Corporate Presentation

February 2019 *(updated February 21, 2019)*

kelt exploration

David J. Wilson
President & Chief Executive Officer

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Vice President & Chief Financial Officer

www.keltexploration.com

Why Invest in Kelt ?

CREATING VALUE DURING DOWNTURNS

- **The Kelt management team has a track record of creating shareholder value during downturns, previously during the 2008-2009 period with Celtic Exploration Ltd., eventually sold in February 2013 for $3.2 billion.**
- **Kelt focuses on long-term growth with emphasis on low-cost land accumulation in resource-style plays and rapid growth of its drilling inventory portfolio.**
- **Kelt successfully acquired large contiguous tracts of Montney acreage in both B.C. and Alberta during the 2015-2016 downturn.**
- **Kelt targets a 2.0 times or better recycle ratio over the long-term on a proved plus probable reserve basis.**

Common Share Information

Stock Exchange listing	TSX
Trading symbol	KEL
Market capitalization	$ 900 million
52-week trading range	$ 3.97 – $ 10.01
Common shares issued (@ Dec/2018)	184.0 million

Stock options (9.8 MM) & RSUs (1.1 MM)	10.9 million (6.0%)
→ average exercise price of stock options is $ 6.20 / share	
Diluted common shares (debentures convert to 16.3 MM shares)	200.3 million
Diluted common shares (incl. all outstanding options & RSUs)	211.2 million
Directors & Officers (D&O's) ownership [1]	14% (15% diluted)

Note:

[1] See slide entitled "Insider Commitment" for details of Insider participation in equity offerings. D&O ownership excludes holdings of retired Director, Eldon McIntyre, who served on the Kelt Board from inception until his retirement in April 2018. Upon retirement, Mr. McIntyre's ownership in Kelt shares represented 3.6% of the Company's outstanding shares.

Convertible Debentures

TSX trading symbol	KEL.DB
Principal amount issued	$ 90.00 million
Principal amount outstanding	$ 89.91 million
Coupon / Maturity date	5.0% / May 31, 2021
52-week trading range	$ 106.50 – $ 186.05

→ D&O's purchased $14.7 million (16%) of the total Debenture offering.

Conversion privilege:

Each debenture will be convertible into common shares of Kelt at the option of the holder at any time prior to close of business on the earliest of:

(a) the business day immediately preceding the maturity date;

(b) if called for redemption (on or after May 31, 2019), on the business day immediately preceding the date specified by the Company for redemption of the debentures; or

(c) if called for repurchase (pursuant to a "Change of Control"), on the business day immediately preceding the payment date;

at a conversion price of $5.50 per common share, subject to adjustment in certain circumstances.

Note: $90,000 of face principal value has been converted to common shares to date.

Insider Commitment

Offering / Market Purchases	Insider Purchases			
	Date	Shares (MM)	Amount (MM)	Price/share
$ 13.9 MM Equity Private Placement	Feb-2013	3.7	$ 8.7	$ 2.32
$ 94.4 MM Equity Private Placement	Apr-2013	5.7	$ 31.5	$ 5.55
$ 92.0 MM Equity Private Placement	Aug-2013	0.5	$ 4.0	$ 8.00
$ 19.6 MM Flow-through Equity Private Placement	Aug-2013	0.5	$ 4.9	$ 9.80
$ 101.1 MM Equity Private Placement	Dec-2013	2.4	$ 19.6	$8.15
$ 33.6 MM Flow-through Equity Private Placement	Mar-2014	1.1	$ 13.5	$ 12.75
$ 33.4 MM Flow-through Equity Private Placement	Mar-2015	1.7	$ 14.7	$ 8.60
$ 90.0 MM Equity Prospectus Offering	Jul-2015	0.4	$ 3.5	$ 8.85
$ 22.1 MM Flow-through Equity Private Placement	Apr-2016	0.2	$ 0.9	$ 4.70
$ 90.0 MM Convertible Debenture Offering *[1]*	May-2016	2.7	$ 14.7	$ 5.50
$ 36.3 MM Flow-through Equity Private Placements	2017-2018	0.1	$ 1.0	$ 8.12
Open Market Purchases	2013-2018	2.9	$ 16.6	$ 5.67
TOTAL *[2]*		21.9	$ 133.6	$ 6.10

Notes:

[1] Convertible debenture includes the option to convert to common shares at $5.50 per common share.

[2] Insiders (excluding a retired director) total current holdings are 25.6 million shares or 13.9% of outstanding shares (includes Kelt shares received from previous Celtic and Artek holdings and is before the conversion of debentures into shares).

Capital Expenditures

($ millions)	2017	2018 Forecast	2019 Budget	2019/18 Change
Drilling & Completions	154.7	178.5	201.0	+ 13%
Equipment, Facilities, & Pipeline Infrastructure	78.0	110.0	60.0	– 45%
Land, Seismic & Asset Acquisitions	11.6	10.0	9.0	– 10%
Capital Expenditures	244.3	298.5	270.0	– 10%
Property Dispositions	(116.3) [1]	(11.5)	–	– 100%
Net Capital Expenditures	128.0	287.0	270.0	– 6%

Note:
[1] Approximately $103.0 MM of disposition proceeds relates to the sale of Karr assets on Jan/18/2017, after closing adjustments.

Drilling Program

Drills	2018 Gross Wells	2018 Net Wells	2019 Gross Wells	2019 Net Wells
Alberta	16	14.6	9	8.0
British Columbia	19	19.0	25	25.0
Non-operated Properties	0	0.0	0	0.0
Total *[1]*	35	33.6	34	33.0

Completions	2018 Gross Wells	2018 Net Wells	2019 Gross Wells	2019 Net Wells
Alberta	21	19.6	9	8.0
British Columbia	8	8.0	27	27.0
Non-operated Properties	0	0.0	0	0.0
Total *[1]*	29	27.6	36	35.0

Note:

[1] There are expected to be 11 DUCs (wells drilled in 2018 but not completed until 2019) at December 31, 2018 as follows: one well at Wembley/Pipestone, a 5-well pad at Fireweed and 5 wells at Inga (from the first six wells of a 24-well pad). Kelt expects to have 8 DUCs (wells drilled in 2019 but not completed until 2020) at December 31, 2019.

Production Outlook

	2017	2018 Forecast	2019 Budget	2019/18 Change
Oil (bbls/d)	6,634	8,500 – 9,100	11,200 – 11,800	30% – 32%
NGLs (bbls/d) *[1]*	2,608	3,000 – 3,300	4,300 – 4,600	39% – 43%
Gas (Mcf/d)	77,330	90,000 – 97,000	105,000 – 112,000	15% – 17%
Combined (BOE/d)	22,130	27,000 – 28,000	33,500 – 34,500	23% – 24%
Per MM Shares (BOE/d)	125	148 – 153	174 – 179	17% – 18%

Note:

[1] The forecasted natural gas liquids production mix is as follows:

	2018	***2019***
Pentane (C5+)	*25%*	*19%*
Butane (C4)	*26%*	*23%*
Propane (C3)	*32%*	*35%*
Ethane (C2)	*17%*	*23%*
Total NGLs	***100%***	***100%***

Expected Timing of 2019 Production Additions

PROJECT	Number of Wells	Expected On-stream Date	Expected Production (IP30) Range BOE/d	Expected Oil/NGLs (IP30) Percentage
Inga (5-9/4-9) 24-well pad	6	Q2 2019	5,800 – 6,200	60% – 65%
Fireweed (B-33-I/A-34-I) pad *[1]*	5	Q3 2019	5,200 – 5,500	60% – 65%
Wembley/Pipestone area *[2]*	11	Q3 2019	10,400 – 10,900	65% – 70%
Inga (5-9/4-9) 24-well pad	6	Q3 2019	5,800 – 6,200	60% – 65%
Inga (5-9/4-9) 24-well pad	6	Q4 2019	5,800 – 6,200	60% – 65%
TOTAL PRODUCTION ADDITIONS	34		33,000 – 35,000	62% – 67%

Note:

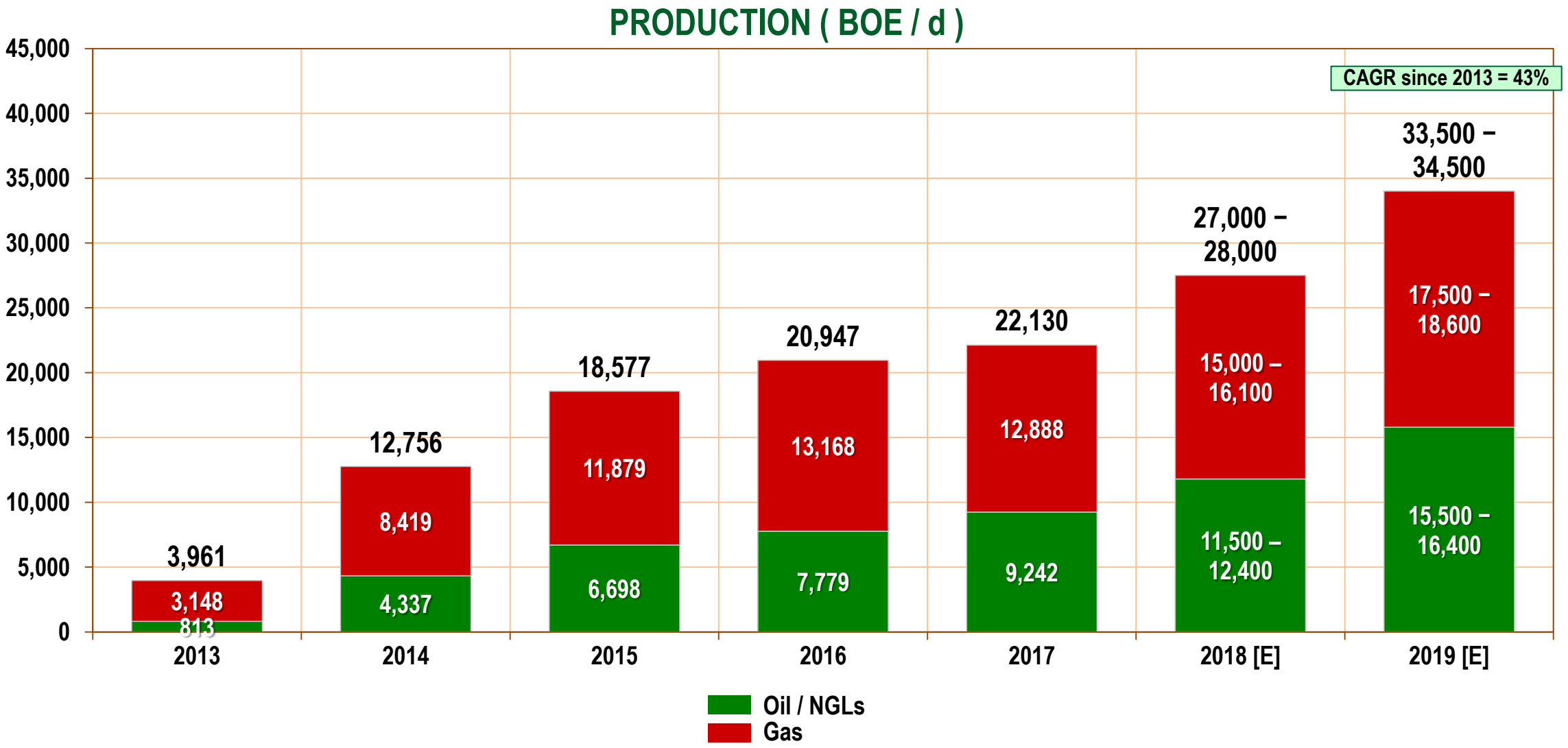
[1] The Fireweed B-33-I/A-34-I pad wells will be put on-stream after the construction of a pipeline from the pad to the Kelt Inga 2-10 Facility has been completed.

[2] The Wembley/Pipestone wells will be put on-stream when the Tidewater Pipestone Sour Deep-Cut Gas Plant, that is currently under construction, commences operations.

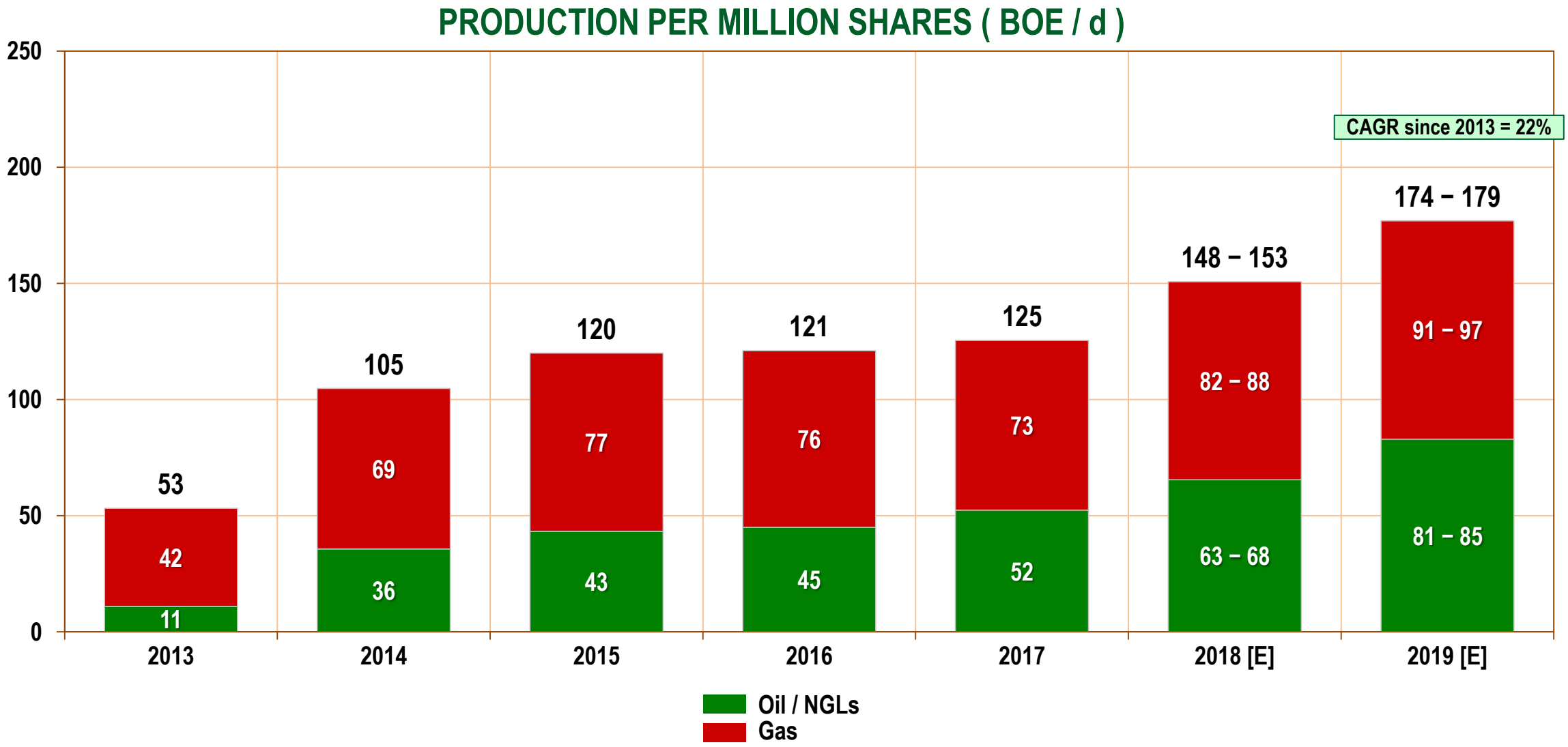
Product Mix

2018	Realized Price	Production Split	Operating Income (MM)	Operating Income Split
Oil & NGLs	$ 62.63/bbl	42%	$ 176.3	84%
Gas	$ 3.19/Mcf	58%	$ 33.3	16%
Total	$ 37.44/BOE	100%	$ 209.6	100%
2019	**Realized Price**	**Production Split**	**Operating Income (MM)**	**Operating Income Split**
Oil & NGLs	$ 57.89/bbl	47%	$ 222.1	85%
Gas	$ 3.28/Mcf	53%	$ 39.4	15%
Total	$ 37.50/BOE	100%	$ 261.5	100%

Annual Production Growth (since inception)



Annual Production per Share Growth (since inception)



Commodity Prices

(CA$, unless otherwise specified)	2017	2018 (E)	2019 Budget	YOY Change
WTI Crude Oil (USD/bbl) *[1]*	US $ 50.95	US $ 67.50	US $ 67.50	–
CLS Crude Oil (CAD/bbl) *[2]* WTI-CLS Basis Differential	$ 61.85 ($4.28 or 6%)	$ 70.93 ($16.28 or 19%)	$ 66.97 ($19.43 or 22%)	– 6% + 19%
NYMEX Natural Gas (USD/mmBtu)	US $ 3.07	US $ 2.95	US $ 3.00	+ 2%
UNION-DAWN Gas Daily Index (USD/MMBtu) CHICAGO [ACE] Gas Daily Index (USD/MMBtu) MALIN Gas Monthly Index (USD/MMBtu) SUMAS-HUNTINGDON Gas Monthly Index (USD/MMBtu) AECO [5A] Gas Daily Index (USD/MMBtu) *[3]* Station 2 [7B] Gas NGX Monthly Index (USD/MMBtu) *[3]*	US $ 3.04 US $ 2.90 US $ 2.82 US $ 2.76 US $ 1.66 US $ 1.20	US $ 3.00 US $ 2.92 US $ 2.43 US $ 2.85 US $ 1.28 US $ 1.13	US $ 2.90 US $ 2.85 US $ 2.45 US $ 2.90 US $ 1.60 US $ 1.30	– 3% – 2% + 1% + 2% + 25% + 15%
Exchange Rate (CAD/USD) Exchange Rate (USD/CAD)	$ 1.298 US $ 0.770	$ 1.292 US $ 0.774	$ 1.280 US $ 0.781	– 1% + 1%
Kelt Oil price ($/bbl) Premium (Discount) to CLS Crude Oil price	$ 59.09 – 4%	$ 71.32 + 1%	$ 67.01 + 0%	– 6%
Kelt NGLs price ($/bbl)	$ 27.72	$ 37.93	$ 33.70	– 11%
Kelt Gas price ($/Mcf) Premium to AECO [5A] CAD price per MMBtu	$ 3.01 + 40%	$ 3.19 + 93%	$ 3.28 + 60%	+ 3%
Kelt combined price ($/BOE)	$ 31.51	$ 37.44	$ 37.50	–

Notes:

[1] WTI – West Texas Intermediate – light sweet crude oil (API 40˚) for settlement at Cushing, Oklahoma, priced in USD.

[2] CLS – Canadian Light Sweet – light sweet crude oil (API 40˚) for settlement at Edmonton, Alberta, priced in CAD.

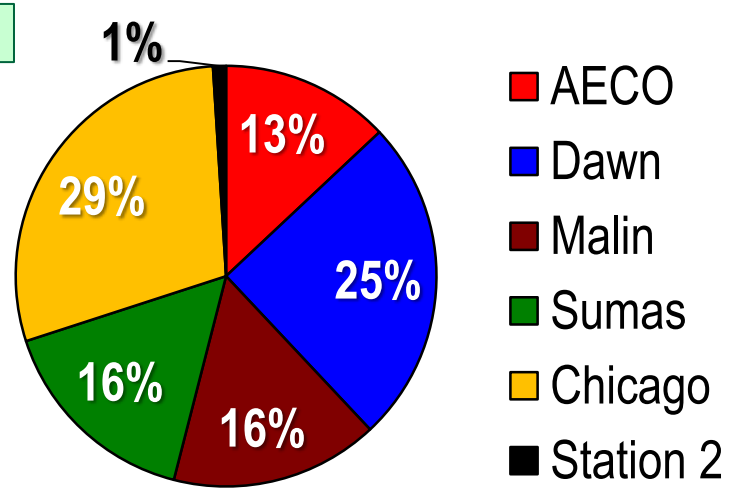
[3] AECO and Station 2 converted from GJ to MMBtu at a factor of 1.0546 GJ / MMBtu (1,000 Btu/scf gas).

