WHITECAP RESOURCES INC

CONTINUING PROFITABLE GROWTH

Whitecap Profile – *TSX: WCP*

• **Shares outstanding** (MM)	
– Basic	368.3
– Fully diluted (1.1% dilutives)	372.3
• **Market capitalization** ($B)	~$4.4
• **Annual dividend** ($/share)	$0.28
• **2017 production guidance** (boe/d)	57,000
– % oil + NGLs	82%
• **2017 cash netback** ($/boe)*	$25.78
• **Reserves** (MMboe)	
– Proved	251.5
– TPP	358.0
– TPP RLI (years)	17.2
• **Oil development drilling inventory**	3,040
– # Years' Inventory	10^+

* 2017 commodity prices used are WTI US$55.00/bbl, C$/US$0.78, Edmonton Par Differential (US-$3.50/bbl) and AECO C$3.00/GJ.

Operational Focus Drives Economic Returns

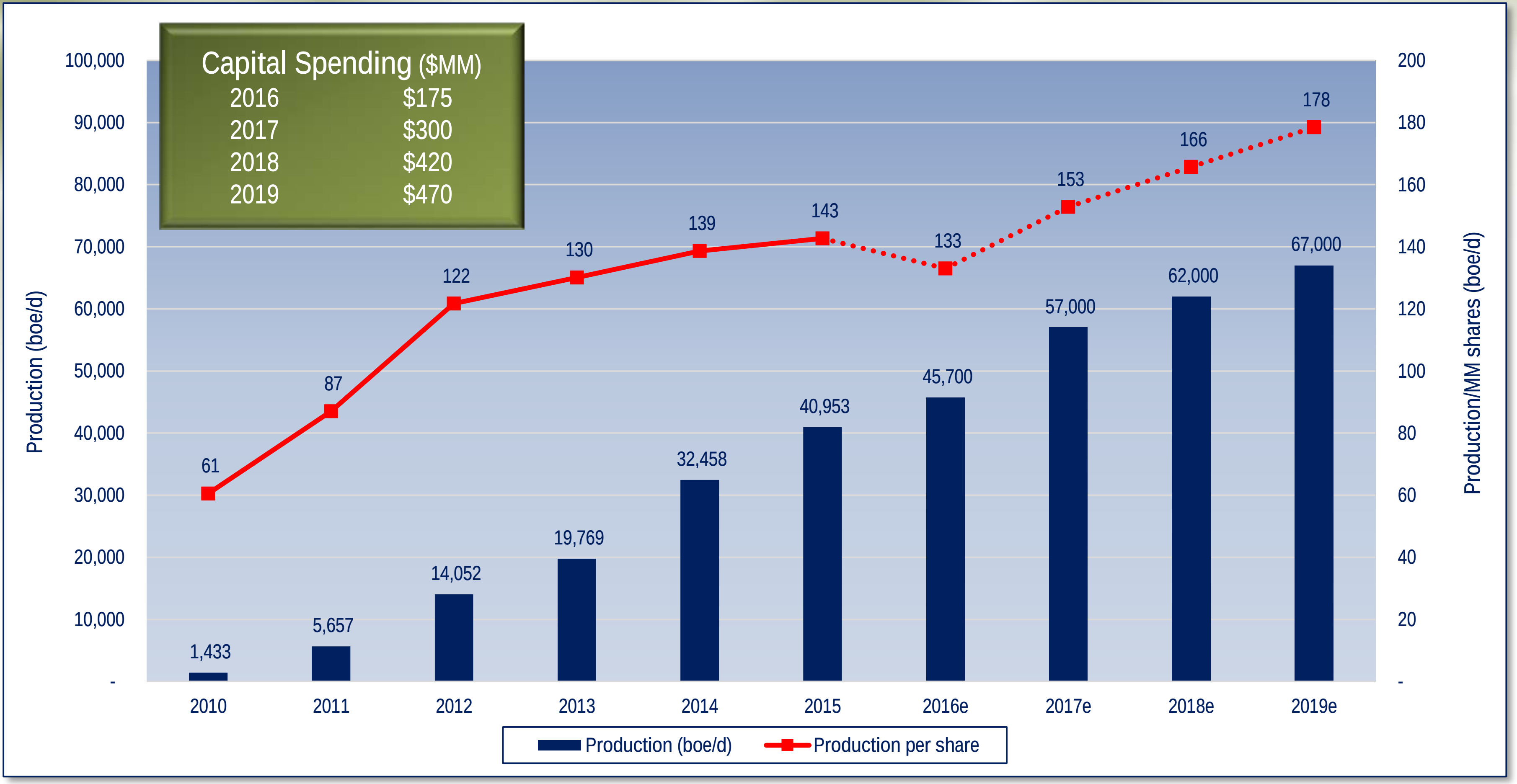
Pillars of Sustainability

- Low Decline Rate
- High Cash Netback
- Strong Capital Efficiencies

Shareholder Returns

- Profitable Organic Growth
  - 5-8% per share / year
- Return on Capital Employed
- Total Shareholder Return > 10% / year

