STORM RESOURCES

2019 Q2 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
FINANCIAL				
Revenue from product sales[(1)]	37,568	48,104	93,334	100,206
Funds flow	12,590	23,405	29,107	46,924
Per share – basic and diluted ($)	0.10	0.19	0.24	0.39
Net income (loss)	7,864	(2,815)	8,471	6,079
Per share – basic and diluted ($)	0.06	(0.02)	0.07	0.05
Cash return on capital employed (“CROCE”)[(2)]	18%	19%	18%	19%
Return on capital employed (“ROCE”)[(2)]	11%	4%	11%	4%
Capital expenditures	23,145	2,918	40,089	25,818
Debt including working capital deficiency[(2)(3)]	102,268	85,073	102,268	85,073
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,557	121,557	121,557
Outstanding end of period – basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales[(1)]	20.72	27.07	25.95	28.22
Transportation costs	(5.96)	(6.25)	(5.84)	(5.92)
Revenue net of transportation	14.76	20.82	20.11	22.30
Royalties	(0.32)	(1.11)	(1.46)	(1.41)
Production costs	(5.89)	(5.46)	(5.99)	(5.51)
Field operating netback[(2)]	8.55	14.25	12.66	15.38
Realized (loss) gain on risk management contracts	(0.22)	0.31	(2.78)	(0.44)
General and administrative	(0.68)	(0.69)	(1.13)	(1.05)
Interest and finance costs	(0.71)	(0.71)	(0.66)	(0.68)
Funds flow per Boe	6.94	13.16	8.09	13.21
Barrels of oil equivalent per day (6:1)	19,923	19,529	19,873	19,618
Natural gas production				
Thousand cubic feet per day	97,510	96,426	97,026	96,248
Price (Cdn$ per Mcf)[(1)]	2.64	3.15	3.55	3.49
Condensate production				
Barrels per day	2,081	1,984	2,140	2,023
Price (Cdn$ per barrel)[(1)]	71.12	86.33	66.85	81.15
NGL production				
Barrels per day	1,591	1,473	1,563	1,554
Price (Cdn$ per barrel)[(1)]	4.87	36.43	17.83	34.66
Wells drilled (net)	-	-	5.0	-
Wells completed (net)	-	-	-	3.0

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 26 of the attached Management’s Discussion and Analysis. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of risk management contracts and lease liability.

PRESIDENT'S MESSAGE

2019 SECOND QUARTER HIGHLIGHTS

Funds flow decreased year over year primarily as a result of production being reduced by 12 days of planned third-party outages, a decline in natural gas prices and a lower NGL price with new annual marketing agreements commencing in April (price declined by 85% from the first quarter). Activity included commencing construction of the Nig gas plant and starting completion of a four-well pad at Nig which is evaluating different intervals in the Montney (two wells in the upper, one in the mid and one in the lower).

- Production was largely unchanged year over year and was consistent with the low end of guidance for the quarter. Planned third-party outages at the McMahon Gas Plant and Alliance Pipeline totaling 12 days reduced production by approximately 9% or 2,000 Boe per day.

- Liquids production (field condensate plus gas plant NGL) increased by 6% year over year and represented 18% of total production and 38% of production revenue.

- At the Nig land block, the first three wells have been producing for more than twelve months with the first year calendar day rate averaging 1,415 Boe per day sales (21% liquids including liquids recovered at the gas plant). Flow test results from the recently completed four wells appear to be consistent with the first three wells with the lower Montney well having the highest condensate-gas ratio (flow tests are short duration and not reliable indicators of future performance).

- Diversified natural gas sales resulted in the realized price averaging $2.64 per Mcf, or $1.54 per Mcf after deducting transportation costs, which was significantly higher than Western Canadian pricing (Station 2 $0.57 per GJ and AECO $0.98 per GJ). Realized price was reduced by approximately 10% as the 12 days of outages reduced sales into the higher priced Chicago market by 11%.

- Controllable cash costs including transportation, production, general and administrative, and interest were $13.24 per Boe in the quarter and consistent with $13.11 per Boe in the prior year. Outages during the quarter increased cash costs per Boe by approximately 7% (unused firm transportation plus less production to cover fixed production costs).

- Funds flow was $12.6 million, or $0.10 per share, a decrease of 47% on a per-share basis year over year with the decrease largely the result of lower pricing (natural gas -16%, condensate -18%, NGL -87%).

- Net income of $7.9 million was an increase from a net loss of $2.8 million in the prior year with the improvement largely from a non-cash mark to market gain on hedging ($9.6 million) that was partially offset by a non-cash deferred income tax expense ($2.5 million).

- Capital investment was $23 million which included $12 million for the Nig gas plant plus $8 million to begin completions on a four-well pad at Nig. Investment was higher than guidance of $15 million to $20 million as a result of advancing the timing of well completions at Nig which were originally budgeted for the third quarter of 2019.

- Year-to-date capital investment is $40.1 million with $17.3 million, or 43%, invested into future growth (Nig gas plant $15.4 million and Fireweed $1.9 million).

