Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
FINANCIAL				
Revenue from product sales[1]	13,870	18,461	29,992	36,972
Funds from operations[2]	5,781	8,170	13,636	21,882
Per share - basic ($)	0.05	0.07	0.11	0.20
Per share - diluted ($)	0.05	0.07	0.11	0.20
Net loss	(20,493)	(4,191)	(25,477)	(7,756)
Per share - basic ($)	(0.17)	(0.04)	(0.21)	(0.07)
Per share - diluted ($)	(0.17)	(0.04)	(0.21)	(0.07)
Net capital invested				
Operations capital expenditures	613	8,864	24,559	44,544
Debt including working capital deficiency[3]	71,254	28,051	71,254	28,051
Common shares (000s)				
Weighted average - basic	119,929	113,090	119,761	112,211
Weighted average - diluted	119,929	113,090	119,761	112,211
Outstanding end of period – basic	120,179	119,355	120,179	119,355
OPERATIONS				
(Cdn$ per Boe)				
Revenue	11.86	21.01	12.55	21.02
Royalties	(0.19)	(1.62)	(0.48)	(1.08)
Production	(6.76)	(8.56)	(6.73)	(8.61)
Transportation	(0.33)	(1.16)	(0.43)	(1.42)
Field operating netback	4.58	9.67	4.91	9.91
Hedging gains	2.24	2.02	2.64	5.19
General and administrative	(1.19)	(1.51)	(1.22)	(1.88)
Interest and finance costs	(0.68)	(0.87)	(0.62)	(0.79)
Funds from operations – per Boe	4.95	9.31	5.71	12.43
Barrels of oil equivalent per day (6:1)	12,852	9,657	13,135	9,716
Gas Production				
Thousand cubic feet per day	63,800	46,391	64,906	47,049
Price (Cdn$ per Mcf)	1.28	2.55	1.45	2.70
NGL production				
Barrels per day	2,219	1,602	2,318	1,548
Price (Cdn$ per barrel)	31.93	41.23	30.47	39.25
Oil Production				
Barrels per day	-	323	-	326
Price (Cdn$ per barrel)	-	57.58	-	50.29
Wells drilled (100% working interest)	-	-	7.0	6.0
Wells completed (100% working interest)	-	-	2.0	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 19 of the attached MD&A.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2016 SECOND QUARTER

- Production averaged 12,852 Boe per day (17% NGL), a year-over-year increase of 33% (32% on a per-share basis) and a quarter-over-quarter decrease of 4%. Production was reduced during April and May as a result of extremely low natural gas prices which resulted in approximately 1,000 Boe per day being shut in.

- NGL production was 2,219 barrels per day, an increase of 39% from the previous year. The price was $31.93 per barrel or 58% of the average Edmonton light oil price (53% of the NGL volume was higher value condensate and plant pentanes).

- There was minimal activity with three horizontal wells commencing production at Umbach during the quarter (one in April and two in June). At the end of the quarter, there was an inventory of nine horizontal wells (9.0 net) that have been drilled but not completed.

- Montney horizontal well performance at Umbach continues to improve with the five most recent wells with enough history averaging 5.5 Mmcf per day gross raw gas over the first 90 calendar days, a 15% increase from the average 2014 and 2015 wells. The four most recent wells with enough history have averaged 5.3 Mmcf per day over the first 180 calendar days, an improvement of 23% from the average 2014 and 2015 wells.

- Funds flow was $5.8 million ($4.95 per Boe), a decrease of 29% from a year ago. Although production per share increased and controllable cash costs decreased, this was more than offset by a 50% decrease in the natural gas price which averaged $1.28 per Mcf in the quarter.

- Controllable cash costs (operating, cash G&A, interest expense) were $8.63 per Boe, a year-over-year decrease of 21%. 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).

- Net loss was $20.5 million or $17.51 per Boe and reflects the extremely low commodity prices in the quarter with funds from operations at $4.95 per Boe being less than the depletion and depreciation rate of $8.21 per Boe. The net loss also includes a mark to market loss of $15.8 million related to the change in the fair value of commodity price hedges since the previous quarter (this is a non-cash item).

- Net capital investment was $0.6 million with investment being minimized as a result of extremely low commodity prices.

- Debt including working capital deficiency was $71.3 million which is 3.1 times annualized second quarter funds flow. This is a reduction of $5.9 million from the previous quarter. In May, the bank credit facility was set at $130.0 million after the annual review was completed (previously $140.0 million).

- Commodity price hedges were added with approximately 24% of current production being hedged for 2017 (there were no hedges for 2017 when first quarter results were released May 12, 2016).

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 39 horizontal wells producing at the end of the second quarter (35.4 net).

Production in the second quarter was 12,852 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 second quarter, three horizontal wells (3.0 net) started production. There is currently an inventory of nine horizontal wells (9.0 net) that have not started producing which includes three completed wells.

Storm's two operated field compression facilities have total capacity of 80 Mmcf per day raw gas with actual throughput in the second quarter averaging 67 Mmcf per day raw gas. Construction of a third field compression facility with initial capacity of 35 Mmcf per day is planned for early 2017 with start-up in April for an estimated total cost of $25.0 million with $10.9 million having been invested to date to purchase major equipment ($6.1 million in Q1 2016 and $4.8 million in 2015). 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 Storm has firm processing commitments totaling 65 Mmcf per day raw gas in 2016.

A summary of horizontal well performance and costs is provided below. The five most recent horizontal wells have averaged 5.5 Mmcf per day gross raw gas over the first 90 calendar days, a 15% improvement from the average 2014 and 2015 horizontal well. On a per-stage basis, the drill and complete cost for the most recent wells has decreased by 28% from 2014.

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	3.1 Mmcf/d 3 hz's
Q4/15 to Q1/16 7 wells	25	1,415 m	$4.3 million $172 K/stage	5.5 Mmcf/d 5 hz's	5.3 Mmcf/d 4 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 28 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, producing 280 Boe per day, was shut in during 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. Although Storm has no oil production, the WTI price is hedged as approximately 80% of NGL production is priced in reference to WTI (condensate, plant pentane and butane). A summary of commodity price hedges is provided below.

Q3 – Q4 2016		
Crude Oil	800 Bopd	WTI Cdn$70.05 floor, Cdn$81.48/Bbl ceiling
Natural Gas	45,500 GJ/d (36,400 Mcf/d)	AECO Cdn$2.33/GJ ($2.91/Mcf)
	11,000 GJ/d (8,800 Mcf/d)	BC Stn 2 price = AECO – Cdn$0.34/GJ
	33,000 Mmbtu/d (27,850 Mcf/d)	Chicago price = AECO + US$0.67/Mmbtu

2017		
Crude Oil	400 Bopd	WTI Cdn$62.69 floor, Cdn$68.33/Bbl ceiling
Natural Gas	20,000 GJ/d (16,000 Mcf/d)	AECO Cdn$2.52/GJ ($3.15/Mcf)
	5,000 GJ/d (4,000 Mcf/d)	BC Stn 2 price = AECO – Cdn$0.44/GJ
	35,000 Mmbtu/d (29,540 Mcf/d)	Chicago price = AECO + US$0.58/Mmbtu

Storm's strategy with respect to natural gas transportation commitments is to diversify natural gas sales by selling at Chicago, AECO and BC Station 2. Current transportation commitments total 65 Mmcf per day in 2016 and increase to 91 Mmcf per day in 2018 (interruptible capacity on the Alliance Pipeline adds up to 11 Mmcf per day in 2016 and 14 Mmcf per day in 2018). A summary is provided below and further information on pipeline tariffs and price deductions is provided in the presentation on Storm's website.

