MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A"), dated August 7, 2015, is management's assessment of the historical financial position and results of Seven Generations Energy Ltd. (the "Company" or "Seven Generations") for the period ended June 30, 2015. This MD&A should be read in conjunction with the MD&A for the year ended December 31, 2014, the audited annual financial statements and notes thereto for the years ended December 31, 2014 and 2013 (the "financial statements") and the unaudited interim financial statements and notes thereto for the three and six months ended June 30, 2015. These financial statements, including the comparative figures, were prepared in accordance with the International Financial Reporting Standards ("IFRS"). Unless otherwise noted, all financial measures are expressed in Canadian dollars and tabular dollar amounts are in thousands. See "Non-IFRS Financial Measures" for information regarding the following non-IFRS financial measures used in this MD&A: "funds from operations", "operating income", "operating netback", "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 page of this MD&A. Additional information about Seven Generations is available on SEDAR at www.sedar.com, including the Company's Annual Information Form dated March 10, 2015 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "VII".

ABOUT SEVEN GENERATIONS ENERGY LTD.

Seven Generations is an independent petroleum company focused on the acquisition, development and value optimization of high quality tight and shale hydrocarbon resource plays. Presently, the Company has a single focus area, which is a large-scale, tight, liquids-rich natural gas property in the Kakwa area of northwest Alberta with approximately 421,000 net Montney acres in the Kakwa River Project (the "Project"). Seven Generations has established the Project's economic viability and is at an early stage of a multi-decade development of the Project. The Company is focused on (i) the development of our large inventory of relatively low supply cost, liquids-rich horizontal well drilling opportunities in the Project; (ii) building facilities to gather and process the produced natural gas, condensate and other natural gas liquids ("NGLs"); and (iii) establishing further opportunities to maximize value.

Seven Generations differentiates itself based on the following core attributes:

- **Quality of Resource** – the upper and middle intervals of the Triassic Montney formation in the Project have emerged as a highly economic play, comparing favourably to other North American tight, liquids-rich natural gas plays based on the low break-even natural gas and liquids prices required for the Company to earn a minimum rate of return. Horizontal wells in the primary development block of the Project have exhibited high production rates of natural gas, condensate and other NGLs;

- **Size of Resource** – Seven Generations controls approximately 421,000 net acres of Montney land (over 437,000 net acres of lands overall) with an average working interest of 99%, which are estimated by McDaniel & Associates Consultants Ltd. ("McDaniel"), the Company's independent qualified reserves evaluator, to hold approximately 400 drilling locations assigned to proved reserves and approximately 200 drilling locations assigned to probable reserves. As at December 31, 2014, McDaniel estimated gross proved plus probable reserves of 788.6 MMboe (approximately 53% of which is condensate and other NGLs) for which it has assessed a net present value (before tax, discounted at 10% and based on McDaniel's forecast prices at the effective date of the estimate) of approximately $7.1 billion;

- **Location and Market Access** – the Company's lands are close to key infrastructure and take-away capacity, including the Alliance and Pembina Peace pipelines, on which it has contracted firm transportation capacity for natural gas, condensate, other NGLs and oil;

- **Control over Operations** – Seven Generations operates approximately 96% of its land and it owns a 100% working interest in its facilities and gathering systems; and

- **Ability to Execute** – the Company has assembled a highly skilled technical and business team with a specialized expertise in resource play identification, capture, development and production. The team has a track record of growing production, reserves and funds from operations and enhancing project economics through technical innovation. The Company's ability to deliver on its high growth objectives is supported by existing marketing and transportation agreements for the first 500 MMcf/d of natural gas production and approximately 40,000 bbls/d of condensate and other NGLs production.

SELECTED FINANCIAL INFORMATION

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per share and volume data)						
Funds from operations [1]	**126,795**	65,972	**92**	**213,684**	120,136	78
Funds from operations per share [1] [2]	**0.47**	0.31	**52**	**0.79**	0.56	41
Operating netback after hedging per boe [1]	**30.52**	39.88	**(24)**	**27.90**	39.21	(29)
Operating income [1]	**28,485**	18,253	**56**	**52,483**	42,735	23
Net income (loss) and comprehensive income (loss)	**(21,950)**	43,926	**(150)**	**(104,648)**	45,090	(332)
Net income (loss) per share [2]	**(0.09)**	0.20	**(145)**	**(0.42)**	0.21	(300)

(1) See "Non-IFRS Financial Measures".
(2) Per share amounts are based on weighted average shares, diluted.

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2015**	2014	**2015**	2014
INCOME STATEMENT				
Oil and natural gas sales	**155,183**	120,749	**263,723**	219,486
Royalties	**(12,886)**	(9,434)	**(28,067)**	(14,820)
	142,297	111,315	**235,656**	204,666
Risk management contracts – realized gain (loss)	**41,683**	(6,873)	**92,338**	(12,278)
Risk management contracts – unrealized loss	**(68,920)**	(1,960)	**(110,012)**	(15,397)
Interest and third party income	**1,744**	1,025	**3,429**	1,936
	116,804	103,507	**221,411**	178,927
Operating expense	**23,537**	9,659	**44,991**	21,050
Transportation expense	**9,893**	7,693	**22,859**	14,319
General and administrative expense	**5,136**	5,233	**11,765**	8,408
Depletion, depreciation and amortization expense	**67,117**	31,280	**127,160**	55,315
Stock based compensation expense	**3,613**	2,742	**6,565**	4,509
Finance expense	**25,290**	16,446	**43,317**	30,245
Foreign exchange loss (gain)	**2,430**	(23,364)	**71,094**	(10,946)
Gain on disposition of assets	**(2,602)**	(1,845)	**(2,602)**	(4,285)
	134,414	47,844	**325,149**	118,615
Income (loss) before taxes	**(17,610)**	55,663	**(103,738)**	60,312
Deferred income tax expense	**4,340**	11,737	**910**	15,222
Net income (loss) and comprehensive income (loss)	**(21,950)**	43,926	**(104,648)**	45,090
Net income (loss) per share – basic	**(0.09)**	0.23	**(0.42)**	0.24
Net income (loss) per share – diluted	**(0.09)**	0.20	**(0.42)**	0.21

WELL INFORMATION

	Three months ended June 30,			Six months ended June 30,		
Number of wells	**2015**	2014	**% Change**	**2015**	2014	**% Change**
Drilled – gross (net)	**17 (17.0)**	15 (15.0)	13	**40 (39.5)**	25 (25.0)	60
Completed – gross (net)	**23 (22.5)**	12 (12.0)	92	**39 (38.5)**	18 (18.0)	117
Brought on production – gross (net)	**23 (23.0)**	2 (2.0)	1,050	**38 (38.0)**	9 (9.0)	322

The well counts include only horizontal Montney wells. Drill counts are based on the rig release date and brought on production counts are based on the first production date after the well is tied in. At June 30, 2015, Seven Generations had an inventory of approximately 51 wells at various stages of construction between drilling, completions and tie in and 79 Montney horizontal wells producing within the Project.

