2017 Annual Report

SEVEN GENERATIONS
ENERGY

Seven Generations Energy Ltd.

Seven Generations is a low-supply cost, growth oriented energy producer dedicated to stakeholder service, responsible development and generating strong returns from its liquids-rich Kakwa River Project in northwest Alberta.

Seven Generations differentiates itself through its core attributes: the quality of its liquids-rich asset, large resource size, desirable location and market access, a high degree of operational control, proven and innovative technical execution and unique operating approaches. We are committed to protecting the natural beauty of the environment and preserving its capacity for current and future generations. While we recognize that our activity and operations impact the air, water, land and natural life, we believe it is vital that we work with all our stakeholders to reduce and minimize our environmental impacts.

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For important additional information, please refer to the "Advisories and Guidance" beginning on page 41.

Seven Generations trades on the Toronto Stock Exchange under the symbol **VII**.

On the cover: Lator natural gas processing plant – Kakwa River Project.

2017 Highlights

10%
Return on capital employed

$1.23 BILLION
Funds from operations **– up 66%**
Funds from operations per share **– up 45%**

175.0 M BOE/D
Total production **– up 49%**
Production per share **– up 30%**

55.7 M BBLS/D
Condensate production **– up 42%**

$22.43 PER BOE
Operating netback **– up 6%**

1.7 BILLION BOE
Proved plus probable reserves **– up 10%**
replacing 351% of production

Our Strategy

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

STAKEHOLDER SERVICE

recognizing that in a competitive world, only those who best serve their stakeholders can expect to survive in the long term.

FINANCIAL SUSTAINABILITY

continued profitable growth to achieve positive free cash flow and earn full-cycle returns on capital employed across the entire commodity price cycle, focusing capital deployment on high return opportunities.

SUPPLY COST

combining resource selection with innovation, technology and efficiency to remain among North America's lowest supply cost, unconventional liquids-rich natural gas developers.

MARKET ACCESS

establishing ample gathering, processing, transportation and marketing capacity for production in order to capture premium prices from diverse markets.

Level 1 Corporate Policy

OUR 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 the society in which they exist. To thrive, companies must differentiate, rise above the pack, stand out 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:

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

President & CEO's Message

LEVERAGING OUR STRENGTHS TO SERVE STAKEHOLDERS AND EARN RETURNS

At Seven Generations, 2017 was a year of enhanced financial returns, profitable growth, differentiated stakeholder service and a leadership transition that marked the natural evolution of our company's growth and progression. Last November, we defined a five-year growth plan to deliver an average annual return on capital employed of 10-15 percent. We continued to leverage our geological, technical and innovative strengths to generate profitable growth during one of the most prolonged downturns in the oil and natural gas industry – an industry that is challenged by oversupply, restricted market access and increasing regulation.

Despite those external headwinds, our return on capital employed was an industry-leading 10 percent, production grew by 49 percent, and production of our highest value product – condensate – increased 42 percent to average 55,700 barrels per day. We are now Canada's largest condensate producer. These notable accomplishments are the outcome of our well-established strategy – stakeholder service, low supply cost, financial sustainability and market access.

The foundation of our business remains our Level 1 Corporate Policy. It is the Code of Conduct that drives our decisions and the basis of our culture at Seven Generations. Through it, we pursue value creation through differentiated stakeholder service. We believe this combination will ensure our success over the long term, despite any difficult market conditions we may encounter along the way.

Marty Proctor
President & Chief Executive Officer

> *We continue to expand and diversify our markets.*

Barry Hucik, Vice President, Drilling, explains innovative techniques to guests on a Kakwa River Project field tour.

SERVING OUR STAKEHOLDERS

We strive to serve all our stakeholders. We build and nurture long-term relationships with ongoing engagement that is personal and direct. Our growing number of employee ambassadors in Grande Prairie and Calgary participate in community functions, meetings and conferences to seek input from stakeholders, understand their views and answer questions about our work. When we are not out engaging communities, we invite them in – to see our Kakwa River Project up close – conducting numerous field tours, hosting regulators, government leaders, investors and analysts, community leaders, university students, First Nations councils and elders, as well as business partners. For shareholders, investment analysts and capital providers, our Investor Day provided a comprehensive review of financial and operational strategies and stakeholder relations. Held in conjunction with our annual meeting in May, shareholders and the public attended our first 7G Science Expo where our staff hosted booths showing operational, technical, strategic, environmental and community initiatives.

We are looking forward to hosting our second 7G Science Expo at our annual meeting on May 3, 2018 in Calgary.

Outside of work, our employees serve stakeholders by rolling up their sleeves to volunteer in a wide variety of projects. These include roadside cleanups, job shadowing, funding and serving hot meals at the Calgary Drop-In & Rehab Centre and the Sturgeon Lake Cree Nation Pow Wow as well as contributing funds to the development of a new state-of-the-art hospital in Grande Prairie that will help build a better foundation for public health care for the people of northwest Alberta and northeast British Columbia. Together with business partners, suppliers, service companies, contractors and community members, we raised more than $535,000 for the Grande Prairie Regional Hospital Foundation, bringing the total amount raised to more than $1.7 million in five years.

RETURN ON CAPITAL EMPLOYED OF 10 PERCENT, FUNDS FROM OPERATIONS UP 45 PERCENT PER SHARE

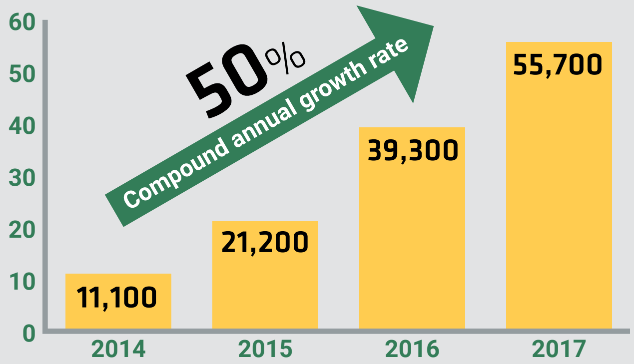
Our return on capital employed was 10 percent in 2017 and our cash return on invested capital was 18 percent – industry leading results. Funds from operations were $1.23 billion, or $3.37 per share, up 66 and 45 percent respectively. These measures demonstrate how Seven Generations is built to withstand a low commodity price environment, and outperform with improving commodity prices.

We exited 2017 in excellent financial shape, with a strong balance sheet and ample liquidity, ending the year with available funding of more than $1.4 billion. Annualizing our fourth quarter funds flow, our net debt to funds flow was 1.2x, which means we have very manageable debt. This is a 34 percent improvement from the fourth quarter of 2016, when it was 1.7x.

RESERVES AND INVENTORY GROWTH

We continued to grow our reserves, replacing 170 percent of our production with proved, developed and producing reserves. Total proved plus probable reserves grew 10 percent to 1.7 billion boe. We defined a new core area, Nest 3, which has 223.9 MMboe of proved plus probable reserves. Our proved plus probable finding, development and acquisition costs decreased by 13 percent, to $10.13 per boe. This bodes well as we develop our growing drilling inventory of wells in the upper and middle Montney Formation, which includes 1,400 Nest locations and 900 Wapiti and Rich Gas well locations. At a current drilling rate of about 100 wells per year, we have decades of drilling ahead.

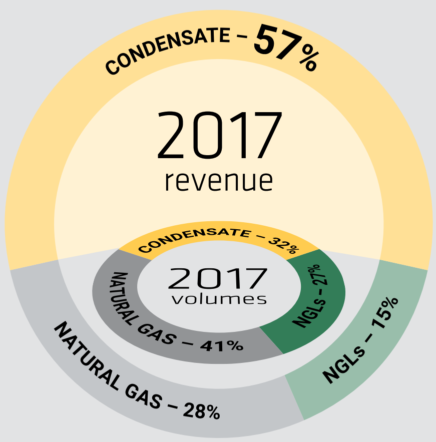
Condensate production bbls/day



7G is a prolific condensate producer. We've seen a 50% compound annual growth rate over the last four years.

PRODUCTION GROWTH OF NEARLY 50 PERCENT

We drilled our 300th Montney well and increased production by 49 percent to 175,000 boe/d in 2017. That equates to about 1,000 boe/d per employee – a tremendous achievement in its own right. We now rank among Canada's top ten oil and natural gas producers. We produce about 20 percent of Canada's condensate. In the fourth quarter, we produced 63,700 barrels per day of condensate at prices similar to the North American light oil benchmark. On a volume basis in 2017, condensate represented 32 percent of our total production, but generated 57 percent of our revenue. We also captured attractive natural gas prices by shipping most of our natural gas to the US Midwest, the US Gulf Coast, and to Central Canada at Dawn, Ontario. Our market access initiatives underpin our strong project economics and returns.



Making up about one third of our volumes, 7G's condensate generated 57% of our 2017 revenue.

Our third wholly owned natural gas processing plant, located in the Gold Creek area, is scheduled to start operations in the fourth quarter of 2018. This plant will increase our available processing capacity for the Kakwa River Project to approximately 1 billion cubic feet per day in its first phase of development and provide the groundwork for continued profitable growth.

> *Condensate generated 57 percent of our revenue.*

OPERATIONS PERFORMANCE

We are very mindful that 2017 marked a year when our shareholders endured a decrease in our valuation. Despite growing production by 49 percent, operational challenges caused 2017 annual average production to be about five percent below the midpoint of our original guidance. Total liquids production in 2017 was within our original budget and condensate production exceeded expectations primarily due to higher than anticipated condensate production outside of Nest 2 and from the use of high intensity slickwater completions. This increased liquids production was more than offset by lower initial natural gas production rates from the use of slickwater completions, resulting in lower total production on a barrel of oil equivalent basis.

Our internal teams and leading industry experts have completed comprehensive evaluations and action plans to solve the operational challenges, which included unplanned downtime at a third-party gas processing plant. Working with the owner of that plant, we are undertaking a series of upgrades in 2018 to raise processing performance to industry norms. We have also re-routed some production to our plants to minimize the impact of third-party natural gas processing plant downtime.

To reduce water disposal costs, we drilled our first water disposal well in 2017. Additional disposal wells are planned for 2018. We are building a water pipeline network to connect the disposal wells and enable produced water to be recycled back to 7G's development pads for re-use in hydraulic fracturing.

MARKET ACCESS ADVANTAGE DRIVES RETURNS

During 2017, our long-standing strategy of securing sufficient transportation capacity to deliver our products to diverse and premium-priced markets continued to drive strong returns. We produce five products, condensate, natural gas and natural gas liquids – ethane, propane and butane.

Condensate is our highest value-product. With high demand and premium prices in Alberta, our realized condensate prices averaged $61.46 per barrel, similar to benchmark prices for light oil. The startup of Pembina's Phase III expansion of the Peace Pipeline in July 2017 nearly tripled our Kakwa River Project takeaway capacity of condensate and natural gas liquids, reducing our trucking costs and traffic on local highways.

Natural gas liquids are sold approximately half in Alberta and half in the US. 7G secured a new long-term propane sale in the fourth quarter of 2017, agreeing to supply Inter Pipeline's planned propane dehydrogenation and polypropylene Heartland Petrochemical Complex. The Complex, expected to commence production in late 2021, will enable 7G to diversify its propane sales and capture stronger realized prices within the Alberta petrochemical value chain.

With an abundant supply of natural gas in Western Canada, Alberta prices tracked lower than in other North American markets. Our 2017 average natural gas price was $3.88 per thousand cubic feet (Mcf), which was about 76 percent above the average sales price for natural gas at Alberta's main trading hub – AECO, where prices averaged $2.20 per Mcf. With about 76 percent of our natural gas sales on Alliance Pipeline going to the Chicago area market, and approximately 20 percent of that to the Gulf Coast, we were able to capture significantly more value for our natural gas.

Our total Alliance pipeline capacity will increase incrementally in late 2018 to 508 MMcf/d. In November 2017, we contracted 77 MMcf/d of firm transportation service on TransCanada's Alberta and mainline natural gas pipelines from the intra-Alberta market to the Dawn hub in Ontario. We also contracted firm capacity that will ramp up to 90 MMcf/d by 2020 on TransCanada's Foothills and Gas Transmission Northwest pipelines to deliver gas to the Malin trading hub on the Oregon border with California.

We are also looking to supply more natural gas to electrical generation plants in Canada and the US. Over the longer term, we are working to advance initiatives that would provide Asia with lower carbon fuels through the export of liquefied natural gas and liquefied propane off Canada's West Coast or via the United States. Seven Generations believes that with broad stakeholder engagement and support, one or more major export terminals can be built to coincide with the next leg of global LNG demand growth anticipated in the mid-2020s. We are looking to play a meaningful supply role by committing our prolific and low-cost supply to help anchor an LNG export terminal. We are also examining opportunities to supply proposed natural gas-to-liquids projects in Western Canada.

CREATING A SAFETY CULTURE

We strive to create a workplace where everyone stays safe – a safety culture where workers look out for themselves and their colleagues. As the depth and breadth of our Kakwa River Project operations have increased, so too have our safety operations. 2017 was a very busy year. We ran up to 13 drilling rigs and four completions spreads, often alongside infrastructure construction. We had hundreds of employees and contractors working in close proximity to one another, with many jobs occurring at once, and, at times, under adverse weather conditions. Our sites accommodate high-activity levels that incorporate safety principles into planning, layout, scheduling and daily operations.

Our 2017 safety performance delivered some gains, and some setbacks. In a year when our field hours worked climbed about 63 percent to more than 15 million, we saw more recordable incidents, but the number of serious injuries declined significantly. Our Lost Time Incident Frequency (LTIF), which captures injuries that prevented individuals from returning to work immediately, decreased by 40 percent. However, our Total Recordable Incident Frequency (TRIF) increased about 14 percent to 0.64, which in part reflects the increased size and scale of our concurrent operations.

In 2018, we will continue to instill our safety culture in new and long-time employees and contractors, refine our safety training processes and monitoring systems, increase inspections and hazard identification, and as always, create a workplace where workers report every safety near miss and incident.

INNOVATION AND APPLICATION OF NEW TECHNOLOGY

At Seven Generations, we innovate and apply technologies to solve operational challenges and improve our capital efficiencies. Over the course of 2017, we advanced our data analytics initiative to reduce non-productive time during pressure pumping operations. Our team of 25 completions engineers – roughly 15 percent of our staff – are constantly innovating and improving processes from every hydraulic fracturing operation to maximize production. We also recently implemented advanced software to improve efficiency at two Super Pad locations and boost our sales gas capacity.

In facility construction, our innovative in-house approach to building fully modular production facilities has improved production cycle times and has the potential to save 25 percent on future tie-in costs.

Looking ahead, the results of 7G's first Science Pad will help identify additional innovation opportunities in 2018. Using the latest micro seismic and fibre optic technology, we will employ digital monitoring on three well completions, which will provide us with a significantly enhanced sub surface view of our hypotheses in action, on a real-time basis.

CARING FOR THE ENVIRONMENT

The environment where we operate is serviced by a skilled 7G team of environmental professionals focused on air, land, water and wildlife.

AIR CARE, KEEPING CARBON INTENSITY LOW

We strive to be the lowest carbon intensity producer on a per barrel of oil equivalent basis. During our most recent reporting year, 2016, our emissions intensity remained flat at 0.0126 tonnes of CO_2 equivalent per BOE even though our production roughly doubled. Seven Generations continues to lead Canadian energy company peers who participated in the Carbon Disclosure Project (CDP) with the lowest carbon intensity.

To underpin and quantify 7G's greenhouse gas management activities, we independently verify our CDP evaluations and conduct a Leak Detection and Repair program that is aimed at reducing methane emissions.

BACKING RESEARCH TO LOWER CARBON AROUND THE GLOBE

We have opened our Kakwa River Project as a real-life laboratory to researchers from Stanford University and the Universities of Alberta and British Columbia. They are conducting an independent life cycle assessment of the net carbon emissions when Kakwa natural gas displaces coal powered electricity generation in Asia.

LESS WATER, MORE RECYCLING

We strive to use non-potable water sources, as well as less surface runoff and river water. We are recycling more water for our completions. We built water storage ponds that are contoured into wildlife-friendly shapes. When we no longer use them, they may contribute to the area's wetland habitat.

LAND – TREADING WITH A SMALLER FOOTPRINT

Our multi-well Super Pads are technologically advanced and designed to minimize our surface footprint. Each of our Super Pads produces the energy of a junior or mid-size energy company and creates efficiencies in production, artificial lift and cost savings.

EMPLOYEE GREEN FUND

We recognize that we have a role to play in serving the environment in our personal lives as well. 7G recently established a multi-year Green Spending program that provides a modest incentive for employees to pay for environmentally friendly transportation, energy efficient appliances or solar panels.

CLOSING OUT A YEAR OF CHANGE

I noted how 2017 was a year of change. Our founding CEO Pat Carlson, who authored our Level 1 Corporate Policy, retired on June 30. With Pat's retirement, I took over as President & CEO.

At the end of February, Susan Targett retired from her role as Executive Vice President, Corporate, and on March 15, we welcomed industry veteran Derek Aylesworth as our Chief Financial Officer.

In closing, my thanks go to our people, the hundreds of employees and contractors who serve our stakeholders through dedication and hard work every day. We appreciate the ongoing guidance and wise counsel of our Board of Directors – governance stewards for all our stakeholders.

And, most importantly, we thank our stakeholders. You are instrumental to our success. We appreciate your continued support and welcome your ongoing engagement on how we can better serve you.

Sincerely,

Marty Proctor
President & Chief Executive Officer

March 2018

Kakwa River Project

Management's Discussion and Analysis

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Seven Generations Energy Ltd. (the "Company" or "Seven Generations") is dated March 13, 2018 and should be read in conjunction with the audited annual consolidated financial statements and notes thereto for the years ended December 31, 2017 and 2016 (the "consolidated financial statements"). These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS").

Unless otherwise noted, all financial measures are expressed in Canadian dollars and tabular dollar amounts are presented in millions. See "Advisories and Guidance" for reconciliations and information regarding the following non-IFRS financial measures used in this MD&A: "funds from operations", "operating income", "operating netback", "corporate netback", "adjusted working capital", "available funding", "net debt", "ROCE", "CROIC" and "adjusted EBITDA". Certain abbreviated terms used throughout this MD&A are explained on the last pages of this MD&A. Additional information about Seven Generations is available on the SEDAR website at www.sedar.com, including the Company's Annual Information Form for the year ended December 31, 2017, dated March 13, 2018 (the "AIF").

About Seven Generations

Seven Generations is a low-supply-cost, growth-oriented energy producer dedicated to stakeholder service, responsible development and generating strong returns from its liquids-rich Kakwa River Project in northwest Alberta. Seven Generations' corporate office is in Calgary, Alberta and its operations headquarters is in Grande Prairie, Alberta. The Company's class A common shares ("common shares") trade on the TSX under the symbol VII.

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

- **Stakeholder service:** recognizing that in a competitive world, only those who best serve their stakeholders can expect to survive in the long term.
- **Supply cost:** combining resource selection with innovation, technology and efficiency to remain among North America's lowest supply cost unconventional liquids-rich natural gas developers.
- **Financial sustainability:** continued profitable growth to achieve positive free cash flow and earn full-cycle returns on capital employed across the entire commodity price cycle, focusing capital deployment on high return opportunities.
- **Market access:** establishing ample gathering, processing, transportation and marketing capacity to expand market access for production in order to capture premium prices from diverse markets.

The Company produces condensate and liquids-rich natural gas primarily from the upper Montney formation of the Kakwa River Project. During the three months ended December 31, 2017, Seven Generations produced 197.3 mboe/d (58% liquids) from approximately 330 net horizontal Montney wells. Development of the Kakwa River Project to date has resulted in the booking of approximately 1.7 billion boe of gross proved plus probable reserves (1) as at December 31, 2017. The Company currently holds over 500,000 net acres of Montney lands in the Kakwa River Project.

Seven Generations' acreage is interconnected with key infrastructure and take-away capacity allowing the Company to deliver the majority of its condensate and liquids-rich natural gas by pipeline to the market. The Company's natural gas transportation capacity also has geographic diversification across North America with exposure to the US Midwest, Gulf of Mexico, Pacific Coast, Alberta and Eastern Canadian markets.

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(1) Based on the reports of McDaniel & Associates Consultants Ltd., Seven Generations' independent qualified reserve evaluators effective December 31, 2017. Refer to Advisories and Guidance and to the AIF for additional important information about the Company's reserves.

HIGHLIGHTS FOR THE THREE AND 12 MONTHS ENDED DECEMBER 31, 2017

- **Return on capital –** The Company continued to deliver strong returns from the Kakwa River Project generating a return on capital employed ("ROCE") [(1)] of 9.8% during the year ended December 31, 2017 (December 31, 2016 – 7.7%). Seven Generations' cash return on invested capital ("CROIC") [(1)] in 2017 was 17.9% compared to 16.4% during the prior year.
- **Cash flows –** During the three and 12 months ended December 31, 2017, Seven Generations generated funds from operations[(1)] of $403.8 million and $1,228.3 million, an increase of 84% and 66%, respectively, compared to the same periods in the prior year, and 42% higher than the third quarter of 2017. The increases were primarily due to higher production and benchmark commodity prices. Cash provided by operating activities also increased by 74% to $310.3 million in the fourth quarter of 2017, relative to the fourth quarter of 2016.
- **Condensate –** During the year ended December 31, 2017, the Company produced 55.7 mbbl/d of condensate, which represented 32% of production on an aggregate per boe basis and accounted for 57% of the Company's petroleum and natural gas sales. Condensate yields remained strong with a condensate-to-gas ratio of 128 bbl/MMcf in 2017 (2016 – 135 bbl/MMcf). The Company's realized price for condensate was $61.46 per bbl which was 93% of the Canadian dollar WTI benchmark price (December 31, 2016 – $50.59 per bbl and 88%, respectively).
- **Natural gas pricing –** With 76% of the Company's natural gas sales in the US Midwest and the Gulf of Mexico, the Company's realized price for natural gas during the year ended December 31, 2017 was $3.88 per Mcf despite substantial declines in the Alberta benchmark price which averaged $2.04 per GJ (approximately $2.20 per Mcf) during the year. Compared to the third quarter of 2017, the Company's realized price increased by 8% to $3.75 per Mcf during the fourth quarter of 2017 primarily due to improved benchmark commodity prices.
- **Nest 3 expansion –** During the year ended December 31, 2017, Seven Generations established a new type curve for the Company's upper Montney acreage located adjacent to and south of the Nest 2 development area of the Kakwa River Project (the "Nest 3" area) based on encouraging results from delineation drilling. The Company's independent reserve engineers confirmed the booking of 2P reserves in Nest 3 and, in the fourth quarter of 2017, the Company sanctioned a field development plan for Nest 3, further expanding the Company's inventory of drilling locations in the Kakwa River Project.
- **Production –** Seven Generations averaged fourth quarter production of 197.3 mboe/d, a 49% increase compared to 132.3 mboe/d during the same period in the prior year and a 7% increase compared to 183.9 mboe/d during the third quarter of 2017. For the year ended December 31, 2017, Seven Generations achieved its mid-year production guidance with production averaging 175.0 mboe/d, a 49% increase compared to 117.8 mboe/d during the prior year, including liquids production of 102.4 mbbl/d (December 31, 2016 – 69.3 mbbl/d).
- **Capital investments –** The Company continued to develop its Montney assets in the Kakwa River Project, investing $322.3 million during the fourth quarter of 2017. The Company drilled 20 wells, completed 16 wells and brought 23 wells on production. Seven Generations continued to invest in strategic infrastructure in the region, completing construction of three new super pads which were on production during the third quarter of 2017. The Company also commenced construction of a third wholly-owned natural gas processing facility. The facility is being designed for up to 250 MMcf/d of natural gas processing capacity and is anticipated to be operational during the fourth quarter of 2018.
- **Available funding [(1)] –** During the second quarter of 2017, Seven Generations expanded its existing undrawn senior secured credit facility from $1.1 billion to $1.4 billion. As part of the amendments, the credit facility was transitioned from a reserve-based structure to a covenant-based structure and matures in 2021. The Company closed the fourth quarter of 2017 with a strong balance sheet which included available funding of $1.5 billion and net debt [(1)] of $1.9 billion. The Company also had adjusted working capital [(1)] of $109.5 million which included cash and cash equivalents of $165.3 million.
- **Balance sheet –** In the fourth quarter of 2017, Seven Generations completed debt refinancing transactions, repurchasing and redeeming all of the Company's outstanding US$700 million 8.25% senior unsecured notes due in 2020 (the "8.25% Notes") and completing a new debt offering of US$700 million 5.375% senior unsecured notes due in 2025 (the "5.375% Notes"). The refinancing transactions extended the Company's debt maturities and reduced the Company's blended effective interest rate on its outstanding senior unsecured notes to 6.3%. The Company's 12-month ratio of net debt[(1)] to funds from operations[(1)] was 1.5:1 for the year ended December 31, 2017 (December 31, 2016 – 2.1).
- **Expanding and diversifying markets –** Starting in the third quarter of 2017, Seven Generations began delivering condensate volumes on Pembina Pipeline Corporation's ("Pembina") Phase III expansion pipeline. Combined with existing liquids take-away capacity, the Company now delivers over 90% of its condensate production to market via pipeline. Having secured NGPL pipeline capacity to the US Gulf Coast in 2016 and capacity to the Dawn, Ontario and northern California markets in 2017, Seven Generations' natural gas transportation capacity now provides geographic diversification across North America including the US Midwest, US Pacific Coast, Alberta and Eastern Canada as well as access to an LNG export facility off the Gulf of Mexico in Louisiana.