Gas Market Risk Management

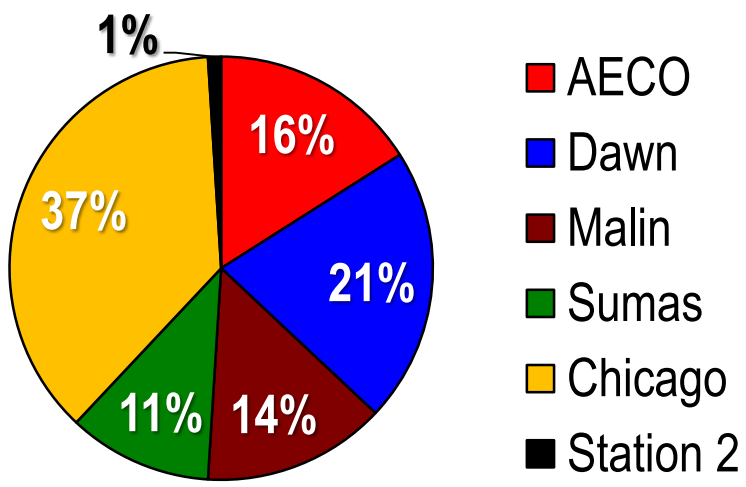
GAS MARKET DIVERSIFICATION

- **The Company has taken a diversified approach to selling its natural gas in order to reduce exposure to single market risk.**
- **Kelt has entered into several contracts that result in price exposure to various gas price hubs in North America.**
- **Estimated percentage of average gas sales at each price hub is expected to be as follows:**

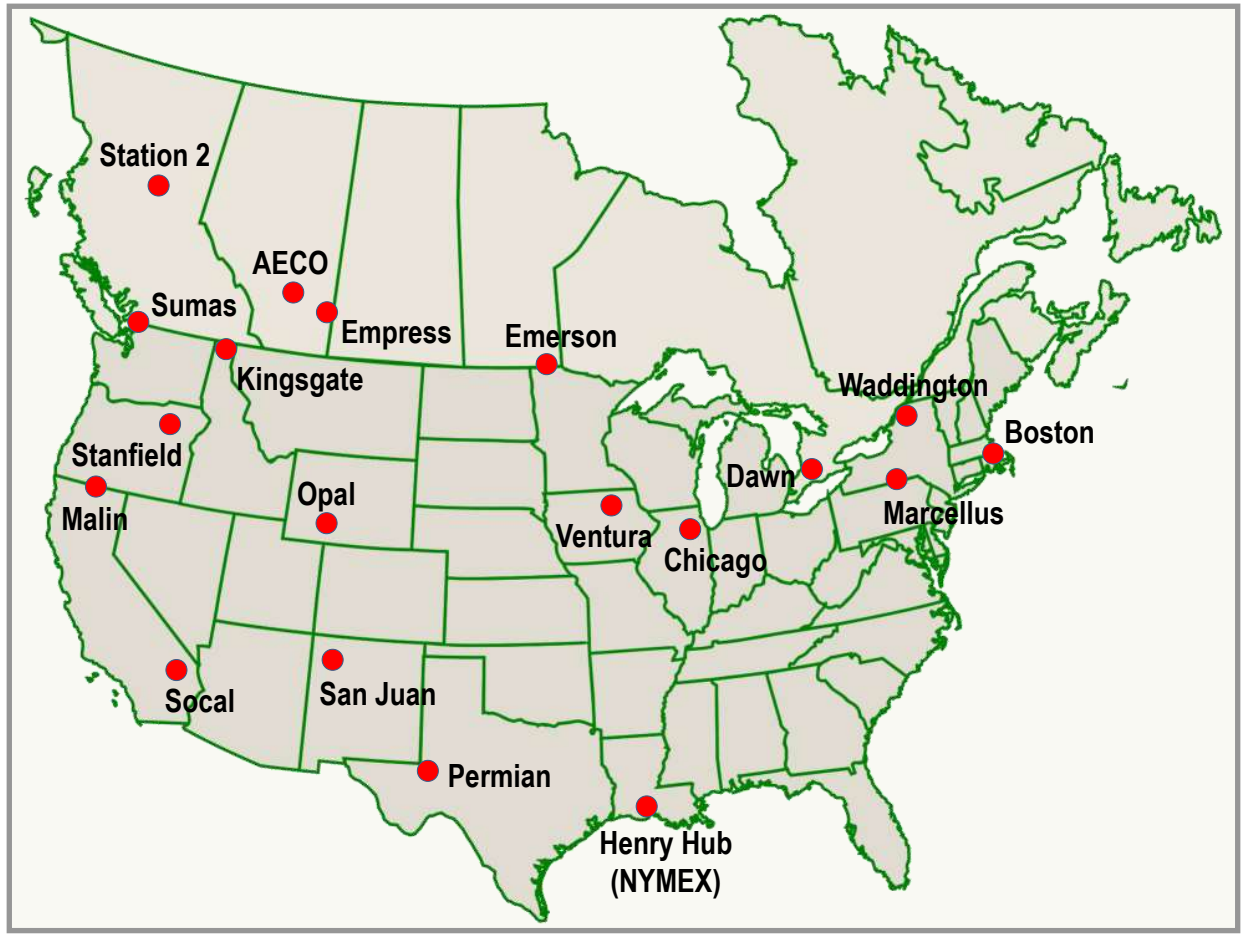
2018:



2019:



North American Natural Gas Hubs



● Natural Gas Price Hub

Kelt 2019 Gas Netback Forecast

Gas Hub	%	Hub Price [1] US$/MMBtu	Netback [2] US$/Mcf	Netback [2,3] CA$/Mcf
NYMEX		3.00		
Dawn	21%	2.90	2.01	2.58
Chicago	37%	2.85	1.76	2.25
Malin	14%	2.45	1.62	2.07
Sumas	11%	2.90	2.18	2.79
AECO	16%	1.60	1.36	1.74
Station 2	1%	1.30	1.23	1.57

Notes:

[1] Hub Price is for 1,000 Btu gas.

[2] Netback is after the estimated premium for Kelt gas heat value, after fuel, transportation and other corporate deductions, and before royalties and operating expenses.

[3] Exchange rate = US$0.781/CA$ or CA$1.280/US$.

Hedging

Commodity	Index	Term	Quantity	Fixed Price
Natural Gas	NYMEX to Dawn Basis Differential	Jan/2019 to Dec/2019	10,000 MMBtu/d	Minus US$0.0975/MMBtu
Natural Gas	NYMEX to Chicago Basis Differential	Jan/2019 to Oct/2019	10,000 MMBtu/d	Minus US$0.14/MMBtu
Natural Gas	Sumas	Nov/2018 to Mar/2019	7,500 MMBtu/d	US$5.97/MMBtu *[1]*
Natural Gas	Malin	Jan/2019 to Mar/2019	5,000 MMBtu/d	US$4.55/MMBtu *[2]*
USD	CAD/USD	Jan/2019 to Dec/2019	US$1.0 MM/month	CA$1.3050

Notes:

*[1] At a fixed Sumas price of US$5.97/MMBtu, Kelt would realize approximately **CA$7.00/Mcf at Station 2**, after adjusting for heat value and after deducting financial basis contracts and transportation costs, for its B.C. gas production delivered at Station 2 to this contract for the Nov18-Mar19 period.*

*[2] At a fixed Malin price of US$4.55/MMBtu, Kelt would realize approximately **CA$5.00/Mcf at NIT**, after adjusting for heat value and after deducting financial basis contracts and transportation costs, for its Alberta gas production delivered at NIT to this contract for the Jan18-Mar19 period.*

2019 Commodity Price Sensitivities

	2019 Forecast	Kelt Oil Price minus 10%		Kelt NGLs Price minus 10%		Kelt Gas Price minus 10%		CAD/USD Exchange Rate minus CAD 0.05	
Kelt Oil Price (CAD/bbl) Kelt NGLs Price (CAD/bbl) Kelt Gas Price (CAD/Mcf)	67.01 33.70 3.28	60.31 33.70 3.28	- 10% n/c n/c	67.01 30.33 3.28	n/c - 10% n/c	67.01 33.70 2.95	n/c n/c - 10%	64.43 32.38 3.15	- 4% - 4% - 4%
Adjusted FFO ($MM) [1] [2]	240.0	215.9	- 10%	235.5	- 2%	226.2	- 6%	224.7	- 6%
Change ($MM)		(24.1)		(4.5)		(13.8)		(15.3)	
Adj. FFO per share, diluted [1] [2]	1.23	1.11	- 10%	1.21	- 2%	1.16	- 6%	1.15	- 6%
Change ($/share)		(0.12)		(0.02)		(0.07)		(0.08)	
Net Bank Debt ($MM)	225.0	249.1		229.5		238.8		240.3	
Net Bank Debt/FFO Ratio [2]	0.9 x	1.2 x		1.0 x		1.1 x		1.1 x	

Note:
[1] See "Financial Advisories"
[2] FFO: Funds from Operations

2019 Discretionary Capital Expenditures

Approximately $40.0 million of capital expenditures that is currently included in the 2019 Budget could be deferred to 2020 if realized commodity prices in 2019 are significantly lower than currently forecasted:

Project	2019 Capital Expenditures (MM)	Forecasted Production Start Date	Impact to 2019 Average Production (BOE/d)
Oak – drill, complete & tie-in 4 wells	$ 28.0	Apr-1-2020	0
Inga 24-well pad – drill 6 wells	$ 12.0	Apr-1-2020	0
TOTAL	$ 40.0		0

"2019 Pro-forma" financial and operating results in this presentation assumes that the Company does not incur the full $40.0 million in discretionary capital expenditures outlined above in 2019.

Commitments:

[1] Kelt has a take-or-pay commitment at the new AltaGas Townsend Deep-Cut Gas Plant that is expected to be constructed by the fourth quarter of 2019. After plant start-up, Kelt has an 18 month period to ramp up its production in order to meet its obligation to deliver a minimum of 75.0 MMcf/d of raw gas.

[2] Kelt has a take-or-pay commitment at the new Tidewater Pipestone Sour Deep-Cut Gas Plant that is expected to be constructed by the third quarter of 2019. At plant start-up, Kelt is obligated to deliver a minimum of 22.5 MMcf/d (75% of its 30.0 MMcf/d firm plant capacity) of raw gas.

2019 Pro-forma Commodity Prices

(CA$, unless otherwise specified)	2019 Budget	2019 Pro-forma	Difference	Percent Change
WTI Crude Oil (USD/bbl) *[1]*	US $ 67.50	US $ 55.00	− 12.50	− 19%
CLS Crude Oil (CAD/bbl) *[2]* WTI-CLS Basis Differential	$ 66.97 ($19.43 or 22%)	$ 63.75 ($8.85 or 12%)	− 3.22	− 5%
NYMEX Natural Gas (USD/mmBtu)	US $ 3.00	US $ 3.00	n/c	n/c
UNION-DAWN Gas Daily Index (USD/MMBtu) CHICAGO [ACE] Gas Daily Index (USD/MMBtu) MALIN Gas Monthly Index (USD/MMBtu) SUMAS-HUNTINGDON Gas Monthly Index (USD/MMBtu) AECO [5A] Gas Daily Index (USD/MMBtu) *[3]* Station 2 [7B] Gas NGX Monthly Index (USD/MMBtu) *[3]*	US $ 2.90 US $ 2.85 US $ 2.45 US $ 2.90 US $ 1.60 US $ 1.30	US $ 2.90 US $ 2.85 US $ 2.85 US $ 3.10 US $ 1.50 US $ 1.20	n/c n/c + 0.40 + 0.20 − 0.10 − 0.10	n/c n/c + 16% + 7% − 6% − 8%
Exchange Rate (CAD/USD) Exchange Rate (USD/CAD)	$ 1.280 US $ 0.781	$ 1.320 US $ 0.758	+ 0.040 − 0.023	+ 3% − 3%
Kelt Oil price ($/bbl) Premium (Discount) to CLS Crude Oil price	$ 67.01 0%	$ 63.27 − 1%	− 3.74	− 6%
Kelt NGLs price ($/bbl)	$ 33.70	$ 27.73	− 5.97	− 18%
Kelt Gas price ($/Mcf) Premium to AECO [5A] CAD price per MMBtu	$ 3.28 + 60%	$ 3.52 + 78%	+ 0.24	+ 7%
Kelt combined price ($/BOE)	$ 37.50	$ 36.10	− 1.40	− 4%

Notes:

[1] WTI – West Texas Intermediate – light sweet crude oil (API 40˚) for settlement at Cushing, Oklahoma, priced in USD.

[2] CLS – Canadian Light Sweet – light sweet crude oil (API 40˚) for settlement at Edmonton, Alberta, priced in CAD.

[3] AECO and Station 2 converted from GJ to MMBtu at a factor of 1.0546 GJ / MMBtu (1,000 Btu/scf gas).

Netbacks

($ / BOE)	2017	2018 (E)	2019 (E)	2019/18 Change	2019 Pro-forma
Revenue/Price	31.51	37.56	37.50	–	36.10
Realized hedging gain (loss)	(0.13)	0.02	0.13	+ 550%	0.12
Royalties (% of revenue/price)	(9.3%)	(9.4%)	(10.2%)	+ 9%	(10.4%)
Transportation expense	(3.13)	(3.79)	(3.99)	+ 5%	(3.92)
Production expense	(10.05)	(9.23)	(9.06)	– 2%	(9.06)
Operating netback *[1]*	15.28	21.02	20.77	– 1%	19.48
G&A expense	(0.94)	(0.80)	(0.76)	– 5%	(0.77)
Interest expense	(0.97)	(0.99)	(0.95)	– 4%	(0.98)
Adjusted funds from operations *[1]*	13.37	19.23	19.06	– 1%	17.73

Note:
[1] See "Financial Advisories".

Financial Outlook

	2017	2018 Forecast	2019 Budget	2019/18 Change	2019 Pro-forma
Revenue ($ MM)	257.6	375.8	473.9	+ 26%	449.5
Operating income ($ MM) [1]	123.4	209.6	261.5	+ 25%	241.8
Adj. funds from operations ($ MM) [1]	108.0	193.0	240.0	+ 24%	220.0
Per share – diluted ($/share)	0.61	1.04	1.23	+ 18%	1.13
Capital expenditures, net ($ MM) [2]	128.0	287.0	270.0	– 6%	230.0
Net bank debt, at year-end ($ MM) [1,3]	136.7	195.0	225.0	+ 15%	210.0
Net bank debt / FFO ratio	1.3 x	1.0 x	0.9 x	– 10%	1.0 x

Notes:

[1] See "Financial Advisories".

[2] Capital expenditures are net of property dispositions.

[3a] Net bank debt includes amounts outstanding under the Company's credit facility, net of working capital. The current borrowing base amount of Kelt's credit facility is $250.0 million.

[3b] In addition to net bank debt, the Company has $90.0 million principal amount of 5% convertible subordinated unsecured debentures outstanding, maturing on May 31, 2021 and convertible to common equity at a price of $5.50 per share, subject to certain conditions and subject to adjustment in certain events.

Core Areas

Fort St. John (BC) :

Inga/Fireweed & Oak/Flatrock

- Stacked Montney light oil and condensate-rich gas
- Doig condensate-rich gas

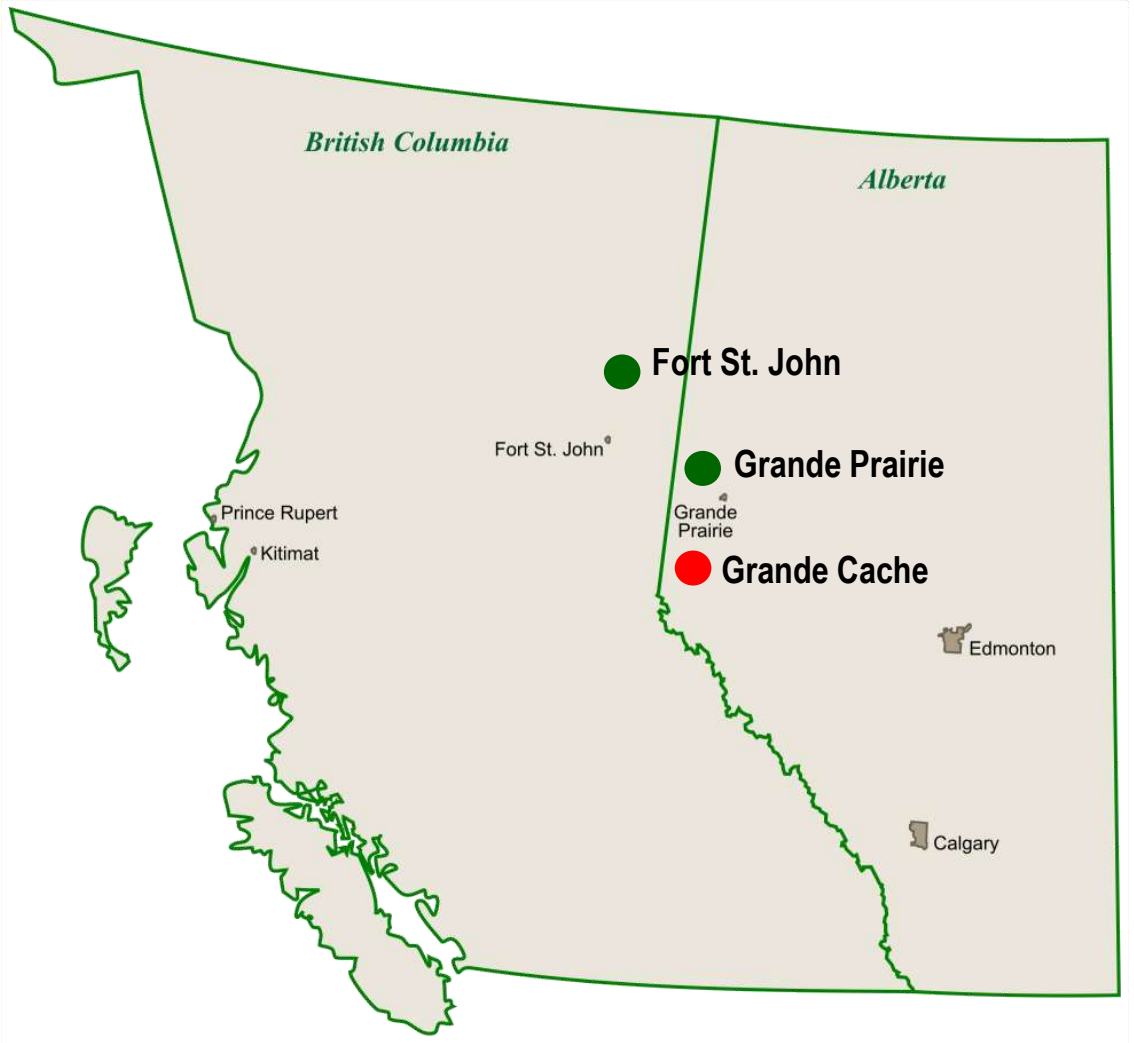
Grande Prairie (AB) :

Pouce Coupe/Progress, Valhalla/La Glace & Pipestone/Wembley

- Stacked Montney light oil
- Montney/Doig gas
- Charlie Lake light oil
- Halfway light oil

Grande Cache (AB) :