RESULTS OF OPERATIONS

Funds from Operations, Operating Income and Net Income (Loss)

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per share amounts)						
Funds from operations	**126,795**	65,972	92	**213,684**	120,136	78
Per share – basic	**0.51**	0.35	46	**0.86**	0.64	34
Per share – diluted	**0.47**	0.31	52	**0.79**	0.56	41
Operating income	**28,485**	18,253	56	**52,483**	42,735	23
Per share – basic	**0.11**	0.10	10	**0.21**	0.21	-
Per share – diluted	**0.11**	0.09	22	**0.19**	0.20	(5)
Net income (loss)	**(21,950)**	43,926	(150)	**(104,648)**	45,090	(332)
Per share – basic	**(0.09)**	0.23	(139)	**(0.42)**	0.24	(275)
Per share – diluted	**(0.09)**	0.20	(145)	**(0.42)**	0.21	(300)

Funds from operations increased by $60.8 million in the second quarter of 2015 to $126.8 million compared to $66.0 million in the same period of 2014. The increase was mostly due to higher production volumes offset by lower netbacks due to lower commodity pricing. Higher interest expense also impacted funds from operations in the second quarter of 2015. For the first half of 2015, funds from operations was $213.7 million, an increase of 78% compared to $120.1 million in the same period in 2014.

For the second quarter of 2015, operating income was $28.5 million compared to $18.3 million in the same period of 2014. Operating income increased by $10.2 million mostly due to higher funds from operations offset by increased depletion charges due to higher production volumes. For the six months ended June 30, 2015, operating income was $52.5 million compared to $42.7 million in the same period of 2014, an increase of 23%.

The Company had a net loss of $22.0 million for the second quarter of 2015 compared to net income of $43.9 million in the comparative 2014 period. In addition to the items impacting operating income noted above, the lower net income was impacted by the weak Canadian dollar resulting in higher unrealized foreign exchange losses on the senior notes and unrealized losses on the risk management contracts. In the first six months of 2015, the Company's net loss was $104.6 million (net loss per share basis, diluted - $0.42) compared to the same period in 2014, which had net income of $45.1 million (net income per share basis, diluted - $0.21), largely impacted by the weaker Canadian dollar and lower commodity price environment.

Daily Production

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Condensate (bbls/d)	**20,702**	9,264	123	**18,269**	8,414	117
NGLs (bbls/d)	**11,914**	4,742	151	**11,978**	4,399	172
Natural gas (MMcf/d)	**130**	60	117	**128**	56	129
Total (boe/d)	**54,219**	23,999	126	**51,509**	22,125	133
Liquids ratio	**60%**	58%	3	**59%**	58%	2

The Company's production for the second quarter of 2015 averaged 54,219 boe/d, which represents a 126% increase over average production of 23,999 boe/d in the second quarter of 2014 and an 11% increase from the first quarter of 2015 which averaged 48,768 boe/d. The Company continued its pace of Kakwa Montney drilling and infrastructure capital investments in the second quarter of 2015, which translated into record production levels.

Commodity Pricing

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Average Benchmark Prices						
Oil – WTI (US$/bbl)	**57.94**	102.96	(44)	**53.26**	100.82	(47)
Oil – Edmonton Par ($/bbl)	**66.95**	106.62	(37)	**58.68**	103.40	(43)
Natural gas – AECO NGX 5A ($/mcf)	**2.65**	4.69	(43)	**2.70**	5.16	(48)
Average exchange rate – (C$ to US$)	**0.813**	0.917	(11)	**0.809**	0.912	(11)

The Company realized the following commodity prices (before hedging):

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Condensate and oil ($/bbl)	**60.29**	97.32	(38)	**54.83**	95.22	(42)
NGLs ($/bbl)	**9.78**	24.15	(60)	**10.10**	26.03	(61)
Natural gas ($/mcf)	**2.63**	5.18	(49)	**2.62**	5.00	(48)
Total ($/boe)	**31.45**	55.29	(43)	**28.29**	54.81	(48)

Realized pricing for the quarter averaged $31.45/boe reflecting an increase in benchmark oil pricing, a main driver of condensate pricing, when compared to pricing during the first quarter of 2015. The broader Alberta condensate market experienced some temporary weakness in pricing during the second quarter as demand softened from local oil sands operations that were taken offline for short periods of time in response to Northern Alberta forest fires. As NGL prices softened during the second quarter of 2015, the Company realized NGL pricing of $9.78/bbl, $0.63/bbl lower than the first quarter of 2015. NGL revenues will continue to be exposed to midcontinent benchmark pricing due to the current Aux Sable extraction agreement.

The Company's average realized price for oil and condensate decreased in the second quarter of 2015 by 38% to $60.29/bbl compared to $97.32/bbl for the same period in 2014. For the first half of 2015, the average realized price for oil and condensate decreased by 42% to $54.83/bbl compared to the same period in 2014. The Company anticipates being able to pipeline a portion of its volumes for the remainder of 2015 on a firm basis and will likely have higher transportation charges and lower realizations on a portion of production that is trucked. The oil and condensate prices realized by the Company reflect the global decline of commodity prices since the second quarter of 2014.

The average realized prices for NGLs reflect a combination of prices for NGLs such as ethane, propane, butane and pentane. The Company's average realized prices decreased for this product stream in the second quarter of 2015 by 60% to $9.78/bbl compared to $24.15/bbl for the same period in 2014. For the first six months of 2015, the average realized prices for NGLs were $10.10/bbl compared to $26.03/bbl for the same period in 2014. The product mix of NGLs is approximately 1/3 ethane, 1/3 propane, 1/5 butane and the remainder is pentane. Approximately 90% of the Company's NGLs are ultimately sold in the Illinois market and 10% in the Alberta market.

The Company's average realized natural gas price decreased by 49% in the second quarter of 2015 to $2.63/mcf compared to $5.18/mcf in 2014. For the six months ended June 30, 2015, the Company's received an average realized natural gas price of $2.62/mcf, a decrease of 48% from $5.00/mcf for the same period in 2014. The Company receives a blend of pricing based on AECO monthly and daily benchmark indexes, with adjustments for heat content. The relative pricing between these two indexes has fluctuated throughout the year. The decreases in realized pricing that Seven Generations has experienced, directly correlate to the decrease in AECO benchmark prices.

Revenues

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Condensate and oil	**113,592**	82,049	38	**181,299**	145,011	25
NGLs	**10,608**	10,418	2	**20,021**	20,725	(3)
Natural gas	**30,983**	28,282	10	**62,403**	53,750	16
Total revenues (1)	**155,183**	120,749	29	**263,723**	219,486	20
Per boe	**31.45**	55.29	(43)	**28.29**	54.81	(48)

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

Revenues increased by $34.5 million to $155.2 million despite significant global commodity price declines in the second quarter of 2015 compared to $120.7 million in the same period of 2014. The increase in revenues is due to higher production volumes ($86.5 million) offset by lower commodity prices ($52.0 million). For the first half of 2015, the increase in revenues by 20% to $263.7 million compared to the same period in 2014 is due to higher production volumes ($150.4 million) offset by lower commodity prices ($106.2 million).

Risk Management Contracts

The Company utilizes financial commodity hedges to ensure sufficient revenue exists to cover interest payments on debt and to partially protect funds from operations against commodity price volatility. The Company also utilizes foreign exchange hedges to mitigate currency exposure on US dollar natural gas hedges.