- Debt including the working capital deficiency was $102 million or 2.0 times annualized quarterly funds flow and represents approximately 50% utilization of the $205 million bank line.

- Commodity price hedges currently protect approximately 39% of forecast production for the remainder of 2019.

- Return on capital employed was 11% and cash return on capital employed was 18%, both on a 12-month trailing basis.

OPERATIONS REVIEW

Umbach, Nig and Fireweed Areas, Northeast British Columbia

Storm's land position is prospective for liquids-rich natural gas from the Montney formation and totaled 121,000 net acres (172 net sections) at the end of the quarter.

Most of the land position is delineated with the 78 horizontal wells (73.9 net) drilled to date by Storm and by multiple producing horizontal wells on adjacent lands. The majority of the horizontal wells in the area have been drilled in the upper part of the Montney formation.

Second quarter field activity included commencing construction of the Nig gas plant and starting the completion of a pad with four horizontal wells (4.0 net) at Nig. The four-well pad at Nig is testing different intervals in the Montney with two wells in the upper, one well in the mid and one well in the lower.

At the end of the quarter, there was an inventory of nine drilled Montney horizontal wells (8.5 net) that had not started producing which included one completed well (0.5 net). During the quarter, one well (1.0 net) started production.

Field activity in the second half of 2019 will be focused on the Nig area and will include constructing the 50 Mmcf per day sour gas plant, drilling and completing an acid gas injection well, constructing a sales gas pipeline and finishing the completion and tie-in of a four-well pad at Nig.

At Umbach (100% working interest), production in the quarter averaged 16,494 Boe per day with 18% liquids and was reduced by 12 days of planned third-party outages. There are currently four standing wells (4.0 net) with none having been completed. Produced raw natural gas is sour (1.2% H_2S) with approximately 85% directed to the McMahon Gas Plant and 15% to the Stoddart Gas Plant. Firm processing commitments total 80 Mmcf raw gas per day (65 Mmcf per day at McMahon plus 15 Mmcf per day at Stoddart). Field compression capacity totals 150 Mmcf per day raw gas with throughput in the second quarter reduced by 12 days of outages and averaging 106 Mmcf per day raw gas (includes 18 Mmcf per day raw from Nig). Growth at Umbach, where there is unused field compression capacity, depends on the natural gas price at Station 2.

At Nig (100% working interest), production in the quarter averaged 3,362 Boe per day with 18% liquids and was reduced by 12 days of planned third-party outages plus 12 days where the wells were shut in for completion of the adjacent four-well pad. There are currently four standing and completed wells (4.0 net) which will be pipeline connected by the end of September. Produced raw natural gas contains approximately 0.2% H_2S. The 50 Mmcf per day sour gas plant that is currently under construction is expected to be completed in January 2020 with the total estimated cost being $81 million ($11.4 million invested in 2018 and the remainder to be invested in 2019). This includes $73 million for the gas plant, $4 million for an acid gas injection well and $4 million for a sales pipeline. Total sales from the gas plant are expected to be 10,500 Boe per day with an estimated operating cost of less than $2.00 per Boe (reduces corporate operating cost to approximately $4.25 per Boe). Liquids is forecast to be 27% of total production (43% condensate, 57% NGL).

At Fireweed (50% working interest), approximately $7 million (net) will be invested in 2019 primarily to drill and complete one horizontal well (0.5 net) and for equipment deposits for a field compression facility. Depending on the timing for regulatory approvals, construction is anticipated to begin in 2020 with start-up in the second half of 2020. Total estimated cost of the facility is $34 million (gross) and it is designed to be expandable to 100 Mmcf per day. Preliminary planning for 2020 includes net investment of approximately $50 million to $55 million to drill and complete eight horizontal wells (4.0 net) and construct the field compression facility. There is currently one standing well (0.5 net) that was completed in 2018 with a length of 1,520 metres (36 frac stages) that averaged 10.9 Mmcf per day raw gas, 660 barrels per day of field condensate and 1,140 barrels per day of frac water with a final flowing casing pressure of 4,800 kPa over the last 12 hours of a six day clean-up. Based on production history from offsetting horizontal wells, first year average field condensate-gas ratios are expected to be 30 to 70 barrels per Mmcf raw which is 100% to 400% higher than at Umbach. Production exiting 2020 is forecast to be over 4,000 Boe per day net to Storm with 25% liquids (67% condensate, 33% NGL).

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not reliable indicators of relative performance as wells are initially rate restricted for several months to manage fluid rates. In addition, recent wells have been affected by outages totaling 43 days to date in 2019.

