Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
FINANCIAL				
Revenue from product sales(1)	21,047	16,283	51,038	53,256
Funds from operations(2)	8,759	7,982	22,395	29,864
Per share - basic ($)	0.07	0.07	0.19	0.26
Per share – diluted ($)	0.07	0.07	0.19	0.26
Net loss	(85)	(961)	(25,562)	(8,717)
Per share - basic ($)	(0.00)	(0.01)	(0.21)	(0.08)
Per share - diluted ($)	(0.00)	(0.01)	(0.21)	(0.08)
Net capital invested	6,980	(4,116)	31,539	40,428
Operations capital expenditures	7,580	19,557	32,139	64,101
Land and property acquisitions (dispositions)	(600)	(23,673)	(600)	(23,673)
Debt including working capital deficiency(3)	69,303	39,994	69,303	39,994
Common shares (000s)				
Weighted average - basic	120,195	119,355	119,907	114,618
Weighted average - diluted	120,195	119,355	119,907	114,618
Outstanding end of period – basic	120,283	119,355	120,283	119,355
OPERATIONS				
(Cdn$ per Boe)				
Revenue	17.22	18.33	14.13	20.12
Royalties	(1.19)	(1.28)	(0.72)	(1.15)
Production	(6.69)	(7.89)	(6.72)	(8.37)
Transportation	(0.39)	(0.94)	(0.42)	(1.26)
Field operating netback	8.95	8.22	6.27	9.34
Realized hedging gains (losses)	(0.03)	2.22	1.74	4.20
General and administrative	(1.03)	(1.07)	(1.15)	(1.60)
Interest and finance costs	(0.72)	(0.39)	(0.65)	(0.65)
Funds from operations – per Boe	7.17	8.98	6.21	11.29
Barrels of oil equivalent per day (6:1)	13,285	9,654	13,185	9,695
Gas Production				
Thousand cubic feet per day	65,914	47,325	65,245	47,142
Price (Cdn$ per Mcf)	2.41	2.46	1.77	2.62
NGL production				
Barrels per day	2,299	1,697	2,311	1,598
Price (Cdn$ per barrel)	30.54	33.32	30.49	37.13
Oil Production				
Barrels per day	-	70	-	240
Price (Cdn$ per barrel)	-	55.93	-	50.84
Wells drilled (100% working interest)	-	-	7.0	6.0
Wells completed (100% working interest)	3.0	4.0	5.0	6.0

(1) Excludes hedging gains and losses.
(2) Certain financial amounts shown above are non-GAAP measurements, including funds from operations and funds from operations per share, operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 26 of the attached Management's Discussion and Analysis ("MD&A") and the reconciliation of funds from operations to the most directly comparable measurement under GAAP, cash flows from operating activities, on page 18 of the attached MD&A.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2016 THIRD QUARTER

- Production averaged 13,285 Boe per day (17% NGL), a year-over-year increase of 38% (37% on a per-share basis) and a quarter-over-quarter increase of 3%. Production increased compared to the previous quarter with two new wells beginning production in late August and in September as a result of the improvement in natural gas prices.

- NGL production was 2,299 barrels per day, an increase of 35% from the previous year. At $30.54 per barrel, the price was 56% of the average Edmonton light oil price (53% of NGL's are higher value condensate and plant pentanes).

- Through the first nine months of 2016, six new horizontal wells have been placed on stream which has maintained production between 12,500 and 13,800 Boe per day. At the end of the quarter, there was an inventory of seven horizontal wells (7.0 net) that had not started production which included one completed well.

- Montney horizontal well performance at Umbach continues to improve with the first two wells completed in 2016 averaging 5.7 Mmcf per day gross raw gas over the first 90 calendar days, a 20% improvement from the average 2014 and 2015 wells.

- Controllable cash costs (operating, cash G&A, interest expense) were $8.44 per Boe, a year-over-year decrease of 10%. Transportation cost is excluded given that the sales price for volumes shipped on the Alliance Pipeline includes a deduction for the pipeline tariff (artificially reduces the transportation cost).

- Funds flow was $8.8 million ($7.17 per Boe), an increase of 10% from a year ago. Excluding hedging gains, the increase was 46%. The year-over-year improvement resulted from production increasing 38% and controllable cash costs per Boe decreasing 10% which was partially offset by a 6% decrease in revenue per Boe.

- Net capital investment was $7.0 million which included completing three horizontal wells (3.0 net) and site preparation for the third field compression facility at Umbach.

- Debt including working capital deficiency was $69.3 million which is 2.0 times annualized third quarter funds flow and is a reduction of $2.0 million from the previous quarter. The bank credit facility remains at $130 million.

- Commodity price hedges for 2017 have increased to represent approximately 39% of current production (an increase from approximately 24% hedged when second quarter results were released August 15, 2016).

- On September 7, Storm announced that it had entered into a natural gas processing arrangement at Umbach with Spectra Energy ("Spectra") that is expected to reduce operating costs by approximately 15% to 20% with the anticipated increase in funds flow being used to increase capital investment and accelerate growth in 2017.

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, 48 horizontal wells have been drilled (44.4 net) with 41 horizontal wells producing at the end of the third quarter (37.4 net). Over the last 12 months, the number of producing wells has increased by 9.0 net wells.

Production in the third quarter was 13,130 Boe per day and NGL recovery was 35 barrels per Mmcf sales with 53% being higher priced field condensate plus pentanes recovered at the gas plant.

During the third quarter, three horizontal wells were completed (3.0 net) and two horizontal wells (2.0 net) started production. At the end of the third quarter, there was an inventory of seven horizontal wells (7.0 net) that had not started producing which included one completed well. Activity in the fourth quarter will include drilling five horizontal wells (5.0 net) and completing five horizontal wells (5.0 net).

Storm's two operated field compression facilities have total capacity of 80 Mmcf per day raw gas with actual throughput in the third quarter averaging 69 Mmcf per day raw gas. Construction has started on the third field compression facility with initial capacity of 35 Mmcf per day and start-up is planned for January 2017. The estimated total cost is unchanged at $25.0 million with $4.8 million incurred in 2015, $19.0 million in 2016, and the remainder planned for 2017. The third facility is expandable to 70 Mmcf per day raw gas for an additional investment of $7.0 million.

Raw gas from Storm's field compression facilities is sent to the McMahon and Stoddart Gas Plants where firm processing commitments average 75 Mmcf per day raw gas in 2017. This includes the recently announced natural gas processing arrangement with Spectra which has an effective date of January 1, 2017 and a total commitment of 65 Mmcf per day of raw gas at terms ranging from 5 to 15 years. The arrangement with Spectra represents a significant step forward by reducing operating costs, supporting future growth with an option to increase contracted capacity, and provides for continued diversification of natural gas sales with access to three sales pipelines through the McMahon Gas Plant (Alliance Pipeline to Chicago, TransCanada NGTL system to AECO, Spectra T-north mainline to BC Station 2).

A summary of horizontal well performance and costs is provided below. On a per-stage basis, the drill and complete cost for 2016 wells has decreased by 25% from 2015.

Year of Completion	**Frac Stages**	**Completed Length**	**Actual Drill & Complete Cost**	**IP 90 Cal Day Mmcf/d Raw**	**IP 180 Cal Day Mmcf/d Raw**	**IP 365 Cal Day Mmcf/d Raw**
2013 6 wells	17	1,190 m	$4.6 million $270 K/stage	3.5 Mmcf/d 6 hz's	2.9 Mmcf/d 6 hz's	2.2 Mmcf/d 6 hz's
2014 12 wells*	19	1,170 m	$4.6 million $240 K/stage	4.9 Mmcf/d 12 hz's	4.4 Mmcf/d 12 hz's	3.5 Mmcf/d 12 hz's
2015 11 wells	22	1,360 m	$4.4 million $200 K/stage	4.7 Mmcf/d 11 hz's	4.2 Mmcf/d 9 hz's	
2016 5 wells	27	1,410 m	$4.0 million $148 K/stage	5.7 Mmcf/d 2 hz's		

* 2014 wells exclude a middle Montney well (comparing upper Montney wells only).

The majority of future horizontal wells are expected to have greater than 1,600 metres of completed length with more than 30 frac stages while the average 2014 and 2015 wells have a completed length of 1,265 metres and an average of 21 frac stages. More information on the type curve and well economics is provided in the presentation on Storm's website.

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 was restarted during September as a result of an improvement in the BC Station 2 natural gas price and averaged 141 Boe per day in the third quarter (was shut in July 2015 due to the low natural gas price at BC Station 2). Cumulative production to date from this well is 5.1 Bcf raw.

HEDGING AND TRANSPORTATION

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

Storm's commodity price hedges are summarized below. For 2017, approximately 38% of current production or 30% of forecast 2017 production is hedged.

Q4 2016		
Crude Oil	950 Bopd	WTI Cdn$68.86/Bbl floor, Cdn$78.48/Bbl ceiling
Natural Gas	43,670 GJ/d (34,900 Mcf/d)	AECO Cdn$2.38/GJ ($2.98/Mcf)
2017		
Crude Oil	775 Bopd	WTI Cdn$64.11/Bbl floor, Cdn$69.24/Bbl ceiling
Natural Gas	30,340 GJ/d (24,300 Mcf/d)	AECO Cdn$2.62/GJ ($3.27/Mcf)
	2,940 GJ/d (2,350 Mcf/d)	Chicago Cdn$3.90/GJ ($4.88/Mcf)

Storm's strategy with respect to natural gas transportation commitments is to diversify natural gas sales by selling at multiple points including Chicago, AECO and BC Station 2. Transportation commitments total 65 Mmcf per day in 2017 and increase to 95 Mmcf per day in 2018 (interruptible capacity on the Alliance Pipeline adds up to 14 Mmcf per day in 2017 and up to 15 Mmcf per day in 2018). As production increases, additional firm transportation will be added. A summary is provided below and further information on pipeline tariffs and price deductions is provided in the presentation on Storm's website.