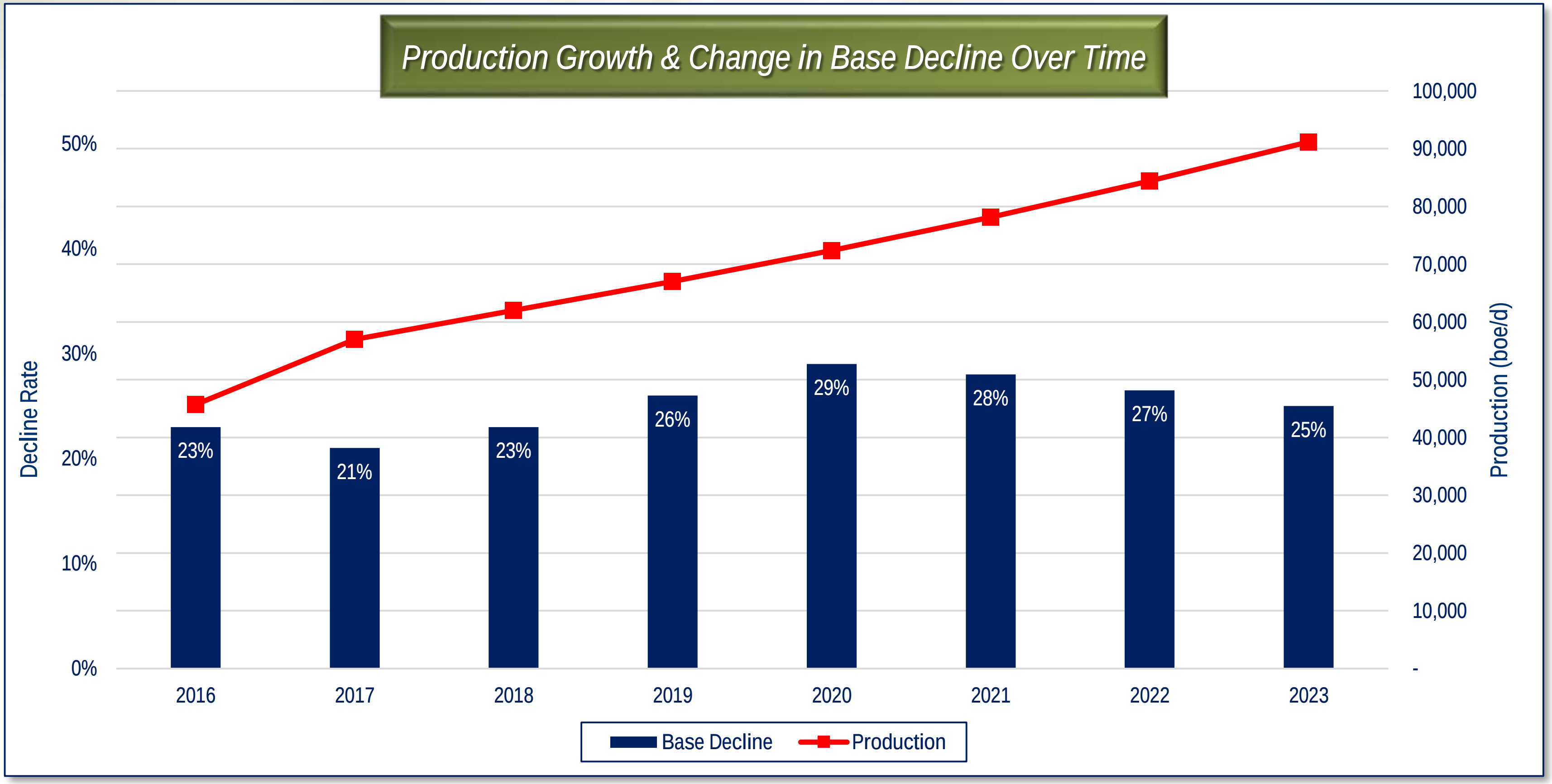
Production per Share Growth



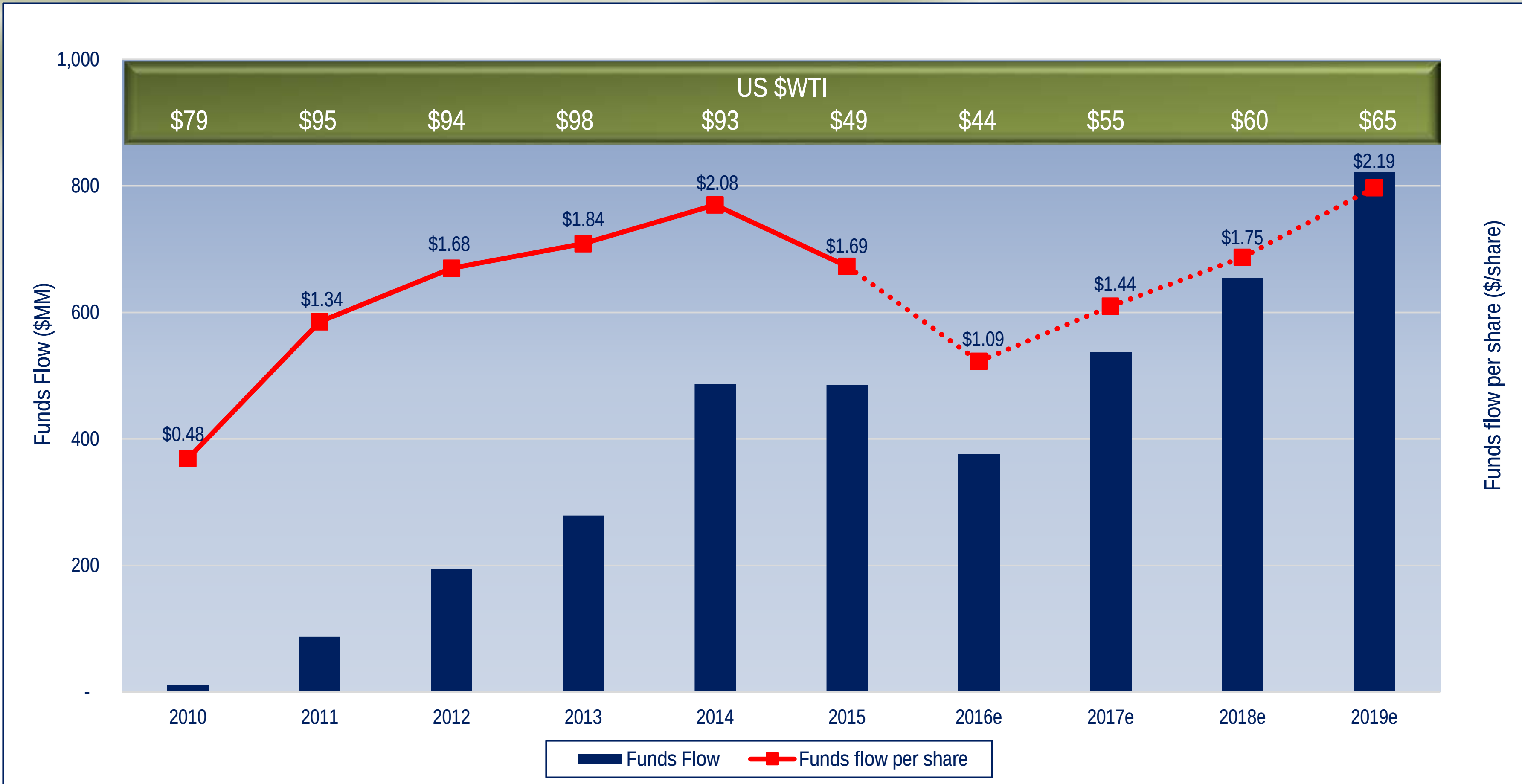
CAGR per share	
2010 – 2015	19%
2016 – 2019e	10%

Predictable and Stable Production Base

- Base and new well production is predictable and repeatable
- High level of certainty of achieving forecasted volumes
  - Areally consistent reservoirs
  - Large resource in place, limited recovery to date
  - 63% of production impacted by waterflood and EOR

