CALGARY, ALBERTA--(Marketwired - Mar 29, 2016) - Anderson Energy Inc. ("Anderson" or the "Company") (TSX:AXL) announces its operating and financial results for the fourth quarter and year ended December 31, 2015. The Company will be filing its audited financial statements and management's discussion and analysis ("MD&A") for the years ended December 31, 2015 and 2014 on SEDAR today. Copies can be found under the Company's profile on www.sedar.com and on the Company's website at www.andersonenergy.ca.

HIGHLIGHTS

- As of December 31, 2015, the Company had no bank debt and positive adjusted working capital of $6.7 million (compared to bank loans of $2.3 million and a $22.5 million adjusted working capital deficiency at the end of 2014).
- Production in the fourth quarter of 2015 was 2,037 BOED (44% oil, condensate and NGL), down 40% from the fourth quarter of 2014. Cardium production represented 1,722 BOED (48% oil, condensate and NGL) of fourth quarter production. 2015 annual production was 2,290 BOED (45% oil, condensate and NGL). TransCanada Pipelines Ltd. ("TCPL") outages had no impact on the Company's fourth quarter production, and impacted annual production by 165 BOED.
- Funds from operations for the year ended December 31, 2015 were $2.6 million compared to $19.2 million in 2014. For the fourth quarter of 2015, funds from operations were less than $0.1 million compared to $5.9 million in the fourth quarter of 2014. At low commodity prices, interest on convertible debentures had a significant impact on funds from operations. It is expected that the convertible debentures will be settled in 2016 and there will be no cash interest paid on the debentures in 2016. Funds from operations before interest on convertible debentures were $9.7 million for the year ended December 31, 2015 and $1.8 million for the fourth quarter of 2015.
- The operating netback in the fourth quarter of 2015 was $15.16 per BOE compared to $27.53 per BOE in the fourth quarter of 2014. The operating netback from Cardium properties in the fourth quarter of 2015 was $21.18 and $23.60 per BOE for the year.
- In light of the changes in commodity prices, the Company has made significant changes to its administrative cost structure that contributed to a 20% reduction in gross general and administrative expenses in 2015 when compared to 2014. Additional changes implemented on March 1, 2016 are expected to reduce 2016 gross G&A expenses by an additional $1.0 million. The Company also implemented changes in the field, which resulted in operating expenses being reduced by 19% to average $10.10 per BOE in 2015 compared to $12.43 per BOE in 2014.
- Anderson's proved plus probable ("P&P") reserves as of December 31, 2015 were 6,517 MBOE (52% oil, condensate and NGL), 29% lower than at the end of 2014. Reductions in reserves volumes were attributable to significant shallow gas dispositions, negative economic factor revisions (largely related to shallow gas estimates) and the Company not conducting an active drilling program in 2015 due to poor commodity prices and uncertainty with respect to the maturing convertible debentures. The reserve life indices at December 31, 2015, using fourth quarter of 2015 annualized production, were 5.0 years for total proved ("TP") reserves and 8.8 years for P&P reserves.
- The Company reduced its producing and non-producing net well count by 31% in 2015 and expects to make further significant reductions in 2016.
- Subsequent to December 31, 2015, a new horizontal oil development project has been added to the Company's portfolio in central Alberta in the Duvernay Carbonates. Anderson has assembled over 12 sections of 100% working interest land in this project area, which is prospective for light oil horizontal drilling at medium depth.
- On January 31, 2016, the Company exercised its right to repay both the principal amount ($50.0 million) and the accrued and unpaid interest ($1.875 million) on the 7.50% Series A convertible unsecured subordinated debentures that matured on January 31, 2016 (the "Series A Debentures") in common shares of the Company. The exchange price was $0.00565616 per common share and 9.171 billion common shares were issued from treasury.
- On February 26, 2016, the Company announced a proposed transaction to exchange the entire principal amount ($46.0 million) of the 7.25% Series B convertible unsecured subordinated debentures maturing June 30, 2017 (the "Series B Debentures"), and the interest that would otherwise accrue on the Series B Debentures to June 30, 2016 ($1.67 million), for common shares of the Company using an exchange price of $0.00565616 per common share, for 8.428 billion common shares to be issued from treasury (the "Exchange Transaction"). The Company has scheduled a meeting of the holders of the Series B Debentures (the "Series B Debentureholders") to consider the Exchange Transaction on April 1, 2016. Approximately 36% of the Series B Debentureholders have signed support agreements pursuant to which they have agreed to vote in favour of the Exchange Transaction. If the Exchange Transaction does not receive sufficient support from the Series B Debentureholders, the Company intends to exercise its right to repay both the principal and the accrued and unpaid interest in common shares at the earliest possible redemption date, which is June 30, 2016.
- If the Series B Debentureholders approve the Exchange Transaction, the Company intends to propose a share consolidation at an annual meeting of shareholders expected to be held in May 2016.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31			*Year ended December 31*		
(thousands of dollars, unless otherwise stated)	*2015*	*2014*	*% Change*	*2015*	*2014*	*% Change*
Oil and gas sales (1)	$ 4,971	$ 11,337	(56%)	$ 25,070	$ 50,659	(51%)
Revenue, net of royalties (1)	$ 4,915	$ 10,513	(53%)	$ 23,339	$ 46,396	(50%)
Funds from operations	$ 14	$ 5,884	(100%)	$ 2,577	$ 19,195	(87%)
Funds from operations per share - basic and diluted	$ -	$ 0.03	(100%)	$ 0.01	$ 0.11	(91%)
Adjusted earnings (loss) before taxes (2)	$ (4,037)	$ (4,136)	2%	$ 13,957	$ (7,538)	285%
Adjusted earnings (loss) before taxes						

