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.
(2) Capital management measure. See the “Specified Financial Measures” in this presentation for information related to this measure.

Corporate Profile

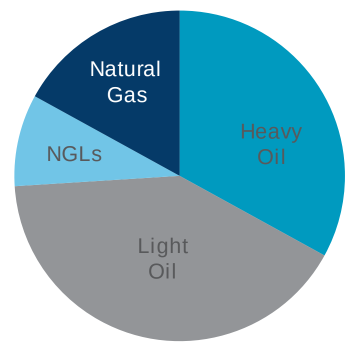
Market Summary	
Ticker Symbol	TSX: BTE
Average Daily Volume (1)	11 million
Shares Outstanding (2)	560 million
Market Capitalization / Enterprise Value (2)	$3.8 billion / $4.9 billion

Operating Statistics	
Production (Gross W.I.) (3)	83,000 – 85,000 boe/d
Production Mix (3)	83% liquids
E&D Expenditures (3)	$450 to $500 million
Reserves – 2P Gross (4)	451 mmboe

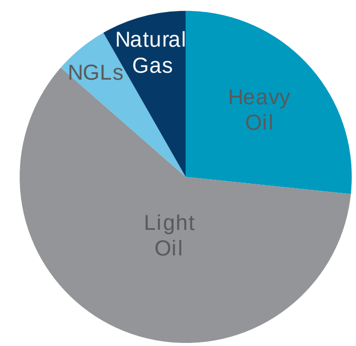
Production by Core Area (5)



Production by Commodity (5)



Revenue by Commodity (6)



(1) Average daily trading volumes for August 2022. Volumes are a composite of all exchanges in Canada.
(2) Enterprise value based on closing share price on the Toronto Stock Exchange on August 31, 2022 and shares outstanding and net debt as at June 30, 2022.
(3) Production, production mix, and exploration and development ("E&D") expenditures represents 2022 guidance.
(4) Baytex reserves as at December 31, 2021 as evaluated by McDaniel & Associates Consultants Ltd.
(5) Production (Gross W.I.) composition based on 2022 guidance. Heavy oil includes Peace River, Lloydminster and Clearwater.
(6) Revenue by commodity composition based on 2021 actuals.

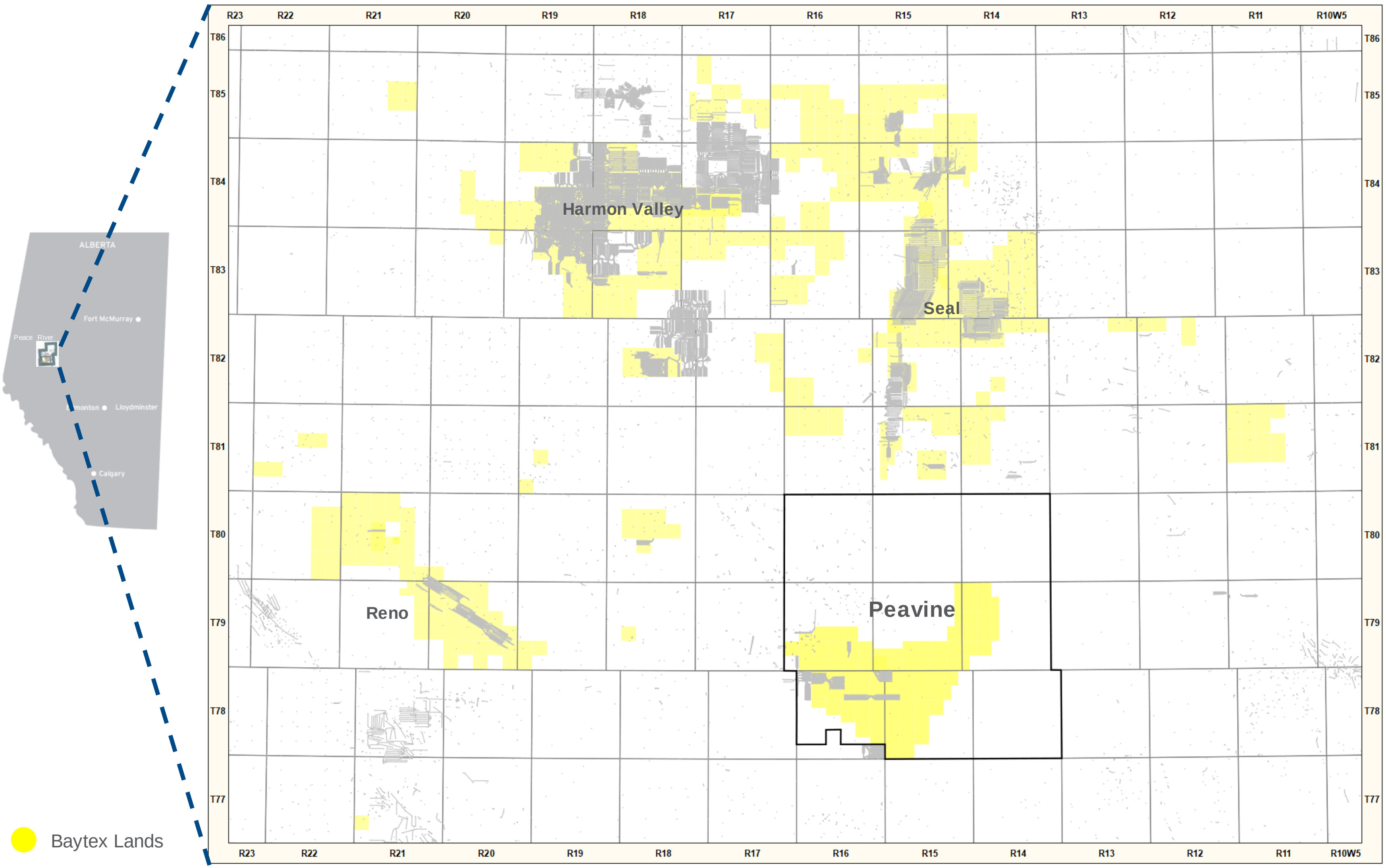
Clearwater Focus

Clearwater Highlights

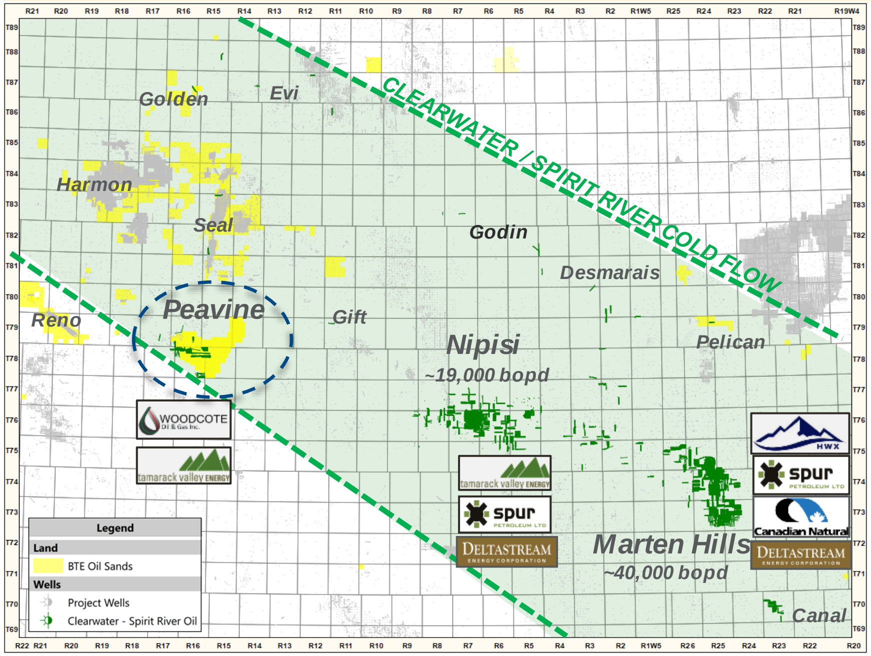
Significand Land Base	▪ > 500 sections in the NW Clearwater fairway with > 125 sections highly prospective for Spirit River (Clearwater equivalent) ▪ Executed two strategic agreements with the Peavine Métis Settlement that cover 80 premium sections of land
Production Growth	▪ Production increased from zero at the beginning of 2021 to 9,100 bbl/d in June (~ 10% of corporate volumes); 2022 exit production rate of 9,000 to 10,000 bbl/d ▪ Five-year plan calls for production of 10,000 bbl/d through 2026; potential upside to 15,000 bbl/d
Superior Well Performance and De-Risked Inventory	▪ 9 Baytex wells rank in the top 10 Clearwater wells drilled to-date on an initial rate basis; outperforming Baytex type curve assumptions ▪ ~ 300 unrisked (200 risked) inventory locations at 4 wells per section
Strong Economics / Free Cash Flow	▪ Payouts of < 5 months and IRR's > 500% at US$75 WTI ▪ 2022 asset level free cash flow[1] of ~ $85 million ▪ Production of 10,000 to 15,000 bbl/d for the next ten years would generate ~ $1 billion of asset level free cash flow[1] at US$75 WTI
Key Infrastructure in Place	▪ Crude oil delivered to 4-33 Battery at Seal (BTE 85% working interest) and shipped to sales through Nipisi pipeline (BTE 40% working interest) ▪ Gas conservation in planning stages

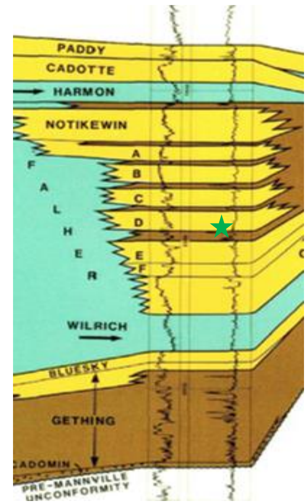
(1) The term "asset level free cash flow" is a non-GAAP measure. See slide 2 for more information.

