# Corporate Presentation

**APRIL 2018**

kelt exploration

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*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 on 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** — **$ 1.2 billion**
- **52-week trading range** — **$ 5.56 – $ 8.20**
- **Common shares issued ( @ Mar/31/2018 )** — **180.5 million**

- **Stock options ( 8.3 MM ) & RSUs ( 0.7 MM )** — **9.0 million ( 5.0% )**
  → **average exercise price of stock options is $ 6.54 / share**
- **Diluted common shares (before convertible debentures)** — **189.5 million**
- **Diluted common shares (debs convert to 16.4 MM shares)** — **205.9 million**
- **Directors & Officers (D&O's) ownership** *[1]* — **17% ( 19% diluted )**

*Note:*
*[1] See slide entitled "Insider Commitment" for details of Insider participation in equity offerings.*

# Convertible Debentures



- **TSX trading symbol** — **KEL.DB**
- **Principal amount outstanding** — **$ 90.0 million**
- **Coupon / Maturity date** — **5.0% / May 31, 2021**
- **52-week trading range** — **$ 133.51 – $ 162.00**

**→ 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.**

# INSIDER COMMITMENT



| Offering / Market Purchases | Insider Purchases | | |
|---|---|---|---|
| | Shares (MM) | Amount ($MM) | Price/share |
| $ 13.9 MM Equity Private Placement | 3.7 | 8.7 | $ 2.32 |
| $ 94.4 MM Equity Private Placement | 5.7 | 31.5 | $ 5.55 |
| $ 92.0 MM Equity Private Placement | 0.5 | 4.0 | $ 8.00 |
| $ 19.6 MM Flow-through Equity Private Placement | 0.5 | 4.9 | $ 9.80 |
| $ 101.1 MM Equity Private Placement | 2.4 | 19.6 | $8.15 |
| $ 33.6 MM Flow-through Equity Private Placement | 1.0 | 13.5 | $ 12.75 |
| $ 33.4 MM Flow-through Equity Private Placement | 1.7 | 14.7 | $ 8.60 |
| $ 90.0 MM Equity Prospectus Offering | 0.4 | 3.5 | $ 8.85 |
| $ 22.1 MM Flow-through Equity Private Placement | 0.2 | 0.9 | $ 4.70 |
| Open Market Purchases | 2.5 | 14.6 | $ 5.82 |
| $ 90.0 MM Convertible Debenture Offering *[1]* | 2.7 | 14.7 | $ 5.50 |
| $ 15.5 MM Flow-through Equity Private Placement | 0.1 | 0.6 | $ 7.75 |
| TOTAL *[2]* | 21.4 | 131.2 | $ 6.12 |

*Notes:*

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

*[2] Insiders total current holdings are **31.4 million shares or 17.4% of outstanding shares** (includes Kelt shares received from previous Celtic and Artek holdings and is before conversion of debentures).*

# Capital Expenditures



| ( $ millions ) | 2016 | 2017 | 2018 Forecast | 2018/17 Change |
|---|---|---|---|---|
| Drilling & Completions | 47.4 | 154.7 | 135.0 | - 13% |
| Facilities, Equipment & Pipeline Infrastructure | 28.5 | 78.0 | 65.0 | - 17% |
| Land, Seismic & Asset Acquisitions | 28.3 | 11.6 | 10.0 | - 14% |
| Capital Expenditures | 104.2 | 244.3 | 210.0 | - 14% |
| Property Dispositions | ( 5.9 ) | ( 116.3 ) [1] | – | |
| Net Capital Expenditures | 98.3 | 128.0 | 210.0 | + 64% |

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 | 2017 Gross Wells | 2017 Net Wells | 2018 Gross Wells | 2018 Net Wells |
|---|---|---|---|---|
| Alberta | 16 | 15.0 | 8 | 7.1 |
| British Columbia | 13 | 13.0 | 12 | 12.0 |
| Non-operated Properties | 11 | 3.2 | 1 | 1.0 |
| Total | 40 | 31.2 | 21 | 20.1 |

| Completions | 2017 Gross Wells | 2017 Net Wells | 2018 Gross Wells | 2018 Net Wells |
|---|---|---|---|---|
| Alberta | 15 | 14.0 | 14 | 13.1 |
| British Columbia | 13 | 13.0 | 13 | 13.0 |
| Non-operated Properties | 11 | 3.2 | 1 | 1.0 |
| Total | 39 | 30.2 | 28 | 27.1 *[1]* |

*Note:*
*[1] There were 7 DUCs (wells drilled in 2017 but not expected to be completed until 2018) from 2017 in the following areas: 5-well pad at Pouce Coupe, 1 well at Progress and 1 well at Inga.*

# Reserves



## LIQUIDS WEIGHTING CONTINUES TO GROW:

- **2017 proved plus probable reserve additions, before dispositions, were weighted 63% to oil/ngls and 37% to gas compared to 40% and 60% respectively in 2016.**
- **The 2018 drilling program will continue to target oil and condensate rich Montney wells.**

| | Oil / Ngls ( Mbbls ) | Gas ( MMcf ) | Combined ( MBOE ) |
|---|---|---|---|
| As at December 31, 2017 | | | |
| Proved plus Probable Reserves | 101,788 | 802,875 | 235,601 |
| Weighting | 43% | 57% | 100% |
| As at December 31, 2016 | | | |
| Proved plus Probable Reserves | 71,893 | 733,037 | 194,066 |
| Weighting | 37% | 63% | 100% |

*Note:*

*[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, 2017 | Proved | Proved + Probable |
|---|---|---|
| 2017 capital expenditures + change in FDC ( $M ) | 315,436 | 343,953 |
| Reserve additions, net ( MBOE ) | 32,837 | 49,592 |
| FD&A cost ( $/BOE ) | 9.61 | 6.94 |
| 2017 operating netback ( $/BOE ) | 15.28 | 15.28 |
| Recycle ratio ( looking back – 2017 ) | 1.6 x | 2.2 x |
| 2018 forecasted operating netback ( $/BOE ) | 20.50 | 20.50 |
| Recycle ratio ( looking forward – 2018 ) | 2.1 x | 3.0 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 2016 were $4.86/BOE (Proved) and $3.47/BOE (P+P).*

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

*[4] FDC: Future development capital.*

# Production Outlook



| | 2016 | 2017 | 2018 Forecast | 2018/17 Change |
|---|---|---|---|---|
| Oil ( bbls/d ) | 5,070 | 6,634 | 10,200 – 10,600 | 54% – 60% |
| Ngls ( bbls/d ) | 2,709 | 2,608 | 3,200 – 3,300 | 23% – 27% |
| Gas ( mcf/d ) | 79,009 | 77,330 | 90,600 – 93,600 | 17% – 21% |
| Combined ( BOE/d ) | 20,947 | 22,130 | 28,500 – 29,500 | 29% – 33% |
| Per MM Shares ( BOE/d ) | 121 | 125 | 158 – 164 | 26% – 31% |

# 2018 Product Mix



| | Production Split | 2018 Forecast ( $MM ) | Income Split |
|---|---|---|---|
| Oil | 36% | 173.0 | 80% |
| Ngls *[1]* | 11% | 20.0 | 9% |
| Gas | 53% | 24.0 | 11% |
| Operating income | 100% | 217.0 | 100% |
| G&A and interest expense | | ( 17.0 ) | |
| Funds from operations | | 200.0 | |

*Note:*

*[1] The 2018 forecasted Ngls production mix is as follows:*

| | |
|---|---|
| *Pentane ( C5+ )* | *26%* |
| *Butane ( C4 )* | *27%* |
| *Propane ( C3 )* | *29%* |
| *Ethane ( C2 )* | *18%* |
| ***Total Ngls*** | ***100%*** |

# Commodity Prices



| ( CA$, unless otherwise specified ) | 2016 | 2017 | 2018 (E) | YOY Change |
|---|---|---|---|---|
| WTI Crude Oil ( USD/bbl ) *[1]* | US $ 43.32 | US $ 50.95 | US $ 58.50 | + 15% |
| CLS Crude Oil ( CAD/bbl ) *[2]* | $ 52.79 | $ 61.85 | $ 69.80 | + 13% |
| NYMEX Natural Gas ( USD/MMBtu ) | US $ 2.43 | US $ 3.07 | US $ 3.05 | – 1% |
| CHICAGO City Gate Gas Daily Index ( USD/MMBtu ) | US $ 2.47 | US $ 2.90 | US $ 2.85 | – 2% |
| DAWN Gas Daily Index ( USD/MMBtu ) | US $ 2.56 | US $ 3.04 | US $ 2.80 | – 8% |
| MALIN Gas Monthly Index ( USD/MMBtu ) | US $ 2.33 | US $ 2.82 | US $ 2.48 | – 12% |
| SUMAS Gas Monthly Index ( USD/MMBtu ) | US $ 2.17 | US $ 2.76 | US $ 2.43 | – 12% |
| AECO 5A Gas Daily Index ( USD/MMBtu ) *[3]* | US $ 1.63 | US $ 1.66 | US $ 1.63 | – 2% |
| Station 2 Gas NGX Daily Index ( USD/MMBtu ) *[3]* | US $1.30 | US $ 1.20 | US $ 1.33 | + 11% |
| Exchange Rate ( CAD/USD ) | $ 1.326 | $ 1.298 | $ 1.266 | – 2% |
| Exchange Rate ( USD/CAD ) | US $ 0.754 | US $ 0.770 | US $ 0.790 | + 3% |
| Kelt Oil price ( $/bbl ) | $ 47.84 | $ 59.09 | $ 66.88 | + 13% |
| Discount to CLS Crude Oil price | - 9.4% | - 4.5% | - 4.2% | |
| Kelt Ngls price ( $/bbl ) | $ 18.28 | $ 27.72 | $ 33.32 | + 20% |
| Kelt Gas price ( $/Mcf ) | $ 2.69 | $ 3.01 | $ 3.05 | + 1% |
| Premium to AECO 5A price per MMBtu | + 24.5% | + 40.0% | + 48.0% | |
| Kelt combined price ( $/BOE ) | $ 24.08 | $ 31.51 | $ 37.42 | + 19% |

*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.*

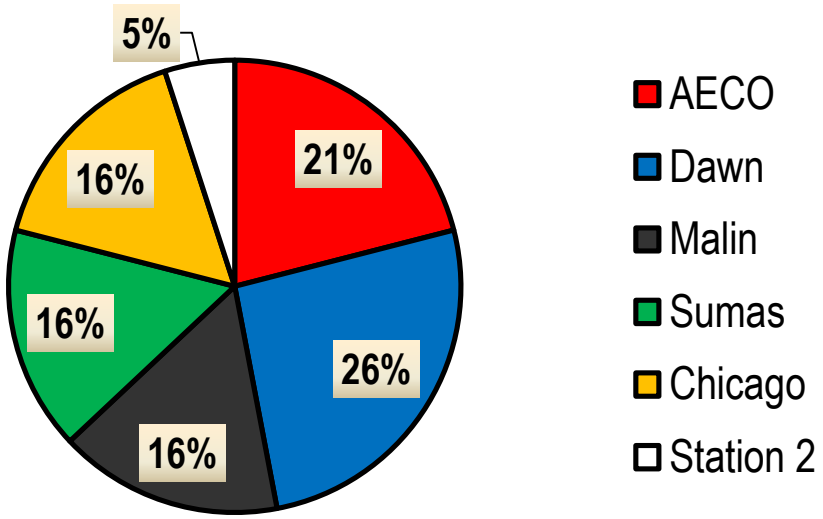
*[3] AECO and Station 2 converted from GJ to MMBtu at a factor of 1.0546 GJ / MMBtu (1,000 Btu/cf gas).*

# 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 2018 average gas sales at each price hub is expected to be as follows:**



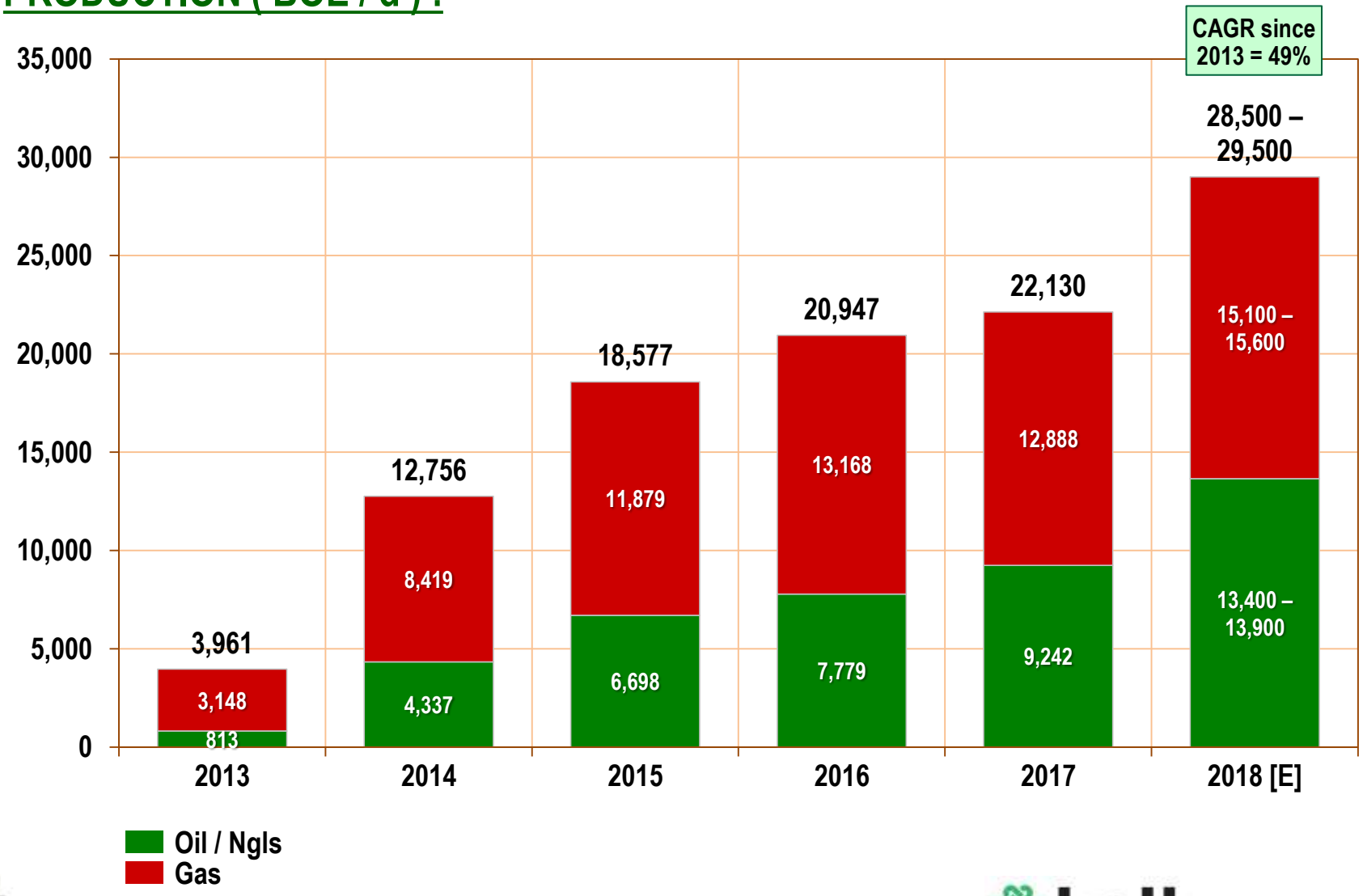

*Note:*

*See "North American Natural Gas Hubs" and "Gas Marketing/Transportation Contracts" slides in the Appendix for detailed information regarding Kelt's gas market contracts.*