per share[2] - basic and diluted	$ (0.02)	$ (0.02)	-	$ 0.08	$ (0.04)	300%
Earnings (loss)	$ (3,477)	$ (53,118)	93%	$ (17,924)	$ (56,520)	68%
Earnings (loss) per share						
Basic and diluted	$ (0.02)	$ (0.31)	94%	$ (0.10)	$ (0.33)	70%
Capital expenditures (net of proceeds on dispositions)	$ 310	$ 22,878	(99%)	$ (30,582)	$ 52,087	(159%)
Bank loans and adjusted working capital (deficiency)				$ 6,745	$ (24,794)	127%
Convertible debentures				$ 93,991	$ 91,326	3%
Shareholders' equity				$ (45,312)	$ (27,806)	(63%)
Average shares outstanding *(thousands)*:						
Basic and diluted	172,550	172,550	-	172,550	172,550	-
Ending shares outstanding *(thousands)*				172,550	172,550	-
Average daily sales:						
Oil and condensate *(bpd)*	714	945	(24%)	880	841	5%
NGL *(bpd)*	182	252	(28%)	157	184	(15%)
Natural gas *(Mcfd)*	6,844	13,188	(48%)	7,511	12,692	(41%)
Barrels of oil equivalent *(BOED)* [3]	2,037	3,396	(40%)	2,290	3,141	(27%)
Average prices:						
Oil and condensate *($/bbl)*	$ 49.78	$ 68.94	(28%)	$ 54.20	$ 90.73	(40%)
NGL *($/bbl)*	$ 11.56	$ 26.92	(57%)	$ 9.76	$ 38.22	(74%)
Natural gas *($/Mcf)*	$ 2.40	$ 3.75	(36%)	$ 2.58	$ 4.30	(40%)
Barrels of oil equivalent *($/BOE)* [3]	$ 26.53	$ 36.29	(27%)	$ 30.00	$ 44.19	(32%)
Realized gain on derivative contracts *($/BOE)*	$ -	$ 4.10	(100%)	$ -	$ 0.64	(100%)
Royalties *($/BOE)*	$ 0.29	$ 2.64	(89%)	$ 2.07	$ 3.72	(44%)
Operating costs *($/BOE)*	$ 10.87	$ 10.03	8%	$ 10.10	$ 12.43	(19%)
Transportation costs *($/BOE)*	$ 0.21	$ 0.19	11%	$ 0.25	$ 0.27	(7%)
Operating netback *($/BOE)* [2]	$ 15.16	$ 27.53	(45%)	$ 17.58	$ 28.41	(38%)
Reserves *(MBOE)*: [3]						
Total proved				3,712	5,279	(30%)
Proved plus probable				6,517	9,210	(29%)
Wells drilled *(gross)*	-	6	(100%)	2	13	(85%)

[1] *Includes royalty and other income classified with oil and gas sales, but excludes realized and unrealized gains or losses on derivative contracts.*

[2] *Adjusted earnings (loss) before taxes, adjusted earnings (loss) before taxes per share and operating netback per BOE are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" in the MD&A for a more complete description of these non-GAAP terms, reconciliations to the closest related GAAP measures, and the purposes for which management uses the non-GAAP measures. These non-GAAP measures may not be comparable with the calculation of similar measures for other entities.*

[3] *Barrels of oil equivalent ("BOE") 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.*

COMMODITY PRICE COLLAPSE

Tremendous swings in both oil and natural gas prices continued in 2015. The average WTI oil price per bbl was approximately $48.76 US in 2015, compared to $92.92 US in 2014. Monthly average WTI oil prices ranged from a high of $59.83 US per bbl in June 2015 to a low of $37.33 US per bbl in December 2015. Oil prices continued to decrease in the first quarter of 2016 due to oversupply and inadequate demand to consume the oversupply. The lowest average monthly price seen to date in 2016 was $30.62 US per bbl, realized in February 2016. Although the US/Canadian dollar exchange rate has moved beneficially from an average of approximately $0.78 in 2015 to approximately $0.73 year to date in 2016, it has not sufficiently compensated for the collapse in WTI pricing. Recent average NYMEX futures pricing for WTI for April through December 2016 is approximately $42.26 US per bbl ($55.95 Canadian per bbl).

Natural gas prices have continued to decrease since the fourth quarter of 2015 and AECO pricing in March 2016 is the lowest it has been since September 1997. US and Canadian natural gas storage levels are historically high for this time of year, therefore natural gas prices will likely be depressed until the onset of winter next year.

In response to the decline in oil prices, the Company stopped its drilling program on January 28, 2015. The Company focused its efforts on reducing operating, administrative and capital costs, in both the office and in the field in order to be positioned to resume drilling when commodity prices improve.