- Cretaceous gas



Kelt Land Fairway

Kelt Lands

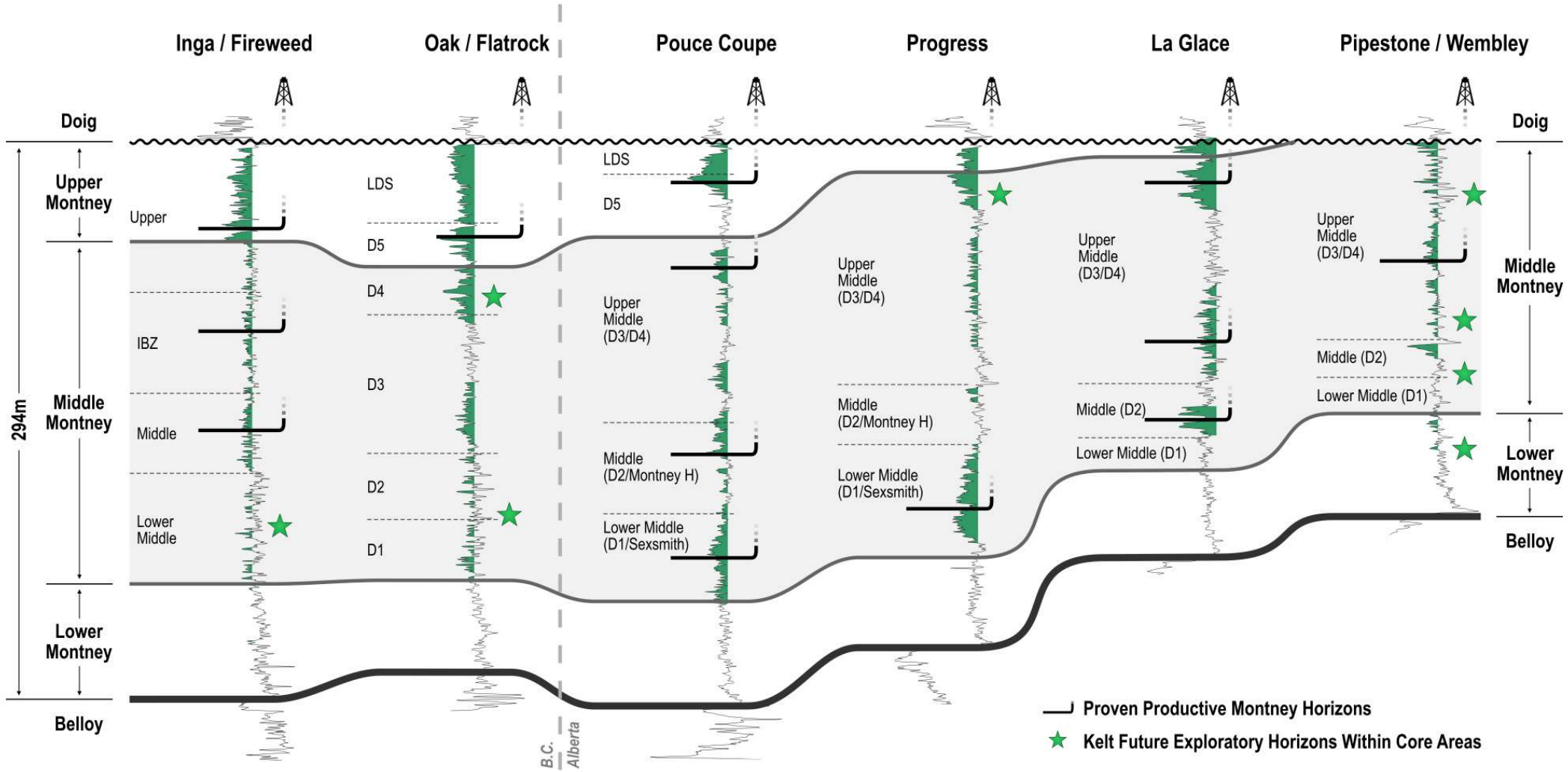
Corporate Land Holdings

August 2018	Net Acres	Net Sections
Developed	224,313	351
Undeveloped	636,727	995
Total	861,040	1,346

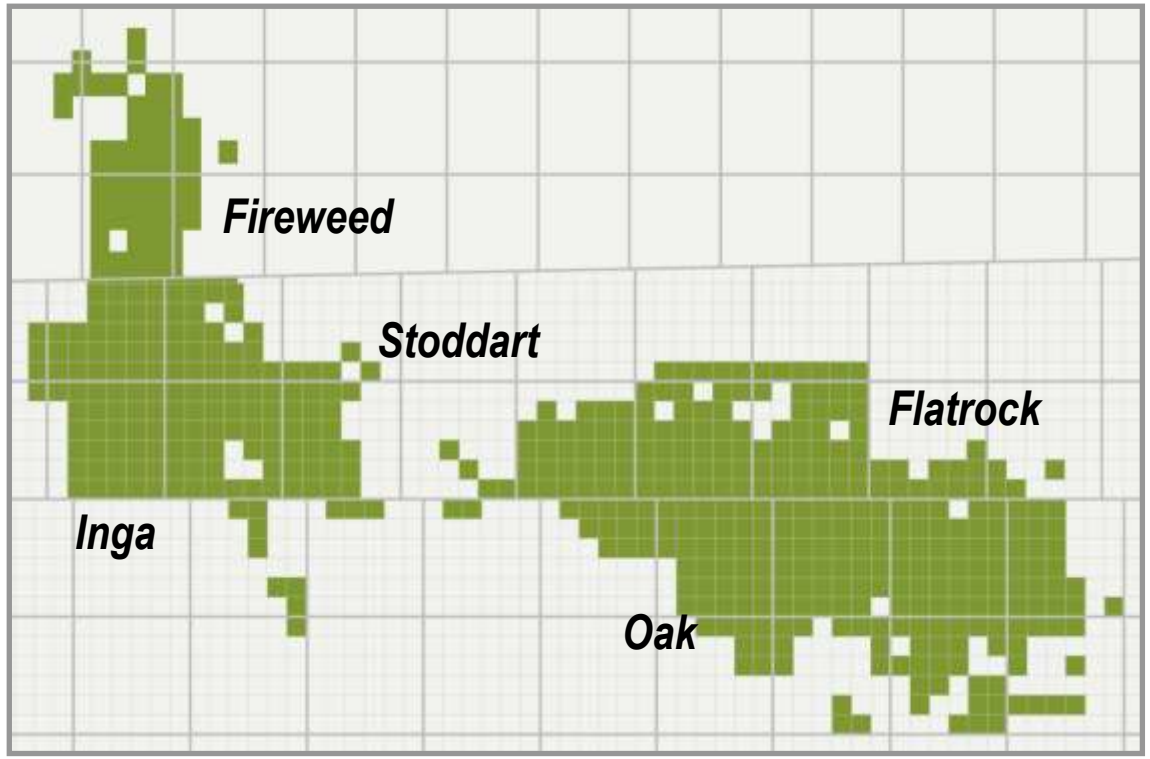
Montney Rights

	Net Acres	Net Sections
British Columbia	363,086	567
Alberta	150,195	235
Total	513,281	802

Kelt Montney Framework



British Columbia Montney Lands



Kelt Lands

Land (Montney Rights)

Gross: 368,038 acres (575 sections)
Net: 363,087 acres (567 sections)

Operations

- **Kelt has been successful delineating the Upper and Middle Montney at Inga/Fireweed.**
- **Kelt is pleased with the initial results from the Montney IBZ at Inga and will continue its delineation program in that formation.**
- **Kelt drilled its first exploration Upper Montney well at Oak in 2017 and followed up with two additional exploration wells in the first quarter of 2018.**

British Columbia Montney Wells

PRODUCTION

Kelt British Columbia Montney Drills
Top 10 IP30 Wells (gross sales, BOE/d):

(1)	Fireweed 00/C-31-I/94-A-12 UM	2,068 (68% oil/ngls)
(2)	Inga 02/15-33-087-23W6 MM	2,066 (79% oil/ngls)
(3)	Fireweed 00/B-90-A/94-A-13 UM	1,895 (63% oil/ngls)
(4)	Inga 02/14-24-087-23W6 UM	1,609 (74% oil/ngls)
(5)	Inga 00/14-24-087-23W6 MM	1,412 (71% oil/ngls)
(6)	Inga 00/08-31-087-23W6 UM	1,296 (74% oil/ngls)
(7)	Inga 02/16-25-088-23W6 UM	1,242 (81% oil/ngls)
(8)	Fireweed 02/C-026-A/094-A-13 UM	1,188 (65% oil/ngls)
(9)	Inga 00/06-07-088-22W6 UM	1,130 (52% oil/ngls)
(10)	Inga 00/09-27-088-22W6 MM	951 (73% oil/ngls)

RESERVES

Typical Well EUR's

Inga/Fireweed Upper Montney (UM)
Sproule 2P EUR = 795 MBOE:

- 54% oil/ngls (429,000 bbls)
- 46% gas (2.2 Bcf)

Inga/Fireweed Middle Montney (MM)
Sproule 2P EUR = 645 MBOE:

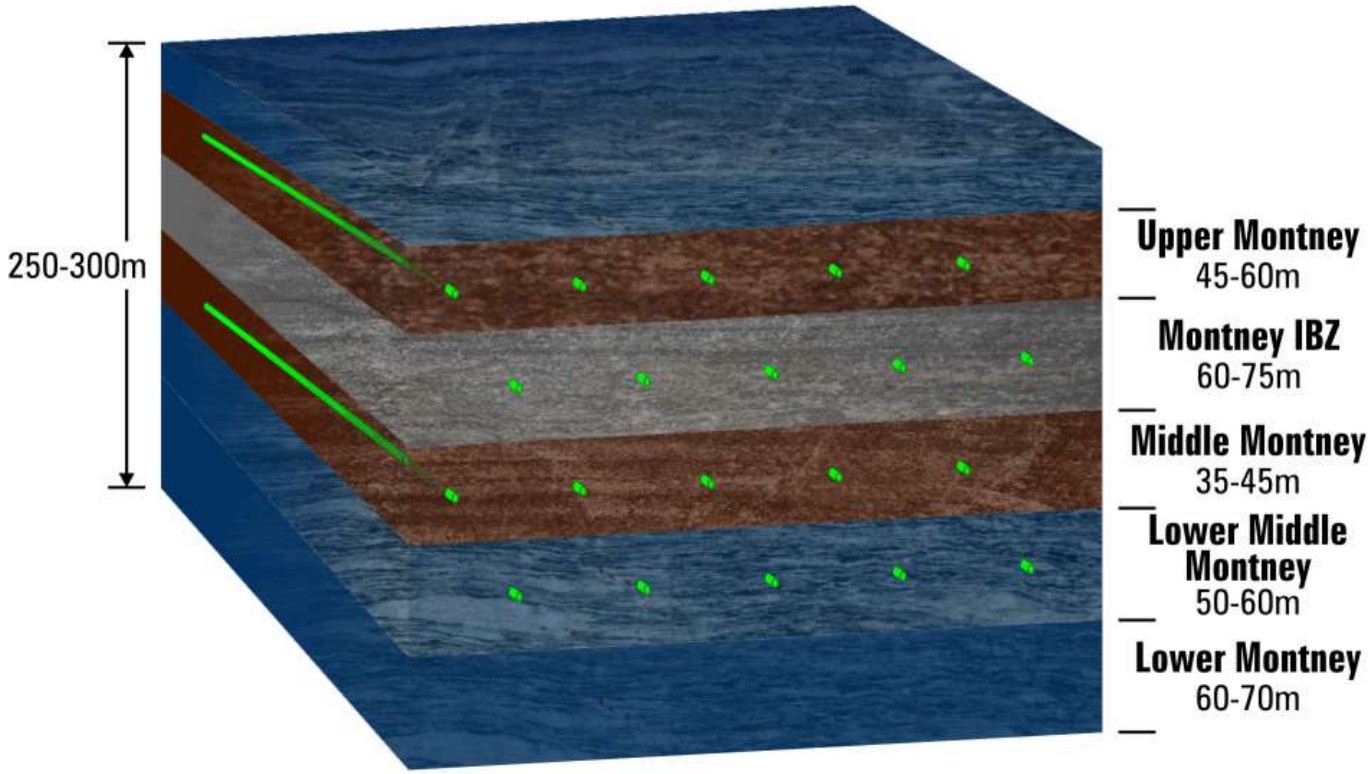
- 59% oil/ngls (380,000 bbls)
- 41% gas (1.6 Bcf)

Note:
[a] Wells are typically completed using the ball drop system with 46 fracture stages at approximately 70 tonnes/stage of proppant and using high intensity fluid pump rates.

B.C. - Stacked Montney Resource Potential

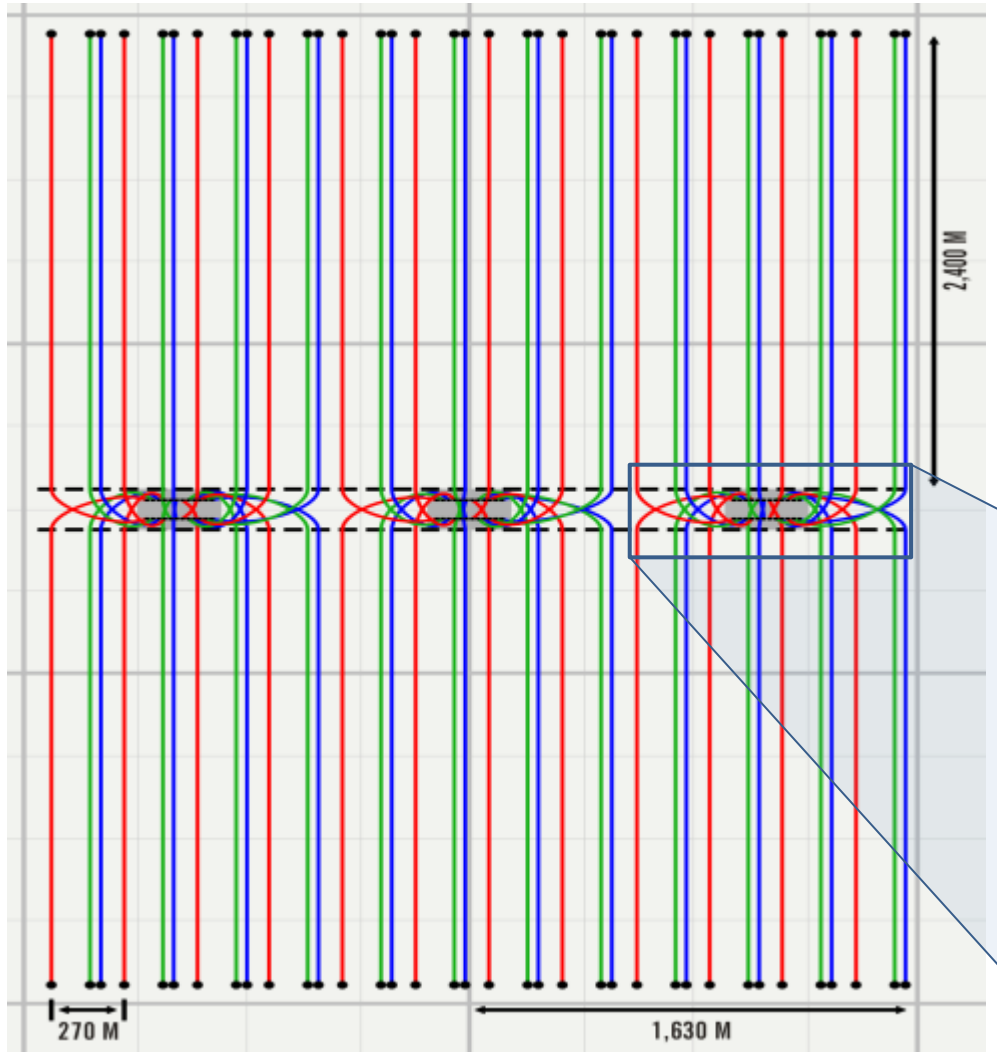
THE MONTNEY CUBE

MULTIPLE STACKED MONTNEY HORIZONS

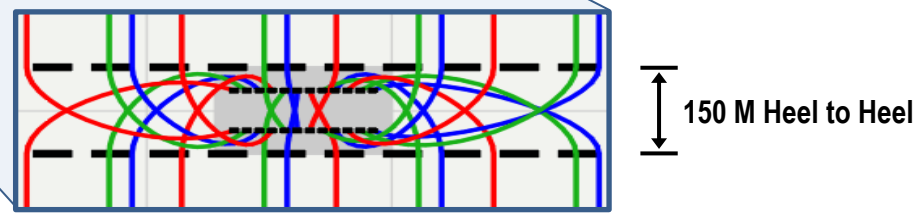


- Kelt has been successful delineating the Upper and Middle Montney at Inga/Fireweed.
- Initial results from the Montney IBZ have been encouraging and Kelt will continue with its delineation program in this formation.
- Kelt has commenced drilling operations on a multi-well (24) pad targeting the three different Montney layers.
- Kelt expects to test the Lower Middle Montney in the near future.

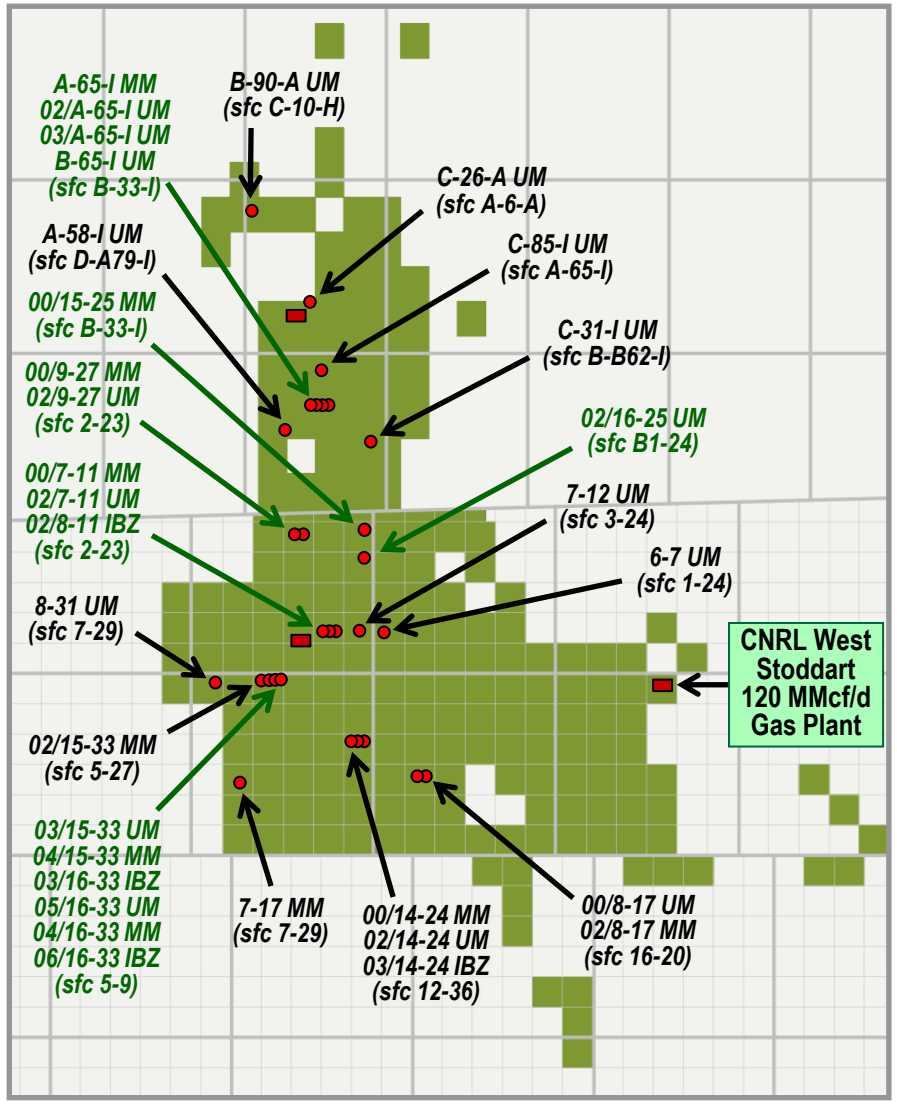
Inga 6-Section / 3-Pad / 72-Well Development Plan



- **Kelt's 2018/2019 capital expenditures to include 24 drills at Inga from the Company's first 24-well multi-layer Montney cube pad that will include 8 Upper, 8 IBZ and 8 Middle Montney wells.**
- **Wells in each Montney interval will be spaced at approximately 270 metres apart.**
- **Vertically, the wells will be spaced in a " > > > " formation.**



Inga / Fireweed Montney Lands



LAND (Montney Rights)