2016	2017	2018
Alliance Pipeline 46 Mmcf/d(1) Chicago price	Alliance Pipeline 51 Mmcf/d(1) Chicago price	Alliance Pipeline 55 Mmcf/d(1) Chicago price
Spectra T-north 9 Mmcf/d BC Stn 2 price	Spectra T-north 9 Mmcf/d BC Stn 2 price	Spectra T-north 26 Mmcf/d BC Stn 2 price
Marketing Arrangement 10 Mmcf/d AECO price -$0.68/GJ		Spectra T-north & TCPL 10 Mmcf/d AECO price

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

OUTLOOK

Production in the third quarter is forecast to be approximately 12,500 to 13,500 Boe per day. Capital investment in the third quarter is expected to be $8.0 to $11.0 million which includes completing and pipeline connecting three to four horizontal wells at Umbach.

When first quarter results were reported on May 12, natural gas prices in April had averaged $1.04/GJ at AECO and US$1.92/Mmbtu at Chicago, the field netback was $2.15 per Boe and production was reduced to meet firm transportation and processing commitments. In such circumstances, Storm's primary objective was to avoid increasing debt in order to preserve the ability to accelerate growth when the natural gas price improved. With the recent improvement in the natural gas price (July was $2.25/GJ at AECO and US$2.73/MMbtu at Chicago), the field netback has improved to approximately $10.00 per Boe and growth is again economically justifiable. If natural gas prices remain at this level during the second half of 2016, additional horizontal wells will be drilled and completed at Umbach and capital investment for 2016 will increase to $36.0 to $50.0 million (was $37.0 to $42.0 million). This includes $6.1 million incurred in the first quarter to purchase major equipment for the third field compression facility at Umbach where start-up is planned for April 2017. Updated guidance for 2016 and preliminary guidance for 2017 is provided below.

2016 Guidance

	May 12, 2016	Updated Aug 15, 2016
Chicago natural gas price	US$2.20/Mmbtu	US$2.40/Mmbtu(1)
AECO natural gas price	$1.60/GJ	$1.95/GJ(1)
BC STN 2 natural gas price	$1.25/GJ	$1.65/GJ(1)
Edmonton light oil price	Cdn$50/Bbl	Cdn$50/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)	$37.0 - $42.0 million	$36.0 - $50.0 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	8 gross (8.0 net) 6 gross (6.0 net) 8 gross (8.0 net)	10 gross (10.0 net) 8 gross (8.0 net) 10 gross (10.0 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 15, 2016	$1.95/GJ	$36.0 to $50.0 million	13,000 – 14,000 Boe/d	12,500 - 13,500 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
February 25, 2016	$2.00/GJ	$80.0 million	15,500 – 16,500 Boe/d	14,000 - 15,000 Boe/d
November 11, 2015	$2.50/GJ	$105.0 million	20,000 – 21,000 Boe/d	16,000 – 18,000 Boe/d
August 13, 2015	$2.80/GJ	$106.0 million	20,000 – 21,000 Boe/d	16,000 – 19,000 Boe/d

2017 Preliminary Guidance

	Aug 15, 2016
Chicago natural gas price	US$3.00 per Mmbtu
AECO natural gas price	$2.65 per GJ
BC STN 2 natural gas price	$2.25 per GJ
Edmonton light oil price	Cdn$55 per Bbl
Estimated average operating costs	$7.00 per Boe
Estimated average royalty rate (% production revenue before hedging)	7% - 9%
Estimated operations capital (excluding acquisitions & dispositions)	$80.0 million
Estimated cash G&A net of recoveries	$4.8 million $0.85 per Boe
Forecast fourth quarter production	16,000 – 18,000 Boe/d (17% NGL)
Forecast annual production	15,000 – 17,000 Boe/d (17% NGL)
Umbach horizontal wells drilled Umbach horizontal wells completed Umbach horizontal wells connected	12 gross (12.0 net) 11 gross (11.0 net) 11 gross (11.0 net)

The AECO - BC Station 2 price differential was -$0.20 per GJ in the second quarter, an improvement from the 2015 average of -$0.85 per GJ. Having the differential return to historical levels (average for 2010 to 2014 was -$0.20 per GJ) is supportive of Storm's future production growth which would be sold at BC Station 2.

Natural gas prices in North America have improved significantly over the last three months as a result of increasing demand in the United States (electric power generation, LNG exports, exports to Mexico) and flat to declining production. With rig counts at historical lows and higher debt levels preventing many producers from increasing capital investment, natural gas prices should continue improving into 2017. Longer term also appears increasingly bullish with LNG export capacity of more than 9 Bcf/d 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.

Although Storm's growth rate in 2016 was reduced by the deferral of activity due to very low natural gas prices in the first half of the year, production is still forecast to increase by 36% per share on a year-over-year basis. Storm's strong financial position will support planned growth in 2017 which includes the addition of a third field compression facility at Umbach with initial capacity of 35 Mmcf per day (April 2017 start-up).

The cost to drill and complete horizontal wells at Umbach has decreased by 28% on a per-stage basis since 2014. Further reductions are expected in the second half of 2016 from lower service costs and from modifying completion techniques.

At Umbach, Storm has a higher quality, liquids-rich land position in the Montney formation which is at a relatively shallow depth resulting in a lower cost to drill and complete horizontal wells. With 155 net sections, there remains room for significant future growth given that there are producing horizontal wells on only 6% of the lands (9 net sections), proved plus probable reserves are assigned on only 20% of the lands (31 net sections), and approximately 33% of the lands have been delineated to date with producing horizontal wells. The focus remains on increasing value for shareholders by converting this large resource into production and cash flow per share growth. This will come from continuing to improve well performance, finding ways to further reduce the cost to drill and complete wells, decreasing controllable cash costs (reducing third party processing fees), and maintaining a strong balance sheet to preserve the ability to accelerate growth when commodity prices are supportive of doing so.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

August 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 August 15, 2016 for the three and six months ended June 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 six months ended June 30, 2016. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2016, (ii) the Company's audited consolidated financial statements for the year ended December 31, 2015, and (iii) the press release issued by the Company on August 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 August 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 six months ended June 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 year ended December 31, 2015. 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 six month periods ended June 30, 2015.