# Annual Production Growth ( since inception )



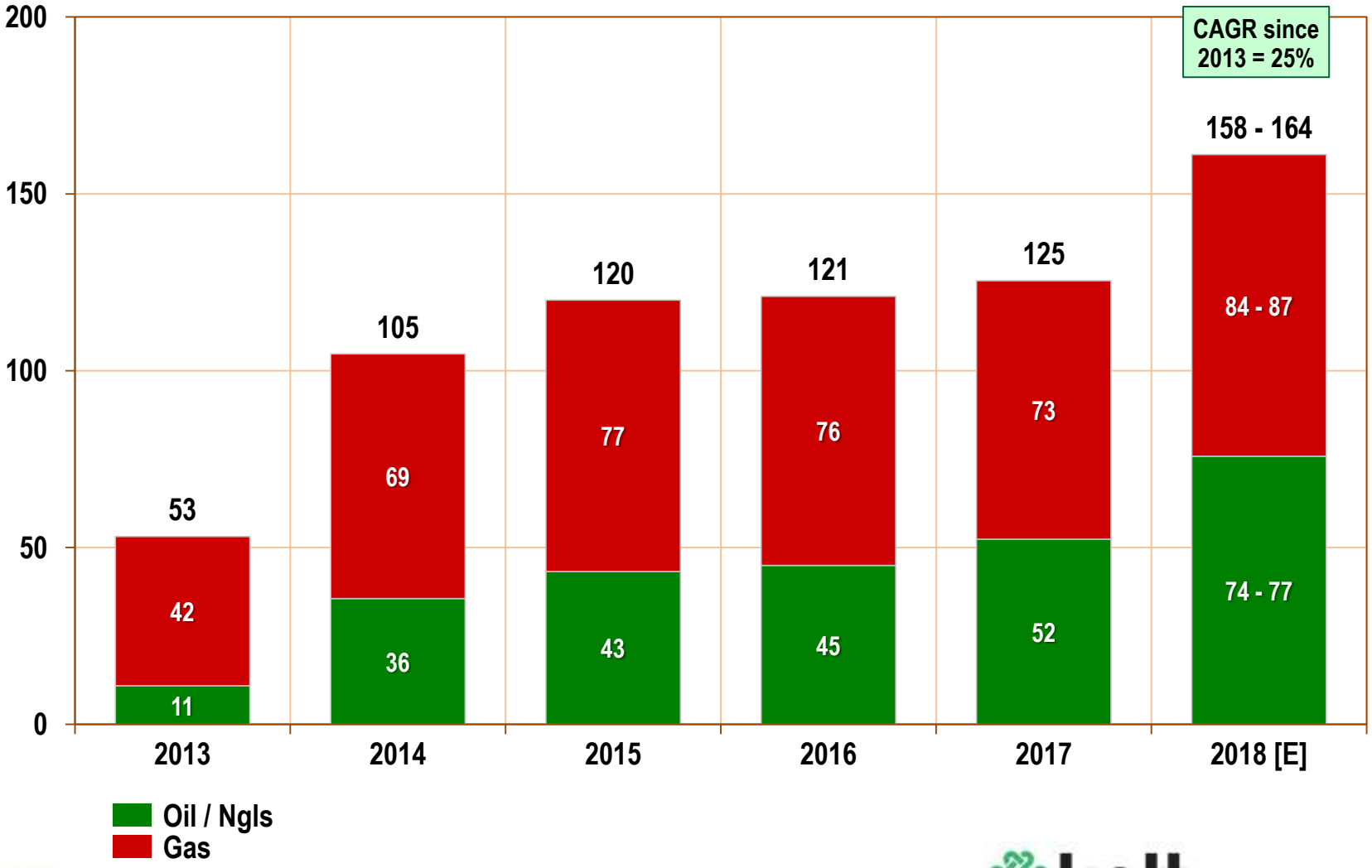
## PRODUCTION ( BOE / d ) :



# Annual Production per Share Growth ( since inception )



## PRODUCTION PER MILLION SHARES ( BOE / d ) :



# Netbacks



| ( $ / BOE ) | 2016 | 2017 | 2018 (E) | 2018/17 Change |
|---|---|---|---|---|
| Price | 24.08 | 31.51 | 37.42 | + 19% |
| Realized hedging gain ( loss ) | 0.02 | ( 0.13 ) | – | – |
| Royalties ( % of price ) | ( 8.6% ) | ( 9.3% ) | ( 10.8% ) | + 16% |
| Transportation expense | ( 2.86 ) | ( 3.13 ) | ( 3.32 ) | + 6% |
| Production expense | ( 9.29 ) | ( 10.05 ) | ( 9.54 ) | – 5% |
| Operating netback *[1]* | 9.87 | 15.28 | 20.50 | + 34% |
| G&A expense | ( 0.91 ) | ( 0.94 ) | ( 0.76 ) | – 19% |
| Interest expense | ( 1.34 ) | ( 0.97 ) | ( 0.85 ) | – 12% |
| Adjusted funds from operations *[1]* | 7.62 | 13.37 | 18.89 | + 41% |

*Note:*
*[1] See "Financial Advisories".*

# Financial Outlook



| | 2016 | 2017 | 2018 Forecast | 2018/17 Change |
|---|---|---|---|---|
| Revenue ( $ MM ) | 184.6 | 257.6 | 396.1 | + 54% |
| Operating income ( $ MM ) *[1]* | 75.7 | 123.4 | 217.0 | + 76% |
| Adj. funds from operations ( $ MM ) *[1]* | 58.4 | 108.0 | 200.0 | + 85% |
| Per share – diluted ( $/share ) | 0.34 | 0.61 | 1.10 | + 80% |
| Capital expenditures, net ( $ MM ) *[2]* | 98.3 | 128.0 | 210.0 | + 64% |
| Net bank debt, at year-end ( $ MM ) *[1,3]* | 138.0 | 136.7 | 140.0 | + 2% |
| Net bank debt / FFO ratio | 2.4 x | 1.3 x | 0.7 x | – 46% |

*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 $185.0 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.*

# 2018 Commodity Price Sensitivities



| | 2018 Forecast | Kelt Oil/NGLs Price minus 10% | | Kelt Gas Price minus 10% | | CAD/USD Exchange Rate minus CAD 0.05 | |
|---|---|---|---|---|---|---|---|
| WTI Crude Oil ( USD/bbl ) | 58.50 | 52.61 | - 10% | 58.50 | n/c | 58.50 | n/c |
| NYMEX Natural Gas ( USD/MMBtu ) | 3.05 | 3.05 | n/c | 2.84 | - 7% | 3.05 | n/c |
| Exchange Rate ( CAD/USD ) | 1.266 | 1.266 | n/c | 1.266 | n/c | 1.216 | - 4% |
| Exchange Rate ( USD/CAD ) | 0.790 | 0.790 | n/c | 0.790 | n/c | 0.823 | + 4% |
| Kelt Oil/NGLs Price ( CAD/bbl ) | 58.89 | 53.00 | - 10% | 58.89 | n/c | 56.57 | - 4% |
| Kelt Gas Price ( CAD/Mcf ) | 3.05 | 3.05 | n/c | 2.75 | - 10% | 2.93 | - 4% |
| Adjusted FFO ( $MM ) *[1] [2]* | 200.0 | 175.3 | - 12% | 189.9 | - 5% | 186.4 | - 7% |
| Change ( $MM ) | | ( 24.7 ) | | ( 10.1 ) | | ( 13.6 ) | |
| Adjusted FFO per share, diluted *[1] [2]* | 1.10 | 0.96 | - 13% | 1.04 | - 5% | 1.02 | - 7% |
| Change ( $/share ) | | ( 0.14 ) | | ( 0.06 ) | | ( 0.08 ) | |
| Net Bank Debt ( $MM ) | 140.0 | 164.7 | | 150.1 | | 153.6 | |
| Net Bank Debt/FFO Ratio *[2]* | 0.7 x | 0.9 x | | 0.8 x | | 0.8 x | |

*Note:*

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

# 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, La Glace & Pipestone/Wembley

→ Stacked Montney light oil

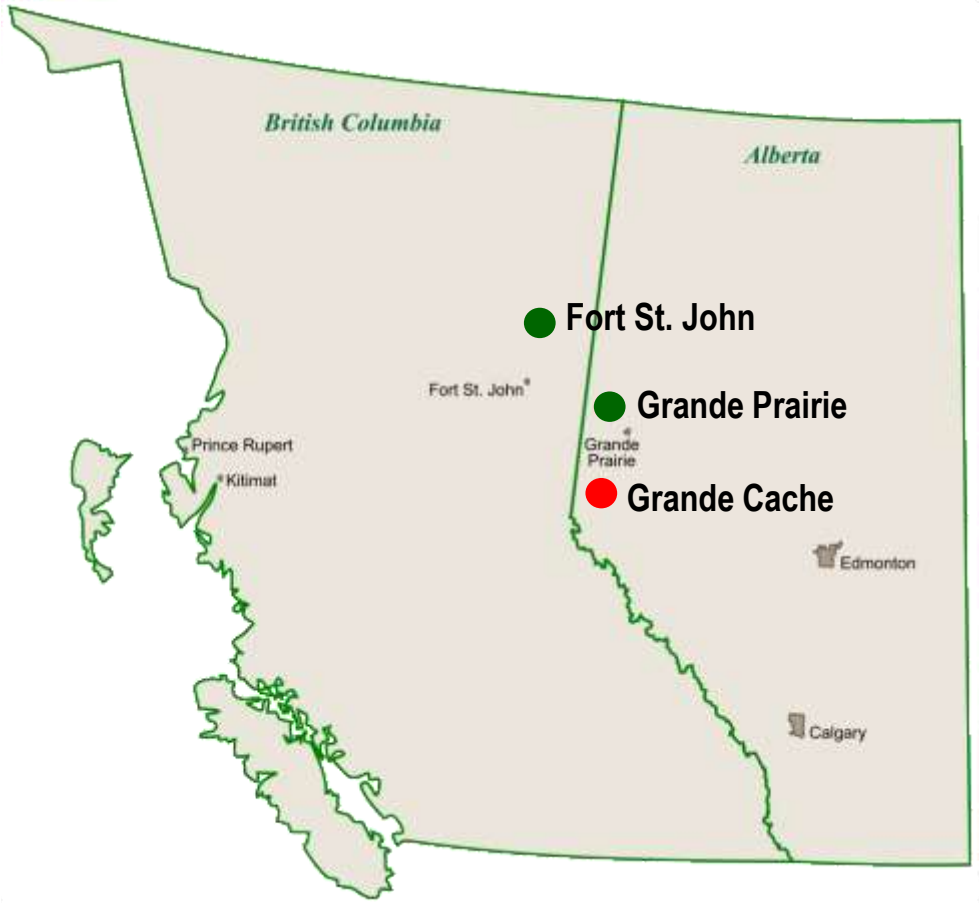
→ Montney/Doig gas

→ Charlie Lake light oil

→ Halfway light oil

## Grande Cache ( AB ) :

→ Cretaceous gas



# Kelt Land Fairway

## Corporate Land Holdings

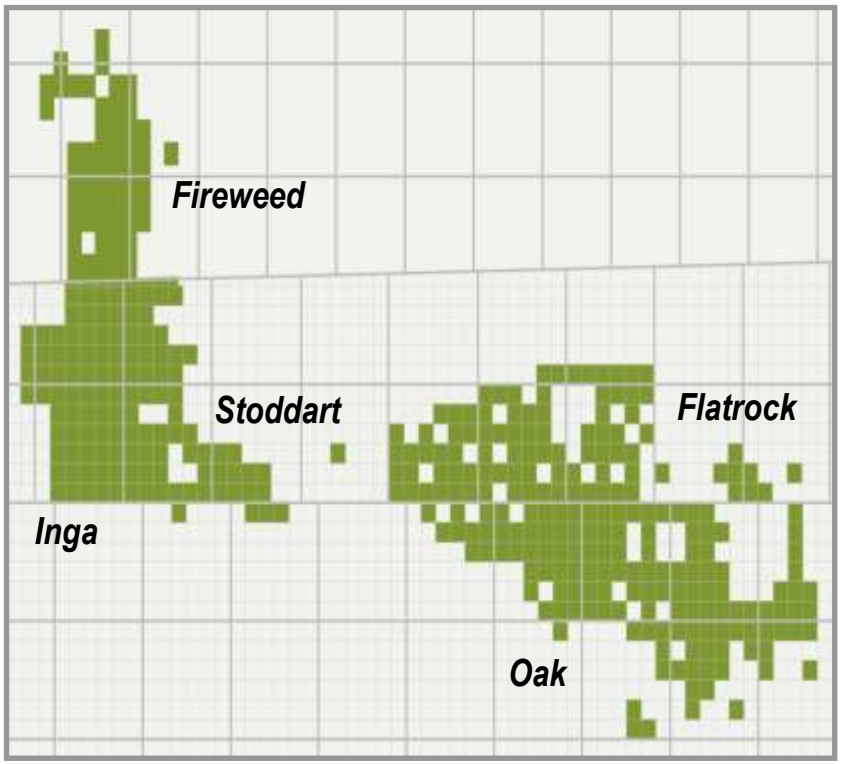
| Dec/31 2017 | Net Acres | Net Sections |
|---|---|---|
| Developed | 210,783 | 329 |
| Undeveloped | 637,853 | 997 |
| Total | 848,636 | 1,326 |

## Montney Rights

| | Net Acres | Net Sections |
|---|---|---|
| British Columbia | 290,091 | 453 |
| Alberta | 148,274 | 232 |
| Total | 438,365 | 685 |

