SEVEN GENERATIONS
ENERGY

NEWS RELEASE TSX: VII

Seven Generations boosts 2016 production 95 percent to 117,800 boe/d, generates record funds from operations of $733 million

Production per share up 65 percent, funds from operations per share up 50 percent

Proved plus probable reserves up 79 percent to 1.53 billion boe

CALGARY, March 8, 2017 – Seven Generations Energy Ltd. nearly doubled production in 2016 to 117,800 barrels of oil equivalent per day (boe/d), up 65 percent from 2015 on a per share basis. Funds from operations increased 77 percent to $733 million, or $2.30 per share – up 50 percent per share compared to 2015. Capital investment in 2016 was $978 million, 25 percent lower than in 2015. Fourth quarter production increased 70 percent compared to a year earlier to average 132,300 boe/d, and funds from operations were $220 million, up 107 percent compared to the fourth quarter of 2015.

"In 2016, we delivered another year of high-growth, low-cost value creation that saw our production and proved reserves each increase by about 95 percent. We continued our high rate of organic production growth and in August we completed a major acquisition of neighbouring resources and market access arrangements that expanded our most prolific Nest assets. Our focus on innovation and operational optimization is boosting production rates, increasing reserves and reducing costs throughout our Kakwa River Project," said Marty Proctor, 7G's President and Chief Operating Officer.

Proved plus probable and contingent best estimate resources each up about 80 percent
During 2016, Seven Generations tied in 60 new producing wells, adding to the conversion of contingent resources into reserves and production. Despite annual production of 43 million barrels of oil equivalent (MMboe), 7G increased proved reserves 95 percent to 825 MMboe, as estimated by McDaniel & Associates Consultants Ltd. (McDaniel) at December 31, 2016. Proved plus probable reserves increased 79 percent to 1.53 billion boe, with liquids making up 53 percent of the total recoverable reserves. Risked contingent best estimate resources were 1.39 billion boe at December 31, 2016, up 80 percent compared to 771 million boe at December 31, 2015.

"These are very strong reserve additions in one of the lowest supply-cost natural gas and liquids projects in North America. We are drilling long wells with larger and more intense hydraulic fractures – innovations that have shown a one-third increase in condensate production per well compared to two years ago. By boosting production of our most valuable product – condensate – during the early life of our wells, we pay for our wells faster, accelerate the time it takes to earn full-cycle returns and increase the value of our project," said Glen Nevokshonoff, 7G's Senior Vice President, Operations.

Strong initial production from wells on major acquisition lands
7G intends to allocate about 40 percent of its 2017 drilling and capital investment to the neighbouring lands it acquired in the summer of 2016, where initial well results are exceeding expectations. 7G recently tied in a six-well pad where wells had an average 30-day, initial production rate of 2,000 boe/d, with condensate yields of about 170 barrels per MMcf. 7G is installing its Super Pad and gas lift infrastructure selectively onto the acquired lands to enable wide scale development.

"These well production rates have exceeded our initial expectations. This confirms our belief that our major acquisition extends our inventory of low-supply cost resource," Nevokshonoff said.

Acquired asset proved plus probable reserves up 36 percent

McDaniel has attributed proved plus probable reserves of 400 MMboe, effective as at December 31, 2016, to the properties 7G acquired in 2016. This represents a 36 percent increase over the 292 MMboe of proved plus probable reserves that were attributable to the assets as at December 31, 2015.

"This significant boost in the proved plus probable reserves verifies the rationale for acquiring these neighbouring lands and affirms the value creation of this transaction," Nevokshonoff said.

Challenging October, lower fourth quarter production and 2016 capital investment

While daily production nearly doubled in 2016, the fourth quarter presented operational challenges that resulted in 2016 production averaging 1.8 percent below the guidance range of 120,000 to 125,000 boe/d. A portion of these challenges stemmed from delays in drilling and completions, resulting in 2016 capital investment of $978 million, which was about 7 percent below the guidance range of $1.05 billion to $1.1 billion. The main contributing factor to the lower production was an outage on the Alliance Pipeline and a maintenance period at the Pembina Cutbank complex, which led to the company having no production for about one-third of October 2016. This outage reduced October production volumes by approximately 50,000 boe/d, fourth quarter volumes by approximately 16,500 boe/d and 2016 annual volumes by approximately 4,200 boe/d. Another contributing factor to lower fourth quarter production was a slower than anticipated ramp up in production volumes following the pipeline outage due to a high percentage of slickwater completions in 2016 and a required adjustment to artificial lift systems. These were all temporary operational matters that were alleviated by the end of the quarter. The resulting lower capital investment yielded a higher than forecast capital efficiency and a higher closing adjusted working capital balance, providing greater cash on hand to fund a portion of the 2017 capital program.