OPERATIONAL AND FINANCIAL RESULTS

Overview

Storm's business in the second quarter was dominated by a continuing deterioration in natural gas pricing. Falling prices applied to each of the three markets in which the Company's production is sold, being Chicago, AECO and Station 2. Virtually all production in the quarter came from Umbach, with the Company's producing well in the Horn River Basin remaining shut in. Faced with this situation, and as stated in the Company's first quarter press release, production in excess of contractual requirements, or about 1,000 Boe per day, was shut in. The result was that average daily production for the quarter amounted to 12,852 Boe, or about 4% less than average daily production for the immediately preceding quarter, although 33% higher than the comparable quarter of 2015. Storm's compression capacity, which puts an upper limit on production, amounts to approximately 14,800 Boe per day, meaning that second quarter production was about 85% of capacity. Volumetrically, NGL amounted to about 17% of total production; however, NGL revenue, in spite of low prices across the NGL spectrum, contributed a remarkable 46% of revenue. This illustrates the dismal state of the natural gas business, as well as how important high margin NGL is to the Company. Approximately 53% of Storm's NGL production comprise condensate and pentanes which are priced with reference to crude oil indices. Storm had production from 39 gross wells at the end of the second quarter and NGL recovery, adjusted for declines, has largely been stable across the producing well inventory.

The natural gas price realized by the Company in the second quarter fell by 21% when compared to the first quarter of 2016 and fell by 50% when compared to the same quarter of 2015. The average selling price for NGL for the quarter increased by 10% when compared to the first quarter of 2016, a reflection of increased crude oil prices, but fell by 23% when compared to the second quarter of 2015. The consequence is that field netbacks for the quarter fell below the estimated cost of replacing production, validating the Company's decision to limit production to levels required under contract.

At quarter end the company had nine standing wells awaiting completion and tie-in, which should be sufficient to offset production declines for the remainder of the year and into 2017. No wells were drilled or completed in the quarter and other capital expenditures were minimal. As a result, total debt at quarter end amounted to $71.3 million, down from $77.2 million at the end of the first quarter. Balance sheet protection remains a paramount consideration for Storm.

Storm's strong financial position has enabled the Company to position itself for future growth in a more benign pricing environment. Equipment required for a new compression facility to expand capacity by 35 Mmcf per day has been purchased and stockpiled. Future installation costs are estimated to be $14 million, with the compression facility scheduled to come on stream in the second quarter of 2017. Capacity at the facility can be doubled to 70 Mmcf per day at an estimated cost of $7 million. Thus for a relatively modest incremental outlay of $21 million, Storm's compression capacity can be increased by 90%. Although no wells were drilled or completed during the second quarter, completions subsequent to quarter end confirm that service costs are at historically low levels.

On the cost side, year-over-year production costs fell by 22% and were largely the same as production costs for the first quarter of 2016. Transportation costs for the quarter fell by 72% year over year and by 38% compared to the first quarter. However, improvements in Storm's cost structure were insufficient to offset the revenue collapse, with field operating netback falling by 53% compared to the same quarter of 2015 and by 12% when compared to the first quarter amount. Storm's hedging program provided some relief; realized hedging gains represented 19% of production revenue per Boe for the quarter, compared to 10% for the prior year quarter and 23% for the first quarter of 2016.

The second quarter saw some restructuring of the junior energy sector. Banks moved aggressively to reduce borrowing availability for many companies; where available, some companies chose to raise equity to strengthen balance sheets; there were a greater number of larger and higher quality asset sales; a number of companies are seeking strategic alternatives. One result is a reduction in the amount of capital available for reinvestment, resulting in an emerging supply response to the commodity pricing crisis. In addition, natural gas prices have improved somewhat in recent weeks from the sub-economic levels of the second quarter. Storm reacted by placing additional hedges which will provide balance sheet protection as Storm moves to build out its high quality, large scale and early stage Umbach property.

Production and Revenue

Production by Area

The Company reported production from the following areas:

				Three Months to June 30, 2016
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d
Umbach – NE BC	63,772	2,219	-	12,847
Horn River Basin – NE BC(2)	-	-	-	-
Grande Prairie – AB	28	-	-	5
Total	63,800	2,219	-	12,852

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

				Three Months to June 30, 2015
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)(1)	Boe/d
Umbach – NE BC	42,308	1,565	-	8,616
Horn River Basin – NE BC	1,692	-	-	282
Grande Prairie – AB	2,391	37	323	759
Total	46,391	1,602	323	9,657

Six Months to June 30, 2016				
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)[1]	Boe/d
Umbach – NE BC	64,833	2,318	-	13,123
Horn River Basin – NE BC[2]	-	-	-	-
Grande Prairie – AB	73	-	-	12
Total	64,906	2,318	-	13,135

Six Months to June 30, 2015				
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)[1]	Boe/d
Umbach – NE BC	42,596	1,498	-	8,598
Horn River Basin – NE BC	1,688	-	-	281
Grande Prairie – AB	2,765	50	326	837
Total	47,049	1,548	326	9,716

In the second quarter of 2016, average Boe-per-day volumes increased by 33% when compared to the second quarter of 2015, and decreased by 4% when compared to the immediately preceding quarter. For the six month period ended June 30, 2016, average Boe production increased by 35% 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 39 wells (35.4 net) at the end of the quarter. The Company's crude oil producing properties in Alberta were sold in mid-2015 and production for the second quarter of 2016 from the remaining Alberta properties was minimal. During the quarter, 1,000 Boe per day of production was shut in, including the Company's production from the Horn River Basin, due to uneconomical natural gas pricing. Production to date in the third quarter of 2016 has averaged approximately 12,800 Boe per day based on field estimates.

The quarter-to-quarter reduction in production in 2016 is consistent with the Company's previously stated intention to limit production to volumes required to meet contract obligations during periods of very low commodity prices.

Daily production per million shares outstanding at the end of the second quarter averaged 107 Boe per day, compared to 81 Boe per day for the second quarter of 2015 and 112 Boe per day for the first quarter of 2016.

The Horn River Basin produces dry natural gas, while Umbach produces natural gas and associated NGL. By volume production in the second quarter approximated 83% natural gas and 17% NGL.

Average Daily Production

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Natural gas (Mcf/d)	63,800	46,391	64,906	47,049
Natural gas liquids (Bbls/d)	2,219	1,602	2,318	1,548
Crude oil (Bbls/d)	-	323	-	326
Total (Boe/d)	12,852	9,657	13,135	9,716

Production Profile and Per-Unit Prices(1)

	Three Months to June 30, 2016		Three Months to June 30, 2015		Six Months to June 30, 2016		Six Months to June 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%	$ 1.28	80%	$ 2.55	82%	$ 1.45	81%	$ 2.70
Natural gas liquids - Bbl	17%	31.93	17%	41.23	18%	30.47	16%	39.25
Crude oil - Bbl	-	-	3%	57.58	-	-	3%	50.29
Per Boe	100%	$ 11.86	100%	$ 21.01	100%	$ 12.55	100%	$ 21.02

(1) Before realized hedging gains of $2.24 per Boe for the three months ended June 30, 2016 and $2.64 per Boe for the six months ended June 30, 2016. In 2015, there were hedging gains of $2.02 per Boe for the three months ended June 30, 2015 and $5.19 per Boe for the six months ended June 30, 2015.

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

- 43% - Adjusted Chicago monthly index price less US$0.05 per Mmbtu
- 28% - Adjusted Chicago daily index price
- 16% - Adjusted AECO daily index price less Cdn$0.68 per GJ
- 13% - 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 differ due to heat content of the Company's natural gas.