# British Columbia Montney Lands






## LAND (Montney Rights)

**Gross: 295,043 acres ( 461 sections )**
**Net: 290,091 acres ( 453 sections )**

## OPERATIONS

- **Kelt has successfully delineated the Upper Montney at Inga/Fireweed**
- **Kelt is pleased with the initial results from the Middle Montney at Inga/ Fireweed and will continue its delineation program in that formation**
- **Kelt expects to test the Upper-Middle (IBZ) Montney at Inga/Fireweed in 2017-2018**
- **Kelt plans to drill two exploration horizontal Upper Montney wells at Oak / Flatrock in 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 ( 32% gas ) |
| (2) Inga 02/15-33-087-23W6 MM | 2,066 ( 21% gas ) |
| (3) Fireweed 00/B-90-A/94-A-13 UM | 1,895 ( 37% gas ) |
| (4) Inga 02/14-24-087-23W6 UM | 1,609 ( 26% gas ) |
| (5) Inga 00/14-24-087-23W6 MM | 1,412 ( 29% gas ) |
| (6) Inga 00/08-31-087-23W6 UM | 1,296 ( 26% gas ) |
| (7) Fireweed 02/C-026-A/094-A-13 UM | 1,188 ( 35% gas ) |
| (8) Inga 00/06-07-088-22W6 UM | 1,130 ( 48% gas ) |
| (9) Stoddart 00/08-17-087-22W6 UM | 906 ( 27% gas ) |
| (10) Inga 00/07-17-087-23W6 MM | 905 ( 31% gas ) |

## 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 )

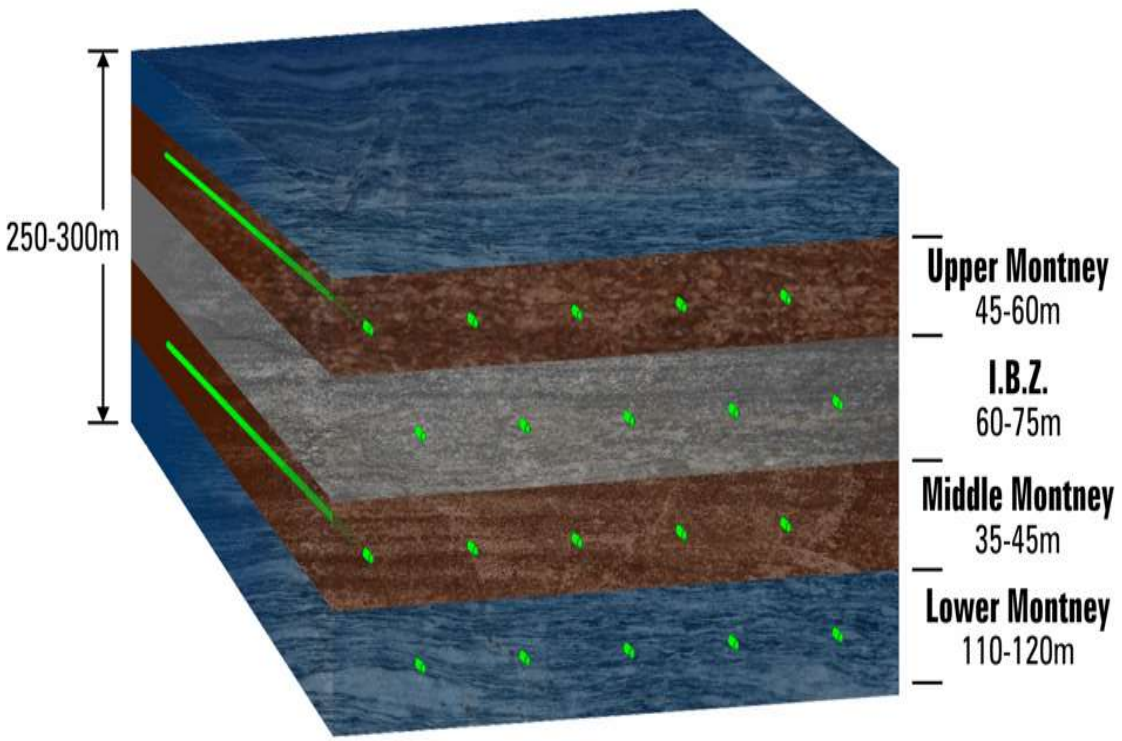
**Inga/Fireweed Middle Montney ( "MM" )**
**Sproule 2P EUR = 645 MBOE**
- 59% oil/ngls ( 380,000 bbls )
- 41% gas ( 1.6 bcf )

*Note:*
*[a] 2017 wells were 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



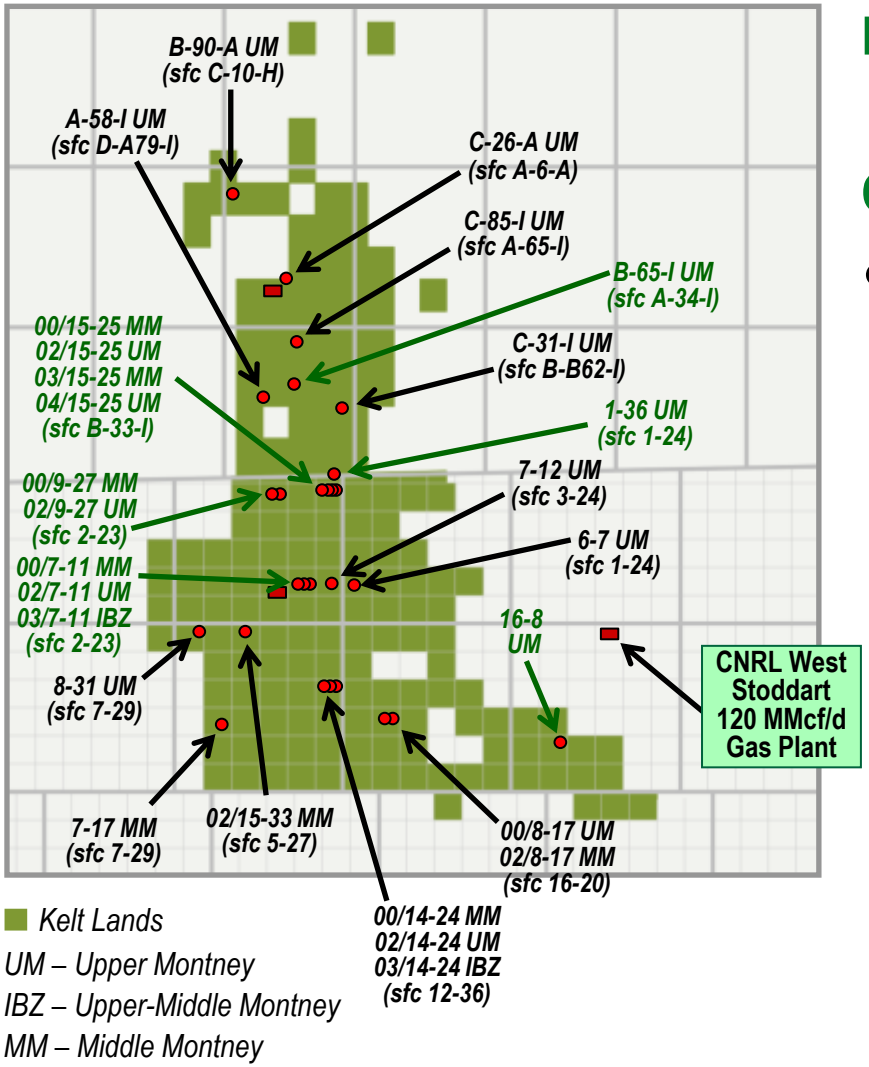
## MULTIPLE STACKED MONTNEY HORIZONS




- Kelt has successfully delineated the Upper Montney at Inga/Fireweed and currently estimates an un-risked drilling inventory of over 700 locations
- Initial results from the Middle Montney at Inga/Fireweed are very encouraging as Kelt continues its delineation program in that formation
- Kelt expects to test the Upper-Middle (IBZ) Montney at Inga/Fireweed in 2017-2018

# Inga / Fireweed Montney Lands






## LAND – MONTNEY RIGHTS

**207 gross sections ( 204 net sections )**

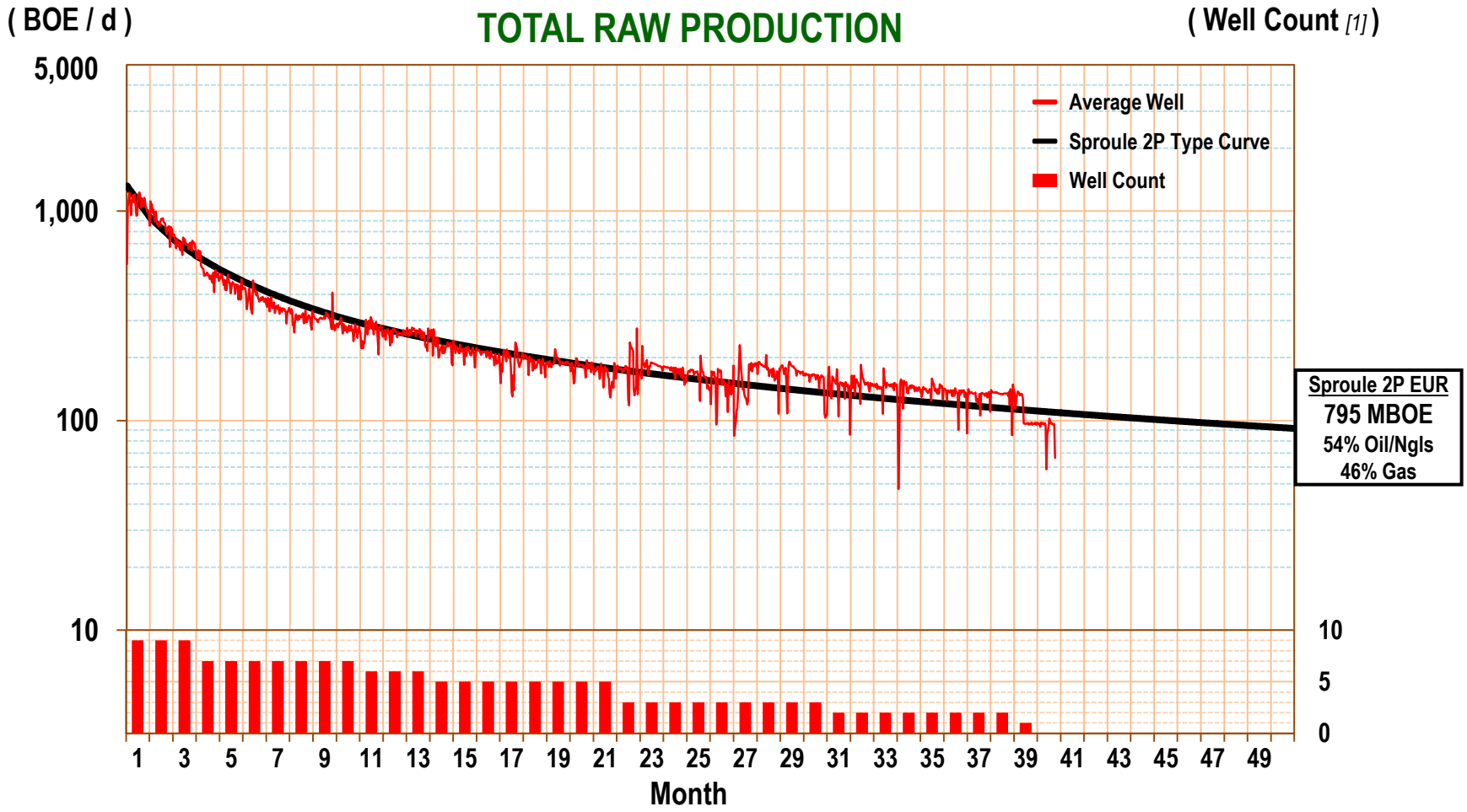
## OPERATIONS

- **Delineation drilling to date has been focused in the Upper Montney and Kelt has four producing wells that were drilled in the Middle Montney 'C' Unit.**

| DRILLING | Prior to 2018 | 2018 (E) | Total |
|---|---|---|---|
| Upper Montney | 10 | 7 | 17 |
| Middle Montney | 4 | 4 | 8 |
| IBZ Montney | 1 | 1 | 2 |
| Total | 15 | 12 | 27 |