Financial position remains strong

Seven Generations had $586 million of adjusted working capital and $631 million of cash and cash equivalents at December 31, 2016. When 7G's $1.1 billion revolving credit facility is combined with adjusted working capital, 7G has in excess of $1.6 billion of available funding.

"We continue to maintain a very strong balance sheet. With our expected growth in production in 2017, we plan to fund this year's capital investment of $1.5 billion to $1.6 billion with cash on hand, cash flow and, if required, draws on our credit facility," said Chris Law, 7G's Chief Financial Officer.

Marketing initiatives continue to advance on several fronts

Seven Generations continues to pursue a variety of market initiatives aimed at establishing new customers for the company's growing production, over the medium and longer term. 7G is targeting buyers of natural gas for North America's emerging liquefied natural gas (LNG) export industry, the replacement of coal with natural gas in Alberta's electrical generation sector and builders and operators of petrochemical plants that require methane, ethane, propane and butane. 7G is also advancing discussions with overseas customers seeking long-term, low-cost supplies of LNG and liquefied propane.

By taking a portfolio approach to its natural gas marketing, 7G sells about two-thirds of its natural gas in the US Midwest, with the remainder split primarily between AECO in Alberta and the US Gulf Coast. 7G's US Gulf Coast sales are via the company's pipeline capacity on Kinder Morgan's NGPL pipeline system, which runs from 7G's Alliance Chicago delivery point to the Henry Hub delivery point in Louisiana.

HIGHLIGHTS FOR THE QUARTER ENDED DECEMBER 31, 2016

- Production averaged 132,300 boe/d, consisting of 58 percent liquids and a liquids-gas ratio of 229 barrels per MMcf of sales gas. Total production was up 70 percent compared to the fourth quarter of 2015.

- Funds from operations were $220 million in the fourth quarter, taking 2016 funds from operations to $733 million, a 77 percent increase from 2015. Cash from operating activities increased 231 percent to $179 million in the fourth quarter and was up 70 percent in 2016 to $645 million.

- Drilled 12 net wells and completed 21 net wells, taking the number of producing Montney wells to 232, of which about one quarter were acquired and used non-7G well construction and design.

- At the beginning of 2017, approximately 84 wells were in various stages of construction between drilling and tie-in. This inventory of in-progress wells has significant productive capacity that will be brought on stream in 2017.

- Capital investments were $284 million in the fourth quarter and $978 million for the year, which was about 7 percent below 2016 guidance of $1.05 billion to $1.10 billion.

- On a per share basis in 2016, funds from operations were up 50 percent to $2.30 per share, and production increased 65 percent to 370 boe/d per million shares, compared to 2015.

2016 RESERVE HIGHLIGHTS – Evaluated by McDaniel as at December 31, 2016

- Proved developed producing reserves were 166 MMboe, up 127 percent from 73 MMboe at December 31, 2015.

- Total proved reserves were 825 MMboe and proved plus probable reserves were 1.53 billion boe, representing an increase of 95 percent and 79 percent, respectively, when compared to 7G's total proved and proved plus probable reserves on December 31, 2015.

- Total proved plus probable reserves at year end were estimated to have a before tax net present value of approximately $10 billion as of December 31, 2016 compared to $6.5 billion at the end of 2015, a 54 percent increase from the December 31, 2015 reserve report, using a discount rate of 10 percent.

- Risked best estimate contingent resources increased 80 percent to 1.39 billion boe at December 31, 2016 compared to 771 million boe at December 31, 2015. The before tax net present value increased 10 percent, from $2.79 billion at December 31, 2015 to $3.07 billion at December 31, 2016.

