SEVEN GENERATIONS
ENERGY LTD

ANNUAL REPORT 2014

SEVEN GENERATIONS IS A HIGH-GROWTH, LIQUIDS-RICH MONTNEY INVESTMENT OPPORTUNITY WITH WORLD-CLASS, WORLD-SCALE ASSETS.

SIGNIFICANT RESERVES AND RESOURCES TO SUPPORT A MULTI-DECADE DRILLING PROGRAM

GROWTH SUPPORTED BY LOCATION ADVANTAGES AND FIRM TRANSPORTATION CONTRACTS

OPERATORSHIP AND OWNERSHIP OF FACILITIES TO CONTROL PACE OF DEVELOPMENT

A PROVEN TEAM WITH DEMONSTRATED ABILITY TO ADD VALUE TO UNCONVENTIONAL PLAYS

Operational highlights:

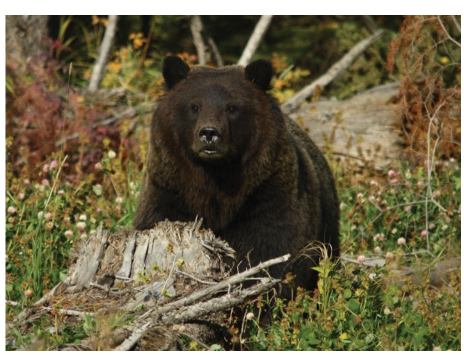
44.2 MBOE/D
Q4 2014 production sales

58% LIQUIDS
Q4 2014 production sales

$35.52/BOE
2014 netback after hedging

55-60 MBOE/D
(50-55% liquids)
2015E production

"Seven Generations" is an ecological concept that urges humans to live sustainably and work for the benefit of the seventh generation into the future. It originated with The Great Law of the Iroquois, which holds that it is appropriate to think ahead and decide whether the decisions made today would benefit the seventh generation. We strongly believe in this concept, and continually strive to ensure that our actions will benefit our stakeholders – both now and in the future.



2014 FOURTH QUARTER AND ANNUAL FINANCIAL AND OPERATING RESULTS

	Three months ended December 31			Year ended December 31		
	2014	2013	**% Change**	**2014**	2013	**% Change**
OPERATIONAL						
Production						
Oil and condensate (bbls/d)	14,747	4,480	**229**	11,061	2,390	**363**
NGLs (bbls/d)	10,783	2,291	**371**	6,989	1,749	**300**
Natural gas (Mmcf/d)	112	29	**286**	79	22	**259**
Oil equivalent (boe/d)	44,178	11,585	**281**	31,136	7,786	**300**
Liquids ratio	58%	58%	**-**	58%	53%	**9**
Realized prices [3]						
Oil and condensate ($/bbl)	69.93	80.63	**(13)**	85.34	85.49	**-**
NGLs ($/bbl)	21.50	24.54	**(12)**	24.10	18.76	**28**
Natural gas ($/mcf)	3.81	3.79	**1**	4.50	3.34	**35**
Oil equivalent ($/boe)	38.23	45.49	**(16)**	47.06	39.83	**18**
Operating netback per boe ($) [1]						
Oil and natural gas revenue [3]	38.23	45.49	**(16)**	47.06	39.83	**18**
Royalties	(3.97)	(2.99)	**33**	(4.57)	(2.76)	**66**
Operating expenses	(4.67)	(7.90)	**(41)**	(4.77)	(7.25)	**(34)**
Transportation expenses [3]	(3.26)	(3.09)	**6**	(3.06)	(2.28)	**34**
Netback prior to hedging	26.33	31.51	**(16)**	34.66	27.54	**26**
Realized hedging gain	5.45	0.05	**10,800**	0.86	0.10	**760**
Netback after hedging	31.78	31.56	**-**	35.52	27.64	**29**
General and administrative expenses per boe	1.82	1.93	**(6)**	1.78	2.86	**(38)**
FINANCIAL **($ thousands, except per share amounts)**						
Oil and natural gas revenue [3]	155,383	48,484	**220**	534,833	113,184	**373**
Funds from operations [1]	101,503	23,114	**339**	327,933	50,273	**552**
Per share – diluted [2]	0.41	0.12	**242**	1.46	0.27	**440**
Operating income [1]	34,815	7,127	**388**	119,521	5,794	**1,963**
Per share – diluted [2]	0.14	0.04	**250**	0.53	0.03	**1,667**
Net income (loss)	68,628	(5,625)	**1,320**	144,200	(14,158)	**1,119**
Per share – diluted [2]	0.28	(0.03)	**1,033**	0.64	(0.08)	**900**
Weighted average shares (000s) – diluted [2]	250,223	192,689	**30**	224,717	183,288	**23**
Total capital investments	370,320	178,238	**108**	1,120,336	574,328	**95**
Available funding [1]	1,133,800	364,877	**211**	1,133,800	364,877	**211**
Net debt [1]	158,270	210,563	**(25)**	158,270	210,563	**(25)**
Debt outstanding	813,880	414,525	**96**	813,880	414,525	**96**

(1) Operating netback, funds from operations, operating income, available funding and net debt are not defined under IFRS. See "Non-IFRS Financial Measures" in Management's Discussion and Analysis.

(2) In 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares, stock options and performance warrants on a two-for-one basis. The share split has been reflected for the three months and years ended December 31, 2014 and 2013 on a retroactive basis.

(3) Certain comparative figures from prior periods have been reclassified to conform to the current year's presentation.

HIGHLIGHTS FOR THE QUARTER AND YEAR ENDED DECEMBER 31, 2014

- Fourth quarter 2014 production was 44,178 boe per day representing a 281% increase over fourth quarter 2013 production of 11,585 boe per day. Annual 2014 production averaged 31,136 boe per day compared to 7,786 boe per day during 2013, an increase of 300%.

- Liquids ratios for the fourth quarter remained constant at 58% of total production on a boe basis, with fourth quarter condensate production representing 34% of Seven Generations Energy Ltd. ("Seven Generations", "7G" or the "Company") total production mix.

- Seven Generations realized a netback after hedging of $35.52 per boe for the year ended December 31, 2014, compared to $27.64 per boe for the year ended December 31, 2013.

- The Company achieved record funds from operations of $327.9 million in 2014 compared to $50.3 million in 2013, an increase of 552%. Funds from operations for the fourth quarter of 2014 was $101.5 million, which was a 339% increase over the fourth quarter 2013.

- McDaniel & Associates Consultants Ltd.'s ("McDaniel") estimated total gross proved reserves ("1P") were 420.7 MMboe, as at December 31, 2014, which was an increase of 28% and 292% since the Company's July 1, 2014 and December 31, 2013 reserve evaluations.

- McDaniel's estimated total gross proved plus probable reserves ("2P"), as at December 31, 2014, increased to 788.6 MMboe, a 22% increase over the Company's July 1, 2014 gross 2P reserves of 649.1 MMboe and a 178% increase over the December 31, 2013 gross 2P reserves of 283.3 MMboe.

- McDaniel's estimated proved developed producing reserves ("PDP") increased to 34.1 MMboe, an increase of 99% over the Company's July 1, 2014 PDP reserves of 17.1 MMboe and a 127% increase over the December 31, 2013 gross PDP reserves of 15.0 MMboe.

- Before tax net present values, using a discount rate of 10% per annum, were $3.1 billion for proved reserves and $7.1 billion for proved plus probable reserves, based on McDaniel's estimates as at December 31, 2014.

- In the fourth quarter of 2014, the Company closed an initial public offering ("IPO") for net proceeds of $880.1 million through the issuance of 51.8 million class A common shares. During the third quarter of 2014, the Company and its lending syndicate agreed to an amendment to the senior secured revolving credit arrangement that increased the borrowing capacity from $150.0 million to $480.0 million and extended the maturity date of the credit facility to September 2017. As of December 31, 2014, the Company had available funding in excess of $1.1 billion.

OPERATIONAL REVIEW

Fourth quarter production averaged 44,178 boe per day, consisting of 34% condensate and 24% other NGLs, with total liquids representing 58% of total production on a per boe basis. Average annual production for 2014 was 31,136 boe per day, consisting of 58% liquids, with liquids production consisting of 36% condensate and 22% other NGLs on a per boe basis.

Based on preliminary field estimates, production for the first two months of 2015 averaged approximately 47,500 boe per day, on track to achieve 7G's annual production guidance. While production continues to ramp up quite rapidly, growth will be constrained later in the year by the Lator plant capacity until the Lator 2 plant expansion is completed in the fourth quarter of 2015, therefore annual production is expected to be consistent with current guidance of 55,000 to 60,000 boe per day.

An average of 10 drilling rigs were operated during the fourth quarter of 2014, with a peak of 14 rigs operating for most of December. Fourteen wells were rig released in the fourth quarter, including 12 Montney wells in the Nest, one Montney well in the Deep Sour region, and one First White Specks emerging target well. For the year ended December 31, 2014, the Company drilled 49 gross wells consisting of 44 Montney horizontal wells in the nest, three Montney horizontal delineation wells, one emerging target well and one vertical well. The average horizontal length for the 12 (12.0 net) Montney wells drilled in the Nest in the fourth quarter of 2014 was 2,870 meters with an average spud to rig release time of 56.6 days. Average horizontal lengths drilled per well in 2014 increased 30% over the prior year's average while average drilling days per well was reduced by 18%.

During the fourth quarter of 2014, 7G completed 10 Montney wells in the Nest, and one Montney horizontal well in the Wapiti region, stimulating a total of 340 stages, averaging 31 stages per well, 3,800 tonnes of proppant per well, and 1.5 tonnes per meter of lateral. When compared to 7G's 2013 activity, average stages completed per well increased 32% and average tonnes of proppant pumped per well increased 20%. The Company used several completion techniques in the fourth quarter of 2014, including two slickwater fracs, one HiWay frac (a Schlumberger proprietary technique), six nitrogen foam fracs with ball drop sliding sleeve systems, and two nitrogen foam fracs using the plug and perf frac delivery system. Two of the fourth quarter 2014 completions were costlier than expected as a result of having to fish coiled tubing that was stuck downhole during milling operations in one well and the other due to a frac that was initiated in the first quarter of 2014 that was suspended due to access issues and not completed until the fourth quarter of 2014.

The company adjusted our liner design and proppant selection mid fourth quarter, which resulted in decreased completions costs per well. 7G continues to work on optimizing its completion design and has several tests planned for 2015 including experimenting with inter-stage spacing, produced water re-use, proppant selection, higher proppant concentration, and proppant carrying fluid type. The Company intends to apply a standard completion design to approximately 85% of its completions while experimenting, in a controlled fashion, with 15% of its wells. Currently, the Company's standard completion design is comprised of a 28 stage ball-drop system, with nitrogen foam as the carrying fluid for approximately 4,500 tonnes of proppant, resulting in a proppant density of 1.5 tonnes per meter of lateral. These design changes, along with other operational efficiencies are expected to result in substantially improved completion costs in 2015.

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Gross wells rig released	14	11	49	23
Average measured depth (m)*	6,070	5,280	5,840	5,090
Average horizontal length (m)*	2,870	2,200	2,660	2,050
Average drilling days per well*	56	52	54	66
Gross wells completed	11	9	38	17
Average number of stages	31	22	29	22
Average tonnes pumped	3,800	2,870	3,330	2,780

*excludes one abandoned and two vertical wells.

During the fourth quarter of 2014, 7G commissioned the Karr 7-11 to Lator condensate pipeline and completed the Lator to Pembina liquids pipeline. The Company anticipates that Pembina will complete its Lator to Fox Creek line looping project in the first quarter of 2015, which will result in reduced condensate transportation costs as the Company shifts from trucking volumes to pipeline connected capacity. Field construction of the 25,000 barrel per day stabilizer at the Karr 7-11 battery also continued in the fourth quarter. The Company expects that the stabilizer will be fully commissioned in the first quarter of 2015, which will help improve condensate quality and reduce pricing discounts.

As of December 31, 2014, the Company had 6 satellite pads and 31 well tie-ins under construction in addition to nine well tie-ins that were completed in the fourth quarter. 7G currently has an inventory of approximately 47 wells at various stages of construction between drilling and tie-in.

CAPITAL INVESTMENTS

Capital investments totalled $370.3 million for the fourth quarter of 2014 and $1.1 billion for the full year of 2014. 2014 capital invested was approximately 5% over 7G's guidance primarily due to progress payments for long lead items for the Lator 2 and Cutbank area plants, payments associated with a new temporary camp that will be occupied in the first quarter of 2015, earlier than planned drilling of an emerging target well and a deep sour well in addition to higher than expected completion costs.

During the fourth quarter of 2014, 7G invested $227.6 million to drill 14 wells and complete 11 multi-stage horizontal wells with a 100% success rate, with nine wells brought onto production. For the year ended December 31, 2014, the Company invested $742.0 million to drill 49 wells and complete 38 wells, and brought 34 wells onto production, compared to 23 wells drilled, 17 wells completed and 14 wells brought on production for the year ended December 31, 2013. Drill counts are based on the rig release date and production counts are based on the first reportable production date.

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Number of wells drilled – gross	14	11	49	23
Number of wells completed – gross	11	9	38	17
Number of wells brought on production – gross	9	10	34	14
($ thousands)				
Drilling	122,493	65,093	391,169	183,375
Completions	105,069	64,138	350,850	138,435
Total drill and complete	227,562	129,231	742,019	321,810

In the fourth quarter 2014, the Company invested $132.6 million into facilities and infrastructure. For the year ended December 31, 2014, 7G invested $323.0 million into facilities and infrastructure with 44% invested in pad and well equipment, 42% in major facilities, 8% in pipelines and 6% in supporting infrastructure.

	Three months ended December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Pad and well equipment	51,547	29,921	140,835	54,401
Major facilities	68,385	5,575	135,654	33,585
Pipelines	5,087	3,700	25,489	64,102
Supporting infrastructure	7,591	5,521	21,058	34,606
Facilities and equipment	132,610	44,717	323,035	186,694

FINANCIAL REVIEW

In the fourth quarter of 2014, the Company closed an initial public offering ("IPO") for net proceeds of $880.1 million through the issuance of 51.8 million class A common shares. During the third quarter of 2014, the Company and its lending syndicate agreed to an amendment to the senior secured revolving credit arrangement that increased the borrowing capacity from $150.0 million to $480.0 million and extended the maturity date of the credit facility to September 2017. As of December 31, 2014, the Company had available funding in excess of $1.1 billion.

Despite falling energy prices in the fourth quarter of 2014, 7G generated fourth quarter and full year 2014 funds from operations of $101.5 million and $327.9 million, which were up 339% and 552%, respectively, over comparable 2013 periods. The increase in funds from operations was primarily due to the increase in production volumes that more than offset the lower liquids and gas pricing.

Fourth quarter and full year 2014 netbacks prior to hedging averaged $26.33 per boe and $34.66 per boe, which were 16% lower and 26% higher than similar periods in 2013, respectively. After hedging, 7G's fourth quarter and annual 2014 netbacks were $31.78 per boe and $35.52 per boe, which were equivalent to and 29% higher than comparable periods in 2013.

As of December 31, 2014, 7G had approximately 68,500 GJ/d of 2015 AECO exposed production hedged at an average price of $3.85/GJ and average 8,200 barrel per day of 2015 liquids production hedged at a WTI price of approximately $101.80 CAD per barrel.

MARKETING

During the fourth quarter of 2014, 7G converted the portion of its outstanding Alliance pipeline commitments that had initially been contracted as firm receipt service to firm full path service and extended the expiry on all outstanding Alliance pipeline commitments to 2022. The conversion in service means that, as of December 2015, all of the Company's gas delivered onto the Alliance Pipeline will be transported to Chicago and will have access to US Midwest markets.

The Company's average realized price for condensate and oil in the fourth quarter of 2014 was $69.93 per barrel, which was an approximate $10 per barrel discount to the Alberta benchmark CRW condensate price. Condensate pricing is expected to improve and trade closer to Alberta benchmark pricing as the Company commissions its condensate stabilizer in the first quarter of 2015, which is expected to improve the quality of marketed product.

The average realized prices for NGLs primarily reflect a combination of prices for NGLs such as ethane, propane, butane and pentanes plus. The Company's average realized prices decreased for this product stream in the fourth quarter of 2014 by 12% to $21.50 per barrel, compared to $24.54 per barrel for the same period in 2013. For the 2014 year end, the Company realized average prices of $24.10 per barrel for its NGLs as compared to $18.76 per barrel for the comparative period in 2013, an increase of 28%.

The Company's average realized natural gas price increased by 1% to $3.81 per mcf for the fourth quarter of 2014, compared to $3.79 per mcf in the same period in 2013. For the year ended December 31, 2014, the Company's average realized natural gas price increased by 35% to $4.50 per mcf compared to $3.34 per mcf in 2013. The Company receives a blend of pricing based on AECO monthly and daily benchmark indexes.

LAND UPDATE

Since the Company's last land update during the third quarter of 2014, 7G has increased its land holdings by 76,480 (gross and net) acres at an average cost of $117 per acre. As of December 31, 2014, the Company held more than 424,000 net acres with Montney rights on 407,475 net acres with an average working interest of 98%. During the fourth quarter of 2014 the Company acquired approximately 68,800 acres at a total cost of $8.2 million.

OUTLOOK

On February 24, 2015, the Company announced its plan to reduce 2015 capital investments downwards by $250 to $300 million, resulting in a revised capital program of $1.30 to $1.35 billion. The Company plans to defer spending of approximately $200 to $250 million and also expects, through negotiations with suppliers and business partners, to capture additional cost savings on 2015 projects of at least $50 million, resulting in an aggregate capital investment reduction of approximately 15% to 20% from the earlier announced budget of $1.60 billion.

The Company anticipates 2015 production to be between 55,000 and 60,000 boe per day and plans to drill 77 new wells in 2015 with 60 new producing wells coming on line in 2015. Currently 7G has initiated but not completed work on an in-process inventory of 47 new wells that will help fuel the Company's production growth. 7G's operated drilling rig count is currently 10 and is expected to ramp up to 13 rigs at mid-year and to 15 rigs for the last two months of 2015.

In 2015, 7G plans to finish the expansion of its Lator refrigeration plant to its 250 Mmcf/d rich gas sales capacity and to initiate the construction of a second refrigeration plant which, when complete in 2016, will increase processing capacity to 500 Mmcf/d and allow the Company to continue to profitably deliver rich gas volumes into its firm transportation commitments.

RESERVES

7G's independent reserves evaluation, effective December 31, 2014, was recently completed by McDaniel & Associates Consultants Ltd. ("McDaniel"). McDaniel prepared the evaluation in compliance with the standards set out in National Instrument 51-101 of the Canadian Securities Administrators and the Canadian Oil and Gas Evaluation Handbook. For additional information regarding the independent reserves evaluation that was conducted by McDaniel, as at December 31, 2014, please see the disclosure that is provided under the heading "Independent Reserves Evaluation" below and the Company's Annual Information Form dated March 10, 2015 ("AIF"), which is available on the SEDAR website at www.sedar.com.

- Total gross 1P reserves of 420.7 MMboe, as at December 31, 2014, represented an increase of 28% and 292% when compared to the Company's July 1, 2014 and December 31, 2013 gross 1P reserves of 328.0 MMboe and 107.2 MMboe, respectively.
- Total gross 2P reserves, as at December 31, 2014, were 788.6 MMboe, a 22% increase over the Company's July 1, 2014 gross 2P reserves of 649.1 MMboe, and a 179% increase over the Company's December 31, 2013 gross 2P reserves of 283.3 MMboe.
- PDP reserves increased to 34.1 MMboe as at December 31, 2014, an increase of 99% over the Company's July 1, 2014 PDP reserves of 17.1 MMboe.
- Before tax net present values, using a discount rate of 10% per annum, were $3.1 billion for gross 1P reserves and $7.1 billion for gross 2P reserves, as of December 31, 2014.
- 2014 finding and development ("F&D") costs, including future development capital, were $14.09 per boe for gross 2P reserves and $17.76 per boe for gross 1P reserves.
- The Company had a recycle ratio of 2.46 times for gross 2P reserves evaluated as at December 31, 2014, based on the aforementioned F&D costs and pre-hedging netbacks of $34.66 per boe, as at December 31, 2014.

	December 31, 2014		July 1, 2014		December 31, 2013	
	MMboe	**$MM [3]**	MMboe	$MM [3]	MMboe	$MM [3]
PDP + PDNP [1]	39	627	26	546	15	315
Proved reserves [2]	421	3,145	328	3,285	107	1,023
Proved plus probable reserves [2]	789	7,108	649	7,032	283	3,104

(1) Proved Developed Producing plus Proved Developed Non-producing.
(2) Company gross reserves as determined by Seven Generations' independent reserve evaluator.
(3) Before Tax Net Present Valued using a 10% Discount Rate.

The Company's oil, NGLs and natural gas reserves are located primarily in the Kakwa area. The July 1, 2014 reserves and resources were prepared in conjunction with the Company's IPO. For definitions and additional information regarding Seven Generations' reserves estimates, refer to the Company's AIF which is available on SEDAR at www.sedar.com.