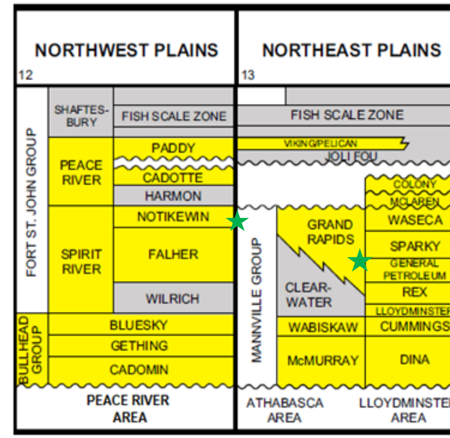
Peace River Area Map



Peavine – Clearwater Reservoir Overview







- Lower Cretaceous Spirit River formation (Falher E)
  - Stratigraphic & depositional equivalent to Clearwater formation
  - Up hole of adjacent Peace River Bluesky development allowing us to leverage our experience
  - Development Mode: open hole multilateral horizontals
- Shaly Sand reservoir - clay rich up to 37% of rock volume
  - ↓ oil saturations per unit thickness; volumetric implications
  - High formation damage risk – KCl / oil-based mud systems

Simplified Productive Area Reservoir Characteristics

	Harmon Valley Bluesky	Peavine Spirit River	Nipisi Clearwater
Depth	550 - 620 m	550 - 650 m	600 - 675 m
Pressure	7.8 kPa/m ~4,600 kPa	8.3 kPa/m ~4,800 kPa	5.5 kPa/m ~3,200 kPa
Temperature	20⁰ C	22⁰ C	25⁰ C
Thickness	5 - 15 m	4 - 8 m	2 - 7 m
Eff Porosity	22 - 30%	15 - 24%	12 - 24%
Viscosity	5,021 – 60,700 cP	2,550 – 58,655 cP	128 – 2,013 cP
API	8.7 – 11.6	8.7 - 13.2	14.3 - 21.2
Permeability	550 – 7,000 mD	100 - 747 mD	45 - 171 mD
Oil Saturation	60 – 80%	30 – 55%	30 – 55%
Clay Content	5 - 7%	25 - 37%	12 - 19%
Recovery Factor	4 - 10%	4 - 15%	3 - 20%

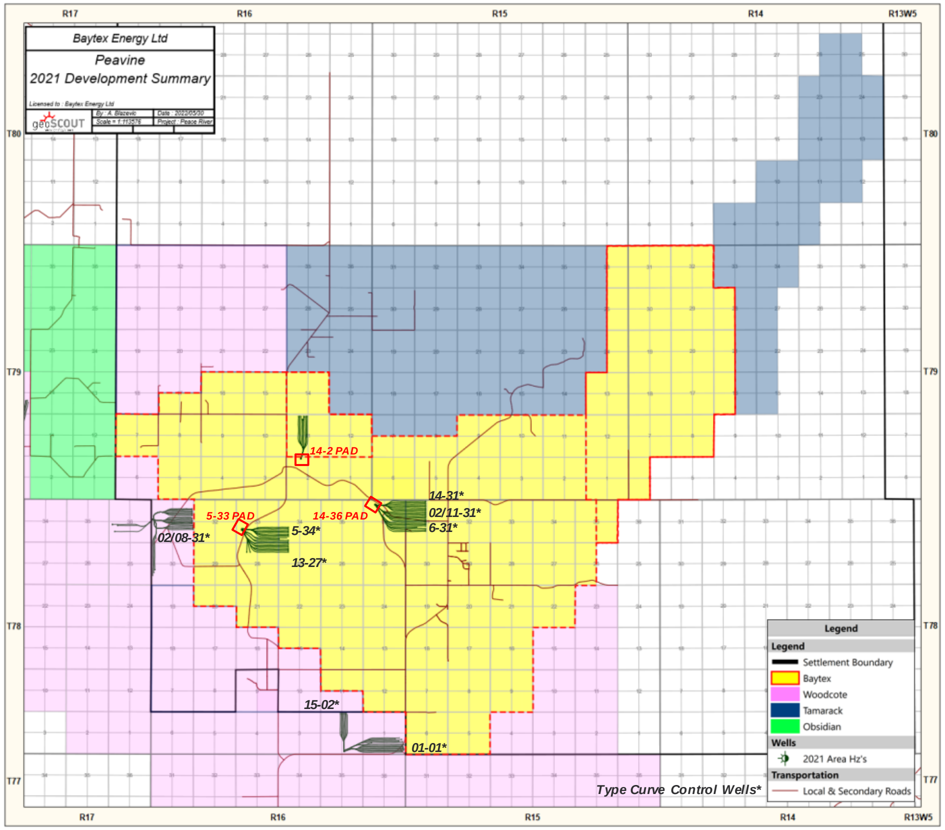
Peavine – 2021/2022 Development Summary

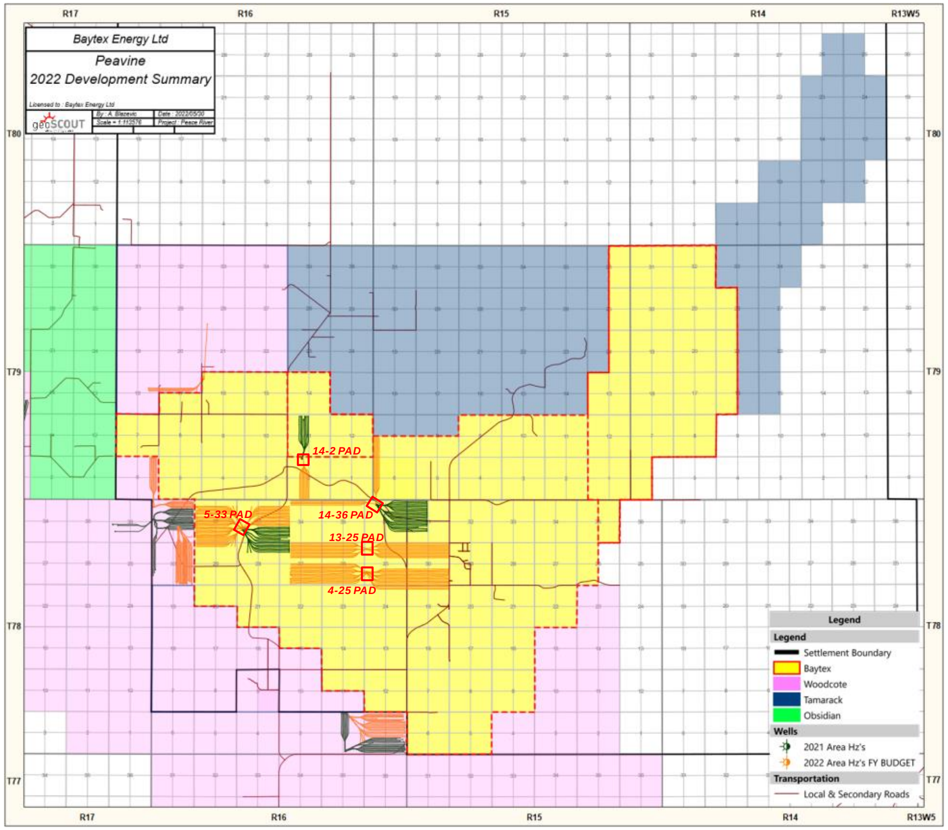
2021 Program - 8 Hz's

- 1 Rig, partial year drilling with Horizon 14
  - 3 New pads with Pilot Strats (5-33, 14-36, 14-2)
  - 78,233m drilling open hole at 98% effective
  - Oil based and KCl mud system comparison trials

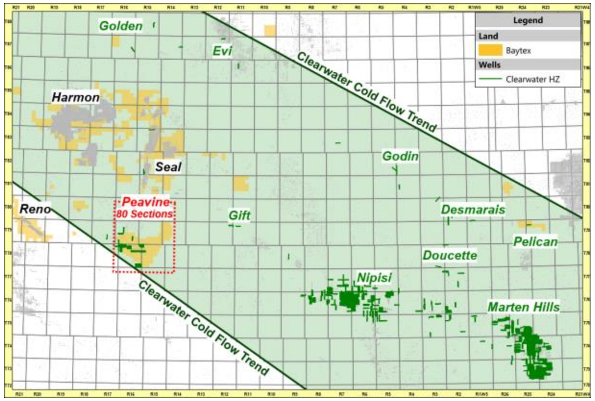
2022 Program – 23 HZ's

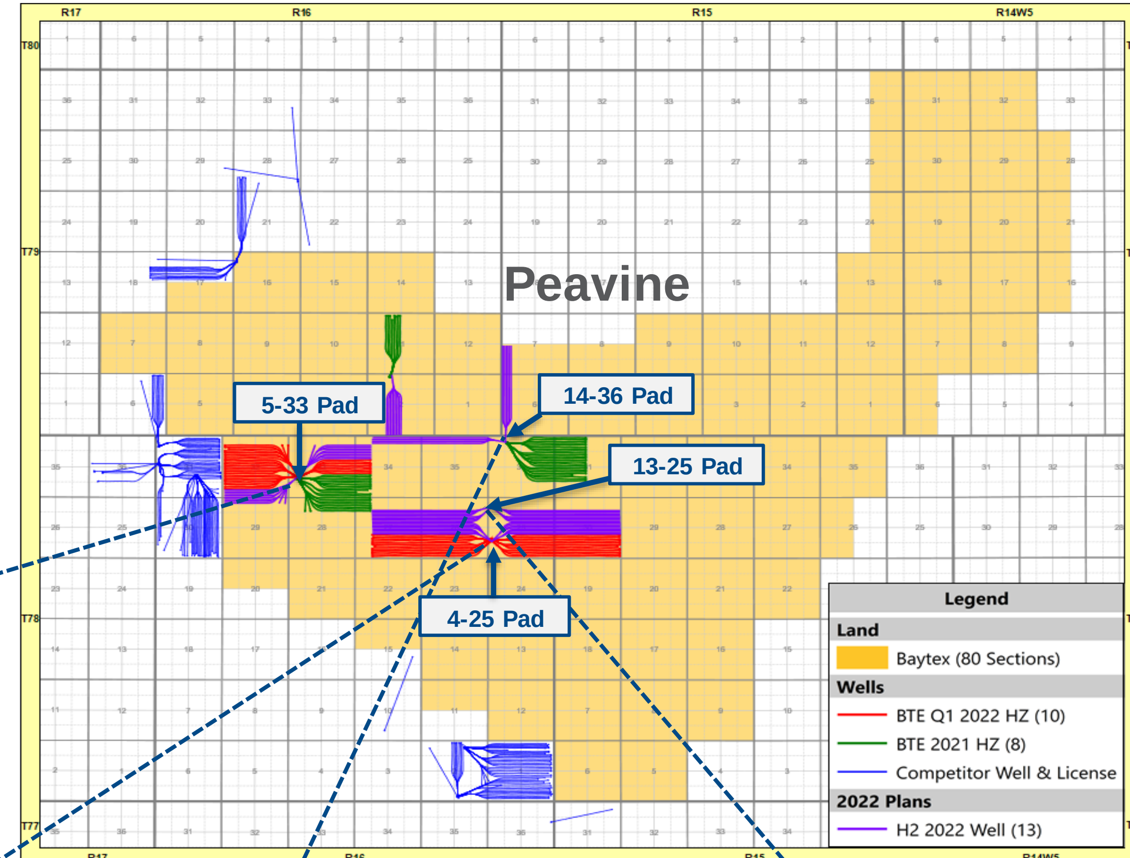
- 1.5 Rigs, Horizon 14 (FY) & Horizon 22 (Q1): 10 Hz's Q1, 13 Hz's H2
  - 2 New pads with Pilot Strats (4-25, 13-25)
  - Extended Reach Hz program test: Q1 success at up to 3,807m MD
  - KCl mud systems with optimization (solids, additives)





Clearwater: H1/2022 Program Accelerates Development





5-33 Pad

- Q1/2022 – 4 new wells onstream in March/April, with IP30's of 300-450 bbl/d per well
- June production ~ 2,200 bbl/d with 8 wells
- 2 additional wells H2/2022

4-25 Pad

- Q1/2022 – 6 ERH wells onstream in March/April
- 4 wells generated IP30's > 1,000 bbl/d per well
- June production ~ 5,700 bbl/d
- 4 additional ERH wells H2/2022

14-36 Pad

- June production 1,100 bbl/d
- IP30 averaged 890 bbl/d per well
- 2 new ERH wells H2/2022

13-25 Pad

- Pad construction complete
- 4 ERH wells H2/2022

"ERH" refers to extended reach horizontal wells and are comprised of four 2-mile long laterals versus a traditional design of eight 1-mile long laterals.