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Umbach 2014 - 2016 33 hz's(1)	22	1350 m	4.9 Mmcf/d(2) 19 Bbls/Mmcf(3) 33 hz's	4.3 Mmcf/d(2) 16 Bbls/Mmcf(3) 33 hz's	3.4 Mmcf/d(2) 13 Bbls/Mmcf(3) 33 hz's
Umbach 2017 - 2018 19 hz's	34	1895 m	4.6 Mmcf/d(2) 24 Bbls/Mmcf(3) 18 hz's	4.3 Mmcf/d(2) 20 Bbls/Mmcf(3) 16 hz's	4.3 Mmcf/d(2) 14 Bbls/Mmcf(3) 12 hz's
Nig 2018 3 hz's	37	2180 m	8.1 Mmcf/d(2) 29 Bbls/Mmcf(3) 3 hz's	8.2 Mmcf/d(2) 25 Bbls/Mmcf(3) 3 hz's	7.5 Mmcf/d(2) 21 Bbls/Mmcf(3) 3 hz's

(1) 2014 - 2016 wells exclude a middle Montney well (this table provides analysis of upper Montney wells only).
(2) Raw gas rate.
(3) Bbls/Mmcf is the condensate-gas ratio or barrels of field condensate per Mmcf raw.

Based on results from the 2017 and 2018 wells, Storm management is using 8.5 Bcf and 14 Bcf raw gas type curves (internal estimates) to forecast production at Umbach and Nig respectively. More detail on well performance and management's type curve is available in the presentation on Storm's website at www.stormresourcesltd.com.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth with the objective being to protect pricing on 50% of current production for the next 12 months and 25% for 13 to 24 months forward (future production growth is not hedged). Approximately 80% of Storm's liquids production (condensate and butane) is priced in reference to WTI. The current hedge position protects approximately 39% of forecast production for the remainder of 2019.

Q3 – Q4 2019	Crude Oil	850 Bpd	WTI Cdn$73.28/Bbl floor, Cdn$87.95/Bbl ceiling
		650 Bpd	WTI Cdn$81.51/Bbl
	Propane	200 Bpd	Conway Cdn$42.87/Bbl
	Natural Gas	38,000 Mmbtu/d (32.0 Mmcf/d)	Chicago Cdn$3.24/Mmbtu
		8,500 Mmbtu/d (7.2 Mmcf/d)	Sumas Cdn$2.67/Mmbtu
		500 GJ/d (0.4 Mmcf/d)	AECO Cdn$2.00/GJ
2020	Crude Oil	200 Bpd	WTI Cdn$76.35/Bbl floor, Cdn$85.06/Bbl ceiling
	Natural Gas	10,750 Mmbtu/d (9.1 Mmcf/d)	Chicago Cdn$3.32/Mmbtu
		375 GJ/d (0.3 Mmcf/d)	AECO Cdn$2.00/GJ

(1) The Alliance Pipeline tariff to Chicago is approximately Cdn$1.20 per Mmbtu including the cost of fuel.

In addition to the commodity price hedges shown above, there are also condensate and natural gas price differential swaps which include:

Q3 – Q4 2019	400 Bpd	Edm condensate WTI –Cdn$6.13/Bbl
2020	200 Bpd	Edm condensate WTI –Cdn$8.00/Bbl
	12,500 Mmbtu/d (10.6 Mmcf/d)	NYMEX – Chicago –US$0.27/Mmbtu

Firm transportation commitments for natural gas provide sales diversification and are summarized below:

Alliance to Chicago(1)	56 – 70 Mmcf/d
Enbridge T-north to Station 2	16 Mmcf/d
Enbridge T-north & TCPL to AECO	13 Mmcf/d
Enbridge T-north to Station 2/Sumas(2)	12 Mmcf/d
Alliance to ATP	5 Mmcf/d
Total	**102 – 116 Mmcf/d**

(1) When available, Preferential Interruptible Service (‘PITS’) adds up to 14 Mmcf/d of capacity on the Alliance Pipeline.
(2) Sumas price less US$0.69/Mmbtu.

In the second quarter, 56% of natural gas sales were at a Chicago price, 32% at Western Canadian pricing and 12% at the Sumas price less a marketing adjustment. 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

Production in the third quarter of 2019 is expected to average 18,000 to 20,000 Boe per day and includes the effect of an unplanned outage at the McMahon Gas Plant from July 30 to August 12 which was required to repair piping leaks and resulted in approximately 16,000 Boe per day being shut in. This is the third outage at the McMahon Gas Plant in 2019 which has resulted in approximately 77% of corporate production being shut in for a total of 37 days (completing the gas plant at Nig will diversify processing which significantly reduces the effect of future outages). In addition, production in 2019 has also been frequently reduced to a level that fulfills firm transportation and processing commitments as a result of low Western Canadian natural gas prices (July averaged $0.64 per GJ at Station 2 and $1.23 per GJ at AECO) in order to avoid selling production below its replacement cost. Western Canadian natural gas prices are not expected to improve near term given numerous maintenance outages scheduled on the NGTL and Enbridge T-south pipeline systems this summer. Capital investment in the third quarter is estimated to be $45 million with approximately 70% allocated to the Nig gas plant.

Updated guidance for 2019 is provided below. Changes include reducing capital investment in response to the ongoing decline in natural gas prices, reducing forecast annual production while increasing estimated operating costs to reflect the multiple outages (total of 43 days), and updating forecast pricing to reflect actual prices to date plus the approximate forward strip for the remainder of the year.