2016 FOURTH QUARTER AND ANNUAL FINANCIAL AND OPERATING RESULTS

	Three months ended December 31, 2016	2015	% Change	Years ended December 31, 2016	2015	% Change
Operational Highlights						
($ millions, except per share and volume data)						
Production						
Condensate (mbbls/d)	**43.2**	25.6	69	**39.3**	21.2	85
NGLs (mbbls/d)	**33.4**	19.2	74	**30.0**	14.3	110
Natural gas (MMcf/d)	**334**	197	70	**291**	149	95
Total (mboe/d)	**132.3**	77.7	70	**117.8**	60.4	95
Liquids %	**58%**	58%	—	**59%**	59%	—
Realized prices						
Condensate and oil ($/bbl)	**56.96**	46.72	22	**50.59**	50.84	—
NGLs ($/bbl)	**18.23**	12.35	48	**13.08**	10.34	26
Natural gas ($/Mcf)	**4.15**	2.57	61	**3.53**	2.65	33
Total ($/boe)	**33.67**	24.97	35	**28.92**	26.84	8
OPERATING NETBACK (1) ($/boe)						
Liquids and natural gas revenues	**$ 33.67**	$ 24.97	35	**$ 28.92**	$ 26.84	8
Royalties	**(0.98)**	(1.69)	(42)	**(0.16)**	(2.63)	(94)
Operating expenses	**(4.86)**	(4.11)	18	**(4.22)**	(4.59)	(8)
Transportation and processing	**(5.92)**	(3.30)	79	**(5.53)**	(2.68)	106
Netback prior to hedging	**21.91**	15.87	38	**19.01**	16.94	12
Realized hedging gain	**0.48**	3.22	(85)	**2.11**	6.83	(69)
Operating netback after hedging	**$ 22.39**	$ 19.09	17	**$ 21.12**	$ 23.77	(11)
General and administrative expenses per boe	**$ 1.18**	$ 1.01	17	**$ 1.09**	$ 1.10	(1)
Selected financial information						
Liquids and natural gas revenue	**409.8**	178.5	130	**1,246.9**	591.9	111
Operating income (1) (3)	**47.6**	(14.2)	nm	**160.6**	52.1	208
Per share - diluted	**0.13**	(0.05)	nm	**0.50**	0.19	163
Net income (loss) for the period (3)	**(104.9)**	(28.9)	263	**(26.2)**	(187.3)	(86)
Per share - diluted	**(0.30)**	(0.11)	173	**(0.09)**	(0.75)	(88)
Funds from operations (1) (3)	**219.7**	106.0	107	**732.6**	414.6	77
Per share - diluted	**0.60**	0.39	54	**2.30**	1.53	50
Cash provided by operating activities	**178.6**	53.9	231	**644.6**	380.1	70
Total capital investments (4)	**283.6**	301.1	(6)	**978.0**	1,309.0	(25)
Adjusted working capital	**585.9**	306.0	91	**585.9**	306.0	91
Available funding (1)	**1,626.7**	1,118.0	46	**1,626.7**	1,118.0	46
Net debt (1)	**1,528.8**	1,250.9	22	**1,528.8**	1,250.9	22
Debt outstanding	**2,111.9**	1,546.8	37	**2,111.9**	1,546.8	37
Weighted average shares –basic (2)	**347.2**	252.9	37	**299.8**	249.6	20
Weighted average shares -diluted (2)	**365.0**	273.1	34	**318.8**	270.1	18

(1) Operating netback, funds from operations, operating income, available funding and net debt are not defined under IFRS. See “Non-IFRS Financial Measures” in Management’s Discussion and Analysis for the years ended December 31, 2016 and 2015.
(2) Basic weighted average shares are used to calculate diluted per share amounts when the company is in a loss position.
(3) Includes $27.4 million ($20.0 million after tax) of prior period royalty recoveries for the year ended December 31, 2016.
(4) Excluding acquisitions and investments.

OPERATIONS

Innovative drilling methods speed up drilling times by 40 to 50 percent

7G has continued to innovate and test new ways to reduce drilling times and lower costs, including the use of underbalanced drilling that increases the rate of drill bit penetration.

"We have also optimized the path of the wells we are drilling, extending the curve of the 90-degree turn from vertical to horizontal. Think of a long, high-speed curve on a highway versus a right turn inside the city. By making the turn path more gradual, there is less friction and drag on the drilling pipe and we are able to drill faster. Each of these optimizations saves time and money, improving our competitiveness," said Barry Hucik, Vice President, Drilling.

In the fourth quarter of 2016, the average cost per metre of lateral well drilled was reduced by 10 percent to $1,405 and the cost to drill a well fell by 15 percent to $3.5 million compared to the same period in 2015. Completions costs also improved substantially because larger proppant injections resulted in the average cost per tonne of proppant injected falling by 38 percent to $886. Despite increasing the number of stages to 38 per well in the fourth quarter, completions costs per well dropped by 5 percent to $5.8 million. The average cost to drill and complete wells in the fourth quarter of 2016 fell by 9 percent to $9.3 million compared to the fourth quarter of 2015.

In drilling, cost reductions most often track the speed of drilling, whereas when completions increase the number of stages and the amount of proppant injected, there is a proportionate increase in time and materials. The value gain anticipated to result from this increase in fracture intensity is expected to materialize from elevated production rates and ultimate resource recoveries produced over time.

Completions are bigger, and cost less

"Despite this increase in stage frequency and proppant volumes, the year-over-year cost to complete each well fell by 5 percent in the fourth quarter and 16 percent during 2016. In addition, with our shift from nitrogen foam fractures to slickwater, we have saved money through optimization of water sourcing and conserved more sales natural gas through flaring reductions. These drilling and completions improvements continue to lower costs through speed of drilling and optimization – key competitive advantages for our company," Nevokshonoff said.

