Q3 - 2017 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
FINANCIAL				
Revenue from product sales(1)	24,100	21,047	88,462	51,038
Funds flow	13,170	8,759	42,757	22,395
Per share – basic and diluted ($)	0.11	0.07	0.35	0.19
Net income (loss)	682	(85)	31,065	(25,562)
Per share – basic and diluted ($)	0.01	-	0.26	(0.21)
Operations capital expenditures(2)	23,895	7,580	55,559	32,139
Land and property acquisitions	-	(600)	-	(600)
Debt including working capital deficiency(2)(3)	101,297	69,303	101,297	69,303
Common shares (000s)				
Weighted average - basic	121,557	120,195	121,522	119,907
Weighted average - diluted	121,613	120,195	121,679	119,907
Outstanding end of period – basic	121,557	120,283	121,557	120,283
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	17.23	17.22	21.08	14.13
Royalties	(0.85)	(1.19)	(1.41)	(0.72)
Production	(6.03)	(6.69)	(6.17)	(6.72)
Transportation	(0.64)	(0.39)	(0.79)	(0.42)
Field operating netback(2)	9.71	8.95	12.71	6.27
Realized (loss) gain on hedging	1.34	(0.03)	(0.72)	1.74
General and administrative	(1.03)	(1.03)	(1.10)	(1.15)
Interest and finance costs	(0.61)	(0.72)	(0.69)	(0.65)
Funds flow per Boe	9.41	7.17	10.20	6.21
Barrels of oil equivalent per day (6:1)	15,193	13,285	15,371	13,185
Natural gas production				
Thousand cubic feet per day	74,318	65,914	75,537	65,245
Price (Cdn$ per Mcf)(1)	2.02	2.41	2.70	1.77
Condensate production				
Barrels per day	1,600	1,210	1,608	1,278
Price (Cdn$ per barrel)(1)	53.52	49.01	58.70	46.51
NGL production				
Barrels per day	1,206	1,089	1,173	1,033
Price (Cdn$ per barrel)(1)	21.66	10.03	21.74	10.70
Wells drilled (100% working interest)	3.0	-	9.0	7.0
Wells completed (100% working interest)	5.0	3.0	9.0	5.0

(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 25 of the attached Management's Discussion and Analysis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2017 THIRD QUARTER HIGHLIGHTS

- Production increased 14% from the prior year (13% on a per-share basis) to average 15,193 Boe per day. The increase was achieved with approximately 2,500 Boe per day being shut in as a result of the maintenance turnaround at the McMahon Gas Plant (loss of 14,000 Boe per day for 14 days in July) and 1,100 Boe per day was shut in during September due to the very low natural gas price at Station 2 ($0.66 per GJ).

- Condensate and NGL production increased 22% from the prior year to 2,806 barrels per day which represented 18% of per-Boe production and 43% of total revenue.

- In response to the low Western Canadian natural gas prices during the quarter, sales were maximized into the higher priced Chicago market which resulted in 71% of third quarter natural gas sales being at Chicago, 5% at Alliance Transfer Point ("ATP") and the remainder at Station 2.

- At the end of the quarter, there was an inventory of ten Montney horizontal wells (10.0 net) at Umbach that had not started producing which includes four completed wells. Two horizontal wells (2.0 net) started production in the quarter while eight horizontal wells (8.0 net) have started production during the first nine months of the year.

- Montney horizontal well performance at Umbach continues to improve as length is increased and as drilling targets areas where field condensate rates are higher. The three wells (3.0 net) completed in 2017 with enough history averaged 4.1 Mmcf per day gross raw gas plus 128 barrels per day of field condensate over the first 180 calendar days (approximately 800 Boe per day sales with 24% liquids including gas plant NGL). After adjusting for the 39 days of downtime with the McMahon Gas Plant turnaround, the gas rate would be 23% higher than the average well completed in 2014 to 2016 while the field condensate rate would be 130% higher.

- Controllable cash costs (production, general and administrative, interest and finance) were $7.67 per Boe which is a year-over-year decrease of 9%. The decrease was mainly due to production costs declining 10% as a result of production growth and the long-term processing arrangement at the McMahon Gas Plant which commenced in January 2017.

- Funds flow was $13.2 million ($9.41 per Boe), an increase of 50% from a year ago. The improvement was primarily from a higher netback combined with a 14% increase in production volumes. The netback increased by $2.24 per Boe with most of this from hedging (+$1.37 per Boe) and lower production costs (+$0.66 per Boe).

- Net income was $0.7 million or $0.01 per share. Hedging continues to have a recurring impact on quarterly net income with the realized and unrealized gains and losses on hedging adding $1.7 million to net income.

- Capital investment was $23.9 million with 81% being invested in drilling and completions at Umbach. This was less than the original forecast of $28.0 million as a result of lower than budgeted drilling and completion costs.

- Total debt including working capital deficiency was $101.3 million which is 1.9 times annualized third quarter funds flow. The bank credit facility is $165.0 million.

- Natural gas sales will be further diversified through recently added marketing arrangements that now result in approximately 54% to 68% of firm transportation capacity for 2018 being sold at the Chicago price, 11% at the Sumas price less a marketing adjustment (US$0.69/Mmbtu), 5% at the ATP price, 3% to 17% at the Station 2 price and 13% at the AECO price.

- Commodity price hedges continue to be added and currently protect approximately 30% of forecast production for 2018.

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 65 horizontal wells (61.4 net).

Production in the third quarter was 15,073 Boe per day with liquids recovery representing 38 barrels per Mmcf sales (57% being higher priced condensate).

Activity in the third quarter included completing five horizontal wells (5.0 net) and drilling three horizontal wells (3.0 net). Two horizontal wells (2.0 net) started production which left an inventory of ten horizontal wells (10.0 net) that had not started producing at the end of the quarter including four completed wells. Eight horizontal wells (8.0 net) have started production in 2017 with production from these wells totaling 4,800 Boe per day in the third quarter.

Since 2013, approximately $100 million has been invested in building out infrastructure (pipelines and facilities) with current capacity totaling 115 Mmcf per day raw gas from three field compression facilities. Throughput in the third quarter was 79 Mmcf per day raw gas (August and September averaged 88 Mmcf per day). Capacity can be increased to 150 Mmcf per day by installing additional compression at a cost of $7.0 million with the installation timing dependent on well performance and commodity prices. The increased compression capacity would support growth in corporate production to approximately 27,000 Boe per day.

Storm's produced raw natural gas is sour (approximately 1.2% H_2S) with 78% directed to the McMahon Gas Plant in the third quarter and 22% directed to the Stoddart Gas Plant. At the Stoddart Gas Plant, the firm processing commitment is 15 Mmcf raw gas per day until April 2018. At the McMahon Gas Plant, the firm processing commitment started in January 2017, totals 65 Mmcf raw gas per day, has terms of 5 to 15 years, and includes the option to add up to 35 Mmcf raw gas per day.

A summary of horizontal well performance and costs is provided below. The drilling and completion cost per meter for the 2017 wells has decreased by 12% from 2016. The 2017 wells are 28% longer than wells completed in 2014 to 2016 and the average rate over the first 180 calendar days is approximately 20% better after adjusting for the 39 days of downtime for the McMahon Gas Plant turnaround. Notably, the field condensate rate averaged 128 barrels per day over the same period, an improvement of 130% after adjusting for the downtime. IP90's are not used for comparing well performance as the majority of new horizontal wells are initially restricted to manage fluid production. Further improvements in well performance and costs will be realized from the wells being drilled in the second half of 2017 which are approximately 60% longer than wells completed in 2014 to 2016.

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
2014 12 hz's(1)	19	1,170 m	$4.6 million $3,900 per meter	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 $3,200 per meter	4.7 Mmcf/d 11 hz's	4.2 Mmcf/d 11 hz's	3.3 Mmcf/d 11 hz's
2016 10 hz's	25	1,300 m	$3.8 million $2,900 per meter	5.1 Mmcf/d 10 hz's	4.2 Mmcf/d 10 hz's	3.6 Mmcf/d 7 hz's
2017 5 hz's	34	1,630 m	$4.2 million $2,600 per meter	4.9 Mmcf/d(2) 5 hz's	4.1 Mmcf/d(3) 3 hz's	

(1) 2014 wells exclude a middle Montney well (this table provides analysis of upper Montney wells only).
(2) Produced for an average of approximately 80 days due to the McMahon maintenance turnaround June 5 to July 14.
(3) Produced for an average of approximately 141 days due to the McMahon maintenance turnaround June 5 to July 14.

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 57 Boe per day in the third quarter and was as shut in at the end of July due to the low natural gas price at Station 2. Cumulative production to date from this well is 5.7 Bcf raw.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth by continually layering in hedges to protect pricing on 50% of current production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. Note that WTI is hedged as approximately 80% of Storm's liquids production is priced in reference to WTI. The current hedge position is summarized below with prices being hedged on approximately 30% of forecast production for 2018.

