MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A"), dated May 3, 2017, is management's assessment of the historical financial position and results of Seven Generations Energy Ltd. (the "Company" or "Seven Generations") for the three months ended March 31, 2017. This MD&A should be read in conjunction with the audited annual consolidated financial statements and notes thereto for the years ended December 31, 2016 and 2015 (the "consolidated financial statements") and the unaudited condensed interim consolidated financial statements and notes thereto for the three months ended March 31, 2017 (the "condensed interim consolidated financial statements"). These condensed interim consolidated financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). Unless otherwise noted, all financial measures are expressed in Canadian dollars and tabular dollar amounts are in millions. See "Non-IFRS Financial Measures" for reconciliations and information regarding the following non-IFRS financial measures used in this MD&A: "funds from operations", "operating income", "operating netback", "adjusted working capital", "available funding" and "net debt". This MD&A contains forward-looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward-looking information, refer to the "Forward-Looking Information Advisory" included at the end of this MD&A. A number of abbreviated terms used throughout this MD&A are explained on the last pages of this MD&A. Additional information about Seven Generations is available on the SEDAR website at www.sedar.com, including the Company's Annual Information Form for the year ended December 31, 2016, dated March 7, 2017 (the "AIF").

ABOUT SEVEN GENERATIONS

Seven Generations is a low supply cost, high-growth Canadian natural gas developer generating long-life value from its liquids-rich Montney Kakwa River Project, located about 100 kilometres south of its operations headquarters in Grande Prairie, Alberta. Seven Generations' corporate headquarters are in Calgary and its Class A Voting Common Shares ("Common Shares") trade on the TSX under the symbol VII.

Seven Generations seeks to differentiate itself based on four key strategies:

- stakeholder service: recognizing that in a competitive world, only those who best serve their stakeholders can expect to survive in the long term;
- supply cost: combining resource selection with innovation, technology and efficiency to remain among North America's lowest supply cost unconventional gas developers;
- financial sustainability: profitable growth to achieve positive free cash flow, earn full-cycle returns on capital employed across the entire commodity price cycle and focused capital deployment on high return opportunities with hedged economics; and
- market access: seek out a position in gathering, processing, transportation and marketing opportunities to expand market access, and leverage market access to capture premium markets for the Company's production.

HIGHLIGHTS FOR THE FIRST QUARTER ENDED MARCH 31, 2017

Financial Performance

Seven Generations achieved first quarter production of 153.1 mboe/d, tracking in line with 2017 guidance of 180 - 190 mboe/d and 73% higher than the same period in 2016. First quarter production delivered higher revenues due to production growth and stronger commodity prices and generated funds from operations of $272.3 million, an increase of 146% relative to the same period in 2016. Cash from operating activities increased by 24% in the first quarter of 2017 relative to the fourth quarter of 2016.

The Company closed the first quarter of 2017 with a strong balance sheet, including available funding of approximately $1.5 billion and net debt of approximately $1.6 billion. The Company has an undrawn $1.1 billion credit facility in addition to adjusted working capital of $500.5 million which includes cash and cash equivalents of $639.6 million.

Capital Investments

The Company continued to focus and execute its strategy on developing its Montney assets investing $362.3 million for the first quarter of 2017, drilling 27 wells and completing 16 wells while bringing 18 wells on production. The Company made advancements in the Montney lands acquired in the third quarter of 2016 by expanding facilities infrastructure and continued the construction of three new super pads to help support improved well performance and growth.

Transportation and Marketing

The Company's lands are close to key infrastructure and take-away capacity, including the Alliance Pipeline, the Nova Gas Transmission Ltd. ("NGTL") system owned by TransCanada Pipelines Limited ("TCPL") and the Peace Pipeline System that is owned by Pembina Pipeline Corporation ("Pembina"). The Company believes the firm service transportation agreements in place with several key partners support the Company's ability to deliver on its high growth objectives. Seven Generations holds total natural gas transportation capacity that grows incrementally over the next two years, reaching approximately 870 MMcf/d in the third quarter of 2018. In the first quarter of 2017, the Company entered into an agreement with TCPL which, pending National Energy Board approval, effective November 1, 2017, will provide the Company access to the Dawn, Ontario market, diversifying the Company's natural gas pricing exposure.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table presents selected operational and financial information:

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	% Change
($ millions, except per share and volume data)					
Production					
Condensate (mbbls/d)	**46.8**	28.4	65	43.2	8
NGLs (mbbls/d)	**42.2**	22.6	87	33.4	26
Liquids (mbbls/d)	**89.0**	51.0	75	76.6	16
Natural gas (MMcf/d)	**384**	225	71	334	15
Total Production (mboe/d)	**153.1**	88.5	73	132.3	16
Liquids %	**58%**	58%	—	58%	—
Financial					
Operating income (1)	**74.8**	9.3	nm	47.6	57
Per share - diluted	**0.21**	0.03	nm	0.13	62
Revenue (2)	**629.8**	256.3	146	262.2	140
Net income (loss) and comprehensive income (loss)	**215.6**	138.4	56	(104.9)	nm
Per share - diluted	**0.59**	0.50	18	(0.30)	nm
Funds from operations (1)	**272.3**	110.6	146	219.7	24
Per share - diluted	**0.75**	0.40	88	0.60	25
Cash provided by operating activities	**335.7**	144.5	132	178.6	88
Capital investments (3)	**362.3**	267.1	36	283.6	28
Adjusted working capital (1)	**500.5**	447.4	12	585.9	(15)
Available funding (1)	**1,540.9**	1,260.4	22	1,626.7	(5)
Net debt (1)	**1,594.1**	1,013.6	57	1,528.8	4
Debt outstanding	**2,092.1**	1,451.6	44	2,111.9	(1)
Weighted average shares -basic (4)	**350.6**	263.2	33	347.2	1
Weighted average shares -diluted (4)	**363.1**	278.9	30	365.0	(1)

(1) See “Non-IFRS Financial Measures”.
(2) Represents the total of liquids and natural gas sales, net of royalties, gains (losses) on risk management contracts and other income.
(3) Excluding acquisitions and equity investments.
(4) Basic weighted average shares are used to calculate diluted per share amounts when the Company is in a loss position.

Operating netback per boe

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	% **Change**	2016	% **Change**
Liquids and natural gas sales	**$ 35.52**	$ 23.34	52	$ 33.67	5
Realized hedging (losses) gains	**(0.52)**	4.50	nm	0.48	nm
Royalties	**(1.22)**	(1.61)	(24)	(0.98)	24
Operating expenses	**(4.99)**	(3.85)	30	(4.86)	3
Transportation, processing and other (1)	**(5.22)**	(4.43)	18	(5.92)	(12)
Operating netback per boe (2)	**$ 23.57**	$ 17.95	31	$ 22.39	5

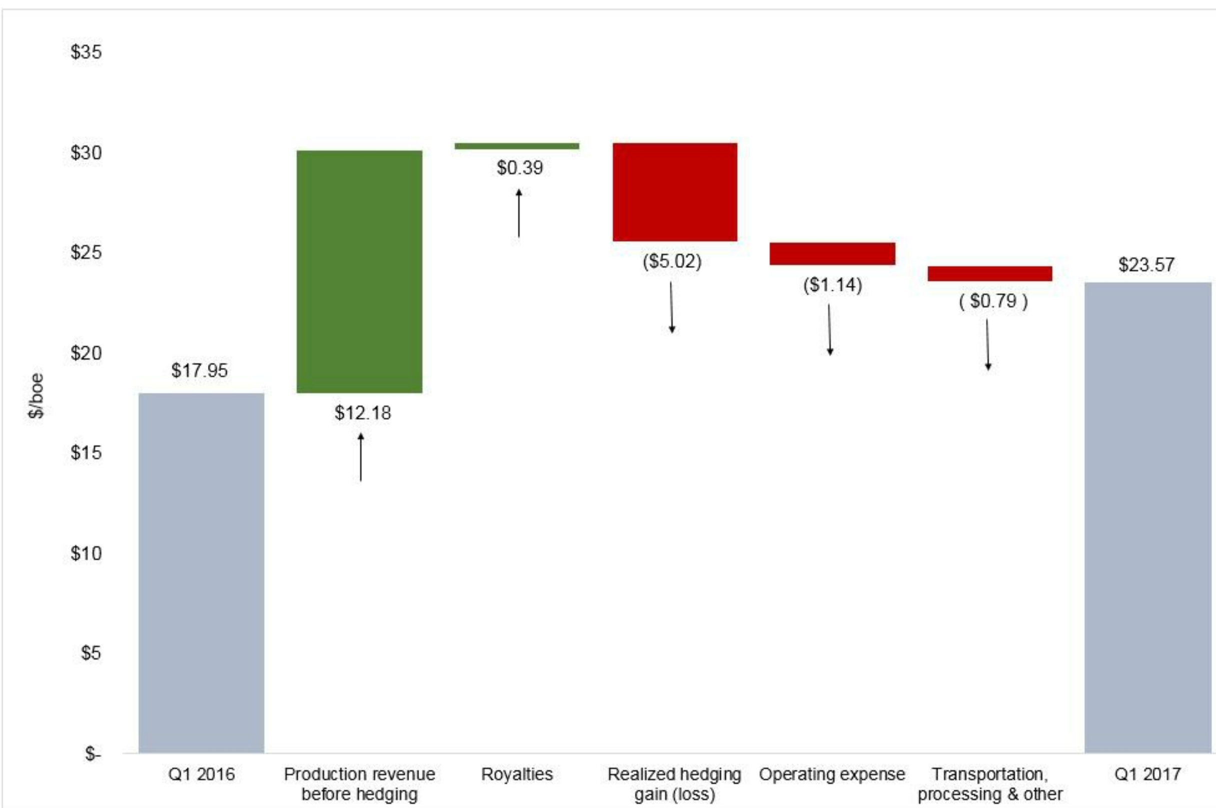
(1) Comparative figures have been reclassified to conform to current period.