2019 Guidance

	Previous May 14, 2019	Current August 13, 2019
Cdn$/US$ exchange rate	0.76	0.755
Chicago daily natural gas - US$/Mmbtu	$2.65	$2.45
Sumas monthly natural gas - US$/Mmbtu	$3.40	$3.40
AECO daily natural gas - Cdn$/GJ	$1.65	$1.55
Station 2 daily natural gas - Cdn$/GJ	$1.20	$1.00
WTI - US$/Bbl	$55.00	$55.00
Edmonton condensate diff - US$/Bbl	-$5.50	-$5.10

2019 Guidance

	Previous May 14, 2019	Current August 13, 2019
Est revenue net of transport (excl hedges) - $/Boe	$17.75 - $18.25	$16.50 - $17.00
Est operating costs - $/Boe	$5.50 - $5.75	$5.75 - $6.00
Est royalty rate (% revenue net transportation)	5% - 7%	5% - 7%
Est mid-point field operating netback - $/Boe	$11.30	$9.87
Est hedging loss - $ million	$8.0 - $10.0	$4.0 - $5.0
Est cash G&A - $ million	$6.0 - $7.0	$6.0 - $6.5
- $/Boe	$0.66 - $0.91	$0.75 - $0.89
Est interest expense - $ million	$5.5 - $6.5	$5.5 - $6.5
Est capital investment (excl A&D) - $ million	$128.0	$110.0
Forecast fourth quarter production - Boe/d	23,000 - 25,000	23,000 - 25,000
% liquids	18%	18%
Forecast annual production - Boe/d	21,000 - 24,000	20,000 - 22,000
% liquids	18%	18%
Est annual funds flow - $ million	$65.0 - $77.0[(1)]	$55.0 - $61.0[(1)]
Horizontal wells drilled - gross	9 (7.5 net)	9 (7.5 net)
Horizontal wells completed - gross	11 (9.5 net)	8 (6.5 net)
Horizontal wells starting production - gross	9 (9.0 net)	7 (7.0 net)

(1) Based on the range for forecast annual production and using the mid-point for each of the estimated field operating netback, estimated cash G&A, estimated hedging gain or loss and estimated interest expense.

Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	WTI (US$/bbl)	Capital Investment ($ million)	Forecast Annual Funds Flow ($ million)	Forecast Annual Production (Boe/d)
Nov 13, 2018	$2.50	$1.25	$60.00	$128.0	$72.0 - $88.0	21,000 - 24,000
Feb 28, 2019	$2.60	$1.25	$55.00	$128.0	$67.0 - $79.0	21,000 - 24,000
May 14, 2019	$2.65	$1.20	$55.00	$128.0	$65.0 - $77.0	21,000 - 24,000
Aug 13, 2019	$2.45	$1.00	$55.00	$110.0	$55.0 - $61.0	20,000 - 22,000

Natural gas prices have declined since last winter with US natural gas prices reduced by supply growing faster than demand (primarily weather related with the milder start to the summer reducing natural gas used for electric power generation) while Western Canadian natural gas prices have been reduced by recurring restrictions or outages for pipeline maintenance exacerbating an oversupply situation. There are indications that the oversupply in Western Canada may be shrinking given the recent narrowing of the NYMEX-AECO price differential.

Since the failure on the Enbridge T-south natural gas pipeline in October 2018, throughput has decreased by 15% to as much as 45% when engineering assessments are being conducted. This has reduced the Station 2 price in relation to AECO. There is currently no certainty on if, or when, capacity can be restored although engineering assessments are ongoing and expected to be completed by late August 2019 with review of the results by the National Energy Board expected by November 2019. Until capacity is restored or until the NGTL North Montney extension into northeast British Columbia is in service (fourth quarter of 2019), the Station 2 price is expected to remain depressed in relation to AECO. The financial effect on Storm has not been material given that typically 15% to 20% of total natural gas sales are at Station 2.

Capital investment in 2019 has been reduced to $110 million from $128 million as a result of the challenges experienced to date in 2019 from both the decline in natural gas prices and the multiple outages experienced at the McMahon Gas Plant which have reduced forecasted funds flow. The reduction comes mainly from deferring the completion and tie-in of three horizontal wells at Umbach into mid-2020. Preliminary estimated capital investment for 2020 is $80 million which is expected to be approximately equal to funds flow. Reducing capital investment will reduce production growth in 2020 but is not expected to affect 2019 production guidance given that the outages to date in 2019 (43 days total) have effectively resulted in production being deferred, plus the corporate decline rate continues to flatten with improving well performance. Changes to capital investment are the primary method used to preserve a strong balance sheet given that commodity prices are not controllable.

More than 90% of capital investment in 2019 is being directed towards Nig and Fireweed with $70 million for the sour gas plant at Nig, $26 million to drill, complete and tie in a four-well pad at Nig, and $7 million at Fireweed.