# Inga / Fireweed Upper Montney Type Curve



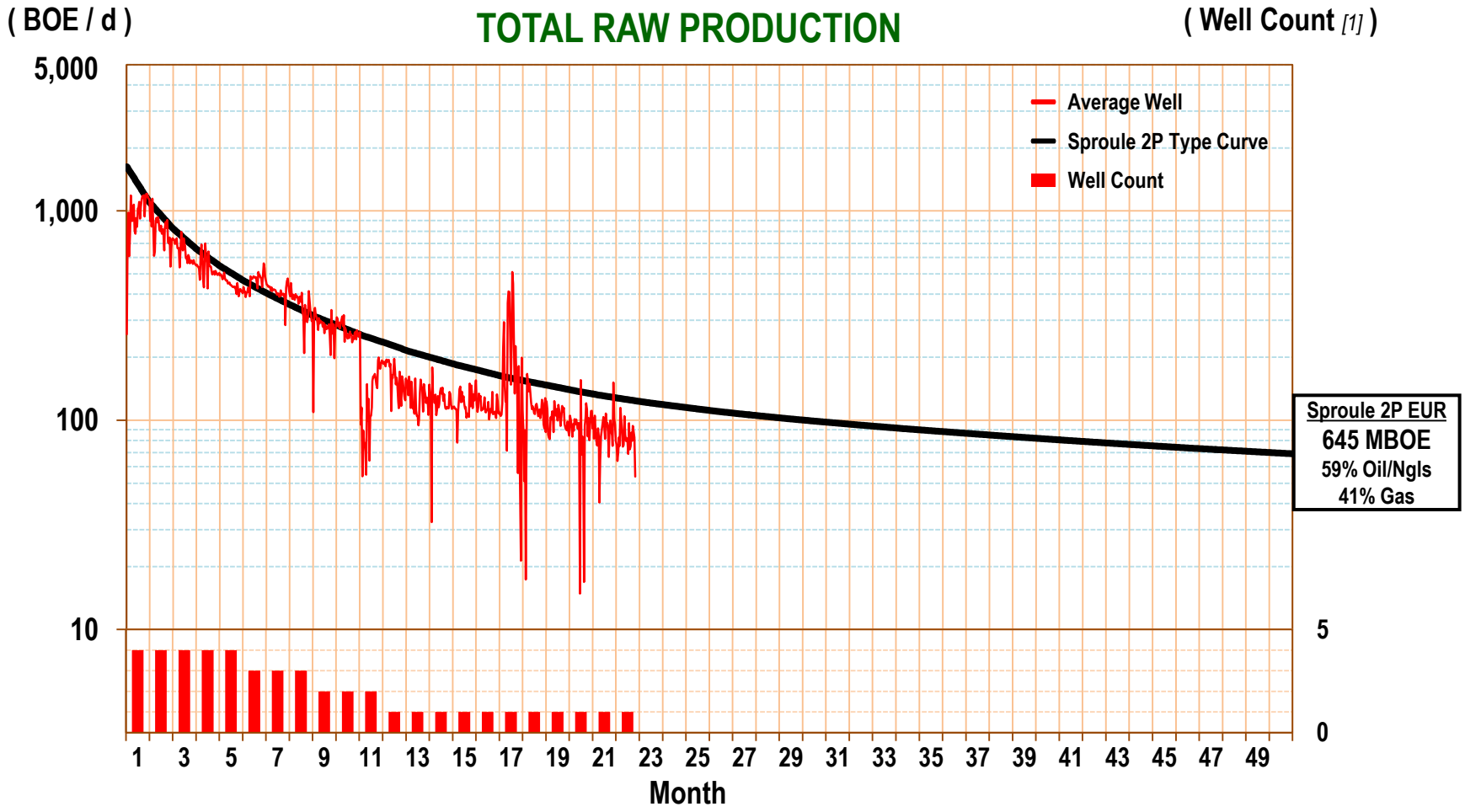



*Note:*

*[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



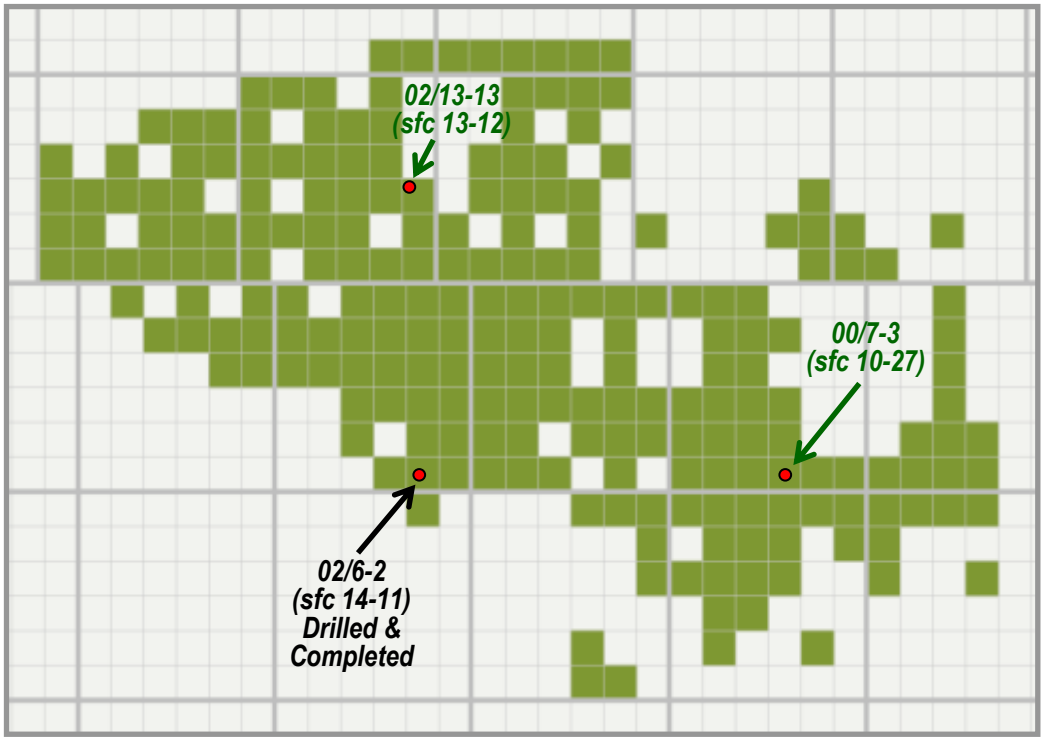



*Note:*

*[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

## LAND

### Montney Rights:

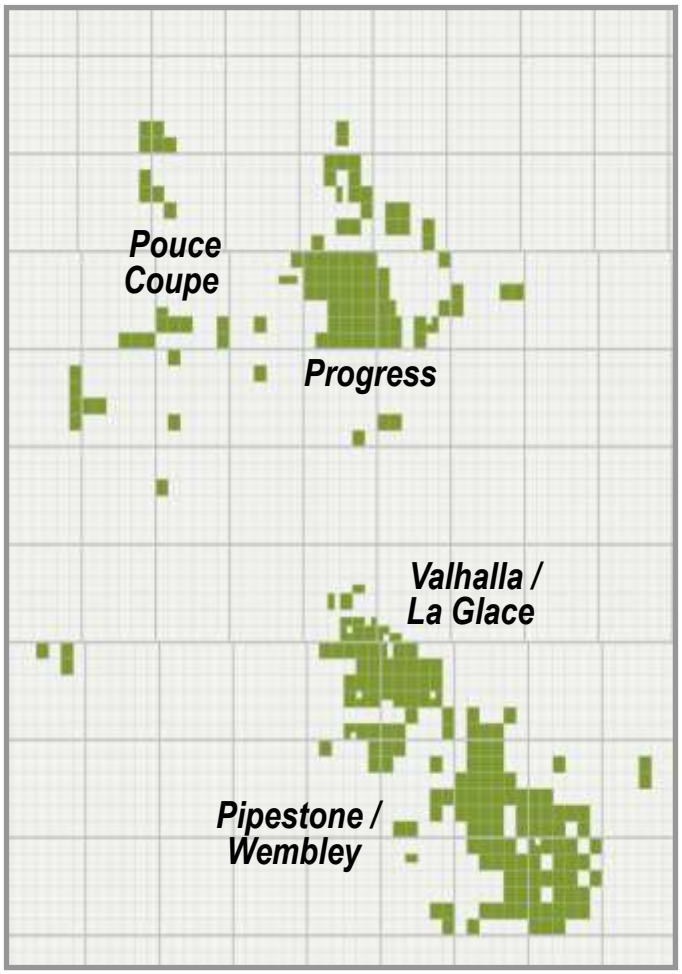
Gross: 149,155 acres ( 233 sections )
Net: 147,883 acres ( 230 sections )

## OPERATIONS

- Oil and gas exploration activity with plans to drill and complete two wells in 2018.
- First well at 02/6-2 was successful and initially produced at restricted rates due to facility capacity constraints.
- Target is Upper Montney (D4 / D5) at depths of 1,500 to 1,600 metres.
- Expectations are 30% to 50% oil/ngls and pressure gradient slightly above normal.

# Alberta Montney Lands






## LAND

### Montney Rights:

**Gross: 172,640 acres ( 270 sections )**
**Net: 148,274 acres ( 232 sections )**

## OPERATIONS

- **Kelt has successfully delineated the Lower-Middle and the Upper-Middle Montney at Pouce Coupe and completed a five-well development pad at Pouce Coupe in early 2017. The Company expects to complete its second five-well development pad in January 2018.**
- **Kelt has had success with the first two wells drilled in the Middle Montney at Progress and has recently drilled three additional wells.**
- **Kelt recently drilled two development wells in the Middle Montney at Valhalla/La Glace**
- **Kelt drilled its first exploration Montney well at Pipestone/Wembley in 2017**

# 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 | 2,045 ( 66% oil/ngls ) |
| (2) Pouce Coupe 02/06-18-078-11W6 UMM | 2,004 ( 68% oil/ngls ) |
| (3) Pouce Coupe 05/07-18-078-11W6 LMM | 1,546 ( 58% oil/ngls ) |
| (4) Pouce Coupe 00/01-09-078-11W6 UMM | 1,529 ( 65% oil/ngls ) |
| (5) Wembley/Pipestone 00/04-01-072-8W6 UM | 1,337 ( 83% oil/ngls ) |
| (6) Pouce Coupe 04/07-18-078-11W6 UMM | 1,320 ( 57% oil/ngls ) |
| (7) La Glace 00/13-33-074-08W6 MM | 1,090 ( 88% oil/ngls ) |
| (8) Pouce Coupe 02/13-08-078-11W6 LMM | 1,068 ( 83% oil/ngls ) |
| (9) La Glace 02/01-05-075-08W6 MM | 1,045 ( 79% oil/ngls ) |
| (10) Pouce Coupe 02/08-18-078-11W6 UMM | 1,034 ( 73% oil/ngls ) |

*Abbreviations:*
*LMM = Lower-Middle Montney also referred to as "Montney Sexsmith" or "D1".*
*UMM = Upper-Middle Montney also referred to as "Montney H" or "D2".*
*MM = Middle Montney.*
*UM = Upper Montney.*

## RESERVES

### Typical well EUR's:

**(1) Pouce Coupe Montney OIL:**
**2P EUR = 600 MBOE ***
- 45% oil/ngls ( 270,000 bbls )
- 55% gas ( 2.0 bcf )

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

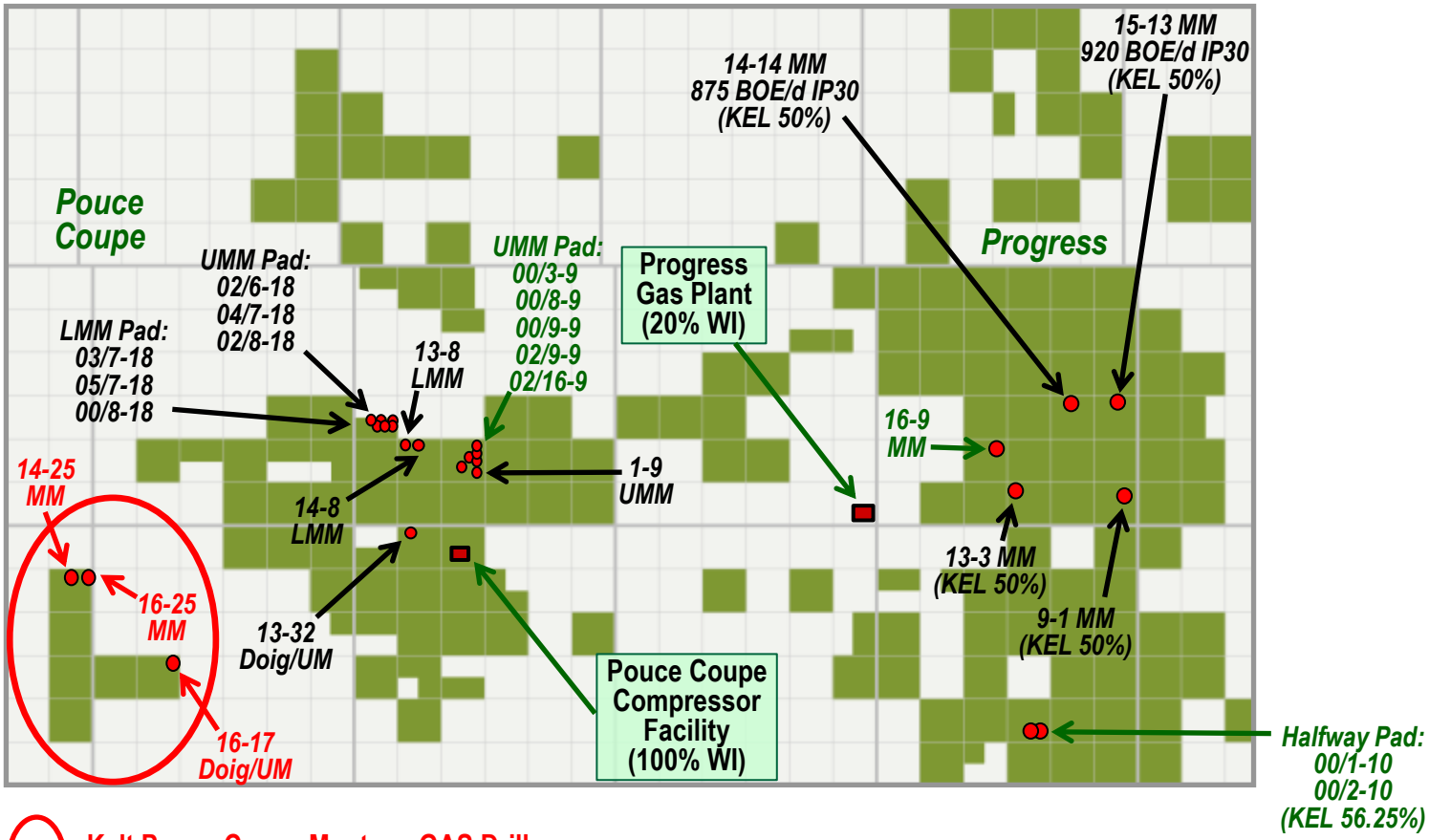
**(2) La Glace Montney OIL:**
**Sproule 2P EUR = 590 MBOE**
- 61% oil/ngls ( 360,000 bbls )
- 39% gas ( 1.4 bcf )

# Pouce Coupe / Progress



Kelt Lands

*Abbreviations:*
*UM – Upper Montney*
*MM – Middle Montney*
*UMM – Upper-middle Montney (may also be referred to as "Montney H" or "Montney D2")*
*LMM – Lower-middle Montney (may also be referred to as "Montney Sexsmith" or "Montney D1")*