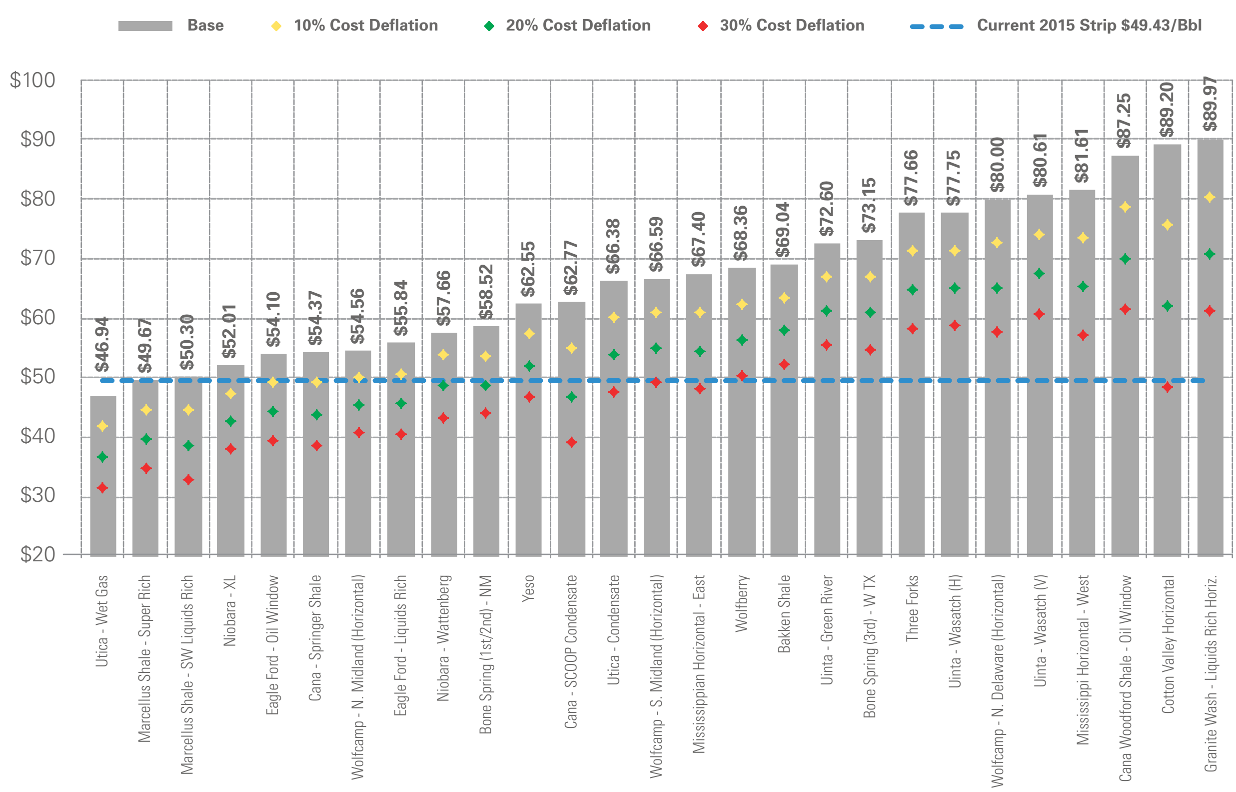
CEO'S MESSAGE TO THE SHAREHOLDERS

March 2015

The free market system is ruthless. It is persistent. It is overbearing. It demands the lowest cost supply and when it has devoured that, it seeks more but always the lowest cost available. That is why we like it. It maximizes the efficiency of our economy – our wants and needs provided at the lowest cost. I am a big believer.

If you have been reading my shareholder messages and our corporate presentations over the past seven years you will know that having the lowest cost supply in our market is a corporate obsession. Mid to late last decade, we designed the Company to compete nose-to-nose with the best in emerging resource plays. We saw the immense resource potential of these plays, enough to flood any established market with new supply. We recognized that the novelty of their commercial development put new entrants on a more level playing field with established companies. We saw that new technology would be required and the experts weren't far ahead of the new entrants. Whatever the final outcome, we figured that there needed to be a battle to secure the best quality supply, the supply that had the potential to be delivered to that overbearing market. We also suspected that there would be a technical showdown and that we needed to stay alert, know what was going on in the technology world and strategically pick what appeared to be the best ways to economize, to reduce supply costs. We needed to attack those costs by testing both established technologies and new ones – all in pursuit of lower supply cost. I feel that all of our employees, from the most senior management, to the most recently hired, understand what we mean by positioning at the "toe of the supply cost boot" and the importance of that statement. The pursuit of lowest cost is ingrained into the corporate culture of Seven Generations Energy Ltd. ("Seven Generations", "7G" or the "Company").

WTI OIL BREAKEVEN PRICE ($ PER BBL) COST DEFLATION SCENARIO – AT $3.00/MCF NATURAL GAS



The above diagram is what we call a supply cost (or threshold price) "boot" diagram. This one is for oil. Each bar indicates the commodity price that is required for the project to earn a threshold rate of return (such as a 15% before tax internal rate of return). In aggregate, the bars generally take the shape of a boot with the lowest supply cost projects at the toe of the boot. Seven Generations seeks to position with the lowest supply cost projects at the "toe" of the supply cost boot.
Graph source: Credit Suisse Oil & Gas Equity Research, February 2015.

The cruel, discriminating, ruthless market interested in only the lowest cost supply arrived last year. We were ready.

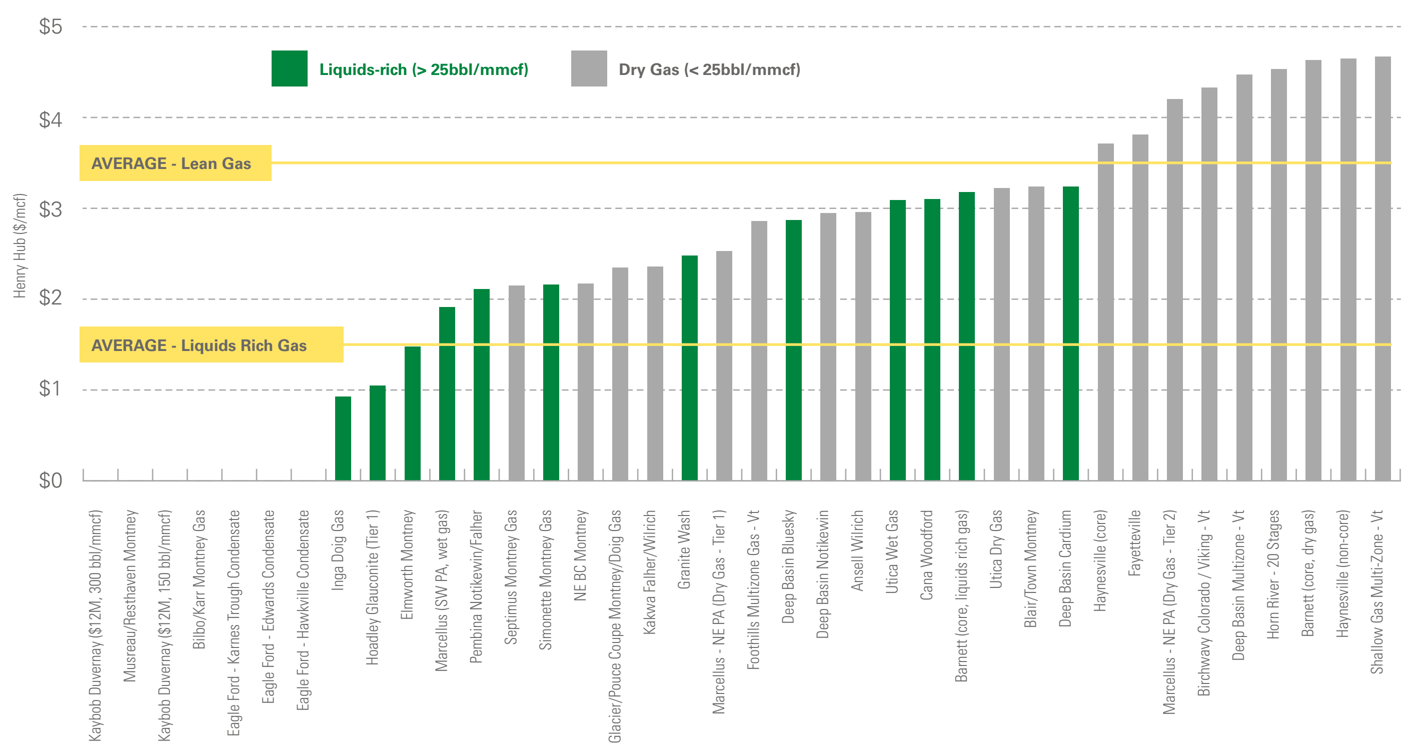
On a very personal note, I learned this market lesson the hard way. At least my family did. My dad was a hard working Swedish immigrant, a farmer who left home to move to Canada, by himself, at 15 years of age. Mom was a daughter of the Canadian prairie, a pioneer woman who had turned soil with a horse drawn plow, whose father helped to win Canada's station as a free and independent nation when he, among his Princess Patricia's Canadian Light Infantry brethren, stormed Vimy Ridge in 1917. My parents were people who knew the meaning of hard work. Yet when the 1950's brought new, bigger, more efficient machinery that resulted in consolidation of farms, the more successful farming operations gobbling up the less successful, my parents found themselves to be gobblees not gobblors. They struggled in poverty until they surrendered and moved to the city to take up low-paying, unskilled labour jobs, usually more than one at one time and, most of the time, earning a little extra by hosting boarders.

In 2001, between my first private start-up and the second and third, I asked the new owner of my parent's farm if I could recover some rocks from my parents' land, rocks that I would use in a massive fireplace that was to be built into our new house in Calgary. A monolith to honour my parents, their struggle and the values that they maintained as they walked the toughest walk that I have ever seen walked. "I've never counted my rocks," was the old gentleman's reply and thus began one of the greatest learning experiences of my life.

My parents died when I was a young adult so I never got a chance to talk about adult things with them. Why did some farmers go on to get wealthy while our operation shriveled? Why didn't my parents buy bigger, more efficient machinery? They were smart and very hard working; why had the economy graded them off the road?

The rock masons that we hired were very particular. They only used a small portion of the rocks that we collected and so we went back many times. In the end there were something like two dozen over-loaded pick-up loads of rocks. At first I was very selective, looking for rocks that had very likely been touched by my parents hands: rocks from mom's rock garden, rocks from the loose stone foundation of the then still-standing three room farm house, a rock at the gate post for the barbed wire fence that kept the grazing cattle out of the farm yard when

MID-CYCLE GAS PLAYS RANKED BY BREAK-EVEN PRICE (US$81/BBL)



This boot diagram shows the same concept for gas projects. Note that, at the constant $US 81 for oil used by the analysts several of the gas projects (the ones at the toe of the boot) do not need any gas revenue to achieve the profitability hurdle that the analyst used. We rely on analyst reports to understand the performance expectations of other projects. We rigorously analyze our own, partly to check for discrepancies with analyst reports but mostly just to thoroughly understand our own economics.

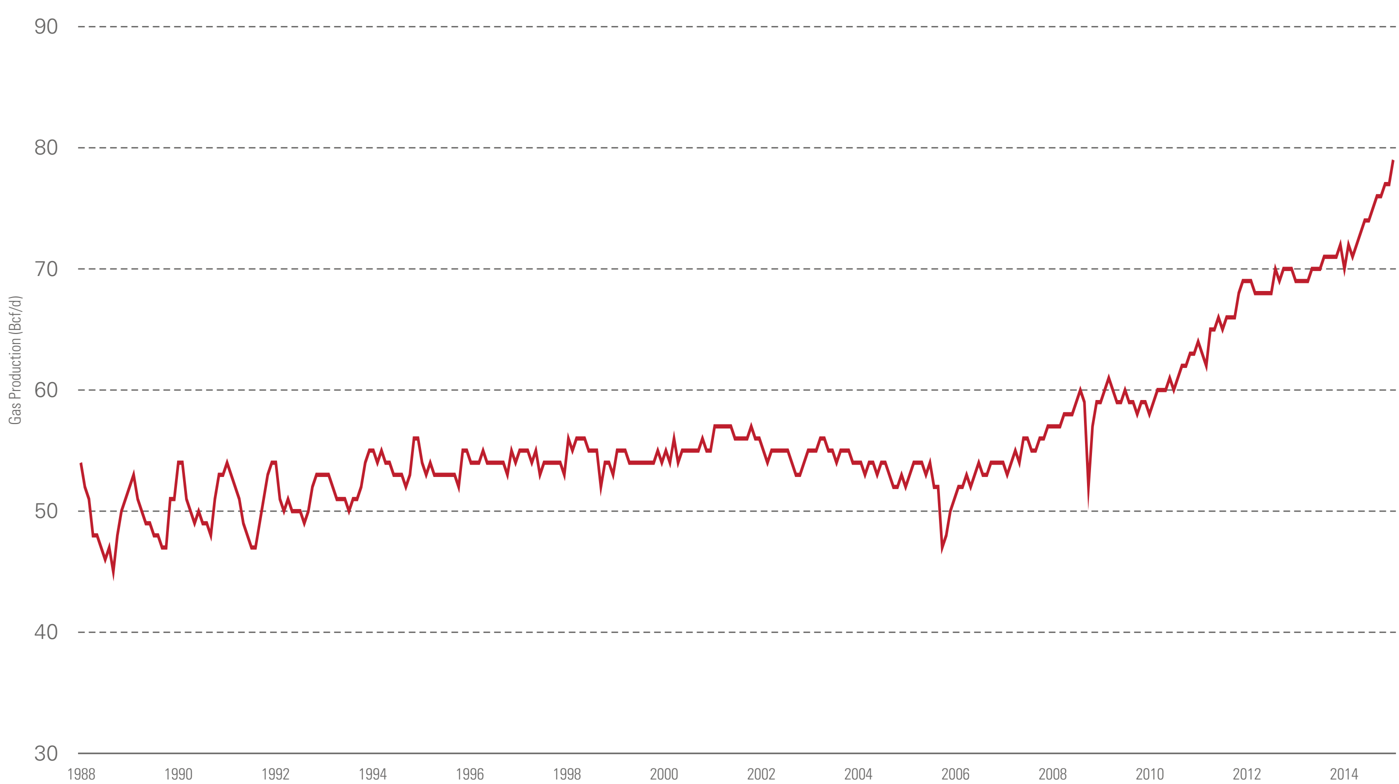
Graph source: Scotiabank Equity Research ('The Playbook'), September 2014 my family lived there. I quarried the flat-surfaced, square edged rocks from the rock piles that my father, mother and my older siblings had deposited around the land.

It was a hot summer, that summer of 2001, and eventually, in search of the right rocks, my wife and I would drive the truck back and forth across the land checking the stone strewn fields for rocks of the right shape and size. That is when the answer to some of my questions on my parents' financial failure occurred to me. The land was on the flank of the Milk River Ridge, the escarpment that forms the continental divide between the Mississippi – Missouri drainage basin and the Saskatchewan drainage basin. It is very hilly and very rocky. It was not high quality grain farm land – not bad for pasture but, with just half a section, that use could not support a family. The land is beautiful, there is a stunning close up view of Old Chief Mountain, a mountain a few miles away in Montana that is a sacred location for the Blackfoot First Nation. It should have been a park or, as it is now, part of a big ranch, not a mixed farm. My parents fought an unwinnable battle to eke a living from that land and lost. The economy rewarded the farmers with the better land, the ones who used their winnings to buy more land which they could more efficiently farm with modern equipment which they also bought. As I looked around at the abandoned equipment, a pull type combine, multiple horse-drawn wagons, I realized that my parents never had a chance in the changing economy of their day. As the realization came to me my tears fell to the same soil that my family's sweat had so long ago quenched.

My parents' marketplace for farm products and ours for hydrocarbons have four key parallels:

1. **Nothing competes with the best quality land.** Both are an over-supplied market with the strongest factor in profit margin being the quality of the land. The price settles, providing thin margins for many, no profit potential for some and strong economics for only a few.

US NATURAL GAS MARKETED PRODUCTION HISTORY (BSCF/D)

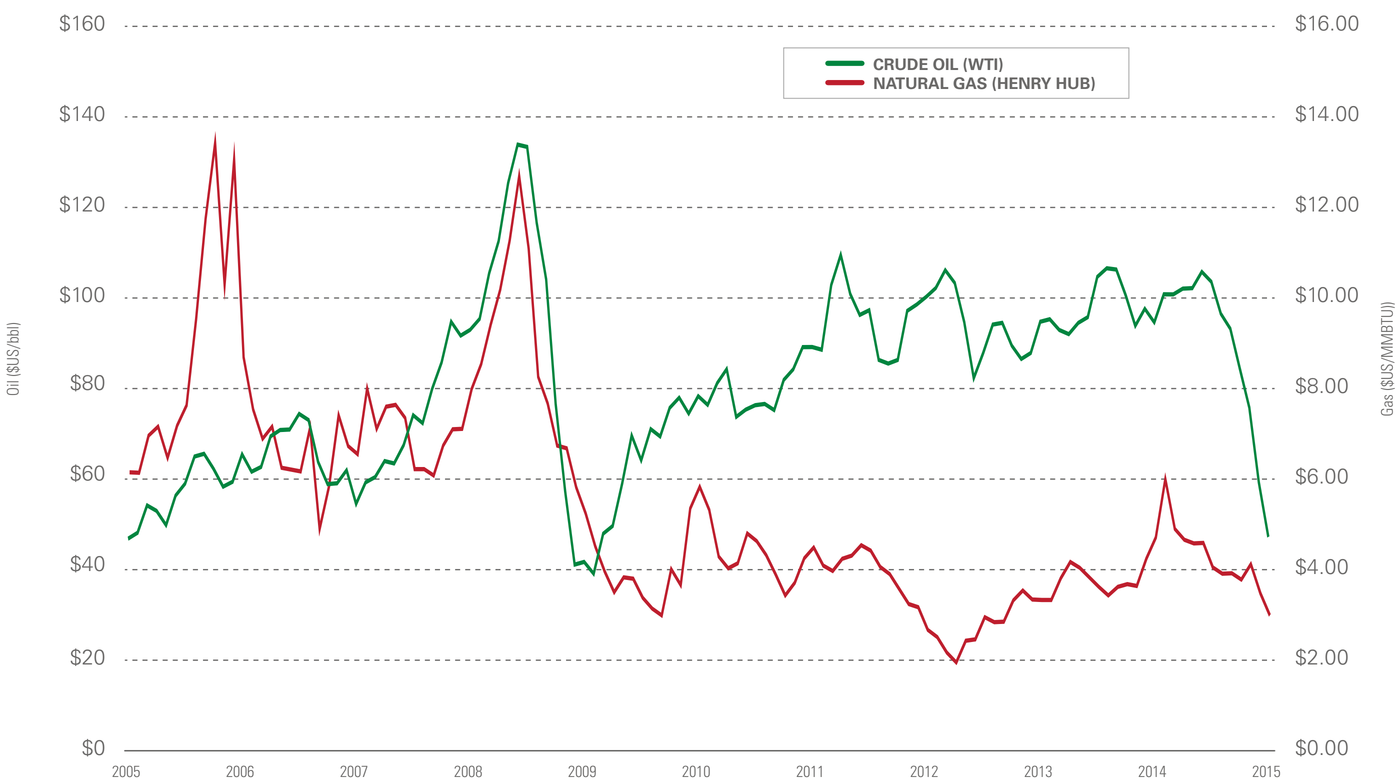


The above chart shows the remarkable growth in US Natural gas production. The growth is attributed mainly to shale and tight gas and oil (solution gas) projects. The incremental production has displaced some Canadian gas out of some previously held markets in both Canada and the USA.
Data source: US Energy Information Administration ("EIA").

2. **The combination of high-quality and large-size open doors for business options, including vertical integration, to meet the needs of the business that the marketplace fails to meet.** In both cases, maximum margin advantages accrue for large scale and high-quality and it must be both – the market does not accept extra size for lack of quality or extra quality for lack of size. The biggest and best get bigger; the small or poor quality, like my parent's farm, are likely to struggle to survive. Big, high-quality operations have the financial capacity to attract capital, to adapt to changing markets, to invest in the equipment needed to transform products to a more marketable form or to invest in the infrastructure required to process and deliver products.

3. **Innovation and operating effectiveness provide advantages, until competitors imitate or surpass.** With the quality and size to compete, new technology and better methods are required to gain the widest margin. The struggle for market share at the toe of the supply cost boot, the fight among those with a chance to win, is with more efficient machinery and better methods yielding lower costs as well as market access assurance through vertical integration and/or long-term delivery contracts which only the most profitable can undertake. The successful farmers of my parents' day were buying bigger machinery to plant and harvest and larger trucks to deliver their grain and they were able to divert their land to grow feed crops for their livestock or food crops based on their market read. We have consistently observed this in the gas market since 2008, as year-over-year, third party research shows that supply costs are coming down within the same plays, demonstrating the impact that technology and learnings are having on relative economics.

NORTH AMERICAN BENCHMARK COMMODITY PRICE HISTORY



The above chart shows that prices have averaged nearly $US 4 per MMBtu since the great recession. Given the US production growth since 2009, it may be prudent to expect softer prices in the near term.
Data source: US Energy Information Administration ("EIA").

4. **Product diversity mitigates commodity downside risk.** Finally, and my parents had just this one of four on their side, product diversity helps manage swings in individual commodities. My parents had a mixed farm, cattle and grain. 7G has liquids-rich gas, liquids priced against oil and natural gas and ethane priced against gas. A year ago, both gas and condensate prices were strong. Before that condensate was strong but gas was weak. Now both prices are weak and we have two nearly independent prospects for revenue recovery – not just one and we can rail our liquids to different markets. For the vast majority of our liquids potential, we aren't tied to a low-reward market with a ribbon of pipe. We are also diversified from a sales standpoint; starting in December 2015, all of our gas will be sold into the Chicago gas market, while virtually all of our condensate will continue to be sold into the Alberta market, and NGLs will be split between Alberta sales and US Midwest sales. Also, forward curves for different products do not move in tandem and we have and will continue to be opportunistic and hedge to lock-in margins when our investment economics look attractive based on prices in the futures market.

Unless a business is built to win in all four of these areas, it is built to be lucky, not to be good. Of course, to be successful, a business needs capital as well but it seems to me that access to capital is a derivative of these four advantages – not an isolated characteristic. I suspect that with these four advantages a producer, whether of petroleum or agricultural products, has a strong probability of getting access to the capital required to maximize its shareholder value. As a management team, over the past four months since the IPO, 7G's spokespeople have expounded upon this fixation on high-quality land, advancing technology, product diversity, vertical integration sufficient to deliver fungible products to open markets and the size required to do all of that. I learned these lessons from my parents' experience and they learned them the hard way: the free market system is ruthless. It is persistent. It is overbearing. It demands the lowest cost supply and when it has devoured that, it seeks more but always the lowest cost available. In an open market, like the North American gas market, a business built with these truths in mind is not so reliant on luck and has a high probability of succeeding.

We have been in the spotlight for many investors and analysts. I can only speculate as to the reasons: recent collapse of commodity prices, newly listed on a public stock exchange, very high projected growth rate with firm pipeline transportation commitments, coverage by a significant number of bank research analysts, tight liquids-rich gas (a high profile sub-sector of the industry), balance between oil and gas price exposure. Investors and analysts have been curious to understand our thinking about business strategy. In the following paragraphs I will summarize the basis of our thinking in the areas attracting the most curiosity:

The North American gas market is oversupplied.

The North American gas market seems close to the free market economy that my introductory economics textbook described. The majority of gas trading is done with minimal regulation in free market economies. Classical supply and demand theory would suggest that price can be the mechanism expected to bring into balance supply and demand. Recent gas price drops can be attributed to oversupply, the result of huge growth in production capability in recent years due in large part to commercialization of recovery processes for (largely previously known) shale gas and tight gas and oil. Markets tend to overshoot the balance point when correcting so there may be some gas price recovery pressure on recent prices, but increasing supply is imposing downward pressure on the price. Gas producers, Seven Generations included, have been very successful in reducing their costs. The result is that more gas can be produced at any given price creating further downward pressure on gas prices. Rather than assuming a recovery to the post January 2009 average of nearly US$4.00/MMBtu, a safer assumption for strategic planning purposes would be that gas prices will

An aside on commodity pricing (my view anyway)

For my entire 40 year career, international oil prices have been set in the global market, for seemingly political reasons, by a small group of producing countries with both oil supply and (external and/or internal) political instability in abundance. Oil prices have cycled up and down as global consumption has increased. With each wave of new technology, deep off-shore drilling and production, arctic drilling and production, oil sands recovery technologies, tight oil recovery, new business opportunities open up and the supply keeps coming. I am among those that believe that the onset of permanent oil scarcity is imminent, that we have nearly exhausted the earth's reasonably accessible supply. I confess that I started my career expecting to be in business the day that oil production peaked, staking a claim to that very barrel that marked the world's maximum productivity but now it appears that I am running out of career faster than the world is running out of oil – that is a good thing.

