STORM RESOURCES

2018 Q3 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
FINANCIAL				
Revenue from product sales(1)	51,253	31,719	151,459	109,373
Funds flow	22,227	13,170	69,151	42,757
Per share – basic and diluted ($)	0.18	0.11	0.57	0.35
Net income	7,174	682	13,253	31,065
Per share – basic and diluted ($)	0.06	0.01	0.11	0.26
Capital expenditures(2)	21,845	23,895	47,663	55,559
Debt including working capital deficiency(2)(3)	84,648	101,297	84,648	101,297
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,522
Weighted average - diluted	121,557	121,613	121,557	121,679
Outstanding end of period - basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	27.24	22.68	27.88	26.07
Transportation costs	(5.98)	(6.09)	(5.94)	(5.78)
Revenue net of transportation	21.26	16.59	21.94	20.29
Royalties	(1.03)	(0.85)	(1.28)	(1.41)
Production costs	(5.54)	(6.03)	(5.52)	(6.17)
Field operating netback(2)	14.69	9.71	15.14	12.71
Realized (loss) gain on hedging	(1.73)	1.34	(0.89)	(0.72)
General and administrative	(0.66)	(1.03)	(0.92)	(1.10)
Interest and finance costs	(0.49)	(0.61)	(0.61)	(0.69)
Funds flow per Boe	11.81	9.41	12.72	10.20
Barrels of oil equivalent per day (6:1)	20,455	15,193	19,900	15,371
Natural gas production				
Thousand cubic feet per day	101,905	74,318	98,154	75,537
Price (Cdn$ per Mcf)(1)	3.21	3.13	3.39	3.72
Condensate production				
Barrels per day	2,059	1,600	2,035	1,608
Price (Cdn$ per barrel)(1)	84.97	53.52	82.46	58.70
NGL production				
Barrels per day	1,412	1,206	1,506	1,173
Price (Cdn$ per barrel)(1)	38.64	21.66	35.92	21.74
Wells drilled (100% working interest)	-	3.0	-	9.0
Wells completed (100% working interest)	5.0	5.0	8.0	9.0

(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 THIRD QUARTER HIGHLIGHTS

- Production increased by 35% on a per-share basis from the prior year to a record 20,455 Boe per day which was consistent with guidance (19,500 to 20,500 Boe per day).

- Liquids production (field condensate plus gas plant NGL) grew by 24% year over year with liquids representing 17% of total production and 41% of production revenue. Condensate increased by 29% while NGL increased by 17% as a result of lower NGL recoveries at the McMahon Gas Plant.

- Growth over the last 12 months has been achieved while investing less than funds flow (debt reduced by $17 million).

- At the end of the quarter, there was an inventory of six Montney horizontal wells (5.5 net) at Umbach that had not started producing which included four completed wells. One horizontal well (1.0 net) started production at the end of the quarter.

- As a result of the continuing improvement in horizontal well performance at Umbach, the internal type curve used by management to forecast production from new wells is being increased to 11 Bcf raw from 9 Bcf raw which is based on the performance of wells completed in 2017 and 2018 that have higher rates and shallower declines than previously forecast.

- At the Nig land block, three wells completed in 2018 are exceeding expectations and have averaged 8.2 Mmcf per day raw gas over the first 120 calendar days plus 225 barrels per day of field condensate (average of 1,600 Boe per day sales with 23% liquids including NGL recovered at the gas plant). The field condensate-gas ratio is approximately 50% higher than the average well at Umbach.

- Diversified sales resulted in the natural gas price net of transportation being $2.13 per Mcf which was materially higher than Western Canadian pricing (AECO was $1.13 per GJ while Station 2 was $1.24 per GJ).

- Production costs, cash G&A and interest expense on a per-Boe basis declined by 11% year over year.

- Funds flow was $22.2 million, or $0.18 per share, a 64% increase on a per-share basis from last year which was largely from higher production volumes and higher liquids prices.

- Net income for the year to date is $13.3 million or $0.11 per share which is a decrease from $31.1 million last year as a result of non-cash unrealized gains or losses on hedging which reduced the year to date by $18.1 million while adding $25.4 million in the previous year.

- Capital investment was $21.8 million which included five horizontal well completions, installing additional compression at Umbach and twinning part of a field gathering pipeline to Nig.

- The balance sheet remains strong with debt including the working capital deficiency being $84.6 million which represents 1.0 times annualized quarterly funds flow and 47% of the bank credit facility ($180 million).

- Commodity price hedges continue to be added and currently protect approximately 42% of forecast production for 2019.

OPERATIONS REVIEW

Umbach, Nig and Fireweed Areas, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 113,000 net acres (161 net sections). During the third quarter, two sections of land were acquired.

Third quarter field activity included completing five horizontal wells (5.0 net), adding compression and twinning part of a gathering pipeline to Nig that will reduce wellhead flowing pressure and increase capacity. One horizontal well started production on September 19th and there remains an inventory of six horizontal wells (5.5 net) that had not started producing at the end of the quarter which includes four completed wells.

Fourth quarter field activity is expected to include drilling five wells (5.0 net) and completing three wells (2.5 net) which includes the standing well (0.5 net) at Fireweed.

The drilling program for this winter and into 2019 will generally target areas where higher field condensate-gas ratios are expected. In the fourth quarter of 2018, two wells (2.0 net) will be drilled at Umbach and three wells (3.0 net) at Nig. During 2019, four wells (4.0 net) will be drilled at Nig including an acid gas disposal well and three wells (1.5 net) at Fireweed. One of the wells at Nig will be drilled into the lower Montney.

At Umbach, approximately $115 million has been invested since 2013 to build infrastructure (pipelines and facilities) with current field compression capacity totaling 150 Mmcf per day raw gas after additional compression was installed at the end of the third quarter. Throughput in the third quarter averaged 107 Mmcf per day raw gas. Current compression capacity supports growth in corporate production to approximately 27,000 Boe per day with growth dependent on the Station 2 price (incremental natural gas production would be directed to Station 2). Produced raw natural gas is sour (approximately 1.2% H_2S) with approximately 85% directed to the McMahon Gas Plant and 15% directed to the Stoddart Gas Plant. 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).

At Nig, the regulatory application for the planned 50 Mmcf per day gas plant (100% working interest) was submitted in mid-September. Depending on when approval is received, site preparation would occur in the first half of 2019, construction in the second half of 2019, and start-up is anticipated to be between the fourth quarter of 2019 and the first quarter of 2020. The main benefits from the gas plant are a forecast operating cost of $2.00 per Boe (reduces the corporate operating cost to approximately $4.25 per Boe) and incremental production totaling approximately 1,500 Boe per day which comes from improved liquids recovery (adds 1,100 barrels per day with 90% NGL) plus a 5% reduction in process shrinkage. The total cost of the project is estimated to be $81 million which includes $73 million for the gas plant, $4 million for an acid gas injection well and $4 million for a sales pipeline. During the third quarter, $2.5 million was invested primarily for equipment deposits and, in the fourth quarter, $11 million is expected to be invested for equipment deposits.

At Fireweed, engineering and design is underway for the planned 50 Mmcf per day field compression facility (50% working interest). The expected cost of the facility is $34 million gross and it is designed to be expandable to 100 Mmcf per day. Depending on when regulatory approvals are received, construction is expected to start later in 2019 or early in 2020 with start-up in the second half of 2020. Based on the production history from offsetting horizontal wells, field condensate-gas ratios are expected to be approximately 25 barrels per Mmcf higher than Umbach over the life of a well and up to 60 barrels per Mmcf higher in the first year. The first phase of development will include drilling and completing up to 12 horizontal wells (6.0 net) which are expected to add 4,000 to 5,000 Boe per day on a net basis (25% liquids) once the facility is completed in the second half of 2020.

Initial flow results after completing the standing well (0.5 net) at Fireweed are encouraging. The well is located at C-74-G/94-A-13, has a completed length of 1,420 metres and was completed using the ball drop hydraulic fracturing method with 2,300 tonnes of proppant pumped into 35 stages using slick-water. After flowing the frac fluid back on a six-day cleanup, the flow rate averaged 10.9 Mmcf per day raw gas plus 660 barrels per day of 54 degree field condensate and 1,140 barrels per day of frac water over the last 12 hours while flowing up the casing with a final flowing pressure of 4,800 kPa. The well was shut in after recovering 23% of the frac water and is expected to remain shut in until the Fireweed field compression facility is completed.

Initial rates from the wells completed in 2018 (all on the Nig land block) have been very strong with no decline to date. Rates over the first 120 calendar days have averaged 8.2 Mmcf per day raw gas plus 225 barrels per day of field condensate (average 1,600 Boe per day sales with 23% liquids including NGL recovered at the gas plant). The field condensate-gas ratio is 50% higher than the average well at Umbach. Current rates are averaging approximately 8.0 Mmcf per day plus 150 barrels per day of field condensate.

Given the improvement in rates that has been realized from longer horizontal wells, Storm management is now using an 11 Bcf raw gas type curve (internal estimate) to forecast production from new wells. Previously, management used a 9 Bcf raw gas type curve (internal estimate). The revised type curve is based on the performance of the wells completed in 2017 which have a shallower decline than previously forecast. Future wells will be materially longer (2,400 metres) and have more frac stages (40 to 46) than the 2017 wells. A summary of horizontal well results is provided below with more information on well performance and management's type curve being 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	1270 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	1750 m	$4.2 million $2,400 per metre	5.0 Mmcf/d 12 hz's	4.5 Mmcf/d 12 hz's	4.3 Mmcf/d 10 hz's
2018 8 hz's	35	1970 m	$5.0 million $2,540 per metre	8.1 Mmcf/d 3 hz's		

(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 protects approximately 58% of forecast production for the fourth quarter of 2018 and 42% for 2019.