COST SAVING MEASURES

1) General and administrative ("G&A") expenses: In 2015, the Company's gross G&A (cash) expenses were $6.6 million. Changes were made to the G&A cost structure in the first quarter of 2015 which contributed to the reduction in gross G&A (cash) expenses of $1.7 million from the 2014 gross G&A (cash) expenses of $8.3 million. Most of the reductions were in the last three quarters of 2015. These changes included the cancellation of bonuses for management, the reduction in bonuses for staff, the reduction in salaries and benefits for both management and staff and the renegotiation of contracts for other services. Approximately 15% of the Company's gross G&A (cash) expenses is capitalized and the balance is expensed. Overhead recoveries were slightly lower than in 2014. The Company had approximately $0.4 million in gross non-cash stock based compensation costs in 2015. During the first quarter of 2016, further reductions were made to staff counts, compensation and other administrative costs which are expected to decrease gross G&A (cash) expenses by $1.0 million in 2016. The reduction in compensation expense in 2016 will be partially offset by one-time severance costs.

2) Operating expenses: With the reduction in commodity prices, the Company has been focusing on reducing field operating expenses. In 2015, shutting in uneconomic shallow gas operations resulted in significant reductions in both manpower and maintenance costs. In addition, capital investments were made to eliminate rental equipment costs associated with field operations. Current initiatives are focused on further optimization of manpower costs, as well as the reconfiguration of existing oil batteries to enable clean oil trucking and significantly reduce emulsion handling costs. The Company's overall operating expenses in 2015 averaged $10.10 per BOE compared to $12.43 per BOE in 2014. The operating expenses budgeted for 2016 are $11.00 per BOE, assuming the Company does not drill any Cardium horizontal wells in 2016. If new Cardium horizontal wells are drilled and brought on production in the second half of 2016, they could reduce annual operating expenses per BOE.

3) Capital expenditures: In previous commodity price downturns, the industry has been able to find significant reductions in per unit capital costs to improve the economic equation. Anderson has been working with suppliers and service providers for improved cost efficiency and operations, and believes up to a 30% reduction in capital costs may be achievable. The Company historically has been a leader in low cost Cardium horizontal drilling and completions and is working towards achieving even lower costs.

TCPL OUTAGES

On December 15, 2014, TCPL issued a notice to all shippers upstream of James River, Alberta regarding the restriction of natural gas volume receipts to certain limits. As a result of the actions taken by TCPL, disruptions to pipeline transportation service in the affected areas (referred to as "outages") resulted in restrictions on the Company's production in various areas, including its Willesden Green Cardium area. The restrictions affected the production of oil, condensate and NGL as well as natural gas. The Company estimates that the impact of the TCPL outages averaged approximately 165 BOED in 2015. The outages affecting the Company's production were essentially over by the end of November 2015.

Anderson's Willesden Green Cardium area now falls outside of the current TCPL restricted area. However, due to the fluctuating nature of the outages and the changing forecasts provided by TCPL, it is difficult to estimate the extent of the impact of potential outages on the Company's future results.

2014/2015 WINTER DRILLING PROGRAM

The Company completed its 2014/2015 winter drilling program in January 2015 with 9 gross (8.1 net capital, 7.0 net revenue) new Cardium oil wells. Due to weak commodity prices, the drilling of the remaining 3 gross (2.2 net) Cardium wells in the planned program was deferred. The average production results exceeded the Company's expectations with an average IP 30 of 413 BOED (85% oil, condensate and NGL). The best well in the drilling program had an IP 30 of 707 BOED (71% oil, condensate and NGL). Included in this drilling program was the Company's first long-reach well which had an IP 30 of 651 BOED (92% oil, condensate and NGL) with 32 frac stages over a 1.5 mile horizontal well section.

Of the nine Cardium wells drilled in the 2014/2015 winter drilling program, five are in the central land block, three are in the northern land block and one is in the southern land block of the greater Willesden Green area.

The IP 30 and product mix results from the Cardium wells from the 2014/2015 winter drilling program compares favourably with the 2013/2014 winter drilling program which had an average IP 30 of 511 BOED (53% oil, condensate and NGL). A comparison of the oil, condensate and NGL components of the BOED production for the two drilling programs shows an average IP 30 of 349 bpd for the 2014/2015 winter drilling program and 272 bpd for the 2013/2014 winter drilling program. Notwithstanding the market perception of the current oil price environment, oil, condensate and NGL remain more valuable than solution gas, and a higher percentage of oil, condensate and NGL in the Company's product mix can be more important to overall revenue and profitability than the overall BOED production rate.

The average IP 30 for the 19 Cardium wells completed with slick water fracture stimulation in the Willesden Green area on Company lands since June 2012 was 469 BOED (68% oil, condensate and NGL). The best single well IP 30 result from these wells was 1,119 BOED (67% oil, condensate and NGL).

By using selective positioning of the horizontal well trajectory, Anderson is realizing higher IP 30 production rates than historical

Willesden Green area industry averages. The Company has now adopted the use of dissolvable frac balls for toe fracs and has moved to less nitrogen usage in heel fracs. Other changes made this year include a redesigned stage tool to reduce the risk of mechanical wellbore failure.

LIGHT OIL HORIZONTAL POTENTIAL DRILLING OPPORTUNITIES

The Company's undeveloped light oil horizontal potential drilling opportunities at March 28, 2016, are outlined below:

Prospect Area (number of potential drilling opportunities)	*Gross*	*Net**
Willesden Green Cardium	74	55.0
West Pembina/Buck Lake Cardium	18	7.5
Willesden Green Glauconite	6	6.0
Total Light Oil Horizontal Potential Drilling Opportunities, March 28, 2016	98	68.5

** Net is net revenue interest.*

GLJ Petroleum Consultants ("GLJ"), the Company's independent reserves evaluator, booked undeveloped reserves to 17.9 of these net potential drilling opportunities at December 31, 2015.