	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)
Q2 – 2015	2.68	2.70	2.52	2.53	2.01	67.72
Q3 – 2015	2.83	2.79	2.75	2.65	1.72	56.23
Q4 – 2015	2.47	2.16	2.34	2.51	1.04	52.95
Q1 – 2016	2.25	2.04	1.74	2.00	1.33	40.81
Q2 – 2016	1.95	2.09	1.33	1.18	1.14	54.78

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 in December 2015 resulting in a differential of $0.41 per GJ in the first quarter of 2016 and $0.20 per GJ in the second quarter of 2016. However, the downward spiral in natural gas prices continued into the first and second quarters of 2016, with the consequence that any benefit accruing to Storm from an easing of the AECO – Station 2 differential was eliminated by the magnitude of the natural gas price collapse.

The realized price for NGL in the second quarter of 2016 fell by 23% relative to the second quarter of 2015 and increased 10% compared to the first 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 generally are aligned with lower crude oil prices. For the second quarter, WTI averaged US$45.59 per barrel and Edmonton light oil was Cdn$54.78 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$3.97 per barrel, compared to Cdn$3.51 per barrel in the second quarter of 2015 and Cdn$5.15 per barrel in the first quarter of 2016.

Increasing natural gas production at Umbach will result 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 46% of revenue from product sales in the second quarter of 2016.

On a per-Boe basis, the realized price for the second quarter of 2016 declined by 44% and 10% compared to the second quarter of 2015 and first quarter of 2016.

Revenue from Product Sales[(1)]

(000s)	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Natural gas	$ 7,422	$ 10,759	$ 17,141	$ 23,004
Natural gas liquids	6,448	6,011	12,851	10,996
Crude oil	-	1,691	-	2,972
Total	$ 13,870	$ 18,461	$ 29,992	$ 36,972

(1) Excludes hedging gains and losses.

Revenue from product sales for the second quarter of 2016 decreased by 25% when compared to the second quarter of 2015 and by 14% when compared to the first quarter of 2016. For the six months periods, the year-over-year revenue decline was 19%. Production volumes grew 33% and 35% year over year for the three and six month periods; however, production growth was offset by the unrelenting fall in commodity prices.

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

(000s)	Natural Gas	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – Q2 2015	$ 10,759	$ 6,011	$ 1,691	$ 18,461
Effect of increased (decreased) production	4,040	2,315	(1,691)	4,664
Effect of changes in average product prices	(7,377)	(1,878)	-	(9,255)
Revenue from product sales – Q2 2016	$ 7,422	$ 6,448	$ -	$ 13,870

The disparity between growth in production and the fall in revenue corresponds to price declines as follows:

Realized Prices per Commodity Unit	Three Months to June 30, 2015		Three Months to March 31, 2016		Three Months to June 30, 2016	
Natural gas (Mcf/d)	$ 2.55	100%	$ 1.62	64%	$ 1.28	50%
Natural gas liquids (Bbls/d)	41.23	100%	29.12	71%	31.93	77%
Crude oil (Bbls/d)	57.58	100%	-	N/A	-	N/A
Total	$ 21.01	100%	$ 13.20	63%	$ 11.86	56%

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 prior to the expiry date.

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 results from the mark-to-market valuation of the unexpired portion of hedging contracts outstanding at the end of the reporting period. The change in fair value recognizes not only the mark-to-market change in the value of contracts outstanding both at the beginning and end of the reporting period, but includes the opening value of contracts which have come to term during the reporting period.

	Three Months to June 30, 2016					Three Months to June 30, 2015				
Realized gain (loss)										
Liquids	$	739	$	3.66	/Bbl	$	-	$	-	/Bbl
Natural gas		1,877	$	0.32	/Mcf		1,775	$	0.42	/Mcf
Total realized gain (loss) – cash	$	2,616	$	2.24	/Boe	$	1,775	$	2.02	/Boe

	Six Months to June 30, 2016					Six Months to June 30, 2015				
Realized gain (loss)										
Liquids	$	2,062	$	4.89	/Bbl	$	5,137	$	15.06	/Bbl
Natural gas		4,258	$	0.36	/Mcf		3,998	$	0.47	/Mcf
Total realized gain (loss) – cash	$	6,320	$	2.64	/Boe	$	9,135	$	5.19	/Boe

	Three Months to June 30, 2016					Three Months to June 30, 2015				
Unrealized gain (loss)										
Liquids – change in fair value	$	(2,353)	$	(11.65)	/Bbl	$	(99)	$	(0.57)	/Bbl
Natural gas – change in fair value		(13,450)	$	(2.32)	/Mcf		(800)	$	(0.19)	/Mcf
Total unrealized gain (loss) – non-cash	$	(15,803)	$	(13.51)	/Boe	$	(899)	$	(1.02)	/Boe

	Six Months to June 30, 2016					Six Months to June 30, 2015				
Unrealized gain (loss)										
Liquids – change in fair value	$	(2,858)	$	(6.78)	/Bbl	$	(4,960)	$	(14.54)	/Bbl
Natural gas – change in fair value		(14,916)	$	(1.26)	/Mcf		(2,776)	$	(0.33)	/Mcf
Total unrealized gain (loss) – non-cash	$	(17,774)	$	(7.43)	/Boe	$	(7,736)	$	(4.40)	/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		
Jul – Dec 2016	700 Bbls	$70.71 - $83.78 Cdn$/Bbl
Jan – Dec 2017	300 Bbls	$61.33 - $68.85 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Jan – Mar 2018	100 Bbls	$60.00 - $70.25 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Crude Oil Swaps		
Jul – Dec 2016	100 Bbls	$65.40 Cdn$/Bbl
Jan – Dec 2017	100 Bbls	$66.75 Cdn$/Bbl
Natural Gas Swaps		
Jul – Dec 2016	45,500 GJ	AECO Cdn$2.33/GJ
Jan – Dec 2017	20,000 GJ	AECO Cdn$2.52/GJ
Natural Gas Differential Swaps		
Jul – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	5,000 GJ	Price at Stn 2 = AECO minus Cdn$0.445/GJ
Jul – 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 of negative $9.8 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 six months ended June 30, 2016, this resulted in unrealized mark-to-market losses of $15.8 million and $17.8 million (2015 – losses of $0.9 million and $7.7 million) when measured against the fair market value of contracts outstanding at the end of the preceding reporting period.

During the second quarter of 2016, the Company realized gains from commodity price contracts in place or terminated in the amount of $2.6 million, compared to gains of approximately $1.8 million in the second quarter of 2015. During the first half of 2016, the Company realized gains from commodity price contracts in the amount of $6.3 million compared to gains of $9.1 million in the first half of 2015.

Natural gas swaps are priced at the AECO monthly index and the Company sells equal physical volumes of natural gas at the same price.

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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Charge for period	$ 227	$ 1,426	$ 1,149	$ 1,899
Percentage of revenue from product sales	2%	8%	4%	5%
Per Boe	$ 0.19	$ 1.62	$ 0.48	$ 1.08

Royalties in the second quarter of 2016 decreased by 84% when compared to the same quarter of 2015 and by 75% compared to the first quarter of 2016 and decreased by 39% when comparing the first half of 2016 to the first half of 2015. Decreased production revenue as a result of lower commodity pricing and the receipt of infrastructure royalty credits which apply to production in British Columbia, resulted in the royalty decreases. The amount of infrastructure credits received is as follows: second quarter 2016 $0.5 million; second quarter 2015 $Nil; first quarter 2016 $Nil; first half 2016 $0.5 million; first half 2015 $1.0 million.