DRILLING AND COMPLETIONS

Drilling	**Q4 2016**	Q4 2015	% change	**2016**	2015	% change
Net Hz Wells Rig Released[1]	**12**	22	(45)	**50**	82	(39)
Average Measured Depth (m)	**5,696**	5,862	(3)	**5,712**	5,891	(3)
Average Horizontal Length (m)	**2,511**	2,653	(5)	**2,589**	2,713	(5)
Average Drilling Days per Well	**31**	36	(14)	**35**	44	(20)
Average Drilling Cost per Lateral Metre ($/m)	**1,405**	1,556	(10)	**1,575**	1,800	(13)
Average Well Cost ($MM)	**3.5**	4.1	(15)	**3.9**	5.0	(22)
Completions						
Net Wells Completed	**21**	13	62	**68**	58	17
Average Number of Stages per Well	**38**	28	36	**32**	29	10
Average Tonnes Pumped per Well	**6,492**	4,930	32	**5,403**	4,395	23
Average Cost per Tonne of proppant ($/t)	**886**	1,438	(38)	**1,050**	1,618	(35)
Average Well Cost ($MM)	**5.8**	6.1	(5)	**5.7**	6.8	(16)
Total Drilling & Completion Cost per Well ($MM)	**9.3**	**10.2**	**(9)**	**9.6**	**11.8**	**(19)**

(1) 7G operated wells drilled in the Nest.

Seven Generations ranks among Canada's top-ten energy companies in carbon disclosure
In 2016, Seven Generations participated in the Carbon Disclosure Project (CDP), which independently surveys hundreds of companies across the globe on emissions performance.

"In our first year of CDP participation, we were pleased to earn a score of B for our carbon disclosure, which assessed our 2015 operations. This score ranks us tied for third place and among the top 10 of the 64 Canadian energy companies named in the CDP Canada Climate Change Report 2016," said Susan Targett, 7G Senior Vice President.

Financial update
Compared to 2015, benchmark West Texas Intermediate (WTI) oil prices were 11 percent lower in 2016, averaging US$43.32 per barrel. Henry Hub natural gas prices were down 3 percent in 2016, averaging US$2.55 per MMBtu. Seven Generations' 2016 full year funds from operations increased 77 percent to $733 million. Total liquids as a percentage of production was consistent at 59 percent year-over-year. In the fourth quarter, funds from operations increased 107 percent to $220 million compared to the fourth quarter of 2015. Fourth quarter operating netbacks were $22.39 per boe after hedging, up 17 percent compared to the fourth quarter of 2015, whereas annual 2016 operating netbacks were down 11 percent to $21.12 per boe compared to 2015.

Managing market risk
Seven Generations employs financial hedges to partially protect against commodity price volatility. In 2016, hedge contributions were a significant source of cash flow, with approximately $91 million in realized gains contributing roughly 12 percent to funds from operations. Hedging price targets are established at levels that are expected to provide a threshold rate of return on capital investment based on a combination of benchmark oil and natural gas prices, projected well performance and capital efficiencies.

Commodity price hedges 2017 – 2019 as of December 31, 2016

	Liquids Hedging				Natural Gas Hedging				FX Hedging	
	WTI Collars		WTI 3 Way Collars		Chi Citygate Swaps		AECO 7A Collars		USD/CAD Swaps	
Year	bbl/d	C$/bbl	bbl/d	C$/bbl	MMbtu/d	MMbtu/d	GJ/d	C$/Gj	USD $MM	C$/US$
2017	12,250	$66.02 - $78.81	8,000	$41.25/$56.88/$77.39	175,000	$3.06	52,500	$2.50 - $3.03	$ 195.71	$1.2943
2018	9,250	$62.79 - $77.85	12,000	$40.83/$56.25/$75.54	135,000	$2.91	50,000	$2.50 - $2.99	$ 143.02	$1.3262
2019	5,500	$60.00 - $79.76	6,000	$41.25/$56.67/$77.15	50,000	$2.95	50,000	$2.50 - $2.99	$ 53.60	$1.3111

OUTLOOK

Building productive capacity for strong growth in the second half of 2017
Seven Generations' capital program in 2017 is weighted towards drilling and completions in the first half of the year. Currently operating 12 rigs, 7G's 2017 rig count is expected to average 9 to 10, and it plans to drill 100 to 110 wells. Capital investment is forecast to be $1.5 billion to $1.6 billion, unchanged from original guidance, with about 60 percent focused on drilling and well completions. Production facilities and infrastructure represent about one-third of the capital budget. Preliminary engineering and construction work is underway for a new natural gas processing plant in the north end of the Kakwa field with an initial processing rate of 250 MMcf/d and expansion capacity to 500 MMcf/d. Unchanged from original guidance, production is expected to average 180,000 to 190,000 boe/d in 2017, representing an approximate 57 percent increase over 2016 average production of 117,800 boe/d. In 2017, 7G's liquids are expected to be 55 to 60 percent of total production.