The number of potential drilling opportunities is slightly lower than in 2015 due to the disposition of some lower working interest lands and economic factors.

The Duvernay Carbonate light oil horizontal project lands acquired in the first quarter of 2016 could yield an incremental four potential horizontal drilling opportunities per section. The Company acquired over 12 sections of 100% working interest lands.

2016 PRODUCTION AND CAPITAL PROGRAM

The Company estimates production will be approximately 1,500 to 1,600 BOED (42% oil, condensate and NGL) for 2016. Production in the first quarter of 2016 is estimated to be 1,750 to 1,850 BOED (42% oil, condensate and NGL). This estimate assumes no drilling is undertaken in 2016 and reflects the recent shut-in of approximately 43 BOED of uneconomic gas production. The Company's capital budget of $3 million is restricted to maintenance capital, capitalized G&A and land acquisition (net of dispositions). The price trigger to consider starting up a new drilling program is estimated to be approximately $50 WTI US per bbl. Where possible, Anderson tries to achieve a 12 month or less payout on new drilling projects and the combination of capital costs, operating costs, fiscal regime and commodity prices are the variables that need to be determined prior to undertaking a capital program. As well, the Company will complete its May 2016 bank line review before undertaking a drilling program. The details of the royalty review need to be completed by the Alberta government and evaluated by the Company, as it could impact whether the Company drills in 2016 or waits until 2017.

WELL COUNT

	December 31, 2015		*December 31, 2014*	
	Gross	*Net*	*Gross*	*Net*
Producing wells				
Oil	63	41.3	75	46.1
Gas	89	51.2	268	156.1
	152	92.5	343	202.2
Non-producing wells	254	177.5	297	189.2
Total active wells	406	270.0	640	391.4

In 2015, significant progress was made in focusing the Company's asset base into the core Cardium operating areas and divesting or shutting in production outside of these focus areas. 199 wellbores were sold and 48 wellbores were abandoned in 2015 resulting in a 37% reduction in the gross active well count (31% reduction in net active well count). In addition, reclamation certificate applications were submitted to the AER for 28 gross (23.7 net) abandoned wells and one reclamation certificate was received. It is expected that reclamation certificate applications will be submitted for a similar number of wells in 2016.

These initiatives are continuing into 2016 with 63 gross (48.4 net) well abandonments planned, of which 16 gross (8.7 net) wells have already been abandoned to date in 2016. With this work underway, the Company is actively reducing its long-term decommissioning obligations. The Company is projecting the non-producing well count at year end 2015 will be further reduced by 25% on a gross basis and 27% on a net basis as a result of the planned 2016 well abandonment program.

Anderson has successfully completed the transition away from its shallow gas legacy and in the fourth quarter of 2015, the remaining 56 gross (34.6 net) producing shallow gas wells contributed approximately 800 Mcfd or 6.5% of the Company's fourth quarter production.

Corporate production is now derived primarily from the Cardium formation in the Willesden Green operating area which represents 85% of the production in the fourth quarter of 2015. Of the remainder, 8.5% is from various deeper producing formations in the general Sylvan Lake area.

This rebalancing of the portfolio has allowed the Company to more effectively focus its resources on the core operating areas resulting in significant reductions in operating expenses, reduced staff count, and the implementation of a wellbore and facilities decommissioning program which takes advantage of the current low-cost structure from service providers.

COMMODITY PRICES

A comparison of Anderson's average oil and condensate price to various market prices is presented below. Average prices are before the impact of any financial derivative contracts used for risk management. The difference between Anderson's realized price and WTI Canadian is due to the price differential between Cushing, Oklahoma and Edmonton, Alberta, product transportation costs from the field to Edmonton, and adjustments for product quality. There were no financial derivative or fixed price contracts in 2015.

CRUDE OIL AND CONDENSATE PRICES

	Three months ended December 31		*Year ended December 31*	
	2015	*2014*	*2015*	*2014*
WTI - $US	$ 42.17	$ 73.12	$ 48.76	$ 92.92
WTI - $Cdn	$ 56.22	$ 82.90	$ 62.11	$ 102.40
Differential from Cushing to Edmonton - $US per bbl	$ 2.46	$ 6.37	$ 3.86	$ 7.19
Edmonton Par - $Cdn per bbl	$ 52.94	$ 75.51	$ 57.16	$ 94.50
Anderson average oil price per bbl	$ 51.68	$ 68.74	$ 54.92	$ 90.22
Anderson average oil and condensate price per bbl*	$ 49.78	$ 68.94	$ 54.20	$ 90.73

**Condensate includes field condensate and plant condensate.*

The 2016 monthly WTI Canadian oil prices were approximately $45.20 per bbl in January, $42.24 per bbl in February and $52.45 per bbl in March. Differentials from Cushing, Oklahoma to Edmonton, Alberta were approximately $3.58 US per bbl in January, $4.08 US per bbl in February and $3.41 US per bbl in March 2016.

Going forward, light oil prices are expected to remain weak in the short term. Over the long term, prices will continue to be volatile and will be influenced by the balance between supply and demand, and by geopolitical events. Differentials between Cushing, Oklahoma and Edmonton, Alberta and the US/Canadian dollar exchange rate will also remain volatile.