Q4 2017		
Crude Oil	1,300 Bpd	WTI Cdn$64.60/Bbl floor, Cdn$68.95/Bbl ceiling
Natural Gas	38,000 GJ/d (30,400 Mcf/d)	AECO Cdn$2.71/GJ
	12,800 Mmbtu/d (10,800 Mcf/d)	Chicago Cdn$4.18/Mmbtu(1)
	5,300 GJ/d (4,200 Mcf/d)	Station 2 Cdn$1.81/GJ
	35,000 Mmbtu/d	Chicago - AECO basis +US$0.58/Mmbtu
	2,670 GJ/d (2,140 Mcf/d)	Station 2 - AECO basis -$0.41/GJ
2018		
Crude Oil	1,110 Bpd	WTI Cdn$64.30/Bbl floor, Cdn$66.59/Bbl ceiling
Propane	200 Bpd	Conway Cdn$38.12/Bbl
Natural Gas	750 GJ/d (600 Mcf/d)	AECO Cdn$2.80/GJ
	24,400 Mmbtu/d (20,700 Mcf/d)	Chicago Cdn$3.92/Mmbtu(1)
	4,000 Mmbtu/d (3,400 Mcf/d)	Chicago US$2.82/Mmbtu(1)
	9,000 Mmbtu/d (7,600 Mcf/d)	Sumas Cdn$3.02/Mmbtu
	3,000 GJ/d (2,400 Mcf/d)	Station 2 - AECO basis -$0.345/GJ

(1) The Alliance Pipeline tariff to Chicago is approximately Cdn$1.21 per Mmbtu including the cost of fuel.

Natural gas transportation capacity totals 102 Mmcf per day sales in 2018 with natural gas production exceeding this directed to Chicago and/or Station 2 using interruptible pipeline capacity (depending on which sales point offers a higher price). Using the firm transportation capacity for 2018 (102 Mmcf per day sales), approximately 54% to 68% will be sold at Chicago pricing, 11% at Sumas pricing less a marketing adjustment, 5% at ATP pricing, 3% to 17% at Station 2 pricing and 13% at AECO pricing. Natural gas marketing arrangements result in the cost of transportation on the Alliance Pipeline for sales in Chicago being deducted from revenue ($7.1 million deducted in the third quarter of 2017). Further information on pipeline tariffs and price deductions is provided in the presentation on Storm's website.

2017	2018
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
Enbridge T-North 16 Mmcf/d Station 2 price	Enbridge T-North 17 Mmcf/d Station 2 price 12 Mmcf/d Sumas price -US$0.69/mmbtu
	Enbridge T-North & TCPL NGTL 13 Mmcf/d AECO price

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

OUTLOOK

Third quarter production was 15,193 Boe per day which was less than guidance of 15,500 to 17,000 Boe per day provided on August 15, 2017. This was primarily due to natural gas prices being lower than forecast which resulted in approximately 1,100 Boe per day that was shut in during September while the start-up of recently completed horizontal wells has been delayed until the fourth quarter.

For the fourth quarter of 2017, production is forecast to be 18,000 to 19,000 Boe per day which represents year-over-year growth of 39% at the mid-point. This is a reduction from guidance provided on August 15, 2017 due to continued weak natural gas prices at Station 2 in October (averaged $0.33/GJ) which further delayed the start-up of new horizontal wells until November. Production to date in the fourth quarter has averaged 17,200 Boe per day based on field estimates. Capital investment is expected to be $26.0 million which includes drilling seven horizontal wells plus completing three horizontal wells at Umbach.

Updated guidance for 2017 is summarized in the tables below. Forecast commodity prices reflect actual year-to-date pricing plus the approximate forward strip for the remainder of 2017. With continuing low natural gas prices at Station 2 delaying the start-up of recently completed horizontal wells, completions originally planned for the fourth quarter have been delayed until 2018. As a result, capital investment will be reduced to $82.0 million (lower end of the range previously indicated) and year-end debt is expected to be at or below 1.5 times fourth quarter funds flow.

2017 Guidance

	August 15, 2017	Updated November 14, 2017
$Cdn/$US exchange rate	0.775	0.77
Chicago daily natural gas - US$/Mmbtu	$2.90	$2.90
AECO daily natural gas - Cdn$/GJ	$2.45	$2.10
Station 2 daily natural gas - Cdn$/GJ	$2.00	$1.70
Edmonton light oil - Cdn$/Bbl	$60.00	$61.00
Estimated average operating costs - $/Boe	$5.75 - $6.00	$6.00
Estimated average royalty rate (% production revenue before hedging)	6% - 8%	6%
Estimated capital investment - $ million (excluding acquisitions & dispositions)	$75.0 - $95.0	$82.0
Estimated cash G&A - $ million	$6.0 - $6.5	$6.0 - $6.5
- $/Boe	$0.95 - $1.05	$1.00 - $1.10
Forecast fourth quarter production - Boe/d % condensate and NGL	19,000 - 21,000 17%	18,000 – 19,000 18%
Forecast annual production - Boe/d % condensate and NGL	16,500 - 18,000 17%	16,200 18%
Umbach horizontal wells drilled Umbach horizontal wells completed Umbach horizontal wells connected	12 - 15 gross (12.0 - 15.0 net) 10 - 16 gross (10.0 - 16.0 net) 13 - 16 gross (13.0 - 16.0 net)	16 gross (16.0 net) 12 gross (12.0 net) 15 gross (15.0 net)

2017 Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	AECO Daily (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
August 15, 2017	$2.90	$2.00	$2.45	$75.0 - $95.0	19,000 - 21,000	16,500 - 18,000
November 14, 2017	$2.90	$1.70	$2.10	$82.0	18,000 - 19,000	16,200

Guidance for 2018 is provided in the table below. Based on the assumptions provided in the table, capital investment is expected to be $55.0 to $90.0 million depending on commodity prices with average annual production forecast to increase by 22% to 32%. The production forecast uses a 6.3 Bcf type curve for future horizontal wells at Umbach with the type curve based on the performance of horizontal wells completed in 2014 to 2016. Recently drilled wells are approximately 60% longer and are expected to outperform this type curve. The cost to drill and complete a horizontal well is estimated to be $4.4 million while the equipping and pipeline tie-in cost is expected to average $0.9 million per well. The timing to install additional compression at Umbach will largely depend on the outlook for the natural gas price at Station 2. For the first half of the year, capital investment is expected to be $25.0 to $44.0 million depending on commodity prices and funds flow.

2018 Guidance

	November 14, 2017
$Cdn/$US exchange rate	0.79
Chicago daily natural gas - US$/Mmbtu	$2.80
Sumas monthly natural gas - US$/Mmbtu	$2.40
AECO daily natural gas - Cdn$/GJ	$1.80 - $2.10
Station 2 daily natural gas - Cdn$/GJ	$1.30 - $1.70
WTI - US$/bbl	$52.00
Edmonton light oil - Cdn$/Bbl	$62.00
Estimated revenue net of transportation - $/Boe (excluding hedging)	$18.00 - $19.25
Estimated average operating costs - $/Boe	$5.75
Estimated average royalty rate (% production revenue before hedging)	6% - 9%
Estimated capital investment - $ million (excluding acquisitions & dispositions)	$55.0 - $90.0
Estimated cash G&A - $ million	$6.0 - $7.0
- $/Boe	$0.70 - $0.95
Estimated interest expense - $ million	$4.5 - $5.5
Forecast fourth quarter production - Boe/d	20,000 - 27,000
% condensate and NGL	17%
Forecast annual production - Boe/d	20,000 - 23,000
% condensate and NGL	17%
Umbach horizontal wells drilled	6 -12 gross (6.0 - 12.0 net)
Umbach horizontal wells completed	11 - 17 gross (11.0 - 17.0 net)
Umbach horizontal wells connected	11 - 16 gross (11.0 - 16.0 net)

The low case for 2018 guidance offers the least exposure to Station 2 natural gas prices and would result in capital investment of $55.0 million with annual average production of 20,000 to 21,000 Boe per day, a year-over-year increase of 22%. This would fill firm transportation capacity which is 102 Mmcf per day sales in 2018. Capital investment would be approximately 75% of funds flow using the low end of the range for forecast commodity prices (year-over-year growth would be achieved while reducing debt).

The high case for 2018 guidance would result in capital investment of $90.0 million with annual average production of 22,000 to 23,000 Boe per day, a year-over-year increase of 32%. Production in the fourth quarter of 2018 would increase to 25,000 to 27,000 Boe per day. Capital investment would largely equal funds flow using the high end of the range for forecast commodity prices. An infrastructure investment of $7.0 million to add compression at Umbach is required to achieve this growth.

Horizontal well performance and capital efficiencies are expected to continue improving with longer wells being drilled at Umbach. The five wells completed in 2017 that have started production are 28% longer and the improvement in initial rates is encouraging although more history is required to determine the magnitude of the improvement. Capital efficiencies have also improved with the drilling and completion cost per meter of length in 2017 decreasing by 12% when compared to wells completed in 2016. Further improvements are expected given that wells drilled in the second half of 2017 are 60% longer than the average well completed in 2014 to 2016 and will target areas where higher field condensate rates are expected.