Clearwater: Superior Well Performance and Economics

Clearwater Lands

- > 500 net sections in the NW Clearwater fairway with > 125 prospective for Spirit River (Clearwater equivalent)
- Executed two strategic land agreements with the Peavine Métis Settlement that cover 80 sections of land
- 50 sections de-risked with potential for greater than 200 locations pending further success
- Successful Clearwater exploration well on Seal legacy lands in late 2021 with follow-up well in H2/2022

Operations Update

- 18 producing wells at Peavine (through June 2022)
- Production increased from zero at the beginning of 2021 to 9,100 bbl/d in June 2022
- 9 Baytex wells rank in the top 10 Clearwater wells drilled to-date on an initial rate basis; outperforming Baytex type curve assumptions
- Expect to bring 24 wells onstream in 2022; program expanded to include 6 additional wells in Q4/2022

Top 15 Clearwater Wells (1)

No.	UWI	Current Operator	Peak Calendar Rate (bbl/day)
1	100/01-30-078-15W5	BAYTEX	1,201
2	102/01-30-078-15W5	BAYTEX	1,110
3	100/03-27-078-16W5	BAYTEX	1,052
4	100/08-30-078-15W5	BAYTEX	1,036
5	102/11-31-078-15W5	BAYTEX	910
6	102/03-27-078-16W5	BAYTEX	864
7	100/06-31-078-15W5	BAYTEX	861
8	100/13-27-078-16W5	BAYTEX	840
9	100/06-27-078-16W5	BAYTEX	748
10	102/12-34-074-25W4	HWX (CVE)	733
11	100/14-31-078-15W5	BAYTEX	716
12	100/16-35-074-25W4	HWX (CVE)	670
13	100/16-26-074-25W4	HWX	670
14	102/12-31-074-24W4	HWX (CVE)	634
15	100/13-34-074-25W4	HWX (CVE)	617

Well Economics (2)

WTI Oil Price	$75/bbl	$85/bbl
Payout:	5 months	4 months
IRR:	> 500%	> 500%
Recycle Ratio:	4.0x	4.9x

(1) Public data obtained from GeoScout.

(2) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: development well cost - $1.7 million; IP30 - 335 bbl/d, IP 365 - 180 bbl/d; EUR – 170 mboe; WCS differential assumption US$12.50/bbl.

Corporate Presentation

H1 2022 Highlights

Strong Peavine Drilling Results, Increased Guidance and Share Buyback Program Initiated

	H1/2022 Highlights
H1 2022 Highlights	▪ Generated production of 82,000 boe/d, a 3% increase over H1/2021 ▪ Generated free cash flow[(1)] of $367 million ($0.65 per basic share) ▪ Reduced net debt[(2)] by 21% to $1.1 billion, from $1.4 billion at YE 2021
Materially Advanced Clearwater Development at Peavine	▪ 10 wells drilled in Q1/2022 generated average 30-day initial production rates of 772 bbl/d per well ▪ Four wells established 30-day initial production rates of > 1,000 bbl/d each and are the strongest Clearwater wells drilled to date in the play ▪ Production increased from zero at the beginning of 2021 to 7,300 bbl/d in Q2/2022 and 9,100 bbl/d in June ▪ H2/2022 drilling program kicked off in July with 14 wells planned
2022 Guidance	▪ Production guidance of 83,000 to 85,000 boe/d represents 5% annual production growth at the mid-point (6% on a per-share basis) ▪ Expect to exit 2022 producing ~ 87,000 to 88,000 boe/d ▪ Exploration and development expenditures ~ 40% of adjusted funds flow
Share Buyback Program	▪ Direct shareholder returns initiated in May with 25% of free cash flow allocated to share buybacks ▪ Repurchased 17.8 million shares through August 2022, 3.1% of shares outstanding

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(2) Information related to this capital management measure is available in the Q2/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

ESG Highlights

GHG Emission Reduction

52% reduction in GHG emissions intensity through 2021, relative to 2018 baseline; 65% target in place

Safety

25% reduction in total recordable injury frequency in 5 years

Gas Conservation

> 95% routine gas conservation in Peace River in 2021

Indigenous Relations

Recent agreements with Peavine Métis Settlement

Spill Volumes

59% reduction in reportable spill volumes over 5 years

Gender Diversity

Target of 30% women Board members by 2023 Shareholder meeting

Abandonment & Reclamation

Reduce 2020 inactive well inventory of ~ 4,500 wells to zero by 2040

Water

Initiated water recycle projects in Kerrobert, Viking and Duvernay

Maintaining Capital Discipline and Driving Meaningful Free Cash Flow

- Production guidance of 83,000 to 85,000 boe/d represents:
  - 5% annual production growth at the mid-point (6% on a per-share basis)
  - 2022 exit production rate of 87,000 to 88,000 boe/d
  - Strong operating momentum and production growth on our Clearwater lands
- Exploration and development capital represents ~ 40% of adjusted funds flow
- Based on the forward strip[1], we expect to generate ~ $700 million of free cash flow[2] in 2022

2022 Guidance	
E&D Expenditures	$450 – 500 million
Production	83,000 - 85,000 boe/d
Oil and NGLs	83%

Operating Area	Net Wells Onstream	E&D ($MM) [3]
Viking	130	$160
Eagle Ford	18	$135
Heavy Oil [4]	40	$110
Clearwater	24	$55
Pembina Duvernay	3	$30
Other [5]	1	$10
Total		$500

(1) Full-year 2022 commodity prices: WTI - US$97/bbl; WCS differential - US$17/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$6.90/mcf; AECO Gas - $5.75/mcf and Exchange Rate (CAD/USD) - 1.28.

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(3) Represents high end of 2022 exploration and development expenditures guidance range.

(4) Heavy oil includes Peace River Bluesky development and Lloydminster.

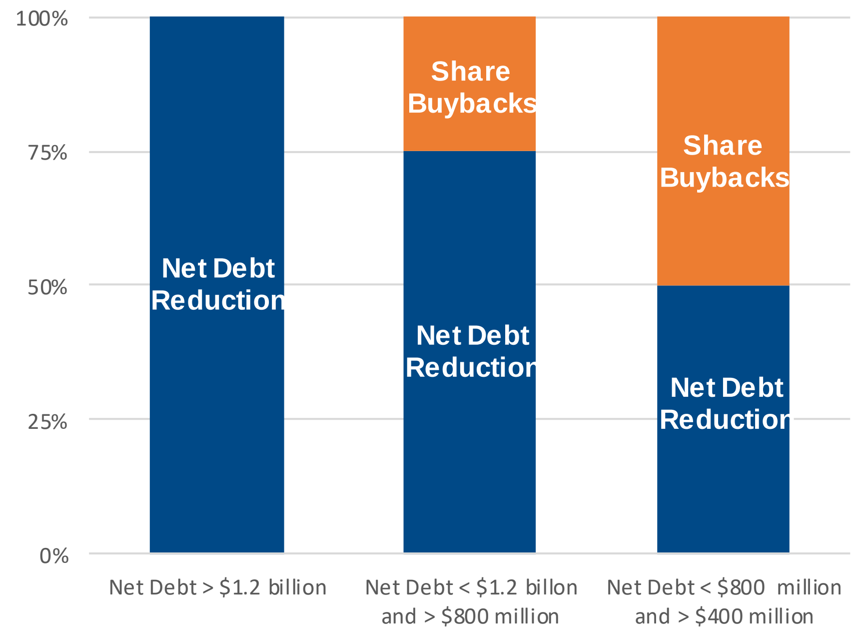
(5) Other development includes 1 net natural gas well.

Uses of Free Cash Flow

Direct shareholder returns

- Current allocation of free cash flow
  - 25% to share buybacks
  - 75% to debt repayment
- Share buybacks commenced May 2022
  - Repurchased 17.8 million shares through August 2022, 3.1% of float
- Target allocation of free cash flow once net debt reaches $800 million[(2)] (late 2022 / early 2023)
  - 50% to share buybacks
  - 50% to debt repayment
- After reaching an ultimate debt target of $400 million[(3)] (late 2023 / early 2024) we will consider steps to further enhance shareholder returns

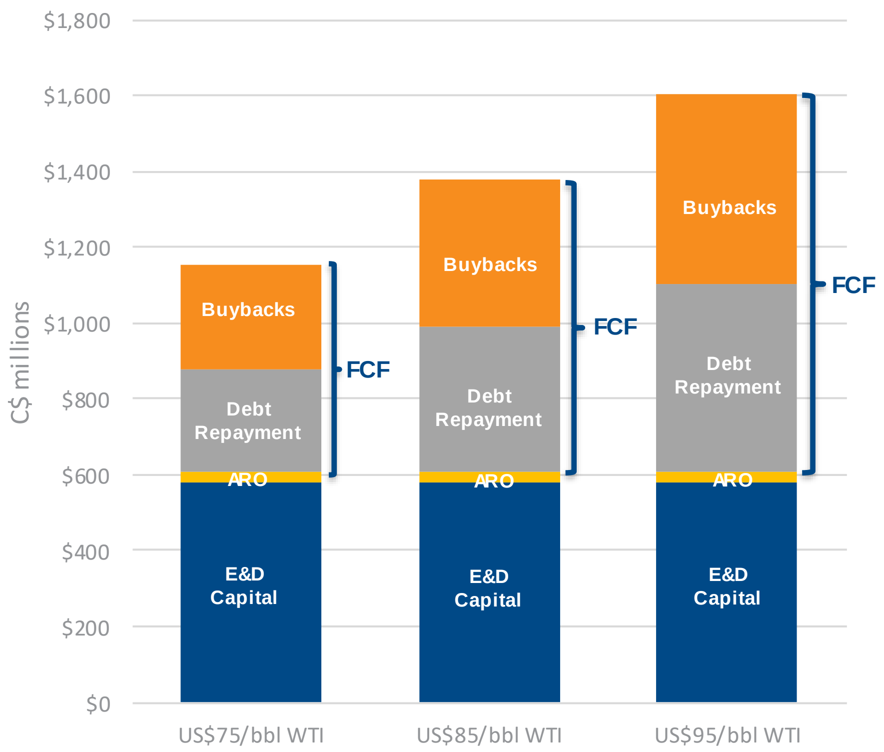
Allocation of Free Cash Flow



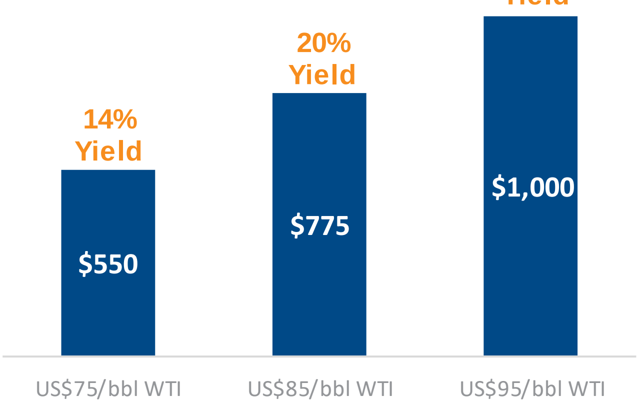
(1) Information related to this capital management measure is available in the Q2/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.
(2) Represents a net debt to EBITDA ratio of 1x at US$55 WTI.
(3) Represents a net debt to EBITDA ratio of 1x at US$45 WTI.