(2) See "Non-IFRS Financial Measures.

For the first quarter of 2017, operating netback per boe was $23.57, higher by 31% relative to the same period in 2016 as a result of higher priced liquids and natural gas sales, partially offset by higher expenses. Liquids and natural gas sales were higher due to increases in benchmark prices which also impacted realized hedging losses. Combined operating and transportation expenses of $10.21 were consistent with 2017 expectations. Operating expenses on a per boe basis were higher as a result of rental equipment and additional water handling. Transportation, processing and other expenses were higher as a result of processing fees associated with the Pembina Kakwa River Plant that the Company assumed as part of an acquisition in the third quarter of 2016. Royalties decreased relative to the first quarter of 2016 as the Company changed its royalty reporting of field condensate in the second quarter of 2016 resulting in lower royalty rates.

Operating netback per boe increased 5% in the first quarter of 2017 as compared to the fourth quarter of 2016 due to improvements in commodity prices, increasing liquids and natural gas sales partially offset by realized hedging losses. Higher royalties were due to increases in commodity prices. Combined operating and transportation costs of $10.21 were 5% lower than $10.78 in the fourth quarter of 2016 as a result of increased condensate sold via pipeline and increased utilization of firm service capacity.

Operating netback per boe for the three months ended March 31:

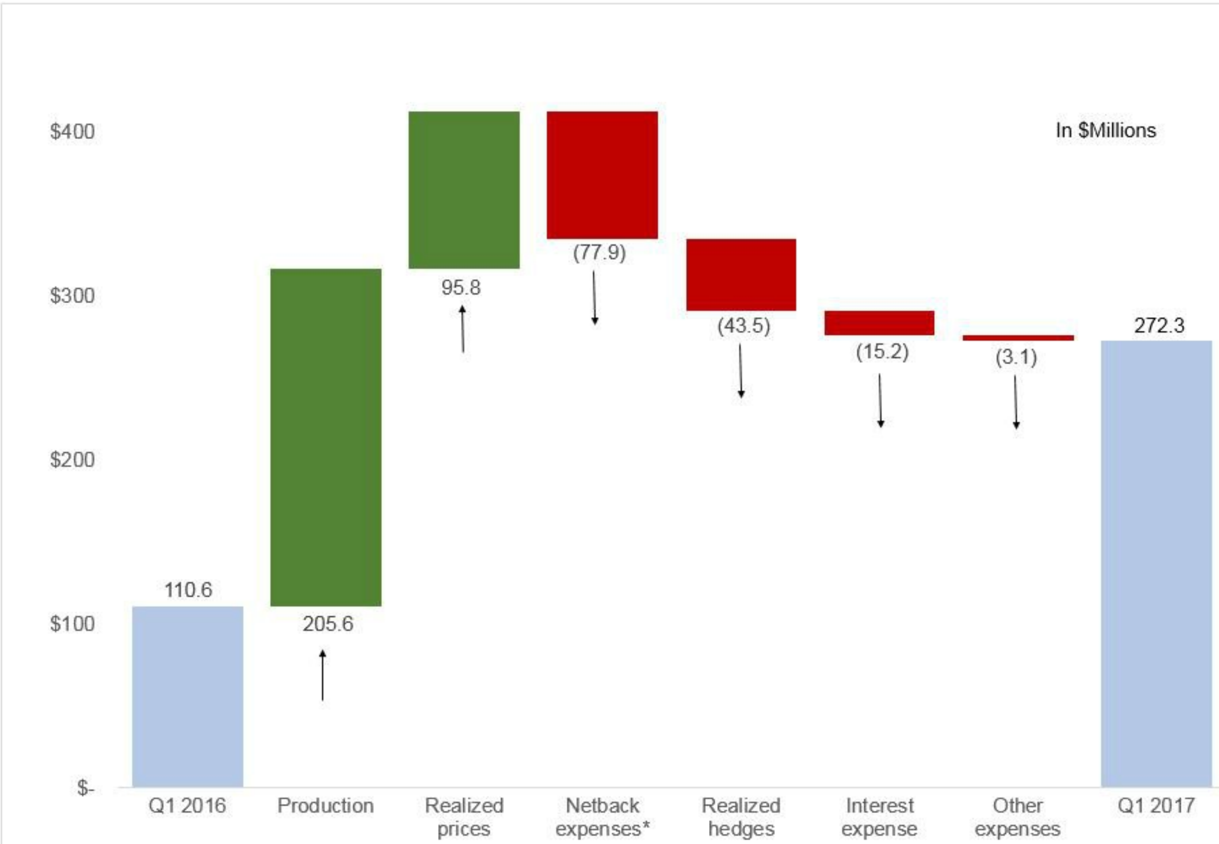


Funds from operations

Funds from operations is a measure of cash flow generated by the Company's operating activities and eliminates the effect of changes in non-cash working capital. Funds from operations increased 146% for the first quarter of 2017 to $272.3 million compared to the first quarter of 2016. The increase was primarily due to significant production growth as well as higher commodity prices partially offset by increases to operating expense, transportation, processing and other expenses and realized hedging losses. Finance expenses were impacted by additional interest expense from senior notes assumed as part of an acquisition in the third quarter of 2016.

Compared to the fourth quarter of 2016, funds from operations were up 24% due to higher liquids and natural gas sales partially offset by realized hedging losses as well as higher royalties and operating expenses.

Funds from operations for the three months ended March 31:



*Netback expenses include royalties, operating expense and transportation, processing and other.

The Company recognized $335.7 million in cash provided by operating activities for the first quarter of 2017, an increase of 88% compared to the fourth quarter of 2016.

Operating income

“Operating income” is a non-IFRS measure which the Company uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating income is net income excluding tax-affected unrealized risk management, unrealized foreign exchange gains and losses, gains on investment in associate and transaction costs on acquisitions. The Company increased operating income to $74.8 million for first quarter of 2017 compared to $9.3 million in the same period of 2016 as a result of significant production and commodity price increases and lower royalties. Higher liquids and natural gas sales were partially offset by increases in transportation, processing and other expenses and operating expenses related to growing activity and volumes. Realized hedging losses resulted from stronger commodity prices as WTI increased by 55% and NYMEX natural gas by 54% compared to the first quarter of 2016.

Operating income of $74.8 million was an increase of $27.2 million, or 57%, relative to the fourth quarter of 2016 due to production growth and higher commodity prices.

Net income (loss)

The Company reported a net income of $215.6 million for the first quarter of 2017 compared to a net income of $138.4 million for the same period in 2016 primarily due to $65.5 million increase in operating income discussed above. In addition, the first quarter of 2017 had $162.8 million of unrealized gains on risk management contracts related to lower future prices (first quarter of 2016 - $44.2 million gains) and $19.7 million of unrealized foreign exchange gains (first quarter of 2016 - $96.4 million gains). On a diluted basis, the Company reported net income per share of $0.59 for the first quarter of 2017.

The Company's net income in the first quarter of 2017 increased from a net loss of $104.9 million in the fourth quarter of 2016 primarily due to unrealized gains resulting from the Company's risk management contracts and increased revenue due to higher production and stronger commodity prices. Since the beginning of the year, the oil futures have decreased resulting in an unrealized gain of $162.8 million in the first quarter of 2017 compared to an unrealized loss of $142.8 million in the fourth quarter of 2016. The Company continues with its disciplined hedging philosophy to support funds from operations.

Capital investments

The Company continued to invest in its Montney assets, deploying capital of $362.3 million in the first quarter of 2017. As announced by the Company in November 2016, capital investment is expected to be between $1.5 billion to $1.6 billion. Drilling and completion operations continue to focus on innovation and efficiencies in order to reduce per well costs. The Company continues to benefit from batch drilling, reducing average spud to rig release time by 13% compared to the first quarter of 2016, utilizing a maximum of 13 rigs in the first quarter. The Company ran two frac spreads through most of the first three months of 2017 and continued to optimize the use of slickwater fracs.

Completions cost for the quarter are consistent with historical costs per tonne. Higher intensity completions, delineation pads, increased water costs and higher pressure pumping rates all lead to an increase in total costs. The first quarter is historically a higher cost quarter due to increased activity along with the cost of operating in colder temperatures. Preliminary production results from the higher intensity fractures are encouraging.

The Company advanced construction on three new Super Pads in the first quarter of 2017. The Company expects these Super Pads to be operational in the second half of 2017. Commissioning of the Karr 2 Stabilizer started at the end of the quarter. The second stabilizer and new Super Pads will support the Company's growing production levels.

