STORM RESOURCES

Q1 - 2017 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
FINANCIAL		
Revenue from product sales[(1)]	37,045	16,121
Funds flow	17,958	7,855
Per share - basic and diluted ($)	0.15	0.07
Net income (loss)	20,631	(4,984)
Per share - basic and diluted ($)	0.17	(0.04)
Operations capital expenditures[(2)]	27,357	23,946
Debt including working capital deficiency[(2)(3)]	97,864	77,162
Common shares (000s)		
Weighted average - basic	121,442	119,591
Weighted average - diluted	121,720	119,591
Outstanding end of period – basic	121,557	119,742
OPERATIONS		
(Cdn$ per Boe)		
Revenue from product sales	24.29	13.20
Royalties	(1.88)	(0.76)
Production	(5.84)	(6.71)
Transportation	(0.69)	(0.53)
Field operating netback[(2)]	15.88	5.20
Realized (losses) gains on hedging	(2.31)	3.03
General and administrative	(1.10)	(1.25)
Interest and finance costs	(0.71)	(0.56)
Funds flow per Boe	11.76	6.42
Barrels of oil equivalent per day (6:1)	16,947	13,418
Gas production		
Thousand cubic feet per day	84,093	66,012
Price (Cdn$ per Mcf)	3.23	1.62
Condensate production		
Barrels per day	1,758	1,452
Price (Cdn$ per barrel)	64.40	41.54
NGL production		
Barrels per day	1,174	964
Price (Cdn$ per barrel)	23.09	10.44
Wells drilled (100% working interest)	6.0	7.0
Wells completed (100% working interest)	4.0	2.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements, including field operating netback, operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 26 of the attached Management's Discussion and Analysis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2017 FIRST QUARTER HIGHLIGHTS

- Production was a record 16,947 Boe per day (17% condensate and NGL), a per-share increase of 24% from the first quarter of last year and a per-share increase of 27% from the previous quarter. The increase was the result of the start-up of a third field compression facility at Umbach on January 12, 2017 plus five new horizontal wells (5.0 net) were turned on during the quarter.

- Condensate and NGL production increased 21% from the first quarter of last year to average 2,932 barrels per day. Revenue from liquids was 34% of total revenue.

- Montney horizontal well performance at Umbach continues to improve as length and the number of fracs are increased. The five wells completed in 2016 with enough production history averaged 4.8 Mmcf per day gross raw gas over the first 180 calendar days, a 14% improvement from the average 2015 wells. The four wells completed to date in 2017 are approximately 25% longer and three of them have been producing for 30 to 60 days with encouraging early data.

- Controllable cash costs (production, general and administrative, interest and finance) were $7.65 per Boe, a decrease of 10% year over year. Production costs declined by 13% from the same period in 2016 and 16% from the fourth quarter of 2016 as a result of the new processing arrangement at Umbach which started on January 1, 2017.

- Funds flow was $18.0 million ($11.76 per Boe), an increase of 129% from a year ago. The increase was driven by an 84% increase in revenue per Boe and a 26% increase in production volumes which was partially offset by a realized hedging loss of $3.5 million or $2.31 per Boe.

- Net income was $20.6 million or $0.17 per share which includes an unrealized mark to market hedging gain of $16.1 million. Notably, excluding the effect of the unrealized hedging gain, net income was $4.5 million, or $0.04 per share.

- Capital investment was $27.4 million including $19.0 million to drill six horizontal wells (6.0 net) and complete four horizontal wells (4.0 net) plus $1.5 million to complete the third field compression facility at Umbach.

- At the end of the quarter, there was an inventory of ten horizontal wells (10.0 net) that had not started producing (includes two completed wells).

- Debt including working capital deficiency was $97.9 million which is 1.4 times annualized first quarter funds flow. Subsequent to quarter end, the bank credit facility was increased to $165.0 million from $130.0 million.

- Commodity price hedges continue to be layered in with approximately 43% of forecast 2017 production currently hedged.

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 109,000 net acres (155 net sections). To date, Storm has drilled 59 horizontal wells (55.4 net).

Production in the first quarter of 2017 was 16,582 Boe per day and liquids recovery was 36 barrels per Mmcf sales with 60% being higher priced field condensate plus pentanes recovered at the gas plant. Compared to the previous quarter, production increased by 28% while liquids recovery was the same.

During the first quarter, six horizontal wells (6.0 net) were drilled, four horizontal wells (4.0 net) were completed and five horizontal wells (5.0 net) started production. At the end of the quarter, there was an inventory of ten horizontal wells (10.0 net) that had not started producing which included two completed wells.

Activity in the second quarter of 2017 will include completing four to six horizontal wells (4.0 to 6.0 net).

Field compression totals 115 Mmcf per day raw gas after start-up of a third facility on January 12, 2017. Throughput in the first quarter averaged 88 Mmcf per day raw gas. The third facility had a final cost of $24.6 million for initial capacity of 35 Mmcf per day and will be expanded to 70 Mmcf per day by adding a second compressor for an additional $7.0 million. Preliminary timing for the expansion is the first half of 2018 and, once completed, total capacity will be 150 Mmcf per day which supports growth in corporate production to approximately 27,000 Boe per day.

Raw gas from Storm's field compression facilities is sent to the McMahon and Stoddart Gas Plants where firm processing commitments average 75 Mmcf per day raw gas in 2017. On January 1, 2017, a new processing arrangement started at the McMahon Gas Plant which has a total commitment of 65 Mmcf per day of raw gas for 5 to 15 years and has reduced corporate production costs in the first quarter by 16% from the fourth quarter of 2016. The arrangement supports future growth with an option to increase contracted capacity and allows continued diversification of natural gas sales with access to three sales pipelines (Alliance Pipeline to Chicago, TCPL system to AECO, T-north to BC Station 2).

A summary of horizontal well performance and costs is provided below. Three of the wells completed in 2017 have started producing and have 30 to 60 days of history. The majority of wells are rate restricted when coming on production to control fluid rates and adding frac stages has increased 'flush' production, therefore, additional production data is required to get an indication as to longer term performance. Future horizontal wells are expected to have completed lengths of 1,700 to 2,100 metres with the newest ball drop completion systems allowing for up to 44 fracs within 4.5 inch casing.

Year of Completion	**Frac Stages**	**Completed Length**	**Actual Drill & Complete Cost**	**IP90 Cal Day Mmcf/d Raw**	**IP180 Cal Day Mmcf/d Raw**	**IP365 Cal Day Mmcf/d Raw**
2013 6 hz's	17	1,190 m	$4.6 million $270 K/stage	3.5 Mmcf/d 6 hz's	2.9 Mmcf/d 6 hz's	2.2 Mmcf/d 6 hz's
2014 12 hz's*	19	1,170 m	$4.6 million $240 K/stage	4.9 Mmcf/d 12 hz's	4.4 Mmcf/d 12 hz's	3.5 Mmcf/d 12 hz's
2015 11 hz's	22	1,360 m	$4.4 million $200 K/stage	4.7 Mmcf/d 11 hz's	4.2 Mmcf/d 11 hz's	3.3 Mmcf/d 10 hz's
2016 10 hz's	25	1,300 m	$3.8 million $152 K/stage	5.1 Mmcf/d 10 hz's	4.8 Mmcf/d 5 hz's	
2017 4 hz's	35	1,670 m	$4.3 million $123 K/stage			

* 2014 wells exclude a middle Montney well (this table provides analysis of upper Montney wells only).

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 119 sections in the Horn River Basin (78,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Storm's one horizontal well averaged 302 Boe per day in the first quarter (previous quarter averaged 310 Boe per day). Cumulative production to date from this well is 5.5 Bcf raw.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer term growth by providing some certainty regarding future revenue and funds flow. The objective is to hedge 50% of most recent quarterly or monthly production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. The WTI price is also hedged given that approximately 80% of Storm's liquids production is priced in reference to WTI (condensate, plant pentane and butane). The hedge position is updated periodically in the presentation posted on Storm's website. Approximately 43% of forecast 2017 production is currently hedged.

Q2 – Q4 2017 Hedges		
Crude Oil	1,050 Bopd	WTI Cdn$64.75/Bbl floor, Cdn$69.60/Bbl ceiling
Natural Gas	36,400 GJ/d (29,200 Mcf/d)	AECO Cdn$2.68/GJ ($3.34/Mcf)
	11,500 Mmbtu/d (9,700 Mcf/d)	Chicago Cdn$4.17/Mmbtu ($4.94/Mcf)(1)
2018 Hedges		
Crude Oil	410 Bopd	WTI Cdn$65.99/Bbl floor, Cdn$70.54/Bbl ceiling
Natural Gas	750 GJ/d (600 Mcf/d)	AECO Cdn$2.80/GJ ($3.50/Mcf)
	18,400 Mmbtu/d (15,500 Mcf/d)	Chicago Cdn$4.00/Mmbtu ($4.75/Mcf)(1)

(1) Hedge price in Chicago doesn't include the Alliance Pipeline tariff to Chicago which was Cdn$1.66 per Mcf in the first quarter including the cost of fuel.

The Company also has natural gas price differential hedges in place (Chicago – AECO and AECO – BC Station 2) with details provided in the notes to the interim consolidated financial statements.

The strategy with respect to natural gas transportation commitments is to mitigate risk by diversifying sales and selling at multiple points. In the first quarter of 2017, 62% of natural gas sales were at Chicago, 32% at BC Station 2 and 6% at Alliance Transfer Point ("ATP"). Approximately 82% of forecast natural gas production in 2017 is covered by firm transportation commitments with the remainder directed to Chicago and/or BC Station 2 using interruptible pipeline capacity (sales point depends on price). Note that the cost of transportation to Chicago and ATP on the Alliance Pipeline is presented as a deduction from revenue with $7.3 million deducted from revenue in the first quarter of 2017. Further information on pipeline tariffs and price deductions is provided in the presentation on Storm's website.

2017 Firm Transportation	**2018 Firm Transportation**
Alliance Pipeline(1) 51 Mmcf/d Chicago price 5 Mmcf/d ATP price	Alliance Pipeline(1) 55 Mmcf/d Chicago price 5 Mmcf/d ATP price
T-north 16 Mmcf/d BC Station 2 price	T-north 29 Mmcf/d BC Station 2 price
	T-north & TCPL 13 Mmcf/d AECO price
2017 Total 72 Mmcf per day	**2018 Total 102 Mmcf per day**

(1) Interruptible capacity on the Alliance Pipeline adds up to 25% of contracted capacity.

ORGANIZATIONAL UPDATE

On May 16, 2017, Mr. Michael Hearn will assume the role of Chief Financial Officer and will replace Mr. Donald McLean who has been associated with Storm and its predecessor companies for 17 years. Mr. Hearn is a Chartered Accountant with 14 years of experience and joined Storm on November 1, 2016 after six years with an independent energy investment bank with his last position being equity research analyst. Prior to that, Mr. Hearn was employed at a junior international producer and also spent six years at a multi-national accounting firm.

On May 16, 2017, Ms. Emily Wignes will assume the role of Vice President, Finance and will replace Mr. John Devlin who has been associated with Storm and its predecessor companies for 13 years. Ms. Wignes is a Chartered Accountant with 15 years of experience and joined Storm on December 1, 2016 after two years at an intermediate producer where her most recent position was Manager, Financial Reporting. Prior to that, Ms. Wignes was employed at other intermediate and large producers and prior thereto at a multi-national accounting firm.