2018 Q4	Crude Oil	800 Bpd	WTI Cdn$67.50/Bbl floor, Cdn$77.75/Bbl ceiling
		700 Bpd	WTI Cdn$64.84/Bbl
	Propane	300 Bpd	Conway Cdn$39.55/Bbl
	Natural Gas	45,500 Mmbtu/d (38.4 Mmcf/d)	Chicago Cdn$3.42/Mmbtu
		11,500 Mmbtu/d (9.7 Mmcf/d)	Sumas Cdn$2.92/Mmbtu
		7,000 GJ/d (5.6 Mmcf/d)	AECO Cdn$1.92/GJ
		7,000 GJ/d (5.6 Mmcf/d)	Station 2 Cdn $1.72/GJ
		3,000 GJ/d (2.4 Mmcf/d)	Station 2 - AECO basis -$0.345/GJ

2019	Crude Oil	875 Bpd	WTI Cdn$71.24/Bbl floor, Cdn$84.60/Bbl ceiling
		625 Bpd	WTI Cdn$78.51/Bbl
	Propane	200 Bpd	Conway Cdn$42.87/Bbl
	Natural Gas	43,500 Mmbtu/d (36.7 Mmcf/d)	Chicago Cdn$3.26/Mmbtu
		8,400 Mmbtu/d (7.1 Mmcf/d)	Sumas Cdn$2.86/Mmbtu
		2,500 GJ/d (2.0 Mmcf/d)	AECO Cdn$1.94/GJ
		2,250 GJ/d (1.8 Mmcf/d)	Station 2 Cdn $1.73/GJ

Transportation capacity for natural gas is summarized below:

56 - 70 Mmcf per day Alliance - Chicago (preferential interruptible service adds up to 14 Mmcf per day)
12 Mmcf per day Enbridge T-north - Station 2 for Sumas price less a marketing adjustment
5 Mmcf per day Alliance - ATP
16 Mmcf per day Enbridge T-north - Station 2
13 Mmcf per day Enbridge T-north & TCPL NGTL - AECO
102 - 116 Mmcf per day

Transportation capacity provides diversification for natural gas sales to several different markets. During the third quarter, 61% of natural gas production was sold in Chicago, 27% in Western Canada and 12% at Sumas. Production exceeding firm capacity is directed to Chicago and/or Station 2 on an interruptible basis depending on which sales point offers a higher net price.

OUTLOOK

For the fourth quarter of 2018, production is forecast to be 19,000 to 21,000 Boe per day with production to date averaging 19,300 Boe per day based on field estimates which includes three days with no production due to outages at the McMahon Gas Plant and the Enbridge T-south pipeline failure on October 9th. The effect of the pipeline failure on the Station 2 price is uncertain at this time due to varying restrictions on flow rates for repairs as well as the timing for storage withdrawals from the Aitken Creek storage facility (some production will be shut in as receipts and deliveries at Station 2 must be equal). To date in the fourth quarter, the Station 2 price has averaged $0.72 per GJ which has resulted in Storm's production being restricted to minimize sales at Station 2. The lower Station 2 price is not expected to have a material effect on Storm's fourth quarter financial results since it is largely mitigated by diversified natural gas sales (less than 15% of sales are at Station 2), existing hedges at Station 2 (5.6 Mmcf per day), unhedged volumes sold at a much higher Sumas price (2.3 Mmcf per day), and the ability to divert some production onto the Alliance Pipeline to the higher priced Chicago market (up to 14 Mmcf per day).

Updated guidance for 2018 is provided below. Capital investment is increasing to $85 million (was $80 million) as the completion of a standing horizontal well at Fireweed was advanced into 2018 from 2019 and the estimated drilling and completion cost for a horizontal well was increased to $5.8 million (was $5.0 million) to reflect increased length with more frac stages (2,400 metres with 40 to 46 frac stages). With the increased length and frac stages, the type curve used by Storm management to forecast production from new wells has been increased to 11 Bcf raw gas (was 9 Bcf raw gas). This is supported by the performance to date of the wells completed in 2017 and 2018. Fourth quarter capital investment is expected to be $37 million which includes $11 million for the Nig Gas Plant. Forecast commodity prices reflect pricing to date and the approximate forward strip for the remainder of the year. Notably, the mid-point of forecast annual funds flow is approximately 15% higher than initial guidance provided in November 2017.

2018 Guidance

	Previous August 14, 2018	Current November 13, 2018
Cdn$/US$ exchange rate	0.78	0.77
Chicago daily natural gas - US$/Mmbtu	$2.70	$2.90
Sumas monthly natural gas - US$/Mmbtu	$2.05	$3.25
AECO daily natural gas - Cdn$/GJ	$1.45	$1.50
Station 2 daily natural gas - Cdn$/GJ	$1.35	$1.30
WTI - US$/Bbl	$66.00	$66.00
Edmonton condensate diff – US$/Bbl		-$3.10
Est revenue net of transport (excluding hedges) - $/Boe	$20.50 - $21.50	$23.00 - $23.50
Est operating costs - $/Boe	$5.75	$5.50 - $5.75
Est royalty rate (% revenue before hedging)	5% - 7%	4% - 6%
Est capital investment (excluding A&D) - $ million	$80.0	$85.0
Est cash G&A - $ million - $/Boe	$6.0 - $7.0 $0.78 - $0.95	$6.0 - $6.5 $0.80 - $0.91
Est interest expense - $ million	$4.0	$4.0
Forecast fourth quarter production - Boe/d % liquids	20,000 - 21,000 18%	19,000 – 21,000 18%
Forecast annual production - Boe/d % liquids	20,000 - 20,500 18%	19,500 – 20,500 18%
Est annual funds flow - $ million	$85.0 - $90.0	$90.0 - $96.0(1)
Umbach horizontal wells drilled - gross Umbach horizontal wells completed - gross Umbach horizontal wells connected - gross	5 (5.0 net) 10 (10.0 net) 8 (8.0 net)	5 (5.0 net) 11 (10.5 net) 7 (7.0 net)

(1) Based on mid-point field operating netback of $16.45 per Boe.

Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	WTI (US$/bbl)	Estimated Operations Capital ($ million)	Forecast Annual Funds Flow ($ million)	Forecast Annual Production (Boe/d)
Nov 14, 2017	$2.80	$1.30 - $1.70	$52.00	$55.0 - $90.0	$73.0 - $90.0	20,000 - 23,000
Mar 1, 2018	$2.60	$1.05	$56.00	$55.0 - $90.0	$70.0 - $78.0	20,000 - 23,000
May 15, 2018	$2.60	$1.20	$64.00	$55.0 - $65.0	$76.0 - $80.0	20,000 - 21,000
Aug 14, 2018	$2.70	$1.35	$66.00	$80.0	$85.0 - $90.0	20,000 – 20,500
Nov 13, 2018	**$2.90**	**$1.30**	**$66.00**	**$85.0**	**$90.0 - $96.0**	**19,500 – 20,500**

Guidance for 2019 is summarized below and includes capital investment of $128 million which includes $68 million for the sour gas plant at Nig and $14 million at Fireweed. Approximately 40% of capital investment will be in the first half of 2019. Drilling plans include five horizontal wells (5.0 net) at Nig including an acid gas disposal well, and three wells (1.5 net) at Fireweed. The estimated cost to drill and complete a horizontal well is $5.8 million for 2,400 metres of length with 40 to 46 frac stages. Capital investment is supported by commodity price hedges which protect approximately 42% of forecast production. The production forecast assumes an 11 Bcf raw gas type curve (internal estimate) for new horizontal wells. If required, capital investment and production growth can be reduced to ensure total debt is maintained at an appropriate level.

2019 Guidance

	November 13, 2018
Cdn$/US$ exchange rate	0.78
Chicago daily natural gas - US$/Mmbtu	$2.50
Sumas monthly natural gas - US$/Mmbtu	$2.50
AECO daily natural gas - Cdn$/GJ	$1.50
Station 2 daily natural gas - Cdn$/GJ	$1.25
WTI - US$/Bbl	$60.00
Edmonton condensate diff - US$/Bbl	-$8.00
Est revenue net of transport (excluding hedges) - $/Boe	$17.50 - $18.00
Est operating costs - $/Boe	$5.50 - $5.75
Est royalty rate (% revenue before hedging)	5% - 7%
Est capital investment (excluding A&D) - $ million	$128.0
Est cash G&A - $ million	$6.0 - $7.0
- $/Boe	$0.66 - $0.91
Est interest expense - $ million	$5.5 - $6.5
Forecast fourth quarter production - Boe/d % liquids	23,000 – 25,000 18%
Forecast annual production - Boe/d % liquids	21,000 – 24,000 18%
Est annual funds flow - $ million	$72.0 - $88.0(1)
Umbach horizontal wells drilled - gross Umbach horizontal wells completed - gross Umbach horizontal wells connected - gross	8 (6.5 net) 11 (9.5 net) 11 (11.0 net)

(1) Based on mid-point field operating netback of $11.05 per Boe.

For the nine months to date in 2018, financial results have improved materially when compared to last year which has further strengthened Storm's balance sheet. Funds flow is up 62% year over year as a result of 29% production growth with diversified natural gas sales mitigating the decline in Western Canadian natural gas prices (decline of 36% at AECO and 24% at Station 2) and growing liquids production benefitting from the 35% increase in the WTI price. In addition, the significant improvement in horizontal well results has reduced capital investment required to grow production. As a result, total debt has decreased by $17 million over the last 12 months.

Storm's improving financial position will be used to self-fund planned growth from Nig (2019 – 2020), Fireweed (2020) and Umbach (contingent on the Station 2 price). This includes a large capital investment to expand infrastructure by constructing a sour gas plant at Nig and constructing a new field compression facility at Fireweed. The upfront investment in infrastructure is large but will provide a significant long-term benefit. Production is expected to increase to 25,000 Boe per day by the end of 2019 and to 30,000 Boe per day by the end of 2020 while increasing liquids as a proportion of total production and reducing operating costs which reduces exposure to current low Western Canadian natural gas prices.

With a large, multi-year drilling inventory in the Montney in an area that is liquids-rich and higher quality, Storm is well positioned to continue growing asset value per share over the next three years by advancing development at both Nig and Fireweed.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

November 13, 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 crude oil. Mboe means 1,000 Boe.

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

Forward-Looking Statements - Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated November 13, 2018 for the three and nine months ended September 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 nine months ended September 30, 2018. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 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 November 13, 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 November 13, 2018.