"During the first quarter, we expect production to average about 150,000 boe/d. The second quarter will see similar vigorous levels of field activity. Production increases will be slightly moderated due to the planned maintenance and liquids processing expansion at the Pembina Cutbank complex in April, which is expected to curtail about 20 percent of our production for about two weeks and impact about 5,000 boe/d of average production in the second quarter. The planned plant modification is designed to increase condensate handling capacity that will set the stage for significantly higher production in the second half of the year," Proctor said.

In 2017, 7G has contracted firm transportation capacity of about 593 MMcf/d on Alliance Pipeline and TransCanada's NGTL system, which incrementally rises to about 868 MMcf/d in late 2018.

RESERVES

Reserve additions yield strong production replacement ratios

With the major acquisition included, 7G's proved reserve replacement ratio was 10.3 times for each boe produced and, on the basis of proved plus probable reserves, the reserve replacement ratio is 16.7 times. The company's finding and development recycle ratio for its proved developed producing reserves was 2.0 times in 2016.

"We continue to add reserves, replace production and invest capital efficiently. It is important to note that we are early in the life of a high-growth project that is achieving strong reserve performance metrics despite the fact that we are investing a significant portion of our capital in Super Pad production facilities, large natural gas processing plants and the associated infrastructure. These major infrastructure investments are providing substantial capacity for our Kakwa River Project to continue robust growth in the years ahead," Nevokshonoff said.

Three-year metrics point to strong long-term reserve performance

"Given that reserve replacement ratios and reserve costs can vary from year to year, reserve metrics over a three-year period provide better insight into longer-term performance. For the first time, 7G has three years of reserve development metrics that show a replacement ratio of 3 times production on our proved developed producing reserves. Our three-year proved plus probable finding, development and acquisition cost was $11.49 per boe, which is very strong performance during a period of high growth with major infrastructure investments," Nevokshonoff said.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

	2016 ($/boe)			**2014-2016** ($/boe)		
	PDP	**1P**	**2P**	**PDP**	**1P**	**2P**
Finding, Development & Acquisition (FD&A)[1]	22.45	16.05	11.68	24.03	15.38	11.49
Finding & Development (F&D)	9.66	14.26	10.97	17.61	14.41	11.16
	(times)			(times)		
FD&A Recycle Ratio[2]	0.8	1.2	1.6	1.0	1.5	2.0
F&D Recycle Ratio[2]	2.0	1.3	1.7	1.3	1.6	2.1
Reserve Replacement Ratio[3]	3.2	10.3	16.7	3.0	10.4	17.4

Notes:
(1) FD&A and F&D costs include the year-over-year change in future development capital to transfer reserves into production.
(2) Recycle Ratio is operating netback (excluding hedging gains) divided by F&D or FD&A costs per boe. Operating netback is determined as revenue (excluding realized hedging gains and losses), less royalties, transportation costs, and operating costs.
(3) Reserves Replacement Ratio is total reserve additions (including acquisitions and divestitures) divided by annual production.

Reserves summary and additional detailed information
7G's independent reserves evaluation, effective December 31, 2016, has been completed by McDaniel, which prepared the evaluation in compliance with the standards set out in National Instrument 51-101 of the Canadian Securities Administrators and the Canadian Oil and Gas Evaluation Handbook.

For additional information regarding the independent reserves evaluation that was conducted by McDaniel as at December 31, 2016, please see the disclosure that is provided under the heading "Statement of Reserves Data" in the company's Annual Information Form, dated March 7, 2017, which is available on the SEDAR website at www.sedar.com.

