



ATHABASCA OIL CORPORATION

FOCUSED | EXECUTING | DELIVERING

SEPTEMBER 2016 CORPORATE UPDATE

ATHABASCA
OIL CORPORATION

Information about Athabasca Oil Corporation (“Athabasca” or the “Company”) contained in this presentation, including management’s assessment of the Company’s future plans and operations, contains certain forward-looking information and forward-looking statements.

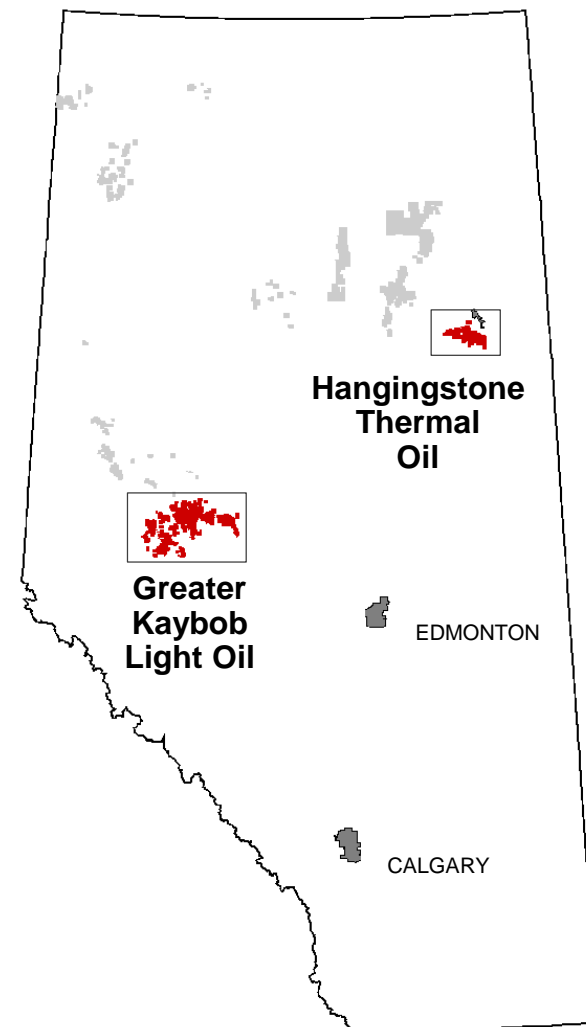
The projections, estimates and beliefs contained in such forward-looking information and statements necessarily involve a number of assumptions and are subject to known and unknown risks and uncertainties, which may cause Athabasca’s actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements.

The material assumptions, risks and uncertainties regarding such forward-looking information and statements are outlined in the additional advisories contained at the end of this document.

ATHABASCA INVESTMENT HIGHLIGHTS

<p>CORE ASSETS</p>	<p><u>Light Oil – JV with Murphy Oil Corporation</u></p> <ul style="list-style-type: none"> ○ Scalable Montney position at Placid (60k acres, 70% WI) ○ Funded Duvernay development at Kaybob (200k acres, 30% WI) <p><u>Thermal Oil</u></p> <ul style="list-style-type: none"> ○ Hangingstone 12,000 bbl/d SAGD thermal project ○ Cash flow torque and future low risk expansion options
<p>TRACK RECORD</p>	<ul style="list-style-type: none"> ○ 2015 exit 15,200 boe/d (76% liquids); >25% 5 year CAGR ○ Industry leading Montney & Duvernay well costs ○ Successful Hangingstone Phase 1 SAGD
<p>STRONG BALANCE SHEET</p>	<ul style="list-style-type: none"> ○ \$608MM liquidity* & \$83MM net cash ○ \$218MM 5-year capital carry in the Duvernay
<p>FUNDED GROWTH</p>	<ul style="list-style-type: none"> ○ Montney – no near-term land expiries, egress in place ○ Duvernay – strong land tenure, egress in place, proven North American shale partner ○ Hangingstone – capital efficient debottleneck opportunity

ALBERTA ASSETS



*Liquidity includes cash (excl. collateralized LC) & short term investments in August 2016

OUR PATH FORWARD

DEFINED & MATERIAL LIGHT OIL GROWTH

- Scalable Montney position
- Funded Duvernay development

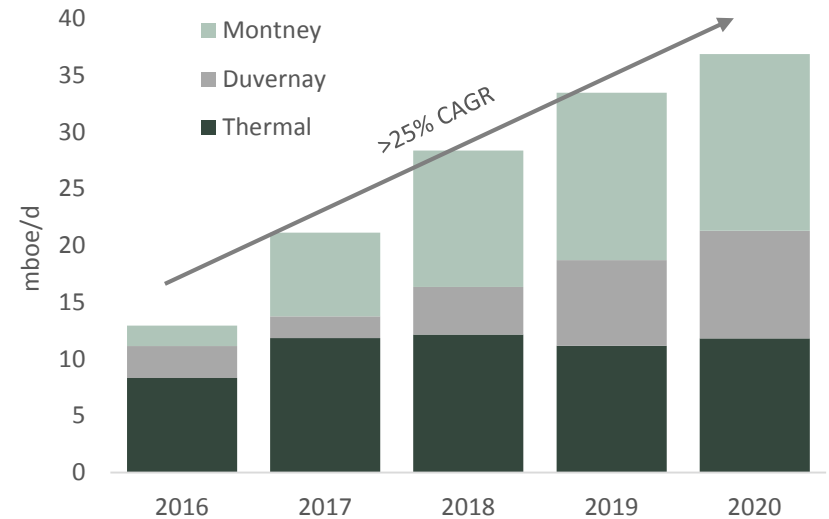
THERMAL LEVERAGE TO OIL PRICES

- Cash flow torque at Hangingstone
- Low decline asset
- Future low risk expansion options

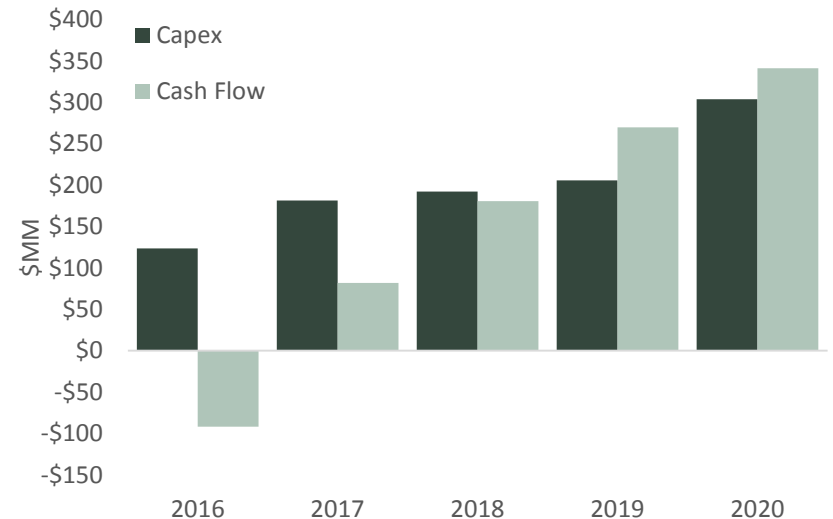
FINANCIAL SUSTAINABILITY

- Ensure sufficient liquidity
- Maintain flexibility

PRODUCTION



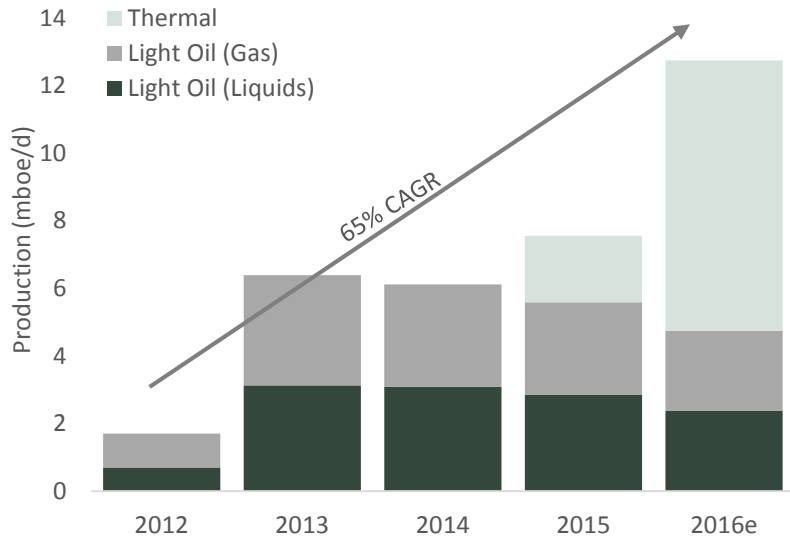
CASH FLOW AND CAPEX



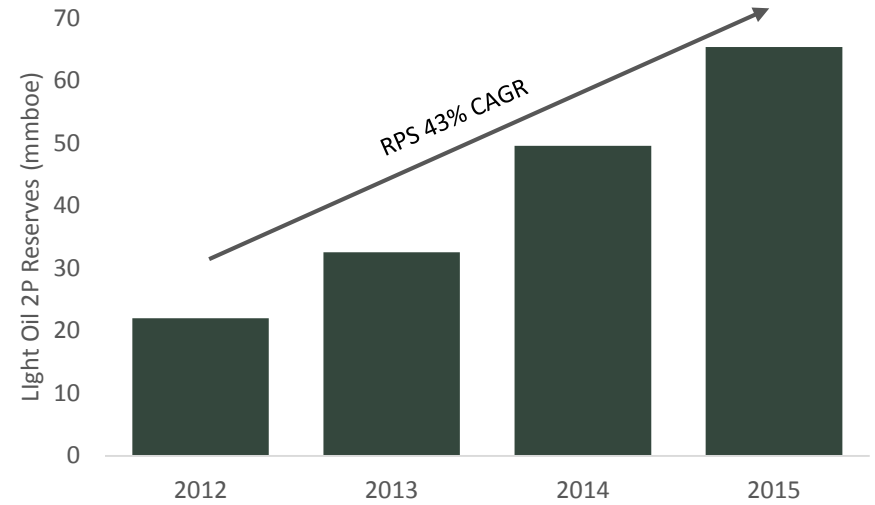
July 2016 GLJ pricing¹, numbers net to AOC. Capex & CF assumes Montney upside development scenario, CF assumes debt reduction targets