See "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" on pages 23 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 nine months ended September 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 nine months ended September 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 nine month periods ended September 30, 2017.

OPERATIONAL AND FINANCIAL RESULTS

Overview

There were no surprises with the third quarter results as production was restricted to meet firm processing and transportation commitments in response to ongoing weakness in Western Canadian natural gas prices. Third quarter production of 20,455 Boe per day was at the high end of the previously announced guidance range of 19,500 to 20,500 Boe per day, and was 35% higher than the comparable quarter of 2017, which was affected by the McMahon Gas Plant turnaround. The third quarter saw production and funds flow that were consistent with the immediately preceding quarter, while there was a return to normal field activity levels with $22 million of capital expenditures incurred in the period.

During the third quarter, condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) accounted for 17% of total production and contributed 41% to revenue in the period compared to 43% in the immediately preceding quarter and 32% in the comparable quarter of 2017. As noted in the past, with the majority of Storm's condensate and NGL revenue streams priced with reference to WTI, the significantly improved fundamentals in the WTI 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 third quarter was up modestly from both the second quarter of 2018 and the same quarter of 2017. When comparing to the same quarter in 2017, condensate and NGL prices were up 59% and 78%, respectively, with a significant increase year over year in pricing across all liquids streams. While condensate and NGL prices remain relatively strong, natural gas prices have remained depressed due to significant year-over-year production growth in Western Canada (greater than 1 Bcf per day) and reduced exports at Empress. Western Canadian natural gas pricing is expected to be volatile through the winter heating season with higher prices corresponding to periods of higher demand resulting from colder temperatures. On a positive note, with storage levels at multi-year lows and with rising demand, the outlook for natural gas prices has improved heading into the winter heating season.

At quarter end, the Company had an inventory of six horizontal wells (5.5 net) that had not started production which included four completed wells. No wells were drilled in the third quarter with the bulk of spending in the period directed to completing five horizontal wells (5.0 net) and various facility and pipeline projects. The compressor to twin the third field compression facility was installed in the third quarter of 2018 bringing total field compression capacity to 150 Mmcf per day. Storm's production to date in the fourth quarter is approximately 19,300 Boe per day based on field estimates and the Company has the capability to accelerate growth quickly when and if prices support the decision to do so. Capital expenditures incurred in the third quarter of 2018 were less than the previously announced guidance of $25 million, primarily due to the timing of payments related to ordering equipment for the Nig Gas Plant, with these costs now expected to be incurred in the fourth quarter of 2018.

Comparison of the field operating netback in the third quarter of 2018 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 that carried on through the first half of July 2017. Nevertheless, compared to the same period in 2017, the field operating netback per Boe in the third quarter of 2018 increased by 51%, primarily due to a material recovery in liquids prices coupled with lower operating costs. Compared to the second quarter of 2018, the field operating netback per Boe was largely unchanged. The effects of a dynamic hedge portfolio, resulted in a realized hedging loss of $3.3 million during the third quarter of 2018 versus a realized hedging gain of $1.9 million in the third quarter of 2017, which eroded the aforementioned increase in the field operating netback year over year.

Total debt, including working capital deficiency, at quarter end amounted to $84.6 million, which was virtually unchanged from the end of the immediately preceding quarter as funds flow matched capital expenditures. With approximately $94.0 million of unused credit capacity, Storm retains considerable financial flexibility to manage its capital expenditure program for the remainder of the year and has the ability to increase or decrease capital expenditures in response to movements in commodity prices.

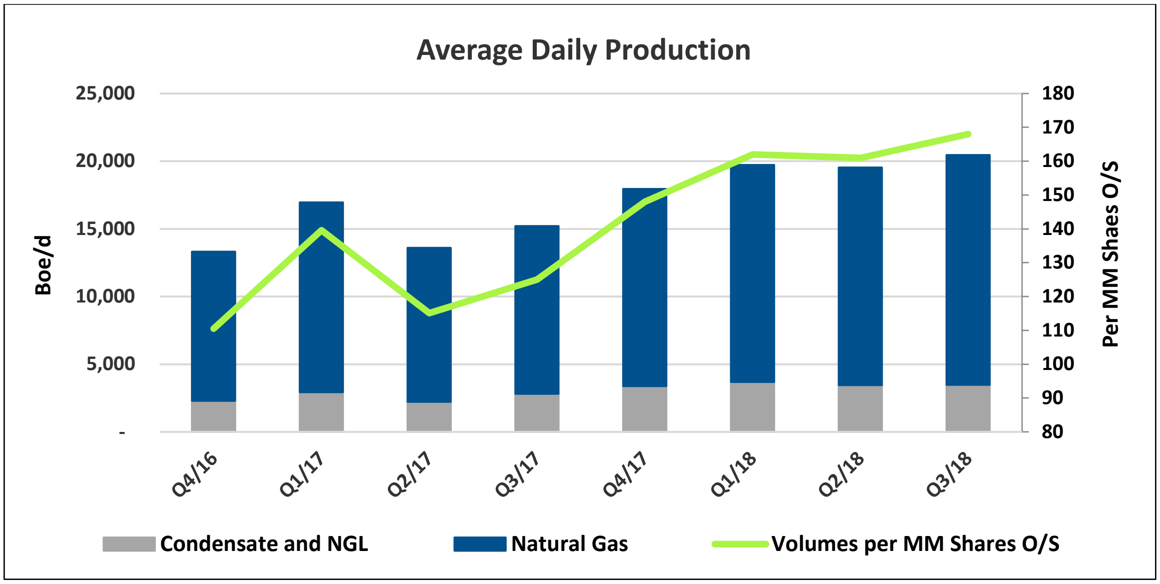
Subsequent to quarter end, the Company's bank syndicate, upon completion of a mid-year review, confirmed Storm's bank facility at $180 million, which had $78.7 million drawn at the end of the third quarter.

Production and Revenue

Average Daily Production

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Year-Over-Year Change	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017	Year-Over-Year Change
Natural gas (Mcf/d)	101,905	74,318	37%	98,154	75,537	30%
Condensate (Bbls/d)	2,059	1,600	29%	2,035	1,608	27%
NGL (Bbls/d)	1,412	1,206	17%	1,506	1,173	28%
Total (Boe/d)	20,455	15,193	35%	19,900	15,371	29%
Natural gas weighting	83%	82%		82%	82%	
Condensate weighting	10%	10%		10%	10%	
NGL weighting	7%	8%		8%	8%	

Production increases for natural gas, condensate and NGL for the third quarter and first nine months of 2018, when compared to the same periods in 2017, came from growth at Umbach where the Company started production from one new 100% working interest horizontal well during the third quarter of 2018 and six new 100% working interest horizontal wells during the nine months ended September 30, 2018, although comparability between the periods was affected by the McMahon Gas Plant turnaround in 2017 which reduced volumes during the comparative period.



Daily production per million shares outstanding at the end of the third quarter averaged 168 Boe per day, compared to 125 Boe per day for the third quarter of 2017, an increase of 34%.

Average Selling Prices[(1)]

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Natural gas - Mcf	$ 3.21	$ 3.13	$ 3.39	$ 3.72
Condensate –Bbl	$ 84.97	$ 53.52	$ 82.46	$ 58.70
NGL - Bbl	$ 38.64	$ 21.66	$ 35.92	$ 21.74
Per Boe	$ 27.24	$ 22.68	$ 27.88	$ 26.07

(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 nine months ended September 30, 2018 increased by 20% and 7%, respectively, compared to the same periods of 2017, driven by increases in condensate and NGL pricing, with a smaller increase in the nine month period as the increase in liquids pricing was partially offset by a decrease in the realized natural gas price.

Benchmark Prices

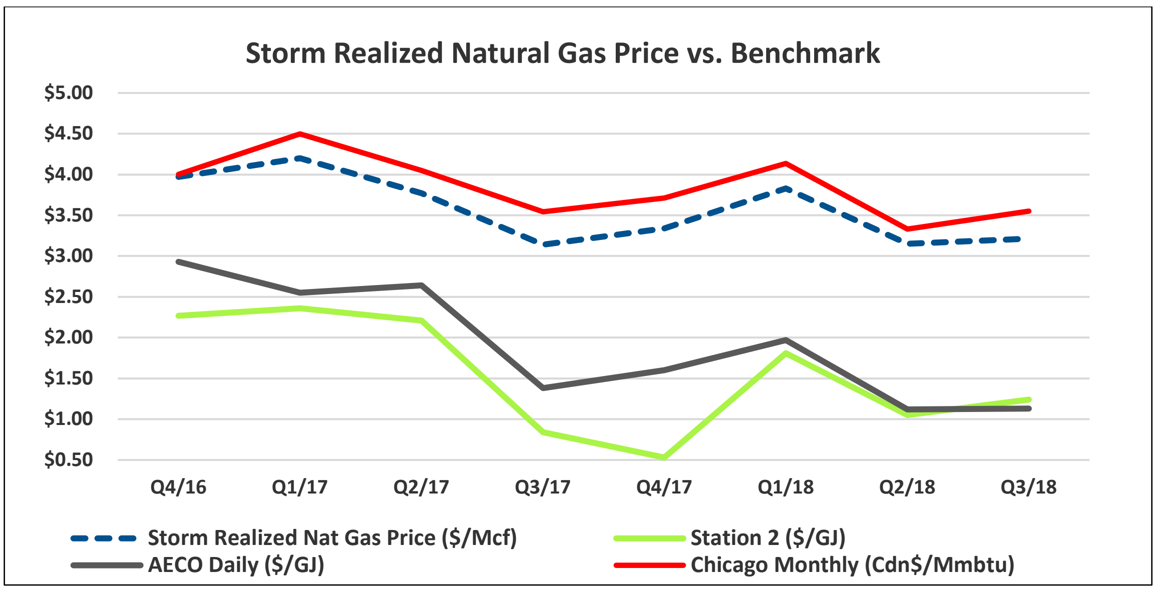
	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Natural gas				
Chicago monthly index (US$/Mmbtu)	2.75	2.83	2.87	3.08
Chicago daily index (US$/Mmbtu)	2.77	2.84	2.79	2.92
Sumas (US$/Mmbtu)	2.01	2.48	2.04	2.60
AECO monthly index (Cdn$/GJ)	1.28	2.01	1.34	2.48
AECO daily index (Cdn$/GJ)	1.13	1.38	1.41	2.19
Station 2 (Cdn$/GJ)	1.24	0.84	1.37	1.80
Crude Oil				
WTI (US$/Bbl)	69.50	48.21	66.75	49.47
Edmonton light oil (Cdn$/Bbl)	81.92	56.74	78.19	60.89
Exchange rate (US$/Cdn$)	0.77	0.80	0.78	0.77

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 will increase the per-Mcf price.