The Company has hedge targets of up to 55% of forecasted production volumes (net of royalties) for the upcoming four quarters, up to 30% of forecasted volumes for the successive four quarters and up to 15% for the four quarters following that. Price targets are established that will provide a threshold rate of return on capital investment based on a combination of benchmark oil and gas prices, projected well performance and capital efficiencies.

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

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Realized gain (loss)	**41,683**	(6,873)	706	**92,338**	(12,278)	852
Unrealized loss	**(68,920)**	(1,960)	3,416	**(110,012)**	(15,397)	615
Total loss	**(27,237)**	(8,833)	208	**(17,674)**	(27,675)	(36)
Realized gain(loss) per boe	**8.45**	(3.15)	368	**9.90**	(3.07)	422

The fair value of unsettled financial instruments is recorded as an asset or liability with the change in value recorded as an unrealized gain or loss in the statements of income and comprehensive income. As at June 30, 2015, the fair value of the risk management contracts was a net asset position of $29.1 million (December 31, 2014 – asset of $139.1 million). Realized gains and losses on these contracts are recognized on the monthly settlement of the contracts. For the second quarter of 2015, the increase in realized gains of $48.6 million compared to the same period in 2014 is due to gains on both the oil and natural gas contracts in place. The Company's risk management position helped to offset commodity price declines in the second quarter of 2015. For the first six months of 2015, the Company had realized gains of $92.3 million compared to a realized loss for the same period in 2014 of $12.3 million.

The Company had the following risk management contracts in place at June 30, 2015:

Commodity	Period	Notional	Average Price/Unit (1)
Natural gas (2)	**Q3 2015**	63,500 GJ/d	C$3.75
Natural gas (2)	**Q4 2015**	73,500 GJ/d	C$3.75
Natural gas (2)	**Q1 2016**	17,500 GJ/d	C$3.79
Natural gas (3)	**Q1 2016**	80,000 MMBtu/d	US$3.22
Natural gas (3)	**Q2 2016**	80,000 MMBtu/d	US$3.22
Natural gas (3)	**Q3 2016**	80,000 MMBtu/d	US$3.22
Natural gas (3)	**Q4 2016**	80,000 MMBtu/d	US$3.22
Natural gas (3)	**Q1 2017**	70,000 MMBtu/d	US$3.28
Natural gas (3)	**Q2 2017**	30,000 MMBtu/d	US$3.26
Oil	**Q3 2015**	7,600 bbls/d	C$101.20
Oil	**Q4 2015**	7,100 bbls/d	C$78.95 - $87.35
Oil	**Q1 2016**	12,000 bbls/d	C$70.00 - $80.89
Oil	**Q2 2016**	12,000 bbls/d	C$70.00 - $80.89
Oil	**Q3 2016**	12,000 bbls/d	C$70.00 - $80.89
Oil	**Q4 2016**	12,000 bbls/d	C$70.00 - $80.89
Oil	**Q1 2017**	9,000 bbls/d	C$70.00 - $84.05
Oil	**Q2 2017**	3,000 bbls/d	C$70.00 - $85.78
Foreign exchange swap (4)	**Q1 2016**	US$23.4 million	C$1.24
Foreign exchange swap (4)	**Q2 2016**	US$23.4 million	C$1.24
Foreign exchange swap (4)	**Q3 2016**	US$23.7 million	C$1.24
Foreign exchange swap (4)	**Q4 2016**	US$23.7 million	C$1.24
Foreign exchange swap (4)	**Q1 2017**	US$20.8 million	C$1.23
Foreign exchange swap (4)	**Q2 2017**	US$8.9 million	C$1.23

(1) For collar contracts, the minimum price has been used in calculating the average for the above table.
(2) AECO gas price.
(3) Chicago Citygate gas price.
(4) US Dollar sales.

For further details regarding the outstanding contracts, refer to Note 14 of the unaudited condensed interim financial statements.

Royalty Expense

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per unit amounts)						
Gross royalties	**15,337**	10,345	48	**31,309**	16,480	90
Gas cost allowance ("GCA")	**(2,451)**	(911)	169	**(3,242)**	(1,660)	95
Net royalties	**12,886**	9,434	37	**28,067**	14,820	89
Per boe	**2.61**	4.32	(40)	**3.01**	3.70	(19)
Effective royalty rate - net	**8%**	8%	-	**11%**	7%	57

Gross royalty expense in the second quarter of 2015 was $15.3 million compared to $10.3 million in 2014 mainly due to higher production. On a net basis, royalty expense was $12.9 million in the second quarter of 2015 compared to $9.4 million for the comparative period in 2014. The average royalty rate as a percentage of revenues for the second quarters of 2015 and 2014 was 8%. The new Montney wells on production qualify for various royalty incentives for a period of time. The percentage of the Company's total production eligible for incentives at any one time will vary depending on the timing that new wells are brought on production and the volumes produced by those wells.

For the first six months of 2015, net royalty expense was $28.1 million compared to $14.8 million for the same period in 2014 for the same reasons discussed above. The Company expects the annual effective royalty rate in 2015 to be 10%-12% due to new wells commencing production that will qualify for royalty incentives.

For the three months ended June 30, 2015, GCA was $2.5 million compared to $0.9 million for the same period in 2014. For the first half of 2015, GCA was $3.2 million, an increase of 95% over the same period in 2014. GCA deductions are estimated during a production year, and are subject to adjustment usually in the second quarter of the following year after actual cost filings have been processed by the Alberta Crown. GCA deductions are largely based on amortization of historical costs, and therefore do not necessarily remain constant on a per unit or percentage of revenue basis.

Interest and Third Party Income

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per unit amounts)						
Interest and other income	**1,450**	782	85	**2,750**	1,408	95
Processing and third party income	**294**	243	21	**679**	528	29
Total	**1,744**	1,025	70	**3,429**	1,936	77
Per boe	**0.35**	0.47	(26)	**0.37**	0.48	(23)

For the second quarter of 2015, the average cash balances held by the Company were higher due to the Company's debt financing that closed early in the second quarter of 2015 for net proceeds of $504.4 million. This contributed to higher interest and other income for the three months ended June 30, 2015 increasing by $0.7 million to $1.5 million compared to $0.8 million in the second quarter of 2014. For the first six months of 2015, interest and other income was $2.8 million compared to $1.4 million for the same period in 2014 due to higher average cash balances related to the Company's initial public offering ("IPO") financing that closed in November 2014 for net proceeds of $880.1 million.

For the three and six months ended June 30, 2015, processing and third party income increased to $0.3 million and $0.7 million from $0.2 million and $0.5 million, respectively, in the same periods in 2014, mainly due to higher volumes from third party wells using Seven Generations' facilities.

Operating Expenses

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per unit amounts)						
Operating expenses	**23,537**	9,659	144	**44,991**	21,050	114
Per boe	**4.77**	4.42	8	**4.83**	5.26	(8)

Operating expenses increased by $13.8 million to $23.5 million in the second quarter of 2015 compared to $9.7 million in the same period of 2014. Operating expenses are higher as a result of more rental equipment and temporary facility costs related to 23 wells brought on production in the second quarter of 2015. For the first half of 2015, operating expenses were $45.0 million compared to $21.1 million for the comparative period of 2014 due to higher liquids production and field activity levels, with 38 new wells on production in 2015 compared to 9 wells for the same period of 2014.