EXECUTION TRACK RECORD

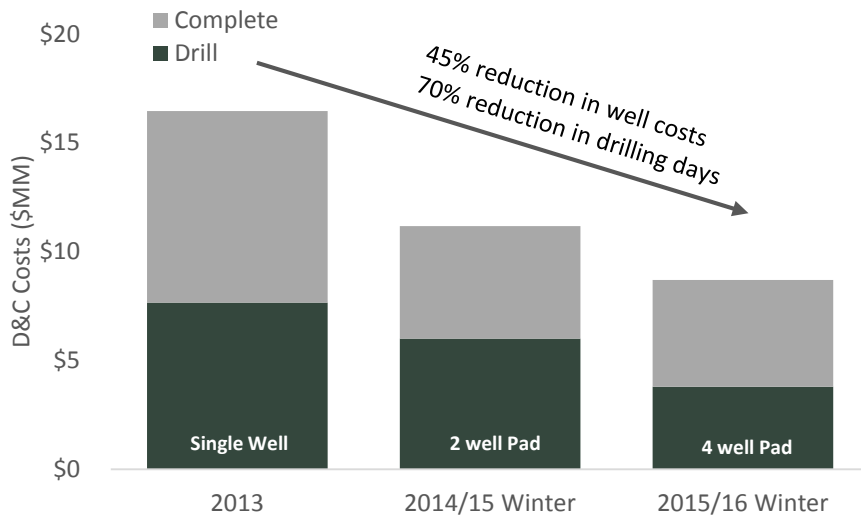
PRODUCTION



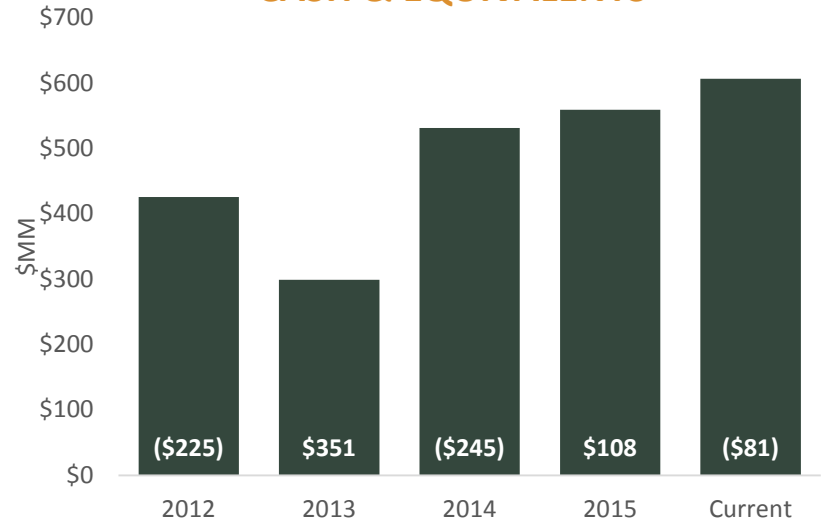
LIGHT OIL RESERVES



DUVERNAY WELL COSTS



CASH & EQUIVALENTS



Cash & equivalents as at year-end unless otherwise indicated
Labeled with net debt

2016 GUIDANCE AND CAPITALIZATION

2016 GUIDANCE

○ CAPITAL

Corporate \$121MM *(incl. \$8MM cap. G&A)*

Light Oil: \$102MM

Thermal Oil: \$11MM

○ PRODUCTION

Corporate 12.0 – 13.5 mboe/d (81% liquids)

Light Oil: 4.5 – 5.0 mboe/d (50% liquids)

Thermal Oil: 7.5 – 8.5 mbb/d

○ FINANCIAL OUTLOOK *(strip Pricing July 5th, 2016)*

Corporate CF: -\$99MM

Light Oil CF: \$25MM

Thermal Oil CF: -\$50MM *(currently in ramp-up phase)*

Net Debt: ~\$35MM

CAPITALIZATION (ATH-TSX)

Share Price (Sept. 8, 2016)	\$1.30	\$/sh
Basic shares outstanding	406	MM
Market capitalization	\$525	MM
August Net Debt / (Cash)	(\$83)	MM
Total enterprise value	\$442	MM
August Liquidity*	\$608	MM
Long term debt	\$550	MM
Tax pools	~\$2,300	MM

*Liquidity includes cash (excl. collateralized LC), cash equivalents and short term investments

LIGHT OIL JOINT VENTURE WITH MURPHY OIL

STRATEGIC RATIONALE

- **Corporate**
 - Reduce development risk profile while maintaining upside potential
 - Strengthen balance sheet and facilitate debt refinancing
- **Montney**
 - Material operated land position with flexibility to control pace of development
- **Duvernay**
 - Partner/operator is an experienced player in the Eagle Ford (700+ oil wells drilled to date)
 - Accelerate delineation of the volatile oil window
 - Limit near-term capital exposure through carry provision

\$800MM LIGHT OIL JOINT VENTURE

- Greater Placid Assets – AOC 70% WI & operator; 60,000 gross Montney acres
- Greater Kaybob Assets – MUR 70% WI & operator; 200,000 gross Duvernay acres
- \$486MM net consideration to AOC
 - \$267MM cash & \$218MM Duvernay carry
- Closed May 13, 2016

CONTINGENT BITUMEN ROYALTY

HIGHLIGHTS

- Contingent bitumen royalty on thermal assets
- Gross proceeds of \$129MM

ROYALTY OVERVIEW

- Sliding scale structure between 0 – 6%

Minimum WTI of ~US\$75/bbl before royalty triggered

- Based on realized bitumen pricing

Net of diluent, transport and storage costs

FUTURE EXPANSION PHASES & PROJECTS

- Limited impact on future project returns
- No commitments to future development phases
- Higher pricing threshold on greenfield assets

SLIDING SCALE PRICING

Hangingstone Project 1			Other Thermal		
Realized Bitumen Price	Royalty	Implied WTI*	Realized Bitumen Price	Royalty	Implied WTI*
\$C/bbl	%	US\$/bbl	\$C/bbl	%	US\$/bbl
<50	0		<60	0	
50-70	1	75-91	60-80	1	78-94
70-90	2	91-108	80-100	2	94-110
\$90-110	3	108-124	100-120	3	110-126
110-130	4	124-141	120-140	4	126-142
130-150	5	141-157	140-160	5	142-159
>150	6	>157	>160	6	>159

**implied WTI based on a 0.8 US\$/C\$ FX assumption and a US\$15/bbl heavy differential*

HS PROJECT 1 NETBACK EXAMPLES

US\$ WTI	\$60	\$75	\$100
C\$	\$/bbl	\$/bbl	\$/bbl
Dilbit Sales	\$70	\$95	\$136
Diluent Cost	-\$28	-\$34	-\$45
Transportation	-\$9	-\$9	-\$9
Realized Bitumen Pricing	\$33	\$51	\$82
Crown Royalties	-\$1	-\$3	-\$8
Royalty	\$0	-\$1	-\$2
Operating Costs	-\$19	-\$19	-\$19
Operating Netback	\$13	\$29	\$54
Annual Royalty %	0%	1%	2%
Annual Royalty Payment	\$0	\$2	\$7
Annual Operating Income	\$53	\$121	\$228

Assumptions: 12,000 bbl/d design capacity, 0.8 US\$/C\$ FX, US\$15/bbl heavy differential and C\$2/mcf AEEO, \$/bbl are based on per bbl of Bitumen



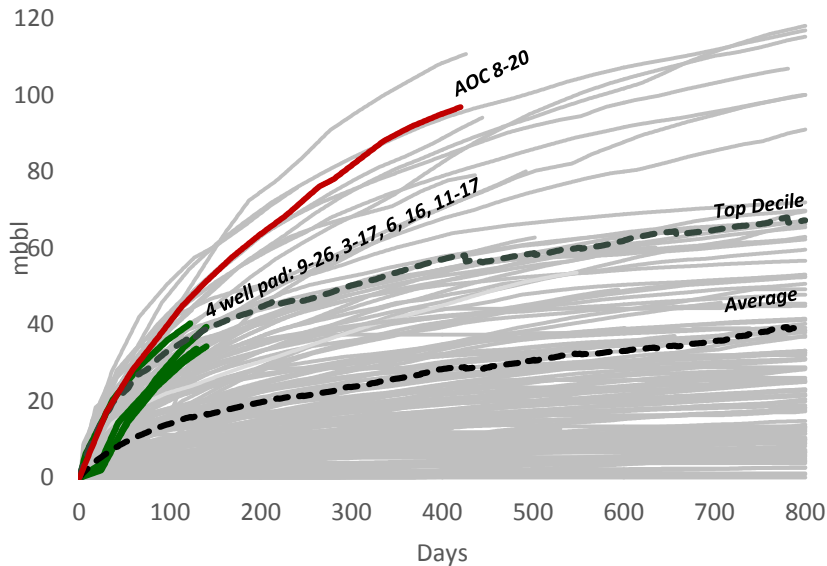
MONTNEY OVERVIEW

REGIONAL MONTNEY OVERVIEW

HIGHLIGHTS

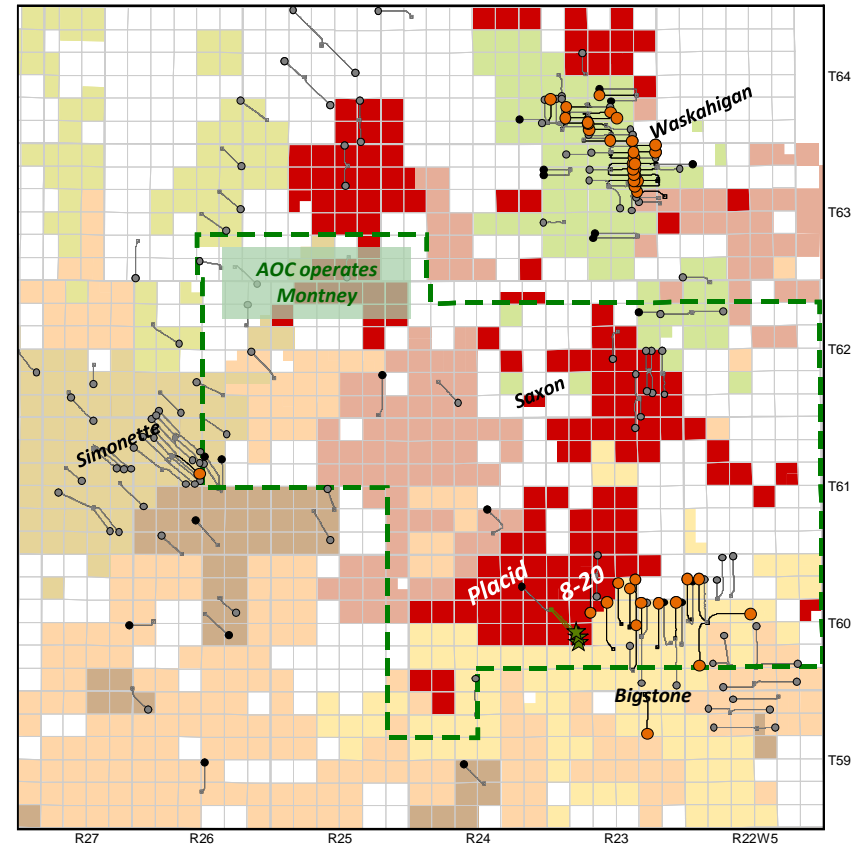
- ~200 Montney wells on production regionally
- Top wells concentrated at Placid, Bigstone and Waskahigan
- Appraisal campaign validates liquids rich sweet spot at Placid
- Initial free liquids 200 – 300 bbl/mmcf

FREE LIQUIDS PRODUCTION



Source: Athabasca, goeSCOUT

MONTNEY ACTIVITY & IP90 HEAT MAP



IP90 Free Liquids:

- Top Quartile
- Second - Bottom Quartile
- NA information

Montney Rights:

- AOC
- RMP
- Cequence
- XTO
- Delphi
- Encana
- ConocoPhillips
- CIOC

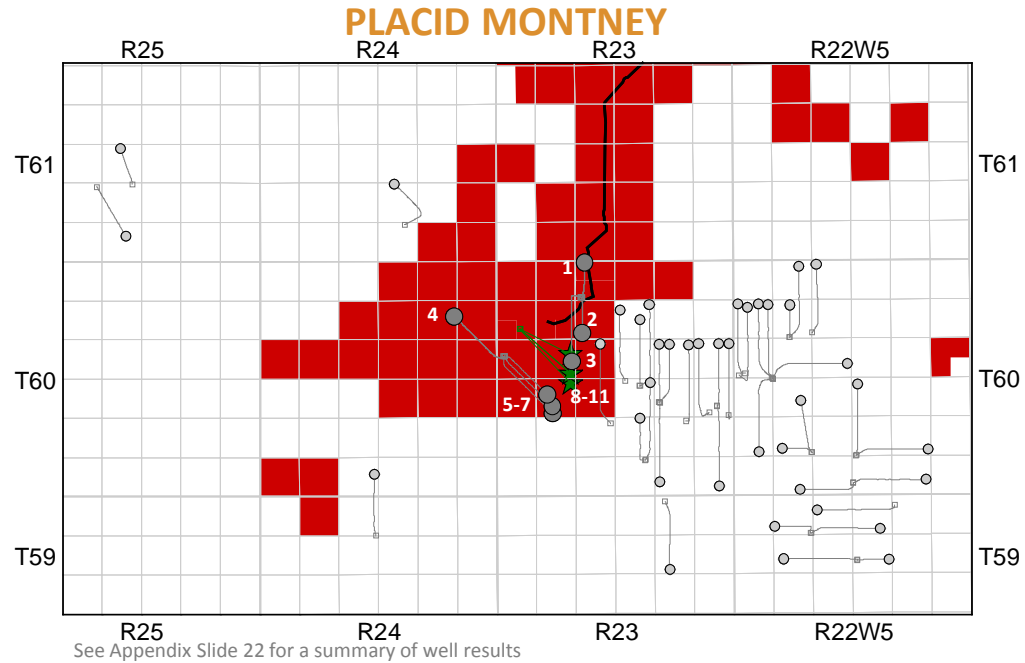
PLACID MONTNEY – TOP QUARTILE LAND

ASSET HIGHLIGHTS (70% WI)

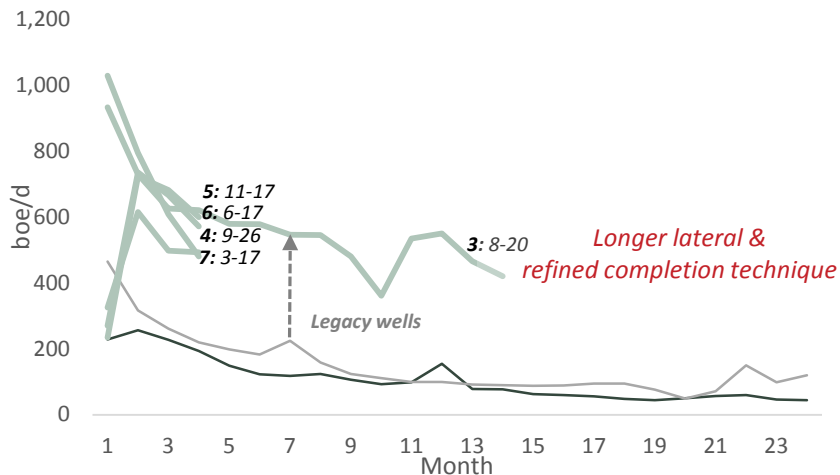
- 25,000 acres
- Prospectivity in two Montney cycles
 - 90 Montney C / 75 Montney D locations¹

RECENT ACTIVITY

- 5 wells to date
 - IP30/90 805 boe/d / 686 boe/d (56% liquids)
- H2 2016 activity (\$66MM)
 - 12 spuds, 4 completions, long lead commitments on an oil battery



WELL DESIGN DRIVING PRODUCTION



ILLUSTRATIVE ECONOMICS²

		US \$40/bbl WTI	US \$50/bbl WTI
Type Curve IP 30 (restricted)	boe/d	~800	
Type Curve EUR	mboe	~550 (45% liquids)	
Capital Efficiency (IP 365)	\$/boe/d	~\$13,000	
Netback	\$/boe	\$20	\$25
Capex	\$MM	\$7-8	
IRR	%	21%	40%
NPV	\$MM	\$1.3	\$3.3
Payout	months	35	24

C\$2.50/GJ flat AECO, lease edge economics
Footnotes and additional information included in the back as endnotes.

SCALABLE MONTNEY POSITION

- AOC operates with a 70% WI

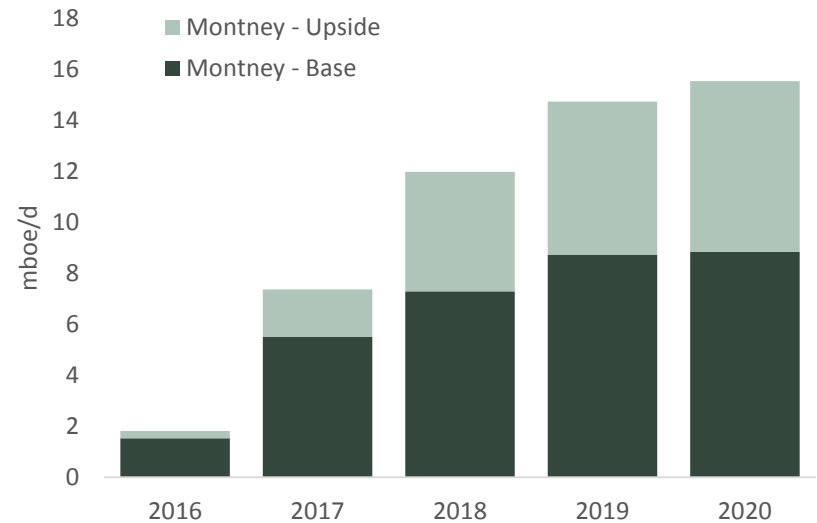
- **Production potential**

- 2017e ~10,000 boe/d gross
~7,000 boe/d net
- 2020e ~20,000 boe/d gross
~14,000 boe/d net

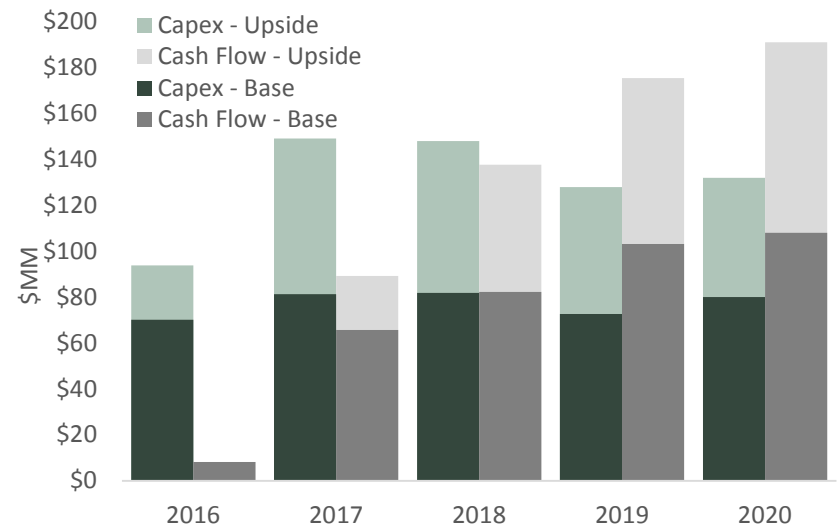
- **Development goals**

- Flexibility to accelerate development
- Achieve self-funding in the mid-term

PRODUCTION PROFILE (NET)



CASH FLOW & CAPITAL PROFILE (NET)



Notes: July 2016 GLJ pricing



DUVERNAY OVERVIEW

THE DUVERNAY – A WORLD CLASS RESOURCE

WORLD CLASS RESOURCE	<ul style="list-style-type: none"> ○ Large in place resource ○ High liquids yield: 100 -1,000 bbl/MMcf liquids ○ Initial results compare favorably to the Eagle Ford ○ Major E&Ps active in the play
DUVERNAY ADVANTAGE	<ul style="list-style-type: none"> ○ Premium pricing on condensate – strong local market ○ Well situated to services and infrastructure
AOC ADVANTAGE	<ul style="list-style-type: none"> ○ 30% WI in 200,000 acres across the liquids fairway ○ Joint venture with \$218MM 5 year capital carry ○ Excellent land tenure – ability to control pace ○ Strategic ownership of key infrastructure
MATERIALITY	<ul style="list-style-type: none"> ○ High Duvernay exposure relative to market cap ○ ~1,500 gross potential well inventory¹ ○ Opportunity to accelerate production & cash flow growth

UNCONVENTIONAL PLAYS IN NORTH AMERICA



LEGEND

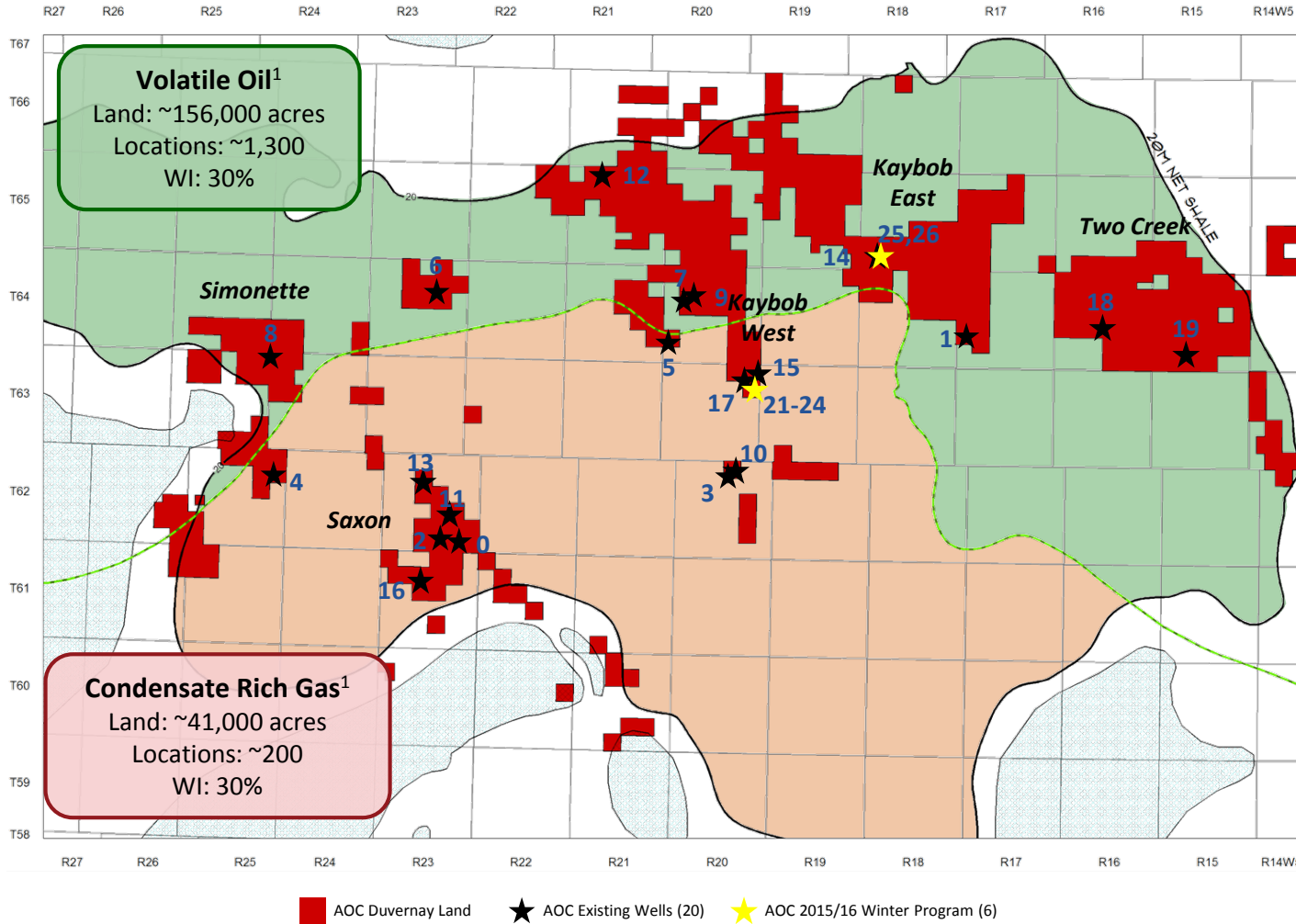
- Unconventional / Tight Liquids-Rich Gas Resource Plays