The table below illustrates the drilling and completions activity for wells drilled in the Nest for the periods indicated:

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	% Change	2016	% Change
Drilling					
Horizontal wells rig released	**23.0**	15.0	53	12.0	92
Average measured depth (m)	**5,875**	5,936	(1)	5,696	3
Average horizontal length (m)	**2,649**	2,694	(2)	2,511	5
Average drilling days per well	**34**	39	(13)	31	10
Average drilling cost per lateral metre	**$ 1,441**	$ 1,597	(10)	$ 1,405	3
Average well cost ($ millions)	**$ 3.8**	$ 4.3	(12)	$ 3.5	9
Completions					
Wells completed	**14.0**	18.0	(22)	21.0	(33)
Average number of stages per well	**39**	27	44	38	3
Average tonnes per stage	**167**	176	(5)	174	(4)
Average tonnes pumped per well	**6,546**	4,770	37	6,492	1
Average cost per tonne	**$ 1,093**	$ 1,214	(10)	$ 886	23
Average well cost ($ millions)	**$ 7.2**	$ 5.8	24	$ 5.8	24
Total Drilling and Completions cost per well ($ millions)	**$ 11.0**	$ 10.1	9	$ 9.3	18

Daily Production

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
Condensate (mbbls/d)	**46.8**	28.4	65	43.2	8
NGLs (mbbls/d)	**42.2**	22.6	87	33.4	26
Natural gas (MMcf/d)	**384**	225	71	334	15
Total (mboe/d)	**153.1**	88.5	73	132.3	16
Liquids percentage	**58%**	58%	—	58%	—

The Company achieved significant production growth in the first quarter of 2017, averaging 153.1 mboe/d, with liquids production of 89.0 mboe/d (58% of total production) and natural gas production of 384 MMcf/d (42% of total production). For the three months ended March 31, 2017, the Company brought on production 18 wells, increasing its total number of Montney horizontal producing wells to 250 at the end of the quarter.

Well Information

	Three months ended March 31,			Three months ended December 31,	
Number of wells (1)	**2017**	2016	**% Change**	2016	**% Change**
Drilled	**27**	15	80	12	125
Completed	**16**	18	(11)	21	(24)
Brought on production	**18**	11	64	10	80

(1) The well counts include only horizontal Montney wells and exclude wells that are re-drilled or abandoned. Drill counts are based on rig release date and brought on production counts are based on the first production date after the well is tied in to permanent facilities.

The Company increased its pace of development in the first quarter of 2017 by drilling 27 wells and bringing 18 wells on production, an increase of 80% and 64%, respectively, from the same period in 2016. Concurrently, the Company ran two completion spreads and completed 16 wells, 11% lower than the same period in 2016.

Compared to the fourth quarter of 2016, the Company more than doubled the number of wells drilled and brought 80% more wells on production. Fewer wells were completed in the first quarter compared to the fourth quarter of 2016 due to a lower concentration of completions per pad.

At March 31, 2017, Seven Generations had an inventory of 86 wells at various stages of construction between drilling, completion and tie-in and 250 Montney horizontal wells producing within the Kakwa River Project (December 31, 2016 - 72 wells under construction and 117 wells producing).

Commodity Pricing

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
Average Benchmark Prices					
Oil – WTI (US$/bbl)	**51.78**	33.45	55	49.29	5
Natural gas - NYMEX (US$/MMbtu)	**3.06**	1.99	54	3.18	(4)
Natural gas - Chicago Citygate (US$/MMbtu) (1)	**3.40**	2.25	51	3.00	13
Natural gas – AECO NGX 5A ($/GJ)	**2.55**	1.73	47	2.93	(13)
Average exchange rate – US$ to C$	**0.756**	0.730	4	0.750	1

(1) Represents Chicago Citygate monthly index price.

Benchmark prices and the Canadian dollar were stronger in the first quarter of 2017 compared to the same period in 2016. WTI, Chicago Citygate and AECO prices were higher by 55%, 51% and 47%, respectively, while the Canadian dollar was 4% stronger compared to the US dollar.

In the first quarter of 2017, WTI increased by 5% from the fourth quarter of 2016 and Chicago Citygate also rose 13% to US$3.40/MMbtu. Conversely, AECO prices decreased 13% to $2.55/GJ, while the Canadian dollar strengthened slightly against the US dollar in the first quarter of 2017.

Seven Generations realized the following commodity prices (before hedging):

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
Condensate ($/bbl)	**64.07**	39.92	60	56.96	12
NGLs ($/bbl)	**18.03**	8.96	101	18.23	(1)
Natural gas ($/Mcf)	**4.36**	3.24	35	4.15	5
Total ($/boe)	**35.52**	23.34	52	33.67	5

For the first quarter of 2017, the Company realized a condensate price of $64.07/boe, an increase of 60% compared to the same period in 2016 due to an increase in WTI of 55% and improved differentials for condensate.

Approximately 70% of the Company's NGLs were sold in the US Midwest market and 30% in the Alberta market. The average realized prices for NGLs reflect a combination of prices for ethane, propane, butane and pentanes plus. The Company's product mix of NGLs is approximately 1/3 ethane, 1/3 propane, 1/5 butane and 1/10 pentanes plus. The Company realized $18.03/bbl for its NGL product stream for the first quarter of 2017, higher than the same period in 2016 by 101% mainly due primarily to WTI denominated pentanes plus sales in Alberta and improving propane and butane prices.

Prior to the third quarter of 2016, the Company had no exposure to the AECO market. For the first quarter of 2017, approximately 20% of natural gas volumes for the Company were sold in the Alberta market realizing a natural gas price of $2.21/Mcf, in comparison to the realized natural gas price for the fourth quarter of 2016 for Alberta sales of $3.28/Mcf. The remaining 80% of natural gas volumes have exposure to Chicago Citygate, sold into the US Midwest market realizing a natural gas price of $4.95/Mcf for the first quarter of 2017. US Midwest natural gas prices were higher than the fourth quarter of 2016 natural gas realized price of $4.35/Mcf, mostly due to a 13% increase in Chicago Citygate benchmark pricing.

Compared to the fourth quarter of 2016, the Company's realized condensate price was higher by 12% primarily attributable to improvements in WTI of 5% and improving condensate differentials.

Liquids and natural gas sales

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
($ millions, except per boe data)					
Condensate	**270.1**	102.0	165	226.4	19
NGLs	**68.5**	19.4	253	56.1	22
Natural gas	**150.8**	66.6	126	127.3	18
Liquids and natural gas sales (1)	**489.4**	188.0	160	409.8	19
Liquids and natural gas sales per boe	**$ 35.52**	$ 23.34	52	$ 33.67	5

(1) Excluding realized and unrealized gains or losses on risk management contracts.

For the first quarter of 2017, the Company generated $489.4 million of liquids and natural gas sales, a significant increase over the same period in 2016. Increased production volumes account for $204.3 million of the variance and $97.1 million is due to stronger commodity pricing.

Compared to the fourth quarter of 2016, the Company's liquids and natural gas sales increased by 19% in the first quarter of 2017 due to a 16% increase in production volumes in addition to higher realized prices. Production volumes account for $57.6 million of the variance while stronger commodity prices account for $22.0 million of the variance.

Risk Management Contracts

Seven Generations continues to execute its mechanistic risk management program. The Company hedges oil and natural gas production and exchange rates to support funds from operations through a three year rolling hedging program. Price targets are established at levels that are expected to provide a minimum rate of return on capital investment based on a combination of projected well performance and capital efficiencies. The Company is authorized to hedge up to 65% of forecasted condensate and natural gas production volumes (net of royalties) for the upcoming four quarters, up to 35% of forecasted volumes for the subsequent four quarters and up to 20% for the four quarters following.

The Company's risk management program resulted in the following:

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
($ millions, except per boe data)					
Realized (loss) gain (1)	**(7.2)**	36.3	nm	5.8	nm
Unrealized gain (loss) (2)	**162.8**	44.2	nm	(142.8)	nm
Risk management gain (loss)	**155.6**	80.5	93	(137.0)	nm
Realized (loss) gain per boe	**$ (0.52)**	$ 4.50	nm	$ 0.48	nm

(1) Represents actual cash settlements or receipts under the respective contracts.
(2) Represents the change in fair value of the contracts during the period.

First quarter realized hedge losses were $7.2 million compared to $36.3 million for realized hedge gains in the same period in 2016 as a result of stronger benchmark prices in the first quarter of 2017.

As at March 31, 2017, the fair value of the risk management contracts increased to a net asset position of $14.5 million (December 31, 2016 – net liability position of $149.4 million) due to lower futures prices since the beginning of 2017, and the realization of losses on lower priced hedges entered in during 2016. The fair value of unsettled derivatives is recorded as an asset or liability with the change in the mark-to-market position of contracts recorded as an unrealized gain or loss in the condensed interim consolidated statements of income and comprehensive income.

The Company had the following risk management contracts in place at March 31, 2017:

	Crude Oil				**Natural Gas**				**Foreign Exchange**	
	WTI Collars		**WTI 3 Way Collars**		**Chicago Citygate Swaps**		**AECO 7A Collars**		**CAD/USD Swaps**	
Period	**bbl/d**	**C$/bbl**	**bbl/d**	**C$/bbl**	**MMbtu/d**	**US$/ MMbtu**	**GJ/d**	**C$/GJ**	**USD $MM**	**US$/C$**
2017 remainder	15,000	$63.98 - $78.10	9,000	$41.11/$56.67/$76.83	166,667	$3.03	53,333	$2.50 - $3.03	138.7	1.3039
2018	14,250	$61.81 - $78.40	12,000	$40.83/$56.25/$75.54	135,000	$2.91	50,000	$2.50 - $2.99	143.0	1.3262
2019	8,500	$60.00 - $79.75	6,000	$41.25/$56.67/$77.15	50,000	$2.95	50,000	$2.50 - $2.99	53.6	1.3111
2020	500	$60.00 - $79.95	—	—	—	—	—	—	—	—

Royalty Expense

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
($ millions, except per boe data)					
Royalties	**16.8**	13.0	29	11.9	41
Royalties per boe	**$ 1.22**	$ 1.61	(24)	$ 0.98	24
Effective royalty rate	**3%**	7%	(57)	3%	—

For the first quarter of 2017, royalties were $16.8 million, an increase of 29% compared to the same period in 2016 attributable to the significant increase in revenue partially offset by lower royalty rates related to a change in field condensate royalty reporting.