Reserves Summary 2015 - 2016

Category	2016 (MMboe)	2015 (MMboe)	Change %
Proved			
Developed Producing	166.11	73.32	127
Developed Non-Producing	10.23	6.12	67
Developed Producing plus Non-Producing	176.35	79.45	122
Undeveloped	648.77	344.52	88
Total Proved	825.11	423.96	95
Total Probable	709.54	435.16	63
Total Proved plus Probable	1,534.65	859.12	79

Reserves Reconciliation 2015 – 2016

	Proved (MMboe)	**Probable** (MMboe)	**Proved Plus Probable** (MMboe)
December 31, 2015	423.96	435.16	859.12
Discoveries	-	-	-
Extensions & Improved Recovery	72.96	167.28	240.24
Technical Revisions	180.19	(98.47)	81.72
Acquisitions	193.45	206.2	399.67
Dispositions	-	-	-
Economic Factors	(2.34)	(0.65)	(2.99)
Production	(43.12)	-	(43.12)
December 31, 2016	825.11	709.54	1,534.65

CORPORATE

Paul Hand brings more than 43 years of capital markets expertise to 7G's Board of Directors
Paul Hand, former Managing Director of RBC Capital Markets, has joined 7G's Board of Directors. Before retiring from RBC in January 2017, Paul had senior responsibility for the firm's capital markets group and advised corporate clients in connection with a wide range of transactions. Hand joined RBC Capital Markets in 1974 and has spent more than 43 years in various investment business roles in the private client, equity capital markets, and institutional equity areas. Hand was previously the Head of Global Equity Trading for 11 years and was directly responsible for the firm's North American and international equity trading. Hand earned a Bachelor of Arts in Economics in 1969 and a Master of Business Administration in 1973 from Queen's University.

Conference Call
7G management will hold a conference call to discuss results and address investor questions on Wednesday, March 8, 2017 at 9:00 a.m. MT (11 a.m. ET).

Participant Dial-In Numbers:

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Seven Generations Energy
Seven Generations is a low-supply-cost, high-growth Canadian natural gas developer generating long-life value from its liquids-rich Kakwa River Project, located about 100 kilometres south of its operations headquarters in Grande Prairie, Alberta. 7G's corporate headquarters are in Calgary and its shares trade on the TSX under the symbol VII.

Further information on Seven Generations is available on the company's website: www.7genergy.com, or by contacting:

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Non-IFRS Financial Measures
This news release includes certain terms or performance measures commonly used in the oil and natural gas industry that are not defined under IFRS, including "funds from operations", "operating income", "operating netback", "available funding", "net debt" and "adjusted working capital". The data presented are intended to provide additional information and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These non-IFRS measures should be read in conjunction with the company's financial statements and accompanying notes.

For more information regarding "funds from operations", "operating income", "operating netback", "available funding", "net debt" and "adjusted working capital", see "Non-IFRS Financial Measures" in the company's Management's Discussion and Analysis for the year ended December 31, 2016 and 2015.

Reader Advisory

This news release contains certain forward-looking information and statements that involve various risks, uncertainties and other factors. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "should", "believe", "plans", and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the Company's strategies, objectives and competitive strengths; reduction of relative costs expected through innovation and operational optimization; elevated production rates and ultimate recoveries anticipated from increasing fracture intensity; resource recovery potential; generation of full-cycle economic returns; expected increase in value of the Kakwa River Project; expected production, production guidance and production growth; expected capital investment in 2017; planned number of wells to be drilled; expected rig count in 2017; expected processing capacity of the natural gas processing plant to be constructed at the north end of the Kakwa field; anticipated liquids yields; significant ramp up of production that is anticipated in the second half of 2017; the expected allocation of 40 percent of the Company's drilling and capital investment in 2017 to the properties that were acquired in 2016; the funding of capital investment in 2017 with cash on hand, cash flow and draws on the Company's credit facility, if required; planned pursuit of new market opportunities and market access initiatives; planned downtime at the Pembina Cutbank complex in April of 2017 and the curtailment of production that will result therefrom. In addition, references to reserves and resources are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated.

With respect to forward-looking information contained in this document, assumptions have been made regarding, among other things: future oil, NGLs and natural gas prices being consistent with current commodity price forecasts (including McDaniel's price forecasts that are included in the Annual Information Form dated March 7, 2017, for the year ended December 31, 2016 (the "AIF"); the Company's continued ability to obtain qualified staff and equipment in a timely and cost-efficient manner; infrastructure and facility design concepts that have been applied by the Company elsewhere in its Kakwa River Project may be successfully applied to the properties that were acquired in 2016; the consistency of the regulatory regime and framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future; the Company's ability to market production of oil, NGLs and natural gas successfully to customers; the Company's future production levels and amount of future capital investment will be consistent with the Company's current development plans and budget; the applicability of new technologies for recovery and production of the Company's reserves and resources may improve capital and operational efficiencies in the future; the recoverability of the Company's reserves and resources; sustained future capital investment by the Company; future cash flows from production; the future sources of funding for the Company's capital program; the Company's future debt levels; geological and engineering estimates in respect of the Company's reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities, and the access, economic, regulatory and physical limitations to which the Company may be subject from time to time; the impact of competition on the Company; and the Company's ability to obtain financing on acceptable terms. For the forward-looking statements regarding the company's ability to achieve full-cycle economic returns, key assumptions were made, including: the anticipated impact of the significant acquisition that was completed in 2016 on the Company and its reserves, production and financial and operating results; the Company's ability to successfully integrate the assets acquired in 2016 into its Kakwa River Project; that the tax regimes and bi-lateral and international trade arrangements that are applicable to the Company will not be significantly revised in a way that will have adverse impacts on the Company.