DUVERNAY ESTIMATED HYDROCARBONS IN PLACE²

- 443 Tcf of natural gas
- 11.3 Bbbl of NGLs
- 61.7 Bbbl of oil

KAYBOB DUVERNAY - LIQUIDS AND OVERPRESSURE DRIVES ECONOMICS

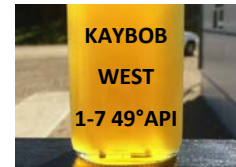
GREATER KAYBOB DUVERNAY EXPOSURE



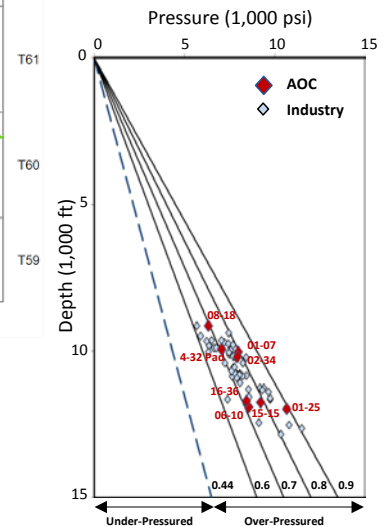
Volatile Oil¹
 Land: ~156,000 acres
 Locations: ~1,300
 WI: 30%

Condensate Rich Gas¹
 Land: ~41,000 acres
 Locations: ~200
 WI: 30%

HIGH QUALITY LIQUIDS



OVERPRESSURED

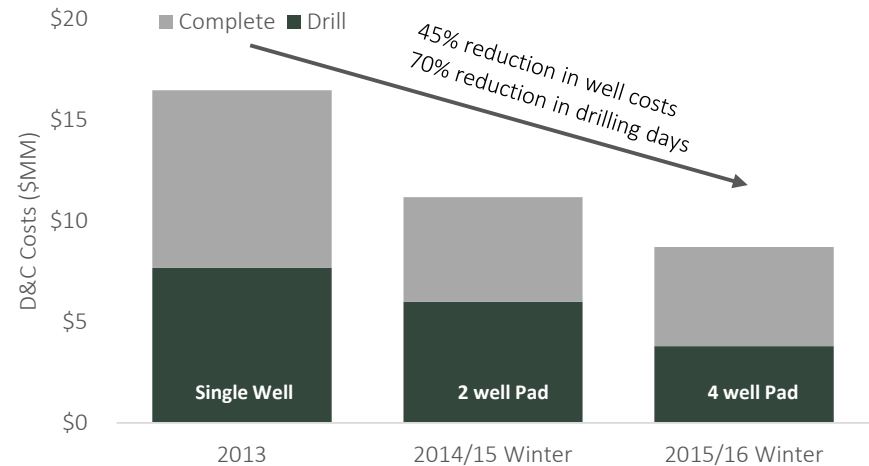


See Slide 24 for a summary of well results
 Footnotes and additional information included in the back as endnotes.

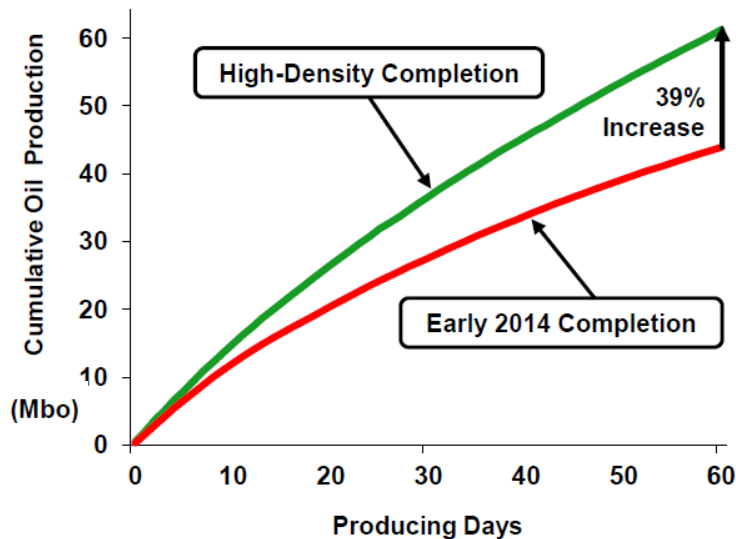
HIGHLIGHTS

- 95% of acreage held into the intermediate term
- 2 well volatile oil proppant test
 - 40% uplift in initial production
 - 02/16-16 758 boe/d IP30 (~2,000 lbs/ft)
 - 00/16-16 541 boe/d IP30 (~1,100 lbs/ft)
- 4 well pad at Kaybob West
 - ~\$9.5MM well cost @ ~2,000lb/ft
 - Q4/16 expected on-stream

KAYBOB WEST WELL COSTS

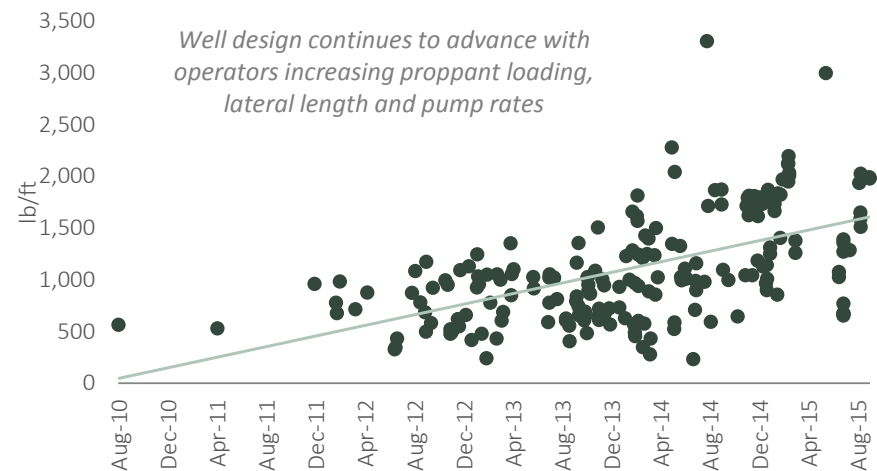


EAGLE FORD COMPLETION ANALOG



Source: EOG Resources

DUVERNAY PROPPANT LOADING



Source: Canadian Discovery

FUNDED DUVERNAY DEVELOPMENT

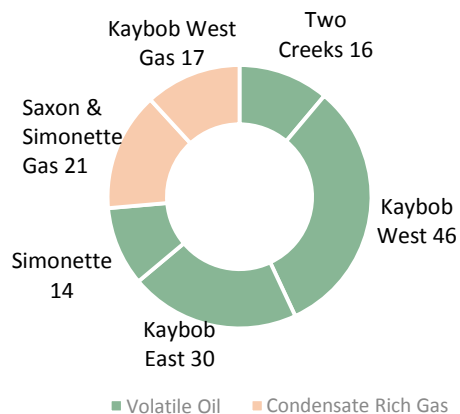
Development goals

- 1,500 gross well potential
- Achieve self funding post carry period
- Continue to drive cost efficiencies with multi-well pad operations

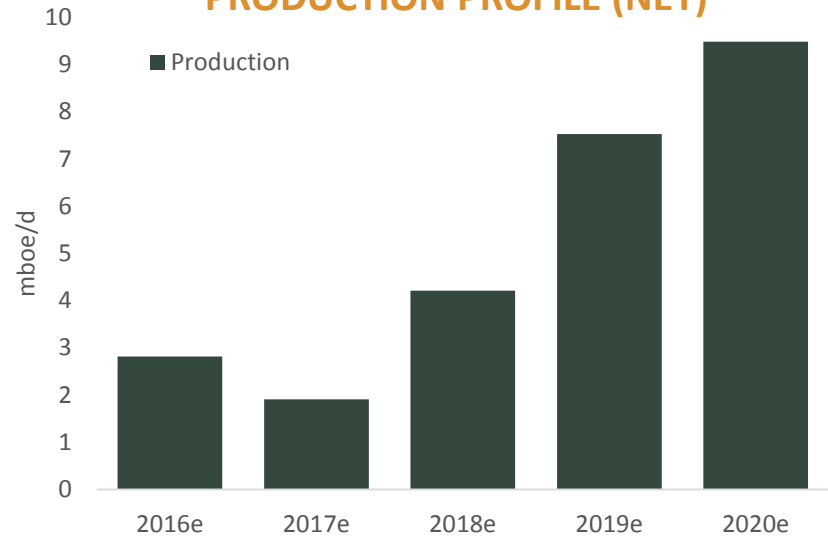
JV highlights

- MUR funds 75% of AOC's 30% WI
\$75MM capital exposure on the first \$1B
- A minimum annual capital amount will be paid by Murphy to Athabasca*

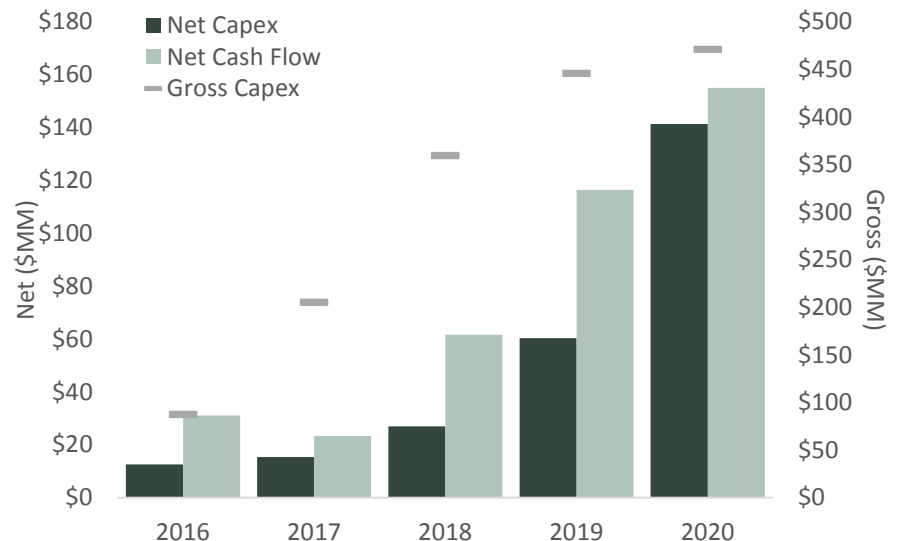
4 YEAR DRILLING PLAN



PRODUCTION PROFILE (NET)



CASH FLOW & CAPITAL PROFILE



Notes: July 2016 GLJ pricing, numbers net to AOC

*a minimum annual capital amount will be paid by Murphy to Athabasca to offset the carry commitment the event the carry is not paid through the development plan