Gas prices in North America are set by an open, competitive market, about as close to the classic free market described in my economics text book as one can get. One significant barrier to entry for gas developers, however, is inadequate transportation and processing infrastructure in some regions. Again, the advantage goes to the developer that has both the size and quality and, again, it must be both to underpin expansion of market access infrastructure from local plants and pipelines to transcontinental pipelines.

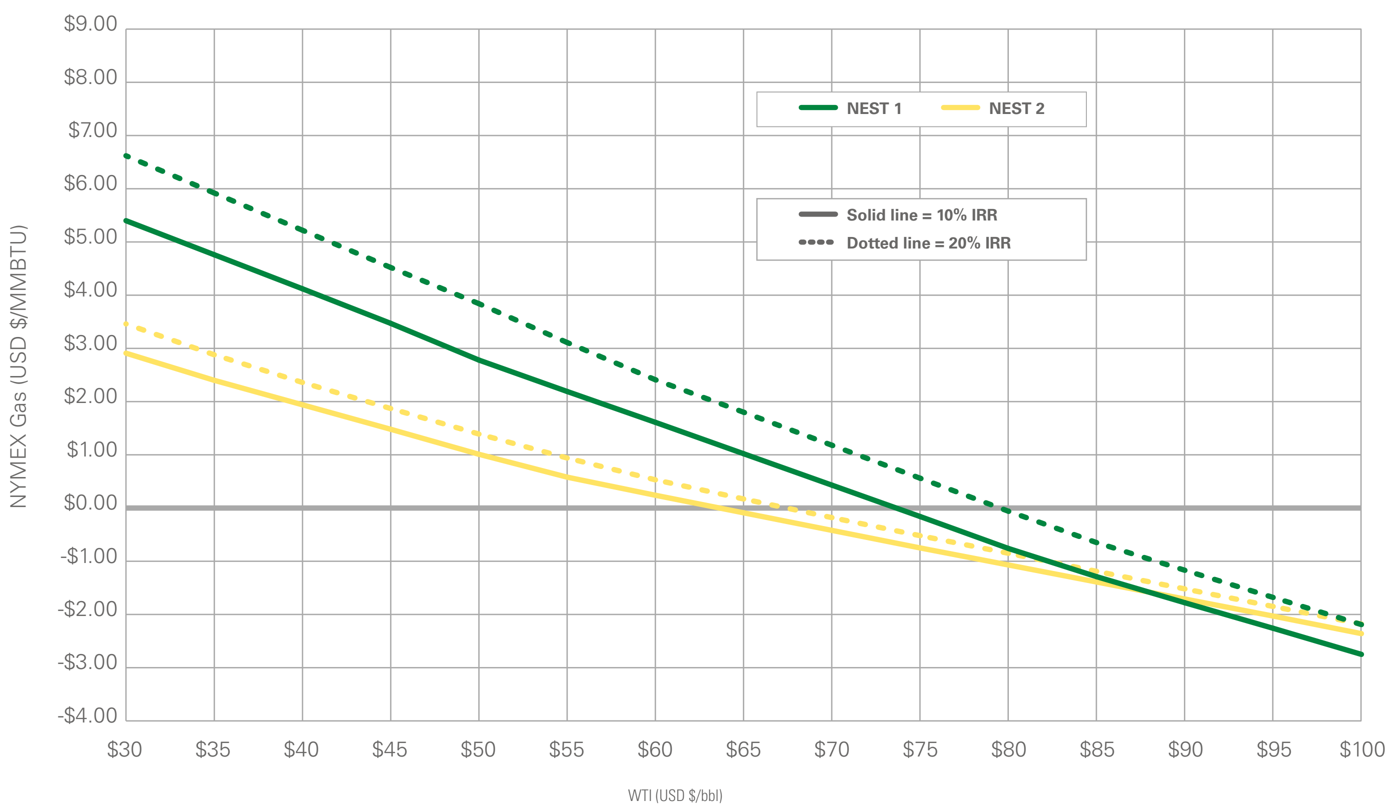
remain low and that we can expect gas prices to average significantly less in near years. The gas price needs to settle at a level that will discourage development of more costly sources and encourage the development of new markets such as gas-fired power generation, petrochemical production and liquefied natural gas ("LNG") export.

Margins should yield attractive economics for projects at the toe of the supply cost boot.

North America is constantly in need of renewal of the supply of gas because production from existing wells generally declines and there has been some, albeit modest, growth in the North American Gas Market in recent years. Back to my introductory economics textbook: when an efficient free market needs additional supply it sends a price signal that motivates suppliers to deliver sufficient commodity to meet the demand. If transportation and processing infrastructure are in place, the lowest cost suppliers, those at the toe of the boot, should be the first to be willing and able to drill new wells to meet new demand. The market demand may be such that several of the projects that are closest to the toe of the boot are lured into growing supply. If that is the case then the ones closest to the toe should have wider margins than the one which just barely met its owner's profitability criterion. In fact, if the market is calling on enough new supply, economics can be quite attractive for the lowest cost suppliers. One inefficiency that the market has is that it takes time and capital to respond. The owner of the lowest cost gas supply will only be able to bring a portion of its gas to market due to practical limitations of financing and managing its rate of growth – so even though the market calls for the lowest cost supply, only some of it can be delivered in short order. To meet demand prices must be sufficient to call gas from the second, third, fourth and so on lowest cost suppliers. This means that the projects at the toe of the boot can have quite attractive economics. To illustrate: in the mid US$2 to US$3/MMBtu range, where benchmark gas prices have been in 2015, about half of the projects on Scotiabank's chart presented previously would meet the Scotia analysts' profitability criteria given compliance with the other assumptions (including oil price) used in the chart. That means that while a lot of projects may contribute gas to meet the demand, some will have marginal economics, while those nearest the toe of the boot might still have very attractive economics. For 7G's best lands, Nest 2 in particular (as defined in prior corporate

INTERNAL RATE OF RETURN: TYPE CURVE SENSITIVITIES

(pre-tax, management P50 type curves)



Key Assumptions:

i) Pricing: NGLs as % of WTI: C3 45%, C4, 55%, Alberta C5+ 101%. AECO basis: > of 15% NYMEX or $0.40/MMBTU. $0.82 USD/CAD FX rate.

ii) Transportation: sales gas $0.35/mcf. Recovered liquids: $3.50/bbl. Average opex (first 3 years) = $4.07/boe (Nest 2), $5.17 (Nest 1).

iii) $6.0MM natural gas deep drilling credit pool. 1,193BTU/scf rich gas. 14.7% raw gas shrink (fuel gas & NGL extraction).

presentations and our IPO prospectus), recent prices have been sufficient to encourage the Company to continue growing production to meet demand and gain market share.

One aspect of most of the lowest gas supply cost gas projects on the Scotiabank chart is that the gas that they produce is liquids-rich. At the oil price that Scotiabank used, several of the projects at the toe of their supply cost boot can meet the profitability criterion without receiving any revenue from the gas. For liquids-rich gas and tight oil that is rich in solution gas, the second commodity is often very important to the overall economics. While the US$81 per barrel (presumably WTI at Cushing) that Scotiabank used in their analysis seems high relative to oil prices that have prevailed so far in 2015, that number seems quite conservative if we compare it to the average price since January 2011 (which, according to the EIA data presented on a previous chart, was more than US$90 per barrel). So a question that arises is: how well do the projects at the toe of Scotiabank's boot compete with the others if the oil price is much lower? To give you a sense of how Seven Generations' Nest 2 Montney type curve compares, we estimate that the gas price required to get a 10% before tax internal rate of return if the oil price is $50 US per barrel would be US$1.01/MMBtu (see graph on page 13 for other cost & price assumptions). While the contribution of the liquids to the profitability of the well is greatly reduced on a boe basis, at US$50 the liquids are still fetching nearly three times the revenue as gas (on a heating value equivalency basis). We think that, unless the liquids are severely impairing productivity (which can happen), rich gas is still preferable to lean gas given the same resource rock quality. With a spectrum of liquid gas ratios to call upon from our lands, we are still focusing development on Nest 2 which, on management's best estimate type curve, yields 110 barrels of field separator condensate per million cubic feet of raw sales gas during the first six months of production.

How oversupply may ultimately affect project valuations.

Historically, with an outlook to shortages of oil and gas and a constant need for the industry to find more petroleum, and therefore to develop increasingly marginal resources, there was some comfort in valuing projects and companies on the basis of their reserves. With reserve evaluation methods largely standardized (at least within securities trading jurisdictions), values of projects could be compared reasonably objectively using reserve values. These estimates use forecasts of production, capital expenditures, operating costs and burdens, along with the evaluator's commodity price forecasts, to estimate a net present value for the resource. With resource plays and other large, early stage developments, the independent evaluators have adopted standards as to how far into the future, and on what degree of assurance of development, production and markets they will include or not include production. With resource plays, for example, the evaluator may book five or 10 years of forecast production if it is comfortable that the projects will be sanctioned and financed by the developer, approved by the regulators and that the products will have markets and transportation. For very large resources, like 7G's Kakwa River Project, the five or 10 year forecast may be just a fraction of what the developer expects to achieve in terms of recovery and peak production rate. Using a limitation of production, given demonstrated operating costs and other burdens translates quite well with the finance industry's standard practice of evaluating a Company based on a multiple of its EBITDA or cash flow generating capacity. Stated differently, in an oversupplied market, large resources with early stage projects that are still in a rapid growth ramp seem likely to be conservatively valued by standard reserve valuation processes. Much of the owner's expected ultimate recovery does not make it into a defined reserves category.

The coal-fired power generation industry may be a good example of where gas project valuation may evolve. Coal-fired electric power generation projects may be backed by decades or even centuries of coal supply. For many, practically, the coal reserve backing the forecasted revenue is irrelevant to value. It doesn't matter to the value of the firm if it has 100 or 400 years of reserves. What matters is how much it is able to earn in a relatively stagnant demand market with its market share. Given the gross oversupply in the gas market, it may be prudent to consider market share and earnings more prominently in valuation.

The most significant conclusion from this line of thinking is that it is important to capture and hold market share, including transportation and processing that enables market access. This then gets us to the response to an often asked question, "Would it be better to shut in and save the Company's reserves to deliver at a higher price?" There are a lot of reasons why the answer to the question is "no", among them:

- We have robust economics on the land that we are focusing our development activity at prices we have averaged over the past six months and at forward prices that we can currently hedge;

- We have transportation and processing contracts which are coveted by other operators who find themselves already short of market access and the easiest way to preserve those is to fill the demand;

- We have an inventory (by management's estimate) of more than 600 wells in our most economically attractive area. This inventory represents seven to 10 years of drilling at the rate required to ramp up production in accordance with our marketing agreements. Deferral of production by more than 10 years is likely to negatively impact our value for the most optimistic gas price forecasts and the lowest costs of capital;

- It will be easier to capture more market access as we get larger. With production at one-fourth to one-third of our contracted (2018) peak delivery rate, we presently have less revenue and less credibility to engage in negotiating for more pipeline space;

- We need to continue to advance technology and operating methods that will reduce the cost and keep the Company in the race for the toe of the supply cost boot. We believe we can find ways to make the more than 300 estimated undeveloped well locations in Nest 1 more profitable and make development of those resources more resilient to low prices. The same can be said for our deep high pressure sour lands and our Wapiti lands; and

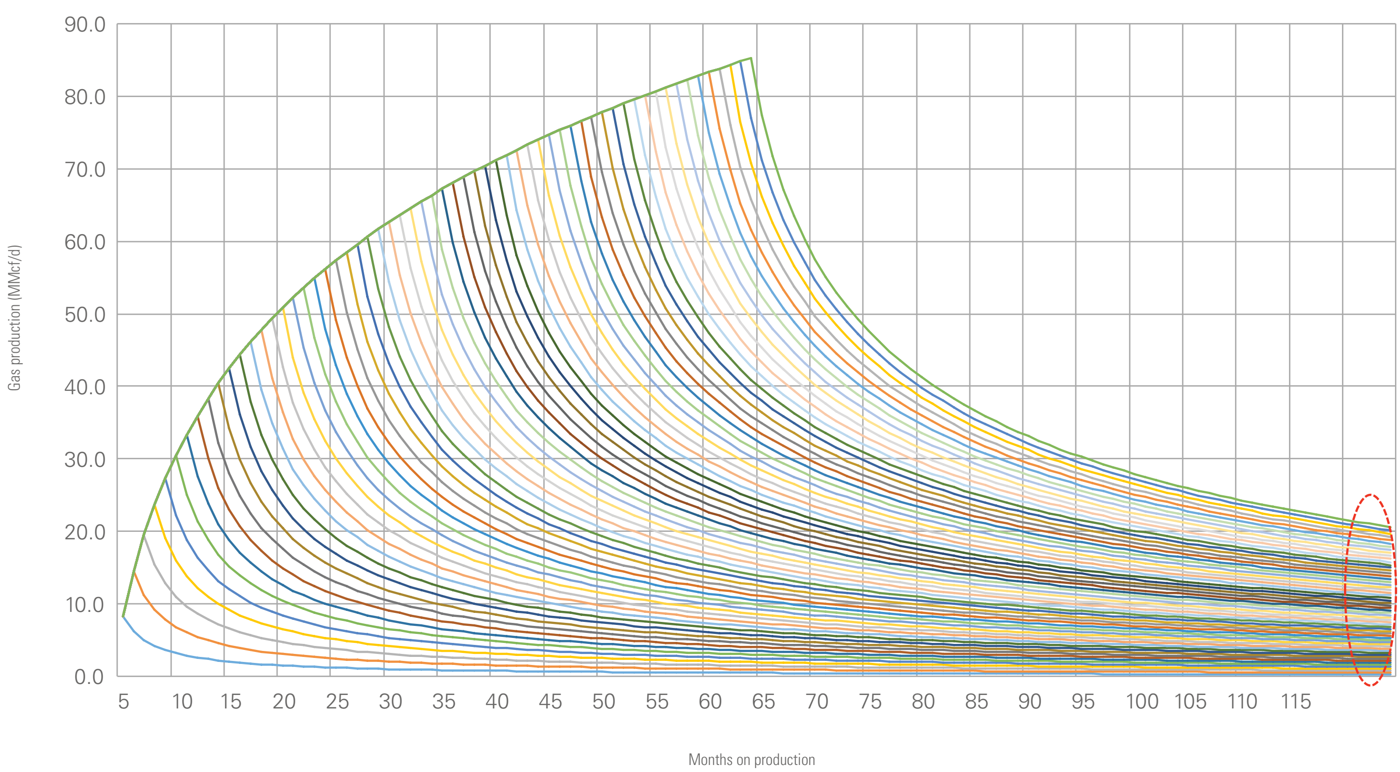
- We can use the downturn in the service and supply industry to engage the most experienced contractors and the best equipment under the best terms, helping to minimize short term cost and maximize long term value through accelerated learning and improved efficiency.

The persistent need for new supply in the North American gas market.

The North American gas market is constantly in need of additional supply. Existing wells decline and there has been some growth in demand in recent years. One presentation that I saw a few years back suggested that the base gas production for North America, at the time dominated by conventional gas production, declined with a constant percentage of about 20 to 25% per year. Early in the development of tight and shale gas wells, operators often experienced more than 50% decline in the first year with lower rates of decline in successive years, often reaching decline rates of less than 10%, or nearly flat production. Since then the market and the base production has evolved to be dominated by the steeply declining shale and tight gas production which should imply that, if new wells are tied in to just meet demand, with no surplus capacity to supply, we should need to replace a large proportion of North America's production each year. As the tight gas industry has matured, there has been a buildup of late life wells providing a base of production that produces with very low decline rates. The situation may be aggravated by the learning of 7G and others that, if wells are constrained when first brought on to production, the overall decline rate is reduced such that the cumulative production of the constrained well exceeds the cumulative production of the aggressively produced well, perhaps even significantly within the first year. What this means is that producers who have a low decline rate base, especially those who have found that initial performance can be improved by constraining new

STACKED GAS PRODUCTION EXAMPLE: LOW TAIL DECLINE ANALYSIS

60 wells, 1 new per month for 5 years



wells, have an advantage in holding market share to those who are in early stages of development and still ramping up. The latter group have no flat base production and have to invest in new gathering, processing and shipping facilities to establish a market share. Again, there is a clear first-mover advantage to securing and holding market share. The analysis below demonstrates this point visually: it is a stacked line graph of gas type curves, with a new type curve added once every month for five years, followed by declines on all wells for the remaining five years. The type curve used is a typical tight gas well, with a steep initial decline (77% in the first year) followed by a flattening in the tail such that, after 10 years, the annual decline rate is in the 7 to 8% range and produces an extremely flat production base. As can be seen in the graph, after five years of no drilling, the wells in aggregate are still producing at 20 to 25% of the peak production point. We are now five to seven years out since tight and shale gas drilling emerged, and this stacked production base is clearly manifesting itself as a supply glut, evidenced most strongly in the persistently high natural gas storage levels at central storage and clearing hubs.

Who needs expanded market access infrastructure?

Gas demand has been relatively stagnant in North America for a few decades. In the most recent years demand has risen to supply new power plants and oil sands plants. Supply of gas by estimates that I am aware of has totally outstripped demand, putting us into a surplus of supply situation. I think pretty much everyone accepts that. A problem that has arisen though, is the location of the market access infrastructure; the transcontinental pipelines that ship gas from producing regions to consuming regions and the gas plants that convert raw gas to its marketable components are not in close proximity to the new lost gas supply. There is about enough pipe for producing regions to supply consuming regions with gas and suppliers in those producing regions are happy enough. Owners of new shale and tight resource developments are more often challenged to find the infrastructure that they need now or that they foresee needing in the future to get their gas to market. Often the stranded gas, the gas with no market access, could be the lowest cost supply if it had access to market. Getting access to market is not as simple as it may seem. Developers may not have enough gas to support a new pipeline by themselves so they need to act in aggregate. Usually a mid-stream utility company, a pipelining and processing specialist, will facilitate the joint action by a group of resource owners to support new infrastructure addition. The producers need to test their lands to gain an understanding of the recovery potential and the threshold price. They then have to determine how much gas that they can deliver with a strong expectation of delivering that gas at a cost that is below the price. Generally market price contracts float with the market price – so the producer must determine his own costs and estimate where the price will be which, as discussed earlier in this letter, is really an exercise in determining where a project fits on the supply cost boot. The producer must ask himself, "Will we be able to produce gas at a profit given the price pressures due to the oversupplied market?" Obviously it is going to be tough for developers with gas supply costs in the middle of the supply cost boot to commit to any market. How can their Boards approve a huge commitment to pipeline and processing capacity when they can't be confident that their gas can be produced profitably? This implies that market access infrastructure expansion must be led by the developers at the toe of the supply cost boot. For Canada, that may mean that the projects at the toe of the supply cost boot (remember: largely liquids-rich gas projects) are the ones that need to underpin new LNG projects off of Canada's west coast. For developers such as 7G, those with a lot of growth potential, those with an array of gas resources, much of it at or near the toe of the boot, there is a need to use the low supply cost and large resource position to secure the best market access arrangement possible. That is a focus for us. In my view, not keeping market access up with our ability to develop high quality resources is the biggest risk we have in maximizing shareholder value. As stated earlier, reserves and resources aren't much good if they cannot be produced for decades. So North America's gas production and gas demand are in balance and, with minor adjustments year-over-year, there is enough resource to keep the market satiated. Some of the resource producing regions, especially those with large, high quality resource plays, have inadequate market access infrastructure and will have to build infrastructure to access markets. In turn, that new infrastructure may make some existing capacity to higher cost supplies redundant. To get the lowest cost supply, North America needs the new infrastructure to expand markets beyond our shores. To get market access, many quality resource owners will have to tackle the local infrastructure shortage problem.

Here are some other possible derivatives of the present market access infrastructure situation:

- Astute high-cost developers may realize their predicament and try to off load their market access commitments or they may try to acquire assets from developers who do not have capacity. Either way, market access is likely to become more valuable;

- There are economies of scale in larger pipelines, economies that can result in a lower tariff for the infrastructure subscribers, economies that can shift gas resources toward the toe of the supply cost boot. Developers are motivated to work with others to aggregate enough volume to secure these economies or they may be motivated to capture additional high quality resources so that they can commit to larger volumes themselves;

- Infrastructure expansion projects are financed over many years, probably a bias to the high end of the 15 to 30 year range. This is done to keep the tariff as low as possible given the expected useful life of plant and pipeline infrastructure. Developers need to consider the anticipated contango as the market works its way through the lowest cost supply and takes on more and more expensive gas to meet its needs over the life of the infrastructure commitment. Developers will also consider the downward pressure on supply costs resulting from what the industry has been able to achieve with new equipment and operating methods already, and the probability that this will continue to reduce costs, making much of the currently marginal resource more attractive in the future. Many producers will take the view that not all of the gas has to have high profitability in the present market;

- Coordination of midstream and upstream companies into a joint infrastructure expansion and execution plan can be very time consuming. Those developers that have the financial capacity may wish to save time by driving the terms of the projects, either for their own gas or for their own gas plus competitor gas, but at terms driven by the major proponent. Developers with large, high-quality resource positions may wish to bolster their positions in order to be in a better position to drive terms. Gas developers may, at least temporarily, vertically integrate into portions of the infrastructure business to get over the need for time consuming consensus building. Many resource developers, especially in the US where there is a corporate vehicle that passes through the taxation to the shareholder, are spinning out their midstream assets now that their needs have been met under direct management of the midstream business during the growth phase; and

- Full vertical integration may provide for overall project profitability or at least provide that appearance outwardly. It would seem ridiculous for a high cost developer to develop its own resources at a higher cost than it could buy production from others. If viewed that way, the fully integrated companies proposing LNG projects may consider export at the price set by the LNG exporters on the Gulf of Mexico to be an alternative to their own investment (adjusted for land and shipping transportation cost and other cost differences). If that is the case, then announced projects may be cancelled or delayed if they can't compete with buying LNG at North American benchmark prices on the Gulf. If such projects are cancelled or delayed, the proponents may want to dump gas from the drilled wells into existing over-loaded North American infrastructure.

The importance of technology.

