CEQUENCE ENERGY ANNOUNCES OPERATIONAL UPDATE, 2016 FINANCIAL AND OPERATING RESULTS AND RESERVES

CALGARY, March 13, 2017– Cequence Energy Ltd. ("Cequence" or the "Company") (TSX: CQE) is pleased to provide an update on its recent operational activities and to announce its year-end reserve evaluation as prepared by its qualified independent reserve evaluator as well as its operating and financial results for the fourth quarter and year ended December 31, 2016. The Company's Consolidated Financial Statements and Management's Discussion and Analysis are available at www.cequence-energy.com and on SEDAR at www.sedar.com.

Recent Operational Highlights

In 2016, the Company restructured the management team with a focus on achieving repeatable, operational successes and efficiencies with financial discipline that protected its balance sheet. Through 2016, the Company executed on implementing various cost savings initiatives which exceeded its financial objectives.

More recently in Q4 2016 and Q1 2017, the Company has continued the execution of its strategic business plan, by demonstrating strong operational successes, with recent operational highlights including:

- Full year production of 897 boe/d (22% liquids) was realized from the 16-33-61-27W5 west Simonette Montney well.
- Two (100% WI) Montney wells were successfully drilled with lateral lengths of 2,700 meters and 3,020 meters each.
- Two gross (one net) Dunvegan wells were brought on production in January 2017. The two wells have IP30 operating rates of 645 bbls/d and 372 bbls/d.
- The 10-11 and 15-11-62-26W5 wells are two of the top 15 performing oil wells in all of Alberta for the month of January 2017 (based on publicly available producing day rate information).

Montney Operations Update

The 16-33-61-27W5 west Simonette Montney well has performed strongly over its first year of operation with a field IP 365 of 897 boe/d (22% total liquids) and a 2016 exit rate of 660 boe/d (20% liquids). This well was the longest Cequence Montney well at 6,100 total meters and a completed lateral length of 3,050 meters utilizing a 71 stage cemented coil shift frac system. Two follow-up Montney wells, located at 1-36 and 8-36-61-1W6M, were recently drilled with lateral lengths of 2,700 meters (76 frac ports) and 3,020 meters (91 frac ports), respectively. Both wells were drilled on budget, with drilling costs of $4.0 million per well, including drilling equipment mobilization costs. The new 8-36-61-1W6 well now represents Cequence's longest Montney well at 6,209 total meters. The completion for the 8-36 well commenced on March 4, 2017 with 3,640 metric tonnes of sand (8 MM lbs) placed in 5.3 days. Completion operations at the 1-36 well began on March 10th and is forecast to take 4 to 5 days. Flow rate information is expected to be released on these wells once they have produced for 30 days.

The western Simonette Montney lands are characterized as having low average gross overriding royalties (1-3%) with higher liquid yields thereby increasing the economics of wells drilled on those lands. Cequence estimates a total of approximately 50 net Montney locations[(1)] exist in the West Simonette lands.

Simonette Dunvegan Oil

Two gross (50% WI) Dunvegan oil wells were drilled in Q4 2016 and brought on production in January 2017. The average drilling, completion, and tie-in cost of the wells was $4.0 million gross or 11% under budget. Since being tied into permanent facilities, the gross IP 30 for the 10-11-62-26W5 well was 645 bbls/d of oil (990 boe/d) while 15-11-62-26W5 well was 372 bbls/d of oil (675 boe/d). Both wells are above the Cequence IP 30 model of 300 bbls/d of oil (550 boe/d), and both wells are identified as two of top 15 performing oil wells in Alberta for the month of January 2017 (based on publicly available producing day rate information).

