STORM RESOURCES

2018 Q2 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
FINANCIAL				
Revenue from product sales(1)	48,104	33,262	100,206	77,654
Funds flow	23,405	11,629	46,924	29,587
Per share – basic and diluted ($)	0.19	0.10	0.39	0.24
Net income (loss)	(2,815)	9,752	6,079	30,383
Per share – basic and diluted ($)	(0.02)	0.08	0.05	0.25
Capital expenditures(2)	2,918	4,307	25,818	31,664
Debt including working capital deficiency(2)(3)	85,073	90,582	85,073	90,582
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,500
Weighted average - diluted	121,557	121,682	121,557	121,702
Outstanding end of period – basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	27.07	26.12	28.22	27.75
Transportation costs	(6.25)	(5.75)	(5.92)	(5.61)
Revenue net of transportation	20.82	20.37	22.30	22.14
Royalties	(1.11)	(1.47)	(1.41)	(1.69)
Production costs	(5.46)	(6.74)	(5.51)	(6.25)
Field operating netback(2)	14.25	12.16	15.38	14.20
Realized (loss) gain on hedging	0.31	(1.10)	(0.44)	(1.76)
General and administrative	(0.69)	(1.17)	(1.05)	(1.13)
Interest and finance costs	(0.71)	(0.76)	(0.68)	(0.73)
Funds flow per Boe	13.16	9.13	13.21	10.58
Barrels of oil equivalent per day (6:1)	19,529	13,991	19,618	15,461
Natural gas production				
Thousand cubic feet per day	96,426	68,308	96,248	76,157
Price (Cdn$ per Mcf)(1)	3.15	3.77	3.49	4.00
Condensate production				
Barrels per day	1,984	1,468	2,023	1,612
Price (Cdn$ per barrel)(1)	86.33	57.65	81.15	61.31
NGL production				
Barrels per day	1,473	1,138	1,554	1,156
Price (Cdn$ per barrel)(1)	36.43	20.45	34.66	21.78
Wells drilled (100% working interest)	-	-	-	6.0
Wells completed (100% working interest)	-	-	3.0	4.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements, including field operating netback, operations capital expenditures, debt including working capital deficiency and all measurements per Boe. See discussion of Non-GAAP Measurements on page 24 of the attached Management's Discussion and Analysis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2018 SECOND QUARTER HIGHLIGHTS

- Production increased by 40% on a per-share basis from the prior year to 19,529 Boe per day which was consistent with guidance (19,500 to 20,500 Boe per day). Production in the quarter was reduced by approximately 800 Boe per day as a result of a gas plant maintenance turnaround in June. Note that production in the prior year quarter was reduced by approximately 4,000 Boe per day for a maintenance turnaround at the McMahon Gas Plant.

- Liquids production (condensate plus NGL) grew by 33% year over year with liquids representing 18% of total production and 43% of production revenue.

- Over the last 12 months, Storm has increased production by 40% on a per-share basis with total capital expenditures being less than funds flow (debt has been reduced by $5.5 million).

- At the end of the quarter, there was an inventory of seven Montney horizontal wells (7.0 net) at Umbach that had not started producing. Three horizontal wells (3.0 net) started production in the quarter, all on the same pad at the Nig land block.

- Horizontal well performance at Umbach continues to improve as length is increased. Wells completed in 2017 are expected to have first year average rates 30% higher than wells completed in 2014 to 2016. The first well completed in 2018 (at the Nig land block) has averaged 7.1 Mmcf per day raw plus 230 barrels per day of field condensate over the first 90 calendar days which is approximately 1,400 Boe per day sales with 26% liquids (field condensate plus plant NGL).

- Revenue net of transportation costs was $20.82 per Boe which is an increase of 2% from last year as higher liquids pricing more than offset a 16% decrease in the natural gas price.

- The field operating netback was $14.25 per Boe, an improvement of 17% compared to last year. The improvement was mainly from production costs declining by 19% to $5.46 per Boe as a result of continuing production growth in addition to the prior year quarter being impacted by the maintenance turnaround at the McMahon Gas Plant.

- Funds flow increased to $23.4 million ($13.16 per Boe) or $0.19 per share, a year-over-year increase of 90% on a per-share basis. The improvement was largely from higher production volumes (prior year was reduced by the McMahon Gas Plant maintenance turnaround) and lower production costs on a per-Boe basis. Compared to the previous quarter, funds flow per share was unchanged with an 18% decrease in the natural gas price being offset by higher liquids pricing, lower G&A costs and a small hedging gain.

- Capital investment was $2.9 million which was significantly less than funds flow of $23.4 million and was less than guidance of $6.0 million as horizontal well completions were deferred due to stronger than forecast well performance.

- The balance sheet remains strong with debt including the working capital deficiency being $85.1 million which is a quarter-over–quarter reduction of approximately $21 million and represents 0.9 times annualized quarterly funds flow.

- Commodity price hedges continue to be added and currently protect approximately 48% of forecast production for the remainder of 2018.

OPERATIONS REVIEW

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 112,000 net acres (159 net sections). During the second quarter, two sections of land were acquired in the Nig area.

There was minimal field activity in the second quarter. Three horizontal wells (3.0 net) started production in the quarter which left an inventory of seven horizontal wells (7.0 net) that had not started producing at the end of the quarter.

Initial rates from the new horizontal wells at the Nig land block have been very strong. All three wells from the first pad are now producing with the first starting production on April 10th, the second on June 3rd and the last well on June 28th (approximately 8 Mmcf per day is currently shut in to free up enough facility capacity to be able to produce all three wells). In July, all three wells were rate restricted with production totaling 26 Mmcf per day raw gas plus 735 barrels per day of field condensate which is an average of approximately 1,680 Boe per day sales per well with 24% liquids including NGL recovered at the gas plant. The wells at Nig are 60% longer than the average well completed in 2014 to 2016 and 20% longer than the average well completed in 2017.

Fourteen horizontal wells (12.5 net) will be drilled this winter starting early in the fourth quarter of 2018. Drilling will target areas where gas-condensate ratios are expected to be higher with three wells at West Umbach, six wells at Nig, two wells at South Umbach and three wells at Fireweed. Horizontal well lengths are planned to be approximately 2,400 metres.

Since 2013, approximately $111 million has been invested in building out infrastructure (pipelines and facilities) with current field compression capacity totaling 115 Mmcf per day raw gas. Throughput in the second quarter averaged 102 Mmcf per day raw gas. Capacity will increase to 150 Mmcf per day in the third quarter of 2018 with the installation of an additional compressor at a cost of approximately $2 million (compressor was previously purchased and delivered to site in the first quarter of 2018). The increased compression capacity would support growth in corporate production to approximately 27,000 Boe per day.

Storm's produced raw natural gas is sour (approximately 1.2% H_2S) with 86% directed to the McMahon Gas Plant and 14% directed to the Stoddart Gas Plant in the second quarter. Firm processing commitments are 65 Mmcf raw gas per day at McMahon (5 to 15 year terms) and 15 Mmcf per day at Stoddart (1 year term).

A summary of horizontal wells is provided below. The primary focus since late 2016 has been to drill longer wells to improve rates and reserves (future wells will increase to approximately 2,400 metres long). The majority of wells are initially rate restricted to manage fluid rates and, as a result, the IP90 and IP180 rates are not indicative of longer term performance. More information on well performance is available in the presentation on Storm's website.

Year of Completion	Frac Stages	Completed Length	Actual Drill & Complete Cost	IP90 Cal Day Mmcf/d Raw	IP180 Cal Day Mmcf/d Raw	IP365 Cal Day Mmcf/d Raw
2014 - 16 33 hz's(1)	22	1,270 m	$4.3 million $3,400 per metre	4.9 Mmcf/d 12 hz's	4.3 Mmcf/d 12 hz's	3.4 Mmcf/d 12 hz's
2017 12 hz's	34	1,750 m	$4.2 million $2,400 per metre	5.0 Mmcf/d 12 hz's	4.6 Mmcf/d 11 hz's	4.2 Mmcf/d 5 hz's
2018 3 hz's	37	2,090 m	$5.4 million $2,600 per metre	7.1 Mmcf/d 1 hz		

(1) 2014 wells exclude a middle Montney well (this table provides analysis of upper Montney wells only).

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth by continually layering in hedges to protect pricing on 50% of current production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. Note that approximately 80% of Storm's liquids production is priced in reference to WTI. The current hedge position is summarized below and protects approximately 48% of forecast production for the second half of 2018.

2018 Q3 – Q4		
Crude Oil	1,500 Bpd	WTI Cdn$66.26/Bbl floor, Cdn$71.73/Bbl ceiling
Propane	300 Bpd	Conway Cdn$39.55/Bbl
Natural Gas	45,500 Mmbtu/d (38,400 Mcf/d)	Chicago Cdn$3.42/Mmbtu
	11,500 Mmbtu/d (9,700 Mcf/d)	Sumas Cdn$2.92/Mmbtu
	3,000 GJ/d (2,400 Mcf/d)	Station 2 - AECO basis -$0.345/GJ
2019		
Crude Oil	1,050 Bpd	WTI Cdn$71.31/Bbl floor, Cdn$79.58/Bbl ceiling
Natural Gas	33,500 Mmbtu/d (28,300 Mcf/d)	Chicago Cdn$3.25/Mmbtu
	4,500 Mmbtu/d (3,800 Mcf/d)	Sumas Cdn$2.55/Mmbtu

Firm transportation capacity totals 102 Mmcf per day and provides diversification for natural gas sales and avoids overexposure to any single market. Firm capacity on the Alliance Pipeline to Chicago totals 55 Mmcf per day with preferential interruptible capacity increasing this by 14 Mmcf per day (increasing total transportation capacity to 116 Mmcf per day sales). Using firm capacity of 102 Mmcf per day sales, approximately 54% to 68% of natural gas will be sold at Chicago pricing, 11% at Sumas pricing less a marketing adjustment, 5% at ATP pricing, and 16% to 30% at Station 2 or AECO pricing. During the second quarter, 69% of natural gas production was sold in Chicago. Natural gas production exceeding firm capacity would be directed to Chicago and/or Station 2 using interruptible pipeline capacity (depending on which sales point offers a higher price net of transportation tariffs).

OUTLOOK

For the third quarter of 2018, production is forecast to be 19,500 to 20,500 Boe per day with production to date in the third quarter averaging 20,200 Boe per day based on field estimates. Capital investment is expected to be $25 million which includes $10 million for the sour gas plant at Nig (further details provided below).

Storm has finalized a growth plan which will result in the construction of a 50 Mmcf per day sour gas plant to develop the Nig land block and the construction of a 50 Mmcf per day field compression facility to develop the Fireweed land block. This is expected to result in corporate production growing to more than 30,000 Boe per day in the second half of 2020 while increasing liquids production and lowering operating costs. In addition, installation of additional compression at Umbach in the third quarter of 2018 provides the option to further accelerate growth by completing additional standing wells if supported by commodity prices. Further details are provided below:

1) On the Nig land block, a 50 Mmcf per day sour gas plant will be built with start-up expected to be between October 2019 and March 2020 depending on the timing for regulatory approvals and for field construction. The gas plant will be filled with the three existing producing wells (3.0 net) at Nig plus an additional six horizontal wells (6.0 net) will be drilled at Nig this winter and completed in 2019. The gas plant is expected to reduce corporate operating costs by approximately $1.50 per Boe (plant operating cost $2.00 per Boe) and increase liquids production by approximately 1,100 barrels per day (90% NGL, 10% plant condensate). Total cost is estimated to be

approximately $81 million which includes the facility, a horizontal acid gas disposal well and a sales gas pipeline. Corporate production is forecast to increase from current levels to approximately 25,000 to 26,000 Boe per day with 20% liquids when the gas plant is completed and with the additional wells being drilled and completed at Nig.