220 gross sections (218 net sections)

2019 DRILLING PLANS

→ **Remaining 19 wells from the Inga (sfc 5-9) 24-well pad.**

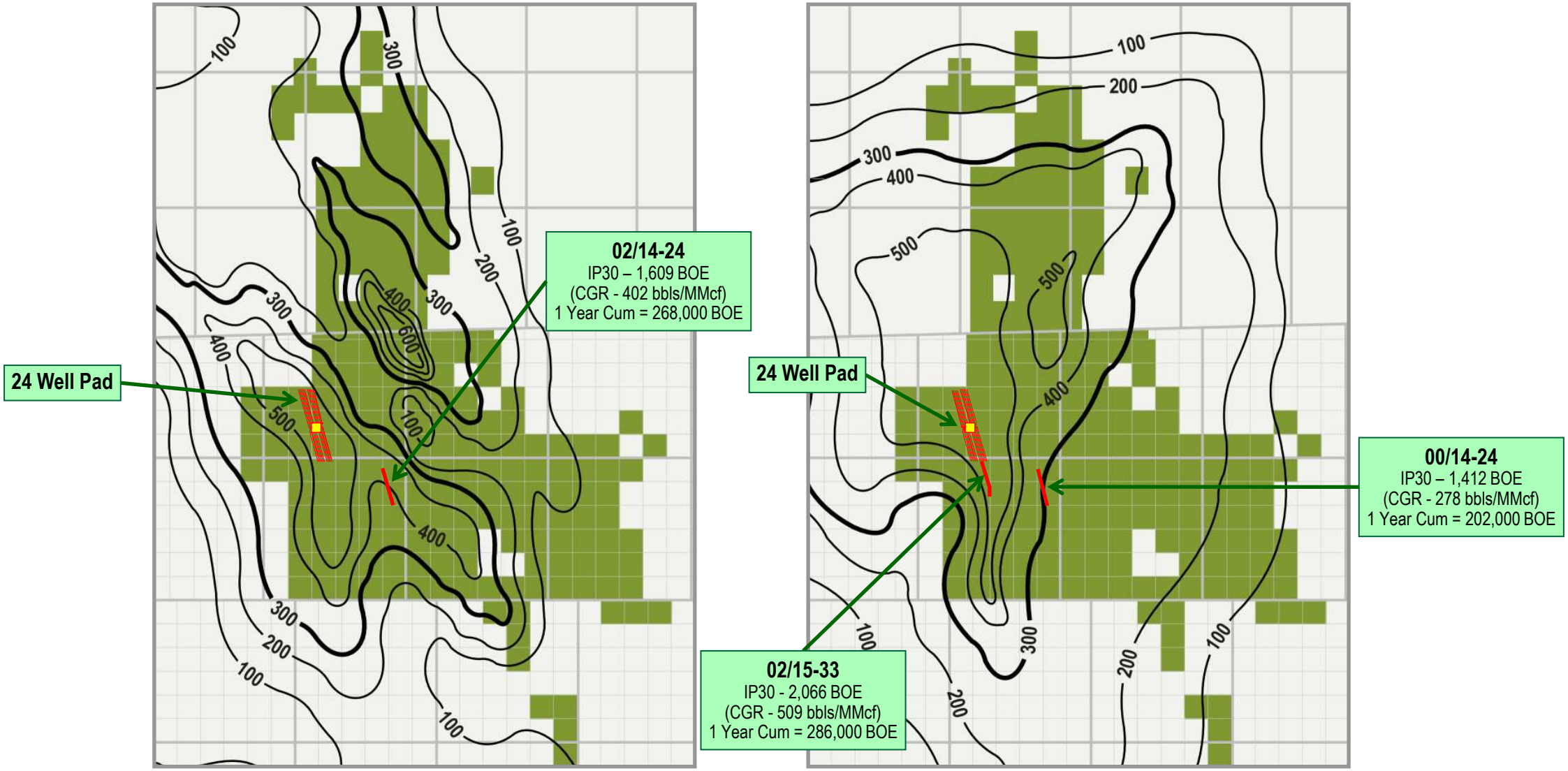
→ **Two additional delineation/development wells.**

DRILLS	Prior to 2018	2018 Forecast	Total
Upper Montney	10	9	19
Middle Montney	4	6	10
Montney IBZ	1	3	4
Total	15	18	33

UM – Upper Montney IBZ – Montney IBZ MM – Middle Montney

Kelt Lands

Inga / Fireweed Upper & Middle Montney CGR (Condensate : Gas Ratio)



Inga Gas Processing & Liquids Handling

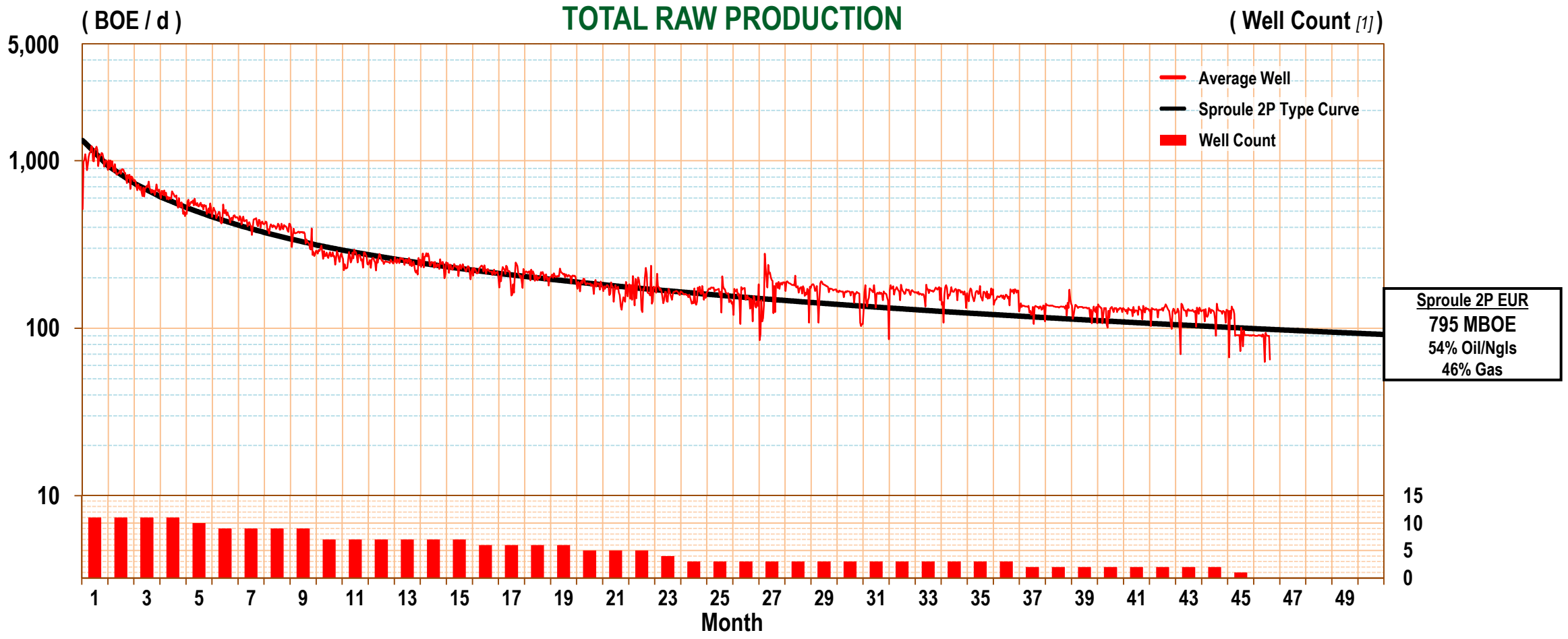
KELT FACILITY ("Inga 2-10 Facility"):

- The Company constructed a 100 MMcf/d compression, dehydration, liquids handling and frac water facility located at Inga which is currently in operation.
- The Inga 2-10 Facility will compress raw gas that will be delivered to the AltaGas Facility where a 99 MMcf deep-cut (C3+) gas plant located at Townsend is currently under construction.

ALTAGAS FACILITY ("Townsend Deep-Cut Gas Plant"):

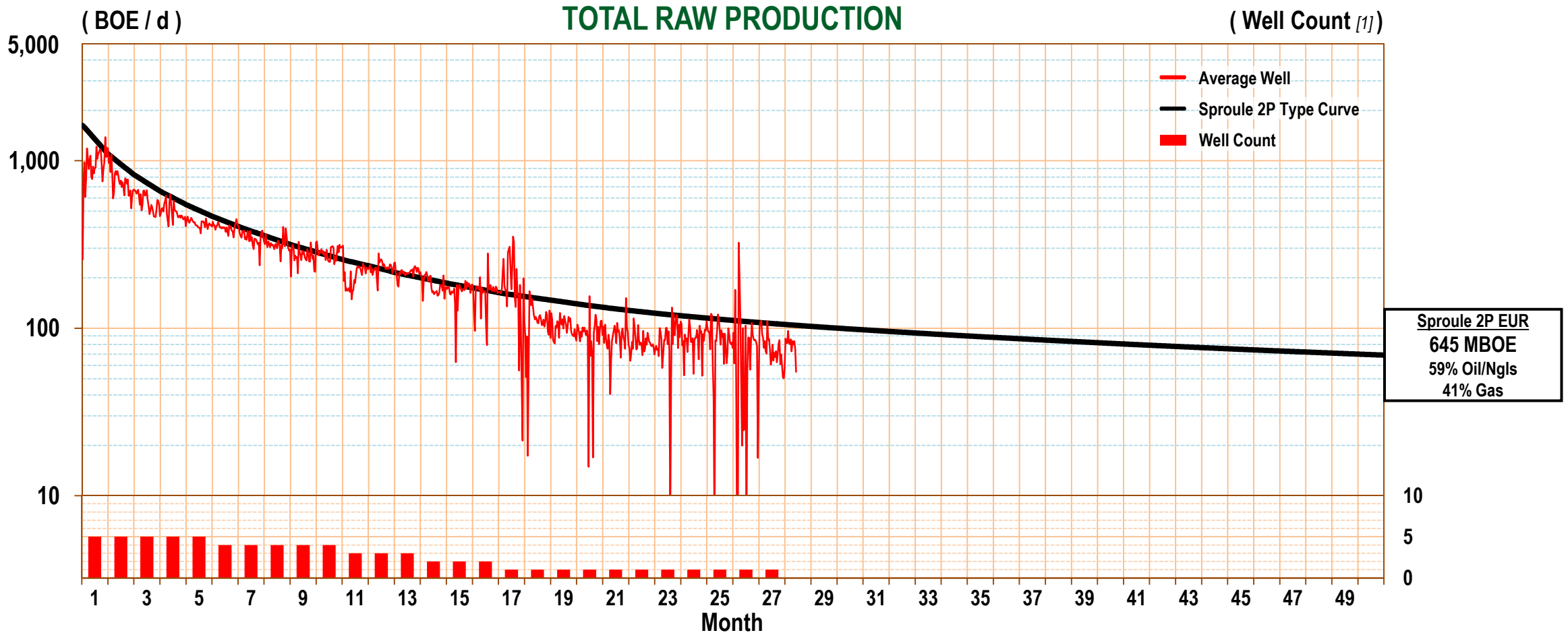
- The Townsend Deep-Cut Gas Plant is expected to commence commercial operations in the fourth quarter of 2019.
- Kelt has an initial "take-or-pay" volume commitment of 75 MMcf/d of raw gas with an extension and/or volume increase option in the first two years. Kelt has an 18 month "ramp-up" period to get to the initial 75 MMcf/d volume commitment.
- During the first three years, Kelt also has the option to commit to a second train for an additional volume of between 50 and 95 MMcf/d.
- Kelt has also secured liquid fractionation and has committed to the sale of all its resulting propane volumes to the AltaGas Ridley Island Facility, giving Kelt access to a Far East Propane Index pricing netback.

Inga / Fireweed Upper Montney Type Curve



Note:
[1] See "Appendix" for list of wells included in the well count and for individual decline curves for each well.

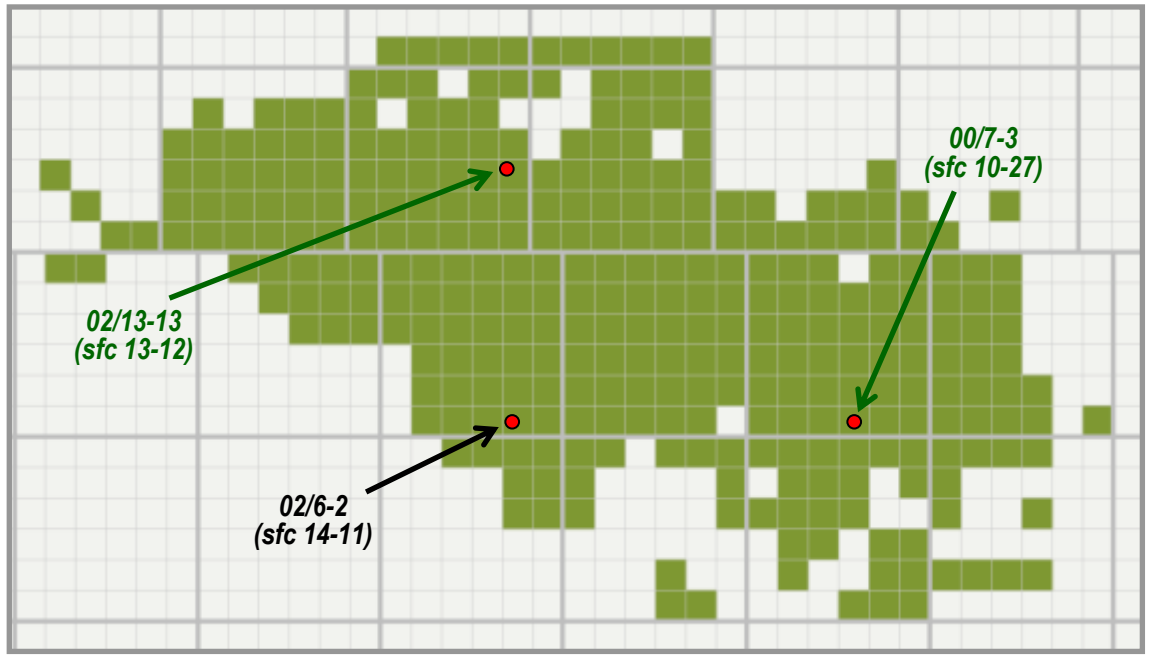
Inga / Fireweed Middle Montney Type Curve



Note:

[1] See "Appendix" for list of wells included in the well count and for individual decline curves for each well.

Oak / Flatrock Montney Lands



Kelt Lands

2019 DRILLING PLANS

→ Four to six Upper Montney delineation wells.

LAND

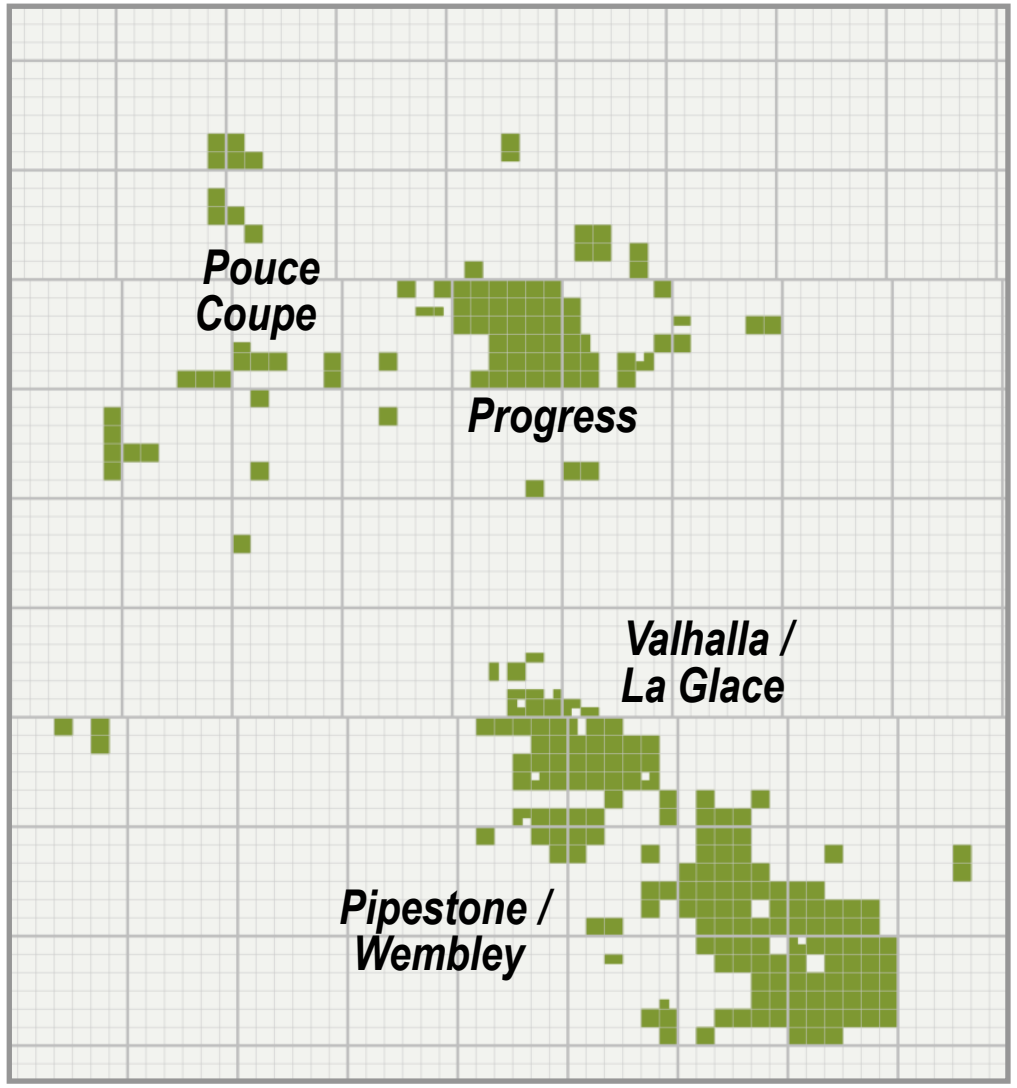
Montney Rights:

Gross: 206,913 acres (323 sections)
Net: 205,641 acres (321 sections)

OPERATIONS

- Oil and gas exploration activity targeting the Upper Montney (D4 / D5) at depths of 1,500 to 1,600 metres.
- Expectations are 30% to 50% oil/ngls and pressure gradients slightly above normal.
- The Company's initial discovery well located at 02/6-2 was successful and is currently on production.
- Two additional exploration tests were drilled in 2018.

Alberta Montney Lands



Kelt Lands

LAND

Montney Rights:

Gross: 174,560 acres (273 sections)
Net: 150,195 acres (235 sections)

OPERATIONS

- Kelt continues with development of the Lower-Middle (D1) and the Middle (D2) Montney at Pouce Coupe. The first five-well pad was completed Q117. The second five-well pad was completed late in Q118 and the Company has just completed the third five-well pad in Q418.
- Kelt has had success with the first two wells drilled in the Middle Montney at Progress and has recently drilled three additional wells.
- Kelt continues with its development drilling in the oil-weighted Montney play at Valhalla/La Glace.
- Kelt continues to have success with its delineation program in the Montney at Wembley/Pipestone.