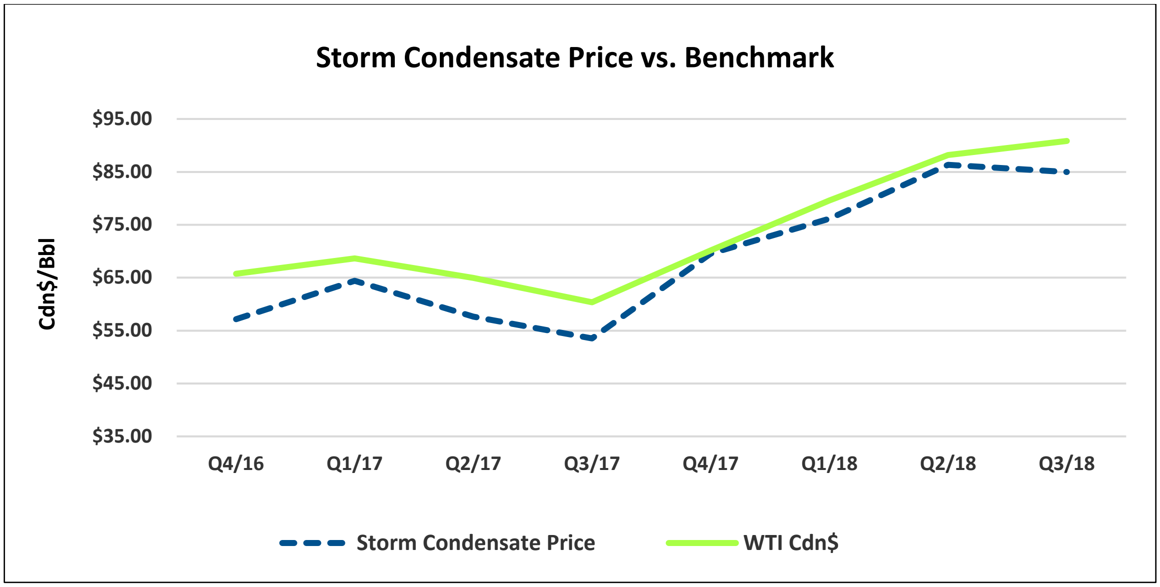
In October, a pipeline rupture occurred on the Enbridge T-south line which is expected to reduce capacity by up to 0.5 Bcf per day for the winter season. As a result of the constraints there has been increased volatility in both Station 2 and Sumas pricing.

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

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Chicago monthly index price	37%	47%	39%	46%
Chicago daily index price	24%	24%	25%	20%
AECO daily index price	2%	-	3%	-
Station 2 daily spot price	20%	24%	16%	29%
Sumas index price	12%	-	12%	-
Alliance Transfer Point ("ATP")	5%	5%	5%	5%
Total	100%	100%	100%	100%



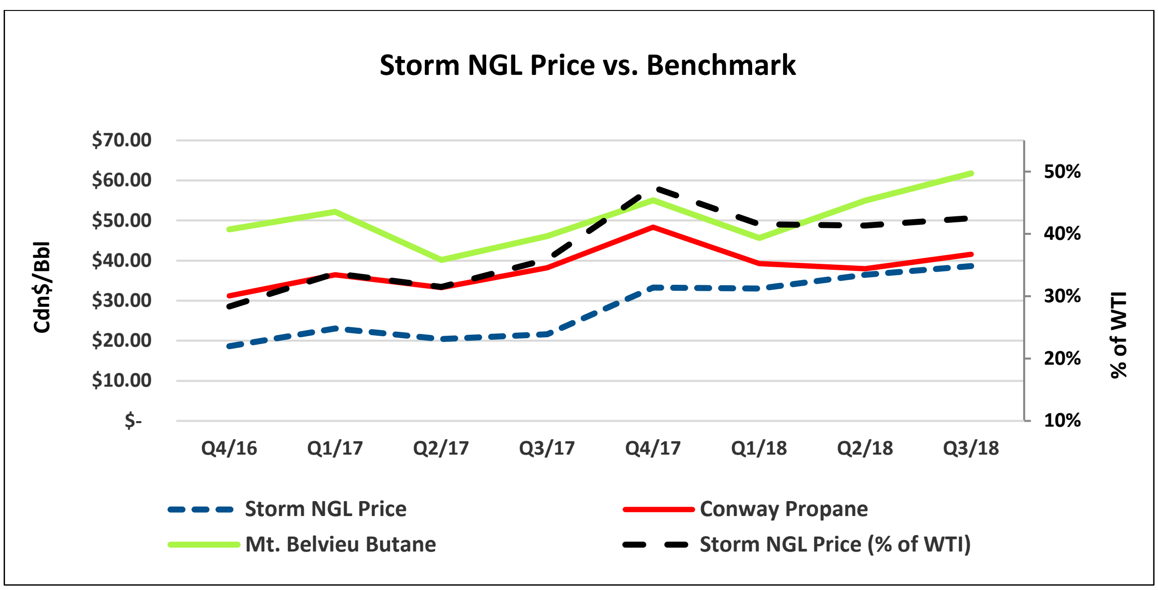
With approximately 60% of the Company's production sold in Chicago, Storm's basket realized natural gas price benefited from stronger Chicago pricing, which was partially offset by lower pricing at Station 2 and AECO. As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was approximately 150% higher than Station 2 pricing in the third quarter of 2018. Natural gas pricing in Western Canada remains below the cost of replacing production for most producers.



The third quarter condensate price increased by 59% from the previous year while the year-to-date price has increased by 40%. The increase is primarily due to higher WTI pricing.

The differential between Storm's condensate price and WTI widened in the third quarter of 2018 primarily due to lower condensate demand during summer months. Condensate differentials continued to widen in the fourth quarter due to pipeline constraints and refinery outages reducing demand for diluent blending, although they are expected to narrow from current levels in 2019.

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 third quarter of 2018 and the first nine months of 2018.



The realized price for NGL, excluding condensate, in the third quarter of 2018 increased by 78% relative to the same period of 2017. For the nine month period ended September 30, 2018, the realized price for NGL, excluding condensate, increased by 65% 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.

Revenue from Product Sales[1]

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Natural gas	$ 30,136	$ 21,436	$ 90,879	$ 76,641
Condensate	16,098	7,880	45,815	25,772
NGL	5,019	2,403	14,765	6,960
Total	$ 51,253	$ 31,719	$ 151,459	$ 109,373
% of Total Revenue by Product Type				
Natural gas	59%	68%	60%	70%
Condensate and NGL	41%	32%	40%	30%
Total	100%	100%	100%	100%

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

Revenue from product sales for the third quarter of 2018 increased by 62% when compared to the third quarter of 2017 as a result of production volumes increasing by 35% and the Company's average realized price increasing by 20%. For the nine month periods, revenue from product sales increased 38% year over year primarily due to production volumes increasing 29%.

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q3 2017	$ 21,436	$ 7,880	$ 2,403	$ 31,719
Effect of changes in production	7,907	2,260	409	10,576
Effect of changes in average product prices	793	5,958	2,207	8,958
Revenue from product sales – Q3 2018	$ 30,136	$ 16,098	$ 5,019	$ 51,253

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q3 2017 YTD	$ 76,641	$ 25,772	$ 6,960	$ 109,373
Effect of changes in production	22,946	6,843	1,974	31,763
Effect of changes in average product prices	(8,708)	13,200	5,831	10,323
Revenue from product sales – Q3 2018 YTD	$ 90,879	$ 45,815	$ 14,765	$ 151,459

Commodity Price Risk Management

	Three Months Ended September 30, 2018		Three Months Ended September 30, 2017	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (563)	$ (2,069)	$ 1,307	$ 1,631
Liquids[1]	(2,690)	(303)	569	(1,793)
Gain (loss) on commodity price contracts	$ (3,253)	$ (2,372)	$ 1,876	$ (162)

	Nine Months Ended September 30, 2018		Nine Months Ended September 30, 2017	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ 2,087	$ (12,529)	$ (3,610)	$ 22,070
Liquids[1]	(6,903)	(5,589)	568	3,364
Gain (loss) on commodity price contracts	$ (4,816)	$ (18,118)	$ (3,042)	$ 25,434

(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 Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Charge for period	$ 1,934	$ 1,190	$ 6,938	$ 5,928
Percentage of revenue from product sales	3.8%	3.8%	4.6%	5.4%
Per Boe	$ 1.03	$ 0.85	$ 1.28	$ 1.41

Royalties, as a percentage of revenue from product sales, in the three months ended September 30, 2018, were consistent with the same period in 2017 due to receiving infrastructure royalty credits ($0.8 million) in the quarter which offset higher royalties due to an increase in benchmark pricing. In addition to infrastructure royalty credits, Storm also receives royalty credits on qualifying wells through the BC Deep Well Royalty Credit Program which reduces the royalty rate on new horizontal wells to 6% for approximately two years. In the third quarter of 2018, 36 wells qualified for the 6% royalty rate compared to 30 wells in the third quarter of 2017.

Royalties, as a percentage of revenue from product sales, decreased in the nine months ended September 30, 2018 compared to the same period in 2017 due to higher infrastructure royalty credits received in 2018 ($1.4 million in 2018 versus $0.3 million in 2017).

Storm has remaining infrastructure royalty credits of $7.9 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 Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Charge for period	$ 10,419	$ 8,425	$ 29,972	$ 25,907
Per Boe	$ 5.54	$ 6.03	$ 5.52	$ 6.17

The increase in total production costs for the three and nine months ended September 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 third quarter of 2018 decreased by 8% compared to the third quarter of 2017 and by 11% when comparing the nine 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 2017.