HANGINGSTONE OVERVIEW

HANGINGSTONE – DEVELOPMENT OVERVIEW

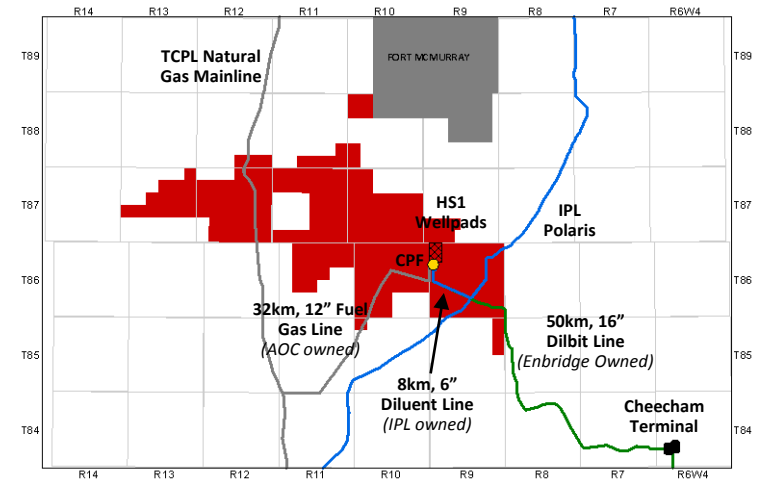
HANGINGSTONE PROJECT 1 (12,000 BBL/D)

- First steam at the end of Q1 2015
- 18 – 24 mo. to reach design capacity post start-up
- Stable production for ~35 years

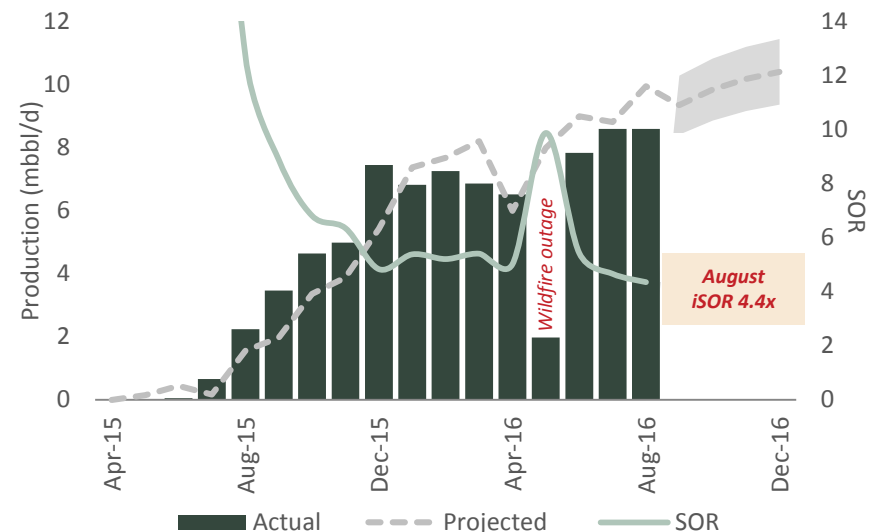
LONG-TERM POTENTIAL

- 80,000 bbl/d potential (4 phases)¹
- Regional infrastructure in place for expansion
- Potential HS2A 8,000 bbl/d debottleneck
 - Sanctioning considered following ramp-up, funding certainty & market conditions
 - ~\$30-35k/bbl/d capital efficiency

REGIONAL MAP



PRODUCTION RAMP UP

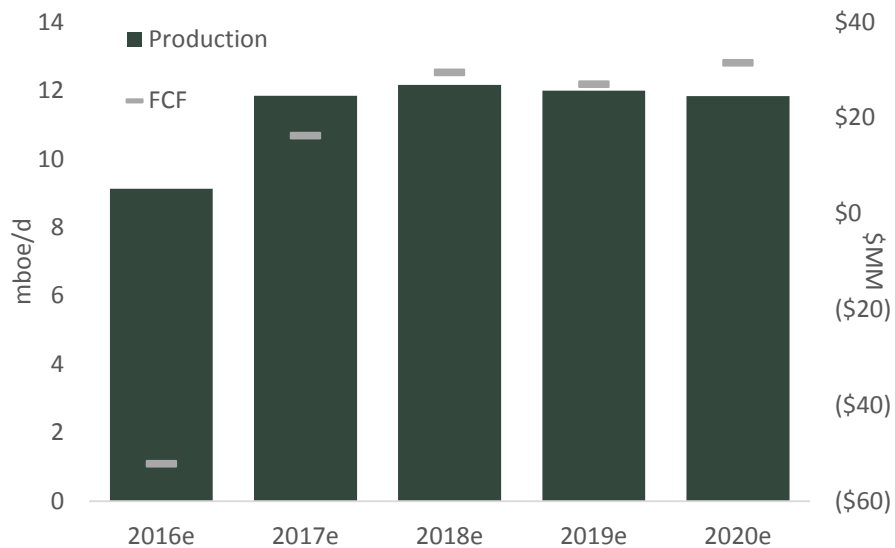


CASH FLOW TORQUE AT HANGINGSTONE

HIGHLIGHTS

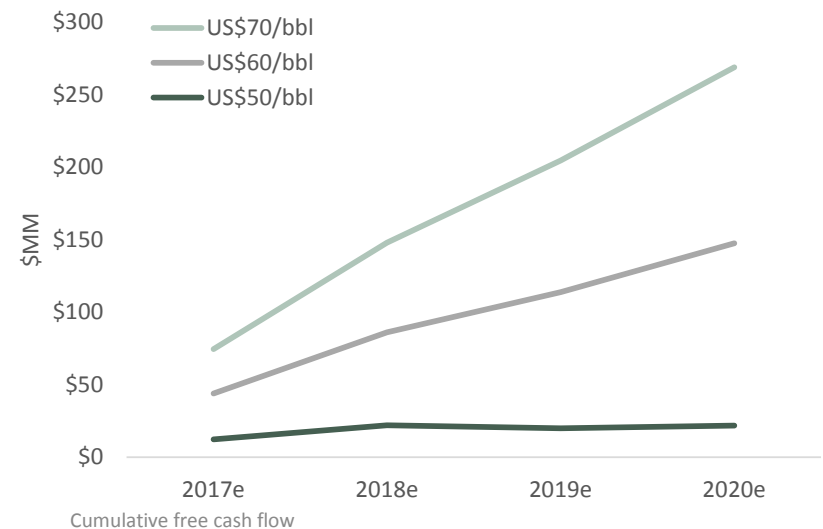
- ~US\$45/bbl WTI operating break-even
- Not expected to drill infill wells for the initial 5 - 7 years