The effect of continuing volatility in Western Canadian natural gas prices is largely mitigated for Storm by liquids production, commodity price hedges and firm transportation capacity which has diversified natural gas sales. Liquids production represented 37% of year-to-date revenue, commodity price hedges are currently in place for approximately 30% of forecast 2018 production, and natural gas sales are now more diversified with only 16% to 30% of firm transportation for 2018 being sold at Western Canadian prices. However, incremental production growth above Storm's firm transportation capacity (102 Mmcf per day sales or 20,000 to 21,000 Boe per day) is largely directed to Station 2 where recent prices have provided for the lowest netback within Storm's marketing portfolio. As a result, capital investment has been designed to be flexible where activity and production growth can be quickly adjusted in direct response to the Station 2 natural gas price (currently there are four newly completed horizontal wells that are pipeline connected and can be turned on). Generating a return on invested capital as well as maintaining a strong balance sheet are important to the long-term sustainability of the Company and the amount of production growth that is achieved will largely be dependent on commodity prices.

With a large liquids-rich resource in the Montney at Umbach offering multiple years of drilling inventory, the longer-term focus continues to be growing net asset value for shareholders by converting resource into production and funds flow growth on a per-share basis.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

November 14, 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 natural gas to one barrel of oil. Mboe means 1,000 Boe.

Initial Production Rates - Initial production rates ("IP") provided refer to actual raw natural gas rates reported to the British Columbia government. IP rates are not necessarily indicative of long-term performance or of ultimate recovery.

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 November 14, 2017 for the three and nine months ended September 30, 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 and nine months ended September 30, 2017. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 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 November 14, 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 Toronto Stock Exchange ("TSX") under the symbol "SRX".

This MD&A is dated November 14, 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 and nine months ended September 30, 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 three and nine month periods ended September 30, 2016.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The third quarter posed yet another challenging operating environment for Storm. The McMahon Gas Plant maintenance turnaround that began on June 5 required an extra 18 days from the original expectation of 21 days, resulting in approximately 80% of Storm's production being shut in for the first 14 days of July. Further, natural gas prices in Western Canadian markets collapsed in the quarter, although this was partially offset by continuing strength in condensate and NGL prices. The Company was able to partially mitigate very low natural gas prices by maximizing sales to the Chicago market, shipping 71% of production in the period on the Alliance pipeline to Chicago where pricing held up reasonably well, although tempered to a degree by a strengthening Canadian dollar. In response to the low price environment, the Company shut in approximately 1,100 Boe per day in September and deferred the startup of new horizontal wells. This resulted in average daily production for the quarter of 15,193 Boe per day, below the low end of the previously announced guidance range of 15,500 to 17,000 Boe per day. Third quarter production was 9% higher than the average daily production achieved in the immediately preceding quarter and 14% higher than the same quarter of 2016. During the third quarter, condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) accounted for 18% of total per Boe production (17% for the third quarter of 2016) and contributed 43% to revenue in the period (31% for the third quarter of 2016).

Storm continues to manage its production growth in response to ongoing volatility in natural gas prices, while ensuring firm transportation and processing commitments are being met. Nevertheless, with significant financial flexibility, improving well results at Umbach, and an inventory of wells awaiting completion, Storm can react quickly and accelerate production growth in the event of a sustained improvement in Western Canadian natural gas prices.

Compared to the immediately preceding quarter, Storm's realized natural gas price fell by 28% and was down 16% compared to the same quarter in 2016. Part of the weakness in natural gas prices was offset by condensate and NGL prices increasing 9% and 116%, respectively, compared to the same quarter in 2016, with a remarkable recovery in propane prices being the primary contributor to the higher NGL price. There remains considerable volatility in Western Canadian natural gas prices with dismal AECO and Station 2 prices persisting through October as a result of ongoing infrastructure maintenance and restrictions and supply growth. The one bright light as of late has been a rally in WTI prices through October and November on the back of a more balanced global inventory outlook and talk of OPEC extending output cuts. The recent rally in WTI has been further aided for Canadian producers by a weakening of the Canadian dollar, which also benefits Storm's realized natural gas price.

At quarter end, the Company had an inventory of ten horizontal wells (10.0 net) that had not started production, including four completed wells. With no wells drilled or completed in the second quarter of 2017 due to road bans, the third quarter saw a return to normal field activity levels. Capital expenditures totaled $23.9 million, which included the drilling of three wells and commencement of a fourth for $8.1 million and the completion of five wells for $11.2 million. Capital expenditures incurred in the third quarter of 2017 were less than the previously announced guidance of $28 million, primarily due to lower than anticipated drilling and completion costs. Given the low natural gas price at Station 2 in the third quarter, only two wells were brought on stream leaving four completed wells at quarter end that had not started production. Based on the current capital program, the well started in September was rig released in the fourth quarter and an additional six wells will be drilled, while three wells are expected to be completed. Based on this level of activity, fourth quarter production is forecasted to be between 18,000 to 19,000 Boe per day. Other capital expenditures in the third quarter included $2.0 million spent on facilities and $1.5 million on equipping and pipelines. The on-stream date for twinning of the third field compression facility remains commodity price dependent.

Similar to the second quarter, field operating netbacks were burdened by lower production volumes and correspondingly higher fixed processing costs associated with the turnaround at the McMahon Gas Plant, thus affecting comparability between periods. Nevertheless, compared to the same period in 2016, the field operating netback per Boe in the third quarter of 2017 increased by 8%, primarily due to lower production costs and lower royalties. Compared to the second quarter of 2017, the field operating netback per Boe fell by 20%, primarily as a result of the weakness in natural gas prices. The benefit of an improved hedge book relative to the same period in 2016 resulted in a realized hedging gain of $1.9 million or $1.34 per Boe during the third quarter of 2017 versus a small realized hedging loss in the third quarter of 2016 leading to fund flows per Boe that was 31% higher year over year.

Total debt, including working capital deficiency, at quarter end amounted to $101.3 million, up from $90.6 million at the end of the second quarter. With approximately $65.0 million of unused credit capacity, Storm retains considerable financial flexibility to manage its capital expenditure program for the remainder of the year and has the ability to increase or decrease capital expenditures in response to movements in commodity prices.

Subsequent to quarter end, the Company's bank syndicate, upon completion of a mid-year review, confirmed Storm's bank facility at $165 million, which was 56% drawn at the end of the third quarter.

Production and Revenue

Average Daily Production

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Natural gas (Mcf/d)	74,318	65,914	75,537	65,245
Condensate (Bbls/d)	1,600	1,210	1,608	1,278
Natural gas liquids (Bbls/d)	1,206	1,089	1,173	1,033
Total (Boe/d)	15,193	13,285	15,371	13,185

In the third quarter of 2017, average Boe-per-day volumes increased by 14% when compared to the third quarter of 2016 and increased by 9% when compared to the immediately preceding quarter. For the nine month period ended September 30, 2017, average Boe-per-day volumes increased by 17% year over year. 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 two new 100% working interest wells during the third quarter of 2017 and eight new 100% working interest wells during the nine months ended September 30, 2017. The Company had production from a total of 53 wells (49.4 net) at the end of the third quarter of 2017, an increase of 12 wells year over year. During the third quarter of 2017, approximately 2,100 Boe per day of production was shut in as a result of the unplanned extension of the turnaround at the McMahon Gas Plant. Production to date in the fourth quarter of 2017 has averaged approximately 17,200 Boe per day based on field estimates.

Daily production per million shares outstanding at the end of the third quarter of 2017 averaged 125 Boe per day, compared to 110 Boe per day for the third quarter of 2016 and 115 Boe per day for the second quarter of 2017.

Production Profile and Per-Unit Prices[1]

	Three Months to Sept. 30, 2017		Three Months to Sept. 30, 2016		Nine Months to Sept. 30, 2017		Nine Months to Sept. 30, 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	Percentage of Total Boe Production	Average Selling Price Before Transportation Costs
Natural gas – Mcf	82%	$ 2.02	83%	$ 2.41	82%	$ 2.70	82%	$ 1.77
Condensate – Bbl	10%	$ 53.52	9%	$ 49.01	10%	$ 58.70	10%	$ 46.51
Natural gas liquids – Bbl	8%	$ 21.66	8%	$ 10.03	8%	$ 21.74	8%	$ 10.70
Per Boe	100%	$ 17.23	100%	$ 17.22	100%	$ 21.08	100%	$ 14.13

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

On a per-Boe basis, the Company's total realized price of $17.23 for the third quarter of 2017 was comparable to the realized price of $17.22 for the third quarter of 2016. For the nine months ended September 30, 2017, the Company's total realized price was $21.08 per Boe, a 49% increase from the same period in 2016 as the first half of 2016 was subject to prolonged weakness in both natural gas and crude oil prices.

A summary of reference prices for the last seven quarters is set out below. Noteworthy is the disparity between Canadian and US index prices particularly when comparing Station 2 pricing in the third quarter of 2017 to Chicago index pricing for the same period. Storm's realized prices differ from market indices due to fluctuations in the foreign exchange rate, varying transportation costs to each market and the higher heat content of the Company's natural gas.