We believe that the gas market is so competitive that the business has to be attacked on two fronts to maximize shareholder value:

1. Securing the highest quality assets including the hydrocarbon resource and the market access infrastructure (which can best be secured with both size and quality); and

2. Positioning for competency in capturing the potential benefits of new technology and better operating practices.

A business that does not secure high quality resources cannot compete and cannot be fixed. A business with high quality assets must competently search for more efficient practices, lest it be heft up into the instep of the supply cost boot by those who are truly the low cost suppliers. The shale and tight gas resource development business is still fairly new. Individual wells are expensive so developers use caution when testing new methods – looking to advance the business incrementally to reduce both the risk and the cost of any adjusted practice that is not successful. (For example, over the last five years or so, and with about 40 wells, by improving many types of equipment and operating practices, Seven Generations has been able to cut its per metre of lateral drilling cost by roughly 50%. The success ratio of the techniques tried was very high and the ideas for further cost cutting have not been exhausted.)

What this means to us is that, to be successful, a developer has to have large, high quality resources and participate in the technology race. The technology race is ongoing. As long as competitors are finding ways to advance the value of their projects, there is a risk of them leap-frogging to a position closer to the toe of the boot, displacing the non-technical developer out of the market. In other words, the technology race is a race that can be lost but never won – another reason to keep advancing the business in the current commodity price environment.

Summary:

Here are our key strategic leanings and steps for moving forward:

- Continue to develop but focus on the large inventory of Nest 2 drilling where, we believe, profitability is most resilient to low prices. We believe that our Nest 2 asset is among the 'toe-of-the-boot" opportunities in the North American industry and, therefore, prices will settle at levels than make its development financeable;

- Continue to apply learnings in Nest 2 to Nest 1 development pad locations. The majority of our optimization work to-date for drilling and completions has been in Nest 2 and a number of Nest 1 locations have displayed well performance and early-stage economic performance well above type curve;

- Shelve the delineation and production capital used to establish type curves of deep high pressure sour and Wapiti sour and zones other than the Upper and Middle Montney because their resources are not needed for a long time without expanded access to markets and they are not profitable or, at best, marginal at the current state of technology adaptation and price environment;

- Continue to experiment to find ways to increase capital efficiency and reduce costs in search of two benefits: direct improved profitability to the lands upon which the technologies are demonstrated and possible applications to other lands such as Deep Southwest and Wapiti that have the potential to move development of these resources to the toe of the supply cost boot;

- Use the continuing activity in the industry downturn to upgrade to the best equipment and services the Canadian gas industry has to offer, and negotiate competitive pricing that recognizes the new market reality;

- Aggressively pursue quality market access expansion opportunities by ourself, with potential upstream partners and with potential midstream partners;

- Look for accretive acquisitions that offer the potential to assist us to balance market access with our resource size. This may include acquiring more land that has resources at or near the toe of the boot. It may include projects or companies that have excess transportation capacity that we can use. In all cases we will look for a strong probability for our pre-deal shareholder value to increase as a fully realized result of the transaction; and

- Use the financial options available to us (debt, equity, joint venture partnerships, offering transportation and processing) to the best advantage in order to continue to grow shareholder value.

Finally, I would like to thank the Board, staff and contractors working for Seven Generations for their professionalism and dedication displayed in their work. I am writing about a dedication that goes far beyond geological maps, or invoices processed, or pipe welded. I am thanking them for the things that they do to contribute to the workplace and the community. Our Code of Conduct is attached. Our broader team strives to deliver what that Code intends, that we live up to the spirit of our name, that we exist to serve the greater good. We believe that to thrive for the long term a corporation must stand out as being different and better than its competitors in meeting the needs of its stakeholders. My thanks go to the employees that talk about their profession at schools in the region, the contractors who identify safety hazards so that we can take measures to protect them and their coworkers, the suppliers of goods and services who generously support our annual golf tournament that benefits Grande Prairie's Queen Elizabeth Hospital Foundation, the employees who proudly tour regulators and community leaders through our operations, and everyone who contributes to our stakeholder engagement efforts. The Grande Prairie area, The Peace Region, as they appropriately call themselves, have welcomed us to be part of their community. We proudly call ourselves Seven Generations Energy Ltd., Grande Prairie's Energy Company.

Sincerely,

Pat Carlson, P.Eng.
CEO

Reader Advisory: for important additional information regarding the forward-looking statements that are set forth above and the risks associated with achieving the results described in those statements, as well as information regarding certain abbreviations have been used, please see the Company's Management's Discussion and Analysis dated March 10, 2015 and in particular the disclosure provided under the heading "Forward-Looking Information Advisory".

SEVEN GENERATIONS CODE OF CONDUCT

We believe that companies have only the rights given to them by society. While people have a natural entitlement to basic rights, corporations are an instrument created by society to provide its needs and ought to have no expectation of basic entitlements other than equitable rights with other corporations, including those wholly owned by a person. We recognize that rights, sufficient to build and operate an energy project, can be granted and taken away by society. Over the longer term, companies can only expect to thrive if they serve the legitimate needs of society in which they exist. To thrive, companies must differentiate, rise above the pack, standout as being among the best with all of their stakeholders. At Seven Generations Energy Ltd., we acknowledge this granted entitlement and accept from our stakeholders a duty to thrive and an understanding of the need to differentiate.

Specifically, in acceptance of this challenge to differentiate with all stakeholders, we acknowledge:

1. The need of society for us to conduct our business in a way that protects the natural beauty of the environment and preserves the capacity of the earth to meet the needs of present and future generations;

2. The need of Canada and Alberta for us to obey all regulations and to proactively assist with the formulation of new policy that enables our company and our industry to better serve society;

3. The need of the communities where we operate to be engaged in the planning of our projects and to participate in the benefits arising from them as they are built and operated;

4. The need of our business partners and infrastructure customers to be treated fairly and attentively;

5. The need of our suppliers and service providers to be treated fairly and paid promptly for equipment and services provided to us and to receive feedback from us that can help them to be competitive and thrive in their businesses;

6. The need of our employees to be compensated fairly and provided a safe, healthy and happy work environment including a healthy work life – outside life balance; and

7. The need of our shareholders and capital providers to have their investment managed responsibly and ethically and to earn strong returns.

We see ourselves as being in the service business, serving the needs of our stakeholders. We seek satisfaction for all stakeholders. Differentiation is imperative. We support an open and competitive business environment, recognizing in the competitive world that we envision, only those who best serve their stakeholders can expect the support required to survive for the longer term.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A"), dated March 10, 2015, is Management's assessment of the historical financial position and results of Seven Generations Energy Ltd. (the "Company" or "Seven Generations") and should be read in conjunction with the audited annual financial statements (the "financial statements") as at and for the years ended December 31, 2014 and 2013. The financial information contained herein has been prepared in accordance with International Financial Reporting Standards ("IFRS"). All dollar amounts are expressed in Canadian currency, unless otherwise noted. Certain financial measures referred to in this MD&A are not prescribed by IFRS. 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" and "available funding". 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".

This MD&A contains additional generally accepted accounting principles ("GAAP") measures, non-GAAP measures and forward-looking statements. Readers are cautioned that the MD&A should be read in conjunction with Seven Generations' disclosure under the headings "Non-GAAP Measures", "Forward-looking Information and Advisory" included at the end of this MD&A.

ABOUT SEVEN GENERATIONS ENERGY LTD.

Seven Generations is a Canadian company focused on the acquisition, development and value optimization of high quality tight and shale hydrocarbon plays. Presently, the Company has a single focus area, the Kakwa River Project, a large-scale, tight, liquids-rich natural gas property located in the Kakwa area of northwest Alberta (the "Project").

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 on its investment needed to add wells to the Project. Horizontal wells in the primary development block of the Project have exhibited high production rates of natural gas, condensate and other natural gas liquids ("NGLs");

- **Size of Resource** – the Company controls approximately 70,200 net acres of Montney land which as at December 31, 2014, are estimated by McDaniel & Associates Consultants Ltd. ("McDaniel"), Seven Generations' independent reserves and resources evaluator, to hold approximately 680 net wells (89% undrilled), which have gross proved plus probable reserves of 789 MMboe;

- **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 98% 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.

Independent Reserve Evaluations

Reserves and Resources (MMboe)	December 31, 2014	July 1, 2014	December 31, 2013
Proved reserves [1]	421	328	107
Proved plus probable reserves [1]	789	649	283

(1) Company gross reserves as determined by Seven Generations' independent reserve evaluator.

The Company's independent reserve evaluators, McDaniel & Associates Consultants Ltd., completed independent reserve evaluations effective December 31, 2014. Based on the evaluator's report and the assumptions made therein, Seven Generations' gross proved plus probable reserves increased 179% to 789 MMboe (approximately 53% of which is condensate and other NGLs) when compared to the December 31, 2013 estimates. At December 31, 2014, the independent reserve evaluators estimate the Company's total gross proved and probable reserves have a before tax net present value of $7.1 billion compared to $3.1 billion (using a 10% discount rate) from the December 31, 2013 reserve report. The Company's oil, NGLs and natural gas reserves are located primarily in the Kakwa area. The July 1, 2014 reserves and resources were prepared in conjunction with the Company's IPO. For definitions and additional information regarding Seven Generations' reserves estimates, refer to the Company's AIF which is available on SEDAR at www.sedar.com.

Selected Financial Information

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
INCOME STATEMENT				
Oil and natural gas sales [1]	155,383	48,484	534,833	113,184
Royalties	(16,145)	(3,188)	(51,890)	(7,853)
	139,238	45,296	482,943	105,331
Risk management contracts – realized gain	22,163	49	9,737	279
Risk management contracts – unrealized gain (loss)	123,772	(1,978)	141,765	(3,299)
Interest and third party income	1,968	628	4,987	2,896
	287,141	43,995	639,432	105,207
Operating expense	18,966	8,425	54,261	20,615
Transportation expense [1]	13,237	3,286	34,833	6,461
General and administrative expense	7,393	2,052	20,258	8,117
Depletion, depreciation and amortization expense	56,923	13,708	159,447	38,921
Stock based compensation expense	3,897	1,552	11,950	9,556
Finance expense	17,058	9,564	63,641	24,447
Foreign exchange loss	25,560	10,740	47,673	10,897
Liquidity event expense	35,947	-	35,947	-
Gain on disposition of assets [1]	-	-	(4,286)	-
	178,981	49,327	423,724	119,014
Income (loss) before taxes	108,160	(5,332)	215,708	(13,807)
Deferred income tax expense	39,532	293	71,508	351
Net income (loss) and comprehensive income (loss)	68,628	(5,625)	144,200	(14,158)
Net income (loss) per share – basic	0.30	(0.03)	0.73	(0.08)
Net income (loss) per share – diluted	0.28	(0.03)	0.64	(0.08)

(1) Certain comparative figures from prior periods have been reclassified to conform to the current year's presentation.

Well Information

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Number of wells drilled – gross (net)	14 (14.0)	11 (10.7)	49 (49.0)	23 (22.7)
Number of wells completed – gross (net)	11 (11.0)	9 (9.0)	38 (38.0)	17 (17.0)
Number of wells brought on production – gross (net)	9 (9.0)	10 (10.0)	34 (33.7)	14 (14.0)

During the year ended December 31, 2014, the Company drilled 49 gross wells and 34 gross wells started production compared to 23 gross wells drilled and 14 gross wells on production in 2013. The well counts include only horizontal Montney wells. Drill counts are based on the rig release date and on production counts are based on the first reportable production date.

Results of Operations

Daily Production

	Three months ended December 31			Year ended December 31		
	2014	2013	**% Change**	**2014**	2013	**% Change**
Oil and condensate (bbls/d)	14,747	4,480	**229**	11,061	2,390	**363**
NGLs (bbls/d)	10,783	2,291	**371**	6,989	1,749	**300**
Natural gas (Mmcf/d)	112	29	**286**	79	22	**259**
Total (boe/d)	44,178	11,585	**281**	31,136	7,786	**300**

The Company's production for the fourth quarter of 2014 averaged 44,178 boe/d, which represents a 281% increase over 11,585 boe/d in the fourth quarter of 2013 and a 23% increase from the third quarter of 2014 which averaged 35,820 boe/d. For the 2014 year, the Company's production increased to 31,136 boe/d compared to 7,786 boe/d for the same period in 2013, an increase of 300%. Since the beginning of 2014, the Company increased the pace of drilling and infrastructure capital investments that translated into significant increases in production. The Company also utilized various techniques to increase production rates per well including longer lateral lengths combined with larger fracs. The higher production volumes are also related to the completed construction of four "super pad" facilities during 2014, which are well pad sites that contain natural gas compression, separation, dehydration and liquids pumping capabilities.

Commodity Pricing

	Three months ended December 31			Year ended December 31		
	2014	2013	**% Change**	**2014**	2013	**% Change**
Average Benchmark Prices						
Oil – WTI (US$/bbl)	73.15	97.46	**(25)**	86.50	97.98	**(12)**
Oil – Edmonton Par ($/bbl)	74.37	86.25	**(14)**	93.94	93.24	**1**
Natural gas – AECO NGX 5A ($/mcf)	3.58	3.48	**3**	4.78	3.12	**53**
Average exchange rate – (CAD$ to US$)	0.881	0.953	**(8)**	0.914	0.971	**(6)**

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

	Three months ended December 31			Year ended December 31		
	2014	2013	**% Change**	**2014**	2013	**% Change**
Oil and condensate ($/bbl)	69.93	80.63	**(13)**	85.34	85.49	**-**
NGLs ($/bbl)	21.50	24.54	**(12)**	24.10	18.76	**28**
Natural gas ($/mcf)	3.81	3.79	**1**	4.50	3.34	**35**
Total ($/boe)	38.23	45.49	**(16)**	47.06	39.83	**18**

The Company's average realized price for oil and condensate decreased in the fourth quarter of 2014 by 13% to $69.93/bbl compared to $80.63/bbl for the same period in 2013. For the 2014 year, the Company realized average price for oil and condensate decreased by $0.15/bbl to $85.34/bbl compared to $85.49/bbl for the comparative period in 2013. The decrease in oil prices realized by the Company is consistent with the benchmark Edmonton Par price.

The average realized prices for NGLs primarily 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 fourth quarter of 2014 by 12% to $21.50/bbl compared to $24.54/bbl for the same period in 2013. For the 2014 year, the Company realized average prices of $24.10/bbl for NGLs as compared to $18.76/bbl for the comparative period in 2013, an increase of 28%. Quality adjustments, mainly due to amounts of butane that remain in the condensate shipped, impact the realized prices the Company received.

The Company's average realized natural gas price increased by 1% in the fourth quarter of 2014 to $3.81/mcf compared to $3.79/mcf in 2013. For the year ended December 31, 2014, the Company's average realized natural gas price increased by 35% to $4.50/mcf compared to $3.34/mcf in 2013. 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.

Revenues

	Three months ended December 31			Year ended December 31		
($ thousands)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Oil and condensate	94,873	33,226	**185**	344,512	74,548	**362**
NGLs	21,329	5,174	**312**	61,470	11,977	**413**
Natural gas	39,181	10,084	**289**	128,851	26,659	**383**
Revenues (excluding realized gains or losses on risk management contracts)	155,383	48,484	**220**	534,833	113,184	**373**

Revenues increased by $106.9 million, or 220%, to $155.4 million in the fourth quarter of 2014 compared to $48.5 million in the same period of 2013. The increase in revenues is due to higher production volumes ($114.6 million) offset by lower commodity prices ($7.7 million). For the year ended December 31, 2014, the increase in revenues was $421.6 million, an increase of 373% compared to the same period in 2013 due to increased production ($401.1 million) and realized prices ($20.5 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. Management has set an internal hedge target of 55% of forecasted production volumes (net of royalties) for the forthcoming four quarters and 30% of net forecasted production volumes for the next three successive quarters. 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 December 31			Year ended December 31		
($ thousands)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Realized gain (loss)	22,163	49	**45,130**	9,737	279	**3,390**
Unrealized gain (loss)	123,772	(1,978)	**6,357**	141,765	(3,299)	**4,397**
Total gain (loss)	145,935	(1,929)	**7,665**	151,502	(3,020)	**5,117**

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 net income and cash flows. At December 31, 2014, the net fair value of the risk management contracts was an asset of $139.1 million (December 31, 2013 – liability of $2.6 million). Realized gains and losses on these contracts are recognized on the monthly settlement of the contracts. For the fourth quarter of 2014, the increase in realized gains of $22.1 million is due to gains on both the oil and natural gas risk management contracts in place. The Company's risk management position helped to offset commodity price declines in the latter part of 2014.

The Company had the following risk management contracts in place at December 31, 2014:

Commodity	Period	Volume	Average Minimum Price [(1)]
Natural gas	Q1 2015	15,500 GJ/d	CAD $3.99
Natural gas	Q1 2015	58,000 GJ/d	CAD $4.00
Natural gas	Q2 2015	55,000 GJ/d	CAD $3.89
Natural gas	Q3 2015	25,000 GJ/d	CAD $3.54
Natural gas	Q4 2015	15,000 GJ/d	CAD $3.77
Natural gas	Q1 2016	17,500 GJ/d	CAD $3.79
Oil	Q1 2015	11,200 bbls/d	CAD $102.30
Oil	Q2 2015	11,000 bbls/d	CAD $102.15
Oil	Q3 2015	6,500 bbls/d	CAD $101.44
Oil	Q4 2015	1,000 bbls/d	CAD $100.75

(1) For collar contracts, the minimum price has been used in calculating the average for the above table.

For further details of the outstanding contracts, refer to Note 19 of the audited annual financial statements.

Royalty Expense

($ thousands, except per unit amounts)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Gross royalties	17,962	4,534	**296**	56,256	11,257	**400**
Gas cost allowance ("GCA")	(1,817)	(1,346)	**35**	(4,366)	(3,404)	**28**
Net royalties	16,145	3,188	**406**	51,890	7,853	**561**
Per boe	3.97	2.99	**33**	4.57	2.76	**66**
Effective royalty rate – net	10%	6%	**67**	9%	7%	**29**

The average royalty rate as a percentage of revenues for the fourth quarter of 2014 was 10% compared to 6% in the same period of 2013. Royalty rates were 9% for the full year of 2014 compared to 7% in 2013. 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. The increase in the overall average royalty rate for the fourth quarter 2014 is due to a lower ratio of production volumes qualifying for royalty incentives compared to 2013. For the first quarter of 2015, the Company expects the effective royalty rate to continue to be approximately 10% due to new wells commencing production that will qualify for royalty incentives.

The total dollar amount of royalties have increased 561% in the year and 406% in the quarter, increases due to higher production and the higher average rates.

For the three months ended December 31, 2014, GCA increased by $0.5 million, or 35%, compared to the same period in 2013. GCA deductions are estimated during a production year, and are subject to adjustment 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

($ thousands, except per unit amounts)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Interest and other income	1,264	272	**365**	3,184	1,285	**148**
Processing and third party income	704	356	**98**	1,803	1,611	**12**
Total	1,968	628	**213**	4,987	2,896	**72**
Per boe – interest and other income	0.31	0.26	**19**	0.28	0.45	**(38)**
Per boe – processing and third party income	0.17	0.33	**(48)**	0.16	0.57	**(72)**

The average cash balances held by the Company for the year ended December 31, 2014 were higher than in the same period of 2013 which increased interest and other income by $1.9 million to $3.2 million.

Processing income and third party income increased to $0.7 million in the fourth quarter of 2014 from $0.4 million in the same period in 2013, which was mainly due to higher volumes from third party wells using Seven Generations' facilities in the fourth quarter of 2014. For the year ended December 31, 2014, processing income increased by $0.2 million or, 12%, to $1.8 million from $1.6 million in the same period of 2013.

Operating Expenses

($ thousands, except per unit amounts)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Operating expenses	18,966	8,425	**126**	54,261	20,615	**163**
Per boe	4.67	7.90	**(41)**	4.77	7.25	**(34)**

Total operating expenses increased in 2014 as a result of higher liquids production and field activity levels, including increased field staff to accommodate super pad operations. Operating expenses also increased due to rental equipment and temporary facility costs for flowback of new wells. Temporary facilities are utilized to tie in wells before permanent facilities are constructed.

Operating expenses per boe have improved in the year ended December 31, 2014 with a number of new wells coming on production. Also, four super pad facilities were constructed and online in the fourth quarter of 2014. The super pad facilities are sites that contain gas compression, separation, dehydration and liquids pumping capabilities.

On a unit of production basis, operating expenses for the fourth quarter of 2014 decreased by $3.23/boe or, 41%, to $4.67/boe as compared to $7.90/boe in the fourth quarter of 2013. For the 2014 year end, operating expenses per boe decreased by $2.48/boe or, 34%, to $4.77/boe as compared to $7.25/boe for the same period in 2013. Since a portion of operating expenses are fixed, the increase in production volumes has helped to reduce the per unit amounts in 2014.

Transportation Expenses

($ thousands, except per unit amounts)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Transportation expenses	13,237	3,286	**303**	34,833	6,461	**439**
Per boe	3.26	3.09	**6**	3.06	2.28	**34**

Transportation expenses include condensate and NGL pipeline tariffs and trucking as well as gas pipeline tariffs charged prior to the custody transfer point. Transportation expenses increase by $9.9 million to $13.2 million for the fourth quarter of 2014 compared to $3.3 million for the same period in 2013. The increase of 303% is in line with the increase in production (281%) as the majority of liquids volumes were transported by truck in 2014. The Company has secured pipeline access and transportation arrangements for 2015 and beyond.

On a unit of production basis, transportation expenses increased by $0.17/boe to $3.26/boe in the fourth quarter of 2014 compared to $3.09/boe for the same period in 2013 primarily due to volumes being trucked further distances.

For the year ended December 31, 2014, on a unit of production basis, transportation expenses increased $0.78/boe or, 34%, to $3.06/boe from $2.28/boe for the comparative period in 2013. The increase is primarily due to condensate being trucked to more remote facilities rather than to the closest pipeline terminal as a result of pipeline capacity constraints in the Grande Prairie area.

General and Administrative Expenses

($ thousands, except per unit amounts)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Gross general and administrative expenses	8,321	2,817	**195**	23,977	10,943	**119**
Capitalized overhead costs	(523)	(559)	**(6)**	(2,661)	(2,159)	**23**
Overhead recoveries	(405)	(206)	**97**	(1,058)	(667)	**59**
Net general and administrative expenses	7,393	2,052	**260**	20,258	8,117	**150**
Per boe – gross	2.05	2.64	**(22)**	2.11	3.85	**(45)**
Per boe – net	1.82	1.93	**(6)**	1.78	2.86	**(38)**

Gross general and administrative expenses for the fourth quarter of 2014 increased by $5.5 million to $8.3 million from $2.8 million for the comparative period in 2013. This increase was mostly due to $2.5 million of expenses related to the IPO and the remainder due to higher head count.