A total of 24 net Dunvegan oil wells have been identified on Cequence lands. [(1)]

(1) See additional information for description of drilling locations

2016 Financial and Reserves Highlights

Financial and reserves highlights of the Company for 2016 include:

- Achieved full year 2016 production of 8,826 boe/d.
- Reduced Q4 2016 operating costs to $7.81/boe, a 16% decrease compared to Q4 2015.
- Reduced G&A expenses for Q4 2016 to $1.81/boe, a 32% decrease compared to Q4 2015.
- Increased funds flow from operations for Q4 2016 to $6.6 million or $0.03/share, a 36% increase compared to Q4 2015.
- Increased Montney reserves with improved recovery factors associated with 300 meter inter-well distances and improved drilling and completion practices.
- Increased proved reserves by 13% from 2015 to 70,391 mboe, replacing annual production by 344%.
- Increased proved plus probable reserves by 8% from 2015 to 136,415 mboe, replacing annual production by 423%.
- Net present value before income taxes of the Company's proved plus probable reserves is $496 million or $2.02 per share (using a discount rate of 10%).

Comparative Financial and Operating Information

Comparative financial and operating information for 2016 and 2015 are as follows:

(000's except per share and per unit amounts)	Three months ended December 31,			Twelve months ended December 31,		
	2016	2015	% Change	**2016**	2015	% Change
FINANCIAL						
Total revenue[1]	**17,253**	16,112	**7**	**59,074**	80,891	**(27)**
Comprehensive loss	**(9,077)**	(146,585)	**(94)**	**(28,057)**	(250,072)	**(89)**
Per share – basic and diluted	**(0.04)**	(0.69)	**(94)**	**(0.13)**	(1.19)	**(89)**
Funds flow from operations [2][5]	**6,625**	4,874	**36**	**11,250**	25,578	**(56)**
Per share, basic and diluted	**0.03**	0.02	**50**	**0.05**	0.12	**(58)**
Capital expenditures, before acquisitions (dispositions)	**11,460**	15,175	**(24)**	**22,590**	62,261	**(64)**
Capital expenditures, including acquisitions (dispositions)	**11,406**	16,351	**(30)**	**17,296**	18,560	**(7)**
Net debt [3][6]	**(64,031)**	(65,447)	**(2)**	**(64,031)**	(65,447)	**(2)**
Weighted average shares outstanding – basic and diluted	**235,028**	211,028	**11**	**217,061**	211,028	**3**
OPERATING						
Production volumes						
Natural gas (Mcf/d)	**45,005**	41,794	**8**	**45,422**	47,589	**(5)**
Crude oil (bbls/d)	**140**	225	**(38)**	**177**	160	**11**
Natural gas liquids (bbls/d)	**209**	300	**(30)**	**237**	475	**(50)**
Condensate (bbls/d)	**760**	723	**5**	**841**	918	**(8)**
Total (boe/d)	**8,609**	8,213	**5**	**8,826**	9,485	**(7)**
Sales prices						
Natural gas, including realized hedges ($/Mcf)	**2.92**	2.89	**1**	**2.27**	3.27	**(31)**
Crude oil and condensate, including realized hedges ($/bbl)	**56.27**	52.32	**8**	**52.17**	53.78	**(3)**
Natural gas liquids ($/bbl)	**25.61**	16.45	**56**	**21.94**	17.04	**29**
Total ($/boe)	**21.78**	21.32	**2**	**18.29**	23.37	**(22)**
Netback ($/boe)						
Price, including realized hedges	**21.78**	21.32	**2**	**18.29**	23.37	**(22)**
Royalties	**(0.59)**	0.67	**188**	**(0.48)**	(0.84)	**(43)**
Transportation	**(1.45)**	(1.77)	**(18)**	**(1.24)**	(1.83)	**(32)**
Operating costs	**(7.81)**	(9.30)	**(16)**	**(8.49)**	(9.17)	**(7)**
Operating netback	**11.93**	10.92	**9**	**8.08**	11.53	**(30)**
General and administrative [5]	**(1.81)**	(2.65)	**(32)**	**(2.77)**	(2.30)	**20**
Interest[4]	**(1.92)**	(2.15)	**(11)**	**(1.93)**	(1.96)	**(2)**
Cash netback	**8.20**	6.12	**34**	**3.38**	7.27	**(54)**