Royalties in the first quarter of 2017 were 41% higher compared to royalties of $11.9 million recorded in the fourth quarter of 2016 due to higher production as well as stronger commodity prices.

The effective royalty rate decreased 57% compared to the same period in 2016 due to a change in reporting of field condensate production resulting in lower royalty rates as well as new wells realizing benefits from Crown incentive programs.

Operating Expenses

		Three months ended March 31,			Three months ended December 31,	
		2017	2016	**% Change**	2016	**% Change**
($ millions, except per boe data)						
Trucking and disposal		**24.6**	9.8	151	23.5	5
Equipment rental and maintenance		**25.6**	9.7	164	15.7	63
Chemicals and fuel		**8.5**	5.9	44	6.7	27
Staff and contractor costs (1)		**7.4**	3.8	95	9.6	(23)
Other		**2.7**	1.8	50	3.6	(25)
Operating expenses		**68.8**	31.0	122	59.1	16
Operating expenses per boe	**$**	**4.99**	$ 3.85	30	$ 4.86	3

(1) The Company incurred $9.1 million of field staff and contractor costs for the three months ended March 31, 2017 (three months ended March 31, 2016 – $5.7 million), of which $7.4 million (three months ended March 31, 2016 – $3.8 million) was recorded as staff and contractor costs in operating expense and $1.7 million was capitalized to oil and natural gas assets (three months ended March 31, 2016 – $1.9 million). Staff and contractor costs include salaries, benefits and contractor costs.

Operating expenses increased to $68.8 million in the first quarter of 2017 primarily due to 73% production growth compared to the same period in 2016. Early in 2016, the Company shifted to the use of slickwater fracking which increases water trucking and disposal costs. Equipment rentals were higher due to the increased use of testers as permanent facilities are built and to assess type curves in areas outside the core of the Nest.

Compared to the fourth quarter of 2016, operating expenses increased 16% mostly due to increased production levels achieved in the first quarter of 2017 and temporary production facility usage. Staff and contractor costs decreased in the first quarter compared to the fourth quarter due to the use of more employees rather than contractors. For the three months ended March 31, 2017, operating expenses per boe were $4.99, up 3% from the fourth quarter of 2016 due to increased testing equipment.

Transportation, Processing and Other Expenses

		Three months ended March 31,			Three months ended December 31,	
		2017	2016	**% Change**	2016	**% Change**
($ millions, except per boe data)						
Pipeline tariffs		**50.6**	30.0	69	49.9	1
Processing		**11.9**	0.1	nm	11.0	8
Trucking and other		**11.8**	9.8	20	16.1	(27)
Marketing gains (1)		**(2.3)**	(4.2)	(45)	(5.0)	(54)
Transportation, processing and other		**72.0**	35.7	102	72.0	—
Transportation, processing and other per boe	**$**	**5.22**	$ 4.43	18	$ 5.92	(12)

(1) Comparative figures have been reclassified to conform to current period presentation.

Transportation, processing and other expense were $72.0 million for the first quarter of 2017, an increase of $36.3 million from the same period in 2016 due primarily to processing expenses related to fees charged on volumes processed through the Pembina Kakwa River Plant, a processing agreement assumed as part of an acquisition in the third quarter of 2016. Increases in production lead to higher pipeline tariffs.

Marketing gains relate to a margin earned from optimizing Seven Generations' capacity on the Alliance Pipeline. For the first quarter of 2017, marketing gains decreased by 45% to $2.3 million as a result of the Company utilizing more of the firm service capacity available due to production growth.

Compared to the fourth quarter of 2016, transportation, processing and other expenses decreased by 12% per boe due to a decrease in trucking costs as the Company maximized available firm service pipeline capacity and sold a higher percentage of condensate via pipeline.

General and Administrative ("G&A") Expenses

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	% Change	2016	% Change
($ millions, except per boe data)					
Personnel	**7.8**	5.9	32	6.6	18
Office costs, travel and other	**2.9**	2.6	12	3.4	(15)
Onerous lease	**—**	—	—	3.6	(100)
Professional fees	**1.2**	0.4	200	0.7	71
Information technology costs	**0.9**	0.8	13	0.5	80
Transaction costs	**—**	—	—	0.3	(100)
Gross G&A expenses	**12.8**	9.7	32	15.1	(15)
Capitalized salaries and benefits	**(1.3)**	(1.1)	18	(0.1)	nm
Operating overhead recoveries	**(0.6)**	(0.5)	20	(0.6)	—
G&A expenses	**10.9**	8.1	35	14.4	(24)
G&A per boe	**$ 0.79**	$ 1.00	(21)	$ 1.18	(33)

Gross G&A expenses increased by 32% to $12.8 million for the first quarter of 2017 relative to the same period in 2016 due to an increase in personnel costs as a result of increased staff count and professional fees to support the Company's growth. Net G&A per boe decreased by 21% to $0.79 per boe due to an increase in production and the Company's continued efforts to maintain a low cost structure.

Relative to the fourth quarter of 2016, G&A expenses were lower in the first quarter of 2017 attributable to a non-recurring onerous lease provision of $3.6 million and transaction costs of $0.3 million in 2016. During the fourth quarter, the Company consolidated its Calgary employees resulting in unused office space. The onerous lease amount represents the Company's estimate of the present value of the difference between the minimum future lease payments and estimated sublease recoveries.

For the first quarter of 2017, capitalized staff costs were $1.3 million, an increase of 18% from the same period of 2016 primarily due to an increase in personnel partially offset by a lower capitalization rate in 2017. Capitalized staff costs relate to personnel directly involved with the capital and infrastructure development of the Kakwa River Project.

Depletion, Depreciation and Amortization

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	% Change	2016	% Change
($ millions, except per boe data)					
Depletion, depreciation and amortization	**157.1**	89.3	76	139.1	13
Depletion, depreciation and amortization per boe	**$ 11.40**	11.08	3	11.43	—

Depletion, depreciation and amortization was $157.1 million for the first quarter of 2017, up 76% over the same period in 2016, attributable to an increased depletable reserve base including estimated future development costs and increased production volumes. Included in the total depletion, depreciation and amortization is $2.1 million of depreciation expense for the first quarter of 2017, an increase of $0.7 million from the same period in 2016, and related to the Company's natural gas plants at Lator and Cutbank, which are depreciated over their estimated useful life. The Lator 2 Plant became operational at the end of 2015 while the Cutbank Plant was commissioned at the end of the first quarter of 2016.

Depletion, depreciation and amortization per barrel of $11.40 per boe for the first quarter of 2017 was consistent with the fourth quarter of 2016.

Stock Based Compensation

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
($ millions, except per boe data)					
Gross stock based compensation	**8.6**	6.9	25	8.3	4
Capitalized stock based compensation	**(2.6)**	(2.1)	24	(2.5)	4
Stock based compensation expense	**6.0**	4.8	25	5.8	3
Stock based compensation per boe	**$ 0.44**	$ 0.60	(27)	$ 0.48	(8)

Stock based compensation is a non-cash expense. The fair value of stock based compensation is calculated using the Black-Scholes pricing model using estimates including the expected life of the instruments, stock price volatility and interest rates. The value of a stock option is calculated on the date of grant and that value is applied throughout the vesting period of the instrument. Values are not restated for subsequent changes in estimated volatility rates, interest rates or underlying market values of the Company's shares. Capitalized stock based compensation is attributable to personnel involved with the capital and infrastructure development of the Kakwa River Project.

Stock based compensation expense for the first quarter of 2017 increased by 25% to $6.0 million attributable to increased fair values with a higher stock price and new grants as compared to the same period in 2016.

Fourth quarter of 2016 stock based compensation expense was higher than the first quarter of 2017 by 3% due to new grants issued in the first three months of 2017.

Finance Expense

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
($ millions, except per boe data)					
Interest on senior notes	**40.6**	29.3	39	39.5	3
Revolving credit facility fees and other	**1.4**	1.2	17	1.9	(26)
Amortization of premium and debt issue costs	**0.3**	0.1	200	—	100
Accretion	**1.0**	0.4	150	1.5	(33)
Total finance costs	**43.3**	31.0	40	42.9	1
Capitalized borrowing costs	**—**	(3.7)	(100)	—	—
Finance expense	**43.3**	27.3	59	42.9	1
Finance expense - per boe	**$ 3.14**	$ 3.39	(7)	$ 3.53	(11)

Finance expense for the first quarter of 2017 increased 59% to $43.3 million primarily due to $12.2 million (US$9.2 million) of additional interest on notes assumed as part of an acquisition in the third quarter of 2016. Higher standby fees resulted from an increase in the credit facility in the third quarter of 2016 to $1.1 billion from $850.0 million.

First quarter finance expense was consistent with the fourth quarter of 2016 but lower on a boe basis due to higher production.

For the first quarter of 2016, the Company capitalized interest and financing costs of $3.7 million, related to the Cutbank natural gas processing facility, which came on-stream at the end of March 2016. Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use.

Foreign Exchange (Gain) Loss

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
($ millions, except exchange rates)					
Unrealized foreign exchange (gain) loss on senior notes	**(19.8)**	(96.7)	(80)	47.7	nm
Unrealized foreign exchange gain on cash held in foreign currencies	**0.7**	0.4	75	0.5	40
Realized foreign exchange (gain) loss	**(0.6)**	(0.3)	100	0.7	nm
Net foreign exchange (gain) loss	**(19.7)**	(96.6)	(80)	48.9	nm
Exchange rate movement	**0.006**	0.049	(88)	(0.018)	(133)
Average exchange rate – US$ to C$	**0.756**	0.730	4	0.750	1

Unrealized foreign exchange gain (loss) mostly relates to the senior notes, denominated in US dollars, with maturity in 2020 (US$700.0 million, bearing interest at 8.25%) and 2023 (US$425.0 million, bearing interest at 6.75%; US$450.0 million, bearing interest at 6.875%), respectively.

