



PRESS RELEASE

(Stock Symbol “**KEL**” – TSX)

August 9, 2017

Calgary, Alberta

KELT REPORTS FINANCIAL AND OPERATING RESULTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2017

Kelt Exploration Ltd. (“Kelt” or the “Company”) has released its financial and operating results for the three and six months ended June 30, 2017. The Company’s financial results are summarized as follows:

FINANCIAL HIGHLIGHTS <i>(CA\$ thousands, except as otherwise indicated)</i>	Three months ended June 30			Six months ended June 30		
	2017	2016	%	2017	2016	%
Revenue, before royalties and financial instruments	60,072	40,718	48	120,297	81,116	48
Adjusted funds from operations ⁽¹⁾	25,333	11,671	117	52,156	17,622	196
Basic (\$/ common share) ⁽¹⁾	0.14	0.07	100	0.30	0.10	200
Diluted (\$/ common share) ⁽¹⁾	0.14	0.07	100	0.29	0.10	190
Loss and comprehensive loss	(4,869)	(20,413)	-76	(7,136)	(46,331)	-85
Basic (\$/ common share)	(0.03)	(0.12)	-75	(0.04)	(0.27)	-85
Diluted (\$/ common share)	(0.03)	(0.12)	-75	(0.04)	(0.27)	-85
Total capital expenditures, net of dispositions	31,630	25,908	22	(3,734)	49,313	-108
Total assets	1,203,174	1,260,245	-5	1,203,174	1,260,245	-5
Bank debt, net of working capital ⁽¹⁾	80,618	139,080	-42	80,618	139,080	-42
Convertible debentures	72,685	69,320	5	72,685	69,320	5
Shareholders' equity	839,485	835,241	1	839,485	835,241	1
Weighted average shares outstanding (000s)						
Basic	175,894	173,818	1	175,805	171,321	3
Diluted	177,316	173,972	2	177,093	171,444	3

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

FINANCIAL STATEMENTS

Kelt’s unaudited condensed consolidated interim financial statements and related notes for the quarter ended June 30, 2017 will be available to the public on SEDAR at www.sedar.com and will also be posted on the Company’s website at www.keltexploration.com on August 9, 2017.

Kelt's operating results for the second quarter ended June 30, 2017 are summarized as follows:

OPERATIONAL HIGHLIGHTS <i>(CA\$ thousands, except as otherwise indicated)</i>	Three months ended June 30			Six months ended June 30		
	2017	2016	%	2017	2016	%
Average daily production						
Oil (bbls/d)	5,929	5,066	17	5,863	5,469	7
NGLs (bbls/d)	1,967	2,632	-25	2,162	2,686	-20
Gas (mcf/d)	76,730	75,060	2	74,525	81,577	-9
Combined (BOE/d)	20,684	20,208	2	20,446	21,751	-6
Production per million common shares (BOE/d) ⁽¹⁾	118	116	2	116	127	-9
Average realized prices, before financial instruments						
Oil (\$/bbl)	56.80	49.76	14	58.48	41.30	42
NGLs (\$/bbl)	29.04	18.21	59	28.36	16.19	75
Gas (\$/mcf)	3.47	1.97	76	3.50	2.16	62
Operating netbacks (\$/BOE) ⁽¹⁾						
Petroleum and natural gas revenue	31.91	22.14	44	32.50	20.49	59
Realized gain (loss) on financial instruments	(0.21)	(0.01)	2000	(0.10)	(0.01)	900
Average realized price, after financial instruments	31.70	22.13	43	32.40	20.48	58
Royalties	(2.47)	(1.65)	50	(3.04)	(1.49)	104
Production expense	(10.27)	(8.87)	16	(9.94)	(9.61)	3
Transportation expense	(3.47)	(2.89)	20	(3.36)	(2.79)	20
Operating netback ⁽¹⁾	15.49	8.72	78	16.06	6.59	144
Undeveloped land						
Gross acres	777,550	665,010	17	777,550	665,010	17
Net acres	658,538	543,530	21	658,538	543,530	21

(1) Refer to advisories regarding non-GAAP financial measures and other key performance indicators.