Notes:

(1) Total revenue is presented gross of royalties and includes realized gains (loss) on commodity contracts.
(2) Funds flow from operations is calculated as cash flow from operating activities before adjustments for decommissioning liabilities expenditures and net changes in non-cash working capital.
(3) Net debt is calculated as working capital (deficiency) less the principal value of senior notes.
(4) Represents finance costs less amortization on transaction costs and accretion expense on senior notes and provisions.
(5) For the three and twelve months ended December 31, 2016, general and administrative expenses and funds flow from operations includes $nil ($nil/boe) and $2,341 ($0.72/ boe) in restructuring charges, respectively.
(6) Prior period amounts have been adjusted to confirm to current period presentation.

Financial Matters

2016 was a challenging year for natural gas prices as AECO averaged $2.18/mcf, representing the lowest annual average natural gas price in over 10 years. The Company responded by reducing capital expenditures, periodically curtailing uneconomic production and pursuing initiatives to reduce both operating and general and administrative expenses. Through the reduction of staff and office space, as well as other cost-saving initiatives, the Company achieved a 22% reduction in general and administrative expenses prior to restructuring in 2016 as compared to 2015. Cequence undertook several operating cost efficiency projects at Simonette, resulting in annual operating expenses of $8.49/boe representing a decrease of 7% from 2015.

For the twelve months ended December 31, 2016, the Company’s natural gas price including realized hedging averaged $2.27/mcf, down $1.00/mcf from $3.27/mcf in 2015. Reference prices remained low throughout most of 2016 as an unseasonably warm North American winter in 2015 and 2016 resulted in record high North American natural gas inventories. Prices increased during the second half of 2016 through a combination of lower North American natural gas drilling activity, increased natural gas usage for power generation and U.S. exports that resulted in an improvement of supply/demand fundamentals and alleviated the large gas storage surplus. For the fourth quarter of 2016, natural gas price including realized hedging improved significantly to average $2.92/mcf.

As a result of improved commodity prices and lower than expected costs, funds flow from operations for the twelve months ended December 31, 2016 was $11.3 million compared to the Company’s revised guidance of $8 million. Fourth quarter funds flow from operations were $6.6 million compared to $4.9 million in the fourth quarter of 2015. For the twelve months ended December 31, 2016, the Company recorded a comprehensive loss of $28.1 million compared to a loss of $250.1 million for the twelve months ended December 31, 2015 when the Company recorded impairments of $230.4 million as a result of a lower outlook for crude oil and natural gas prices.

Capital expenditures, prior to dispositions, were $22.6 million for the twelve months ended December 31, 2016, a decrease of 64% from 2015. Consistent with 2015, the Company’s 2016 capital expenditures were focused on its Simonette property. The Simonette gas plant (50% WI) was completed during the first quarter of 2016, which is expected to provide the Company with improved long term market access for its natural gas production. During the twelve months ended December 31, 2016, Cequence drilled two Montney wells and drilled and completed two (one net) Dunvegan wells. The Company’s drilling program commenced in the fourth quarter of 2016 and was partly funded by the Company’s $10 million flow-through common share financing in October 2016.

The Company continued to prudently manage its balance sheet in 2016. As at December 31, 2016, the Company’s senior credit facility remained undrawn, and the Company had net debt of $64 million. The Company has hedged approximately 50% of its expected 2017 natural gas production (net of royalties) at an average price of $3.02/mcf.

2016 Operational and Production Matters

In 2016, the Company spent $22.6 million of capital before divestitures ($17.3 million net of divestitures), with approximately $9.1 million (40%) weighted toward netback improvement projects including commissioning the Simonette 13-11 refrigeration plant, adding a connection to the Nova Gas Transmission system, reducing field rentals, and initiating an infield water disposal solution. For the year ended December 31, 2016, operating costs averaged $8.49 per boe in 2016, down 7% from 2015, while the Company's operating costs for the fourth quarter of 2016 were $7.81, down 16% from the same period in 2015.