2) In the Fireweed area, Storm has agreed to pool and jointly develop existing undeveloped lands with offsetting lands owned by a private company (no change to Storm's net land position). Storm is contributing 26 net sections to the pooling and will be the operator with a 50% working interest. Preliminary planning is underway to construct a 50 Mmcf per day field compression facility with start-up expected in mid-2020 depending on timing for regulatory approvals and for field construction. Preliminary planning also includes drilling and completing twelve horizontal wells in 2019 and 2020. Based on offsetting well results, condensate production at Fireweed is expected to be higher than Umbach by approximately 25 barrels per Mmcf. When the facility is completed, net forecast production additions are expected to be 4,000 to 5,000 Boe per day with 25% liquids.

3) At Umbach, additional compression (35 Mmcf per day) will be installed in the third quarter of 2018 at a cost of approximately $2 million which will allow for the completion of standing horizontal wells to accelerate production growth if supported by the Station 2 price (greater than $1.50 to $1.75 per GJ). The additional compression will increase sales capacity by approximately 7,000 Boe per day.

The reduction in operating costs associated with the sour gas plant at Nig is expected to mitigate the impact of commodity price volatility and low Western Canadian natural gas prices.

Incremental natural gas produced from Nig and Fireweed will be sold at Station 2. Full cycle rates of return from both projects are expected to be very attractive at Station 2 $1.25 per GJ, WTI US$60 per barrel, and Edmonton light oil Cdn$68 per barrel (Cdn$1 = US$0.78, differential –US$7 per barrel).

Updated guidance for 2018 is provided below with capital investment increased to $80 million (from $55 to $65 million) with approximately $14 million of the increase being directed to the sour gas plant at Nig (primarily deposits for equipment) and the remainder to accelerate drilling. Forecast commodity prices have been updated to reflect pricing to date and the approximate forward strip for the remainder of the year. Estimated funds flow has increased by approximately $10 million as a result of commodity prices to date being higher than initially forecast.

2018 Guidance

	Previous May 15, 2018	Current August 14, 2018
Cdn$/US$ exchange rate	0.79	0.78
Chicago daily natural gas - US$/Mmbtu	$2.60	$2.70
Sumas monthly natural gas - US$/Mmbtu	$1.95	$2.05
AECO daily natural gas - Cdn$/GJ	$1.35	$1.45
Station 2 daily natural gas - Cdn$/GJ	$1.20	$1.35
WTI - US$/Bbl	$64.00	$66.00
Edmonton light oil - Cdn$/Bbl	$73.00	$76.00
Est revenue net of transport (excl hedges) - $/Boe	$19.00 - $19.50	$20.50 - $21.50
Est operating costs - $/Boe	$5.75	$5.75
Est royalty rate (% revenue before hedging)	6% - 8%	5% - 7%
Est capital investment (excl A&D) - $ million	$55.0 - $65.0	$80.0
Est cash G&A - $ million - $/Boe	$6.0 - $7.0 $0.78 - $0.95	$6.0 - $7.0 $0.78 - $0.95
Est interest expense - $ million	$4.0	$4.0

	Previous May 15, 2018	Current August 14, 2018
Forecast fourth quarter production - Boe/d	20,000 - 21,000	20,000 - 21,000
% liquids	18% liquids	18% liquids
Forecast annual production - Boe/d	20,000 - 21,000	20,000 - 20,500
% liquids	18% liquids	18% liquids
Est annual funds flow at 20,000 Boe/d - $ million	$76.0 - $80.0	$85.0 - $90.0
Umbach horizontal wells drilled - gross	3 - 6 (3.0 - 6.0 net)	5 (5.0 net)
Umbach horizontal wells completed - gross	8 - 11 (8.0 - 11.0 net)	10 (10.0 net)
Umbach horizontal wells connected - gross	10 (10.0 net)	8 (8.0 net)

Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	AECO Daily (Cdn$/GJ)	Estimated Operations Capital ($ million)	Forecast Fourth Quarter Production (Boe/d)	Forecast Annual Production (Boe/d)
Nov 14, 2017	$2.80	$1.30 - $1.70	$1.80 - $2.10	$55.0 - $90.0	20,000 - 27,000	20,000 - 23,000
Mar 1, 2018	$2.60	$1.05	$1.40	$55.0 - $90.0	20,000 - 27,000	20,000 - 23,000
May 15, 2018	$2.60	$1.20	$1.35	$55.0 - $65.0	20,000 - 21,000	20,000 - 21,000
Aug 14, 2018	**$2.70**	**$1.35**	**$1.45**	**$80.0**	**20,000 – 21,000**	**20,000 – 20,500**

Preliminary guidance for 2019 includes capital investment of $125 million which includes approximately $67 million for the sour gas plant at Nig and $15 million at Fireweed. It is anticipated that a total of 10 horizontal wells will be drilled (8.5 net), 11 horizontal wells will be completed (9.0 net) and 10 horizontal wells (10.0 net) would start production. This is expected to result in production averaging 21,000 to 23,000 Boe per day.

Capital investment required to maintain production at approximately 20,000 Boe per day is estimated to be $60 million in 2018 (versus forecast funds flow of $85 - $90 million) and $20 million in 2019. This is likely to decrease given improved performance from the horizontal wells at the Nig land block.

Growth will be funded with debt plus free funds flow. The significant improvement in performance of the 2017 and 2018 horizontal wells has resulted in forecast funds flow exceeding capital investment required to maintain production and the resulting free funds flow is expected to provide most of the funding for the sour gas plant at Nig. Using current forward strip pricing results in forecast total debt peaking at approximately 80% of the current bank credit facility in the quarter before the start-up of the sour gas plant at Nig. If necessary, capital investment and production growth will be reduced to ensure debt does not exceed this level.

Storm's ongoing hedging program, diversified natural gas sales and liquids production mitigate commodity price volatility. Although natural gas prices declined from the first quarter to the second quarter of 2018, funds flow was unchanged as the price decrease was offset by gains on natural gas hedging and higher liquids prices. In addition, Storm's diversified natural gas sales resulted in only 13% being sold in the second quarter at Western Canadian pricing which showed the most weakness quarter over quarter with AECO declining 43% to average $1.12 per GJ and Station 2 declining 42% to average $1.05 per GJ. Since last fall, AECO and Station 2 prices have been weak relative to US prices as supply growth in Alberta and British Columbia has exceeded contracted takeaway capacity on the TCPL/NGTL system. The majority of Storm natural gas sales (69%) were at Chicago where the price declined by 8% quarter over quarter to average US$2.66 per Mmbtu.

With a large, multi-year drilling inventory in the Montney in an area that is liquids-rich and higher quality, Storm's business plan continues to be focused on adding value by converting resource into debt adjusted funds flow growth on a per-share basis.

Respectfully,

Brian Lavergne,
President and Chief Executive Officer

August 14, 2018

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

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

Forward-Looking Statements - Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated August 14, 2018 for the three and six months ended June 30, 2018.

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, 2018. 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, 2018, (ii) the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2017, and (iii) the press release issued by the Company on August 14, 2018, 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 29, 2018 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

The Company trades on the Toronto Stock Exchange ("TSX") under the symbol "SRX".

This MD&A is dated August 14, 2018.

See "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" on pages 22 to 24.

BASIS OF PRESENTATION

Financial data presented below have been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three and six months ended June 30, 2018, prepared in accordance with International Accounting Standard ("IAS") 34 "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS"). Accounting policies adopted by the Company are referred to in Note 3 to the audited consolidated financial statements for the year ended December 31, 2017 and updated for new standards, as applicable, in Note 3 of the financial statements for the three and six months ended June 30, 2018. The reporting and the functional currency is the Canadian dollar.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the three and six month periods ended June 30, 2017.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The narrative from the last eight months continues to hold true with Storm maintaining a flat production profile that meets firm processing and transportation commitments in response to ongoing weakness in Western Canadian natural gas prices. Second quarter production of 19,529 Boe per day was within the previously announced guidance range of 19,500 to 20,500 Boe per day, and was 40% higher than the comparable quarter of 2017, which bore the brunt of the McMahon gas plant turnaround. The second quarter of 2018 saw production and funds flow remain essentially unchanged from the immediately preceding quarter, while only $3 million of capital expenditures were incurred, allowing the Company to reduce its net debt position by approximately $21 million.

During the second quarter of 2018, condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) accounted for 18% of total production and contributed 43% to revenue in the period compared to 36% in the immediately preceding quarter and 30% in the comparable quarter of 2017. As previously noted, with the majority of Storm's condensate and NGL revenue streams priced with reference to crude oil, the significantly improved fundamentals in the crude oil market help to differentiate Storm's business plan, particularly in light of the ability to focus drilling on areas with higher liquids.

The natural gas price realized by the Company in the second quarter fell by 18% when compared to the first quarter of 2018, and similarly was down 16% when compared to the same quarter of 2017. This decrease was muted compared to the significant decline in Western Canadian natural gas benchmark pricing of approximately 40% from the prior quarter and over 50% from the second quarter of 2017. When comparing to the same quarter in 2017, condensate and NGL prices were up 50% and 78%, respectively, with a significant recovery year over year in pricing across all liquids streams. While condensate and NGL prices remain relatively strong, natural gas prices continue to languish in the face of robust supply growth, although with a large year-over-year deficit in storage levels due to a supportive demand picture, the outlook for natural gas prices heading into the winter heating season looks more and more constructive with each passing day.

At quarter end, the Company had an inventory of seven horizontal wells (7.0 net) that had not started production, all of which awaited completion. No wells were drilled or completed in the second quarter with minimal capital expenditures in the period primarily directed to facilities, equipping and pipelines. As a result, total debt, including working capital deficiency, at quarter end amounted to $85.1 million, down from $105.6 million at the end of the first quarter. Storm retains considerable financial flexibility to manage its capital expenditure program for the remainder of the year with the ability to increase or decrease capital expenditures in response to movements in commodity prices.

With the additional compression for twinning of the third field compression facility already on site, the installation process will be completed in the third quarter of 2018 at a cost of $2 million, the result of which will increase total field compression capacity to 150 Mmcf per day. Storm's current production is approximately 20,000 Boe per day based on field estimates and installation of the aforementioned compression will support growth to approximately 27,000 Boe per day. This will provide Storm with the capability to accelerate growth quickly when and if prices support the decision to do so.

Comparison of the field operating netback in the second quarter to the same period in the prior year is less meaningful in light of the lower production volumes and correspondingly higher fixed processing costs associated with the planned turnaround at the McMahon Gas Plant in June 2017. Nevertheless, compared to the same period in 2017, the field operating netback per Boe in the second quarter of 2018 increased by 17%, primarily due to a material recovery in liquids prices coupled with lower royalties and operating costs. Compared to the first quarter of 2018, the field operating netback per Boe fell by 14%, largely the result of an 18% decrease in the realized natural gas price. The effects of a dynamic hedge portfolio resulted in a realized hedging gain of $0.6 million during the second quarter of 2018 versus a realized hedging loss of $1.4 million in the second quarter of 2017, which further buoyed the aforementioned increase in the field operating netback year over year.