Both Mr. Donald McLean and Mr. John Devlin will continue to provide advisory services on an as needed basis in the near term. Their contributions to Storm and its predecessor companies have been significant and much appreciated.

OUTLOOK

For the second quarter of 2017, production is anticipated to be 14,000 to 15,000 Boe per day which includes the effect of a maintenance turnaround at the McMahon Gas Plant which will result in approximately 75% of Storm's production being shut in for 21 days. Note that production in April averaged approximately 18,400 Boe per day based on field estimates. Capital investment in the second quarter is expected to be approximately $13 to $18 million which includes completing four to six horizontal wells at Umbach.

Guidance for 2017 includes an increase to forecast production as a result of well performance exceeding expectations and a reduction to forecast royalty rates. As well, forecast commodity prices are updated to reflect actual first quarter pricing.

2017 Guidance

	Updated November 15, 2016	Updated March 2, 2017	Updated May 15, 2017
$Cdn/$US exchange rate	0.77	0.77	0.75
Chicago spot natural gas (US$/Mmbtu)	$3.00	$3.00	$3.00
AECO spot natural gas (Cdn$/GJ)	$2.65	$2.50	$2.50
BC Stn 2 spot natural gas (Cdn$/GJ)	$2.20	$2.00	$2.10
Edmonton light oil (Cdn$/bbl)	$55.00	$59.00	$62.00
Estimated average operating costs ($/Boe)	$5.50 - $5.75	$5.50 - $6.00	$5.50 - $6.00
Estimated average royalty rate (% production revenue before hedging)	9% - 11%	9% - 11%	7% - 10%
Estimated operations capital ($ million) (excluding acquisitions & dispositions)	$75.0 - $80.0	$75.0 - $80.0	$75.0 - $80.0
Estimated cash G&A - $ million	$5.3	$5.3	$5.3
- $/Boe	$0.85	$0.85	$0.85
Forecast fourth quarter production (Boe/d)	18,000 - 20,000	18,000 - 20,000	19,000 - 21,000
% condensate and NGL	17%	17%	17%

Forecast annual production (Boe/d)	16,500 - 18,000	16,500 - 18,000	17,000 - 18,000
% condensate and NGL	17%	17%	17%
Umbach horizontal wells drilled	12 gross (12.0 net)	12 gross (12.0 net)	12 gross (12.0 net)
Umbach horizontal wells completed	14 gross (14.0 net)	14 gross (14.0 net)	14 gross (14.0 net)
Umbach horizontal wells connected	15 gross (15.0 net)	15 gross (15.0 net)	15 gross (15.0 net)

2017 Guidance History

	Chicago (US$/mmbtu)	BC Station 2 (Cdn$/GJ)	AECO (Cdn$/GJ)	Estimated Operations Capital ($ million)	Forecast Fourth Quarter Production (Boe/d)	Forecast Annual Production (Boe/d)
September 7, 2016	$3.00	$2.25	$2.65	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
November 15, 2016	$3.00	$2.20	$2.65	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
March 2, 2017	$3.00	$2.00	$2.50	$75.0 - $80.0	18,000 - 20,000	16,500 - 18,000
May 15, 2017	$3.00	$2.10	$2.50	$75.0 - $80.0	19,000 - 21,000	17,000 - 18,000

There is flexibility to adjust 2017 capital investment depending on commodity prices and funds flow which may affect forecast production. The current hedge position will provide some cushion in the event of a material decline in commodity prices. Note that some cost inflation is expected based on 2017 first quarter results and capital investment assumes the cost to drill and complete a horizontal well at Umbach is $4.3 million, an increase of 13% from the 2016 actual cost.

The outlook for natural gas prices remains positive as a result of a growing supply/demand deficit in the United States. Data from the Energy Information Administration (“EIA”) shows 2016 demand (consumption) exceeded supply (dry gas production plus net imports) by 0.9 Bcf per day. So far in 2017, January and February supply is 1.1 Bcf per day lower than the 2016 average which further widens the deficit. Longer term, demand continues to increase as a result of five LNG export facilities currently operating or under construction on the US Gulf Coast. In addition, US pipeline capacity to Mexico is expected to increase by more than 6 Bcf per day by the end of 2018 from six new pipelines.

Most of Storm’s firm transportation commitments have been added over the last two years with the intent of reducing risk by diversifying natural gas sales (not betting for or against pricing in any single market). A good example supporting the diversification of sales is the continued narrowing of the AECO – BC Station 2 price differential which is contrary to the consensus view that the differential would widen with continued production growth from northeast British Columbia (“NE BC”). Since late 2015, the differential has narrowed to average -$0.19 per GJ in the first quarter of 2017 versus -$0.41 per GJ in 2016 and -$0.85 per GJ in 2015. Although production growth has continued, the differential has not been impacted as most of the growth has been directed onto the TCPL system to AECO (the differential can be temporarily affected by outages and/or constraints on the TCPL system or Alliance Pipeline where more natural gas is redirected to BC Station 2). Also helping was the Alliance Pipeline re-contracting in late 2015 where most of the capacity was taken up by producers instead of marketers. TCPL is planning to further increase capacity out of NE BC with the North Montney extension which adds 1.5 Bcf per day of takeaway in early 2019 if a variance application is approved by the National Energy Board (“NEB”). It is unlikely that production can grow this much over the next two years, so some of the incremental volume for this expansion is likely to be sourced from natural gas redirected away from BC Station 2 which further supports a narrower differential. In the first quarter of 2017, approximately 32% of Storm’s natural gas sales benefitted from the narrowing differential.

There continues to be an effort directed toward reducing Storm’s cost structure to improve competitiveness in the continuing lower price environment. Production costs per Boe have decreased by 16% from the fourth quarter of 2016 with the new processing arrangement at Umbach. Further reductions in per-Boe costs are expected with continued production growth at Umbach. Reserve addition costs are being reduced with longer horizontal wells that access more gas in place plus adding fracs on tighter spacing is increasing recovery. Recent results from longer 2017 wells are encouraging and further improvement is expected as longer wells are drilled and brought on production.

Current commodity prices are supportive of the near-term plan to grow average 2017 production by more than 30% from 2016 levels by investing $75 to $80 million which will result in year-end net debt of approximately $95 to $100 million, a year-over-year increase of 5% to 10%. The preliminary plan for 2018 is for a further 25% to 35% increase in production volumes. Growth in 2017 and 2018 is further supported by firm transportation commitments, hedging and the infrastructure at Umbach which supports growth to 27,000 Boe per day (after adding a second compressor at the third field compression facility).

With a large resource in the Montney at Umbach offering multiple years of drilling inventory, the objective remains to grow net asset value for shareholders by converting the resource into production and funds flow growth on a per-share basis.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

May 15, 2017

Boe Presentation – For the purpose of calculating unit revenues and costs, natural gas is converted to a barrel of oil equivalent ("Boe") using six thousand cubic feet ("Mcf") of natural gas equal to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel ("Bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All Boe measurements and conversions in this report are derived by converting natural gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Mboe means 1,000 Boe.

Oil and Gas Metrics - Oil and gas metrics, including FD&A, recycle ratio, FDC, and reserves life index or RLI, do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods.

Initial Production Rates - References to initial production rates, and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered to be preliminary.

Forward-Looking Statements – Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated May 15, 2017 for the three months ended March 31, 2017.

MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

Set out below is management's discussion and analysis ("MD&A") of financial and operating results for Storm Resources Ltd. ("Storm" or the "Company") for the three months ended March 31, 2017. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, 2017, (ii) the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2016, and (iii) the press release issued by the Company on May 15, 2017, and other operating and financial information included in this report. All of these documents as well as the Company's Annual Information Form dated March 31, 2017 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

The Company trades on the TSX Venture Exchange under the symbol "SRX".

This MD&A is dated May 15, 2017.

See "Forward Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" on pages 24 to 26.

BASIS OF PRESENTATION

Financial data presented below have largely been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three months ended March 31, 2017, prepared in accordance with International Accounting Standard ("IAS") 34 "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS"). Accounting policies adopted by the Company are referred to in Note 3 to the audited consolidated financial statements for the year ended December 31, 2016. The reporting and the functional currency is the Canadian dollar.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the immediately prior three month period ended December 31, 2016 and for the three month period ended March 31, 2016.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The seasonal price rally that began in the back half of 2016 on the hopes of a colder than normal winter peaked late in December, following a bout of cold weather that led to strong storage draws, before losing steam into the new year as further cold weather did not materialize. Another warm winter resulted in natural gas storage remaining stubbornly high, leading to a decline in natural gas prices. Nevertheless, natural gas prices in the first quarter of 2017 were stronger than this time last year, with Storm's realized price being double that of the first quarter of 2016. With declining natural gas production in the US and increasing demand, market fundamentals appear to be improving with the current forward strip reflecting a price where Storm can continue to grow its production base while providing an attractive rate of return. Storm benefitted from the diversification of sales points during the first quarter of 2017, with strong prices in the Chicago market, specifically the monthly index, being further buoyed by a weak Canadian dollar. The Company's realized price for the first quarter was $3.23 per Mcf, 99% higher than the $1.62 per Mcf realized in the same period of 2016. For perspective, the Chicago daily index price in US dollars and AECO daily index price both increased 46% relative to the first quarter of 2016, while the Station 2 price increased 77%. With an improving pricing environment, production growth from the Western Canadian Sedimentary Basin remains robust leading to ongoing concerns over egress from the region. Storm is well positioned in this regard with firm transportation agreements totaling 72 Mmcf per day in 2017, or approximately 80% of forecasted production, further increasing to 102 Mmcf per day in 2018.

In the first quarter of 2017, Storm's Boe-per-day production grew by 26% year over year and by 27% when compared to the immediately prior quarter. The increase in production was a result of the commissioning of the Company's third field compression facility on January 12, 2017, which added 35 Mmcf per day of processing capacity, bringing total field compression capacity to 115 Mmcf per day of raw natural gas. It is expected this third field compression facility will be twinned in due course at a modest cost of $7 million, resulting in total field compression capacity of 150 Mmcf per day. Storm's current production is over 18,000 Boe per day based on field estimates compared to current processing capacity of over 20,000 Boe per day. Increasing production beyond 20,000 Boe per day requires the aforementioned twinning of the third field compression facility, currently planned for the first half of 2018, and will increase Storm's potential production base from current levels to volumes of approximately 27,000 Boe per day, approximately double that of 2016. As previously disclosed, production for the second quarter of 2017 will be affected by a 21-day maintenance turnaround at the McMahon gas plant.

Field operating netback and funds flow per Boe for the first quarter amounted to $15.88 and $11.76, respectively, a material increase from $5.20 and $6.42 from the same period in 2016. The increases in the field operating netback and funds flow from comparative periods were due to higher realized commodity prices and continuing reductions in controllable cash costs. Higher pricing also resulted in a realized loss on commodity price contracts, reducing funds flow per Boe by $2.31 in the first quarter of 2017. Condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) remained consistent at 17% of the Company's total production base, and continue to contribute a meaningful amount, or 34%, to top line revenue in the first quarter of 2017. From a cost perspective, the most significant development in the quarter was the commencement of the new processing arrangement on January 1, 2017, resulting in first quarter production costs per Boe of $5.84, down 13% from the same period in 2016 and down 16% from the fourth quarter of 2016. It should be recognized that the netback measurements do not reflect supply cost. The best proxy for such a number would be the most recent measurement of finding and development cost for proved developed producing reserves ("PDP"), which for Storm amounted to $6.89 per Boe for the year ended December 31, 2016. Using Storm's first quarter funds flow of $11.76 per Boe results in a PDP recycle ratio of approximately 1.7 times, a noteworthy improvement relative to the recycle ratio of 1.0 times achieved in the year ended December 31, 2016.