Operating expenses per boe have been relatively consistent at less than $5.00 per boe.

Transportation Expenses

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per unit amounts)						
Transportation expenses	**9,893**	7,693	29	**22,859**	14,319	60
Per boe	**2.00**	3.52	(43)	**2.45**	3.57	(31)

Transportation expenses increased by $2.2 million to $9.9 million for the second quarter of 2015 compared to $7.7 million for the same period in 2014. Transportation expenses include condensate and NGL pipeline tariffs and trucking, as well as gas pipeline tariffs charged prior to the custody transfer point. The Company's secured pipeline access for condensate began this year. As a result, there was an increase in the portion of volumes sold via pipeline compared to previous periods. However, the overall increase in production volumes partially offset this and a large portion of volumes continue to be trucked. For the first half of 2015, transportation expenses were $22.9 million, an increase of $8.6 million compared to $14.3 million in the same period of 2014. The increase in absolute transportation costs are mainly related to increased production.

On a unit of production basis, transportation expenses decreased by $1.52/boe to $2.00/boe in the second quarter of 2015 compared to $3.52/boe for the same period in 2014 primarily due to higher proportion of volumes being transported via pipeline in 2015. For the first six months of 2015, transportation expenses per boe were $2.45/boe, a decline of 31% compared to the same period in 2014.

General and Administrative Expenses

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per unit amounts)						
Personnel	**4,619**	4,369	6	**9,855**	6,419	54
Professional fees	**438**	719	(39)	**898**	1,478	(39)
Rent	**397**	273	45	**800**	547	46
Other office costs	**1,558**	1,015	53	**3,574**	1,885	90
Gross general and administrative expenses	**7,012**	6,376	10	**15,127**	10,329	46
Capitalized overhead costs	**(1,524)**	(955)	60	**(2,554)**	(1,488)	72
Overhead recoveries	**(352)**	(188)	87	**(808)**	(433)	87
Net general and administrative expenses	**5,136**	5,233	(2)	**11,765**	8,408	40
Per boe – gross	**1.42**	2.92	(51)	**1.62**	2.58	(37)
Per boe – net	**1.04**	2.40	(57)	**1.26**	2.10	(40)

Gross general and administrative expenses for the second quarter of 2015 increased by $0.6 million to $7.0 million from $6.4 million for the comparative period in 2014. On a quarter over quarter basis, this increase was mostly due to an increase in the number of employees and higher personnel costs and additional rent for leased space to support the Company's expanded activities. Gross general and administration expenses on a unit of production basis decreased by 51% for the three months ended June 30, 2015 to $1.42/boe when compared to $2.92/boe for the same period in 2014. This decrease on a per boe basis is due to higher production levels.

For the six months ended June 30, 2015, gross general and administrative expenses were $15.1 million compared to $10.3 million for the same period in 2014. The increase of $4.8 million is mostly due to higher costs to support the Company's expanded activities, $1.5 million of retention costs and $0.7 million of other one-time charges recorded in the first quarter of 2015, including IPO related expenses of $0.2 million.

For capitalized overhead costs, there was a 60% increase in the second quarter of 2015 compared to the same period in 2014. This was mostly attributable to increased personnel involved with the capital and infrastructure development of the Project in the second quarter of 2015. For the first half of 2015, capitalized overhead costs were $2.6 million versus $1.5 million for the comparative period in 2014.

Overhead recoveries were $0.4 million and $0.8 million compared to $0.2 million and $0.4 million, respectively for the three and six months ended June 30, 2015, compared to $0.2 million and $0.4 million for the same periods in 2014. Overhead recoveries relate to spending incurred on properties with minority partners.

Depletion, Depreciation and Amortization

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per unit amounts)						
Depletion, depreciation & amortization	**67,117**	31,280	115	**127,160**	55,315	130
Per boe	**13.68**	14.32	(5)	**13.68**	13.81	(1)

Depletion, depreciation and amortization expense was $67.1 million and $127.2 million for three and six months ended June 30, 2015, compared to $31.3 million and $55.3 million, respectively, in the same periods of 2014. The increase is consistent with the higher production volumes and continued capital investments in the Project.

Stock Based Compensation

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Gross stock based compensation	**5,163**	3,880	33	**9,295**	6,759	38
Capitalized stock based compensation	**(1,550)**	(1,138)	36	**(2,730)**	(2,250)	21
Net stock based compensation	**3,613**	2,742	32	**6,565**	4,509	46

Stock based compensation is a non-cash expense. Gross stock based compensation for the second quarter of 2015 has increased by $1.3 million to $5.2 million compared to $3.9 million for the same period of 2014. For the first half of 2015, gross stock based compensation expense was $9.3 million, an increase of 38% over the comparative period. The increase is mostly due the Company's higher stock price in 2015 resulting in higher fair values for awards granted, as well as additional awards granted to new employees in 2015 and 2014.

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 or performance warrant is calculated on the date of grant and that value is applied throughout the life 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.

Finance Expense

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Interest on senior notes	**23,465**	15,698	49	**41,285**	29,036	42
Revolving credit facility fees and other	**2,145**	564	280	**2,648**	972	172
Amortization of premium and debt issue costs	**(25)**	(212)	(88)	**(260)**	(364)	(29)
Accretion	**381**	396	(4)	**670**	601	11
Total finance expense	**25,966**	16,446	58	**44,343**	30,245	47
Capitalized interest	**(676)**	-	100	**(1,026)**	-	100
Net finance expense	**25,290**	16,446	54	**43,317**	30,245	43

In May 2013 and February 2014, under the same indenture, the Company issued senior unsecured notes of US$400.0 million and US$300.0 million (US$321.0 million with premium), respectively. The notes bear interest at 8.25% per annum (calculated using a 360-day year). In April 2015**,** the Company issued US$425.0 million of additional senior notes bearing interest at 6.75% with a 2023 maturity. Net proceeds from the latter financing were $504.4 million.

Interest expense on senior notes for the second quarter of 2015 was $23.5 million (US$19.2 million), which is recorded in Canadian dollars using average monthly exchange rates, compared to $15.7 million (US$14.4 million) for the same period in 2014. For the first half of 2015, the Company recorded interest expense of $41.3 million (US$33.6 million), an increase of $12.3 million over the comparative period in 2014 due the higher average debt balance outstanding and the weaker Canadian dollar in 2015.

The standby fees and other charges associated with the Company's revolving credit facility increased to $2.1 million in the three months ended June 30, 2015 compared to $0.6 million in the same period of 2014. For the first six months of 2015, the revolving credit facility and other fees were $2.6 million compared to $1.0 million in 2014. This is mostly due to higher standby fees as a result of the increase to the borrowing capacity on the credit facility in the first quarter of 2015 from $480.0 million to $650.0 million.

In the three and six months ended June 30, 2015, the Company capitalized $0.7 and $1.0 million, respectively, in interest and financing costs related to its Cutbank facility that is expected to be on stream in 2016.