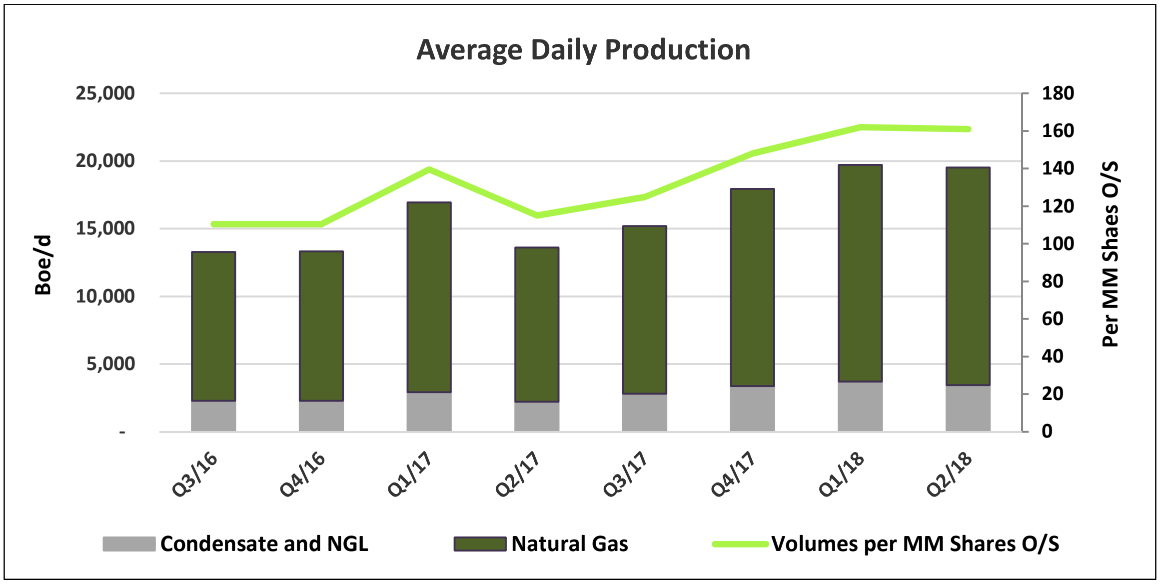
During the quarter, the Company's credit facility was increased by $15 million to $180 million, an increase of 9%. The credit facility is predominantly based on the banking syndicate's assessment of the value of the Company's proved developed producing ("PDP") reserves as collateral. The credit facility increase was supported by the increase in 2017 year-end PDP reserves, which grew by 33% year over year, while the net present value of PDP reserves (before tax, discounted at 10%) increased by 23% based on InSite Petroleum Consultants Ltd. December 31, 2017 commodity price forecast. No additional covenants were required and there were minor adjustments made to the interest rate structure, which is expected to result in slightly lower borrowing costs on a go-forward basis. The expanded credit facility provides the Company with considerable financial flexibility to manage its capital expenditure program for the foreseeable future.

Production and Revenue

Average Daily Production

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Natural gas (Mcf/d)	96,426	68,308	96,248	76,157
Condensate (Bbls/d)	1,984	1,468	2,023	1,612
NGL (Bbls/d)	1,473	1,138	1,554	1,156
Total (Boe/d)	19,529	13,991	19,618	15,461
Natural gas weighting	82%	81%	82%	82%
Condensate weighting	10%	11%	10%	10%
NGL weighting	8%	8%	8%	8%

Production increases for natural gas, condensate and NGL for the second quarter and first six months of 2018, when compared to the same periods in 2017, came from growth at Umbach where the Company started production from three new 100% working interest horizontal wells during the second quarter of 2018 and five new 100% working interest horizontal wells during the six months ended June 30, 2018, although comparability between the periods was affected by the McMahon gas plant turnaround in June 2017 which significantly reduced volumes during the quarter.



Storm's second quarter 2018 production increased 40% from the second quarter of 2017 and increased 27% when comparing the six month periods.

Daily production per million shares outstanding at the end of the second quarter averaged 161 Boe per day, compared to 115 Boe per day for the second quarter of 2017, an increase of 40%.

Average Selling Prices[1]

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Natural gas - Mcf	$ 3.15	$ 3.77	$ 3.49	$ 4.00
Condensate –Bbl	$ 86.33	$ 57.65	$ 81.15	$ 61.31
NGL - Bbl	$ 36.43	$ 20.45	$ 34.66	$ 21.78
Per Boe	$ 27.07	$ 26.12	$ 28.22	$ 27.75

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

On a per-Boe basis, the Company's average realized price for the three and six months ended June 30, 2018 increased by 4% and 2%, respectively, compared to the same periods of 2017, driven by increases in condensate and NGL pricing, partially offset by a decrease in the realized natural gas price.

Benchmark Prices

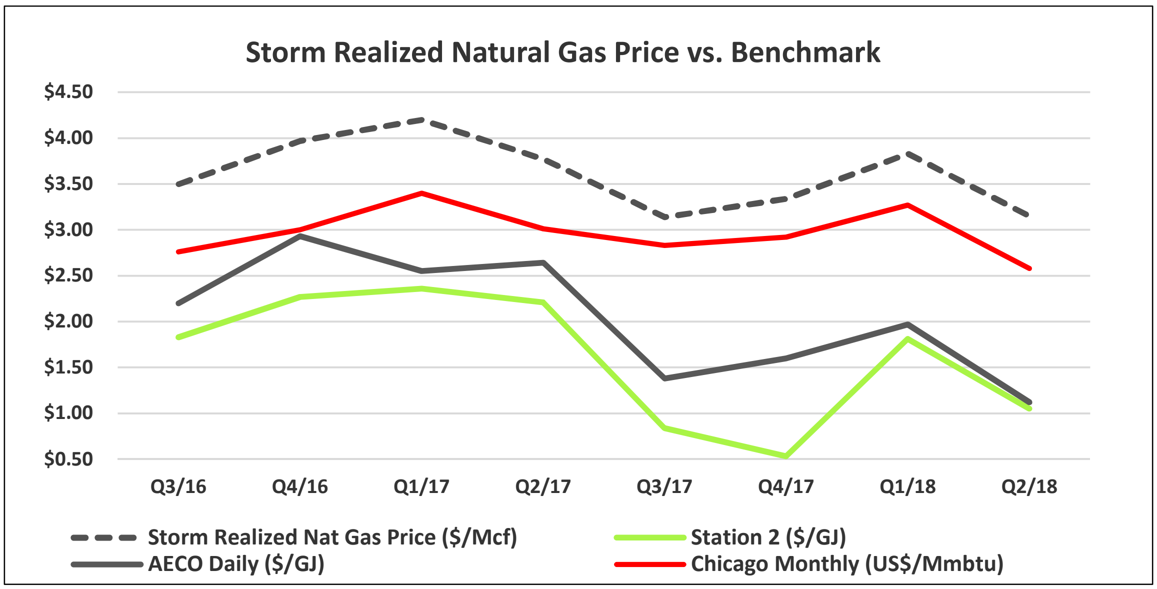
	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Natural gas				
Chicago monthly index (US$/Mmbtu)	2.58	3.01	2.93	3.21
Chicago daily index (US$/Mmbtu)	2.66	2.93	2.81	2.96
Sumas (US$/Mmbtu)	1.64	2.49	2.05	2.66
AECO monthly index (Cdn$/GJ)	0.97	2.63	1.37	2.71
AECO daily index (Cdn$/GJ)	1.12	2.64	1.54	2.60
Station 2 (Cdn$/GJ)	1.05	2.21	1.43	2.29
Crude Oil				
WTI (US$/Bbl)	67.88	48.29	65.37	50.10
Edmonton light oil (Cdn$/Bbl)	80.58	61.92	76.33	62.96
Exchange rate (US$/Cdn$)	0.77	0.74	0.78	0.75

Storm's realized prices differ from market indices due to fluctuations in the foreign exchange rate and the higher heat content of the Company's natural gas.

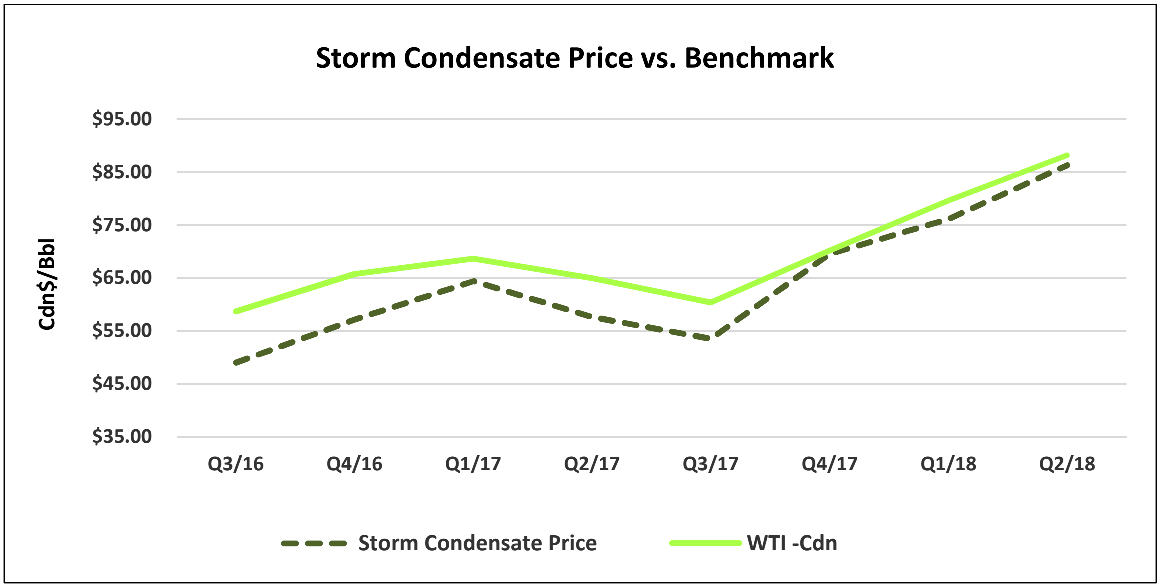
With supply levels remaining elevated through the first six months of 2018 and the 2018 maintenance season underway, Western Canadian natural gas prices are expected to remain volatile for the remainder of the summer.

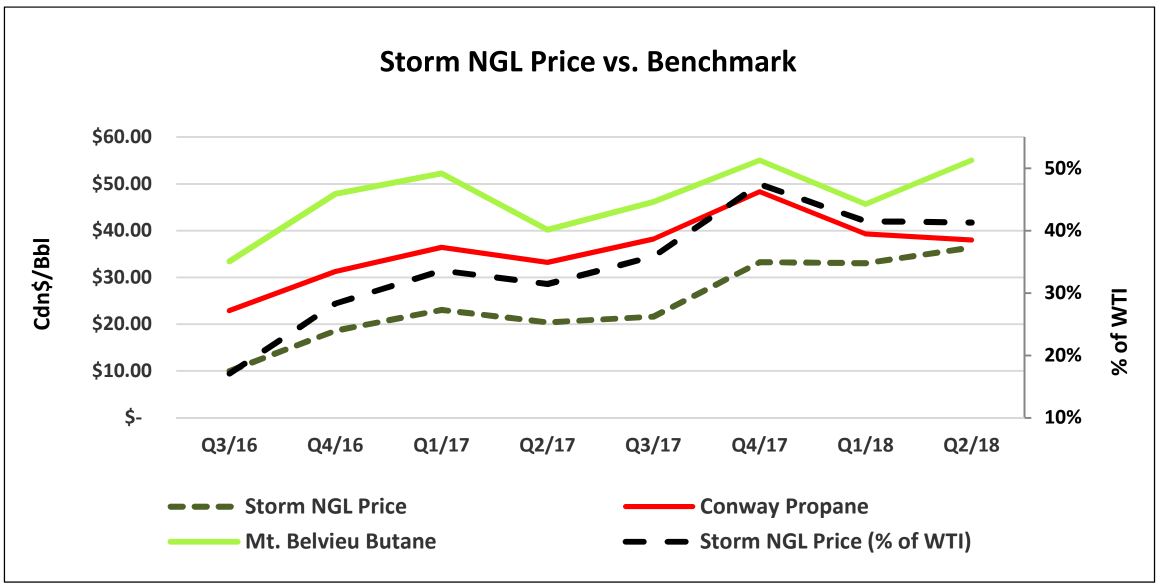
The Company's production during the second quarter was sold as follows:

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Chicago monthly index price	40%	40%	40%	44%
Chicago daily index price	29%	22%	25%	18%
AECO daily index price	7%	-	4%	-
Station 2 daily spot price	6%	33%	13%	32%
Sumas index price	12%	-	12%	-
Alliance Transfer Point ("ATP")	6%	5%	6%	6%
Total	100%	100%	100%	100%



Storm's realized natural gas price for the second quarter of 2018 was $3.15 per Mcf. With approximately 70% of the Company's production sold in Chicago, Storm's basket realized natural gas price benefited from stronger Chicago pricing, which was partially offset by lower pricing at Station 2 and AECO. As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was 200% higher than Station 2 pricing in the second quarter of 2018. Natural gas pricing in Western Canada remains below the cost of replacing production for most producers.