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 projects. Storm realized credits of $0.8 million in 2013, $1.9 million in 2014, $2.0 million in 2015 and $0.5 million in 2016. The remaining credits total $8.8 million which will reduce future royalties. The timing of receipt of future credits is dependent on commodity prices and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary.

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.

The Alberta government's royalty program changes will not have a material impact on Storm given the limited production base in Alberta.

Production Costs

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Charge for period	$ 7,906	$ 7,523	$ 16,099	$ 15,147
Percentage of revenue from product sales	57%	41%	53%	41%
Per Boe	$ 6.76	$ 8.56	$ 6.73	$ 8.61

Total production costs for the second quarter and first half of 2016 increased by 5% and 6% when compared to the same periods of 2015. The increase in total production costs is aligned with increased production at Umbach. Per-Boe charges continue to decline.

Production costs per Mcf of natural gas for the second quarter averaged $1.36 with total production costs averaging $6.76 per Boe, a year-over-year reduction of 21%. For the comparable six month periods production costs per Boe fell by 22%. Production costs of natural gas liquids are included with natural gas costs. Production costs per Boe for the first and second quarters of 2016 were virtually identical.

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.

Transportation Costs

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Charge for period	$ 388	$ 1,023	$ 1,033	$ 2,499
Percentage of revenue from product sales	3%	6%	3%	7%
Per Boe	$ 0.33	$ 1.16	$ 0.43	$ 1.42

Transportation costs largely comprise pipeline tariffs for natural gas, as well as trucking costs for wellhead condensate. Total transportation costs for the second quarter of 2016 decreased by 62%, and by 72% 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 2015. Compared to the first quarter of 2016, per-Boe costs fell by $0.20, or 38%, due to lower trucking costs for wellhead NGL and higher volumes of natural gas sold in markets with no direct transportation cost. As the sales point for natural gas shipped on the Alliance Pipeline is the processing facility in British Columbia, the sales price is net of the cost to the shipper of moving natural gas to Chicago. For the comparable six month periods transportation costs fell by 59% and 70% per Boe.

Field Netbacks

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

Three Months to June 30, 2016	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 1.28	$ 31.93	$ -	$ 11.86
Royalties	0.05	(2.64)	-	(0.19)
Production costs	(1.36)	-	-	(6.76)
Transportation costs	(0.03)	(1.13)	-	(0.33)
Field operating netback before hedging	$ (0.06)	$ 28.16	$ -	$ 4.58
Realized hedging gains (losses)	0.32	3.66	-	2.24
Total operating income per commodity unit	$ 0.26	$ 31.82	$ -	$ 6.82
Total operating income (000s)	$ 1,539	$ 6,425	$ -	$ 7,964

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

Three Months to June 30, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.55	$ 41.23	$ 57.58	$ 21.01
Royalties	(0.12)	(5.97)	(1.47)	(1.62)
Production costs	(1.66)	-	(17.90)	(8.56)
Transportation costs	(0.16)	(1.60)	(4.36)	(1.16)
Field operating netback before hedging	$ 0.61	$ 33.66	$ 33.85	$ 9.67
Realized hedging gains (losses)	0.42	-	-	2.02
Total operating income per commodity unit	$ 1.03	$ 33.66	$ 33.85	$ 11.69
Total operating income (000s)	$ 4,364	$ 4,908	$ 994	$ 10,266

Six Months to June 30, 2016	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 1.45	$ 30.47	$ -	$ 12.55
Royalties	-	(2.68)	-	(0.48)
Production costs	(1.36)	-	-	(6.73)
Transportation costs	(0.03)	(1.52)	-	(0.43)
Field operating netback before hedging	$ 0.06	$ 26.27	$ -	$ 4.91
Realized hedging gains (losses)	0.36	4.89	-	2.64
Total operating income per commodity unit	$ 0.42	$ 31.16	$ -	$ 7.55
Total operating income (000s)	$ 4,889	$ 13,141	$ -	$ 18,031

Six Months to June 30, 2015	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.70	$ 39.25	$ 50.29	$ 21.02
Royalties	(0.01)	(6.11)	(2.41)	(1.08)
Production costs	(1.65)	-	(18.67)	(8.61)
Transportation costs	(0.17)	(2.66)	(4.62)	(1.42)
Field operating netback before hedging	$ 0.87	$ 30.48	$ 24.59	$ 9.91
Realized hedging gains (losses)	0.47	-	86.93	5.19
Total operating income per commodity unit	$ 1.34	$ 30.48	$ 111.52	$ 15.10
Total operating income (000s)	$ 11,433	$ 8,540	$ 6,589	$ 26,562

Total operating income in the second quarter of 2016 declined by 22% when compared to the second quarter of 2015, and by 32% when comparing the first half of 2016 to the same period in 2015. Per Boe, excluding hedging gains and losses, field operating netback fell by 53% in the second quarter of 2016 in comparison to the same quarter of 2015, and by 50% when comparing the six month periods to June 30. Year over year, production and transportation costs per Boe each fell considerably, but these cost reductions were insufficient to counter the effect of reduced commodity prices which caused per-Boe production revenue to fall by 44% and by 40% for the comparable three and six month periods. Compared to the first quarter of 2016, per-Boe revenue fell by 10% and field operating netback per Boe fell by 12%.

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest and finance costs, amounted to $8.63 for the second quarter of 2016, $10.94 for the equivalent quarter of 2015 and $8.52 for the first quarter of 2016. Transportation costs are excluded as the sales price received by the Company is net of the cost to the purchaser of shipping on the Alliance Pipeline to Chicago under arrangements which became effective late in 2015, which affects comparability between 2016 and 2015. Comparing the second quarter of 2016 to the same quarter of 2015, all components of cash costs decreased on a per-Boe basis. Although it is reasonable to expect future reductions in cash costs per commodity unit, they are likely to be small in the absence of production growth; further, the oilfield service industry is probably at its limit in terms of being able to absorb further price reductions.

General and Administrative Costs

Total Costs	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Charge for period – before recoveries	$ 1,434	$ 1,684	$ 3,376	$ 4,536
Overhead recoveries	(43)	(355)	(458)	(1,238)
Charge for period – net of recoveries	$ 1,391	$ 1,329	$ 2,918	$ 3,298
Per Boe	$ 1.19	$ 1.51	$ 1.22	$ 1.88

Gross general and administrative costs for the second quarter and first half of 2016 decreased by 15% and 26%, respectively, when compared to the same periods of 2015. The decrease is largely attributable to lower personnel costs and lower bonus payouts. Overhead recoveries decreased as a result of lower field capital spending.

On a per-Boe measure, net general and administrative costs for the quarter decreased by 21% compared to the second quarter of 2015, and by 35% when comparing the first half of 2016 to the same period in 2015.