PRODUCTION & FCF PROFILE



July 2016 GLJ pricing, \$10MM annual thermal capex

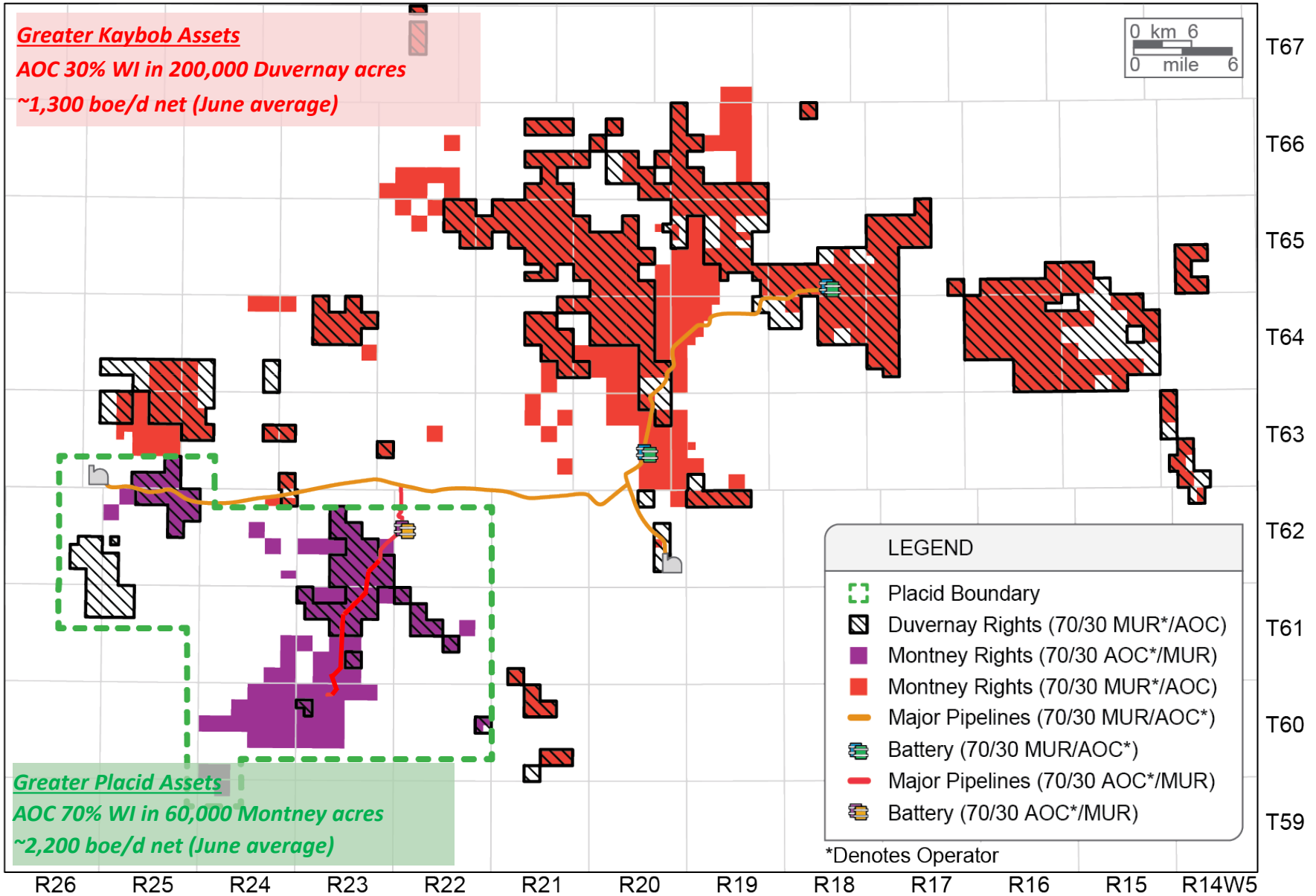
5 YR FREE CASH FLOW OUTLOOK



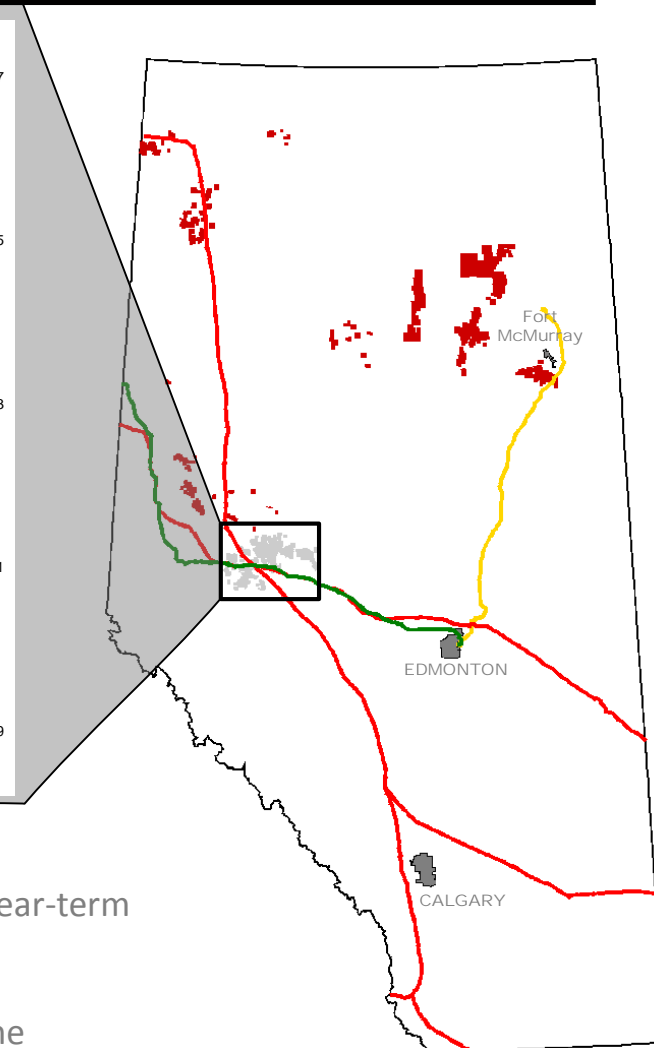
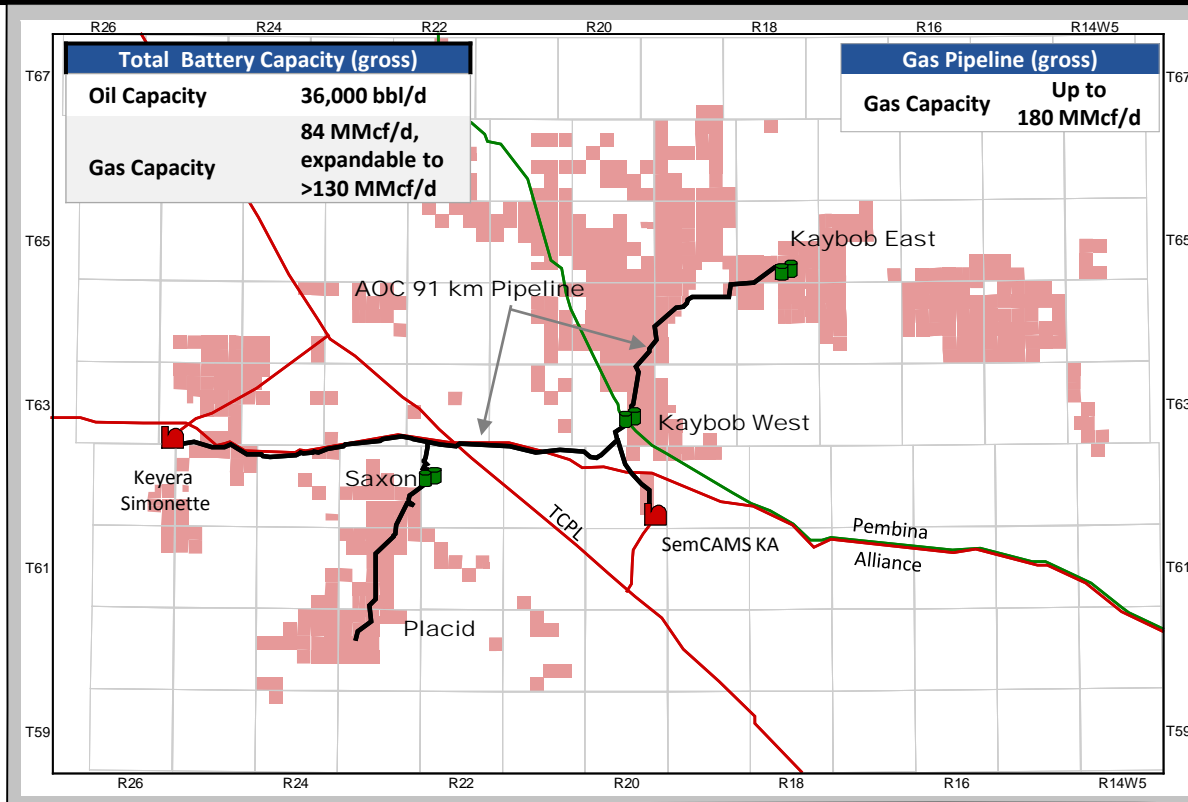


SUPPLEMENTAL INFORMATION

JOINT VENTURE MAP



CONTROL OF STRATEGIC INFRASTRUCTURE



- AOC retains operatorship of the regional midstream infrastructure in the near-term
- 91km gas pipeline; dually connected to regional gas plants
- 3 batteries process field condensate; connected to Pembina’s Peace Pipeline
- Flexibility with takeaway options; scalable for future growth

- Gas pipelines (TCPL/Alliance)
- Oil pipelines (Pembina)
- Diluent pipelines (Inter Pipeline)

PLACID MONTNEY WELL SUMMARY

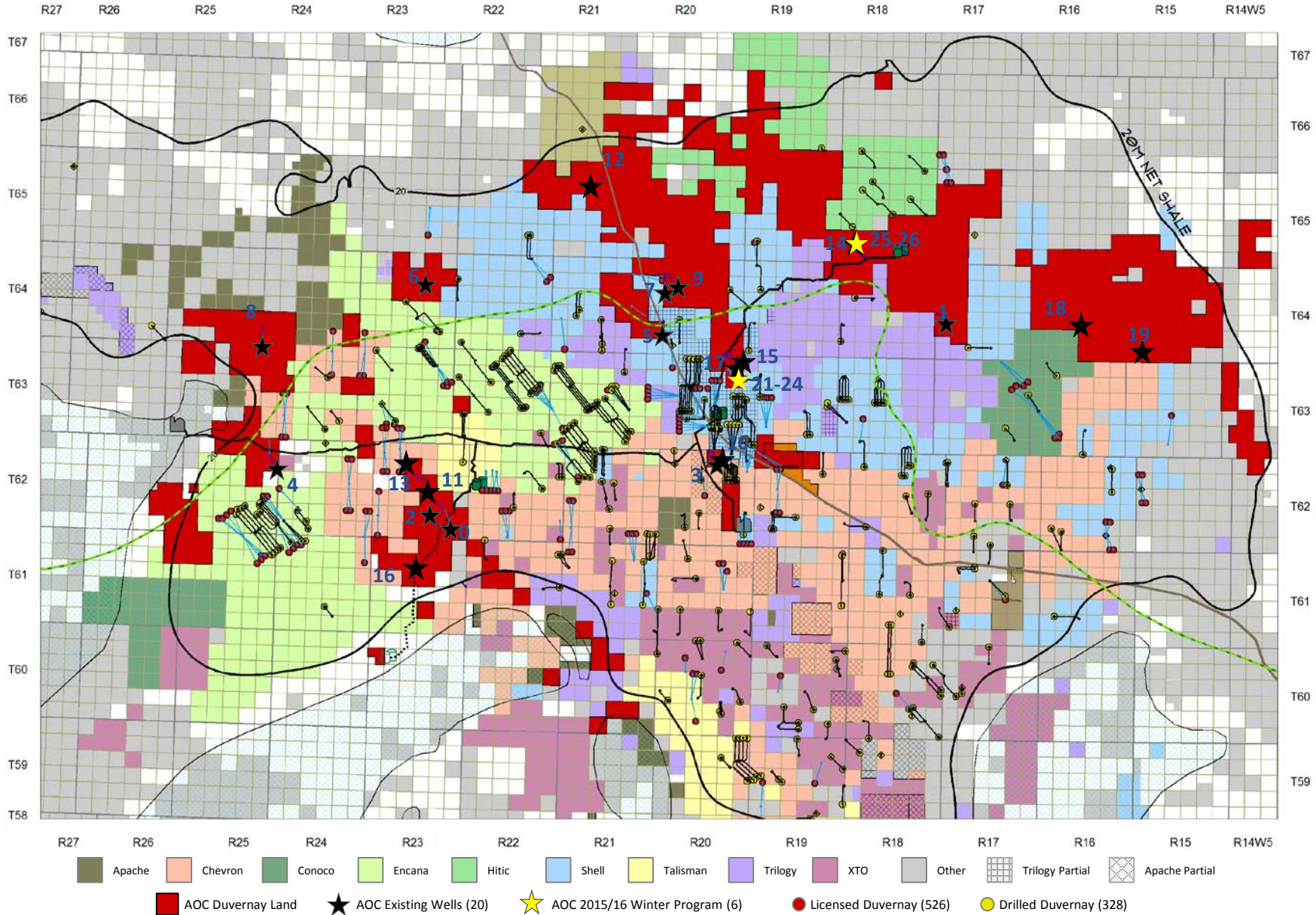
Well	UWI	Key Dates			Completions Summary			Production**					
		Spud	On Prod.	Spud - RR	Lateral	Stages	Proppant Loading	IP30***			Cum. Production To Date		
#		mmm-yy	mmm-yy	days	m	#	lb/ft	boe/d	% liquids	bbl/mmcft*	mboe	% liquids	bbl/mmcft*
Legacy Wells:													
1	02/13-33-060-23W5/2	Jun-11	Dec-11	46	1,195	15	161	416	48%	157	94	32%	66
2	00/04-28-060-23W5/0	Jan-12	Jul-12	32	1,154	14	258	412	57%	222	124	40%	93
2014/15 Winter Program:													
3	00/08-20-060-23W5/0	Nov-14	Mar-15	44	2,214	23	607	899	65%	270	232	50%	130
4	02/09-26-060-24W5/2	Dec-14	Mar-16	52	2,062	23	640	1,070	62%	216	78	60%	169
2015/16 Winter Program:													
5	00/11-17-060-23W5/0	Sep-15	Apr-16	22	2,156	31	966	733	67%	278	69	60%	207
6	00/06-17-060-23W5/0	Sep-15	Apr-16	22	2,589	25	649	752	59%	194	67	54%	159
7	00/03-17-060-23W5/0	Sep-15	Apr-16	27	2,765	30	729	573	67%	270	48	61%	211
2015/16 Winter Program:													
8	00/16-17-060-23W5/0	Jul-16											
9	00/01-20-060-23W5/0	Jul-16											
10	02/01-20-060-23W5/0	Jul-16											
11	02/09-20-060-23W5/0	Jul-16											

* Includes free condensate/oil only on Raw gas

** All production data as of June 30, 2016

*** IP30 rates are based on estimated sales volumes including NGL's, excluding days with zero production, once the production is going through AOC facilities (post testing/completions cleanup)