Capital expenditures for the first quarter of 2017 totalled $27.4 million and included the drilling of six wells for a total amount of $9.9 million. During the quarter, four wells were completed, while five wells were brought on stream. At quarter end the Company had an inventory of 10 standing wells, of which eight awaited completion, with the remaining two wells completed and tied in but not yet producing. Based on the current capital program, another six wells will be drilled in the second half of the year, and an additional 10 wells will be completed over the remainder of the year. Based on this level of activity, fourth quarter production is forecast to be 19,000 to 21,000 Boe per day. Other capital expenditures in the quarter included $1.7 million spent on facilities and $5.6 million on equipping and pipelines. Capital expenditures in the first quarter were approximately 1.5 times cash flow for the quarter, with this outlay representing approximately 34% of the total capital budget for 2017. It is anticipated that in future quarters the gap between cash flow and capital expenditures will narrow.

Subsequent to quarter end, the Company's credit facility was increased by $35 million to $165 million, an increase of 27%. The credit facility is predominantly based on the banking syndicate's assessment of the value of the Company's PDP reserves as collateral. The credit facility increase is consistent with the increase in PDP reserves, which grew by 22% year over year, while the net present value of PDP reserves (before tax, 10%) increased by 49% based on InSite Petroleum Consultants Ltd. December 31, 2016 commodity price deck. While the revised credit facility provides increased financial flexibility, it will have no effect on the Company's capital or operating programs at this time. No additional covenants were required and the interest rate structure is unchanged.

Production and Revenue

Production by Area

The Company reported production from the following areas:

	Three Months Ended March 31, 2017			
Producing Area	Natural Gas (Mcf/d)	Condensate[1] (Bbls/d)	Natural Gas Liquids[2] (Bbls/d)	Boe/d
Umbach – NE BC	81,902	1,758	1,174	16,582
Horn River Basin – NE BC	1,812	-	-	302
Grande Prairie – AB	379	-	-	63
Total	84,093	1,758	1,174	16,947

Producing Area	Natural Gas (Mcf/d)	Condensate[1] (Bbls/d)	Natural Gas Liquids[2] (Bbls/d)	Boe/d
	Three Months Ended March 31, 2016			
Umbach – NE BC	65,894	1,452	964	13,398
Horn River Basin – NE BC[3]	-	-	-	-
Grande Prairie – AB	118	-	-	20
Total	66,012	1,452	964	13,418

Producing Area	Natural Gas (Mcf/d)	Condensate[1] (Bbls/d)	Natural Gas Liquids[2] (Bbls/d)	Boe/d
	Three Months Ended December 31, 2016			
Umbach – NE BC	63,916	1,381	911	12,945
Horn River Basin – NE BC[3]	1,863	-	-	310
Grande Prairie – AB[3]	394	-	(1)	65
Total	66,173	1,381	910	13,320

(1) Includes field condensate and plant pentanes.
(2) Includes butane and propane.
(3) Production shut in for part of period due to pricing.

In the first quarter of 2017, average Boe-per-day volumes increased by 26% when compared to the first quarter of 2016, and increased by 27% when compared to the immediately preceding quarter. Production increases for natural gas, condensate and NGL, when compared to both periods in 2016, came from growth at Umbach where the Company started production from five new 100% working interest wells during the quarter. The Company had production from a total of 50 wells (46.4 net) at the end of the first quarter, an increase of 14 wells year over year. Production to date in the second quarter of 2017 has averaged over 18,000 Boe per day based on field estimates.

Production in the first quarter approximated 83% natural gas, 10% condensate and 7% NGL, consistent with that achieved in 2016.

Average Daily Production

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Natural gas (Mcf/d)	84,093	66,012	66,173
Condensate (Bbls/d)	1,758	1,452	1,381
Natural gas liquids (Bbls/d)	1,174	964	910
Total (Boe/d)	16,947	13,418	13,320

Low natural gas prices in the first half of 2016 resulted in production being reduced to the level required to meet firm processing and transportation commitments. Improved pricing later in 2016 resulted in shut-in production being restored along with acceleration of the Company's capital program in the fourth quarter, which saw December 2016 monthly production increase to approximately 14,700 Boe per day. This upward trend continued through the first quarter of 2017 with March 2017 production increasing to approximately 17,900 Boe per day, in part, illustrative of the ability of the Company's production base to respond quickly to commodity price movements.

Daily production per million shares outstanding at the end of the first quarter averaged 139 Boe per day, compared to 112 Boe per day for the first quarter of 2016 and 110 Boe per day for the fourth quarter of 2016.

Production Profile and Per-Unit Prices(1)

	Three Months Ended March 31, 2017		Three Months Ended March 31, 2016		Three Months Ended December 31, 2016	
	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs
Natural gas - Mcf	83%	$ 3.23	82%	$ 1.62	83%	$ 2.86
Condensate - Bbl	10%	$ 64.40	11%	$ 41.54	10%	$ 57.17
Natural gas liquids - Bbl	7%	$ 23.09	7%	$ 10.44	7%	$ 18.64
Per Boe	100%	$ 24.29	100%	$ 13.20	100%	$ 21.42

(1) Before realized gains and losses on commodity price contracts.

The Company's production during the first quarter of 2017 was sold as follows:

- 48% - Adjusted Chicago monthly index price
- 32% - Station 2 daily spot price
- 14% - Adjusted Chicago daily index price
- 6% - Alliance Transfer Point (ATP)

Natural gas sold with reference to the Chicago index price is subject to a pricing reduction equal to the pipeline tariff to Chicago (first quarter 2017 $1.66 per Mcf) as title to the gas transfers at the natural gas processing plant in British Columbia.

A summary of reference prices for the last five quarters is set out below. Note that pricing comparability between markets is affected by foreign exchange and lack of uniformity between commodity units. Storm's realized prices also differ due to heat content of the Company's natural gas. Noteworthy is the disparity between Canadian and US index prices and the continuing improvement in Station 2 pricing in the first quarter of 2017 when compared to the prior twelve months.

	Storm Realized Natural Gas Price (Cdn$/Mcf)	Chicago Monthly Index (US$/Mmbtu)	Chicago Daily Index (US$/Mmbtu)	AECO Daily Index (Cdn$/GJ)	AECO Monthly Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	US$/Cdn$
2017							
Q1	3.23	3.40	2.98	2.55	2.79	2.36	0.76
2016							
Q4	2.86	3.00	2.97	2.93	2.67	2.27	0.75
Q3	2.41	2.76	2.78	2.20	2.09	1.83	0.77
Q2	1.28	1.95	2.09	1.33	1.18	1.14	0.78
Q1	1.62	2.25	2.04	1.74	2.00	1.33	0.73
Average - 2016	2.05	2.49	2.47	2.05	1.98	1.64	0.75

The AECO daily index - Station 2 differential averaged -$0.41 per GJ in 2016 and -$0.19 per GJ in the first quarter of 2017. Although Station 2 pricing has improved versus AECO since late 2015, continued production growth from the Montney in northeast British Columbia may affect pricing in the future.

Storm's realized natural gas price for the first quarter of 2017 was $3.23 per Mcf, approximately 20% ahead of the average AECO daily benchmark price for the quarter and a large improvement from the 7% discount in the previous quarter. Benefits to Storm were stronger Chicago pricing (specifically the Chicago monthly index) and a favorable US$/Cdn$ exchange rate which was partially offset by lower Station 2 pricing relative to AECO daily index prices.

	Storm Realized Price				
	Condensate (Cdn$/Bbl)	Natural Gas Liquids (Cdn$/Bbl)	WTI (US$/Bbl)	Edmonton Light Oil (Cdn$/Bbl)	US$/Cdn$
2017					
Q1	64.40	23.09	51.91	63.99	0.76
2016					
Q4	57.17	18.64	49.29	61.58	0.75
Q3	49.01	10.03	44.94	54.80	0.77
Q2	50.05	11.63	45.59	54.78	0.78
Q1	41.54	10.44	33.45	40.81	0.73
Average - 2016	49.34	12.51	43.32	52.99	0.75

Storm's liquids stream in the first quarter of 2017 contained approximately 60% condensate, which is generally priced with reference to benchmark pricing for Edmonton light oil. Storm received an average price of $64.40 per barrel for the first quarter of 2017 for condensate, compared to $41.54 per barrel in the first quarter of 2016. The US$/Cdn$ exchange rate adjusted differential between WTI and Edmonton light oil was -Cdn$4.68 per barrel in the first quarter of 2017, consistent with -Cdn$5.15 per barrel in the first quarter of 2016. The realized price for NGL, excluding condensate, in the first quarter of 2017 increased by 121% relative to the same period in 2016, due to both stronger butane and propane pricing, led by propane which posted an impressive rally late in 2016 that carried into 2017.

Increasing natural gas production at Umbach has resulted in growing volumes of higher value condensate. The significance of this is illustrated by the contribution from this revenue stream, which comprised 10% of Boe production but amounted to 28% of revenue from product sales in the first quarter of 2017.

On a per-Boe basis, the Company's total realized price of $24.29 for the first quarter of 2017 increased by 84% and 13% when compared to the first and fourth quarters of 2016, respectively.

Revenue from Product Sales(1)

(000s)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Natural gas	$ 24,417	$ 9,719	$ 17,423
Condensate	10,189	5,486	7,259
Natural gas liquids	2,439	916	1,562
Total	$ 37,045	$ 16,121	$ 26,244

(1) Before realized gains and losses on commodity price contracts.

Revenue from product sales for the first quarter of 2017 increased by 130% when compared to the first quarter of 2016 and increased by 41% when compared to the immediately preceding quarter. Quarterly production volumes increased by 26% year over year and by 27% when compared to the immediately preceding quarter. Pricing strengthened in the first quarter of 2017, increasing by 84% over the first quarter of 2016 and by 13% over the fourth quarter of 2016.

A reconciliation of year-over-year and quarter-over-quarter revenue changes is as follows:

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – Q1 2016	$ 9,719	$ 5,486	$ 916	$ 16,121
Effect of changes in production	2,526	1,011	175	3,712
Effect of changes in average product prices	12,172	3,692	1,348	17,212
Revenue from product sales – Q1 2017	$ 24,417	$ 10,189	$ 2,439	$ 37,045

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – Q4 2016	$ 17,423	$ 7,259	$ 1,562	$ 26,244
Effect of changes in production	4,237	1,787	407	6,431
Effect of changes in average product prices	2,757	1,143	470	4,370
Revenue from product sales – Q1 2017	$ 24,417	$ 10,189	$ 2,439	$ 37,045

Realized and Unrealized Gain (Loss) on Commodity Price Contracts

The realized gain (loss) on commodity price contracts consists of cash settlements on contracts which, in whole or in part, have come to term during the reporting period, plus cash settlements relating to contracts which the Company terminated during the reported period.

The term liquids below refers to crude oil contracts. Although the Company has no crude oil production, approximately 80% of the condensate and NGL stream is priced with reference to crude oil. In the absence of a liquid market for condensate and NGL price contracts, the Company may enter into crude oil contracts as a proxy for a condensate and NGL hedge.