Share-Based Compensation

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Charge for period	$ 729	$ 783	$ 1,552	$ 1,768
Per Boe	$ 0.62	$ 0.89	$ 0.65	$ 1.01

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 second quarter of 2016 compared to the same quarter of 2015 and by 12% for the six month period. The year-over-year decrease in share-based compensation in both the three and six 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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Depletion	$ 8,357	$ 7,673	$ 17,076	$ 15,498
Depreciation	1,243	1,005	2,472	2,399
Charge for period	$ 9,600	$ 8,678	$ 19,548	$ 17,897
Per Boe	$ 8.21	$ 9.88	$ 8.18	$ 10.18

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 33% growth in production resulted in the total charge for depletion and depreciation increasing by 9% in the second quarter of 2016 compared to the same quarter of 2015. For the six month periods, production grew by 35% with the depletion and depreciation charge growing by 10%. The disproportionately low increase in the 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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Charge for period	$ 92	$ 137	$ 179	$ 270
Per Boe	$ 0.08	$ 0.16	$ 0.07	$ 0.15

Accretion represents the time value increase for each reporting period for the Company's decommissioning liability. The decreased year-over-year charge for accretion 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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Charge for period	$ 793	$ 765	$ 1,477	$ 1,382
Percentage of revenue from product sales	6%	4%	5%	4%
Per Boe	$ 0.68	$ 0.87	$ 0.62	$ 0.79

Interest costs in 2016, for both the three and six 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 second quarter of 2016 the Company recognized a loss of $50,000 (2015 – loss of $220,000) 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 June 30, 2016	Maximum Annual Deduction
Canadian oil and gas property expense	$ 44,000	10%
Canadian development expense	102,000	30%
Canadian exploration expense	22,000	100%
Undepreciated capital cost	80,000	20 - 100%
Operating losses	191,000	100%
Other	3,000	20 - 100%
Total	$ 442,000	

Net Income (Loss)

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Net income (loss)	$ (20,493)	$ (4,191)	$ (25,477)	$ (7,756)
Per basic and diluted share	$ (0.17)	$ (0.04)	$ (0.21)	$ (0.07)

Of the per-share loss of $0.17 for the second quarter of 2016, $0.13 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 three and six months ended June 30, 2015, losses of $60,000 and $110,000, respectively, were 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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Chinook Energy Inc.	Common Shares	1,000,000	$ -	$ (60)	$ -	$ (110)
Other comprehensive loss for period			$ -	$ (60)	$ -	$ (110)

(1) Shares owned at June 30, 2016.

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

	Three Months to June 30, 2016		Three Months to June 30, 2015		Six Months to June 30, 2016		Six Months to June 30, 2015	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Cash from operating activities	$2,902	$0.03	$8,792	$0.08	$13,647	$0.11	$22,729	$0.21
Net change in non-cash working capital items	2,879	0.02	(622)	(0.01)	(11)	-	(847)	(0.01)
Non-GAAP funds from operations	$5,781	$0.05	$8,170	$0.07	$13,636	$0.11	$21,882	$0.20

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 second quarter of 2016 decreased by 29% from the second quarter of 2015, and by 38% for the six month periods. Production growth was insufficient to overcome the continuing commodity price collapse.

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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Revenue from product sales	11.86	21.01	12.55	21.02
Realized hedging gains	2.24	2.02	2.64	5.19
Royalties	(0.19)	(1.62)	(0.48)	(1.08)
Production	(6.76)	(8.56)	(6.73)	(8.61)
Transportation	(0.33)	(1.16)	(0.43)	(1.42)
General and administrative	(1.19)	(1.51)	(1.22)	(1.88)
Interest and finance costs	(0.68)	(0.87)	(0.62)	(0.79)
Funds from operations	4.95	9.31	5.71	12.43
Share-based compensation	(0.62)	(0.89)	(0.65)	(1.01)
Depletion, depreciation and accretion	(8.29)	(10.04)	(8.25)	(10.33)
Exploration and evaluation costs expensed	-	-	-	(0.06)
Unrealized revaluation loss on investments	(0.04)	(0.25)	(0.03)	(0.13)
Loss on assets held for sale	-	(1.87)	-	(0.93)
Unrealized loss on commodity price contracts	(13.51)	(1.02)	(7.43)	(4.40)
Net loss per Boe	(17.51)	(4.76)	(10.65)	(4.43)

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, 57% was drawn at June 30, 2016. Subject to a mid-year review in October 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 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 June 30, 2016 debt including working capital deficiency, excluding mark-to-market value of hedging contracts, amounted to $71.3 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

Minimal field activity in the second quarter of 2016 resulted in the Company spending only $0.6 million (2015 - $8.9 million) on field operations.

During the first half of 2016, seven 100% working interest horizontal wells were drilled, two horizontal wells were completed, and four horizontal wells were brought on production. At June 30, 2016 there were 9 wells awaiting tie-in and completion.

Major field capital outlays in the first half include $16.0 million on drilling and completions and $7.5 million on facilities, equipping and tie-ins, all in the Umbach area.

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Land and lease	$ 314	$ 184	$ 1,000	$ 520
Drilling	12	120	11,895	12,373
Completions	-	79	4,062	6,966
Facilities, equipping and pipelines	258	8,254	7,538	23,632
Recompletions and workovers	17	226	50	1,032
Property acquisition, adjustments, and administrative assets	12	1	14	21
Total capital expenditures	$ 613	$ 8,864	$ 24,559	$ 44,544

Net capital investment was allocated as follows:

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Exploration and evaluation	$ 314	$ 184	$ 989	$ 500
Property and equipment	299	8,680	23,570	44,044
Total – net of dispositions	$ 613	$ 8,864	$ 24,559	$ 44,544

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 June 30, 2016 was $28.5 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 2.0%. 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 June 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
Six months to Jun.30/16	Stock option exercises	712	$ 2.04	1,452
Total at June 30, 2016		120,179	$ 3.27	$ 393,368

(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 half of 2016, stock options were exercised at an average price of $2.04 per optioned share and 712,000 common shares were issued for proceeds of $1,452,000.

Issued and outstanding common shares at June 30, 2016 totaled 120,179,312 and at August 15, 2016, the date of this MD&A, totaled 120,192,312.

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 $28,600 and decrease to $26,300 at July 1, 2016. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $188.8 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended June 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 third quarter of 2014 to the second quarter of 2016 have been affected by one dominant trend – production growth has been insufficient to offset the relentless fall in commodity prices.

	2016		2015				2014	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production revenue ($000s)(1)	16,486	19,826	18,624	18,256	20,236	25,871	28,556	24,131
Non-GAAP funds from operations ($000s)(2)	5,781	7,855	9,182	7,982	8,170	13,712	13,892	11,784
Per share								
- basic ($)	0.05	0.07	0.08	0.07	0.07	0.12	0.13	0.11
- diluted ($)	0.05	0.07	0.08	0.07	0.07	0.12	0.12	0.11
Net income (loss) ($000s)	(20,493)	(4,984)	1,850	(961)	(4,191)	(3,565)	(7,422)	5,473
Per share								
- basic ($)	(0.17)	(0.04)	0.02	(0.01)	(0.04)	(0.03)	(0.07)	0.05
- diluted ($)	(0.17)	(0.04)	0.02	(0.01)	(0.04)	(0.03)	(0.07)	0.05
Net capital expenditures ($000s)	613	23,946	31,081	(4,116)(4)	8,864	35,680	20,095	30,426
Average daily production - Boe	12,852	13,418	10,730	9,654	9,657	9,776	10,173	7,160
Net debt ($000s)(3)	71,254	77,162	61,721	39,994	28,051	85,098	63,080	56,157

(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 June 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. Reserve estimates are prepared 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.