  Seven Generations continues to advance its pursuit of new markets for its products including petrochemicals, natural gas-to-power and LNG/LPG exports in the pursuit of higher realized prices for its condensate and liquids-rich natural gas production. During the year, the Company entered into a purchase and sale agreement to deliver propane feedstock to a planned third party C3 dehydration and polypropylene manufacturing facility which is anticipated to operational by 2022.

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

	Three months ended December 31,			Three months ended September 30,		Year ended December 31,		
	2017	2016	% Change	2017	% Change	**2017**	2016	% Change
Production								
Condensate (mbbl/d)	**63.7**	43.2	47	57.8	10	**55.7**	39.3	42
NGLs (mbbl/d)	**51.4**	33.4	54	50.6	2	**46.7**	30.0	56
Liquids (mbbl/d)	**115.1**	76.6	50	108.4	6	**102.4**	69.3	48
Natural gas (MMcf/d)	**493.4**	334.0	48	453.2	9	**435.5**	291.0	50
Total Production (mboe/d)	**197.3**	132.3	49	183.9	7	**175.0**	117.8	49
Liquids %	**58%**	58%	—	59%	(2)	**58%**	59%	(2)
Realized prices								
Condensate ($/bbl)	**68.10**	56.96	20	54.75	24	**61.46**	50.59	21
Natural gas ($/Mcf)	**3.75**	4.15	(10)	3.46	8	**3.88**	3.53	10
NGLs ($/bbl)	**24.40**	18.23	34	20.22	21	**19.98**	13.08	53
Total ($/boe)	**37.65**	33.67	12	31.30	20	**34.56**	28.92	20
Realized hedging gains ($/boe)	**0.38**	0.48	(21)	0.84	(55)	**0.25**	2.11	(88)
Royalty expense ($/boe)	**(1.18)**	(0.98)	20	(0.86)	37	**(0.97)**	(0.16)	nm
Operating expenses ($/boe)	**(5.69)**	(4.86)	17	(5.43)	5	**(5.60)**	(4.22)	33
Transportation, processing and other ($/boe)	**(6.30)**	(5.92)	6	(6.07)	4	**(5.81)**	(5.53)	5
Operating netback ($/boe) (1)	**24.86**	22.39	11	19.78	26	**22.43**	21.12	6
G&A ($/boe)	**(0.65)**	(1.16)	(44)	(0.65)	—	**(0.72)**	(0.92)	(22)
Finance expense and other ($/boe)	**(1.96)**	(3.18)	(38)	(2.33)	(16)	**(2.48)**	(3.04)	(18)
Corporate netback ($/boe)(1)	**22.25**	18.05	23	16.80	32	**19.23**	17.16	12
Financial Results(1)								
Revenue ($) (2)	**615.1**	262.2	136	517.2	20	**2,353.5**	1,064.1	122
Operating income ($) (1)(5)	**129.3**	47.6	172	63.5	104	**326.3**	160.6	103
Per share – diluted ($)	**0.36**	0.13	177	0.17	112	**0.90**	0.50	80
Net income (loss) ($) (5)	**83.6**	(104.9)	nm	85.7	(2)	**562.5**	(26.2)	nm
Per share – diluted ($) (4)	**0.23**	(0.30)	nm	0.24	(4)	**1.54**	(0.09)	nm
Funds from operations ($) (1)(5)	**403.8**	219.7	84	284.3	42	**1,228.3**	740.0	66
Per share – diluted ($)	**1.11**	0.60	85	0.78	42	**3.37**	2.32	45
Cash provided by operating activities ($) (5)	**310.3**	178.7	74	314.1	(1)	**1,154.3**	644.6	79
Adjusted EBITDA (1)	**434.4**	255.3	70	320.0	36	**1,373.1**	868.6	58
CROIC (%) (1)(6)	**17.9**	16.4	9	16.3	10	**17.9**	16.4	9
ROCE (%) (1)(6)	**9.8**	7.7	27	9.3	5	**9.8**	7.7	27
Balance sheet								
Capital investments ($) (3)	**322.3**	283.6	14	454.3	(29)	**1,651.4**	978.0	69
Adjusted working capital ($) (1)	**109.5**	585.9	(81)	77.7	41	**109.5**	585.9	(81)
Available funding ($) (1)	**1,467.4**	1,626.7	(10)	1,419.0	3	**1,467.4**	1,626.7	(10)
Net debt ($) (1)	**1,866.4**	1,528.8	22	1,925.0	(3)	**1,866.4**	1,528.8	22
Debt outstanding ($)	**1,956.4**	2,111.9	(7)	1,998.8	(2)	**1,956.4**	2,111.9	(7)
Weighted average shares – basic (4)	**354.7**	347.2	2	354.4	—	**353.3**	299.8	18
Weighted average shares – diluted (4)	**363.9**	365.0	—	364.0	—	**364.4**	318.4	14

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance. Certain comparative figures have been adjusted to confirm to current period presentation.
(2) Represents the total of liquids and natural gas sales, net of royalties, gains (losses) on risk management contracts and other income.
(3) Excluding acquisitions and equity investments.
(4) Basic weighted average shares are used to calculate diluted per share amounts when the Company is in a loss position.
(5) For the year ended December 31, 2016, figures include $27.4 million ($20.0 million after tax) of prior-period royalty recoveries.
(6) Calculated based on 12-months trailing financial results as at the reporting dates.

Operating netback per boe – three months ended

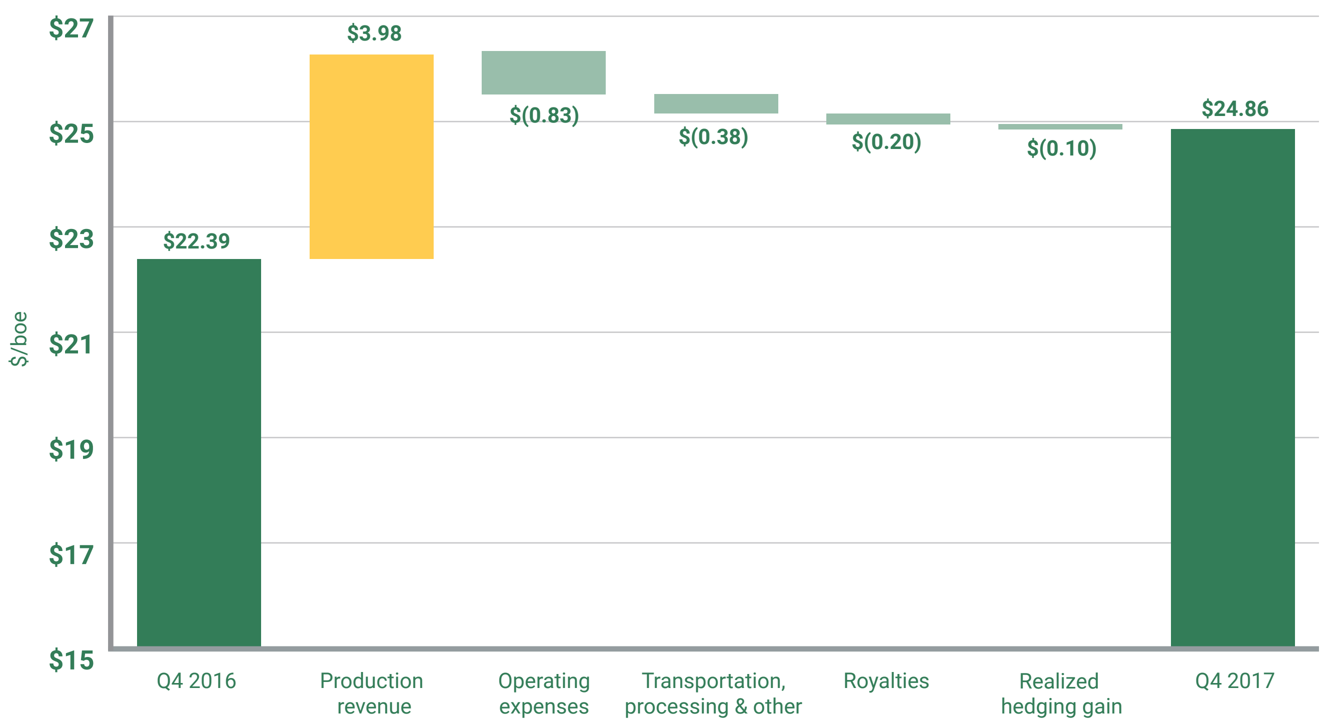
	Three months ended December 31,			Three months ended September 30,	
	2017	2016	% Change	**2017**	% Change
Liquids and natural gas sales	**$ 37.65**	$ 33.67	12	**$ 31.30**	20
Realized hedging gains	**0.38**	0.48	(21)	**0.84**	(55)
Royalty expense	**(1.18)**	(0.98)	20	**(0.86)**	37
Operating expenses	**(5.69)**	(4.86)	17	**(5.43)**	5
Transportation, processing and other	**(6.30)**	(5.92)	6	**(6.07)**	4
Operating netback per boe [(1)]	**$ 24.86**	$ 22.39	11	**$ 19.78**	26

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

During the fourth quarter of 2017, operating netback was $24.86 per boe, a 11% increase compared to $22.39 per boe during the same period in the prior year. Compared to the third quarter of 2017, the fourth quarter operating netback per boe increased by 26% from $19.78 per boe. The increases in the operating netback were primarily due to higher realized prices from higher benchmark crude oil prices, partially offset by increases in operating, transportation and processing expenses.

Operating expenses per boe increased during the fourth quarter of 2017 compared to the prior year primarily due to higher transport and disposal costs as a result of increased water handling. Per boe transportation and processing expenses increased primarily due to higher processing fees incurred on production flowing through third-party facilities and increases in firm transportation.

CHANGE IN OPERATING NETBACK DURING THE THREE MONTHS ENDED DECEMBER 31, 2017



Operating netback per boe – year ended

	Year ended December 31,		
	2017	2016	% Change
Liquids and natural gas sales	**$ 34.56**	$ 28.92	20
Realized hedging gains	**0.25**	2.11	(88)
Royalty expense	**(0.97)**	(0.16)	nm
Operating expenses	**(5.60)**	(4.22)	33
Transportation, processing and other	**(5.81)**	(5.53)	5
Operating netback per boe (1)	**$ 22.43**	$ 21.12	6

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

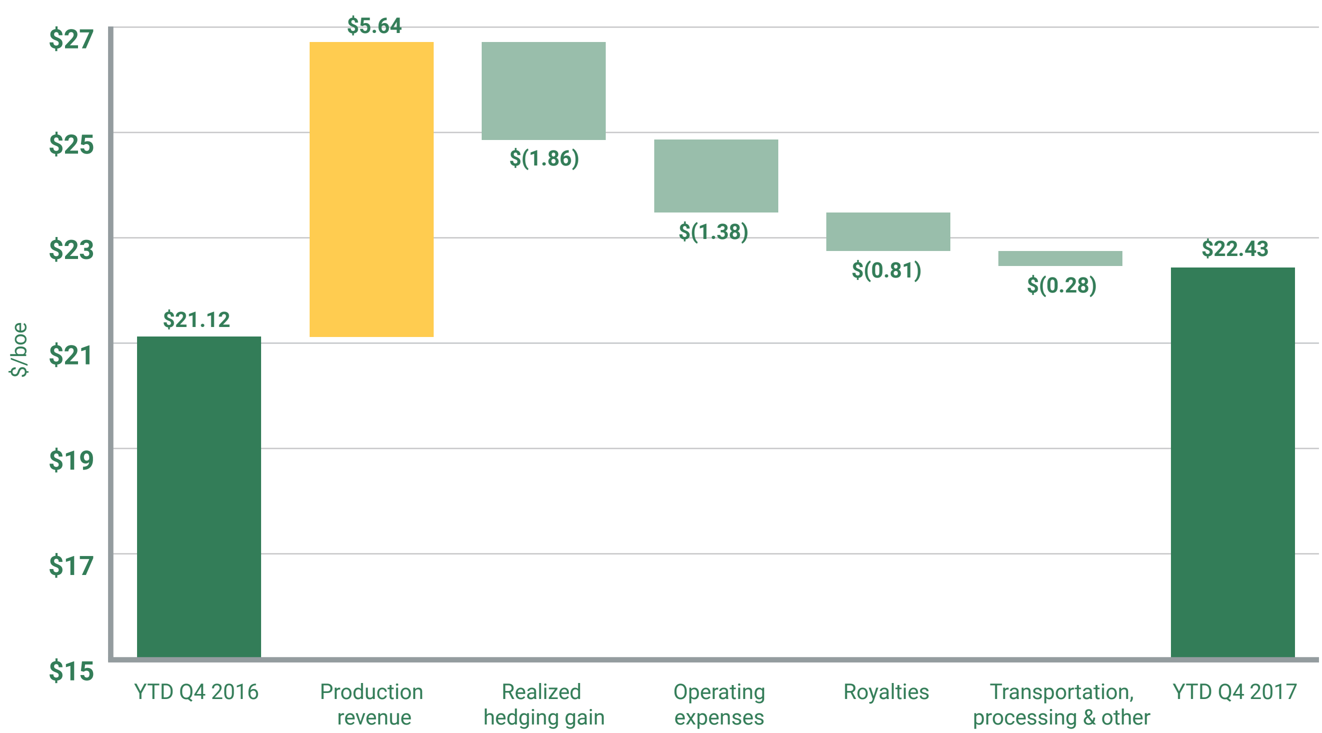
During the year ended December 31, 2017, operating netback per boe was $22.43, a 6% improvement compared to $21.12 per boe in the prior year. The increase in operating netback per boe was primarily due to higher benchmark commodity prices, partially offset by declines in the Company's realized hedging gains and higher netback expenses during the year including higher transport tolls from selling directly to end markets.

Realized hedging gains declined due to lower average pricing for the Company's hedge contracts in 2017 and higher benchmark commodity prices. Royalty expenses on a per boe basis were lower in 2016 primarily due to $27.4 million of one-time adjustments for 2015 GCA relating to the expansion of the Company's natural gas processing facilities and estimate revisions for prior year condensate royalties.

Per boe operating expenses in 2017 increased by 33% compared to the prior year, primarily due to higher trucking and disposal costs as a result of of increased water handling and increased use of temporary testing equipment on new wells. Per boe operating costs were also negatively impacted by spring road bans, limited disposal availability and inflationary pressure on hauling rates during the second quarter of 2017.

Compared to the prior year, per boe transportation and processing expenses increased by 5% during the year ended December 31, 2017, primarily due to higher processing fees incurred on production flowing through third-party facilities and increases in firm transportation costs, partially offset by lower trucking costs due to a higher proportion of liquids volumes delivered by pipeline.

CHANGE IN OPERATING NETBACK DURING THE YEAR ENDED DECEMBER 31, 2017



Funds from operations – three months ended

The following table reconciles the Company's cash provided by operating activities to funds from operations:

($ millions, except per boe data)	Three months ended December 31, 2017	2016	% Change	Three months ended September 30, 2017	% Change
Cash provided by operating activities	**$ 310.3**	$ 178.7	74	**$ 314.1**	(1)
Transaction costs on acquisitions	**—**	0.3	(100)	**—**	—
Prepaid processing fees on third-party facilities	**1.5**	—	100	**(4.0)**	nm
Changes in non-cash working capital	**92.0**	40.7	126	**(25.8)**	nm
Funds from operations [(1)]	**$ 403.8**	$ 219.7	84	**$ 284.3**	42

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

During the three months ended December 31, 2017, Seven Generations earned funds from operations of $403.8 million, an increase of 84% compared to $219.7 million during the same period in the prior year. The majority of the growth in funds from operations during the fourth quarter of 2017 was primarily due to higher production from ongoing drilling activities at the Kakwa River Project as well as higher benchmark commodity prices. These improvements were partially offset by increases in the Company's operating and transportation expenses attributable to higher production and operational activity in the field.

Compared to the third quarter of 2017, funds from operations during the fourth quarter improved by 42% primarily due to higher benchmark commodity prices and production volumes, partially offset by higher operating expenses incurred to support additional wells on stream as well as higher transportation and processing expenses incurred to bring the production growth to market.

During the three months ended December 31, 2017, the Company's cash provided by operating activities was $310.3 million compared to $178.7 million during the same period in the prior year. Consistent with the change in funds from operations, fourth quarter cash provided by operating activities improved primarily due to higher production and higher realized prices.

CHANGE IN FUNDS FROM OPERATIONS DURING THE THREE MONTHS ENDED DECEMBER 31, 2017

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

Funds from operations – year ended

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

	Year ended December 31,		
($ millions, except per boe data)	**2017**	2016	% Change
Cash provided by operating activities	**$ 1,154.3**	$ 644.6	79
Transaction costs on acquisitions	**—**	7.4	(100)
Prepaid processing fees on third-party facilities	**21.0**	—	100
Changes in non-cash working capital	**53.0**	88.0	(40)
Funds from operations (1)	**$ 1,228.3**	$ 740.0	66

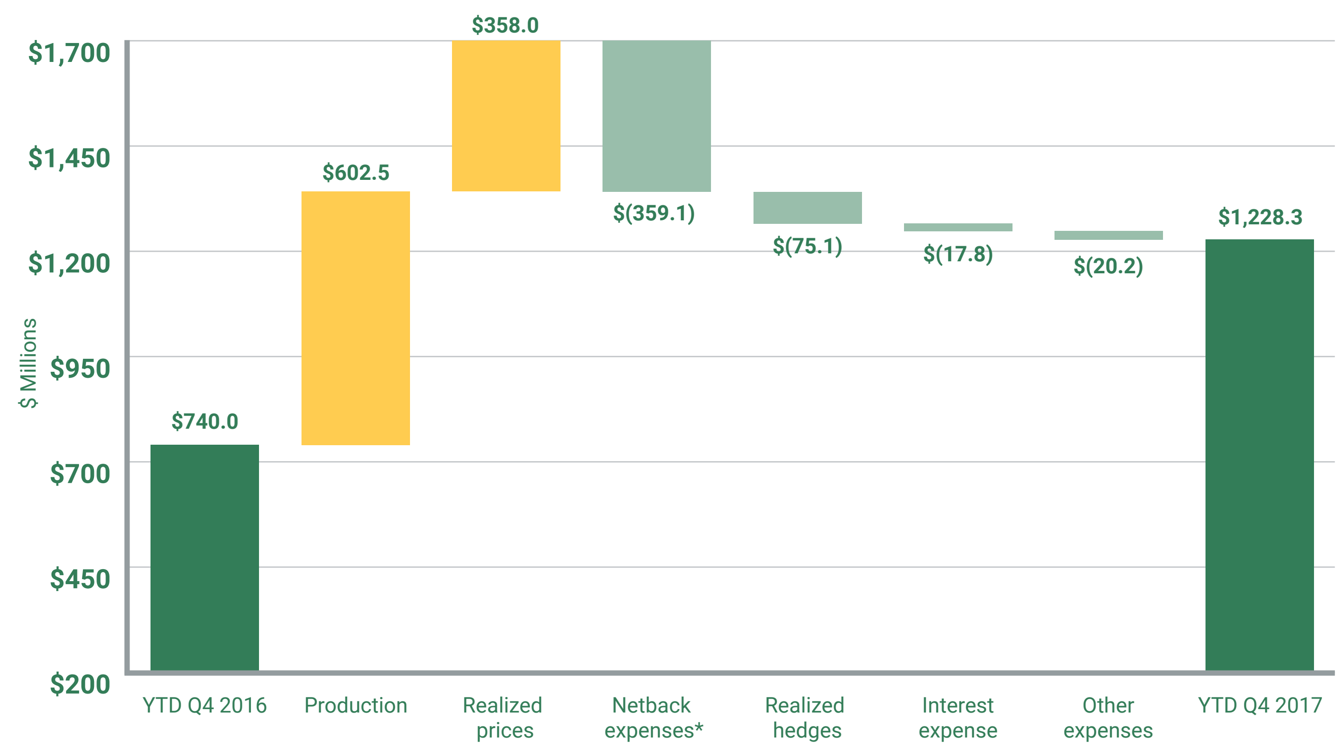
(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

During the year ended December 31, 2017, Seven Generations earned funds from operations of $1,228.3 million, an increase of $488.3 million, or 66%, compared to the prior year. The majority of the growth in funds from operations was due to higher production from ongoing drilling activities at the Kakwa River Project, Montney assets acquired during the third quarter of 2016 and higher benchmark commodity prices.

The improvements in funds from operations were partially offset by increases in the Company's operating and transportation expenses attributable to higher production and operational activity in the field as well as declines in realized hedging gains. Funds from operations were also impacted by additional interest expense on the notes that were assumed as part of the significant asset acquisition completed during the third quarter of 2016.

During the year ended December 31, 2017, the Company's cash provided by operating activities was $1,154.3 million compared to $644.6 million in the prior year. Consistent with the change in funds from operations, cash provided by operating activities increased primarily due to higher production and higher benchmark commodity prices.

CHANGE IN FUNDS FROM OPERATIONS DURING THE YEAR ENDED DECEMBER 31, 2017



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

Operating income

The following tables reconcile the Company's net income (loss) to operating income:

	Three months ended December 31,				Three months ended September 30,	
	2017		2016	% Change	**2017**	% Change
Net income (loss)	**$**	**83.6**	$ (104.9)	nm	**$ 85.7**	(2)
Unrealized losses on risk management contracts		**55.6**	142.8	(61)	**13.5**	312
Foreign exchange (gain) loss on senior notes		**5.0**	47.7	(90)	**(73.7)**	nm
Redemption premium on senior notes		**—**	—	—	**37.2**	(100)
Transaction costs		**—**	0.3	(100)	**—**	—
Loss on investment in associate		**—**	—	—	**14.4**	(100)
Deferred tax (recovery) expense relating to adjustments		**(14.9)**	(38.3)	(61)	**(13.6)**	10
Operating income (1)	**$**	**129.3**	$ 47.6	172	**$ 63.5**	104

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

	Year ended December 31,		
	2017	2016	% Change
Net income (loss)	**$ 562.5**	$ (26.2)	nm
Unrealized (gains) losses on risk management contracts	**(186.7)**	271.6	nm
Foreign exchange gains on senior notes	**(137.3)**	(17.1)	703
Redemption premium on senior notes	**37.2**	—	100
Transaction costs	**—**	7.4	(100)
Loss on investment in associate	**10.2**	—	100
Deferred tax (recovery) expense relating to adjustments	**40.4**	(75.1)	nm
Operating income (1)	**$ 326.3**	$ 160.6	103

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

During the three and 12 months ended December 31, 2017, the Company's operating income was $129.3 million and $326.3 million, respectively, compared to $47.6 million and $160.6 million during the same periods in the prior year. The increase in operating income for both periods was primarily due to higher funds from operations during 2017 due to higher production and higher realized prices, partially offset by higher depletion and depreciation expense from additional production as well as lower realized hedging gains.

Compared to the third quarter of 2017, operating income improved by 104% from $63.5 million to $129.3 during the fourth quarter, primarily due to higher production and condensate prices.

Net income (loss)

For the year ended December 31, 2017, the Company incurred net income of $562.5 million compared a net loss of $26.2 million during the prior year. The increase in net income in 2017 was primarily due to the Company's higher operating income, foreign exchange gains on the Company's senior notes from a strengthening Canadian dollar and unrealized gains on risk management contracts due to an overall net decline in average commodity price futures in 2017. The increases in net income were partially offset by the redemption premium on the Company's 8.25% Notes.

During the three months December 31, 2017, the Company reported net income of $83.6 million compared to a net loss of $104.9 million during the three months ended December 31, 2016. The increase in net income (loss) was primarily due to an increase in the Company's operating income and lower unrealized losses on risk management contracts due to lower natural gas futures in the fourth quarter of 2017 relative to the Company's derivative positions.

Compared to the third quarter of 2017, the Company's net income in the fourth quarter was relatively consistent, declining by 2% from $85.7 million to $83.6 million. The decrease was primarily due to a foreign exchange gain recognized on the Company's senior notes from a strengthening Canadian dollar during the third quarter and unrealized losses on risk management contracts primarily in the fourth quarter due to an increase in oil futures. The decline was mostly offset by higher operating income in the fourth quarter of 2017 and the redemption premium on the senior notes being recognized during the third quarter of 2017.