MESSAGE TO SHAREHOLDERS

Average production for the three months ended June 30, 2017 was 20,684 BOE per day, up 2% compared to average production of 20,208 BOE per day during the second quarter of 2016. Production during the second quarter of 2017 reflects the disposition of the majority of the Company's oil and gas assets at Karr which included approximately 1,300 BOE per day of production. The Karr disposition was completed on January 18, 2017.

The Company's average production during the second quarter of 2017 was below original estimates as third party outages and downtime exceeded expectations. The following downtime and outages negatively affected 2017 second quarter production: TransCanada Pipeline Ltd. restricted a portion of firm service production on the NGTL pipeline system upstream of the James River receipt area in June for approximately two weeks; turnaround operations at the McMahon Gas Plant lasted longer than originally expected; compression downtime on the Westcoast pipeline system during the McMahon plant outage resulted in partial outages at the West Stoddart Gas Plant, where the majority of the Company's gas in British Columbia is processed; an outage at the Younger Gas Plant in British Columbia, where repairs were conducted, reduced the amount of NGL recoveries that Kelt normally realizes during the period of repairs; in June 2017, the Alliance Pipeline system declared a force majeure resulting from excavation and inspection of the upper and lower sections of its pipeline segment in the area of the slope movement near the Wapiti River requiring Kelt to shut-in significant volumes of production in both British Columbia and Alberta; and at Spirit River, the Company was required to also shut-in approximately 400 BOE per day of production that flowed through a third party gathering system. The owner of the pipeline gathering system does not intend to complete the

repairs required to bring the system back to operation at this time. Kelt is currently reviewing alternative options to bring that production back on stream.

Initial production rates from recent drilling results in both British Columbia and Alberta have exceeded the Company's estimates. As a result, despite the lower second quarter production, Kelt has not changed its full year guidance of average daily production of 23,500 BOE per day. The Company intends to review its production guidance again in September and will provide updated information at that time.

At La Glace, Alberta, the Company drilled and completed two wells in the Middle Montney. The wells were completed using gelled-water with 36 fracture stages and approximately 40 tonnes of proppant per stage. The well located at 02/13-33-074-08W6 had an IP30 rate (gross estimated sales) of 790 BOE per day of which 90% was oil and NGLs. The second well located at 02/04-23-074-08W6 had an IP30 rate (gross estimated sales) of 888 BOE per day of which 69% was oil and NGLs. Given the lower capital expenditures per well and the resulting quick payback on these wells, at under six months in the current commodity price environment, Kelt has drilled two additional wells at La Glace in July 2017.

At Inga, British Columbia, the Company drilled its third Middle Montney well on its large contiguous land block. The well was completed using slick-water with 46 fracture stages and approximately 70 tonnes of proppant per stage. The well located at 02/15-33-087-23W6 had an IP24 rate (gross estimated sales) of 2,157 BOE per day of which 81% was oil and NGLs. This is the highest Middle Montney initial production rate recorded to date at Inga/Fireweed. In the current commodity price environment, given the high oil content of the initial production, this well is expected to payback in approximately six months. With the success to date in the Middle Montney, Kelt expects to drill additional Middle Montney wells at Inga during the second half of 2017 and in 2018.

At Pipestone/Wembley, Alberta where the Company has recently increased its land position to 59,080 acres (92 sections) of lands with Montney rights, Kelt has drilled its first horizontal exploratory well located at 00/04-01-072-08W6. This well has now been completed using slick-water with 50 fracture stages and approximately 70 tonnes of proppant per stage. Initial production results are expected to be available in September 2017.

At Inga/Stoddart, British Columbia where the Company has 104,862 acres (164 sections) of lands with Baldonnel rights, Kelt has drilled its first horizontal exploratory well located at 00/13-29-087-21W6. This well is currently being completed using slick-water with 30 planned fracture stages and approximately 26 tonnes of proppant per stage.