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.

Exploration and Evaluation Assets

Costs incurred by the Company in the initial 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. 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;
- 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 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; 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 very 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. 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 year ended December 31, 2015 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.

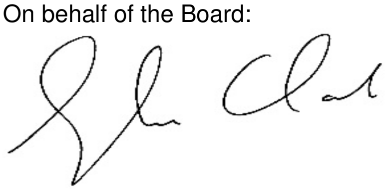
CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Interim Consolidated Statements of Financial Position

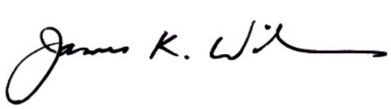
(Canadian $000s) (unaudited)	June 30, 2016	December 31, 2015
ASSETS		
Current		
Accounts receivable (Note 10)	$ 7,853	$ 9,635
Prepaids and deposits	2,278	728
Fair value of commodity price contracts (Note 10)	-	7,984
	10,131	18,347
Exploration and evaluation (Note 3)	120,457	119,356
Property and equipment (Note 4)	309,500	302,955
	$ 440,088	$ 440,658
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 7,354	$ 15,007
Fair value of commodity price contracts (Note 10)	7,156	-
	14,510	15,007
Bank indebtedness (Note 5)	74,031	57,077
Fair value of commodity price contracts (Note 10)	2,634	
Decommissioning liability (Note 6)	18,829	16,016
	110,004	88,100
Shareholders' equity		
Share capital (Note 7)	387,697	385,766
Contributed surplus (Note 8)	7,810	6,738
Deficit	(65,423)	(39,946)
	330,084	352,558
Commitments (Note 12)		
	$ 440,088	$ 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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Revenue				
Revenue from product sales	$ 13,870	$ 18,461	$ 29,992	$ 36,972
Royalties	(227)	(1,426)	(1,149)	(1,899)
Net revenue	$ 13,643	$ 17,035	$ 28,843	$ 35,073
Realized gain on commodity price contracts (Note 10)	2,616	1,775	6,320	9,135
Unrealized loss on commodity price contracts (Note 10)	(15,803)	(899)	(17,774)	(7,736)
Income from hedging activities	(13,187)	876	(11,454)	1,399
Expenses				
Production	7,906	7,523	16,099	15,147
Transportation	388	1,023	1,033	2,499
General and administrative (Note 12)	1,391	1,329	2,918	3,298
Share-based compensation (Note 8)	729	783	1,552	1,768
Depletion and depreciation (Note 4)	9,600	8,678	19,548	17,897
Exploration and evaluation costs expensed	-	-	-	103
Accretion (Note 6)	92	137	179	270
	20,106	19,473	41,329	40,982
Loss before the following:	(19,650)	(1,562)	(23,940)	(4,510)
Interest and finance costs	(793)	(765)	(1,477)	(1,382)
Unrealized revaluation loss on investment	(50)	(220)	(60)	(220)
Loss on assets held for sale	-	(1,644)	-	(1,644)
Net loss for the period	(20,493)	(4,191)	(25,477)	(7,756)
Other comprehensive income (loss)				
Reversal of prior period unrealized gain on investments	-	(60)	-	(110)
Comprehensive loss for the period	$ (20,493)	$ (4,251)	$ (25,477)	$ (7,866)
Net loss per share (Note 9)				
- basic	$ (0.17)	$ (0.04)	$ (0.21)	$ (0.07)
- diluted	$ (0.17)	$ (0.04)	$ (0.21)	$ (0.07)

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Six Months to June 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	-	-	(25,477)	-	(25,477)
Issue of common shares (Note 7)	1,451	-	-	-	1,451
Share-based compensation (Note 8)	-	1,552	-	-	1,552
Share-based compensation on options exercised (Note 7)	480	(480)	-	-	-
Balance, end of period	$ 387,697	$ 7,810	$ (65,423)	$ -	$ 330,084

(Canadian $000s) (unaudited)				Six Months to June 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	-	-	(7,756)	-	(7,756)
Issue of common shares (Note 7)	36,460	-	-	-	36,460
Share issue costs (Note 7)	(2,151)	-	-	-	(2,151)
Share-based compensation (Note 8)	-	1,768	-	-	1,768
Share based compensation on options exercised (Note 7)	19	(19)	-	-	-
Reversal of prior period unrealized gain on investments	-	-	-	(110)	(110)
Balance, end of period	$ 385,489	$ 5,112	$(40,835)	$ -	$ 349,766

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Operating activities				
Net loss for the period	$ (20,493)	$ (4,191)	$ (25,477)	$ (7,756)
Non-cash items:				
Share-based compensation (Note 8)	729	783	1,552	1,768
Depletion, depreciation and accretion (Notes 4 and 6)	9,692	8,815	19,727	18,167
Exploration and evaluation costs expensed (Note 3)	-	-	-	103
Loss on assets held for sale	-	1,644	-	1,644
Unrealized revaluation loss on investment (Note 10)	50	220	60	220
Unrealized loss on commodity price contracts (Note 10)	15,803	899	17,774	7,736
Net change in non-cash working capital items (Note 11)	(2,879)	622	11	847
	2,902	8,792	13,647	22,729
Financing activities				
Proceeds from issue of common shares (Note 7)	792	34,309	1,451	34,309
Increase (decrease) in bank indebtedness	3,579	(18,344)	16,954	(627)
	4,371	15,965	18,405	33,682
Investing activities				
Additions to exploration and evaluation assets (Note 3)	(314)	(184)	(989)	(500)
Additions to property and equipment (Note 4)	(299)	(8,680)	(23,570)	(44,044)
Net change in non-cash working capital items (Note 11)	(6,660)	(15,893)	(7,493)	(11,867)
	(7,273)	(24,757)	(32,052)	(56,411)
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 six months ended June 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 with minor operations in Alberta 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 August 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

	Six Months Ended June 30, 2016	Year ended December 31, 2015
Balance, beginning of period	$ 119,356	$ 126,805
Additions	989	5,350
Exploration and evaluation expenditures expensed	-	(154)
Future decommissioning costs	112	313
Disposals	-	(2,843)
Transfer to property and equipment	-	(10,115)
Balance, end of period	$ 120,457	$ 119,356

4. PROPERTY AND EQUIPMENT

	Six Months Ended June 30, 2016	Year ended December 31, 2015
Cost		
Balance, beginning of period	$ 389,781	$ 379,207
Additions	23,570	89,749
Future decommissioning costs	2,523	1,831
Disposals	-	(91,121)
Transfer from exploration and evaluation assets	-	10,115
Balance, end of period	$ 415,874	$ 389,781
Accumulated depletion and depreciation		
Balance, beginning of period	$ (86,826)	$ (110,744)
Depletion and depreciation	(19,548)	(34,583)
Disposals	-	58,501
Balance, end of period	$ (106,374)	$ (86,826)
Net book value, beginning of period	$ 302,955	$ 268,463
Net book value, end of period	$ 309,500	$ 302,955

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

5. BANK INDEBTEDNESS

As at June 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 June 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 $5.0 million in support of future gas transportation and processing obligations (Note 12). 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 $28.5 million (December 31, 2015 - $25.6 million), which is expected to be paid over the next 25 years. A risk-free discount rate of 2.0% (December 31, 2015 – 2.25%) and an inflation rate of 1.9% (December 31, 2015 – 1.9%) was used to calculate the present value of the decommissioning obligation, amounting to $18.8 million.