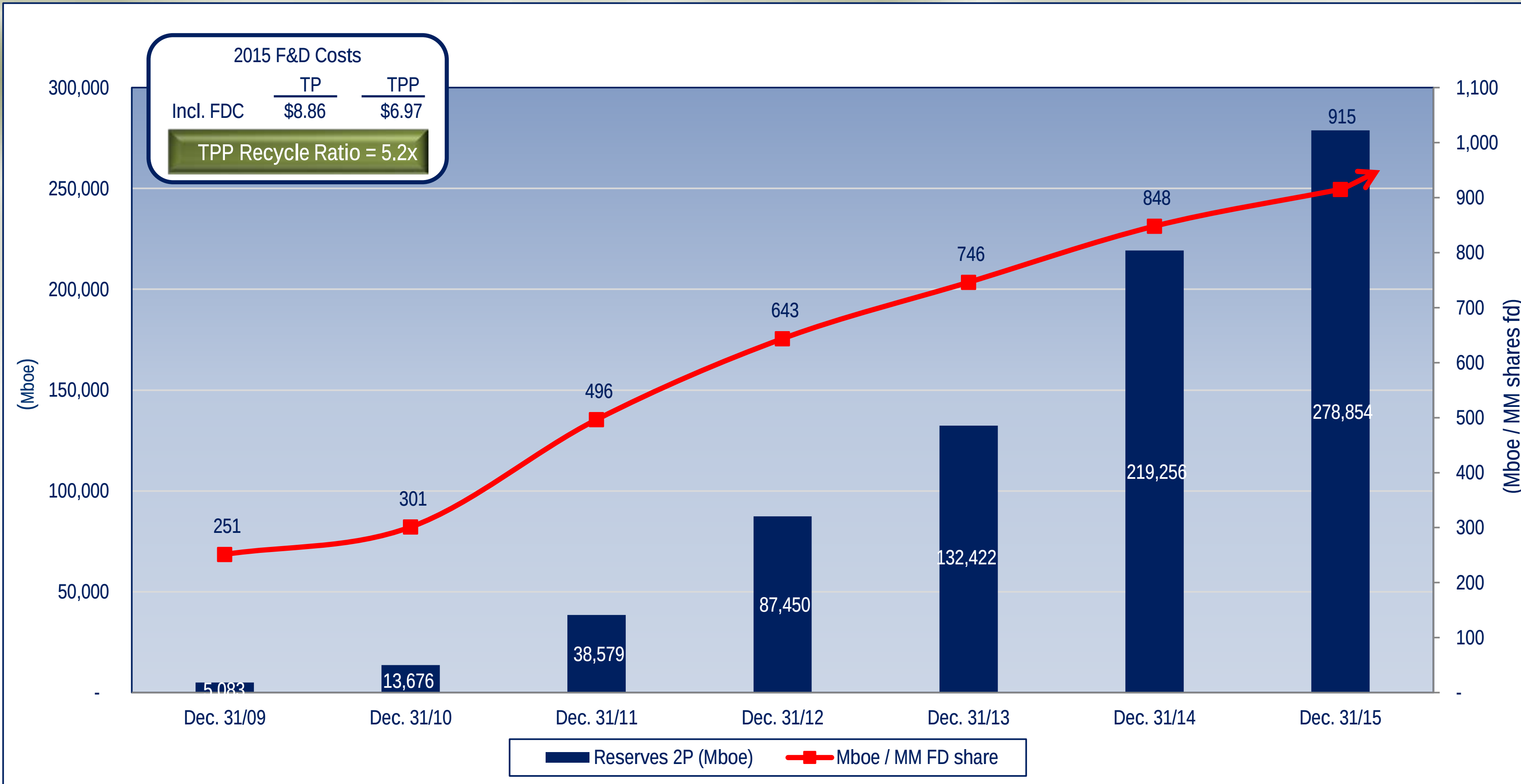


Funds Flow per Share Growth



CAGR per share	
2010 – 2015	29%
2016 – 2019e	26%

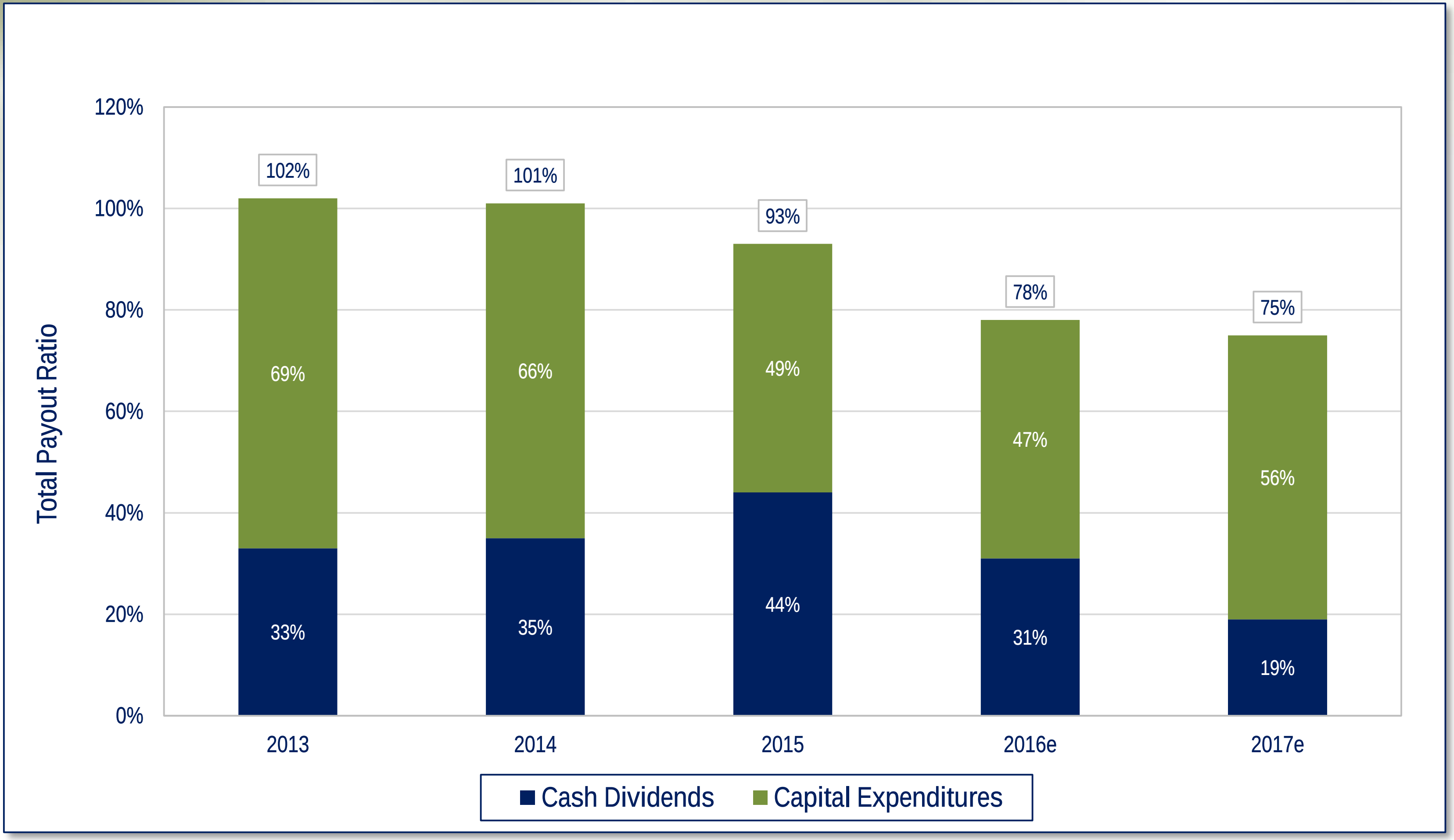
2P Reserves per Share Growth



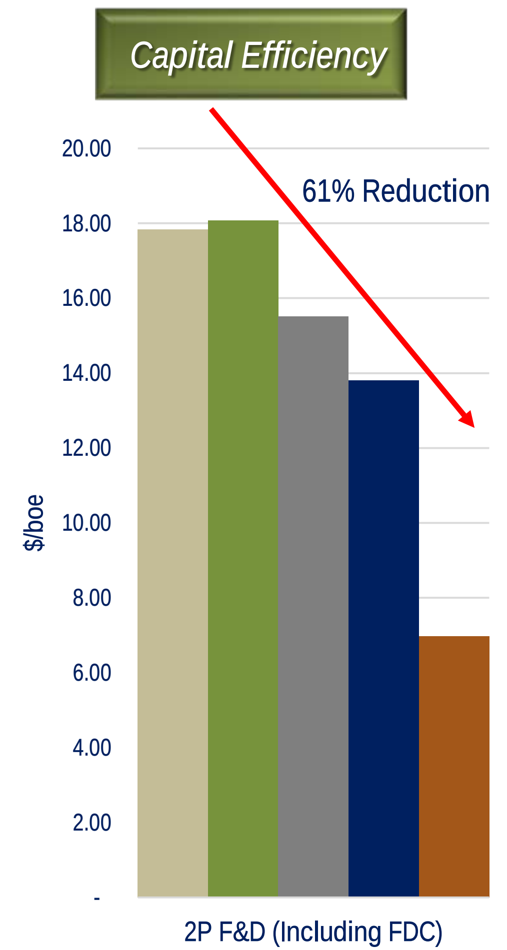
CAGR per share

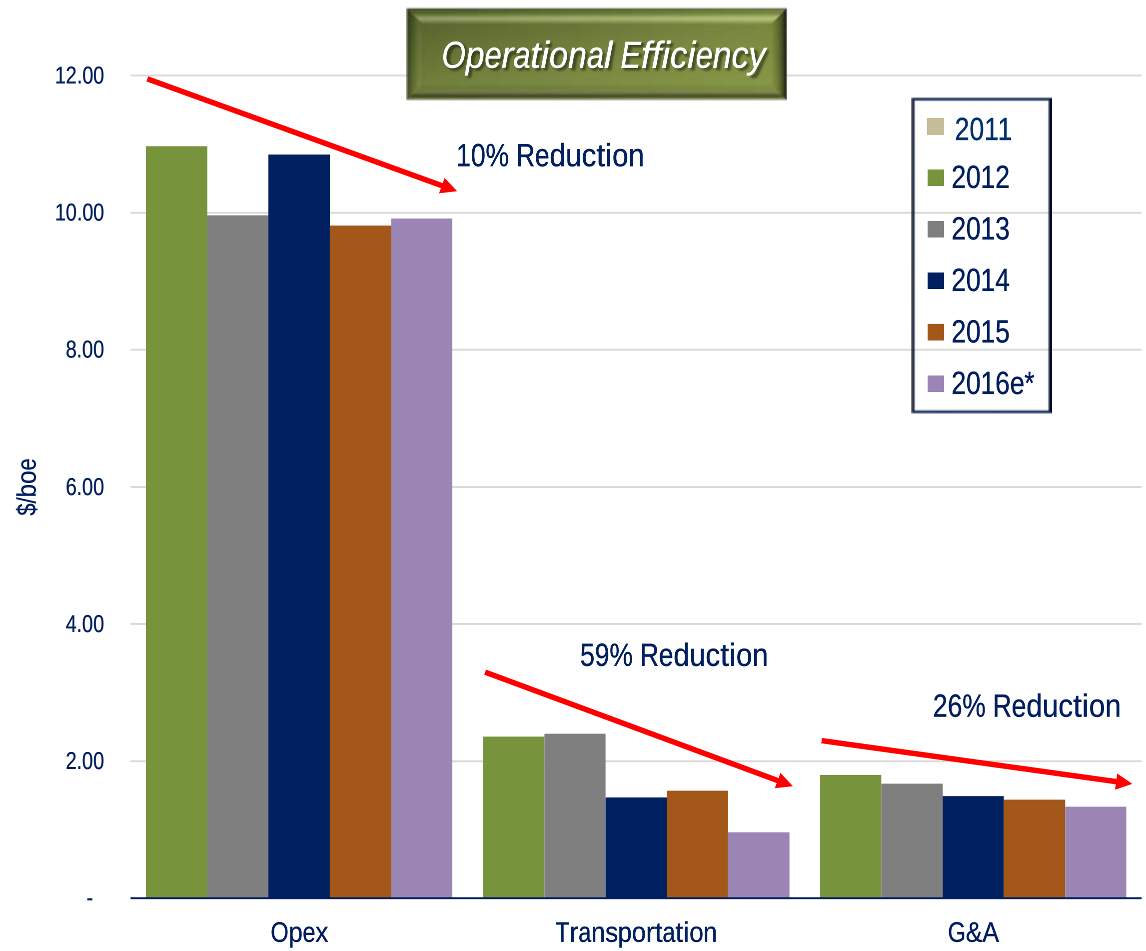
2009 – 2015 23%

Internally Funded Growth + Dividend Model – No DRIP



Efficiency and Cost Focus



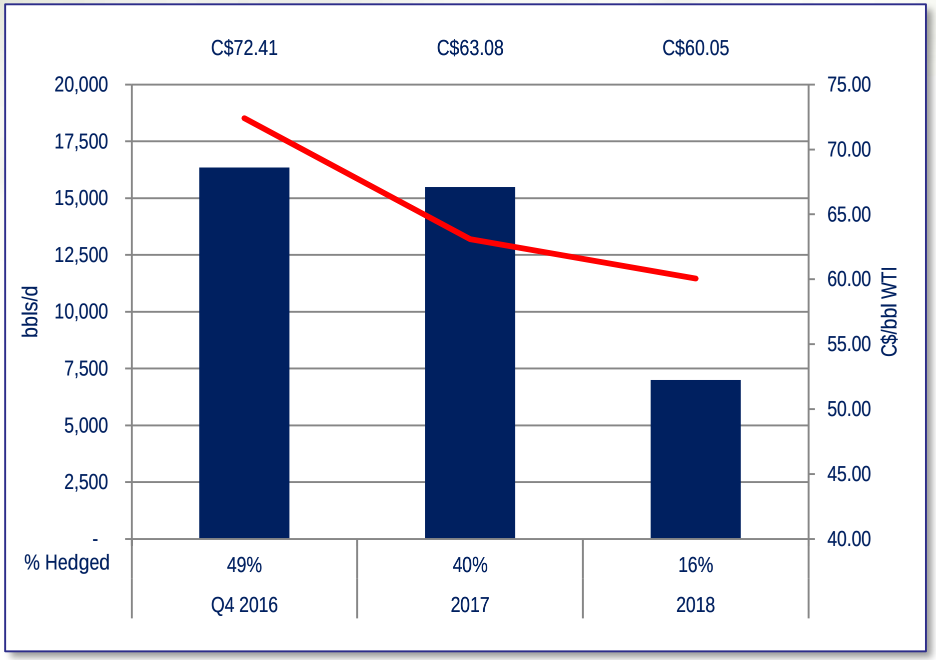


* Whitecap estimate as of October 31, 2016

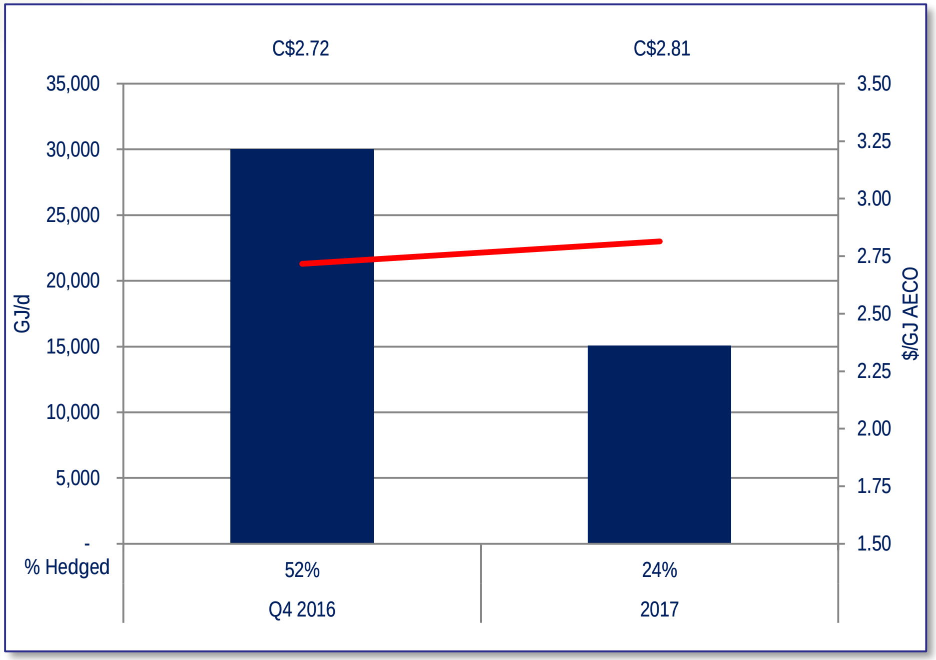
Financial Prudence and Risk Management

- Mitigate price volatility and protect economic returns on capital deployed
- Predictability for WCP funds flow ⟶ Capital reinvestment and Dividend payments

Oil Hedges



Gas Hedges



Production Hedged
Average Price Hedged

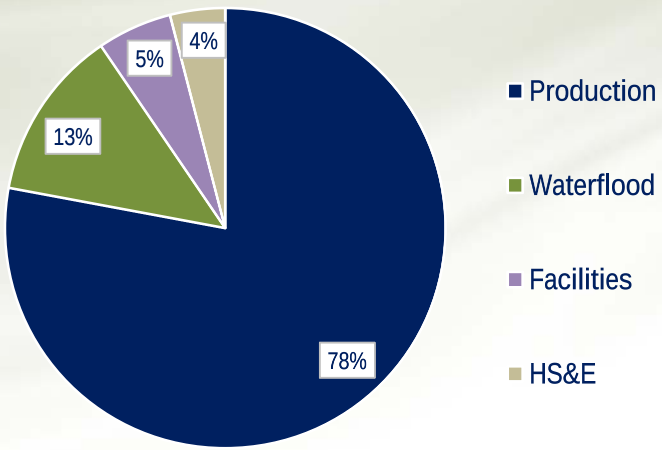
Setting Up For A Strong 2017

	2016	2017 Outlook	% Change