Commodity prices have improved from 2016 levels and have shown significant gains in the second quarter of 2017 compared to the second quarter of 2016. Kelt's realized average oil price during the second quarter of 2017 was \$56.80 per barrel, up 14% from \$49.76 per barrel in the second quarter of 2016. The realized average NGLs price during the second quarter of 2017 was \$29.04 per barrel, up 59% from \$18.21 per barrel in the corresponding quarter of 2016. Kelt's realized average gas price for the second quarter of 2017 was \$3.47 per MCF, up 76% from \$1.97 per MCF in the second quarter of the previous year.

The Company continues to realize higher average gas prices compared to the AECO index price through its gas market diversification strategy. In British Columbia, where there have been gas egress congestion and bottlenecks in the past, for the upcoming gas year (November 1, 2017 to October 31, 2018), Kelt has contracted service for approximately 25,000 MMBtu per day of gas sales for its British Columbia production. Approximately 15,000 MMBtu per day will be delivered to the Station 2 Hub and Kelt will receive the Sumas Hub USD Monthly Index price less US\$0.695 per MMBtu. Approximately 10,000 MMBtu per day will be delivered to an Alliance pipeline receipt point and Kelt will receive the Chicago Hub Gas Daily Index price less transportation charges. As a result, Kelt will have minimal to no exposure to Station 2 pricing in its British Columbia gas market portfolio. In Alberta, the Company has contracts in place to sell 15,000 MMBtu per day of gas at NIT and to receive the Malin Hub USD Index price less US\$0.70 per MMBtu (November 1, 2017 to October 31, 2020) and 23,700 MMBtu per day of gas at the Dawn hub in southern Ontario less transportation charges (November 1, 2017 to October 31, 2020). These contracts provide Kelt with gas market diversification and ensure that the Company's future gas sales revenue is not subject to the risks associated with a single market.

For the three months ended June 30, 2017, revenue was \$60.1 million and adjusted funds from operations was \$25.3 million (\$0.14 per share, diluted), compared to \$40.7 million and \$11.7 million (\$0.07 per share, diluted) respectively, in the second quarter of 2016. At June 30, 2017, bank debt, net of working capital was \$80.6 million, down 42% from \$139.1 million at June 30, 2016.

Capital expenditures incurred during the three months ended June 30, 2017, prior to property dispositions, were \$35.0 million. The Company spent \$19.6 million (56%) on drilling and completion operations, \$14.1 million (40%) on facilities, pipelines and equipment and \$1.2 million (4%) on land and seismic. In addition, during the second quarter of 2017, Kelt received cash proceeds of \$3.3 million from minor property dispositions.

Kelt has recently moved to development drilling from multi-well pads as part of its future development plan for its vast corporate Montney acreage. Capital efficiencies gained from pad drilling and improved completion results with increased fracture stages, greater proppant tonnage and high intensity pump rates have resulted in short payback periods in the current commodity price environment. The tables below show the estimated payback of capital incurred to drill and complete all new Montney wells that the Company has brought on production in 2017 (except the Inga 00/14-24-087-23W6 well which was brought on production on December 12, 2016). Two Montney wells drilled at Progress are not included in Table 1 as these wells are currently in the process of being brought on stream.

Table 1 – Paybacks for 2017 Montney Development Wells:

Well	Drill & Complete Cost (\$ MM) [1]	Initial Test Date	Production Start Date [2]	Actual Cumulative to May 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	150.7	4.8	31.90	22.8	0.5	0.4	761
Pouce Coupe 03/07-18-078-11W6	4.1	2017-01-26	2017-01-26	125.4	4.0	31.84	23.8	0.6	0.4	792
Pouce Coupe 04/07-18-078-11W6	5.0	2017-01-24	2017-03-03	101.4	3.0	30.00	83.8	2.2	0.7	440
Pouce Coupe 05/07-18-078-11W6	4.3	2017-01-23	2017-03-08	105.0	3.2	30.08	40.2	1.2	0.4	578
Pouce Coupe 00/01-09-078-11W6	5.0	2017-02-21	2017-03-11	89.8	3.0	33.50	70.3	2.1	0.6	450
Pouce Coupe 03/16-25-077-13W6	5.8	2017-02-25	2017-06-19	26.5	0.4	13.83	426.1	5.8	0.8	1,061
La Glace 02/13-33-074-08W6	3.8	2017-04-01	2017-04-01	42.8	1.8	42.86	56.0	2.1	0.5	406
La Glace 02/04-23-074-08W6	4.0	2017-05-26	2017-05-26	2.1	0.1	26.88	131.8	4.2	0.7	347

Notes: Refer to explanatory notes provided under Table 2.