A comparison of Anderson's average plant gate natural gas price to various market prices is presented below. Average plant gate prices are before the impact of any financial derivative or fixed price contracts used for risk management. The difference between the AECO price and Anderson's plant gate price is due to transportation costs and the heat content of the gas. There were no financial derivative or fixed-price contracts during 2015.

The average heat content of the Company's natural gas has increased from 1,070 Btu/scf in the fourth quarter of 2014 to 1,121 Btu/scf in the fourth quarter of 2015 due to the new Cardium gas having higher heat content than the Company's legacy shallow gas production. Natural gas is sold on the basis of heat content; therefore, higher heat content gas will yield higher prices per unit of measured volume.

NATURAL GAS PRICES

	Three months ended December 31		*Year ended December 31*	
	2015	*2014*	*2015*	*2014*
NYMEX $US per MMBtu	$ 2.24	$ 3.84	$ 2.63	$ 4.27
AECO $CAD per GJ	$ 2.33	$ 3.41	$ 2.55	$ 4.25
AECO $CAD per MMBtu	$ 2.46	$ 3.60	$ 2.69	$ 4.48
Anderson average plant gate price per Mcf	$ 2.40	$ 3.69	$ 2.58	$ 4.40

In 2016, AECO natural gas prices were approximately $2.25 per GJ ($2.37 per MMBtu) in January, $1.69 per GJ ($1.78 per

MMBtu) in February and $1.31 per GJ ($1.38 per MMBtu) in March.

Natural gas prices are influenced by weather events and are tempered by the increasing supply of new shale gas. Until meaningful exports of natural gas commence from North America through liquefied natural gas projects, the Company believes that natural gas prices will be range-bound by weather events. Currently, Alberta natural gas prices are very weak due to a warm Alberta winter and continued growth in Western Canadian gas supply, as operators ramped up their drilling activity in anticipation of future LNG exports from British Columbia. However, North American natural gas storage can be no more than full heading into next winter, prompting the possibility of industry production shut-ins this summer and fall. The onset and severity of the North American winter will dictate the prices of natural gas next winter.

FINANCIAL RESULTS

Oil and gas sales in the fourth quarter of 2015 were lower than the third quarter of 2015 due to continued decreases in commodity prices.

On a BOE basis, oil and gas sales averaged $26.53 per BOE in the fourth quarter of 2015 compared to $30.18 per BOE in the third quarter of 2015 and $36.29 per BOE in the fourth quarter of 2014. During the fourth quarter of 2015, liquids revenue (oil, condensate and NGL) represented 70% of total oil and gas sales. The Company's operating netback was $15.16 per BOE in the fourth quarter of 2015 compared to $18.92 per BOE in the third quarter of 2015 and $27.53 per BOE in the fourth quarter of 2014. There were no commodity hedging contracts in 2015. Realized hedging gains of $4.10 per BOE were realized in the fourth quarter of 2014. Lower operating costs per BOE reflect cost saving measures implemented in 2015. Anderson's operating netback for Cardium properties in the fourth quarter of 2015 was $21.18 per BOE, compared to $22.14 per BOE in the third quarter of 2015, and $32.79 per BOE in the fourth quarter of 2014, exclusive of hedging in 2014.

Funds from operations for the year ended December 31, 2015 were $2.6 million compared to $19.2 million in 2014. For the fourth quarter of 2015, funds from operations were less than $0.1 million compared to $5.9 million in the fourth quarter of 2014. At low commodity prices, interest on convertible debentures had a significant impact on funds from operations. It is expected that the convertible debentures will be settled in 2016 and there will be no cash interest paid on the debentures in 2016. Funds from operations before interest on convertible debentures were $9.7 million for the year ended December 31, 2015 and $1.8 million for the fourth quarter of 2015. In addition, accrued and unpaid interest of $1.6 million at December 31, 2015 was subsequently paid in common shares and not cash. Funds from operations in 2016 will include interest on convertible debentures until their maturity, redemption or other settlement and all of this remaining interest is expected to be paid in common shares.

The Company reported a loss of $3.5 million in the fourth quarter of 2015.

OIL AND GAS NETBACKS

	Average natural gas price ($/Mcf)	*Average oil and condensate price ($/bbl)*	*Revenue ($/BOE)*	*Operating netback ($/BOE)*	*Cash interest expense ($/BOE)*	*Funds from operations ($/BOE)*
Q1 2015	2.65	47.90	28.72	14.98	7.57	1.13
Q2 2015	2.51	65.00	34.48	21.54	8.88	7.08
Q3 2015	2.73	54.56	30.18	18.92	9.11	4.17
Q4 2015	2.40	49.78	26.53	15.16	9.70	0.08

Capital expenditures, before dispositions of $38.2 million, were $7.7 million for the year ended December 31, 2015. Capital expenditures were $0.3 million in the fourth quarter of 2015 compared to $0.6 million in the third quarter of 2015. Capital investments in the last three quarters of 2015 were focused on maintenance activities and operating expense reduction initiatives.

COMMODITY HEDGING CONTRACTS

The Company has not hedged any crude oil or natural gas volumes at this time.

The Company continues to evaluate the merits of commodity hedging as part of a price management strategy and to provide a floor for funds from operations.