2023 Free Cash Flow Generation and Shareholder Return Potential

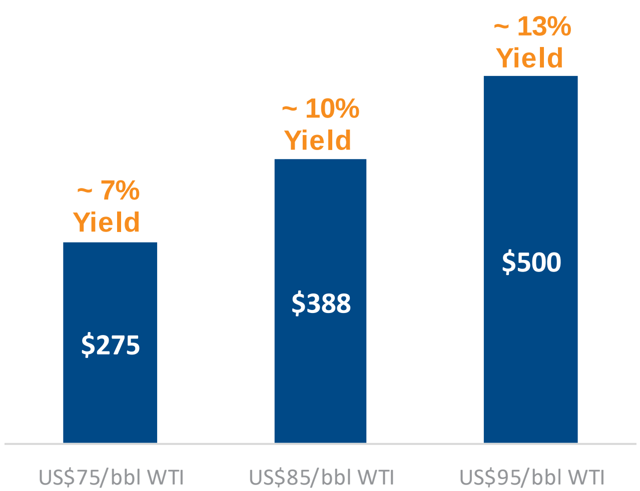
Target 50% of Free Cash Flow (1)(2) to Share Buybacks



2023 Free Cash Flow ($ millions) (1)(3)



2023 Free Cash Flow Allocated to Share Buybacks ($ millions) (4)



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(2) For illustrative purposes only and should not be relied upon as indicative of future results. Baytex's actual results may vary. 2023 budget has not been finalized and is subject to a variety of factors including prior year's results. Free cash flow profile incorporates 25% inflation on exploration and development capital and 15% inflation on operating and transportation expenses, as compared to 2021. Assumes $800 million net debt target is achieved at the end of 2022.

(3) Free cash flow yield represents the estimated 2023 free cash flow divided by market capitalization as at August 31, 2022.

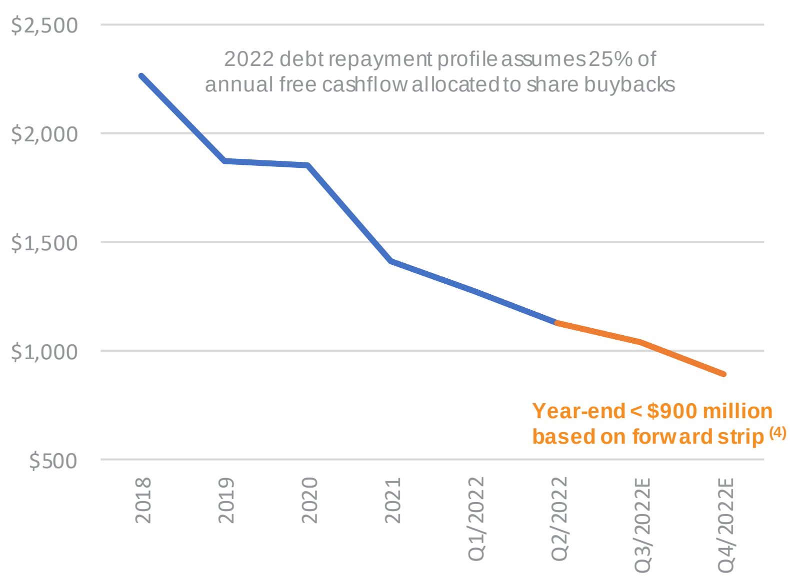
(4) Yield for share buybacks represents the estimated 2023 free cash flow allocated to share buybacks divided by market capitalization as at August 31, 2022.

Committed to Maintaining Strong Financial Flexibility

- **Strong liquidity**
- **Credit facilities extended to 2026 and increased to US$850 million**
- **Redeemed US$200 million long-term notes due 2024 on June 1st**

Net Debt(1) (June 30, 2022)	$ millions
Credit facilities (2)	$497
Long-term notes	$644
Long-term debt	$1,141
Working Capital	($17)
Net Debt	$1,123

Net Debt(1) Profile ($ millions)



Long-Term Notes Maturity Schedule (3) ($ millions)

(1) Information related to this capital management measure is available in the Q2/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

(2) Revolving credit facilities total US$850 million and mature April 2026. The revolving credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

(3) S&P corporate rating "B+" and senior unsecured debt rating "BB-" ; Fitch corporate rating "B+" and senior unsecured debt rating "BB-"; Moody's corporate rating "B1" and senior unsecured debt rating "B3".

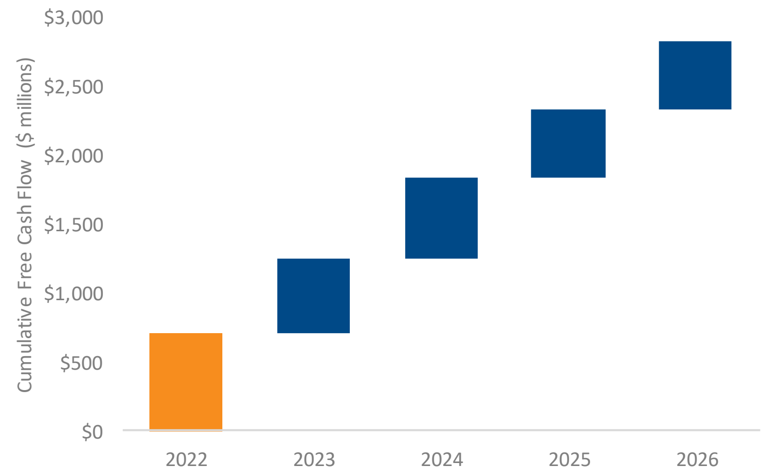
(4) 2022 full-year commodity prices: WTI - US$97/bbl; WCS differential - US$17/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$6.90/mcf; AECO Gas - $5.75/mcf and Exchange Rate (CAD/USD) - 1.28.

5-Year Plan Generates $2.8 billion Cumulative Free Cash Flow

Highlights of 5-Year Plan

- **$2.8 billion cumulative free cash flow[(1)]**
- **Exploration and development expenditures represent ~ 50% of adjusted funds flow**
- **2-4% annual production growth**

Free Cash Flow[(1)] Profile (after-tax)



	Production (boe/d)	Adjusted Funds Flow[(2)] ($ MM)	Adjusted Funds Flow[(2)] ($ per share)	E&D Expenditures ($MM)	ARO / Leasing Expenditures ($MM)	After-Tax Free Cash Flow[(1)] ($MM)
2022	84,000	$1,222	$2.25	$500	$22	$700
2023	88,000	$1,155	$2.22	$580	$25	$550
2024	91,000	$1,180	$2.44	$580	$25	$575
2025	93,000	$1,105	$2.41	$580	$25	$500
2026	95,000	$1,105	$2.57	$580	$25	$500

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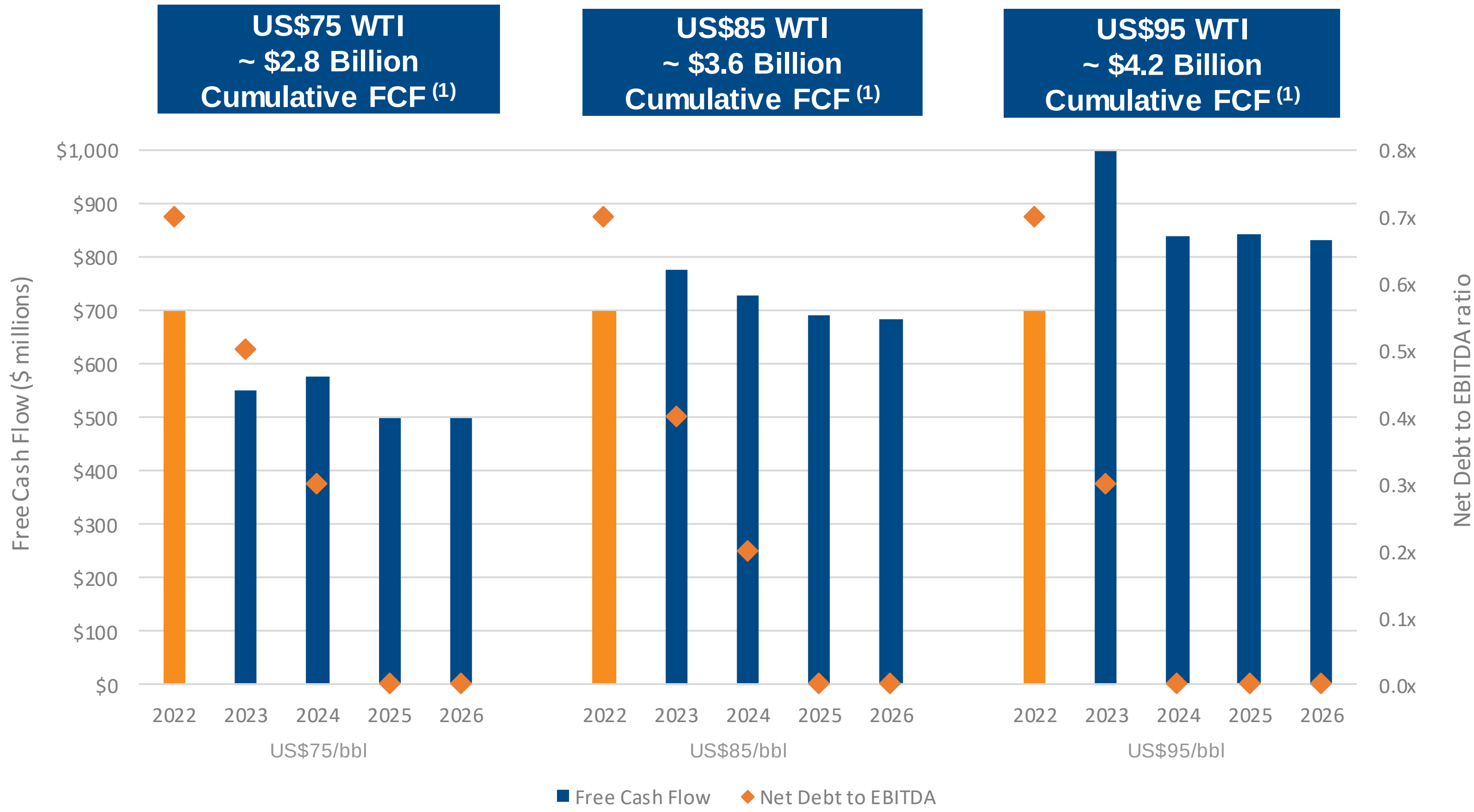
(4) Year one (2022) based on H1/2022 actual results and forward strip commodity prices for the balance of the year. Full-year 2022 commodity prices: WTI - US$97/bbl; WCS differential - US$17/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$6.90/mcf; AECO Gas - $5.75/mcf and Exchange Rate (CAD/USD) - 1.28.

(5) Years two through five (2023 to 2026) based on the following commodity price assumptions: WTI - US$75/bbl; WCS differential - US$12.50/bbl; MSW differential – US$4/bbl, NYMEX Gas - US$4.00/mcf; AECO Gas - $4.00/mcf and Exchange Rate (CAD/USD) - 1.25.

(6) Free cash flow profile incorporates 25% inflation on exploration and development capital and 15% inflation on operating and transportation expenses, as compared to 2021.

5-Year Plan – Free Cash Flow Profile (after-tax)



Notes:

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(3) Year one (2022) based on H1/2022 actual results and forward strip commodity prices for the balance of the year. Full-year 2022 commodity prices: WTI - US$97/bbl; WCS differential - US$17/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$6.90/mcf; AECO Gas - $5.75/mcf and Exchange Rate (CAD/USD) - 1.28.

(4) Years two through five (2023 to 2026) based on the long-term WTI price assumption in the chart and the following commodity price assumptions: WCS differential - US$12.50/bbl; MSW differential – US$4/bbl, NYMEX Gas - US$4.00/mcf; AECO Gas - $4.00/mcf and Exchange Rate (CAD/USD) - 1.25.

(5) Net Debt to EBITDA ratio calculation is based on forecast net debt at each year-end and forecast EBITDA for that particular year. For 2022: 75% of free cashflow is allocated to debt repayment and 25% of free cash flow is allocated to share buybacks. For 2023-2026: 50% of free cashflow is allocated to debt repayment and 50% of free cash flow is allocated to share buybacks. Net Debt to EBITDA ratio is a capital management measure. See the "Specified Financial Measures" in this presentation for information related to this measure.