Foreign Exchange Loss (Gain)

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Unrealized foreign exchange loss (gain) on senior notes	**(7,858)**	(27,285)	(71)	**75,950**	(12,215)	(722)
Unrealized foreign exchange loss (gain) on cash held in foreign currencies	**5,021**	(3,303)	(252)	**1,950**	(874)	(323)
Realized foreign exchange loss (gain)	**407**	7,224	94	**(6,806)**	2,143	418
Net foreign exchange loss (gain)	**2,430**	(23,364)	(110)	**71,094**	(10,946)	(749)
As at June 30:						
1 C$ equivalent of US$	**1.249**	1.067	17	**1.249**	1.067	17

The Company's exposure to foreign exchange gains and losses mostly relates to the US dollar senior unsecured notes, as well as US dollar cash balances. For the three months ended June 30, 2015, the unrealized foreign exchange gains were $7.9 million compared to foreign exchange gains in the comparative quarter of 2014 of $27.3 million due to the weaker Canadian dollar.

The exchange rate fell to 0.801 at June 30, 2015 from 0.862 at December 31, 2014, resulting in total unrealized foreign exchange losses of $76.0 million for the first half of 2015. The senior unsecured notes do not mature until 2020 (US$700.0 million) and 2023 (US$425.0 million). Realized foreign exchange gains relate to the actual conversion of US dollars to Canadian dollars as well as translation of remaining cash balances still held in US dollars and the settlement of normal revenues and invoices denominated in US dollars. Total realized foreign exchange gains were $6.8 million for the six months ended June 30, 2015.

Gain on Disposition of Assets

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Gain on disposition of assets	**2,602**	1,845	41	**2,602**	4,285	(39)

During the three months ended June 30, 2015, the Company closed asset swap arrangements in which non-producing assets were acquired and non-producing assets were disposed of. For purposes of determining the gain on disposition, the estimated fair market value was based on the fair value of the assets received. The Company recorded a gain of $2.6 million for the three and six months ended June 30, 2015.

Deferred Income Tax Expense

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Deferred income tax expense	**4,340**	11,737	(63)	**910**	15,222	(94)

For the three months ended June 30, 2015, a deferred income tax expense of $4.3 million was recognized compared to $11.7 million deferred income tax expense in the second quarter of 2014. The decrease in the second quarter of 2015 reflects lower net income related to lower combined realized commodity prices offset by increased production volumes.

On a year-to-date basis for the period ended June 30, 2015, the Company recognized a deferred income tax expense of $0.9 million compared to $15.2 million deferred income tax expense for the same period in 2014. The Company's future income tax rate increased to 27% to reflect the recent change to provincial tax rates and increased deferred income taxes by $5.9 million. Permanent differences included stock based compensation, a non-deductible expense, and foreign exchange gains or losses relating to the issue of the senior notes, which are one-half taxable or deductible. These impacted the deferred income tax provision by $1.7 million and $9.3 million, respectively, for the first six months of 2015. Also for the six months ended June 30, 2015, the valuation allowance was increased by $11.0 million due to unrealized foreign exchange losses for which no benefit has been realized.

The Company has no current income tax expense given its total tax pools of $2.7 billion at June 30, 2015. Of this amount, $0.5 billion is available in 2015 for deduction in computing taxable income.

The Canada Revenue Agency is currently conducting an audit of certain historic tax pools generated before oil and gas operations commenced in 2008. Without these tax pools, deferred income tax liability could increase by approximately $25.3 million. While the final outcome of the audit cannot be predicted with certainty, Seven Generations believes its positions as filed are supportable under applicable law and the Company has not recognized a provision in its financial statements for any potential reassessments.

Capital Investments

	Three months ended June 30,			**Six months ended June 30,**		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Land acquisitions	**259**	30,057	(99)	**1,059**	39,076	(97)
Drilling and completions	**222,164**	155,284	43	**487,043**	279,578	74
Facilities and equipment	**128,588**	34,172	276	**229,311**	99,978	129
Other (1)	**3,299**	1,531	115	**5,297**	2,961	79
Total capital investments	**354,310**	221,044	60	**722,710**	421,593	71
Property dispositions	**-**	(1,920)	(100)	**-**	(9,420)	(100)
Capital investment, net of dispositions	**354,310**	219,124	62	**722,710**	412,173	75

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

For the second quarter of 2015, the Company invested $354.3 million on its capital program. The Company's 2015 capital budget is $1.30 - $1.35 billion.

In the second quarter of 2015, $222.2 million was invested for drilling and completions. The Company drilled 17 wells and completed 23 wells in its Nest area. The average lateral length of wells completed was approximately 2,700 metres and an average proppant density of approximately 1.5 tonnes per meter. Drilling and completion costs for the second quarter of 2015 averaged $12.5 million per well. The Company also brought on production 23 (net) wells in the second quarter of 2015.

During the six months ended June 30, 2015, the Company invested $487.0 million in drilling and completions activities. The Company drilled 40 wells and completed 39 new wells in the first half of 2015.

Investments of $128.6 million were made in the three months ended June 30, 2015 for facilities and infrastructure development including the advancement of the construction of the 200 MMcf/d Lator 2 sweet gas plant and the 250 MMcf/d Cutbank sweet gas plant. Pilings and lease work were completed at the Cutbank gas plant site while contractors were on site to set some of the major equipment received for the Lator 2 gas plant.

For the first half of 2015, the Company invested $229.3 million in facilities. The consultation process for the Cutbank sales pipeline, a 29 km, 24" pipeline project moved ahead while planning for construction of four new Superpad sites was being finalized. Surveys and approvals for pipeline projects at two pad sites were also completed in the first six months of 2015.

At June 30, 2015, the Company held 359,996 gross acres (354,201 net) of undeveloped land compared to December 31, 2014 landholdings of 354,556 gross acres (348,762 net).

LIQUIDITY AND CAPITAL RESOURCES

The capital structure of the Company is as follows:

As at	**June 30, 2015**	December 31, 2014
Total debt [(1)]	**1,395,485**	813,880
Total equity [(2)]	**1,841,893**	1,910,926
Total capital	**3,237,378**	2,724,806

(1) Senior unsecured notes.
(2) Equity is defined as share capital plus contributed surplus plus any retained earnings and other comprehensive income.

The Company's objective for managing capital continues to be to maintain a strong balance sheet and capital base to provide financial flexibility to position the Company for future growth and development. 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 Company will strive to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its capital investments.

At June 30, 2015, the Company had cash and cash equivalents of approximately $0.8 billion and adjusted working capital of $0.7 billion. In the second quarter of 2015, the Company announced and completed a private placement offering of US$425.0 million of senior notes, bearing interest at 6.75%, which mature in 2023. Net proceeds from this debt financing were $504.0 million. In the second quarter, the Company and its lending syndicate also agreed to an amendment to the senior secured revolving credit arrangement that increased the borrowing capacity from $480.0 million to $650.0 million. With these transactions, the Company increased its available funding at June 30, 2015 to $1.3 billion. The Company expects that funds from operations and available funding will support the ongoing capital investment program in respect of the Project for 2015 and 2016.