The unrealized gain (loss) on commodity price contracts is a non-cash charge resulting from the year-over-year and quarter-over-quarter change in the fair value of commodity price contracts outstanding at the end of the reporting period. The change in fair value recognizes the mark-to-market change in the value of contracts outstanding both at the beginning and end of the reporting period and also removes the opening value of contracts which have come to term during the reporting period.

	Three Months Ended March 31, 2017		Three Months Ended March 31, 2016		Three Months Ended December 31, 2016	
Realized gain (loss)						
Natural gas	$ (3,422)	$ (0.45) /Mcf	$ 2,382	$ 0.40 /Mcf	$ (2,119)	$ (0.35) /Mcf
Liquids	(96)	$ (0.61) /Bbl	1,323	$ 6.02 /Bbl	345	$ 1.64 /Bbl
Total realized gain(loss) – cash(1)	$ (3,518)	$ (2.31) /Boe	$ 3,705	$ 3.03 /Boe	$ (1,774)	$ (1.45) /Boe

	Three Months Ended March 31, 2017		Three Months Ended March 31, 2016		Three Months Ended December 31, 2016	
Unrealized gain (loss)						
Natural gas	$ 13,752	$ 1.82 /Mcf	$ (1,466)	$ (0.24) /Mcf	$ (11,192)	$ (1.84) /Mcf
Liquids	2,373	$ 8.99 /Bbl	(505)	$ (2.30) /Bbl	(2,733)	$ (12.97) /Bbl
Total realized gain(loss) – non-cash(1)	$ 16,125	$ 10.57 /Boe	$ (1,971)	$ (1.61) /Boe	$ (13,925)	$ (11.36) /Boe

(1) The terms cash and non-cash are non-GAAP references.

The Company had in place the following commodity price contracts at the date of this report:

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Apr – May 2017	8,000 GJ	AECO Cdn$2.81/GJ
Apr – Jun 2017	14,000 GJ	AECO Cdn$2.62/GJ
Jul – Dec 2017	19,500 GJ	AECO Cdn$2.83/GJ
Apr – Dec 2017	17,000 GJ	AECO Cdn$2.56/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Apr – May 2017	10,400 Mmbtu	Chicago Cdn$4.16/Mmbtu
Apr – Jun 2017	1,900 Mmbtu	Chicago Cdn$4.312/Mmbtu
Jul – Dec 2017	12,800 Mmbtu	Chicago Cdn$4.16/Mmbtu
Jan – Jun 2018	26,850 Mmbtu	Chicago Cdn$4.10/Mmbtu
Jan – Dec 2018	5,000 Mmbtu	Chicago Cdn$3.78/Mmbtu
Natural Gas Differential Swaps		
Apr – Dec 2017	7,670 GJ	Price at Stn 2 = AECO minus Cdn$0.410/GJ
Jan – Dec 2018	3,000 GJ	Price at Stn 2 = AECO minus Cdn$0.345/GJ
Apr – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Apr – Dec 2017	500 Bbls	$62.80 - $70.75 Cdn$/Bbl
Jul – Dec 2017	200 Bbls	$64.50 - $72.88 Cdn$/Bbl
Jan – Mar 2018	250 Bbls	$63.00 - $69.83 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Jan – Jun 2018	150 Bbls	$68.00 - $73.00 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl

Crude Oil Swaps		
Apr – Jun 2017	550 Bbls	$66.20 Cdn$/Bbl
Jul – Sep 2017	100 Bbls	$65.10 Cdn$/Bbl
Jul – Dec 2017	300 Bbls	$68.40 Cdn$/Bbl
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$70.80 Cdn$/Bbl

The fair market value of contracts outstanding at March 31, 2017 was a net liability position of $6.0 million (March 31, 2016 – net asset of $6.0 million) and is included in current and non-current assets or current and non-current liabilities, as appropriate. For the three months ended March 31, 2017, this resulted in an unrealized mark-to-market gain of $16.1 million (2016 – loss of $2.0 million) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

During the three months ended March 31, 2017, the Company realized losses from commodity price contracts settled during the quarter in the amount of $3.5 million, compared to gains of approximately $3.7 million in the first quarter of 2016. The majority of the loss related to natural gas differential swaps between Chicago and AECO.

Natural gas swaps priced at the AECO or Chicago monthly index are matched by sales of equal physical volumes of natural gas.

The Company's risk management program is not based on a speculative assessment of the direction of commodity prices. The program's purpose is to reduce the effect of commodity price volatility on funds flow to enable the Company to maintain a disciplined and sustainable development program. This is of particular importance at Umbach, where exploitation of the resource is at an early stage and capital investment programs necessary to delineate the scope and scale of a potentially decades-long project have to be insulated from the effects of near-term price movements.

Royalties

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Charge for period	$ 2,866	$ 922	$ 1,217
Percentage of revenue from product sales	7.7%	5.7%	4.6%
Per Boe	$ 1.88	$ 0.76	$ 0.99

Royalties in the first quarter of 2017 increased to 7.7% from 5.7% of revenue from product sales when compared to the first quarter of 2016. Royalties increased due to higher production revenue driven largely by an increase in natural gas pricing. These increases were partially offset by an increase in wells eligible for the BC Deep Well Royalty Credit Program, which reduces the royalty rate on eligible wells from 13% to 6% for approximately two years. In the first quarter of 2017, 27 wells qualified for the 6% royalty rate versus 14 wells in the first quarter of 2016 and 24 wells in the fourth quarter of 2016. The timing of receipt of infrastructure royalty credits also plays a role in quarterly comparisons with $0.7 million of infrastructure royalty credits received in the fourth quarter of 2016. No infrastructure royalty credits were received in either the first quarter of 2016 or 2017. Excluding royalty credits, higher production revenue in the first quarter of 2017 from a combination of both increased production volumes and stronger pricing was the main driver of the higher royalties relative to the fourth quarter of 2016.

Storm has remaining infrastructure royalty credits of $8.1 million that will reduce future royalties. The timing of receipt of future credits is dependent on commodity prices and production levels and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary, likely materially, as these credits are recognized.

Production Costs

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Charge for period	$ 8,905	$ 8,193	$ 8,518
Percentage of revenue from product sales	24.0%	50.8%	32.5%
Per Boe	$ 5.84	$ 6.71	$ 6.95

Total production costs for the first quarter of 2017 increased 9% when compared to the first quarter of 2016 and by 5% when compared to the fourth quarter of 2016. The increase in total production costs is aligned with increased production at Umbach partially offset by lower gas processing fees as a result of the new processing agreement that came into effect on January 1, 2017. Production costs per Boe for the first quarter of 2017 decreased by 13% when compared to the first quarter of 2016 and by 16% when compared to the fourth quarter of 2016. Per-Boe costs fell as a result of the lower per-unit fee associated with the new processing arrangement while production growth reduces the fixed cost component of per-Boe costs.

Production costs per Mcf of natural gas for the first quarter of 2017 averaged $1.18 with total production costs averaging $5.84 per Boe, a year-over-year and quarter-over-quarter reduction of 13% and 16%, respectively. Production costs of NGL are included with natural gas costs. The equivalent charges for the first quarter of 2016 were $1.36 per Mcf of natural gas with total production costs averaging $6.71 per Boe. Production costs per Mcf for natural gas for the fourth quarter of 2016 averaged $1.40 with total production costs averaging $6.95 per Boe.

Transportation Costs

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Charge for period	$ 1,048	$ 645	$ 673
Percentage of revenue from product sales	2.8%	4.0%	2.6%
Per Boe	$ 0.69	$ 0.53	$ 0.55

Transportation costs include pipeline tariffs for natural gas sold at BC Station 2, as well as trucking costs for condensate. Total transportation costs for the first quarter of 2017 increased by 62%, and by 30% on a per-Boe basis, when compared to the first quarter of 2016. Transportation costs for the first quarter of 2017 increased by 56% over the fourth quarter of 2016 while per-Boe transportation costs increased by 25%. With condensate production for the first quarter of 2017 increasing 21% over the first quarter of 2016 and 27% over the fourth quarter of 2016, higher transportation costs corresponds to a higher volume of trucked condensate coupled with higher trucking rates.

As the sales point for natural gas shipped on the Alliance Pipeline is the gas processing facility in British Columbia, the sales price received by the Company is net of the cost of transporting natural gas to Chicago and is thus captured on a net basis as part of revenue from product sales.

Field Operating Netbacks

Details of field netbacks, measured per commodity unit produced, are as follows:

	Three Months Ended March 31, 2017			
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.23	$ 64.40	$ 23.09	$ 24.29
Royalties	(0.22)	(5.98)	(2.46)	(1.88)
Production costs	(1.18)	-	-	(5.84)
Transportation costs	(0.08)	(2.72)	-	(0.69)
Field operating netback	$ 1.75	$ 55.70	$ 20.63	$ 15.88
Realized losses on commodity price contracts	(0.45)	(0.61)	-	(2.31)
Field operating netback including hedging	$ 1.30	$ 55.09	$ 20.63	$ 13.57

	Three Months Ended March 31, 2016			
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 1.62	$ 41.54	$ 10.44	$ 13.20
Royalties	(0.05)	(3.57)	(1.41)	(0.76)
Production costs	(1.36)	-	-	(6.71)
Transportation costs	(0.04)	(3.14)	(0.01)	(0.53)
Field operating netback	$ 0.17	$ 34.83	$ 9.02	$ 5.20
Realized gains on commodity price contracts	0.40	10.02	-	3.03
Field operating netback including hedging	$ 0.57	$ 44.85	$ 9.02	$ 8.23

	Three Months Ended December 31, 2016			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.86	$ 57.17	$ 18.64	$ 21.42
Royalties	(0.05)	(5.82)	(2.03)	(0.99)
Production costs	(1.40)	-	-	(6.95)
Transportation costs	(0.05)	(3.09)	-	(0.55)
Field operating netback	$ 1.36	$ 48.26	$ 16.61	$ 12.93
Realized gains (losses) on commodity price contracts	(0.35)	2.72	-	(1.45)
Field operating netback including hedging	$ 1.01	$ 50.98	$ 16.61	$ 11.48

(1) Production costs of condensate and natural gas liquids are presented within natural gas costs.
(2) Realized gains and losses on crude oil contracts are included in the condensate field operating netback including hedging.

Excluding realized gains and losses on commodity price contracts, the field operating netback per Boe in the first quarter of 2017 increased by 205% and by 23%, respectively, when compared to the first and fourth quarters of 2016. Year over year, per-Boe production revenue increased by $11.09, or 84%, with price recovery the dominant variable in the considerable improvement to the corporate field operating netback. Year over year, production costs per Boe decreased 13% as a result of lower gas processing fees, further buoying the field operating netback.

General and Administrative Costs

Total Costs	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Charge for period – before recoveries	$ 2,169	$ 1,942	$ 1,755
Overhead recoveries	(495)	(415)	(589)
Charge for period – net of recoveries	$ 1,674	$ 1,527	$ 1,166
Per Boe	$ 1.10	$ 1.25	$ 0.95

General and administrative costs before recoveries for the first quarter of 2017 increased by 12% when compared to the first quarter of 2016 and increased by 24% compared to the fourth quarter of 2016. The increase in general and administrative costs for the first quarter of 2017 relative to the immediately preceding quarter is primarily attributable to the payout of bonus amounts earned under the compensation program. The increase in general and administrative costs for the first quarter of 2017 relative to the same period in 2016 is primarily due to an increase in the number of office employees. Overhead recoveries for the periods presented fluctuate in response to the relative magnitude of field capital expenditures.