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

	Six Months Ended June 30, 2016	Year Ended December 31, 2015
Balance, beginning of period	$ 16,016	$ 23,553
Obligations incurred	1,662	1,961
Obligations disposed	-	(10,122)
Change in rate estimates(1)	972	(68)
Change in cost estimates	-	251
Accretion expense	179	441
Balance, end of period	$ 18,829	$ 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)	712	1,931
Balance as at June 30, 2016	120,179	$ 387,697

(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 six 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 six months of 2016, 712,000 common shares were issued upon the exercise of stock options for proceeds of $1,451,000 and related prior period share-based compensation of $480,000 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 June 30, 2016, a total of 12,017,931 common shares were available for issuance. Options in respect of 10,008,500 common shares have been issued, of which 3,018,000 have been exercised or cancelled at June 30, 2016. Options in respect of 6,990,500 common shares were issued and outstanding at June 30, 2016. At August 15, 2016, the date of this report, a total of 12,019,231 common shares are available for issuance under the stock option plan, options in respect of 6,977,500 common shares were issued and outstanding and 5,041,731 are available for future issue.

Details of the options outstanding at June 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	(712)	$ 2.04
Cancelled during the period	(50)	$ 4.20
Outstanding at June 30, 2016	6,991	$ 3.68
Number exercisable at June 30, 2016	3,180	$ 3.39

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	1,330	0.6	$ 1.75	1,330	$ 1.75
$2.64 - $3.95	1,881	3.4	$ 3.35	-	-
$3.96 - $5.20	3,780	2.1	$ 4.52	1,850	$ 4.57
Total	6,991	2.2	$ 3.68	3,180	$ 3.39

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 half of 2016 and 2015.

Share-based compensation expense of $729,000 and $1,552,000 was charged to the consolidated statement of loss during the three and six months to June 30, 2016 (2015 - $783,000 and $1,768,000) with an equivalent offset to contributed surplus. Volatility is based on the historical trading price variances of the Company's share price using market data.

9. NET INCOME (LOSS) PER SHARE

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

	Three Months to June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Net loss for the period	$ (20,493)	$ (4,191)	$ (25,477)	$ (7,756)
Weighted average number of common shares outstanding – basic				
Common shares outstanding at beginning of period	119,742	111,322	119,467	111,322
Effect of shares issued	187	1,768	294	889
Weighted average number of common shares outstanding – basic	119,929	113,090	119,761	112,211
Effect of outstanding options	-	-	-	-
Weighted average number of common shares outstanding - diluted	119,929	113,090	119,761	112,211
Net loss per share				
- basic	$ (0.17)	$ (0.04)	$ (0.21)	$ (0.07)
- diluted	$ (0.17)	$ (0.04)	$ (0.21)	$ (0.07)

At June 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 June 30, 2016 is as follows:

	Carrying Amount as at June 30, 2016	
Accounts receivable	$	7,853
Prepaids and deposits		2,278
Total	$	10,131

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. 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 default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at June 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		
Jul – Dec 2016	700 Bbls	$70.71 - $83.78 Cdn$/Bbl
Jan – Dec 2017	300 Bbls	$61.33 - $68.85 Cdn$/Bbl
Jan – Dec 2018	100 Bbls	$60.00 - $69.00 Cdn$/Bbl
Jan – Mar 2018	100 Bbls	$60.00 - $70.25 Cdn$/Bbl
Apr – Jun 2018	100 Bbls	$64.00 - $71.00 Cdn$/Bbl
Crude Oil Swaps		
Jul – Dec 2016	100 Bbls	$65.40 Cdn$/Bbl
Jan – Dec 2017	100 Bbls	$66.75 Cdn$/Bbl
Natural Gas Swaps		
Jul – Dec 2016	45,500 GJ	AECO Cdn$2.33/GJ
Jan – Dec 2017	20,000 GJ	AECO Cdn$2.52/GJ
Natural Gas Differential Swaps		
Jul – Dec 2016	11,000 GJ	Price at Stn 2 = AECO minus Cdn$0.3375/GJ
Jan – Dec 2017	5,000 GJ	Price at Stn 2 = AECO minus Cdn$0.445/GJ
Jul – 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 of negative $9.8 million (December 31, 2015 – positive $8.0 million) is included in current assets or current and non-current liabilities as appropriate. This resulted in unrealized mark-to-market losses of $15,800,000 (2015 – loss of $899,000) and $17,800,000 (2015 – loss of $7,736,000) when measured against the fair market value at the preceding period end. These amounts are recognized in the consolidated statement of loss for the three and six months ended June 30, 2016.

During the three and six months ended June 30, 2016, the Company realized gains from commodity price contracts in place or terminated in the amount of $2,616,000 and $6,320,000 respectively (2015 – gains of $1,775,000 and $9,135,000 respectively).

Sensitivities

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

	Six Months Ended June 30, 2016	
Factor	Change in Net Income	Change in Net Income Per Share
US$1.00/Bbl change in the price of WTI[1]	$ 510,000	-
$0.10/Mcf change in the price of natural gas	$ 1,180,000	$ 0.01
1% change in the interest rate	$ 670,000	$ 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 June 30, 2016	Three Months to June 30, 2015	Six Months to June 30, 2016	Six Months to June 30, 2015
Accounts receivable	$ 28	$ 5,944	$ 1,721	$ 4,655
Prepaids and deposits	(1,057)	2,431	(1,550)	200
Accounts payable and accrued liabilities	(8,510)	(23,646)	(7,653)	(15,875)
Change in non-cash working capital	$ (9,539)	$ (15,271)	$ (7,482)	$ (11,020)
Relating to:				
Operating activities	$ (2,879)	$ 622	$ 11	$ 847
Investing activities	(6,660)	(15,893)	(7,493)	(11,867)
	$ (9,539)	$ (15,271)	$ (7,482)	$ (11,020)
Interest paid during the period	$ 765	$ 679	$ 1,338	$ 1,198
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	$ 458	$ 916	$ 687	$ -	$ -	$ -	$ 2,061
Natural gas sales commitments	22,504	45,575	36,081	21,804	19,321	43,516	188,801
Total	$ 22,962	$ 46,491	$ 36,768	$ 21,804	$ 19,321	$ 43,516	$ 190,862

In the first half of 2016, the Company made office lease payments of approximately $472,000 (2015 - $462,000) 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

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Stock Exchange Listing

TSX Venture Exchange
Trading Symbol “SRX”

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

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

Executive Offices

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Abbreviations

3-D	Three-dimensional
API	American Petroleum Institute
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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