Actual results could differ materially from those anticipated in the forward-looking information that is contained herein as a result of the risks and risk factors that are set forth in the AIF, which is available on SEDAR at www.sedar.com, including, but not limited to: volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto; general economic, business and industry conditions; variance of the Company's actual capital costs, operating costs and economic returns from those anticipated; the ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms; risks related to the exploration, development and production of oil and natural gas reserves and resources; negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels; actions by governmental authorities, including changes in government regulation, royalties and taxation; potential legislative and regulatory changes, including changes that may be implemented following the 2016 U.S. presidential election; the rescission, or amendment to the conditions of, groundwater licenses of the Company; management of the Company's growth; the ability to successfully identify and make attractive acquisitions, joint ventures or investments, or successfully integrate future acquisitions or businesses; the availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel; adoption or modification of climate change legislation by governments; the absence or loss of key employees; uncertainty associated with estimates of oil, NGLs and natural gas reserves and resources and the variance of such estimates from actual future production; dependence upon compressors, gathering lines, pipelines and other facilities, certain of which the Company does not control; the ability to satisfy obligations under the Company's firm commitment transportation arrangements; the uncertainties related to the Company's identified drilling locations; the high-risk nature of successfully stimulating well productivity and drilling for and producing oil, NGLs and natural gas; operating hazards and uninsured risks; the possibility that the Company's drilling activities may encounter sour gas; execution risks associated with the Company's business plan; failure to acquire or develop replacement reserves; the concentration of the Company's assets in the Kakwa River Project area; unforeseen title defects; aboriginal claims; failure to accurately estimate abandonment and reclamation costs; development and exploratory drilling efforts and well operations may not be profitable or achieve the targeted return; horizontal drilling and completion technique risks and failure of drilling results to meet expectations for reserves or production; limited intellectual property protection for operating practices and dependence on employees and contractors; third-party claims regarding the Company's right to use technology and equipment; expiry of certain leases for the undeveloped leasehold acreage in the near future; failure to realize the anticipated benefits of acquisitions or dispositions; failure of properties acquired now or in the future to produce as projected and inability to determine reserve and resource potential, identify liabilities associated with acquired properties or obtain protection from sellers against such liabilities; changes in the application, interpretation and enforcement of applicable laws and regulations; restrictions on drilling intended to protect certain species of wildlife; potential conflicts of interests; actual results differing materially from management estimates and assumptions; seasonality of the Company's activities and the Canadian oil and gas industry; alternatives to and changing demand for petroleum products; extensive competition in the Company's industry; changes in the Company's credit ratings; third party credit risk; dependence upon a limited number of customers; lower oil, NGLs and natural gas prices and higher costs; failure of 2D and 3D seismic data used by the Company to accurately identify the presence of oil and natural gas; risks relating to commodity price hedging instruments; terrorist attacks or armed conflict; cyber security risks, loss of information and computer systems; inability to dispose of non-strategic assets on attractive terms; security deposits required under provincial liability management programs; reassessment by taxing authorities of the Company's prior transactions and filings; variations in foreign exchange rates and interest rates; third-party credit risk including risk associated with counterparties in risk management activities related to commodity prices and foreign exchange rates; sufficiency of insurance policies; potential litigation; variation in future calculations of non-IFRS measures; sufficiency of internal controls; breach of agreements by counterparties and potential enforceability issues in contracts; impact of expansion into new activities on risk exposure; inability of the Company to respond quickly to competitive pressures; and the risks related to the common shares that are publicly traded and the Company's senior notes and other indebtedness.