Average production (boe/d)	45,700	57,000	25%
• per million shares	133	153	15%
Funds flow ($MM)	$376	$536	43%
• per share	$1.09	$1.44	32%
Development capital ($MM)	$175	$300	71%
Total dividends	$117	$103	(12%)
• $ per share (average)	$0.35	$0.28	(20%)
Total payout ratio	78%	75%	(3%)
Net debt to funds flow	2.2x	1.4x	(36%)
• Q4 annualized	1.9x	1.3x	(32%)

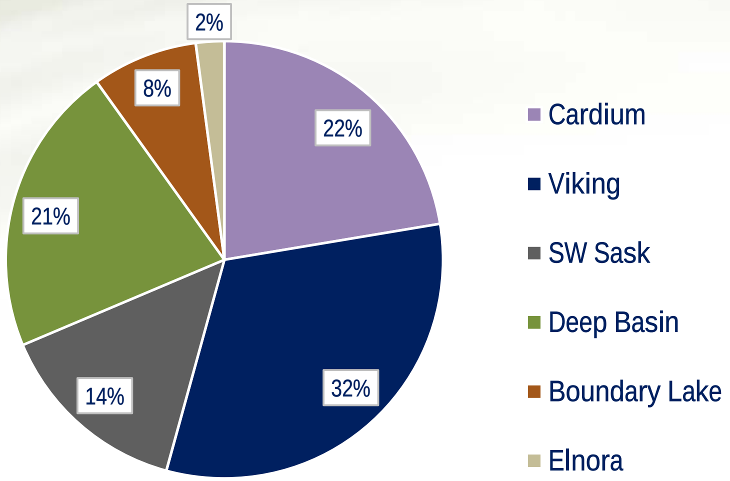
* 2017 commodity prices used are WTI US$55.00/bbl, C$/US$0.78, Edmonton Par Differential (US-$3.50/bbl) and AECO C$3.00/GJ.

2017 Development Capital

Capital by Type

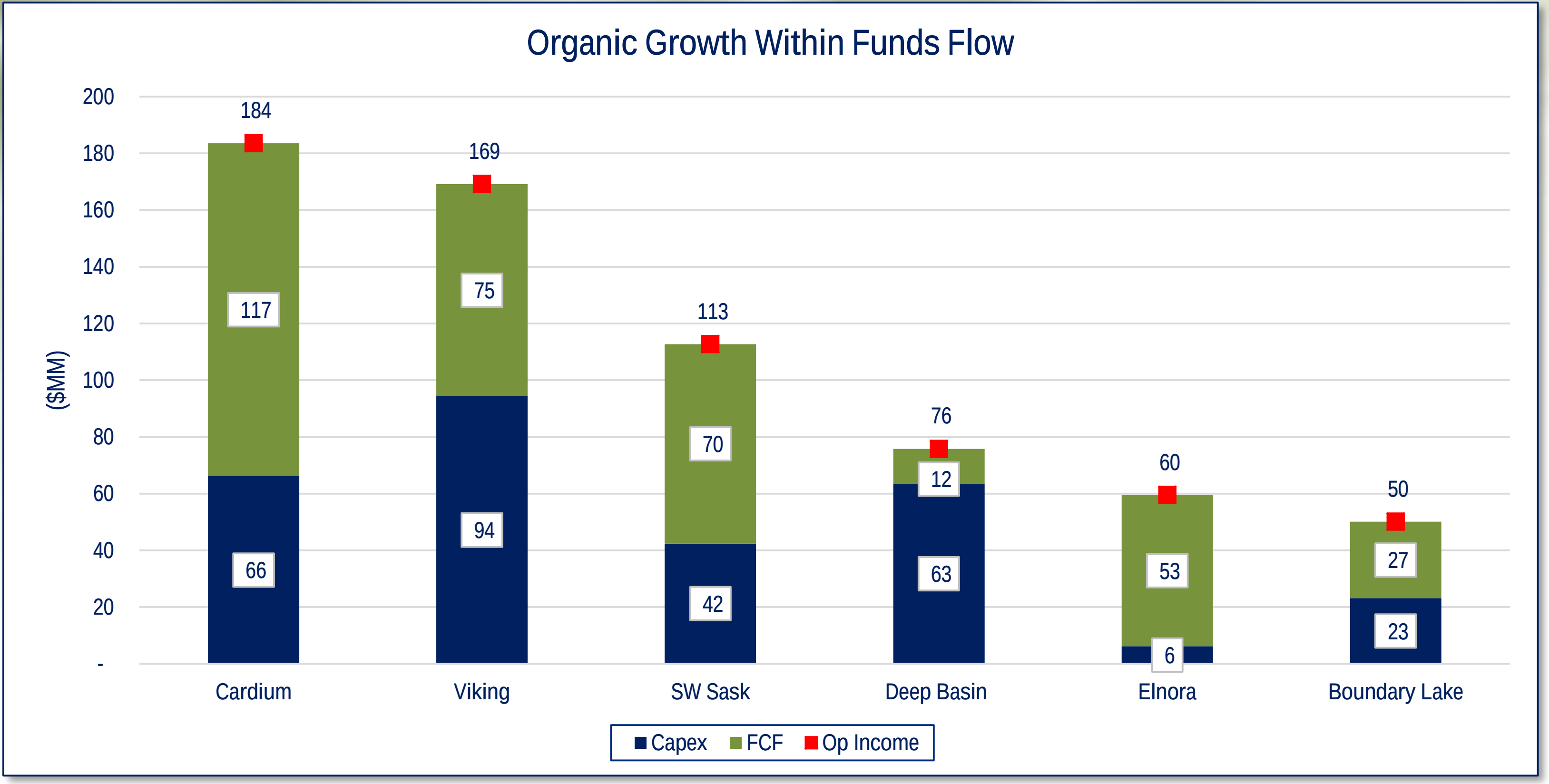


Capital by Area



	2016	2017
Development Capital ($MM)	$175	$300
Wells (gross #)	97	187

Sustainable Asset Base: Capital + Dividend < Funds Flow



	2017 Capex / Op Inc	Production Growth
Cardium	36%	16%
Viking	56%	22%
SW Sask	38%	6%
Deep Basin	84%	28%
Elnora	10%	(2%)
Boundary Lake	46%	7%