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 June 30, 2015:

	Total	Less than 1 year	1-3 years	4-5 years	Thereafter
($ thousands)					
Senior notes [(1)]	**1,405,125**	-	-	-	1,405,125
Interest on senior notes	**637,705**	48,009	215,922	215,922	157,852
Firm transportation and processing agreements [(2)]	**1,852,737**	23,363	662,731	516,543	650,100
Operating leases [(3)]	**14,016**	1,216	4,595	3,104	5,101
Deferred obligation and retention [(4, 5)]	**21,000**	20,500	500	-	-
Estimated contractual obligations	**3,930,583**	93,088	883,748	735,569	2,218,178

(1) Balance represents US$1,125.0 million 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 the counterparty transportation company.
(3) The Company is committed under operating leases for office premises.
(4) In November 2014, the Board of Directors approved a retention bonus plan for management and employees in aggregate of $6.0 million, payable over the two-year period starting November 5, 2014.
(5) With the closing of the IPO on November 5, 2014, certain terms and conditions pursuant to the Amended and Restated Shareholder Agreement ("USA") that was effective while Seven Generations was a private company were satisfied and $36.0 million was recognized as a liability. The settlement of the liability is payable in cash in 2015 as approved by the Board.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has certain fixed lease arrangements which were entered into in the normal course of operations. All leases are operating leases, where the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. These arrangements are disclosed in the Note 17 to the condensed interim financial statements of the Company. No asset or liability has been recorded for these leases on the balance sheet at June 30, 2015 or December 31, 2014.

The Company did not have any physical delivery contracts outstanding at June 30, 2015 or December 31, 2014.

FINANCIAL INSTRUMENTS

Financial instrument classification and measurement

The Company's financial instruments include cash and cash equivalents, accounts receivable, 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 sheet include cash and cash equivalents, risk management contracts and the credit facility. The credit facility has a floating rate of interest and therefore the carrying value approximates the fair value. 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 $1,458.5 million as at June 30, 2015 (December 31, 2014 – $782.0 million).

The Company reviewed the terms of the senior notes and determined the prepayment options meet the definition of an embedded derivative. The Company determined the fair value of the prepayment options was not material and an embedded derivative has not been recorded.

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.

Risk management contracts, the credit facility and fair value disclosure for the senior notes are classified as Level 2 measurements. Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted prices or indices. The fair value of risk management contracts are derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates for the Company's risk management contracts. Management's assumptions rely on external observable market data including interest rate yield curves. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract. Seven Generations does not have any fair value measurements classified as Level 3. There were no transfers within the hierarchy in the six months ended June 30, 2015. The carrying value of the Company's accounts receivable, 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 to offset by counterparty the related financial assets and financial liabilities on the Company's balance sheets.

The following is a summary of financial assets and financial liabilities that are subject to offset:

As at June 30, 2015	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	43,992	(10,085)	33,907
Long-term asset	12,456	(11,750)	706
Current liability	(10,690)	10,085	(605)
Long-term liability	(16,651)	11,750	(4,901)
Net position	29,107	-	29,107

As at December 31, 2014	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	138,122	-	138,122
Long-term asset	997	-	997
Net position	139,119	-	139,119

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

	June 30, 2015	December 31, 2014
Risk management contracts		
Natural gas	**16,627**	29,548
Oil	**13,777**	109,571
Foreign exchange swap	**(1,297)**	-
Net position	**29,107**	139,119

During the three and six months ended June 30, 2015, the Company's risk management contracts resulted in a realized gain of $41.6 million and $92.3 million (three and six months ended June 30, 2014 – realized loss $6.9 million and $12.3 million) and an unrealized loss of $68.9 million and $110.0 million (three and six months ended June 30, 2014 – unrealized loss of $2.0 million and $15.4 million).

SUBSEQUENT EVENT

On August 7, 2015, the Company reached a long-term transportation agreement for 107 million cubic feet per day of firm transportation receipt service to Alberta's AECO trading hub on TransCanada's Nova Gas Transmission Ltd. (NGTL) system. This agreement is for a term of eight years and is expected to commence in mid-2018, subject to NGTL's system expansion. The total tolls over the term of this agreement could accumulate up to $70 million.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Class A Common Voting Shares and an unlimited number of Class B Common Non-Voting Shares without nominal or par value. As at August 7, 2015, Seven Generations had 251,333,760 Class A Common Voting Shares, 9,500 Class B Common Non-Voting Shares, 11,673,412 stock options and 21,086,258 performance warrants outstanding.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company is required to comply with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")*. Pursuant to NI 52-109, the Chief Executive Officer and Chief Financial Officer are required to certify the design of Seven Generations' disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR") as at June 30, 2015. The Company adopted the 2013 COSO Framework to design its ICFR. There were no material weaknesses in the design of DC&P and ICFR at June 30, 2015, and no changes in ICFR during the period beginning on January 1, 2015 and ended on June 30, 2015 that have materially affected, or are reasonably likely to materially affect Seven Generations' ICFR. 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.

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 financial statements for the year ended December 31, 2014. The preparation of 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 asset retirement 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' share-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 financial statements, refer to Note 5 "Significant Accounting Judgments, Estimates and Assumptions" in the audited financial statements for the year ended December 31, 2014.

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 risk include, but are not limited to:

- volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto;
- 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;
- the availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel;
- 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 possibility that the Company's drilling activities may encounter sour gas;
- execution of the Company's business plan;
- the concentration of the Company's assets in the Kakwa area;
- management of the Company's growth;
- First Nations claims;
- limited intellectual property protection for operating practices and dependence on employees and contractors;
- environmental, health and safety requirements;
- extensive competition in the Company's industry;
- third party credit risk;
- dependence upon a limited number of customers;
- variations in foreign exchange rates and interest rates;
- litigation; and
- general economic, business and industry conditions.

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

Future accounting policy changes

In February 2015, the IASB tentatively decided to require an entity to apply IFRS 9 "Financial Instruments" for annual periods beginning on or after January 1, 2018. IFRS 9 is still available for early adoption. The impact of the standard on the Company's financial statements is currently being evaluated.

In May 2015, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. IFRS 15 will be applied by Seven Generations on January 1, 2017 and the Company is currently evaluating the impact of the standard on the financial statements.

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", "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 financial statements and the accompanying notes.

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, decommissioning expenditures and liquidity event expense. The Company uses funds from operations as an integral part of its internal reporting to measure its performance and 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 to cash flows 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 June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Cash provided by operating activities	**90,902**	35,377	157	**208,114**	103,172	102
Decommissioning expenditures	**-**	-	-	**-**	206	(100)
Changes in non-cash operating working capital	**35,893**	30,595	17	**5,570**	16,758	(67)
Funds from operations	**126,795**	65,972	92	**213,684**	120,136	78

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, excluding realized foreign exchange gains and losses, unrealized gains and losses on risk management contracts and the respective income tax impact of these adjustments.

The following table reconciles the net income to operating income:

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Net income (loss) for the period	**(21,950)**	43,926	(150)	**(104,648)**	45,090	(332)
Unrealized loss on risk management contracts (1)	**68,920**	1,960	(3,416)	**110,012**	15,397	(615)
Unrealized foreign exchange loss (gain) (2)	**2,023**	(27,285)	(107)	**77,900**	(12,215)	(738)
Gain on disposition of assets (3)	**(2,602)**	(1,846)	41	**(2,602)**	(4,285)	(39)
Deferred tax (recovery) expense relating to these adjustments	**(17,906)**	1,498	1,295	**(28,179)**	(1,252)	2,150
Operating income	**28,485**	18,253	56	**52,483**	42,735	23

(1) Unrealized gains and losses on risk management contracts result from the fair market valuation of the hedge contracts as at June 30.
(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) Non-recurring gain resulting from disposition of assets.