RESERVES

GLJ has completed a reserves report (the "GLJ Report") of all the Company's oil and natural gas properties effective December

31, 2015, prepared in accordance with procedures and standards contained in National Instrument 51-101 ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). The reserves definitions used in preparing the report are those contained in the COGE Handbook and NI 51-101. At December 31, 2015, the Company had 2,545 MBOE proved developed producing ("PDP") reserves (46% oil and NGL(1)), 3,712 MBOE TP reserves (51% oil and NGL) and 6,517 MBOE P&P reserves (52% oil and NGL). The reserve life indices at December 31, 2015, using fourth quarter of 2015 annualized production, were 5.0 years for TP reserves and 8.8 years for P&P reserves. The GLJ price forecast used in the evaluation is shown in the MD&A for the year ended December 31, 2015.

The Cardium formation represents approximately 83%, 88% and 88% respectively of PDP, TP and P&P total BOE reserves volumes and 99%, 99% and 97% respectively of the total Company PDP, TP and P&P net present value using a 10% discount rate ("NPV 10"). The Cardium reserve life indices, using fourth quarter of 2015 annualized Cardium production, were 5.2 years for TP reserves and 9.2 years for P&P reserves.

(1) *NGL in the GLJ reserves report includes condensate and other NGL.*

SUMMARY OF OIL AND GAS RESERVES

	December 31, 2015					*December 31, 2014*				
Gross Working Interest Oil and Gas Reserves	Oil *(Mbbls)*	NGL(1) *(Mbbls)*	Gas *(MMcf)*	Total *(MBOE)*	After tax NPV 10 *($M)*(2)	Oil *(Mbbls)*	NGL(1) *(Mbbls)*	Gas *(MMcf)*	Total *(MBOE)*	After tax NPV 10 *($M)*(2)
Proved developed producing	919	262	8,181	2,545	34,404	1,093	315	13,772	3,704	51,637
Proved developed non-producing	23	3	167	54	476	25	17	2,881	522	2,535
Total proved	1,529	356	10,963	3,712	41,548	1,716	414	18,896	5,279	60,644
Proved plus probable	2,779	604	18,804	6,517	64,984	3,257	755	31,187	9,210	96,138

(1) NGL in the GLJ reserves report includes condensate and other NGL.
(2) The estimated net present value of future net revenues presented in the table above does not necessarily represent the fair market value of the Company's reserves.

The after tax P&P NPV 10 value of reserves was 32% lower than last year. P&P reserves volumes decreased by 29% largely due to property dispositions, production and reductions in price forecasts (economic factors), which reduced both volumes and values. The average GLJ price forecast for 2016 to 2020 was 26% lower for Edmonton Par oil prices (30% in 2016) and 21% lower for AECO natural gas prices (27% in 2016) when the December 31, 2015 price forecast was compared to the December 31, 2014 price forecast.

CONTINUITY OF GROSS WORKING INTEREST RESERVES

	Proved Developed Producing (MBOE)	*Total Proved (MBOE)*	*Proved Plus Probable (MBOE)*
Opening balance, December 31, 2014	3,704	5,279	9,210
Extensions and improved recovery	272	177	57
Technical revisions	599	431	(419)
Acquisitions	-	-	-
Dispositions	(948)	(1,020)	(1,209)
Economic factors	(246)	(320)	(286)
Production	(836)	(836)	(836)
Closing balance, December 31, 2015	2,545	3,712	6,517

The Company will provide more detailed information from its current reserves report in its annual information form for the year ended December 31, 2015, which will be filed this week.

Total future development costs included in the reserves evaluation were $23.7 million for TP reserves and $45.7 million for P&P reserves on an undiscounted basis. Future development costs included in TP and P&P reserves decreased 18% and 31% respectively from 2014 due to capital cost reductions related to lower costs of services and more efficient completion techniques in 2015, as well as a small decrease in the number of locations included in the report.

The Company's finding, development and acquisition costs as of December 31, 2015 were indeterminate, as the significant dispositions outstripped the field capital expenditures undertaken in 2015.

Oil and NGL as a percentage of total MBOE reserves has increased to 46% of PDP, 51% of TP and 52% of P&P reserves from

38%, 40% and 44% respectively in 2014, when the Company set a goal of achieving at least 50% liquids in the reserves base.

UNDEVELOPED LAND

Anderson has 64,825 gross (25,673 net) undeveloped acres of land at December 31, 2015. Undeveloped land value has been estimated at $1.8 million by management.

Subsequent to December 31, 2015, the Company acquired over 7,800 additional undeveloped acres of 100% working interest land at crown land sales in Alberta, and disposed of 3,163 gross (94 net) acres of land pursuant to shallow gas asset sales.

The lands acquired relate to a new medium depth horizontal oil development project in central Alberta targeting the Duvernay Carbonates.

NET ASSET VALUE

The Company completed a net asset value estimate using the GLJ December 31, 2015 price and cost assumptions, pro forma the repayment of the Series A Debentures and the redemption of the Series B Debentures for common shares. This calculation is done assuming the Series B Debentureholders approve the Exchange Transaction on April 1, 2016.

(dollars in thousands, except per share amounts)	*10%*	*12%*	*15%*
After tax P&P reserves at December 31, 2015 (1)	$64,984	$58,598	$50,852
Add undeveloped land (2)	1,800	1,800	1,800
Add adjusted net working capital (3)	6,745	6,745	6,745
Add adjustments related to settlement of debentures (4)	712	712	712
Deduct decommissioning obligations not included in GLJ Report (1)	(6,710)	(5,917)	(5,114)
Net asset value (5)	$67,531	$61,938	$54,995

(1) GLJ includes well abandonment and reclamation costs for all wells with reserves. Abandonment and reclamation costs associated with non-reserves wells and major facilities have not been included in the GLJ Report and are deducted separately for the purpose of this net asset value estimate.