Net general and administrative costs for the first quarter of 2017 on a per-Boe measure decreased by 12% compared to the first quarter of 2016, and increased by 16% compared to the fourth quarter of 2016. General and administrative costs for the fourth and first quarters of a fiscal year tend to be higher due to the inclusion of certain costs specific to year-end reporting along with the annual bonus payout, if earned. Generally, the Company's general and administrative cost structure is predictable year to year and per-Boe declines are due to increased production volumes.

Share-Based Compensation

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Charge for period	$ 954	$ 823	$ 808
Per Boe	$ 0.63	$ 0.67	$ 0.66

Share-based compensation is a non-cash charge which reflects the estimated value of stock options issued to Storm's directors, officers and employees. Share-based compensation increased by 16% in the first quarter of 2017 compared to the same quarter of 2016 and increased by 18% when compared to the immediately prior quarter. The increase in share-based compensation is primarily attributable to a higher option valuation associated with options granted in December 2016.

Depletion and Depreciation

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Depletion	$ 10,614	$ 8,719	$ 8,643
Depreciation	1,404	1,229	1,333
Charge for period	$ 12,018	$ 9,948	$ 9,976
Per Boe	$ 7.88	$ 8.15	$ 8.14

Property and equipment is subject to depletion and depreciation charges. Depletion is calculated using unit-of-production methodology under which drilling and completion costs plus future development costs associated with individual cash generating units are depleted using a factor calculated by dividing production for each reporting period by proved plus probable reserves at the beginning of the period.

The charge for depreciation for the period relates to facility and equipment costs and office equipment included with property and equipment costs. Such costs are depreciated over the useful life of the asset on a straight line basis.

The 26% increase in production volumes resulted in the total charge for depletion and depreciation increasing by 21% in the first quarter of 2017 compared to the same quarter of 2016. The quarterly year-over-year per-Boe charge fell by 3% due to the effect of increased production volumes with respect to depreciation. Increased depreciation charges year over year corresponds to increased investment in facilities.

Interest and Finance Costs

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Charge for period	$ 1,076	$ 684	$ 910
Percentage of revenue from product sales	2.9%	4.2%	3.5%
Per Boe	$ 0.71	$ 0.56	$ 0.74

Interest costs for the first quarter of 2017 increased by 57% compared to the same quarter of 2016, and increased by 18% compared to the fourth quarter of 2016, driven by additional bank borrowings used to fund development of the Company's Umbach property.

The interest rate on the Company's credit facility is based on bankers acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Income Taxes

Due to uncertainty of realization, no deferred income tax asset has been recognized in respect of potential future income tax reductions resulting from the use of accumulated tax losses. Details of Storm's tax pools are as follows:

Tax Pool	As at March 31, 2017	Maximum Annual Deduction
Canadian oil and gas property expense	$ 41,000	10%
Canadian development expense	116,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	85,000	20 - 100%
Operating losses	205,000	100%
Other	2,000	20 - 100%
Total	$ 471,000	

Net Income (Loss)

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Net income (loss)	$ 20,631	$ (4,984)	$ (12,898)
Per basic and diluted share	$ 0.17	$ (0.04)	$ (0.11)

The effect of the mark-to-market valuation of commodity price contracts was significant in terms of the net income for the quarter ended March 31, 2017. For the first quarter of 2017, the unrealized gain on commodity price contracts amounted to $16.1 million compared to an unrealized loss in the first quarter of 2016 of $2.0 million and a $13.9 million unrealized loss in the fourth quarter of 2016.

The increase in net income in the first quarter of 2017 compared to the first quarter of 2016 and the fourth quarter of 2016 is also attributed to higher revenue from product sales due to increases in production volumes and product prices.

Of the per-share net income of $0.17 for the first quarter of 2017, $0.13 represented the unrealized gain on commodity price contracts.

Funds Flow

	Three Months Ended March 31, 2017		Three Months Ended March 31, 2016		Three Months Ended December 31, 2016	
		Per diluted share		Per diluted share		Per diluted share
Funds flow	$ 17,958	$ 0.15	$ 7,855	$ 0.07	$ 11,985	$ 0.10

Funds flow for the first quarter of 2017 increased by 129% from the first quarter of 2016, and increased by 50% compared to the fourth quarter of 2016. Compared to the first quarter of 2016, the increased funds flow in the first quarter of 2017 was largely a result of an 84% increase in Storm's realized price on a per-Boe basis coupled with a 26% increase in production as well as continued reductions in Storm's overall cost structure. A similar story emerges when comparing the first quarter of 2017 to the fourth quarter of 2016, as funds flow benefited from a realized price that was 13% higher while production growth increased 27%.

The Company uses funds flow, a measure that is not defined under IFRS. Funds flow is cash from operations before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies and is used by lenders to establish interest rates.

Corporate Netbacks

($/Boe)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Revenue from product sales	24.29	13.20	21.42
Realized gains (losses) on commodity price contracts	(2.31)	3.03	(1.45)
Royalties	(1.88)	(0.76)	(0.99)
Production	(5.84)	(6.71)	(6.95)
Transportation	(0.69)	(0.53)	(0.55)
General and administrative	(1.10)	(1.25)	(0.95)
Interest and finance costs	(0.71)	(0.56)	(0.74)
Funds flow	11.76	6.42	9.79
Share-based compensation	(0.63)	(0.67)	(0.66)
Depletion, depreciation and accretion	(7.95)	(8.22)	(8.21)
Exploration and evaluation costs expensed	(0.20)	-	(0.03)
Unrealized revaluation loss on investment	(0.05)	(0.01)	(0.04)
Unrealized gain (loss) on commodity price contracts	10.57	(1.61)	(11.36)
Net income (loss) per Boe	13.50	(4.09)	(10.51)

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest and finance costs, decreased 10% to $7.65 in the first quarter of 2017 compared to $8.52 for the equivalent quarter of 2016 and decreased 11% compared to $8.64 for the fourth quarter of 2016. Transportation costs are excluded as the sales price on part of the Company's production is net of the cost to the purchaser of shipping on the Alliance Pipeline to Chicago. Comparing the first quarter of 2017 to the same quarter of 2016, all components of controllable cash costs decreased on a per-Boe basis with the exception of interest costs which increased. When comparing to the fourth quarter of 2016, all components of controllable cash costs per Boe for the first quarter of 2017 decreased, with the exception of general and administrative costs, which reflected a bonus payout in the first quarter of 2017. Lower gas processing fees commencing January 1, 2017 have resulted in reductions in cash costs per commodity unit.

INVESTMENT AND FINANCING

Financial Resources and Liquidity

Subsequent to March 31, 2017, the credit facility was increased to $165.0 million from $130.0 million in recognition of production and reserve growth at Umbach. The credit facility is available until April 27, 2018 at which time the borrowing base amount will be reviewed using independently prepared reserve information. In the ordinary course of business, the Company has the option to extend for an additional year; if this does not happen, the facility will be termed out with the amount outstanding becoming payable in full one year later. The credit facility is syndicated with three banks.

At March 31, 2017, the Company was in compliance with all covenants under the credit facility, the sole financial covenant being that debt including working capital deficiency cannot exceed the facility credit limit. At March 31, 2017 debt including working capital deficiency, amounted to $97.9 million.

In quarters of high field activity, Storm operates with a working capital deficit, which will be reduced in quarters of lower field activity. The Company's capital budget is set by management at the beginning of the calendar year and approved by the Board of Directors. It is updated regularly with changes subject to approval by the Board of Directors. Management is accountable to the Board of Directors for the execution of the business plan represented by the budget and reports to the Board at least four times a year.

Capital Expenditures

In the first quarter of 2017, the Company spent $27.4 million (2016 - $23.9 million) on field operations, primarily on drilling and completing wells at Umbach. During the quarter, six 100% working interest horizontal wells were drilled, four 100% working interest horizontal wells were completed and five horizontal wells were brought on production. At March 31, 2017 there were two standing completed wells and eight wells awaiting completion.

Major field capital outlays in the first quarter of 2017 included $19.0 million on drilling and completions, $5.6 million on equipping and pipelines and $1.7 million on facilities, all in the Umbach area. The facility expenditures primarily related to completion and commissioning of the third field compression facility on January 12, 2017 which added processing capacity of 35 Mmcf per day raw gas.

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Land and lease	$ 256	$ 686	$ 240
Drilling	9,879	11,856	11,000
Completions	9,103	4,089	8,771
Facilities	1,682	6,180	11,576
Equipping and pipelines	5,635	1,100	1,776
Recompletions and workovers	802	33	7
Property acquisition, adjustments and administrative assets	-	2	29
Total capital expenditures	$ 27,357	$ 23,946	$ 33,399

Net capital investment was allocated as follows:

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	Three Months Ended December 31, 2016
Exploration and evaluation	$ 250	$ 675	$ 240
Property and equipment	27,107	23,271	33,159
Total capital expenditures	$ 27,357	$ 23,946	$ 33,399

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, general and administrative and capital costs payable. When appropriate, net payables in respect of cash calls issued to partners regarding capital projects and estimates of amounts owing but not yet invoiced to the Company are included in accounts payable. The level of accounts payable and accrued liabilities at March 31, 2017 corresponds to the active field program at Umbach, the first quarter likely being the most active quarter of 2017.

Decommissioning Liability

The Company's decommissioning liability represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. The undiscounted amount of the liability at March 31, 2017 was $31.2 million (2016 - $28.2 million) and reflects (i) liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, (iii) changes in estimates of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of oil and gas properties, (v) less actual decommissioning costs incurred, and (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value is 2.3% (December 31, 2016 – 2.2%). Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring of actual abandonment and reclamation costs, supported by external information from industry sources. It also has regard to industry best practices, as well as provincial and other regulation and evolution of same.

Share Capital

Details of share issuances from inception to March 31, 2017 are as follows:

		Number of Shares (000s)	Price per Share	Gross Proceeds[(1)] ($000s)
June 8, 2010	Issued upon incorporation		$ 1.00	$ -
August 17, 2010	Issued under the Arrangement	17,515	$ 3.28	57,600
August 17, 2010	Issued under private placement	2,300	$ 3.28	7,544
September 22, 2010	Issued upon exercise of warrants	6,562	$ 3.28	21,522
		26,377		86,666
January 12, 2012	Issued on acquisition of SGR	11,761	$ 3.73	43,869
March 23, 2012	Issued under private placement	6,946	$ 3.40	23,615
March 23, 2012	Issued on acquisition of Bellamont	16,740	$ 2.37	39,674
		35,447		107,158
May 1, 2013	Issued under private placement	12,580	$ 1.88	23,650
May 1, 2013	Issued under insider private placement	3,000	$ 1.88	5,640
June 30, 2013	Shares cancelled	(21)	$ 2.37	(50)
November 19, 2013	Issued under private placement	9,000	$ 3.35	30,150
November 19, 2013	Issued under insider private placement	1,100	$ 3.35	3,685
		25,659		63,075
January 31, 2014	Issued pursuant to Umbach acquisition	13,629	$ 4.25	57,925
February 14, 2014	Issued under private placement	7,250	$ 4.10	29,725
February 14, 2014	Issued under insider private placement	1,250	$ 4.10	5,125
Year ended Dec.31/14	Stock option exercises	1,710	$ 3.26	5,580
		23,839		98,355
June 10, 2015	Issued under private placement	8,000	$ 4.55	36,400
Year ended Dec.31/15	Stock option exercises	145	$ 1.81	262
		8,145		36,662
Year ended Dec.31/16	Stock option exercises	1,297	$ 1.97	2,558
Three months to Mar.31/17	Stock option exercises	793	$ 1.83	1,456
Total at March 31, 2017		121,557	$ 3.26	$ 395,930

(1) Before share issue costs and transfers from contributed surplus.