	Storm Realized Natural Gas Price (Cdn$/Mcf)	Chicago Monthly Index (US$/Mmbtu)	Chicago Daily Index (US$/Mmbtu)	AECO Monthly Index (Cdn$/GJ)	AECO Daily Index (Cdn$/GJ)	Station 2 Daily Index (Cdn$/GJ)	AECO-Station 2 Differential (Cdn$/GJ)	US$/Cdn$
2017								
Q3	2.02	2.83	2.84	2.01	1.38	0.84	(0.54)	0.80
Q2	2.81	3.01	2.93	2.63	2.64	2.21	(0.43)	0.74
Q1	3.23	3.40	2.98	2.79	2.55	2.36	(0.19)	0.76
2016								
Q4	2.86	3.00	2.97	2.67	2.93	2.27	(0.66)	0.75
Q3	2.41	2.76	2.78	2.09	2.20	1.83	(0.37)	0.77
Q2	1.28	1.95	2.09	1.18	1.33	1.14	(0.19)	0.78
Q1	1.62	2.25	2.04	2.00	1.74	1.33	(0.41)	0.73
Average 2016	2.05	2.49	2.47	1.98	2.05	1.64	(0.41)	0.75

During the third quarter of 2017, AECO and Station 2 prices fell considerably due to a combination of factors on the TransCanada Pipelines Limited ("TCPL") NGTL and Enbridge (Spectra) pipeline systems. The most notable were a change in the methodology by which TCPL restricts gas flows during maintenance and continued robust supply growth from the Western Canadian sedimentary basin driving record high storage levels. Western Canadian natural gas prices are expected to remain volatile for the foreseeable future.

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

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Chicago monthly index price[1]	47%	43%	46%	43%
Chicago daily index price[1]	24%	29%	20%	27%
Station 2 daily spot price	24%	12%	29%	15%
AECO daily index price[1]	-	16%	-	15%
Alliance Transfer Point ("ATP")	5%	-	5%	-
Total (Boe/d)	100%	100%	100%	100%

(1) Adjusted for marketing-related fees.

Natural gas sold with reference to the Chicago index price is subject to a pricing reduction equal to the pipeline tariff to Chicago (approximately Cdn$1.15 to $1.20 per GJ) as title to the natural gas transfers at the processing plant in British Columbia.

Storm's realized natural gas price for the third quarter of 2017 was $2.02 per Mcf. With over 70% of production sold in Chicago, Storm's basket realized natural gas price benefited from stronger Chicago pricing, which was partially offset by materially lower Station 2 pricing. Despite a 54% decrease in Station 2 pricing in the third quarter of 2017 compared to the third quarter of 2016, Storm's realized natural gas price decreased by only 16% over the same period due to the Company's diversified marketing strategy. Station 2 pricing at levels seen in the third quarter and through October were quite simply uneconomic and likely below the cost of replacement for all producers.

	Storm Realized Price				
	Condensate (Cdn$/Bbl)	Natural Gas Liquids (Cdn$/Bbl)	WTI (US$/Bbl)	Edmonton Light Oil (Cdn$/Bbl)	US$/Cdn$
2017					
Q3	53.52	21.66	48.21	56.74	0.80
Q2	57.65	20.45	48.29	61.92	0.74
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 third quarter of 2017 comprised approximately 57% condensate, which is generally priced with reference to benchmark pricing for Edmonton light oil. The realized price for condensate in the third quarter of 2017 increased by 9% relative to the third quarter of 2016 and fell by 7% compared to the second quarter of 2017. The US$/Cdn$ exchange rate adjusted differential between WTI and Edmonton light oil was -Cdn$3.67 per barrel in the third quarter of 2017 versus -Cdn$3.86 per barrel in the third quarter of 2016. The realized price for NGL, excluding condensate, in the third quarter of 2017 increased by 116% relative to the same period in 2016. The increase in realized NGL prices was primarily due to a material recovery in propane pricing year over year. Propane prices recently reached three-year highs on the back of tight supplies with inventory levels running below the five-year average.

Increasing natural gas production at Umbach has resulted in higher-value condensate becoming a significant contributor to revenue. The contribution from this revenue stream comprised 10% of Boe production but amounted to 33% of revenue from product sales in the third quarter of 2017. Equivalent amounts for the first nine months of 2017 comprised 10% of Boe production and 29% of revenue from product sales.

Revenue from Product Sales(1)

(000s)	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Natural gas	$ 13,817	$ 14,587	$ 55,730	$ 31,727
Condensate	7,880	5,455	25,772	16,282
Natural gas liquids	2,403	1,005	6,960	3,029
Total	$ 24,100	$ 21,047	$ 88,462	$ 51,038

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

Revenue from product sales for the third quarter of 2017 increased by 15% when compared to the third quarter of 2016 as a result of production volumes increasing by 14%. For the nine month periods, the increase in year-over-year revenue from product sales was 73% with per-Boe pricing increasing 49% and production volumes increasing 17%.

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

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – Q3 2016	$ 14,587	$ 5,455	$ 1,005	$ 21,047
Effect of changes in production volumes	1,863	1,761	108	3,732
Effect of changes in average product prices	(2,633)	664	1,290	(679)
Revenue from product sales – Q3 2017	$ 13,817	$ 7,880	$ 2,403	$ 24,100

(000s)	Natural Gas	Condensate	Natural Gas Liquids	Total
Revenue from product sales – Q2 2017	$ 17,496	$ 7,703	$ 2,118	$ 27,317
Effect of changes in production volumes	1,748	785	151	2,684
Effect of changes in average product prices	(5,427)	(608)	134	(5,901)
Revenue from product sales – Q3 2017	$ 13,817	$ 7,880	$ 2,403	$ 24,100

Realized and Unrealized Gain (Loss) on Commodity Price Contracts

The realized gain (loss) on commodity price contracts consists of the portion of contracts that have settled in cash during the reporting period.

The term liquids below refers to crude oil contracts. Although the Company has no crude oil production, condensate and a portion of the NGL stream is priced with reference to crude oil and, as a result, the Company enters 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 representing the change in the mark-to-market position of unexpired contracts at the end of the period.

	Three Months to Sept. 30, 2017			Three Months to Sept. 30, 2016		
Realized gain (loss)						
Natural gas	$ 1,307	$ 0.19	/Mcf	$ (880)	$ (0.15)	/Mcf
Liquids[2]	569	$ 2.20	/Bbl	839	$ 3.97	/Bbl
Total realized gain (loss) – cash[1]	$ 1,876	$ 1.34	/Boe	$ (41)	$ (0.03)	/Boe

	Nine Months to Sept. 30, 2017			Nine Months to Sept. 30, 2016		
Realized gain (loss)						
Natural gas	$ (3,610)	$ (0.18)	/Mcf	$ 3,379	$ 0.19	/Mcf
Liquids[2]	568	$ 1.29	/Bbl	2,901	$ 4.58	/Bbl
Total realized gain (loss) – cash[1]	$ (3,042)	$ (0.72)	/Boe	$ 6,280	$ 1.74	/Boe

	Three Months to Sept. 30, 2017			Three Months to Sept. 30, 2016		
Unrealized gain (loss)						
Natural gas – change in fair value	$ 1,631	$ 0.24	/Mcf	$ 2,214	$ 0.37	/Mcf
Liquids – change in fair value[2]	(1,793)	$ (6.95)	/Bbl	(654)	$ (3.09)	/Bbl
Total unrealized gain (loss) – non-cash[1]	$ (162)	$ (0.12)	/Boe	$ 1,560	$ 1.28	/Boe

	Nine Months to Sept. 30, 2017			Nine Months to Sept. 30, 2016		
Unrealized gain (loss)						
Natural gas – change in fair value	$ 22,070	$ 1.07	/Mcf	$ (12,702)	$ (0.71)	/Mcf
Liquids – change in fair value[2]	3,364	$ 4.43	/Bbl	(3,512)	$ (5.55)	/Bbl
Total unrealized gain (loss) – non-cash[1]	$ 25,434	$ 6.06	/Boe	$ (16,214)	$ (4.49)	/Boe

(1) The terms cash and non-cash are non-GAAP references.
(2) Liquids includes field condensate, plant pentanes, butane and propane.

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		
Oct – Dec 2017	38,000 GJ	AECO Cdn$2.71/GJ
Nov – Dec 2017	8,000 GJ	Station 2 Cdn$1.79/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Oct – Dec 2017	12,800 Mmbtu	Chicago Cdn$4.18/Mmbtu
Jan – Jun 2018	34,850 Mmbtu	Chicago Cdn$4.01/Mmbtu
Jan – Dec 2018	4,000 Mmbtu	Chicago US$2.815/Mmbtu
Jan – Dec 2018	5,000 Mmbtu	Chicago Cdn$3.78/Mmbtu
Jan – Dec 2018	9,000 Mmbtu	Sumas Cdn$3.02/Mmbtu
Jul – Dec 2018	4,000 Mmbtu	Chicago Cdn$3.52/Mmbtu
Natural Gas Differential Swaps		
Jan – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Oct – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Oct – Dec 2017	700 Bbls	$63.29 - $71.36 Cdn$/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	200 Bbls	$60.00 - $67.88 Cdn$/Bbl
Crude Oil Swaps		
Oct – Dec 2017	600 Bbls	$66.13 Cdn$/Bbl
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Propane Swaps		
Jan – Dec 2018	200 Bbls	$38.12 Cdn$/Bbl

During the third quarter of 2017, the Company realized a gain from commodity price contracts settled during the quarter in the amount of $1.9 million, compared to a loss of $0.04 million in the third quarter of 2016. During the first nine months of 2017, the Company realized a loss from commodity price contracts in the amount of $3.0 million compared to a gain of $6.3 million in the first nine months of 2016. The majority of the loss recognized for the first nine months of 2017 related to natural gas differential swaps between Chicago and AECO which expire at the end of 2017.