Transportation Costs

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Charge for period	$ 11,257	$ 8,512	$ 32,277	$ 24,223
Per Boe	$ 5.98	$ 6.09	$ 5.94	$ 5.78

Transportation costs include pipeline tariffs for natural gas sold at various price points, as well as trucking costs and pipeline tariffs for condensate. Total transportation costs for the third quarter of 2018 increased by 32%, and decreased by 2% per Boe, when compared to the third quarter of 2017. Transportation costs for the first nine months of 2018 increased by 33%, and by 3% per Boe, when compared to the same period in 2017. Higher total transportation costs reflect higher production volumes (year-over-year increase of 35% for the third quarter and 29% for the nine month period). On a per-Boe basis, lower transportation costs for the third quarter of 2018 are largely the result of directing less natural gas to Chicago on the Alliance Pipeline which has a higher cost interruptible service (61% of natural gas sales in Chicago in the third quarter of 2018 versus 71% in the previous year), which was partially offset by higher costs for moving condensate.

Transportation costs, on a per-Boe basis, for the nine months ended September 30, 2018 increased 3% from the same period in 2017 due to higher transportation costs relating to condensate.

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 September 30, 2018				
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.21	$ 84.97	$ 38.64	$ 27.24
Royalties	(0.01)	(7.40)	(3.70)	(1.03)
Production costs	(1.11)	-	-	(5.54)
Transportation costs	(1.08)	(5.78)	-	(5.98)
Field operating netback	$ 1.01	$ 71.79	$ 34.94	$ 14.69
Realized loss on commodity price contracts	(0.06)	(13.92)	(0.42)	(1.73)
Field operating netback including hedging	$ 0.95	$ 57.87	$ 34.52	$ 12.96

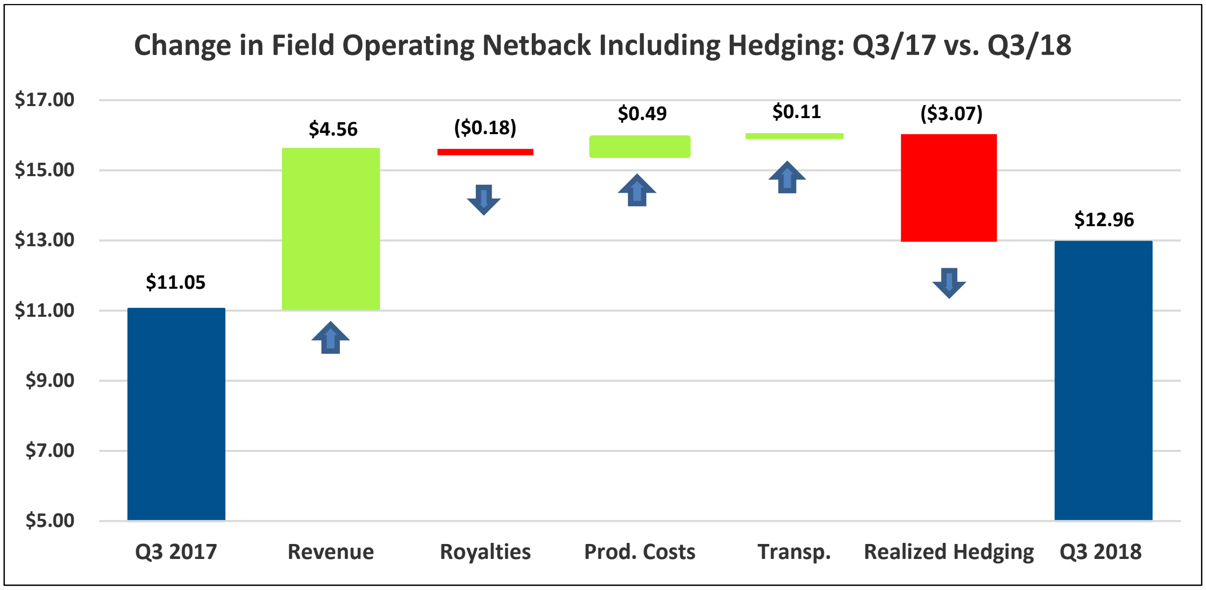
Three Months to September 30, 2017				
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.13	$ 53.52	$ 21.66	$ 22.68
Royalties	(0.04)	(4.86)	(1.66)	(0.85)
Production costs	(1.23)	-	-	(6.03)
Transportation costs	(1.17)	(3.35)	-	(6.09)
Field operating netback	$ 0.69	$ 45.31	$ 20.00	$ 9.71
Realized gain on commodity price contracts	0.19	2.20	-	1.34
Field operating netback including hedging	$ 0.88	$ 47.51	$ 20.00	$ 11.05

Nine Months to September 30, 2018				
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.39	$ 82.46	$ 35.92	$ 27.88
Royalties	(0.06)	(7.30)	(3.31)	(1.28)
Production costs	(1.12)	-	-	(5.52)
Transportation costs	(1.10)	(5.15)	-	(5.94)
Field operating netback	$ 1.11	$ 70.01	$ 32.61	$ 15.14
Realized gain (loss) on commodity price contracts	0.08	(12.41)	(0.01)	(0.89)
Field operating netback including hedging	$ 1.19	$ 57.60	$ 32.60	$ 14.25

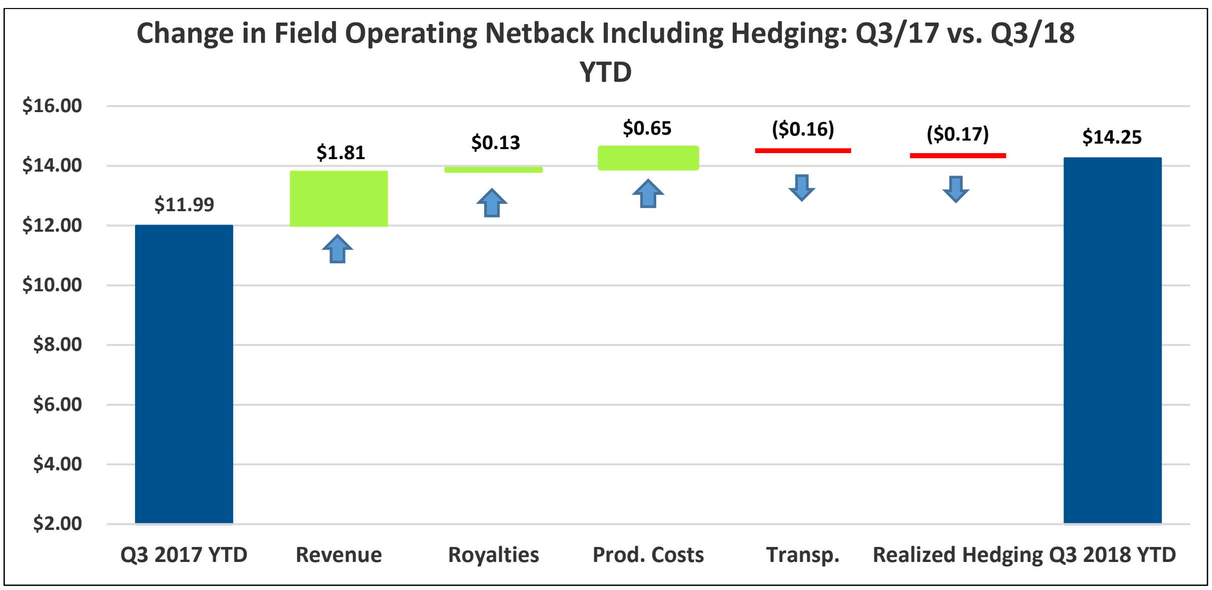
Nine Months to September 30, 2017				
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.72	$ 58.70	$ 21.74	$ 26.07
Royalties	(0.14)	(5.43)	(2.02)	(1.41)
Production costs	(1.26)	-	-	(6.17)
Transportation costs	(1.09)	(4.19)	-	(5.78)
Field operating netback	$ 1.23	$ 49.08	$ 19.72	$ 12.71
Realized gain (loss) on commodity price contracts	(0.18)	1.29	-	(0.72)
Field operating netback including hedging	$ 1.05	$ 50.37	$ 19.72	$ 11.99

(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 third quarter 2018 field operating netback increased by 51% (17% increase including hedging) compared to the same period in 2017.



The field operating netback for the first nine months of 2018 increased by 19%, both including and excluding hedging, compared to the first nine months of 2017.



General and Administrative Costs

	Three Months to Sept. 30, 2018		Three Months to Sept. 30, 2017		Nine Months to Sept. 30, 2018		Nine Months to Sept. 30, 2017	
Charge for period – before recoveries	$	1,740	$	1,781	$	6,095	$	5,563
Overhead recoveries		(500)		(335)		(1,111)		(949)
Charge for period – net of recoveries	$	1,240	$	1,446	$	4,984	$	4,614
Per Boe	$	0.66	$	1.03	$	0.92	$	1.10

General and administrative costs before recoveries for the third quarter of 2018 decreased by 2% when compared to the third quarter of 2017 due to costs incurred in the third quarter of 2017 relating to the Company's graduation from the TSX Venture Exchange to the TSX, partially offset by higher compensation costs in 2018. General and administrative costs before recoveries for the nine months ended September 30, 2018 increased by 10% 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 third quarter of 2018 decreased by 36% compared to the third quarter of 2017, and decreased by 16% when comparing the first nine 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 Sept. 30, 2018		Three Months to Sept. 30, 2017		Nine Months to Sept. 30, 2018		Nine Months to Sept. 30, 2017	
Charge for period	$	923	$	852	$	3,321	$	2,902
Average interest rate[(1)]		4.6%		3.9%		4.8%		4.4%
Per Boe	$	0.49	$	0.61	$	0.61	$	0.69

(1) Includes financing and standby fees.