First quarter net foreign exchange gains decreased 80% to $19.7 million compared to the same period in 2016 primarily due to decreased exchange rate movement impacting foreign exchange on the senior notes through the first three months of 2017 compared to a strengthening Canadian dollar in the same period in 2016.

The strengthening of the Canadian dollar resulted in an unrealized foreign exchange gain on the senior notes of $19.8 million in the first quarter of 2017 compared to a $47.7 million unrealized foreign exchange loss on a weaker Canadian dollar in the fourth quarter 2016.

Realized foreign exchange gains and losses relate to the actual conversion of US dollars to Canadian dollars and the settlement of transactions denominated in US dollars including revenue and expenditures in the US market. Total realized foreign exchange gains were $0.6 million for the three months ended March 31, 2017 ($0.3 million for the three months ended March 31, 2016).

Investment in Steelhead LNG

In the third quarter of 2016, the Company invested $25.8 million in Steelhead LNG Limited Partnership ("Steelhead LNG") for a 34.0% equity interest, which is reported in the consolidated financial statements using the equity method of accounting given the judgment that Seven Generations has significant influence.

Steelhead LNG also granted Seven Generations an option to increase its ownership interest to 50%, subject to certain conditions, which terminates upon the earlier of (i) one year from the Company's investment in Steelhead LNG and (ii) thirty days from Steelhead LNG signing a binding offtake agreement that meets certain thresholds.

Steelhead LNG is a Vancouver-based energy company focused on the development of LNG projects in British Columbia.

For the three months ended March 31, 2017, the Company's share of Steelhead LNG's net loss was $1.8 million recognized in market access initiatives in the condensed interim consolidated statement of income and comprehensive income.

Market access initiatives with Steelhead LNG

Concurrent with the investment in Steelhead LNG, the Company entered into a development arrangement with Steelhead LNG, in which the Company agreed to contribute $3.0 million in cash and committed to invest up to $9.0 million to participate in the pre-development of transportation alternatives to the west coast of British Columbia. In February 2017, the Company amended the terms of its agreement with Steelhead LNG to provide funds for general corporate matters and accordingly was issued additional equity units of Steelhead LNG, increasing its equity interest to 36.5%.

At March 31, 2017, the Company had incurred $1.5 million of the $9.0 million committed funds, of which $0.9 million was recognized in market access initiatives in the condensed interim consolidated statement of income and comprehensive income for the three months ended March 31, 2017 (year ended December 31, 2016 - $0.6 million).

Steelhead LNG and Seven Generations have also entered into an option agreement under which Seven Generations has an option to supply natural gas to any LNG facility developed by Steelhead LNG on the west coast of British Columbia upon fulfillment of certain terms and conditions.

Due to common directorships and certain significant shareholders, these transactions were considered related party transactions and measured at the exchange value. Azimuth Capital Management ("Azimuth") has a majority ownership in Steelhead LNG. Three of Seven Generations' directors have professional ties to Azimuth.

At the end of each reporting period, the Company reviews for impairment indicators to ensure that the carrying value of its investments in associates is recoverable. At March 31, 2017, there were no indicators of impairment regarding the Company's investment in Steelhead LNG.

Investment in Associate	
Balance at December 31, 2015	—
Cash contribution for equity interest	25.8
Equity share of net loss	(3.9)
Balance at December 31, 2016	21.9
Equity share of net loss	(1.8)
Gain on issue of equity interest	3.0
Balance at March 31, 2017	**23.1**

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
Pre-development expenditures	**0.9**	—	100	1.1	(18)
Non-cash items:					
Equity share of net loss	**1.8**	—	100	2.2	(18)
Gain on issue of equity interest	**(3.0)**	—	100	—	(100)
Market access initiatives	**(0.3)**	**—**	100	3.3	(109)

Capital Investments

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
Land and other (1)	**5.1**	6.9	(26)	2.0	155
Drilling and completions	**259.1**	152.6	70	186.7	39
Facilities and equipment	**98.1**	107.6	(9)	94.9	3
Total capital investments	**362.3**	267.1	36	283.6	28

(1) Other includes capitalized salaries and benefits, capitalized interest and office investments.

Total capital investment in the first quarter of 2017 increased by 36% to $362.3 million relative to the same period in 2016 as the Company focused on executing its capital plan for fiscal 2017. The Company's well count included 27 rig released wells and 16 wells completed in the first quarter of 2017. Metrics for 2017 first quarter wells drilled include an average cost of $1,441 per lateral meter, a decrease of 10% from the same period in 2016 due partially to fewer drilling days, with an average depth of 5,875 meters and an average horizontal length of 2,649 meters. Completion costs per tonne of $1,093 were consistent with historical costs and 10% lower than the first quarter of 2016. Completions intensity of frac spreads continued to increase with an average number of stages per well of 39 and 6,546 tonnes pumped per well. The Company continuously strives to reduce unit costs. Total drilling and completion per well costs were 9% higher than in the first quarter of 2016, coming in at $11.0 million (drilling - $3.8 million; completions - $7.2 million) with higher intensity completions and delineation pads in the first quarter of 2017.

The Company advanced front-end engineering design for the construction of the Company's new natural gas processing plant, which is planned to have a first train of 250 MMcf/d of processing capacity. Construction is expected to commence in the second quarter of 2017 with first production in mid-2018.

The Company started the construction of three new Super Pads in the first quarter of 2017. The Company expects these Super Pads to be operational in the second half of 2017. Seven Generations' Super Pads are designed to facilitate raw gas dehydration and free liquid separation from the liquids-rich natural gas, enabling a steady flow of production. The Company is adapting its field facility designs for the properties that were acquired in the third quarter of 2016 to incorporate some of the proven technology and design concepts that have been effective elsewhere in the Kakwa River Project.

Compared to the fourth quarter of 2016, capital investments increased 28% in the first quarter due to more drilling activity and an increase in facilities infrastructure related to new Super Pads construction and advancements in the planning of the new natural gas processing plant.

Seven Generations controls approximately 514,000 net acres of Montney land (over 542,000 net acres of land overall) with an average working interest of 96% on approximately 803 net Montney sections.

LIQUIDITY AND CAPITAL RESOURCES

The capital structure of the Company is as follows:

	March 31, 2017	December 31, 2016
Net debt [1]	**1,594.1**	1,528.8
Market capitalization [2]	**8,549.4**	10,968.7
Total capitalization	**10,143.5**	12,497.5

(1) See "Non-IFRS Financial Measures".
(2) Market capitalization is calculated using the total Common Shares outstanding at March 31, 2017 multiplied by the closing share price of $24.30 at March 31, 2017 (closing share price of $31.31 at December 31, 2016).

The Company manages capital by maintaining a strong liquidity position and focusing on financial strength through a prudent balance of debt and equity in its capital structure and taking into account the level of risk being incurred in its capital investments. Due to the high quality, large size and long life of its assets, the Company aligns its goals and strategic objectives with investors that share a longer-term time horizon. The Company's business plan targets a trailing ratio of net debt to funds from operations of less than 2.0; the ratio was 1.8 for the twelve months ended March 31, 2017 (year ended December 31, 2016 - 2.1).

In the third quarter of 2016, the Company's lenders agreed to increase the borrowing capacity of the senior secured revolving credit arrangement from $850.0 million to $1.1 billion. At March 31, 2017, the credit facility was undrawn.

The Company has US$425.0 million of 6.75% senior notes, due in 2023, US$700 million of 8.25% senior notes, due in 2020 and US$450 million of 6.875% senior notes, due in 2023. Subject to certain exceptions and qualifications, the senior notes have no financial covenants but limit the Company's ability to, among other things: make payments and distributions; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; make certain dispositions; transfer assets; and engage in amalgamations, mergers or consolidations. At March 31, 2017, the Company was in compliance with the covenants on the senior notes.

At March 31, 2017, the Company had available funding of $1.5 billion. The Company's capital investments for 2017 are expected to be between $1.5 billion and $1.6 billion. The Company strives to grow and maximize long-term shareholder value by ensuring it has the financing capacity to fund projects that are expected to add value to shareholders. The 2017 capital investment program will continue to focus development of the Kakwa River Project. The Company plans to fund these investments from cash on hand and funds from operations.

Financial instrument classification and measurement

The Company's financial instruments include cash and cash equivalents, accounts receivable, deposits, risk management contracts, accounts payable and accrued liabilities, the credit facility and senior notes.

The Company's financial instruments that are carried at fair value on the balance sheets include cash and cash equivalents and risk management contracts. The senior notes are carried at amortized cost, net of transaction costs and accrete to the principal balance on maturity using the effective interest rate method. The fair value of senior notes is approximately $2,192.6 million as at March 31, 2017 (December 31, 2016 - $2,254.0 million).

Seven Generations classifies the fair value of these instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information.
- Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed in the marketplace.
- Level 3 - Valuations in this level are those inputs for the asset or liability that are not based on observable market data.

Cash and cash equivalents are classified as Level 1 measurements. Risk management contracts and fair value disclosure for the senior notes are classified as Level 2 measurements. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. Seven Generations does not have any fair value measurements classified as Level 3. There were no transfers within the hierarchy in the three months ended March 31, 2017 and 2016. The carrying value of the Company's accounts receivable, deposits, accounts payable and accrued liabilities approximate their fair values due to the short-term maturity of these instruments.