OUTLOOK

The following table summarizes the Company's 2018 capital and operational guidance:

2018 Guidance ($ millions)	
Capital budget	
Drilling and completion	**$ 980 – 1,020**
Facilities and infrastructure	**590 – 630**
Construction, land and other	**105 – 125**
2018 Capital budget ($)	**$ 1,675 – 1,775**
Drilling and completion activities	
Average number of rigs	**8 – 10**
Average number of frac spreads	**2 – 3**
Number of wells drilled	**80 – 90**
Number of wells completed	**90 – 100**
Number of wells placed on production	**80 – 90**
Production	
Total production (mboe/d)	**200 – 210**
Liquids percentage (%)	**55% – 60%**
Operating Results (1)	
Funds from operations – US$50/bbl	**$ 1,250 – 1,300**
Funds from operations – US$55/bbl	**$ 1,400 – 1,475**
Royalties (%)	**5% – 8%**
Operating expenses ($/boe)	**$ 4.50 – 5.00**
Transportation, processing and other ($/boe)	**$ 6.00 – 6.50**
G&A expense ($/boe)	**$ 0.65 – 0.75**

(1) Pricing assumptions: WTI: US$50.00/bbl, NYMEX: US$3.00/mmbtu, CAD:USD: 1.28:1, condensate as a % of WTI: 98%, NGLs as a % of WTI: C4 60%, C3 35%, C2 pricing consistent with the Company's processing and marketing agreements, Chicago basis: US$0.15 discount to NYMEX, AECO basis: US$1.15 discount to NYMEX, Dawn basis: US$0.10/MMbtu discount to NYMEX.

During the fourth quarter of 2017, Seven Generations approved a 2018 capital investment program of $1.675 to $1.775 billion, targeting an average production range of 200 to 210 mboe/d in 2018.

Seven Generations plans to operate an average of eight to ten rigs to drill 80 to 90 wells in 2018, which includes six to seven exploration wells outside of the Nest and two water disposal wells. The Company also plans to complete 90 to 100 wells in 2018 utilizing an average of two to three completions crews and anticipates 80 to 90 wells on production by the end of the year.

Beyond core development drilling and completions in the Nest 2 lands, the 2018 capital program includes resource evaluation activities in the Lower Montney formation, Wapiti and Deep Southwest areas as well as additional development in the Nest 1 core area and the newly defined Nest 3 area.

The Company plans to invest approximately $150 million in 2018 to complete the first phase of a third wholly-owned natural gas processing facility at the north end of the Kakwa River Project (the "Gold Creek Facility") with an initial designed processing capacity of 250 MMcf/d. The facility was designed with a number of basic infrastructure pre-builds that would enable the Company to double the processing capacity of the facility and build two sales pipelines. The Gold Creek Facility is scheduled to commence operations during the fourth quarter of 2018.

Other infrastructure developments include the construction of a pipeline interconnect in the Kakwa River Project between Pembina's Kakwa River natural gas processing facility and the Company's wholly-owned and operated gas processing facilities that will enable the Company to divert an additional approximate 70 MMcf/d of natural gas in order to better manage operational interruptions and improve netbacks.

As part of the Company's ongoing cost reduction plan, Seven Generations drilled its first water disposal well in 2017 with at least two additional disposal wells planned in 2018. Seven Generations plans to build a water pipeline network to connect these disposal wells and allow produced water to be recycled back to the Company's development pads for use in hydraulic fracturing. This water infrastructure initiative in 2018 is designed to further reduce water sourcing, trucking and disposal costs as well as improve field safety and lower environmental impacts.

RESERVES

Seven Generations utilized an independent qualified reserve evaluator, McDaniel & Associates Consultants Ltd. ("McDaniel"), to perform a reserve evaluation of the Company's Kakwa River Project. The following table summarizes Seven Generations' proved plus probable reserves based on McDaniel's report, as at December 31, 2017:

	Year ended December 31,					
	2017			2016		
	MMboe		**$MM (3)**	MMboe		$MM (3)
Reserve Category (1)						
PDP + PDNP (2)	**217**	**$**	**2,554**	176	$	2,120
Gross proved reserves ("1P")	**870**	**$**	**6,133**	825	$	5,146
Gross proved plus probable reserves ("2P")	**1,695**	**$**	**11,988**	1,535	$	9,996

(1) Refer to Advisories and Guidance for additional information regarding the Company's estimated reserves and the estimated net present value of future net revenue.
(2) Gross proved developed producing plus gross proved developed non-producing reserves.
(3) Estimated pre-tax net present value of discounted cash flows from reserves using a 10% discount rate.

As at December 31, 2017, Seven Generations' total gross 1P and 2P Reserves were 870 MMboe and 1,695 MMboe, respectively, an increase of 5% and 10%, compared to the prior year. Increases in the Company's 1P and 2P Reserves were primarily due to additional reserves bookings in the Nest 3 exploration area of the Kakwa River Project.

During the year ended December 31, 2017, Seven Generations established a new type curve for the Company's upper Montney acreage in Nest 3 area based on encouraging results from delineation drilling in the region. In the fourth quarter of 2017, the Company sanctioned a field development plan for Nest 3, further expanding the Company's inventory of potential drilling locations within the Kakwa River Project.

Using a discount rate of 10%, the Company's total gross 2P reserves as at December 31, 2017 were estimated to have a pre-tax net present value of approximately $12.0 billion, a 20% increase compared to $10.0 billion from the previous year's reserve report. The increases in the estimated discounted cash flows from 2P reserves was primarily due to reserves additions from drilling activities and higher net present values following the completion of the 2017 capital investment program.

CAPITAL INVESTMENTS

The following table summarizes Seven Generations' capital investments for the periods indicated:

	Three months ended December 31,			Three months ended September 30,	
	2017	2016	% Change	**2017**	% Change
Drilling and completions	**$ 167.4**	$ 186.7	(10)	**$ 252.8**	(34)
Facilities and infrastructure [(2)]	**115.0**	78.5	46	**176.5**	(35)
Land and other [(1)(2)]	**39.9**	18.4	117	**25.0**	60
Total capital investments	**$ 322.3**	$ 283.6	14	**$ 454.3**	(29)

(1) Other includes camps, workovers, construction, office investments and capitalized salaries and benefits.
(2) Comparative figures have been reclassified to conform to current period presentation.

	Year ended December 31,		
	2017	2016	% Change
Drilling and completions	**$ 1,021.9**	$ 597.7	71
Facilities and infrastructure [(2)]	**530.6**	337.1	57
Land and other [(1)(2)]	**98.9**	43.2	129
Total capital investments	**$ 1,651.4**	$ 978.0	69

(1) Other includes camps, workovers, construction, office investments and capitalized salaries and benefits.
(2) Comparative figures have been reclassified to conform to current period presentation.

During the year ended December 31, 2017, Seven Generations invested $1,651.4 million, in line with the Company's revised 2017 capital guidance. The revised budget was 3% higher than the Company's initial 2017 capital budget primarily due to the acceleration of certain key 2018 initiatives to the fourth quarter of 2017 and inflationary pressure on completion activities during the second quarter of 2017. 2018 accelerated capital included initial construction activities on a five-well pad in the Company's core Nest 1 area designed to provide important tests in both inter-well spacing and an improved completions design. The Company also accelerated its investment in water infrastructure to support its 2018 program. Seven Generations also commenced construction of an interconnect that will provide the Company with the option to send natural gas into either the Alliance System or the NTGL System to optimize price realizations and enable the Company to direct volumes to mitigate the impact of disruptions at facilities owned by other parties.

Drilling and completions

During the three and 12 months ended December 31, 2017, Seven Generations invested $167.4 million and $1,021.9 million, respectively, on drilling and completions activities. During the fourth quarter, the Company drilled 20 wells, completed 16 wells and brought 23 wells on production. The following tables summarize the Company's well activity:

	Three months ended December 31,			Three months ended September 30,	
Montney Well activity [(1)]	**2017**	2016	% Change	**2017**	% Change
Wells drilled (rig-released)	**20**	12	67	**16**	25
Wells completed	**16**	21	(24)	**25**	(36)
Wells brought on production	**23**	10	130	**39**	(41)

(1) These gross well counts include all horizontal Montney wells and exclude wells that were re-drilled or abandoned. Drilling counts are based on rig release date and brought on production counts are based on the first production date after the wells were tied in to permanent facilities.

Montney Well activity (1)	Year ended December 31, 2017	2016	% Change
Drilled	**93**	50	86
Completed	**91**	68	34
Brought on production	**103**	60	72

(1) These gross well counts include all horizontal Montney wells and exclude wells that were re-drilled or abandoned. Drilling counts are based on rig release date and brought on production counts are based on the first production date after the wells were tied in to permanent facilities.

As at December 31, 2017, Seven Generations had an inventory of 56 wells at various stages of construction between drilling, completion and tie-in and 330 producing horizontal Montney wells within the Kakwa River Project (December 31, 2016 – 84 wells under construction and 232 wells producing).

The following table summarizes Seven Generations' drilling and completion metrics for development activities in the Nest area for the periods indicated. The following metrics exclude expiry and delineation activities outside of the Nest:

	Three months ended December 31,			Three months ended September 30,		Year ended December 31,		
Nest Activity	**2017**	2016	% Change	**2017**	% Change	**2017**	2016	% Change
Drilling (1)								
Horizontal wells rig released	**20**	12	67	**15**	33	**88**	50	76
Average measured depth (m)	**5,278**	5,696	(7)	**5,905**	(11)	**5,742**	5,712	1
Average horizontal length (m)	**2,128**	2,511	(15)	**2,756**	(23)	**2,537**	2,589	(2)
Average drilling days per well	**29**	31	(6)	**33**	(12)	**33**	35	(6)
Average drill cost per lateral metre ($) (2)	**$ 1,760**	$ 1,405	25	**$ 1,472**	20	**$ 1,592**	$ 1,575	1
Average well cost ($ millions) (2)	**$ 3.6**	$ 3.5	3	**$ 4.0**	(10)	**$ 3.9**	$ 3.9	—
Completion (1)								
Wells completed	**16**	21	(24)	**25**	(36)	**88**	68	29
Average number of stages per well	**39**	37	5	**45**	(13)	**41**	32	28
Average tonnes pumped per well	**5,643**	6,481	(13)	**6,425**	(12)	**6,236**	5,403	15
Average cost per tonne (2)	**$ 1,107**	$ 971	14	**$ 1,134**	(2)	**$ 1,190**	$ 1,050	13
Average well cost ($ millions) (2)	**$ 6.2**	$ 6.3	(2)	**$ 7.3**	(15)	**$ 7.3**	$ 5.7	28
Total D&C cost per well ($ millions) (2)	**$ 9.8**	$ 9.8	—	**$ 11.3**	(13)	**$ 11.2**	$ 9.6	17

(1) The drilling and completion counts include only horizontal Montney wells in the Nest. The drilling counts and metrics exclude wells that are re-drilled or abandoned.
(2) Information provided is based on field estimates and are subject to change.

During the three months ended December 31, 2017, the Company rig-released 20 wells in the Nest with an average horizontal length of 2,128 metres and averaging 29 drilling days per well. Seven Generations also completed 16 Nest wells during the period. The Company reduced the intensity of its completions during the fourth quarter of 2017, averaging 39 stages and 5,643 tonnes pumped per well compared to an average of 45 stages and 6,425 tonnes pumped per well during the third quarter of 2017.

Compared to the third quarter of 2017, per well costs declined by 13% during the fourth quarter of 2017 to $9.8 million, which was closer in line with 2016 drilling and completion costs. The cost reductions were primarily due to shorter laterals drilled, additional utilization of recycled water and lower average tonnes pumped per well.

Average drilling and completion costs per well increased to $11.2 million during the year ended December 31, 2017, compared to $9.6 million during the prior year. The increases were largely due to service cost inflation, water handling and disposal cost pressures, extended well testing through temporary production equipment and eight nitrogen-foam completions during the second quarter of 2017.

Facilities and infrastructure

During the three and twelve months ended December 31, 2017, the Company invested $115.0 million and $530.6 million, respectively, in facilities and infrastructure to support the Company's production growth in the Kakwa River Project.

The Company completed construction of three new super pads which were operational during the third quarter of 2017, bringing Seven Generations' total number of super pads to 12 in the Kakwa River Project. During the fourth quarter of 2017, the Company commenced construction of a fourth super pad which is anticipated to be operational in 2018 and also completed the expansion of an existing super pad.

Seven Generations' super pads decentralize the traditional gas processing plant and gathering system model by placing compression, dehydration and separation at the pad site. The super pads allow for a more efficient use of infrastructure and provide high-pressure dry gas for artificial lift. The three new super pads were constructed on properties that were acquired in the third quarter of 2016 and they incorporate some of the proven technology and design concepts that have been effective elsewhere in the Kakwa River Project.

The Company has two wholly-owned gas processing facilities that have a combined processing capacity of 510 MMcf/d for natural gas. For liquids handling, the Company has a condensate stabilization facility at its Karr facility. During the year, Seven Generations added a second condensate stabilizer to expand the Karr facility's capacity to 60 mbbl/d.

For the year ended December 31, 2017, Seven Generations invested $121.5 million on engineering, procurement of long-lead items and initial construction activities for the Gold Creek Facility to continue to support the Company's growing Montney production base. The facility is being designed for up to 250 MMcf/d of natural gas processing capacity and is anticipated to be operational during the fourth quarter of 2018.

The Company also has access to additional third-party processing capacity at the Pembina Kakwa River natural gas plant, which is designed to provide additional processing capacity of up to 250 MMcf/d for natural gas and 20 mbbl/d for condensate. During the year ended December 31, 2017, the Company invested $21.0 million to upgrade the third-party facility under the terms of a long-term processing agreement assumed by Seven Generations as part of the significant asset acquisition in 2016. The investments were capitalized and are being amortized to transportation, processing and other expenses over the 20 year term of the agreement.

OPERATING RESULTS

Daily production

	Three months ended December 31,			Three months ended September 30,	
Sales volumes	**2017**	2016	% Change	**2017**	% Change
Condensate (mbbl/d)	**63.7**	43.2	47	**57.8**	10
Natural gas (MMcf/d)	**493.4**	334.0	48	**453.2**	9
NGLs (mbbl/d)	**51.4**	33.4	54	**50.6**	2
Total (mboe/d)	**197.3**	132.3	49	**183.9**	7
Liquids percentage	**58%**	58%	—	**59%**	(2)
Condensate-to-gas ratio (bbls/MMcf)	**129**	129	—	**128**	1

	Year ended December 31,		
Sales volumes	**2017**	2016	% Change
Condensate (mbbl/d)	**55.7**	39.3	42
Natural gas (MMcf/d)	**435.5**	291.0	50
NGLs (mbbl/d)	**46.7**	30.0	56
Total (mboe/d)	**175.0**	117.8	49
Liquids percentage	**58%**	59%	(2)
Condensate-to-gas ratio (bbls/MMcf)	**128**	135	(5)

During the three and 12 months ended December 31, 2017, Seven Generations averaged 197.3 mboe/d and 175.0 mboe/d, respectively, compared to 132.3 mboe/d and 117.8 mboe/d during the same periods in the prior year. The increases in production were primarily due to 103 wells being brought on stream during the year ended December 31, 2017. The Company's production also increased as a result of acquiring 66 producing wells as part of the asset acquisition during the third quarter of 2016.

Seven Generations 2017 production was within its revised guidance of 175 - 180 Mboe/d. The Company's original 2017 production guidance was 180 - 190 Mboe/d, which consisted of a budget of 50 - 55 mbbl/d of condensate, 50 - 55 mbbl/d of NGLs and 475 - 480 MMcf/d of natural gas. Total liquids production in 2017 was within the Company's original budget and condensate production exceeded expectations primarily due to higher than anticipated condensate production outside of Nest 2 and from the use of high intensity slickwater completions. Considering only barrels of oil equivalent, improvements in the liquids recoveries were more than offset by lower initial natural gas production rates from the use of slickwater treatments. Combined with unplanned outages at a third-party natural gas processing facility during the third quarter of 2017, the Company reduced its aggregate mid-year production guidance by 4% at the midpoint compared to the original guidance.

Compared to the third quarter of 2017, fourth quarter volumes increased by 7% primarily due to new production from 23 wells and the unplanned nine-day third party processing facility outage in August.

During the three months ended December 31, 2017, Seven Generations' gas production from the Kakwa River Project continued to maintain high liquids content, averaging 58% liquids and having a condensate-to-gas ratio of 129 bbl/MMcf compared to 128 bbl/MMcf (59% liquids) during the third quarter of 2017 and 129 bbl/MMcf (58% liquids) during the fourth quarter of 2016.

As at December 31, 2017, Seven Generations had approximately 330 net horizontal Montney producing wells in the Kakwa River Project with an inventory of 56 wells at various stages of construction between drilling, completion and tie-in.

Benchmark prices

	Three months ended December 31,			Three months ended September 30,	
Average Monthly Benchmark Prices	**2017**	2016	% Change	**2017**	% Change
Oil – WTI (US$/bbl)	**$ 55.40**	$ 49.29	12	**$ 48.21**	15
Natural gas – NYMEX Henry Hub (US$/MMBtu)	**$ 2.92**	$ 3.18	(8)	**$ 2.94**	(1)
Natural gas – Chicago Citygate (US$/MMBtu)	**$ 2.92**	$ 3.00	(3)	**$ 2.83**	3
Natural gas – AECO 5A ($/GJ)	**$ 1.60**	$ 2.93	(45)	**$ 1.39**	15
Average exchange rate – C$ to US$	**1.272**	1.333	(5)	**1.252**	2

	Year ended December 31,		
Average Monthly Benchmark Prices	**2017**	2016	% Change
Oil – WTI (US$/bbl)	**$ 50.95**	$ 43.47	17
Natural gas – NYMEX Henry Hub (US$/MMBtu)	**$ 3.02**	$ 2.55	18
Natural gas – Chicago Citygate (US$/MMBtu)	**$ 3.04**	$ 2.49	22
Natural gas – AECO 5A ($/GJ)	**$ 2.04**	$ 2.05	—
Average exchange rate – C$ to US$	**1.297**	1.325	(2)

The majority of Seven Generations' condensate production is delivered and sold in Edmonton, Alberta through Pembina's pipeline systems. The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing in North America. The price that Seven Generations receives for its condensate production is primarily driven by the price of WTI, adjusted for changes in foreign exchange rates, transportation costs and quality differentials. During the year ended December 31, 2017, Seven Generations' realized condensate price was 93% of the Canadian dollar equivalent WTI benchmark price (December 31, 2016 – 88%).

During the three and 12 months ended December 31, 2017, the WTI price increased by 12% and 17%, respectively, compared to the same periods in the prior year. Compared to the third quarter of 2017, the benchmark price for WTI increased by 15% during the fourth quarter of 2017. The increases were primarily due to declines in the global supply of crude oil following the curtailment of petroleum production by OPEC, which was announced during the fourth quarter of 2016, as well as lower global crude oil inventories and continued demand growth.

Seven Generations sells approximately 76% of its natural gas production in the United States primarily via the Alliance Pipeline System, the majority of which is sold in Chicago, Illinois. Starting in the fourth quarter of 2016, the Company also began delivering natural gas to the US Gulf of Mexico in Louisiana on the NGPL pipeline system. Accordingly, Chicago Citygate and Henry Hub prices were the primary benchmarks for the Company's natural gas sales in the United States in 2017.

During the year ended December 31, 2017, Chicago Citygate and Henry Hub prices increased by 22% and 18%, respectively, compared to the prior year, primarily due to higher demand for natural gas in the United States. Compared to the third quarter of 2017 and the fourth quarter of 2016, Chicago Citygate and Henry Hub prices remained relatively consistent as higher demand for natural gas due to colder weather in 2017 were more than offset by growth in shale gas supplies during the period.

During the fourth quarter of 2017, Seven Generations commenced shipping a portion of its natural gas to the Dawn, Ontario market on the TCPL system. The Company anticipates that approximately 13% of its natural gas will be sold in Eastern Canada in 2018.

The remainder of Seven Generations' natural gas production is sold in Alberta on the NGTL system. The AECO 5A price is the primary benchmark for the Company's natural gas sales in Alberta. During the three and 12 months ended December 31, 2017 and 2016, the AECO 5A benchmark price sold at a significant discount to the Henry Hub and Chicago City Gate benchmark prices primarily due to high natural gas supplies from Western Canada relative to limited economic transportation and egress solutions out of the basin.

Compared to the third quarter of 2017, the AECO 5A price increased by 15% during the fourth quarter of 2017 primarily due to higher seasonal demand for natural gas from colder weather as well as pipeline service curtailments during the third quarter of 2017.

Realized prices

	Three months ended December 31,			Three months ended September 30,	
	2017	2016	% Change	**2017**	% Change
Condensate ($/bbl)	**$ 68.10**	$ 56.96	20	**$ 54.75**	24
Natural gas ($/Mcf)	**3.75**	4.15	(10)	**3.46**	8
NGLs ($/bbl)	**24.40**	18.23	34	**20.22**	21
Total ($/boe)	**$ 37.65**	$ 33.67	12	**$ 31.30**	20

	Year ended December 31,		
	2017	2016	% Change
Condensate ($/bbl)	**$ 61.46**	50.59	21
Natural gas ($/Mcf)	**3.88**	3.53	10
NGLs ($/bbl)	**19.98**	13.08	53
Total ($/boe)	**$ 34.56**	28.92	20

During the three and 12 months ended December 31, 2017, the Company's realized condensate prices improved by 20% and 21%, respectively, compared to the same periods in the prior year, primarily due to increases in the WTI benchmark price. Compared to the third quarter of 2017, condensate prices also increased during the fourth quarter of 2017 primarily due to increases in benchmark commodity prices.

Seven Generations' product mix of NGLs averaged approximately 40% ethane, 30% propane, 20% butane and 10% pentanes plus in 2017. Approximately 50% of the Company’s NGLs are sold in the US Midwest market and 50% in the Alberta market. The Company's realized price for NGLs during the three and 12 months ended December 31, 2017 increased by 34% and 53%, respectively, compared to the same periods in 2016. The increases were primarily due improved propane and butane benchmark prices. Compared to the third quarter of 2017, the Company's realized NGL price improved by 21% during the fourth quarter of 2017 primarily due to higher benchmark prices.

During the year ended December 31, 2017, the Company's realized natural gas price improved by 10% compared to the prior year, primarily due to improvements in the US gas benchmark prices.

Compared to the fourth quarter of 2016, realized natural gas prices declined by 10% primarily due to sharp declines in the AECO 5A benchmark price during the third and fourth quarter of 2017. Despite these declines, Seven Generations' realized natural gas prices remained strong as a result of Company's geographic and natural gas pricing diversity with exposure in the Midwest, Gulf Coast and Eastern Canadian markets which sustained higher relative prices.

Liquids and natural gas sales

($ millions, except per boe data)	Three months ended December 31, 2017	2016	% Change	Three months ended September 30, 2017	% Change
Condensate	**$ 398.9**	$ 226.4	76	**$ 291.3**	37
Natural gas	**170.1**	127.3	34	**144.1**	18
NGLs	**114.4**	56.1	104	**94.1**	22
Liquids and natural gas sales (1)	**$ 683.4**	$ 409.8	67	**$ 529.5**	29
Liquids and natural gas sales per boe	**$ 37.65**	$ 33.67	12	**$ 31.30**	20

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

($ millions, except per boe data)	Year ended December 31, 2017	2016	% Change
Condensate	**$ 1,248.9**	$ 726.8	72
Natural gas	**617.4**	376.2	64
NGLs	**341.0**	143.9	137
Liquids and natural gas sales (1)	**$ 2,207.3**	$ 1,246.9	77
Liquids and natural gas sales per boe	**$ 34.56**	$ 28.92	20

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

During the three months ended December 31, 2017, Seven Generations recognized $683.4 million in liquids and natural gas sales, a 67% improvement compared to $409.8 million during the same period in the prior year. Higher production volumes accounted for $203.0 million of the variance and $70.6 million was due to stronger realized prices. Compared to the third quarter of 2017, revenues improved by $153.9 million primarily due to higher prices of $113.8 million and increased volumes of $40.1 million.

During the year ended December 31, 2017, the Company's liquids and natural gas sales increased by 77% to $2.21 billion compared to $1.25 billion during the year ended December 31, 2016. The increase was due to higher production volumes and higher realized prices, accounting for $602.4 million and $358.0 million of the variance, respectively.

Risk management contracts

Seven Generations continues to execute its routine risk management program. The Company hedges liquids and natural gas production and exchange rates to support funds from operations through a rolling three year hedging program. Price targets are established at levels that are expected to provide a threshold rate of return on capital investment based on a combination of projected well performance and capital efficiencies.

The Company hedges up to 65% of forecasted condensate and natural gas production volumes (net of royalties) for the upcoming four quarters, up to 35% of forecasted volumes for the subsequent four quarters and up to 20% for the four quarters following.