For the year ended December 31, 2014, gross general administrative expenses are higher by $13.0 million or 119%, compared to the same period in 2013. This increase is primarily attributable to increased personnel costs and additional rent for leased space to support the Company's expanded activities as well as costs related to the IPO. However, as a result of higher production levels, gross general and administration expenses on a unit of production basis decreased by 22% for the three months ended December 31, 2014 and 45% for the year, when compared to the same periods of 2013.

For capitalized overhead costs, there was a 6% reduction in the fourth quarter of 2014 compared to the same period in 2013. This decrease is attributable to a lower capitalization rate in 2014 as more of the Company's activity is focused on operations.

Overhead recoveries increased by $0.4 million to $1.1 million for the year ended December 31, 2014. Overhead recoveries relate to spending incurred on properties with minority partners.

Depletion, Depreciation and Amortization

	Three months ended December 31			Year ended December 31		
($ thousands, except per unit amounts)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Total depletion, depreciation and amortization	56,923	13,708	**315**	159,447	38,921	**310**
Per boe	14.01	12.86	**9**	14.04	13.70	**2**

Depletion, depreciation and amortization expense was $57.0 million and $159.4 million for the three months and year ended December 31, 2014, compared to $13.7 million and $38.9 million in the comparative periods of 2013, respectively. The increase is consistent with the increase in production and continued capital investments in the Kakwa play.

Stock Based Compensation

	Three months ended December 31			Year ended December 31		
($ thousands)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Gross stock based compensation	6,060	2,796	**117**	18,012	13,991	**29**
Capitalized stock based compensation	(2,163)	(1,244)	**74**	(6,062)	(4,435)	**37**
Net stock based compensation	3,897	1,552	**151**	11,950	9,556	**25**

Stock based compensation is a non-cash expense. Gross stock based compensation for the fourth quarter of 2014 has increased by $3.3 million to $6.1 million compared to $2.8 million for the same period of 2013. The increase is mostly due the Company's higher stock price in 2014 resulting in higher fair values for awards granted, as well as additional awards granted to new employees. For the year ended December 31, 2014, there was an increase of $4.0 million, or 29%, to $18.0 million in gross stock based compensation as compared to $14.0 million in the same period of 2013. In both 2014 and 2013, the stock options and performance warrants granted in 2008 were amended to extend the expiry date by one year. As a result of these amendments, a one-time charge of $0.8 million (net – $0.6 million) of expense was recognized in 2014 and $2.1 million (net – $1.7 million) in 2013.

The stock based compensation values are estimated using the Black-Scholes pricing model in which estimates for expected life of the instruments, current market value of the shares compared to exercise price, stock volatility and interest rates are all important variables. 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.

Gain on Disposition of Assets

($ thousands)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Gain on disposition of assets	-	-	**-**	4,286	-	**100**

During the year ended December 31, 2014, 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 $4.3 million for the year ended December 31, 2014.

Finance Expense

($ thousands)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Interest on senior notes	16,543	8,735	**89**	61,303	22,113	**177**
Revolving credit facility fees and other	857	235	**265**	2,142	793	**170**
Amortization of premium and debt issue costs	(114)	360	**(132)**	(466)	808	**(158)**
Accretion	272	234	**16**	1,162	733	**59**
Total finance expense	17,558	9,564	**84**	64,141	24,447	**162**
Capitalized interest	(500)	-	**100**	(500)	-	**100**
Net finance expense	17,058	9,564	**78**	63,641	24,447	**160**

On May 10, 2013, the Company issued US$400.0 million of senior unsecured notes. On February 5, 2014, an additional US$300.0 million (US$321.0 million with premium) of senior unsecured notes were issued under the same indenture. The notes bear interest at 8.25% per annum (calculated using a 360-day year). Interest expense for the fourth quarter of 2014 was $16.5 million (US$14.6 million), which is recorded in Canadian dollars using average monthly exchange rates. Interest expense has increased compared to prior year given the higher average debt balance outstanding in 2014.

The standby fees and other charges associated with the Company's revolving credit facility increased to $0.9 million and $2.1 million in the three months and year ended December 31, 2014 compared to $0.2 million and $0.8 million in the same periods of 2013, respectively. This is due to higher standby fees as a result of the increases to the borrowing capacity on the credit facility in 2014 from $150.0 million to $480.0 million.

Accretion expense relates to decommissioning liabilities which are recorded over time at their present value. For the year ended December 31, 2014, accretion was $1.2 million compared to $0.7 million for the comparative period in 2013. The increase reflects the increase in the ARO liability associated with the passage of time and additional field activity. Accretion and amortization of premium and debt issue costs are non-cash expenses.

In fourth quarter and year ended December 31, 2014, the Company capitalized $0.5 million in interest and financing costs related to its Cutbank facility that is expected to be onstream in 2016.

Foreign Exchange Loss (Gain)

($ thousands)	Three months ended December 31 2014	2013	% Change	Year ended December 31 2014	2013	% Change
Unrealized	27,562	12,878	**114**	53,406	19,975	**167**
Realized	(2,002)	(2,138)	**(6)**	(5,733)	(9,078)	**(37)**
Net foreign exchange loss	25,560	10,740	**138**	47,673	10,897	**337**
As at December 31:						
CDN$ equivalent of 1 US$	0.862	0.940	**(8)**	0.862	0.940	**(8)**

The Company's exposure to foreign exchange gains and losses relates to the US dollar senior unsecured notes, as well as US dollar cash balances. The Company's senior unsecured notes are comprised of US$400.0 million carried forward from December 31, 2013 at an exchange rate of 0.940 and US$300.0 million issued in February 2014 at an exchange rate of 0.901. The exchange rate fell to 0.862 at December 31, 2014 resulting in total unrealized foreign exchange losses of $53.4 million for the year ended and $27.6 million for the fourth quarter. The senior unsecured notes do not mature until 2020. 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. The Company converted a total of US$278.0 million to Canadian dollars in 2014, most of that in the first half of the year. Total realized foreign exchange gains were $2.0 million and $5.7 million for the three months and year ended December 31, 2014, respectively.

Liquidity Event Expense

	Three months ended December 31			Year ended December 31		
($ thousands)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Liquidity event expense	35,947	-	**100**	35,947	-	**100**

Pursuant to the Amended and Restated Shareholders Agreement, the Company was obligated to compensate, with cash or shares, certain directors, officers and employees prior to the completion of a change of control, liquidity event or qualified initial public offering (the "Liquidity Event"). With the closing of the IPO on November 5, 2014, the Liquidity Event condition was satisfied and the Company recognized a liability of $36.0 million. The settlement of the liability was approved by the Board of Directors to be payable in cash in 2015.

Deferred Income Tax Expense

	Three months ended December 31			Year ended December 31		
($ thousands)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Deferred income tax expense	39,532	293	**13,392**	71,508	351	**20,273**

For the year ended December 31, 2014, deferred income tax expense increased to $71.5 million from $0.4 million in the same period of 2013. The Company recognized a deferred income tax expense of $39.5 million for the three months ended December 31, 2014 compared to $0.3 million in the same period of 2013. The increases in both the fourth quarter of 2014 and the year ended December 31, 2014 reflect higher net income related to increased production volumes and due to higher combined realized commodity prices for the 2014 year. The Company's effective income tax rate is impacted by permanent differences. Stock based compensation is a non-deductible expense and foreign exchange gains or losses relating to the issue of the senior notes are one-half taxable or deductible. The majority of the permanent differences for the year ended December 31, 2014 relate to $2.8 million for non-taxable stock based compensation expense and $6.3 million for non-taxable portion of foreign exchange losses arising on the translation of the US dollar denominated senior notes. During the three months ended December 31, 2014, the Company recognized a valuation allowance for capital losses of $8.2 million.

The Company has no current income tax expense given its total tax pools of $1.7 billion at December 31, 2014. Of this amount, $0.4 billion is available in 2014 for deduction in computing taxable income.

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

	Three months ended December 31			Year ended December 31		
($ thousands, except per share amounts)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Funds from operations	101,503	23,114	**339**	327,933	50,273	**552**
Per share – basic [1]	0.45	0.14	**221**	1.65	0.30	**450**
Per share – diluted [1]	0.41	0.12	**242**	1.46	0.27	**441**
Operating income	34,815	7,127	**388**	119,521	5,794	**1,963**
Per share – basic [1]	0.15	0.04	**275**	0.60	0.03	**1,900**
Per share – diluted [1]	0.14	0.04	**250**	0.53	0.03	**1,667**
Net income (loss)	68,628	(5,625)	**1,331**	144,200	(14,158)	**1,119**
Per share – basic [1]	0.30	(0.03)	**1,100**	0.73	(0.08)	**1,013**
Per share – diluted [1]	0.28	(0.03)	**1,033**	0.64	(0.08)	**900**

(1) In 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares, stock options and performance warrants on a two-for-one basis. The share split has been reflected for the three months and years ended December 31, 2014 and 2013 on a retroactive basis.

Funds from operations increased by $78.4 million in the fourth quarter of 2014 to $101.5 million compared to $23.1 million in the same period of 2013. The increase was mostly due to higher production volumes offset by lower netbacks due to lower commodity pricing as well as higher interest expense and general administrative expense. For the year ended December 31, 2014, funds from operations increased by $277.6 million to $327.9 million compared to $50.3 million in the same period of 2013. This increase is mainly due to higher production volumes.

For the fourth quarter of 2014, operating income was $34.8 million compared to $7.1 million in the same period of 2013. This was higher by $27.7 million mainly because of higher production volumes offset by lower commodity prices and increased depletion. Operating income for the year ended December 31, 2014 was $119.5 million compared to $5.8 million in 2013. The increase of $113.7 million can be attributed to higher production volumes offset by higher depletion.

Net income increased by $74.2 million to $68.6 million for the fourth quarter of 2014 compared to a net loss of $5.6 million in the comparative 2013 period. The increase in net income was attributable to the items impacting funds from operations noted above as well as unrealized gains on risk management contracts of $123.8 million. This was offset by higher depletion charges as production volumes have increased, the liquidity event expense of $36.0 million, $27.6 million of unrealized foreign exchange losses and $39.5 million for deferred income tax expense. The net income for the year ended December 31, 2014 was $144.2 million as compared to a net loss of $14.2 million for the same period in 2013. The annual increase was due to higher funds from operations and unrealized risk management gains offset by unrealized foreign exchange losses, increased depletion charges, the liquidity event expense and higher deferred income tax expense.

Capital Investments

	Three months ended December 31			Year ended December 31		
($ thousands)	**2014**	2013	**% Change**	**2014**	2013	**% Change**
Land acquisitions	8,200	2,925	**180**	48,684	61,298	**(21)**
Geological and geophysical	-	77	**(100)**	268	82	**227**
Drilling and completions	227,562	129,231	**76**	742,019	321,810	**131**
Facilities and equipment	132,610	44,717	**197**	323,035	186,694	**73**
Capitalized salaries and benefits	776	665	**17**	3,562	2,315	**54**
Capitalized interest	495	-	**100**	495	-	**100**
Office and other	677	623	**9**	2,273	2,129	**7**
Total capital investment	370,320	178,238	**108**	1,120,336	574,328	**95**
Property dispositions	-	-	**-**	(9,420)	-	**(100)**
Capital investment, net of dispositions	370,320	178,238	**108**	1,110,916	574,328	**93**

Over the past year, Seven Generations has significantly accelerated its capital investment program. During 2014, the Company had nine drilling rigs operating in the first half of the year and 13 rigs operating in the second half. By comparison, in 2013, the Company had two rigs operating in the first half of the year and seven rigs operating in the second half. In addition, there was an increased level of completion activity in the latter half of 2014 compared to 2013, which resulted in the higher production levels achieved in the fourth quarter of 2014. In the fourth quarter of 2014, the Company completed the construction and commissioning of a pipeline from Karr to Lator to help advance tie in to the Pembina mainline. Seven Generations also continued to acquire additional undeveloped land acreage in the Kakwa area in both 2014 and 2013.

At December 31, 2014, the Company held 354,556 gross acres (348,762 net) of undeveloped land, an increase of 60% (gross and net) compared to December 31, 2013 landholdings of 222,076 gross acres (218,310 net).

Liquidity and Capital Resources

The capital structure of the Company is as follows:

As at	December 31, 2014	December 31, 2013
Total debt [(1)]	813,880	414,525
Total equity [(2)]	1,910,926	827,953
Total capital	2,724,806	1,242,478

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

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.

On May 10, 2013, the Company closed a private placement of US$400.0 million of senior unsecured notes. On February 5, 2014, the Company closed a private placement of an additional US$300.0 million of senior unsecured notes issued under the same indenture. The notes issued in February 2014 were issued at 107% of par, resulting in gross proceeds to the Company of US$321.0 million. The notes bear interest at 8.25% per annum (calculated using a 360-day year) payable on May 15 and November 15 of each year. The notes will mature May 15, 2020.

In December 2013, the Company closed a private equity placement of approximately 20.0 million Class A Common Shares at $12.50 per share, for total gross proceeds of $251.0 million (net $238.3 million).

In the fourth quarter of 2014, the Company closed its IPO for net proceeds of $880.1 million, including the exercise of the underwriters' over-allotment option for net proceeds of $121.5 million.

In the fourth quarter of 2014, the Company increased its revolving credit facility to $480.0 million, which has a three year term ending in September 2017. The credit facility is subject to a redetermination of the borrowing base semi-annually and is secured by a floating charge over the Company's assets. The credit facility bears interest rates based on a pricing grid that increases as a result of the increased ratio of indebtedness to earnings before interest, taxes, depreciation, depletion and amortization. The credit facility also includes standby fees on balances not drawn.

The Company had available funding of $1.1 billion at December 31, 2014 and plans to use these funds, along with funds from operations, for the execution of its 2015 capital program. Seven Generations intends to fund continued accelerated development of the Kakwa Project beyond 2015 with remaining available funding, cash flow from operations and additional debt or equity financings.

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 December 31, 2014:

($ thousands)	Total	Less Than 1 Year	1-3 Years	4-5 Years	Thereafter
Senior notes (1)	812,070	-	-	-	812,070
Interest on senior notes (1)	360,103	66,996	133,992	133,992	25,123
Firm transportation and processing agreements (2)	1,775,622	25,788	386,591	487,939	875,304
Operating leases (3)	14,717	2,217	4,295	3,104	5,101
Estimated contractual obligations	2,962,512	95,001	524,878	625,035	1,717,598

(1) Debt outstanding represents US$700.0 million (2013 – $US400.0 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.

Seven Generations entered into agreements with Pembina Pipeline Corporation for firm transportation and processing services, of which the above estimates for timing of payments are subject to completion of certain pipeline and facility upgrades by the counterparty. The Company has an agreement with Aux Sable Canada LP and, separately, with Alliance Pipeline Ltd. to deliver up to 500 Mmcf/d of peak rich gas volumes by 2018. The natural gas agreements expire in 2022. Seven Generations also has take or pay agreements in place for up to 40,000 bbls/d of condensate and other NGLs production by 2017. The liquids agreements expire in 2026. The minimum commitments under these agreements are reflected in the table above.

In the third quarter of 2014, the Company entered into an agreement to have a third party provide a 24-hour dedicated crew for hydraulic fracturing. The agreement has an initial term of one year. The Company may terminate the agreement on less than 60 days notice and payment to the third party of an amount equal to $50,000 for each day less than 60 days that notice of the termination is given.

In November 2014, the Board of Directors approved a retention bonus plan for management and employees. The retention bonuses will be payable in four equal installments payable every six months starting on May 5, 2015. Each installment payment will be contingent upon the individual still being employed by the Company on the date of payment. The maximum retention bonuses will be $6 million, payable over the two-year period starting November 5, 2014.

The Company is also committed to payments of $36.0 million in 2015 as disclosed under the heading "Liquidity Event Expense" in this MD&A and in Note 18 of the Company's financial statements for the year ended December 31, 2014.

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 22 to the annual financial statements of the Company. No asset or liability has been recorded for these leases on the balance sheet at December 31, 2014 or December 31, 2013.

The Company did not have any physical delivery contracts outstanding at December 31, 2014 or December 31, 2013.

Financial Instruments

Financial Instrument Classification and Measurement

The Company's financial instruments include cash and cash equivalents, outstanding cheques in excess of bank balances, 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, outstanding cheques in excess of bank balances, 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.

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 and outstanding cheques in excess of bank balances are classified as Level 1 measurements. Risk management contracts, the credit facility 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 years ended December 31, 2014. 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.

The classification, carrying values and fair values of the Company's financial instruments are as follows:

	2014		2013	
As at December 31	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
FINANCIAL ASSETS				
Fair Value Through Profit and Loss				
Cash and cash equivalents	848,136	848,136	310,737	310,737
Risk management contracts	139,119	139,119	-	-
Loans and Receivables				
Accounts receivable	64,417	64,417	30,500	30,500
Deposits	5,034	5,034	1,710	1,710
FINANCIAL LIABILITIES				
Fair Value Through Profit and Loss				
Outstanding cheques in excess of bank balances	-	-	3,252	3,252
Risk management contracts	-	-	2,646	2,646
Other Financial Liabilities				
Accounts payable and accrued liabilities	268,108	268,108	125,687	125,687
Senior notes payable	813,880	782,000	414,525	434,000

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 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

As at December 31, 2013	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	68	(68)	-
Current liability	(2,714)	68	(2,646)
Net position	(2,646)	-	(2,646)

Market Risk

Market risk is the risk that changes in market prices including commodity prices, interest rates and foreign exchange risks will affect the Company's income (loss) or the value of financial instruments. The objective of market risk management is to reduce exposures to acceptable limits while optimizing returns.

(a) Commodity price risk

Commodity price risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by world economic events that dictate the levels of supply and demand. The Company uses derivative financial instruments to manage its exposure to fluctuations in commodity prices. The Company considers these transactions to be effective economic hedges; however, the Company's contracts do not qualify as effective hedges for accounting purposes. The Company does not enter into commodity contracts other than to meet the Company's expected sales requirements.

During the year ended December 31, 2014, the Company's risk management contracts resulted in a realized gain of $9.7 million (2013 – $0.3 million) and an unrealized gain of $141.8 million (2013 – unrealized loss of $3.3 million).

The following table demonstrates the impact of changes in commodity pricing on income before tax, based on risk management contracts in place at December 31, 2014:

	Gain (Loss)
10% increase in AECO/GJ	(7,234)
10% decrease in AECO/GJ	7,234
10% increase in US$ WTI/bbl	(19,514)
10% decrease in US$ WTI/bbl	19,514

(b) Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The senior notes payable bear interest at a fixed rate. The Company's credit facility bears a floating rate of interest and, accordingly, the Company is exposed to interest rate fluctuations to the extent that any advances remaining outstanding under the facility. During May 2013, the Company borrowed up to $30.7 million on the credit facility for a period of one week. During the year ended December 31, 2014, no amounts were drawn on the credit facility.

(c) Foreign currency exchange risk

Foreign currency exchange risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in foreign exchange rates.

Prices for oil are determined in global markets and generally denominated in US dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the US dollar will reduce the prices received by the Company for its oil and natural gas sales.

The Company is exposed to foreign exchange rate fluctuations on the principal and interest related to the senior notes payable, as well as on cash balances held in US dollars. The foreign currency risk associated with interest payments is partially offset by a marketing arrangement for the Company's natural gas liquids, excluding condensate, which is denominated in US dollars.

The following table demonstrates the impact of changes in the Canadian to US dollar exchange rate on income before tax, based on US denominated balances outstanding at December 31, 2014:

	Gain (Loss)
$0.01 increase in CAD/USD exchange rate	8,538
$0.01 decrease in CAD/USD exchange rate	(8,739)

The carrying amount of the Company's US dollar denominated monetary assets and liabilities as at December 31 was as follows:

	2014	2013
Assets	78,042	67,053
Liabilities	822,573	419,083

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises primarily from the Company's receivables from oil and natural marketers and joint venture partners and hedging assets. The Company's maximum exposure to credit risk is equal to the carrying amount of these instruments.

Substantially all of the Company's accounts receivable are with oil and natural gas marketers and joint venture partners under normal industry sale and payment terms and are subject to normal industry credit risk. Receivables from oil and natural gas marketers are normally collected on or about the 25th day of the following month. The Company sells the majority of its production to two oil and natural gas marketers and is therefore subject to concentration risk. Production is sold to marketers with investment grade credit ratings, if available in the area of production. The Company historically has not experienced any collection issues with its oil and natural gas marketers. As at December 31, 2014, the Company's most significant marketer accounted for $21.1 million (2013 – $11.6 million) of total receivables and 4% of total revenues (2013 – 10%). Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner pre-approval of significant capital expenditures. However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling and disagreements with partners. As the operator of properties, the Company has the ability to withhold production from joint interest partners in the event of non-payment. As at December 31, 2014, receivables outstanding for more than 90 days totalled less than $0.1 million (2013 – $0.1 million). The Company believes all of the accounts receivable will be collected. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

All the Company's cash and cash equivalents are held with Canadian chartered banks and as such, the Company is exposed to credit risk on any default by the institutions of amounts in excess of the minimum guaranteed amount. The Company considers the risk of default by a Canadian chartered bank to be remote. As at December 31, 2014, the Company does not invest any cash in complex investment vehicles with higher risk such as asset backed commercial paper. All of the Company's risk management contracts are with Schedule 1 Canadian chartered banks or high credit-quality financial institutions.

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 a part of the IPO, the Company agreed to apply restrictions to the transfer of common shares issued prior to the IPO without the consent of the underwriters. At December 31, 2014, 193.0 million shares were restricted from trading until 180 days from the IPO or May 5, 2015. As at March 10, 2015, Seven Generations had 244,716,068 Class A Common Voting Shares and 523,475 Class B Common Non-voting Shares issued and outstanding.

On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. The Class B Common Non-voting Shares were not divided. On conversion of Class B Common Non-voting Shares into Class A Common Voting Shares, holders will receive two Class A Common Voting Shares for each Class B Common Non-voting Share converted. In December 2014, the Company amended the terms of the stock options and performances warrants, issued prior to the completion of the IPO, such that upon exercise, the holders of these instruments will receive two Class A Common Voting Shares (rather than Class B Non-voting Shares) to reflect the two-for-one stock split.

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". Given that Seven Generations became a reporting issuer in the fourth quarter of 2014, the Company is not required to make any representations regarding the maintenance and establishment of disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR") in place as at December 31, 2014. Management will certify the design of the Company's DC&P and ICFR as at March 31, 2015 and the effectiveness of DC&P and ICFR as at December 31, 2015. The evaluation of ICFR will be based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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 involve 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 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

As of January 1, 2014, the Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's financial statements is provided below.