The fair market value of contracts outstanding at September 30, 2017 was a net asset position of $3.3 million (December 31, 2016 – net liability of $22.2 million) and is included in current and non-current assets or current and non-current liabilities, as appropriate. For the three months ended September 30, 2017, the change in fair market value resulted in an unrealized mark-to-market loss of $0.2 million and an unrealized mark-to-market gain of $25.4 million for the nine months ended September 30, 2017 (2016 – gain of $1.6 million and loss of $16.2 million, respectively) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

Physical Delivery Sales Contract

The Company also enters into physical delivery sales contracts from time to time to manage commodity price risk. These contracts are considered normal executory contracts and are not recognized in the consolidated statement of income (loss) and comprehensive income (loss) until volumes are delivered.

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Jan 2018 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Royalties

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Charge for period	$ 1,190	$ 1,457	$ 5,928	$ 2,606
Percentage of revenue from product sales	4.9%	6.9%	6.7%	5.1%
Per Boe	$ 0.85	$ 1.19	$ 1.41	$ 0.72

Royalties in the third quarter of 2017, as a percentage of revenue from product sales, decreased to 4.9% from 6.9% in the third quarter of 2016 and increased to 6.7% for the nine months ended September 30, 2017 from 5.1% for the same period in 2016. Royalties in the third quarter of 2017 decreased due to an increase in wells eligible for the BC Deep

Well Royalty Credit Program, which reduces the royalty rate on eligible wells to 6% for approximately two years. Also contributing to the decrease in royalties in the third quarter of 2017 was the receipt of infrastructure royalty credits of $0.3 million as no infrastructure royalty credits were received in the third quarter of 2016. In the third quarter of 2017, 30 wells qualified for the 6% royalty rate compared to 19 wells in the third quarter of 2016. Royalties for the nine months ended September 30, 2017 increased due to higher production revenue driven by an increase in commodity prices, which was partially offset by an increase in the number of wells eligible for the 6% royalty rate under the BC Deep Well Royalty Credit Program.

Storm has remaining infrastructure royalty credits of $7.9 million that will reduce future royalties. The timing of receipt and accounting recognition of future credits is dependent on commodity prices and production levels from individual wells and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary, likely materially, as these credits are earned.

Production Costs

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Charge for period	$ 8,425	$ 8,177	$ 25,907	$ 24,276
Percentage of revenue from product sales	35.0%	38.9%	29.3%	47.6%
Per Boe	$ 6.03	$ 6.69	$ 6.17	$ 6.72

Total production costs for the three and nine months ended September 30, 2017 increased by 3% and 7%, respectively, when compared to the same periods of 2016. The increase in total production costs is due to increased production at Umbach, partially offset by lower natural gas processing fees as a result of a new processing agreement that came into effect on January 1, 2017. The percentage increase in production costs is considerably less than the percentage increase in production volumes, indicative of the Company's efforts to reduce per-Boe costs.

Production costs per Boe for the third quarter of 2017 decreased 10% when compared to the third quarter of 2016 due in part to lower per-unit processing costs associated with the aforementioned new processing agreement. Production costs per Boe for the first nine months of 2017 decreased by 8% when compared to the same period of 2016, also as a result of the lower per-unit processing fee and with production growth reducing the fixed cost component of per-Boe costs. These decreases to production costs per Boe were muted by the additional costs associated with production being reduced during the 39-day maintenance turnaround at the McMahon Gas Plant which meant that the firm processing commitment was not fully utilized.

Transportation Costs

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Charge for period	$ 893	$ 480	$ 3,312	$ 1,513
Percentage of revenue from product sales	3.7%	2.3%	3.7%	3.0%
Per Boe	$ 0.64	$ 0.39	$ 0.79	$ 0.42

Transportation costs include pipeline tariffs for natural gas sold at Station 2, as well as trucking costs for wellhead condensate. Total transportation costs for the third quarter of 2017 increased by $0.4 million when compared to the third quarter of 2016. Transportation costs for the first nine months of 2017 increased by $1.8 million when compared to the same period in 2016. Higher transportation costs are due to an increase in natural gas volumes sold at Station 2 and higher condensate production. Natural gas sold at Station 2 increased from 12% of total natural gas production volumes in the third quarter of 2016 to 24% in the third quarter of 2017. Condensate production for the third quarter of 2017 increased 32% over the same period in 2016. In addition to the higher Station 2 and condensate volumes, the nine month period ended September 30, 2017 was also affected by increased trucking costs attributable to extended road bans relative to the same period in 2016.

As the sales point for natural gas shipped on the Alliance Pipeline is at the gas processing facilities 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 Netbacks

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

Three Months to September 30, 2017	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.02	$ 53.52	$ 21.66	$ 17.23
Royalties	(0.04)	(4.86)	(1.66)	(0.85)
Production costs	(1.23)	-	-	(6.03)
Transportation costs	(0.06)	(3.35)	-	(0.64)
Field operating netback	$ 0.69	$ 45.31	$ 20.00	$ 9.71
Realized gain on commodity price contracts	0.19	2.20	-	1.34
Field operating netback including hedging	$ 0.88	$ 47.51	$ 20.00	$ 11.05

Three Months to September 30, 2016	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.41	$ 49.01	$ 10.03	$ 17.22
Royalties	(0.13)	(5.16)	(1.02)	(1.19)
Production costs	(1.35)	-	-	(6.69)
Transportation costs	(0.03)	(2.79)	-	(0.39)
Field operating netback	$ 0.90	$ 41.06	$ 9.01	$ 8.95
Realized gain (loss) on commodity price contracts	(0.15)	3.97	-	(0.03)
Field operating netback including hedging	$ 0.75	$ 45.03	$ 9.01	$ 8.92

Nine Months to September 30, 2017	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.70	$ 58.70	$ 21.74	$ 21.08
Royalties	(0.14)	(5.43)	(2.02)	(1.41)
Production costs	(1.26)	-	-	(6.17)
Transportation costs	(0.07)	(4.19)	-	(0.79)
Field operating netback	$ 1.23	$ 49.08	$ 19.72	$ 12.71
Realized gain (loss) on commodity price contracts	(0.18)	1.29	-	(0.72)
Field operating netback including hedging	$ 1.05	$ 50.37	$ 19.72	$ 11.99

Nine Months to September 30, 2016	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	Natural Gas Liquids ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 1.77	$ 46.51	$ 10.70	$ 14.13
Royalties	(0.04)	(4.34)	(1.02)	(0.72)
Production costs	(1.36)	-	-	(6.72)
Transportation costs	(0.03)	(2.72)	-	(0.42)
Field operating netback	$ 0.34	$ 39.45	$ 9.68	$ 6.27
Realized gain on commodity price contracts	0.19	4.58	-	1.74
Field operating netback including hedging	$ 0.53	$ 44.03	$ 9.68	$ 8.01

(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 within the condensate netback.

Excluding realized gains and losses on commodity price contracts, the field operating netback per Boe in the third quarter of 2017 increased by 8% to $9.71 compared to $8.95 for the third quarter of 2016. The increase in the field operating netback for the third quarter of 2017 is primarily due to a 10% decrease in per-Boe production costs. For the nine months ended September 30, 2017, the field operating netback per Boe increased by 103% to $12.71 compared to $6.27 for the same period in 2016. Price recovery was the dominant variable in the considerable improvement in the field operating netback for the nine months ended September 30, 2017 compared to the same period in 2016. Year-over-year production costs per Boe for the nine months ended September 30, 2017 decreased 8%, in part as a result of lower natural gas processing fees.

General and Administrative Costs

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Charge for period – before recoveries	$ 1,781	$ 1,389	$ 5,563	$ 4,765
Overhead recoveries	(335)	(136)	(949)	(594)
Charge for period – net of recoveries	$ 1,446	$ 1,253	$ 4,614	$ 4,171
Per Boe	$ 1.03	$ 1.03	$ 1.10	$ 1.15

General and administrative costs before recoveries for the third quarter and first nine months of 2017 increased by 28% and 17%, respectively, when compared to the same periods of 2016. The increase in general and administrative costs is primarily attributable to costs incurred relating to the Company's graduation from the TSX Venture Exchange to the TSX in September 2017. Overhead recoveries for the periods presented fluctuate in response to the relative magnitude of field capital expenditures.

Net general and administrative costs for the third quarter of 2017 on a per-Boe measure were comparable to the third quarter of 2016, and decreased by 4% when comparing the first nine months of 2017 to the same period in 2016. 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 to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Charge for period	$ 1,012	$ 764	$ 2,914	$ 2,316
Per Boe	$ 0.72	$ 0.63	$ 0.69	$ 0.64

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 32% in the third quarter of 2017 compared to the third quarter of 2016 and increased by 26% when comparing the nine month periods. The increase in share-based compensation in both the three and nine month periods is primarily attributable to a higher option valuation associated with options granted in December 2016.