($ millions, except per boe data)	Three months ended December 31, 2017	2016	Three months ended September 30, 2017
Realized gain	**$ 6.9**	$ 5.8	**$ 14.2**
Unrealized gain (loss)	**(55.6)**	(142.8)	**(13.5)**
Risk management gain (loss)	**$ (48.7)**	$ (137.0)	**$ 0.7**
Realized gain per boe	**$ 0.38**	$ 0.48	**$ 0.84**

($ millions, except per boe data)	Year ended December 31, 2017	2016
Realized gain	**$ 15.7**	$ 90.8
Unrealized gain (loss)	**186.7**	(271.6)
Risk management gain (loss)	**$ 202.4**	$ (180.8)
Realized gain per boe	**$ 0.25**	$ 2.11

Derivative contract settlements are recognized as a realized gain or loss in net income. The fair value of the Company's unsettled derivatives are recorded as an asset or liability at each reporting period with any change in the mark-to-market position of contracts recognized as an unrealized gain or loss in net income.

During the year ended December 31, 2017, the Company recognized an unrealized derivative gain of $186.7 million, compared to an unrealized derivative loss of $271.6 million during the prior year. The 2017 unrealized gain was primarily due to declines in commodity price futures, mainly natural gas, during the first and second quarters of 2017. The unrealized derivative loss incurred in 2016 was primarily due to commodity price futures appreciating in 2016 as well as the realization of previous gains.

The Company recognized an unrealized derivative loss of $55.6 million during the fourth quarter of 2017 primarily due to an increase in the benchmark price for oil price futures during the fourth quarter of 2017 and a strengthening of the Canadian dollar relative to the Company's fixed contract positions. The unrealized derivative loss of $142.8 million incurred during the fourth quarter of 2016 was mainly due to oil price futures recoveries in late 2016.

During the year ended December 31, 2017, Seven Generations incurred realized derivative gains of $15.7 million, compared to $90.8 million during the prior year. The decline in net realized derivative gains was primarily due to higher average pricing for the Company's hedge contracts relative to benchmark commodity prices in 2016, as well as improvements in commodity benchmark prices in 2017.

As at December 31, 2017, the fair value of the risk management contracts increased to a net asset position of $38.3 million (December 31, 2016 – net liability position of $149.4 million) primarily due to declines in gas futures prices during the first and second quarters of 2017.

The Company had the following risk management contracts as at December 31, 2017:

	Crude Oil						Natural Gas				Foreign Exchange	
	C$ WTI Collars		C$ WTI 3 Way Collars		US$ WTI Collars		Chicago Citygate Swaps		AECO 7A Collars/Swaps		C/US Swaps	
Period	**bbl/d**	**C$/bbl**	**bbl/d**	**C$/bbl**	**bbl/d**	**US$/bbl**	**MMbtu/d**	**US$/MMbtu**	**GJ/d**	**C$/GJ**	**US $MM**	**US$/C$**
2018	17,250	$61.20 – $77.32	12,000	$40.83/$56.25/$75.54	2,000	$52.25 – $57.30	205,000	$2.88	60,000	$2.44 – $2.85	215.1	1.3100
2019	16,000	$58.91 – $75.94	7,500	$41.00/$56.33/$75.92	2,000	$52.25 – $57.30	120,000	$2.85	60,000	$2.44 – $2.85	124.8	1.2907
2020	7,000	$57.50 – $71.61	1,500	$40.00/$55.00/$70.98	2,000	$52.25 – $57.30	32,500	$2.74	10,000	$2.13 – $2.13	32.5	1.2683

Royalty expense

($ millions, except per boe data)	Three months ended December 31, 2017	2016	% Change	Three months ended September 30, 2017	% Change
Royalties	**$ 21.5**	$ 11.9	81	**$ 14.5**	48
Royalties per boe	**$ 1.18**	$ 0.98	20	**$ 0.86**	37
Effective royalty rate	**3.1%**	3.0%	3	**2.7%**	15

($ millions, except per boe data)	Year ended December 31, 2017	2016	% Change
Royalties	**$ 62.1**	$ 6.7	nm
Royalties per boe	**$ 0.97**	$ 0.16	nm
Effective royalty rate	**2.8%**	1.0%	180

The Company's royalties are paid to the Province of Alberta. All of Seven Generations' new wells in the Kakwa River Project qualify for Crown incentive programs which have a low initial royalty rate until a threshold return of capital has been reached. During the three and 12 months ended December 31, 2017, royalty expenses were $21.5 million (3.1% of revenue) and $62.1 million (2.8% of revenue), respectively.

For the year ended December 31, 2016, Seven Generations recognized royalty expenses of $6.7 million (1.0% of revenue). The low royalty rate was primarily due to $27.4 million in one-time credits for 2015 GCA related to the Company's expansion of natural gas processing facilities, and a recovery for amendments to past condensate royalties. Prior to the second quarter of 2016, the Company reported condensate as a natural gas equivalent. In the second quarter, Seven Generations started reporting field condensate separately at the wellhead. With the change in reporting, a recovery was recorded in 2016 to recognize the expected refund of past condensate royalties.

Operating expenses

	Three months ended December 31,			Three months ended September 30,	
($ millions, except per boe data)	**2017**	2016	% Change	**2017**	% Change
Trucking and disposal	**$ 46.8**	$ 15.7	198	**$ 38.3**	22
Equipment rental and maintenance	**27.6**	23.5	17	**26.2**	5
Chemicals and fuel	**10.1**	6.7	51	**10.2**	(1)
Staff and contractor costs	**12.0**	9.6	25	**9.8**	22
Other	**6.8**	3.6	89	**7.3**	(7)
Operating expenses	**$ 103.3**	$ 59.1	75	**$ 91.8**	13
Operating expenses per boe	**$ 5.69**	$ 4.86	17	**$ 5.43**	5

	Year ended December 31,		
($ millions, except per boe data)	**2017**	2016	% Change
Trucking and disposal	**$ 159.9**	$ 62.0	158
Equipment rental and maintenance	**98.5**	56.6	74
Chemicals and fuel	**38.8**	25.4	53
Staff and contractor costs	**39.4**	25.7	53
Other	**21.2**	12.2	74
Operating expenses	**$ 357.8**	$ 181.9	97
Operating expenses per boe	**$ 5.60**	$ 4.22	33

During the three and 12 months ended December 31, 2017, operating expenses were $103.3 million and $357.8 million, respectively, compared to $59.1 million and $181.9 million during the same periods in the prior year. The increase in operating costs were primarily due to the Company's production growth and higher field activity to support ongoing operations.

Operating costs on a per boe basis increased by 17% and 33% during the three and 12 months ended December 31, 2017, respectively, compared to the same periods in the prior year. The increases were primarily due to higher trucking and disposal costs associated with the Company's use of slickwater fracking as well as higher than normal use of temporary rental equipment for the Company's new wells that were awaiting tie-in to permanent natural gas processing facilities. Operating costs per boe were also impacted by spring road bans, limited disposal availability and increasing hauling rates experienced during the second quarter of 2017.

Compared to the third quarter of 2017, operating costs increased by $11.5 million to $103.3 million primarily due to additional wells on stream. On a per boe basis operating expenses increased by 5% from $5.43 per boe to $5.69 per boe primarily due to higher higher trucking and disposal costs on new wells during the fourth quarter.

As part of the Company's ongoing cost reduction plan, Seven Generations began recycling its flow back water during the fourth quarter of 2017. The Company drilled its first water disposal well in 2017 with two additional disposal wells planned for early 2018. Seven Generations intends to build a water pipeline network to connect these injection wells and enable produced water to be recycled back to the Company's development pads for use in hydraulic fracturing which is expected to reduce water sourcing, trucking and disposal costs.

Transportation, processing and other expenses

($ millions, except per boe data)	Three months ended December 31, 2017	2016	% Change	Three months ended September 30, 2017	% Change
Pipeline tariffs	$ **85.2**	49.9	71	$ **80.7**	6
Processing	**25.3**	11.0	130	**18.6**	36
Trucking and other	**11.9**	16.1	(26)	**10.1**	18
Third party marketing gains	**(8.0)**	(5.0)	60	**(6.7)**	19
Transportation, processing and other	$ **114.4**	$ 72.0	59	$ **102.7**	11
Transportation, processing and other per boe	$ **6.30**	$ 5.92	6	$ **6.07**	4

($ millions, except per boe data)	Year ended December 31, 2017	2016	% Change
Pipeline tariffs	$ **263.9**	164.2	61
Processing	**80.7**	21.2	nm
Trucking and other	**49.8**	66.9	(26)
Third party marketing gains	**(23.0)**	(13.7)	68
Transportation, processing and other	$ **371.4**	238.6	56
Transportation, processing and other per boe	$ **5.81**	$ 5.53	5

Seven Generations' transportation and processing expenses primarily relate to tolls on the Pembina Peace, NGTL, TCPL, NGPL and Alliance Pipeline Systems. The Company trucks a portion of its liquids volumes that are in excess of current pipeline transportation capacity or that are not tied directly into the Pembina system. The Company incurs processing and fractionation fees for volumes handled at the Pembina, Keyera, Plains and Aux Sable facilities, as well as the Pembina KakwaRiver Gas Plant under a natural gas processing agreement that was assumed as part of the asset acquisition during the third quarter of 2016.

The Company's transportation and processing expenses are partially offset by marketing gains which relate to a margin earned by the Company for optimizing its capacity on the Alliance Pipeline System.

During the three and 12 months ended December 31, 2017, transportation, processing and other expenses were $114.4 million and $371.4 million, respectively, compared to $72.0 million and $238.6 million during the same periods in the prior year. The increases were primarily due to the Company's growth in production volumes as well as the processing fees charged on volumes processed through the Pembina Kakwa River Plant, which commenced midway through the third quarter of 2016.

Per boe transportation and processing expenses increased by 5% in 2017 primarily due to the processing fees, partially offset by lower trucking costs as a result of a higher proportion of liquids being delivered by pipeline. Starting in the third quarter of 2017, Seven Generations began delivering condensate volumes on Pembina's Phase III expansion pipeline. Combined with existing liquids take-away capacity, during the year ended December 31, 2017, approximately 80% of the Company's condensate production was sold via pipeline and over 90% during the third and fourth quarters of 2017, compared to 45% during 2016.

Transportation and processing expenses increased by $11.7 million, or 11%, during the fourth quarter of 2017, compared to the third quarter of 2017, primarily due to higher pipeline tariffs from higher volumes delivered during the fourth quarter. Per boe transportation and processing expenses increased by 4% primarily due to higher processing fees at third party facilities. During the fourth quarter of 2017, the Company also began delivering natural gas on the TCPL mainline to Dawn, Ontario.

Take or pay commitments

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

	2018	2019	2020	2021	2022	Expiring (1)
Transportation						
Condensate						
Pembina (mbbl/d)	56.3	56.6	65.3	73.8	73.8	**June 30, 2030**
Natural gas						
Alliance (MMcf/d)	475	508	508	508	425	**October 31, 2022**
NGTL Receipt (MMcf/d)	293	392	558	660	682	**April 30, 2029**
NGTL Empress Delivery (MMcf/d)	80	80	80	80	67	**October 31, 2022**
TCPL Delivery (MMcf/d)	77	77	77	77	77	**October 31, 2027**
NGTL A/BC Delivery (MMcf/d)	—	2	58	92	92	**June 30, 2042**
Foothills (BC) Delivery (MMcf/d)	—	2	58	91	91	**May 31, 2030**
GTN (MMcf/d) (2)	—	11	58	92	92	**October 31, 2035**
NGPL (MMcf/d) (3)	83	—	—	—	—	**October 31, 2018**
NGLs						
Pembina (mbbl/d)	26.4	26.4	29.7	33.1	33.1	**June 30, 2030**
Processing						
Natural gas (MMcf/d)	173	193	200	200	200	**April 20, 2036**
NGLs (mbbl/d)	40.3	38.2	38.2	38.2	38.2	**March 31, 2028**

(1) When lines include multiple contracts of various expiration dates, the expiration date relating to the largest component of the contract has been referenced.
(2) Gas Transmission Northwest LLC ("GTN") which is owned by an affiliate of TransCanada.
(3) The Company holds an option to extend the NGPL take or pay commitment for a minimum of 10 years.

Physical delivery contracts

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

Daily average volumes committed for the year ended December 31,	Chicago Citygate MMBtu/d	Gulf of Mexico MMBtu/d	Dawn MMBtu/d	AECO GJ/d
2018	199,537	36,000	40,000	38,470
2019	—	—	—	19,808

Market access initiatives

In 2016, Seven Generations invested $25.8 million for a 34.0% equity interest in Steelhead LNG Limited Partnership ("Steelhead LNG"), a Vancouver-based energy company focused on the development of LNG projects in British Columbia. Concurrent with the investment, the Company also entered into a development arrangement with Steelhead LNG, whereby the Company agreed to contribute $3.0 million in cash upfront and committed to invest up to an additional $9.0 million to participate in the pre-development of transportation alternatives to the west coast of British Columbia. As at December 31, 2017, the Company held a 24.4% equity interest in Steelhead LNG as a result of subsequent equity issuances to other parties.

During the year ended December 31, 2017, the Company recognized a net loss on Steelhead of $21.0 million, primarily consisting of Seven Generation's share of Steelhead's losses of $10.8 million and an impairment loss of $14.4 million, partially offset by a gain of $4.2 million in respect of additional Steelhead equity units issued to Seven Generations during the year.

In 2017, Seven Generations identified indicators of impairment for its investment in Steelhead LNG primarily due to the value of consideration received by Steelhead LNG in exchange for equity units that were issued by the entity during the fourth quarter of 2017. The Company tested the asset for impairment and determined that its Steelhead LNG investment may not be fully recoverable. The Company recognized an impairment loss of $14.4 million. The recoverable value of the investment was primarily based on the price of the equity units issued.

Steelhead LNG is also considered a related party due to common directorships and certain significant shareholders including Azimuth Capital Management who has a majority ownership in Steelhead LNG and has professional ties with four of Seven Generation's directors. All related party transactions have been measured at the exchange value.

Depletion and depreciation

($ millions, except per boe data)	Three months ended December 31, 2017	Three months ended December 31, 2016	% Change	Three months ended September 30, 2017	% Change
Depletion and depreciation	**$ 209.2**	$ 139.1	50	**$ 192.7**	9
Depletion and depreciation per boe	**$ 11.53**	$ 11.43	1	**$ 11.39**	1

($ millions, except per boe data)	Year ended December 31, 2017	2016	% Change
Depletion and depreciation	**$ 730.2**	$ 483.6	51
Depletion and depreciation per boe	**$ 11.43**	$ 11.22	2

Depletion and depreciation was $209.2 million and $730.2 million during the three and twelve months ended December 31, 2017, respectively, compared to $139.1 million and $483.6 million during the same periods in the prior year. The increase was primarily due to higher production in 2017 relative to the prior periods. The depletion rate also increased in 2017 from $11.22 per boe to $11.43 per boe, primarily due to a higher average depletable asset base during the year as a result of the asset acquisition that was completed during the third quarter of 2016.

Compared to the third quarter of 2017, depletion and depreciation increased by 9% from $192.7 million to $209.2 million during the third quarter of 2017 primarily due to higher production from new wells brought on production, partially offset by a 10% increase in 2P reserves recognized during the fourth quarter of 2017 resulting in a lower depletion rate.

LIQUIDITY AND CAPITAL RESOURCES

Capital management

The Company manages capital by maintaining a strong liquidity position and focusing on financial strength through a prudent balance of debt and equity in its capital structure, and taking into account the level of risk being incurred in its capital investments. Due to the high quality, large size and long life of its assets, the Company aligns its goals and strategic objectives with investors that share a longer-term time horizon. The Company's business plan targets a trailing 12-month ratio of net debt to funds from operations of less than 2.0. The ratio was 1.5:1 for the year ended December 31, 2017 (December 31, 2016 – 2.1).

The Company approved a 2018 capital budget between $1.675 billion and $1.775 billion. The Company plans to fund these investments through cash on hand and funds from operations as well as draws on its credit facility. 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.

Available funding

($ millions)	December 31, 2017	December 31, 2016
Current assets	$ **523.0**	$ 830.4
Current liabilities	**(394.8)**	(316.2)
Working capital	**128.2**	514.2
Adjusted for:		
Current portion of risk management assets	**(36.2)**	—
Current portion of risk management liabilities	**17.5**	71.7
Adjusted working capital (1)	**109.5**	585.9
Credit Facility capacity (2)	**1,357.9**	1,100.0
Cash collateral for letters of credit	**—**	(59.2)
Available funding (1)	$ **1,467.4**	$ 1,626.7

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.
(2) As at December 31, 2017, $42.1 million in letters of credit were issued and outstanding under the Credit Facility. The letters of credit expired during the first quarter of 2018.

During the second quarter of 2017, Seven Generations expanded its existing undrawn senior secured credit facility from $1.1 billion to $1.4 billion (the "Credit Facility"). As part of the amendments, the Credit Facility was transitioned from a reserve-based structure to a covenant-based structure. The Credit Facility matures on June 9, 2021.

The Credit Facility is secured by a floating charge over the Company's assets and contains certain covenants that limit the Company's ability to, among other things: incur additional secured indebtedness; create or permit liens to exist; and make certain dispositions and transfers of assets. The following two financial covenants are associated with the Credit Facility:

- Senior Secured Net Debt to Adjusted EBITDA Ratio – cannot exceed 2.50:1
- Adjusted EBITDA to Interest Expense Ratio – cannot be less than 2.50:1

For the purposes of the Credit Facility covenant calculations, the Adjusted EBITDA figures are based on trailing 12-month operating results at each quarterly reporting date. Senior Secured Net Debt consists of amounts drawn under the Credit Facility excluding the balance of the outstanding senior unsecured notes, less cash and cash equivalents.

As at December 31, 2017, the Company was in compliance with the covenants under the undrawn Credit Facility. The Senior Secured Net Debt to Adjusted EBITDA Ratio and Adjusted EBITDA to Interest Expense Ratio were (0.09):1 and 7.81:1, respectively.

As at December 31, 2017, $42.1 million in letters of credit were issued and outstanding under the Credit Facility (December 31, 2016 – nil). During the fourth quarter of 2017, the Company also entered into a unsecured demand letter of credit facility of $76.4 million. As at December 31, 2017, $60.5 million in letters of credit were issued and outstanding under the facility.

The following tables reconcile net income (loss) to adjusted EBITDA for periods indicated:

	Three months ended December 31,			Three months ended September 30,	
($ millions, except per boe data)	**2017**	2016	% Change	**2017**	% Change
Net income (loss)	$ **83.6**	$ (104.9)	nm	$ **85.7**	(2)
Current and deferred income taxes	**38.2**	(18.5)	nm	**6.0**	nm
Depletion and depreciation	**209.2**	139.1	50	**192.7**	9
Finance expense	**36.6**	42.9	(15)	**73.2**	(50)
Stock-based compensation	**6.2**	5.8	7	**8.1**	(23)
Unrealized (gain) loss on risk management contracts	**55.6**	142.8	(61)	**13.5**	nm
Foreign exchange (gain) loss on senior notes and other	**5.0**	47.7	(90)	**(73.7)**	nm
Loss on investment in associate	**—**	—	—	**14.5**	(100)
Transaction costs	**—**	0.3	(100)	**—**	—
Adjusted EBITDA (1)	$ **434.4**	$ 255.2	70	$ **320.0**	36

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

($ millions, except per boe data)	Year ended December 31, 2017	2016	% Change
Net income (loss)	**$ 562.5**	$ (26.2)	nm
Current and deferred income taxes	**172.5**	(7.4)	nm
Depletion and depreciation	**730.2**	483.6	51
Finance expense	**193.2**	138.7	39
Stock-based compensation	**28.5**	18.0	58
Unrealized (gain) loss on risk management contracts	**(186.7)**	271.6	nm
Foreign exchange (gain) loss on senior notes and other	**(137.3)**	(17.1)	nm
Loss on investment in associate	**10.2**	—	100
Transaction costs	**—**	7.4	(100)
Adjusted EBITDA (1)	**$ 1,373.1**	$ 868.6	58

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.

Capital structure

Indebtedness and market capitalization

($ millions)	December 31, 2017	December 31, 2016
US$700 million 8.25% senior notes, due May 15, 2020	**$ —**	$ 939.9
US$425 million 6.75% senior notes, due May 1, 2023	**533.2**	570.6
US$450 million 6.875% senior notes, due June 30, 2023	**564.5**	604.2
US$700 million 5.375% senior notes, due September 30, 2025	**$ 878.2**	$ —
Senior notes principal	**1,975.9**	2,114.7
Adjusted working capital (1)	**(109.5)**	(585.9)
Net debt (1)	**1,866.4**	1,528.8
Market capitalization (2)	**6,306.6**	10,968.7
Total capitalization	**$ 8,173.0**	$ 12,497.5

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.
(2) Market capitalization was determined as the total common shares outstanding multiplied by the closing share price of $17.78 as at December 31, 2017 (closing share price of $31.31 at December 31, 2016).

The Company closed the fourth quarter of 2017 with a strong balance sheet, including available funding of $1.5 billion and net debt of $1.9 billion. The Company also had adjusted working capital of $109.5 million which included cash and cash equivalents of $165.3 million.

During the fourth quarter of 2017, Seven Generations completed refinancing transactions, repurchasing and redeeming all of the Company's outstanding US$700 million 8.25% senior unsecured notes due in 2020 (the "8.25% Notes") and completing a new debt offering of US$700 million 5.375% senior unsecured notes due in 2025 (the "5.375% Notes"). The refinancing transactions extended the Company's debt maturities and reduced the Company's combined effective interest rate on all of its senior unsecured notes to 6.3%.

At any time prior to September 30, 2020, the Company has the option to redeem the 5.375% Notes at the make-whole redemption price set forth in the 5.375% Note indenture. On or after September 30 of each of the following years, Seven Generations may redeem the 5.375% Notes at the following specified redemption prices:

- September 30, 2020 – 104.031% of principal
- September 30, 2021 – 102.688% of principal
- September 30, 2022 – 101.344% of principal
- September 30, 2023 and thereafter – 100% of principal

Prior to September 30, 2020, the Company also holds the option to redeem up to 35% of the 5.375% Notes at a redemption price of 105.375% using the proceeds of one or more equity offerings, or by paying a make-whole premium represented by the present value of interest that would otherwise be payable over the remaining term of the debt in excess of the applicable redemption premium. The Company holds prepayment options on its 6.75% Notes and 6.875% Notes which carry an average cost of 105.2% of the debt principal in 2018. The cost of the prepayment options decline each year until reaching par in 2021. Refer to the Company's consolidated financial statements for further details. The indentures are also available on SEDAR.

Subject to certain exceptions and qualifications, the senior notes have no financial covenants but limit the Company's ability to, among other things: make payments and distributions; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; make certain dispositions; transfer assets; and engage in amalgamations, mergers or consolidations.

Finance expense

	Three months ended December 31,			Three months ended September 30,	
($ millions, except per boe data)	**2017**	2016	% Change	**2017**	% Change
Interest on senior notes	**$ 34.5**	$ 39.5	(13)	**$ 36.8**	(6)
Premium on redemption of senior notes	**0.2**	—	100	**37.1**	(99)
Revolving credit facility fees and bank fees	**1.2**	1.9	(37)	**1.4**	(14)
Accretion	**1.1**	1.5	(27)	**1.0**	10
Amortization of premiums and debt issuance costs	**0.4**	—	100	**(2.0)**	nm
Finance costs	**37.4**	42.9	(13)	**74.3**	(50)
Capitalized borrowing costs	**(0.8)**	—	(100)	**(1.1)**	(100)
Finance expense	**$ 36.6**	$ 42.9	(15)	**$ 73.2**	(50)
Finance expense per boe	**$ 2.02**	$ 3.53	(43)	**$ 4.33**	(53)

	Year ended December 31,		
($ millions, except per boe data)	**2017**	2016	% Change
Interest on senior notes	**$ 149.3**	$ 131.3	14
Premium on redemption of senior notes	**37.2**	—	100
Revolving credit facility fees and bank fees	**5.4**	7.5	(28)
Accretion	**3.8**	2.8	46
Amortization of premiums and debt issuance costs	**(0.6)**	0.8	nm
Finance costs	**195.1**	142.4	37
Capitalized borrowing costs	**(1.9)**	(3.7)	(49)
Finance expense	**$ 193.2**	$ 138.7	39
Finance expense per boe	**$ 3.02**	$ 3.22	(6)

The Company's finance expense primarily relates to interest on its senior unsecured notes held by the Company with an aggregate combined principal amount of US$1.6 billion. The Company also incurs standby fees on its $1.4 billion undrawn Credit Facility. Accretion relates to the unwinding of the discount factor applied to the Company's decommissioning obligations. Seven Generations also amortizes debt issuance costs and debt premiums to net income over the term of its debt instruments.

For the three months ended December 31, 2017, financing costs were $37.4 million compared to $74.3 million during the third quarter of 2017. The decline was primarily due the redemption premium on the 8.25% Notes that was expensed during the third quarter of 2017. Excluding the impact of the redemption premium, quarter over quarter financing costs were relatively consistent as lower interest expense incurred on the 5.375% Notes (issued on October 2, 2017 to replace the 8.25% Notes) were offset by interest expense incurred on a portion of the 8.25% Notes that were not repaid until October 25, 2017.