IAS 36 "Impairment of Assets" has been amended to reduce the circumstances in which the recoverable amount of cash generating units is required to be disclosed and clarify the disclosures required when an impairment loss has been recovered or reversed in the period. The retrospective adoption of these amendments will only impact the Company's disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

IAS 32 "Financial Instruments: Presentation" is effective January 1, 2014, and has been amended to clarify certain requirements for offsetting financial assets and liabilities. IAS 32 relates to presentation and disclosure of financial instruments and the retrospective adoption of this standard did not have a material impact on the Company's financial statements.

IAS 39 "Financial Instruments: Recognition and Measurement" has been amended to clarify that there would be no requirement to discontinue hedge accounting if a hedging derivative was novated, provided certain criteria are met. The retrospective adoption of the amendments does not have any impact on the Company's financial statements.

IFRIC 21 "Levies" was developed by the IFRS Interpretations Committee and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this standard does not have any material impact on the Company's financial statements.

Future Accounting Policy Changes

In February 2014, 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 full impact of the standard on the Company's financial statements will not be known until changes are finalized.

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. 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" and "available funding". 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. The liquidity event expense in the fourth quarter of 2014 relating to the IPO has been excluded as it is not expected to recur and did not arise as a result of the Company's oil and gas operations. 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 December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Cash provided by operating activities	80,667	744	301,909	41,875
Decommissioning expenditures	-	-	206	-
Liquidity event expense	35,947	-	35,947	-
Changes in non-cash operating working capital	(15,111)	22,370	(10,129)	8,398
Funds from operations	101,503	23,114	327,933	50,273

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

The following table reconciles the net income (loss) to operating income.

	Three months ended December 31		Year ended December 31	
($ thousands)	**2014**	2013	**2014**	2013
Net income (loss)	68,628	(5,625)	144,200	(14,158)
Unrealized foreign exchange loss (1)	27,562	12,878	53,406	19,975
Unrealized (gain) loss on risk management contract (2)	(123,772)	1,978	(141,765)	3,299
Liquidity event expense (3)	35,947	-	35,947	-
Gain on disposition of assets (4)	-	-	(4,286)	-
Deferred tax expense relating to these adjustments	26,450	(2,104)	32,019	(3,322)
Operating income	34,815	7,127	119,521	5,794

(1) 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.
(2) Unrealized gains and losses on risk management contracts result from the fair market valuation of the hedge contracts as at December 31, 2014.
(3) Non-recurring costs related to IPO.
(4) 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:

($ thousands)	December 31, 2014	December 31, 2013
Current assets	1,060,030	343,816
Current liabilities	(268,231)	(131,703)
Working capital	791,799	212,113
Adjusted for:		
Current portion risk management contracts	(138,122)	2,646
Current portion of deferred credits	123	118
Adjusted working capital	653,800	214,877
Undrawn credit facility capacity	480,000	150,000
Available funding	1,133,800	364,877

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.

($ thousands)	December 31, 2014	December 31, 2013
Senior notes at amortized cost	813,880	414,525
Less unamortized premium and debt issue costs	(1,810)	10,915
Senior notes principal	812,070	425,440
Adjusted for:		
Current assets	(1,060,030)	(343,816)
Current liabilities	268,231	131,703
Current portion risk management contracts	138,122	(2,646)
Current portion of deferred credits	(123)	(118)
Net debt	158,270	210,563

SELECTED QUARTERLY INFORMATION

($ thousands, except per share amounts)	Q4 2014	Q3 2014	Q2 2014	Q1 2014	YE 2014
FINANCIAL					
Oil and condensate revenues (3)	94,873	104,628	82,049	62,962	344,512
NGLs revenues (3)	21,329	19,416	10,418	10,307	61,470
Natural gas revenues (3)	39,181	35,920	28,282	25,468	128,851
Total revenues (3)	155,383	159,964	120,749	98,737	534,833
Realized hedging gain (loss)	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 (3)	(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	(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 – basic (2)	0.45	0.55	0.35	0.29	1.65
Per share – diluted (2)	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 – basic (2)	0.15	0.22	0.10	0.13	0.60
Per share – diluted (2)	0.14	0.19	0.09	0.11	0.53
Net income	68,628	30,482	43,926	1,164	144,200
Per share – basic (2)	0.30	0.16	0.23	0.01	0.73
Per share – diluted (2)	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
Total non-current financial liabilities	813,880	785,830	748,596	776,277	813,880
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 (3)					
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

(1) See "Non-IFRS Financial Measures".

(2) On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. As of December 1, 2014, all options and performance warrants issued prior to the completion of the IPO (as defined herein) were exercisable into twice as many Common Shares as the number of Class B Common Non-voting Shares they were exercisable for prior to December 1, 2014. The share split has been reflected in the condensed interim statements for the three months and year ended December 31, 2014 and on a retroactive basis.

(3) Certain comparative figures from prior periods have been reclassified to conform to the current year's presentation.

SELECTED QUARTERLY INFORMATION – continued

($ thousands, except per share amounts)	Q4 2013	Q3 2013	Q2 2013	Q1 2013	YE 2013
FINANCIAL					
Oil and condensate revenues (3)	33,226	14,346	13,568	13,408	74,548
NGLs revenues (3)	5,174	2,830	1,421	2,552	11,977
Natural gas revenues (3)	10,084	4,992	6,592	4,991	26,659
Total revenues (3)	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)	(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	(133)	(24)	6	10	(141)
Other	7	-	-	-	7
Funds from operations (1)	23,114	4,780	9,223	13,156	50,273
Per share – basic (2)	0.14	0.03	0.06	0.08	0.30
Per share – diluted (2)	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 – basic (2)	0.04	(0.05)	0.03	0.01	0.03
Per share – diluted (2)	0.04	(0.05)	0.03	0.01	0.03
Net income (loss)	(5,625)	(955)	(8,454)	876	(14,158)
Per share – basic (2)	(0.03)	(0.01)	(0.05)	0.01	(0.08)
Per share – diluted (2)	(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
Total non-current financial liabilities	414,525	404,208	412,293	59	414,525
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 (3)					
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

(1) See "Non-IFRS Financial Measures".
(2) On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. As of December 1, 2014, all options and performance warrants issued prior to the completion of the IPO (as defined herein) were exercisable into twice as many Common Shares as the number of Class B Common Non-voting Shares they were exercisable for prior to December 1, 2014. The share split has been reflected in the condensed interim statements for the three months and year ended December 31, 2014 and on a retroactive basis.
(3) Certain comparative figures from prior periods have been reclassified to conform to the current year's presentation.

SELECTED QUARTERLY INFORMATION – continued

($ thousands, except per share amounts)	Q4 2012	Q3 2012	Q2 2012	Q1 2012	YE 2012
FINANCIAL					
Oil and condensate revenues (3)	8,992	9,379	7,507	5,444	31,322
NGLs revenues (3)	1,627	1,539	1,420	1,376	5,962
Natural gas revenues (3)	5,627	4,462	3,561	2,723	16,373
Total revenues (3)	16,246	15,380	12,488	9,543	53,657
Realized hedging gain	224	520	655	404	1,803
Processing and third party income	405	485	575	568	2,033
Interest and other income	433	431	223	93	1,180
Royalties	(2,922)	(959)	(859)	(793)	(5,533)
Operating expenses	(3,233)	(2,227)	(2,204)	(2,101)	(9,765)
Transportation expenses (3)	(73)	(61)	(15)	(52)	(201)
General and administrative expense	(1,808)	(1,491)	(1,324)	(1,304)	(5,927)
Interest expense	(50)	(51)	(117)	(49)	(267)
Foreign exchange	-	-	-	-	-
Other	(618)	-	-	-	(618)
Funds from operations (1)	8,604	12,027	9,422	6,309	36,362
Per share – basic (2)	0.05	0.07	0.07	0.05	0.25
Per share – diluted (2)	0.05	0.07	0.07	0.05	0.24
Operating income (loss) (1)	162	258	(152)	(1,688)	(1,420)
Per share – basic (2)	-	-	-	(0.01)	(0.01)
Per share – diluted (2)	-	-	-	(0.01)	(0.01)
Net loss	(379)	(247)	(875)	(1,073)	(2,574)
Per share – basic (2)	-	-	(0.01)	(0.01)	(0.02)
Per share – diluted (2)	-	-	(0.01)	(0.01)	(0.02)
Capital investments					
Land	16,775	21,461	10,916	10,584	59,736
Drilling and completions	43,007	25,545	13,169	21,196	102,917
Facilities and equipment	42,346	14,331	3,496	10,033	70,206
Other	669	477	522	442	2,110
Total capital investments (before dispositions)	102,797	61,814	28,103	42,255	234,969
Total assets	679,271	629,064	566,205	370,750	679,271
Total non-current financial liabilities	5	-	-	-	5
Available funding (1)	135,089	229,336	235,286	56,605	135,089
Net debt (1)	(95,089)	(189,336)	(195,286)	(16,605)	(95,089)
Debt outstanding	-	-	-	-	-
OPERATING					
Average daily production					
Oil and condensate (bbls/d)	1,143	1,205	1,042	692	1,021
NGLs (bbls/d)	296	323	313	220	288
Natural gas (Mmcf/d)	17	20	19	13	17
Total (boe/d)	4,316	4,763	4,512	3,123	4,180
Realized prices (3)					
Oil and condensate ($/bbl)	85.52	84.58	79.15	86.43	83.78
NGLs ($/bbl)	59.81	51.85	49.92	68.76	59.81
Natural gas ($/mcf)	3.54	2.50	2.07	2.26	3.54

(1) See "Non-IFRS Financial Measures".
(2) On September 8, 2014, the Company amended its articles of incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. As of December 1, 2014, all options and performance warrants issued prior to the completion of the IPO (as defined herein) were exercisable into twice as many Common Shares as the number of Class B Common Non-voting Shares they were exercisable for prior to December 1, 2014. The share split has been reflected in the condensed interim statements for the three months and year ended December 31, 2014 and on a retroactive basis.
(3) Certain comparative figures from prior periods have been reclassified to conform to the current year's presentation.

Forward-Looking Information Advisory

This document contains certain forward-looking information and statements that involves 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: expectations regarding the balancing of debt and equity in the Company's capital structure; the mitigation of risk associated with Company's capital investments; the Company's estimates of its future obligations under the heading "Contractual Obligations"; the number of wells that can or will be drilled; the number of wells expected to come on production in 2015; the number of drilling rigs expected to be utilized; the Company's expected sources of financing; anticipated supply costs; future cost savings to be realized; plans to defer spending; projected capital expenditures; anticipated break-even market prices and project economics; the Company's prospects for revenue recovery; expectations for the transportation of the Company's products; anticipated production and recovery; revenue growth projections; opportunities for increased market share; commodity price projections; estimated internal rates of return; anticipated type-curves and well production and decline profiles; the use of hedging in the future; the expected timing and completion of: the Lator 2 plant expansion, the Pembina Lator to Fox Creek pipeline, the 25,000 bbl/d stabilizer at the Karr 7-11 battery and the expected benefits to the derived therefrom; the expected timing of the completion and occupation of a temporary camp being set up by the Company; anticipated go-forward strategy; expectations regarding future market access; and other market predictions. 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, natural gas liquids 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, 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 the covenants in the credit agreement related to the Company's credit facilities and/or the covenants in the indenture 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: (i) 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; (ii) as at July 1, 2014, are based upon the report that was prepared by McDaniel, evaluating the Company's oil, natural gas and NGL reserves, dated July 23, 2014; and, as at December 31, 2013, are based upon the report that was prepared by McDaniel, evaluating the Company's oil, natural gas and NGL reserves, dated February 24, 2014. 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 and to the Company's Supplemented PREP Prospectus dated October 29, 2014, which are available on the SEDAR website at www.sedar.com.

Finding and development costs have been calculated for proven reserves by taking the sum of: (i) exploration costs; (ii) development costs; and (iii) the change in estimated future development costs relating to proved reserves during the year; divided by the additions to proved reserves during the year. Finding and development costs for proved plus probable reserves have been calculated by taking the sum of: (i) exploration costs; (ii) development costs; and (iii) the change in estimated future development costs during the year; divided by the additions to proved plus probable reserves during the year. Comparative information for 2013 and the average of the three most recent years has not been provided for finding and development costs as no independent reserve reports were prepared for the Company as at December 31, 2012 or 2011. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Oil and Gas Definitions

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

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

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.

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

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
Btu	British thermal units
Btu/scf	British thermal units per standard cubic foot
C3	propane
C4	butane
C5+	pentanes plus
CAD$	Canadian dollars
GJ	gigajoule
GJ/d	gigajoules per day
IRR	internal rate of return
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	million British thermal units
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
US$ or $US	United Stated 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 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.

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF SEVEN GENERATIONS ENERGY LTD.:

We have audited the accompanying financial statements of Seven Generations Energy Ltd., which comprise the balance sheets as at December 31, 2014 and 2013 and the statements of income (loss) and comprehensive income (loss), statements of changes in equity and statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Seven Generations Energy Ltd. as at December 31, 2014 and 2013, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards

Deloitte LLP.

Chartered Accountants
March 10, 2015
Calgary, Canada

BALANCE SHEETS

(thousands of Canadian dollars)

As at December 31	Notes	2014	2013
Assets			
Current assets			
Cash and cash equivalents	6	848,136	310,737
Accounts receivable		64,417	30,500
Risk management contracts	19	138,122	-
Deposits and prepaid expenses		9,355	2,579
		1,060,030	343,816
Risk management contracts	19	997	-
Oil and natural gas assets	7	2,049,760	1,060,387
Goodwill		4,010	4,010
		3,114,797	1,408,213
Liabilities			
Current liabilities			
Outstanding cheques in excess of bank balances		-	3,252
Accounts payable and accrued liabilities	10	268,108	125,687
Risk management contracts	19	-	2,646
Current portion of deferred credits	23	123	118
		268,231	131,703
Senior notes	9	813,880	414,525
Deferred credits	23	973	1,048
Decommissioning liabilities	11	52,163	23,656
Deferred income taxes	12	68,624	9,328
		1,203,871	580,260
Equity			
Share capital	13	1,719,779	790,064
Contributed surplus		54,684	45,626
Retained earnings (deficit)		136,463	(7,737)
		1,910,926	827,953
		3,114,797	1,408,213

See accompanying notes to the financial statements.

Approved by the Board of Directors

Dale Hohm

Kent Jespersen

Dale Hohm　　　　Kent Jespersen

STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(thousands of Canadian dollars, except per share amounts)

Year ended December 31	Notes	2014	2013
Revenues			
Oil and natural gas sales		534,833	113,184
Royalties		(51,890)	(7,853)
		482,943	105,331
Risk management contracts			
Realized gain	19	9,737	279
Unrealized gain (loss)	19	141,765	(3,299)
Interest and third party income		4,987	2,896
		639,432	105,207
Expenses			
Operating		54,261	20,615
Transportation		34,833	6,461
General and administrative	16	20,258	8,117
Depletion, depreciation and amortization		159,447	38,921
Stock based compensation	14	11,950	9,556
Finance expense	17	63,641	24,447
Foreign exchange loss	21	47,673	10,897
Liquidity event expense	18	35,947	-
Gain on disposition of assets	7	(4,286)	-
		423,724	119,014
Income (loss) before taxes		215,708	(13,807)
Taxes			
Deferred income tax expense	12	71,508	351
Net income (loss) and comprehensive income (loss)		144,200	(14,158)
Net income (loss) per share	15		
Basic		0.73	(0.08)
Diluted		0.64	(0.08)

See accompanying notes to the financial statements.

STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars)

	Notes	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	**Total**
Balance at December 31, 2012		545,057	32,581	6,421	584,059
Net loss for the year		-	-	(14,158)	(14,158)
Issue of common shares	13	250,992	-	-	250,992
Share issue costs (net of deferred tax)	13	(9,535)	-	-	(9,535)
Stock based compensation	14	-	11,915	-	11,915
Value attributed to modification of stock options and performance warrants	13,14	-	2,076	-	2,076
Exercise of stock options	13,14	1,383	(518)	-	865
Exercise of performance warrants	13,14	2,167	(428)	-	1,739
Balance at December 31, 2013		790,064	45,626	(7,737)	827,953
Net income for the year		-	-	144,200	144,200
Issue of common shares	13	931,500	-	-	931,500
Share issue costs (net of deferred tax)	13	(36,637)	-	-	(36,637)
Stock based compensation	14	-	18,012	-	18,012
Exercise of stock options	13,14	15,708	(5,668)	-	10,040
Exercise of performance warrants	13,14	19,144	(3,286)	-	15,858
Balance at December 31, 2014		**1,719,779**	**54,684**	**136,463**	**1,910,926**

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

(thousands of Canadian dollars)

Year ended December 31	Notes	2014	2013
Operating activities			
Net income (loss) for the year		144,200	(14,158)
Deferred income tax expense		71,508	351
Depletion, depreciation and amortization		159,447	38,921
Unrealized loss (gain) on risk management contracts	19	(141,765)	3,299
Stock based compensation	14	11,950	9,556
Amortization of premium and debt issue costs	17	(471)	808
Accretion	17	1,162	733
Gain on disposition of assets		(4,286)	-
Unrealized foreign exchange loss		50,311	10,756
Decommissioning expenditures		(206)	-
Other		(70)	7
Changes in non-cash working capital	21	10,129	(8,398)
Cash provided by operating activities		301,909	41,875
Financing activities			
Issue of common shares	13	957,398	253,596
Share issue costs	13	(48,849)	(12,714)
Issue of senior notes	9	356,342	404,960
Debt issue costs	9	(9,840)	(11,201)
Borrowings under revolving credit facility	8	-	30,700
Repayments under revolving credit facility	8	-	(30,700)
Cash provided by financing activities		1,255,051	634,641
Investing activities			
Oil and natural gas asset additions	7	(1,120,336)	(574,328)
Proceeds on disposition of property	7	9,420	-
Changes in non-cash working capital	21	91,512	49,873
Cash used in investing activities		(1,019,404)	(524,455)
Foreign exchange gain on cash held in foreign currencies		3,095	9,219
Increase in cash and cash equivalents		540,651	161,280
Cash and cash equivalents, beginning of year		307,485	146,205
Cash and cash equivalents, end of year		848,136	307,485
Cash and cash equivalents are comprised of:			
Cash and cash equivalents		848,136	310,737
Outstanding cheques in excess of bank balances		-	(3,252)
		848,136	307,485

Supplementary disclosure of cash flow information (Note 21).
See accompanying notes to the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2014 AND 2013

(all tabular amounts in thousands of Canadian dollars, except share, per share and price information)

1. NATURE OF BUSINESS

Seven Generations Energy Ltd. ("Seven Generations" or the "Company") is incorporated under the *Canada Business Corporations Act* and commenced operations in 2008. Seven Generations is a Canadian company focused on the exploration, development and production of oil and natural gas properties in western Canada. Seven Generations' principal place of business is located at 300, 140 – 8th Avenue SW, Calgary, Alberta T2P 1B3. The Company is publicly traded on the Toronto Stock Exchange as of November 5, 2014, under the symbol "VII".

2. BASIS OF PREPARATION

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

These financial statements have been prepared on the historical cost basis, except for certain financial instruments which are measured at fair value as explained in Note 20. The financial statements are presented in Canadian dollars, which is Seven Generations' functional currency.

The financial statements were approved and authorized for issue by the Board of Directors on March 10, 2015.

Certain comparative figures from prior periods have been reclassified to conform to the current year's presentation. Certain pipeline tariffs after the custody transfer point have been reclassified from transportation expense to oil and natural gas revenues in the statements of income (loss) and comprehensive (loss). Exploration and evaluation assets have been separately disclosed from developed and producing properties in Note 7, Oil and natural gas assets.

3. SIGNIFICANT ACCOUNTING POLICIES

Property, Plant and Equipment

(a) Oil and Natural Gas Assets

Oil and natural gas properties are carried at cost, less accumulated depletion and depreciation and accumulated impairment losses, if any.

Oil and natural gas properties represent all costs directly attributable to development of oil and natural gas reserves after technical feasibility and commercial viability have been established. These include lease acquisitions, geological and geophysical costs, drilling and completion costs, production equipment, pipelines and gathering equipment, processing facilities and associated turnarounds, other directly attributable costs, borrowing costs of qualifying assets and estimates of decommissioning liabilities.

Depletion of intangible oil and natural gas assets is calculated using the unit-of-production method based on estimated recoverable reserves before royalties. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing estimated recoverable reserves and excludes the cost of assets not yet available for use. Tangible oil and natural gas assets are depreciated over their estimated useful lives, which may be the same as the estimated life of the underlying reserves.

(b) Exploration and Evaluation Assets

Exploration and evaluation ("E&E") assets are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. The Company capitalizes all E&E costs after the right to explore has been obtained related to exploration properties, including geological and geophysical costs, land acquisition costs and costs for drilling, completion and testing of exploration wells. When technical feasibility and commercial viability is established, the associated E&E assets are tested for impairment at the lower of cost and the estimated recoverable amount is transferred to property, plant and equipment. Any costs in excess of the estimated recoverable amount are charged to expense.

E&E assets are not amortized.

Farm-in and farm-out arrangements for E&E properties are accounted for at cost. No gain or loss is recognized on the disposition of a working interest through a farm-out arrangement.

(c) Other Fixed Assets

Other fixed assets include office furniture and fixtures, computer equipment and field vehicles. They are carried at cost and depreciated over their estimated useful lives at annual rates ranging from 20% to 100%.

Financial Instruments

Financial assets and liabilities are recognized when the Company becomes party to the contractual provisions of the instrument and are initially measured at fair value. Transaction costs, other than for financial instruments at fair value through profit and loss, are added to or deducted from the fair value of the financial instrument on recognition. Transaction costs for financial instruments at fair value through profit and loss are recognized immediately in net income (loss).

Measurement in subsequent periods is dependent upon whether the financial instrument has been classified as fair value through profit and loss, available for sale, held to maturity, loans and receivables or other financial liabilities. The classification depends on the nature and purposes of the financial instrument and is determined at the time of initial recognition.

Financial instruments designated as fair value through profit and loss are subsequently measured at fair value with changes to those fair values recognized immediately in net income (loss). Available for sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income (loss), net of tax. Amounts recognized in other comprehensive income (loss) for available for sale financial assets are transferred to net income (loss) when realized through disposal or impairment. Held to maturity investments, loans and receivables and other financial liabilities are subsequently measured at amortized cost using the effective interest method less any impairment.

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts are considered to consist of a host contract plus an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. The Company has no material embedded derivatives.

Impairment

(a) Financial Assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative impact on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net income (loss). An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. The impairment reversal is recognized in net income (loss).

(b) Non-Financial Assets

The carrying amount of property, plant and equipment is reviewed at each reporting date to determine whether there is any indication of impairment. If such indication exists, then the asset's recoverable amount is estimated. For goodwill, an impairment test is completed each year. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved plus probable reserves.