In addition to favourable economic results from its Montney development drilling program, the Company expects to achieve short paybacks on its capital incurred on Montney delineation and step-out wells. A move to pad drilling on these newly de-risked lands should result in further improvements in capital efficiencies in the future.

Table 2 – Paybacks for 2017 Montney Delineation/Step-out Wells:

Well	Drill & Complete Cost (\$ MM) [1]	Initial Test Date	Production Start Date [2]	Actual Cumulative to May 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 00/14-24-087-23W6 [Middle Montney]	6.5	2016-12-12	2016-12-12	135.6	4.6	34.17	58.2	2.0	0.8	449
Fireweed C-31-I/94-A-12 [Upper Montney]	6.9	2017-01-16	2017-01-16	142.9	3.6	25.13	151.5	3.3	1.4	313
Stoddart 00/08-17-087-22W6 [Upper Montney]	7.4 [5]	2017-03-22	2017-04-25	32.6	0.9	28.02	259.6	6.5	2.6	177
Inga 02/15-33-087-23W6 [Middle Montney]	5.5	2017-07-06	2017-07-13	-	-	-	193.7	5.7	0.5	656

Notes:

[1] Half-cycle capital – equipment and tie-in costs for delineation/step-out wells are not included in the payback period calculation, as the initial tie-in costs for single wells will eventually benefit additional wells drilled from the same pad. 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 for development wells.

[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 May 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. Actual production for June and July 2017, based on field estimates, is included in estimated future production.

[5] During completion operations, the Stoddart 8-17 well experienced fracking and drill-out problems which added approximately \$1.0 million to the completion costs.

The Company's Board of Directors has agreed to increase the 2017 capital expenditure budget by a net \$10.0 million. Total exploration and development capital expenditures planned for 2017 are \$191.0 million (previously \$173.0 million) and proceeds from property dispositions are expected to be \$111.0 million (previously \$103.0 million), resulting in a net capital expenditure budget of \$80.0 million (previously \$70.0 million). The increase in the capital expenditure budget reflects an additional \$18.0 million for infrastructure expenditures and additional proceeds from minor property dispositions in the amount of \$8.0 million (\$3.3 million of which was already completed at June 30, 2017 and the balance is an estimate for further transactions expected to occur in the second half of 2017).

On July 31, 2017, the Company completed the purchase of a major infrastructure package for \$12.5 million. After a new lease has been surveyed and built, this infrastructure package will be moved from its existing location in northeastern British Columbia and installed on a new site at Inga, British Columbia, in close proximity to the Company's existing Inga facility located at 15-03-088-23W6. The infrastructure package includes four 4,700 horse power gas compressors with aggregate capacity of 100 MMCF per day, two 50 MMCF per day gas dehydration units, a fuel gas conditioning skid, a high pressure flare system, four 750 barrel tanks, a vapor recovery unit, instrument air compressors, three electric power generators, a master control centre building and several other buildings and associated equipment. This infrastructure purchase is expected to lower future production expenses regardless of whether the Company elects to construct its own gas plant at Inga, or alternatively, continues to process gas through third party facilities in British Columbia.

Kelt has also commenced installation of blending facilities at its three main oil terminals located at Inga, La Glace and Progress, which are now pipeline connected to oil sales and water injection. These new facilities are expected to provide the Company with higher price realizations for its oil and butane sales in each of these areas and are anticipated to be completed prior to year-end.

The Company is well positioned financially to execute its capital program during the remainder of 2017 and expects to enter 2018 with strong operational momentum.