Funding for growth from Nig and Fireweed will come from re-investing funds flow exceeding maintenance capital requirements and from available capacity on the bank line. Maintaining corporate production at 20,000 to 22,000 Boe per day requires approximately $18 million to drill, complete, and tie in three horizontal wells at Nig based on an estimated corporate decline rate of 20% and using the first year average calendar day rate of 1,415 Boe per day sales that was achieved by the first three wells at Nig.

In the second half of 2019, debt including working capital deficiency is expected to exceed the targeted level of 1.0 to 1.5 times annualized funds flow during the construction of the Nig gas plant as the entire $81 million project cost must be invested before any incremental funds flow is realized. After the Nig gas plant is completed, debt to funds flow is expected to return to targeted levels. If required, capital investment in 2020 can be reduced to maintain debt at targeted levels.

The near-term plan continues to be focused on growing funds flow by adding infrastructure at Nig in 2019 to reduce per-Boe operating costs and increase liquids production while development at Fireweed in 2020 will grow condensate production. Growth at Umbach is contingent on a higher natural gas price at Station 2. Both Nig and Fireweed offer attractive full cycle rates of return assuming Station 2 $1.25 per GJ, WTI US$55 per barrel and a Cdn$/US$ exchange rate of 0.76 (see the presentation on Storm's website for further details). Corporate production is forecast to increase to approximately 24,000 Boe per day in the fourth quarter of 2019 (4,300 barrels per day of liquids) and to approximately 28,000 Boe per day in the fourth quarter of 2020 (6,500 barrels per day of liquids).

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

August 13, 2019

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

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

Forward-Looking Statements - Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated August 13, 2019 for the three and six months ended June 30, 2019.

MANAGEMENT'S DISCUSSION & ANALYSIS

INTRODUCTION

Set out below is management's discussion and analysis ("MD&A") of financial and operating results for Storm Resources Ltd. ("Storm" or the "Company") for the three and six months ended June 30, 2019. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2019, (ii) the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2018, and (iii) the press release issued by the Company on August 13, 2019, 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, 2019 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

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

This MD&A is dated August 13, 2019.

See discussion related to "Forward Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" on pages 24 to 26.

BASIS OF PRESENTATION

Financial data presented below have been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three and six months ended June 30, 2019, 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, 2018 and updated for new standards, as applicable, in Note 3 of the financial statements for the three and six months ended June 30, 2019. The reporting and the functional currency is the Canadian dollar.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the three and six month periods ended June 30, 2018.

OPERATIONAL AND FINANCIAL RESULTS

Overview

Similar to the first quarter of 2019, the second quarter was affected by third-party outages reducing Storm's production and funds flow. The McMahon Gas Plant incurred a six day planned outage in May followed by a six day planned outage on the Alliance pipeline to Chicago in June. These third-party outages, coupled with weakening natural gas prices attributable to robust supply levels and decreased demand, resulted in a challenging quarter for the Company. Second quarter production of 19,923 Boe per day was consistent with the low end of the previously announced guidance range of 20,000 to 22,000 Boe per day and was largely flat with the comparable quarter of 2018, as production was shut in for the outages and also in response to periods of very low natural gas prices at AECO and Station 2. The second quarter of 2019 saw production remain essentially unchanged from the immediately preceding quarter, while funds flow fell approximately $4 million largely due to lower natural gas and NGL pricing. Storm incurred capital expenditures of $23.1 million, approximately half of which related to advancement of the Nig gas plant with the remaining spending largely relating to the commencement of completion operations on a four-well pad on the Nig land block.

During the second quarter of 2019, condensate (includes field condensate and plant pentanes) plus NGL (includes butane and propane) accounted for 18% of total production and contributed 38% to revenue in the period compared to 30% of revenue in the immediately preceding quarter and 43% of revenue in the comparable quarter of 2018. As the majority of Storm's condensate and NGL revenue streams are based on crude oil reference prices, participation in the crude oil market remains an important part of Storm's business plan, particularly in light of the ability to focus drilling on areas where higher liquids recoveries are expected.

The natural gas price realized by the Company in the second quarter fell by 41% when compared to the first quarter of 2019, and was down 16% when compared to the same quarter of 2018. The decrease versus the prior quarter was the result of a significant decline in both US based and Western Canadian natural gas benchmark pricing as the winter heating season came to an end and supply levels remained elevated. The decrease when comparing to the second quarter of 2018 was mostly attributable to weaker Chicago and Station 2 natural gas pricing because of record supply levels in North America and decreased demand owing to the onset of spring weather with a milder start to summer. Station 2 pricing continued to be affected by ongoing constraints on the T-south natural gas pipeline. When comparing to the same quarter in 2018, condensate and NGL prices were down 18% and 87%, respectively. Benchmark crude oil pricing decreased in 2019 compared to 2018 as a result of a lower oil demand forecast due to trade tensions between China and the US which continued to affect the global economy, tempered by supply levels that were reduced by output cuts and US sanctions on Iran and Venezuela. Elevated supply levels for NGL in Western Canada and constrained take-away capacity materially reduced Storm's realized NGL price. Given further weakness in propane pricing, Storm's NGL price net of transportation is now anticipated to be approximately 5% to 10% of WTI in Canadian dollar terms for the contract period that commenced in April 2019 and ends in March 2020 versus the previously announced range of 10% to 15%. This is materially lower than the average of 43% of WTI in Canadian dollars that was realized in 2018.