Depletion and Depreciation

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Depletion	$ 9,711	$ 8,731	$ 29,040	$ 25,807
Depreciation	1,501	1,255	4,363	3,727
Charge for period	$ 11,212	$ 9,986	$ 33,403	$ 29,534
Per Boe	$ 8.02	$ 8.17	$ 7.96	$ 8.17

A 14% increase in production volumes resulted in the total charge for depletion and depreciation increasing by 12% in the third quarter of 2017 compared to the same quarter of 2016. Comparing the nine month periods, production volumes grew by 17% with the depletion and depreciation charge increasing by 13%. The quarterly and year-to-date per-Boe decreases in depletion correspond to lower finding and development costs at Umbach. Increased depreciation charges year over year correspond to increased investment in facilities incurred during the nine months ended September 30, 2017.

Interest and Finance Costs

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Charge for period	$ 852	$ 880	$ 2,902	$ 2,357
Average interest rate[1]	3.9%	4.9%	4.4%	4.5%
Per Boe	$ 0.61	$ 0.72	$ 0.69	$ 0.65

(1) Includes financing and standby fees.

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.

Interest costs for the third quarter of 2017 decreased by 3% compared to the third quarter of 2016 driven by lower average interest rates as a result of a decrease in the debt to funds flow ratio, which more than offset an increase in bank borrowings. Interest costs for the nine months ended September 30, 2017 increased by 23% when comparing to the same period in 2016, primarily driven by additional bank borrowings used to fund development of the Company's Umbach property which was partially offset by lower average interest rates.

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 September 30, 2017	Maximum Annual Deduction
Canadian oil and gas property expense	39,000	10%
Canadian development expense	114,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	81,000	20 - 100%
Operating losses	216,000	100%
Other	2,000	20 - 100%
Total	475,000	

Net Income (Loss)

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Net income (loss)	$ 682	$ (85)	$ 31,065	$ (25,562)
Per basic and diluted share	$ 0.01	$ -	$ 0.26	$ (0.21)

The mark-to-market valuation of commodity price contracts resulted in a considerable distortion on reported net income for the nine months ended September 30, 2017. The unrealized gain on commodity price contracts for the nine months ended September 30, 2017 included in the measurement of net income amounted to $25.4 million compared to an unrealized loss for the nine months ended September 30, 2016 of $16.2 million.

The increase in net income, excluding unrealized gains and losses on commodity price contracts, in the third quarter of 2017 and the nine months ended September 30, 2017 compared to the same periods in 2016 is primarily attributed to higher revenue from product sales.

Funds Flow

	Three Months to Sept. 30, 2017		Three Months to Sept. 30, 2016		Nine Months to Sept. 30, 2017		Nine Months to Sept. 30, 2016	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$13,170	$0.11	$8,759	$0.07	$42,757	$0.35	$22,395	$0.19

Funds flow for the third quarter of 2017 increased by 50% from the third quarter of 2016, and by 91% when comparing the first nine months of 2017 to the same period in 2016. Compared to the third quarter of 2016, the increase in funds flow in the third quarter of 2017 was due to higher revenue driven by a 14% increase in production volumes and a $1.9 million realized gain on commodity price contracts. When comparing the first nine months of 2017 to the same period in 2016, funds flow benefited from a realized price that was 49% higher while production volumes increased 17%. The aforementioned increase to funds flow from higher realized prices and higher production for the nine months ended September 30, 2017 was partially offset by a $3.0 million realized loss on commodity price contracts.

Funds flow, a measure that is not defined under IFRS, 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 applied to credit facilities.

Corporate Netbacks

($/Boe)	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Revenue from product sales	17.23	17.22	21.08	14.13
Realized gain (loss) on commodity price contracts	1.34	(0.03)	(0.72)	1.74
Royalties	(0.85)	(1.19)	(1.41)	(0.72)
Production	(6.03)	(6.69)	(6.17)	(6.72)
Transportation	(0.64)	(0.39)	(0.79)	(0.42)
General and administrative	(1.03)	(1.03)	(1.10)	(1.15)
Interest and finance costs	(0.61)	(0.72)	(0.69)	(0.65)
Funds flow per Boe	9.41	7.17	10.20	6.21
Share-based compensation	(0.72)	(0.63)	(0.69)	(0.64)
Depletion, depreciation and accretion	(8.10)	(8.24)	(8.04)	(8.24)
Exploration and evaluation costs expensed	-	-	(0.09)	-
Unrealized revaluation gain (loss) on investment	0.01	(0.01)	(0.03)	(0.02)
Gain on sale of oil and gas properties	-	0.36	-	0.12
Unrealized gain (loss) on commodity price contracts	(0.12)	1.28	6.06	(4.49)
Net income (loss) per Boe	0.48	(0.07)	7.41	(7.06)

Controllable cash costs per Boe, including production costs, general and administrative costs and interest and finance costs, decreased 9% to $7.67 in the third quarter of 2017 compared to $8.44 for the third quarter of 2016 and decreased 7% to $7.96 for the first nine months of 2017 compared to $8.52 for the first nine months of 2016. Transportation costs are excluded as the sales price on a portion of the Company's production is net of the cost to the purchaser of shipping on the Alliance Pipeline to Chicago. Comparing the third quarter of 2017 to the third quarter of 2016, all components of controllable cash costs decreased on a per-Boe basis with the exception of general and administrative costs which were flat between periods due to incremental costs associated with the Company's graduation to the TSX being offset by the decrease in general and administrative costs per Boe resulting from higher production volumes. All components of controllable cash costs for the nine months ended September 30, 2017 decreased when compared to the same period in 2016, with the exception of interest costs which have increased due to higher bank borrowings. Lower natural gas processing fees commencing January 1, 2017 have contributed to reductions in cash costs per commodity unit.

INVESTMENT AND FINANCING

Financial Resources and Liquidity

On April 25, 2017, the Company's 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 evaluated reserve information. In the ordinary course of business, the Company has the option to extend the credit facility 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 September 30, 2017, the Company was in compliance with all covenants under the credit facility; the sole financial covenant is that debt including working capital deficiency cannot exceed the credit facility limit. At September 30, 2017, debt including working capital deficiency amounted to $101.3 million, representing 61% of the available credit facility.

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 expenditure 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 updates the Board on progress at least four times a year.

Capital Expenditures

In the third quarter of 2017, the Company spent $23.9 million (2016 - $7.6 million) on field operations, primarily on drilling three wells and completing five wells at Umbach.

In the first nine months of 2017, the Company spent $55.6 million (2016 - $32.1 million) on field operations, primarily on drilling and completing wells at Umbach. During the nine months ended September 30, 2017, nine 100% working interest horizontal wells were drilled, nine 100% working interest horizontal wells were completed and eight horizontal wells were brought on production.

Major field capital outlays in the first nine months of 2017 included $38.5 million on drilling and completions, $9.2 million on equipping and pipelines and $5.5 million on facilities, all in the Umbach area.

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Land and seismic	$ 673	$ 174	$ 1,079	$ 1,173
Drilling	8,121	(476)	18,000	11,419
Completions	11,211	5,632	20,482	9,694
Facilities	1,958	909	5,494	7,262
Equipping and pipelines	1,516	1,256	9,232	2,442
Recompletions and workovers	416	84	1,262	134
Property acquisition, adjustments and administrative assets	-	1	10	15
Total capital expenditures	$ 23,895	$ 7,580	$ 55,559	$ 32,139
Proceeds on disposition of oil and gas properties	-	(600)	-	(600)
Net capital expenditures	$ 23,895	$ 6,980	$ 55,559	$ 31,539

Net capital investment was allocated as follows:

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Exploration and evaluation	$ 673	$ (307)	$ 1,073	$ 682
Property and equipment	23,222	7,287	54,486	30,857
Total capital expenditures, net of dispositions	$ 23,895	$ 6,980	$ 55,559	$ 31,539

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 September 30, 2017 corresponds to the active field program at Umbach during the third quarter.

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 September 30, 2017 was $34.8 million (December 31, 2016 - $28.3 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 was 2.5% (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 and with reference to industry best practices, as well as provincial and other regulation and evolution of same.

Share Capital

Details of share issuances from inception to September 30, 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
Nine months to Sept.30/17	Stock option exercises	793	$ 1.83	1,456
Total at September 30, 2017		121,557	$ 3.26	$ 395,930

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

During the first nine months 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 September 30, 2017 and at November 14, 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 that commenced October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.5 million over the term of the lease. At September 30, 2017, the remaining office lease commitment is $0.9 million. In addition, the Company has natural gas transportation and processing commitments valued at a total of approximately $334.9 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended September 30, 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 were 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 implement a larger capital expenditure program in the fourth quarter of 2016 which increased production in the first quarter of 2017 as new wells were turned on. The second and third quarters of 2017 saw a retreat in pricing for natural gas and condensate and a decrease in volumes due to a planned maintenance turnaround at the McMahon Gas Plant in June that involved an unanticipated extension into July, which affected revenue and funds flow. With road bans in place for the better part of the second quarter of 2017, capital expenditures were limited as no wells were drilled or completed during the quarter. As road bans were lifted, the third quarter saw a return to normal field activity levels with three wells drilled and five wells completed. However, low natural gas prices in the third quarter of 2017 resulted in production being reduced to the level required to meet firm processing and transportation commitments.