Compared to the fourth quarter of 2016, financing and interest costs declined by 15% from $42.9 million to $36.6 million during the fourth quarter of 2017, primarily due to a higher average value of the Canadian dollar, relative to the US dollar, which averaged 1.272:1 during the fourth quarter, compared to 1.297:1 during the same period in the prior year.

During the year ended December 31, 2017, financing costs were $195.1 million, compared to $142.4 million during the prior year. The increase in financing costs was primarily due to the redemption premium on the 8.25% Notes, as well as additional interest expense on its senior unsecured notes that were assumed as part of the significant asset acquisition during the third quarter of 2016. The Company also recognized higher accretion expense from increases in decommissioning obligations as a result of drilling activities and the significant asset acquisition.

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. During the year December 31, 2016, the Company capitalized interest and financing costs of $3.7 million relating to the Cutbank natural gas processing facility, which became ready for use at the end of March 2016. Capitalized borrowing costs of $1.9 million recognized during 2017 relate to initial construction activities for a third wholly-owned gas processing facility in the Kakwa River Project.

Foreign exchange (gain) loss

	Three months ended December 31,		Three months ended September 30,
($ millions, except exchange rates)	**2017**	2016	2017
Foreign exchange gain (loss) on US senior notes	**$ (10.2)**	$ (47.7)	$ 78.9
Unrealized foreign exchange gain (loss) on US working capital	**4.6**	(0.5)	(5.2)
Realized foreign exchange loss on US transactions	**(3.6)**	(0.7)	(3.1)
Net foreign exchange gain (loss)	**$ (9.2)**	$ (48.9)	$ 70.6

	Year ended December 31,	
($ millions, except exchange rates)	**2017**	2016
Foreign exchange gain (loss) on US senior notes	**$ 140.0**	$ 17.2
Unrealized foreign exchange loss on US working capital	**(2.7)**	(0.5)
Realized foreign exchange gain (loss) on US transactions	**(7.7)**	1.5
Net foreign exchange gain	**$ 129.6**	$ 18.2

The Company's foreign exchange gains and losses are primarily related to the US denominated senior unsecured notes which are remeasured in Canadian dollars at each reporting period. As at December 31, 2017, a 10% increase to the value of the Canadian dollar relative to the US dollar would result in a gain of approximately $197.6 million (10% decline – loss of $197.6 million) to the amortized cost of the notes.

During the year ended December 31, 2017, the net foreign exchange gain of $129.6 million was primarily due to an increase in the value of the Canadian dollar from 1.344:1 to 1.255:1 (CAD:USD), which mostly occurred during the first three quarters of 2017. The value of the Canadian dollar remained relatively flat during the fourth quarter, declining slightly from 1.248:1 to 1.255:1.

The net foreign exchange gain of $18.2 million during the year ended December 31, 2016 was primarily due to an unrealized gain on the 8.25% Notes and the 6.75% Notes due to an increase in the value of the Canadian dollar from 1.385:1 to 1.344:1, year over year. The net unrealized gain was partially offset by an unrealized loss on the 6.875% Notes due to a decline in the value of the Canadian dollar from the date of acquisition on August 18, 2016 until the end year, from 1.277:1 to 1.344:1, respectively.

During the third quarter of 2017, Seven Generations incurred net foreign exchange gain $70.6 million primarily due to the strengthening of the Canadian dollar from 1.302:1 to1.248:1. The net foreign exchange loss of $48.9 million during the fourth quarter of 2016 was primarily due to a decline in the value of the Canadian dollar from 1.312:1 to 1.344:1.

Realized foreign exchange gains and losses on US transactions primarily relate to the actual conversion of US dollars to Canadian dollars and the settlement of transactions denominated in US dollars, including revenues and expenditures in the US market.

Contractual obligations

The following table lists the Company's estimated future minimum contractual obligations as at December 31, 2017:

($ millions)	2018	2019	2020	2021	2022	Thereafter	Total
Senior notes (1)	—	—	—	—	—	1,975.9	**1,975.9**
Interest on senior notes	122.0	122.0	122.0	122.0	122.0	78.6	**688.6**
Firm transportation and processing agreements	434.2	452.3	490.4	517.0	481.6	2,553.5	**4,929.0**
Office leases	4.2	3.4	3.2	3.2	3.3	2.6	**19.9**
Estimated contractual obligations	560.4	577.7	615.6	642.2	606.9	4,610.6	**7,613.4**

(1) Balance represents the US$1.575 billion principal converted to Canadian dollars at the exchange rate of US$1=C$1.255 at period end.

See Transportation, Processing and Other discussion under the Operating Results in this MD&A for additional information with respect to the Company's transportation and processing commitments.

Off-balance sheet arrangements

The Company has certain fixed lease arrangements which were entered into in the normal course of operations. All material leases are classified as operating leases and the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. These minimum commitments are disclosed under "Contractual Obligations" above. No asset or liability has been recorded for these leases on the balance sheet at December 31, 2017 or 2016.

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

Outstanding share data

The Company is authorized to issue an unlimited number of Common Shares and an unlimited number of class B common non-voting shares without nominal or par value. The following table summarizes the number of common shares and convertible securities outstanding as at March 12, 2018:

As at March 12, 2018	
Common shares issued and outstanding	**354,959,612**
Convertible securities:	
Stock options	**12,140,921**
Performance warrants	**8,155,054**
Performance share units ("PSUs")	**635,995**
Restricted share units ("RSUs")	**442,664**
Deferred share units ("DSUs")	**186,655**

During the year ended December 31, 2017, total outstanding equity compensation units decreased by 1.3 million units primarily due to the exercise of 3.1 million performance warrants and 1.3 million stock options, partially offset by the issuance of 3.1 million new equity unit grants, net of forfeitures.

The vesting of PSUs is conditional on the satisfaction of certain performance criteria as determined by the Company's Board of Directors. If the Company satisfies the performance criteria, PSUs become eligible to vest and a pre-determined multiplier is applied to eligible PSUs. In calculating stock-based compensation for the PSUs, the Company has used an adjustment factor of 1.0, which assumes that the Company will be within the 50% percentile of its relative peer group based on total shareholder return at the respective vesting dates. During the year ended December 31, 2017, Seven Generations issued 80,772 PSUs in respect of the applicable PSU performance multipliers.

As at December 31, 2017, assuming the highest performance multiplier is available to all PSU tranches, the maximum number of common shares issuable pursuant to the outstanding PSUs is 1,056,597.

For additional information regarding these compensation plans, refer to Seven Generations' consolidated financial statements for the year ended December 31, 2017 and Information Circular and Proxy Statement dated March 13, 2018, which are available on the SEDAR website at www.sedar.com.

OTHER CORPORATE EXPENSES

General and administrative

($ millions, except per boe data)	Three months ended December 31, 2017	2016	% Change	Three months ended September 30, 2017	% Change
Personnel	**$ 7.9**	$ 6.6	20	**$ 7.6**	4
Office costs, travel and other	**4.1**	7.0	(41)	**3.2**	28
Professional fees	**1.0**	0.7	43	**0.7**	43
Information technology costs	**0.6**	0.5	20	**1.1**	(45)
Transaction costs	**—**	0.3	(100)	**—**	—
Gross G&A expenses	**13.6**	15.1	(10)	**12.6**	8
Capitalized salaries and benefits	**(0.9)**	(0.1)	800	**(1.0)**	(10)
Operating overhead recoveries	**(0.9)**	(0.6)	50	**(0.6)**	50
G&A expenses	**$ 11.8**	$ 14.4	(18)	**$ 11.0**	7
G&A per boe	**$ 0.65**	$ 1.16	(44)	**$ 0.65**	—

($ millions, except per boe data)	Year ended December 31, 2017	2016	% Change
Personnel	**$ 34.1**	$ 26.6	28
Office costs, travel and other	**13.4**	13.7	(2)
Professional fees	**4.1**	2.6	58
Information technology costs	**4.5**	2.5	80
Transaction costs	**—**	7.4	(100)
Gross G&A expenses	**56.1**	52.8	6
Capitalized salaries and benefits	**(7.2)**	(3.5)	106
Operating overhead recoveries	**(2.9)**	(2.2)	32
G&A expenses	**$ 46.0**	$ 47.1	(2)
G&A per boe	**$ 0.72**	$ 0.92	(22)

During the year ended December 31, 2017, G&A expenses decreased from $47.1 million to $46.0 million, compared to the prior year, primarily due to the inclusion of $7.4 million in transaction costs related to the significant asset acquisition that was completed during the third quarter of 2016. The decrease in G&A costs was mostly offset by an increase in G&A expenses from higher staff counts, professional fees and information technology costs incurred to support operations and Company growth.

Compared to the fourth quarter of 2016, G&A expenses declined from $14.4 million to $11.8 million during the fourth quarter of 2017, primarily due to a loss of $3.6 million in respect of an onerous lease provision on under-utilized office space. The decline was partially offset by higher costs incurred to support ongoing operations and the Company's growth.

During the three and 12 months ended December 31, 2017, the Company's G&A per boe declined by 44% and 22%, respectively, compared to the same periods in the prior year, primarily due to higher production growth relative to the increase in G&A expenses.

Stock-based compensation

($ millions, except per boe data)	Three months ended December 31, 2017	2016	% Change	Three months ended September 30, 2017	% Change
Gross stock-based compensation	**$ 8.4**	$ 8.3	1	**$ 11.6**	(28)
Capitalized stock-based compensation	**(2.2)**	(2.5)	(12)	**(3.5)**	(37)
Stock-based compensation expense	**$ 6.2**	$ 5.8	7	**$ 8.1**	(23)
Stock-based compensation per boe	**$ 0.34**	$ 0.48	(29)	**$ 0.48**	(29)

($ millions, except per boe data)	Year ended December 31, 2017	2016	% Change
Gross stock-based compensation	**$ 40.3**	$ 25.7	57
Capitalized stock-based compensation	**(11.8)**	(7.7)	53
Stock-based compensation expense	**$ 28.5**	$ 18.0	58
Stock-based compensation per boe	**$ 0.45**	$ 0.42	7

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

Stock-based compensation expense was $6.2 million during the three months ended December 31, 2017 compared to $5.8 million during the three months ended December 31, 2016. For year ended December 31, 2017, stock-based compensation was $28.5 million compared to $18.0 million during the year ended December 31, 2016. The increases in equity compensation expenses in 2017 were primarily due to the Company's annual equity award grants issued to employees in April 2017, and a higher average balance of awards outstanding during the year.

Compared to the third quarter of 2017, stock-based compensation expense declined by 23% from $8.1 million to $6.2 million during the fourth quarter of 2017, primarily due to additional equity units that were issued during the third quarter of 2017 as a result of the PSU performance multipliers relating to grants issued in prior years. Stock-based compensation expense for PSUs is recognized over the vesting period assuming a performance multiplier of 1.0. Additional expense is recognized at the date of vesting for any additional equity units that are issued in respect of the multiplier.

Income tax expense (recovery)

($ millions)	Three months ended December 31, 2017	2016	% Change	Three months ended September 30, 2017	% Change
Current income tax expense	**$ 0.5**	$ 0.3	67	**$ 0.5**	—
Deferred income tax expense (recovery)	**37.7**	(18.8)	nm	**5.5**	nm
Income tax expense (recovery)	**$ 38.2**	$ (18.5)	(306)	**$ 6.0**	nm

Seven Generations' income taxes primarily relate to deferred income tax from the Company's operating income and losses. The following table reconciles the expected income tax based on current tax rates to the actual amounts recognized:

	Three months ended December 31,		Three months ended September 30,
	2017	2016	**2017**
Net income (loss) before income taxes	**$ 121.8**	$ (123.3)	**$ 91.7**
Statutory income tax rate	**27%**	27%	**27%**
Expected income tax recovery	**32.9**	(33.3)	**24.8**
Adjustments related to the following:			
Non-taxable portion of foreign exchange losses	**1.3**	6.6	**(10.6)**
Stock-based compensation	**1.8**	1.6	**2.3**
Change in unrecognized deferred tax asset	**1.6**	6.9	**(8.3)**
Other and change in tax rates	**0.6**	(0.3)	**(2.2)**
Income tax (recovery) expense	**$ 38.2**	$ (18.5)	**$ 6.0**

	Year ended December 31,		
($ millions)	**2017**	2016	% Change
Current income tax expense	**$ 2.9**	$ 1.4	107
Deferred income tax expense (recovery)	**169.6**	(8.8)	nm
Income tax expense (recovery)	**$ 172.5**	$ (7.4)	nm

For the year ended December 31,	**2017**	2016
Net income (loss) before income taxes	**$ 735.0**	$ (33.6)
Statutory income tax rate	**27%**	27%
Expected income tax expense (recovery)	**198.5**	(9.1)
Adjustments related to the following:		
Non-taxable portion of foreign exchange gains	**(18.9)**	(2.2)
Stock-based compensation	**8.2**	4.9
Change in unrecognized deferred tax asset	**(13.3)**	(1.3)
Change in tax rates and other	**(2.0)**	0.3
Income tax expense (recovery)	**$ 172.5**	$ (7.4)

During the year ended December 31, 2017, the Company recognized $2.9 million in current income tax expense relating to foreign sourced income earned from the Company's US subsidiary (December 31, 2016 – $1.4 million).

As at December 31, 2017, Seven Generations had approximately $5.5 billion of tax pools in Canada available for future deduction, including $0.9 billion tax pools available for immediate deduction.

Selected Quarterly Information

The following table summarizes selected consolidated financial information for the Company for the preceding 12 quarters:

($ millions, except per share amounts, production and unit prices)	Q4 2017	Q3 2017	Q2 2017	Q1 2017	YTD 2017
FINANCIAL					
Liquids and natural gas sales	**$ 683.4**	$ 529.5	$ 505.1	$ 489.3	$ 2,207.3
Realized hedging gains (losses)	**6.9**	14.2	1.8	(7.2)	15.7
Interest, processing and third party income	**1.9**	1.5	1.2	1.3	5.9
Royalties	**(21.5)**	(14.5)	(9.3)	(16.8)	(62.1)
Operating expenses	**(103.3)**	(91.8)	(93.9)	(68.8)	(357.8)
Transportation, processing and other	**(114.4)**	(102.7)	(82.3)	(72.0)	(371.4)
General and administrative (2)	**(11.8)**	(11.0)	(12.3)	(10.9)	(46.0)
Interest expense (2)	**(34.9)**	(37.1)	(38.7)	(42.0)	(152.7)
Foreign exchange gain (loss) (2)	**3.6**	(3.1)	(1.0)	0.6	0.1
Other	**(6.1)**	(0.7)	(2.5)	(1.4)	(10.7)
Funds from operations (1)	**403.8**	284.3	268.1	272.1	1,228.3
Per share – diluted	**1.11**	0.78	0.73	0.75	3.37
Revenues	**615.0**	517.2	591.8	629.4	2,353.4
Operating income (1)	**129.3**	63.4	59.5	74.1	326.3
Per share – diluted	**0.36**	0.17	0.16	0.20	0.90
Net income (loss)	**83.6**	85.7	178.1	215.1	562.5
Per share – diluted	**0.23**	0.24	0.49	0.59	1.54
Capital investments:					
Drilling and completions	**167.4**	252.8	342.3	259.4	1,021.9
Facilities and infrastructure	**115.0**	176.5	153.9	85.2	530.6
Land and other	**39.9**	25.0	16.3	17.7	98.9
Total capital investments	**322.3**	454.3	512.5	362.3	1,651.4
Total assets	**7,294.5**	7,257.4	7,172.0	6,851.0	7,294.5
Available funding (1)	**1,467.4**	1,419.0	1,587.1	1,540.9	1,467.4
Net debt (1)	**1,866.4**	1,925.0	1,797.2	1,594.1	1,866.4
Debt outstanding	**$ 1,956.4**	$ 1,088.1	$ 2,041.9	$ 2,092.1	$ 1,956.4
OPERATING					
Average daily production					
Condensate (mbbl/d)	**63.7**	57.8	54.2	46.8	55.7
Natural gas (MMcf/d)	**493.4**	453.2	409.6	384.5	435.5
NGLs (mbbl/d)	**51.4**	50.6	42.8	42.2	46.7
Total (mboe/d)	**197.3**	183.9	165.2	153.1	175.0
Realized prices					
Condensate ($/bbl)	**$ 68.10**	$ 54.75	$ 58.57	$ 64.07	$ 61.46
Natural gas ($/Mcf)	**3.75**	3.46	4.09	4.36	3.88
NGLs ($/bbl)	**24.40**	20.22	16.45	18.03	19.98
OPERATING NETBACK (1) ($/boe)					
Liquids and natural gas revenues	**37.65**	31.30	33.60	35.52	34.56
Realized hedging gain (loss)	**0.38**	0.84	0.12	(0.52)	0.25
Royalties	**(1.18)**	(0.86)	(0.62)	(1.22)	(0.97)
Operating expenses	**(5.69)**	(5.43)	(6.24)	(4.99)	(5.60)
Transportation, processing and other	**(6.30)**	(6.07)	(5.47)	(5.22)	(5.81)
Operating netback after hedging	**$ 24.86**	$ 19.78	$ 21.39	$ 23.57	$ 22.43

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

Selected Quarterly Information – continued

($ millions, except per share amounts, production and unit prices)	Q4 2016	Q3 2016	Q2 2016	Q1 2016	YE 2016
FINANCIAL					
Liquids and natural gas sales	$ 409.8	$ 361.7	$ 287.4	$ 188.0	$ 1,246.9
Realized hedging gains	5.8	19.2	29.5	36.3	90.8
Interest, processing and third party income	1.3	1.5	1.1	0.8	4.7
Royalties (2)	(11.9)	(0.4)	18.6	(13.0)	(6.7)
Operating expenses	(59.1)	(47.0)	(44.8)	(31.0)	(181.9)
Transportation, processing and other	(72.0)	(74.7)	(56.2)	(35.7)	(238.6)
General and administrative (3)	(10.8)	(7.3)	(10.0)	(8.0)	(36.1)
Interest expense (3)	(41.3)	(37.7)	(29.2)	(26.9)	(135.1)
Foreign exchange gain (loss) (3)	(0.7)	0.3	1.7	0.2	1.5
Other	(1.4)	(3.5)	(0.5)	(0.1)	(5.5)
Funds from operations (1)	219.7	212.1	197.6	110.6	740.0
Per share – diluted	0.60	0.64	0.66	0.40	2.47
Revenues	262.2	373.3	172.3	256.3	1,064.1
Operating income (1)	47.6	47.7	56.0	9.3	160.6
Per share – diluted	0.13	0.15	0.19	0.03	0.50
Net income (loss)	(104.9)	(2.2)	(57.5)	138.4	(26.2)
Per share – diluted	(0.30)	(0.01)	(0.21)	0.50	(0.09)
Capital investments:					
Drilling and completions	186.7	133.4	125.0	152.6	597.7
Facilities and infrastructure	78.5	62.6	88.1	107.9	337.1
Land and other	18.6	11.7	6.2	6.7	43.2
Total capital investments (before acquisitions)	283.8	207.7	219.3	267.2	978.0
Total assets	6,602.4	6,401.2	4,004.5	4,126.2	6,602.4
Available funding (1)	1,626.7	1,673.4	1,246.1	1,260.4	1,626.7
Net debt (1)	1,528.8	1,436.6	1,020.1	1,013.4	1,528.8
Debt outstanding	$ 2,111.9	$ 2,063.0	$ 1,443.9	$ 1,451.5	$ 2,111.9
OPERATING					
Average daily production					
Condensate (mbbl/d)	43.2	46.5	38.8	28.4	39.3
Natural gas (MMcf/d)	334.0	314.0	290.0	225.0	291.0
NGLs (mbbl/d)	33.4	33.8	30.2	22.6	30.0
Total (mboe/d)	132.3	132.6	117.4	88.5	117.8
Realized prices					
Condensate ($/bbl)	$ 56.96	$ 49.93	$ 52.05	$ 39.92	$ 50.59
Natural gas ($/Mcf)	4.15	3.92	2.62	3.24	3.53
NGLs ($/bbl)	18.23	11.23	12.49	8.96	13.08
OPERATING NETBACK (1) ($/boe)					
Liquids and natural gas revenues	33.67	29.64	26.91	23.34	28.92
Realized hedging gain	0.48	1.58	2.77	4.50	2.11
Royalty expense (recovery)	(0.98)	(0.04)	1.74	(1.61)	(0.16)
Operating expenses	(4.86)	(3.85)	(4.20)	(3.85)	(4.22)
Transportation, processing and other	(5.92)	(6.12)	(5.26)	(4.43)	(5.53)
Operating netback after hedging	$ 22.39	$ 21.21	$ 21.96	$ 17.95	$ 21.12

(1) See "Non-IFRS Financial Measures" under Advisories and Guidance.
(2) Includes $27.4 million ($20.0 million after tax) of prior period royalty recoveries for the year ended December 31, 2016, recognized in Q2 2016.
(3) Excludes non-cash items and non-recurring transaction costs.

Selected Quarterly Information – continued

($ millions, except per share amounts, production and unit prices)	Q4 2015	Q3 2015	Q2 2015	Q1 2015	YE 2015
FINANCIAL					
Liquids and natural gas sales	$ 178.5	$ 149.7	$ 155.2	$ 108.5	$ 591.9
Realized hedging gain	23.0	35.3	41.7	50.6	150.6
Interest, processing and third party income	1.6	1.7	1.7	1.7	6.7
Royalties	(12.1)	(17.7)	(12.9)	(15.2)	(57.9)
Operating expenses	(29.4)	(26.8)	(23.5)	(21.5)	(101.2)
Transportation, processing and other	(22.7)	(13.5)	(9.9)	(12.9)	(59.0)
General and administrative	(7.2)	(5.4)	(5.1)	(6.6)	(24.3)
Interest expense [2]	(29.1)	(28.2)	(24.9)	(18.0)	(100.2)
Foreign exchange gain (loss) and other [2]	3.4	(0.2)	4.5	0.3	8.0
Funds from operations [1]	106.0	94.9	126.8	86.9	414.6
Per share – diluted	0.39	0.35	0.47	0.32	1.53
Revenues	244.7	209.4	116.8	104.5	675.4
Operating income (loss) [1]	(14.2)	13.8	28.5	24.0	52.1
Per share – diluted	(0.05)	0.05	0.11	0.09	0.19
Net loss	(28.9)	(53.7)	(22.0)	(82.7)	(187.3)
Per share – diluted	(0.11)	(0.21)	(0.09)	(0.34)	(0.75)
Capital investments:					
Drilling and completions	181.1	145.6	222.2	264.9	813.8
Facilities and infrastructure	114.2	134.5	128.6	100.7	478.0
Land and other	5.8	5.0	3.6	2.8	17.2
Total capital investments	301.1	285.1	354.4	368.4	1,309.0
Total assets	3,758.9	3,707.7	3,559.8	3,170.4	3,758.9
Available funding [1]	1,118.0	1,141.2	1,326.0	861.4	1,118.0
Net debt [1]	1,250.9	989.8	710.2	505.2	1,250.9
Debt outstanding	$ 1,546.8	$ 1,491.2	$ 1,395.5	$ 888.4	$ 1,546.8
OPERATING					
Average daily production					
Condensate (mbbl/d)	25.6	22.6	20.7	15.8	21.2
Natural gas (MMcf/d)	197.0	143.0	130.0	125.0	149.0
NGLs (mbbl/d)	19.2	14.1	11.9	12.0	14.3
Total (mboe/d)	77.7	60.6	54.2	48.8	60.4
Realized prices					
Condensate ($/bbl)	$ 46.72	$ 49.18	$ 60.29	$ 47.59	$ 50.84
Natural gas ($/Mcf)	2.57	2.81	2.63	2.62	2.65
NGLs ($/bbl)	12.35	7.99	9.78	10.41	10.34
OPERATING NETBACK [1] ($/boe)					
Liquids and natural gas revenues	24.97	26.86	31.45	24.73	26.84
Realized hedging gain	3.22	6.32	8.45	11.54	6.83
Royalties	(1.69)	(3.18)	(2.61)	(3.46)	(2.63)
Operating expenses	(4.11)	(4.81)	(4.77)	(4.89)	(4.59)
Transportation, processing and other	(3.30)	(2.42)	(2.00)	(2.95)	(2.68)
Operating netback after hedging	$ 19.09	$ 22.77	$ 30.52	$ 24.97	$ 23.77

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

The Company's total production has steadily increased over the past 12 quarters due to a successful drilling program and added production from the significant asset acquisition completed in 2016. The Company has continued to see positive funds from operations despite a volatile commodity price environment.

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

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

Advisories and Guidance

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, income and expenses. A summary of the Company's significant accounting policies, estimates and assumptions, including new accounting pronouncements that will be adopted in future accounting periods, can be found in notes 3 – 5 of the audited consolidated financial statements for the years ended December 31, 2017 and 2016. There were no material changes to the Company's critical accounting policies and estimates during the year ended December 31, 2017.