Q4 2016	2017	2018
Alliance Pipeline(1) 46 Mmcf/d Chicago price 5 Mmcf/d ATP price	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
Spectra T-north 9 Mmcf/d BC Stn 2 price	Spectra T-north 9 Mmcf/d BC Stn 2 price	Spectra T-north 22 Mmcf/d BC Stn 2 price
Marketing Arrangement 3 Mmcf/d AECO price -$0.68/GJ		Spectra T-north & TCPL 13 Mmcf/d AECO price

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

ORGANIZATIONAL UPDATE

Mr. Donald McLean, Chief Financial Officer, has announced he will be retiring in mid-2017. Mr. McLean joined the 'first' Storm in 2001 and has been involved in all four Storm companies. In addition, Mr. John Devlin, Vice President, Finance, has also announced he will be retiring in mid-2017. Mr. Devlin joined the 'third' Storm in 2005 and has been involved in the last two Storm companies. Each of Mr. McLean and Mr. Devlin has provided valuable contributions to the success of Storm. Successors to both will be identified through an internal process.

OUTLOOK

Fourth quarter production is forecast to be approximately 13,000 to 14,000 Boe per day depending on commodity prices. Production in October averaged 12,200 Boe per day and was impacted by a nine-day outage on the Alliance Pipeline plus an 11-day outage on the Spectra T-north Fort St. John lateral to BC Station 2. Capital investment is expected to be $37 million and activity will include construction of the third field compression facility at Umbach ($11 million), drilling five horizontal wells ($10 million), and completing and equipping five horizontal wells ($11 million).

On September 7, 2016, Storm announced that it had entered into a natural gas processing arrangement with Spectra at Umbach with the expected increase in funds flow being used to increase capital investment and accelerate growth in 2017. Expected service cost reductions are also supportive of accelerating growth. Guidance for 2016 and 2017 is provided below and is unchanged from what was provided September 7th except for updating commodity prices.

2016 Guidance

	September 7, 2016	November 15, 2016
Chicago natural gas price	US$2.40/Mmbtu(1)	US$2.45/Mmbtu(1)
AECO natural gas price	$1.95/GJ(1)	$2.00/GJ(1)
BC STN 2 natural gas price	$1.65/GJ(1)	$1.65/GJ(1)
Edmonton light oil price	Cdn$50/Bbl(1)	Cdn$52/Bbl(1)
Estimated average operating costs	$7.00/Boe	$7.00/Boe
Estimated average royalty rate (% production revenue before hedging)	5% - 6%	5% - 6%
Estimated operations capital (excluding acquisitions & dispositions)	$70.0 million	$65.0 - $70.0 million
Estimated cash G&A net of recoveries	$5.7 million $1.20/Boe	$5.7 million $1.20/Boe
Forecast fourth quarter production	13,000 – 14,000 Boe/d (18% NGL)	13,000 – 14,000 Boe/d (18% NGL)
Forecast annual production	12,500 – 13,500 Boe/d (18% NGL)	12,500 – 13,500 Boe/d (18% NGL)
Umbach horizontal wells drilled Umbach horizontal wells completed Umbach horizontal wells connected	12 gross (12.0 net) 10 gross (10.0 net) 10 gross (10.0 net)	12 gross (12.0 net) 10 gross (10.0 net) 11 gross (11.0 net)

(1) Assumed commodity prices are approximately equal to realized prices to date and the current forward strip.

2016 Guidance History

	AECO Natural gas price	Estimated Operations Capital	Forecast Fourth Quarter Production	Forecast Annual Production
August 13, 2015	$2.80/GJ	$106.0 million	20,000 – 21,000 Boe/d	16,000 – 19,000 Boe/d
November 11, 2015	$2.50/GJ	$105.0 million	20,000 – 21,000 Boe/d	16,000 – 18,000 Boe/d
February 25, 2016	$2.00/GJ	$80.0 million	15,500 – 16,500 Boe/d	14,000 - 15,000 Boe/d
May 12, 2016	$1.60/GJ	$37.0 to $42.0 million	13,000 – 14,000 Boe/d	12,500 - 13,500 Boe/d
August 15, 2016	$1.95/GJ	$36.0 to $50.0 million	13,000 – 14,000 Boe/d	12,500 - 13,500 Boe/d
September 7, 2016	$1.95/GJ	$70.0 million	13,000 – 14,000 Boe/d	12,500 - 13,500 Boe/d

2017 Guidance

	September 7, 2016	November 15, 2016
Chicago natural gas price	US$3.00 per Mmbtu	US$3.00 per Mmbtu
AECO natural gas price	$2.65 per GJ	$2.65 per GJ
BC STN 2 natural gas price	$2.25 per GJ	$2.20 per GJ
Edmonton light oil price	Cdn$55 per Bbl	Cdn$55 per Bbl
Estimated average operating costs	$5.50 - $5.75/Boe	$5.50 - $5.75/Boe
Estimated average royalty rate (% production revenue before hedging)	9% - 11%	9% - 11%
Estimated operations capital (excluding acquisitions & dispositions)	$75.0 - $80.0 million	$75.0 - $80.0 million
Estimated cash G&A net of recoveries	$5.3 million $0.85/Boe	$5.3 million $0.85/Boe
Forecast fourth quarter production	18,000 – 20,000 Boe/d (17% NGL)	18,000 – 20,000 Boe/d (17% NGL)
Forecast annual production	16,500 – 18,000 Boe/d (17% NGL)	16,500 – 18,000 Boe/d (17% NGL)
Umbach horizontal wells drilled Umbach horizontal wells completed Umbach horizontal wells connected	12 gross (12.0 net) 13 gross (13.0 net) 15 gross (15.0 net)	12 gross (12.0 net) 14 gross (14.0 net) 15 gross (15.0 net)

Capital investment in 2016 includes $19 million for the third field compression facility which is expected to be operational in January 2017. Initial capacity will be 35 Mmcf per day which can be expanded to 70 Mmcf per day for an additional investment of $7 million. Once the expansion is completed, capacity from Storm's three field compression facilities will exceed 150 Mmcf per day of raw gas which supports growth in corporate production to 25,000 to 27,000 Boe per day.

Capital investment in 2017 assumes a cost of $4.1 million to drill and complete a horizontal well at Umbach plus a total of $14.0 million for infrastructure expansion at Umbach which includes gathering pipelines and the remaining equipment at the third field compression facility.

Forecast production for 2017 is dependent on capital investment which may be adjusted up or down depending on commodity prices and funds flow. Hedges will continue to be layered in for 2017 and 2018 in support of planned growth which increases certainty on future funds flow.

Approximately 74% of forecast natural gas production in 2017 is covered by firm transportation agreements with the majority being capacity on the Alliance Pipeline (65% of forecast 2017 production). Including 'priority interruptible transportation service' (PITS) on the Alliance Pipeline, 90% of forecast 2017 production is covered. Storm's capacity on the Alliance Pipeline reduces exposure to widening natural gas price differentials between markets in Canada and the United States (Chicago – AECO differential -US$0.54 per Mmbtu in December 2015 widened to -US$1.03 per Mmbtu in September 2016). Differentials have widened as a result of growth in western Canadian production and exceed the pipeline transportation cost which is unusual but unlikely to change until production declines or export pipeline capacity is added.

Natural gas prices in North America were very low in the first half of 2016 (AECO $1.53/GJ, NYMEX US$2.12/Mmbtu) as a result of very high levels of natural gas in storage following a warmer winter which reduced residential and commercial heating demand. However, prices have improved significantly since mid-2016 as a result of the supply/demand balance tightening in the United States. In August, the year-over-year supply/demand balance was tighter by 7 Bcf per day with natural gas production down 2 Bcf per day while demand was up 5.3 Bcf per day (notably electric power generation was +4.1 Bcf per day and LNG exports plus exports to Mexico were +1.7 Bcf per day). Most of the growth in natural gas production in the United States over the last two to three years has been from the

Marcellus/Utica shales and re-initiating growth likely requires higher natural gas prices given many Marcellus/Utica producers have high cost structures plus sell natural gas at discounted prices (reflecting the higher pipeline tariffs to move natural gas to Chicago or the Gulf Coast). Recently, the warm start to the winter heating season has caused a decline in natural gas prices but the tighter supply/demand balance means it is unlikely to be a repeat of last winter where high storage levels at the end of March depressed prices. The longer term outlook appears increasingly bullish with LNG export capacity of more than 9 Bcf per day currently operating or under construction on the US Gulf Coast plus US exports to Mexico are expected to continue increasing as multiple new export pipelines and interconnections are completed over the next two years.

With 155 net sections at Umbach, there remains room for significant future growth with producing horizontal wells on only 6% of the lands (9 net sections) and proved plus probable reserves assigned on only 20% of the lands (31 net sections). The focus remains on converting this large resource into per-share growth in production and cash flow while preserving balance sheet flexibility.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

November 15, 2016

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

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 15, 2016 for the three and nine months ended September 30, 2016.

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, 2016. 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, 2016, (ii) the Company's audited consolidated financial statements for the years ended December 31, 2015 and 2014, and (iii) the press release issued by the Company on November 15, 2016, 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, 2016 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

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

This MD&A is dated November 15, 2016.

See "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" beginning on page 24.

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, 2016, prepared in accordance 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 years ended December 31, 2015 and 2014. The reporting and the measurement 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, 2015.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The third quarter in no way offered an attractive operating environment from a commodity price perspective; nevertheless the improvement over the immediately prior quarter was considerable, as illustrated by Storm's average realized price per Mcf for natural gas increasing by nearly 90% from the disastrous $1.28 per Mcf realized in the second quarter. Boe production for the quarter was up modestly compared to the second quarter as the Company continues to manage its production levels in response to ongoing volatility in natural gas prices, while ensuring firm transportation and processing commitments are being met. Nevertheless, with a strong balance sheet, continuous improvements in well results at Umbach, an inventory of wells awaiting completion, and 35 Mmcf/d of additional compression capacity coming on line in January 2017, Storm remains well poised to capitalize on an improved pricing scenario. Compared to the third quarter of the prior year, production grew by 38%.