Storm received an average price of $86.33 per barrel for condensate, a 50% increase from the price realized in the same period of 2017. For the six months ended June 30, 2018, Storm's realized price for condensate increased 32% when compared to the same period of 2017. The increase in condensate pricing is due to higher crude oil benchmark pricing and increased demand for condensate. The realized price for NGL, excluding condensate, in the second quarter of 2018 increased by 78% relative to the same period of 2017. For the six month period ended June 30, 2018, the realized price for NGL, excluding condensate, increased by 59% year over year. The increase in realized NGL prices for both of the aforementioned periods was primarily due to a material recovery in propane and WTI pricing year over year.

Higher value condensate has become a significant contributor to revenue. The contribution from this revenue stream comprised 10% of Boe production but amounted to approximately 30% of revenue from product sales in each of the second quarter of 2018 and the first six months of 2018.

Revenue from Product Sales[1]

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Natural gas	$ 27,629	$ 23,441	$ 60,743	$ 55,205
Condensate	15,590	7,703	29,717	17,892
NGL	4,885	2,118	9,746	4,557
Total	$ 48,104	$ 33,262	$ 100,206	$ 77,654
% of Total Revenue by Product Type				
Natural gas	57%	70%	61%	71%
Condensate and NGL	43%	30%	39%	29%
Total	100%	100%	100%	100%

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

Revenue from product sales for the second quarter of 2018 increased by 45% when compared to the second quarter of 2017 primarily as a result of production volumes increasing by 40%. For the six month periods, revenue from product sales increased 29% year over year primarily due to production volumes increasing 27%.

A reconciliation of year-over-year revenue changes for the three month periods ending June 30 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q2 2017	$ 23,441	$ 7,703	$ 2,118	$ 33,262
Effect of changes in production	9,640	2,707	623	12,970
Effect of changes in average product prices	(5,452)	5,180	2,144	1,872
Revenue from product sales – Q2 2018	$ 27,629	$ 15,590	$ 4,885	$ 48,104

A reconciliation of year-over-year revenue changes for the six month periods ending June 30 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q2 2017 YTD	$ 55,205	$ 17,892	$ 4,557	$ 77,654
Effect of changes in production	14,564	4,563	1,567	20,694
Effect of changes in average product prices	(9,026)	7,262	3,622	1,858
Revenue from product sales – Q2 2018 YTD	$ 60,743	$ 29,717	$ 9,746	$ 100,206

Commodity Price Risk Management

	Three Months Ended June 30, 2018		Three Months Ended June 30, 2017	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ 3,133	$ (9,841)	$ (1,495)	$ 6,686
Liquids[1]	(2,577)	(3,807)	95	2,785
Gain (loss) on commodity price contracts	$ 556	$ (13,648)	$ (1,400)	$ 9,471

	Six Months Ended June 30, 2018		Six Months Ended June 30, 2017	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ 2,650	$ (10,461)	$ (4,917)	$ 20,439
Liquids[1]	(4,213)	(5,285)	(1)	5,157
Gain (loss) on commodity price contracts	$ (1,563)	$ (15,746)	$ (4,918)	$ 25,596

(1) Liquids includes field condensate, plant pentanes, butane and propane.

The term liquids above refers to crude oil contracts. Although the Company has no crude oil production, condensate and a portion of the NGL stream is priced with reference to crude oil and, as a result, the Company enters into crude oil contracts as a proxy for a condensate and NGL hedge.

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

The unrealized gain (loss) on commodity price contracts is a non-cash charge representing the change in the mark-to-market position of unexpired contracts at the end of the period.

Royalties

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Charge for period	$ 1,968	$ 1,872	$ 5,004	$ 4,738
Percentage of revenue from product sales	4.1%	5.6%	5.0%	6.1%
Per Boe	$ 1.11	$ 1.47	$ 1.41	$ 1.69

Royalties, as a percentage of revenue from product sales, decreased in the three and six months ended June 30, 2018 compared to the same periods in 2017 primarily due to a decrease in commodity prices for natural gas along with the receipt of infrastructure royalty credits in 2018. There were no royalty credits received in the three and six months ended June 30, 2017.

The BC Deep Well Royalty Credit Program reduces the royalty rate on new horizontal wells to 6% for approximately two years. In the second quarter of 2018, 36 wells qualified for the 6% royalty rate compared to 28 wells in the second quarter of 2017.

Storm has remaining infrastructure royalty credits of $8.7 million that will reduce future royalties. Future royalty payments are dependent on commodity prices and production levels from individual wells and thus the timing to receive future royalty credits cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary as these credits are earned.

Production Costs

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Charge for period	$ 9,703	$ 8,577	$ 19,553	$ 17,482
Per Boe	$ 5.46	$ 6.74	$ 5.51	$ 6.25

The increase in total production costs for the three and six months ended June 30, 2018 when compared to the same periods of 2017 is primarily due to increased production. The percentage increase in production costs is considerably less than the percentage increase in production volumes, indicative of the Company's efforts to reduce per-Boe costs.

Production costs per Boe for the second quarter of 2018 decreased by 19% compared to the second quarter of 2017 and by 12% when comparing the six month periods. The decreases were due in part to continued production growth, while the prior periods were also affected by the McMahon gas plant turnaround in June 2017.

Transportation Costs

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Charge for period	$ 11,108	$ 7,316	$ 21,020	$ 15,711
Per Boe	$ 6.25	$ 5.75	$ 5.92	$ 5.61

Transportation costs include pipeline tariffs for natural gas sold at various price points, as well as trucking costs for wellhead condensate. Total transportation costs for the second quarter of 2018 increased by 52%, and by 9% per Boe, when compared to the second quarter of 2017. Transportation costs for the first six months of 2018 increased by 34%, and by 6% per Boe, when compared to the same period in 2017. Higher total transportation cost reflects higher production volumes (year-over-year increase of 40% for the second quarter and 27% for the six month period). On a per-Boe basis, higher transportation costs are largely the result of directing more natural gas to Chicago on the Alliance Pipeline using higher cost interruptible service (69% of natural gas sales in Chicago in the second quarter versus 62% in the previous year).

As a result of the adoption of IFRS 15, *Revenue from Contracts with Customers* on January 1, 2018, transportation costs for the Alliance Pipeline that were previously deducted from revenue to reflect contractual arrangements are now included within transportation costs; comparative periods have been restated to conform to current period presentation.

Field Netbacks

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

Three Months to June 30, 2018	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.15	$ 86.33	$ 36.43	$ 27.07
Royalties	(0.02)	(7.83)	(3.06)	(1.11)
Production costs	(1.11)	-	-	(5.46)
Transportation costs	(1.16)	(5.04)	-	(6.25)
Field operating netback	$ 0.86	$ 73.46	$ 33.37	$ 14.25
Realized (loss) gain on commodity price contracts	0.36	(14.50)	0.32	0.31
Field operating netback including hedging	$ 1.22	$ 58.96	$ 33.69	$ 14.56

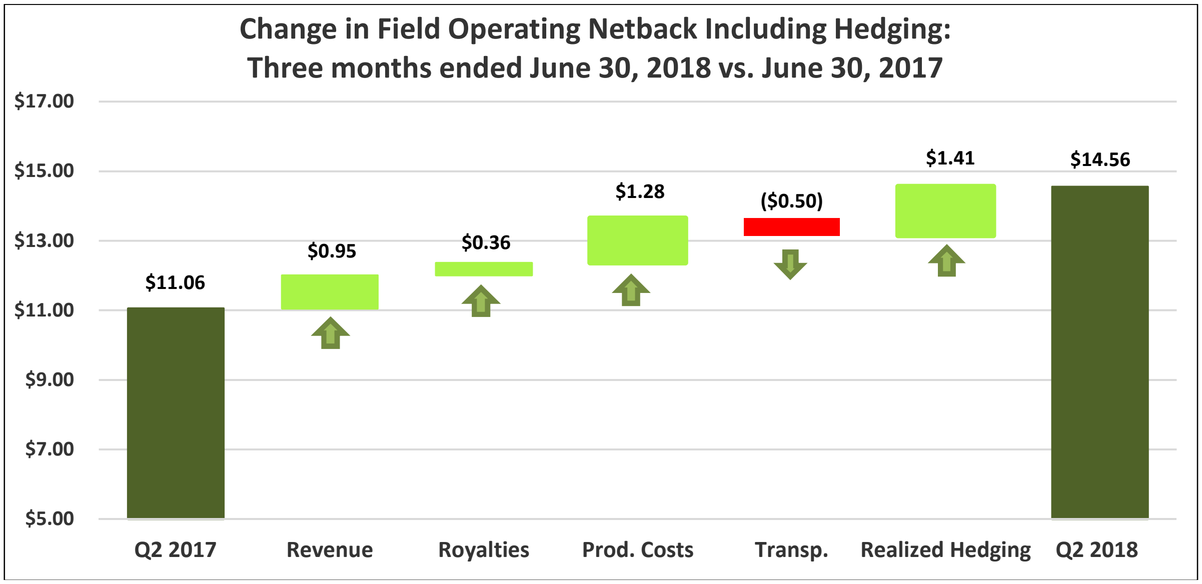
Three Months to June 30, 2017	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.77	$ 57.65	$ 20.45	$ 26.12
Royalties	(0.15)	(5.41)	(1.97)	(1.47)
Production costs	(1.38)	-	-	(6.74)
Transportation costs	(1.03)	(6.87)	-	(5.75)
Field operating netback	$ 1.21	$ 45.37	$ 18.48	$ 12.16
Realized (loss) gain on commodity price contracts	(0.24)	0.71	-	(1.10)
Field operating netback including hedging	$ 0.97	$ 46.08	$ 18.48	$ 11.06

Six Months to June 30, 2018	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.49	$ 81.15	$ 34.66	$ 28.22
Royalties	(0.08)	(7.24)	(3.13)	(1.41)
Production costs	(1.12)	-	-	(5.51)
Transportation costs	(1.11)	(4.82)	-	(5.92)
Field operating netback	$ 1.18	$ 69.09	$ 31.53	$ 15.38
Realized (loss) gain on commodity price contracts	0.15	(11.64)	0.17	(0.44)
Field operating netback including hedging	$ 1.33	$ 57.45	$ 31.70	$ 14.94

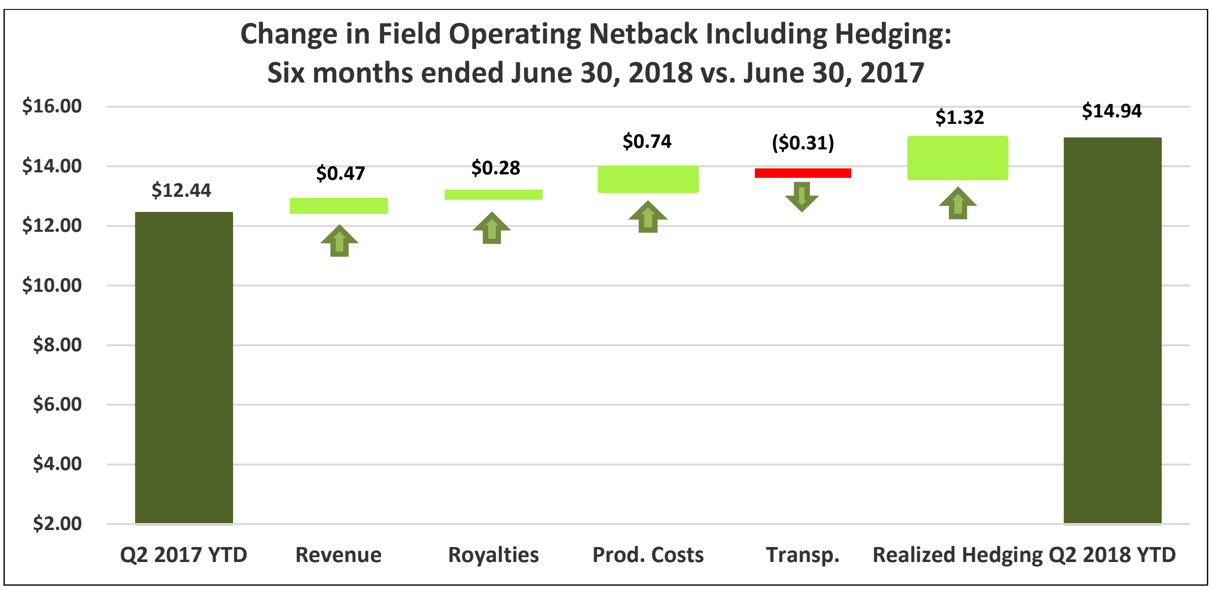
Six Months to June 30, 2017	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 4.00	$ 61.31	$ 21.78	$ 27.75
Royalties	(0.19)	(5.72)	(2.22)	(1.69)
Production costs	(1.27)	-	-	(6.25)
Transportation costs	(1.04)	(4.62)	-	(5.61)
Field operating netback	$ 1.50	$ 50.97	$ 19.56	$ 14.20
Realized loss on commodity price contracts	(0.36)	-	-	(1.76)
Field operating netback including hedging	$ 1.14	$ 50.97	$ 19.56	$ 12.44

(1) Production costs of condensate and NGL are included within natural gas costs.
(2) Realized gains and losses on crude oil contracts are included within the condensate netback.