NON-IFRS FINANCIAL MEASURES

This document 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", "corporate netback", "adjusted EBITDA", "CROIC", "ROCE", "adjusted working capital", "available funding" and "net debt". The data presented is intended to provide additional information and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These non-IFRS measures should be read in conjunction with the Company's consolidated financial statements and the accompanying notes. Readers are cautioned that the non-IFRS measures do not have any standardized meaning and should not be used to make comparisons between the Company and other companies without also taking into account any differences in the way the calculations were prepared.

Funds from operations

"Funds from operations" is a financial measure not presented in accordance with IFRS and is equal to cash provided by operating activities adjusted for changes in non-cash operating working capital, transaction costs on acquisitions and prepaid processing fees on third-party facilities. The Company uses funds from operations as an integral part of its internal reporting to measure its performance and it is considered an important indicator of the operational strength of the Company's business. Funds from operations is a measure of the cash flow generated by the Company's operating activities and eliminates the effect of changes in non-cash working capital, which is included in cash provided by operating activities. Funds from operations is not intended to be a performance measure that should be regarded as an alternative to, or more meaningful than, either net income as an indicator of operating performance, or cash provided by 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. In the 2016 Management's Discussion and Analysis, transaction costs were included in the funds from operations non-GAAP financial measure. In 2017, the Company began excluding the transaction costs from the non-GAAP financial measure in order to exclude non-recurring corporate costs of the Company. Also refer to the "Highlights" section in this MD&A for further details.

Operating income

"Operating income" is a non-IFRS measure that the Company uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating income is defined as net income (loss), excluding unrealized gains and losses on risk management contracts, unrealized foreign exchange gains and losses, realized foreign exchange gains and losses on debt repayments, accrued redemption premiums on senior notes, gains and losses on disposition of assets, transaction costs, net losses on investments in associates and the respective income tax impact of those adjustments. Refer to the "Highlights" section in this MD&A for further details.

Operating and corporate netback

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

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure and does not have a standardized meaning under IFRS. Adjusted EBITDA is calculated as net income (loss) before interest, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items. This measure is consistent with the Adjusted EBITDA formula prescribed under the Credit Facility and allows management and others to evaluate the Company’s operational performance, relative to other companies, and its ability to meet its ongoing financial obligations using cash provided by operating activities. Also refer to the "Liquidity and Capital Resources" section in this MD&A for further details.

CROIC & ROCE

Cash return on invested capital ("CROIC") is non-GAAP financial measure and does not have a standardized meaning under IFRS. CROIC is determined by dividing the average gross carrying value of Company's oil and natural assets by Adjusted EBITDA (as described above). For the purposes of the CROIC calculation, the average carrying value of the Company's oil and natural gas assets, as taken from the Company's consolidated balance sheet, excludes accumulated depletion and depreciation. For the year ended December 31, 2017, the CROIC of 17.9% was calculated as Adjusted EBITDA of $1.4 billion divided by average gross PP&E of $7.7 billion. For the year ended December 31, 2016, the CROIC of 16.4% was calculated as Adjusted EBITDA of $0.9 billion divided by average gross PP&E of $5.2 billion. For the three months ended September 30, 2017, the CROIC of 16.3% was calculated as Adjusted EBITDA of $1.2 billion divided by average gross PP&E of $7.3 billion.

Return on capital employed (“ROCE") is non-GAAP financial measure and does not have a standardized meaning under IFRS. ROCE is determined by dividing the average carrying value of Company's net assets by adjusted earnings before interest and taxes ("Adjusted EBIT"). For the purposes of the ROCE calculation, net assets are defined as total assets on the Company's consolidated balance sheet less current liabilities. Adjusted EBIT is calculated as Adjusted EBITDA (as described above) less depletion and depreciation. For the year ended December 31, 2017, the ROCE of 9.8% was calculated as Adjusted EBIT of $0.7 billion divided by average net assets of $6.6 billion. For the year ended December 31, 2016, the ROCE of 7.7% was calculated as Adjusted EBIT of $0.4 billion divided by average net assets of $4.9 billion. For the three months ended September 30, 2017, the ROCE of 9.3% was calculated as Adjusted EBIT of $0.5 billion divided by average net assets of $5.8 billion. The CROIC and ROCE measures allow management and others to evaluate the Company’s capital spending efficiency and ability to generate profitable returns by measuring the Company's earnings relative to the capital employed in the business.

Adjusted working capital and available funding

“Available funding” is comprised of adjusted working capital and undrawn portions of the credit facility, less any cash held as collateral for letters of credit. "Adjusted working capital" is comprised of current assets less current liabilities and excludes the current portion of risk management contracts and senior unsecured notes. The available funding measure allows management and other users to evaluate the Company’s short term liquidity. Also refer to the "Liquidity and Capital Resources" section in this MD&A for further details.

Net debt

“Net debt” is a financial measure not presented in accordance with IFRS and is calculated as long-term debt less adjusted working capital. Long-term debt for the senior unsecured 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 (held at amortized cost). 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. Also refer to the "Liquidity and Capital Resources" section in this MD&A for further details.

CONTROLS AND PROCEDURES

Disclosure controls and procedures

Part 1 of National Instrument 52-109 – Certification of Disclosure in Issuer's Annual and Interim Filings defines disclosure controls and procedures ("DC&P") as "controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer’s management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure".

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

Internal control over financial reporting

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

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

RISK FACTORS

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

- volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto;
- general economic, business and industry conditions;
- variance of the Company's actual capital costs, operating costs and economic returns from those anticipated;
- the ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms;
- risks related to the exploration, development and production of oil and natural gas reserves and resources;
- negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels;
- actions by governmental authorities, including changes in government regulation, royalties and taxation;
- potential legislative and regulatory changes;
- the rescission, or amendment to the conditions, of groundwater licenses of the Company;
- management of the Company's growth;
- the ability to successfully identify and make attractive acquisitions, joint ventures or investments, or successfully integrate future acquisitions or businesses;
- the availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel;
- adoption or modification of climate change legislation by governments;
- the absence or loss of key employees;
- uncertainty associated with estimates of oil, NGLs and natural gas reserves and resources and the variance of such estimates from actual future production;
- dependence upon compressors, gathering lines, pipelines and other facilities, certain of which the Company does not control;
- the ability to satisfy obligations under the Company's firm commitment transportation arrangements;
- the uncertainties related to the Company's identified drilling locations;
- the high-risk nature of successfully stimulating well productivity and drilling for and producing oil, NGLs and natural gas;
- operating hazards and uninsured risks;
- the risk of fires, floods and natural disasters;
- the possibility that the Company's drilling activities may encounter sour gas;
- execution of the Company's business plan;
- failure to acquire or develop replacement reserves;
- the concentration of the Company's assets in the Kakwa River Project;
- unforeseen title defects;
- aboriginal claims;
- failure to accurately estimate abandonment and reclamation costs;
- development and exploratory drilling efforts and well operations may not be profitable or achieve the targeted return;
- horizontal drilling and completion technique risks and failure of drilling results to meet expectations for reserves or production;
- limited intellectual property protection for operating practices and dependence on employees and contractors;
- third-party claims regarding the Company's right to use technology and equipment;
- expiry of certain leases for the undeveloped leasehold acreage in the near future;
- failure to realize the anticipated benefits of acquisitions or dispositions;
- failure of properties acquired now or in the future to produce as projected and inability to determine reserve and resource potential, identify liabilities associated with acquired properties or obtain protection from sellers against such liabilities;

- changes in the interpretation and enforcement of applicable laws and regulations;
- restrictions on drilling intended to protect certain species of wildlife;
- potential conflicts of interests;
- actual results differing materially from management estimates and assumptions;
- seasonality of the Company's activities and the oil and gas industry;
- alternatives to and changing demand for petroleum products;
- extensive competition in the Company's industry;
- changes in the Company's credit ratings;
- third party credit risk;
- dependence upon a limited number of customers;
- lower oil, NGLs and natural gas prices and higher costs;
- failure of 2D and 3D seismic data used by the Company to accurately identify the presence of oil and natural gas;
- risks relating to commodity price hedging instruments;
- terrorist attacks or armed conflict;
- cyber security risks, loss of information and computer systems;
- inability to dispose of non-strategic assets on attractive terms;
- the potential for security deposits to be required under provincial liability management programs;
- reassessment by taxing authorities of the Company's prior transactions and filings;
- variations in foreign exchange rates and interest rates;
- risks associated with counterparties in risk management activities related to commodity prices and foreign exchange rates;
- sufficiency of insurance policies;
- potential for litigation;
- variation in future calculations of non-IFRS measures;
- sufficiency of internal controls;
- breach of agreements by third parties and potential enforceability issues in contracts;
- impact of expansion into new activities on risk exposure;
- inability of the Company to respond quickly to competitive pressures; and
- the risks related to the common shares that are publicly traded and the senior notes and other indebtedness.

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

Forward-looking information advisory

This document contains certain forward looking information and statements that involve various risks, uncertainties and other factors. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "should", "believe", "plans", and similar expressions are intended to identify forward looking information or statements. In particular, but without limiting the foregoing, this document contains forward-looking information and statements pertaining to the following: the Company's strategies, objectives and competitive strengths; the Company's goal of achieving full-cycle returns on capital employed across the entire commodity price cycle; the continued use of prudent leverage as part of the Company's capital structure; the ability to expand the Company's market access and capture premium markets for the Company's production; ability to combine resource selection with innovation, technology and efficiency to remain among North America's lowest supply-cost unconventional natural gas developers; the expectation that the Company's first Science Pad will help identify innovation opportunities in 2018; ability to achieve the Company's growth objectives, supported by the Company's processing capacity and firm service transportation agreements; the Company's estimated inventory of drilling locations; the anticipated processing capacity and completion date of the new gas processing facility that is being constructed, the first phase of which is expected to be operational in the fourth quarter of 2018; that pre-builds at the new facility will enable the Company to double the facility's processing capacity and build two sales pipelines in the future; the expectation that the additional NGTL system receipt capacity that was obtained in 2017 will accommodate the Company's transportation requirements from the new natural gas processing facility that is under construction; the markets that Seven Generations will be able to deliver its natural gas to in the future; the future outlooks described under the heading "Outlook", including planned capital investments, planned drilling and completion activities, the Company's production forecasts and estimated operating costs; potential cost savings from the utilization of innovative modular facility design; expected timing of bringing new wells and super pads on-stream; the number of wells to be drilled, completed and brought on-stream; the number of rigs and completions crews to be utilized; the planned construction of a pipeline interconnect between Pembina's Kakwa River natural gas processing facility and the Company's wholly-owned and operated gas processing facilities, which it is expected will allow the Company to divert natural gas in order to better manage operational interruptions and improve netbacks; plans to drill water disposal wells and build a water infrastructure network to connect injection wells and allow produced water to be recycled for use in the Company's hydraulic fracturing operations, as well as the estimated costs that are expected in connection therewith; that the three new super pads that were constructed and the two super pads that were expanded in the fourth quarter of 2017 will be operational in 2018; the expectation that the Company's hedging targets will provide threshold rates of return on capital invested, based on a combination of projected well performance and expected capital efficiencies; the achievement of the Company's targeted net debt to funds flow ratio of less than 2.0 times; the future transportation and processing capacity that has been secured under the Company's contracts; planned propane sales to Inter Pipeline's propane dehydrogenation and polypropylene Heartland Petrochemical Complex, which is expected to commence production in late 2021, and enable 7G to diversify its propane sales and capture stronger realized prices within the Alberta Petrochemical Value Chain; plans to fund investments with cash on hand, funds from operations and draws on the Credit Facility, if needed; and the Company's estimates of its future obligations under the heading "Contractual Obligations". In addition, information and statements in this MD&A relating to reserves and the estimated net present value of future cash flows to be generated therefrom are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the they can be profitably produced in the future.

With respect to forward-looking information contained in this document, assumptions have been made regarding, among other things: future oil, NGLs and natural gas prices being consistent with current commodity price forecasts after factoring in quality adjustments at the Company's points of sale; the Company's continued ability to obtain qualified staff and equipment in a timely and cost-efficient manner; drilling and completion techniques; infrastructure and facility design concepts that have been successfully applied by the Company elsewhere in its Kakwa River Project may be successfully applied to other properties within the Kakwa River Project including, the properties that were acquired as part of the significant acquisition that was completed in 2016; the consistency of the regulatory regime and framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future; the Company's ability to market production of oil, NGLs and natural gas successfully to customers; the Company's future production levels and amount of future capital investment will be consistent with the Company's current development plans and budget; the applicability of new technologies for recovery and production of the Company's reserves and resources may improve capital and operational efficiencies in the future; the recoverability of the Company's reserves and resources; sustained future capital investment by the Company; future cash flows from production; the future sources of funding for the Company's capital program; the Company's future debt levels; geological and engineering estimates in respect of the Company's reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities, and the access, economic, regulatory and physical limitations to which the Company may be subject from time to time; the impact of competition on the Company; and the Company's ability to obtain financing on acceptable terms.

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

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

Independent reserves evaluation

The estimates of the Company's reserves, contingent resources and prospective resources and the net present value attributable to the Company's reserves, as at December 31, 2017, are based upon reports dated March 13, 2018 that were prepared by McDaniel, evaluating the Company's oil, natural gas and NGL reserves, contingent resources and prospective resources. The estimates of reserves, contingent resources and prospective resources provided in this document are estimates only and there is no guarantee that the estimated reserves, contingent resources and prospective resources will be recovered. Actual reserves, contingent resources and prospective resources may be greater than or less than the estimates provided in this in this document and the differences may be material. Estimates of net present value of future net revenue attributable to the Company's reserves, do not represent fair market value and there is uncertainty that the net present value of future net revenue will be realized. There is no assurance that the forecast price and cost assumptions applied by McDaniel in evaluating Seven Generations' reserves, contingent resources and prospective resources will be attained and variances could be material. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. There is also uncertainty that it will be commercially viable to produce any part of the contingent resources. The estimates include contingent resources and prospective resources that are considered too uncertain with respect to the chance of development and chance of discovery to be classified as reserves. For important additional information about the reserves and resources evaluations that were conducted by McDaniel, please refer to the AIF, which is available on SEDAR at www.sedar.com.

Certain oil and gas terms

Certain terms used in this MD&A that are not otherwise defined herein are provided below:

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

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

developed 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.

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

gross means:

- in relation to reserves, the applicable working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests;
- in relation to wells, the total number of wells in which the Company has an interest; and
- in relation to properties, the total area of properties in which the Company has an interest.

net means:

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

prospective resources means quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

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.

Industry metrics

The carbon intensity estimates for 7G that are provided herein were calculated by the company with the assistance of third parties. 7G quantified and reported its GHG emissions using what is referred to as the “operational control” approach. 7G’s deemed organizational boundary included its corporate offices and all natural gas extraction and processing facilities (including well pads). 7G elected to report its Scope 1 and 2 GHG emissions and not to report its Scope 3 GHG emissions. For the purposes of 7G’s GHG emissions reporting:

- Scope 1 emissions were defined as direct emissions from GHG sources that 7G owned or controlled (including, but not limited to, emissions from stationary equipment, mobile combustion, and process emissions and fugitive emissions);
- Scope 2 emissions were defined as indirect GHG emissions that resulted from 7G’s consumption of energy in the form of purchased electricity; and
- Scope 3 emissions were defined as 7G’s indirect emissions other than those covered in Scope 2, including from all sources not owned or controlled by 7G, but which occurred as a result of 7G’s activities.

Notably, 7G’s drilling and completion activities in the relevant periods were conducted by third parties and, consequently, those activities were deemed to be Scope 3.

7G used third parties to help quantify its GHG emissions. For the 2015 and 2016 reporting years, Deloitte LLP was retained by 7G to evaluate GHG emissions from all major facilities located in Alberta (gas plants, gas gathering systems and batteries) in accordance with Alberta’s Specified Gas Emitters Regulation (SGER) reporting program, Alberta’s Specified Gas Reporting Regulation and Environment and Climate Change Canada’s Greenhouse Gas Emissions Reporting Program. To conduct this quantification, emission calculation methods were taken from the approved reference sources listed in the SGER guidance publication titled “Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications”. Additional quantification of Scope 1 GHG emissions (e.g., vented emissions and fugitives) was conducted by DXD Consulting Inc. (DXD) using API 2009 guidance and emissions factors. Scope 2 emissions were quantified by DXD using utility statements for all purchased electricity (i.e., Calgary and Grande Prairie offices and the company’s Lator 1 facilities).

For the 2016 reporting year, third party verification of both the SGER (i.e., Scope 1 GHG emissions) report developed on behalf of 7G by Deloitte LLP and the CDP’s Climate Change 2017 Questionnaire and CDP Oil and Gas Sector Module 2017 (i.e., Scope 1 and 2 GHG) reports developed by 7G was conducted by Brightspot Climate Inc. This verification was completed in accordance with the ISO 14064:3 standard.

Finding, development and acquisition costs have been calculated by the company as the sum of exploration and development capital, plus acquisition capital, plus changes in future development costs for the given year, divided by total reserve additions for that year. Finding and development costs are calculated as the sum of exploration and development costs, plus changes in future development costs (excluding future development capital associated with acquisitions and dispositions), divided by reserve additions (excluding reserves added via acquisitions). Finding and development both including and excluding acquisitions are presented since acquisition and disposition activity can result in reserve replacement metrics that are not indicative of the long-term cost structure that is expected from the company’s assets. Reserves replacement ratios are calculated as total reserves additions (taking into account acquisitions and divestitures) divided by annual production. Management utilizes these metrics for internal measurement.

Readers are advised that the metrics contained in this circular may not be comparable to similarly defined metrics presented by other entities, and comparisons should not be made between such measures provided by the company and by other companies without also taking into account any differences in the way that the calculations were prepared.

Potential drilling locations

The references to drilling locations or potential drilling opportunities that are contained herein have been prepared by qualified reserves evaluators from Seven Generations as at the date hereof. These estimated locations refer to the Company’s estimated drilling inventory that has yet to be developed. Of the 1,400 potential drilling locations that are estimated to be contained within the company’s Nest area, 68% were attributed proved plus probable reserves and 32% were attributed best estimate contingent resources in McDaniel’s reports evaluating the reserves and resources attributable to the Company’s properties, as at December 31, 2017. Of the 900 potential drilling locations that are estimated to be contained within in the Company’s Wapiti and Rich Gas areas, 5% were attributed proved plus probable reserves, 70% were attributed best estimate contingent resources and 25% were attributed best estimate prospective resources in McDaniel’s reports evaluating the reserves and resources attributable to the Company’s properties, as at December 31, 2017. For the purposes of estimating potential drilling locations, the Company has assumed well spacing of 12 wells per section and a lateral well lengths of 2,500 metres based upon industry practice and internal review. The anticipated well spacing and lateral well length is expected to change over time as technology and the Company’s understanding of the reservoir changes.

Definitions and abbreviations

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

AECO	physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
bbl or bbls	barrel or barrels
boe	barrels of oil equivalent (1)
bcf	billion cubic feet
C$ or CAD	Canadian dollars
CO_2	carbon dioxide
CROIC	cash return on invested capital
d	day
Deep Southwest	the "Deep Southwest" area that is shown in the map provided in the AIF
D&C	drilling and completion
EBITDA	earnings before interest, taxes depreciation and amortization
GCA	gas cost allowance
GHG	greenhouse gas
GJ	gigajoules
GTN	Gas Transmission Northwest LLC
G&A	general and administrative
LNG	liquefied natural gas
m	metres
mbbl	thousands of barrels
mboe	thousands of barrels of oil equivalent (1)
Mcf	thousand cubic feet
MMBtu	million British thermal units
MMcf	million cubic feet
mmboe	million barrels of oil equivalent (1)
Nest	Nest 1, Nest 2 and Nest 3 areas combined
Nest 1	the "Nest 1" area that is shown in the map provided in the AIF
Nest 2	the "Nest 2" area that is shown in the map provided in the AIF
Nest 3	the "Nest 3" area that is shown in the map provided in the AIF
NGLs	natural gas liquids
NGPL	Natural Gas Pipeline Company of America LLC
NGTL	Nova Gas Transmission Ltd.
nm	not meaningful information
NYMEX	New York Mercantile Exchange
OPEC	Organization of Petroleum Exporting Countries
PDP	gross proved developed producing reserves
PDNP	gross proved developed non-producing reserves
Rich gas	the 'Rich Gas' area that is shown in the map provided in the AIF
ROCE	return on capital employed
SEDAR	System for Electronic Document Analysis and Retreival
super pads	the Company's decentralized field conditioning plants that separate field condensate and natural gas
TCPL	TransCanada Pipelines Limited
TSX	Toronto Stock Exchange
US	United States of America
US$ or USD	United States dollars
Wapiti	the "Wapiti" area that is shown in the map provided in the AIF
WTI	West Texas Intermediate
YE	year end
YTD	year to date
$MM	millions of dollars

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

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

Independent Auditor's Report

March 13, 2018

To the Shareholders of Seven Generations Energy Ltd.

We have audited the accompanying consolidated financial statements of Seven Generations Energy Ltd. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016 and the consolidated statements of comprehensive income (loss), changes in equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated 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 consolidated 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 consolidated financial statements.

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

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Seven Generations Energy Ltd. and its subsidiaries as at December 31, 2017 and December 31, 2016 and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, AB

Consolidated Balance Sheets

(millions of Canadian dollars)

As at December 31,	Notes	2017	2016
Assets			
Current assets			
Cash and cash equivalents	6	$ 165.3	$ 630.8
Accounts receivable	7	302.7	181.9
Risk management contracts	10	36.2	—
Deposits and prepaid expenses		18.8	17.7
		523.0	830.4
Risk management contracts	10	36.1	—
Oil and natural gas assets	8	6,733.0	5,750.1
Investment in associate	9	2.4	21.9
		7,294.5	6,602.4
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		377.3	244.5
Risk management contracts	10	17.5	71.7
		394.8	316.2
Risk management contracts	10	16.5	77.7
Senior notes	12	1,956.4	2,111.9
Other long-term liabilities	13	198.0	165.0
Deferred income taxes	14	278.4	108.8
		2,844.1	2,779.6
Equity			
Share capital	15	3,864.4	3,830.5
Contributed surplus		100.6	69.4
Retained earnings (Deficit)		485.4	(77.1)
		4,450.4	3,822.8
		$ 7,294.5	$ 6,602.4

Commitments and contingencies (Note 23)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

Dale Hohm
Director

Kent Jespersen
Director

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars)

For the year ended December 31,	Notes		2017		2016
Revenues					
Liquids and natural gas sales	18	$	2,207.3	$	1,246.9
Royalties expense			(62.1)		(6.7)
			2,145.2		1,240.2
Risk management contracts					
Realized gain	10		15.7		90.8
Unrealized gain (loss)	10		186.7		(271.6)
Other income			5.9		4.7
			2,353.5		1,064.1
Expenses					
Operating expenses	19		357.8		181.9
Transportation, processing and other	20		371.4		238.6
General and administrative			46.0		47.1
Depletion and depreciation	8		730.2		483.6
Stock-based compensation	22		28.5		18.0
Finance expense	21		193.2		138.7
Foreign exchange gain			(129.6)		(18.2)
Loss on associate	9		21.0		8.0
			1,618.5		1,097.7
Income (loss) before taxes			735.0		(33.6)
Income Taxes					
Current income tax expense	14		2.9		1.4
Deferred income tax expense (recovery)	14		169.6		(8.8)
			172.5		(7.4)
Net income (loss) and comprehensive income (loss)		$	562.5	$	(26.2)
Net income (loss) per share					
Basic	17	$	1.59	$	(0.09)
Diluted	17	$	1.54	$	(0.09)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(millions of Canadian dollars)

For the year ended December 31,	Notes	2017	2016
Operating activities			
Net income (loss) for the period		**562.5**	(26.2)
Items not affecting cash:			
Deferred income tax expense (recovery)	14	**169.6**	(8.8)
Depletion and depreciation	8	**730.2**	483.6
Unrealized loss (gain) on risk management contracts	10	**(186.7)**	271.6
Stock-based compensation	22	**28.5**	18.0
Non-cash finance expenses and other	21	**2.4**	7.2
Premium on redemption of senior notes	21	**37.2**	—
Loss on associate	9	**19.5**	3.9
Foreign exchange gain on senior notes and other	12	**(134.9)**	(16.7)
Prepaid processing fees on third-party facilities	8	**(21.0)**	—
Changes in non-cash working capital	25	**(53.0)**	(88.0)
Cash provided by operating activities		**1,154.3**	644.6
Financing activities			
Redemption of US$700 million 8.25% senior notes	12	**(912.7)**	—
Issuance of US$700 million 5.375% senior notes	12	**859.7**	—
Issuance of common shares for cash	15	**—**	1,047.7
Share issuance costs	15	**—**	(43.7)
Exercise of equity compensation units	15	**25.0**	55.7
Changes in non-cash working capital	25	**—**	—
Cash provided by (used in) financing activities		**(28.0)**	1,059.7
Investing activities			
Investments in oil and natural gas assets	8	**(1,651.4)**	(978.0)
Acquisitions	8	**—**	(505.1)
Investments in associates	9	**—**	(25.8)
Changes in non-cash working capital	25	**61.9**	30.9
Cash used in investing activities		**(1,589.5)**	(1,478.0)
Foreign exchange loss on cash in foreign currencies		**(2.3)**	(0.5)
Increase (decrease) in cash and cash equivalents		**(465.5)**	225.8
Cash and cash equivalents, beginning of period		**630.8**	405.0
Cash and cash equivalents, end of period		**165.3**	630.8

Supplementary disclosure of cash flow information (Note 25)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Equity

(millions of Canadian dollars)

For the year ended December 31,	Notes	2017	2016
Share capital			
Balance, beginning of period		**$ 3,830.5**	$ 1,775.7
Issuance of common shares	15	**–**	1,047.7
Issuance of common shares for Acquisition	8	**–**	965.1
Share issuance costs, net of deferred tax	15	**–**	(31.8)
Exercise of equity compensation units	22	**33.9**	73.8
Balance, end of period		**3,864.4**	3,830.5
Contributed surplus			
Balance, beginning of period		**69.4**	61.8
Stock-based compensation	22	**40.1**	25.7
Exercise of equity compensation units	22	**(8.9)**	(18.1)
Balance, end of period		**100.6**	69.4
Retained earnings (deficit)			
Balance, beginning of period		**(77.1)**	(50.9)
Net income for the period		**562.5**	(26.2)
Balance, end of period		**485.4**	(77.1)
Total shareholders equity, beginning of period		**$ 3,822.8**	$ 1,786.6
Total shareholders equity, end of period		**$ 4,450.4**	$ 3,822.8

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

As at and for the years ended December 31, 2017 and 2016

(all tabular amounts in millions of Canadian dollars, except 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 condensate and natural gas properties in Western Canada. Seven Generations’ principal place of business is located at 4400, 525 – 8 Avenue SW Calgary, AB T2P 1G1. The Company’s class A voting common shares ("common shares") are publicly traded on the Toronto Stock Exchange under the symbol “VII”. These consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 13, 2018.