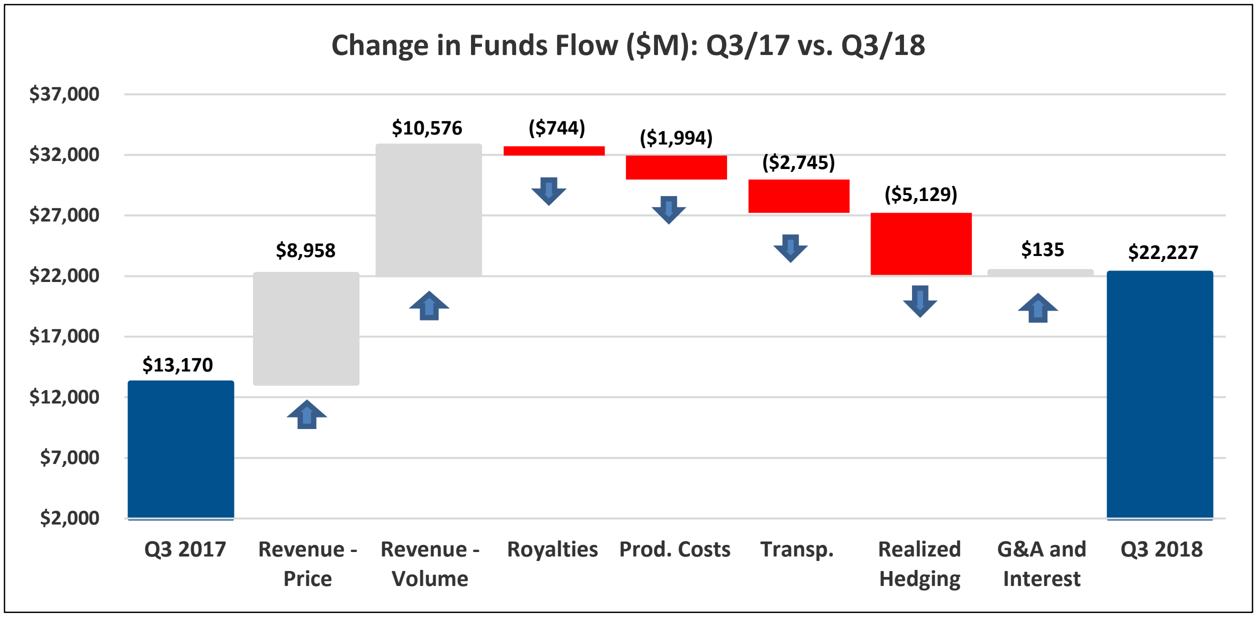
The interest rate on the Company's bank facility is based on bankers acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Interest costs for the third quarter of 2018 increased by 8% compared to the same quarter of 2017, and increased by 14% when comparing the nine month periods. The increase in interest costs in the third quarter of 2018 is due to higher interest driven by interest rate increases from the Bank of Canada, partially offset by lower debt levels. The increase in interest costs for the nine months ended September 30, 2018 from the same period of 2017 is driven by a higher interest rate environment and higher average bank borrowings used to fund the Company's capital program.

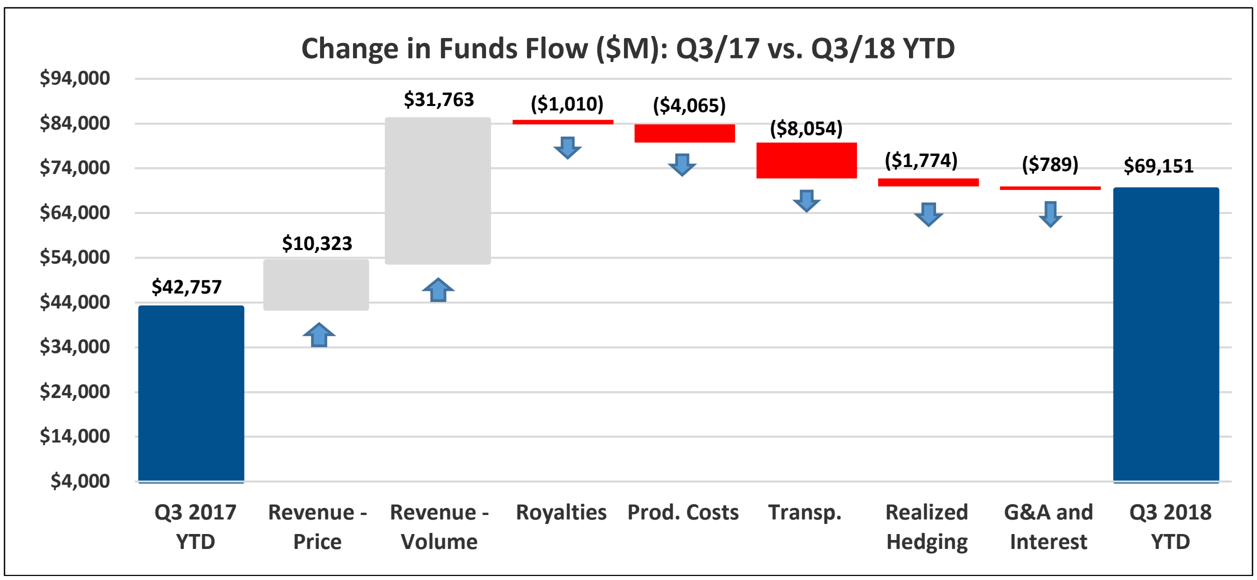
Funds Flow

	Three Months to Sept. 30, 2018		Three Months to Sept. 30, 2017		Nine Months to Sept. 30, 2018		Nine Months to Sept. 30, 2017	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$22,227	$0.18	$13,170	$0.11	$69,151	$0.57	$42,757	$0.35

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 and higher realized prices were the predominant factors in funds flow growth of 69% in the third quarter of 2018 versus the third quarter of 2017.



Funds flow for the first nine months of 2018 increased by 62% from the same period of 2017. Funds flow benefited from both production growth and stronger realized pricing relative to the first nine months of 2017.

Share-Based Compensation

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Charge for period	$ 823	$ 1,012	$ 2,289	$ 2,914
Per Boe	$ 0.44	$ 0.72	$ 0.42	$ 0.69

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 third quarter of 2018 compared to the third quarter of 2017 and decreased by 21% when comparing the nine month periods. The decrease in share-based compensation in both the three and nine month periods is primarily attributable to a lower option valuation associated with options granted in 2018.

Depletion and Depreciation

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Depletion	$ 10,057	$ 9,711	$ 29,818	$ 29,040
Depreciation	1,715	1,501	5,000	4,363
Charge for period	$ 11,772	$ 11,212	$ 34,818	$ 33,403
Per Boe	$ 6.26	$ 8.02	$ 6.41	$ 7.96

Depletion and depreciation increased by 5% in the third quarter of 2018 compared to the same quarter of 2017 due to a 35% increase in production volumes which was partially offset by lower finding and development costs. Comparing the first nine months of 2018 with the same period in 2017, depletion and depreciation increased by 4% as a result of a 29% 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

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Net income	$ 7,174	$ 682	$ 13,253	$ 31,065
Per basic and diluted share	$ 0.06	$ 0.01	$ 0.11	$ 0.26

The mark-to-market valuation of commodity price contracts resulted in a considerable distortion to the reported net income for the three and nine months ended September 30, 2018 relative to the comparable periods in 2017. The unrealized loss on commodity price contracts for the three and nine months ended September 30, 2018 amounted to $2.4 million and $18.1 million, respectively, compared to an unrealized loss for the three months ended September 30, 2017 of $0.2 million and an unrealized gain of $25.4 million for the nine months ended September 30, 2017.

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

Corporate Netbacks

($/Boe)	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Revenue from product sales	27.24	22.68	27.88	26.07
Realized gain (loss) on commodity price contracts	(1.73)	1.34	(0.89)	(0.72)
Royalties	(1.03)	(0.85)	(1.28)	(1.41)
Production	(5.54)	(6.03)	(5.52)	(6.17)
Transportation	(5.98)	(6.09)	(5.94)	(5.78)
General and administrative	(0.66)	(1.03)	(0.92)	(1.10)
Interest and finance costs	(0.49)	(0.61)	(0.61)	(0.69)
Funds flow	11.81	9.41	12.72	10.20
Share-based compensation	(0.44)	(0.72)	(0.42)	(0.69)
Depletion, depreciation and accretion	(6.33)	(8.10)	(6.48)	(8.04)
Exploration and evaluation costs expensed	-	-	(0.05)	(0.09)
Unrealized revaluation gain (loss) on investments	0.02	0.01	-	(0.03)
Unrealized gain (loss) on commodity price contracts	(1.26)	(0.12)	(3.33)	6.06
Net income	3.80	0.48	2.44	7.41

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 September 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 September 30, 2018, debt including working capital deficiency amounted to $84.6 million, representing 47% of the available credit facility.

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

Capital Expenditures

In the third quarter of 2018, the Company incurred capital expenditures of $21.8 million compared to $23.9 million in the third quarter of 2017.

In the first nine months of 2018, the Company incurred capital expenditures of $47.7 million (first nine months of 2017 - $55.6 million) primarily related to completing eight horizontal wells, building a pipeline to the Nig land block and installing additional compression at Umbach.

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Land and seismic	$ 1,878	$ 673	$ 2,803	$ 1,079
Drilling	289	8,121	289	18,000
Completions	10,798	11,211	19,853	20,482
Facilities	4,690	1,958	10,693	5,494
Equipping and pipelines	4,006	1,516	12,599	9,232
Recompletions and workovers	35	416	772	1,262
Property acquisition and administrative assets	149	-	654	10
Total capital expenditures	$ 21,845	$ 23,895	$ 47,663	$ 55,559

Net capital investment was allocated as follows:

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Exploration and evaluation	$ 1,878	$ 673	$ 2,991	$ 1,073
Property and equipment	19,967	23,222	44,672	54,486
Total capital expenditures	$ 21,845	$ 23,895	$ 47,663	$ 55,559

Decommissioning Liability

The Company's decommissioning liability represents the present value of estimated future costs to be incurred to abandon and reclaim wells and facilities, drilled, constructed or purchased by Storm. The undiscounted amount of the liability at September 30, 2018 was $37.4 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 2.4% (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. The Company had a lease of office premises for a period of five years that commenced October 1, 2013 and ended on September 30, 2018 for a base rent, including operating costs and property tax, totaling approximately $4.6 million over the term of the lease. 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 transportation and processing commitments valued at a total of approximately $398.7 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended September 30, 2018 appears below. During the second half 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. While the first and fourth quarters of 2017 saw a normalized level of capital expenditures, production and funds flow, the second and third quarters of 2017 were affected by a planned maintenance turnaround at the McMahon Gas Plant in June that involved an unanticipated extension into July, which affected revenue and funds flow.