The second quarter 2018 field operating netback increased by 17% (32% increase including hedging) compared to the same period in 2017.



The field operating netback for the first six months of 2018 increased by 8% (20% increase including hedging) compared to the first six months of 2017.



General and Administrative Costs

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Charge for period – before recoveries	$ 1,538	$ 1,613	$ 4,356	$ 3,782
Overhead recoveries	(318)	(119)	(612)	(614)
Charge for period – net of recoveries	$ 1,220	$ 1,494	$ 3,744	$ 3,168
Per Boe	$ 0.69	$ 1.17	$ 1.05	$ 1.13

General and administrative costs before recoveries for the second quarter of 2018 decreased by 5% when compared to the second quarter of 2017 due to lower compensation costs. General and administrative costs before recoveries for the six months ended June 30, 2018 increased by 15% compared to the same period of 2017 due to the payout of an annual performance bonus in the first quarter of 2018.

Fluctuations in overhead recoveries are in response to changes in field capital expenditures.

Net general and administrative costs on a per-Boe measure for the second quarter of 2018 decreased by 41% compared to the second quarter of 2017, and decreased by 7% when comparing the first six months of 2018 to the same period of 2017. Generally, the Company's general and administrative cost structure is predictable year to year and per-Boe declines are due to increased production volumes.

Interest and Finance Costs

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Charge for period	$ 1,256	$ 974	$ 2,398	$ 2,050
Average interest rate(1)	5.4%	4.4%	4.8%	4.8%
Per Boe	$ 0.71	$ 0.76	$ 0.68	$ 0.73

(1) Includes financing and standby fees.

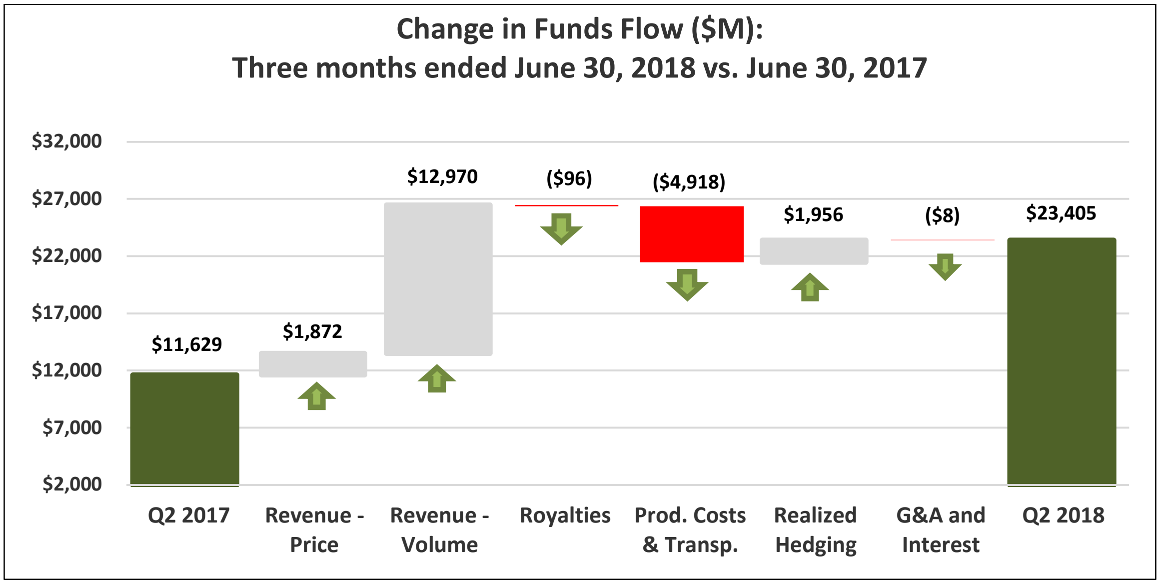
The interest rate on the Company's bank facility is based on bankers acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Interest costs for the second quarter of 2018 increased by 29% compared to the same quarter of 2017, and increased by 17% when comparing the six month periods. The increase in interest costs in the second quarter of 2018 is primarily attributable to the timing of payment of costs associated with the annual bank line renewal. The increase in interest costs for the six months ended June 30, 2018 from the same period of 2017 is primarily driven by additional bank borrowings used to fund the Company's capital program.

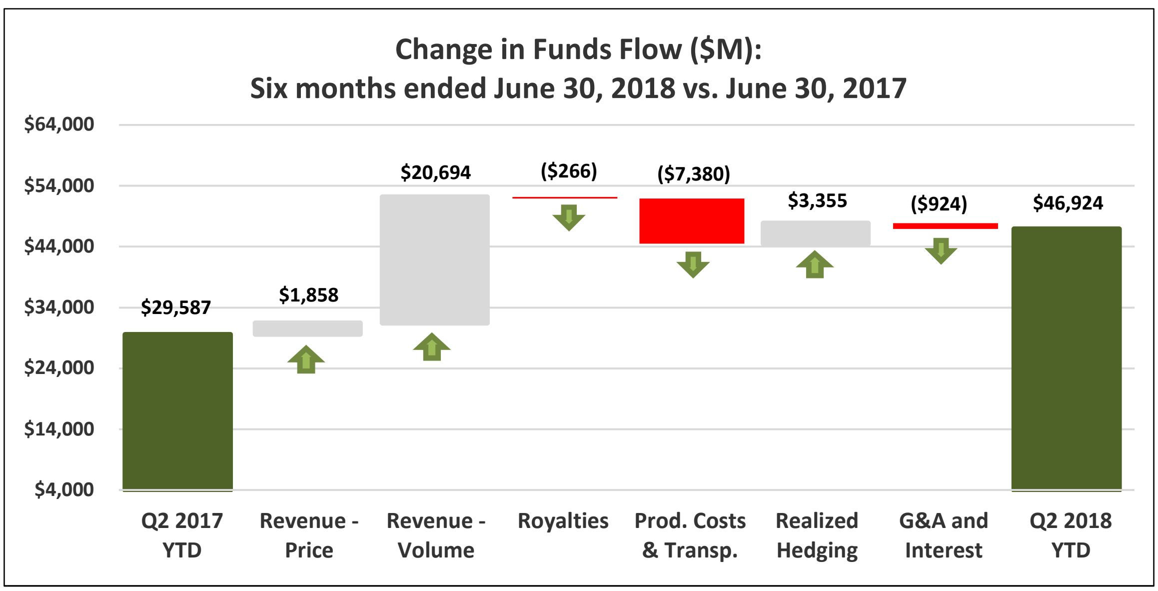
Funds Flow

	Three Months to June 30, 2018		Three Months to June 30, 2017		Six Months to June 30, 2018		Six Months to June 30, 2017	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$23,405	$0.19	$11,629	$0.10	$46,924	$0.39	$29,587	$0.24

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



Production growth, realized hedging gains and higher realized prices were the predominant factors in funds flow growth of 101% in the second quarter of 2018 versus the second quarter of 2017.



Funds flow for the first six months of 2018 increased by 59% from the same period of 2017. Funds flow benefited from both production growth and stronger realized pricing relative to the first six months of 2017.

Share-Based Compensation

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Charge for period	$ 772	$ 948	$ 1,466	$ 1,902
Per Boe	$ 0.43	$ 0.74	$ 0.41	$ 0.68

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 19% in the second quarter of 2018 compared to the second quarter of 2017 and decreased by 23% when comparing the six month periods. The decrease in share-based compensation in both the three and six month periods is primarily attributable to a lower option valuation associated with options granted in 2018.

Depletion and Depreciation

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Depletion	$ 9,926	$ 8,715	$ 19,761	$ 19,328
Depreciation	1,673	1,458	3,285	2,863
Charge for period	$ 11,599	$ 10,173	$ 23,046	$ 22,191
Per Boe	$ 6.53	$ 7.99	$ 6.49	$ 7.93

Depletion and depreciation increased by 14% in the second quarter of 2018 compared to the same quarter of 2017 due to a 40% increase in production volumes which was partially offset by lower finding and development costs. Comparing the first six months of 2018 with the same period in 2017, depletion and depreciation increased by 4% as a result of a 27% increase in production volumes which was partially offset by lower finding and development costs. The quarterly and year-to-date per-Boe decreases in depletion correspond to lower finding and development costs at Umbach.

Net Income (Loss)

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Net income (loss)	$ (2,815)	$ 9,752	$ 6,079	$ 30,383
Per basic and diluted share	$ (0.02)	$ 0.08	$ 0.05	$ 0.25

The mark-to-market valuation of commodity price contracts resulted in a considerable distortion to the reported net income (loss) for the three and six months ended June 30, 2018 relative to the comparable periods in 2017. The unrealized loss on commodity price contracts for the three and six months ended June 30, 2018 amounted to $13.6 million and $15.7 million, respectively, compared to an unrealized gain for the three and six months ended June 30, 2017 of $9.5 million and $25.6 million, respectively.

Excluding unrealized gains and losses on commodity price contracts, the increase in net income in the three and six months ended June 30, 2018 compared to the same periods of 2017 is primarily attributable to increased production levels driving increased revenue.

Corporate Netbacks

($/Boe)	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Revenue from product sales	27.07	26.12	28.22	27.75
Realized gain (loss) on commodity price contracts	0.31	(1.10)	(0.44)	(1.76)
Royalties	(1.11)	(1.47)	(1.41)	(1.69)
Production	(5.46)	(6.74)	(5.51)	(6.25)
Transportation	(6.25)	(5.75)	(5.92)	(5.61)
General and administrative	(0.69)	(1.17)	(1.05)	(1.13)
Interest and finance costs	(0.71)	(0.76)	(0.68)	(0.73)
Funds flow	13.16	9.13	13.21	10.58
Share-based compensation	(0.43)	(0.74)	(0.41)	(0.68)
Depletion, depreciation and accretion	(6.60)	(8.08)	(6.56)	(8.01)
Exploration and evaluation costs expensed	(0.06)	(0.06)	(0.08)	(0.13)
Unrealized revaluation gain (loss) on investments	0.01	(0.03)	(0.02)	(0.04)
Unrealized gain (loss) on commodity price contracts	(7.68)	7.44	(4.43)	9.15
Net income (loss)	(1.60)	7.66	1.71	10.87

INVESTMENT AND FINANCING

Financial Resources and Liquidity

In April 2018, the Company's credit facility was increased to $180 million from $165 million in recognition of production and reserve growth at Umbach. The credit facility is available until April 26, 2019 at which time the borrowing base amount will be reviewed using independently evaluated reserve information. In the ordinary course of business, the Company has the option to extend the credit facility for an additional year; if this does not happen, the facility will be termed out with the amount outstanding becoming payable in full one year later. The credit facility is syndicated with three banks.