Operating Netback

"Operating netback" is calculated on a per boe basis and is determined by deducting royalties, operating and transportation 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.

Available Funding

"Available funding" is comprised of adjusted working capital and the undrawn credit facility capacity. Adjusted working capital is comprised of current assets less current liabilities and excludes (current) risk management contracts and deferred credits. 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:

	June 30, 2015	December 31, 2014
($ thousands)		
Current assets	**900,655**	1,060,030
Current liabilities	**(191,522)**	(268,231)
Working capital	**709,133**	791,799
Adjusted for:		
Current asset - risk management contracts	**(33,907)**	(138,122)
Current liability - risk management contracts	**605**	-
Current portion of deferred credits	**123**	123
Adjusted working capital	**675,954**	653,800
Undrawn credit facility capacity	**650,000**	480,000
Available funding	**1,325,954**	1,133,800

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 (deficit). 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 surplus (deficit) 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:

	June 30, 2015	December 31, 2014
($ thousands)		
Senior notes at amortized cost	**1,395,485**	813,880
Less unamortized premium and debt issue costs	**(9,331)**	(1,810)
Senior notes principal	**1,386,154**	812,070
Adjusted for:		
Current assets	**(900,655)**	(1,060,030)
Current liabilities	**191,522**	268,231
Current asset - risk management contracts	**33,907**	138,122
Current liability - risk management contracts	**(605)**	-
Current portion of deferred credits	**(123)**	(123)
Net debt	**710,200**	158,270

SELECTED QUARTERLY INFORMATION

	Q4 2015	Q3 2015	Q2 2015	Q1 2015	YTD 2015
FINANCIAL ($ thousands, except per share amounts)					
Total revenues			**155,183**	108,540	263,723
Realized hedging gain			**41,683**	50,655	92,338
Processing and third party income			**294**	385	679
Interest and other income			**1,450**	1,300	2,750
Royalties			**(12,886)**	(15,181)	(28,067)
Operating expenses			**(23,537)**	(21,454)	(44,991)
Transportation expenses			**(9,893)**	(12,966)	(22,859)
General and administrative expense			**(5,136)**	(6,629)	(11,765)
Interest expense			**(24,946)**	(17,973)	(42,919)
Foreign exchange loss			**4,614**	242	4,856
Other			**(31)**	(30)	(61)
Funds from operations (1)			**126,795**	86,889	213,684
Per share – diluted			**0.47**	0.32	0.79
Operating income (1)			**28,485**	23,998	52,483
Per share – diluted			**0.11**	0.09	0.19
Net loss			**(21,950)**	(82,698)	(104,648)
Per share – diluted			**(0.09)**	(0.34)	(0.42)
Capital investments:					
Land			**259**	780	1,039
Drilling and completions			**222,164**	264,879	487,043
Facilities and equipment			**128,588**	100,723	229,311
Other			**3,299**	2,018	5,317
Total capital investments (before dispositions)			**354,310**	368,400	722,710
Total assets			**3,559,768**	3,170,401	3,562,213
Available funding (1)			**1,325,954**	861,385	1,325,954
Net debt (1)			**710,200**	505,234	710,200
Debt outstanding			**1,395,485**	888,356	1,395,485
OPERATING					
Average daily production					
Oil and condensate (bbls/d)			**20,702**	15,810	18,269
NGLs (bbls/d)			**11,914**	12,042	11,978
Natural gas (MMcf/d)			**130**	125	128
Total (boe/d)			**54,219**	48,768	51,509
Realized prices					
Oil and condensate ($/bbl)			**60.29**	47.59	54.83
NGLs ($/bbl)			**9.78**	10.41	10.10
Natural gas ($/mcf)			**2.63**	2.62	2.62
OPERATING NETBACK (1)					
Oil and natural gas revenues			**31.45**	24.73	28.29
Realized hedging gain			**8.45**	11.54	9.90
Royalties			**(2.61)**	(3.46)	(3.01)
Operating expenses			**(4.77)**	(4.89)	(4.83)
Transportation expenses			**(2.00)**	(2.95)	(2.45)
Operating netback after hedging			**30.52**	24.97	27.90

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

SELECTED QUARTERLY INFORMATION - continued

	Q4 2014	Q3 2014	Q2 2014	Q1 2014	YE 2014
FINANCIAL ($ thousands, except per share amounts)					
Total revenues	155,383	159,964	120,749	98,737	534,833
Realized hedging gain	22,163	(148)	(6,873)	(5,405)	9,737
Processing and third party income	704	571	243	285	1,803
Interest and other income	1,264	512	782	626	3,184
Royalties	(16,145)	(20,925)	(9,434)	(5,386)	(51,890)
Operating expenses	(18,966)	(14,245)	(9,659)	(11,391)	(54,261)
Transportation expenses	(13,237)	(7,277)	(7,693)	(6,626)	(34,833)
General and administrative expense	(7,393)	(4,457)	(5,233)	(3,175)	(20,258)
Interest expense	(16,905)	(16,037)	(16,262)	(13,746)	(62,950)
Foreign exchange (gain) loss	(5,334)	8,367	(618)	223	2,638
Other	(31)	(31)	(30)	22	(70)
Funds from operations (1)	101,503	106,294	65,972	54,164	327,933
Per share – diluted	0.41	0.48	0.31	0.25	1.46
Operating income (1)	34,815	41,972	18,253	24,481	119,521
Per share – diluted	0.14	0.19	0.09	0.11	0.53
Net income	68,628	30,482	43,926	1,164	144,200
Per share – diluted	0.28	0.14	0.20	0.01	0.64
Capital investments:					
Land	8,200	1,408	30,057	9,019	48,684
Drilling and completions	227,562	234,879	155,284	124,294	742,019
Facilities and equipment	132,610	90,447	34,172	65,806	323,035
Other	1,948	1,689	1,531	1,430	6,598
Total capital investments (before dispositions)	370,320	328,423	221,044	200,549	1,120,336
Total assets	3,114,797	2,019,134	1,844,172	1,818,627	3,114,797
Available funding (1)	1,133,800	547,700	427,222	574,581	1,133,800
Net debt (1)	158,270	716,300	469,678	349,269	158,270
Debt outstanding	813,880	785,830	748,596	775,809	813,880
OPERATING					
Average daily production					
Oil and condensate (bbls/d)	14,747	12,580	9,264	7,554	11,061
NGLs (bbls/d)	10,783	8,289	4,741	4,054	6,989
Natural gas (MMcf/d)	112	90	60	52	79
Total (boe/d)	44,178	35,820	23,999	20,231	31,136
Realized prices					
Oil and condensate ($/bbl)	69.93	90.41	97.32	92.61	85.34
NGLs ($/bbl)	21.50	25.46	24.15	28.25	24.10
Natural gas ($/mcf)	3.81	4.35	5.18	5.47	4.50
OPERATING NETBACK (1)					
Oil and natural gas revenues	38.23	48.54	55.29	54.23	47.06
Realized hedging gain	5.45	(0.04)	(3.15)	(2.97)	0.86
Royalties	(3.97)	(6.35)	(4.32)	(2.96)	(4.57)
Operating expenses	(4.67)	(4.32)	(4.42)	(6.26)	(4.77)
Transportation expenses	(3.26)	(2.21)	(3.52)	(3.64)	(3.06)
Operating netback after hedging	31.78	35.62	39.88	38.40	35.52