Financial assets and financial liabilities subject to offsetting

The Company's risk management contracts are subject to master netting agreements that create a legally enforceable right of counterparties, which could have an impact on the related financial assets and financial liabilities on the Company's balance sheet. The following is a summary of financial assets and financial liabilities that are subject to offset:

March 31, 2017	Gross amounts of recognized financial assets (liabilities)	Gross amounts of recognized financial assets (liabilities) offset in balance sheet	Net amounts of recognized financial assets (liabilities) recognized in balance sheet
Risk management contracts			
Current asset	**13.3**	**(6.9)**	**6.4**
Long-term asset	**25.7**	**(10.5)**	**15.2**
Current liability	**(12.0)**	**6.9**	**(5.1)**
Long-term liability	**(12.5)**	**10.5**	**(2.0)**
Net position	**14.5**	**—**	**14.5**

December 31, 2016	Gross amounts of recognized financial assets (liabilities)	Gross amounts of recognized financial assets (liabilities) offset in balance sheet	Net amounts of recognized financial assets (liabilities) recognized in balance sheet
Risk management contracts			
Current asset	1.5	(1.5)	—
Long-term asset	3.6	(3.6)	—
Current liability	(73.2)	1.5	(71.7)
Long-term liability	(81.3)	3.6	(77.7)
Net position	(149.4)	—	(149.4)

The following is a summary of the carrying value of risk management contracts in place by contract type:

	March 31, 2017	December 31, 2016
Natural gas	**9.2**	(70.0)
Oil	**5.9**	(71.0)
Foreign exchange swap	**(0.6)**	(8.4)
Net position asset (liability)	**14.5**	(149.4)

OFF-BALANCE SHEET ARRANGEMENTS

The Company has certain fixed lease arrangements which were entered into in the normal course of operations. All material leases are classified as operating leases and the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. These arrangements are disclosed in Note 19 to the condensed interim consolidated financial statements of the Company. No asset or liability has been recorded for these leases on the balance sheet at March 31, 2017 or 2016.

The Company enters into physical delivery contracts in its various gas markets on month-to-month and term contract basis. Pricing of the physical delivery contracts is primarily based on published North American natural gas indices and fixed prices. These instruments are not used for trading or speculative purposes. These contracts are considered normal sales contracts and are not recorded at fair value in the consolidated financial statements.

The following table illustrates the average daily volumes the Company has committed to deliver on a term contract basis as at March 31, 2017:

	Alliance Chicago Exchange	AECO Hub	Gulf Coast
Contracts expiring in the year ended December 31,	**MMBtu/d**	**GJ/d**	**MMBtu/d**
2017	195,000	31,670	40,000
2018	19,167	21,600	33,333
2019	—	19,800	—

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of Class B Common Non-Voting Shares without nominal or par value. As of the date of this MD&A, Seven Generations had 352,904,958 Common Shares (and no other shares), 12,505,746 stock options, 9,644,828 performance warrants, 359,727 Performance Share Units ("PSUs"), 221,055 Restricted Share Units and 114,281 Deferred Share Units outstanding.

The vesting of PSUs are conditional on the satisfaction of certain performance criteria as determined by the Company's Board of Directors. If the Company satisfies the performance criteria, PSUs become eligible to vest and a pre-determined multiplier is applied to eligible PSUs. In calculating stock based compensation for the PSUs the Company used an adjustment factor of 1.0, which assumed that the Company will be within the 50% percentile of its relative peer group, based on total shareholder return at the respective vesting dates. Upon vest date in the second quarter of 2016, the performance criteria for the first tranche of vested PSUs met the highest performance multiplier of 2.0 for total shareholder return criteria relative to the Company's peer group resulting in an additional 48,817 Common Shares being issuable upon the redemption of these PSUs. The second tranche of PSUs will vest in the second quarter of 2017. Assuming the highest performance multiplier, as at March 31, 2017, the maximum number of Common Shares issuable pertaining to the outstanding PSUs is 631,622.

CONTRACTUAL OBLIGATIONS

Seven Generations enters into contractual obligations in the ordinary course of conducting its business. The following table lists the Company's estimated material contractual obligations at March 31, 2017:

	Total	2017 Remaining	2018	2019	2020	2021	2022 & Thereafter
Senior notes (1)	**2,094.6**	—	—	—	930.9	—	1,163.7
Interest on senior notes	**768.3**	156.1	156.1	156.1	108.1	79.3	112.6
Firm transportation and processing agreements (2)	**4,334.1**	286.7	442.9	462.0	475.8	486.4	2,180.3
Office leases	**25.0**	3.3	4.3	3.6	3.5	3.5	6.8
Estimated contractual obligations	**7,222.0**	446.1	603.3	621.7	1,518.3	569.2	3,463.4

(1) Balance represents US$1.6 billion principal converted to Canadian dollars at the closing exchange rate for the period end.
(2) Subject to completion of certain pipeline and facility upgrades by a counterparty transportation company.

The following table outlines the take or pay obligations, on average over the next five years under the Company's significant transportation and processing agreements:

	2017 Remaining	2018	2019	2020	2021	Expiring[1]
Transportation						
Condensate						
Pembina (mbbls/d)	33.2	42.2	42.4	49	55.3	June 30, 2030
Natural gas						
Alliance (MMcf/d)	445	475	508	508	508	October 31, 2025
NGTL Receipt (MMcf/d) [2]	158	293	368	363	349	June 30, 2026
NGTL Delivery (MMcf/d) [2]	18	80	80	80	80	October 31, 2022
TCPL Mainline (MMcf/d)	17	77	77	77	77	October 31, 2027
NGPL (MMcf/d) [3]	100	83	—	—	—	October 31, 2018
NGLs						
Pembina (mbbls/d) [4]	17.1	19.8	19.8	22.3	24.8	June 30, 2030
Processing						
Natural gas (MMcf/d) [4]	158	173	193	200	200	April 20, 2036
NGLs (mbbls/d)	37.5	34.9	33.8	33.8	33.8	March 31, 2028

(1) When lines include multiple contracts of various expiration dates, the latest expiration date has been referenced.
(2) The timing of the firm commitments under the agreement with NGTL, a wholly owned subsidiary of TCPL, is dependent upon the completion of NGTL system expansion, which is expected mid-2018.
(3) Natural Gas Pipeline Company of America LLC ("NGPL").
(4) The timing of the firm commitments under the agreement with Pembina Pipeline Corporation ("Pembina") is dependent upon the completion of the Phase 3 expansion, which is expected July 1, 2017.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

A summary of the Company’s significant accounting policies can be found in Notes 3 and 4 to the audited consolidated financial statements for the years ended December 31, 2016 and 2015. The preparation of consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, income and expenses. The financial and operating results of Seven Generations incorporate certain estimates including:

- estimated revenues, royalties and operating expenses on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and amortization charges that are based on estimates of oil and natural gas reserves, and future costs to develop those reserves, that Seven Generations expects to recover in the future;
- estimated fair values of financial instruments that are subject to fluctuation depending on the underlying commodity prices, foreign exchange rates and interest rates, volatility curves and the risk of non-performance;
- estimated value of decommissioning obligations that are dependent upon estimates of future costs and timing of expenditures;
- estimated future recoverable value of oil and natural gas properties and goodwill and any associated impairment charges or recoveries; and
- estimated compensation expense under Seven Generations’ stock based compensation plans.

Seven Generations employs individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates. For further information on the determination of certain estimates inherent in the consolidated financial statements, refer to Note 5 “Significant Accounting Judgments, Estimates and Assumptions” in the audited consolidated financial statements for the years ended December 31, 2016 and 2015.

RISK ASSESSMENT

The acquisition, exploration and development of oil and natural gas properties and the production, transportation and marketing of oil and natural gas involves many risks, which may influence the ultimate success of the Company. While the management of Seven Generations realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks. These risks include, but are not limited to the following:

- 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;
- 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 of 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;
- governmental regulations;
- changes in the interpretation and enforcement of applicable laws and regulations;
- environmental, health and safety requirements;
- 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 for litigation;
- variation in future calculations of non-IFRS measures;
- sufficiency of internal controls;
- breach of agreements by third parties 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 senior notes and other indebtedness.

For additional information regarding the risks that the Company is exposed to, see the disclosure provided under the heading “Risk Factors” in the AIF, which is available on the SEDAR website at www.sedar.com.

CHANGES IN ACCOUNTING POLICIES

Changes in accounting policies

The Company adopted IAS 7 "Statement of Cash Flows" and IAS 12 "Income Taxes" during the three months ended March 31, 2017 with no material impact on the Company's consolidated financial statements.

Future accounting policy changes

In February 2014, the IASB issued IFRS 9 "Financial Instruments", which replaces IAS 39, "Financial Instruments: Recognition and Measurement" for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 includes a principle-based approach for classification and measurement of financial assets, a single expected loss impairment model and a substantially-reformed approach to hedge accounting. The impact of the standard has been evaluated and is expected to have no material impact on the Company’s consolidated financial statements.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue", IAS 11 "Construction Contracts" and related interpretations. In July 2015, the IASB issued an amendment to IFRS 15, deferring the effective date by one year and is required to be adopted either retrospectively or using a modified transition approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The impact of the standard has been evaluated and is expected to have no material impact on the Company’s consolidated financial statements. Additional disclosure may be required upon implementation of IFRS 15 in order to provide sufficient information to enable users to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from the contracts with customers.

In January 2016, the IASB issued IFRS 16 "Leases" which replaces IAS 17 "Leases" for annual periods beginning on or after January 1, 2019, with earlier application permitted if IFRS 15 "Revenue from Contracts with Customers" is also applied. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a 'right-of-use asset' for virtually all lease contracts. The Company is currently evaluating the impact of the standard on the consolidated financial statements.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified under applicable securities legislation.