Capital expenditures for the second quarter of 2019 totaled $23.1 million and included $13.9 million for facilities (primarily the Nig gas plant), $7.9 million for initiating completion operations on a four-well pad at Nig, $0.9 million for land, and $0.4 million for equipping and pipelines. During the second quarter one well was brought on stream. At quarter end the Company had an inventory of nine (8.5 net) standing horizontal wells, of which eight (8.0 net) awaited or were in various stages of completion, with the remaining one (0.5 net) well completed but not yet producing. Based on the current capital program, two (1.5 net) wells will be drilled in the second half of the year, and an additional six (5.5 net) wells will be completed over the remainder of the year which includes an acid gas injection well at Nig. Based on this level of activity, fourth quarter production is forecast to be 23,000 to 25,000 Boe per day. Capital expenditures in the second quarter of 2019 outpaced funds flow due to spending on construction activities relating to the sour gas plant at Nig. It is anticipated that for the remainder of the year planned capital expenditures will also be in excess of funds flow with the difference expected to be financed with the Company's credit facility. Total debt, including working capital deficiency, at quarter end amounted to $102.3 million, up from $91.6 million at the end of the first quarter.

Field operating netback per Boe for the second quarter of 2019 amounted to $8.55, a decrease compared to $14.25 in the same period of 2018, while funds flow per Boe decreased to $6.94 from $13.16 in the same period of 2018. The reduction in the field operating netback and the funds flow netback versus the comparative period was primarily a result of lower realized pricing for both natural gas and liquids.

During the quarter, the Company's credit facility was increased by $25 million to $205 million, an increase of 14%. The credit facility is predominantly based on the banking syndicate's assessment of the value of the Company's PDP reserves as collateral. Despite a challenging outlook for natural gas prices in the short term, the credit facility increase was supported by the increase in PDP reserves, which grew by 25% year over year, while the net present value of PDP reserves (before tax, discounted at 10%) increased by 22% based on InSite Petroleum Consultants Ltd. December 31, 2018 commodity price deck. The revised credit facility provides increased financial flexibility as Storm executes on construction of the Nig gas plant. No new material covenants were required and there were no changes to the interest rate structure.

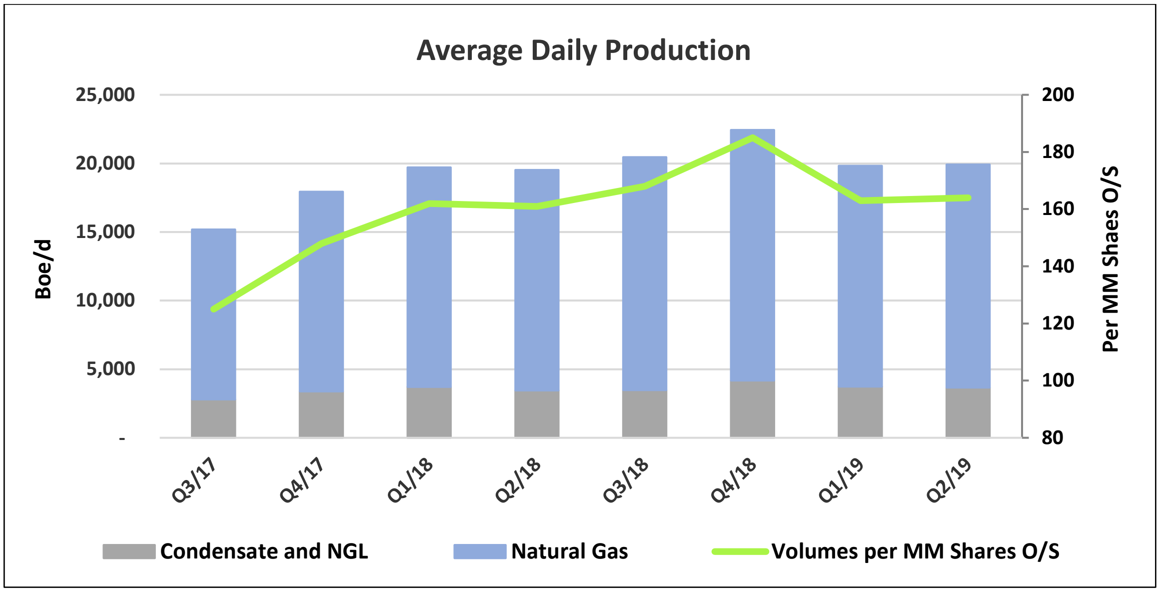
Production and Revenue

Average Daily Production

	Three Months to June 30, 2019	Three Months to June 30, 2018	Quarter-Over-Quarter Change	Six Months to June 30, 2019	Six Months to June 30, 2018	Year-Over-Year Change
Natural gas (Mcf/d)	97,510	96,426	1%	97,026	96,248	1%
Condensate (Bbls/d)	2,081	1,984	5%	2,140	2,023	6%
NGL (Bbls/d)	1,591	1,473	8%	1,563	1,554	1%
Total (Boe/d)	19,923	19,529	2%	19,873	19,618	1%
Natural gas weighting	82%	82%		81%	82%	
Condensate weighting	10%	10%		11%	10%	
NGL weighting	8%	8%		8%	8%	