Independent Reserves Evaluation

Estimates of the Company's reserves and contingent resources and the net present value of future net revenue attributable to the Company's reserves and contingent resources as at December 31, 2016, are based upon the reports that were prepared by McDaniel, dated March 7, 2017 (the "2016 Reserves and Contingent Resources Reports"). Estimates of the Company's reserves and contingent resources and the net present value of future net revenue attributable to the Company's reserves and contingent resources as at December 31, 2015, are based upon the reports that were prepared by McDaniel, dated March 7, 2016 ("McDaniel Contingent Resources Report"). Estimates of the reserves that were attributable to the assets that were acquired by the Company in 2016 are based upon the report that was prepared by McDaniel dated July 5, 2016, evaluating the reserves attributable to those assets as at December 31, 2015. The estimates of reserves and contingent resources provided in this document are estimates only and there is no guarantee that the estimated reserves or contingent resources will be recovered. Actual reserves and contingent resources may be greater than or less than the estimates provided in this in this document, and the differences may be material. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Estimates of net present value of future net revenue attributable to the Company's reserves and contingent resources do not represent the fair market value of the Company's reserves and contingent resources and there is uncertainty that the net present value of future net revenue will be realized. There is no assurance that the forecast price and cost assumptions applied by McDaniel in evaluating Seven Generations' reserves, contingent resources and prospective resources will be attained and variances could be material. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources that are described herein. For important additional information regarding the independent reserves and resources evaluations that were conducted by McDaniel, please refer to the AIF, the annual information form dated March 8, 2016, the Material Change Report dated July 12, 2016 and the Company's Short Form Prospectus dated July 19, 2016 which are available on the SEDAR website at www.sedar.com.

Note Regarding Oil and Gas Metrics

Seven Generations has adopted the standard of 6 Mcf:1 bbl when converting natural gas to boes. Condensate and other NGLs are converted to boes at a ratio of 1 bbl:1 bbl. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based roughly on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the Company's sales point. Given the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 bbl, utilizing a conversion ratio at 6 Mcf: 1 bbl may be misleading as an indication of value.

Finding, development and acquisition costs have been calculated by the Company as the sum of exploration and development capital, plus acquisition capital, plus changes in future development costs for the given year, divided by total reserve additions for that year. Finding and development costs are calculated as the sum of exploration and development costs, plus changes in future development costs (excluding future development capital associated with acquisitions and dispositions), divided by reserve additions (excluding reserves added via acquisitions). Finding and development both including and excluding acquisitions are presented since acquisition and disposition activity can result in reserve replacement metrics that are not indicative of the long-term cost structure that is expected from the Company's assets. Management utilizes finding and development metrics for its internal measurement. Readers are advised that this information may not be comparable to similarly defined measures presented by other entities and comparisons should not be made between such measures provided by the Company and by other companies without also taking into account any differences in the way that the calculations were prepared.

Oil and Gas Definitions

Terms that are used in this news release that are not otherwise defined herein are provided below:

best estimate is a classification of estimated resources described in the Canadian Oil and Gas Evaluation Handbook, which is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Resources in the best estimate case have a 50% probability that the actual quantities recovered will equal or exceed the estimate.

contingent resources are the quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

developed producing reserves are those gross reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

developed reserves are those gross reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

gross means (i) in relation to the Company's interest in production or reserves, its "company gross reserves", which are the Company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company; and (ii) in relation to wells, the total number of wells in which the Company has an interest.

net means, in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

operating netback is determined as revenue (excluding realized hedging gains and losses), less royalties, transportation costs, and operating costs.

probable reserves are those additional gross reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

proved reserves are those gross reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

recycle ratio means operating netback (excluding hedging gains) divided by F&D or FD&A costs per boe.

reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

<u>Abbreviations</u>

AECO	means means the physical storage and trading hub for natural gas on the TransCanada Alberta Transmission System, which is the delivery point for the various benchmark Alberta index prices
bbl	barrel
bbls	barrels
boe	barrels of oil equivalent
C$ or CAD	Canadian dollars
d	day
IFRS	International Financial Reporting Standards
F&D	finding and development costs
FD&A	finding, development and acquisition costs
Gj	gigajoules
hz	horizontal
IFRS	International financial reporting standards
LNG	means natural gas that has been converted to liquid form for the purpose of storage or transport
m	metres
Mboe	thousand barrels of oil equivalent
Mbbls	thousands of barrels
mcf	thousand cubic feet
MM	millions
MMbbls	millions of barrels
MMboe	millions of barrels of oil equivalent

MMbtu	million British thermal units
MMcf	million cubic feet
Nest	the primary development block of the Kakwa River Project
Nest 1	the area that is contained within the primary development block of the Kakwa River Project that is shown in the Company's Corporate Presentation on its website at www.7genergy.com
Nest 2	the higher return prospects that are contained within the primary development block of the Kakwa River Project that is shown in the Company's Corporate Presentation on its website at www.7genergy.com
NGLs	natural gas liquids
NGTL	means the Nova Gas Transmission Ltd. system
PDP	gross total proved developed producing reserves
US$ or USD	United States dollars
WTI	West Texas Intermediate
1P	gross total proved reserves
2P	gross total proved plus probable reserves
$MM	millions of dollars

Seven Generations Energy Ltd. is also referred to as **Seven Generations**, **Seven Generations Energy**, **7G, we, our, the company** or **the Company**.