(6) Free cash flow profile incorporates 25% inflation on exploration and development capital and 15% inflation on operating and transportation expenses, as compared to 2021.

Crude Oil Hedge Portfolio

	Q3/2022	Q4/2022	H2/2022	2023
WTI Fixed Hedges				
Volumes (bbl/d)	10,000	10,000	10,000	---
Fixed Price (US$/bbl)	$53.50	$53.50	$53.50	---
WTI 3-Way Option (1)				
Volumes (bbl/d)	10,500	10,500	10,500	9,500
Average Sold Put / Put / Sold Call (US$/bbl)	$48/$58/68	$48/$58$68	$48/$58/$68	$62/$78/$96
Total Hedge Volumes (bbl/d)	20,500	20,500	20,500	9,500
Hedge (%) (2)	40%	40%	40%	18%
Basis Differential Hedges				
WCS Volumes (bbl/d)	17,000	17,000	17,000	---
WCS Price Relative to WTI (US$/bbl)	($12.28)	($12.28)	($12.28)	---
MSW Volume (bbl/d)	6,750	6,750	6,750	---
MSW Price Relative to WTI (US$/bbl)	($3.73)	($3.73)	($3.73)	---

(1) WTI 3-way options consist of a sold put, a bought put and a sold call. In a $48/$58/$68 example, Baytex receives WTI+$10/bbl when WTI is at or below $48/bbl; Baytex receives $58/bbl when WTI is between $48/bbl and $58/bbl; Baytex receives WTI when WTI is between $58/bbl and $68/bbl; and Baytex receives $68/bbl when WTI is above $68/bbl.

(2) Percentage of hedged volumes are based on 2022 annual production guidance (excluding NGL), net of royalties

2022E Adjusted Funds Flow Sensitivities

Sensitivities	Estimated Effect on Annual Adjusted Funds Flow[1] ($MM)	
	Excluding Hedges	Including Hedges
Change of US$1.00/bbl WTI crude oil	$24.1	$15.1
Change of US$1.00/bbl WCS heavy oil differential	$8.4	$3.3
Change of US$1.00/bbl MSW light oil differential	$7.0	$5.3
Change of US$0.25/mcf NYMEX natural gas	$7.6	$4.8
Change of $0.01 in the C$/US$ exchange rate	$11.5	$11.5

(1) Information related to this capital management measure is available in the Q2/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

Asset Overview

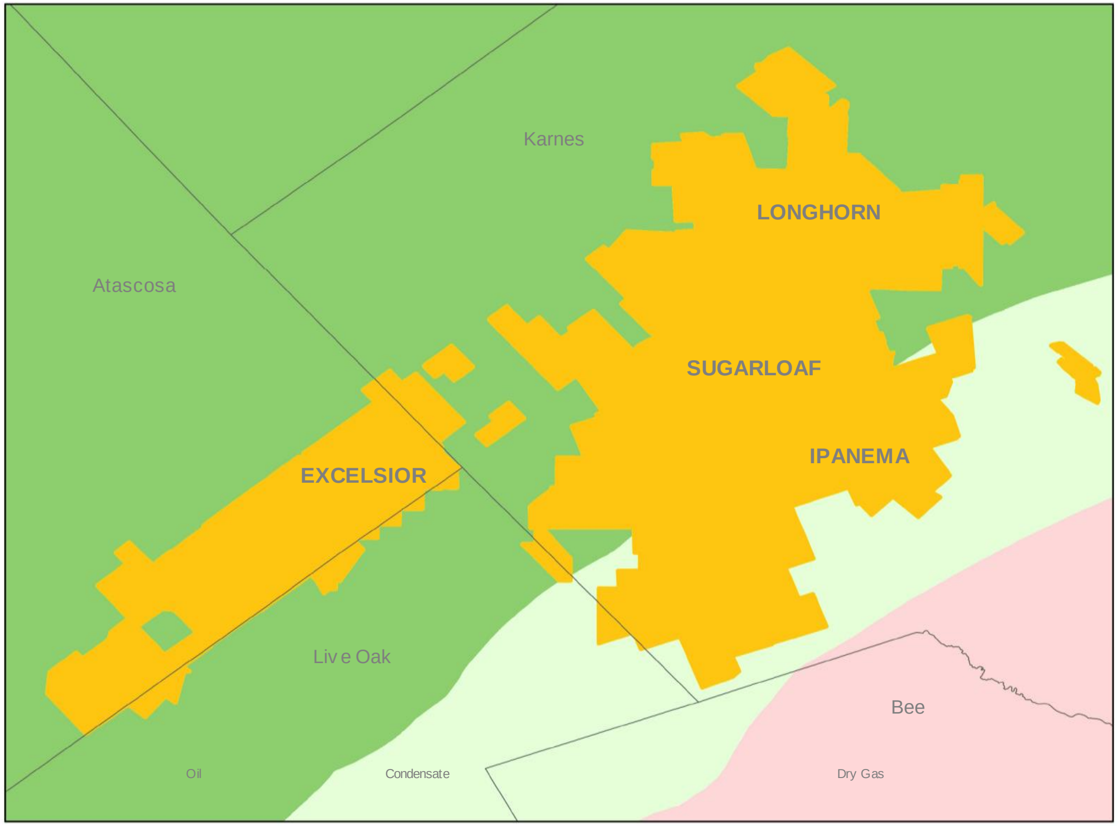
Asset Highlights

Geographic and play diversification with ~ 10 or more years drilling inventory in each core area

	Eagle Ford	Viking	Heavy Oil	Pembina Duvernay
Production *(Gross; H1/2022)*	27,800 boe/d	17,200 boe/d	29,200 boe/d	2,000 boe/d
Oil and NGLs *(Gross; H1/2022)*	81%	88%	92%	82%
2P Reserves (1) *(Gross)*	201 mmboe	77 mmboe	132 mmboe	22 mmboe
Asset Highlights	▪ 19,900 net acres in the core of Karnes county with outstanding operating partner, Marathon. ▪ Stable production base with low sustaining capital has driven ~ $1.4 billion of asset level free cash flow since 2016 (2)	▪ 419,615 net acres of land in the Viking play ▪ Shallow, light oil resource play with strong netbacks - ~$68/boe at US$85 WTI ▪ Stable production base drives meaningful asset level free cash flow	▪ Dominant land position of 672,640 net acres ▪ Low decline production ▪ Innovative multi-lateral horizontal drilling with top tier capital efficiency ▪ Growing Peavine to 10,000 bbl/d ▪ Continue Clearwater appraisal drilling at Peavine and Seal	▪ 128,000 net acres of 100% W.I. lands in the Pembina area ▪ Offset development and 11 wells drilled to-date have de-risked ~ 40% of acreage position ▪ Measured delineation planned

(1) Baytex reserves as at December 31, 2021 as evaluated by McDaniel & Associates Consultants Ltd. See “Advisories”.
(2) The term “asset level free cash flow” is a non-GAAP measure. See slide 2 for more information.

Eagle Ford: Core of Karnes County

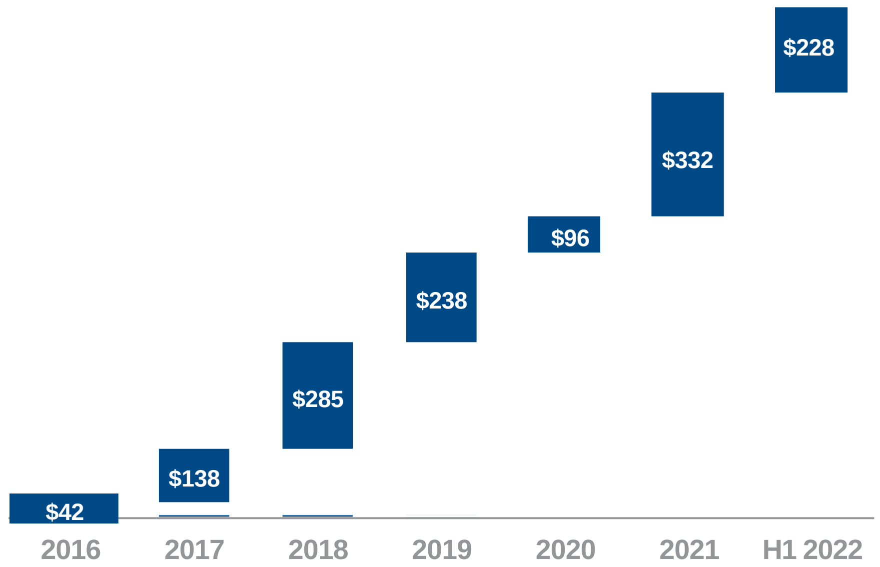


- 19,900 net acres in the core of the Eagle Ford shale in south Texas
- Four AMI's (Longhorn, Sugarloaf, Ipanema and Excelsior) with an average 25% W.I.
- Produced 27,800 boe/d (81% liquids) in H1/2022
- H1/2022 - 37 gross (8.6 net) wells established average 30-day IP rates of ~ 1,600 boe/d per well
- Expect to bring ~ 18 net wells on production in 2022

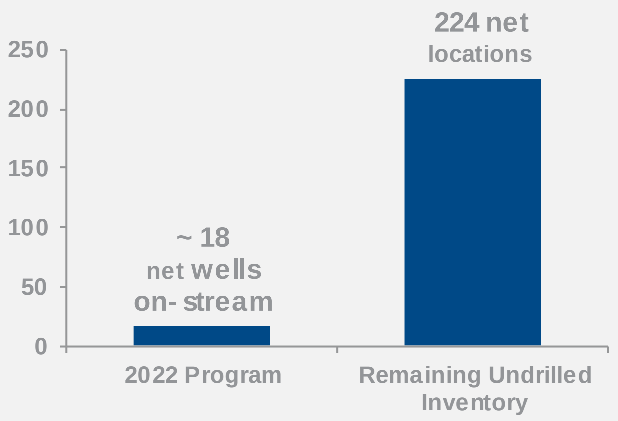
Eagle Ford: Strong Free Cash Flow and Deep Drilling Inventory

Free Cash Flow (1) (C$ millions)

$1.4 billion cumulative asset level free cash flow since 2016



> 10 year drilling inventory (2)

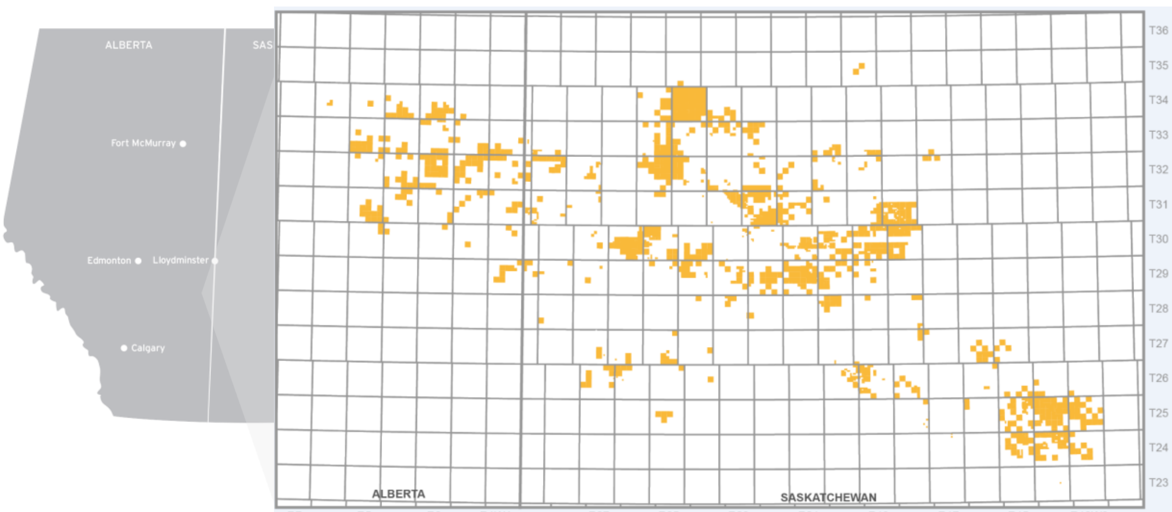


Well Economics (3)

WTI Oil Price	$75/bbl	$85/bbl
Payout:	10 months	9 months
IRR:	139%	197%
Recycle Ratio:	3.6x	4.1x

(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q2/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.
(2) Net locations includes 187 proved plus probable undeveloped reserves locations at year-end 2021 and 37 unbooked future locations. See "Advisories"
(3) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: well cost $7.6 million (6,000 foot lateral); IP365 - 700 boe/d; EUR – 800 mboe).