NGL production with high value content at Umbach is an important differentiator for Storm. NGL amounted to 17% of total production, but contributed 31% of revenue from product sales. This was down from 46% in the second quarter; however, natural gas prices in the second quarter were at a multi-decade low. On the cost side royalties per Boe increased somewhat as a consequence of higher prices, operating and general and administrative costs fell, while transportation and interest and finance costs increased slightly. Generally Storm's cost structure is stable. Compared to the second quarter, field netback prior to hedging adjustments grew by 95% due to an improved, but still historically low gas price. Funds from operations grew by 52%; removing the effect of realized hedging adjustments benefiting the prior quarter, the increase would have been a remarkable 177%. The field netback of $8.95 per Boe for the quarter exceeds management's estimate of the cost of replacing production sold, meaning that Storm is operating profitably and earning a return on capital, in spite of a hostile commodity price environment. Conservative balance sheet management means that cash flow can be reinvested, rather than applied to debt reduction.

Improved pricing resulted in additions to Storm's hedge book at prices exceeding those used in the budget for 2017. The increased stability of budgeted cash flow in 2017, coupled with a general improvement in the business environment, has resulted in the Company bringing forward start-up of a third compression facility at Umbach from the second quarter of 2017 to January of 2017. Storm's compression capacity is currently 80 Mmcf raw gas per day; the new facility will expand capacity to 115 Mmcf per day. Total costs of the new facility will approximate $25 million and will be met from Storm's existing financial resources. Of this amount $11 million has already been incurred, with the remaining amount to be spent in the final quarter of 2016 and the first quarter of 2017. The new compression facility will be twinned in due course for an incremental cost of $7 million. Completion and the later twinning of the new facility will provide the capacity to increase Storm's production base from current levels to volumes in excess of 25,000 Boe per day.

During 2015 and 2016 Storm analysed the design, operation and financing of a gas processing facility, commissioning of which would have resulted in a considerable reduction in operating costs. After an extensive review, it was determined that this avenue was not in the best interests of the Company as a higher rate of return could be achieved by drilling and completing horizontal wells supported by a new processing arrangement with Spectra Energy. As such, as disclosed in early September, the Company entered into an additional processing agreement with Spectra which should result in operating costs falling by about 15-20% from current levels. Further, the Spectra agreement is effective January 1, 2017, whereas reductions in operating costs from plant ownership would only have emerged in mid-to-late 2018. The additional processing agreement does not preclude Storm from revisiting the construction of a Company owned gas plant, when production levels exceed those covered by processing agreements.

No wells were drilled in the quarter. Three wells were completed, leaving the Company with a quarter-end well inventory of one standing well awaiting start-up and six wells awaiting completion.

Subsequent to quarter end the Company's bank syndicate, upon completion of a mid-year review, confirmed Storm's bank facility at $130 million, which was 55% drawn at the end of the third quarter.

Production and Revenue

Production by Area

The Company reported production from the following areas:

	Three Months to September 30, 2016				Three Months to September 30, 2015			
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d
Umbach NE BC	64,995	2,299	-	13,131	45,888	1,684	-	9,332
Horn River Basin NE BC(2)	843	-	-	141	819	-	-	137
Grande Prairie AB	76	-	-	13	618	13	70	185
Total	65,914	2,299	-	13,285	47,325	1,697	70	9,654

(1) Crude oil production was sold early third quarter of 2015.
(2) Production shut in for part of period due to pricing.

	Nine Months to September 30, 2016				Nine Months to September 30, 2015			
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d
Umbach NE BC	64,889	2,311	-	13,126	43,705	1,561	-	8,845
Horn River Basin NE BC(2)	283	-	-	47	1,395	-	-	232
Grande Prairie AB	73	-	-	12	2,042	37	240	618
Total	65,245	2,311	-	13,185	47,142	1,598	240	9,695

In the third quarter of 2016, average Boe-per-day volumes increased by 38% when compared to the third quarter of 2015, and increased by 3% when compared to the immediately preceding quarter. For the nine month period ended September 30, 2016, average Boe production increased by 36% year over year. Production increases for natural gas and NGL, when compared to both periods in 2015, came from growth at Umbach where the Company had production from 41 wells (37.4 net) at the end of the quarter, an increase of nine wells year over year. The Company's crude oil producing properties in Alberta were sold in mid-2015 and production for the third quarter of 2016 from non-Umbach properties was minimal.

The Horn River Basin produces dry natural gas, while Umbach produces natural gas and associated NGL. Production volume in the third quarter approximated 83% natural gas and 17% NGL, consistent with prior quarters.

Average Daily Production

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Natural gas (Mcf/d)	65,914	47,325	65,245	47,142
Natural gas liquids (Bbls/d)	2,299	1,697	2,311	1,598
Crude oil (Bbls/d)	-	70	-	240
Total (Boe/d)	13,285	9,654	13,185	9,695

Low natural gas prices in the first part of the quarter resulted in production being reduced to the level required to meet firm processing and transportation commitments. Improved pricing in the final weeks resulted in shut-in production being restored, illustrative of the ability of the Company's production base to respond quickly to commodity price movements. Production to date in the fourth quarter of 2016 has averaged approximately 12,500 Boe per day based on field estimates and has been reduced by the nine-day outage on the Alliance Pipeline plus an 11-day outage on the Spectra T-north lateral.

Daily production per million shares outstanding at the end of the third quarter averaged 110 Boe per day, compared to 81 Boe per day for the third quarter of 2015 and 107 Boe per day for the second quarter of 2016.

Production Profile and Per-Unit Prices(1)

	Three Months to Sept. 30, 2016		Three Months to Sept. 30, 2015		Nine Months to Sept. 30, 2016		Nine Months to Sept. 30, 2015	
	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	83%	$ 2.41	82%	$ 2.46	82%	$ 1.77	81%	$ 2.62
Natural gas liquids - Bbl	17%	30.54	17%	33.32	18%	30.49	16%	37.13
Crude oil - Bbl	-	-	1%	55.93	-	-	3%	50.84
Per Boe	100%	$ 17.22	100%	$ 18.33	100%	$ 14.13	100%	$ 20.12

(1) Before realized hedging loss of $0.03 per Boe for the three months ended September 30, 2016 and realized hedging gains of $1.74 per Boe for the nine months ended September 30, 2016. In 2015, hedging gains were $2.22 per Boe for the three months ended September 30, 2015 and $4.20 per Boe for the nine months ended September 30, 2015.

Following the introduction of new marketing arrangements late in 2015, the Company's production during the third quarter of 2016 was sold as follows:

- 43% - Adjusted Chicago monthly index price less US$0.05 per Mmbtu
- 29% - Adjusted Chicago daily index price
- 16% - Adjusted AECO daily index price less Cdn$0.68 per GJ
- 12% - Station 2 daily spot price

Natural gas sold with reference to the Chicago daily index price is subject to a pricing adjustment equal to the pipeline tariff to Chicago as title to the gas transfers at the natural gas processing plant in British Columbia. A summary of reference prices for the last five quarters for each market is set out below. Note that pricing comparability between markets is affected by foreign exchange and lack of uniformity between commodity units. Storm's realized prices also differ due to heat content of the Company's natural gas. Noteworthy is the disparity between Canadian and US index prices and the remarkable improvement in Station 2 pricing in the third quarter when compared to any quarter in the prior twelve months.

	Storm Realized Price (Cdn$/Mcf)	Chicago Monthly Index (US$/Mmbtu)	Chicago Daily Index (US$/Mmbtu)	AECO Daily Index (Cdn$/GJ)	AECO Monthly Index (Cdn$/GJ)	Station 2 (Cdn$/GJ)	Edmonton Par (Cdn$/Bbl)
Q3 – 2015	2.46	2.83	2.79	2.75	2.65	1.72	56.23
Q4 – 2015	1.78	2.47	2.16	2.34	2.51	1.04	52.95
Q1 – 2016	1.62	2.25	2.04	1.74	2.00	1.33	40.81
Q2 – 2016	1.28	1.95	2.09	1.33	1.18	1.14	54.78
Q3 – 2016	2.41	2.76	2.78	2.20	2.09	1.83	54.80

In 2015, transmission interruptions and curtailments in Alberta resulted in increased natural gas volumes moving to the Station 2 market. Further, natural gas production also increased in geographic areas where production is normally directed to Station 2. The consequence was a considerable widening in the AECO – Station 2 differential. The pipeline restrictions that contributed to the widening differential were partially removed late in 2015 resulting in a differential of $0.41 per GJ in the first quarter of 2016, $0.19 per GJ in the second quarter of 2016 and $0.37 per GJ in the third quarter of 2016. The downward spiral in natural gas prices that prevailed throughout the first and second quarters of 2016 showed a reversal in the third quarter of 2016.

The realized price for NGL in the third quarter of 2016 fell by 8% relative to the third quarter of 2015 and fell by 4% compared to the second quarter of 2016. Storm's NGL stream in the quarter contained 53% condensate and pentanes, which are generally priced with reference to crude oil. Correspondingly, realized prices for Storm's NGL are aligned with crude oil prices. For the third quarter, WTI averaged US$44.94 per barrel and Edmonton light oil was Cdn$54.80 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$3.86 per barrel, compared to Cdn$4.56 per barrel in the third quarter of 2015 and Cdn$3.97 per barrel in the second quarter of 2016.

Increasing natural gas production at Umbach has resulted in growing volumes of higher value condensate and pentane production. The significance of this is illustrated by the contribution from NGL which comprised 17% of Boe production but amounted to 31% of revenue from product sales in the third quarter of 2016. The comparable amounts for the second quarter of 2016, when natural gas prices were lowest, were 17% of Boe production and 46% of revenue.

On a per-Boe basis, the realized price for the third quarter of 2016 declined by 6% when compared to the prior year and increased by 45% when compared to the immediately prior quarter.