2017 Sensitivities

Oil (US$WTI)	$40.00	$45.00	$50.00	$55.00	$60.00	$65.00
FX (C$/US$)	$0.72	$0.74	$0.76	$0.78	$0.80	$0.82
Oil (Cdn$/WTI)	$55.56	$60.81	$65.79	$70.51	$75.00	$79.27
AECO (C$/GJ)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
Funds flow netback ($/boe)	$18.64	$21.13	$23.46	$25.78	$27.71	$29.33
Average production (boe/d)	57,000	57,000	57,000	57,000	57,000	57,000
Funds flow ($MM)	$388	$440	$488	$536	$577	$610
• Per share	$1.04	$1.18	$1.31	$1.44	$1.54	$1.63
Development capital ($MM)	($300)	($300)	($300)	($300)	($300)	($300)
Dividend ($MM)	($103)	($103)	($103)	($103)	($103)	($103)
Free funds flow ($MM)	($15)	$37	$85	$133	$173	$207
Total payout ratio (%)	104%	92%	83%	75%	70%	66%
Debt to funds flow	2.2x	1.8x	1.5x	1.3x	1.1x	1.0x

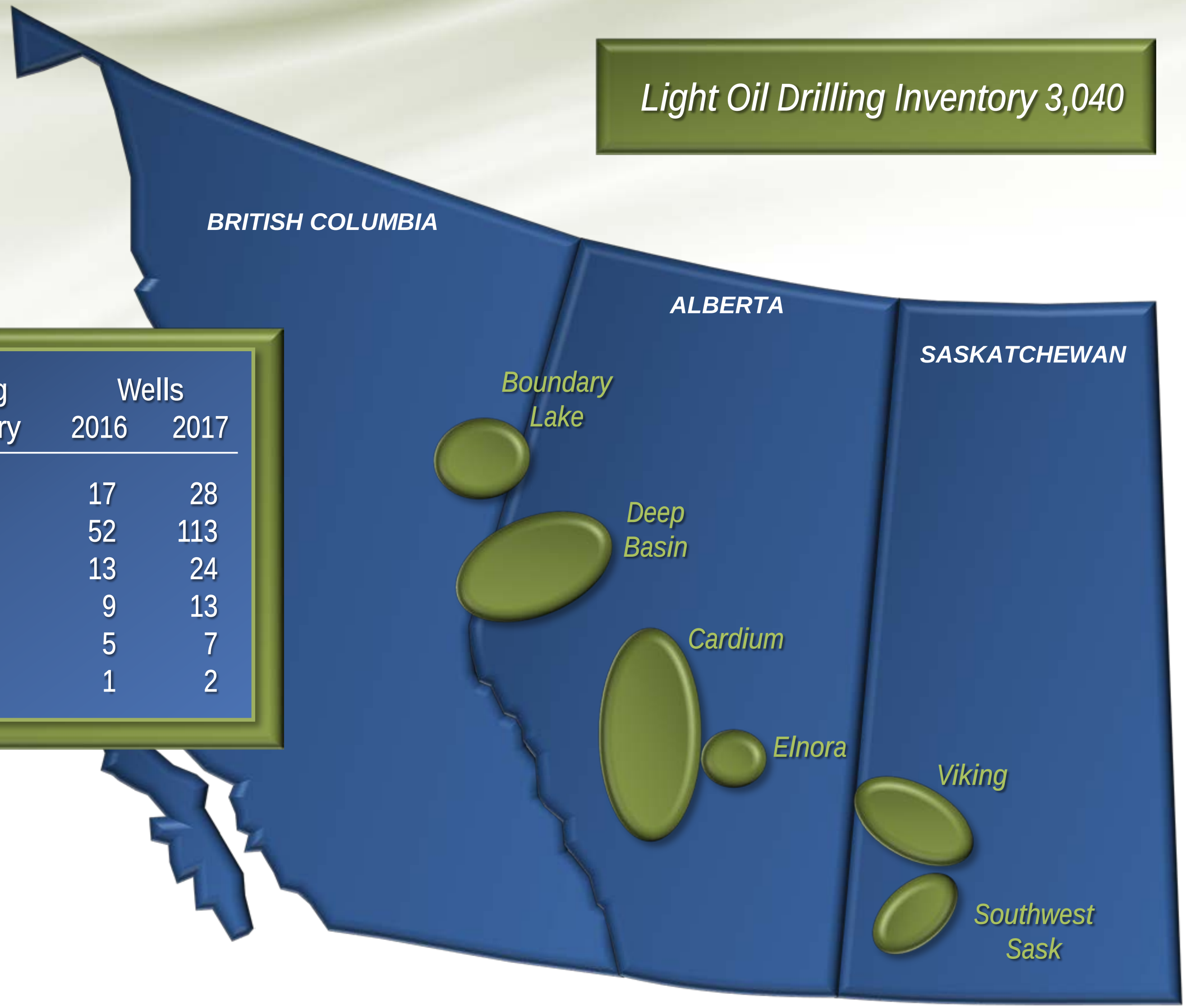
Free Funds Flow Priorities

1. Debt management
   - target debt to cash flow of < 1.5x
2. Development capital
   - increase spending on organic growth projects
3. Complementary tuck-in acquisitions
   - within core operating areas using balance sheet strength
4. Sustainable dividend
   - supported by stronger commodity price and increased hedging

Core Areas of Operations

Light Oil Drilling Inventory 3,040

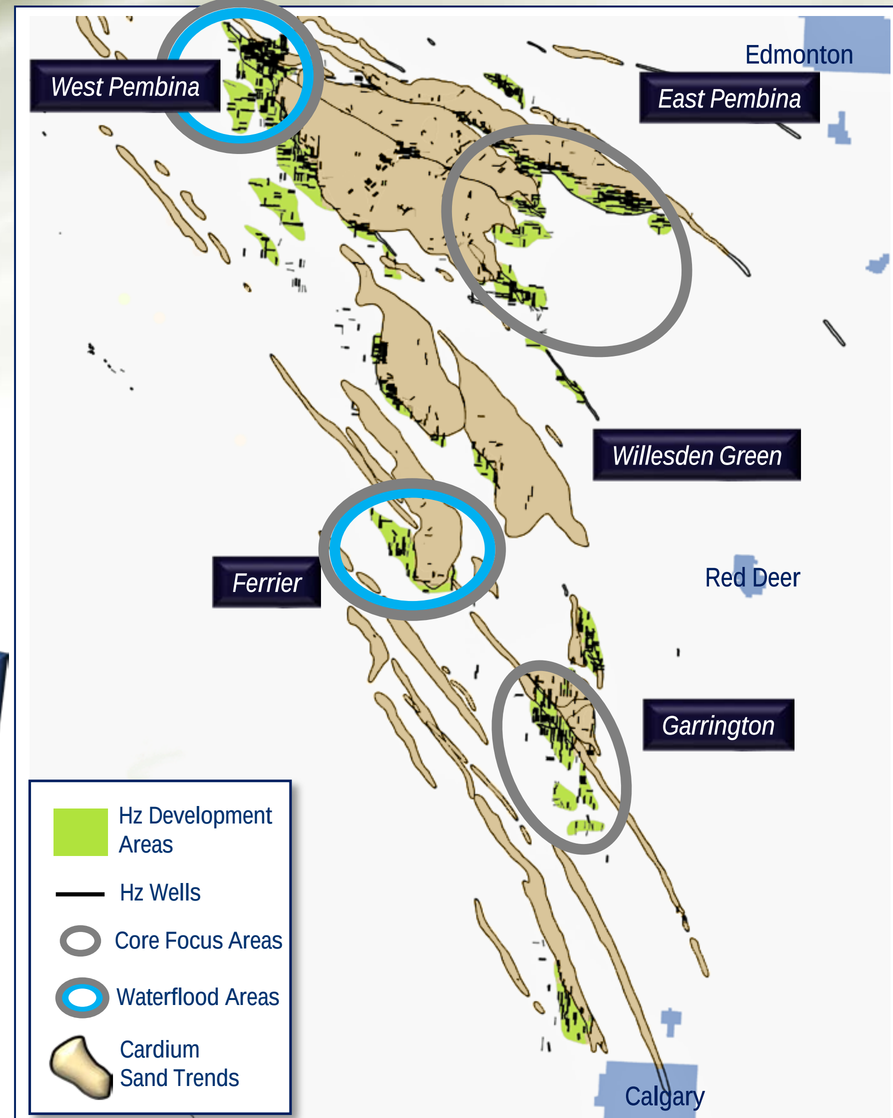
	Current Prod'n	Drilling Inventory	Wells 2016	Wells 2017
Cardium	13,000	716	17	28
Viking	8,800	1,126	52	113
SW Sask	11,800	660	13	24
Deep Basin	6,900	413	9	13
Boundary Lake	4,900	110	5	7
Elnora	4,600	4	1	2



Refer to notes located at the end of the presentation

Cardium Resource Play – repeatable low risk growth

- Industry leading capital efficiencies
  - Continuing capital efficiency improvement:
    - ERH drilling
    - Advancing frac designs and efficiencies
    - Optimizing recovery downspacing & waterflood advancement
- Large growth inventory, 20+ years
  - Robust well economics
  - Light sweet oil (39° API), strong cash netbacks
  - 7 low decline legacy waterfloods with growth potential
- Cardium drilling program
  - 2016: 17 wells (5 ERH)
  - 2017: 28 wells (12 ERH)
- Cardium gross DOIIP 1.6bn bbls (1.2 net)
  - Recovered to date 9.3% (146.8 MMbbls)
  - Possible oil RF = 18 - 20%