Viking Light Oil: 460 Highly Prospective Sections



Baytex Lands

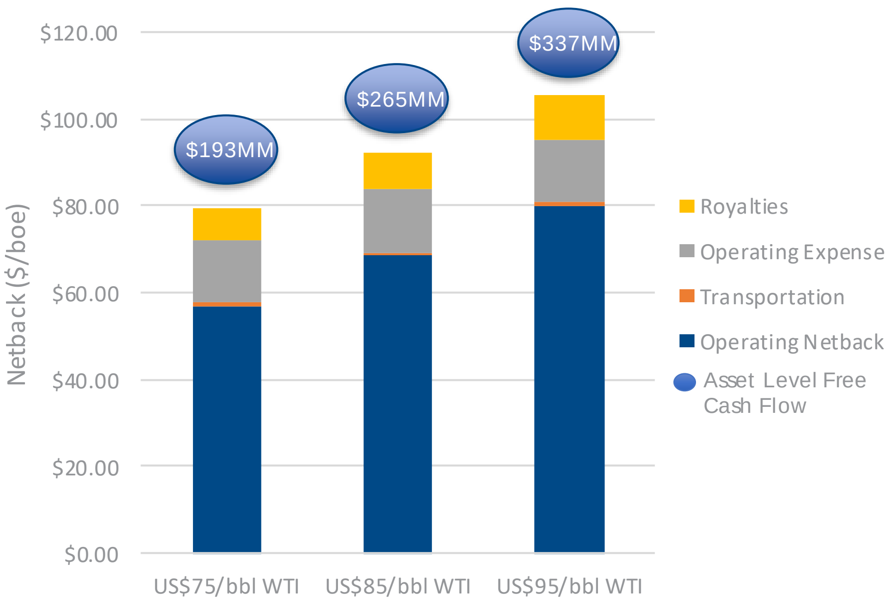
- Shallow (700 m), light oil (36° API) resource play
- Produced 17,200 boe/d (88% oil) in H1/2022
- Strong operating netback[(1)] ~ $68/boe at US$85 WTI
- $211 million of asset level free cash flow[(1)] in 2021
- Expect to bring ~ 130 net wells on production in 2022

(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See “Specified Financial Measures” in the Q2/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

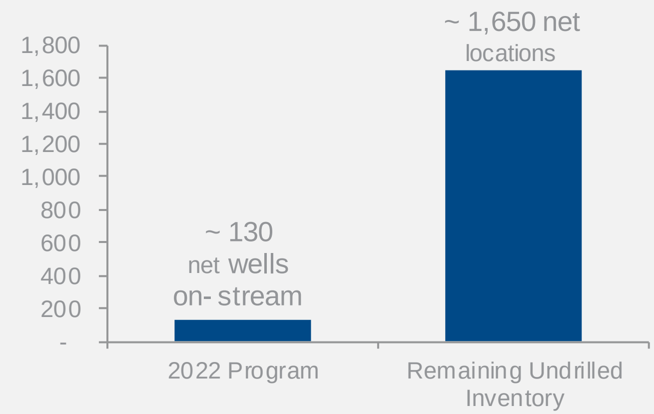
Viking: High Netback Light Oil

High Operating Netback [1] Light Oil ($/boe)

Strong price realizations, low cost structure and high free cash flow [1]



> 10 year drilling inventory [3]



Well Economics [4]

WTI Oil Price	$75/bbl	$85/bbl
Payout:	1.2 years	11 months
IRR:	80%	130%
Recycle Ratio:	2.0x	2.3x

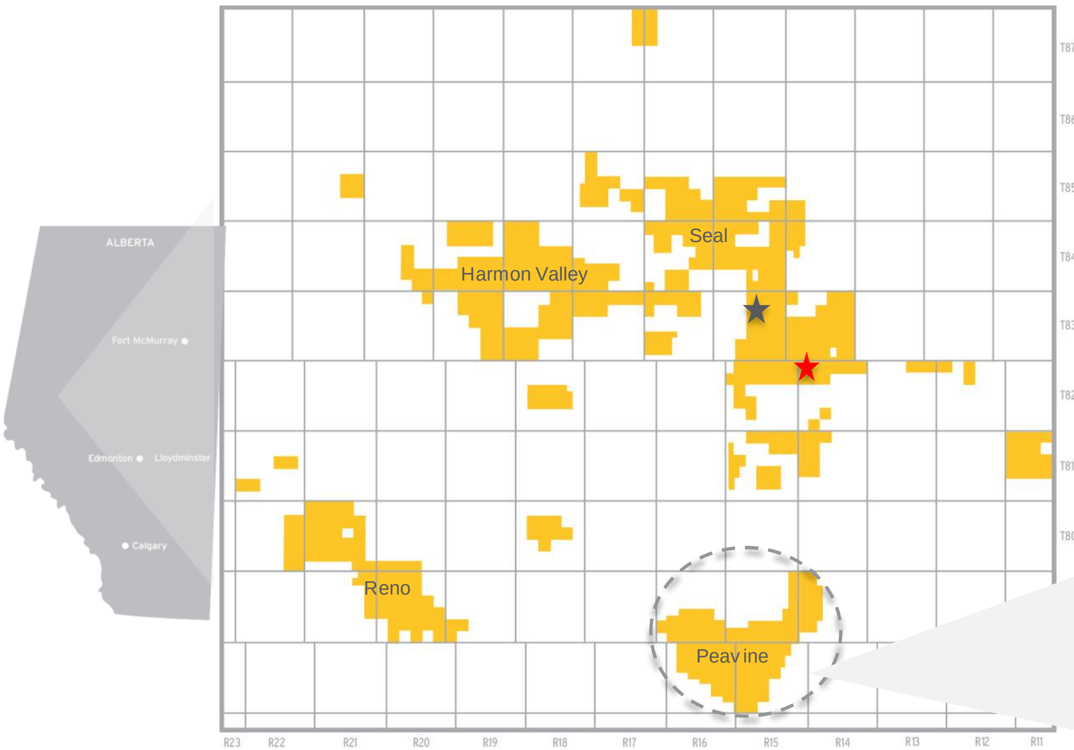
(1) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q2/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

(2) Net locations includes 1,158 proved plus probable undeveloped reserves locations at year-end 2021 and 490 unbooked future locations. See "Advisories"

(3) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: well cost - $1.2 million; IP365 - 45 boe/d; EUR - 40 mboe. MSW differential assumption US$4/bbl.

Peace River: Innovative Multi-Lateral Development

- Produced 12,900 boe/d in H1/2022 (85% oil)
- Dominant 560 net sections
- 9 net Bluesky multi-lateral wells planned for 2022
- Long life polymer flood at Seal

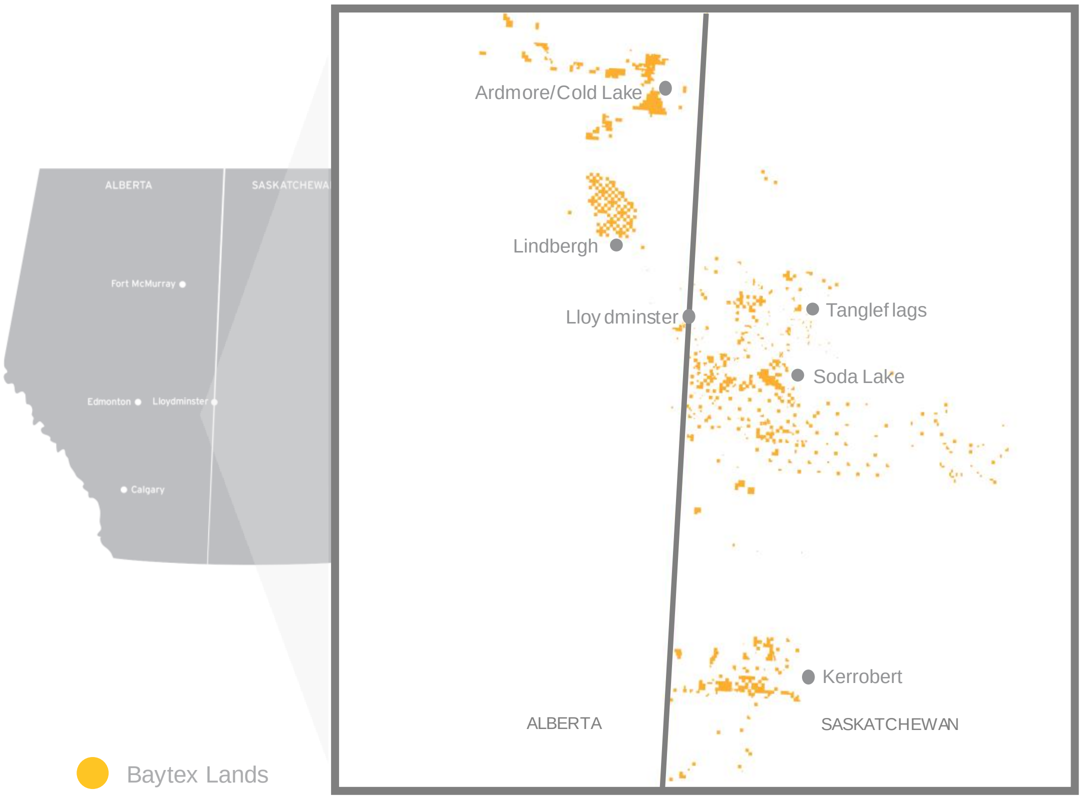


Baytex Lands ★ Seal Clearwater (Q4/2021) ★ Seal Clearwater (Q4/2022)

Clearwater

- Produced 7,300 boe/d (100% oil) in Q2/2022
- Strategic agreements with Peavine Métis Settlement cover 80 contiguous sections
- Growing Peavine to 10,000 boe/d
- Continue exploration and appraisal at Peavine and Seal
- Expect to bring 24 net Clearwater wells onstream in 2022 (23 net wells at Peavine, 1 net well at Seal)