During the first quarter of 2017, stock options were exercised at an average price of $1.83 per optioned share and 793,000 common shares were issued for proceeds of $1,456,000.

Issued and outstanding common shares at March 31, 2017 and at May 15, 2017, the date of this MD&A, totaled 121,556,812.

CONTRACTUAL OBLIGATIONS

In the course of its business, Storm enters into various contractual obligations, including the following:

- purchase of services;
- royalty agreements;
- operating agreements;
- processing and transportation agreements;
- right of way agreements;
- lease obligations for accommodation, office equipment and automotive equipment;
- banking agreements; and
- commodity price contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years commencing October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.6 million over the term of the lease. At March 31, 2017, the remaining office lease commitment is $1.4 million. In addition, the Company has gas transportation and processing commitments totalling approximately $359.9 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended March 31, 2017 appears below. Although there are variations between quarters in various elements of revenue and cost, as set out in the MD&A for each quarter, the results from the fourth quarter of 2015 to mid-way through the third quarter of 2016 have been affected by one dominant trend – production growth was insufficient to offset the relentless fall in commodity prices. However, during the third quarter of 2016, pricing for the Company's commodities began to improve, enabling the Company to increase production and to implement a larger capital program. As such, there was a significant increase in capital spending in the fourth quarter of 2016, while funds flow was strong, far outpacing that achieved in any of the prior quarters of 2016 and 2015. This positive trend continued into the first quarter of 2017, with another active capital program that resulted in a step change in average daily production along with a material increase in funds flow, primarily due to the improved pricing dynamic.

	2017			2016				2015
($000s unless otherwise stated)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue from product sales	37,045	26,244	21,047	13,870	16,121	14,480	16,283	18,461
Funds flow	17,958	11,985	8,759	5,781	7,855	9,182	7,982	8,170
Per share – basic and diluted ($)	0.15	0.10	0.07	0.05	0.07	0.08	0.07	0.07
Net income (loss)	20,631	(12,898)	(85)	(20,493)	(4,984)	1,850	(961)	(4,191)
Per share – basic and diluted ($)	0.17	(0.11)	(0.00)	(0.17)	(0.04)	0.02	(0.01)	(0.04)
Net capital expenditures	27,357	33,399	6,980	613	23,946	31,081	(4,116)[2]	8,864
Average daily production (Boe)	16,947	13,320	13,285	12,852	13,418	10,730	9,654	9,657
Debt including working capital deficiency[1]	97,864	89,841	69,303	71,254	77,162	61,721	39,994	28,051

(1) A non-GAAP measure as defined in the non-GAAP measurements section of this MD&A.
(2) Net of property disposition for proceeds of $23.6 million.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the reporting period ended March 31, 2017 are based on accounting policies, estimates and judgments which reflect information available to management at the time of preparation. Certain amounts in the financial statements are derived from a fully completed transaction cycle, or are validated by events subsequent to the end of the reporting date, or are based on established and effective measurement and control systems. However, certain other amounts, as described below, are based on estimations made by management using information which involves an element of measurement uncertainty. The degree of uncertainty related to each of the following items will vary: further, it may change between reporting periods. Variations between amounts estimated and actual results could have a material effect on Storm's operating results and financial position.

Oil and Gas Reserves

Estimates of quantities of proven and probable reserves of natural gas and NGL (which includes condensate) are not a financial measurement. However, estimated future cash flows associated with reserves are used in impairment assessments for exploration and evaluation assets and property and equipment, the measurement of decommissioning obligations and depletion and depreciation of property and equipment. Such estimates of cash flows involve assumptions regarding future commodity prices, exchange rates, discount rates, inflation rates and future production and transportation costs, and of necessity involve uncertainty. Reserve estimates are prepared annually by independent qualified reserve evaluators in accordance with independently established industry standards using, in part, data supplied by the Company. The results of the independent reserve evaluation are reviewed by the Reserves Committee of the Company's board of directors. In certain circumstances the Company will prepare internal estimates of reserves which may be used in accounting measurements applicable to interim reporting periods.

Accounts Receivable, Accounts Payable and Accrued Liabilities

At the end of each reporting period the Company estimates the amount receivable from product sales and from joint venture partners to the extent that these amounts are not determinable from purchaser statements or amounts invoiced to partners. In addition, the Company estimates the cost of services and materials provided by suppliers during the reporting period if these costs have not been invoiced to the Company by the reporting date. The Company estimates and recognizes such revenues and costs using well established measurement procedures. Nonetheless, such procedures reflect judgment by management and are thus subject to measurement uncertainty. In addition, estimates of services and materials not invoiced, either to or by the Company, relate in large part to the Company's capital programs, the level of which can vary considerably between reporting periods. As a result, the amount of accounts receivable, accounts payable and accrued liabilities subject to estimation will vary and in periods of high field activity the amount subject to estimation may be a large part of the total amount.

Commodity Price Contracts

The Company periodically enters into contracts which fix a price or a price range for future periods for natural gas and crude oil. Each such contract is valued at the end of each reporting period, with the change in value of outstanding contracts being included in the measurement of income for the period. The period end value is based on option pricing models using estimates for future circumstances and is correspondingly subject to both mathematical and input uncertainty. Crude oil contracts are used as a proxy for condensate and NGL contracts as part of the Company's condensate and NGL stream is priced with reference to crude oil index prices.

Exploration and Evaluation Assets

Costs incurred by the Company in the assessment phase of a property offering development potential are categorized as exploration and evaluation assets. Such costs are transferred to CGUs, generally when production commences or reserves are assigned, or are expensed if management determines that the costs incurred will yield no future economic benefit or if the lease associated with the property expires. The amounts transferred to property and equipment, or expensed, and the timing of the decisions relative to each, are subject to measurement uncertainty. Furthermore, the carrying amount of exploration and evaluation assets at the end of each reporting period represents an asset whose value can only be established in future periods. The carrying amount of exploration and evaluation assets is reviewed at the end of each reporting period for indicators of impairment. If such indicators exist the carrying amount will be measured against the estimated recoverable amount and if necessary reduced. This review involves estimates and judgments by management and thus involves a high degree of uncertainty.

Property and Equipment, and Depletion and Depreciation

Amounts transferred from exploration and evaluation assets to property and equipment represent the accumulated net costs associated with the property transferred. The timing and the measure of the amount to be transferred involves estimation and judgment by management, and the estimates used could differ from similar estimates developed by other parties. In addition, acquired property and equipment is initially recorded at fair value as determined by management. Measurement of fair value includes estimation and judgment and is inherently subjective and uncertain.

Property and equipment is subject to depletion and depreciation, and charges for depletion and depreciation are based on estimates which may only be validated in future periods, if ever. Such charges involve estimates by management of the useful economic life for assets subject to depletion and depreciation, the quantities of oil and gas reserves used in the depletion calculation, the future prices at which such reserves may be sold, and future costs to develop and produce such reserves. Further, for non-reserve assets such as facilities and pipelines, estimates of the useful life of these assets must be made.

The carrying amounts of property and equipment are reviewed each reporting period to determine whether there are indicators of impairment. If there are such indicators, an impairment test per CGU is completed involving the calculation of an estimated recoverable amount; as a result adjustments to the carrying amount may be made. All of these involve assumptions regarding uncertain future events and circumstances.

Decommissioning Liability

Storm records as a liability the discounted estimated fair value of obligations associated with the decommissioning of field assets. The carrying amount of exploration and evaluation assets and property and equipment is increased by an amount equivalent to the liability. In summary, the decommissioning liability reflects the present value of estimated costs to complete the abandonment and reclamation of field assets as well as the estimated timing of incurrence of these costs. The liability is increased each reporting period to reflect the passage of time, with the charge for accretion included in earnings. The liability is also adjusted to reflect changes in the amount and timing of future retirement obligations as well as asset dispositions and is reduced by the amount of any costs incurred in the period. Adjustments are also made to the liability in response to changes in discount and inflation rates. The amount of future decommissioning costs, the timing of incurrence of such costs, the discount rate and, correspondingly, the charge for accretion, are subject to uncertainty of estimation. In addition, the decommissioning activities to which the estimates relate are likely to take place many years, potentially decades, in the future. The long timeline between incurrence and eventual satisfaction of the obligation will inevitably affect the accuracy of the estimation process.

Share-Based Compensation

To determine the charge for share-based compensation, the Company estimates the fair value of stock options at the time of issue using assumptions regarding the life of the option, dividend yields, interest rates and the volatility of the security under option. Although the assumptions used to value a specific option remain unchanged throughout the life of the option, assumptions may change with respect to subsequent option grants. In addition, the assumptions used may not properly represent the fair value of stock options at any time; as no alternative valuation model is applied, the difference between the Company's estimation of fair value and the actual value of the option is not measurable. Although the methodology used to measure the charge for share-based compensation is largely uniform across Storm's peers, inputs to the calculation, and thus the charge, may vary considerably.

Income Taxes

The measurement of Storm's tax pools, losses and deferred tax assets and liabilities requires interpretation of complex laws and regulations. All tax filings and compliance with tax regulations are subject to audit and reassessment, potentially several years after the initial filing. In addition, the amount and timing of use of tax pools may be affected by future legislation. Accordingly, the amounts of tax pools available for future use may differ significantly from the amounts estimated in the financial statements.

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, particularly with respect to 2017 guidance under the heading "Outlook", contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations or financial position. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices in each market in which production is sold;

- future production volumes in the fourth quarter of 2017, annual production for 2017 and production growth to 27,000 Boe per day in 2018, production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2017 guidance;
- future value of unrealized commodity price contracts;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2017 capital program;
- future drilling, completion and tie-in of wells along with the associated costs on a per-well basis;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital programs and future availability of such sources;
- future availability of drilling rigs, field service providers and completion and tie-in equipment being available as required, with costs of securing these services not materially exceeding expectations;
- development plans for Storm's properties;
- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency;
- availability and use of credit facilities;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future amounts and use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2017 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and natural gas liquids, specifically a reduction of production costs as a result of a new processing agreement effective January 1, 2017;
- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed, including twinning of the third field compression facility;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations;
- references to the intentions of management or the Company; and
- changes to any of the foregoing.