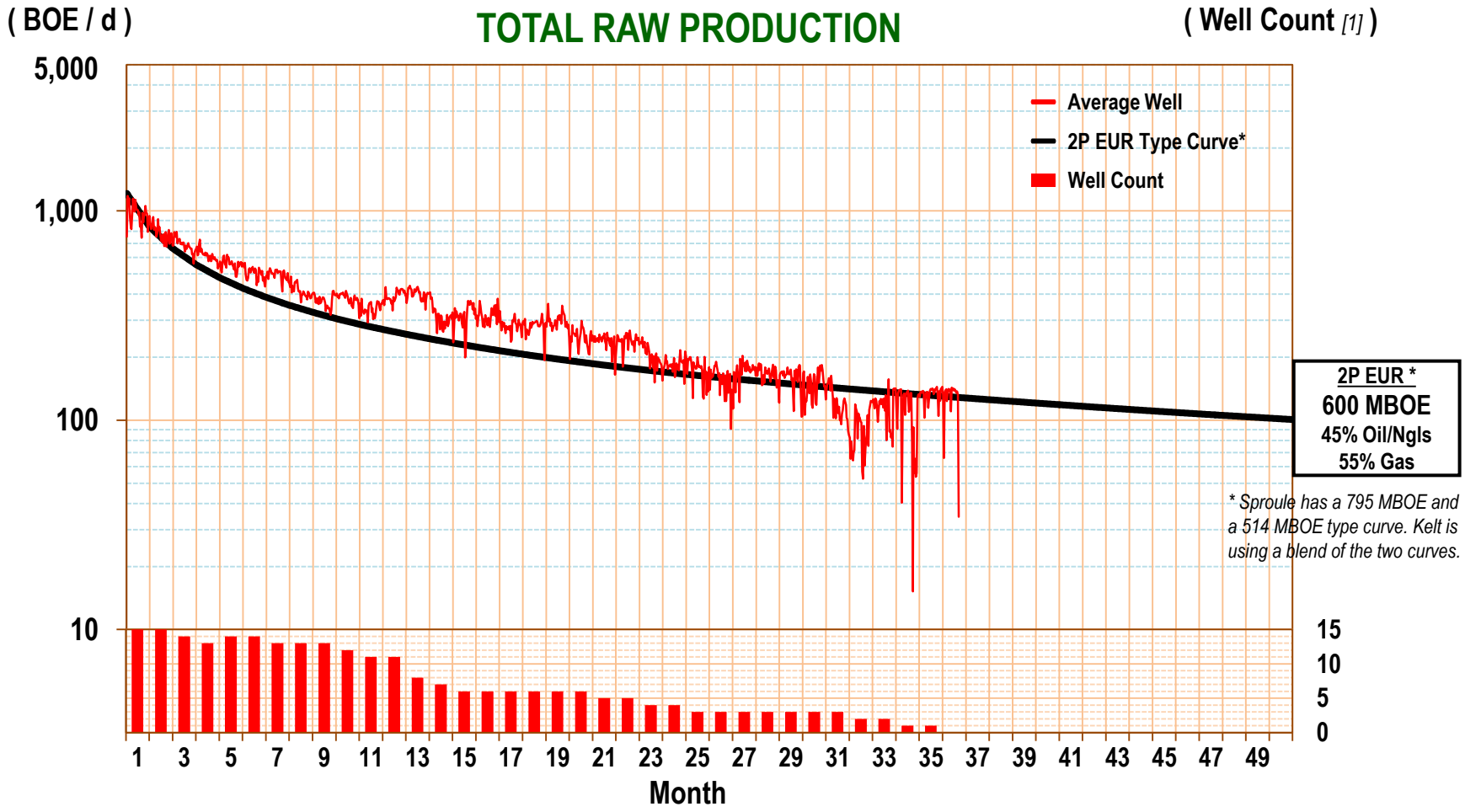

**Kelt Pouce Coupe Montney GAS Drills**
**Top IP30 Wells (gross sales, BOE/d):**

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

*Note:*
*[a] 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



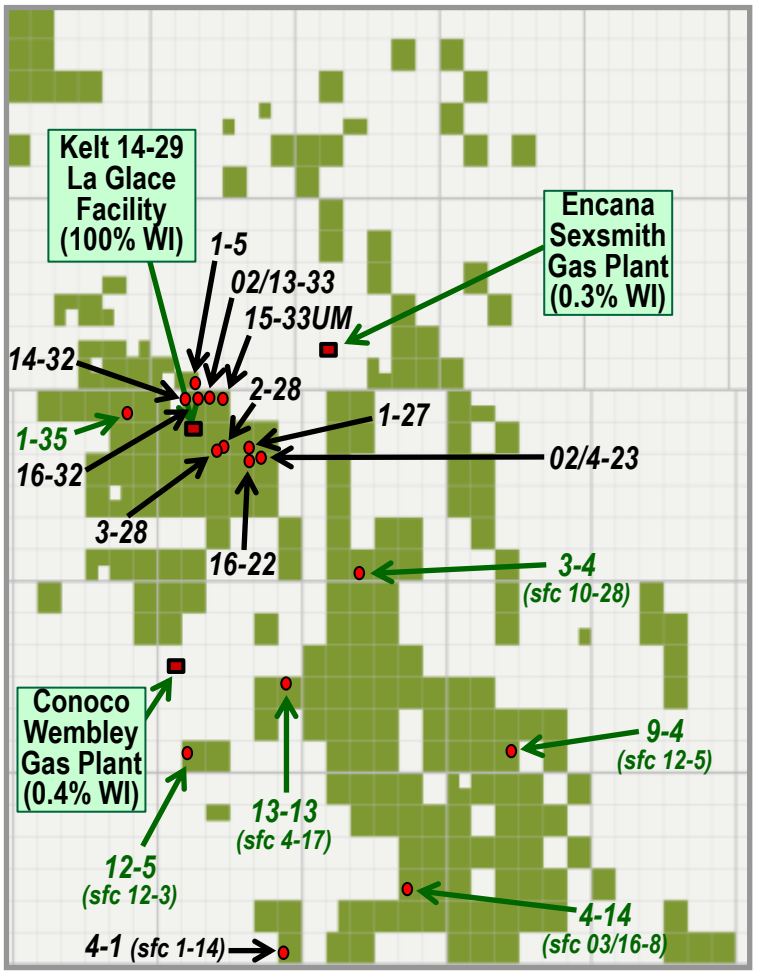



*Note:*

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

# Valhalla / La Glace and Pipestone / Wembley

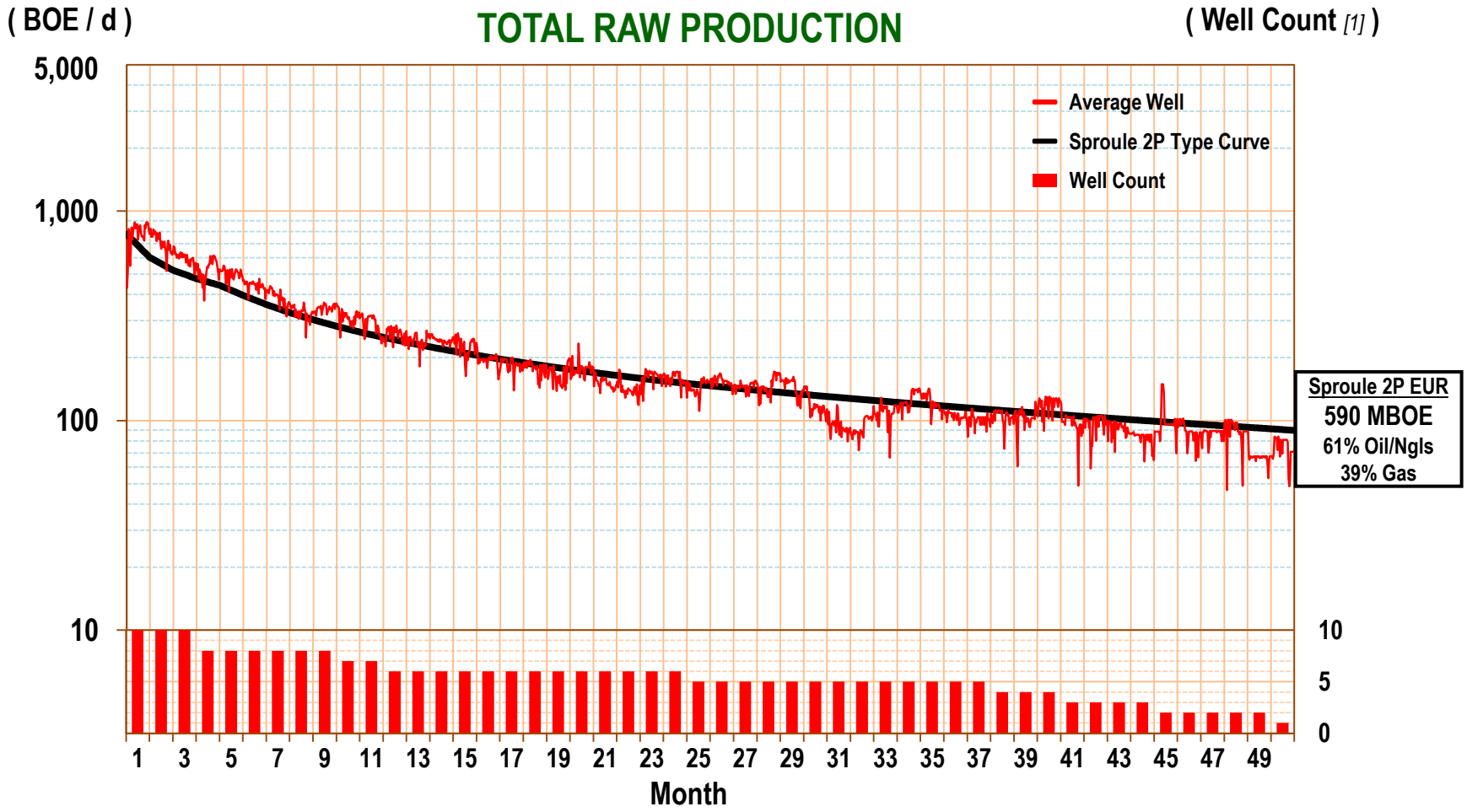





- Drilling has been focused on the Middle Montney. Upper Montney also productive - tested in the 15-33 well
- Ownership in pipeline infrastructure, minor interests in gas plants and 100% interest in the Kelt La Glace facility which has a handling capacity of 3,500 bbls/d of oil and 20 mmcf/d of gas
- Kelt expects to drill five exploration Montney wells at Pipestone/ Wembley in 2018 (the first well at 4-1 drilled in 2017 was successful).
- Kelt has entered into an agreement with a mid-stream company for firm processing of 25.0 MMcf/d of raw gas under a 5-year take-or-pay arrangement at a proposed deep cut natural gas processing plant that is expected to be constructed at Pipestone/Wembley and is expected to be on-stream by the third quarter of 2019.

# 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.*

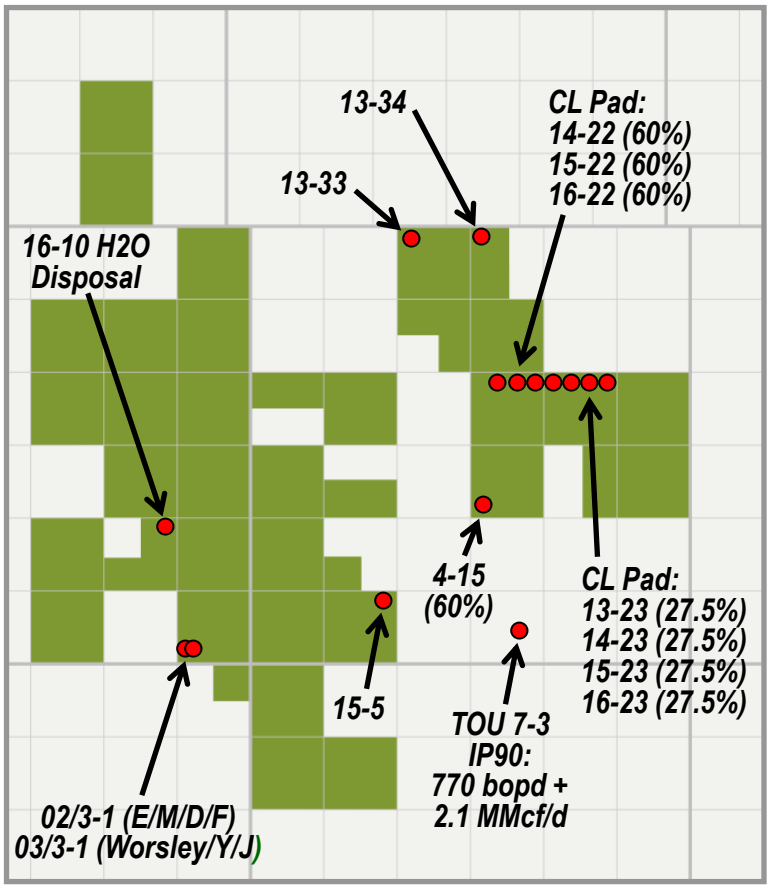
*[2] Production Start Date is the date when the well commenced steady production after tie-in operations were completed. The payback period is calculated from this date.*

*[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.*

# Spirit River – Charlie Lake



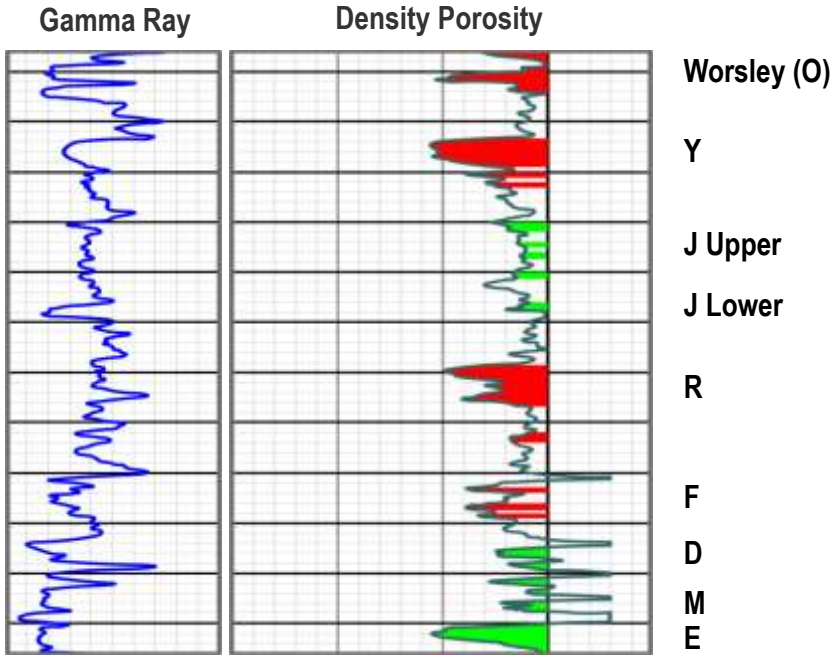



## LAND

**Gross: 42,880 acres ( 67 sections )**
**Net: 35,352 acres ( 55 sections )**

**Charlie Lake: 28 net sections**
**Doe Creek: 17 net sections**

## CHARLIE LAKE:



# Net Asset Value



| ( millions ) | Dec/31 2016 | Dec/31 2017 | % change |
|---|---|---|---|
| P&NG reserves, NPV10% BT | 1,730.7 | 2,111.5 | + 22% |
| Decommissioning obligations, NPV10% BT [1] | ( 9.5 ) | ( 12.8 ) | + 35% |
| Undeveloped land | 212.5 | 239.1 | + 13% |
| Net bank debt | ( 138.0 ) | ( 136.7 ) | – 1% |
| Proceeds from exercise of stock options [2] | 29.7 | 60.4 | + 103% |
| NET ASSET VALUE | 1,825.4 | 2,261.5 | + 24% |
| Diluted common shares outstanding | 198.5 | 204.4 | + 3% |
| NET ASSET VALUE PER SHARE | $ 9.20 | $ 11.06 | + 20% |

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 $6.77 and $7.19 per common share respectively as at December 31, 2016 and 2017.*

*[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, 2017 closing price of $7.19, the convertible debentures are "in-the-money" and 16.4 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.
- Last winter, gas demand was below average due to record mild temperatures in the U.S. northeast and mid-west (Dec/16 to Feb/17).
- U.S. gas storage surplus at the end of the 2016-17 winter (compared to the five year average) has now been eliminated primarily due to the cold start to the 2017-18 winter. At February 23, 2018, U.S. gas storage was 372 bcf below the five-year average.