At June 30, 2018, the Company was in compliance with all covenants under the credit facility; the sole financial covenant is that debt including working capital deficiency cannot exceed the credit facility limit. At June 30, 2018, debt including working capital deficiency amounted to $85.1 million, representing 49% of the available credit facility.

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

Capital Expenditures

In the second quarter of 2018, the Company incurred capital expenditures of $2.9 million compared to $4.3 million in the second quarter of 2017.

In the first six months of 2018, the Company incurred capital expenditures of $25.8 million (first six months of 2017 - $31.7 million) primarily related to completing three horizontal wells at Nig, building a pipeline to tie in the Nig wells and purchasing additional compression to twin the Company's third field compression facility.

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Land and seismic	$ 351	$ 150	$ 925	$ 407
Drilling	-	-	-	9,879
Completions	171	168	9,055	9,271
Facilities	664	1,854	6,003	3,535
Equipping and pipelines	1,150	2,081	8,593	7,716
Recompletions and workovers	84	44	737	846
Property acquisition and administrative assets	498	10	505	10
Total capital expenditures	$ 2,918	$ 4,307	$ 25,818	$ 31,664

Net capital investment was allocated as follows:

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Exploration and evaluation	$ 539	$ 150	$ 1,113	$ 400
Property and equipment	2,379	4,157	24,705	31,264
Total capital expenditures	$ 2,918	$ 4,307	$ 25,818	$ 31,664

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, 2018 was $36.8 million (December 31, 2017 - $36.3 million) and reflects (i) liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, (iii) changes in estimates of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of crude oil and natural gas properties, (v) less actual decommissioning costs incurred, and (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value was 2.2% (December 31, 2017 – 2.2%). Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation, including monitoring of actual abandonment and reclamation costs, supported by external information from industry sources and with reference to industry best practices, as well as provincial and other regulation and evolution of same.

CONTRACTUAL OBLIGATIONS

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

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

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years that commenced October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.6 million over the term of the lease. At June 30, 2018, the remaining office lease commitment is $0.2 million. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The aggregate commitment approximates $6.0 million over seven years. In addition, as at the date of this report, the Company has natural gas transportation and processing commitments valued at a total of approximately $361.5 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended June 30, 2018 appears below. Although there are variations between quarters in various elements of revenue and cost, as set out in the MD&A for each quarter, the results from the third quarter of 2016 reflect the relentless fall in commodity prices in the period resulting in a reduction to capital investment and a flat production profile. However, during the third quarter of 2016, pricing for the Company's commodities began to improve, enabling the Company to implement a larger capital expenditure program in the fourth quarter of 2016 which increased production in the first quarter of 2017 as new wells were turned on.

The second and third quarters of 2017 saw a retreat in pricing for natural gas and condensate and a reduction in production due to a planned maintenance turnaround at the McMahon Gas Plant in June that involved an unanticipated extension into July, which affected revenue and funds flow. With road bans in place for the better part of the second quarter of 2017, capital expenditures were limited as no wells were drilled or completed during the quarter. As road bans were lifted, the third quarter saw a return to normal field activity levels with three wells drilled and five wells completed. However, low natural gas prices in the third quarter of 2017 resulted in production being managed to the level required to meet firm processing and transportation commitments.

Despite a decrease of 37% in Station 2 pricing in the fourth quarter of 2017 compared to the preceding quarter, Storm's realized price increased 23% to $26.37 per Boe, primarily due to an increase in liquids pricing. Production volumes increased 18% compared to the preceding quarter, which contributed to higher revenue and funds flow in the fourth quarter of 2017.

In the first quarter of 2018, Storm benefited from an increase in realized pricing due to stronger natural gas and condensate prices coupled with higher production volumes supported by additional firm transportation to the Chicago market that came into effect in December 2017. Most notably, benchmark pricing for Station 2 increased 242% when comparing the first quarter of 2018 to the preceding quarter. This resulted in yet another period of strong funds flow generation that was in excess of net capital expenditures, leading to a modest reduction in debt levels relative to the prior period.

In the second quarter of 2018, natural gas benchmark pricing declined from the preceding quarter, reflecting seasonality coupled with pipeline outages. Despite a decrease in natural gas pricing, the Company benefited from a rally in crude oil pricing which supported higher condensate pricing. Although total product revenue declined, funds flow for the second quarter of 2018 was consistent with the preceding quarter primarily due to a hedging gain and lower cash costs. A modest level of capital spending in the quarter allowed Storm to reduce its net debt position by $20.5 million.

	2018		2017				2016	
($000s unless otherwise stated)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue from product sales	48,104	52,102	43,506	31,719	33,262	44,392	32,976	27,656
Funds flow	23,405	23,519	21,323	13,170	11,629	17,958	11,985	8,759
Per share – basic and diluted ($)	0.19	0.19	0.18	0.11	0.10	0.15	0.10	0.07
Net income (loss)	(2,815)	8,894	8,624	682	9,752	20,631	(12,898)	(85)
Per share – basic and diluted ($)	(0.02)	0.07	0.07	0.01	0.08	0.17	(0.11)	(0.00)
Net capital expenditures	2,918	22,900	26,126	23,895	4,307	27,357	33,399	6,980
Average daily production (Boe)	19,529	19,708	17,936	15,193	13,991	16,947	13,320	13,285
Debt including working capital deficiency(1)	85,073	105,585	106,124	101,297	90,582	97,864	89,841	69,303

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

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, as outlined in Storm's August 14, 2018 press release, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations or financial position. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices in each market in which production is sold including prices as outlined in 2018 guidance;
- future average production volumes in the fourth quarter of 2018, annual production for 2018 and preliminary average annual production in 2019 of 21,000 to 23,000 Boe per day, along with production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2018 guidance;
- future reduction to corporate operating costs by approximately $1.50 per Boe with the start-up of the Nig sour gas plant;
- future value of unrealized commodity price contracts;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2018 capital expenditure program including 2018 capital investment of $80 million, preliminary 2019 capital investment of $125 million and total cost of approximately $81 million for the Nig sour gas plant;
- future capital to maintain 20,000 Boe per day of $60 million in 2018 and $20 million in 2019;
- third quarter 2018 production and capital investment of 19,500 to 20,500 Boe per day and $25.0 million, respectively;
- future growth plans through 2020 including timing for the start-up of the Nig sour gas plant and the Fireweed field compression facility;
- future production levels of 25,000 to 26,000 Boe per day upon start-up of the Nig sour gas plant and 30,000 to 31,000 Boe per day with start-up of the Fireweed field compression facility;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including the amounts outlined in 2018 guidance and per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital expenditure programs and future availability of such sources;
- drilling rigs, field service providers and completion and tie-in equipment being available as required, with costs of securing these services not materially exceeding expectations;
- development plans for Storm's properties;

- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency including forecasted debt levels peaking at approximately 80% of the current bank credit facility prior to start-up of the Nig sour gas plant;
- availability and use of credit facilities including approximately $88 million of unused credit capacity at quarter end;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future amounts and use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells including improvements on future wells from drilling longer wells leading to first year average rates that are expected to be more than 30% higher;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2018 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and NGL, specifically the anticipated sales percentage allocation in 2018 to Chicago, Sumas, Station 2 and AECO markets;
- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed, including twinning of the third field compression facility;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations;
- references to the intentions of management or the Company; and
- changes to any of the foregoing.

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

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

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

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

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

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

BUSINESS RISKS

There are a number of risks facing participants in the Canadian crude oil and natural 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 29, 2018 for the year ended December 31, 2017 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2017 under the heading "Business Risks".

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

IFRS 9 *Financial Instruments*

On January 1, 2018, the Company retrospectively adopted IFRS 9 *Financial Instruments*, which replaces IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected credit loss" impairment method and a substantially reformed approach to hedge accounting. Prior to the adoption of IFRS 9, the Company did not apply hedge accounting to its commodity price contracts and there was no change to this approach with adoption of IFRS 9. IFRS 9 contains three principal categories for financial assets: measured at amortized cost, fair value through other comprehensive income and fair value through profit and loss. The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. The adoption of IFRS 9 resulted in a change in classification of the Company's financial assets, which primarily consist of accounts receivable and commodity price contracts. The expected credit loss model applies to the Company's accounts receivable. As at March 31, 2018, 100% of the Company's accounts receivable was outstanding for less than 60 days. Based on an analysis of historic credit losses, the average expected credit loss applied to accounts receivable did not result in a material adjustment. Prior to the adoption of IFRS 9, the Company's accounts receivable were classified as loans and receivables and subsequent to the adoption of IFRS 9 will be classified at amortized cost. The Company's commodity price contracts will continue to be classified as fair value through profit and loss. The terms of these instruments are substantially consistent with those of the Company's peers within the crude oil and natural gas industry and are relatively short-term in nature. The adoption of IFRS 9 did not result in any material change on the valuation of the Company's financial assets.

IFRS 15 Revenue from Contracts with Customers

On January 1, 2018, the Company retrospectively adopted IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts* using the following practical expedients:

- Electing to apply the standard retrospectively only to contracts that were not completed contracts on January 1, 2018; and
- For modified contracts, evaluating the original contracts together with any contract modification at the date of initial application.

The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery.

The Company reviewed its various revenue streams and underlying contracts with customers and concluded that the adoption of the new standard required presentation changes in revenue and transportation that did not affect net income or funds flow. In addition, Storm has expanded the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type. Additional disclosure as required under IFRS 15 can be found in Note 7.

In conjunction with the adoption of IFRS 15, the Company completed a review of the financial statement presentation of its revenue transactions. As a result, certain comparative amounts in the 2017 unaudited interim consolidated financial statements have been reclassified, for comparability purposes, as follows:

	Three Months Ended June 30, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 27,317	$ 5,945	$ 33,262
Transportation	$ 1,371	$ 5,945	$ 7,316
Net income and comprehensive income for the period	$ 9,752	-	$ 9,752

	Six Months Ended June 30, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 64,362	$ 13,292	$ 77,654
Transportation	$ 2,419	$ 13,292	$ 15,711
Net income and comprehensive income for the period	$ 30,383	-	$ 30,383

Future Accounting Policy Changes

A description of additional accounting standards that will be adopted in future periods can be found in Note 4 of the Company's audited consolidated financial statements for the year ended December 31, 2017.

The Company is continuing its assessment and evaluation of the effect of the adoption of IFRS 16 on the consolidated financial statements.