KAYBOB DUVERNAY ACTIVITY UPDATE



KAYBOB DUVERNAY WELL SUMMARY

Duvernay Well Summary													
Well	UWI	Key Dates		Drilling Summary		Completions Summary		Production***					
		Spud	On Prod.	Spud - RR	Lateral	Stages**	Proppant Loading	IP30****			Cum. Production To Date		
#		mmm-yy	mmm-yy	days	m	#	lb/ft	boe/d	% liquids	bbl/mmcft*	mboe	% liquids	bbl/mmcft*
2011/12 Program:													
0	04-02-062-23W5	Oct-11		42				Vertical strat test; producing from the Montney					
1	08-18-064-17W5	Jan-12	Mar-12	29	1,238	12	717	775	87%	1,163	128	81%	555
2	06-10-062-23W5	Feb-12	Sep-12	64	1,140	9	499	600	51%	175	151	37%	70
3	02-34-062-20W5	Aug-12	Nov-12	53	1,248	14	997	1,350	60%	245	523	54%	127
2013/14 Winter Program:													
4	01-25-062-25W5	Sep-13	Mar-14	53	1,288	16	1,212	1,461	65%	315	254	52%	161
5	01-07-064-20W5	Sep-13	Feb-14	46	1,636	17	1,246	750	74%	475	232	59%	149
6	13-23-064-23W5	Nov-13	-	29				Vertical Land Retention Well					
7	04-29-064-20W5	Nov-13	Apr-14	36	1,315	17	1,238	615	81%	710	110	72%	288
8	16-36-063-25W5	Dec-13	Dec-14	63	1,485	14	1,044	337	88%	1,235	47	82%	738
9	08-29-064-20W5	Jan-14	Mar-14	33	1,572	16	859	784	82%	763	161	77%	406
2014/15 Winter Program:													
10	08-34-062-20W5	Oct-14	Jan-15	60	1,350	14	1,046	617	53%	189	225	49%	97
11	15-15-062-23W5	Oct-14	Jul-15	70	1,602	16	1,143	851	57%	189	130	44%	79
12	14-33-065-21W5	Oct-14		43				Vertical Land Retention Well					
13	12-28-062-23W5	Nov-14	Nov-15	78	1,701	16	1,289	1,380	62%	269	111	58%	149
14	02-07-065-18W5	Nov-14		40				Horizontal Land Retention Well					
15	08-36-063-20W5	Dec-14	Nov-15	36	1,564	14	1,077	581	74%	417	64	61%	198
16	01-28-061-23W5	Jan-15		31				Vertical Land Retention Well					
17	01-36-063-20W5	Jan-15	Nov-15	37	1,963	19	1,027	781	73%	395	108	63%	229
18	01-16-064-16W5	Feb-15		43				Horizontal Land Retention Well					
19	13-05-064-15W5	Feb-15		23				Vertical Land Retention Well					
20	13-28-062-23W5							Deferred Drilling					
2015/16 Winter Program:													
21	02-25-063-20W5	Oct-15		20	1,057	22	2,094						Q4 On Production
22	02/01-25-063-20W5	Oct-15		18	1,485	25	1,950						Q4 On Production
23	03/01-25-063-20W5	Oct-15		16	1,425	30	2,118						Q4 On Production
24	09-25-063-20W5	Oct-15		17	1,137	24	1,815						Q4 On Production
25	16-06-065-18W5	Sep-15	Feb-16	17	1,425	15	1,190	541	88%	1,000	38	82%	532
26	02/16-06-065-18W5	Sep-15	Feb-16	13	1,311	19	2,035	758	86%	825	53	78%	410

* Includes free condensate only

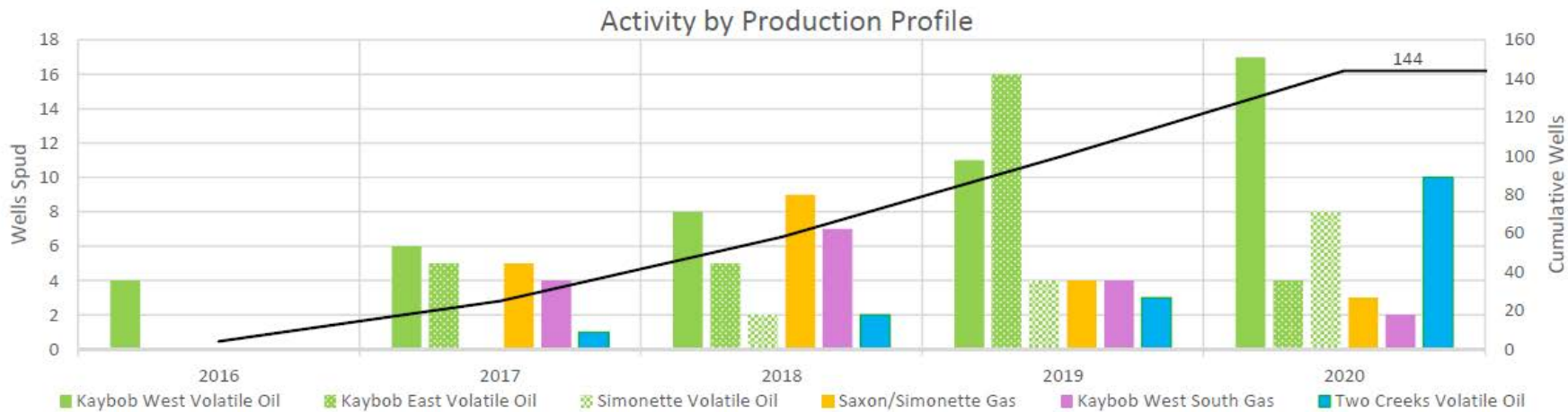
** Typically 4 clusters per stage

*** All production data as of June 30, 2016; may differ from public data in some cases due to single stream reporting

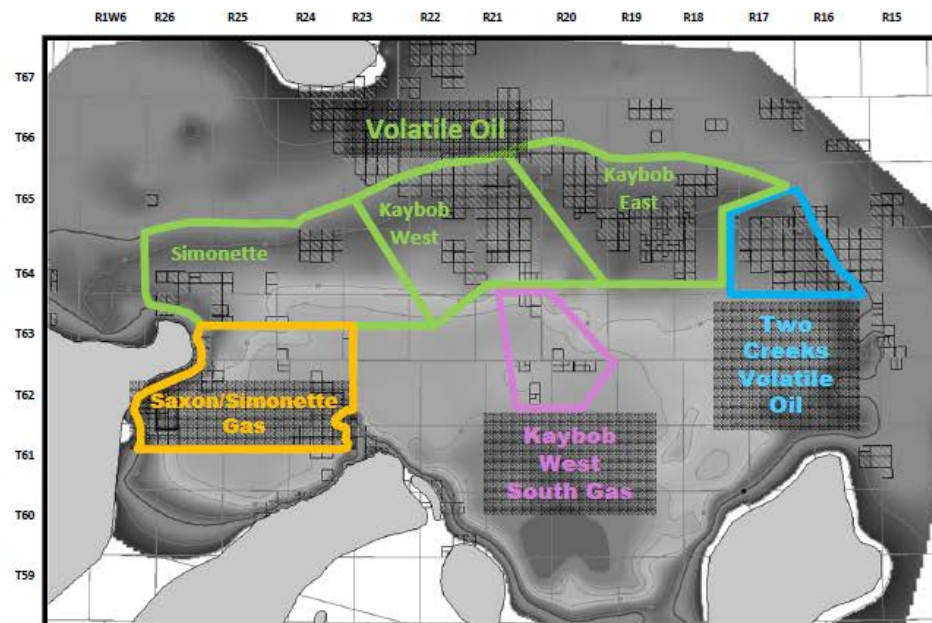
**** Initial production volumes are typically restricted as a production management practice to maximize recoveries long term and IP30 rates are based on estimated sales volumes including NGL's, excluding days with zero production, once the production is going through AOC facilities (post testing/completions cleanup)

KAYBOB DUVERNAY JOINT DEVELOPMENT PLAN

Joint development agreements for Kaybob Duvernay and Placid Montney available on SEDAR



Wells Spud per year by Type Curve	2016	2017	2018	2019	2020	TOTAL
Two Creeks Volatile Oil	-	1	2	3	10	16
Kaybob West Volatile Oil	4	6	8	11	17	46
Kaybob East Volatile Oil	-	5	5	16	4	30
Simonette Volatile Oil	-	-	2	4	8	14
Saxon/Simonette Gas	-	5	9	4	3	21
Kaybob West South Gas	-	4	7	4	2	17
TOTAL	4	21	33	42	44	144



DEBT AND CREDIT FACILITY OVERVIEW

CREDIT FACILITIES	CURRENT	INTEREST RATE	PRE-PAYMENT TERMS
Cdn \$45MM Senior Secured Credit Facility (April 2017 maturity)	Undrawn	~ 6%	Pre-payable without penalty
Cdn \$110MM Cash Collateralized Letter of Credit Facility (On Demand)	\$110	0.25% for LCs	n/a
OUTSTANDING DEBT	CURRENT	INTEREST RATE	PRE-PAYMENT TERMS
Cdn \$550MM Senior Secured Second Lien Notes due November 2017*	\$550	7.50%	Prior to 11/2016 – 103.75% 11/2016 and beyond – 100%

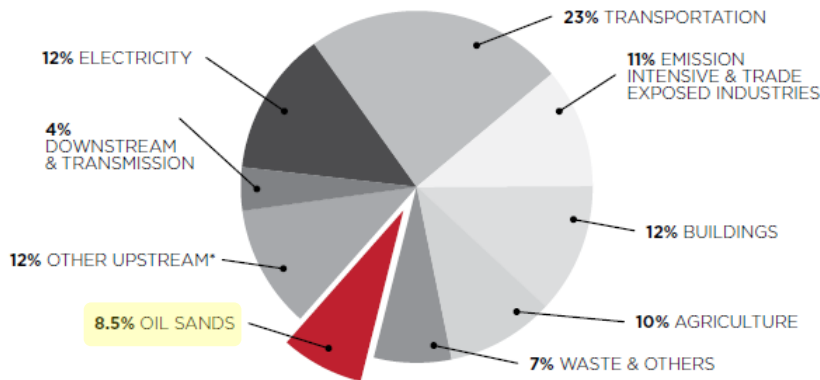
* The senior secured second lien notes have an assigned B credit rating from both DBRS and S&P

ALBERTA'S OIL SANDS A GLOBAL ENVIRONMENTAL LEADER

HIGHLIGHTS

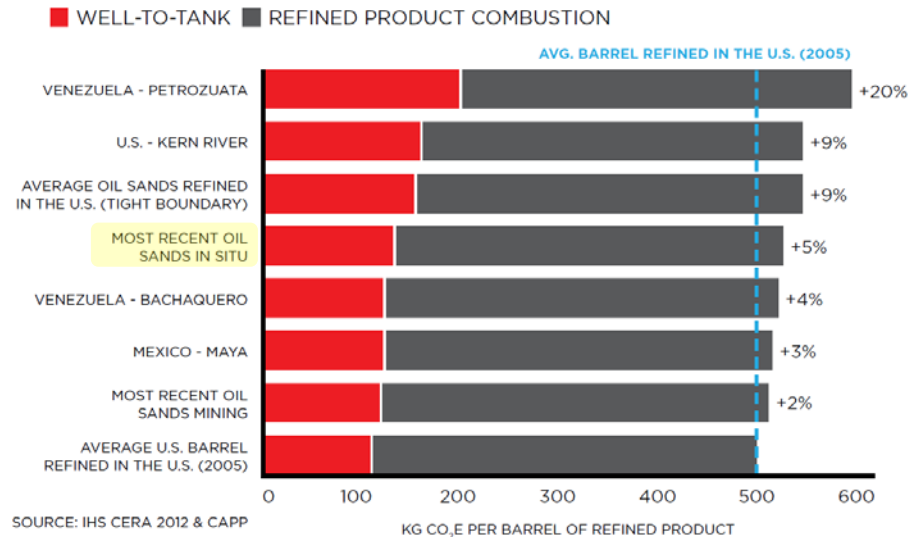
- Canada, with 0.5% of the world's population, produces about 2% of global CO2 emissions
- Oil sands accounted for ~8.5% of Canada GHG emissions and about 0.13% of global GHG emissions
- Since 1990 Canada's oil sands industry has reduced greenhouse gases emissions per barrel by 28%

CANADA'S GHG EMISSIONS BY SECTOR 2013



* Includes conventional oil and natural gas producing sector
SOURCE: ENVIRONMENT CANADA 2015

FULL-CYCLE GHG EMISSIONS OIL SANDS & U.S. REFINED CRUDES



SOURCE: IHS CERA 2012 & CAPP

MANAGEMENT TEAM AND BOARD

MANAGEMENT TEAM

Rob Broen, P.Eng.