(2) Management estimate based on publicly available information with respect to recent land sale activity.

(3) Adjusted net working capital is current assets less current liabilities at December 31, 2015 before unrealized gains and losses on derivative contracts and the current portion of convertible debentures.

(4) Adjustments to working capital for interest expense accrued and included in working capital at December 31, 2015 of $1,562,500 that was paid in common shares versus cash in January 2016, less estimated costs associated with the settlement of debentures of $850,000.

(5) Does not include management's estimated value for approximately 74% of the Cardium net potential drilling opportunities that are not included in the GLJ reserves report at December 31, 2015, nor management's estimated value for Duvernay Carbonate light oil horizontal potential drilling opportunities.

EXCHANGE TRANSACTION

On January 31, 2016, the Company exercised its right to repay both the principal amount ($50.0 million) and the accrued and unpaid interest ($1.875 million) on the Series A Debentures in common shares of the Company, pursuant to a maturity notice delivered in December 2015 to the holders of the Series A Debentures. The Company issued approximately 9.171 billion common shares from treasury at approximately $0.00565616 per share in regards to that repayment. The exchange price was based on 95% of the 20 day volume weighted average trading price of the common shares on the Toronto Stock Exchange ("TSX") ending five days prior to the maturity date.

On February 26, 2016, the Company announced a proposed transaction to exchange the entire principal amount of the Series B Debentures ($46.0 million), and the interest that would otherwise accrue on the Series B Debentures to June 30, 2016 ($1.67 million) for common shares of the Company on the basis of a price of $0.00565616 per share, for approximately 8.428 billion common shares issued from treasury. The Company has scheduled a meeting of the Series B Debentureholders to consider the Exchange Transaction on April 1, 2016. Pursuant to the existing indenture, an extraordinary resolution approving the Exchange Transaction is required to be passed at a meeting of the Series B Debentureholders in which the holders of not less than 25% of the principal value of the Series B Debentures outstanding are present in person or by proxy. The extraordinary resolution must be passed by 66 2/3% of the votes represented at the meeting. Approximately 36% of the Series B Debentureholders have signed support agreements pursuant to which they have agreed, among other things, to vote the Series B Debentures beneficially owned or controlled or directed by them, directly or indirectly, in favour of the Exchange Transaction and all matters related thereto at the meeting. The Exchange Transaction is subject to approval by the TSX. If the Exchange Transaction does not receive sufficient support from the Series B Debentureholders, the Company intends to exercise its right under the terms of the existing indenture (as supplemented) governing the Series B Debentures to repay both the principal and the accrued and unpaid interest in common shares at the earliest possible redemption date, which is June 30, 2016.

SHARE CONSOLIDATION

If the Exchange Transaction is approved by the Series B Debentureholders, the Company will put forward a special resolution to be voted on by the common shareholders at its next annual meeting, expected to be held in May 2016, to approve a share consolidation at a ratio to be determined by the board of directors of Anderson. A share consolidation is also known as a "reverse stock split".

If the Exchange Transaction is not approved by the Series B Debentureholders, the share consolidation will be delayed until sometime after the June 30, 2016 redemption date for the Series B Debentureholders.

As a result of the issuance of common shares on the repayment of the Series A Debentures and the planned issuance of common shares to settle the Series B Debentures, Anderson expects to have in excess of 17 billion common shares outstanding. The current trading price is $0.005 per common share and trading is very light.

The purpose of doing a share consolidation is to reduce the number of outstanding shares in order to improve the trading liquidity of the common shares.

- More liquidity will make it easier for existing shareholders to sell and new shareholders to buy the shares when they want to.
- More liquidity provides better support for the overall market capitalization of the Company, which will help the Company in negotiations with other industry participants (e.g. potential sale, merger or financing opportunities).
- A share price similar to our peers will allow for better peer comparisons.
- A higher share price will encourage institutional investors and investment funds to invest in the Company, who may be reluctant or prohibited from investing in stocks trading below $1.00 per share.
- Theoretically, a share consolidation should not change the value to a shareholder. As the number of shares decrease, the value per share should increase by a corresponding amount. However, there may be some initial market volatility and there may be downward pressure as the market settles on a value for the common shares. Ultimately, the trading price should reflect the underlying value of the Company.

PEOPLE

On September 3, 2015, J.C. Anderson, a founder and director of Anderson passed away. J.C. was a legend in the oil and gas industry and he will be deeply missed by all of those who had the privilege to know him.

On March 23, 2016, Elias A. Foscolos was appointed to the board of directors. Elias has a Bachelor of Science degree in Chemical Engineering and a Master of Business Administration. He is currently working as a research analyst in the energy services industry and as a lecturer at the University of Calgary in the Finance department. He has over 25 years of experience in engineering and financial consulting.

SUMMARY

In 2015, the Company shut down its drilling program in response to the collapse in commodity prices. It focused its efforts on reducing both G&A and operating expenses with initiatives undertaken in April 2015 and continuing through to March 2016. The Company also continued its efforts to transition away from shallow gas production through a variety of disposition and abandonment initiatives, to allow it to focus on its horizontal oil plays. As of January 2016, 85% of Anderson's production and 88% of its P&P reserves come from the Cardium formation. In 2015, the Company reduced its producing and non-producing net well count by 31% and expects to make further significant reductions in 2016.