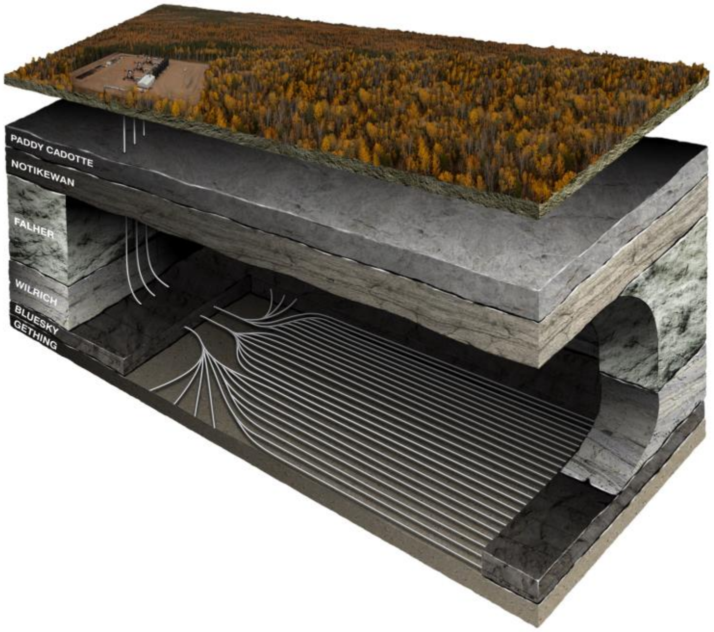
Lloydminster: Significant Land Position and Drilling Inventory



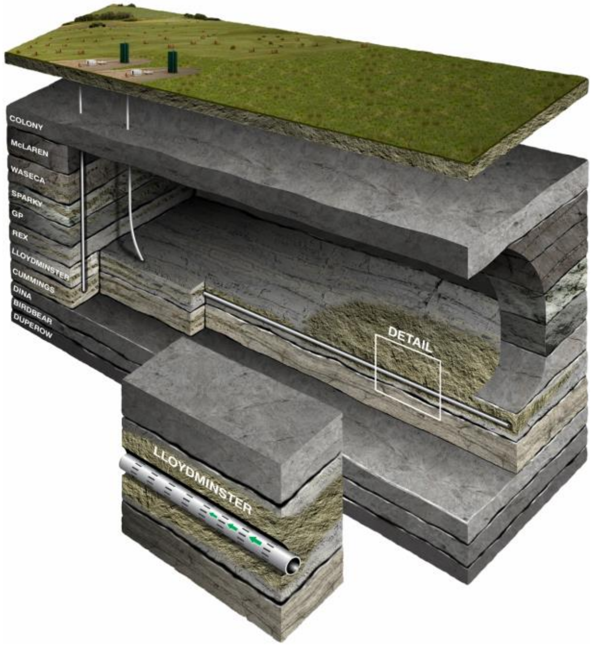
- Produced 11,100 boe/d in H1/2022 (97% oil)
- Strong capital efficiencies
- Applying multi-lateral horizontal drilling and production techniques
- Long-life water and polymer floods at Soda Lake and Tangleflags
- Expect to bring ~ 31 net wells on production in 2022

Heavy Oil Innovation

Peace River
Multi-Lateral Horizontal



Lloydminster
Horizontal



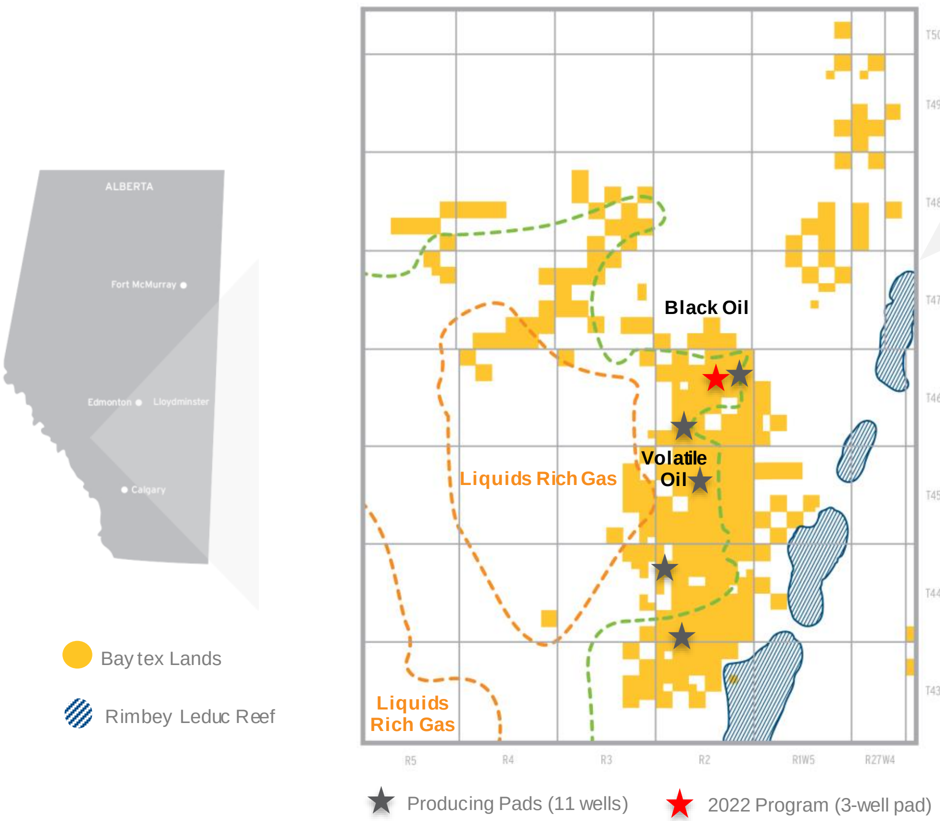
Well Economics (1)

WTI Oil Price	$75/bbl	$85/bbl
Payout:	1.0 year	9 months
IRR:	110%	170%
Recycle Ratio:	3.3x	3.9x

WTI Oil Price	$75/bbl	$85/bbl
Payout:	9 months	7 months
IRR:	205%	320%
Recycle Ratio:	2.8x	3.4x

(1) Individual well economics based on constant pricing and costs, and Baytex's assumptions regarding an expected type curve that uses the following assumptions: Peace River Bluesky: well cost - $3.2 million; IP 365 - 175 boe/d; EUR – 270 mboe; Lloydminster single lined horizontal: well cost - $1.1 million ; IP 365 - 80 boe/d; EUR – 65 mboe. WCS differential assumption US$12.50/bbl.

Pembina Area Duvernay Light Oil: Emerging Resource Play



Pembina Duvernay

- Continue to advance the delineation of the Pembina Duvernay Shale
- ~ 200 sections of 100% WI lands
- Eleven wells drilled to date have delineated a minimum of 100-125 sections
- Produced 2,000 boe/d (82% liquids) in H1/2022
- In Q2/2022, completed a 3-well pad (2,400 metres depth, 1.85 mile horizontal laterals). D&C costs of $8.1 million per well were on budget. Wells onstream in July.

High Quality Oil Development

	Eagle Ford	Viking	Peace River	Lloydminster	Pembina Duvernay
Formation	Lower Eagle Ford Upper Eagle Ford Austin Chalk	Viking	Bluesky Clearwater	Mannville Group	Duvernay
Depth (metres)	3,300-3,900	700	550-800 (Bluesky) 500-600 (Clearwater)	350-800	2,200-2,400
Oil API	Oil: 40-45° Condensate: 44-55°	36°	9-12° (Bluesky) 12-13° (Clearwater)	10-16°	42-44°
Porosity	4.6% - 9%	23%	24-30% (Bluesky) 21-30% (Clearwater)	30%	3% - 6%
Permeability	0.33 - 0.41 millidarcies	0.5 - 50 millidarcies	1-10 darcies (Bluesky) 0.01-1 darcies (Clearwater)	0.5 - 5 darcies	10 nanodarcy
Completion	Plug and perf	Pin point coil	Open hole multi-lateral	Horizontal slotted liner / open-hole multi-lateral	Plug and perf
Expected Well Costs (drill, complete, equip and tie-in)	$7.6 million 6,000 foot lateral	$1.2 million	$3.2 million (Bluesky) $1.7 million (Clearwater)	$1.1 million	$8.9 million
Land - gross (net) sections	122 (31)	763 (656)	582 (580)	637 (491)	200 (200) Pembina area
Reserves at YE 2021 (mmboe)					
Proved developed producing	70	20	17	10	3
Proved	150	51	28	26	12
Proved plus probable	201	77	48	84	22
Drilling inventory (risked) at YE 2021 – net locations (booked/unbooked)	187 / 37	1,158 / 490	98 / 334	145 / 423	29 / 231

Environment, Social and Governance (ESG)

ESG at Baytex

As a **responsible** energy company, we take a **sustainable** approach to managing and developing our business into the future. We aspire to create an organization that **future generations** will be proud to be a part of.

OUR VALUES

We have built into our culture a strong connection and sense of responsibility to our communities and stakeholders. Our core values of sustainability, connection, and empowerment guide our actions and decision-making as a responsible energy company.

SUSTAINABILITY

For us, sustainability means managing our ESG impacts, strengthening our corporate resilience, and remaining relevant into the future.

CONNECTION

We believe that fostering positive relationships and strong connections, inside and outside our company, are key to developing the innovative solutions needed to thrive as a company and as a society.

EMPOWERMENT

We recognize that individual decisions and actions determine our collective culture and, ultimately, the success of our company. In all areas of our business, we foster a culture of empowerment and shared accountability.

OUR ESG VISION

Baytex will be a leader in the responsible production of energy the world needs for the future.

OUR APPROACH

- We believe environmental, social, and governance performance is key to our long-term success.
- We focus on pragmatic and impactful opportunities to continuously improve our operating practices.
- We set meaningful targets to improve our performance and have a track record of delivering on our commitments.
- We monitor our impacts and provide transparent disclosures to our stakeholders.

How Focusing on ESG Creates Value

By incorporating environmental, social and governance factors into our business and reporting on our performance, we create value for shareholders and remain focused on advancing a **responsible energy future**.

	ENVIRONMENT	SOCIAL	GOVERNANCE
Our Focus	» Responsibly develop our assets » Reduce our GHG emissions intensity » Restore inactive sites for future generations » Reduce freshwater use	» Create a culture of safety » Engage our employees » Support diversity in our workforce » Be a good neighbour	» Ensure effective Board leadership » Be ethical, transparent, and accountable » Tie compensation to key ESG matters
How it Contributes to Company Value Creation	» Improves the reliability of our operations and reduces costs » Helps to build trust with regulators and stakeholders and maintains social licence » Reduces corporate end-of-life liability » Supports decarbonization of our operations	» Supports the consistent and safe execution of our business plan and enhances company performance » Maintains social licence and enables growth in our operations by reducing non-technical project delays	» Sets strategic direction and improves decision-making » Enables shareholders and stakeholders to make informed decisions » Encourages a culture of continuous improvement

Our ESG Scorecard

Continual improvement is an important element of our culture. We set short and long-term targets to address our impact on air, water, land and people. Each year, we report on our progress towards those targets.