President & Chief Executive Officer

Kim Anderson, CA

Chief Financial Officer

Kevin Smith, P. Eng.

Vice President Light Oil

Blair Hockley, P. Eng.

Vice President Thermal Oil

Rod Sousa, CFA

Vice President Corporate Development

Anne Schenkenberger, LLB

Vice President General Counsel & Corporate Secretary

Matt Taylor, CFA

Vice President Capital Markets & Communications

BOARD OF DIRECTORS

Ronald Eckhardt

Chair and member of the Reserves Committee

Rob Broen, P.Eng.

President & Chief Executive Officer and member of the Reserves Committee

Bryan Begley

Chair of the Reserves Committee and member of the Compensation & Governance Committee

Carlos Fierro

Member of the Compensation & Governance Committee and member of the Audit Committee

Marshall McRae, CA

Chair of the Audit Committee

Bob Rooney, Q.C.

Chair of the Compensation & Governance Committee and member of the Audit Committee

Slide

Endnotes

3 (1) GLJ price deck summary:

		Pricing (GLJ - AS OF Jul1 /16)				
		2016e	2017e	2018e	2019e	2020e
WTI	<i>US\$/bbl</i>	\$44.75	\$55.00	\$58.00	\$63.00	\$67.00
FX	<i>C\$/US\$</i>	0.751	0.775	0.800	0.825	0.850
Condensat	<i>C\$/bbl</i>	\$58.50	\$71.00	\$72.25	\$75.25	\$78.00
WCS	<i>C\$/bbl</i>	\$40.75	\$52.25	\$54.25	\$57.75	\$61.00
AECO	<i>C\$/mcf</i>	\$2.15	\$3.20	\$3.20	\$3.40	\$3.60

10 (1) Gross Montney inventory based on 4 wells per section; see reader advisory “Drilling Locations” for more detail
 (2) Illustrative type curve reflects IP30 sales volumes

13 (1) Gross inventories based on 4-6 wells per section; see reader advisory “Drilling Locations” for more detail
 (2) ERCB/AGS open file report 2012-06 – Summary of Alberta’s shale and siltstone hosted hydrocarbon resource potential – P50 resource estimate

14 (1) Gross acres and inventories. Well inventory based on 4-6 wells per section; see reader advisory “Drilling Locations” for more detail. Retained 95% of land prospective for commercial development into the intermediate term. Continued lands gain 5-years of tenure beyond the 4-year primary term

18 (1) Based on DeGolyer and MacNaughton report as of December 31, 2015

READER ADVISORIES

Forward-looking Information:

This presentation contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words “anticipate,” “plan,” “continue,” “estimate,” “expect,” “may,” “will,” “project,” “should,” “believe,” “target,” “predict,” “pursue” and “potential” and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company’s current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company’s industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this presentation should not be unduly relied upon. This information speaks only as of the date of this presentation. In particular, this presentation may contain forward-looking information pertaining to the following (among other things): the impact that (a) the royalty granted to Burgess Energy Holdings L.L.C. on the Company’s thermal oil assets (the “Royalty”), (b) the reduction of the Company’s revolving credit facility, (c) the unwinding of the Company’s US dollar foreign exchange hedge, (d) the establishment of a \$110 million cash collateralized letter of credit facility and (e) the repayment of the TLB (collectively the “Royalty and Refinancing Transactions”) will have on the Company’s financial position and balance sheet strength; the benefits expected to be realized by the Company from the joint venture transaction with Murphy Oil Corporation (the “JV Transaction”), including the impact on the Company’s financial position and balance sheet strength; the impact that the JV Transaction and Royalty and Refinancing Transactions will have on the Company’s corporate competitiveness the expected acceleration of delineating the Duvernay volatile oil window; the Company’s forecasted production and reserves growth; the Company’s forecasted cash flow; the Company’s capital structure at the end of 2016; Athabasca’s plans to retire debt in 2016, improve debt maturity horizons, ensure sufficient liquidity and maintain flexibility; the Company’s strategic focus and related goals; the Company’s plans for, and results of, exploration and development activities; the timing of the ramp-up of production and achieving plateau production from Hangingstone Project 1 (“HS1”); the timing of receipt of regulatory approvals, including in respect of the Company’s expansion of the Hangingstone project; the Company’s 2016 year-end production guidance corporately, as well as individually from the Company’s Light Oil and Thermal Oil divisions; the timing of drilling, completion and tie-in operations in the Company’s Light Oil division; the economy returns expected to be realized from the Company’s Duvernay wells at Kaybob and Montney wells at Placid; the Company’s estimates of the production potential from its Montney assets; the benefits expected to be realized from the use of recovery technologies in the Company’s Light Oil division, including multi-stage, energized hybrid completion technology and the utilization of a high proppant loading completion design; the use of in-situ recovery methods such as Steam Assisted Gravity Drainage (“SAGD”) for production of recoverable bitumen, including the potential benefits of such methods the Company’s drilling plans, in particular, with respect to the Duvernay and Montney formations and the costs of such drilling operations; the Company’s business and financing strategies and plans; expectations regarding the Company’s 2016 Light Oil and Thermal Oil division capital budgets and the future allocation of capital; the Company’s expected flexibility in its pace of development; the Company’s forecasted oil price; the Company’s forecasted annual operating netbacks and 5 year free cash flow outlook for its Hangingstone project; the reductions and efficiencies in Duvernay well drilling and completion costs expected to be realized by the Company; projected Light Oil type curves; the expected quality and composition of the hydrocarbons that will be produced from certain of the Company’s Light Oil assets; future sources of funding; cash flow growth and cash flow potential; reserve growth potential; the receipt of proceeds from the final promissory note issued by Phoenix Energy Holdings Ltd. (“Phoenix”) (the “Promissory Note”); the Company’s estimated future commitments; and economic and financial forecasts and estimates.

With respect to forward-looking information contained in this presentation, assumptions have been made regarding, among other things: commodity prices for crude oil, natural gas and bitumen blend; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its business and the effects that such regulatory framework will have on the Company; the impact that the Royalty and Refinancing Transactions and the JV Transaction will have on the Company, including on the Company’s financial condition and results of operations; the Company’s cash-flow break-even commodity price; geological and engineering estimates in respect of the Company’s reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities; the Company’s ability to meet its re-financing objectives; the applicability of technologies for the recovery and production of the Company’s reserves and resources; the quality of the quality of the Company’s Thermal Oil and Light Oil assets; the Company’s ability to obtain qualified staff and equipment in a timely and cost efficient manner; the value of the Company’s tax pools; the Company’s Light Oil well type curves; the impact that the timing of the Company’s receipt of payments made by Phoenix under the Promissory Notes will have on the Company, including the Company’s financial condition, capital programs and results of operations; future capital expenditures to be made by the Company; the future sources of funding for the Company’s substantial capital programs; the Company’s future debt levels; and the Company’s ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company’s most recent annual information form dated March 10, 2016 (“AIF”), which is available on SEDAR at www.sedar.com, including, but not limited to: uncertainty and fluctuations in commodity prices for crude oil, natural gas and bitumen blend; changes to royalty regimes; political and general economic, market and business conditions in Alberta, Canada, the United States and globally; global financial uncertainty; environmental risks and hazards and the cost of compliance with environmental regulations; dependence on Murphy Oil Corporation as the Company’s joint venture participant in the Company’s Duvernay and Montney assets; dependence on Murphy Oil Corporation as the operator of the Company’s Duvernay assets; the potential for adverse consequences in the event that the Company defaults under certain of the agreements in respect of the JV Transaction; the potential for adverse consequences in the event that Murphy defaults under certain of the agreements in respect of the JV Transaction; the potential for management estimates and assumptions to be inaccurate; potential profitability being dependent on factors beyond the control of the Company; regulatory approvals and compliance; the substantial capital requirements of Athabasca’s projects and the ability to obtain financing for Athabasca’s capital requirements; changes to the Company’s credit rating; failure by counterparties to make payments or perform their obligations to Athabasca in compliance with the terms of contractual arrangements (including under the JV Transaction and the Promissory Notes) and the possible consequences thereof; aboriginal claims; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; failure to meet development schedules and potential cost overruns; variations in foreign exchange and interest rates; risks related to future acquisition and joint venture activities; reliance on, competition for, loss of, and failure to attract key personnel; uncertainties inherent in estimating quantities of reserves and resources; changes to Athabasca’s status given the current stage of development; uncertainties inherent in SAGD and other bitumen recovery processes; risks inherent in Athabasca’s operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources; risks associated with hydraulic fracturing; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca’s assets; increases in operating costs could make Athabasca’s projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks related to Athabasca’s filings with taxation authorities; failure to accurately estimate abandonment and reclamation costs; exploration, development and production risks inherent in crude oil and natural gas operations, including the production of crude oil and natural gas using multi-stage fracture and other stimulation technologies; the risks of induced seismicity; reliance on third party infrastructure; seasonality; hedging risks; risks associated with establishing and maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca’s operations, properties or assets; competition for, among other things, capital, the acquisition of reserves and resources and export pipeline capacity; the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; alternatives to and changing demand for petroleum; risks related to Athabasca’s common shares; and risks pertaining to Athabasca’s senior secured notes and amended credit facilities.

In addition, any information and statements in this presentation relating to “reserves” and “resources” are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. The assumptions relating to the Company’s reserves and resources are contained in the reports of GLJ Petroleum Consultants Ltd. (“GLJ”) and DeGolyer and MacNaughton Canada Limited (“D&M”), each dated effective December 31, 2015. There is no certainty that it will be commercially viable to produce any portion of the resources. The estimates of reserves and future net revenue for individual properties in this Presentation may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. For important additional information about the Company’s reserves and resources, please refer to the AIF. For additional information regarding the specific contingencies which prevent the classification of the Company’s Contingent Resources as reserves, please see “Independent Reserve and Resource Evaluations – Contingent Resources Estimates” in the AIF. “Contingent Resources”, “Best Estimate”, “Proved Reserves” and “Probable Reserves” have the meanings given to those terms in the AIF.

The forward-looking statements included in this presentation are expressly qualified by this cautionary statement. Athabasca does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

READER ADVISORIES (CONT.)

Additional Oil and Gas Information:

"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 equivalent (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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil 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.

Test Results and Initial Production Rates:

The well test results and initial production rates provided in this presentation should be considered to be preliminary, except as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

Drilling Locations: the ~1,500 Duvernay drilling locations referenced in this presentation includes: 5 proved undeveloped locations, 33 probable undeveloped locations, with the balance being unbooked locations. The ~165 Montney inventory (C & D intervals) referenced in this presentation includes 8 probable undeveloped locations, with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ Petroleum Consultants Ltd. as of December 31, 2015 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results and additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.



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