Strategically, in 2016, a significant new horizontal oil development project has been added to the Company's portfolio in central Alberta targeting the Duvernay Carbonates.

The Company has cash in the bank, unused bank lines and a sizable inventory of Cardium potential drilling opportunities. In the second quarter of 2016, the Company expects to have settled all of its outstanding convertible debentures. Once a share consolidation is completed, the Company should be more attractive to both investors and industry participants. The industry and its workforce is going through a very difficult downturn. It is difficult to predict when this will turn around and what structural and political changes await the industry. Although the Company is about to be debt free with cash in the bank, it still needs higher commodity prices to invest in its drilling projects.

The Company has hunkered down, waiting for an eventual improvement in oil prices. Company engineers estimate that with a $50 WTI US per bbl oil price, the Company can achieve a 12 month payout with new drilling projects. Historically, the Company has been an industry leader in IP 30 Cardium well results and in achieving low capital costs per well in the Cardium play. When drilling resumes, the Company expects to resume its position as a leader on both parameters in this play.

I appreciate the support of the Board of Directors and the financial sacrifices that staff and management had to make to reposition the Company for the future. Anderson's most recent investor presentation will be posted on the Company's website at www.andersonenergy.ca.

Thank you for your continued patience.

Brian H. Dau
President & Chief Executive Officer
March 29, 2016

FORWARD-LOOKING STATEMENTS

Certain statements in this news release including, without limitation, management's business strategy and assessment of future plans and operations; benefits and valuation of the development prospects described herein; number of potential drilling opportunities; drilling program success; timing and location of drilling and tie-in of wells and the costs thereof; timing of shut-in and abandonment of wells and impact thereof; productive capacity of the wells; expected production rates and risks to such expectations; improved production from slick water fracture technology; percentage of production from oil, condensate and natural gas liquids; dates of commencement of production; amount of capital expenditures and the timing and method of financing thereof; value of undeveloped land; reserves and net present value of future net revenue from reserves; ability to attain cost savings and amount thereof; tax horizon; expectations related to future operating netbacks; impact of changes in commodity prices on operating results; programs to optimize, rationalize, consolidate and improve profitability of assets, including the impact from shutting-in or abandonment of wells; factors on which the continued development of the Company's oil and gas assets are dependent; the impact of the TCPL outages on past and future production; benefits of recently completed transactions including the result on the Company's liquidity;
benefits of the Exchange Transaction and the impact of the Exchange Transaction on Anderson and its capital structure, financial position, liquidity and net asset value, including that the Exchange Transaction will create a financially stronger company and better allow for the pursuit of its business and operational goals; growth potential of Anderson's asset base; the results of the annual review of Anderson's bank facility; Anderson's common share interests assuming the completion of the Exchange Transaction; Anderson's ability to implement its plans relating to the Exchange Transaction and the share consolidation; anticipated dates and information relating to the Series B Debentureholder meeting, the closing of the Exchange Transaction and the timing of the share consolidation; Anderson's intentions if the Exchange Transaction is not approved; the potential outcome of litigation and disputes; commodity price outlook; and general economic outlook may constitute "forward-looking information" within the meaning of applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation; loss of markets; volatility of commodity prices; currency fluctuations; imprecision of reserves estimates; environmental risks; competition from other producers; inability to retain drilling rigs and other services; adequate weather to conduct operations; sufficiency of budgeted capital, operating and other costs to carry out planned activities; wells not performing as expected; incorrect assessment of the value of acquisitions and farm-ins; failure to realize the anticipated benefits of acquisitions and farm-ins; delays resulting from or inability to obtain required regulatory approvals; changes to government regulation; availability of third-party transportation and processing facilities; ability to access sufficient capital from internal and external sources; ability of Anderson's common shares to remain listed on the TSX; the receipt in a timely manner, of regulatory and Series B Debentureholder approval in respect of the Exchange Transaction; the plans of Series B Debentureholders and other counterparties related to the Exchange Transaction; the expected costs of the Exchange Transaction; and other factors, many of which are beyond the Company's control.
The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as the factors are interdependent, and management's future course of action would depend on its assessment of all information at the time. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements and readers should not place undue reliance on the assumptions and forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Anderson's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at Anderson's website (www.andersonenergy.ca).

The forward-looking statements contained in this news release are made as at the date of this news release and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. Although the intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants, BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one 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. In recent years, the value ratio based on the price of crude oil as compared to natural gas has been significantly higher than the energy equivalency of 6:1, and utilizing a conversion of natural gas volumes on a 6:1 basis may be misleading as an indication of value.

Short-term production rates can be influenced by flush production effects from fracture stimulations in horizontal wellbores and may not be indicative of longer-term production performance or reserves. Individual well performance may vary.

ABBREVIATIONS

bbl - barrel	AECO - intra-Alberta Nova inventory transfer price
bpd - barrels per day	Bcf - billion cubic feet
BOE - barrels of oil equivalent	Btu - British thermal unit
BOED - barrels of oil equivalent per day	GJ - gigajoule
m3 - cubic meters	Mcf - thousand cubic feet
Mbbls - thousand barrels	Mcfd - thousand cubic feet per day
MBOE - thousand barrels of oil equivalent	MMBtu - million British thermal units
Mstb - thousand stock tank barrels	MMcf - million cubic feet
NGL - natural gas liquids, excluding condensate	scf - standard cubic foot
WTI - West Texas Intermediate	US - United States

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