For the purpose of impairment testing, the goodwill acquired in a business combination is allocated to the CGUs that are expected to benefit from the synergies of the combination. E&E assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to property, plant and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income (loss). Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amount of the other assets in the unit (or group of units) on a prorata basis.

At each reporting date, E&E assets are reviewed for indications of impairment. When the carrying amount of a particular asset exceeds its recoverable amount, an impairment loss is charged to expense.

An impairment loss in respect of goodwill is not reversed. In respect of property, plant and equipment, impairment losses recognized in prior years are assessed at each reporting date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates that were used to determine the recoverable amount when the impairment was recognized. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Provisions

(a) General

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that the Company will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the end of the reporting period, taking into account the risks and uncertainties surrounding the obligation. When a provision is measured using the cash flows estimated to settle the obligation, its carrying amount is the present value of those cash flows where the effect of the time value of money is material.

(b) Decommissioning Liabilities

The Company records a liability for obligations associated with the decommissioning of its oil and natural gas assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability, there is a corresponding increase in the carrying amount of the related asset, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings. Estimates used are evaluated on a periodic basis and any adjustments are applied prospectively. Actual costs incurred upon settlement of the obligations are charged against the liability.

Income Taxes

Income tax comprises current and deferred taxes. Income tax is recognized in net income (loss), except when it relates to items that are recognized in other comprehensive income (loss) or directly in equity, in which case the related tax expense or recovery is also recognized in other comprehensive income (loss) or equity, respectively.

Current income tax expense is the expected cash tax payable on the taxable income for the period, using tax rates that have been enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax liabilities are generally recognized for all temporary differences, except for temporary differences arising from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither taxable income nor accounting net income (loss). Deferred income tax is determined on a non-discounted basis using tax rates that have been enacted or substantively enacted at the reporting date and that are expected to apply in the periods that the temporary differences reverse. A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Stock Based Compensation

The Company follows the fair value method of valuing equity-settled stock based payments which include stock options and performance warrants. Under this method, compensation cost attributable to stock options and performance warrants granted to employees, officers, and directors of Seven Generations is measured at fair value at the date of grant and expensed over the vesting period with a corresponding increase in contributed surplus. Upon the exercise of the stock options and performance warrants, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed, including contingent liabilities, are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. Goodwill is subsequently carried at cost less accumulated impairment losses, if any. Any deficiency of the cost of acquisition below the fair value of the net identifiable assets acquired is credited to net income (loss) in the period of acquisition. Associated transaction costs are expensed when incurred.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at balance sheet date. Non-monetary assets and liabilities are translated at the historical exchange rate in effect when the asset was acquired or the liability was incurred. Revenues and expenses are translated at average exchange rates for the period. Translation gains and losses are recognized in the statement of net income (loss) and comprehensive income (loss) in the period in which they are incurred and are reported on a net basis.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, deposits held with financial institutions and other short-term highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when title passes from the Company to its customers.

Borrowing Costs

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 or sale. A qualifying asset is an asset that requires a period of one year or greater to complete or prepare for its intended use or sale. All other borrowing costs are recognized in net income (loss) using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company's outstanding borrowings during the period.

Jointly Operated Assets

The Company's oil and natural gas activities may involve jointly operated assets. The financial statements of the Company include the Company's share of these jointly operated assets and a proportionate share of the related revenue and costs.

Per Share Information

Basic per share information is calculated on the basis of the weighted average number of common shares outstanding during the period. For diluted per share information, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income (loss). Diluted per share information is calculated using the treasury stock method which assumes that proceeds received from the exercise of in-the-money stock options plus the unamortized stock based compensation expense would be used to buy back common shares at the average market price for the period.

4. NEW ACCOUNTING POLICIES

Changes in Accounting Polices

As of January 1, 2014, the Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's financial statements is provided below.

International Accounting Standard ("IAS") 36 "Impairment of Assets" has been amended to reduce the circumstances in which the recoverable amount of cash generating units is required to be disclosed and clarify the disclosures required when an impairment loss has been recovered or reversed in the period. The retrospective adoption of these amendments will only impact the Company's disclosures in the notes to the financial statements in periods when an impairment loss or impairment reversal is recognized.

IAS 32 "Financial Instruments: Presentation" is effective January 1, 2014, and has been amended to clarify certain requirements for offsetting financial assets and liabilities. IAS 32 relates to presentation and disclosure of financial instruments and the retrospective adoption of this standard did not have a material impact on the Company's financial statements.

IAS 39 "Financial Instruments: Recognition and Measurement" has been amended to clarify that there would be no requirement to discontinue hedge accounting if a hedging derivative was novated, provided certain criteria are met. The retrospective adoption of the amendments does not have any impact on the Company's financial statements.

International Financial Reporting Interpretations Committee ("IFRIC") 21 "Levies" was developed by the IFRS Interpretations Committee and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this standard does not have any material impact on the Company's financial statements.

Future Accounting Policy Changes

In February 2014, the International Accounting Standards Board ("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 2014, 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.

5. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

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. Actual results may differ from these estimates. The estimates and associated assumptions are based on historical experience and management's judgment regarding other factors that are considered to be relevant and reasonable in the circumstances. Anticipating future events involves uncertainty and consequently the estimates used by management in the preparation of financial statements may change as future events unfold, additional experience is acquired or the Company's operating environment changes.

The amounts recorded for depletion and depreciation of oil and natural gas properties are based on estimated recoverable reserves and future costs. The level of estimated recoverable reserves and associated future cash flows are also key determinants in assessing whether the carrying values of the Company's oil and natural gas properties and goodwill have been impaired. By their nature, these estimates of reserves and future cash flows are subject to measurement uncertainty. Reserve estimates are determined in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The determination of reserve estimates involves the exercise of judgment and the use of estimates for oil and natural gas volumes in place, recovery factors, production rates, future commodity prices and future royalty, operating and capital costs.

IFRS requires that the Company's oil and natural gas properties be aggregated into CGUs, based on their ability to generate largely independent cash flows, which are used to assess the properties for impairment. The determination of the Company's CGUs is subject to management's judgment. The Company's assets are currently held in one CGU.

The Company's provisions for decommissioning liabilities are based on judgment regarding interpretation of current legal and constructive requirements and estimates of future costs and expected timing for remediation. Actual costs may differ from estimated costs because of changes in laws and regulations, reserves, market conditions, discovery and analysis of site conditions and changes in technology.

The Company uses the Black-Scholes model to estimate the fair value of stock options and performance warrants granted. This requires assumptions regarding interest rates, dividend rates, the underlying volatility of the shares and the expected life and forfeitures of the stock options and performance warrants.

The estimated fair values of financial instruments, by their very nature, are subject to measurement uncertainty. Fair value of financial instruments, where active market quotes are not available, are estimated using the Company's assessment of available market inputs and other assumptions. These estimates may vary from the actual prices that will be achieved upon settlement of the financial instruments.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations. As such, income taxes are subject to measurement uncertainty. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. In addition, the recoverability of loss carryforwards and investment tax credits is uncertain. The Company records deferred income tax assets and liabilities using income tax rates substantively enacted at the balance sheet date.

6. CASH AND CASH EQUIVALENTS

As at December 31	2014	2013
Cash	1,448	4,329
Government securities, bearing interest at a weighted average rate of 0.8% (December 31, 2013 – 0.7%) [(1)]	846,688	306,408
	848,136	310,737

(1) Includes term deposit balance of US$66.0 million ($76.6 million) (December 31, 2013 – US$58.0 million ($61.7 million)).

7. OIL AND NATURAL GAS ASSETS

	Exploration and Evaluation	Developed and Producing	Other	Total
Cost				
Balance at December 31, 2012	79,999	499,338	835	580,172
Additions	60,343	510,697	3,288	574,328
Non-cash capitalized costs [(1)]	-	7,219	-	7,219
Balance at December 31, 2013	140,342	1,017,254	4,123	1,161,719
Additions	61,652	1,056,411	2,273	1,120,336
Dispositions	-	(5,134)	-	(5,134)
Non-cash capitalized costs [(1)]	-	33,618	-	33,618
Balance at December 31, 2014	**201,994**	**2,102,149**	**6,396**	**2,310,539**
Accumulated depletion, depreciation and amortization				
Balance at December 31, 2012	-	61,982	429	62,411
Depletion, depreciation and amortization expense	-	38,618	303	38,921
Balance at December 31, 2013	-	100,600	732	101,332
Depletion, depreciation and amortization expense	-	158,387	1,060	159,447
Balance at December 31, 2014	**-**	**258,987**	**1,792**	**260,779**
Net book value				
Balance at December 31, 2013	140,342	916,654	3,391	1,060,387
Balance at December 31, 2014	**201,994**	**1,843,162**	**4,604**	**2,049,760**

(1) Non-cash capitalized costs include capitalized stock based compensation, decommissioning obligation assets, land swap additions and non-cash interest and financing.

As at December 31, 2014, the calculation for depletion included an estimated $8.9 billion (2013 – $2.7 billion) for future development capital associated with undeveloped estimated recoverable proved plus probable reserves and excluded $144.7 million (2013 – $140.1 million) for the cost of undeveloped land for which no recoverable reserves have been assigned and for other capital projects not yet in use.

During the year ended December 31, 2014, the Company capitalized $9.8 million (2013 – $6.7 million) of general and administrative expenses based on actual direct salaries and benefits paid to development personnel specifically related to capital activities, including $6.1 million (2013 – $4.4 million) related to stock based compensation.

During the years ended December 31, 2014, the Company capitalized $0.5 million (2013 – $Nil) of borrowing costs.

During the year ended December 31, 2014, the Company closed asset swap arrangements of non-producing assets. For purposes of determining the gain on disposition, the estimated fair market value was based on the fair value of the asset received. The Company recorded a gain of $4.3 million on the assets disposed of for the year ended December 31, 2014.

At the end of each reporting period, the Company performs an asset impairment review to ensure that the carrying value of its oil and natural gas properties and associated goodwill is recoverable. The Company also performs an annual goodwill impairment test. The Company determined that oil and natural gas properties and goodwill were not impaired at December 31, 2014 and 2013. In determining the recoverable amount, the Company calculated a value in use of its oil and natural gas properties applying a pre-tax discount rate of 10% on cash flows from proved plus probable reserves. The estimated cash flows were consistent with the estimates of the Company's independent reserves evaluator. The Company also considered additional values for other reserves and resources and undeveloped land not included in proved plus probable reserves.

8. BANK DEBT

At December 31, 2014, the Company had available a $480.0 million revolving credit facility (2013 – $150.0 million) with a syndicate of banks (the "credit facility"), which has a three year term ending in September 2017. The credit facility is subject to a redetermination of the borrowing base semi-annually and is secured by a floating charge over the Company's assets. The credit facility bears interest rates based on a pricing grid that increases or decreases based on the ratio of indebtedness to earnings before interest, taxes, depreciation, depletion and amortization. The credit facility also includes standby fees on balances not drawn.

During the year ended December 31, 2014, no amounts were drawn on the credit facility. During the year ended December 31, 2013, the Company borrowed up to $30.7 million on the credit facility for a period of one week. As at December 31, 2014 and December 31, 2013, there was no balance outstanding on the credit facility.

9. SENIOR NOTES

Year ended December 31	2014	2013
Balance, beginning of year	414,525	-
Issuance of debt	356,342	404,960
Debt issue costs	(9,840)	(11,201)
Unrealized foreign exchange loss	53,319	19,958
Amortization of premium and debt issue costs	(466)	808
Balance, end of year (1)	813,880	414,525

(1) Balance of debt and unamortized discount and premium at December 31, 2014 is US$701.1 million ($814.3. million) (2013 – US$388.9 million ($403.3 million)).

On May 10, 2013, the Company closed a private placement of US$400.0 million of senior unsecured notes. The notes bear interest at 8.25% per annum (calculated using a 360-day year) payable on May 15 and November 15 of each year, commencing on November 15, 2013. The notes will mature May 15, 2020. After May 15 of each of the following years, the notes are redeemable at the Company's option, in whole or in part, at the following redemption prices (expressed as a percentage of the principal amount of the notes): 2016 at 106.188%, 2017 at 104.125%, 2018 at 102.063% and 2019 at 100%. At any time prior to May 15, 2016, the Company may redeem up to US$140.0 million principal amount of the notes at a redemption price equal to 108.250% of the principal amount of the notes redeemed with the net proceeds of an equity offering by the Company. In addition, at any time prior to May 15, 2016, the Company may redeem all or a part of the notes at a redemption price equal to 100% of the aggregate principal amount plus an applicable premium that will be the greater of: (a) 1.0% of the principal amount; and (b) an amount equal to the excess of the present value at such redemption date of the redemption price at May 15, 2016 (106.188%) plus all accrued interest due through May 15, 2016 over the principal amount of the note, with the present value being computed using a discount rate based on current US Treasury yields plus 50 basis points. The Company reviewed the terms of the senior notes to determine if the prepayment options were embedded derivatives. While 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.

On February 5, 2014, the Company closed a private placement of US$300.0 million of senior unsecured notes issued under a supplemental indenture to the indenture governing the terms of the US$400.0 million of senior unsecured notes issued on May 10, 2013. The February 2014 notes were issued at 107% of par, resulting in gross proceeds to the Company of US$321.0 million. The terms for this second placement are the same as above.

Subject to certain exceptions and qualifications, the senior unsecured 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; transfers of assets; and engage in amalgamations, mergers or consolidations.

The notes are carried at amortized cost, net of transaction costs. The notes accrete up to the principal balance on maturity using the effective interest rate method and an effective interest rate of 7.3% and 8.6% for each respective 2014 and 2013 issuance. Exchange rates used for the 2014 issuance of US$300.0 million and the 2013 issuance of $400.0 million was 0.901 and 0.940, respectively.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31	2014	2013
Trade	18,849	72,892
Accrued liabilities	249,259	52,795
	268,108	125,687

11. DECOMMISSIONING LIABILITIES

Year ended December 31	2014	2013
Balance, beginning of year	23,656	21,298
Liabilities incurred	20,873	2,621
Changes in estimates (1)	2,367	2,683
Changes in estimated discount rates	4,311	(3,679)
Decommissioning expenditures	(206)	-
Accretion	1,162	733
Balance, end of year	52,163	23,656

(1) Changes in the status of wells and the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

The total future decommissioning liability was estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the decommissioning liabilities at December 31, 2014 is approximately $90.9 million (2013 – $46.4 million) which is expected to be incurred over the next 35 years with the majority of costs incurred between 2036 and 2049. At December 31, 2014 a risk-free rate of 2.3% (2013 – 3.2%) and an inflation rate of 2.0% (2013 – 2.0%) were used to calculate the provision for decommissioning liabilities.

12. DEFERRED INCOME TAXES

The provision for deferred income tax expense is different from the amount computed by applying the combined Canadian federal and provincial income tax rate to income (loss) before income taxes. The reasons for the differences are as follows:

Year ended December 31	2014	2013
Income (loss) before taxes	215,708	(13,807)
Canadian statutory income tax rate	25.0%	25.0%
Expected income tax expense (recovery)	53,927	(3,452)
Add (deduct):		
Non-deductible stock based compensation	2,987	2,389
Non-deductible portion of foreign exchange losses	6,308	1,487
Valuation allowance	8,210	-
Other	76	(73)
	71,508	351

Changes in the components of the deferred tax liability are as follows:

	January 1, 2014	Movement	December 31, 2014
Property, plant and equipment	35,957	43,190	79,147
Mark-to-market financial instruments	(661)	35,441	34,780
Investment tax credits	(9,127)	-	(9,127)
Non-capital losses	(4,668)	-	(4,668)
Decommissioning liabilities	(5,914)	(7,127)	(13,041)
Financing costs	(3,758)	(8,695)	(12,453)
Unrealized foreign exchange losses	(2,191)	(6,704)	(8,895)
Other	(310)	(5,019)	(5,329)
	9,328	51,086	60,414
Valuation allowance	-	8,210	8,210
	9,328	59,296	68,624

	January 1, 2013	Movement	December 31, 2013
Property, plant and equipment	33,680	2,277	35,957
Mark-to-market financial instruments	163	(824)	(661)
Investment tax credits	(9,127)	-	(9,127)
Non-capital losses	(4,740)	72	(4,668)
Decommissioning liabilities	(5,324)	(590)	(5,914)
Financing costs	(2,066)	(1,692)	(3,758)
Unrealized foreign exchange losses	-	(2,191)	(2,191)
Capital loss	(410)	410	-
Other	(20)	(290)	(310)
	12,156	(2,828)	9,328

The changes in the deferred tax liability were allocated to:

Year ended December 31	2014	2013
Income statement	71,508	351
Share capital	(12,212)	(3,179)
	59,296	(2,828)

The Company has no current income tax expense given its total tax pools of $1.7 billion at December 31, 2014 (2013 – $0.9 billion). As at December 31, 2014, the Company had non-capital losses of approximately $18.7 million (2013 – $18.7 million) available for deduction against future taxable income which mostly expire after 2027 and investment tax credits of $9.1 million (2013 – $9.1 million) with expiries starting in 2021.

13. SHARE CAPITAL

Authorized

Unlimited number of Class A Common Voting Shares
Unlimited number of Class B Common Non-voting Shares
Unlimited number of A, B, C, and D Preferred Shares
Unlimited number of Special Voting Shares

On May 29, 2014, shareholders approved a resolution to amend the Company's Articles of Incorporation to allow holders of Class B Common Shares to convert into Class A Common Shares on a 1 for 1 basis.

On September 8, 2014, the Company amended its Articles of Incorporation to divide the issued and outstanding Class A Common Voting Shares on a two-for-one basis. As a result of this division of the Class A Common Voting Shares, Class B Common Non-voting Shares may now be converted, at the option of the holder of Class B Common Non-voting Shares or the Company, on the basis of one Class B Common Non-voting Share for two Class A Common Voting Shares (on a post-division basis). In December 2014, the Company amended the terms of the stock options and performances warrants, issued prior to the completion of the initial public offering ("IPO"), such that upon exercise, the holders of these instruments will receive two Class A Common Voting Shares (rather than Class B Non-voting Shares) to reflect the two-for-one stock split.

The share split has been reflected in these financial statements for the year ended December 31, 2014 on a retroactive basis for the Class A Common Voting Shares, stock options, performance warrants and per share information.

At December 31, 2014 and 2013, there are no Preferred Shares or Special Voting Shares issued and outstanding.

Issued and Outstanding

Year ended December 31	2014 Number (000s)	2014 Amount	2013 Number (000s)	2013 Amount
Class A Common Voting Shares				
Balance, beginning of year	185,420	783,514	165,340	542,057
Issued on IPO (a)	51,750	931,500	-	-
Issued for cash (b)	-	-	20,080	250,992
Share issue costs, net of deferred tax (a,b)	-	(36,637)	-	(9,535)
Issued on exercise of stock options	110	275	-	-
Transfer from contributed surplus on exercise of stock options	-	130	-	-
Conversion of Class B Common Non-voting Shares [1]	7,436	37,268	-	-
Balance, end of year	244,716	1,716,050	185,420	783,514

(1) Class B Common Non-voting shares convert into Class A Common Voting Shares on a two-for-one basis.

(a) On November 5, 2014, the Company closed an IPO for gross proceeds of $931.5 million through the issuance of 51.8 million Class A Common Voting Shares at a price of $18.00 per common share including an over-allotment option exercised by the underwriters for gross proceeds of $121.5 million. Share issue costs related to the IPO and equity financing were $51.4 million, including the underwriters' commission for 5% of the gross proceeds of the IPO. Of this amount, the Company expensed $2.5 million (Note 17) in the income statement with the remainder charged against share capital. The Company also recognized a deferred income tax benefit of $12.2 million related to the share issue costs. As a part of the IPO, the Company agreed to apply restrictions to the transfer of common shares issued prior to the IPO without the consent of the underwriters. At December 31, 2014, 193.0 million shares were restricted from trading until 180 days from the IPO or May 5, 2015.

(b) In December 2013, the Company issued 20.0 million Class A shares at $12.50 per share for gross proceeds of $251.0 million. Share issue costs related to the equity financing were $12.7 million and the Company recognized a deferred income tax benefit of $3.2 million related to the share issue costs.

Year ended December 31	2014 Number (000s)	2014 Amount	2013 Number (000s)	2013 Amount
Class B Common Non-voting Shares				
Balance, beginning of year	966	6,550	600	3,000
Issued on exercise of stock options	1,770	9,765	173	865
Issued on exercise of performance warrants	1,505	15,858	193	1,739
Transfer from contributed surplus on exercise of stock options and performance warrants	-	8,824	-	946
Conversion to Class A Common Voting Shares [1]	(3,718)	(37,268)	-	-
Balance, end of year	523	3,729	966	6,550

(1) Class B Common Non-voting shares convert into Class A Common Voting Shares on a two-for-one basis.

14. STOCK BASED COMPENSATION

Stock Options

The Company has issued stock options to its directors, officers, and employees to acquire up to 12.4 million Class A Common Voting Shares. These stock options ("Pre-IPO stock options") were granted under the stock option plan provided for in the Amended and Restated Shareholder Agreement ("USA") effective while Seven Generations was a private company. These stock options originally granted the holders the right to acquire one Class B Common Non-voting Share for each stock option exercised. In December 2014, the terms of the Pre-IPO stock options were amended to provide consistency with the two-for-one stock split of Class A Common Voting Shares that occurred in September 2014. After the amendment in December 2014, each stock option grants the holder the right to acquire one Class A Common Voting Share instead of a Class B Common Non-voting Share. The number of Pre-IPO stock options outstanding was doubled as a result of the stock split and the exercise price of each option outstanding was reduced by one-half. The Pre-IPO stock options have a seven-year term from the date of grant and vest over a period of three years. After the November 5, 2014 closing of the IPO, no additional Pre-IPO stock options may be granted under this plan.

In anticipation of an IPO, the Company's stock option plan was amended and restated on August 27, 2014 (the "New Plan"). Stock options awarded after the closing of the IPO are issued under the New Plan. These stock options are exercisable for Class A Common Voting Shares rather than Class B Common Non-voting Shares. The stock options will vest over a period of three years, or as otherwise set out by the Board in the applicable grant agreement, and have a maximum term of ten years. The maximum number of Class A Common Voting Shares issuable under the New Plan and other share based compensation arrangements (excluding the performance warrants) must not exceed 10% of the aggregate of the number of outstanding Class A Common Voting Shares plus two times the number of outstanding Class B Common Non-voting Shares. As at December 31, 2014, no stock options were issued under the New Plan.