		2017					2016	2015
($000s unless otherwise stated)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue from product sales	24,100	27,317	37,045	26,244	21,047	13,870	16,121	14,480
Funds flow	13,170	11,629	17,958	11,985	8,759	5,781	7,855	9,182
Per share – basic and diluted ($)	0.11	0.10	0.15	0.10	0.07	0.05	0.07	0.08
Net income (loss)	682	9,752	20,631	(12,898)	(85)	(20,493)	(4,984)	1,850
Per share – basic and diluted ($)	0.01	0.08	0.17	(0.11)	(0.00)	(0.17)	(0.04)	0.02
Net capital expenditures	23,895	4,307	27,357	33,399	6,980	613	23,946	31,081
Average daily production (Boe)	15,193	13,991	16,947	13,320	13,285	12,852	13,418	10,730
Debt including working capital deficiency[1]	101,297	90,582	97,864	89,841	69,303	71,254	77,162	61,721

(1) A non-GAAP measure as defined in the non-GAAP measurements section of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the reporting period ended September 30, 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 expenditure 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, as outlined in Storm's November 14, 2017 press release, 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 including prices as outlined in 2017 and 2018 guidance;
- future average production volumes in the fourth quarter of 2017 and 2018, annual production for 2017 and 2018, production growth to 20,000 to 23,000 Boe per day in 2018, along with production volumes by commodity and production declines, and year-over-year production growth percentages for both 2017 and 2018;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2017 and 2018 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 expenditure program and the 2018 capital expenditure program including estimated fourth quarter 2017 and first half 2018 capital expenditures;
- future drilling, completion and tie-in of wells along with the associated costs on a per-well basis, specifically $4.4 million per well forecasted for drilling and completions and $0.9 million per well for equipping and tie-in;
- 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 expenditure programs and future availability of such sources;
- 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 including the estimated 2017 year-end debt to annualized fourth quarter funds flow ratio being at or below 1.5 times;
- availability and use of credit facilities including $65 million of unused credit capacity at quarter end;
- 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 including improvements on future wells from drilling longer wells leading to outperformance of the 6.3 Bcf type curve;
- 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 and 2018 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 and anticipated sales percentage allocation in 2018 to Chicago, Sumas, Station 2 and AECO markets;
- 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 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 natural 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.

Controllable cash costs per Boe, including production costs, general and administrative costs and interest and finance costs, are used by management to assess financial and operational performance.

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 corporate 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 September 30, 2017.

Future Accounting Policy Changes

In April 2016, the IASB issued its final amendments to 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.

The Company intends to retroactively adopt IFRS 15 on January 1, 2018. The Company has completed reviewing its various revenue streams and underlying contracts with customers and has concluded that the adoption of the new standard will likely result in presentation changes in revenue and transportation, which will not affect net income or loss or funds flow. In addition, Storm will expand the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type.

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. Currently, the Company does not apply hedge accounting to its commodity price contracts nor does it intend to with adoption of IFRS 9. 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. The Company does not expect that the adoption of IFRS 9 will have a significant effect on the valuation of the Company's financial assets.

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.

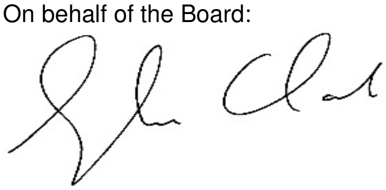
CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

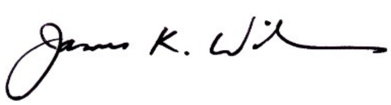
(Canadian $000s) (unaudited)	September 30, 2017	December 31, 2016
ASSETS		
Current		
Accounts receivable (Note 11)	$ 10,214	$ 13,199
Prepaids and deposits	2,696	1,176
Fair value of commodity price contracts (Note 11)	4,580	483
	17,490	14,858
Fair value of commodity price contracts (Note 11)	195	-
Exploration and evaluation (Note 4)	108,719	110,395
Property and equipment (Note 5)	366,794	340,364
	$ 493,198	$ 465,617
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 21,207	$ 25,382
Fair value of commodity price contracts (Note 11)	1,496	20,622
	22,703	46,004
Bank indebtedness (Note 6)	93,000	78,834
Fair value of commodity price contracts (Note 11)	-	2,016
Decommissioning liability (Note 7)	22,280	18,983
	137,983	145,837
Shareholders' equity		
Share capital (Note 8)	391,444	389,316
Contributed surplus (Note 9)	11,112	8,870
Deficit	(47,341)	(78,406)
	355,215	319,780
Commitments (Note 13)		
	$ 493,198	$ 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 to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Revenue				
Revenue from product sales	$ 24,100	$ 21,047	$ 88,462	$ 51,038
Royalties	(1,190)	(1,457)	(5,928)	(2,606)
Net revenue	22,910	19,590	82,534	48,432
Realized (loss) gain on commodity price contracts (Note 11)	1,876	(41)	(3,042)	6,280
Unrealized gain (loss) on commodity price contracts (Note 11)	(162)	1,560	25,434	(16,214)
Net revenue and commodity price contracts	24,624	21,109	104,926	38,498
Expenses				
Production	8,425	8,177	25,907	24,276
Transportation	893	480	3,312	1,513
General and administrative	1,446	1,253	4,614	4,171
Share-based compensation (Note 9)	1,012	764	2,914	2,316
Depletion and depreciation (Note 5)	11,212	9,986	33,403	29,534
Exploration and evaluation costs expensed (Note 4)	-	-	373	-
Accretion (Note 7)	112	85	326	264
Interest and finance costs	852	880	2,902	2,357
Unrealized revaluation loss (gain) on investment	(10)	10	110	70
Gain on sale of oil and gas properties	-	(441)	-	(441)
Total expenses	23,942	21,194	73,861	64,060
Net income (loss) and comprehensive income (loss) for the period	$ 682	$ (85)	$ 31,065	$ (25,562)
Net income (loss) per share (Note 10)				
Basic and diluted	$ 0.01	$ -	$ 0.26	$ (0.21)

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)	Nine Months to September 30, 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	-	-	31,065	31,065
Issue of common shares (Note 8)	1,456	-	-	1,456
Share-based compensation (Note 9)	-	2,914	-	2,914
Share-based compensation on options exercised (Note 8)	672	(672)	-	-
Balance, end of period	$ 391,444	$ 11,112	$ (47,341)	$ 355,215

(Canadian $000s) (unaudited)	Nine Months to September 30, 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	-	-	(25,562)	(25,562)
Issue of common shares (Note 8)	1,632	-	-	1,632
Share-based compensation (Note 9)	-	2,316	-	2,316
Share-based compensation on options exercised (Note 8)	567	(567)	-	-
Balance, end of period	$ 387,965	$ 8,487	$ (65,508)	$ 330,944

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Operating activities				
Net income (loss) for the period	$ 682	$ (85)	$ 31,065	$ (25,562)
Non-cash items:				
Unrealized loss (gain) on commodity price contracts (Note 11)	162	(1,560)	(25,434)	16,214
Depletion, depreciation and accretion (Notes 5 and 7)	11,324	10,071	33,729	29,798
Share-based compensation (Note 9)	1,012	764	2,914	2,316
Exploration and evaluation costs expensed (Note 4)	-	-	373	-
Unrealized revaluation loss (gain) on investment	(10)	10	110	70
Gain on sale of oil and gas properties	-	(441)	-	(441)
Funds flow	13,170	8,759	42,757	22,395
Net change in non-cash working capital items (Note 12)	(3,153)	(344)	2,848	(333)
	10,017	8,415	45,605	22,062
Financing activities				
Proceeds from issue of common shares (Note 8)	-	181	1,456	1,632
Increase (decrease) in bank indebtedness	8,841	(3,006)	14,166	13,948
	8,841	(2,825)	15,622	15,580
Investing activities				
Additions to property and equipment (Note 5)	(23,222)	(7,406)	(54,486)	(30,976)
Additions to exploration and evaluation assets (Note 4)	(673)	(174)	(1,073)	(1,163)
Proceeds on disposal of exploration and evaluation assets	-	481	-	481
Proceeds on disposal of property and equipment	-	119	-	119
Net change in non-cash working capital items (Note 12)	5,037	1,390	(5,668)	(6,103)
	(18,858)	(5,590)	(61,227)	(37,642)
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 and nine months ended September 30, 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 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 November 14, 2017.

Basis of Measurement

The Company's financial statements have been prepared on a going concern basis consistent with prior periods, and follow the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 11.

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. NEW ACCOUNTING POLICIES

In April 2016, the IASB issued its final amendments to 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.

The Company intends to retroactively adopt IFRS 15 on January 1, 2018. The Company has completed reviewing its various revenue streams and underlying contracts with customers and has concluded that the adoption of the new standard will likely result in presentation changes in revenue and transportation, which will not affect net income or loss or funds flow. In addition, Storm will expand the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type.

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. Currently, the Company does not apply hedge accounting to its commodity price contracts nor does it intend to with adoption of IFRS 9. 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. The Company does not expect that the adoption of IFRS 9 will have a significant effect on the valuation of the Company's financial assets.

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.

4. EXPLORATION AND EVALUATION

	Nine Months Ended September 30, 2017	Year ended December 31, 2016
Balance, beginning of period	$ 110,395	$ 119,356
Additions	1,073	1,402
Expiries - exploration and evaluation costs expensed	(373)	(41)
Future decommissioning costs	151	100
Disposals	-	(100)
Transfer to property and equipment	(2,527)	(10,322)
Balance, end of period	$ 108,719	$ 110,395

Management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment at September 30, 2017 and none were identified.