Refer to notes located at the end of the presentation

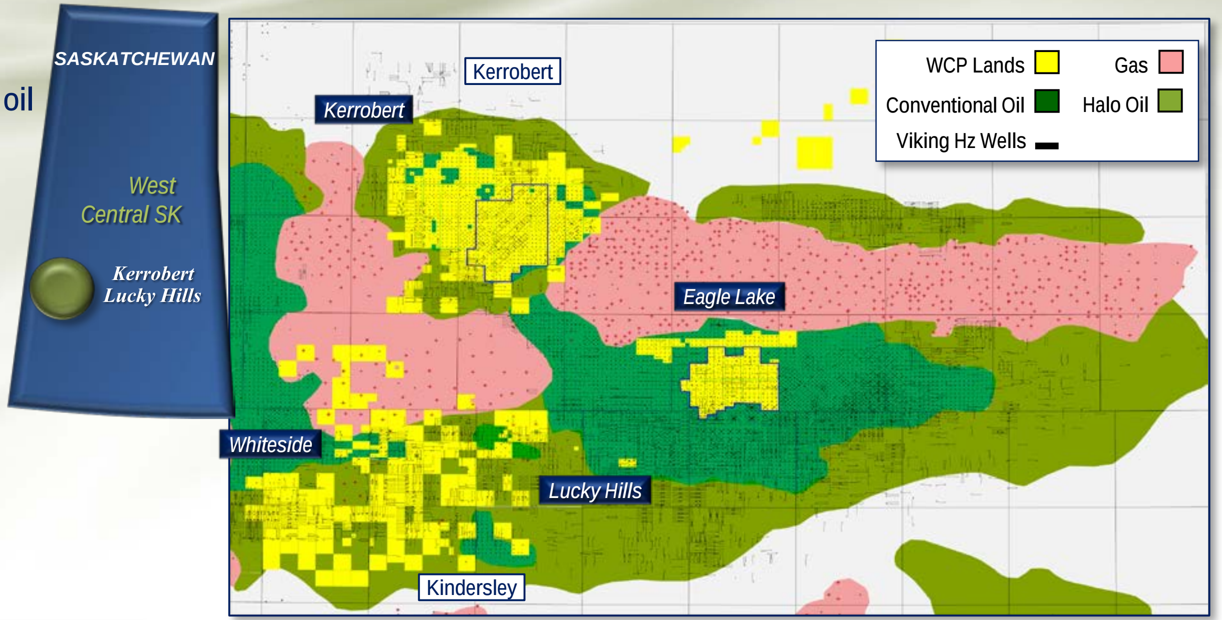
Exceptional Type Curve Economics

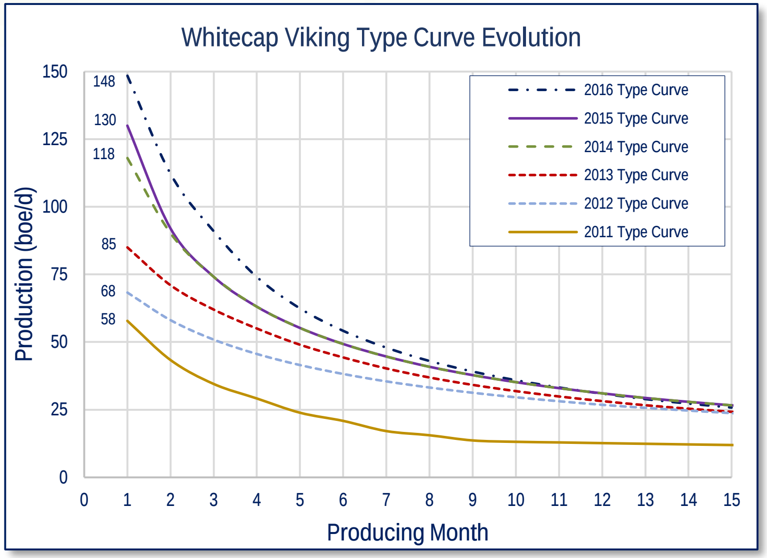
Type Well Economics	West Pembina Cardium Standard 1.0	West Pembina Cardium ERH 1.5
Drill, Complete, Equip, Tie-in ($MM)	$2.15	$2.45
Production, IP30 (boe/d)	317	476
Production, IP365 (boe/d)	159	239
$P+P_A$ Reserves (Mboe)	222	328
Year 1 Oil + NGLs (%)	92%	92%
NPV BT_{10} ($MM)	$5.39	$8.16
Profit to investment ratio	2.50	3.33
Rate of return (%)	>325%	>500%
Payout (years)	0.56	0.37
Reserve cost ($/boe)	$9.67	$7.46
Production efficiency ($/boe/d – IP365)	$13,486	$10,245
Initial operating netback ($/boe)	$51.25	$50.09
Recycle ratio	5.3	6.7

Refer to notes located at the end of the presentation

Saskatchewan Viking Oil – top decile resource play

- Top tier inventory for sustainable growth
  - 10 years' high quality inventory, 36° API light oil
  - Long-term growth, increasing ERH drilling
- Industry leading capital efficiencies
  - High netback, short payout
  - Exceptional economic rates of return
- Drilling program
  - 2016: 52 wells (24 ERH)
  - 2017: 113 wells (59 ERH)
- Gross DOIIP 1.6bn bbls (1.5 net)
  - Recovered to date 3.6% (60.1 MMbbls)
  - Possible oil RF = 8 - 12%





Type Well Economics	Viking Resource Standard 1.0	ERH 1.5
Drill, Complete, Equip, Tie-in ($MM)	$0.62	$0.79
Production, IP30 (boe/d)	148	235
Production, IP365 (boe/d)	64	94
P+P$_A$ Reserves (Mboe)	69	114
Year 1 Oil + NGLs (%)	83%	86%
NPV BT$_{10}$ ($MM)	$1.71	$2.84
Profit to investment ratio	2.76	3.59
Rate of return (%)	>400%	>500%
Payout (years)	0.35	0.26
Reserve cost ($/boe)	$8.99	$6.95
Production efficiency ($/boe/d – IP365)	$9,666	$8,362
Initial operating netback ($/boe)	$44.70	$46.07
Recycle ratio	5.0	6.6

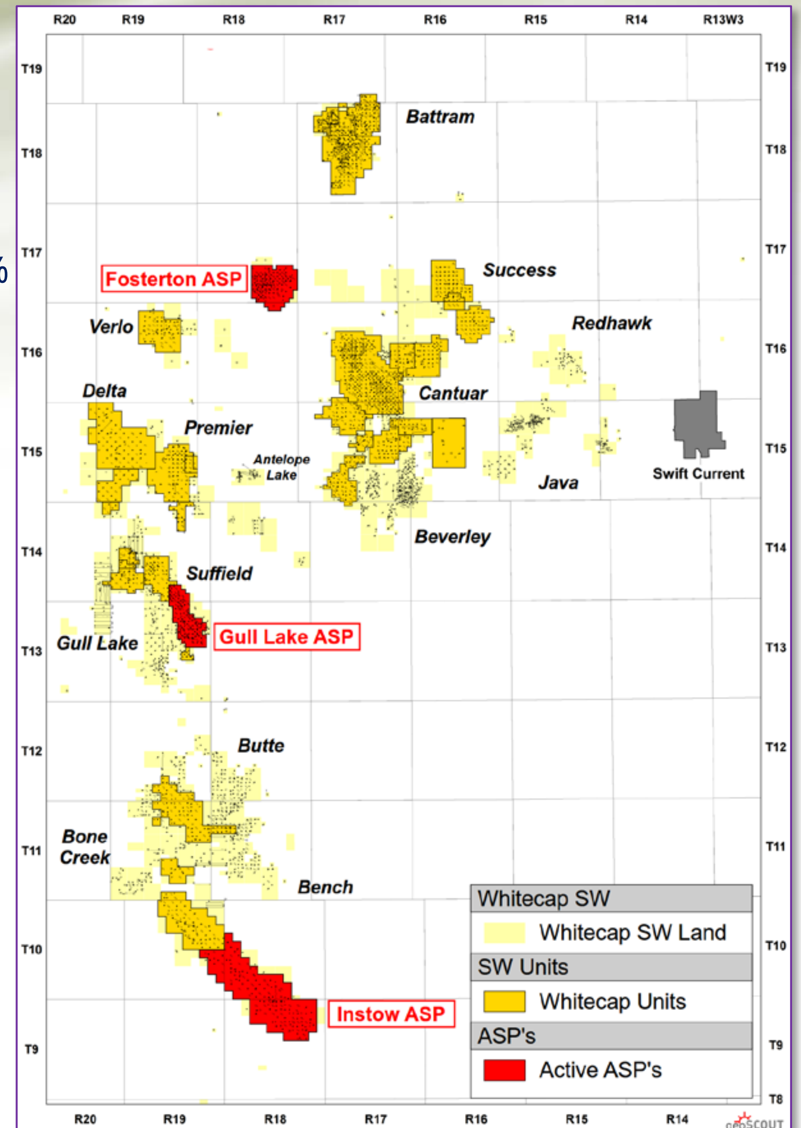
Refer to notes located at the end of the presentation