Revenue from Product Sales(1)

(000s)	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Natural gas	$ 14,587	$ 10,723	$ 31,727	$ 33,727
Natural gas liquids	6,460	5,202	19,311	16,199
Crude oil	-	358	-	3,330
Total	$ 21,047	$ 16,283	$ 51,038	$ 53,256

(1) Excludes hedging gains and losses.

Revenue from product sales for the third quarter of 2016 increased by 29% when compared to the third quarter of 2015 and by 52% when compared to the second quarter of 2016. For the nine month periods, there was a year-over-year revenue decrease of 4%. Production volumes grew 38% and 36% year over year for the three and nine month periods; however, production growth was offset by the fall in commodity prices which, however, began to reverse in the third quarter of 2016.

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

(000s)	Natural Gas	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – Q3 2015	$ 10,723	$ 5,202	$ 358	$ 16,283
Effect of increased (decreased) production	4,167	1,846	(358)	5,655
Effect of changes in average product prices	(303)	(588)	-	(891)
Revenue from product sales – Q3 2016	$ 14,587	$ 6,460	$ -	$ 21,047

(000s)	Natural Gas	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – Q2 2016	$ 7,422	$ 6,448	$ -	$ 13,870
Effect of increased production	269	265	-	534
Effect of changes in average product prices	6,896	(253)	-	6,643
Revenue from product sales – Q3 2016	$ 14,587	$ 6,460	$ -	$ 21,047

Realized and Unrealized Gain (Loss) on Commodity Price Contracts

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

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

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

	Three Months to Sept. 30, 2016			Three Months to Sept. 30, 2015		
Realized gain (loss)						
Liquids	$ 839	$ 3.97	/Bbl	$ -	$ -	/Bbl
Natural gas	(880)	$ (0.15)	/Mcf	1,973	$ 0.45	/Mcf
Total realized gain (loss) – cash	$ (41)	$ (0.03)	/Boe	$ 1,973	$ 2.22	/Boe

	Three Months to Sept. 30, 2016			Three Months to Sept. 30, 2015		
Unrealized gain (loss)						
Liquids – change in fair value	$ (654)	$ (3.09)	/Bbl	$ 2,234	$ 13.75	/Bbl
Natural gas – change in fair value	2,214	0.37	/Mcf	(1,486)	$ (0.34)	/Mcf
Total unrealized gain (loss) – non-cash	$ 1,560	$ 1.28	/Boe	$ 748	$ 0.84	/Boe

	Nine Months to Sept. 30, 2016			Nine Months to Sept. 30, 2015		
Realized gain (loss)						
Liquids	$ 2,901	$ 4.58	/Bbl	$ 5,137	$ 78.42	/Bbl
Natural gas	3,379	$ 0.19	/Mcf	5,970	$ 0.46	/Mcf
Total realized gain (loss) – cash	$ 6,280	$ 1.74	/Boe	$ 11,107	$ 4.20	/Boe

	Nine Months to Sept. 30, 2016			Nine Months to Sept. 30, 2015		
Unrealized gain (loss)						
Liquids – change in fair value	$ (3,512)	$ (5.55)	/Bbl	$ (2,726)	$ (41.61)	/Bbl
Natural gas – change in fair value	(12,702)	$ (0.71)	/Mcf	(4,262)	$ (0.33)	/Mcf
Total unrealized gain (loss) – non-cash	$ (16,214)	$ (4.49)	/Boe	$ (6,988)	$ (2.64)	/Boe

The Company had in place the following hedging arrangements at the date of this report:

Period Hedged	Daily Volume	Average Price
Crude Oil Collars		
Oct – Dec 2016	700 Bbls	$70.71 - $83.78 Cdn$/Bbl
Jan – Dec 2017	500 Bbls	$62.80 - $70.75 Cdn$/Bbl
Jan – Mar 2018	350 Bbls	$62.14 - $69.59 Cdn$/Bbl
Apr – Jun 2018	200 Bbls	$62.00 - $70.00 Cdn$/Bbl
Jul – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Crude Oil Swaps		
Oct – Dec 2016	250 Bbls	$63.66 Cdn$/Bbl
Jan – Jun 2017	400 Bbls	$66.60 Cdn$/Bbl
Jul – Sep 2017	200 Bbls	$65.925 Cdn$/Bbl
Oct – Dec 2017	100 Bbls	$66.75 Cdn$/Bbl
Natural Gas Swaps		
Oct 2016	51,000 GJ	AECO Cdn$2.32/GJ
Nov – Dec 2016	40,000 GJ	AECO Cdn$2.43/GJ
Jan – May 2017	39,000 GJ	AECO Cdn$2.63/GJ
Jun 2017	31,000 GJ	AECO Cdn$2.59/GJ
Jul – Dec 2017	23,000 GJ	AECO Cdn$2.61/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jan – May 2017	2,000 Mmbtu	Chicago Cdn$4.04/Mmbtu
Jan – Jun 2017	1,900 Mmbtu	Chicago Cdn$4.312/Mmbtu
Jul – Dec 2017	2,000 Mmbtu	Chicago Cdn$4.00/Mmbtu
Jan – Jun 2018	9,850 Mmbtu	Chicago Cdn$3.88/Mmbtu
Jul – Dec 2018	3,000 Mmbtu	Chicago Cdn$3.70/Mmbtu
Natural Gas Differential Swaps		
Oct – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	8,000 GJ	Price at Stn 2 = AECO minus Cdn$0.408/GJ
Jan – Dec 2018	3,000 GJ	Price at Stn 2 = AECO minus Cdn$0.345/GJ
Oct – Dec 2016	33,000 Mmbtu	Price at Chicago = AECO plus US$0.672/Mmbtu
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu

The fair market value of contracts outstanding at September 30, 2016 of negative $8.2 million (December 31, 2015 – positive $8.0 million) is included in current assets or current and non-current liabilities as appropriate. For the three and nine months ended September 30, 2016, this resulted in an unrealized mark-to-market gain of $1.6 million and an unrealized loss of $16.2 million (2015 – gain of $0.7 million and loss of $7.0 million) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

During the third quarter of 2016, the Company realized losses from commodity price contracts in place or terminated in the amount of $41,000, compared to gains of approximately $2.0 million in the third quarter of 2015. During the first nine months of 2016, the Company realized gains from commodity price contracts in the amount of $6.3 million compared to gains of $11.1 million in the first nine months of 2015.

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

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

Royalties

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Charge for period	$ 1,457	$ 1,136	$ 2,606	$ 3,035
Percentage of revenue from product sales	6.9%	7.0%	5.1%	5.7%
Per Boe	$ 1.19	$ 1.28	$ 0.72	$ 1.15

Total royalties in the third quarter of 2016 increased by 28% when compared to the same quarter of 2015 and decreased by 14% when comparing the nine month periods. Increased production revenue resulted in the royalty increase in the three month period. Lower production revenue as a result of lower commodity prices more than offsetting increased production caused the royalty decrease in the nine month period.

Future production will further benefit from British Columbia's Infrastructure Royalty Credit Program. Since 2012, Storm has received approval for $14.0 million of royalty credits for various infrastructure projects. Storm recognized credits of $0.8 million in 2013, $1.9 million in 2014, $2.0 million in 2015 and $0.5 million in 2016. Remaining credits total $8.8 million which will reduce future royalties. The timing of receipt of future credits is dependent on commodity prices and production levels and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary, likely materially.

In March 2014, the British Columbia provincial government announced the expansion of the Deep Well Royalty Credit Program by extending royalty credits to all horizontal wells. Hitherto, wells with a vertical depth of less than 1,900 metres were not eligible for the program. Horizontal wells at Umbach, drilled after April 1, 2014, will receive a royalty credit of $0.5 million to $0.7 million per well, depending on the total measured vertical depth of the well. In conjunction with this change, wells that are eligible for this expanded credit program will bear a minimum royalty at a rate of 6%. Again, the timing of receipt of royalty credits under the program cannot be readily predicted. Correspondingly, the royalty rate reported in future quarters may vary considerably.

No accounting recognition has been given to future benefits potentially accruing to Storm from either the Infrastructure Royalty Credit or the Deep Well Royalty Credit programs.

Royalties payable in Alberta are not material to the Company's operations.

Production Costs

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Charge for period	$ 8,177	$ 7,009	$ 24,276	$ 22,156
Percentage of revenue from product sales	38.9%	43.0%	47.6%	41.6%
Per Boe	$ 6.69	$ 7.89	$ 6.72	$ 8.37

Total production costs for the three and nine month periods of 2016 increased by 17% and 10% when compared to the same periods of 2015, considerably less than production increases for the same period of 38% and 36%, respectively. Per-Boe charges continue to decline.

Production costs per Mcf of natural gas for the third quarter averaged $1.35 with total production costs averaging $6.69 per Boe, a year-over-year reduction of 15%. For the comparable nine month periods production costs per Boe fell by 20%. Production costs of natural gas liquids are included with natural gas costs. Production costs per Boe for the second quarter of 2016 amounted to $6.76.

Year-over-year production growth resulted in the fixed cost component of production costs per Boe falling. In addition, lower service costs also contributed to the decline in per-unit production costs. The sale of higher cost properties in Alberta in mid-2015 also resulted in a year-over-year decline in per-unit production costs for the comparable nine month periods. Lower gas processing fees commencing in January 2017 should result in further reductions in per-Boe production costs.

Transportation Costs

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Charge for period	$ 480	$ 836	$ 1,513	$ 3,335
Percentage of revenue from product sales	2.3%	5.1%	3.0%	6.3%
Per Boe	$ 0.39	$ 0.94	$ 0.42	$ 1.26

Transportation costs include pipeline tariffs for natural gas, as well as trucking costs for wellhead condensate. Total transportation costs for the third quarter of 2016 decreased by 43%, and by 59% on a per-Boe basis, over the same period in 2015. The year-over-year cost reduction reflects natural gas marketing arrangements entered into in late 2015, lower NGL trucking costs and the sale of certain oil properties in mid-2015. As the sales point for natural gas shipped on the Alliance Pipeline is the gas processing facility in British Columbia, the sales price is net of the cost of moving natural gas to Chicago. For the comparable nine month periods transportation costs fell by 55% in total and by 67% per Boe.