5. PROPERTY AND EQUIPMENT

	Nine Months Ended September 30, 2017	Year ended December 31, 2016
Cost		
Balance, beginning of period	$ 466,700	$ 389,781
Additions	54,486	64,136
Future decommissioning costs	2,820	2,581
Disposals	-	(120)
Transfer from exploration and evaluation assets	2,527	10,322
Balance, end of period	$ 526,533	$ 466,700
Accumulated depletion and depreciation		
Balance, beginning of period	$ (126,336)	$ (86,826)
Depletion and depreciation	(33,403)	(39,510)
Balance, end of period	$ (159,739)	$ (126,336)
Net book value, beginning of period	$ 340,364	$ 302,955
Net book value, end of period	$ 366,794	$ 340,364

Management reviewed the carrying amounts of property and equipment for indicators of impairment at September 30, 2017 and none were identified.

6. BANK INDEBTEDNESS

As at September 30, 2017, the Company had an extendible revolving credit facility in the amount of $165.0 million (December 31, 2016 – $130.0 million) based on a bank determined borrowing base related to the Company's producing reserves. 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. 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 September 30, 2017, the Company is in compliance with all covenants under the credit facility.

As at September 30, 2017, the Company had issued letters of credit in the amount of $7.9 million (December 31, 2016 - $8.1 million) in support of future natural gas transportation and processing obligations and future reclamation liabilities. Availability under the Company's credit facility is reduced by a like amount.

7. 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 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 $34.8 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 2.5% (December 31, 2016 – 2.2%) and an inflation rate of 2.0% (December 31, 2016 – 1.6%) was used to calculate the present value of the decommissioning obligation, amounting to $22.3 million at September 30, 2017.

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

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
Balance, beginning of period	$ 18,983	$ 16,016
Obligations incurred	2,420	3,159
Obligations disposed	-	(61)
Change in rate estimates(1)	551	(478)
Accretion expense	326	347
Balance, end of period	$ 22,280	$ 18,983

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

8. 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 September 30, 2017	121,557	$ 391,444

During the first nine months 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.

9. 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 September 30, 2017 and at November 14, 2017, the date of this report, a total of 12,155,681 common shares were available for issuance, options in respect of 7,914,000 common shares were issued and outstanding and options in respect of 4,241,681 common shares were available for future issue.

Details of the options outstanding at September 30, 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	320	4.27
Exercised during the period	(793)	1.83
Outstanding at September 30, 2017	7,914	4.46
Number exercisable at September 30, 2017	3,678	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	1,891	2.2	3.35	617	3.35
$3.96 - $5.50	6,023	1.8	4.80	3,061	4.55
Total	7,914	1.9	4.46	3,678	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 nine months ended September 30, 2017 of $4.27 per share include the following:

	2017
Share price	$3.91 - $5.27
Exercise price	$3.91 - $5.27
Volatility	52%
Forfeiture rate	10%
Expected option life (years)	3.7
Risk-free interest rate	0.7% - 1.4%

No options were granted in the first nine months of 2016.

Share-based compensation expense of $1.0 million and $2.9 million was charged to the consolidated statement of income (loss) during the three and nine months to September 30, 2017, respectively (2016 - $0.8 million and $2.3 million, respectively) with an equivalent offset to contributed surplus.

10. NET INCOME (LOSS) PER SHARE

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

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Net income (loss) for the period	$ 682	$ (85)	$ 31,065	$ (25,562)
Weighted average number of common shares outstanding – basic				
Common shares outstanding at beginning of period	121,557	120,179	120,764	119,467
Effect of shares issued	-	16	758	440
Weighted average number of common shares outstanding – basic	121,557	120,195	121,522	119,907
Dilutive effect of outstanding options(1)	56	-	157	-
Weighted average number of common shares outstanding - diluted	121,613	120,195	121,679	119,907
Net income (loss) per share				
Basic and diluted	$ 0.01	$ -	$ 0.26	$ (0.21)

(1) Excludes the effect of 6.0 million weighted average common shares related to stock options that were anti-dilutive for both the three and nine months ended September 30, 2017 (5.2 million and 4.8 million weighted average common shares related to stock options for the three and nine months ended September 30, 2016, respectively).

11. 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 and nine months ended September 30, 2017 and in the comparable periods in the prior year.

The Company's commodity price contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at September 30, 2017:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Commodity price contracts			
Current asset	17,267	(12,687)	4,580
Long-term asset	907	(712)	195
Current liability	(14,183)	12,687	(1,496)
Long-term liability	(712)	712	-
Net position	3,279	-	3,279

As at December 31, 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 September 30, 2017, the Company's most significant marketer accounted for $4.6 million of total receivables and 54% of total revenues for each of the three and nine months ended September 30, 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. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at September 30, 2017.

The maximum exposure to credit risk at September 30, 2017 was the carrying amount of accounts receivable of $10.2 million and commodity price contract assets of $4.8 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 asset position of $3.3 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 three months ended September 30, 2017, this resulted in an unrealized mark-to-market loss of $0.2 million and an unrealized mark-to-market gain of $25.4 million for the nine months ended September 30, 2017 (2016 – gain of $1.6 million and loss of $16.2 million, respectively) 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) and comprehensive income (loss).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Oct – Dec 2017	38,000 GJ	AECO Cdn$2.71/GJ
Nov – Dec 2017	8,000 GJ	Station 2 Cdn$1.79/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Oct – Dec 2017	12,800 Mmbtu	Chicago Cdn$4.18/Mmbtu
Jan – Jun 2018	34,850 Mmbtu	Chicago Cdn$4.01/Mmbtu
Jan – Dec 2018	4,000 Mmbtu	Chicago US$2.815/Mmbtu
Jan – Dec 2018	5,000 Mmbtu	Chicago Cdn$3.78/Mmbtu
Jan – Dec 2018	9,000 Mmbtu	Sumas Cdn$3.02/Mmbtu
Jul – Dec 2018	4,000 Mmbtu	Chicago Cdn $3.52/Mmbtu
Natural Gas Differential Swaps		
Jan – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Oct – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu
Crude Oil Collars		
Oct – Dec 2017	700 Bbls	$63.29 - $71.36 Cdn$/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	200 Bbls	$60.00 - $67.88 Cdn$/Bbl
Crude Oil Swaps		
Oct – Dec 2017	600 Bbls	$66.13 Cdn$/Bbl
Jan – Jun 2018	100 Bbls	$70.05 Cdn$/Bbl
Jan – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Propane Swaps		
Jan – Dec 2018	200 Bbls	$38.12 Cdn$/Bbl

During the three months ended September 30, 2017, the Company realized a gain from commodity price contracts in place of $1.9 million and recognized a realized loss of $3.0 million for the nine months ended September 30, 2017 (2016 – loss of $0.04 million and gain of $6.3 million, respectively).

Physical Delivery Sales Contract

The Company also enters into physical delivery sales contracts from time to time to manage commodity price risk. These contracts are considered normal executory contracts and are not recognized in the consolidated statement of income (loss) and comprehensive income (loss) until volumes are delivered.

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Jan 2018 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Sensitivities

Using the Company's actual production volumes, royalty rates and bank indebtedness for the nine months ended September 30, 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:

	Nine Months Ended September 30, 2017	
Factor	Change in Net Income	Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI[(1)]	$ 900	$ 0.01
$0.10/Mcf change in the price of natural gas	$ 1,950	$ 0.02
1% change in the interest rate	$ 713	$ 0.01

(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.

12. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to Sept. 30, 2017	Three Months to Sept. 30, 2016	Nine Months to Sept. 30, 2017	Nine Months to Sept. 30, 2016
Accounts receivable	$ (7,172)	$ (859)	$ 2,875	$ 862
Prepaids and deposits	(1,994)	(226)	(1,520)	(1,776)
Accounts payable and accrued liabilities	11,050	2,131	(4,175)	(5,522)
Change in non-cash working capital	$ 1,884	$ 1,046	$ (2,820)	$ (6,436)
Relating to:				
Operating activities	$ (3,153)	$ (344)	$ 2,848	$ (333)
Investing activities	5,037	1,390	(5,668)	(6,103)
Change in non-cash working capital	$ 1,884	$ 1,046	$ (2,820)	$ (6,436)
Interest paid during the period	$ 955	$ 841	$ 2,741	$ 2,179
Income taxes paid during the period	$ -	$ -	$ -	$ -

13. COMMITMENTS

At September 30, 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	$ 215	$ 646	$ -	$ -	$ -	$ -	$ 861
Natural gas transportation and processing commitments	12,486	47,333	33,001	31,184	21,163	188,881	334,048
Total	$ 12,701	$ 47,979	$ 33,001	$ 31,184	$ 21,163	$ 188,881	$ 334,909

CORPORATE INFORMATION

Officers

Brian Lavergne
President and 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
President and 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

Toronto Stock 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

Suite 200, 640 – 5th Avenue S.W.
Calgary, Alberta, T2P 3G4 Canada
Tel: (403) 817-6145 Fax: (403) 817-6146
www.stormresourcesltd.com

Abbreviations

ATP	Alliance Transfer Point
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
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
Mbbl	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
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
NGL	Natural gas liquids
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

Storm Resources Ltd.
Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4
Phone: (403)817-6145   Fax: (403)817-6146

www.stormresourcesltd.com