Corporate production for the three and twelve months ended December 31, 2016 averaged 8,609 boe/d and 8,826 boe/d, respectively, compared to production of 8,213 boe/d and 9,485 boe/d in 2015. In November, Cequence began a program to drill two gross (one net) Dunvegan oil wells and two gross (two net) Montney wells. This drilling program saw $9.0 million spent in the fourth quarter of 2016 with the wells scheduled to come on production during the first quarter of 2017. As these wells did not contribute to production in 2016, they are not included in the proved developed producing reserve category in the GLJ Report.

For the first quarter of 2017, Cequence has contracts on Alliance and TCPL that average 40,366 GJ/d at a blended discount to AECO of $0.31/GJ. Beginning April 1, 2017 the Company's contracted volume on these pipelines drops down to 20,000 GJ/d, and on November 1, 2017, the Company's contracted volume reduces to 10,000 GJ/d. The Company is pursuing additional firm service but currently will be relying on interruptible service on both the Alliance and TCPL pipeline systems. Interruptible transportation service may be more volatile than firm service and may result in higher transportation charges or inconsistent production times until additional firm service is contracted. Beginning, April 1, 2018 the Company will have 35,000 GJ/d of firm service with TCPL from its Simonette property.

The Company has entered into a binding contract to ship 10,850 GJ/d of natural gas on the TransCanada mainline system from the Empress receipt point to the Dawn hub in Ontario subject to regulatory approval with the National Energy Board and financial assurances. The term of the contract is 10 years and has early termination rights that can be exercised following the initial five years of service. The toll for this service is $0.77/GJ. The Company currently expects to begin shipping gas under these arrangements on April 1, 2018. The contract provides Cequence with pricing diversification for approximately 20 percent of its natural gas production.

2016 Independent Reserve Evaluation Matters

GLJ Petroleum Consultants ("GLJ") prepared the reserves report effective December 31, 2016 (collectively referred to herein as the "GLJ Report") for the oil, natural gas liquids and natural gas reserves attributable to the properties of Cequence. The GLJ Report was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101 ("NI 51-101"). Reserves highlights of the Company include:

- Achieved FD&A costs (including changes to FDC) of $10.20 per boe on a proved plus probable basis, $11.20 per boe on a proved basis and $31.41 per boe on a proved developed producing basis.
- 3 year average FD&A costs (including changes to FDC) are: $5.90 per boe on a proved plus probable basis, $9.38 per boe on a proved basis and $5.91 per boe on a proved developed producing basis.
- Increased Montney proved reserves by 19% to 56.7 MMboe and proved plus probable reserves by 15% to 112.4 MMboe. The Montney proved and probable undeveloped wells have a median un-escalated development cost of less than $6.90/boe.
- Upside identified on the West Simonette Montney lands. The recently drilled wells at 1-36-61-1W6 and 8-36-61-1W6 were booked by the qualified independent reserve evaluator as probable reserves and contingent resources, respectively.
- Netback for the fourth quarter of 2016 was $12.15/boe excluding hedging.

The tables below are a summary of the oil, NGL and natural gas reserves attributable to the properties of Cequence and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on forecast price and cost assumptions. The calculated NPVs include a deduction for estimated future well abandonment and reclamation costs. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of Cequence's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Summary of Oil, Natural Gas and NGL Reserves