Production for natural gas, condensate and NGL for the second quarter of 2019 was comparable to the second quarter of 2018 as production levels in the second quarter of 2019 were affected by planned outages at the McMahon Gas Plant in May (six days) and Alliance Pipeline in June (six days) which, in aggregate, reduced production in the quarter by approximately 2,000 Boe per day. In addition to the planned outages in the second quarter of 2019, production was also voluntarily curtailed at times in response to weak natural gas pricing at Station 2.

When comparing the first six months of 2019 to the same period of 2018, production was comparable despite being negatively affected by outages. These outages reduced production by approximately 3,000 Boe per day for the six months ended June 30, 2019. The Company started production from one new 100% working interest horizontal well during the second quarter of 2019.



Daily production per million shares outstanding at the end of the second quarter averaged 164 Boe per day, compared to 161 Boe per day for the second quarter of 2018, an increase of 2%.

Average Selling Prices(1)

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Natural gas – Mcf	$ 2.64	$ 3.15	$ 3.55	$ 3.49
Condensate – Bbl	$ 71.12	$ 86.33	$ 66.85	$ 81.15
NGL – Bbl	$ 4.87	$ 36.43	$ 17.83	$ 34.66
Per Boe	$ 20.72	$ 27.07	$ 25.95	$ 28.22

(1) Before realized gains and losses on risk management contracts.

On a per-Boe basis, the Company's average realized price for the three months ended June 30, 2019 decreased by 23% compared to the same period of 2018, with the decrease driven by lower NGL, natural gas and condensate pricing. As previously communicated, Storm's NGL price for the April 2019 to March 2020 contract year was expected to be approximately 10% to 15% of WTI. The Company's NGL price for the second quarter of 2019 was 6% of WTI which was below expectations primarily because of a lower propane price. Decrease in natural gas pricing is primarily due to a reduction in prices at Chicago and Station 2.

On a per-Boe basis, the Company's average realized price for the first six months of 2019 decreased by 8% when compared to the first six months of 2018, primarily driven by decreases in condensate and NGL pricing, partially offset by a slight increase in natural gas prices.

Condensate pricing decreased as a result of a decrease in WTI pricing and a wider differential between WTI and Edmonton condensate.

Benchmark Prices

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Natural gas				
Chicago monthly index (US$/Mmbtu)	2.45	2.58	2.89	2.93
Chicago daily index (US$/Mmbtu)	2.31	2.66	2.67	2.81
Sumas (US$/Mmbtu)	2.10	1.64	4.45	2.05
AECO monthly index (Cdn$/GJ)	1.11	0.97	1.48	1.37
AECO daily index (Cdn$/GJ)	0.98	1.12	1.73	1.54
Station 2 (Cdn$/GJ)	0.56	1.05	0.90	1.43
Crude Oil				
WTI (US$/Bbl)	59.81	67.88	57.36	65.37
WTI (Cdn$/Bbl)	80.01	88.16	76.48	83.81
Edmonton condensate (Cdn$/Bbl)	74.73	88.84	70.96	84.29
Exchange rate (US$/Cdn$)	0.75	0.77	0.75	0.78

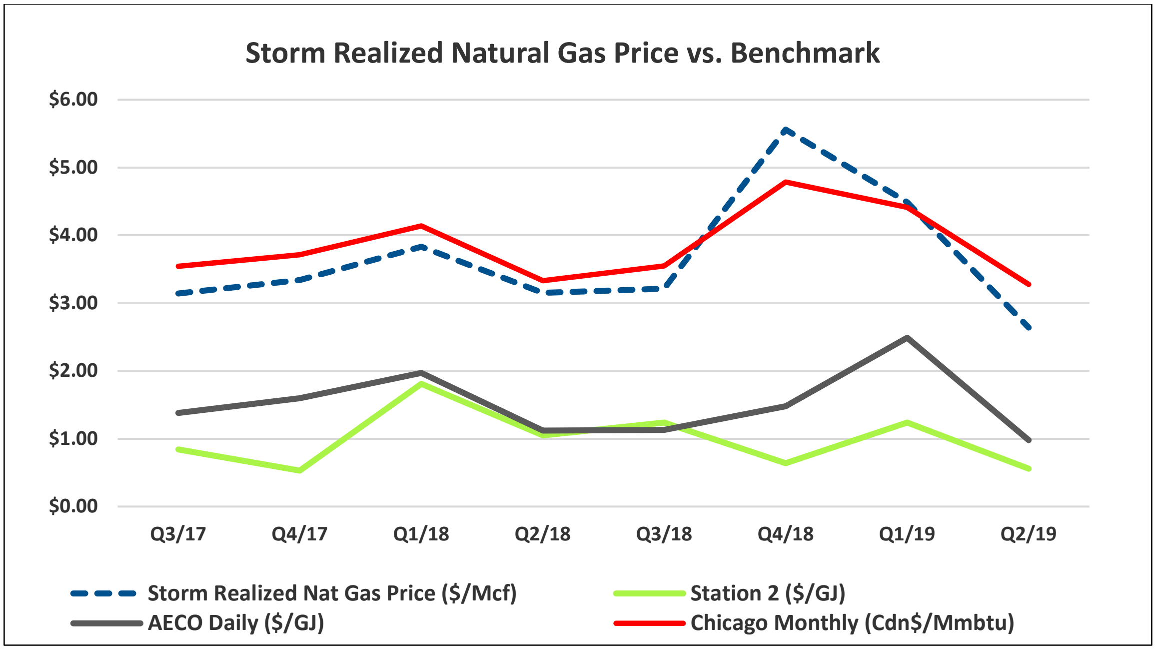
Storm's realized prices differ from market indices due to fluctuations in the foreign exchange rate and the higher heat content of the Company's natural gas will increase the per-Mcf price.