Internal Control over Financial Reporting

The CEO and the CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The CEO and CFO are required to cause the Company to disclose any change in the Company's internal controls over financial reporting that occurred during the most recent interim period, January 1, 2017 to March 31, 2017, that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No changes in internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that while Seven Generations' officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the control system will prevent all errors or fraud.

NON-IFRS FINANCIAL MEASURES

This MD&A 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", "adjusted working capital", "available funding" and "net debt". The data presented is 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 audited consolidated financial statements and the accompanying notes.

Readers are cautioned that the non-IFRS measures do not have any standardized meaning and should not be used to make comparisons between the Company and other companies without also taking into account any differences in the way the calculations were prepared.

Funds from Operations

"Funds from operations" is a financial measure not presented in accordance with IFRS and is equal to cash provided by operating activities adjusted for changes in non-cash operating working capital. The Company uses funds from operations as an integral part of its internal reporting to measure its performance and it is considered an important indicator of the operational strength of the Company's business. Funds from operations is a measure of the cash flow generated by the Company's operating activities and eliminates the effect of changes in non-cash working capital, which is included in cash flow provided by operating activities. Funds from operations is not intended to be a performance measure that should be regarded as an alternative to, or more meaningful than, either net income as an indicator of operating performance, or cash flow from operating activities as a measure of liquidity. In addition, funds from operations is not intended to represent funds available for dividends, reinvestment or other discretionary uses.

The following table reconciles the cash flow from operating activities to funds from operations:

	Three months ended March 31,			Three months ended December 31,	
	2017	2016	**% Change**	2016	**% Change**
Cash provided by operating activities	**335.7**	144.5	132	178.7	88
Changes in non-cash working capital	**(63.4)**	(33.9)	87	41.0	(255)
Funds from operations	**272.3**	110.6	146	219.7	24

Operating Income

"Operating income" is a non-IFRS measure which the Company uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating income is defined as net income (loss), excluding unrealized gains and losses on risk management contracts, unrealized foreign exchange gains and losses, gains and losses on disposition of assets, transaction costs and the respective income tax impact of those adjustments.

The following table reconciles the net income to operating income:

	Three months ended March 31,		Three months ended December 31,
	2017	2016	2016
Net income (loss) for the period	**215.6**	138.4	(104.9)
Unrealized (gains) losses - risk management contracts (1)	**(162.8)**	(44.2)	142.8
Unrealized foreign exchange (gains) losses (2)	**(19.7)**	(96.8)	47.7
Gain on investment in associate (3)	**(3.0)**	—	—
Transaction costs (4)	**—**	—	0.3
Deferred tax (recovery) expense relating to these adjustments	**44.7**	11.9	(38.3)
Operating income	**74.8**	9.3	47.6

(1) Unrealized gains/losses on risk management contracts result from the fair market valuation of the hedge contracts as at March 31.
(2) Unrealized foreign exchange gains and losses result from the translation of the US$ denominated senior notes and cash and cash equivalents using period end exchange rates.
(3) Gain resulting from investment in associate.
(4) Transaction costs from acquisition.

Operating Netback

"Operating netback" is calculated on a per boe basis and is determined by deducting royalties, operating and transportation, processing and other expenses from oil and natural gas revenue and, except where otherwise indicated, after adjusting for realized hedging gains or losses. Operating netback is utilized by the Company and others to better analyze the operating performance of its oil and natural gas assets.

Adjusted Working Capital and Available Funding

"Available funding" is comprised of adjusted working capital and the undrawn credit facility capacity, less any cash held as collateral for letters of credit. "Adjusted working capital" is comprised of current assets less current liabilities and excludes current portion of risk management contracts. The available funding measure allows management and other users to evaluate the Company's short term liquidity. A summary of the reconciliation of available funding is set forth below:

	March 31, 2017	December 31, 2016
Current assets	**838.9**	830.4
Current liabilities	**(337.1)**	(316.2)
Working capital	**501.8**	514.2
Adjusted for:		
Current asset - risk management contracts	**(6.4)**	—
Current liability - risk management contracts	**5.1**	71.7
Adjusted working capital	**500.5**	585.9
Undrawn credit facility capacity	**1,100.0**	1,100.0
Cash collateral for letters of credit	**(59.6)**	(59.2)
Available funding	**1,540.9**	1,626.7

Net Debt

"Net debt" is a financial measure not presented in accordance with IFRS and is equal to long-term debt less adjusted working capital surplus. Long-term debt for the senior notes is calculated as the principal amount outstanding converted to Canadian dollars at the closing exchange rate for the period, and excludes unamortized premiums and debt issue costs. Adjusted working capital is calculated as current assets less current liabilities as they appear on the balance sheets, and excludes current unrealized risk management contracts and deferred credits. The Company uses net debt to assess liquidity and general financial strength. Net debt should not be considered an alternative to, or more meaningful than, current assets or current liabilities as determined in accordance with IFRS.

The following table presents a calculation of the non-IFRS financial measure of net debt:

	March 31, 2017	December 31, 2016
Senior notes at amortized cost	**2,092.1**	2,111.9
Unamortized premium and debt issue costs	**2.5**	2.8
Senior notes principal	**2,094.6**	2,114.7
Less:		
Adjusted working capital	**(500.5)**	(585.9)
Net debt	**1,594.1**	1,528.8

SELECTED QUARTERLY INFORMATION

For the quarterly periods in 2017, 2016 and 2015, the Company's total production has steadily increased over the past eight quarters due to a successful drilling program with added production from an acquisition of Montney assets in 2016. The Company has continued to see positive funds from operations despite a volatile commodity price environment.

Total capital investments have fluctuated primarily due to the timing of investments in drilling and infrastructure development. The Company's balance sheet has remained strong with total assets continuing to increase proportionately higher in comparison to debt outstanding.

Changes to comparative quarter periods between 2017, 2016 and 2015, net income (loss) are attributable to variations in operating income as the Company's operations grow and mature as well as unrealized hedging fluctuations and the impact of foreign exchange changes on the US dollar denominated senior notes.

SELECTED QUARTERLY INFORMATION - continued

	Q4 2017	Q3 2017	Q2 2017	**Q1 2017**	YTD 2017
FINANCIAL ($ millions, except per share amounts, production rates and unit prices)					
Liquids and natural gas revenues				**489.4**	489.4
Realized hedging loss				**(7.2)**	(7.2)
Interest, processing and third party income				**1.6**	1.6
Royalties				**(16.8)**	(16.8)
Operating expenses				**(68.8)**	(68.8)
Transportation, processing and other				**(72.0)**	(72.0)
General and administrative (2)				**(10.9)**	(10.9)
Interest expense (2)				**(42.0)**	(42.0)
Foreign exchange loss (2)				**0.6**	0.6
Other				**(1.6)**	(1.6)
Funds from operations (1)				**272.3**	272.3
Per share – diluted				**0.75**	0.75
Operating income (1)				**74.8**	74.8
Per share – diluted				**0.21**	0.21
Net income (loss)				**215.6**	215.6
Per share – diluted				**0.59**	0.59
Capital investments:					
Land and other				**5.1**	5.1
Drilling and completions				**259.1**	259.1
Facilities and equipment				**98.1**	98.1
Total capital investments				**362.3**	362.3
Total assets				**6,851.0**	6,851.0
Available funding (1)				**1,540.9**	1,540.9
Net debt (1)				**1,594.1**	1,594.1
Debt outstanding				**2,092.1**	2,092.1
OPERATING					
Average daily production					
Oil and condensate (mbbls/d)				**46.8**	46.8
NGLs (mbbls/d)				**42.2**	42.2
Natural gas (MMcf/d)				**384**	384
Total (mboe/d)				**153.1**	153.1
Realized prices					
Oil and condensate ($/bbl)				**64.07**	64.07
NGLs ($/bbl)				**18.03**	18.03
Natural gas ($/Mcf)				**4.36**	4.36
OPERATING NETBACK (1) ($/boe)					
Liquids and natural gas revenues				**$ 35.52**	$ 35.52
Realized hedging loss				**(0.52)**	(0.52)
Royalties				**(1.22)**	(1.22)
Operating expenses				**(4.99)**	(4.99)
Transportation, processing and other				**(5.22)**	(5.22)
Operating netback after hedging				**$ 23.57**	$ 23.57

(1) See "Non-IFRS Financial Measures".
(2) Excludes non-cash items.