	Light and Medium Crude Oil		Tight Oil		Conventional Natural Gas		Shale Gas		NGL		Total Oil Equivalent	
Reserves Category	Gross[(2)] (Mbbl)	Net[(3)] (Mbbl)	Gross[(2)] (Mbbl)	Net[(3)] (Mbbl)	Gross[(2)] (MMcf)	Net[(3)] (MMcf)	Gross[(2)] MMcf	Net[(3)] MMcf	Gross[(2)] (Mbbl)	Net[(3)] (Mbbl)	Gross[(2)] (MBOE)	Net[(3)] (MBOE)
Proved												
Developed Producing	446	342	1,314	880	34,330	31,576	53,573	45,909	442	320	16,853	14,456
Developed Non-Producing	252	205	34	23	5,950	5,348	1,424	1,298	41	30	1,556	1,365
Undeveloped	687	602	6,023	4,849	32,271	30,005	235,487	200,835	647	530	51,983	44,454
Total Proved	1,385	1,150	7,371	5,752	72,551	66,929	290,485	248,041	1,130	880	70,391	60,276
Probable	1,251	1,026	7,373	5,294	52,877	47,793	285,853	231,940	944	706	66,024	53,648
Total Proved plus Probable	2,636	2,175	14,745	11,046	125,428	114,722	576,338	479,981	2,074	1,586	136,415	113,924

Notes:

(1) Columns may not add due to rounding.

(2) "Gross" reserves means the Company's working interest (operated and non-operated) share before deduction of royalties payable to others and without including any royalty interests of the Company.

(3) "Net" reserves means the Company's working interest (operated and non-operated) share after deduction of royalty obligations plus the Company's royalty interests in reserves.

Summary of Net Present Value of Future Net Revenue

	Before Future Income Tax Expenses Discounted at (%/year)					
Reserves Category	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	10 ($/mcfe)
Proved						
Developed Producing	154,612	128,864	110,677	97,615	87,876	1.28
Developed Non-Producing	17,704	14,929	12,990	11,551	10,435	1.59
Undeveloped	474,568	242,069	121,777	54,948	15,652	0.46
Total Proved	646,883	385,863	245,445	164,114	113,963	0.68
Probable	1,031,940	468,772	251,049	149,184	94,862	0.78
Total Proved plus Probable	1,678,823	854,634	496,493	313,298	208,824	0.73

	After Future Income Tax Expenses Discounted at (%/year)				
Reserves Category	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved					
Developed Producing	154,612	128,864	110,677	97,615	87,876
Developed Non-Producing	17,704	14,929	12,990	11,551	10,435
Undeveloped	461,381	238,229	120,574	54,546	15,510
Total Proved	633,696	382,022	244,241	163,712	113,820
Probable	751,386	351,754	193,945	118,354	77,021
Total Proved plus Probable	1,385,082	733,776	438,186	282,065	190,842

Notes:

(1) Columns may not add due to rounding.

(2) It should not be assumed that the undiscounted and discounted future net revenues estimated by GLJ represent the fair market value of the reserves.

GLJ employed the following pricing, exchange rate and inflation rate assumptions as of January 1, 2016 in the GLJ Report in estimating Cequence's reserves data using forecast prices and costs:

	Natural Gas		Light Crude Oil		Pentanes Plus		
	Henry Hub	AECO Gas Price	WTI	Edmonton	Edmonton	Inflation Rates	Exchange Rate
Year	($US/MMBtu)	($Cdn/MMBtu)	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	%/year	($US/$Cdn)
Forecast							
2017	3.60	3.46	55.00	69.33	72.11	2.0	0.750
2018	3.20	3.10	59.00	72.26	74.79	2.0	0.775
2019	3.40	3.27	64.00	75.00	78.75	2.0	0.800
2020	3.60	3.49	67.00	76.36	79.80	2.0	0.825
2021	3.80	3.67	71.00	78.82	82.37	2.0	0.850
2022	4.00	3.86	74.00	82.35	86.06	2.0	0.850
2023	4.20	4.05	77.00	85.88	89.32	2.0	0.850
2024	4.31	4.16	80.00	89.41	92.99	2.0	0.850
2025	4.39	4.24	83.00	92.94	97.59	2.0	0.850
2026	4.48	4.32	86.05	95.61	99.91	2.0	0.850
Thereafter escalation rate of 2%							

The following table summarizes the elements of future net revenue attributable to reserves estimated using forecast prices and costs.