Alberta Montney Wells

PRODUCTION

Kelt Alberta Montney OIL Drills
Top 10 IP30 Wells (gross sales, BOE/d):

(1)	Pouce Coupe 03/07-18-078-11W6 LMM (D1)	2,045 (66% oil/ngls)
(2)	Pouce Coupe 02/06-18-078-11W6 MM (D2)	2,004 (68% oil/ngls)
(3)	Pouce Coupe 02/16-09-078-11W6 MM (D2)	1,652 (67% oil/ngls)
(4)	Pouce Coupe 05/07-18-078-11W6 LMM (D1)	1,546 (58% oil/ngls)
(5)	Pouce Coupe 00/01-09-078-11W6 MM (D2)	1,529 (65% oil/ngls)
(6)	Wembley/La Glace 00/01-35-074-09W6 UMM (D3/D4)	1,422 (67% oil/ngls)
(7)	Wembley/Pipestone 00/04-01-072-08W6 UMM (D3/D4)	1,337 (83% oil/ngls)
(8)	Pouce Coupe 04/07-18-078-11W6 MM (D2)	1,320 (57% oil/ngls)
(9)	Pouce Coupe 02/09-09-078-11W6 MM (D2)	1,093 (71% oil/ngls)
(10)	Valhalla/La Glace 00/13-33-074-08W6 MM (D2)	1,090 (88% oil/ngls)

Abbreviations:
UM = Upper Montney or D5.
UMM = Upper-Middle Montney or D3/D4.
MM = Middle Montney or D2 (at Pouce Coupe also referred to as "Montney H").
LMM = Lower-Middle Montney or D1 (at Pouce Coupe also referred to as "Montney Sexsmith").

RESERVES

Typical Well EUR's

Pouce Coupe Montney OIL Sproule 2P EUR = 600 MBOE*:

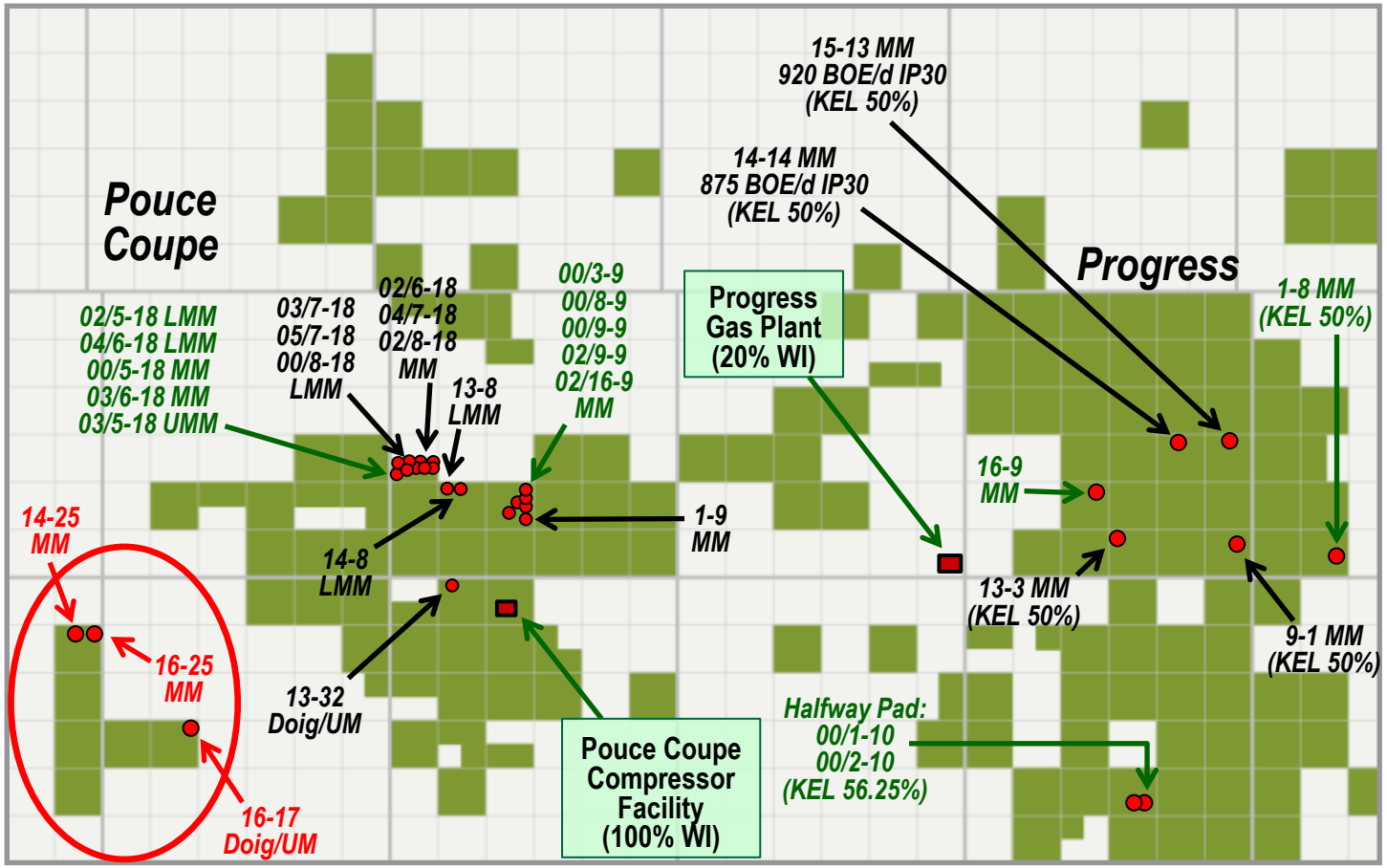
- 45% oil/ngls (270,000 bbls)
- 55% gas (2.0 Bcf)

La Glace Montney OIL Sproule 2P EUR = 590 MBOE:

- 61% oil/ngls (360,000 bbls)
- 39% gas (1.4 Bcf)

** Sproule has a 795 MBOE and a 514 MBOE type curve. Kelt is using a blend of the two curves.*

Pouce Coupe / Progress



Kelt Lands

Abbreviations:
UM = Upper Montney (D5)
UMM = Upper-Middle Montney (D3/D4)
MM = Middle Montney (D2 or may be referred to as "Montney H")
LMM = Lower-Middle Montney (D1 or may be referred to as "Montney Sexsmith")

OPERATIONS

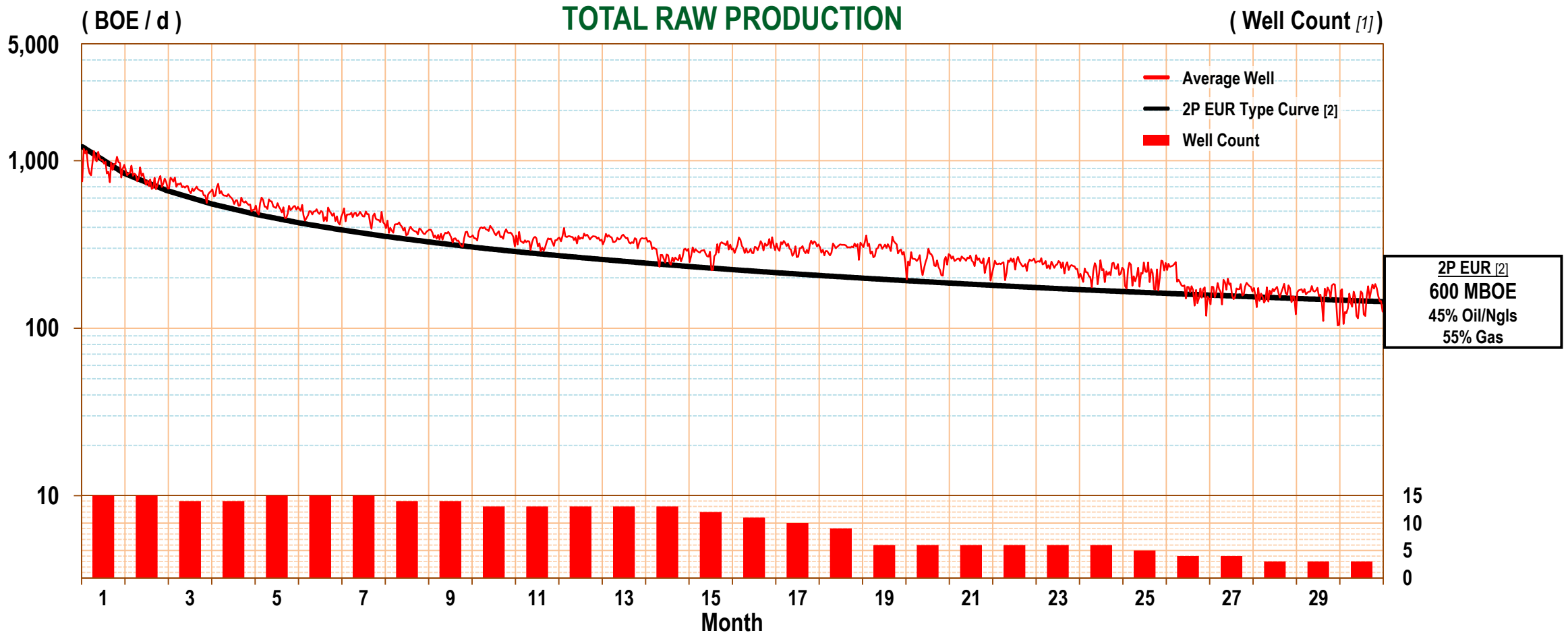
- **Kelt recently completed its first well (03/5-18) at Pouce Coupe in the Upper-Middle Montney (D4).**
- **Results from the 03/5-18 well are encouraging with an initial 58% oil/ngls weighting.**
- **The Company will evaluate the well's performance over the next few months as this zone could unlock additional drilling inventory on Kelt's lands.**

Kelt Pouce Coupe Montney GAS Drills Top IP30 Wells (gross sales, BOE/d):

(1)	**Pouce Coupe 03/16-25-077-13W6 MM**	**2,317 (94% gas)**
(2)	**Pouce Coupe 00/14-25-077-13W6 MM** *[1]*	**1,400 (95% gas)**
(3)	**Pouce Coupe 00/16-17-077-12W6 UM** *[1]*	**1,071 (90% gas)**

Note:
[1]The Pouce Coupe 14-25 and 16-17 wells were drilled with approximately two mile horizontal laterals and were put on production at restricted gas rates due to limited compression capacity.

Pouce Coupe / Progress Montney Oil Type Curve

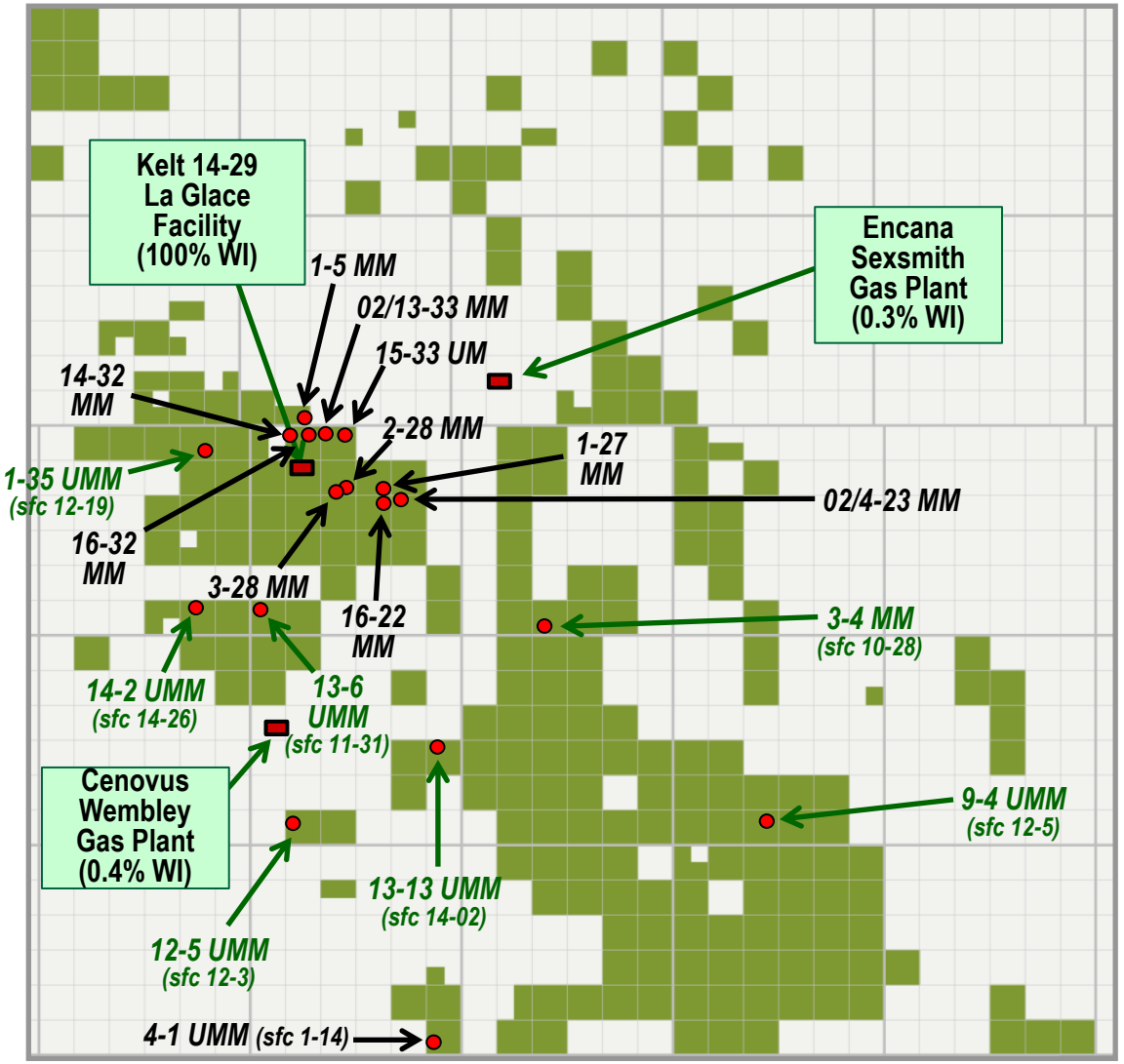


Note:

[1] See "Appendix" for list of wells included in the well count and for individual decline curves for each well.

[2] Sproule has a 795 MBOE and a 514 MBOE type curve. Kelt is using a blend of the two curves.

Valhalla / La Glace and Wembley / Pipestone



OPERATIONS

- Ownership in pipeline infrastructure, minor interests in gas plants and 100% interest in the Kelt La Glace Facility which has a handling capacity of 3,500 bbls/d of oil and 20 MMcf/d of gas.
- Kelt has entered into an agreement with Tidewater Midstream and Infrastructure Ltd. for firm processing of 30.0 MMcf/d of raw gas under a 10-year take-or-pay arrangement at the Pipestone Sour Deep-Cut Gas Processing Plant that is currently under construction and which is expected to be on-stream by mid-2019.
- At Wembley/Pipestone, as a follow-up to the discovery well at 4-1 (IP30 1,337 BOE/d), Kelt drilled, completed and tested five additional wells in 2018 and drilled two more wells (13-6 & 14-2) in Q418 which were completed in Q119.

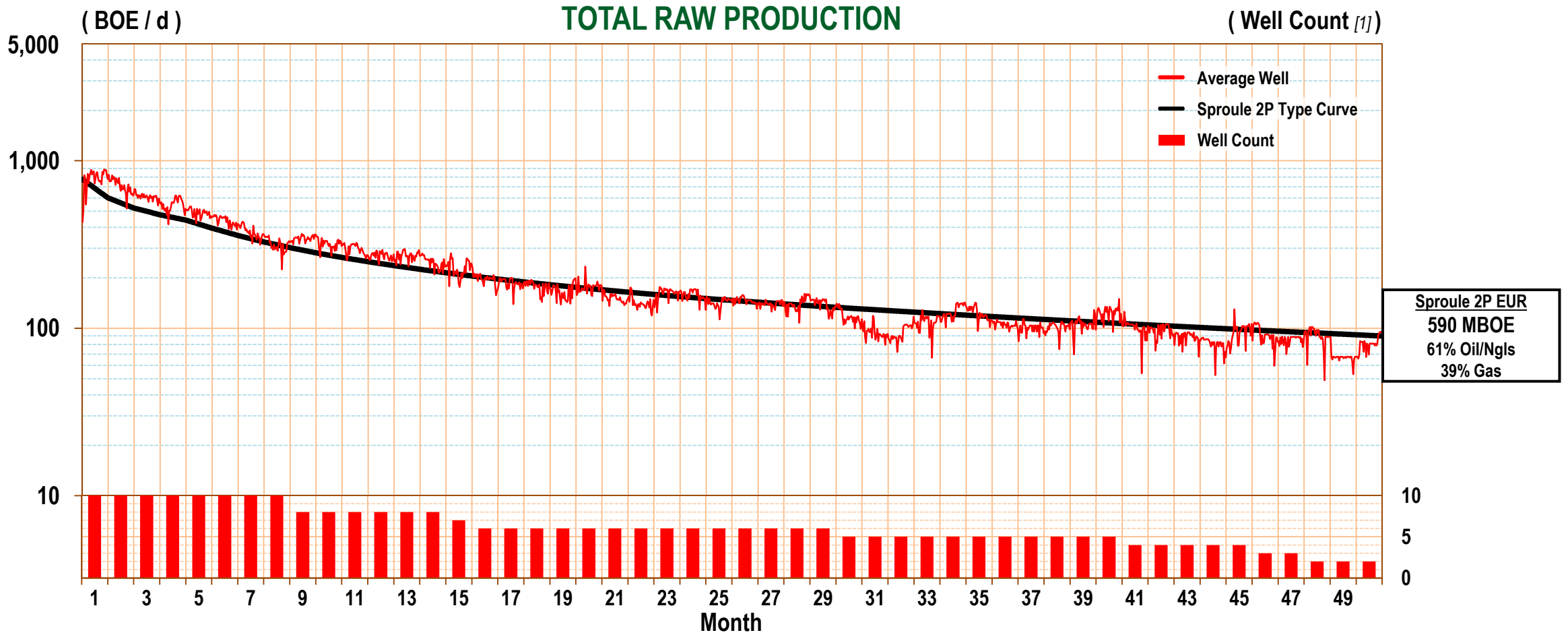
2019 DRILLING PLANS

→ Six Upper-Middle (D3/D4) Montney wells.

→ One water injection/disposal well.

Kelt Lands UM – Upper Montney (D5) UMM – Upper-Middle Montney (D3/D4) MM – Middle Montney (D2)

La Glace Montney Oil Type Curve



Note:

[1] See "Appendix" for list of wells included in the well count and for individual decline curves for each well.

2017 Montney Development Wells – Paybacks

Well	Drill & Complete Cost ($ MM) [1]	Initial Test Date	Production Start Date [2]	Actual Cumulative to Dec 31, 2017 [3]			Remaining to Payback [4]		Payback Period (Years)	Last Month's Production Rate at Payback (BOE/d)
				Production (MBOE)	Operating Income ($ MM)	Operating Netback ($/BOE)	Production Estimate (MBOE)	Operating Income Estimate ($ MM)		
Pouce Coupe 02/06-18-078-11W6	4.8	2017-01-26	2017-01-26	291.5	8.4	28.65	0.0	0.0	0.4	771
Pouce Coupe 03/07-18-078-11W6	4.1	2017-01-26	2017-01-26	237.6	6.6	27.67	0.0	0.0	0.4	791
Pouce Coupe 04/07-18-078-11W6	5.0	2017-01-24	2017-03-03	217.1	5.8	26.75	0.0	0.0	0.8	464
Pouce Coupe 05/07-18-078-11W6	4.3	2017-01-23	2017-03-08	200.6	5.5	27.63	0.0	0.0	0.5	588
Pouce Coupe 00/01-09-078-11W6	5.1	2017-02-21	2017-03-11	210.4	6.8	32.36	0.0	0.0	0.6	538
Pouce Coupe 03/16-25-077-13W6	5.8	2017-02-25	2017-06-19	314.6	3.5	11.05	213.2	3.2	0.9	1,550
La Glace 02/13-33-074-08W6	3.9	2017-04-01	2017-04-01	131.1	5.0	37.77	0.0	0.0	0.6	304
La Glace 02/04-23-074-08W6	4.1	2017-05-26	2017-05-26	118.0	3.3	27.66	40.6	1.2	0.9	305

Notes:

[1] Half-cycle capital – equipment and tie-in costs for pad wells are on average an incremental $300,000 per well and are included in the payback period calculation.

[2] Production Start Date is the date when the well commenced steady production after tie-in operations were completed. The payback period is calculated from this date.