Disclosure Controls and Internal Controls Over Financial Reporting

The Company has designed disclosure controls and procedures (“DCP”) to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company’s ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

ADDITIONAL INFORMATION

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

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	June 30, 2018	December 31, 2017
ASSETS		
Current		
Accounts receivable (Note 12)	$ 11,490	$ 15,104
Prepaids and deposits	688	4,542
Fair value of commodity price contracts (Note 12)	-	2,842
	12,178	22,488
Fair value of commodity price contracts (Note 12)	-	209
Exploration and evaluation (Note 4)	105,105	103,907
Property and equipment (Note 5)	390,562	388,959
	$ 507,845	$ 515,563
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 9,944	$ 24,777
Fair value of commodity price contracts (Note 12)	11,479	478
	21,423	25,255
Bank indebtedness (Note 6)	87,307	100,993
Fair value of commodity price contracts (Note 12)	1,794	100
Decommissioning liability (Note 8)	25,035	24,474
	135,559	150,822
Shareholders' equity		
Share capital (Note 9)	391,444	391,444
Contributed surplus (Note 10)	13,480	12,014
Deficit	(32,638)	(38,717)
	372,286	364,741
Commitments (Note 14)		
	$ 507,845	$ 515,563

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

Director

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

(Canadian $000s except per-share amounts) (unaudited)	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Revenue				
Revenue from product sales (Note 7)	$ 48,104	$ 33,262	$ 100,206	$ 77,654
Royalties	(1,968)	(1,872)	(5,004)	(4,738)
Net revenue	46,136	31,390	95,202	72,916
Realized gain (loss) on commodity price contracts (Note 12)	556	(1,400)	(1,563)	(4,918)
Unrealized gain (loss) on commodity price contracts (Note 12)	(13,648)	9,471	(15,746)	25,596
Net revenue and commodity price contracts	33,044	39,461	77,893	93,594
Expenses				
Production	9,703	8,577	19,553	17,482
Transportation	11,108	7,316	21,020	15,711
General and administrative	1,220	1,494	3,744	3,168
Share-based compensation (Note 10)	772	948	1,466	1,902
Depletion and depreciation (Note 5)	11,599	10,173	23,046	22,191
Exploration and evaluation costs expensed (Note 4)	98	75	277	373
Accretion (Note 8)	128	112	255	214
Interest and finance costs	1,256	974	2,398	2,050
Unrealized revaluation (gain) loss on investment	(25)	40	55	120
Total expenses	35,859	29,709	71,814	63,211
Net income (loss) and comprehensive income (loss) for the period	$ (2,815)	$ 9,752	$ 6,079	$ 30,383
Net income (loss) per share (Note 11)				
- Basic and diluted	$ (0.02)	$ 0.08	$ 0.05	$ 0.25

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Six Months to June 30, 2018
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 391,444	$ 12,014	$ (38,717)	$ 364,741
Net income for the period	-	-	6,079	6,079
Issue of common shares (Note 9)	-	-	-	-
Share-based compensation (Note 10)	-	1,466	-	1,466
Share-based compensation on options exercised (Note 9)	-	-	-	-
Balance, end of period	$ 391,444	$ 13,480	$ (32,638)	$ 372,286

(Canadian $000s) (unaudited)				Six Months to June 30, 2017
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 389,316	$ 8,870	$ (78,406)	$ 319,780
Net income for the period	-	-	30,383	30,383
Issue of common shares (Note 9)	1,456	-	-	1,456
Share-based compensation (Note 10)	-	1,902	-	1,902
Share-based compensation on options exercised (Note 9)	672	(672)	-	-
Balance, end of period	$ 391,444	$ 10,100	$ (48,023)	$ 353,521

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Operating activities				
Net income (loss) for the period	$ (2,815)	$ 9,752	$ 6,079	$ 30,383
Non-cash items:				
Unrealized (gain) loss on commodity price contracts (Note 12)	13,648	(9,471)	15,746	(25,596)
Depletion, depreciation and accretion (Notes 5 and 8)	11,727	10,285	23,301	22,405
Share-based compensation (Note 10)	772	948	1,466	1,902
Exploration and evaluation costs expensed (Note 4)	98	75	277	373
Unrealized revaluation (gain) loss on investment	(25)	40	55	120
Funds flow	23,405	11,629	46,924	29,587
Net change in non-cash working capital items (Note 13)	(2,687)	5,648	(499)	6,001
	20,718	17,277	46,425	35,588
Financing activities				
Proceeds from issue of common shares (Note 9)	-	-	-	1,456
Increase (decrease) in bank indebtedness	(12,050)	(5,775)	(13,686)	5,325
	(12,050)	(5,775)	(13,686)	6,781
Investing activities				
Additions to property and equipment (Note 5)	(2,183)	(4,157)	(24,509)	(31,264)
Additions to exploration and evaluation assets (Note 4)	(351)	(150)	(925)	(400)
Acquisition of property and equipment (Note 5)	(196)	-	(196)	-
Acquisition of exploration and evaluation assets (Note 4)	(188)	-	(188)	-
Net change in non-cash working capital items (Note 13)	(5,750)	(7,195)	(6,921)	(10,705)
	(8,668)	(11,502)	(32,739)	(42,369)
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, 2018 and 2017

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

1. REPORTING ENTITY

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

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

2. BASIS OF PRESENTATION

Statement of Compliance

The financial statements have been prepared in accordance with International Accounting Standard (“IAS”) 34 “Interim Financial Reporting” using accounting policies consistent with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). These financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s audited financial statements as at and for the year ended December 31, 2017. All financial information is reported in thousands of Canadian dollars, which is the functional currency of the Company.

These financial statements were authorized for issue by the Board of Directors on August 14, 2018.

Basis of Measurement

The Company’s financial statements have been prepared on a going concern basis consistent with prior years, and follow the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 12.

Significant Accounting Judgments, Estimates and Assumptions

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

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

Critical judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are described in Note 5 to the Company’s audited consolidated financial statements for the year ended December 31, 2017.

3. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

IFRS 9 *Financial Instruments*

On January 1, 2018, the Company retrospectively adopted IFRS 9 *Financial Instruments*, which replaces IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected credit loss" impairment method and a substantially reformed approach to hedge accounting. Prior to the adoption of IFRS 9, the Company did not apply hedge accounting to its commodity price contracts and there was no change to this approach with adoption of IFRS 9. IFRS 9 contains three principal categories for financial assets: measured at amortized cost, fair value through other comprehensive income and fair value through profit and loss. The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. The adoption of IFRS 9 resulted in a change in classification of the Company's financial assets, which primarily consist of accounts receivable and commodity price contracts. The expected credit loss model applies to the Company's accounts receivable. As at June 30, 2018, 100% of the Company's accounts receivable was outstanding for less than 60 days. Based on an analysis of historic credit losses, the average expected credit loss applied to accounts receivable did not result in a material adjustment. Prior to the adoption of IFRS 9, the Company's accounts receivable were classified as loans and receivables and subsequent to the adoption of IFRS 9 will be classified at amortized cost. The Company's commodity price contracts will continue to be classified as fair value through profit and loss. The terms of these instruments are substantially consistent with those of the Company's peers within the crude oil and natural gas industry and are relatively short-term in nature. The adoption of IFRS 9 did not result in any material change to the valuation of the Company's financial assets.

IFRS 15 Revenue from Contracts with Customers

On January 1, 2018, the Company retrospectively adopted IFRS 15 *Revenue from Contracts with Customers,* which replaces IAS 18 *Revenue* and IAS 11 *Construction Contracts* using the following practical expedients:

- Electing to apply the standard retrospectively only to contracts that were not completed contracts on January 1, 2018; and
- For modified contracts, evaluating the original contracts together with any contract modification at the date of initial application.

The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The Company primarily enters into non-complex and routine revenue contracts with customers that require daily physical delivery of produced volumes priced at the current daily or monthly average spot price. Performance obligations are met upon delivery of the volumes at the processing facility and the transaction price is established based on the date of delivery.

The Company reviewed its various revenue streams and underlying contracts with customers and concluded that the adoption of the new standard required presentation changes in revenue and transportation that did not affect net income or funds flow. In addition, Storm has expanded the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type. Additional disclosure as required under IFRS 15 can be found in Note 7.

In conjunction with the adoption of IFRS 15, the Company completed a review of the financial statement presentation of its revenue transactions. As a result, certain comparative amounts in the 2017 unaudited interim consolidated financial statements have been reclassified, for comparability purposes, as follows:

	Three Months Ended June 30, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 27,317	$ 5,945	$ 33,262
Transportation	$ 1,371	$ 5,945	$ 7,316
Net income and comprehensive income for the period	$ 9,752	-	$ 9,752

	Six Months Ended June 30, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 64,362	$ 13,292	$ 77,654
Transportation	$ 2,419	$ 13,292	$ 15,711
Net income and comprehensive income for the period	$ 30,383	-	$ 30,383

Future Accounting Policy Changes

A description of additional accounting standards that will be adopted in future periods can be found in Note 4 of the Company's audited consolidated financial statements for the year ended December 31, 2017.

The Company is continuing its assessment and evaluation of the effect of the adoption of IFRS 16 on the consolidated financial statements.

Update to Significant Accounting Policies

Financial Instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are de-recognized when the rights to receive cash flows from the instruments have expired, or when the Company has transferred substantially all risks and rewards of ownership.

Financial instruments are measured at fair value upon initial recognition. Measurement in subsequent periods is dependent on the financial instrument's classification, as described below:

- *Fair value through profit or loss*
  Financial assets and liabilities designated at fair value through profit or loss are initially recognized and subsequently measured at fair value with subsequent changes in fair value charged to the consolidated statement of income (loss). The Company classifies its commodity price contracts as fair value through profit or loss.
- *Amortized cost*
  Amortized cost and other financial liabilities are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at amortized cost using the effective interest rate method, net of any impairment. The Company includes accounts receivable, accounts payable and accrued liabilities and bank indebtedness within the amortized cost category.
- *Fair value through other comprehensive income*
  Financial assets designated at fair value through other comprehensive income are measured at fair value with changes in fair value recognized in other comprehensive income (loss), net of tax. The Company does not currently have any financial assets classified as fair value through other comprehensive income.

Financial assets and liabilities are offset and the net amount reported in the consolidated statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Impairment of financial assets

The Company recognizes loss allowances for expected credit losses on its financial assets measured at amortized cost. Loss allowances are measured at an amount equal to the anticipated life of expected credit losses resulting from possible default events over the life of the financial assets.

Commodity price contracts

Commodity price contracts may be used by the Company to manage exposure to market risks related to commodity prices, exchange rates and interest rates. Storm does not use derivative contracts for speculative purposes. The Company does not designate its derivative contracts as hedges and, as such, does not apply hedge accounting. All derivative contracts are classified at fair value through profit and loss.

Revenue Recognition

Revenue recognition from the sale of commodities is calculated by reference to consideration specified in contracts with customers and recognized when control of the product is transferred to the buyer. This is generally at the time the customer obtains legal title to the product and when it is physically transferred to the delivery mechanism agreed with the customer, often pipelines or other transportation methods.

The Company sells its production pursuant primarily to variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors depending on the contract terms. Under its contracts, the Company is required to deliver volumes of natural gas, condensate and NGL to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to fluctuations in commodity prices. Natural gas, condensate and NGL are mostly sold under contracts of varying price and volume terms. Revenues are typically collected on the 25th day of the month following production.

The Company evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

4. EXPLORATION AND EVALUATION

	Six Months Ended June 30, 2018	Year ended December 31, 2017
Balance, beginning of period	$ 103,907	$ 110,395
Additions	1,113	1,838
Expiries - exploration and evaluation costs expensed	(277)	(386)
Future decommissioning costs	362	192
Transfer to property and equipment	-	(8,132)
Balance, end of period	$ 105,105	$ 103,907

Management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment at June 30, 2018 and none were identified.

5. PROPERTY AND EQUIPMENT

	Six Months Ended June 30, 2018	Year ended December 31, 2017
Cost		
Balance, beginning of period	$ 559,524	$ 466,700
Additions	24,705	79,847
Future decommissioning costs	(56)	4,845
Disposals	-	-
Transfer from exploration and evaluation assets	-	8,132
Balance, end of period	$ 584,173	$ 559,524
Accumulated depletion and depreciation		
Balance, beginning of period	$ (170,565)	$ (126,336)
Depletion and depreciation	(23,046)	(44,229)
Balance, end of period	$ (193,611)	$ (170,565)
Net book value, beginning of period	$ 388,959	$ 340,364
Net book value, end of period	$ 390,562	$ 388,959

Management reviewed the carrying amounts of property and equipment for indicators of impairment at June 30, 2018 and none were identified.

6. BANK INDEBTEDNESS

As at June 30, 2018, the Company had an extendible revolving credit facility in the amount of $180 million (December 31, 2017 – $165 million) based on a bank determined borrowing base related to the Company's producing reserves. At June 30, 2018, 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 credit facility amount. The credit facility is available to the Company until April 26, 2019, at which time the borrowing base amount will be reviewed and in the ordinary course of business the Company will have the option to extend the facility for an additional year. If the credit facility is not extended, the facility moves into a term phase whereby the outstanding loan amount is to be repaid one year later. Interest is paid on the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company.