Field Netbacks

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

Three Months to September 30, 2016	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.41	$ 30.54	-	$ 17.22
Royalties	(0.13)	(3.20)	-	(1.19)
Production costs	(1.35)	-	-	(6.69)
Transportation costs	(0.03)	(1.47)	-	(0.39)
Field operating netback before hedging	$ 0.90	$ 25.87	-	$ 8.95
Realized hedging gains (losses)	(0.15)	3.97	-	(0.03)
Total operating income per commodity unit	$ 0.75	$ 29.84	-	$ 8.92
Total operating income (000s)	$ 4,581	$ 6,311	-	$ 10,892

Note: Production costs of natural gas liquids are included with natural gas costs.

Three Months to September 30, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.46	$ 33.32	$ 55.93	$ 18.33
Royalties	(0.09)	(4.52)	(2.81)	(1.28)
Production costs	(1.59)	-	(14.14)	(7.89)
Transportation costs	(0.12)	(1.87)	(3.98)	(0.94)
Field operating netback before hedging	$ 0.66	$ 26.93	$ 35.00	$ 8.22
Realized hedging gains (losses)	0.45	-	-	2.22
Total operating income per commodity unit	$ 1.11	$ 26.93	$ 35.00	$ 10.44
Total operating income (000s)	$ 4,845	$ 4,205	$ 224	$ 9,274

Nine Months to September 30, 2016	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 1.77	$ 30.49	-	$ 14.13
Royalties	(0.04)	(2.85)	-	(0.72)
Production costs	(1.36)	-	-	(6.72)
Transportation costs	(0.03)	(1.50)	-	(0.42)
Field operating netback before hedging	$ 0.34	$ 26.14	-	$ 6.27
Realized hedging gains (losses)	0.19	4.58	-	1.74
Total operating income per commodity unit	$ 0.53	$ 30.72	-	$ 8.01
Total operating income (000s)	$ 9,470	$ 19,453	-	$ 28,923

Nine Months to September 30, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.62	$ 37.13	$ 50.84	$ 20.12
Royalties	(0.04)	(5.54)	(2.45)	(1.15)
Production costs	(1.63)	-	(18.22)	(8.37)
Transportation costs	(0.16)	(2.38)	(4.56)	(1.26)
Field operating netback before hedging	$ 0.79	$ 29.21	$ 25.61	$ 9.34
Realized hedging gains (losses)	0.46	-	78.42	4.20
Total operating income per commodity unit	$ 1.25	$ 29.21	$ 104.03	$ 13.54
Total operating income (000s)	$ 16,278	$ 12,744	$ 6,814	$ 35,836

Total operating income in the third quarter of 2016 increased by 17% when compared to the third quarter of 2015, and increased by 37% when compared to the second quarter of 2016. Per Boe, excluding realized hedging gains and losses, field operating netback increased by 9% in the third quarter of 2016 in comparison to the same quarter of 2015, and increased by 95% when compared to the second quarter of the year. For the nine month periods, total operating income fell by 19% and field operating netback per Boe prior to hedging gains fell by 33%.

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest and finance costs, amounted to $8.44 for the third quarter of 2016, $9.35 for the equivalent quarter of 2015 and $8.63 for the second quarter of 2016. Transportation costs are excluded as the sales price on part of the Company's production is net of the cost to the purchaser of shipping on the Alliance Pipeline to Chicago under arrangements which became effective late in 2015, and thus affects comparability between 2016 and 2015. Comparing the third quarter of 2016 to the same quarter of 2015, production and general and administrative costs decreased while interest costs increased. Lower gas processing fees commencing in January 2017 should result in future reductions in cash costs per commodity unit.

General and Administrative Costs

Total Costs	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Charge for period – before recoveries	$ 1,389	$ 1,411	$ 4,765	$ 5,947
Overhead recoveries	(136)	(463)	(594)	(1,701)
Charge for period – net of recoveries	$ 1,253	$ 948	$ 4,171	$ 4,246
Per Boe	$ 1.03	$ 1.07	$ 1.15	$ 1.60

Gross general and administrative costs for the third quarter and first nine months of 2016 decreased by 2% and 20%, respectively, when compared to the same periods of 2015 and by 3% when compared to the second quarter of 2016. The decreases are largely attributable to lower personnel costs and lower bonus payouts. Overhead recoveries increased or decreased for the various periods in response to changes in field capital expenditures.

On a per-Boe measure, net general and administrative costs for the quarter fell by 4% compared to the third quarter of 2015, and by 28% when comparing the first nine months of 2016 to the same period in 2015. Compared to the second quarter of 2016, general and administrative costs fell by 13%. Generally, the Company's general and administrative cost structure is stable and per-Boe declines are due to increased production volumes.

Share-Based Compensation

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Charge for period	$ 764	$ 821	$ 2,316	$ 2,589
Per Boe	$ 0.63	$ 0.92	$ 0.64	$ 0.98

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 decreased by 7% in the third quarter of 2016 compared to the same quarter of 2015 and by 11% for the nine month period. The year-over-year decrease in share-based compensation in both the three and nine month periods is attributable to stock options granted in 2012 and 2013 being fully expensed in 2015 and 2016.

Depletion and Depreciation

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Depletion	$ 8,731	$ 7,336	$ 25,807	$ 22,834
Depreciation	1,255	1,043	3,727	3,442
Charge for period	$ 9,986	$ 8,379	$ 29,534	$ 26,276
Per Boe	$ 8.17	$ 9.43	$ 8.17	$ 9.93

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

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

A 38% growth in production resulted in the total charge for depletion and depreciation increasing by 19% in the third quarter of 2016 compared to the same quarter of 2015. Compared to the second quarter of 2016 the charge grew by 4% while Boe production grew by a like amount. For the nine month periods, production grew by 36% with the depletion and depreciation charge growing by 12%. The disproportionately low increase in the year-over-year depletion and depreciation charge corresponds to lower finding and development costs at Umbach as well as the sale of higher cost Alberta properties in mid-2015.

Accretion

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Charge for period	$ 85	$ 84	$ 264	$ 354
Per Boe	$ 0.07	$ 0.09	$ 0.07	$ 0.13

Accretion represents the time value increase for each reporting period for the Company's decommissioning liability. The decreased year-over-year charge for accretion for the comparable nine month periods is due to the sale of Alberta properties in mid-2015, which carried a disproportionately high future abandonment cost.

Interest and Finance Costs

(000s)	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Charge for period	$ 880	$ 345	$ 2,357	$ 1,727
Percentage of revenue from product sales	4.2%	2.1%	4.6%	3.2%
Per Boe	$ 0.72	$ 0.39	$ 0.65	$ 0.65

Interest costs in 2016, for both the three and nine month periods, increased year over year as a result of additional bank borrowings used to fund development of the Company's Umbach property.

The interest rate on the Company's bank 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 from operations ratio.

Unrealized Revaluation Loss on Investment

In the third quarter of 2016 the Company recognized a loss of $10,000 (2015 – loss of $330,000) representing the mark-to-market reduction in the carrying amount of the Company's investment in Chinook Energy Inc. ("Chinook"), as measured against the market value at the end of the previous reporting period. The Company's investment in Chinook is not a material asset and is included with accounts receivable.

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, 2016	Maximum Annual Deduction
Canadian oil and gas property expense	$ 43,000	10%
Canadian development expense	97,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	76,000	20 - 100%
Operating losses	199,000	100%
Other	3,000	20 - 100%
Total	$ 440,000	

Net Income (Loss)

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Net loss	$ (85)	$ (961)	$ (25,562)	$ (8,717)
Per basic and diluted share	$ (0.00)	$ (0.01)	$ (0.21)	$ (0.08)

Of the per-share loss of $0.21 for the nine months to September 30, 2016, $0.14 represented the unrealized loss on commodity price contracts.

Other Comprehensive Loss

Other comprehensive income comprises net loss for the period plus unrealized gains and losses resulting from the mark-to-market valuation of certain assets and liabilities. For the nine months ended September 30, 2015, a loss of $110,000 was recognized in other comprehensive income representing the reversal of prior mark-to-market gains in value of the investment in Chinook.

Listed Securities	Holding	Number of Shares(1)	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Chinook Energy Inc.	Common Shares	1,000,000	$ -	$ -	$ -	$ (110)
Other comprehensive loss for period			$ -	$ -	$ -	$ (110)

(1) Shares owned at September 30, 2016.

Cash Flows from Operating Activities and Non-GAAP Funds from Operations

	Three Months to Sept. 30, 2016		Three Months to Sept. 30, 2015		Nine Months to Sept. 30, 2016		Nine Months to Sept. 30, 2015	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Cash from operating activities	$8,415	$0.07	$5,687	$0.05	$22,062	$0.19	$28,414	$0.25
Net change in non-cash working capital items	344	0.00	2,295	0.02	333	0.00	1,450	0.01
Non-GAAP funds from operations	$8,759	$0.07	$7,982	$0.07	$22,395	$0.19	$29,864	$0.26

The reconciling item between funds from operations and cash flows from operating activities is the change in non-cash operating working capital items.

Non-GAAP funds from operations for the third quarter of 2016 increased by 10% from the third quarter of 2015, by 52% when compared to the second quarter of 2016, and fell by 25% for the nine month period. Production growth was insufficient to overcome the commodity price drop in the nine month period.

Non-GAAP funds from operations is not a measure recognized by GAAP, although it is widely used by investors, analysts and other financial statement users. It is also used by the Company's banking syndicate to determine debt to cash flow ratios and other measures of credit worthiness and thus determines interest rates on borrowings. The most directly comparable measure under GAAP is cash flows from operating activities, as set out above.