	Revenue ($000s)	Royalties ($000s)	Operating Costs ($000s)	Development Costs ($000s)	Abandonment and Reclamation Costs ($000s)	Future Net Revenue Before Income Taxes ($000s)	Income Taxes ($000s)	Future Net Revenue After Income Taxes ($000s)
Proved Reserves	2,170,700	258,163	665,417	565,039	35,197	646,883	13,187	633,696
Proved Plus Probable Reserves	4,694,133	660,680	1,379,033	921,574	54,024	1,678,823	293,741	1,385,082

Future Net Revenue by Product Type

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (3) (discounted at 10% per year) ($000s)	Unit Value $/boe	Unit Value $/MMcf
Proved Reserves				
	Light and Medium Oil (1)	16,771	13.41	2.23
	Conventional Natural Gas (2)	46,047	4.04	0.67
	Shale Natural Gas	182,627	3.84	0.64
	Total	245,445	4.07	0.68
Proved Plus Probable Reserves	Light and Medium Oil (1)	28,572	11.50	1.92
	Conventional Natural Gas (2)	80,934	4.18	0.70
	Shale Natural Gas	386,988	4.20	0.70
	Total	496,493	4.36	0.73

Notes:
(1) Includes solution gas and other by-products
(2) Including by-products but excluding solution gas
(3) Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

FD&A and F&D both including and excluding FDC have been calculated as described in the Additional Advisories section of this news release. Cequence's finding, development and acquisition costs are as follows:

	Proved Developed Producing	Proved	Proved Plus Probable
FD&A Including Change in FDC			
2016 FD&A Costs ($000s)	17,296	17,296	17,296
2016 Change in FDC ($000s)	1,799	106,972	121,948
2016 Capital Expenditures including change in FDC ($000s)	19,095	124,268	139,244
2016 Reserve Additions (MBOE)	608	11,099	13,651
2016 FD&A Including Change in FDC ($/BOE)	31.41	11.20	10.20
3 year average FD&A Including Change in FDC ($/BOE)	5.91	9.38	5.90
F&D Including Change in FDC			
2016 F&D Costs ($000s)	22,590	22,590	22,590
2016 Change in FDC ($000s)	1,799	106,972	121,948
2016 Capital Expenditures including change in FDC ($000s)	24,389	129,562	144,538

2016 Reserve Additions (MBOE)	608	11,195	14,270
2016 F&D Including Change in FDC ($/BOE)	40.11	11.57	10.13
3 year average F&D Including Change in FDC ($/BOE)	19.53	14.65	10.02
FDC – December 31, 2016 ($000s)	2,374	565,039	921,574
FDC – December 31, 2015 ($000s)	575	458,067	799,625
2016 Change in FDC ($000s)	1,799	106,972	121,949
FDC Related to 2016 Net Acquisitions (Dispositions) ($000s)	(5,294)	(5,294)	(5,294)
2016 Change in FDC Excluding FDC on Net Acquisitions (Dispositions) ($000s)	7,093	112,266	127,243

Note:

(1) In addition to F&D costs, Cequence also calculates FD&A costs which incorporate both the costs and associated reserve additions related to acquisitions net of any dispositions during the year. Since acquisitions can have a significant impact on Cequence's annual reserve replacement costs, the Company believes that FD&A costs provide a more meaningful portrayal of Cequence's cost structure.

(2) Capital expenditures for the FD&A calculation include cash expenditures on property and equipment of $22,590, net cash expenditures on property acquisition and dispositions of ($5,294).

About Cequence

Cequence is a publicly traded Canadian energy company involved in the acquisition, exploitation, exploration, development and production of natural gas and crude oil in western Canada. Further information about Cequence may be found in its continuous disclosure documents filed with Canadian securities regulators at www.sedar.com.