Apart from minimal capital expenditures in the second quarter of 2018, the quarterly results for 2018 have been relatively consistent in terms of capital expenditures, production and funds flow, supported by stable Chicago natural gas prices and materially stronger liquids pricing. With funds flow outpacing capital expenditures, debt has been reduced by approximately $21 million since the start of the year.

			2018				2017	2016
($000s unless otherwise stated)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue from product sales	51,253	48,104	52,102	43,506	31,719	33,262	44,392	32,976
Funds flow	22,227	23,405	23,519	21,323	13,170	11,629	17,958	11,985
Per share – basic and diluted ($)	0.18	0.19	0.19	0.18	0.11	0.10	0.15	0.10
Net income (loss)	7,174	(2,815)	8,894	8,624	682	9,752	20,631	(12,898)
Per share – basic and diluted ($)	0.06	(0.02)	0.07	0.07	0.01	0.08	0.17	(0.11)
Net capital expenditures	21,845	2,918	22,900	26,126	23,895	4,307	27,357	33,399
Average daily production (Boe)	20,455	19,529	19,708	17,936	15,193	13,991	16,947	13,320
Debt including working capital deficiency(1)	84,648	85,073	105,585	106,124	101,297	90,582	97,864	89,841

(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 November 13, 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 and 2019 guidance;
- future average production volumes in the fourth quarter of 2018 and 2019 and annual production for 2018 and 2019, 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 and 2019 guidance;
- future reduction to corporate operating costs to approximately $4.25 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 $85 million, 2019 capital investment of $128 million and total cost of approximately $81 million for the Nig sour gas plant;
- fourth quarter 2018 production and capital investment of 19,000 to 21,000 Boe per day and $37 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 cost of the Fireweed compression facility of $34 million, field condensate-gas ratios that are approximately 25 barrels per Mmcf higher than Umbach over the life of a well and up to 60 barrels per Mmcf higher in the first year, and additional production of 4,000 to 5,000 Boe per day in the second half of 2020;
- future production levels of 25,000 Boe per day by the end of 2019 and 30,000 Boe per day by the end of 2020;
- 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 and 2019 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;
- availability and use of credit facilities including approximately $94 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 drilling longer wells, specifically management's estimated 11 Bcf raw gas type curve for new wells;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2018 and 2019 guidance;

- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and NGL, specifically the anticipated sales 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;
- 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 crude 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 September 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 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 September 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	$ 24,100	$ 7,619	$ 31,719
Transportation	$ 893	$ 7,619	$ 8,512
Net income and comprehensive income for the period	$ 682	-	$ 682

	Nine Months Ended September 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	$ 88,462	$ 20,911	$ 109,373
Transportation	$ 3,312	$ 20,911	$ 24,223
Net income and comprehensive income for the period	$ 31,065	-	$ 31,065

Future Accounting Policy Changes

On January 1, 2019, the Company will be required to adopt IFRS 16 *Leases* which requires lessees to recognize assets and liabilities for effectively almost all leases previously classified as operating leases. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a “right-of-use asset” for leases. The lease liability will be calculated at the present value of the remaining lease payments, discounted using the Company’s borrowing rate on January 1, 2019. The Company intends to use the modified retrospective approach on adoption of IFRS 16 and to use the following practical expedients permitted under the standard, either applied on a lease-by-lease basis or to a class of underlying assets:

- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value.

As of September 30, 2018, the Company continues to complete a detailed assessment on the potential effect of the adoption of IFRS 16 on its financial statements. For the duration of the year, the Company will be focused on completing its assessment, developing and implementing changes to policies, internal controls and business and accounting processes. The actual impact of applying the standard will be dependent on the Company’s borrowing rate, lease portfolio and practical expedients applied on adoption on January 1, 2019.

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 September 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 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4.

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	September 30, 2018	December 31, 2017
ASSETS		
Current		
Accounts receivable (Note 12)	$ 15,100	$ 15,104
Prepaids and deposits	845	4,542
Fair value of commodity price contracts (Note 12)	-	2,842
	15,945	22,488
Fair value of commodity price contracts (Note 12)	-	209
Exploration and evaluation (Note 4)	106,952	103,907
Property and equipment (Note 5)	398,289	388,959
	$ 521,186	$ 515,563
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 21,848	$ 24,777
Fair value of commodity price contracts (Note 12)	13,271	478
	35,119	25,255
Bank indebtedness (Note 6)	78,745	100,993
Fair value of commodity price contracts (Note 12)	2,374	100
Decommissioning liability (Note 8)	24,665	24,474
	140,903	150,822
Shareholders' equity		
Share capital (Note 9)	391,444	391,444
Contributed surplus (Note 10)	14,303	12,014
Deficit	(25,464)	(38,717)
	380,283	364,741
Commitments (Note 14)		
	$ 521,186	$ 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 and Comprehensive Income

(Canadian $000s except per-share amounts) (unaudited)	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Revenue				
Revenue from product sales (Note 7)	$ 51,253	$ 31,719	$ 151,459	$ 109,373
Royalties	(1,934)	(1,190)	(6,938)	(5,928)
Net revenue	49,319	30,529	144,521	103,445
Realized gain (loss) on commodity price contracts (Note 12)	(3,253)	1,876	(4,816)	(3,042)
Unrealized gain (loss) on commodity price contracts (Note 12)	(2,372)	(162)	(18,118)	25,434
Net revenue and commodity price contracts	43,694	32,243	121,587	125,837
Expenses				
Production	10,419	8,425	29,972	25,907
Transportation	11,257	8,512	32,277	24,223
General and administrative	1,240	1,446	4,984	4,614
Share-based compensation (Note 10)	823	1,012	2,289	2,914
Depletion and depreciation (Note 5)	11,772	11,212	34,818	33,403
Exploration and evaluation costs expensed (Note 4)	-	-	277	373
Accretion (Note 8)	129	112	384	326
Interest and finance costs	923	852	3,321	2,902
Unrealized revaluation (gain) loss on investment	(43)	(10)	12	110
Total expenses	36,520	31,561	108,334	94,772
Net income and comprehensive income for the period	$ 7,174	$ 682	$ 13,253	$ 31,065
Net income per share (Note 11)				
- Basic and diluted	$ 0.06	$ 0.01	$ 0.11	$ 0.26

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)		Nine Months to September 30, 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	-	-	13,253	13,253
Share-based compensation (Note 10)	-	2,289	-	2,289
Share-based compensation on options exercised (Note 9)	-	-	-	-
Balance, end of period	$ 391,444	$ 14,303	$ (25,464)	$ 380,283

(Canadian $000s) (unaudited)		Nine Months to September 30, 2017		
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 389,316	$ 8,870	$ (78,406)	$ 319,780
Net income for the period	-	-	31,065	31,065
Issue of common shares (Note 9)	1,456	-	-	1,456
Share-based compensation (Note 10)	-	2,914	-	2,914
Share-based compensation on options exercised (Note 9)	672	(672)	-	-
Balance, end of period	$ 391,444	$ 11,112	$ (47,341)	$ 355,215

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Operating activities				
Net income for the period	$ 7,174	$ 682	$ 13,253	$ 31,065
Non-cash items:				
Unrealized (gain) loss on commodity price contracts (Note 12)	2,372	162	18,118	(25,434)
Depletion, depreciation and accretion (Notes 5 and 8)	11,901	11,324	35,202	33,729
Share-based compensation (Note 10)	823	1,012	2,289	2,914
Exploration and evaluation costs expensed (Note 4)	-	-	277	373
Unrealized revaluation (gain) loss on investment	(43)	(10)	12	110
Funds flow	22,227	13,170	69,151	42,757
Net change in non-cash working capital items (Note 13)	(773)	(3,153)	(1,272)	2,848
	21,454	10,017	67,879	45,605
Financing activities				
Proceeds from issue of common shares (Note 9)	-	-	-	1,456
Increase (decrease) in bank indebtedness	(8,562)	8,841	(22,248)	14,166
	(8,562)	8,841	(22,248)	15,622
Investing activities				
Additions to property and equipment (Note 5)	(19,967)	(23,222)	(44,476)	(54,486)
Additions to exploration and evaluation assets (Note 4)	(1,878)	(673)	(2,803)	(1,073)
Acquisition of property and equipment (Note 5)	-	-	(196)	-
Acquisition of exploration and evaluation assets (Note 4)	-	-	(188)	-
Net change in non-cash working capital items (Note 13)	8,953	5,037	2,032	(5,668)
	(12,892)	(18,858)	(45,631)	(61,227)
Change in cash during the period	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	$ -	$ -	$ -	$ -

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

As at and for the three and nine months ended September 30, 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 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4. 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 November 13, 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 September 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 September 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	$ 24,100	$ 7,619	$ 31,719
Transportation	$ 893	$ 7,619	$ 8,512
Net income and comprehensive income for the period	$ 682	-	$ 682

	Nine Months Ended September 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	$ 88,462	$ 20,911	$ 109,373
Transportation	$ 3,312	$ 20,911	$ 24,223
Net income and comprehensive income for the period	$ 31,065	-	$ 31,065

Future Accounting Policy Changes

On January 1, 2019, the Company will be required to adopt IFRS 16 *Leases* which requires lessees to recognize assets and liabilities for effectively almost all leases previously classified as operating leases. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a "right-of-use asset" for leases. The lease liability will be calculated at the present value of the remaining lease payments, discounted using the Company's borrowing rate on January 1, 2019. The Company intends to use the modified retrospective approach on adoption of IFRS 16 and to use the following practical expedients permitted under the standard, either applied on a lease-by-lease basis or to a class of underlying assets:

- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value.