SELECTED QUARTERLY INFORMATION - continued

	Q4 2016	Q3 2016	Q2 2016	Q1 2016	YE 2016
FINANCIAL ($ millions, except per share amounts, production rates and unit prices)					
Liquids and natural gas revenues	409.8	361.7	287.4	188.0	1,246.9
Realized hedging gains	5.8	19.2	29.5	36.3	90.8
Interest, processing and third party income	1.3	1.5	1.1	0.8	4.7
Royalties (2)	(11.9)	(0.4)	18.6	(13.0)	(6.7)
Operating expenses	(59.1)	(47.0)	(44.8)	(31.0)	(181.9)
Transportation, processing and other	(72.0)	(74.7)	(56.2)	(35.7)	(238.6)
General and administrative (3)	(10.8)	(14.7)	(10.0)	(8.0)	(43.5)
Interest expense (3)	(41.3)	(37.7)	(29.2)	(26.9)	(135.1)
Foreign exchange loss (3)	(0.7)	0.3	1.7	0.2	1.5
Other	(1.4)	(3.5)	(0.5)	(0.1)	(5.5)
Funds from operations (1)	219.7	204.7	197.6	110.6	732.6
Per share – diluted	0.60	0.62	0.66	0.40	2.30
Operating income (1)	47.6	47.7	56.0	9.3	160.6
Per share – diluted	0.13	0.15	0.19	0.03	0.50
Net income (loss)	(104.9)	(2.2)	(57.5)	138.4	(26.2)
Per share – diluted	(0.30)	(0.01)	(0.21)	0.50	(0.09)
Capital investments:					
Land and other	2.0	3.9	3.6	7.1	16.6
Drilling and completions	186.7	133.4	125.0	152.6	597.7
Facilities and equipment	94.9	70.5	90.7	107.6	363.7
Total capital investments (before acquisitions)	283.6	207.8	219.3	267.3	978.0
Total assets	6,602.4	6,401.2	4,004.5	4,126.2	6,602.4
Available funding (1)	1,626.7	1,673.4	1,246.1	1,260.4	1,626.7
Net debt (1)	1,528.8	1,436.6	1,020.1	1,013.4	1,528.8
Debt outstanding	2,111.9	2,063.0	1,443.9	1,451.5	2,111.9
OPERATING					
Average daily production					
Oil and condensate (mbbls/d)	43.2	46.5	38.8	28.4	39.3
NGLs (mbbls/d)	33.4	33.8	30.2	22.6	30.0
Natural gas (MMcf/d)	334	314	290	225	291
Total (mboe/d)	132.3	132.6	117.4	88.5	117.8
Realized prices					
Oil and condensate ($/bbl)	56.96	49.93	52.05	39.92	50.59
NGLs ($/bbl)	18.23	11.23	12.49	8.96	13.08
Natural gas ($/Mcf)	4.15	3.92	2.62	3.24	3.53
OPERATING NETBACK (1) ($/boe)					
Liquids and natural gas revenues	$ 33.67	$ 29.65	$ 26.91	$ 23.34	$ 28.92
Realized hedging gain	0.48	1.57	2.77	4.50	2.11
Royalties	(0.98)	(0.03)	1.74	(1.61)	(0.16)
Operating expenses	(4.86)	(3.85)	(4.20)	(3.85)	(4.22)
Transportation, processing and other(3)	(5.92)	(6.12)	(5.26)	(4.43)	(5.53)
Operating netback after hedging	$ 22.39	$ 21.22	$ 21.96	$ 17.95	$ 21.12

(1) See “Non-IFRS Financial Measures”.

(2) Includes $27.4 million ($20.0 million after tax) of prior period royalty recoveries for the year ended December 31, 2016, recognized in Q2 2016.

(3) Excludes non-cash items.

SELECTED QUARTERLY INFORMATION - continued

	Q4 2015 [2]	Q3 2015	Q2 2015	Q1 2015	YE 2015
FINANCIAL ($ millions, except per share amounts, production rates and unit prices)					
Liquids and natural gas revenues	178.5	149.7	155.2	108.5	591.9
Realized hedging gain	23.0	35.3	41.7	50.6	150.6
Interest, processing and third party income	1.6	1.7	1.7	1.7	6.7
Royalties	(12.1)	(17.7)	(12.9)	(15.2)	(57.9)
Operating expenses	(29.4)	(26.8)	(23.5)	(21.5)	(101.2)
Transportation, processing and other	(22.7)	(13.5)	(9.9)	(12.9)	(59.0)
General and administrative	(7.2)	(5.4)	(5.1)	(6.6)	(24.3)
Interest expense [2]	(29.1)	(28.2)	(24.9)	(18.0)	(100.2)
Foreign exchange loss and other [2]	3.4	(0.2)	4.5	0.3	8.0
Funds from operations [1]	106.0	94.9	126.8	86.9	414.6
Per share – diluted	0.39	0.35	0.47	0.32	1.53
Operating income (loss) [1]	(14.2)	13.8	28.5	24.0	52.1
Per share – diluted	(0.05)	0.05	0.11	0.09	0.19
Net loss	(28.9)	(53.7)	(22.0)	(82.7)	(187.3)
Per share – diluted	(0.11)	(0.21)	(0.09)	(0.34)	(0.75)
Capital investments:					
Land and other	5.8	5.0	3.6	2.8	17.2
Drilling and completions	181.1	145.6	222.2	264.9	813.8
Facilities and equipment	114.2	134.5	128.6	100.7	478.0
Total capital investments	301.1	285.1	354.4	368.4	1,309.0
Total assets	3,758.9	3,707.7	3,559.8	3,170.4	3,758.9
Available funding [1]	1,118.0	1,141.2	1,326.0	861.4	1,118.0
Net debt [1]	1,250.9	989.8	710.2	505.2	1,250.9
Debt outstanding	1,546.8	1,491.2	1,395.5	888.4	1,546.8
OPERATING					
Average daily production					
Oil and condensate (mbbls/d)	25.6	22.6	20.7	15.8	21.2
NGLs (mbbls/d)	19.2	14.1	11.9	12.0	14.3
Natural gas (MMcf/d)	197	143	130	125	149
Total (mboe/d)	77.7	60.6	54.2	48.8	60.4
Realized prices					
Oil and condensate ($/bbl)	46.72	49.18	60.29	47.59	50.84
NGLs ($/bbl)	12.35	7.99	9.78	10.41	10.34
Natural gas ($/Mcf)	2.57	2.81	2.63	2.62	2.65
OPERATING NETBACK [1] ($/boe)					
Liquids and natural gas revenues	24.97	26.86	31.45	24.73	26.84
Realized hedging gain	3.22	6.32	8.45	11.54	6.83
Royalties	(1.69)	(3.18)	(2.61)	(3.46)	(2.63)
Operating expenses	(4.11)	(4.81)	(4.77)	(4.89)	(4.59)
Transportation, processing and other[2]	(3.30)	(2.42)	(2.00)	(2.95)	(2.68)
Operating netback after hedging	$ 19.09	$ 22.77	$ 30.52	$ 24.97	$ 23.77

(1) See "Non-IFRS Financial Measures".
(2) Excludes non-cash items.

Forward-Looking Information Advisory

This document 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 document contains forward-looking information and statements pertaining to the following: the Company's strategies, objectives and competitive strengths; the ability to remain as one of North America's lowest supply cost unconventional natural gas developers through innovation, the application of technology and increased efficiency; the generation of positive free cash flow, the achievement of cash flow self-sufficiency and full-cycle returns on capital employed across the entire commodity cycle; focussed capital deployment on high return opportunities with hedged economics; the pursuit of market access opportunities; the ability to capture premium markets for the Company's production; anticipated transportation and processing capacity, including the contracted capacity with TCPL for access to the Dawn market in Ontario which is subject to National Energy Board approval; expectation that the three new Super Pads that are currently being constructed will be operational in the second half of 2017; the expectation that the Karr 2 condensate stabilizer will improve condensate quality and lead to better pricing; expectation that the Company's hedging program will provide for threshold rates of return on the Company's capital investments; the anticipated capacity of the new natural gas processing plant that is being planned and the anticipated timing of the commencement of construction and first production for that facility; sources of funding; achievement of the Company's growth objectives; forecast production and capital investments; the Company's targeted net debt to funds flow ratio of less than 2.0 times; the expected completion of the planned NGTL system expansion in mid-2018 and the Pembina Phase 3 expansion in July of 2017; hedging targets; and the Company's estimates of its future obligations under the heading "Contractual Obligations".

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 AIF) after factoring in quality adjustments at the Company's points of sale; 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 as part of the acquisition; 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 positive free cash flow and full-cycle returns on the capital that is deployed, key assumptions were made, including: the anticipated impact of the significant asset 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 assets acquired 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. With respect to statements regarding the Company's ability to secure premium markets for the Company's production, assumptions have been made regarding the laws and regulations governing such initiatives pertaining to taxation, the environment, aboriginal peoples, Crown royalty rates and incentive programs relating to the oil and gas industry.

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; 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.

Any financial outlook and future-oriented financial information contained in this document regarding prospective financial performance, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action based on management's assessment of the relevant information that is currently available. Projected operational information contains forward-looking information and is based on a number of material assumptions and factors, as are set out above. These projections may also be considered to contain future oriented financial information or a financial outlook. The actual results of the Company's operations for any period will likely vary from the amounts set forth in these projections and such variations may be material. Actual results will vary from projected results. Readers are cautioned that any such financial outlook and future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein. The forward-looking information and statements contained in this document speak only as of the date hereof and the Company does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Definitions and Abbreviations

Terms and abbreviations that are used in this MD&A that are not otherwise defined herein are provided below:

AECO	physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
bbl or bbls	barrel or barrels
boe	barrels of oil equivalent(1)
C$ or CAD	Canadian dollars
d	day
GJ	gigajoules
LNG	liquefied natural gas
mbbls	thousands of barrels(1)
mboe	thousands of barrels of oil equivalent(1)
LNG	liquefied natural gas
m	metres
Mcf	thousand cubic feet
MMBtu	million British thermal units
MMcf	million cubic feet

Nest	means the primary development block of the Kakwa River Project.
NGLs	natural gas liquids
NGX	Natural Gas Exchange Inc.
nm	not meaningful information
NYMEX	New York Mercantile Exchange
OPEC	Organization of Petroleum Exporting Countries
Q1	first quarter of the year
Q2	second quarter of the year
Q3	third quarter of the year
Q4	fourth quarter of the year
Super Pads	the Company's decentralized field conditioning plants that separate field condensate and natural gas
TSX	Toronto Stock Exchange
US$ or USD	United States dollars
WTI	West Texas Intermediate
$MM	millions of dollars

(1) 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.