Southwest Saskatchewan – stable production, multi-zone

- Overview
  - Sustainable oil growth region with 11,800 boe/d (98% oil)
  - Stable production base – historical decline 2.3% per year
  - Increases WCP production impacted by waterflood / EOR from 54 - 63%
  - 5% growth per year with 50% of funds flow at $45/bbl WTI
  - Large asset base with 23 oil properties
    - 18 operated (mainly waterflood), 2 non-op waterflood properties
    - 3 ASP flood projects (1 non-op), majority of the capital already spent

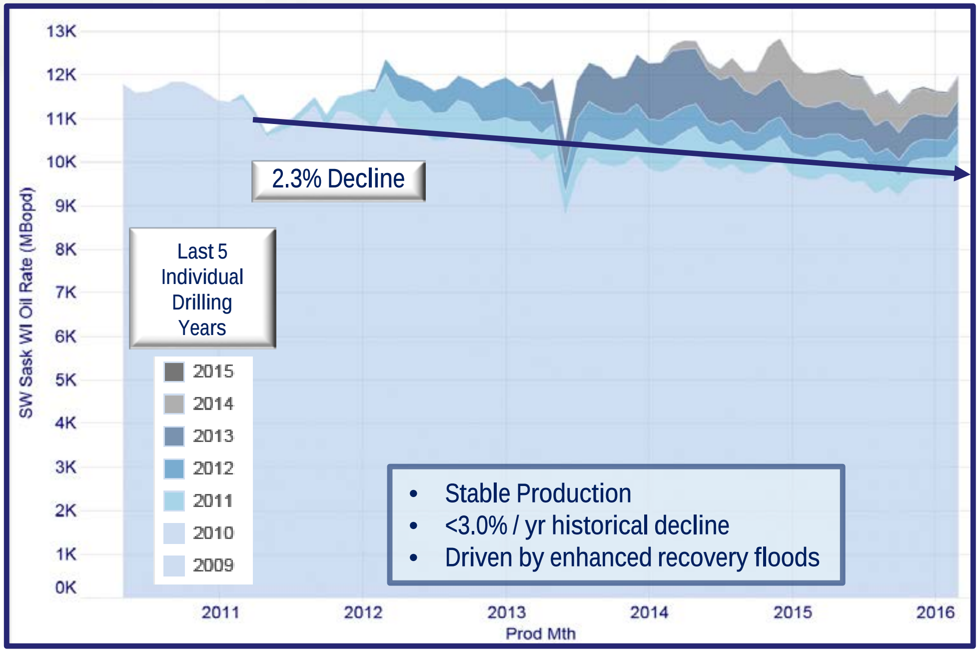
- Drilling program
  - 2016: 13 wells
  - 2017: 24 wells

- Gross DOIIP 2.6bn bbls (1.5 net)
  - Recovered to date 22.9% (595 MMbbls)
  - Possible oil RF = 36%



Strong Repeatable Economics

- Key Characteristics
  - Multi-zone potential for growth (6 zones)
  - 92% production under enhanced oil recovery ("EOR")
  - ASP is 22% of current production, 18% of 2P reserves
  - ASP polymer net capital: $333.5MM spent
    $64MM remaining
  - Excellent LMR (liability management ratio) of 4.37



Type Well Economics	Conventional Plays	Unconventional Plays
Drill, Complete, Equip, Tie-in ($MM)	$1.05	$1.17
Production, IP30 (boe/d)	100	127
Production, IP365 (boe/d)	68	73
P+P_A Reserves (Mboe)	110	120
Year 1 Oil + NGLs (%)	100%	100%
NPV BT_{10} ($MM)	$2.29	$2.23
Profit to investment ratio	2.18	1.91
Rate of return (%)	140%	121%
Payout (years)	0.98	1.04
Reserve cost ($/boe)	$9.55	$9.75
Production efficiency ($/boe/d – IP365)	$15,371	$15,981
Initial operating netback ($/boe)	$42.49	$42.55
Recycle ratio	4.5	4.4

Deep Basin Light Oil – Dunvegan and Cardium Oil

- Strong play characteristics, large growth potential
  - 39° to 42° API oil
  - Large OOIP of 6 to 15.5 MMboe/section
  - No formation water
  - Low declines and strong stabilized rates
- Drilling program
  - 2016: 9 Hz wells (6 ERH)
  - 2017: 13 Hz wells (3 ERH)
- Gross DOIIP 892 MMbbls (571 net)
  - Recovered to date 0.31% (2.8 MMbbls)
  - Possible oil RF = 10 - 15%

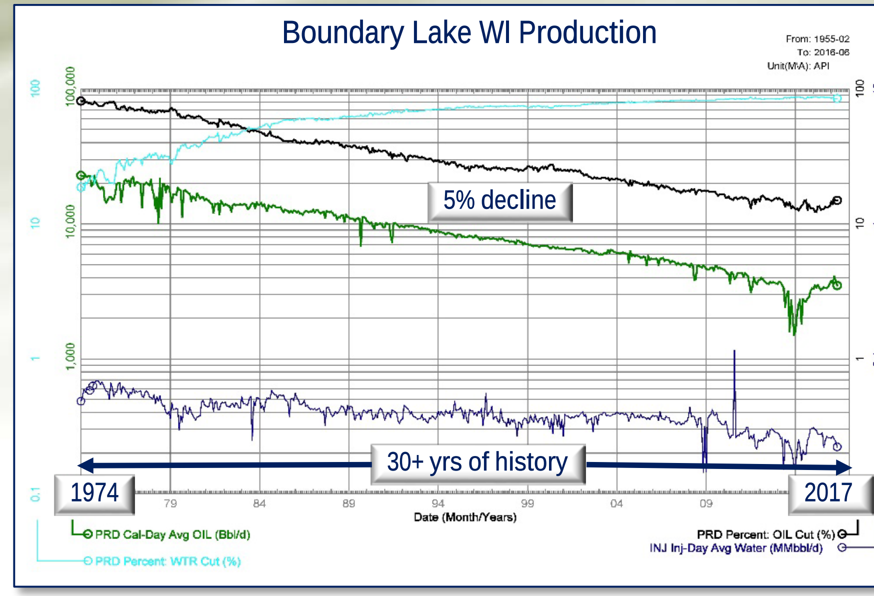
Type Well Economics	Karr Dunvegan	Wapiti Cardium	
	Standard 1.0	Standard 1.0	ERH 2.0
Drill, Complete, Equip, Tie-in ($MM)	$3.22	$2.59	$3.84
Production, IP30 (boe/d)	404	260	487
Production, IP365 (boe/d)	272	225	424
$P+P_A$ Reserves (Mboe)	332	511	997
Year 1 Oil + NGLs (%)	73%	75%	75%
NPV BT_{10} ($MM)	$6.07	$6.62	$13.15
Profit to investment ratio	1.89	2.55	3.42
Rate of return (%)	200%	179%	328%
Payout (years)	0.69	0.82	0.61
Reserve cost ($/boe)	$9.71	$5.07	$3.85
Production efficiency ($/boe/d – IP365)	$11,854	$11,500	$9,055
Initial operating netback ($/boe)	$40.14	$36.15	$34.91
Recycle ratio	4.1	7.1	9.1

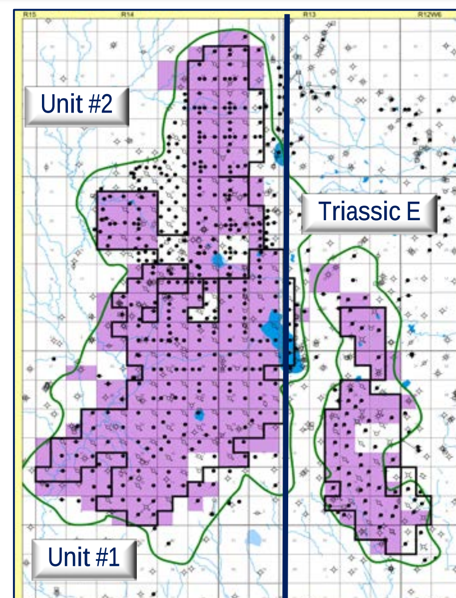
Refer to notes located at the end of the presentation

Boundary Lake – large low decline resource with growth potential

- Long-term, low decline asset
  - Operated, 35° API light oil, 91% oil + NGLs
  - Avg 90% WI in 3 operated units
- Legacy oil pool under a pattern waterflood
  - No development capital from 1998 to 2014
  - Consistent decline of 5% over the past 30 years
  - Upside evaluation to date – 110 (98.4 net) locations
- Drilling program: 2016 – 5 wells

  2017 – 7 wells
- Gross DOIIP 697 MMbbls (640 net)
  - Recovered to date = 34.4% (239.5 MMbbls)
  - Possible oil RF = 43 - 46%





The Whitecap Growth Plan

- Long-Term Value Growth Orientation
  - Executing on rolling 3 year business plan
  - Return on capital discipline
  - Provide superior shareholder returns
- Organic Per Share Growth Within Funds Flow
  - Capital + Dividend < Funds Flow
  - Sustainable dividend, NO DRIP
- Maintaining Financial Flexibility
  - Balance sheet strength
  - Unutilized debt capacity

Research Coverage

- AltaCorp Capital
- Barclays Capital Canada
- BMO Capital Markets
- Canaccord Genuity
- CIBC World Markets
- Clarus Securities
- Cormark Securities
- Desjardins Capital Markets
- GMP|FirstEnergy Capital
- Haywood Securities
- Macquarie Securities Group
- National Bank Financial
- Peters & Co.
- Raymond James
- RBC Capital Markets
- Scotiabank Global
- TD Securities

TSX:WCP

WHITECAP RESOURCES INC

www.wcap.ca

December 7, 2016

Footnotes

Slide 2: - Reserves are McDaniel's reserves evaluation effective December 31, 2015 plus Whitecap's internal evaluation of the SW Saskatchewan acquisition effective April 1, 2016.