# Management



David J. Wilson, President & CEO

Sadiq H. Lalani, Vice President & CFO

Douglas J. Errico, Vice President, Land

Patrick Miles, Vice President, Exploration

Douglas O. MacArthur, Vice President, Operations

Alan G. Franks, Vice President, Production

Bruce D. Gigg, Vice President, Engineering

Ashley D. Hohm, Vice President, Finance

William C. Guinan, Corporate Secretary

# Board of Directors



| | |
|---|---|
| **Robert J. Dales** | **Compensation (Chair), Nominating, Audit, Reserves** |
| **Geri L. Greenall** | **Audit, Nominating** |
| **William C. Guinan** | **Chairman of the Board, HSE** |
| **Eldon A. McIntyre** *[1]* | **Reserves (Chair), Nominating, Audit, Compensation** |
| **Neil G. Sinclair** | **Audit (Chair), Nominating (Chair), Compensation, HSE, Reserves** |
| **David J. Wilson** | **HSE (Chair)** |

*Notes:*

*[1] Mr. McIntyre will be retiring and is not standing for re-election to the Board at Kelt's next Annual General Meeting of Shareholders to be held on April 18, 2018.*
*[2] Mr. Michael R. Shea is currently not a director of the Company, however, he will be standing for election to the Board at Kelt's next Annual General Meeting of Shareholders to be held on April 18, 2018.*
*[3] HSE – Health, Safety & Environment Committee.*

# APPENDIX



- ABBREVIATIONS
- QUARTERLY FORECAST OF 2018 WTI & NYMEX PRICES
- QUARTERLY PRODUCTION GROWTH
- QUARTERLY CASH COSTS
- MAP OF NORTH AMERICAN NATURAL GAS HUBS
- GAS MARKETING & TRANSPORTATION CONTRACTS
- SPROULE RESERVES PLUS FUTURE DEVELOPMENT CAPITAL
- GRANDE CACHE – CRETACEOUS DRY GAS PROPERTY
- INGA DOIG – 2017 WELL PAYBACKS
- WELL TYPE CURVES
- DISCLAIMERS