Statements relating to "reserves" or "resources" including related financial measurements, such as net present value, are forward-looking statements, as they imply, based on estimates and assumptions, including assumptions regarding future prices, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include the material uncertainties and risks described or incorporated by reference in this MD&A under "Critical Accounting Estimates"; "Business Risks"; "Financial Reporting Update"; and the material assumptions and observations described under the headings "Overview"; "Production and Revenue"; "Realized and Unrealized Gain (Loss) on Commodity Price Contracts"; "Royalties"; "Production Costs"; "Transportation Costs"; "Field Operating Netbacks"; "General and Administrative Costs"; "Share-Based Compensation"; "Depletion and Depreciation"; "Interest and Finance Costs"; "Income Taxes"; "Net Income (Loss)"; "Funds Flow"; "Financial Resources and Liquidity"; "Capital Expenditures"; "Accounts Payable and Accrued Liabilities"; "Decommissioning Liability"; "Share Capital"; "Contractual Obligations"; industry conditions including commodity prices, facility and pipeline capacity constraints and access to processing facilities and to market for production; currency fluctuations; imprecision of reserve estimates and related costs including future royalties, production and transportation costs and future development costs; environmental risks; competition from other industry participants; the lack of availability of qualified personnel or management; stock market volatility; ability to access sufficient capital from internal and external sources; and the ability of the Company to realize value from its properties. All of these caveats should be considered in the context of current economic conditions, in particular low , in a historical context, prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing domestic and international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm's actual results, performance or achievement, could differ materially from those expressed in, or implied by, these forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

Boe Presentation - Natural gas is converted to a barrel of oil equivalent ("Boe") using six thousand cubic feet ("Mcf") of natural gas equal to one barrel of oil unless otherwise stated. Boe may be misleading, particularly if used in isolation. A Boe conversion ratio of six Mcf to one barrel ("Bbl") is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All Boe measurements and conversions in this report are derived by converting natural gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

Non-GAAP Measurements - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles ("GAAP"). Specifically, "debt including working capital deficiency", "field operating netbacks", "field operating netbacks including hedging", "cash costs", the terms "cash" and "non-cash", and measurements "per commodity unit" and "per Boe" do not have any standardized meaning as prescribed by GAAP and are regarded as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare enterprises may not be valid. Non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, lenders, analysts and other parties.

Field operating netbacks and field operating netbacks including hedging are common non-GAAP measurements applied in the oil and gas industry and are used by management to assess operational performance of assets. Field operating netbacks are calculated by deducting royalties, production and transportation expenses from revenue from product sales and are presented on a per-Boe basis.

Debt including working capital deficiency is defined as bank indebtedness plus working capital surplus or deficiency excluding the mark-to-market value of commodity price contracts. Management believes this is a key measure to assess the Company's liquidity and is used by the Company's lenders to set interest rates.

BUSINESS RISKS

There are a number of risks facing participants in the Canadian oil and gas industry. Some risks are common to all businesses while others are specific to the industry. Information with respect to such risks is set out in Storm's Annual Information Form dated March 31, 2017 for the year ended December 31, 2016 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2016 under the heading "Business Risks".

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

There were no material new or amended accounting standards adopted during the quarter ended March 31, 2017.

Future Accounting Policy Changes

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts*. The standard is required to be adopted either retrospectively or using the modified transition approach for fiscal years beginning on or after January 1, 2018, with early adoption permitted. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery. Upon initial assessment of the Company's significant revenue contracts, the adoption of IFRS 15 may result in presentation changes in revenue which are not expected to affect net income or loss.

In July 2014, the IASB issued IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected loss" impairment method and a substantially reformed approach to hedge accounting. This standard is effective for annual periods beginning on or after January 1, 2018. The Company's financial assets primarily consist of accounts receivable and derivative commodity price contracts. The terms of these instruments are substantially consistent with those of the Company's peers within the oil and gas industry and are relatively short-term in nature. Upon initial assessment, the Company does not expect that the adoption of IFRS 9 will have a material effect on the Company.

In January 2016 the IASB issued IFRS 16 *Leases* which requires lessees to recognize assets and liabilities for most leases. This standard replaces IAS 17 *Leases* and will be effective for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if IFRS 15 *Revenue from Contracts with Customers* is also adopted. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a "right-to-use asset" for essentially all lease contracts. The Company is currently evaluating the effect of this standard.

ADDITIONAL INFORMATION

Additional information relating to the Company can be viewed at www.sedar.com or on the Company's website at www.stormresourcesltd.com. Information can also be obtained by contacting the Company at Storm Resources Ltd., Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4.

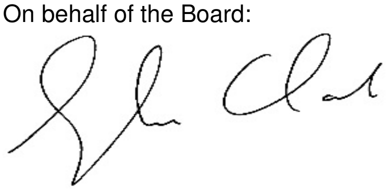
CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

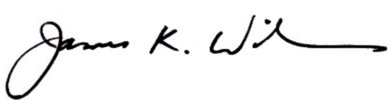
(Canadian $000s) (unaudited)		March 31, 2017		December 31, 2016
ASSETS				
Current				
Accounts receivable (Note 10)	$	12,514	$	13,199
Prepaids and deposits		901		1,176
Fair value of commodity price contracts (Note 10)		681		483
		14,096		14,858
Fair value of commodity price contracts (Note 10)		236		-
Exploration and evaluation (Note 3)		110,527		110,395
Property and equipment (Note 4)		356,952		340,364
	$	481,811	$	465,617
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current				
Accounts payable and accrued liabilities	$	21,345	$	25,382
Fair value of commodity price contracts (Note 10)		6,668		20,622
		28,013		46,004
Bank indebtedness (Note 5)		89,934		78,834
Fair value of commodity price contracts (Note 10)		279		2,016
Decommissioning liability (Note 6)		20,764		18,983
		138,990		145,837
Shareholders' equity				
Share capital (Note 7)		391,444		389,316
Contributed surplus (Note 8)		9,152		8,870
Deficit		(57,775)		(78,406)
		342,821		319,780
Commitments (Note 12)				
	$	481,811	$	465,617

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:



Director



Director

Condensed Interim Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

(Canadian $000s except per-share amounts) (unaudited)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Revenue		
Revenue from product sales	$ 37,045	$ 16,121
Royalties	(2,866)	(922)
Net revenue	34,179	15,199
Realized (loss) gain on commodity price contracts (Note 10)	(3,518)	3,705
Unrealized gain (loss) on commodity price contracts (Note 10)	16,125	(1,971)
Net revenue and commodity price contracts	46,786	16,933
Expenses		
Production	8,905	8,193
Transportation	1,048	645
General and administrative	1,674	1,527
Share-based compensation (Note 8)	954	823
Depletion and depreciation (Note 4)	12,018	9,948
Exploration and evaluation costs expensed (Note 3)	298	-
Accretion (Note 6)	102	87
Interest and finance costs	1,076	684
Unrealized revaluation loss on investment	80	10
Total expenses	26,155	21,917
Net income (loss) and comprehensive income (loss) for the period	$ 20,631	$ (4,984)
Net income (loss) per share (Note 9)		
- Basic and diluted	$ 0.17	$ (0.04)

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)			Three Months Ended March 31, 2017	
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 389,316	$ 8,870	$ (78,406)	$ 319,780
Net income for the period	-	-	20,631	20,631
Issue of common shares (Note 7)	1,456	-	-	1,456
Share-based compensation (Note 8)	-	954	-	954
Share-based compensation on options exercised (Note 7)	672	(672)	-	-
Balance, end of period	$ 391,444	$ 9,152	$ (57,775)	$ 342,821

(Canadian $000s) (unaudited)			Three Months Ended March 31, 2016	
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 385,766	$ 6,738	$ (39,946)	$ 352,558
Net loss for the period	-	-	(4,984)	(4,984)
Issue of common shares (Note 7)	659	-	-	659
Share-based compensation (Note 8)	-	823	-	823
Share-based compensation on options exercised (Note 7)	209	(209)	-	-
Balance, end of period	$ 386,634	$ 7,352	$ (44,930)	$ 349,056

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Operating activities		
Net income (loss) for the period	$ 20,631	$ (4,984)
Non-cash items:		
Unrealized loss (gain) on commodity price contracts (Note 10)	(16,125)	1,971
Depletion, depreciation and accretion (Notes 4 and 6)	12,120	10,035
Share-based compensation (Note 8)	954	823
Exploration and evaluation costs expensed (Note 3)	298	-
Unrealized revaluation loss on investment	80	10
Funds flow	17,958	7,855
Net change in non-cash working capital items (Note 11)	353	2,890
	18,311	10,745
Financing activities		
Proceeds from issue of common shares (Note 7)	1,456	659
Increase in bank indebtedness	11,100	13,375
	12,556	14,034
Investing activities		
Additions to exploration and evaluation assets (Note 3)	(250)	(675)
Additions to property and equipment (Note 4)	(27,107)	(23,271)
Net change in non-cash working capital items (Note 11)	(3,510)	(833)
	(30,867)	(24,779)
Change in cash during the period	-	-
Cash, beginning of period	-	-
Cash, end of period	$ -	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

As at and for the three months ended March 31, 2017 and 2016

Tabular amounts in thousands of Canadian dollars, except per-share amounts
(unaudited)

1. REPORTING ENTITY

Storm Resources Ltd. (the “Company” or "Storm"), is an oil and gas exploration and development company incorporated in the province of Alberta, Canada on June 8, 2010 and is listed on the TSX Venture Exchange under the symbol “SRX”. The Company operates primarily in the province of British Columbia and its head office is located at Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4. The Company became a reporting issuer in August 2010.

These unaudited condensed interim consolidated financial statements (the “financial statements”) include the accounts of Storm and its wholly owned subsidiary, Storm Gas Resource Corp. All inter-entity transactions have been eliminated upon consolidation. Storm’s operations are viewed as a single operating segment by the chief decision maker of the Company for the purpose of resource allocation and assessing asset performance.

2. BASIS OF PRESENTATION

Statement of Compliance

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standard (“IAS”) 34 “Interim Financial Reporting” using accounting policies consistent with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). These financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s audited financial statements as at and for the years ended December 31, 2016 and 2015. All financial information is reported in thousands of Canadian dollars, which is the functional currency of the Company.

These financial statements were authorized for issue by the Board of Directors on May 15, 2017.

Basis of Measurement

The Company’s financial statements have been prepared on a going concern basis consistent with prior years, and follow the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 10.

Significant Accounting Judgments, Estimates and Assumptions

The preparation of the financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, shareholders' equity, revenue and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are continuously reviewed with the financial statement effect being recognized in the reporting period that the changes to estimates are made.

Critical judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are described in Note 5 to the Company’s audited consolidated financial statements for the year ended December 31, 2016.

3. EXPLORATION AND EVALUATION

	Three Months Ended March 31, 2017	Year ended December 31, 2016
Balance, beginning of period	$ 110,395	$ 119,356
Additions	250	1,402
Exploration and evaluation expenditures expensed	(298)	(41)
Future decommissioning costs	180	100
Disposals	-	(100)
Transfer to property and equipment	-	(10,322)
Balance, end of period	$ 110,527	$ 110,395

Management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment at March 31, 2017 and none were identified.

4. PROPERTY AND EQUIPMENT

	Three Months Ended March 31, 2017	Year ended December 31, 2016
Cost		
Balance, beginning of period	$ 466,700	$ 389,781
Additions	27,107	64,136
Future decommissioning costs	1,499	2,581
Disposals	-	(120)
Transfer from exploration and evaluation assets	-	10,322
Balance, end of period	$ 495,306	$ 466,700
Accumulated depletion and depreciation		
Balance, beginning of period	$ (126,336)	$ (86,826)
Depletion and depreciation	(12,018)	(39,510)
Balance, end of period	$ (138,354)	$ (126,336)
Net book value, beginning of period	$ 340,364	$ 302,955
Net book value, end of period	$ 356,952	$ 340,364

Management reviewed the carrying amounts of property and equipment for indicators of impairment at March 31, 2017 and none were identified.

5. BANK INDEBTEDNESS

As at March 31, 2017, the Company had an extendible revolving credit facility in the amount of $130.0 million (December 31, 2016 – $130.0 million) based on a bank determined borrowing base related to the Company's producing reserves. Interest is paid on the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company. The only financial covenant is that debt including working capital deficiency should not exceed the credit facility amount. At March 31, 2017, the Company is in compliance with all covenants under the credit facility.