As at June 30, 2018, the Company had issued letters of credit in the amount of $7.6 million (December 31, 2017 - $7.3 million) in support of future natural gas transportation and processing obligations. Availability under the Company's credit facility is reduced by a like amount.

7. REVENUE FROM PRODUCT SALES

The following table presents the Company's revenue from product sales disaggregated by revenue source:

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Natural gas	$ 27,629	$ 23,441	$ 60,743	$ 55,205
Condensate	15,590	7,703	29,717	17,892
NGL	4,885	2,118	9,746	4,557
Total	$ 48,104	$ 33,262	$ 100,206	$ 77,654

Storm's revenue was generated mostly in British Columbia where the production was sold primarily to one major marketer, which accounted for 44% and 49% of the Company's total revenue from product sales for the three and six months ended June 30, 2018, respectively. The majority of revenues are derived from variable price contracts based on index prices. Of total natural gas revenue for the six months ended June 30, 2018, 65% received Chicago index based pricing, 13% received Station 2 pricing, 12% received Sumas pricing, 6% received ATP pricing and the remaining 4% received AECO pricing.

8. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning crude oil and natural 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 $36.8 million (December 31, 2017 - $36.3 million), with the majority of payments being made in the years 2034 to 2054. A risk-free discount rate of 2.2% (December 31, 2017 – 2.2%) and an inflation rate of 2.0% (December 31, 2017 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $25.0 million at June 30, 2018.

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

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Balance, beginning of period	$ 24,474	$ 18,983
Obligations incurred	425	3,028
Obligations settled	(194)	-
Change in rate estimates[1]	75	2,009
Accretion expense	255	454
Balance, end of period	$ 25,035	$ 24,474

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

9. 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, 2017	121,557	$ 391,444
Shares issued on stock option exercises	-	-
Balance as at June 30, 2018	121,557	$ 391,444

During the first six months of 2018, there were no common shares issued upon the exercise of stock options.

10. 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 volume weighted average price of the shares on the TSX for the five trading days immediately preceding the date of grant, have a four-year term and vest in one-third tranches over three years. Under the stock option plan, at June 30, 2018, a total of 12,155,681 common shares were available for issuance. At June 30, 2018, options in respect of 8,276,700 common shares were issued and outstanding and options in respect of 3,878,981 common shares were available for future issue. At August 14, 2018, the date of this report, options in respect of 8,369,700 were issued and outstanding and options in respect of 3,785,981 common shares are available for future issue.

Details of the options outstanding at June 30, 2018 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2017	7,914	$ 4.46
Granted during the period	2,395	$ 2.86
Forfeited during the period	(399)	$ 4.10
Expired during the period	(1,633)	$ 4.69
Outstanding at June 30, 2018	8,277	$ 3.96
Number exercisable at June 30, 2018	3,737	

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$2.86 - $3.34	2,380	3.5	$ 2.86	-	-
$3.35 - $4.50	3,723	1.1	$ 3.85	2,949	$ 3.93
$4.51 - $5.50	2,174	2.3	$ 5.37	788	$ 5.35
Total	8,277	2.1	$ 3.96	3,737	$ 4.23

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

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the six months ended June 30, 2018 of $1.03 per share include the following:

	2018
Share price	$2.86
Exercise price	$2.86
Volatility	46%
Forfeiture rate	10%
Expected option life (years)	3.7
Risk-free interest rate	1.8%

Share-based compensation expense of $0.8 million and $1.5 million was charged to the consolidated statement of income (loss) during the three and six months to June 30, 2018, respectively (2017 - $0.9 million and $1.9 million, respectively) with an equivalent offset to contributed surplus.

11. NET INCOME (LOSS) PER SHARE

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

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Net income (loss) for the period	$ (2,815)	$ 9,752	$ 6,079	$ 30,383
Weighted average number of common shares outstanding – basic				
Common shares outstanding at beginning of period	121,557	121,557	121,557	120,764
Effect of shares issued	-	-	-	736
Weighted average number of common shares outstanding – basic	121,557	121,557	121,557	121,500
Dilutive effect of outstanding options(1)	-	125	-	202
Weighted average number of common shares outstanding - diluted	121,557	121,682	121,557	121,702
Net income (loss) per share				
Basic and diluted	$ (0.02)	$ 0.08	$ 0.05	$ 0.25

(1) Excludes effect of 8.3 million and 8.7 million weighted average common shares related to stock options that were anti-dilutive for the three and six months ended June 30, 2018, respectively (6.0 million and 5.9 million weighted average common shares related to stock options for each of the three and six months ended June 30, 2017, respectively).

12. FINANCIAL INSTRUMENTS

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

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

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

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's commodity price contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the three and six months ended June 30, 2018.

The Company's commodity price contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at June 30, 2018:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Commodity price contracts			
Current asset	$ 13,261	$ (13,261)	$ -
Long-term asset	6,848	(6,848)	-
Current liability	(24,740)	13,261	(11,479)
Long-term liability	(8,642)	6,848	(1,794)
Net position	$ (13,273)	$ -	$ (13,273)

The following is a summary of the Company's financial assets and financial liabilities that were subject to offset as at December 31, 2017:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Commodity price contracts			
Current asset	$ 6,212	$ (3,370)	$ 2,842
Long-term asset	268	(59)	209
Current liability	(3,848)	3,370	(478)
Long-term liability	(159)	59	(100)
Net position	$ 2,473	$ -	$ 2,473

Accounts Receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. Receivables from crude oil and natural gas marketers are typically collected on or about the 25th of the following month. The Company's production is sold to organizations whose credit worthiness is in part assessable from publicly available information. As at June 30, 2018, the Company's most significant marketer accounted for $5.2 million (June 30, 2017 - $1.5 million) of total receivables and 44% and 49% (three and six months ended June 30, 2017 – 60%) of total revenues for the three and six months ended June 30, 2018, respectively. Where operations involve partners in a joint venture, the Company attempts to mitigate the risk from joint venture receivables by obtaining pre-approval and cash call deposits from its partners in advance of significant capital expenditures. Receivables from joint ventures are typically collected within one to three months of the joint venture bill being issued. As at June 30, 2018, there were no receivables outstanding for more than 60 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at June 30, 2018.

The maximum exposure to credit risk at June 30, 2018 was the carrying amount of accounts receivable of $11.5 million.

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

Commodity Price Contracts

At the date of this report, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts at June 30, 2018, a net liability position of $13.3 million (December 31, 2017 – net asset position of $2.5 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the three and six months ended June 30, 2018, this resulted in unrealized mark-to-market losses of $13.6 million and $15.7 million, respectively (2017 – unrealized gains of $9.5 million and $25.6 million, respectively) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Jul – Dec 2018	11,500 Mmbtu	Sumas Cdn$2.92/Mmbtu
Jul – Dec 2018	45,500 Mmbtu	Chicago Cdn$3.42/Mmbtu
Jan – Jun 2019	22,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Jul – Dec 2019	1,500 Mmbtu	Chicago Cdn$3.18/Mmbtu
Jan – Dec 2019	4,500 Mmbtu	Sumas Cdn$2.56/Mmbtu
Jan – Dec 2019	21,500 Mmbtu	Chicago Cdn$3.21/Mmbtu
Jan – Jun 2020	6,500 Mmbtu	Chicago Cdn$3.24/Mmbtu
Natural Gas Differential Swaps		
Jul – Dec 2018	3,000 GJ	Price at Station 2 = AECO minus Cdn$0.345/GJ
Jan – Dec 2020	12,500 Mmbtu	Price at Chicago = NYMEX minus US$0.27/Mmbtu
Jan – Dec 2021	10,000 Mmbtu	Price at Chicago = NYMEX minus US$0.27/Mmbtu
Crude Oil Collars		
Jul – Dec 2018	800 Bbls	$67.50 - $77.75 Cdn$/Bbl
Jan – Jun 2019	650 Bbls	$68.83 - $80.74 Cdn$/Bbl
Jul – Dec 2019	300 Bbls	$71.00 - $82.02 Cdn$/Bbl
Jan – Dec 2019	250 Bbls	$70.60 - $83.26 Cdn$/Bbl

Crude Oil Swaps		
Jul – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Jan – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Jul – Dec 2019	100 Bbls	$71.55 Cdn$/Bbl
Jan – Dec 2019	100 Bbls	$83.60 Cdn$/Bbl
Propane Swaps		
Jul – Dec 2018	300 Bbls	$39.55 Cdn$/Bbl

The Company realized a gain from commodity price contracts in place in the amount of $0.6 million for the three months ended June 30, 2018 and realized a loss of $1.6 million for the six months ended June 30, 2018 (2017 – realized loss of $1.4 million and $4.9 million, respectively).

Physical Delivery Sales Contract

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

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

Sensitivities

The following table summarizes the effects of movement in commodity prices on net income (loss) due to changes in the fair value of commodity price contracts in place at June 30, 2018. Changes in the fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Factor	Six Months Ended June 30, 2018
Increase of US$10.00/Bbl in the price of WTI[(1)]	$ (6,219)
Decrease of US$10.00/Bbl in the price of WTI[(1)]	$ 6,219
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$ (2,441)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$ 2,441

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

13. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to June 30, 2018	Three Months to June 30, 2017	Six Months to June 30, 2018	Six Months to June 30, 2017
Accounts receivable	$ 786	$ 9,442	$ 3,559	$ 10,047
Prepaids and deposits	(25)	199	3,854	474
Accounts payable and accrued liabilities	(9,198)	(11,188)	(14,833)	(15,225)
Change in non-cash working capital	$ (8,437)	$ (1,547)	$ (7,420)	$ (4,704)
Relating to:				
Operating activities	$ (2,687)	$ 5,648	$ (499)	$ 6,001
Investing activities	(5,750)	(7,195)	(6,921)	(10,705)
Change in non-cash working capital	$ (8,437)	$ (1,547)	$ (7,420)	$ (4,704)
Interest paid during the period	$ 1,224	$ 974	$ 2,351	$ 1,786
Income taxes paid during the period	$ -	$ -	$ -	$ -

14. COMMITMENTS

At June 30, 2018, the Company has the following long-term commitments over the next five years and thereafter:

	2018	2019	2020	2021	2022	Thereafter	Total
Natural gas transportation and processing commitments	$ 28,389	$ 49,237	$ 32,523	$ 22,733	$ 22,538	$ 206,123	$ 361,543
Office lease	422	796	803	808	816	2,565	6,210
Total	$ 28,811	$ 50,033	$ 33,326	$ 23,541	$ 23,354	$ 208,688	$ 367,753

At present the Company has an office lease for a period of five years that commenced October 1, 2013 for a base rent, including operating costs and property tax, totaling approximately $4.6 million over the term of the lease. At June 30, 2018, the remaining commitment with respect to this lease is $0.2 million. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The aggregate commitment approximates $6.0 million over seven years.

CORPORATE INFORMATION

Officers

Brian Lavergne
President & Chief Executive Officer

Robert S. Tiberio
Chief Operating Officer

Michael J. Hearn
Chief Financial Officer

Emily Wignes
Vice President, Finance

Jamie P. Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
President & Chief Executive Officer

Sheila A. Leggett

Gregory G. Turnbull (2)

P. Grant Wierzba (2)(3)

James K. Wilson (1)

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

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Stock Exchange Listing

Toronto Stock Exchange
Trading Symbol "SRX"

Solicitors

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

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

Executive Offices

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

Abbreviations

ATP	Alliance Transfer Point
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
GJ	Gigajoules
GJ/d	Gigajoules per day
Mbbl	Thousands of barrels
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
Mmbtu	Millions of British Thermal Units
Mmbtu/d	Millions of British Thermal Units per day
Mmcf	Millions of cubic feet
Mmcf/d	Millions of cubic feet per day
NGL	Natural gas liquids
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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

www.stormresourcesltd.com