2. Basis of Preparation

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). They have been prepared on a historical cost basis, except for financial instruments which are measured at their estimated fair value. The Company's presentation currency is Canadian dollars and all amounts are reported in Canadian dollars unless noted otherwise. References to "US$" are to United States dollars. These consolidated financial statements include the accounts of Seven Generations and its wholly owned subsidiary, Seven Generations Energy (US) Corp. All inter-company transactions have been eliminated.

3. Significant Accounting Policies

FINANCIAL INSTRUMENTS

All financial instruments are initially recognized at fair value on the consolidated balance sheet, with the exception of the senior notes which are recognized at amortized cost. The Company classifies each financial instrument into one of the following categories: "held for trading", "loans & receivables", "held to maturity", "equity investment" or "other financial liabilities".

The fair value measurement of the Company's financial instruments are classified 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 at the reporting date.
- Level 2 – Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed in the marketplace but are not readily observable in an actively traded market.
- Level 3 – Valuation inputs that are not based on observable market data.

Financial Instrument	Classification	Level Valuation	Measurement
Assets			
Cash and cash equivalents	Held for trading	Level 1	Fair value
Accounts receivable	Loans & receivables	Level 3	Fair value
Risk management contracts	Held for trading	Level 2	Fair value
Investment in associate	Equity investment	Level 3	Equity method
Liabilities			
Accounts payable and accrued liabilities	Other financial liabilities	Level 3	Fair value
Risk management contracts	Held for trading	Level 2	Fair value
Senior notes	Other financial liabilities	Level 2	Amortized cost

Transaction costs related to fair value through profit or loss instruments are immediately recognized in earnings. Transaction costs related to other financial liabilities are included in earnings or netted with the fair value of the financial instrument.

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence that one or more events have had a negative impact on the estimated future cash flows of that asset. All impairment losses are recognized in the consolidated statement of comprehensive income (loss).

Oil and natural gas assets

Oil and natural gas assets are measured at cost less accumulated depletion, depreciation and accumulated impairment losses. Property, plant and equipment ("PP&E") represents all costs directly attributable to the development of oil and natural gas reserves after technical feasibility and commercial viability have been established. Exploration and evaluation assets ("E&E") are those investments for which technical feasibility and commercial viability have not yet been determined. The Company capitalizes these costs after the right to explore has been obtained, including geological and geophysical costs, land acquisition costs, drilling costs, and costs incurred for the completion and testing of exploration wells. Once technical feasibility and commercial viability have been established, E&E assets are tested for impairment and reclassified to PP&E. Technical feasibility and commercial viability are established when proved reserves are determined to exist and the Company has sanctioned the E&E assets for commercial development.

The majority of the Company's PP&E is depleted using the unit-of-production method based on estimated recoverable proved plus probable reserves. Natural gas reserves and production are converted to barrels of oil equivalent based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus the estimated future costs required to develop the Company's estimated recoverable proved plus probable reserves, and excludes the cost of assets not yet available for use in the manner intended by management. Significant components, such as natural gas plants, are depreciated separately on a straight-line basis over their estimated useful lives. Corporate assets are depreciated over their estimated useful lives using the declining-balance method.

Impairment

Seven Generations reviews its oil and natural gas assets for indicators of impairment at each reporting date. For the purposes of the review, the Company’s PP&E and E&E assets are grouped into cash-generating units ("CGUs") which are defined as the smallest group of assets that generates cash inflows that are largely independent of the cash inflows of other assets or group of assets. PP&E and E&E assets that are in the same CGU are combined. If impairment indicators exist, the CGU is tested for impairment and a loss is recognized if the carrying amount of the CGU exceeds its estimated recoverable amount.

The recoverable amount of the CGU is determined as the greater of its fair value less costs to sell ("FVLCTS") and value in use ("VIU"). FVLCTS is based on the amount obtainable from the sale of an asset or CGU in an arm’s length transaction between knowledgeable parties, less the cost of disposal. In assessing VIU, the estimated future cash flows of the CGU are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and risks specific to the asset. The recoverable amounts of the Company’s CGUs are generally estimated using discounted cash flows from the Company’s proved plus probable reserves (Level 3 valuation) and/or imputed from relevant sales transactions on assets with similar geological and geographic characteristics (Level 3 valuation).

Provisions

Provisions are recognized when the Company has a present legal or constructive obligation as a result of a past event and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The Company's provisions primarily consist of decommissioning obligations associated with the dismantling, decommissioning and site disturbance remediation activities for its oil and natural gas assets.

Decommissioning liabilities are measured at the present value of the expected cash outflow using the relevant risk-free rate. The liability is accreted in the consolidated statement of comprehensive income (loss) at each reporting date to reflect the passage of time. Actual expenditures incurred upon settlement of the obligations reduce the provision.

Investment in associate

The Company accounts for its investment in associate using the equity method of accounting as Seven Generations is considered to have significant influence. Significant influence is generally regarded as the ability to participate in the financial and operational decisions of the associate without having control or joint-control over the associate.

The carrying value of the investment in associate is increased or decreased for the Company's share of equity contributions and withdrawals, as well as the Company's share of income and losses, respectively. The carrying value of the Company's investment in associate is also reviewed for indicators of impairment at each reporting date. If indicators of impairment exist, the investment is tested for impairment and a loss is recognized if the carrying amount of the investment in associate exceeds its estimated recoverable amount. The estimated recoverable amount is primarily based on observable equity issuances made by the associate.

Stock-based compensation

The Company's stock-based compensation expense relates to stock options, performance warrants, performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs") granted to employees, officers and directors of Seven Generations. Awards are measured at fair value on the date of grant and are expensed over the vesting periods.

The fair value of stock options and warrant grants are primarily determined using the Black-Scholes option pricing model. The fair value of DSUs, PSUs and RSUs are primarily based on the Company's share price on the date of grant. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of stock options, performance warrants, PSUs and RSUs that vest. DSUs are fully expensed at grant date because they vest immediately.

PSUs may be granted with certain market conditions that are determined by the Company's Board of Directors. If the Company satisfies the market conditions, a pre-determined adjustment factor is applied to the vested PSUs at the end of the performance period, based upon the relative share price performance of the Company compared to a peer group. The expense recognized over the PSU vesting period is the fair value of the PSUs with an estimated adjustment factor. If the actual adjustment factor is higher than estimated, an additional expense is recognized on vesting for the incremental fair value.

When equity compensation units are exercised or released, the consideration received, together with the expense previously recognized in contributed surplus, is recorded as an increase to share capital. The Company's stock-based compensation plans allow the holder of the award to receive cash or common shares at the Company's discretion, equal to the fair market value of the Company's common shares calculated at the date of such payment. Because the Company does not intend to settle in cash, the plans are accounted for as equity-settled share-based compensation arrangements.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and other short-term highly liquid investments with a maturity of three months or less and are presented as a current asset on the balance sheet. GIC Collateral accounts are primarily used to secure letters of credit issued as security in respect of long-term transportation commitments.

Income taxes

Income tax is comprised of current and deferred taxes which are recognized in the statement of comprehensive income (loss), except when it relates to share capital, in which case, it is recognized directly in equity. 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.

Deferred tax is recognized on temporary differences between the carrying value of assets and liabilities for financial reporting purposes and the tax values. Deferred income tax is determined on an undiscounted basis using tax rates that have been enacted or substantively enacted and that are expected to apply in future periods when the temporary differences are anticipated to reverse. A deferred tax asset is only recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilized.

Revenue

Revenue from the sale of condensate, natural gas, and natural gas liquids ("NGLs") is recognized when the risks and rewards of ownership of the products are transferred to the buyer.

Foreign currency translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the average exchange rates for the period. Gains and losses from foreign currency translations are recognized in the consolidated statement of comprehensive income (loss).

Jointly operated assets

The Company’s oil and natural gas activities include jointly operated oil and natural gas assets and liabilities. These consolidated financial statements include the Company’s share of these jointly operated assets and liabilities and a proportionate share of the related revenue and expenses.

Per share information

Basic per share information is calculated using the weighted average number of common shares outstanding during the period. Diluted per share information is calculated using the basic weighted average number of common shares outstanding during the period, adjusted for the potential number of shares which could have had a dilutive effect on net income (loss) during the period.

Business combinations

Business combinations are accounted for using the acquisition method. Identifiable assets, liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the fair value of the consideration paid, equity instruments issued and liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately as a gain in net income. Transaction costs associated with business combinations are expensed as incurred.

4. Significant Accounting Judgments, Estimates and Assumptions

JUDGMENTS

The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. Actual results may differ from these estimates.

Oil and natural gas assets are grouped into CGUs based on their ability to generate largely independent cash flows. The determination of the Company's CGUs is subject to management's judgment. The Company's oil and natural gas assets are currently held in one CGU. In addition, the Company applies judgment when determining the classification of oil and natural gas assets as PP&E or E&E assets. In making this determination, management considers various factors, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's Board of Directors.

The Company applies judgment in determining when the transfer of risks and rewards of ownership from the sale of condensate, natural gas and NGLs occurs. Revenues are generally recognized upon the transfer of asset title.

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

ESTIMATES AND ASSUMPTIONS

The amounts recorded for depletion of oil and natural gas assets are based on estimated reserves and future development costs. The estimated recoverable reserves and associated future cash flows are also key in determining if the Company's natural gas assets have been impaired. These estimates are subject to measurement uncertainty. The determination of reserves involves estimates for oil and natural gas volumes in place, recovery factors, production rates, future commodity prices and future royalty, operating, and capital costs. The Company's reserve estimates have been determined in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook.

Impairment test calculations require the use of estimates and judgments including estimates relating to future commodity prices, quantity of reserves, expected production volumes, land values, discount rates, recovery factors and future development and operating costs.

The Company's provision for decommissioning liabilities are based on assumptions regarding the interpretation of current legal and constructive requirements as well as estimates of future costs and expected timing of remediation.

The Company's stock-based compensation expense is subject to measurement uncertainty as a result of estimates related to forfeiture rates, expected life and underlying volatility of the Company's common shares.

The estimated fair value of financial instruments are subject to measurement uncertainty. The fair value of financial instruments without an actively traded market 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.

5. New Accounting Policies

These consolidated financial statements follow the same accounting policies as the consolidated financial statements for the year ended December 31, 2016. The accounting pronouncements listed below will be adopted in future accounting periods:

- **IFRS 15 Revenue from Contracts with Customers** was issued in May 2014 and replaces IAS 18 Revenue, IAS 11 Construction Contracts, and related interpretations. IFRS 15 provides a single, five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted.

  Seven Generations will retrospectively adopt IFRS 15 on January 1, 2018. The Company has determined that there will not be any material changes in the measurement or timing of revenue recognition as a result of IFRS 15. However, the Company will expand disclosures to its consolidated financial statements as prescribed by IFRS 15.

- **IFRS 9 Financial Instruments** was issued in July 2014 and replaces IAS 39 Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces multiple rules in IAS 39. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

  Seven Generations will retrospectively adopt IFRS 9 on January 1, 2018. The Company has determined that there will not be any material changes in the disclosure, measurement or carrying value of the Company's financial instruments as a result of the adoption of IFRS 9.

- **IFRS 16 Leases** was issued in January 2016 and replaces IAS 17 Leases. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition by lessees of assets and liabilities for most leases, including subleases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 Revenue from Contracts with Customers. The standard is required to be adopted either retrospectively or using a modified retrospective approach.

  Seven Generations will adopt IFRS 16 on January 1, 2019. The Company is currently evaluating the impact of the standard on the consolidated financial statements. The Company has commenced its project planning and scoping phase and is in the process of identifying leases which fall within the scope of IFRS 16.

6. Cash and Cash Equivalents

As at December 31,		2017		2016
Cash	$	164.5	$	325.5
GIC Collateral accounts		—		59.2
Short-term investments [1]		0.8		246.1
Cash and cash equivalents	$	165.3	$	630.8

(1) As at December 31, 2017, the short term investments bore interest at a weighted average rate of 1.35% (December 31, 2016 – 0.8%).

As at December 31, 2017, the credit risk associated with the Company's cash and cash equivalents balances was considered low as the balances were held with two large Canadian chartered banks.

7. Accounts Receivable

As at December 31,		2017		2016
Oil and natural gas sales	$	243.2	$	137.8
GST, royalty recoveries and other		46.5		42.5
Joint venture billings		13.0		1.6
Accounts receivable	$	302.7	$	181.9

As at December 31, 2017, management believes collection risk on the outstanding accounts receivable balances was low given the high credit quality of the Company's material counterparties and history of collections. There were no material amounts past due as at December 31, 2017.

8. Oil and Natural Gas Assets

		Exploration and evaluation		Developed and producing		Other assets		Total
Cost								
Balance at December 31, 2015	$	222.6	$	3,423.0	$	12.2	$	3,657.8
Acquisition		300.0		1,772.3		—		2,072.3
Additions		—		976.1		1.9		978.0
Dispositions		—		(6.0)		—		(6.0)
Transfers from E&E to PP&E		(11.0)		11.0		—		—
Non-cash capitalized costs (1)		—		75.9		—		75.9
Balance at December 31, 2016		511.6		6,252.3		14.1		6,778.0
Additions		**19.6**		**1,628.3**		**3.5**		**1,651.4**
Transfers from E&E to PP&E		**(200.0)**		**200.0**		**—**		**—**
Prepaid processing fees on third-party facilities		**—**		**—**		**21.0**		**21.0**
Non-cash capitalized costs (1)		**—**		**41.3**		**—**		**41.3**
Balance at December 31, 2017		**331.2**		**8,121.9**		**38.6**		**8,491.7**
Accumulated depletion and depreciation								
Balance at December 31, 2015		—		541.0		3.3		544.3
Depletion and depreciation		—		481.5		2.1		483.6
Balance at December 31, 2016		—		1,022.5		5.4		1,027.9
Amortization of prepaid processing expenses		—		—		0.6		0.6
Depletion and depreciation		**4.5**		**724.1**		**1.6**		**730.2**
Balance at December 31, 2017	**$**	**4.5**	**$**	**1,746.6**	**$**	**7.6**	**$**	**1,758.7**
Net book value								
Balance at December 31, 2016	$	511.6	$	5,229.8	$	8.7	$	5,750.1
Balance at December 31, 2017	**$**	**326.7**	**$**	**6,375.3**	**$**	**31.0**	**$**	**6,733.0**

(1) For the year ended December 31, 2017, non-cash capitalized costs consisted of $29.7 million of decommissioning obligation assets and $11.6 million of stock-based compensation (year ended December 31, 2016 – $68.0 million and $7.7 million).

On August 18, 2016, the Company acquired assets for consideration valued at $1.9 billion at the time of announcement (the "Acquisition"). In connection with the Acquisition, the Company acquired $2.1 billion of oil and natural gas assets, assumed US$450.0 million of senior unsecured notes (Note 12) and assumed $10.7 million of decommissioning liabilities (Note 13). Consideration for the net assets acquired included the issuance of 33.5 million common shares (Note 15), $505.1 million of cash and $6.0 million of undeveloped acreage. The Acquisition also included approximately $2.4 billion of take or pay commitments assumed by Seven Generations.

During the year ended December 31, 2017, the Company invested $21.0 million to upgrade a third-party processing facility under the terms of a long-term processing agreement assumed by Seven Generations as part of the Acquisition. The prepaid expenditures were capitalized and will be amortized to processing expenses over the 20 year term of the agreement.

As at December 31, 2017, $339.7 million in oil and natural gas assets were not subject to depletion and depreciation as they were not ready for use in the manner intended by management (December 31, 2016 – $503.7 million).

In the fourth quarter of 2017, Seven Generations sanctioned the development of the Nest 3 exploration area within the Kakwa River Project ("Nest 3"). With technical feasibility and commercial viability having been established through delineation drilling and other exploration activities, the $200.0 million carrying value of Nest 3 was transferred into the Company's developing and producing assets.

In the fourth quarter of 2017, Seven Generations identified indicators of impairment as a result of declines in the forecasted commodity prices utilized in the Company's 2017 reserve report, compared to the prior year. Seven Generations performed an impairment test on the Kakwa River Project using after-tax discounted future cash flows with a two percent inflation rate and a discount rate of 10%. As at December 31, 2017, the recoverable value of the Kakwa River Project exceeded its carrying value, and no impairment was identified. The following table summarizes the price forecast used in the Company's discounted cash flow estimates:

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Thereafter
WTI (US$/bbl)	$58.50	$58.70	$62.40	$69.00	$73.10	$74.50	$76.00	$77.50	$79.10	$80.70	+2% per year
Henry Hub (US$/MMBtu)	3.00	3.05	3.25	3.55	3.80	3.85	3.95	4.00	4.10	4.15	+2% per year
AECO Spot Price ($/MMBtu)	2.25	2.65	3.05	3.40	3.60	3.65	3.75	3.80	3.90	3.95	+2% per year
US$ to C$	0.790	0.790	0.800	0.825	0.850	0.850	0.850	0.850	0.850	0.850	0.850

9. Investment in Associate

In 2016, Seven Generations invested $25.8 million for a 34.0% equity interest in Steelhead LNG Limited Partnership ("Steelhead LNG"), a Vancouver-based energy company focused on the development of LNG projects in British Columbia. Concurrent with the investment, the Company also entered into a development arrangement with Steelhead LNG, whereby the Company agreed to contribute $3.0 million in cash upfront and committed to invest up to an additional $9.0 million to participate in the pre-development of transportation alternatives to the west coast of British Columbia. As at December 31, 2017, the Company held a 24.4% equity interest in Steelhead LNG as a result of subsequent equity issuances to other parties.

The following table summarizes the change in the carrying value of the Company's investment in Steelhead LNG:

For the year ending December 31,		**2017**		2016
Balance, beginning of year	**$**	**21.9**	$	—
Investment in Steelhead LNG equity units		**—**		25.8
Recovery from additional equity units issued to Seven Generations		**4.2**		—
Share of Steelhead LNG's net loss		**(9.3)**		(3.9)
Impairment loss		**(14.4)**		—
Balance, end of year	**$**	**2.4**	$	21.9

The following table summarizes the Company's net loss on the investment in associate:

For the year ending December 31,		**2017**		2016
Share of Steelhead LNG's net loss	**$**	**9.3**	$	3.9
Midstream expenses incurred by Seven Generations		**1.5**		4.1
Recovery from additional equity units issued to Seven Generations		**(4.2)**		—
Impairment loss		**14.4**		—
Loss on associate	**$**	**21.0**	$	8.0

In 2017, Seven Generations agreed to provide a portion of the guarantee for Steelhead LNG's $14.9 million credit facility which is currently being used to fund its operations (Seven Generation's portion of the total guarantee is $5.4 million). The credit facility matures on April 11, 2018 and may be further extended.

In 2017, Seven Generations identified indicators of impairment for its investment in Steelhead LNG primarily due to the value of consideration received by Steelhead LNG in exchange for equity units that were issued by the entity during the fourth quarter of 2017. The Company tested the asset for impairment and determined that its Steelhead LNG investment may not be fully recoverable. The Company recognized an impairment loss of $14.4 million. The recoverable value of the investment was primarily based on the price of the equity units issued.

10. Risk Management Contracts

The Company periodically enters into risk management contracts to manage its commodity price, foreign currency and interest rate exposure. The Company had the following risk management contracts in place as at December 31, 2017:

	Crude Oil						Natural Gas				Foreign Exchange	
	C$ WTI Collars		C$ WTI 3 Way Collars		US$ WTI Collars		Chicago Citygate Swaps		AECO 7A Collars/Swaps		C/US Swaps	
Period	bbl/d	C$/bbl	bbl/d	C$/bbl	bbl/d	US$/bbl	MMbtu/d	US$/ MMbtu	GJ/d	C$/GJ	US $MM	US$/C$
2018	17,250	$61.20 – $77.32	12,000	$40.83/$56.25/$75.54	2,000	$52.25 – $57.30	205,000	$2.88	60,000	$2.44 – $2.85	215.1	1.3100
2019	16,000	$58.91 – $75.94	7,500	$41.00/$56.33/$75.92	2,000	$52.25 – $57.30	120,000	$2.85	60,000	$2.44 – $2.85	124.8	1.2907
2020	7,000	$57.50 – $71.61	1,500	$40.00/$55.00/$70.98	2,000	$52.25 – $57.30	32,500	$2.74	10,000	$2.13 – $2.13	32.5	1.2683

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

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

As at December 31,	2017	2016
Natural gas	$ 70.2	$ (70.0)
Oil	(50.5)	(71.0)
Foreign exchange swap	18.6	(8.4)
Net position asset (liability)	$ 38.3	$ (149.4)

The Company's risk management contracts are subject to master netting agreements that create the legal right to settle on a net basis. The following is a summary of financial instruments that are subject to offsetting:

	2017			2016		
As at December 31,	Derivative Asset	Derivative Liability	Net	Derivative Asset	Derivative Liability	Net
Balance sheet classification						
Current asset	$ 44.1	(7.9)	$ 36.2	$ —	$ —	$ —
Long-term asset	37.5	(1.4)	36.1	—	—	—
Current liability	3.3	(20.8)	(17.5)	1.5	(73.2)	(71.7)
Long-term liability	3.4	(19.9)	(16.5)	3.6	(81.3)	(77.7)
Net position asset (liability)	$ 88.3	$ (50.0)	$ 38.3	$ 5.1	$ (154.5)	$ (149.4)

As the Company operates in Canada and the United States, fluctuations in foreign exchange rates can have a significant effect on the Company's liquids and natural gas sales. An increase in the value of the Canadian dollar, compared to the US dollar, will generally reduce the prices received by the Company for its liquids and natural gas sales. The Company manages foreign currency exchange risk relating to its oil and natural gas sales by entering into a variety of foreign exchange risk management contracts.

The following table demonstrates the impact of changes in commodity pricing and changes in the foreign exchange rate on net income before tax, based on risk management contracts in place as at December 31, 2017:

As at December 31, 2017		Gain (Loss)
10% increase in C$ WTI/bbl	$	(119.8)
10% decrease in C$ WTI/bbl		96.9
10% increase in US$ Chicago Citygate/MMbtu		(46.3)
10% decrease in US$ Chicago Citygate/MMbtu		46.3
10% increase in C$ AECO/GJ		(7.0)
10% decrease in C$ AECO/GJ		7.2
10% increase in US$ to C$		(49.1)
10% decrease in US$ to C$	$	49.1

Refer to Note 12 for information on the Company's exposure to foreign exchange rate fluctuations related to the senior notes.

11. Bank Debt

During the second quarter of 2017, Seven Generations expanded its existing undrawn senior secured credit facility from $1.1 billion to $1.4 billion (the "Credit Facility"). As part of the amendments, the Credit Facility was transitioned from a reserve-based structure to a covenant-based structure that matures on June 9, 2021.