[3] Actual production and operating income cumulative to date is up to Dec 31, 2017 and includes any production and operating income generated during the test period, prior to the Production Start Date.

*[4] **Estimated operating income required to payback is calculated based on actual sales prices received to date**. Estimated future production is calculated based on internally generated production forecasts/decline curves for each respective well.*

Net Asset Value

(millions)	Dec/31 2017	Dec/31 2018	% change
P&NG reserves, NPV10% BT	2,111.5	3,128.6	+ 48%
Decommissioning obligations, NPV10% BT *[1]*	(12.8)	(9.0)	– 29%
Undeveloped land	239.1	279.7	+ 17%
Net bank debt	(136.7)	(196.4)	+ 44%
Proceeds from exercise of stock options *[2]*	60.4	6.4	– 89%
NET ASSET VALUE	2,261.5	3,209.3	+ 42%
Diluted common shares outstanding *[3]*	204.4	207.0	+ 1%
NET ASSET VALUE PER SHARE	$ 11.06	$ 15.51	+ 40%

Notes:

[1] The present value of decommissioning obligations included above is incremental to the amount included in the present value of P&NG reserves as evaluated by Sproule.

[2] The calculation of proceeds from exercise of stock options and the diluted number of common shares outstanding only include stock options that are "in-the-money" based on the closing price of KEL of $7.19 and $4.64 per common share respectively as at December 31, 2017 and 2018.

[3] The 5% convertible debentures that mature on May 31, 2021 are convertible to common shares at $5.50 per share. At the December 31, 2018 closing price of $4.64 per share, the convertible debentures are "out-of-the-money" and 20.4 million shares issuable at a 5% discount are included in diluted common shares outstanding. At the December 31, 2017 closing price of $7.19, the convertible debentures are "in-the-money" and 16.3 million shares issuable upon conversion are included in diluted common shares outstanding.

Future Considerations

Kelt:

- The Company has numerous potential future drilling opportunities on its existing lands that will provide for continued growth in the years to come.
- The Company has amassed vast Montney acreage in new plays to complement its existing development Montney lands.
- The Company will continue to de-risk its undeveloped exploration lands as it embarks on full scale development of its de-risked Montney resource.

Crude Oil:

- Significant reductions in global capital investment since 2015 expected to impact future global supply growth.
- Global crude oil demand continues to grow.

Natural Gas:

- U.S. gas exports (Mexico and LNG) have increased year-over-year.
- U.S. gas storage surplus at the end of the 2016-17 winter (compared to the five year average) was eliminated primarily due to the colder than normal 2017-18 winter; however, U.S. gas storage is currently at a five-year low.

Management

David J. Wilson, President & CEO

Sadiq H. Lalani, Vice President & CFO

Douglas J. Errico, Vice President, Land

Alan G. Franks, Vice President, Production

Bruce D. Gigg, Vice President, Engineering

David A. Gillis, Vice President, Finance

Douglas O. MacArthur, Vice President, Operations

Patrick Miles, Vice President, Exploration

Carol Van Brunschot, Vice President, Marketing

William C. Guinan, Corporate Secretary

Board of Directors

Robert J. Dales	**Lead Director, Compensation (Chair), Audit, Reserves**
Geri L. Greenall	**Reserves (Chair), Audit, Nominating**
William C. Guinan	**Chairman of the Board, HSE**
Michael R. Shea	**Nominating (Chair), Compensation, Reserves**
Neil G. Sinclair	**Audit (Chair), Compensation, HSE, Nominating**
David J. Wilson	**HSE (Chair)**

Notes:

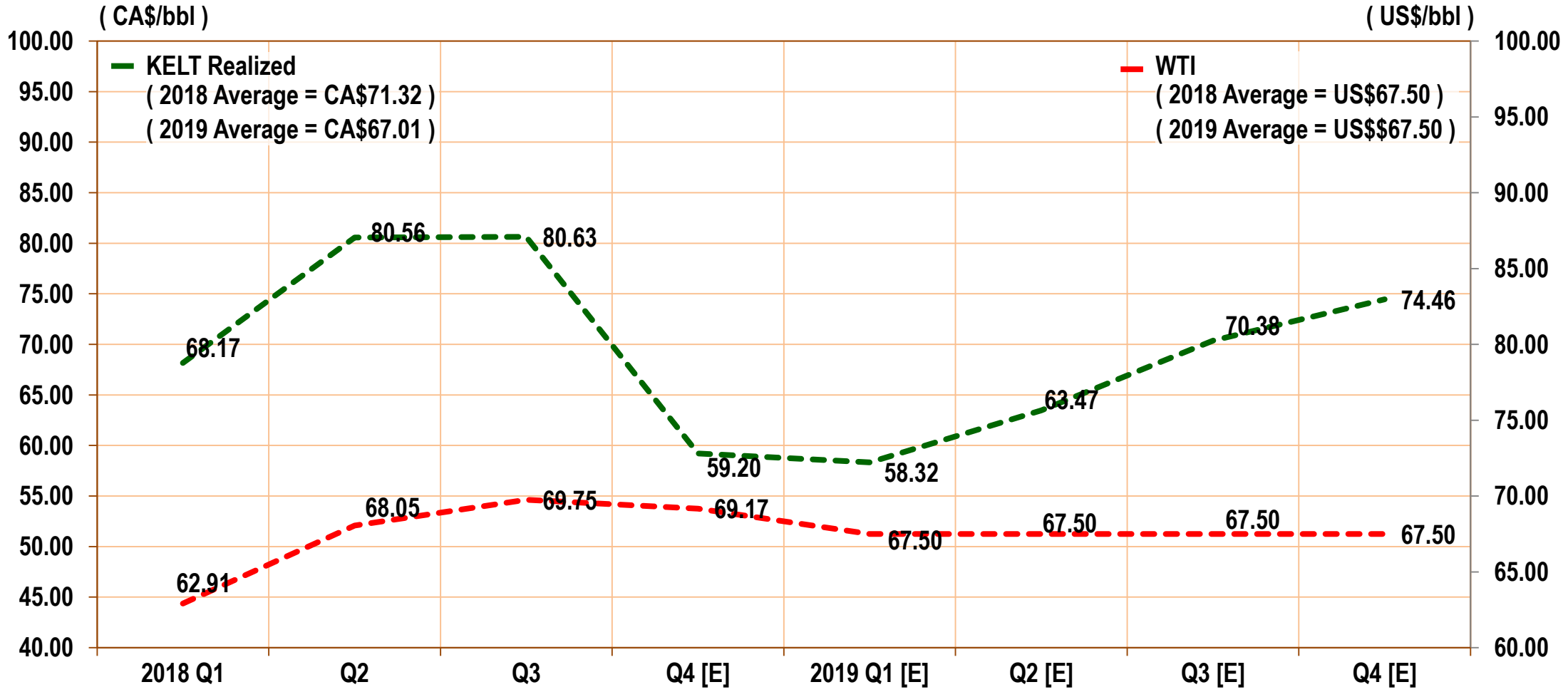
[1] Mr. Eldon A. McIntyre, who had been a director of Kelt since inception of the Company, retired from the Board on April 18, 2018.

[2] HSE – Health, Safety & Environment Committee.

Appendix

- Quarterly Forecast of 2019 WTI Oil & NYMEX Gas Prices
- Behind Pipe Production and DUCs
- Quarterly Production Growth
- Quarterly Cash Costs
- Reserves FD&A Costs plus Future Development Capital
- Spirit River – Charlie Lake Light Oil/Gas Property
- Grande Cache – Cretaceous Gas Property
- Inga Doig – 2017 Well Paybacks
- Well Type Curves
- Abbreviations
- Disclaimers

Kelt's 2019 Oil Price Forecast

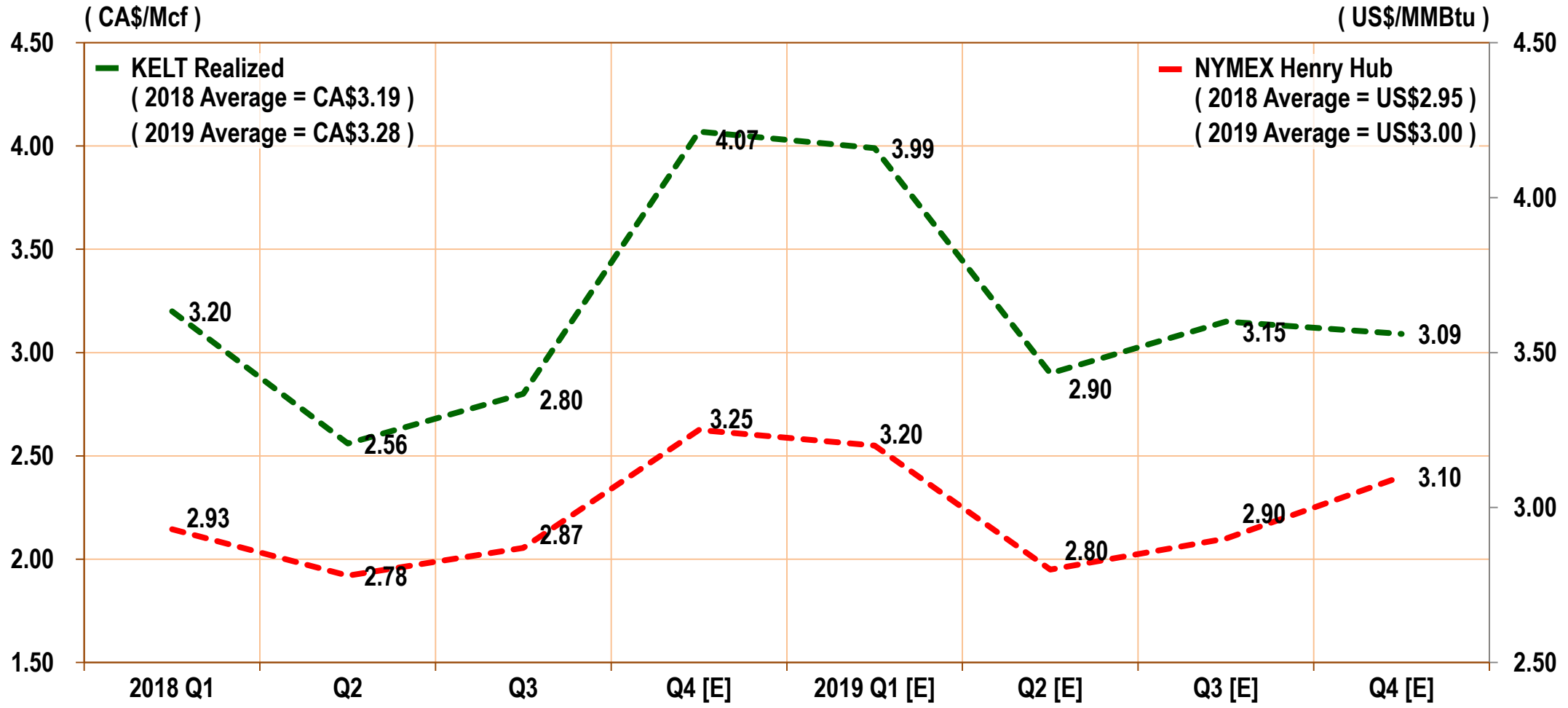


Notes:

2018: WTI to CLS differentials/discount = CA$9.52 (Q1), CA$10.05 (Q2), CA$15.42 (Q3), CA$30.00 (Q4); resulting in an average for 2018 = CA$16.27.

2019: WTI to CLS differentials/discount = CA$30.00 (Q1), CA$23.00 (Q2), CA$15.00 (Q3), CA$10.00 (Q4); resulting in an average for 2019 = CA$19.43.

Kelt's 2019 Gas Price Forecast



Behind Pipe Production and DUCs

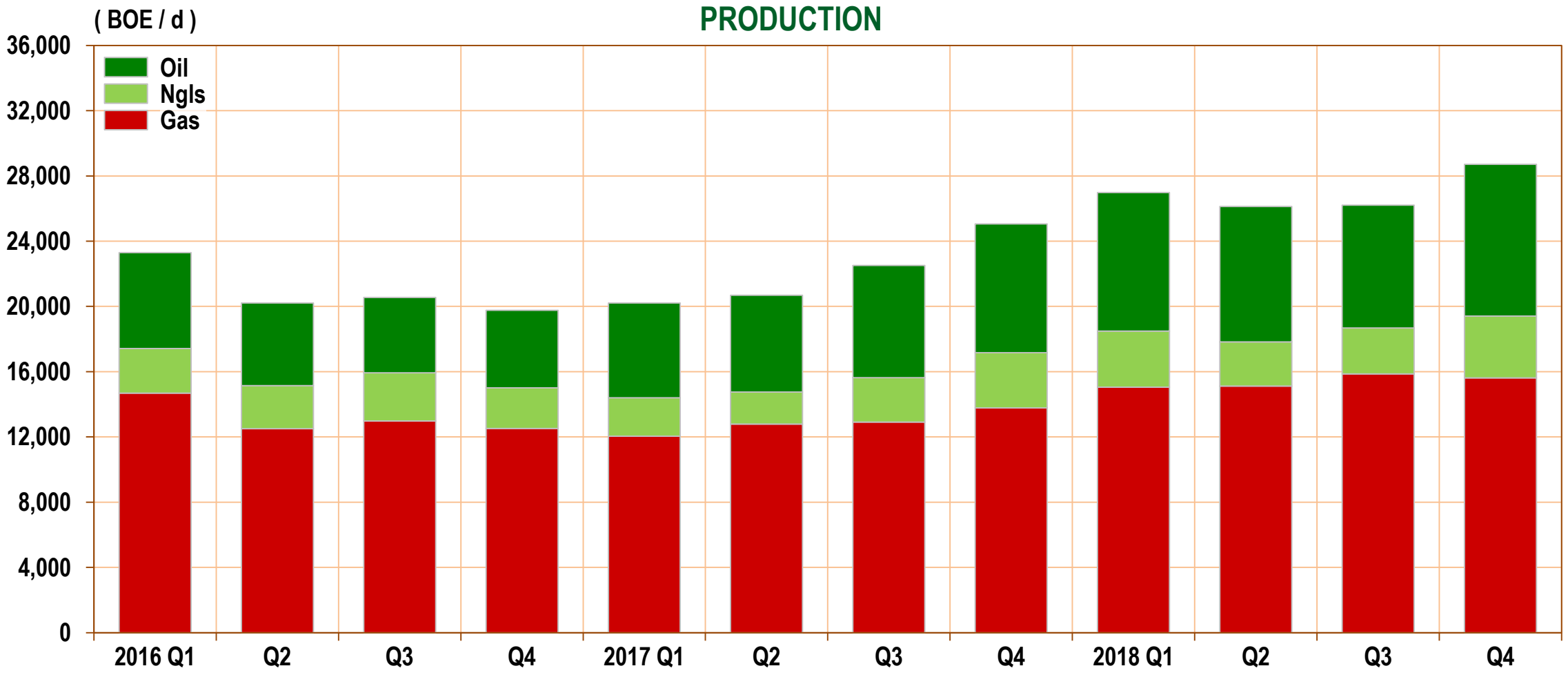
The following wells are expected to be drilled & completed as at December 31, 2018, however, production from these wells is not expected to be put on-stream until 2019:

- Wembley/Pipestone 00/09-04-073-06W6 Upper-Middle Montney (D3/D4).
- Wembley/Pipestone 00/12-05-073-08W6 Upper-Middle Montney (D3/D4).
- Wembley/Pipestone 00/13-13-073-08W6 Upper-Middle Montney (D3/D4).
- Wembley/Valhalla 00/03-04-074-07W6 Middle Montney (D2).
- Wembley/Valhalla 00/13-06-074-08W6 Upper-Middle Montney (D3/D4).

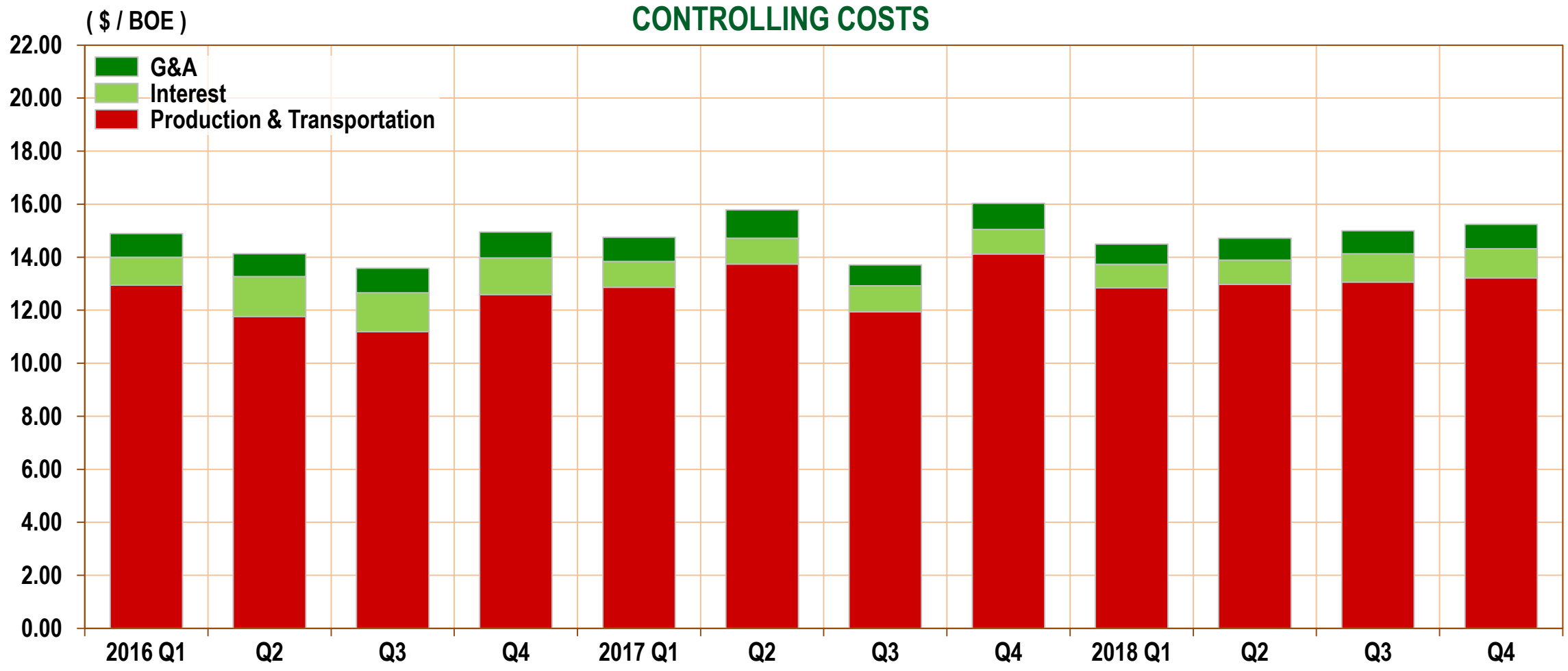
The following wells are expected to be drilled but not completed (DUCs) as at December 31, 2018. These wells are expected to be completed in 2019 and production from these wells is expected to be put on-stream in 2019:

- Fireweed 00/15-25-088-23W6 Middle Montney (5-well pad).
- Fireweed A-065-I/94-A-12 Middle Montney (5-well pad).
- Fireweed 02/A-065-I/94-A-12 Upper Montney (5-well pad).
- Fireweed 03/A-065-I/94-A-12 Upper Montney (5-well pad).
- Fireweed B-065-I/94-A-12 Upper Montney (5-well pad).
- Inga 03/16-33-087-23W6 IBZ Montney (6-well pad).
- Inga 04/16-33-087-23W6 Middle Montney (6-well pad).
- Inga 05/16-33-087-23W6 Upper Montney (6-well pad).
- Inga 06/16-33-087-23W6 IBZ Montney (6-well pad).
- Inga 03/15-33-087-23W6 Upper Montney (6-well pad).
- Wembley/Valhalla 00/14-02-074-09W6 UM Montney (D3/D4).