Corporate Netbacks

($/Boe)	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Revenue from product sales	17.22	18.33	14.13	20.12
Realized hedging gains (losses)	(0.03)	2.22	1.74	4.20
Royalties	(1.19)	(1.28)	(0.72)	(1.15)
Production	(6.69)	(7.89)	(6.72)	(8.37)
Transportation	(0.39)	(0.94)	(0.42)	(1.26)
General and administrative	(1.03)	(1.07)	(1.15)	(1.60)
Interest and finance costs	(0.72)	(0.39)	(0.65)	(0.65)
Funds from operations	7.17	8.98	6.21	11.29
Share-based compensation	(0.63)	(0.92)	(0.64)	(0.98)
Depletion, depreciation and accretion	(8.24)	(9.52)	(8.24)	(10.06)
Exploration and evaluation costs expensed	-	(0.06)	-	(0.06)
Unrealized revaluation loss on investments	(0.01)	(0.37)	(0.02)	(0.21)
Gain (loss) on sale of oil and gas properties	0.36	(0.03)	0.12	(0.63)
Unrealized gain (loss) on commodity price contracts	1.28	0.84	(4.49)	(2.64)
Net loss per Boe	(0.07)	(1.08)	(7.06)	(3.29)

INVESTMENT AND FINANCING

Financial Resources and Liquidity

At the beginning of 2015, Storm's bank facility amounted to $130.0 million. In April 2015, the facility was increased to $150.0 million in recognition of production and reserve growth at Umbach. In July 2015, subsequent to the disposal of non-core assets in Alberta, the facility was reduced to $140.0 million. In May 2016 the facility was further reduced to $130.0 million, in response to a commodity price driven lower lending value. Of this amount, 55% was drawn at September 30, 2016. The facility is available until April 28, 2017 at which time the borrowing base amount will be reviewed using current and independently prepared reserve information. In the ordinary course, the Company has the option to extend for an additional year; if this does not happen, the facility will be termed out with the amount outstanding becoming payable in full one year later. The facility is syndicated with three banks.

The Company is in compliance with all covenants under the credit facility, the sole financial covenant being that debt including working capital (deficiency) cannot exceed the facility credit limit. At September 30, 2016 debt including working capital (deficiency), excluding mark-to-market value of hedging contracts, amounted to $69.3 million.

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

Capital Expenditures

In the third quarter of 2016 the Company spent $7.6 million (2015 - $19.6 million) on field operations, primarily on completing three wells at Umbach and commencing construction of the third field compression facility.

During the first nine months of 2016, seven 100% working interest horizontal wells were drilled, five horizontal wells were completed, and six horizontal wells were brought on production. At September 30, 2016 there was one completed well awaiting tie-in and six wells awaiting completion.

Major field capital outlays in the first nine months include $21.1 million on drilling and completions and $9.7 million on facilities, equipping and tie-ins, all in the Umbach area.

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Land and lease	$ 174	$ 234	$ 1,173	$ 754
Drilling	(476)	619	11,419	12,992
Completions	5,632	10,118	9,694	17,084
Facilities, equipping and pipelines	2,165	8,474	9,704	32,106
Recompletions and workovers	84	106	134	1,138
Property acquisition adjustments and administrative assets	1	6	15	27
Total expenditures	$ 7,580	$ 19,557	$ 32,139	$ 64,101
Proceeds on disposition of oil and gas properties	(600)	(23,673)	(600)	(23,673)
Net capital expenditures	$ 6,980	$ (4,116)	$ 31,539	$ 40,428

Net capital investment was allocated as follows:

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Exploration and evaluation	$ (307)	$ (1,665)	$ 682	$ (1,165)
Property and equipment	7,287	(2,451)	30,857	41,593
Total – net of dispositions	$ 6,980	$ (4,116)	$ 31,539	$ 40,428

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.

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, 2016 was $25.8 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, (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value is 1.7%. Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring of actual abandonment and reclamation costs, supported by external information from industry sources. It also has regard to industry best practices, as well as provincial and other regulation and evolution of same.

Share Capital

Details of share issuances from inception to September 30, 2016 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
Nine months to Sept.30/16	Stock option exercises	816	$ 2.00	1,632
Total at September 30, 2016		120,283	$ 3.27	$ 393,548

(1) Before share issue costs.

In June 2015, the Company issued 8,000,000 common shares pursuant to a bought deal financing at a price of $4.55 per common share for gross proceeds of $36,400,000. This financing closed on June 10, 2015. Net proceeds received totaled $34.3 million.

During 2015, stock options were exercised at an average price of $1.81 per optioned share and 145,000 common shares were issued for proceeds of $262,000. During the first nine months of 2016, stock options were exercised at an average price of $2.00 per optioned share and 816,000 common shares were issued for proceeds of $1,632,000.

Issued and outstanding common shares at September 30, 2016 totaled 120,282,812 and at November 15, 2016, the date of this MD&A, totaled 120,356,812.

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 agreement; and
- commodity price contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years commencing October 1, 2013 for a base rent, not including operating costs, totaling approximately $3.0 million over the term of the lease. Current monthly operating costs amount to $26,300. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $367.6 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended September 30, 2016 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 for the period from the fourth quarter of 2014 to mid way in the third quarter of 2016 have been affected by one dominant trend – production growth was insufficient to offset the relentless fall in commodity prices. However, during the third quarter of 2016, pricing for the Company's commodities began to improve, enabling the Company to bring on shut-in production and to implement a larger capital program.

	2016			2015				2014
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production revenue ($000s)[1]	21,006	16,486	19,826	18,624	18,256	20,236	25,871	28,556
Non-GAAP funds from operations ($000s)[2]	8,759	5,781	7,855	9,182	7,982	8,170	13,712	13,892
Per share								
- basic ($)	0.07	0.05	0.07	0.08	0.07	0.07	0.12	0.13
- diluted ($)	0.07	0.05	0.07	0.08	0.07	0.07	0.12	0.12
Net income (loss) ($000s)	(85)	(20,493)	(4,984)	1,850	(961)	(4,191)	(3,565)	(7,422)
Per share								
- basic ($)	(0.00)	(0.17)	(0.04)	0.02	(0.01)	(0.04)	(0.03)	(0.07)
- diluted ($)	(0.00)	(0.17)	(0.04)	0.02	(0.01)	(0.04)	(0.03)	(0.07)
Net capital expenditures ($000s)	6,980	613	23,946	31,081	(4,116)[4]	8,864	35,680	20,095
Average daily production - Boe	13,285	12,852	13,418	10,730	9,654	9,657	9,776	10,173
Net debt ($000s)[3]	69,303	71,254	77,162	61,721	39,994	28,051	85,098	63,080

(1) Includes realized hedging gains and losses.
(2) See Non-GAAP Measurements on page 26 of this MD&A.
(3) Includes working capital deficiency and excludes the fair value of commodity price contracts.
(4) Net of property disposition for proceeds of $23.6 million.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the reporting period ended September 30, 2016 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 or incorporate estimations made by management using information which involve 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 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 reports.

Accounts Receivable, Accounts Payable and Accrued Liabilities

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

Commodity Price Contracts

The Company periodically enters into contracts which fix a price or a price range for future periods for natural gas and crude oil. Each such contract is valued at the end of each reporting period, with the change in value of outstanding contracts being included in the measurement of income for the period. The period end value is based on option pricing models using estimates for future circumstances and is correspondingly subject to both mathematical and input uncertainty. Crude oil contracts are used as a proxy for NGL contracts as part of the Company's 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 reduced appropriately. This review involves estimates of external circumstances and future events 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 are 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, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations or financial position. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices in each market in which production is sold;
- future production volumes, production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit;
- future capital expenditures and their allocation to specific projects, activities or periods;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future non-GAAP funds from operations and future cash flows, including per-share amounts and the categorization of such cash flows;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital programs and future availability of such sources;
- development plans;
- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency;
- availability and use of credit facilities;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;

- future amounts and use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, interest and general and administrative costs in total and by commodity unit;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas and natural gas liquids;
- 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;
- 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”; “Accretion”; “Interest and Finance Costs”; “Income Taxes”; “Net Income (Loss)”; “Other Comprehensive Loss”; “Cash Flows from Operating Activities and Non-GAAP Funds from Operations”; “Financial Resources and Liquidity”; “Capital Expenditures”; “Accounts Payable and Accrued Liabilities”; “Decommissioning Liability”; “Share Capital”; “Contractual Obligations”; industry conditions including commodity prices, 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 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 trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company’s business. Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm’s actual results, performance or achievement, could differ materially from those expressed in, or implied by, these forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

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

Non-GAAP Measurements - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles ("GAAP"). Specifically, "funds from operations", "funds from operations per share", "debt including working capital deficiency", "netbacks", "field operating netbacks", "corporate netbacks", "field operating netback", "field operating netback before hedging", "total operating income", "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. In particular, funds from operations is not intended to represent, or be equivalent to, cash flow from operating activities calculated in accordance with GAAP, which is measured on the Company's consolidated statements of cash flows. Funds from operations and other non-GAAP terms are used to benchmark operations against prior periods and peer group companies and are widely used by investors, analysts and other parties. Funds from operations is also used by lenders to measure compliance with debt covenants and thus set interest costs. Reference is made to the discussion in this MD&A under "Cash Flows from Operating Activities and Non-GAAP Funds from Operations".

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, 2016 for the years ended December 31, 2015 and 2014 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2015 under the heading "Business Risks".

FINANCIAL REPORTING UPDATE

Accounting Changes

Future Accounting Policies

Leases

In January 2016 the IASB issued IFRS 16 Leases, which requires lessees to recognize assets and liabilities for most leases. The standard replaces IAS17 and will be effective for annual periods beginning on or after January 1, 2019.

Financial Instruments

IFRS 9 Financial Instruments is intended to replace IAS 39 Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and also requires a single impairment method to be used, replacing the multiple rules of IAS 39. Although new hedge accounting requirements have been introduced, Storm does not employ hedge accounting for risk management contracts currently in place. This standard is effective for annual periods beginning on or after January 1, 2018.

Revenue

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers which replaces IAS18 and IAS11. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018.

The Company is currently evaluating the effect of these standards on Storm's financial statements.