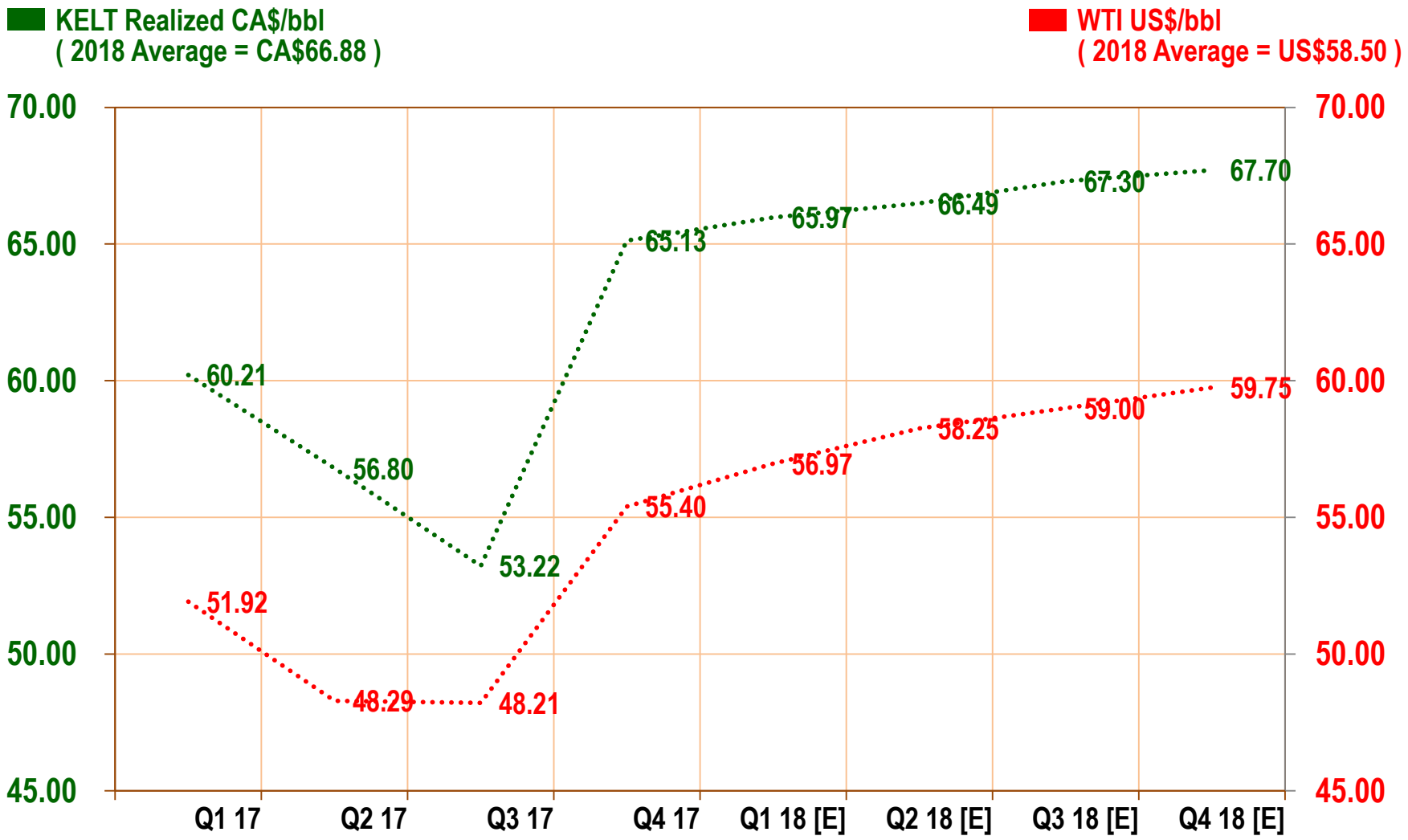
# Abbreviations



**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

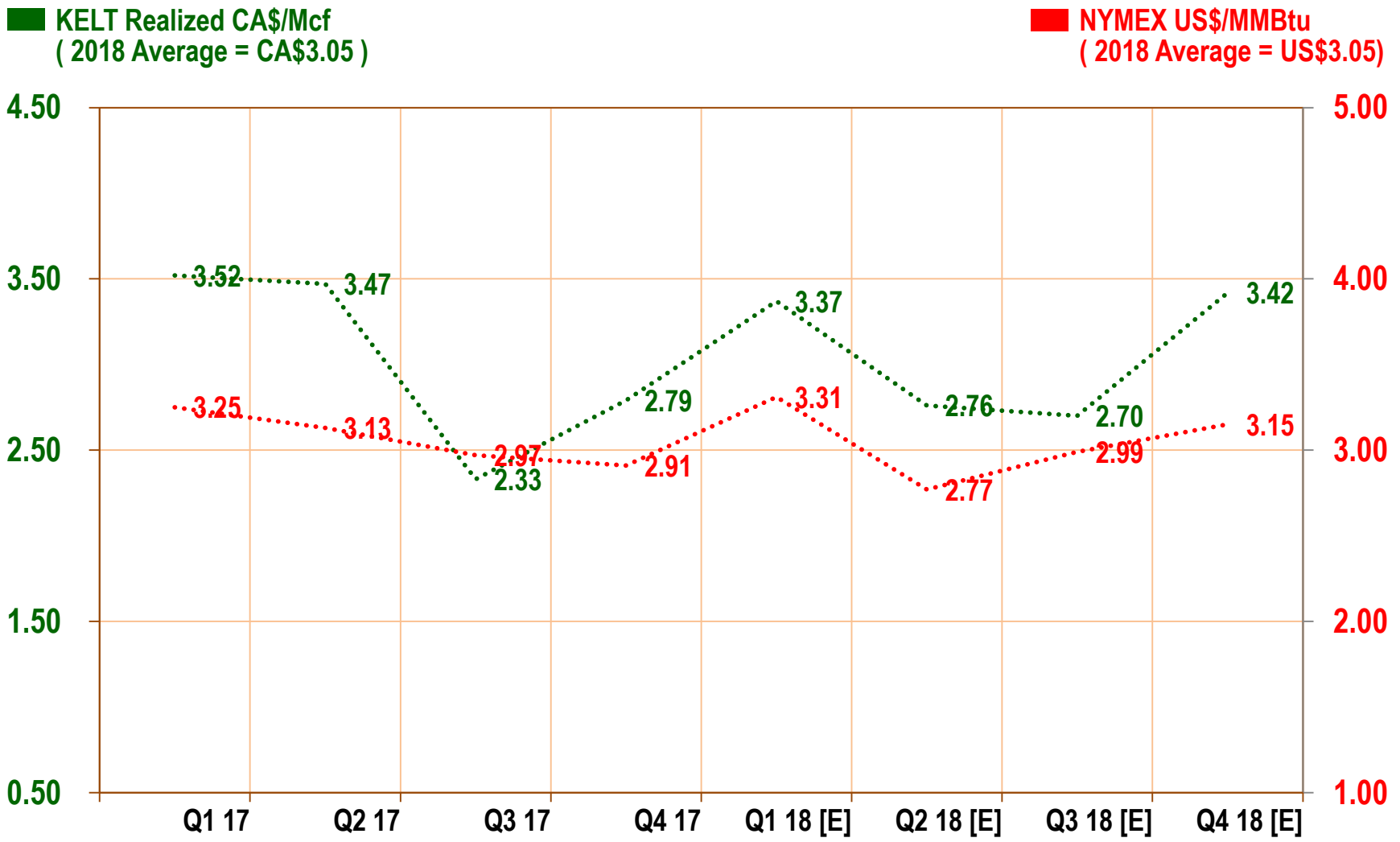
# Kelt's 2018 Oil Price Forecast





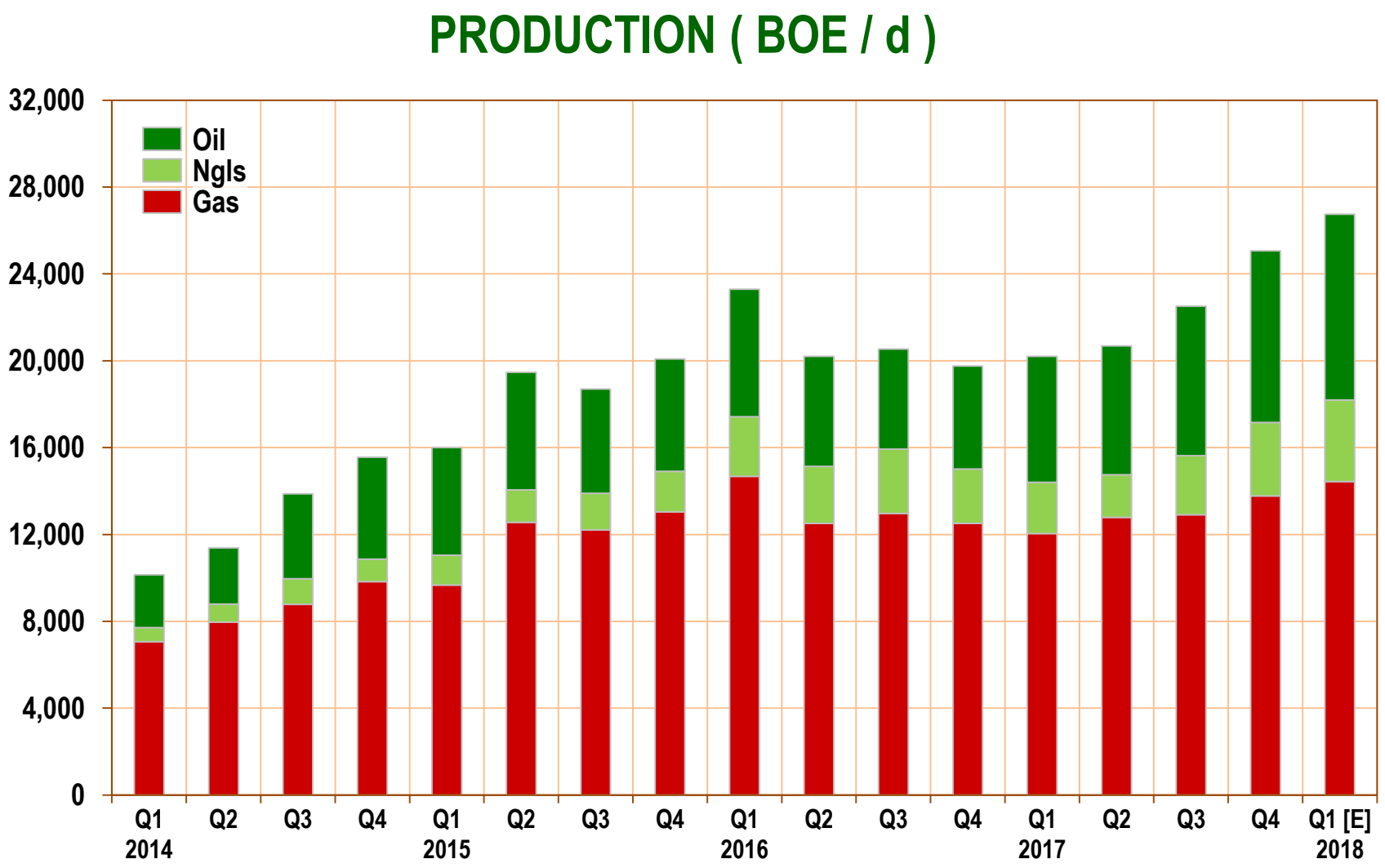
# Kelt's 2018 Gas Price Forecast





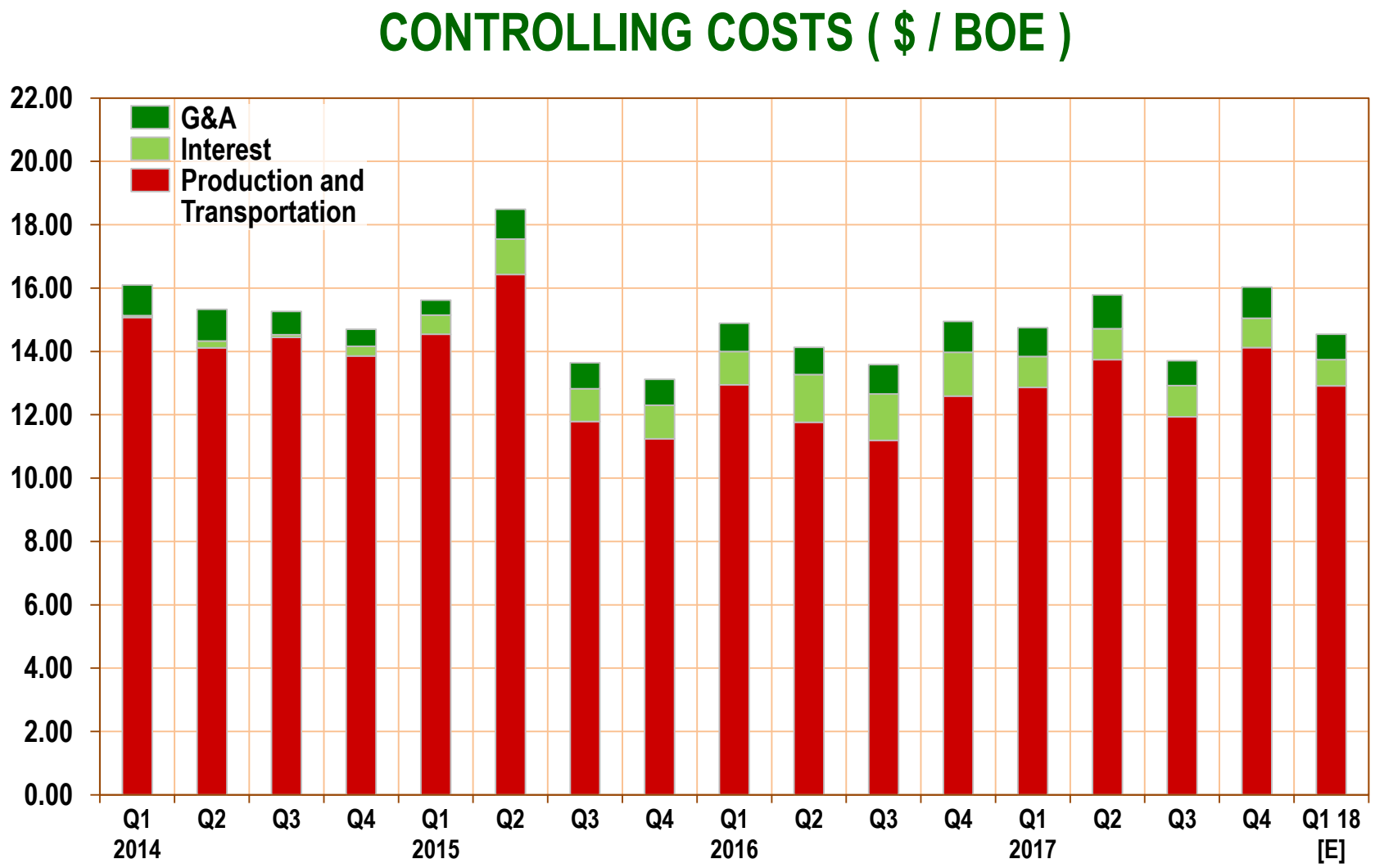
# Quarterly Production Growth





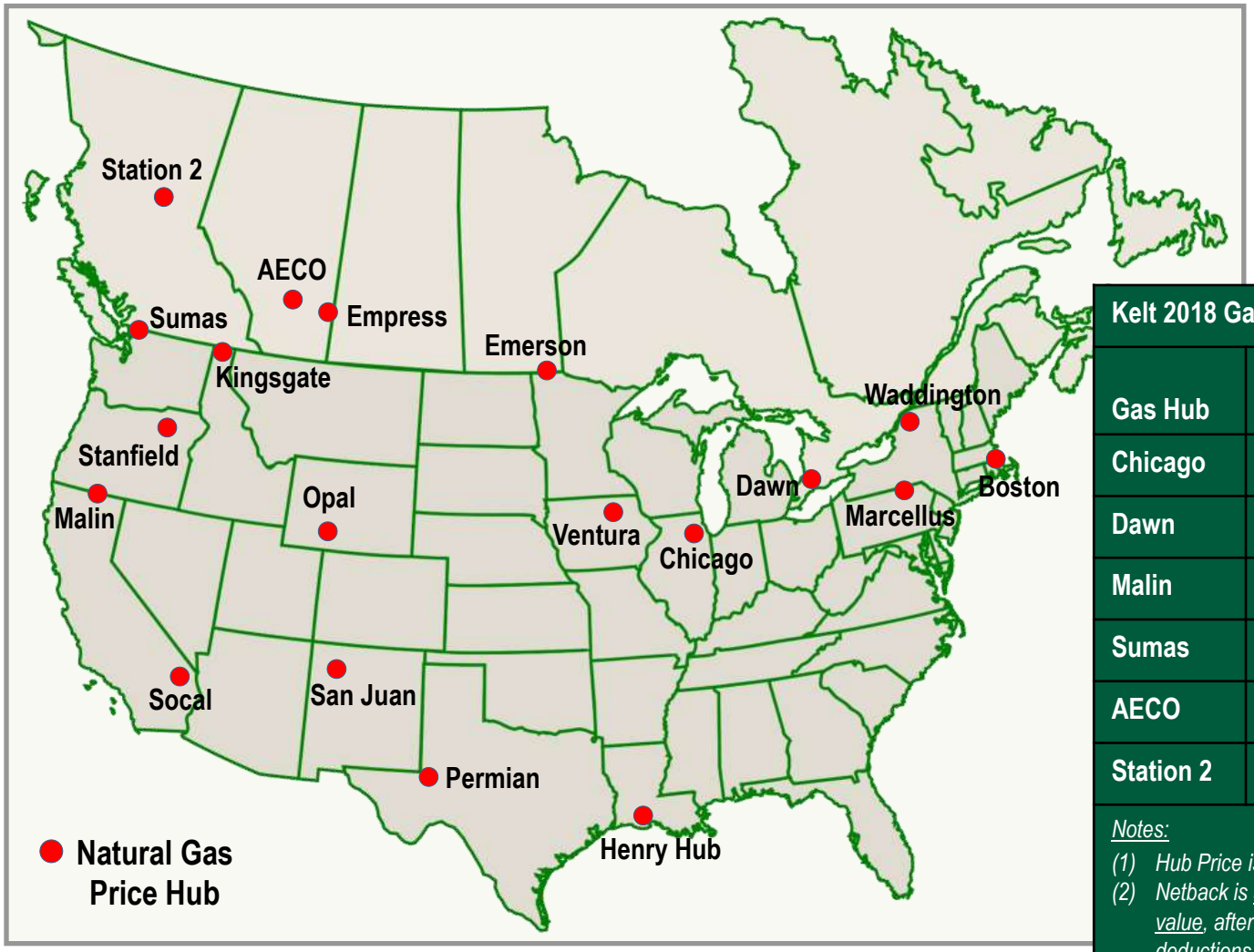
# Quarterly Cash Costs





# North American Natural Gas Hubs






**Kelt 2018 Gas Netback Forecast:**

| Gas Hub | % | Hub Price US$/MMBtu | Netback US$/Mcf |
|---|---|---|---|
| Chicago | 16% | 2.85 | 2.02 |
| Dawn | 26% | 2.80 | 1.99 |
| Malin | 16% | 2.48 | 1.73 |
| Sumas | 16% | 2.43 | 1.69 |
| AECO | 21% | 1.63 | 1.57 |
| Station 2 | 5% | 1.33 | 1.25 |

*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, but before royalties and operating expenses.*

*(3) Exchange rate = US$0.790/C$ or C$1.266/US$.*

# B.C. Gas Marketing / Transportation Contracts



| Supply Term (Firm Transportation) | Volume (MMcf/d) | Upstream Hub |
|---|---|---|
| Nov/1/2017 – Oct/31/2018 | 10.3 *[2]* | Alliance Receipt Point |
| Nov/1/2017 – Oct/31/2018 | 10.0 | TNLH Receipt Point |
| Nov/1/2017 – Oct/31/2020 *[1]* | 1.8 | TNLH Receipt Point |
| Apr/1/2018 – Oct/31/2020 *[1]* | 10.6 | TNLH Receipt Point |
| Apr/1/2019 – Mar/31/2039 | 60.0 *[3]* | North Montney Receipt Point |

| Market Term (Sales) | Volume (MMcf/d) | Market Price |
|---|---|---|
| Nov/1/2017 – Oct/31/2018 | 12.9 | CHICAGO City Gate USD Gas Daily Index |
| Nov/1/2017 – Oct/31/2020 | 12.0 | SUMAS USD Monthly Index less US$0.679/MMBtu |
| Nov/1/2017 – Oct/31/2018 | 3.0 | SUMAS USD Monthly Index less US$0.760/MMBtu |
| Jan/1/18 – Dec/31/18 | 4.8 *[4]* | Station 2 NGX Day Ahead Index |

*Notes:*

*[1] Renewable contracts.*

*[2] The Company also has access to priority interruptible transportation service ("PITS") equating to 25% of its firm service volume on the Alliance pipeline system.*

*[3] Subject to National Energy Board ("NEB") approval of TransCanada Corporation's variance application for the North Montney Mainline Project in northeast British Columbia.*

*[4] Approximately 2.9 MMcf/d of sales at Station 2 are based on volumes expected to be delivered on interruptible transportation services.*

***TNLH –** Transmission North ("T-North") Long Haul (Enbridge owned pipeline with delivery to the Station 2 Hub).*

# Alberta Gas Marketing / Transportation Contracts



| Supply Term (Firm Transportation) | Volume (MMcf/d) | Upstream Hub |
|---|---|---|
| Nov/1/2017 – Oct/31/2022 *[1]* | 24.6 *[2]* | NGTL FT-D Delivery Point |
| Nov/1/2017 – Oct/31/2020 *[1]* | 2.0 *[4]* | Alliance Receipt Point |
| Apr/1/2018 – Oct/31/2020 *[1]* | 2.1 *[4]* | Alliance Receipt Point |
| Apr/1/2018 – Mar/31/2019 *[1]* | 55.5 | NGTL FT-R Receipt Point |

| Market Term (Sales) | Volume (MMcf/d) | Market Price |
|---|---|---|
| Nov/1/2017 – Oct/31/2027 *[3]* | 23.7 | DAWN USD Daily Index |
| Nov/1/2017 – Oct/31/2020 | 15.0 | MALIN USD NGI FOM Index less US$0.70/MMBtu |
| Nov/1/2017 – Oct/31/2020 | 2.5 | CHICAGO City Gate USD Gas Daily Index |
| Apr/1/2018 – Oct/31/2020 | 2.6 | CHICAGO City Gate USD Gas Daily Index |
| Jan/1/2018 – Dec/31/2018 | 18.3 *[5]* | AECO CAD Daily ( 5A ) Index |

*Notes:*

*[1] Renewable contracts.*

*[2] Kelt has entered into an agreement to deliver 24.6 MMcf/d of natural gas from NIT to the Empress Hub (NGTL FT-D) for a five year term from Nov/1/2017 to Oct/31/2022.*

*[3] TransCanada Corporation's long-term fixed pricing toll on the Canadian Mainline from the Empress Hub in Alberta to the Dawn Hub in Southern Ontario fixed at CA$0.77/GJ.*

*[4] The Company also has access to priority interruptible transportation service ("PITS") equating to 25% of its firm service volume on the Alliance pipeline system.*

*[5] Approximately 4.3 MMcf/d of sales at AECO are based on volumes expected to be delivered on interruptible transportation services.*

**NGTL FT-R –** *TCPL's NGTL System Firm Transport Receipt Point at NIT ("Nova Inventory Transfer")*
**NGTL FT-D –** *TCPL's NGTL System Firm Transport Delivery Point at the Empress Hub*
**AECO –** *main gas price Hub in Alberta*

# Reserves



| | DEC/31/2016 ( MMBOE ) | DEC/31/2017 ( MMBOE ) | Percent Change | NPV 10% BT DEC/31/2017 ( $ MM ) |
|---|---|---|---|---|
| Proved Developed Producing | 34.5 | 37.9 | + 10% | $ 423 |
| Total Proved | 108.2 | 133.0 | + 23% | $ 1,093 |
| Proved plus Probable ( P+P ) | 194.1 | 235.6 | + 21% | $ 2,112 |
| Oil / Ngls ( P+P % ) | 37% | 43% | | |
| Gas ( P+P% ) | 63% | 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.*

# Sproule P+P Reserves – FDC

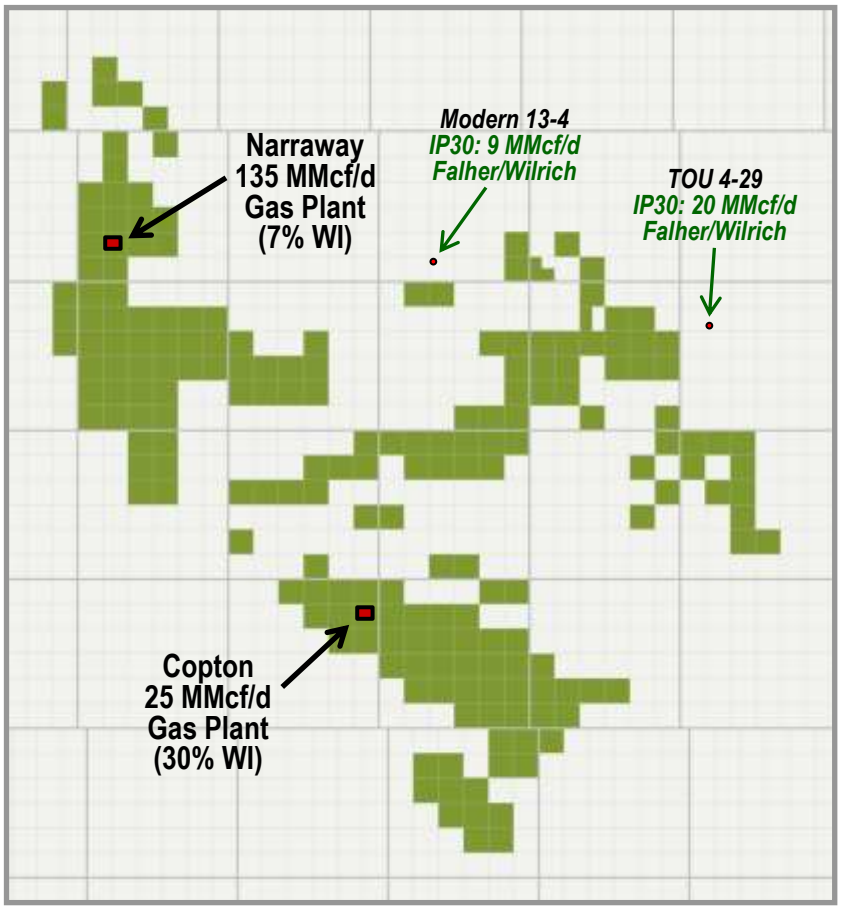


| December 31, 2017 | FDC ( $MM ) | Net HZ Wells |
|---|---|---|
| Alberta Montney wells | 176 | 37 |
| B.C. Montney wells | 638 | 103 |
| TOTAL Montney wells | 814 | 140 |
| Other formation wells | 342 | 74 |
| Other expenditures | 7 | - |
| TOTAL | 1,163 | 214 |

*Notes:*
*[1] FDC is per the evaluation report prepared by Sproule Associates Limited effective December 31, 2017.*
*[2] FDC = Future Development Capital.*
*[3] HZ = horizontal.*

# Grande Cache






Kelt Lands

## LAND

**Gross: 141,120 acres ( 220 sections )**
**Net: 99,716 acres ( 155 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.*