Quarterly Production Growth



Quarterly Cash Costs



Reserves

	Dec/31/2017 (MMBOE)	Dec/31/2018 (MMBOE)	Percent Change	NPV 10% BT Dec/31/2017 ($ MM)
Proved Developed Producing	37.9	40.7	+ 7%	$ 481
Total Proved	133.0	158.4	+ 19%	$ 1,499
Proved plus Probable (P+P)	235.6	302.7	+ 28%	$ 3,129
Oil / Ngls (P+P %)	43%	43%		
Gas (P+P%)	57%	57%		

Notes:

[1] Reserves are per the reports prepared by Sproule Associates Limited. Reserve volumes include Company gross working interest share of remaining reserves, as determined in accordance with NI 51-101.

Finding, Development & Acquisition Costs

As at December 31, 2018	Proved	Proved + Probable
2018 capital expenditures + change in FDC ($M)	381,046	596,004
Reserve additions, net (MBOE)	35,298	76,905
FD&A cost ($/BOE)	10.80	7.75
2018 operating netback ($/BOE)	20.56	20.56
Recycle ratio (looking back – 2017)	1.9 x	2.7 x

Notes:

[1] Reserves are per the reports prepared by Sproule Associates Limited. Reserve volumes include Company gross working interest share of remaining reserves, as determined in accordance with NI 51-101.

[2] FD&A in 2017 were $9.61/BOE (Proved) and $6.94/BOE (P+P).

[3] FD&A: Finding, development & acquisition (net of dispositions).

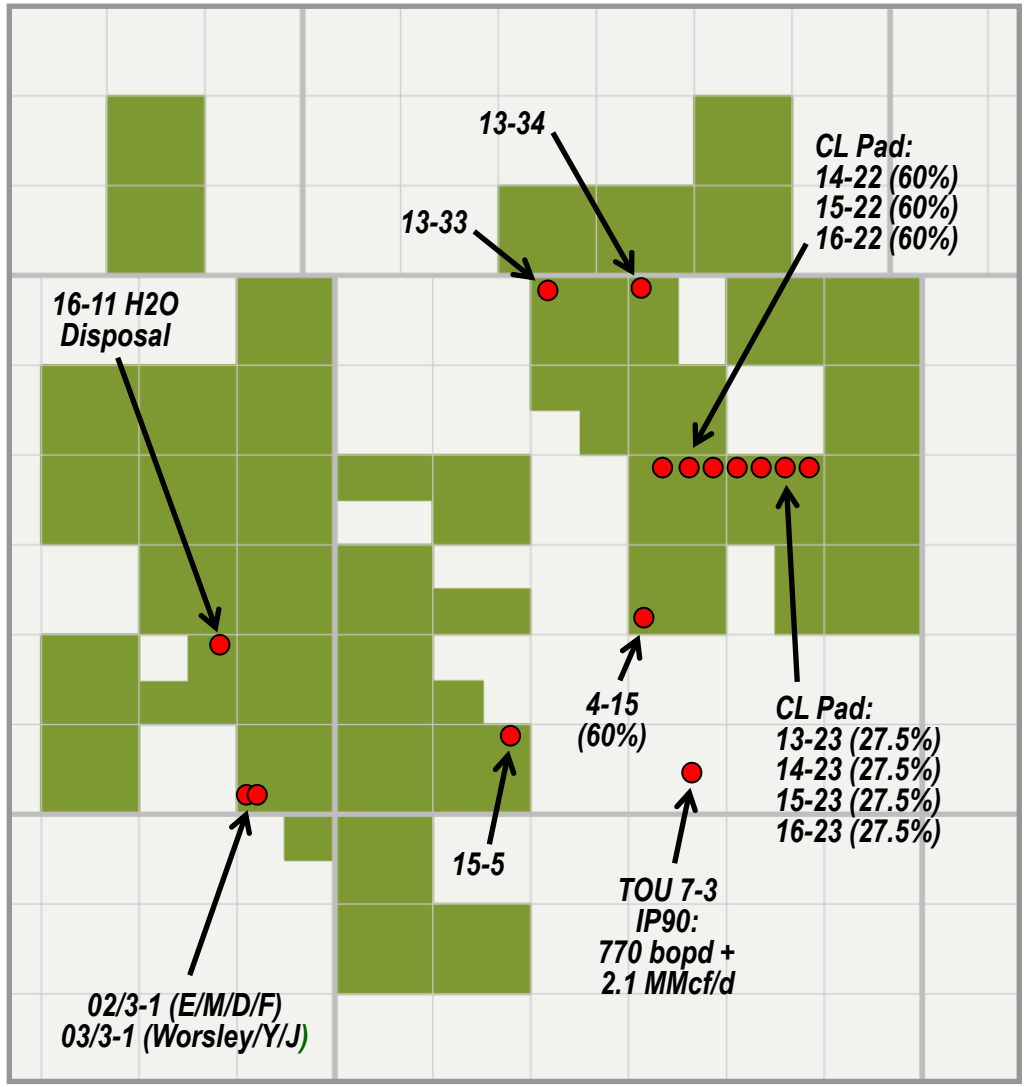
[4] FDC: Future development capital.

Sproule P+P Reserves – FDC

December 31, 2018	FDC ($MM)	Net HZ Wells
Alberta Montney wells	332	59
B.C. Montney wells	744	140
TOTAL Montney wells	1,076	199
Other formation wells	355	77
Other expenditures	43	-
TOTAL	1,474	276

Abbreviations:
[1] FDC is per the evaluation report prepared by Sproule Associates Limited effective December 31, 2018.
[2] FDC = Future Development Capital.
[3] HZ = horizontal.

Spirit River – Charlie Lake

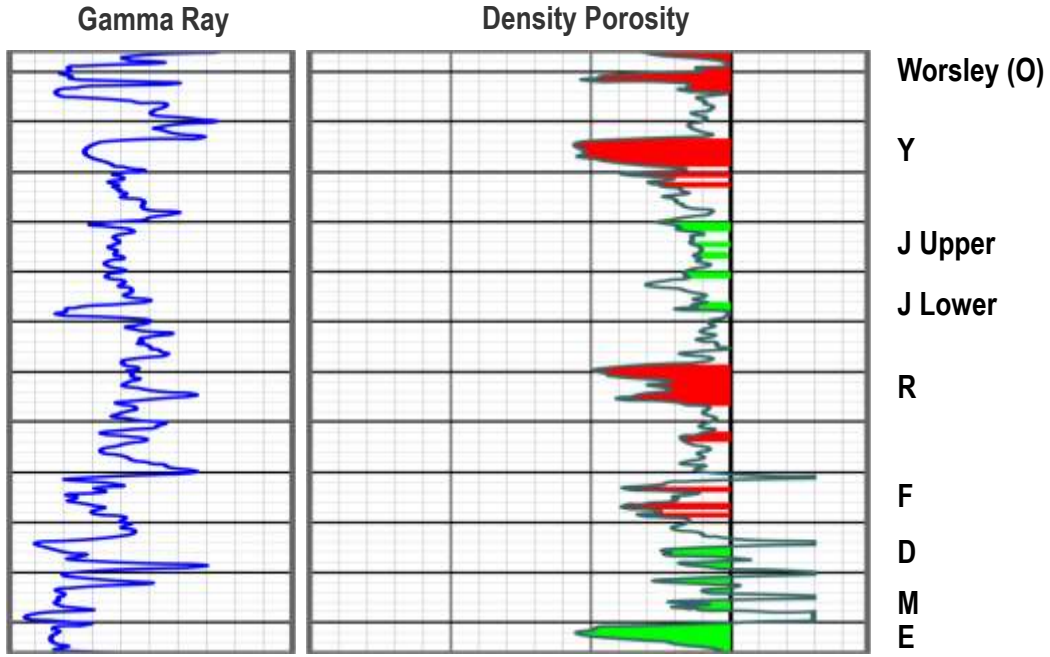


Land

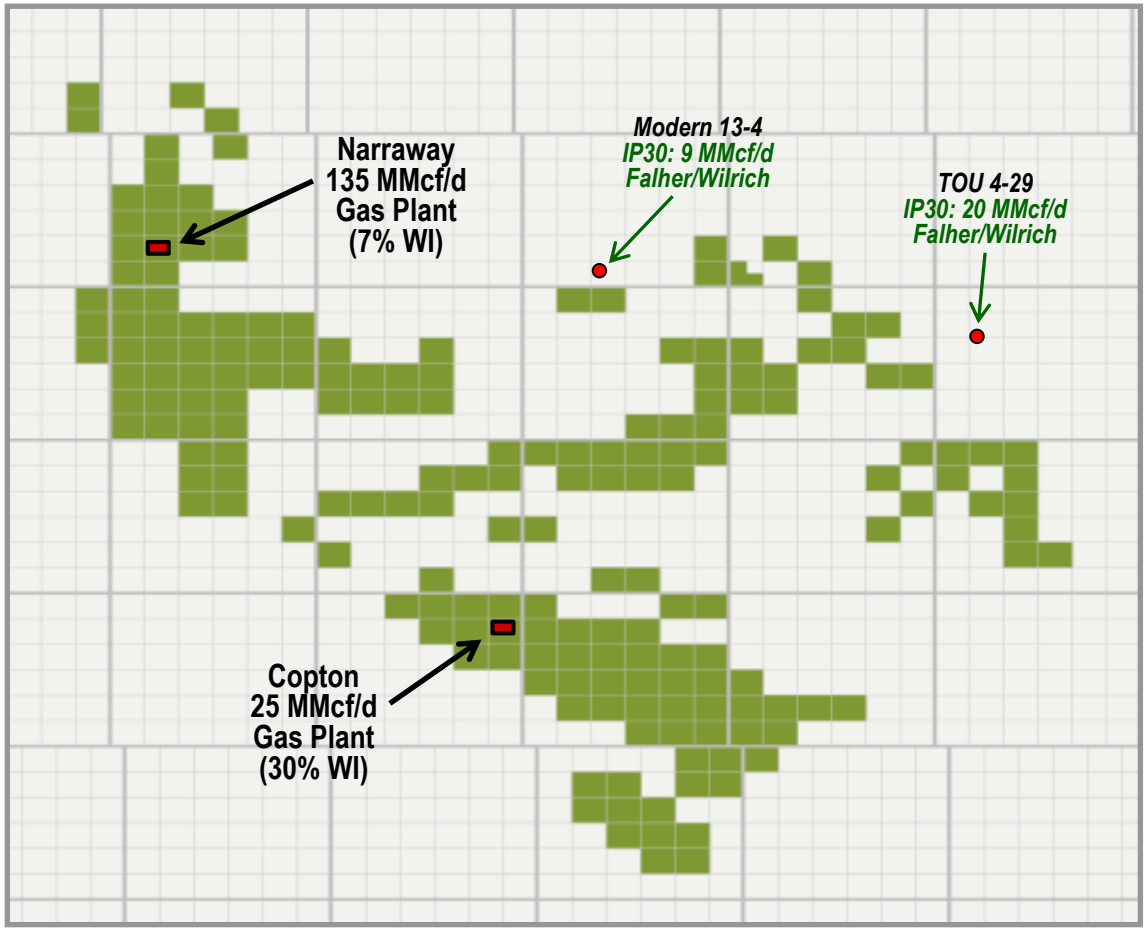
Gross: 30,560 acres (48 sections)
Net: 23,151 acres (36 sections)

Charlie Lake: 20.25 net sections

Charlie Lake:



Grande Cache



LAND

Gross: 128,160 acres (200 sections)
Net: 90,824 acres (142 sections)

OPERATIONS

- Low decline Cretaceous natural gas production
- Ownership interests in gas gathering infrastructure and in the Narraway and Copton Gas Plants
- Low operating expenses
- Successful Falher/Wilrich gas wells offsetting Kelt acreage

2017 B.C. Inga DOIG Development Wells – Paybacks

- **Kelt drilled two Doig wells in 2017 where 2P Type Curves target an IP30 of 2,000 BOE/d (26% gas / 74% oil/ngls) and EURs of 1,080 MBOE (49% gas / 51% oil/ngls).**
- **Kelt has 31 (28.4 net) future 2P HZ development locations booked as inventory in the Doig in its Dec/31/17 reserves evaluation.**

Well	Drill & Complete Cost ($ MM) *[1]*	Initial Test Date	Production Start Date *[2]*	Actual Cumulative to Dec 31, 2017 *[3]*			Remaining to Payback *[4]*		Payback Period (Years)	Last Month's Production Rate at Payback (BOE/d)
				Production (MBOE)	Operating Income ($ MM)	Operating Netback ($/BOE)	Production Estimate (MBOE)	Operating Income Estimate ($ MM)		
Inga 00/15-33-087-23W6/0 [Doig]	6.9	2017-06-29	2017-06-29	165.5	5.3	31.88	75.4	2.0	0.8	525
Inga 00/07-02-088-23W6/0 [Doig]	7.3	2017-07-14	2017-07-14	182.3	6.1	33.45	51.6	1.5	0.6	820

Notes:

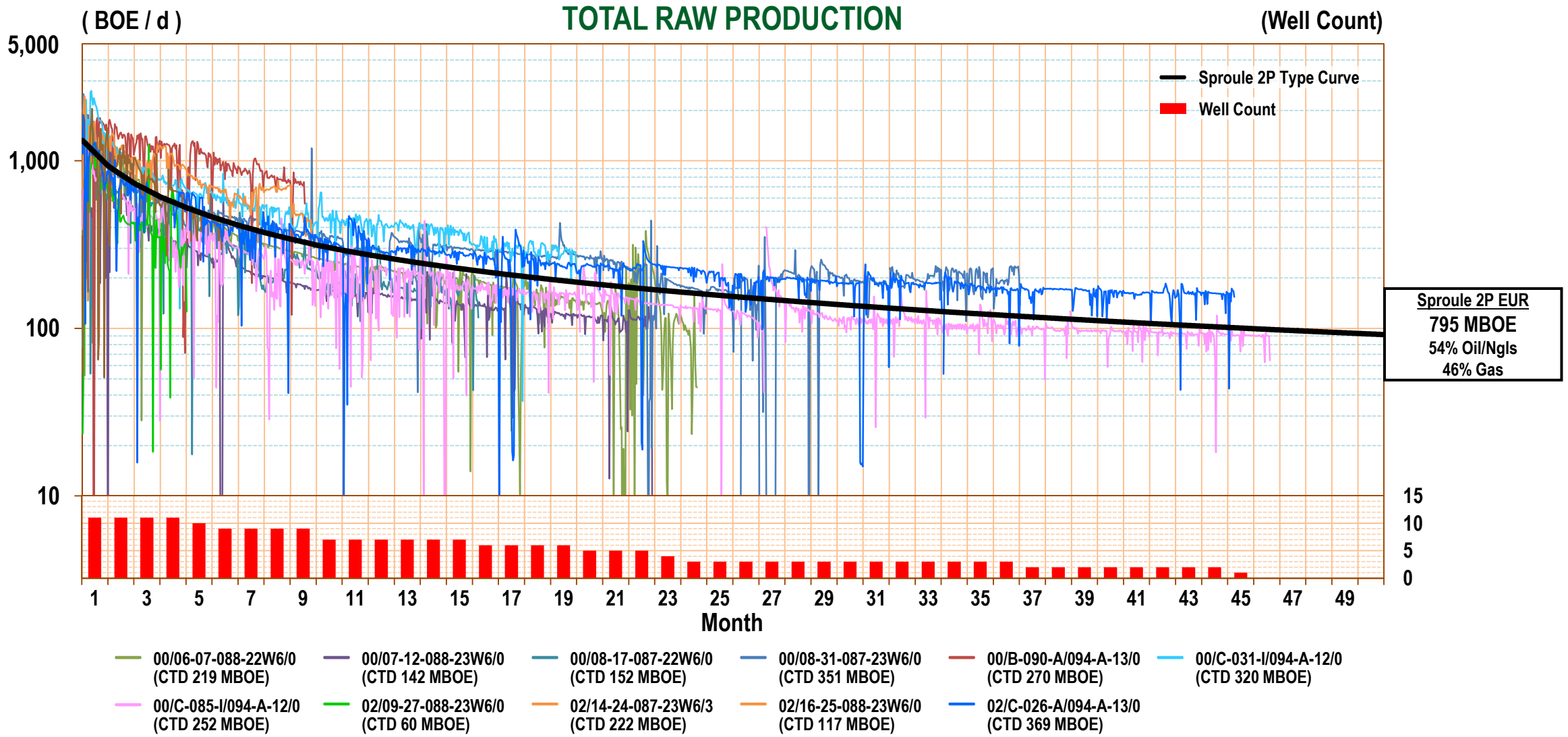
[1] Half-cycle capital – equipment and tie-in costs for pad wells are on average an incremental $300,000 per well and are included in the payback period calculation.

[2] Production Start Date is the date when the well commenced steady production after tie-in operations were completed. The payback period is calculated from this date.

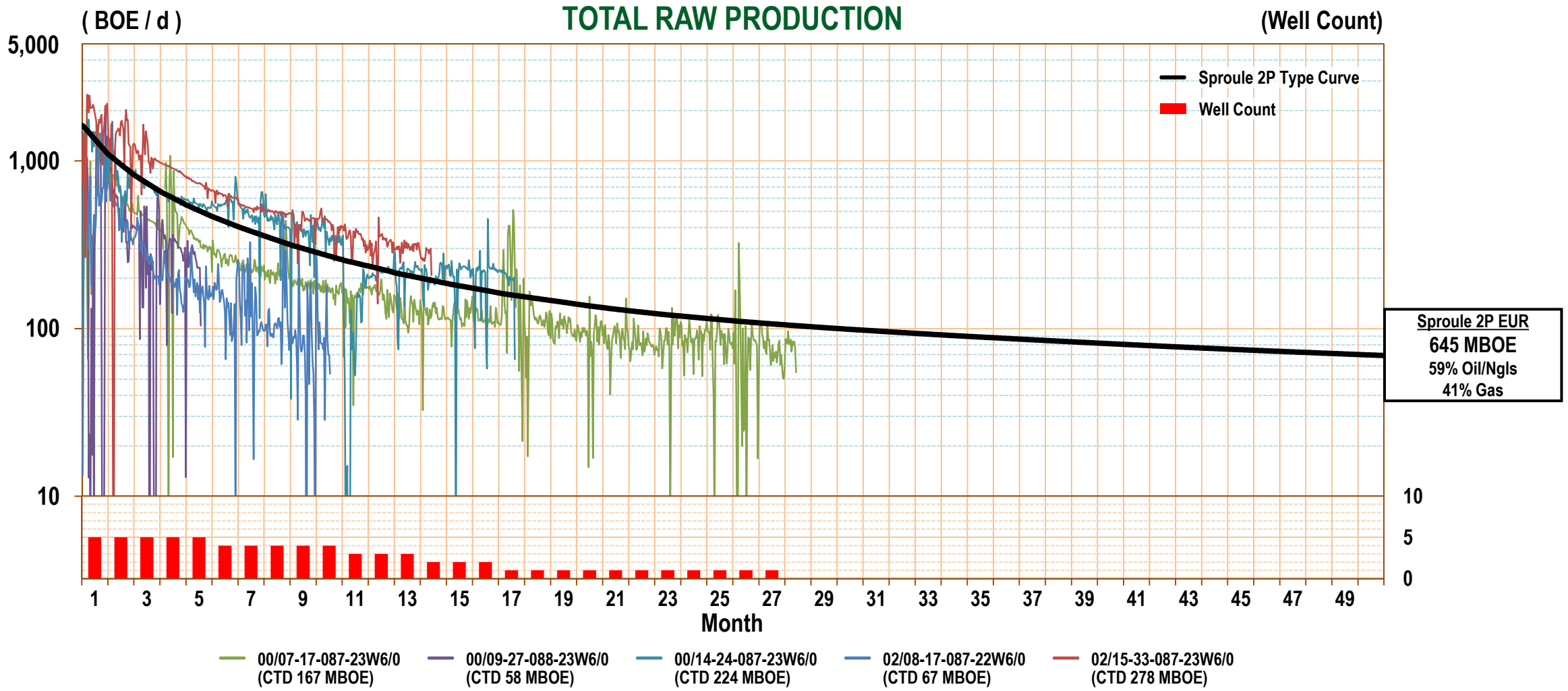
[3] Actual production and operating income cumulative to date is up to Dec 31, 2017 and includes any production and operating income generated during the test period, prior to the Production Start Date.