The following table sets forth a reconciliation of stock options exercisable into Class A Common Voting Shares:

	Number of Options (000s)	Weighted Average Exercise Price ($)
Balance at December 31, 2012	11,650	3.02
Granted	2,257	5.71
Exercised	(346)	2.50
Forfeited	(135)	2.86
Balance at December 31, 2013	13,426	3.49
Granted	2,927	17.11
Exercised	(3,650)	2.75
Forfeited	(318)	5.81
Balance at December 31, 2014	12,385	6.71

A summary of stock options outstanding and exercisable into Class A Common Voting Shares at December 31, 2014 is as follows:

	Options Outstanding		Options Vested	
Exercise price ($)	Number of Options (000s)	Weighted Average Remaining Life (Years)	Number of Options (000s)	Weighted Average Remaining Life (Years)
2.50	5,736	2.7	5,723	2.6
5.50	3,760	5.0	1,824	4.9
12.50	489	6.2	15	5.9
17.50	1,892	6.4	-	-
18.00	508	6.7	-	-
	12,385	4.3	7,562	3.2

The fair value of stock options granted was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Year ended December 31	**2014**	2013
Fair value of options granted ($/option)	7.81	2.13
Risk-free interest rate (%)	1.4	1.1
Expected life (years)	3.9	2.1
Expected forfeiture rate (%)	3.0	3.0
Expected volatility (%) [(1)]	60.0	65.0
Expected dividend yield (%)	-	-

(1) Expected volatility is based on the historical share price volatility from a peer group of listed companies.

During the year ended December 31, 2013, the stock options granted in 2008 were amended to extend the expiry date by one year in order to realign compensation with the Company's business plan. The incremental fair value of the stock option modifications of $0.4 million was expensed in the year ended December 31, 2013. The fair value was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Fair value of option modification ($/option)	0.11
Risk-free interest rate (%)	1.22
Expected life (years)	2.5
Expected forfeiture rate (%)	3.0
Expected volatility (%)	65
Expected dividend yield (%)	-

During the year ended December 31, 2014, the stock options granted in 2008 were amended to extend the expiry date by one year in order to realign compensation with the Company's business plan. The incremental fair value of the stock option modifications was a nominal amount for the year ended December 31, 2014. The fair value was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Fair value of option modification ($/option)	0.02
Risk-free interest rate (%)	1.13
Expected life (years)	1.5
Expected forfeiture rate (%)	3.0
Expected volatility (%)	60
Expected dividend yield (%)	-

Performance Warrants

The Company has issued performance warrants to its directors, officers, and employees to acquire up to 26.0 million Class A Common Non-voting Shares. These performance warrants were granted pursuant to the USA effective while Seven Generations was a private company. These performance warrants originally granted the holders the right to acquire one Class B Common Non-voting Share for each performance warrant exercised. In December 2014, the terms of the performance warrants were amended to provide consistency with the two-for-one stock split of Class A Common Voting Shares that occurred in September 2014. After the amendment in December 2014, each warrant grants the holder the right to acquire one Class A Common Voting Share instead of a Class B Common Non-voting Share. The number of performance warrants outstanding was doubled as a result of the stock split and the exercise price of each warrant outstanding was reduced by one-half. The performance warrants have a seven-year term from the date of grant and vest over a period of five years. After the November 5, 2014 closing of the IPO, no additional performance warrants may be granted.

The following table sets forth a reconciliation of performance warrants exercisable into Class A Common Voting Shares:

	Number of Warrants (000s)	Weighted Average Exercise Price ($)
Balance at December 31, 2012	27,792	5.33
Granted	2,236	6.01
Exercised	(386)	4.50
Forfeited	(817)	5.28
Balance at December 31, 2013	28,825	5.39
Granted	1,350	17.38
Exercised	(3,011)	5.27
Forfeited	(1,196)	6.31
Balance at December 31, 2014	25,968	5.99

A summary of performance warrants outstanding and exercisable into Class A Common Voting Shares at December 31, 2014 is as follows:

	Warrants Outstanding		Warrants Vested	
Weighted average exercise price ($)	Number of Warrants (000s)	Weighted Average Remaining Life (Years)	Number of Warrants (000s)	Weighted Average Remaining Life (Years)
5.25	19,121	2.6	15,050	2.4
5.85	5,545	4.8	1,810	4.7
12.50	94	6.1	7	5.9
17.50	1,208	6.4	-	-
	25,968	3.2	16,867	2.6

The fair value of performance warrants granted was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Year ended December 31	2014	2013
Fair value of warrants granted ($/warrant)	8.87	2.02
Risk-free interest rate (%)	1.4	1.1
Expected life (years)	4.9	2.1
Expected forfeiture rate (%)	3.0	3.0
Expected volatility (%) [1]	60.0	65.0
Expected dividend yield (%)	-	-

(1) Expected volatility is based on the historical share price volatility from a peer group of listed companies.

During the year ended December 31, 2013, the performance warrants granted in 2008 were amended to extend the expiry date by one year in order to realign compensation with the Company's business plan. The incremental fair value of the performance warrant modifications of $1.7 million was expensed in the year ended December 31, 2013. The fair value was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Fair value of option modification ($/option)	0.21
Risk-free interest rate (%)	1.22
Expected life (years)	2.5
Expected forfeiture rate (%)	3.0
Expected volatility (%)	65
Expected dividend yield (%)	-

During the year ended December 31, 2014, the performance warrants granted in 2008 were amended to extend the expiry date by one year in order to realign compensation with the Company's business plan. The incremental fair value of the performance warrant modifications of $0.8 million was expensed in the year ended December 31, 2014. The fair value was estimated using a Black-Scholes pricing model with the following weighted average assumptions:

Fair value of option modification ($/option)	0.12
Risk-free interest rate (%)	1.13
Expected life (years)	1.5
Expected forfeiture rate (%)	3.0
Expected volatility (%)	60
Expected dividend yield (%)	-

Compensation Plans

On August 27, 2014, the Board of Directors (the "Board") adopted a Performance and Restricted Share Unit ("PRSU") Plan and a Deferred Share Unit ("DSU") Plan. The maximum number of Class A Common Voting Shares that may be issued to officers and employees under the PRSU Plan is 1,000,000. Each Share Unit issued under the PRSU Plan will grant to the holder the right to receive a Class A Voting Common Share or, in certain circumstances, the cash equivalent of a Class A Common Share, based on the achievement of certain performance criteria. The vesting schedule of the PRSUs will be determined at the discretion of the Compensation Committee of the Board. The maximum number of Class A Common Voting Shares that may be issued to non-executive directors under the DSU Plan is 600,000. Each DSU may be redeemed for a Class A Common Voting Share issued by the Company from treasury. The vesting schedule of the DSUs will be determined at the discretion of the Compensation Committee, but generally in the case of DSUs granted in lieu of director retainers or as annual incentives, the DSUs vest immediately on the award date. At December 31, 2014, no units had been issued for either of these plans.

15. PER SHARE AMOUNTS

Basic and diluted per share amounts have been calculated based on the following:

Year ended December 31 (1)	2014	2013
In (000s)		
Weighted average number of common shares – basic	198,742	167,802
Effect of outstanding stock options and performance warrants (2)	25,975	15,486
Weighted average number of common shares – diluted	224,717	183,288

(1) All numbers reflect two-for-one share split.
(2) 2,399,468 anti-dilutive stock options and 1,207,670 anti-dilutive performance warrants have been excluded above (2013 – 33,000 anti-dilutive stock options).

16. GENERAL AND ADMINISTRATIVE EXPENSES

Year ended December 31	2014	2013
Personnel	12,912	7,227
IPO expenses	2,506	-
Professional fees	2,636	739
Rent	1,210	453
Other office costs	4,713	2,524
Gross expenses	23,977	10,943
Capitalized salaries and benefits	(2,661)	(2,159)
Operating overhead recoveries	(1,058)	(667)
	20,258	8,117

17. FINANCE EXPENSE

Year ended December 31	2014	2013
Interest on senior notes	61,303	22,113
Revolving credit facility fees and other	2,142	793
Amortization of premium and debt issue costs	(466)	808
Accretion	1,162	733
Total finance costs	64,141	24,447
Capitalized borrowing costs	(500)	-
Total finance expense	63,641	24,447

18. LIQUIDITY EVENT EXPENSE

Pursuant to the USA, the Company was obligated to compensate, with cash or shares, certain directors, officers and employees prior to the completion of a change of control, liquidity event or qualified initial public offering (the "Liquidity Event"). With the closing of the IPO on November 5, 2014, the Liquidity Event condition was satisfied and the Company recognized a liability of $36.0 million. The settlement of the liability was approved by the Board of Directors to be payable in cash in 2015.

For purposes of Note 24, the allocation of Liquidity Event payments to key management personnel will be determined in 2015.

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT CONTRACTS

Financial Instrument Classification and Measurement

The Company's financial instruments include cash and cash equivalents, outstanding cheques in excess of bank balances, 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, outstanding cheques in excess of bank balances, 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.

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 and outstanding cheques in excess of bank balances are classified as Level 1 measurements. Risk management contracts, the credit facility 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 years ended December 31, 2014. 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.

The classification, carrying values and fair values of the Company's financial instruments are as follows:

As at December 31	2014 Carrying Value	2014 Fair Value	2013 Carrying Value	2013 Fair Value
FINANCIAL ASSETS				
Fair Value Through Profit and Loss				
Cash and cash equivalents	848,136	848,136	310,737	310,737
Risk management contracts	139,119	139,119	-	-
Loans and Receivables				
Accounts receivable	64,417	64,417	30,500	30,500
Deposits	5,034	5,034	1,710	1,710
FINANCIAL LIABILITIES				
Fair Value Through Profit and Loss				
Outstanding cheques in excess of bank balances	-	-	3,252	3,252
Risk management contracts	-	-	2,646	2,646
Other Financial Liabilities				
Accounts payable and accrued liabilities	268,108	268,108	125,687	125,687
Senior notes payable	813,880	782,000	414,525	434,000

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 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

As at December 31, 2013	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	68	(68)	-
Current liability	(2,714)	68	(2,646)
Net position	(2,646)	-	(2,646)

Market Risk

Market risk is the risk that changes in market prices including commodity prices, interest rates and foreign exchange risks will affect the Company's income (loss) or the value of financial instruments. The objective of market risk management is to reduce exposures to acceptable limits while optimizing returns.

(a) Commodity Price Risk

Commodity price risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by world economic events that dictate the levels of supply and demand. The Company uses derivative financial instruments to manage its exposure to fluctuations in commodity prices. The Company considers these transactions to be effective economic hedges; however, the Company's contracts do not qualify as effective hedges for accounting purposes. The Company does not enter into commodity contracts other than to meet the Company's expected sales requirements.

The following risk management contracts were outstanding at December 31, 2014:

Commodity	Term	Contract	Volume	Average Price/Unit
Natural gas	Jan 2015 – Dec 2015	Fixed Price	8,500 GJ/d	CDN$3.82
Natural gas	Jan 2015 – Mar 2015	Fixed Price	2,000 GJ/d	CDN$4.70
Natural gas	Jan 2015 – Mar 2015	Costless Collar	39,000 GJ/d	CDN$4.00 – $5.45
Natural gas	Jan 2015 – Mar 2015	Fixed Price	5,000 GJ/d	CDN$4.00
Natural gas	Jan 2015 – Mar 2015	Costless Collar	19,000 GJ/d	CDN$4.00 – $5.39
Natural gas	Apr 2015 – Dec 2015	Fixed Price	30,000 GJ/d	CDN$3.91
Natural gas	Apr 2015 – Jun 2015	Fixed Price	25,000 GJ/d	CDN$3.86
Natural gas	Jul 2015 – Dec 2015	Fixed Price	10,000 GJ/d	CDN$3.43
Natural gas	Jul 2015 – Sept 2015	Fixed Price	5,000 GJ/d	CDN$3.86
Natural gas	Jul 2015 – Dec 2015	Fixed Price	10,000 GJ/d	CDN$3.50
Natural gas	Oct 2015 – Dec 2015	Fixed Price	15,000 GJ/d	CDN$3.77
Natural gas	Jan 2016 – Mar 2016	Fixed Price	17,500 GJ/d	CDN$3.79
Oil	Apr 2015 – Jun 2015	Fixed Price	11,000 bbls/d	CDN$102.15
Oil	Jan 2015 – Dec 2015	Fixed Price	1,100 bbls/d	CDN$99.81
Oil	Jan 2015 – Mar 2015	Fixed Price	10,100 bbls/d	CDN$102.57
Oil	Jul 2015 – Sept 2015	Fixed Price	6,500 bbls/d	CDN$102.57
Oil	Oct 2015 – Dec 2015	Fixed Price	1,000 bbls/d	CDN$100.75

During the year ended December 31, 2014, the Company's risk management contracts resulted in a realized gain of $9.7 million (2013 – $0.3 million) and an unrealized gain of $141.8 million (2013 – unrealized loss of $3.3 million).

The following table demonstrates the impact of changes in commodity pricing on income before tax, based on risk management contracts in place at December 31, 2014:

	Gain (Loss)
10% increase in AECO/GJ	(7,234)
10% decrease in AECO/GJ	7,234
10% increase in US$ WTI/bbl	(19,514)
10% decrease in US$ WTI/bbl	19,514

(b) Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The senior notes payable bear interest at a fixed rate. The Company's credit facility bears a floating rate of interest and, accordingly, the Company is exposed to interest rate fluctuations to the extent that any advances remaining outstanding under the facility. During May 2013, the Company borrowed up to $30.7 million on the credit facility for a period of one week. During the year ended December 31, 2014, no amounts were drawn on the credit facility.

(c) Foreign Currency Exchange Risk

Foreign currency exchange risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in foreign exchange rates.

Prices for oil are determined in global markets and generally denominated in US dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the US dollar will reduce the prices received by the Company for its oil and natural gas sales.

The Company is exposed to foreign exchange rate fluctuations on the principal and interest related to the senior notes payable, as well as on cash balances held in US dollars. The foreign currency risk associated with interest payments is partially offset by a marketing arrangement for the Company's natural gas liquids, excluding condensate, which is denominated in US dollars.

The following table demonstrates the impact of changes in the Canadian to US dollar exchange rate on income before tax, based on US denominated balances outstanding at December 31, 2014:

	Gain (Loss)
$0.01 increase in CAD/USD exchange rate	8,538
$0.01 decrease in CAD/USD exchange rate	(8,739)

The carrying amount of the Company's US dollar denominated monetary assets and liabilities as at December 31 was as follows:

	2014	2013
Assets	78,042	67,053
Liabilities	822,573	419,083

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises primarily from the Company's receivables from oil and natural marketers and joint venture partners and hedging assets. The Company's maximum exposure to credit risk is equal to the carrying amount of these instruments.

Substantially all of the Company's accounts receivable are with oil and natural gas marketers and joint venture partners under normal industry sale and payment terms and are subject to normal industry credit risk. Receivables from oil and natural gas marketers are normally collected on or about the 25th day of the following month. The Company sells the majority of its production to two oil and natural gas marketers and is therefore subject to concentration risk. Production is sold to marketers with investment grade credit ratings, if available in the area of production. The Company historically has not experienced any collection issues with its oil and natural gas marketers. As at December 31, 2014, the Company's most significant marketer accounted for $21.1 million (2013 – $11.6 million) of total receivables and 4% of total revenues (2013 – 10%). Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner pre-approval of significant capital expenditures. However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling and disagreements with partners. As the operator of properties, the Company has the ability to withhold production from joint interest partners in the event of non-payment. As at December 31, 2014, receivables outstanding for more than 90 days totalled less than $0.1 million (2013 – $0.1 million). The Company believes all of the accounts receivable will be collected. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

All the Company's cash and cash equivalents are held with Canadian chartered banks and as such, the Company is exposed to credit risk on any default by the institutions of amounts in excess of the minimum guaranteed amount. The Company considers the risk of default by a Canadian chartered bank to be remote. As at December 31, 2014, the Company does not invest any cash in complex investment vehicles with higher risk such as asset backed commercial paper. All of the Company's risk management contracts are with Schedule 1 Canadian chartered banks or high credit-quality financial institutions.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meets its financial obligations as they fall due. The Company manages its liquidity risk through ensuring, as reasonably as possible, that it will have sufficient liquidity to meets its liabilities when due without incurring unacceptable losses or risking damage to the Company's reputation. At December 31, 2014, the Company had $848.1 million of cash and cash equivalents on hand, plus a $480.0 million undrawn revolving credit facility. Management believes it has sufficient funding to meet foreseeable liquidity requirements. The Company prepares capital expenditure budgets which are regularly monitored and updated as considered necessary. As well, the Company utilizes authorizations for expenditures on both operated and non-operated projects to manage capital expenditures.

The following are the contractual maturities of financial liabilities at December 31, 2014:

	Less Than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts payable and accrued liabilities	268,108	-	-	-	268,108
Senior notes payable [1]	-	-	-	812,070	812,070
Interest on senior notes payable [1]	66,996	133,992	133,992	25,123	360,103
Total	335,104	133,992	133,992	837,193	1,440,281

(1) Balances denominated in US dollars have been translated at the December 31, 2014 exchange rate of 0.862.

20. CAPITAL MANAGEMENT

The capital structure of the Company is as follows:

As at December 31	**2014**	2013
Total debt [1]	813,880	414,525
Total equity [2]	1,910,926	827,953
Total capital	2,724,806	1,242,478

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

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. Near-term major acquisitions and capital development will be funded by funds flow from operations, cash or cash equivalents, equity financings, the credit facility (Note 8) and debt financings (Note 9). 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 expenditures.

The Company had working capital of $653.8 million (current assets less current liabilities excluding current portion of risk management contracts and deferred credits) plus $480.0 million of undrawn credit facility capacity creating available funding of $1.1 billion at December 31, 2014 and plans to use these funds, along with funds from operations, for the execution of its 2015 capital program.

Subject to certain exceptions and qualifications, the senior unsecured notes limit the Company's ability to, among other things: make restricted payments, incur additional indebtedness, issue disqualified or preferred stock; create or permit liens to exist; create or permit to exist restrictions on the ability to make payments and distributions; make certain dispositions; transfers of assets; and engage in amalgamations, mergers or consolidations; and engage in certain transactions with affiliates.

21. SUPPLEMENTAL CASH FLOW INFORMATION

Change in Non-Cash Working Capital

Year ended December 31	2014	2013
Accounts receivable	(33,917)	(20,883)
Deposits and prepaid expenses	(6,776)	(1,559)
Accounts payable and accrued liabilities	142,334	63,917
	101,641	41,475
Relating to:		
Operating activities	10,129	(8,398)
Investing activities	91,512	49,873

Foreign Exchange Loss (Gain)

Year ended December 31	2014	2013
Unrealized foreign exchange loss	53,406	19,975
Realized foreign exchange gain	(5,733)	(9,078)
	47,673	10,897

Other Cash Flow Information

Year ended December 31	2014	2013
Cash interest paid	57,271	22,906
Cash taxes paid	-	-

22. COMMITMENTS

The following table lists the Company's estimated material contractual commitments at December 31, 2014:

	Total	Less Than 1 Year	1-3 Years	4-5 Years	Thereafter
Senior notes (1)	812,070	-	-	-	812,070
Interest on senior notes (1)	360,103	66,996	133,992	133,992	25,123
Firm transportation and processing agreements (1)	1,775,622	25,788	386,591	487,939	875,304
Operating leases	14,717	2,217	4,295	3,104	5,101
Estimated contractual obligations	2,962,512	95,001	524,878	625,035	1,717,598

(1) Balances denominated in US dollars have been translated at the December 31, 2014 exchange rate of 0.862.

Seven Generations entered into agreements with Pembina Pipeline Corporation for firm transportation and processing services, of which the above estimates for timing of payments are subject to completion of certain pipeline and facility upgrades by the counterparty. The Company has an agreement with Aux Sable Canada LP and, separately, with Alliance Pipeline Ltd. to deliver up to 500 Mmcf/d of peak rich gas volumes by 2018. The natural gas agreements expire in 2022. Seven Generations also has take or pay agreements in place for up to approximately 40,000 bbls/d of condensate and other NGLs production by 2017. The liquids agreements expire in 2026. The minimum commitments under these agreements are reflected in the table above.

Effective August 27, 2014, the Company entered into an agreement to have a third party provide a 24-hour dedicated crew for hydraulic fracturing. The agreement has an initial term of one year. The Company may terminate the agreement on less than 60 days notice and payment to the third party of an amount equal to $50,000 for each day less than 60 days that notice of the termination is given.

23. DEFERRED CREDITS

Leasehold inducements were received in 2013 when the Company entered into a corporate office lease. These inducements are recognized as a deferred liability and amortized over the term of the lease.

24. RELATED PARTY TRANSACTIONS

Key management personnel are comprised of all directors and officers of the Company. Excluding the Liquidity Event expense disclosed in Note 18, the amounts recognized in the financial statements for transactions with key management personnel are as follows:

Year ended December 31	2014	2013
Salaries, benefits and other short-term compensation	6,276	3,782
Stock based compensation	9,538	9,691
	15,814	13,473

In November 2014, the Board of Directors approved a retention bonus plan for management and employees. The retention bonuses will be payable in four equal installments payable every six months starting on May 5, 2015. Each installment payment will be contingent upon the individual being employed by the Company on the date of payment. The maximum retention bonuses will be $6 million, payable over the two-year period starting November 5, 2014. The allocation payments to key management for this retention plan will be determined in 2015.

CORPORATE INFORMATION

MANAGEMENT

Pat Carlson
Chief Executive Officer

Marty Proctor
President and Chief Operating Officer

Harry Cupric
Chief Financial Officer

Randy Evanchuk
Executive Vice President

Steve Haysom
Senior Vice President

Susan Targett
Vice President, Land

Christopher Law
Vice President, Corporate Planning

Glen Nevokshonoff
Vice President, Development

Merlyn Spence
Vice President, Construction and Marketing

Barry Hucik
Vice President, Drilling

Randall Hnatuik
Vice President, Business Development

Kevin Johnston
Vice President, Accounting and Controller

DIRECTORS

Kent Jespersen
Chairman

Pat Carlson
Chief Executive Officer

Michael Kanovsky

Kevin Brown

Jeff van Steenbergen

Jeff Donahue

Kaush Rakhit

Dale Hohm

Bill McAdam

CORPORATE OFFICE

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BANKS

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Bank of Montreal
Canadian Imperial Bank of Commerce
The Bank of Nova Scotia
The Toronto-Dominion Bank
Alberta Treasury Branches
Canadian Western Bank
National Bank of Canada

AUDITORS

Deloitte LLP

LEGAL COUNSEL

Stikeman Elliott LLP

INDEPENDENT EVALUATORS

McDaniel & Associates Consultants Ltd.

STOCK SYMBOL

VII
Toronto Stock Exchange

SEVEN GENERATIONS
ENERGY LTD

Seven Generations Energy Ltd. 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, the Kakwa River Project, a large-scale, tight, liquids- rich natural gas property located in the Kakwa area of northwest Alberta. 7G has a corporate headquarters in Calgary, Alberta and an operations headquarters in Grande Prairie, Alberta. Seven Generations shares are traded on the Toronto Stock Exchange under the symbol **VII**.

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