For further information contact:

Todd Brown, Chief Executive Officer, (403) 806-4049, tbrown@cequence-energy.com
David Gillis, Executive Vice President and Chief Financial Officer, (403) 806-4041, dgillis@cequence-energy.com

Forward-looking Statements or Information

Certain statements included in this press release 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 "believe", "expect", "plan", "estimate", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements or information in this press release may include, but are not limited to, statements or information with respect to: the Company's guidance and forecasts and expectations regarding market access for the Company's natural gas production. 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 press release, assumptions have been made regarding, among other things: the impact of increasing competition; 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 operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Company to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of 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; 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.*

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 may cause actual results to differ materially from the forward-looking statements or information. The material risk factors affecting the Company and its business are contained in the Company's Annual Information Form which is available on SEDAR at www.sedar.com.

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

Additional Advisories

The press release contains references to terms commonly used in the oil and gas industry.

Total revenue is a non-GAAP term that represents production revenue gross of royalties and including realized gain (loss) on commodity contracts. Management utilizes this measure to analyze revenue and commodity pricing and its impact on operating performance.

Funds flow from operations is a non-GAAP term that represents cash flow from operating activities before adjustments for decommissioning liability expenditures, proceeds from the sale of commodity contracts and changes in non-cash working capital. The Company evaluates its performance based on earnings and funds flow from operations. The Company considers funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The Company's calculation of funds flow from operations may not be comparable to that reported by other companies. Funds flow from operations per share is calculated using the same weighted average number of shares outstanding used in the calculation of income (loss) per share.

Operating and cash netback is not defined by IFRS in Canada and is referred to as a non-GAAP measure. Operating netback equals total revenue less royalties, operating costs and transportation costs. Cash netback equals the operating netback less general and administrative expenses and interest expense. Management utilizes these measures to analyze operating performance.

FD&A costs and F&D costs have been calculated in accordance with NI 51-101. F&D costs refers to all current year net capital expenditures, excluding property acquisitions and dispositions with associated reserves, and including changes in FDC on a proved or proved plus probable basis. FD&A costs incorporate both costs and associated reserve additions related to acquisitions net of any dispositions during the year. Further information on how the Company calculates F&D and FD&A costs is available in the Company's Annual Information Form filed on SEDAR. Management uses F&D costs as a measure to assess the performance of the Company's resources required to locate and extract new hydrocarbon reservoirs. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. FD&A and F&D costs used by Cequence may not be comparable to similar measures used by other issuers.

Recycle ratio is measured by dividing the operating netback by appropriate F&D or FD&A costs per boe for the year. Operating netback is calculated using production revenues, including realized gains and losses on commodity hedging, less royalties, transportation and operating expenditures, calculated on a per boe equivalent basis. Reserve replacement ratio measures the amount of reserves added to a Company`s reserve base during the year relative to the amount of oil and gas produced. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time.

Non-GAAP measures do not have a standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers.

This news release contains estimates of the net present value of the Company's future net revenue from its reserves. Such amounts do not represent the market value of the Company's reserves.

BOEs are presented on the basis of one BOE for six Mcf of natural gas. Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

For fiscal 2016 the ratio between the average price of West Texas Intermediate ("WTI") crude oil at Cushing and NYMEX natural gas was approximately 17:1 ("Value Ratio"). The Value Ratio is obtained using the 2016 WTI average price of $43.34 (US$/Bbl) for crude oil and the 2016 NYMEX average price of $2.55 (US$/MMbtu) for natural gas. This Value Ratio is significantly different from the energy equivalency ratio of 6:1 and using a 6:1 ratio would be misleading as an indication of value.

The Company's estimate that it has 50 net Montney locations on its West Simonette lands. Including in the 50 locations are 26 locations included in the GLJ report and 24 additional wells identified by management to be prospective. The Company identifies 24 net Dunvegan oil wells prospective on its land. There are 8 wells identified in the GLJ report and the remainder are based on internal estimates. Unbooked locations do not do not have attributed reserves and there is no certainty that if these locations would result in additional oil and gas reserves or production.

The TSX has neither approved nor disapproved the contents of this news release.