*[4] **Estimated operating income required to payback is calculated based on actual sales prices received to date.** Estimated future production is calculated based on internally generated production forecasts/decline curves for each respective well.*

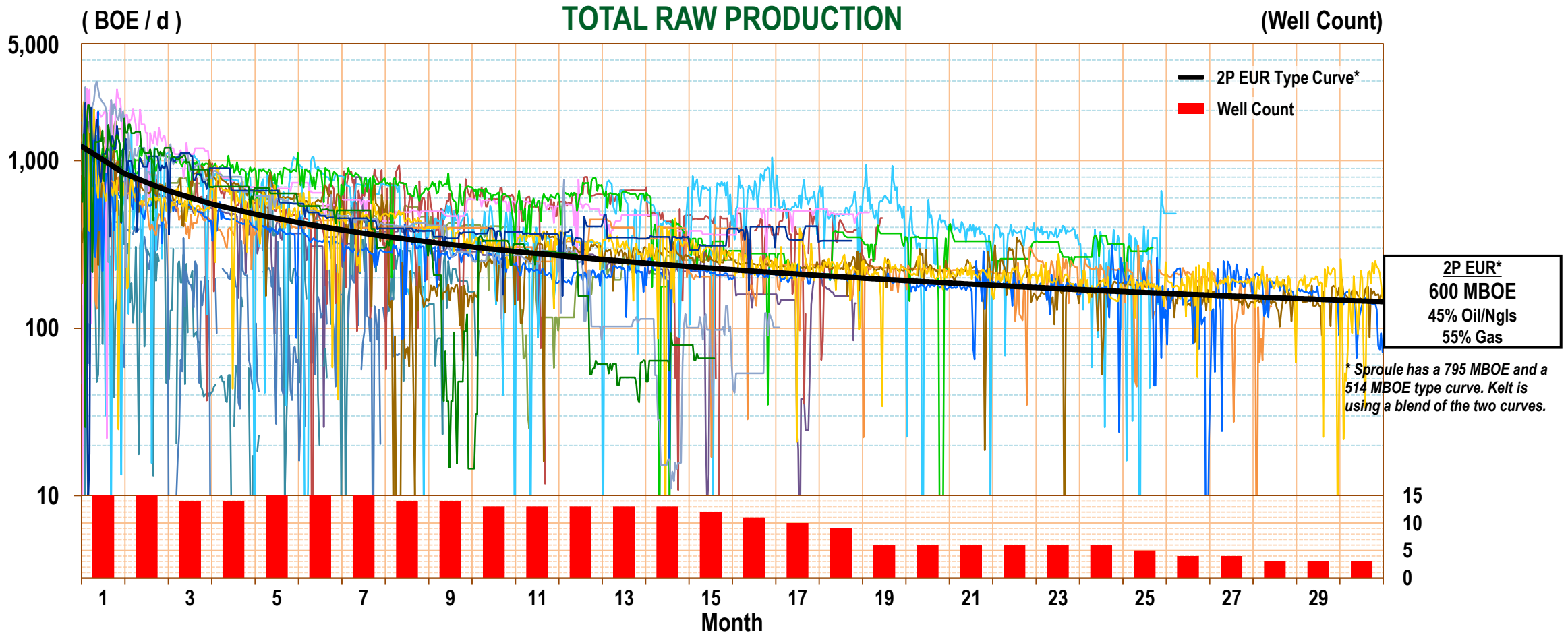
Inga / Fireweed Upper Montney Type Curve



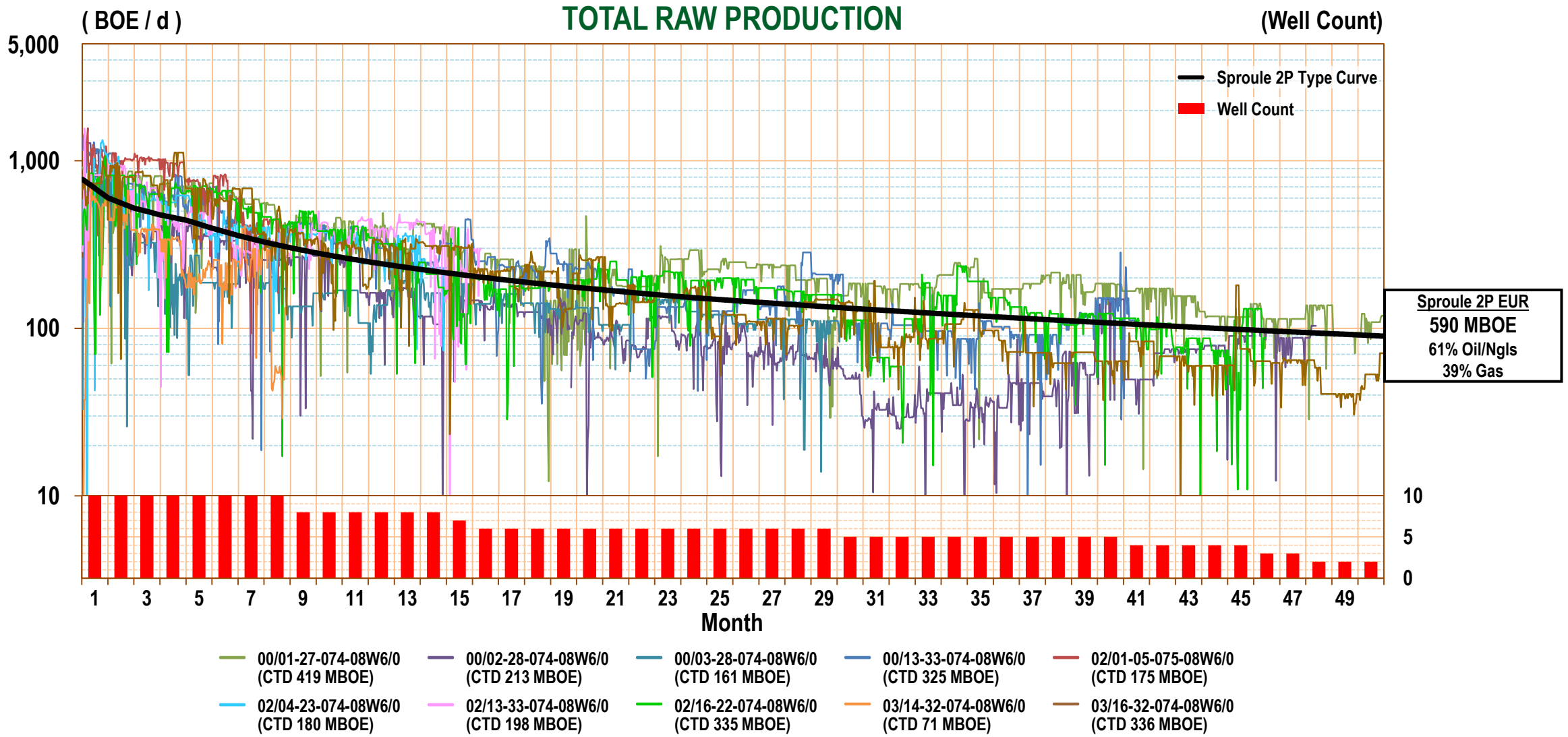
Inga / Fireweed Middle Montney Type Curve



Pouce Coupe / Progress Montney Oil Type Curve



La Glace Montney Oil Type Curve



Abbreviations

GAAP: Canadian generally accepted accounting principles as set out in the *CPA Canada Handbook – Accounting.*
IFRS: International Financial Reporting Standards as issued by the International Accounting Standards Board ("**IASB**').
FFO: Funds from operations
WTI: West Texas Intermediate
CLS: Canadian Light Sweet
NYMEX: New York Mercantile Exchange
AECO: Alberta Energy Company "C" Meter Station of the NOVA Pipeline System
MRF: Modernized Royalty Framework (Alberta)
PDP: Proved developed producing reserves.
1P: Proved reserves.
2P or P+P: Proved plus probable reserves.
BOE/d: barrels of oil equivalent per day
bbls/d: barrels per day
Mcf/d: thousand cubic feet per day
GJ: gigajoules
LT: long tonnes
MM: million
LNG: liquefied natural gas

Disclaimer

Forward Looking Statements

Certain statements included in this corporate presentation (the **"Presentation"**) constitute forward looking statements or forward looking information under applicable securities legislation. Such forward looking statements or information are 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 purposes, such as making investment decisions. Forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", "goal", "objective", "assume", "forecast" or similar words suggesting future outcomes or statements regarding an outlook.

Forward looking statements or information in this Presentation include, but are not limited to, statements or information with respect to: Kelt Exploration Ltd.'s (**"Kelt"** or the **"Company"**) business strategy and objectives; statements with respect to the performance characteristics of Kelt's oil and natural gas properties and wells; potential future drilling locations; development plans, exploration plans, delineation drilling, in-fill drilling, optimization plans and effect on costs and production; the Company's focus for 2018 and 2019, including capital expenditures, budgeted drilling and completion costs per well, drilling program, maintaining a strong balance sheet and cost reductions; anticipated production including production mix; estimated recoverable resources; expansion of infrastructure; timing of drilling and completions; plans to investigate or participate in infrastructure projects; the Company's plan to continue to evaluate construction of processing facilities and sales pipelines; forecasted pricing; actual and estimated internal rates of return, which include assumptions respecting production and other costs, pricing, well depths, royalty rates and taxes; 2018 forecasted activities and 2019 budgeted activities, 2019 discretionary capital expenditures of $75.0 million that could be postponed or not incurred, 2019 Pro-forma financial and operating results with lower oil and NGL prices and higher gas prices compared to the 2019 Budget; economic metrics including capital, IRR, net present values, EUR, netbacks, and production rates; that the estimated future production and operating income for the 2017 Montney and Doig development wells will be sufficient to payback the drill and complete capital costs incurred for each respective well; the expectation that the Company's gas market diversification will limit exposure to single market risk.

In addition, the statements contained herein relating to "reserves" and "resources" are by their nature forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves or resources described exist in the quantities predicted or estimated and that the reserves or resources can be profitably produced in the future. Actual reserves or resources may be greater than or less than the estimates provided herein.

Future Oriented Financial Information

This Presentation contains Future Oriented Financial Information ("FOFI") within the meaning of applicable securities laws. The FOFI has been prepared by Kelt's management to provide an outlook of the Company's activities and results. The FOFI has been prepared based on a number of assumptions including the assumptions discussed under the heading "Forward Looking Statements" and assumptions with respect to the costs and expenditures to be incurred by the Company, capital equipment and operating costs, foreign exchange rates, taxation rates for the Company, general and administrative expenses and the prices to be paid for the Company's production. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the FOFI or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable.

Disclaimer

The actual results of operations of the Company and the resulting financial results will likely vary from the amounts set forth in the analysis presented in this Presentation, and such variation may be material. The Company and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, because this information is highly subjective and subject to numerous risks including the risks discussed under the heading "Forward Looking Statements", it should not be relied on as necessarily indicative of future results.

Except as required by applicable securities laws, Kelt undertakes no obligation to update such FOFI and forward looking statements and information.

Assumptions

Forward looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct.

In addition to other factors and assumptions which may be identified in this Presentation, assumptions have been made regarding, among other things: commodity prices; the accuracy of geological and geophysical data and its interpretations of that data; estimated decline rates; the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of the Company to operate in a safe, efficient and effective manner; the ability of the Company to obtain financing on acceptable terms; that the Company will have sufficient cash flow, debt or equity or other financial resources to fund its capital and operating expenditures as needed; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Company to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; that the estimates of the Company's reserve volumes and assumptions related thereto are accurate in all material respects; and the ability of the Company to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

Disclaimer

Risks and Uncertainties

Forward looking statements or information are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward looking statements or information. These risks and uncertainties which may cause actual results to differ materially from the forward looking statements or information include, among other things: the ability of management to execute its business plan; general economic and business conditions; the risk of instability affecting the jurisdictions in which the Company operates; the risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; risks and uncertainties involving geology of oil and gas deposits; the uncertainty of reserves estimates and reserves life; the ability of the Company to add production and reserves through acquisition, development and exploration activities; the Company's ability to enter into or renew leases; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to production (including decline rates), costs and expenses; fluctuations in oil and gas prices, foreign currency exchange rates and interest rates; risks inherent in the Company's marketing operations, including credit risk; uncertainty in amounts and timing of royalty payments; health, safety and environmental risks; risks associated with potential future lawsuits and regulatory actions against the Company; uncertainties as to the availability and cost of financing; changes in income tax rates; changes in incentive programs related to the oil and gas industry; and financial risks affecting the value of the Company's investments.

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

No Obligation to Update

The forward looking statements or information contained in this Presentation are made as of the date hereof and the Company 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 required by applicable securities laws.

The forward looking statements or information contained in this Presentation are expressly qualified by this cautionary statement.

Disclaimer

Oil and Gas Advisories

Barrel of Oil Equivalent Presentation

This Presentation contains various references to the abbreviation BOE which means barrels of oil equivalent. Where amounts are expressed on a BOE basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel and sulphur volumes have been converted to oil equivalence at 0.6 long tons per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and is significantly different than the value ratio based on the current price of crude oil and natural gas. This conversion factor is an industry accepted norm and is not based on current prices. Such abbreviation may be misleading, particularly if used in isolation.

References to **"oil"** in this Presentation include crude oil and field condensate.

References to **"natural gas liquids"** or **"ngls"** include pentane, butane, propane, and ethane.

References to **"liquids"** includes field condensate and ngls.

References to **"gas"** in this discussion include natural gas and sulphur.

Type Well Production and Economics

This Presentation contains references to type well, or "type curve", production and economics, which are derived, at least in part, from available information respecting the well economics of other companies and, as such, there is no guarantee that Kelt will achieve the stated or similar results, capital costs and return costs per well. Any references to peak rates, test rates or initial production rates or declines are useful for confirming the presence of hydrocarbons, however, such rates and declines 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 ultimate recovery. In addition, such rates or declines may also include recovered fluids used in well completion stimulation.

Readers are cautioned not to place reliance on such rates in calculating aggregate production for the Company.

Disclaimer

Reserves

Unless otherwise specified, reserve estimates disclosed in this Presentation were prepared by Sproule Associates Limited ("**Sproule**") in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**") and the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and using Sproule's forecast prices. There is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward looking statements. EUR is not indicative of reserves. Estimates of the net present value of the future net revenue from Kelt's reserves do not represent the fair market value of Kelt's reserves. Reserves estimates contained herein have been made assuming that funding is likely to be available to Kelt for the development of the applicable property.

Future Drilling Locations

Unless otherwise specified, the information in this Presentation pertaining to future drilling locations or drilling inventories is based solely on internal estimates made by management and such locations have not been reflected in any independent reserve or resource evaluations prepared pursuant to NI 51-101. Similarly, unless otherwise specified, the information in this Presentation pertaining to targeted reserve volumes from future drilling is intended to indicate that in making its internal drilling decisions, the Company seeks to target drilling locations that, based on previous drilling results and its own internal assessments, it believes will on average ultimately generate the indicated volumes. This Presentation discloses drilling locations which are unbooked locations and are internal estimates based on Kelt's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources and have been identified by management as an estimation of multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Kelt 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 we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Estimated Ultimate Recovery

Estimated Ultimate Recovery ("**EUR**") is an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well. EUR is not a defined term within the COGE Handbook and therefore any reference to EUR in this Presentation is not deemed to be reported under the requirements of NI 51-101. Readers are cautioned that there is no certainty that the Company will ultimately recover the estimated quantity of oil or gas from such reserves or wells.

Disclaimer

Financial Advisories

All dollar amounts are referenced in Canadian dollars, except when otherwise noted.

Non-GAAP Financial Measures and Other Key Performance Indicators

This Presentation contains certain financial measures, as described below, which do not have standardized meanings prescribed by GAAP. In addition, this Presentation contains other key performance indicators ("KPI"), financial and non-financial, that do not have standardized meanings under the applicable securities legislation. As these non-GAAP financial measures and KPI are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

Non-GAAP Financial Measures

"Operating income" is calculated by deducting royalties, production expenses and transportation expenses from oil and gas revenue, after realized gains or losses on associated financial instruments. The Company refers to operating income expressed per unit of production as an **"Operating netback"**.

"Adjusted funds from operations" is calculated as cash provided by operating activities before changes in non-cash operating working capital, and adding back: transaction costs associated with acquisitions and dispositions, provisions for potential credit losses, and settlement of decommissioning obligations. Adjusted funds from operations per common share is calculated on a consistent basis with profit (loss) per common share, using basic and diluted weighted average common shares as determined in accordance with GAAP. Adjusted funds from operations and operating income or netbacks are used by Kelt as key measures of performance and are not intended to represent operating profits nor should they be viewed as an alternative to cash provided by operating activities, profit or other measures of financial performance calculated in accordance with GAAP. For a reconciliation of cash provided by operating activities to adjusted funds from operations and the calculation of operating income derived from the individual financial statement line items in accordance with GAAP see the management's discussion and analysis of the financial condition and results of operations of the Corporation.

"Net bank debt" is used synonymously with, and is equal to, "bank debt, net of working capital". "Net bank debt" is calculated by adding the working capital deficiency to bank debt. The working capital deficiency is equal to total current assets net of total current liabilities. The Company uses a "net bank debt to trailing adjusted funds from operations ratio" as a benchmark on which management monitors the Company's capital structure and short-term financing requirements. Management believes that this ratio, which is a non-GAAP financial measure, provides investors with information to understand the Company's liquidity risk. The "net bank debt to trailing adjusted funds from operations ratio" is also indicative of the "debt to cash flow" calculation used to determine the applicable margin for a quarter under the Company's Credit Facility agreement (though the calculation may not always be a precise match, it is representative).

Disclaimer

Other Key Performance Indicators

Production per common share: is calculated by dividing total production by the basic weighted average number of common shares outstanding, as determined in accordance with GAAP.

NPV10% BT: the anticipated net present value of the future net cash flow before taxes and after capital expenditures, discounted at a rate of 10%.

IRR: Internal rate of return. IRR is the discount rate required to arrive at a NPV equal to zero. Rates of return set forth in this Presentation are for illustrative purposes. There is no guarantee that such rates of return will be achieved in the future.

Reserves Replacement: the estimated amount of reserves added to the reserves base during the year relative to the amount of oil and gas produced.

IP30: the initial production from a well for the first 720 hours (30 days) based on operating/producing hours.

Finding, development and acquisition ("FD&A") cost: is the sum of capital expenditures incurred in the period and the change in future development capital ("FDC") required to develop reserves. FD&A cost per BOE is determined by dividing current period net reserve additions into the corresponding period's FD&A cost. Readers are cautioned that the aggregate of capital expenditures incurred in the year, comprised of exploration and development costs and acquisition costs, and the change in estimated FDC generally will not reflect total FD&A costs related to reserves additions in the year. For calculations relating to FD&A costs and recycle ratios, see the management's discussion and analysis of the financial condition and results of operations of the Company for the year ended December 31, 2017.

Recycle ratio: is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital investment by comparing the operating netback per BOE to FD&A cost per BOE.

Net asset value per common share: is calculated by adding the present value of petroleum and natural gas reserves, undeveloped land value and proceeds from exercise of stock options, less the present value of decommissioning obligations and bank debt, net of working capital, and dividing by the diluted number of common shares outstanding. The calculation of proceeds from exercise of stock options and the diluted number of common shares outstanding only include stock options that are "in-the-money" based on the closing price of KEL common shares as at the calculation date. The diluted number of common shares outstanding includes common shares issuable upon conversion of the convertible debentures that are "in-the-money" based on the closing price of KEL common shares as at the calculation date.

Corporate Presentation

kelt exploration

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Calgary, Alberta
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Fax: 403-291-0155
Website: www.KeltExploration.com