As of September 30, 2018, the Company continues to complete a detailed assessment on the potential effect of the adoption of IFRS 16 on its financial statements. For the duration of the year, the Company will be focused on completing its assessment, developing and implementing changes to policies, internal controls and business and accounting processes. The actual impact of applying the standard will be dependent on the Company's borrowing rate, lease portfolio and practical expedients applied on adoption on January 1, 2019.

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

	Nine Months Ended September 30, 2018	Year ended December 31, 2017
Balance, beginning of period	$ 103,907	$ 110,395
Additions	2,991	1,838
Expiries - exploration and evaluation costs expensed	(277)	(386)
Future decommissioning costs	331	192
Transfer to property and equipment	-	(8,132)
Balance, end of period	$ 106,952	$ 103,907

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

5. PROPERTY AND EQUIPMENT

	Nine Months Ended September 30, 2018	Year ended December 31, 2017
Cost		
Balance, beginning of period	$ 559,524	$ 466,700
Additions	44,672	79,847
Future decommissioning costs	(524)	4,845
Transfer from exploration and evaluation assets	-	8,132
Balance, end of period	$ 603,672	$ 559,524
Accumulated depletion and depreciation		
Balance, beginning of period	$ (170,565)	$ (126,336)
Depletion and depreciation	(34,818)	(44,229)
Balance, end of period	$ (205,383)	$ (170,565)
Net book value, beginning of period	$ 388,959	$ 340,364
Net book value, end of period	$ 398,289	$ 388,959

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

6. BANK INDEBTEDNESS

As at September 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 September 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 September 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 Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Natural gas	$ 30,136	$ 21,436	$ 90,879	$ 76,641
Condensate	16,098	7,880	45,815	25,772
NGL	5,019	2,403	14,765	6,960
Total	$ 51,253	$ 31,719	$ 151,459	$ 109,373

Storm's revenue was generated mostly in British Columbia where the production was sold primarily to one major marketer, which accounted for 46% and 49% of the Company's total revenue from product sales for the three and nine months ended September 30, 2018, respectively. The majority of revenues are derived from variable price contracts based on index prices. Of total natural gas revenue for the nine months ended September 30, 2018, 64% received Chicago index based pricing, 16% received Station 2 pricing, 12% received Sumas pricing, 5% received ATP pricing and the remaining 3% 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 \$37.4 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 2.4% (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 \$24.7 million at September 30, 2018.

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

	Nine Months Ended September 30, 2018	Year Ended December 31, 2017
Balance, beginning of period	\$ 24,474	\$ 18,983
Obligations incurred	821	3,028
Obligations settled	(194)	-
Change in rate estimates(1)	(820)	2,009
Accretion expense	384	454
Balance, end of period	\$ 24,665	\$ 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 and September 30, 2018	121,557	\$ 391,444

During the first nine 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 September 30, 2018, a total of 12,155,681 common shares were available for issuance. At September 30, 2018, and at November 13, 2018, the date of this report, options in respect of 8,369,700 common shares were issued and outstanding and options in respect of 3,785,981 common shares were available for future issue.

Details of the options outstanding at September 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	2,488	\$ 2.86
Forfeited during the period	(399)	\$ 4.10
Exercised during the period	(1,633)	\$ 4.69
Outstanding at September 30, 2018	8,370	\$ 3.96
Number exercisable at September 30, 2018	3,760	

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	2,473	3.3	$ 2.86	-	-
$3.35 - $4.50	3,723	0.8	$ 3.85	2,959	$ 3.93
$4.51 - $5.50	2,174	2.1	$ 5.37	801	$ 5.35
Total	8,370	1.9	$ 3.96	3,760	$ 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 nine months ended September 30, 2018 of $1.03 per share include the following:

	2018
Share price	$2.87
Exercise price	$2.87
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 $2.3 million was charged to the consolidated statement of income during the three and nine months to September 30, 2018, respectively (2017 - $1.0 million and $2.9 million, respectively) with an equivalent offset to contributed surplus.

11. NET INCOME PER SHARE

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

	Three Months to Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Net income for the period	$ 7,174	$ 682	$ 13,253	$ 31,065
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	-	-	-	758
Weighted average number of common shares outstanding – basic	121,557	121,557	121,557	121,522
Dilutive effect of outstanding options[(1)]	-	56	-	157
Weighted average number of common shares outstanding - diluted	121,557	121,613	121,557	121,679
Net income per share				
Basic and diluted	$ 0.06	$ 0.01	$ 0.11	$ 0.26

(1) Excludes the effect of 8.4 million and 8.8 million weighted average common shares related to stock options that were anti-dilutive for the three and nine months ended September 30, 2018, respectively (6.0 million weighted average common shares related to stock options for both the three and nine months ended September 30, 2017).

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 nine months ended September 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 September 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	$ 24,749	$ (24,749)	$ -
Long-term asset	5,895	(5,895)	-
Current liability	(38,020)	24,749	(13,271)
Long-term liability	(8,269)	5,895	(2,374)
Net position	$ (15,645)	$ -	$ (15,645)

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 September 30, 2018, the Company's most significant marketer accounted for $6.3 million (December 31, 2017 - $6.1 million) of total receivables and 46% and 49% (three and nine months ended September 30, 2017 – 54%) of total revenues for the three and nine months ended September 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 September 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 September 30, 2018.

The maximum exposure to credit risk at September 30, 2018 was the carrying amount of accounts receivable of $15.1 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. No receivables were impaired as at September 30, 2018.

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 September 30, 2018, a net liability position of $15.6 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 nine months ended September 30, 2018, this resulted in an unrealized mark-to-market loss of $2.4 million and $18.1 million, respectively (2017 - an unrealized mark-to-market loss of $0.2 million for the three months ended September 30 and an unrealized mark-to-market gain of $25.4 million for the nine months ended September 30) 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 and comprehensive income.

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Oct – Dec 2018	45,500 Mmbtu	Chicago Cdn$3.42/Mmbtu
Oct – Dec 2018	11,500 Mmbtu	Sumas Cdn$2.92/Mmbtu
Oct 2018 – Mar 2019	3,000 GJ	AECO Cdn$1.90/GJ
Oct 2018 – Mar 2019	3,000 GJ	Stn 2 Cdn$1.70/GJ
Nov 2018 – Mar 2019	6,000 GJ	AECO Cdn$1.95/GJ
Nov 2018 – Mar 2019	6,000 GJ	Stn 2 Cdn$1.75/GJ
Jan – Mar 2019	3,500 Mmbtu	Sumas Cdn$4.77/Mmbtu
Jan – Jun 2019	22,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Jul – Dec 2019	11,500 Mmbtu	Chicago Cdn$3.27/Mmbtu
Jul – Dec 2019	2,000 Mmbtu	Sumas Cdn$2.90/Mmbtu
Jan – Dec 2019	26,500 Mmbtu	Chicago Cdn$3.23/Mmbtu
Jan – Dec 2019	6,500 Mmbtu	Sumas Cdn$2.60/Mmbtu
Nov 2018 – Mar 2020	1,500 GJ	AECO Cdn$2.00/GJ
Jan – Jun 2020	15,500 Mmbtu	Chicago Cdn$3.27/Mmbtu
Natural Gas Differential Swaps		
Oct – 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$0.274/Mmbtu
Jan – Dec 2021	12,500 Mmbtu	Price at Chicago = NYMEX minus US$0.256/Mmbtu
Crude Oil Collars		
Oct – Dec 2018	800 Bbls	$67.50 - $77.67 Cdn$/Bbl
Jan – Jun 2019	650 Bbls	$68.83 - $80.74 Cdn$/Bbl
Jul – Dec 2019	600 Bbls	$74.39 - $89.91 Cdn$/Bbl
Jan – Dec 2019	250 Bbls	$70.60 - $83.26 Cdn$/Bbl
Crude Oil Swaps		
Oct – Dec 2018	700 Bbls	$64.84 Cdn$/Bbl
Jan – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Jul – Dec 2019	400 Bbls	$80.90 Cdn$/Bbl
Jan – Dec 2019	250 Bbls	$82.49 Cdn$/Bbl
Propane Swaps		
Oct – Dec 2018	300 Bbls	$39.55 Cdn$/Bbl
Jan – Dec 2019	200 Bbls	$42.87 Cdn$/Bbl

The Company realized a loss from commodity price contracts in place in the amount of $3.3 million for the three months ended September 30, 2018 and realized a loss of $4.8 million for the nine months ended September 30, 2018 (2017 – realized gain of $1.9 million and a realized loss of $3.0 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 and comprehensive income until volumes are delivered.

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Oct 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 due to changes in the fair value of commodity price contracts in place at September 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	Nine Months Ended September 30, 2018
Increase of US$10.00/Bbl in the price of WTI(1)	$ (6,303)
Decrease of US$10.00/Bbl in the price of WTI(1)	$ 6,303
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$ (2,318)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$ 2,318

(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 Sept. 30, 2018	Three Months to Sept. 30, 2017	Nine Months to Sept. 30, 2018	Nine Months to Sept. 30, 2017
Accounts receivable	$ (3,567)	$ (7,172)	$ (8)	$ 2,875
Prepaids and deposits	(157)	(1,994)	3,697	(1,520)
Accounts payable and accrued liabilities	11,904	11,050	(2,929)	(4,175)
Change in non-cash working capital	$ 8,180	$ 1,884	$ 760	$ (2,820)
Relating to:				
Operating activities	$ (773)	$ (3,153)	$ (1,272)	$ 2,848
Investing activities	8,953	5,037	2,032	(5,668)
Change in non-cash working capital	$ 8,180	$ 1,884	$ 760	$ (2,820)
Interest paid during the period	$ 886	$ 955	$ 3,237	$ 2,741
Income taxes paid during the period	$ -	$ -	$ -	$ -

14. COMMITMENTS

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

	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and processing commitments	$ 14,179	$ 50,579	$ 36,316	$ 26,821	$ 26,627	$ 244,187	$ 398,709
Office lease	199	801	808	813	821	2,580	6,022
Total	$ 14,378	$ 51,380	$ 37,124	$ 27,634	$ 27,448	$ 246,767	$ 404,731

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

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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
kPa	Kilopascal
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

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