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

SELECTED QUARTERLY INFORMATION - continued

	Q4 2013	Q3 2013	Q2 2013	Q1 2013	YE 2013
FINANCIAL ($ thousands, except per share amounts)					
Total revenues	48,484	22,168	21,581	20,951	113,184
Realized hedging gain	49	17	53	160	279
Processing and third party income	356	501	347	407	1,611
Interest and other income	272	506	274	233	1,285
Royalties	(3,188)	(2,227)	(318)	(2,120)	(7,853)
Operating expenses	(8,425)	(4,502)	(4,168)	(3,520)	(20,615)
Transportation expenses	(3,286)	(962)	(1,326)	(887)	(6,461)
General and administrative expense	(2,052)	(2,006)	(2,175)	(1,884)	(8,117)
Interest expense	(8,970)	(8,691)	(5,051)	(194)	(22,906)
Foreign exchange (gain) loss	(133)	(24)	6	10	(141)
Other	7	-	-	-	7
Funds from operations (1)	23,114	4,780	9,223	13,156	50,273
Per share – diluted	0.12	0.03	0.05	0.08	0.27
Operating income (loss) (1)	7,127	(8,053)	5,246	1,474	5,794
Per share – diluted	0.04	(0.05)	0.03	0.01	0.03
Net income (loss)	(5,625)	(955)	(8,454)	876	(14,158)
Per share – diluted	(0.03)	(0.01)	(0.05)	0.01	(0.08)
Capital investments:					
Land	2,925	8,991	35,875	13,507	61,298
Drilling and completions	129,231	102,314	44,697	45,568	321,810
Facilities and equipment	44,717	29,707	39,806	72,464	186,694
Other	1,365	1,173	1,058	930	4,526
Total capital investments (before dispositions)	178,238	142,185	121,436	132,469	574,328
Total assets	1,408,213	1,134,257	1,103,583	698,450	1,408,213
Available funding (1)	364,877	189,586	328,137	16,441	364,877
Net debt (1)	210,563	282,534	152,583	23,559	210,563
Debt outstanding	414,525	404,208	412,293	-	414,525
OPERATING					
Average daily production					
Oil and condensate (bbls/d)	4,480	1,614	1,681	1,760	2,390
NGLs (bbls/d)	2,291	1,639	1,313	1,749	1,749
Natural gas (MMcf/d)	29	23	19	16	22
Total (boe/d)	11,585	7,084	6,182	6,240	7,786
Realized prices					
Oil and condensate ($/bbl)	80.63	96.63	88.67	84.62	85.49
NGLs ($/bbl)	24.54	18.77	11.89	16.22	18.76
Natural gas ($/mcf)	3.79	2.36	3.79	3.38	3.34
OPERATING NETBACK (1)					
Oil and natural gas revenues	37.30	38.36	34.01	45.49	39.83
Realized hedging gain	0.28	0.10	0.03	0.05	0.10
Royalties	(3.78)	(0.56)	(3.42)	(2.99)	(2.76)
Operating expenses	(6.27)	(7.41)	(6.91)	(7.90)	(7.25)
Transportation expenses	(1.58)	(2.35)	(1.48)	(3.09)	(2.28)
Operating netback after hedging	25.95	28.14	22.23	31.56	27.64

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

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 expectation that the Project will be a multi-decade development project; the Company’s ability to deliver on its growth objectives and meet the commitments in its marketing and transportation agreements; the Company’s hedging targets; the Company’s expected annual effective royalty rate for 2015; the expectation that the Cutbank facility will be on stream in 2016; the potential impact of tax related reviews that are currently in progress; expectations regarding the balancing of debt and equity in the Company’s capital structure; the mitigation of risk associated with the Company’s capital investments; the expectation that funds from operations and available funding will support the ongoing capital investment program for the Project for 2015 and 2016; the Company’s estimates of its future obligations under the heading “Contractual Obligations”; and the Company’s expectation that it will be able to pipeline a portion of its oil and condensate volumes for the remainder of 2015 on a firm basis and that it will likely have higher transportation charges and lower realizations on the portion of its oil and condensate production that is transported by truck. In addition, references to reserves are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated.

With respect to forward-looking information contained in this document, assumptions have been made regarding, among other things: future oil, condensate and other NGLs and natural gas prices; the Company’s ability to obtain qualified staff and equipment in a timely and cost efficient manner; the Company’s ability to market production of oil, condensate and other NGLs and natural gas successfully to customers; the Company’s future production levels; the applicability of technologies for the Company’s reserves; future capital investments by the Company; future cash flows from production; 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, the geography of the areas in which the Company is conducting exploration and development activities, and the access, economic 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.

Actual results could differ materially from those anticipated in this forward-looking information 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, natural gas liquids 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; risks related to the exploration, development, production and transportation 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; the management of the Company’s growth; the availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel; the absence or loss of key employees; uncertainty associated with estimates of oil, natural gas liquids and natural gas reserves 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; shortage or lack of available of pipeline capacity or other transportation facilities; the ability to satisfy obligations under the Company’s firm commitment transportation arrangements; uncertainties related to the Company’s identified drilling locations; the concentration of the Company’s assets in the Kakwa area; unforeseen title defects; First Nations claims; failure to accurately estimate abandonment and reclamation costs; changes in the interpretation and enforcement of applicable laws and regulations; terrorist attacks or armed conflicts; 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; impact of expansion into new activities on risk exposure; risks related to the senior unsecured notes and other indebtedness, including: potential inability to comply with the covenants in the credit agreement related to the Company’s credit facilities and/or the covenants in the indentures in respect of the senior secured notes; seasonality of the Company’s activities and the Canadian oil and gas industry; and extensive competition in the Company’s industry.

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.

Independent Reserves Evaluation

Estimates of the Company's reserves and the net present value of future net revenue attributable to the Company's reserves as at December 31, 2014, are based upon the report that was prepared by McDaniel, evaluating the Company's oil, natural gas and NGL reserves, dated February 19, 2015. The estimates of reserves provided in this document are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided in this in this document, and the difference may be material. Estimates of net present value of future net revenue attributable to the Company's reserves do not represent fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions applied by McDaniel in evaluating Seven Generations' reserves will be attained and variances could be material. For important additional information regarding the independent reserves evaluations that were conducted by McDaniel, please refer to the AIF, which is available on the SEDAR website at www.sedar.com.

Oil and Gas Definitions

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

net means:
- in relation to the Company's interest in production or reserves, the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
- in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
- in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

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

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

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

Abbreviations

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	barrel
bbls	barrels
bbls/d	barrels per day
boe (1)	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian dollars
GJ	gigajoule
GJ/d	gigajoules per day
m	metres
mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMboe	millions of barrels of oil equivalent
MMBtu/d	million British thermal units per day
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
US$	United Stated dollars
WTI	West Texas Intermediate

(1) Seven Generations has adopted the standard of 6 mcf:1 bbl when converting natural gas to oil equivalent. Condensate and other NGLs are converted to oil equivalent 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.