The Credit Facility is secured by a floating charge over the Company's assets and contains certain covenants that limit the Company's ability to, among other things: incur additional indebtedness; create or permit liens to exist; and make certain dispositions and transfers of assets. The following two financial covenants are associated with the Credit Facility:

- Senior Secured Net Debt to Adjusted EBITDA Ratio – cannot exceed 2.50:1
- Adjusted EBITDA to Interest Expense Ratio – cannot be less than 2.50:1

For the purposes of the covenant calculation, Adjusted EBITDA is calculated as net income (loss) before interest, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items. Senior Secured Net Debt consists of amounts drawn under the Credit Facility (excluding the balance of the unsecured senior notes), less cash and cash equivalents.

As at December 31, 2017, the Company was in compliance with the covenants under the Credit Facility. The Senior Secured Net Debt to Adjusted EBITDA Ratio and Adjusted EBITDA to Interest Expense Ratio were (0.09):1 and 7.81:1, respectively.

As at December 31, 2017, $42.1 million in letters of credit were issued and outstanding under the Credit Facility (December 31, 2016 – nil). During the fourth quarter of 2017, the Company also entered into a unsecured demand letter of credit facility of $76.4 million. As at December 31, 2017, $60.5 million in letters of credit were issued and outstanding under the facility.

12. Senior Notes

As at December 31,		2017		2016
US$700 million 8.25% senior notes, due May 15, 2020	$	—	$	939.9
US$425 million 6.75% senior notes, due May 1, 2023		533.2		570.6
US$450 million 6.875% senior notes, due June 30, 2023		564.5		604.2
US$700 million 5.375% senior notes, due September 30, 2025	$	878.2	$	—
		1,975.9		2,114.7
Less unamortized debt issue costs		(24.3)		(25.5)
Plus unamortized premium		4.8		22.7
Balance, end of year	$	1,956.4	$	2,111.9

(1) The US dollar senior notes were translated into Canadian dollars at the period end exchange rate of US$1=C$1.25 (December 31, 2016 – US$1=C$1.34).

The senior notes are carried at amortized cost, net of premiums and transaction costs, and are accreted to their principal balance at maturity using the effective interest rate method. As at December 31, 2017, the fair value of senior notes was $2,059.2 million (December 31, 2016 – $2,254.0 million).

During the fourth quarter of 2017, Seven Generations completed refinancing transactions, repurchasing and redeeming all of the Company's outstanding US$700 million 8.25% senior unsecured notes due in 2020 (the "8.25% Notes") and completing a new debt offering of US$700 million 5.375% senior unsecured notes due in 2025 (the "5.375% Notes"). The refinancing transactions extended the Company's debt maturities and reduced the Company's combined effective interest rate on all of its senior unsecured notes to 6.3%. As part of the refinancing, the Company recognized financing expenses of C$37.1 million in respect of the tender and call premiums on the 8.25% Notes.

The following table summarizes the changes in senior notes arising from financing activities:

For the year ending December 31,		**2017**		2016
Balance, beginning of year	**$**	**2,111.9**	$	1,546.8
Redemption of US$700 million 8.25% senior notes (1)		**(875.6)**		—
Issuance of US$700 million 5.375% senior notes		**859.7**		—
Assumption of US$450 million 6.875% senior notes		**—**		580.3
Impact of foreign exchange gains on senior notes and other		**(139.6)**		(15.2)
Balance, end of year	**$**	**1,956.4**	$	2,111.9

(1) Excludes redemption premium of C$37.1 million.

Following the repayment of the 8.25% Notes, the Company recognized a realized foreign exchange gain of $65.3 million for the year ended December 31, 2017. Since the dates of issuance for the $8.25% Notes in 2013 and 2014, the Company has recognized a cumulative net realized foreign exchange loss of $136.6 million. The Company has the option to redeem the senior notes at the following specified redemption prices:

	US$700 5.375% million senior notes (1)	US$425 6.75% million senior notes (2)	US$450 6.875% million senior notes (3)
2017	105.4%	106.8%	106.9%
2018	105.4%	105.1%	105.2%
2019	105.4%	103.4%	103.4%
2020	104.0%	101.7%	101.7%
2021	102.7%	100.0%	100.0%
2022	101.3%	100.0%	100.0%
2023 and thereafter	100.0%	100.0%	100.0%

(1) The change in redemption price for the US$700 million 5.375% senior notes takes effect on September 30th of each year. Prior to September 30, 2020, the redemption option is only available if the 5.375% Notes are repaid using the proceeds of one or more equity offerings or by paying a make-whole premium represented by the present value of interest that would otherwise be payable over the remaining term of the debt in excess of the applicable redemption premium.

(2) The change in redemption price for the US$425 million 6.75% senior notes takes effect on May 1st of each year. Prior to May 1st, 2018, the redemption option is only available if the 6.75% Notes are repaid using the proceeds of one or more equity offerings or by paying a make-whole premium represented by the present value of interest that would otherwise be payable over the remaining term of the debt in excess of the applicable redemption premium.

(3) The change in redemption price for the US$450 million 6.875% senior notes takes effect on June 30th of each year. Prior to June 30th, 2018, the redemption option is only available if the 6.875% Notes are repaid using the proceeds of one or more equity offerings or by paying a make-whole premium represented by the present value of interest that would otherwise be payable over the remaining term of the debt in excess of the applicable redemption premium.

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 certain payments and distributions; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; make certain dispositions; transfer assets; and engage in amalgamations, mergers or consolidations.

The Company is exposed to foreign exchange rate fluctuations on the principal and interest related to senior notes. As at December 31, 2017, a 10% increase to the value of the Canadian dollar relative to the US dollar would result in a gain of approximately $197.6 million (10% decline – loss of $197.6 million) to the amortized cost of the notes.

13. Other Long-term Liabilities

As at December 31,		2017		2016
Decommissioning liabilities	$	**194.2**	$	160.7
Onerous lease		**3.2**		3.6
Deferred credits		**0.6**		0.7
Other long-term liabilities	$	**198.0**	$	165.0

DECOMMISSIONING LIABILITIES

For the year ended December 31,		2017		2016
Balance, beginning of year	$	**160.7**	$	79.1
Liabilities incurred		**23.9**		21.3
Liabilities acquired (Note 8)		**—**		10.7
Change in estimates		**5.4**		27.9
Change in discount rates (1)		**0.4**		18.9
Accretion (Note 21)		**3.8**		2.8
Balance, end of year	$	**194.2**	$	160.7

(1) Change in discount rates for the year ended December 31, 2016 includes a $20.5 million increase to acquired liabilities for the decrease from the 6.3% credit adjusted risk free rate at acquisition to a risk free rate of 2.3% at period end.

As at December 31, 2017, the total undiscounted, uninflated estimated cash flows required to settle the Company's decommissioning liabilities was approximately $205.8 million (December 31, 2016 – $164.8 million). These liabilities are anticipated to be incurred over the next 35 years with the majority of costs incurred between 2041 and 2052. As at December 31, 2017, the Company utilized a risk free rate of 2.2% (December 31, 2016 – 2.3%) and an inflation rate of 2.0% (December 31, 2016 – 2.0%).

14. Income Taxes

The following table reconciles the Company's expected income tax expense (recovery) calculated at the Canadian statutory rate of 27% (2016 – 27%) for the year ended December 31, 2017 and 2016:

For the year ended December 31,		2017		2016
Net income (loss) before income taxes	$	**735.0**	$	(33.6)
Statutory income tax rate		**27%**		27%
Expected income tax expense (recovery)		**198.5**		(9.1)
Adjustments related to the following:				
Non-taxable portion of foreign exchange gains		**(18.9)**		(2.2)
Change in unrecognized deferred tax asset		**(13.3)**		(1.3)
Stock-based compensation		**8.2**		4.9
Change in tax rates and other		**(2.0)**		0.3
Income tax expense (recovery)	$	**172.5**	$	(7.4)

For the year ended December 31, 2017, $2.9 million was recorded in current income tax expense relating to foreign sourced income from the Company's wholly owned US subsidiary (December 31, 2016 – $1.4 million). As at December 31, 2017, the Company had $5.5 billion tax pools available for future deduction, including $0.9 billion available for immediate deduction against taxable income (December 31, 2016 – $5.0 billion and $0.9 billion, respectively). The non-capital losses begin to expire after 2033.

Changes in the deferred tax balances are as follows:

As at December 31,		2015		Movement		2016		Movement		**2017**
Property, plant and equipment	$	193.0	$	142.3	$	335.3	$	129.8	**$**	**465.1**
Risk management contracts		33.3		(73.6)		(40.3)		50.6		**10.3**
Non-capital losses		(63.1)		(61.6)		(124.7)		2.8		**(121.9)**
Decommissioning liabilities		(21.4)		(22.0)		(43.4)		(9.0)		**(52.4)**
Financing costs		(10.9)		(4.9)		(15.8)		(5.1)		**(20.9)**
Unrealized foreign exchange losses		(40.0)		2.1		(37.9)		17.9		**(20.0)**
Other		(1.3)		(1.6)		(2.9)		(4.1)		**(7.0)**
		89.6		(19.3)		70.3		182.9		**253.2**
Unrecognized deferred tax asset		39.8		(1.3)		38.5		(13.3)		**25.2**
	$	129.4	$	(20.6)	$	108.8	$	169.6	**$**	**278.4**

As at December 31, 2017, the unrecognized deferred tax asset consisted of foreign exchange capital losses of $19.0 million and $6.2 million related to investments in associates.

The changes in the deferred tax liability were allocated to:

Year ended December 31,		**2017**	2016
Income statement	**$**	**169.6**	(8.8)
Share capital		**—**	(11.8)
	$	**169.6**	(20.6)

15. Share Capital

The Company's authorized share capital consists of an unlimited number of common shares, class B common non-voting shares, preferred A, B, C and D shares and special voting shares. There are no class B common non-voting shares, preferred shares or special voting shares issued and outstanding.

	2017			2016		
Year ended December 31,	**Number (millions)**		**Amount ($)**	Number (millions)		Amount ($)
Balance, beginning of year	**350.3**	**$**	**3,830.5**	254.4	$	1,775.7
Issued for cash	**—**		**—**	52.1		1,047.7
Issued for Acquisition (Note 8)	**—**		**—**	33.5		965.1
Share issue costs, net of deferred income taxes	**—**		**—**	—		(31.8)
Exercise of stock options and performance warrants	**4.4**		**25.0**	10.3		55.7
Transfer from contributed surplus on exercise of equity compensation	**—**		**8.9**	—		18.1
Balance, end of year	**354.7**	**$**	**3,864.4**	350.3	$	3,830.5

On February 24, 2016, the Company completed a private placement of 21.4 million common shares at a price of $14.00 per share for gross proceeds of $300.0 million. Net proceeds after commissions and expenses were approximately $287.0 million.

On July 26, 2016, the Company closed a bought-deal financing arrangement issuing 30.7 million subscription receipts at $24.35 per subscription receipt for gross proceeds of $747.7 million. Each holder of the subscription receipts received one common share for each subscription receipt held upon the closing of the Acquisition (Note 8). Net proceeds after commissions and expenses were approximately $717.7 million.

On August 18, 2016, the Company closed the Acquisition and as part of the consideration, issued 33.5 million common shares. The closing price of the common shares on August 18, 2016 was $28.81 per share.

16. Capital Management

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 growth and development. The Company strives to grow and maximize long-term shareholder value by ensuring it has the financial capacity to fund projects that are expected to add value to shareholders. Near-term major acquisitions and capital development are anticipated to be funded by funds from operations, cash and cash equivalents and draws on its Credit Facility (Note 11). The Company endeavors 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.

As at December 31,		**2017**		2016
Senior notes	**$**	**1,956.4**	$	2,111.9
Shareholders' equity		**4,450.4**		3,822.8
Capital managed	**$**	**6,406.8**	$	5,934.7

The Company manages its liquidity risk through its capital structure, forecasting cash flows and available credit. As at December 31, 2017, the Company had $165.3 of cash and cash equivalents, and its undrawn Credit Facility of $1.4 billion (Note 11). Management believes it has sufficient funding to meet the Company's foreseeable liquidity requirements.

17. Per Share Amounts

For the year ended December 31,	**2017**	2016
Weighted average number of common shares – basic	**353.3**	299.8
Dilutive effect of outstanding equity compensation units (1)	**11.1**	—
Weighted average number of common shares – diluted	**364.4**	299.8

(1) For the year ended December 31, 2016, 18.6 million units have been excluded from the diluted earnings per share calculation since these are anti-dilutive as the Company was in a net loss position.

18. Liquids and Natural Gas Sales

For the year ended December 31,		**2017**		2016
Condensate	**$**	**1,248.9**	$	726.8
Natural gas		**617.4**		376.2
NGLs		**341.0**		143.9
Liquids and natural gas sales	**$**	**2,207.3**	$	1,246.9
Sales by country				
Canada	**$**	**1,588.3**	$	835.2
United States	**$**	**619.0**	$	411.7

The Company enters into physical delivery contracts on the Alliance Pipeline to Chicago, Illinois, the NGPL pipeline to the Gulf of Mexico, the TCPL Canadian Mainline to Dawn, Ontario and the NGTL pipeline in Alberta on a month-to-month and term contract basis. Pricing of the physical delivery contracts is primarily based on published North American natural gas indices and fixed prices. The following table summarizes the average daily volumes the Company has committed to deliver on a term contract basis as at December 31, 2017:

Daily average volumes committed for the year ended December 31,	Chicago Citygate MMBtu/d	Gulf of Mexico MMBtu/d	Dawn MMBtu/d	AECO GJ/d
2018	199,537	36,000	40,000	38,470
2019	—	—	—	19,808

From time to time, the Company purchases oil and natural gas for resale on a monthly basis in order to optimize the Company's transportation and take or pay commitment capacities. For the year ended December 31, 2017, $101.2 million of product purchased was netted against liquids and natural gas sales (December 31, 2016 – nil). Any gain on liquids and natural gas sales in excess of purchases are presented as marketing gains under transportation, processing, and other expenses (Note 20).

19. Operating Expenses

For the year ended December 31,	2017	2016
Trucking and disposal	$ 159.9	$ 62.0
Equipment rental and maintenance	98.5	56.6
Chemicals and fuel	38.8	25.4
Staff and contractor costs	39.4	25.7
Other	21.2	12.2
Operating expenses	$ 357.8	$ 181.9

20. Transportation, Processing and Other Expenses

For the year ended December 31,	2017	2016
Pipeline tariffs	$ 263.9	$ 164.2
Processing	80.7	21.2
Trucking and other	49.8	66.9
Third party marketing gains	(23.0)	(13.7)
Transportation, processing and other	$ 371.4	$ 238.6

21. Finance Expense

For the year ended December 31,	2017	2016
Interest on senior notes	$ 149.3	$ 131.3
Premium on redemption of senior notes (Note 12)	37.2	—
Revolving credit facility fees and bank fees	5.4	7.5
Accretion (Note 13)	3.8	2.8
Amortization of premiums and debt issuance costs	(0.6)	0.8
Finance costs	195.1	142.4
Capitalized borrowing costs	(1.9)	(3.7)
Finance expense	$ 193.2	$ 138.7

22. Stock-based Compensation

The Company's current stock-based compensation plans consist of stock options, performance warrants, performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs").

The following table summarizes the Company's outstanding equity compensation units as at December 31, 2017 and 2016:

	December 31, 2017			December 31, 2016		
	Units (millions)	**Weighted Average Exercise Price ($)**	**Weighted Average Remaining Life (years)**	Units (millions)	Weighted Average Exercise Price ($)	Weighted Average Remaining Life (years)
Stock options (a)	**12.4**	**$ 16.63**	**5.4**	11.2	$ 13.95	5.4
Performance warrants (b)	**8.3**	**6.91**	**1.3**	11.4	6.62	1.9
PSUs and RSUs (c)	**1.1**	**—**	**8.7**	0.6	—	8.9
DSUs [1] (d)	**0.2**	**—**	**—**	0.1	—	—
Units outstanding	**22.0**	**$ 12.00**	**4.0**	23.3	$ 9.96	3.6

(1) DSUs fully vest on grant date and expire within one year of the Director's departure from Seven Generations' Board.

(A) STOCK OPTIONS

The Company's stock option plan allows for the granting of options to officers, employees and service providers of the Company. Options granted are generally fully exercisable for common shares after three years and expire ten years after the grant date.

For the year ended December 31,	**2017**	2016
Balance, beginning of year	**11.2**	12.0
Granted	**2.6**	2.6
Exercised	**(1.2)**	(3.2)
Forfeited	**(0.2)**	(0.2)
Balance, end of year	**12.4**	11.2

The fair value of stock options granted during the year was estimated using the Black-Scholes pricing model. The following weighted-average assumptions were used during the year ended December 31, 2017 and 2016:

For the year ended December 31,	**2017**	2016
Fair value of options granted ($)	**7.54**	12.92
Risk-free interest rate (%)	**1.1**	0.8
Expected life (years)	**5.0**	6.0
Expected forfeiture rate (%)	**5.0**	4.4
Expected volatility (%)	**33.0**	45.2
Expected dividend yield (%)	**—**	—

A summary of stock options outstanding and exercisable into common shares at December 31, 2017 is as follows:

	Outstanding		Exercisable	
Exercise Price ($)	**Number of Options (Millions)**	**Weighted Average Remaining Life (Years)**	Number of Options (Millions)	Weighted Average Remaining Life (Years)
2.50 – 7.49	**3.7**	**1.4**	3.6	1.4
7.50 – 17.49	**1.8**	**6.9**	1.1	6.6
17.50 – 19.99	**2.2**	**3.9**	2.1	3.5
20.00 – 24.99	**2.3**	**9.3**	—	7.3
25.00 – 30.90	**2.4**	**8.4**	0.8	8.4
16.63	**12.4**	**5.4**	7.6	3.4

(B) PERFORMANCE WARRANTS

Prior to the Company's Initial Public Offering ("IPO") that was completed on November 5, 2014, Seven Generations issued performance warrants to its directors, officers, and employees. These performance warrants were granted pursuant to the Amended and Restated Shareholder Agreement effective while Seven Generations was a private company. Subsequent to the IPO, no additional performance warrants may be granted.

For the year ended December 31,	**2017**	2016
Balance, beginning of year	**11.4**	18.5
Exercised	**(3.1)**	(7.1)
Balance, end of year	**8.3**	11.4

A summary of performance warrants outstanding and exercisable into common shares at December 31, 2017 is as follows:

	Outstanding		Exercisable	
Exercise Price ($)	**Number of Options (Millions)**	**Weighted Average Remaining Life (Years)**	Number of Options (Millions)	Weighted Average Remaining Life (Years)
3.75 – 5.00	**1.6**	**0.5**	1.6	0.5
5.00 – 5.49	**0.9**	**0.5**	0.9	0.5
5.50 – 5.74	**1.7**	**1.9**	1.5	1.9
5.75 – 6.49	**1.6**	**1.0**	1.5	1.0
6.50 – 17.50	**2.5**	**1.8**	2.0	1.5
6.91	**8.3**	**1.3**	7.5	1.1

(C) PERFORMANCE SHARE UNITS AND RESTRICTED SHARE UNITS

The Company's Performance and Restricted Share Unit Plan ("PRSU Plan") allows for the granting of PSUs and RSUs to officers and employees of the Company. PSUs and RSUs represent the right for the holder to receive common voting shares or, at the election of holder and the Company, a cash payment equal to the fair market value of the common shares calculated at the date of such payment. PSUs and RSUs granted to date under the PRSU Plan generally vest annually over a three year period.

For the year ended December 31,	**2017**	2016
Balance, beginning of year	**0.6**	0.4
Granted	**0.6**	0.2
Exercised	**(0.1)**	—
Balance, end of year	**1.1**	0.6

The weighted average fair value of PRSUs granted during the year ended December 31, 2017 was $24.32. The vesting of PSUs is conditional on the satisfaction of certain performance criteria as determined by the Company's Board of Directors. If the Company satisfies the performance criteria, PSUs become eligible to vest and a pre-determined multiplier is applied to eligible PSUs. In calculating stock-based compensation for the PSUs, the Company used an adjustment factor of 1.0, which assumes that the Company will be within the 50th percentile of its relative peer group, based on total shareholder return at the respective vesting dates. During the year ended December 31, 2017, PSU multipliers achieved on vested units ranged from 1.69 – 2.00 (December 31, 2016 – 2.0).

(D) DEFERRED SHARE UNITS

The Deferred Share Unit Plan ("DSU Plan") allows for granting of DSUs to directors of the Company. DSUs represent the right for the holder to receive common shares, or, at the election of the holder and the Company, a cash payment equal to fair market value of the common share calculated at the date of such payment. DSUs granted under the DSU Plan vest immediately upon grant. As at December 31, 2017, there were 0.2 million DSUs outstanding (December 31, 2016 – 0.1 million).

23. Commitments and Contingencies

The following table lists the Company's estimated material contractual commitments as at December 31, 2017:

	2018	2019	2020	2021	2022	Thereafter	**Total**
Senior notes [1]	$ —	$ —	$ —	$ —	$ —	$ 1,975.9	**$ 1,975.9**
Interest on senior notes	122.0	122.0	122.0	122.0	122.0	78.6	**688.6**
Firm transportation and processing agreements	434.2	452.3	490.4	517.0	481.6	2,553.5	**4,929.0**
Office leases	4.2	3.4	3.2	3.2	3.3	2.6	**19.9**
Estimated contractual obligations	$560.4	$577.7	$615.6	$642.2	$606.9	$ 4,610.6	**$ 7,613.4**

(1) Balance represents the US$1.575 billion principal converted to Canadian dollars at the exchange rate of US$1=C$1.25 at period end.

The Company is involved in legal claims arising in the normal course of business. The final outcome of such claims cannot be predicted with certainty and management believes that it has appropriately assessed any impact to the consolidated financial statements.

24. Related Party Transactions

Seven Generations' related parties primarily consist of the Company's directors and officers. Amounts paid to directors and officers for the year ended December 31, 2017 were as follows:

For the year ended December 31,	**2017**	2016
Stock-based compensation	**$ 18.7**	$ 10.7
Salaries, benefits and other short-term compensation	**9.6**	7.9
Retention expense	**—**	1.1
	$ 28.3	$ 19.7

Steelhead LNG is also considered a related party due to common directorships and certain significant shareholders (Note 9), including Azimuth Capital Management who has a majority ownership in Steelhead LNG and has professional ties with four of Seven Generation's directors. All related party transactions have been measured at the exchange value.

25. Supplemental Cash Flow Information

CHANGE IN NON-CASH WORKING CAPITAL

For the year ended December 31,		2017		2016
Accounts receivable	$	(120.9)	$	(105.5)
Deposits and prepaid expenses		(0.8)		(5.3)
Accounts payable and accrued liabilities		132.8		53.7
		11.1		(57.1)
Realized foreign exchange loss on non-cash working capital		(2.7)		–
Change in current portion of prepaid processing fees		0.5		–
		8.9		(57.1)
Relating to:				
Operating activities	$	(53.0)	$	(88.0)
Financing activities	$	–	$	–
Investing activities	$	61.9	$	30.9
Other cash flow information				
Cash interest paid	$	189.2	$	139.9
Cash taxes paid	$	2.8	$	1.5

Corporate Information

Management

Marty Proctor
President & CEO

Christopher Law
CFO

Glen Nevokshonoff
COO

Kyle Brunner
Vice President & General Counsel

Chris Feltin
Vice President, Corporate Planning

Randall Hnatuik
Vice President, Business Development

Barry Hucik
Vice President, Drilling

Kevin Johnston
Vice President, Accounting & Controller

Jordan Johnsen
Vice President, Operations & Engineering

Brian Newmarch
Vice President, Capital Markets

Charlotte Raggett
Vice President, Midstream Business Development

Directors

Kent Jespersen
Chairman

Marty Proctor
President & CEO

Kevin Brown

Pat Carlson

Avik Dey

Harvey Doerr

Paul Hand

Dale Hohm

Bill McAdam

Kaush Rakhit

M. Jacqueline Sheppard

Jeff van Steenbergen

Corporate Office

4400, 525 – 8 Avenue S.W.
Calgary, Alberta, T2P 1G1
Telephone: (403) 718-0700
Fax: (403) 532-8020

Trustee and Transfer Agent

Computershare Trust Company of Canada
600, 530 – 8 Avenue S.W.
Calgary, Alberta, T2P 3S8

Banks

Royal Bank of Canada

Bank of Montreal

Canadian Imperial Bank of Commerce

Credit Suisse AG, Toronto Branch

Export Development Canada

JP Morgan Chase Bank, N.A., Toronto Branch

National Bank of Canada

The Bank of Nova Scotia

The Toronto-Dominion Bank

Alberta Treasury Branches

Barclays Bank PLC

Fédération des Caisses Desjardins Du Québec

Wells Fargo Bank, N.A., Canadian Branch

Auditors

PricewaterhouseCoopers LLP

Legal Counsel

Stikeman Elliott LLP

Independent Evaluators

McDaniel & Associates Consultants Ltd.

Stock Symbol
VII
Toronto Stock Exchange

4400, 525 – 8 Avenue S.W.
Eighth Avenue Place East
Calgary, Alberta, T2P 1G1

(403) 718-0700
info@7genergy.com

www.7genergy.com

Seven Generations trades
on the Toronto Stock Exchange
under the symbol **VII**.

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