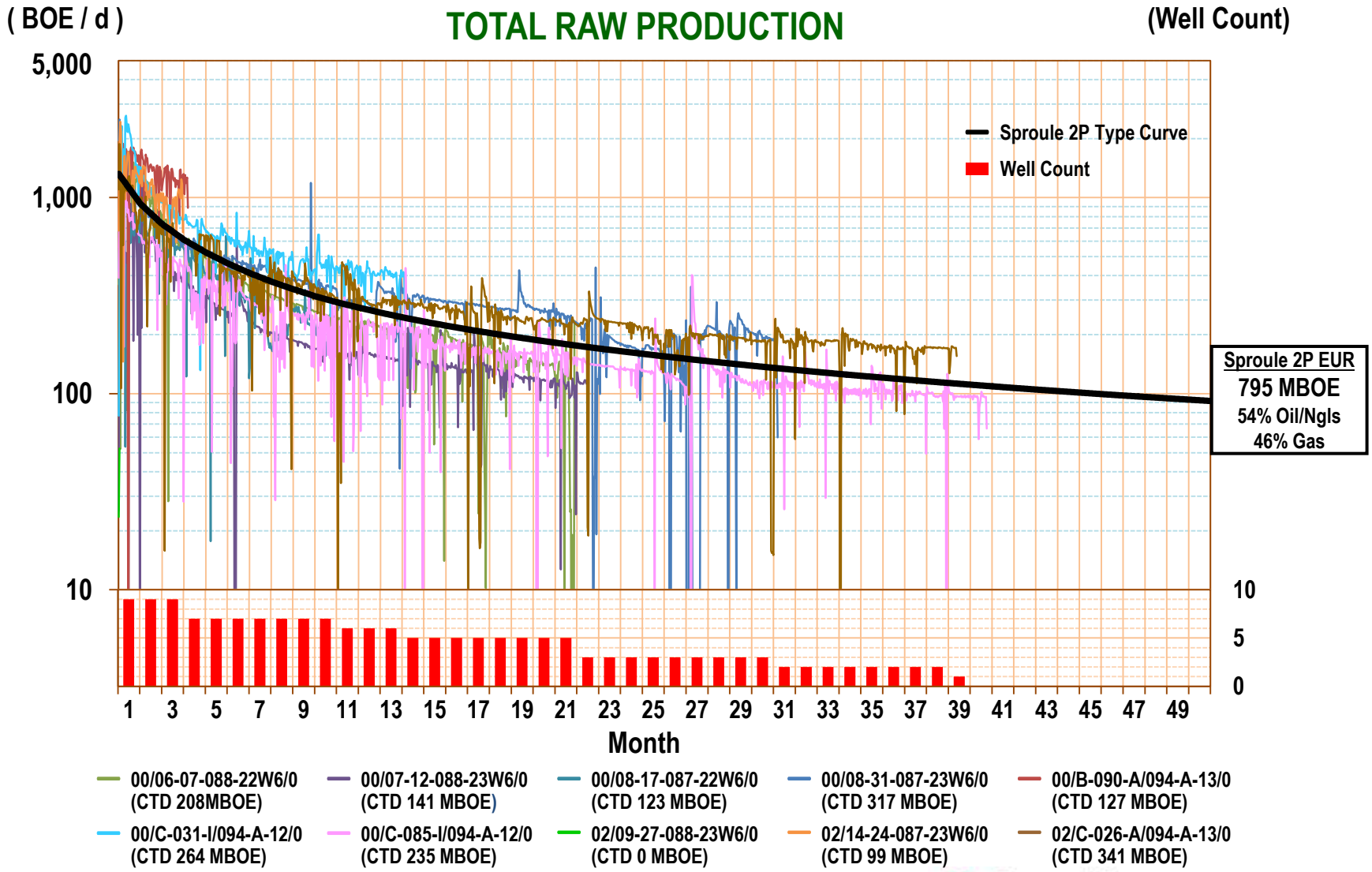
*[2] Production Start Date is the date when the well commenced steady production after tie-in operations were completed. The payback period is calculated from this date.*

*[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.*

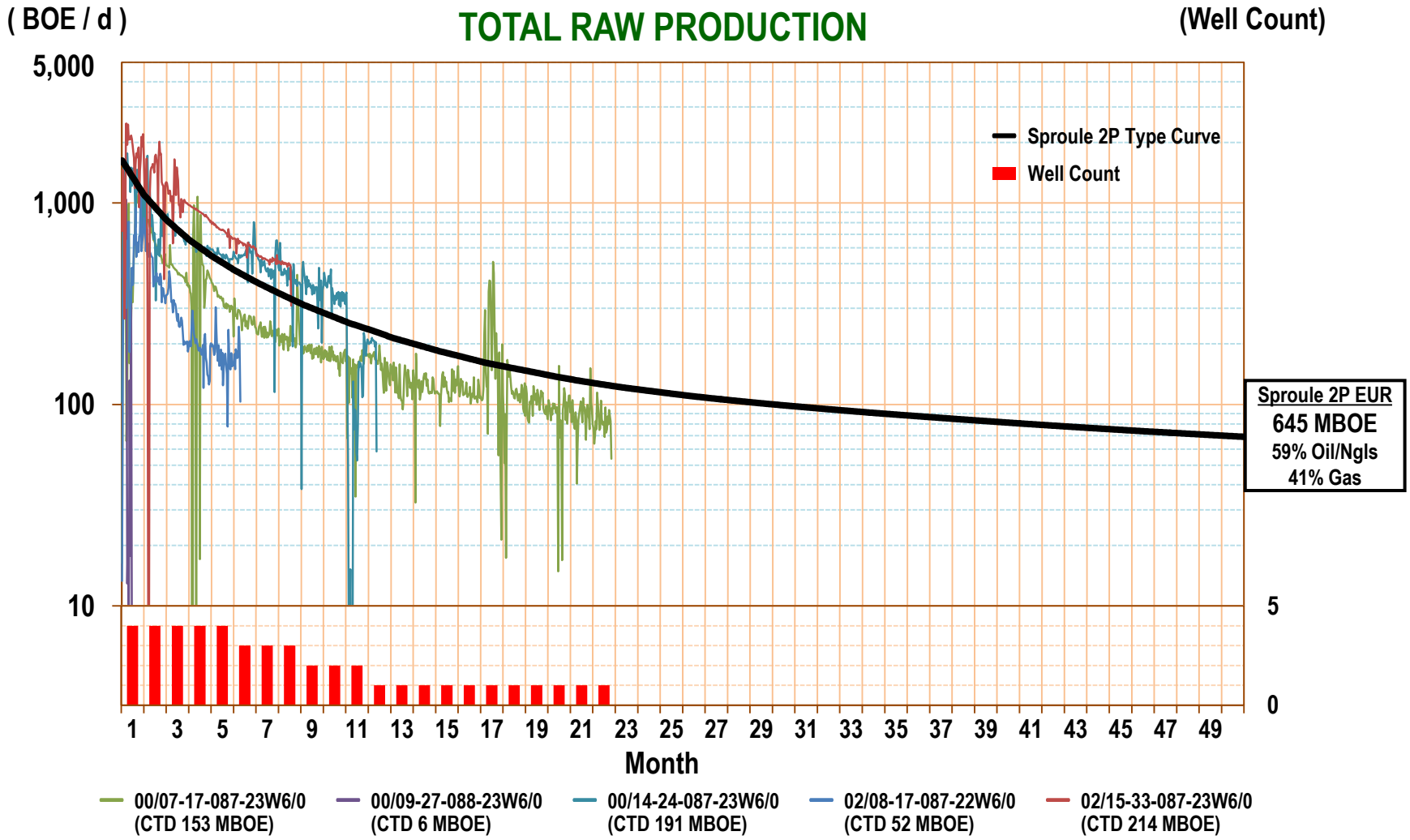
# Inga / Fireweed Upper Montney Type Curve





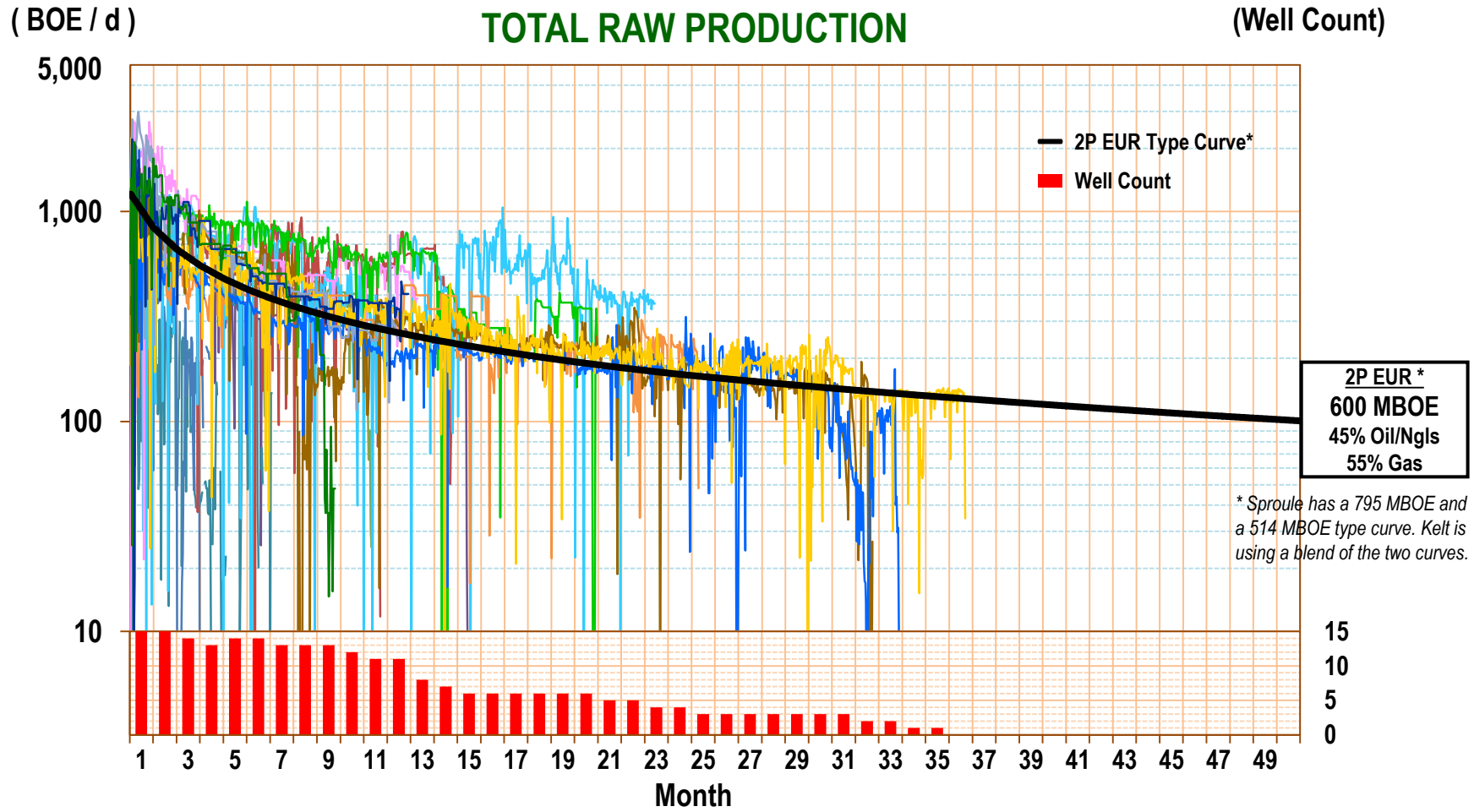
# Inga / Fireweed Middle Montney Type Curve





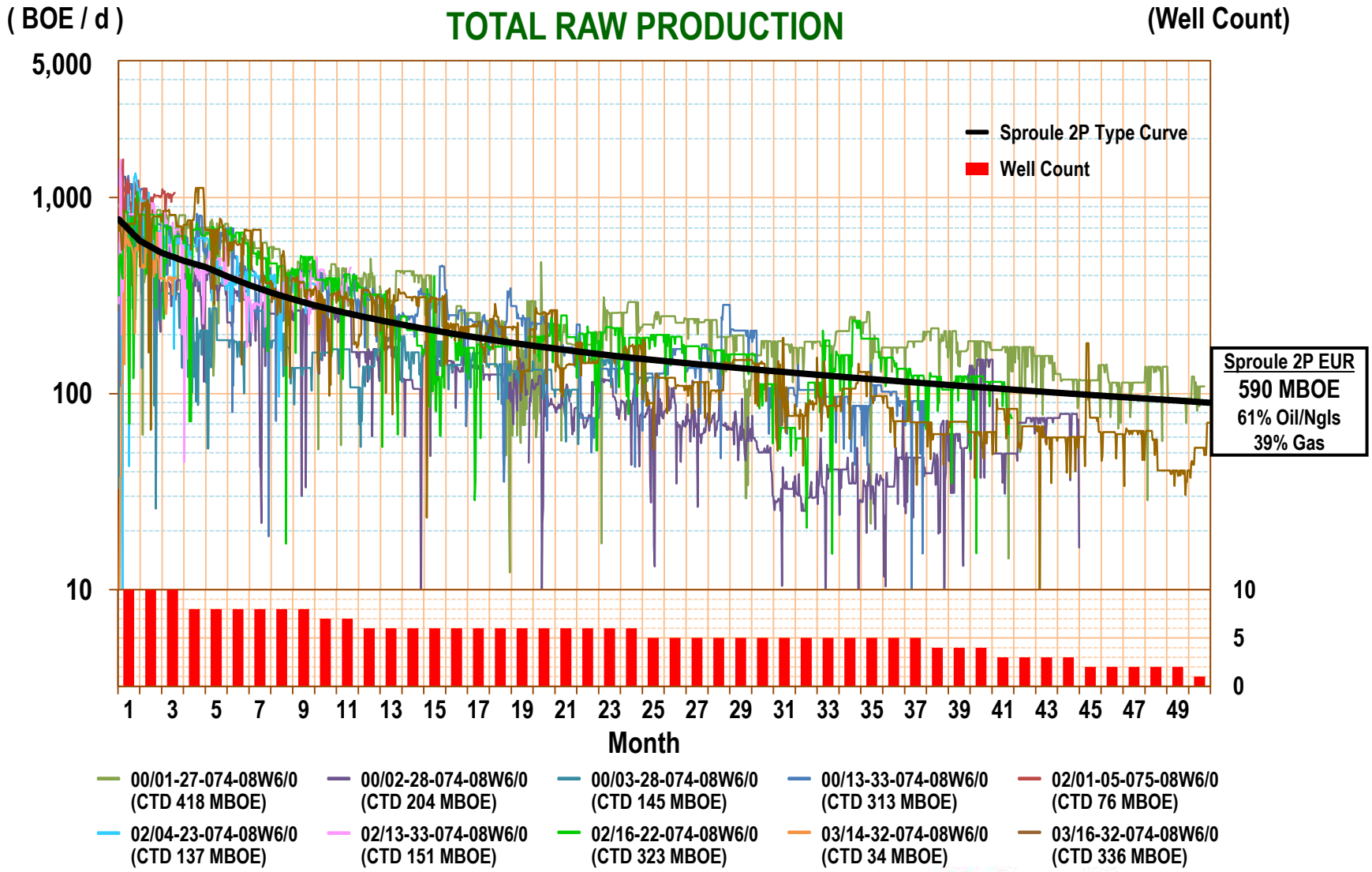
# Pouce Coupe / Progress Montney Oil Type Curve





# La Glace Montney Oil Type Curve





# 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, 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 budgeted activities; 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 for the year ended December 31, 2017.

**"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: t**he 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: t**he estimated amount of reserves added to the reserves base during the year relative to the amount of oil and gas produced.

**IP30: t**he 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

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