Slides 2, 8, 11, 13: - 2017 commodity prices used are WTI US$55.00/bbl, C$/US$0.78, Edmonton Par Differential (US-$3.50) and AECO C$3.00/GJ.

Slide 6:
- 2016 commodity prices used are WTI US$43.54/bbl, C$/US$0.76, Edmonton Par Differential (US-$3.37) and AECO C$2.02/GJ.
- 2017 commodity prices used are WTI US$55.00/bbl, C$/US$0.78, Edmonton Par Differential (US-$3.50) and AECO C$3.00/GJ.
- 2018 commodity prices used are WTI US$60.00/bbl, C$/US$0.80, Edmonton Par Differential (US-$3.50) and AECO C$3.00/GJ.
- 2019 commodity prices used are WTI US$65.00/bbl, C$/US$0.82, Edmonton Par Differential (US-$3.50) and AECO C$3.00/GJ.

Slides 7, 9: - F&D calculations are done in accordance with NI 51-101. Refer to Whitecap's 2016 press release dated February 10, 2016 for F&D performance and additional disclosures.

Slides 8, 11: - 2016 commodity prices used are WTI US$43.54/bbl, C$/US$0.76, Edmonton Par Differential (US-$3.37) and AECO C$2.02/GJ.

Slide 10:
- Based on Q4 2016 WTI US$49.00, C$/US$0.75, 2017 WTI US$53.00, C$/US$0.75 and 2018 WTI US$54.00, C$/US$0.75.
- The Q4 2016 average crude oil price includes 16,350 bbls/d swaps at C$72.89 net of 6,000 bbls/d sold puts at US$50.00.
- The 2017 average crude oil price includes 15,500 bbls/d swaps at C$64.99 net of 3,000 bbls/d sold puts at US$60.00.
- The 2018 average crude oil price includes 7,000 bbls/d swaps at C$63.73 net of 3,000 bbls/d sold puts at US$60.00.

Slides 17, 19, 22-23:
- Refer to the Oil and Gas Advisory section of this presentation for additional information on DOIIP.
- Reserves are based on McDaniel's reserve report effective January 1, 2016.
- Possible oil RF calculated as (proven + probable + possible reserves + current production) / DOIIP (all as of January 1, 2016 effective date).

Slides 18-19, 21-22: - New well economics are effective Jan. 1, 2017 and netback price assumptions based on McDaniel's July 1, 2016 escalated price forecast.

Slide 20:
- Refer to the Oil and Gas Advisory section of this presentation for additional information on DOIIP.
- Reserves are based on Whitecap's internal evaluation of the SW Saskatchewan acquisition effective April 1, 2016.

Forward-Looking Statements

Special Note Regarding Forward-Looking Statements and Forward-Looking Information

This presentation contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends" and similar expressions are intended to identify forward-looking information or statements. More particularly and without limitation, this presentation includes forward-looking information and statements about our strategy, plans and focus, future dividends and dividend policy, forecast annual growth rates, the source of funding of dividend payments, planned capital expenditures and the source of funding of our capital program, projected payout ratios and dividend yields, expected future production and product mix, anticipated tax horizon, the quantity and estimated value of reserves, waterflood expansion plans and the results to be obtained therefrom, forecast operating and financial results including funds flow, free funds flow, and operating and cash netbacks, future decline rates, drilling inventories and drilling plans, hedging plans and the benefits to be obtained from our hedging program, anticipated debt levels and our debt to funds flow ratio, forecasted commodity prices and differentials, forecasted exchange rates, anticipated production costs and capital efficiencies and the benefits to be obtained from recent acquisitions.

This presentation contains certain information relating to economics for drilling opportunities in the areas that Whitecap has an interest. Such information includes, but is not limited to, anticipated production rates, anticipated reserves, anticipated capital costs, anticipated finding and development costs, anticipated ultimate reserves recoverable and recycle ratios. Certain of the drilling opportunities identified have no associated reserves or resources which can presently be classified as recoverable. As such the information presented with respect to such drilling opportunities do not represent estimates of future production or estimates of reserves or future net revenue associated with the drilling opportunities. No resources may ultimately be recovered from the drilling opportunities identified herein which have no associated reserves. In addition, references in this presentation to initial production (“IP”) rates and production type curves and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Whitecap.

Additionally, readers are advised that historical results, growth and acquisitions described in this presentation may not be reflective of future results, growth and acquisitions with respect to Whitecap.

The forward-looking statements and information are based on certain key expectations and assumptions made by Whitecap and its management, including expectations and assumptions concerning general economic conditions in Canada, the United States and elsewhere, and oil and gas industry conditions, including applicable royalty rates and environmental and tax laws and regulations. Although Whitecap believes that the expectations and assumptions on which such forward-looking statements and information are based are reasonable as of the date hereof, undue reliance should not be placed on the forward-looking statements and information because Whitecap can give no assurance that they will prove to be correct.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks including, but not limited to the risks associated with the oil and gas industry in general.

Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements and information contained in this presentation are made as of the date hereof and Whitecap undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Oil and Gas Advisory

"Boe" means barrel of oil equivalent on the basis of 6 mcf of natural gas to 1 bbl of oil. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6: 1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

The estimated values of the future net reserves of the reserves disclosed in this presentation do not represent the market value of such reserves. The estimates of reserves and future net reserve for individual properties may not reflect the same confidence level as estimates of reserves and future net reserve for all properties due to the effects of aggregation.

This presentation contains references to estimates of oil classified as Discovered Oil Initially In Place ("DOIIP") which are not, and should not be confused with, oil reserves. DOIIP is defined in the Canadian Oil and Gas Evaluation Handbook as the quantity of oil that is estimated to be in place within a known accumulation prior to production. DOIIP is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as reserves and contingent resources and the remainder as at evaluation date is by definition classified as unrecoverable. The accuracy of resource estimates is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. The size of the resource estimate could be positively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir is larger than what is currently estimated based on the interpretation of seismic and well control. The size of the resource estimate could be negatively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir are less than what is currently estimated based on the interpretation of the seismic and well control.

Contingent resources are those quantities of oil estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. All contingent resources represented in this document are considered Economic Contingent Resources based on the McDaniel & Associates Consultants Ltd. January 1 Price Forecast and an economic hurdle rate of the before tax net present value at a discount rate of 10% being greater than 0 (i.e. ROR >= 10%). The primary contingency which prevents the classification of Whitecap's contingent resources as reserves is capital budgeting restraints that allow the resources to be developed within a reasonable time frame. This time frame can be defined as 3 – 4 years. As additional drilling and/or development takes place, it is expected that some or all of the contingent resources will be booked as reserves.

The best estimate of the contingent resources is determined on the basis that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will be equal or exceed the best estimate. The remainder of the DOIIP beyond what has been cumulatively produced, classified as proved plus probable plus possible reserves, or classified as contingent resource is currently considered to be the unrecoverable portion.

Estimates of DOIIP and contingent resources described herein are estimates only; the actual resources may be higher or lower than those calculated in the independent evaluation. *There is no certainty that it will be economically viable to produce any portion of the resources.* The estimates of COOIP and Economic Contingent Resources have been prepared internally by a qualified reserves evaluator in accordance with NI 51-101 and the COGEH handbook and are effective as of January 1, 2013. The estimates of Reserves presented herein have been prepared by McDaniel & Associates Consultants Ltd., Whitecap's independent qualified reserves evaluator.

Non-GAAP Financial Measures

NON-GAAP MEASURES

This presentation includes non-GAAP measures as further described herein. These non-GAAP measures do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS or, alternatively, "GAAP") and therefore may not be comparable with the calculation of similar measures by other companies.

"Cash dividends per share" represents cash dividends declared per share by Whitecap.

"Cash netbacks" are determined by deducting general and administrative expense and cash interest from operating netbacks.

"Cash interest" is determined by deducting unrealized interest hedging gains from or adding unrealized interest hedging losses to interest and finance expense.

"Development capital" represents expenditures on PP&E excluding corporate and other assets.

"Free funds flow" is determined by deducting development capital and dividend payments from funds flow.

"Funds flow" represents cash flow from operating activities adjusted for changes in non-cash working capital and transaction costs. Management considers funds flow per share to be key measures as they demonstrate Whitecap's ability to generate the cash necessary to pay dividends, repay debt and make capital investments. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow provides a useful measure of Whitecap's ability to generate cash that is not subject to short-term movements in non-cash operating working capital.

"Net debt" is calculated as bank debt plus working capital deficiency adjusted for the current portion of risk management contracts. Net debt is used by management to analyze the financial position and leverage of Whitecap.

"Net debt to funds flow" is calculated as net debt divided by funds flow.

"Operating netbacks" are determined by deducting hedging losses or adding hedging gains and deducting royalties, production expenses, transportation expenses, Alberta Carbon Tax and settlement of decommissioning liabilities from oil and gas revenue. Operating netbacks are per boe measures used in operational and capital allocation decisions.

"Total Payout Ratio" is calculated as development capital plus cash dividends declared divided by funds flow.