Management looks forward to updating shareholders with 2017 third quarter results on or about November 9, 2017.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

This press release contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words “expect”, “anticipate”, “continue”, “estimate”, “objective”, “ongoing”, “may”, “will”, “project”, “should”, “believe”, “plans”, “intends” and similar expressions are intended to identify forward-looking information or statements. In particular, this press release contains forward-looking statements pertaining to the following: the expectation that the Company’s new firm service gas transportation contracts will limit exposure to discounted Station 2 pricing for its operations in northeastern BC; the anticipated improvement in Kelt’s price realizations for its oil and butane sales following the installation of blending facilities at the Company’s three main oil terminals, which are expected to be completed prior to December 31, 2017; the expectation that the recent purchase of a major infrastructure package in northeastern BC will reduce the Company’s production expenses in the future; that the estimated future production and operating income for the 2017 Montney development wells (Table 1) and delineation/step-out wells (Table 2) will be sufficient to payback the drill and complete capital costs incurred for each respective well; the Company’s ability to continue accumulating land at a low-cost in its core operating areas and potentially monetize non-core assets; and the Company’s expected future financial position and operating results, as well as the amount and timing of future development capital expenditures. Statements relating to “reserves” or “resources” are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserves may be greater than or less than the estimates provided herein.

Although Kelt believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Kelt cannot give any assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; failure to obtain necessary regulatory approvals for planned operations; health, safety and environmental risks; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; volatility of commodity prices, currency exchange rate fluctuations; imprecision of reserve estimates; and competition from other explorers) as well as general economic conditions, stock market volatility; and the ability to access sufficient capital. We caution that the foregoing list of risks and uncertainties is not exhaustive.

In addition, the reader is cautioned that historical results are not necessarily indicative of future performance. The forward-looking statements contained herein are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

Certain information set out herein may be considered as “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Kelt’s reasonable expectations as to the anticipated results of its proposed business activities for the periods indicated. Readers are cautioned that the financial outlook may not be appropriate for other purposes.

NON-GAAP FINANCIAL MEASURES AND OTHER KEY PERFORMANCE INDICATORS

This press release contains certain financial measures, as described below, which do not have standardized meanings prescribed by GAAP. In addition, this press release 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 petroleum and natural 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 (if applicable): 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.

Other KPI

“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.

MEASUREMENTS

All dollar amounts are referenced in thousands of Canadian dollars, except when noted otherwise. This press release 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 either energy content or current prices. Such abbreviation may be misleading, particularly if used in isolation. References to “oil” in this press release include crude oil and field condensate. References to “natural gas liquids” or “NGLs” include pentane, butane, propane, and ethane. References to “liquids” include field condensate and NGLs. References to “gas” in this discussion include natural gas and sulphur.

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MMBTU	million British Thermal Units

GJ	gigajoule
BOE	barrel of oil equivalent
BOE/d	barrel of oil equivalent per day
NGLs	natural gas liquids
AECO	Alberta Energy Company "C" Meter Station of the NOVA Pipeline System
NIT	NOVA Inventory Transfer ("AB-NIT"), being the reference price at the AECO Hub
WTI	West Texas Intermediate
NYMEX	New York Mercantile Exchange
Station 2	Spectra Energy receipt location
API	American Petroleum Institute
IP24	initial production from a well for the first 576 hours (24 days) based on operating/producing hours
IP30	initial production from a well for the first 720 hours (30 days) based on operating/producing hours
US\$	United States dollars
CA\$	Canadian dollars
TSX	the Toronto Stock Exchange
KEL	trading symbol for Kelt Exploration Ltd. common shares on the TSX
KEL.DB	trading symbol for Kelt Exploration Ltd. 5% convertible debentures on the TSX
GAAP	Generally Accepted Accounting Principles
KPI	Key Performance Indicators

For further information, please contact:

KELT EXPLORATION LTD., Suite 300, 311 – 6th Avenue SW, Calgary, Alberta, Canada T2P 3H2

DAVID J. WILSON, President and Chief Executive Officer (403) 201-5340, or

SADIQ H. LALANI, Vice President and Chief Financial Officer (403) 215-5310.

Or visit our website at www.keltexploration.com.