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

Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	September 30, 2016	December 31, 2015
ASSETS		
Current		
Accounts receivable (Note 10)	$ 8,702	$ 9,635
Prepaids and deposits	2,505	728
Fair value of commodity price contracts (Note 10)	-	7,984
	11,207	18,347
Exploration and evaluation (Note 3)	120,540	119,356
Property and equipment (Note 4)	306,365	302,955
	$ 438,112	$ 440,658
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 9,485	$ 15,007
Fair value of commodity price contracts (Note 10)	7,635	-
	17,120	15,007
Bank indebtedness (Note 5)	71,025	57,077
Fair value of commodity price contracts (Note 10)	595	-
Decommissioning liability (Note 6)	18,428	16,016
	107,168	88,100
Shareholders' equity		
Share capital (Note 7)	387,965	385,766
Contributed surplus (Note 8)	8,487	6,738
Deficit	(65,508)	(39,946)
	330,944	352,558
Commitments (Note 12)		
	$ 438,112	$ 440,658

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

Director

Interim Consolidated Statements of Loss and Comprehensive Loss

(Canadian $000s except per-share amounts) (unaudited)	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Revenue				
Revenue from product sales	$ 21,047	$ 16,283	$ 51,038	$ 53,256
Royalties	(1,457)	(1,136)	(2,606)	(3,035)
Net revenue	$ 19,590	$ 15,147	$ 48,432	$ 50,221
Realized gain (loss) on commodity price contracts (Note 10)	(41)	1,973	6,280	11,107
Unrealized gain (loss) on commodity price contracts (Note 10)	1,560	748	(16,214)	(6,988)
Income (loss) from hedging activities	1,519	2,721	(9,934)	4,119
Expenses				
Production	8,177	7,009	24,276	22,156
Transportation	480	836	1,513	3,335
General and administrative (Note 12)	1,253	948	4,171	4,246
Share-based compensation (Note 8)	764	821	2,316	2,589
Depletion and depreciation (Note 4)	9,986	8,379	29,534	26,276
Exploration and evaluation costs expensed	-	51	-	154
Accretion (Note 6)	85	84	264	354
	20,745	18,128	62,074	59,110
Income (loss) before the following:	364	(260)	(23,576)	(4,770)
Interest and finance costs	(880)	(345)	(2,357)	(1,727)
Unrealized revaluation loss on investment	(10)	(330)	(70)	(550)
Gain (loss) on sale of oil and gas properties	441	(26)	441	(1,670)
Net loss for the period	(85)	(961)	(25,562)	(8,717)
Other comprehensive income (loss)				
Reversal of prior period unrealized gain on investments	-	-	-	(110)
Comprehensive loss for the period	$ (85)	$ (961)	$ (25,562)	$ (8,827)
Net loss per share (Note 9)				
- basic	$ (0.00)	$ (0.01)	$ (0.21)	$ (0.08)
- diluted	$ (0.00)	$ (0.01)	$ (0.21)	$ (0.08)

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Nine Months to September 30, 2016	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	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 7)	1,632	-	-	-	1,632
Share-based compensation (Note 8)	-	2,316	-	-	2,316
Share-based compensation on options exercised (Note 7)	567	(567)	-	-	-
Balance, end of period	$387,965	$ 8,487	$ (65,508)	$ -	$330,944

(Canadian $000s) (unaudited)				Nine Months to September 30, 2015	
	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Equity
Balance, beginning of period	$351,161	$ 3,363	$ (33,079)	$ 110	$321,555
Net loss for the period	-	-	(8,717)	-	(8,717)
Issue of common shares (Note 7)	36,460	-	-	-	36,460
Share issue costs (Note 7)	(2,149)	-	-	-	(2,149)
Share-based compensation (Note 8)	-	2,589	-	-	2,589
Share based compensation on options exercised (Note 7)	19	(19)	-	-	-
Reversal of prior period unrealized gain on investments	-	-	-	(110)	(110)
Balance, end of period	$385,491	$ 5,933	$ (41,796)	$ -	$349,628

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Operating activities				
Net loss for the period	$ (85)	$ (961)	$ (25,562)	$ (8,717)
Non-cash items:				
Share-based compensation (Note 8)	764	821	2,316	2,589
Depletion, depreciation and accretion (Notes 4 and 6)	10,071	8,463	29,798	26,630
Exploration and evaluation costs expensed (Note 3)	-	51	-	154
Unrealized revaluation loss on investment (Note 10)	10	330	70	550
Loss (gain) on sale of oil and gas properties (Note 4)	(441)	26	(441)	1,670
Unrealized loss (gain) on commodity price contracts (Note 10)	(1,560)	(748)	16,214	6,988
Net change in non-cash working capital items (Note 11)	(344)	(2,295)	(333)	(1,450)
	8,415	5,687	22,062	28,414
Financing activities				
Proceeds from issue of common shares (Note 7)	181	-	1,632	34,311
Increase (decrease) in bank indebtedness	(3,006)	(12,258)	13,948	(12,885)
	(2,825)	(12,258)	15,580	21,426
Investing activities				
Additions to exploration and evaluation assets (Note 3)	(174)	(234)	(1,163)	(734)
Additions to property and equipment (Note 4)	(7,406)	(19,323)	(30,976)	(63,367)
Proceeds on disposal of exploration and evaluation assets (Note 3)	481	1,899	481	1,899
Proceeds on disposal of property and equipment (Note 4)	119	21,774	119	21,774
Net change in non-cash working capital items (Note 11)	1,390	2,455	(6,103)	(9,412)
	(5,590)	6,571	(37,642)	(49,840)
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, 2016 and 2015

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 listed on the TSX Venture Exchange under the symbol “SRX”. The Company operates primarily in the province of British Columbia and its head office is located at Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4. The Company became a reporting issuer in August 2010.

These unaudited condensed interim consolidated financial statements (the “financial statements”) include the accounts of Storm and its wholly owned subsidiary.

2. BASIS OF PRESENTATION

Statement of Compliance

The financial statements have been prepared in accordance with IAS 34 Interim Financial Reporting, based on International Financial Reporting Standards (“IFRS”) as issued and amended from time to time by the International Accounting Standards Board (“IASB”). The financial statements follow the same accounting policies and methods of computation as used in the audited consolidated financial statements for the years ended December 31, 2015 and 2014. The note disclosures do not include all disclosures applicable to annual audited consolidated financial statements. Accordingly, the financial statements should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2015 and 2014 and the notes thereto.

These financial statements were authorized for issue by the Board of Directors on November 15, 2016.

Basis of Measurement

The Company’s financial statements have been prepared on a going concern basis consistent with prior reporting 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 10.

Use of Estimates and Judgments

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, income, expenses and cash flows. 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 changes to estimates are made.

Judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are described in Note 3 to the Company’s audited consolidated financial statements for the year ended December 31, 2015.

3. EXPLORATION AND EVALUATION

	Nine Months Ended September 30, 2016	Year ended December 31, 2015
Balance, beginning of period	$ 119,356	$ 126,805
Additions	1,163	5,350
Exploration and evaluation expenditures expensed	-	(154)
Future decommissioning costs	60	313
Disposals	(39)	(2,843)
Transfer to property and equipment	-	(10,115)
Balance, end of period	$ 120,540	$ 119,356

4. PROPERTY AND EQUIPMENT

	Nine Months Ended September 30, 2016	Year ended December 31, 2015
Cost		
Balance, beginning of period	$ 389,781	$ 379,207
Additions	30,976	89,749
Future decommissioning costs	2,088	1,831
Disposals	(120)	(91,121)
Transfer from exploration and evaluation assets	-	10,115
Balance, end of period	$ 422,725	$ 389,781
Accumulated depletion and depreciation		
Balance, beginning of period	$ (86,826)	$ (110,744)
Depletion and depreciation	(29,534)	(34,583)
Disposals	-	58,501
Balance, end of period	$ (116,360)	$ (86,826)
Net book value, beginning of period	$ 302,955	$ 268,463
Net book value, end of period	$ 306,365	$ 302,955

Management reviewed the carrying amounts of exploration and evaluation and property and equipment assets for indicators of impairment at September 30, 2016 and none were identified.

5. BANK INDEBTEDNESS

As at September 30, 2016, the Company had an extendible revolving bank facility in the amount of $130.0 million (December 31, 2015 – $140.0 million) based on the Company's producing reserves. The revolving facility is available to the Company until April 28, 2017, at which time the borrowing base amount will be reviewed and in the ordinary course the Company will have the option to extend the facility for an additional year. If the revolving facility is not extended, the facility moves into a term phase whereby the loan is to be retired with one payment one year later, in an amount equal to the outstanding principal. Interest is paid on the revolving facility at bankers acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company. At September 30, 2016, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that debt including working capital deficiency should not exceed the facility amount.

The Company has issued letters of credit in the amount of $6.1 million in support of future gas transportation and processing obligations (Note 12) and future reclamation liabilities. Availability under the Company's bank facility is reduced by a like amount.

6. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning oil and gas production assets, including well sites, gathering systems and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's decommissioning obligation is approximately $25.8 million (December 31, 2015 - $25.6 million), which is expected to be paid over the next 25 years. A risk-free discount rate of 1.7% (December 31, 2015 – 2.25%) and an inflation rate of 1.5% (December 31, 2015 – 1.9%) was used to calculate the present value of the decommissioning obligation, amounting to $18.4 million.

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

	Nine Months Ended September 30, 2016	Year Ended December 31, 2015
Balance, beginning of period	$ 16,016	$ 23,553
Obligations incurred	1,639	1,961
Obligations disposed	(61)	(10,122)
Change in rate estimates(1)	570	(68)
Change in cost estimates	-	251
Accretion expense	264	441
Balance, end of period	$ 18,428	$ 16,016

(1) Relates to changes in inflation and discount rates.

7. SHARE CAPITAL

Authorized

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

Issued

	Number of Common Shares	Consideration
Balance as at December 31, 2014	111,322	$ 351,161
Shares issued pursuant to private placement(1)	8,000	36,400
Share issue costs(1)	-	(2,149)
Shares issued on stock option exercises(2)	145	354
Balance as at December 31, 2015	119,467	$ 385,766
Shares issued on stock option exercises(3)	816	2,199
Balance as at September 30, 2016	120,283	$ 387,965

(1) On June 10, 2015 the Company issued 8,000,000 common shares, pursuant to a bought deal financing, at a price of $4.55 per common share for gross proceeds of $36,400,000 before issue costs of approximately $2.1 million.