OUR TARGETS	2021 PROGRESS	LOOKING FORWARD
GHG EMISSIONS By 2025, **reduce our emissions intensity by 65%** from our 2018 baseline	**Reduced our emissions intensity by 52%** compared to our 2018 baseline	Execute our first annual **GHG mitigation budget** Develop an **emissions reduction pathway** to 2025 and beyond
ABANDONMENT AND RECLAMATION Restore our 2020 end-of-life well inventory through our **"4,500 Wells by 2040"** initiative, returning them to their pre-disturbance productivity	Completed 198 well abandonments - **the most in company history**	Five-year commitment to **invest $100 million from 2022 to 2026,** or approximately $20 million per year
WATER USE By 2022, **evaluate and test new methods** to reduce the freshwater use intensity of our operations	Pilot projects resulted in **40% of completions water** coming from non-fresh water sources	Develop an **internal water management framework** that prioritizes reducing freshwater use
ENGAGEMENT AND DIVERSITY By 2022, expand our baseline to **include multiple dimensions of diversity** and enhance our processes to measure **employee engagement**	Completed a **3rd party employee engagement survey** and set a baselines for engagement and key diversity variables	Committed to **at least 30% of our directors being women** by our 2023 shareholder meeting

Not started · In progress · Completed

Supplementary Information

2022 Guidance and Cost Assumptions

Exploration and development expenditures ($ millions)	$450 - $500
Production (boe/d)	83,000 – 85,000
Expenses:	
Average royalty rate (%) (1)	21.0% - 22.0%
Operating ($/boe) (2)	$13.75 - $14.25
Transportation ($/boe) (2)	$1.50 - $1.60
General and administrative ($ millions) (2)	$43 ($1.40/boe)
Interest ($ millions) (2)	$75 ($2.45/boe)
Leasing expenditures ($ millions)	$3
Asset retirement obligations ($ millions)	$20

(1) Non-GAAP financial ratio that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See "Specified Financial Measures" in the Q2/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.

(2) Information related to this supplementary financial measure is available in the Q2/2022 MD&A under the heading "Specified Financial Measures" and is incorporated by reference into this presentation.

Summary of Operating and Financial Metrics

	Q1 2021	Q2 2021	Q3 2021	Q4 2021	2021	Q1 2022	Q2 2022
Benchmark Prices							
WTI crude oil (US$/bbl)	$57.84	$66.07	$70.56	$77.19	$67.92	$94.29	$108.41
NYMEX natural gas (US$/mcf)	$2.69	$2.83	$4.01	$5.83	$3.84	$4.95	$7.17
Production							
Crude oil (bbl/d)	57,419	58,403	57,610	58,468	57,977	59,301	61,593
Natural gas liquids (bbl/d)	6,238	7,563	7,174	7,984	7,244	7,636	7,468
Natural gas (mcf/d)	90,739	91,172	90,528	86,029	89,606	83,574	84,169
Oil equivalent (boe/d) (1)	**78,780**	**81,162**	**79,872**	**80,789**	**80,156**	**80,867**	**83,090**
% Liquids	**81%**	**81%**	**82%**	**82%**	**82%**	**82%**	**83%**
Netback ($/boe)							
Total sales, net of blending and other expenses (2)	$51.84	$57.19	$63.85	$70.42	$60.93	$86.89	$105.44
Royalties (3)	(9.44)	(11.04)	(12.32)	(13.47)	(11.59)	(16.86)	(22.69)
Operating expense (3)	(11.36)	(11.22)	(11.46)	(12.83)	(11.72)	(13.85)	(14.21)
Transportation expense (3)	(1.24)	(1.01)	(1.06)	(1.10)	(1.10)	(1.27)	(1.56)
Operating Netback (2)	$29.80	$33.92	$39.01	$43.02	$36.52	$54.91	$66.98
General and administrative (3)	(1.23)	(1.44)	(1.36)	(1.54)	(1.39)	(1.61)	(1.54)
Cash financing and interest (3)	(3.44)	(3.19)	(3.10)	(2.87)	(3.15)	(2.81)	(2.71)
Realized financial derivative gain (loss) (3)	(2.93)	(5.28)	(7.34)	(9.49)	(6.30)	(11.59)	(16.41)
Other (4)	(0.12)	(0.20)	(0.21)	(0.23)	(0.19)	(0.48)	(0.60)
Adjusted funds flow (5)	**$22.08**	**$23.81**	**$27.00**	**$28.89**	**$25.49**	**$38.42**	**$45.72**

(1) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(2) Non-GAAP financial measure that is not a standardized financial measure under IFRS and may not be comparable to similar measures disclosed by other issuers. See “Specified Financial Measures” in the Q2/2022 MD&A for information related to this non-GAAP financial measure, which information is incorporated by reference into this presentation.
(3) Information related to this supplementary financial measure is available in the Q2/2022 MD&A under the heading “Specified Financial Measures” and is incorporated by reference into this presentation.
(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share based compensation. Refer to the Q2/2022 MD&A for further information on these amounts.
(5) Information related to this capital management measure is available in the Q2/2022 MD&A under the heading “Specified Financial Measures” and is incorporated by reference into this presentation.

Forward Looking Statements Advisory

Any "financial outlook" or "future oriented financial information" in this presentation as defined by applicable securities laws, has been approved by management of Baytex. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other circumstances.

In the interest of providing the shareholders of Baytex and potential investors with information regarding Baytex, including management's assessment of future plans and operations, certain statements in this presentation are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this presentation peak only as of the date hereof and are expressly qualified by this cautionary statement.

Specifically, this presentation contains forward-looking statements relating to but not limited to: that we have 10+ years of drilling inventory in core areas and strong capital efficiencies across the portfolio; we have >125 net prospective Clearwater sections; exploration and development expenditures are targeted at less than 50% of adjusted funds flow at a US$75 WTI price; that our 5-year plan (2022-2026) generates ~$3 Billion of free cash flow; that we intend to allocate ~25% of our free cash flow to share buybacks which will increase to 50% of free cash flow when we hit our $800 million net debt target, expected late 2022 / early 2023; our GHG emissions intensity reduction and end of life well inventory reduction targets; expectations for 2022 as to Baytex's production on a boe/d basis, percentage of production that will be liquids, exploration and development expenditures and our expected production by area and commodity; expected exit production rate of 87,000 to 88,000 boe/d for 2022; our Clearwater highlights, including that: we have >125 sections highly prospective for Sprit River (Clearwater equivalent), our five-year plan calls for production of 10,000 bbl/d, with upside to 15,000 bbl/d, that we have 300 un-risked (200 risked) inventory locations at 4 wells per section, the Peavine wells have payouts of <5 months and IRRs >500% at $75 WTI, expected 2022 asset level free cash flow of ~$85 million, that production of 10,000 to 15,000 bbl/d for ten years would generate ~$1 Billion of asset level free cash flow at $75 WTI and gas conservation is in planning stages; 23 horizontal wells at Peavine planned for 2022; Clearwater H2/2022 drilling plans; in 2022, that exploration and development expenditures represent <40% of adjusted funds flow and expected free cash flow is ~$700 million; by operating area, the number of net wells onstream and capital expenditures in 2022; upon net debt reaching $400 million (expected late 2023/early 2024) we will consider steps to further enhance shareholder returns; our 2022 expectations for exploration and development spending, ARO expenditures, share buybacks, debt repayment and the associated yield at US$75/85/95bbl WTI; our expected net debt in 2022; that our 5-year plan generates ~$3 billion of cumulative free cash flow, targets capital spending at <50% of adjusted funds flow and generates 2-4% annual production growth; for each year of our 5-year plan: expected average daily production, adjusted funds flow, adjusted funds flow per share, capital expenditures, ARO / leasing expenditures and after-tax free cash flow; for our 5-year plan the approximate after-tax free cumulative cash flow it will generate at US$75/85/95bbl WTI and the associated net debt to EBITDA ratios; the percentage of our expected production that is hedged for 2022 and 2023; the sensitivity of our expected 2022 adjusted funds flow to changes in WTI prices, WCS and MSW differentials, natural gas prices and the Canada-United States foreign exchange rate on a hedged and unhedged basis; for the Eagle Ford that we expect to bring ~18 net wells on production in 2022; for the Viking that a stable production base drives meaningful asset level free cash flow, we expect to bring ~130 wells online in 2022, the asset has strong price realizations and a low cost structure and the approximate free cashflow it will generate at US$75/85/95bbl WTI in 2022; in Heavy Oil, that low decline production provides capital allocation flexibility, innovative multi-lateral horizontal drilling generates strong capital efficiencies, 9 net Bluesky multilateral wells are planned for 2022 and 24 Clearwater wells are planned for 2022; for the Northwest Clearwater that we have >125 sections prospective for Sprit River (Clearwater equivalent), we will drill a follow-up Clearwater well on our legacy Seal lands in H2/2022, that we have de-risked 50 sections and believe the play holds the potential for >200 locations and we expect to bring 24 wells onstream in 2022 (with 6 additional wells in Q4/2022); we expect to bring ~31 net wells on production in 2022 in Lloydminster and pursue a long-life polymer flood and water flood projects at Soda Lake and Tangleflags; in Pembina Area Duvernay, we have delineated a minimum of 100-125 sections and continue to advance the delineation; the expected individual well payout, IRR and recycle ratio for wells in the Eagle Ford, Viking, Peace River, Clearwater and Lloydminster areas; the expected drill, complete, equip and tie-in well costs, reserves and drilling inventory for our Eagle Ford, Peace River, Clearwater, Lloydminster, Viking and Pembina Duvernay assets; our values, visions and approach to ESG; that we are committed to corporate sustainability; the components of our GHG emissions reduction strategy; our new ESG targets: reducing our GHG emissions intensity by 65% by 2025 from our 2018 baseline, reducing our 2020 end of life well inventory of 4,500 wells to zero by 2040 and spending $100 million from 2022 to 2026 on abandonment and reclamation, developing an internal management framework that prioritizes reduced freshwater use, and having 30% women directors by our 2023 shareholder meeting; and our 2022 guidance for exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

Forward Looking Statements Advisory (Cont.)

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; the ability to add production and reserves through exploration and development activities; capital expenditure levels; the ability to borrow under credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; the ability to develop crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for year ended December 31, 2021, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

Specified Financial Measures Advisory

In this presentation, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, and average royalty rate) which do not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS"). While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers.

Refer to "Specified Financial Measures" in the Q2/2022 MD&A for additional information on the following specified financial measures, which information is incorporated by reference into this presentation.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations.

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

Operating netback per boe

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures Advisory

This presentation contains the terms "adjusted funds flow", "net debt", "net debt to adjusted funds flow ratio" and "net debt to EBITDA" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Net debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net debt is comprised our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash, and trade and other receivables. We also use a net debt to Bank EBITDA ratio to evaluate the amount of debt we have in our capital structure on an ongoing basis. Net debt to EBITDA ratio is comprised of net debt divided by Bank EBITDA. Bank EBITDA is calculated in accordance with our credit facility which is accessible on the SEDAR website at www.sedar.com.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and the our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirements obligations settled during the applicable period. We also use a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements. Net debt to adjusted funds flow is comprised of net debt divided by adjusted funds flow.

Advisory Regarding Oil and Gas Information

The reserves information contained in this presentation has been prepared in accordance with National Instrument 51-101 -Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators ("NI 51-101"). The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserves definitions.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves and future production from such reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Complete NI 51-101 reserves disclosure for year-end 2021 is included in our Annual Information Form for the year ended December 31, 2021 which will be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission no later than March 31, 2022.

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. 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. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Eagle Ford, Baytex's net drilling locations include 129 proved and 58 probable locations as at December 31, 2021 and 37 unbooked locations. In the Viking, Baytex's net drilling locations include 936 proved and 222 probable locations as at December 31, 2021 and 490 unbooked locations. In Peace River (including Clearwater), Baytex's net drilling locations include 61 proved and 37 probable locations as at December 31, 2021 and 334 unbooked locations. In Lloydminster, Baytex's net drilling locations include 82 proved and 63 probable locations as at December 31, 2021 and 423 unbooked locations. In the Duvernay, Baytex's net drilling locations include 17 proved and 12 probable locations as at December 31, 2021 and 231 unbooked locations.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Notice to United States Readers

The petroleum and natural gas reserves contained in this presentation have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this presentation may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, in this presentation future net revenue from its reserves has been determined and disclosed estimated using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, the reserve estimates and production volumes in this presentation may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

Notes

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