As at March 31, 2017, the Company had issued letters of credit in the amount of $8.2 million in support of future gas transportation and processing obligations and future reclamation liabilities. Availability under the Company's credit facility is reduced by a like amount.

Subsequent to March 31, 2017 the Company's bank syndicate completed the annual borrowing base review with the result being that the Company's credit facility was increased to $165.0 million. No additional covenants were imposed. The credit facility is available to the Company until April 27, 2018, at which time the borrowing base amount will be reviewed and in the ordinary course of business the Company will have the option to extend the facility for an additional year. If the credit facility is not extended, the facility moves into a term phase whereby the outstanding loan amount is to be repaid one year later.

6. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning oil and gas production assets, including well sites, gathering systems and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's decommissioning obligation is approximately $31.2 million (December 31, 2016 - $28.3 million), which is expected to be paid over the next 30 years with the majority of payments being made in the years 2034 to 2047. A risk-free discount rate of 2.3% (December 31, 2016 – 2.2%) and an inflation rate of 1.6% (December 31, 2016 – 1.6%) was used to calculate the present value of the decommissioning obligation, amounting to $20.8 million at March 31, 2017.

The following table provides a reconciliation of the carrying amount of the obligation:

	Three Months Ended March 31, 2017	Year Ended December 31, 2016
Balance, beginning of period	$ 18,983	$ 16,016
Obligations incurred	1,909	3,159
Obligations disposed	-	(61)
Change in rate estimates(1)	(230)	(478)
Accretion expense	102	347
Balance, end of period	$ 20,764	$ 18,983

(1) Relates to changes in inflation rates, risk-free discount rates and estimated settlement dates.

7. SHARE CAPITAL

Authorized

An unlimited number of voting common shares without nominal or par value
An unlimited number of first preferred shares without nominal or par value

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2016	120,764	$ 389,316
Shares issued on stock option exercises	793	2,128
Balance as at March 31, 2017	121,557	$ 391,444

During the first quarter of 2017, 793,000 common shares were issued upon the exercise of stock options for proceeds of $1,456,000 and related prior period share-based compensation of $672,000 was transferred to share capital from contributed surplus.

8. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers and employees. Options are granted at the market price of the shares on the last business day prior to the date of grant, have a four-year term and vest in one-third tranches over three years. Under the stock option plan, at March 31, 2017, a total of 12,155,681 common shares were available for issuance. Options in respect of 7,739,000 common shares were issued and outstanding at March 31, 2017, with options in respect of 4,416,681 common shares available for future issue.

At May 15, 2017, the date of this quarterly report, options in respect of 7,844,000 common shares were issued and outstanding and 4,311,681 are available for future issue.

Details of the options outstanding at March 31, 2017 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2016	8,387	$ 4.21
Granted during the period	145	$ 4.46
Exercised during the period	(793)	$ 1.83
Outstanding at March 31, 2017	7,739	$ 4.46
Number exercisable at March 31, 2017	3,651	$ 4.34

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$2.64 - $3.95	1,851	2.7	$ 3.35	617	$ 3.35
$3.96 - $5.50	5,888	2.2	$ 4.81	3,034	$ 4.54
Total	7,739	2.3	$ 4.46	3,651	$ 4.34

The fair value of employee stock options is measured using the Black-Scholes option pricing model. Measurement inputs include the share price on measurement date, exercise price of the instrument, expected volatility, forfeiture rate, weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends and the risk-free interest rate (based on government bonds).

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the three months ended March 31, 2017 of $4.46 per share include the following:

	2017
Share price	$4.15 - $5.27
Exercise price	$4.15 - $5.27
Volatility	52%
Forfeiture rate	10%
Expected option life (years)	3.7
Risk-free interest rate	0.8% - 1.0%

No options were granted in the first quarter of 2016.

Share-based compensation expense of $1.0 million was charged to the consolidated statement of income (loss) during the three months to March 31, 2017 (2016 - $0.8 million) with an equivalent offset to contributed surplus. Volatility is based on the historical trading price variances of the Company's share price using market data.

9. NET INCOME (LOSS) PER SHARE

Basic and diluted net income (loss) per share were calculated as follows:

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Net income (loss) for the period	$ 20,631	$ (4,984)
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of period	120,764	119,467
Effect of shares issued	678	124
Weighted average number of common shares outstanding – basic	121,442	119,591
Dilutive effect of outstanding options[1]	278	-
Weighted average number of common shares outstanding - diluted	121,720	119,591
Net income (loss) per share		
- Basic and diluted	$ 0.17	$ (0.04)

(1) Excludes effect of 5.8 million weighted average common shares related to stock options that were anti-dilutive for the three months ended March 31, 2017 (7.6 million weighted average common shares related to stock options for the three months ended March 31, 2016).

10. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness and commodity price contracts.

Storm classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

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

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's commodity price contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the three months ended March 31, 2017.

As at March 31, 2017 and 2016, the net financial liability and asset recognized in relation to the fair value of commodity price contracts was equal to the gross financial amounts as there were no offsets.

Accounts Receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. Receivables from oil and natural gas marketers are typically collected on or about the 25th of the following month. The Company's production is sold to organizations whose credit worthiness is in part assessable from publicly available information. As at March 31, 2017, the Company's most significant marketer accounted for $6.6 million of total receivables and 60% of total revenues for the three months ended March 31, 2017. Where operations involve partners in a joint venture, the Company attempts to mitigate the risk from joint venture receivables by obtaining pre-approval and cash call deposits from its partners in advance of significant capital expenditures. Receivables from joint ventures are typically collected within one to three months of the joint venture bill being issued. As at March 31, 2017, there were no receivables outstanding for more than 30 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at March 31, 2017.

The maximum exposure to credit risk at March 31, 2017 was the carrying amount of accounts receivable of $12.5 million and commodity price contract assets of $0.9 million.

A provision for impairment is established when there is objective evidence that the Company will not be able to collect all amounts due according to the original terms of the receivable. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganization and default or significant delinquency in payments are considered indicators that a receivable is impaired.

Derivative Commodity Price Contracts

At the date of this report, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts, a net liability position of $6.0 million (December 31, 2016 – net liability of $22.2 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the quarter ended March 31, 2017, this resulted in an unrealized mark-to-market gain of $16.1 million (2016 – loss of $2.0 million) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income (loss).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Apr – May 2017	8,000 GJ	AECO Cdn$2.81/GJ
Apr – Jun 2017	14,000 GJ	AECO Cdn$2.62/GJ
Jul – Dec 2017	19,500 GJ	AECO Cdn$2.83/GJ
Apr – Dec 2017	17,000 GJ	AECO Cdn$2.56/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Apr – May 2017	10,400 Mmbtu	Chicago Cdn$4.16/Mmbtu
Apr – Jun 2017	1,900 Mmbtu	Chicago Cdn$4.312/Mmbtu
Jul – Dec 2017	12,800 Mmbtu	Chicago Cdn$4.16/Mmbtu
Jan – Jun 2018	26,850 Mmbtu	Chicago Cdn$4.10/Mmbtu
Jan – Dec 2018	5,000 Mmbtu	Chicago Cdn$3.78/Mmbtu
Natural Gas Differential Swaps		
Apr – Dec 2017	7,670 GJ	Price at Stn 2 = AECO minus Cdn$0.410/GJ
Jan – Dec 2018	3,000 GJ	Price at Stn 2 = AECO minus Cdn$0.345/GJ
Apr – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Apr – Dec 2017	500 Bbls	$62.80 - $70.75 Cdn$/Bbl
Jul – Dec 2017	200 Bbls	$64.50 - $72.88 Cdn$/Bbl
Jan – Mar 2018	250 Bbls	$63.00 - $69.83 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Jan – Jun 2018	150 Bbls	$68.00 - $73.00 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Crude Oil Swaps		
Apr – Jun 2017	550 Bbls	$66.20 Cdn$/Bbl
Jul – Sep 2017	100 Bbls	$65.10 Cdn$/Bbl
Jul – Dec 2017	300 Bbls	$68.40 Cdn$/Bbl
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$70.80 Cdn$/Bbl

During the three months ended March 31, 2017, the Company realized losses from commodity price contracts in place in the amount of $3.5 million (2016 – gains of $3.7 million).

Sensitivities

Using the Company's actual production volumes, royalty rates and bank indebtedness for the first three months of 2017, the estimated after-tax effect that changes in certain factors would have on net income and net income per share is set out below:

	Three Months Ended March 31, 2017	
Factor	Change in Net Income	Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI[1]	$ 320	$ -
$0.10/Mcf change in the price of natural gas	$ 710	$ 0.01
1% change in the interest rate	$ 225	$ -

(1) A portion of the Company's condensate and NGL production is sold at a price based on WTI.

The Company's income tax assets are sufficient to eliminate taxes payable on the increases to income resulting from above; accordingly, before and after tax amounts are the same.

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three months Ended March 31, 2017	Three Months Ended March 31, 2016
Accounts receivable	$ 605	$ 1,693
Prepaids and deposits	275	(493)
Accounts payable and accrued liabilities	(4,037)	857
Change in non-cash working capital	$ (3,157)	$ 2,057
Relating to:		
Operating activities	$ 353	$ 2,890
Investing activities	(3,510)	(833)
Change in non-cash working capital	$ (3,157)	$ 2,057
Interest paid during the period	$ 812	$ 573
Income taxes paid during the period	$ -	$ -

12. COMMITMENTS

As at March 31, 2017, the Company has the following long-term commitments over the next five years and thereafter:

	2017	2018	2019	2020	2021	Thereafter	Total
Office lease	$ 692	$ 692	$ -	$ -	$ -	$ -	$ 1,384
Natural gas transportation and processing commitments	37,168	47,952	33,301	31,434	21,163	188,881	359,899
Total	$ 37,860	$ 48,644	$ 33,301	$ 31,434	$ 21,163	$188,881	$361,283

CORPORATE INFORMATION

Officers

Brian Lavergne
President & CEO

Robert S. Tiberio
Chief Operating Officer

Michael J. Hearn
Chief Financial Officer

Emily Wignes
Vice President, Finance

Jamie P. Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
CEO

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

(1) Member, Audit Committee (2) Member, Reserves Committee (3) Member, Compensation, Governance and Nomination Committee

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Stock Exchange Listing

TSX Venture Exchange
Trading Symbol “SRX”

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

ATB Financial
Canadian Imperial Bank of Commerce
Royal Bank of Canada
Calgary, Alberta

Executive Offices

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Abbreviations

3-D	Three-dimensional
API	American Petroleum Institute
ATP	Alliance Transfer Point
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Bcfe	Billions of cubic feet equivalent
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
GJ	Gigajoules
GJ/d	Gigajoules per day
kPa	One thousand pascals
Mbbl	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
Mmbbl	Millions of barrels
Mmboe	Millions of barrels of oil equivalent
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
Mstb	Thousand stock tank barrels
NAV	Net Asset Value
NGL	Natural gas liquids (includes butane & propane)
NPV	Net present value
OGIP	Original Gas in Place
OPEC	Organization of Petroleum Exporting Countries
psig	pounds per square inch gage pressure
Scf/ton	Standard cubic foot per ton
STOOIP	Stock Tank Original Oil in Place
Tcf	Trillions of cubic feet
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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