(2) During the first nine months of 2015, 33,000 common shares were issued upon the exercise of stock options for proceeds of $60,000 and related prior period share-based compensation of $19,000 was transferred to share capital from contributed surplus.

(3) During the first nine months of 2016, 816,000 common shares were issued upon the exercise of stock options for proceeds of $1,632,000 and related prior period share-based compensation of $567,000 was transferred to share capital from contributed surplus.

8. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers and employees. Options are granted at the market price of the shares on the last business day prior to the date of grant, have a four-year term and vest in tranches of one third over three years. Under the stock option plan, at September 30, 2016, a total of 12,028,281 common shares were available for issuance. Options in respect of 10,008,500 common shares have been issued, of which 3,121,500 have been exercised or cancelled at September 30, 2016. Options in respect of 6,887,000 common shares were issued and outstanding at September 30, 2016. At November 15, 2016, the date of this report, a total of 12,035,681 common shares are available for issuance under the stock option plan, options in respect of 7,005,000 common shares were issued and outstanding and 5,030,681 are available for future issue.

Details of the options outstanding at September 30, 2016 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2014	5,957	$ 3.54
Granted during the year	1,941	$ 3.38
Exercised during the year	(145)	$ 1.81
Outstanding at December 31, 2015	7,753	$ 3.53
Exercised during the period	(816)	$ 2.00
Cancelled during the period	(50)	$ 4.20
Outstanding at September 30, 2016	6,887	$ 3.71
Number exercisable at September 30, 2016	3,090	$ 3.46

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
$1.75 - $2.63	1,226	0.3	$ 1.75	1,226	$ 1.75
$2.64 - $3.95	1,881	3.2	$ 3.35	-	-
$3.96 - $5.20	3,780	1.8	$ 4.52	1,864	$ 4.57
Total	6,887	1.9	$ 3.71	3,090	$ 3.46

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).

No options were granted in the first nine months of 2016. 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, 2015 of $1.86 per share include the following:

	2015
Share price	$ 4.71
Exercise price	$ 4.71
Volatility	53%
Forfeiture rate	10%
Expected option life (years)	3.7
Dividends	-
Risk-free interest rate	0.5%

Share-based compensation expense of $0.8 million and $2.3 million was charged to the consolidated statement of loss during the three and nine months to September 30, 2016 (2015 - $0.8 million and $2.6 million) with an equivalent offset to contributed surplus. Volatility is based on the historical trading price variances of the Company’s share price using market data.

9. NET LOSS PER SHARE

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

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Net loss for the period	$ (85)	$ (961)	$ (25,562)	$ (8,717)
Weighted average number of common shares outstanding – basic				
Common shares outstanding at beginning of period	120,179	119,355	119,467	111,322
Effect of shares issued	16	-	440	3,296
Weighted average number of common shares outstanding – basic	120,195	119,355	119,907	114,618
Effect of outstanding options	-	-	-	-
Weighted average number of common shares outstanding - diluted	120,195	119,355	119,907	114,618
Net loss per share				
- basic	$ (0.00)	$ (0.01)	$ (0.21)	$ (0.08)
- diluted	$ (0.00)	$ (0.01)	$ (0.21)	$ (0.08)

At September 30, 2016 and 2015, all outstanding stock options were considered anti-dilutive as the Company was in a loss position.

10. FINANCIAL INSTRUMENTS

The fair value of the Company's derivative 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.

Risk Management

Credit risk

Credit risk is the risk of financial loss to the Company if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk at September 30, 2016 is as follows:

	Carrying Amount as at September 30, 2016
Accounts receivable	$ 8,702
Prepaids and deposits	2,505
Total	$ 11,207

Derivative Commodity Price Contracts

The Company enters into derivative commodity price contracts with counterparties with an acceptable credit rating and with a demonstrated capability to execute such contracts. The contracts, individually and in aggregate, are subject to controls established by the Board of Directors and limitations set out in the Company's banking agreement.

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. The Company's production is sold to organizations whose credit worthiness is in part assessable from publicly available information. 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. The Company does not typically obtain collateral from joint venture partners.

No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at September 30, 2016.

Market risk

Commodity Prices

At the date of this report, Storm has the undernoted commodity price contracts in place.

Period Hedged	Daily Volume	Average Price
Crude Oil Collars		
Oct – Dec 2016	700 Bbls	$70.71 - $83.78 Cdn$/Bbl
Jan – Dec 2017	500 Bbls	$62.80 - $70.75 Cdn$/Bbl
Jan – Mar 2018	350 Bbls	$62.14 - $69.59 Cdn$/Bbl
Apr – Jun 2018	200 Bbls	$62.00 - $70.00 Cdn$/Bbl
Jul – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Crude Oil Swaps		
Oct – Dec 2016	250 Bbls	$63.66 Cdn$/Bbl
Jan – Jun 2017	400 Bbls	$66.60 Cdn$/Bbl
Jul – Sep 2017	200 Bbls	$65.925 Cdn$/Bbl
Oct – Dec 2017	100 Bbls	$66.75 Cdn$/Bbl
Natural Gas Swaps		
Oct 2016	51,000 GJ	AECO Cdn$2.32/GJ
Nov – Dec 2016	40,000 GJ	AECO Cdn$2.43/GJ
Jan – May 2017	39,000 GJ	AECO Cdn$2.63/GJ
Jun 2017	31,000 GJ	AECO Cdn$2.59/GJ
Jul – Dec 2017	23,000 GJ	AECO Cdn$2.61/GJ
Jan – Mar 2018	3,000 GJ	AECO Cdn$2.80/GJ
Jan – May 2017	2,000 Mmbtu	Chicago Cdn$4.04/Mmbtu
Jan – Jun 2017	1,900 Mmbtu	Chicago Cdn$4.312/Mmbtu
Jul – Dec 2017	2,000 Mmbtu	Chicago Cdn$4.00/Mmbtu
Jan – Jun 2018	9,850 Mmbtu	Chicago Cdn$3.88/Mmbtu
Jul – Dec 2018	3,000 Mmbtu	Chicago Cdn$3.70/Mmbtu
Natural Gas Differential Swaps		
Oct – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	8,000 GJ	Price at Stn 2 = AECO minus Cdn$0.408/GJ
Jan – Dec 2018	3,000 GJ	Price at Stn 2 = AECO minus Cdn$0.345/GJ
Oct – Dec 2016	33,000 Mmbtu	Price at Chicago = AECO plus US$0.672/Mmbtu
Jan – Dec 2017	35,000 Mmbtu	Price at Chicago = AECO plus US$0.577/Mmbtu

The fair market value of these contracts at September 30, 2016 of negative $8.2 million (December 31, 2015 – positive $8.0 million) is included in current assets or current and non-current liabilities as appropriate. This resulted in an unrealized mark-to-market gain of $1.6 million (2015 – gain of $0.7 million) for the three months ended September 30, 2016 and an unrealized loss of $16.2 million (2015 – loss of $7.0 million) for the nine months ended September 30, 2016 when measured against the fair market value at the beginning of the respective period. These amounts are recognized in the consolidated statement of loss.

During the three and nine months ended September 30, 2016, the Company realized a loss from commodity price contracts in place, or terminated in the period in the amount of $41,000 and a gain of $6.3 million, respectively (2015 – gains of $2.0 million and $11.1 million, respectively).

Sensitivities

Using the Company's actual production volumes, royalty rates and bank indebtedness for the first nine months of 2016, the estimated after-tax effect that changes in certain factors would have on net loss and net loss per share is set out below:

	Nine Months Ended September 30, 2016	
Factor	Change in Net Loss	Change in Net Loss Per Share
US$1.00/Bbl change in the price of WTI[(1)]	$ 760,000	$ 0.01
$0.10/Mcf change in the price of natural gas	$ 1,740,000	$ 0.01
1% change in the interest rate	$ 680,000	$ 0.01

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

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

11. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to Sept. 30, 2016	Three Months to Sept. 30, 2015	Nine Months to Sept. 30, 2016	Nine Months to Sept. 30, 2015
Accounts receivable	$ (859)	$ (3,045)	$ 862	$ 1,609
Prepaids and deposits	(226)	(144)	(1,776)	56
Accounts payable and accrued liabilities	2,131	3,349	(5,522)	(12,527)
Change in non-cash working capital	$ 1,046	$ 160	$ (6,436)	$ (10,862)
Relating to:				
Operating activities	$ (344)	$ (2,295)	$ (333)	$ (1,450)
Investing activities	1,390	2,455	(6,103)	(9,412)
	$ 1,046	$ 160	$ (6,436)	$ (10,862)
Interest paid during the period	$ 841	$ 356	$ 2,179	$ 1,554
Income taxes paid during the period	$ -	$ -	$ -	$ -

12. COMMITMENTS

The Company has the following long-term commitments over the next five years:

	2016	2017	2018	2019	2020	Remainder	Total
Office lease	$ 229	$ 916	$ 687	$ -	$ -	$ -	$ 1,832
Natural gas sales commitments	11,335	48,327	47,038	31,792	29,933	199,204	367,630
Total	$ 11,564	$ 49,243	$ 47,725	$ 31,792	$ 29,933	$ 199,204	$ 369,462

In the first nine months of 2016, the Company made office lease payments of approximately $701,000 (2015 - $693,000) which were included in general and administrative expense.

CORPORATE INFORMATION

Officers

Brian Lavergne
President & CEO

Robert S. Tiberio
Chief Operating Officer

Donald G. McLean
Chief Financial Officer

John Devlin
Vice President, Finance

Jamie P. Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
CEO

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

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

Stock Exchange Listing

TSX Venture Exchange
Trading Symbol “SRX”

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

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

Executive Offices

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Abbreviations

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

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