In October 2018, a pipeline rupture occurred on the Enbridge T-south line which reduced pipeline capacity. This has increased volatility in pricing for both Station 2 (lower) and Sumas (higher). During the first half of 2019, the monthly Sumas index price averaged US$4.45 per Mmbtu resulting in increased revenue for Storm which was offset by increased hedging losses on Storm's sales at Sumas. Sumas pricing in the second quarter of 2019 normalized to US$2.10 per Mmbtu with decreased demand in the Pacific Northwest.

WTI crude oil pricing, on which a large part of the Company's condensate and NGL revenue is based, declined 12% from US$67.88 per barrel during the second quarter of 2018 to US$59.81 per barrel for the second quarter of 2019 due to continued market concerns over supply outpacing demand. In addition to the decrease in the WTI price was the widening of the Edmonton condensate differential from a premium of US$0.95 per barrel in the second quarter of 2018 to a discount of US$3.96 per barrel for the second quarter of 2019. The condensate differential for the third quarter of 2019 is expected to settle at an approximate US$5.00 per barrel discount to WTI.

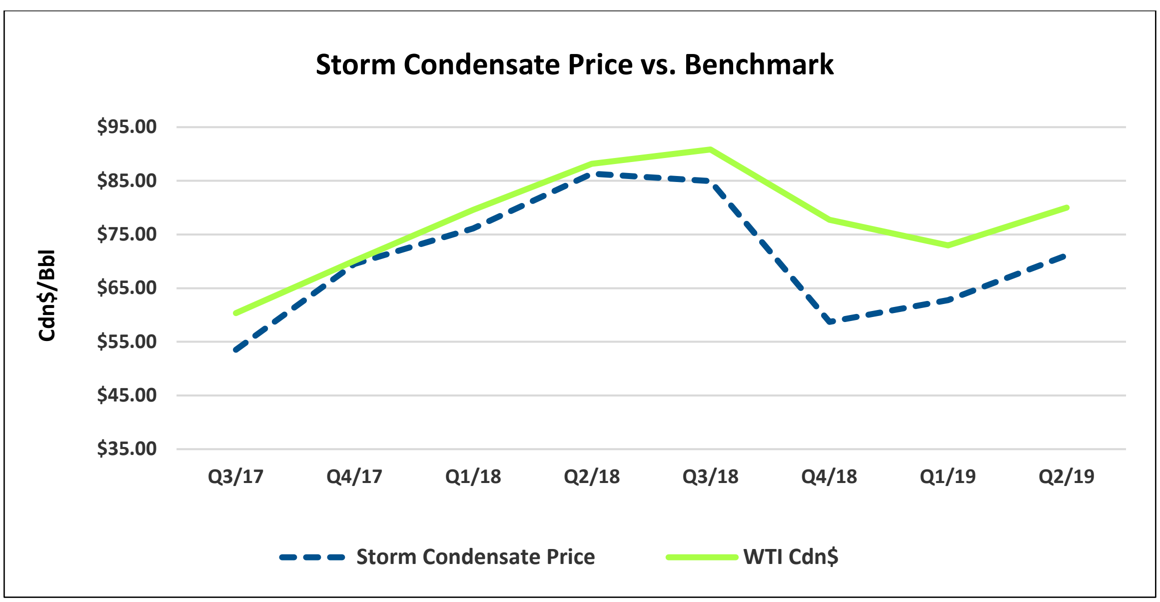
The Company's production during the second quarter was sold as follows:

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Chicago monthly index price	43%	40%	39%	40%
Chicago daily index price	13%	29%	16%	25%
AECO daily index price	9%	7%	10%	4%
Station 2 daily spot price	21%	6%	21%	13%
Sumas index price	12%	12%	11%	12%
Alliance Transfer Point ("ATP")	2%	6%	3%	6%
Total	100%	100%	100%	100%



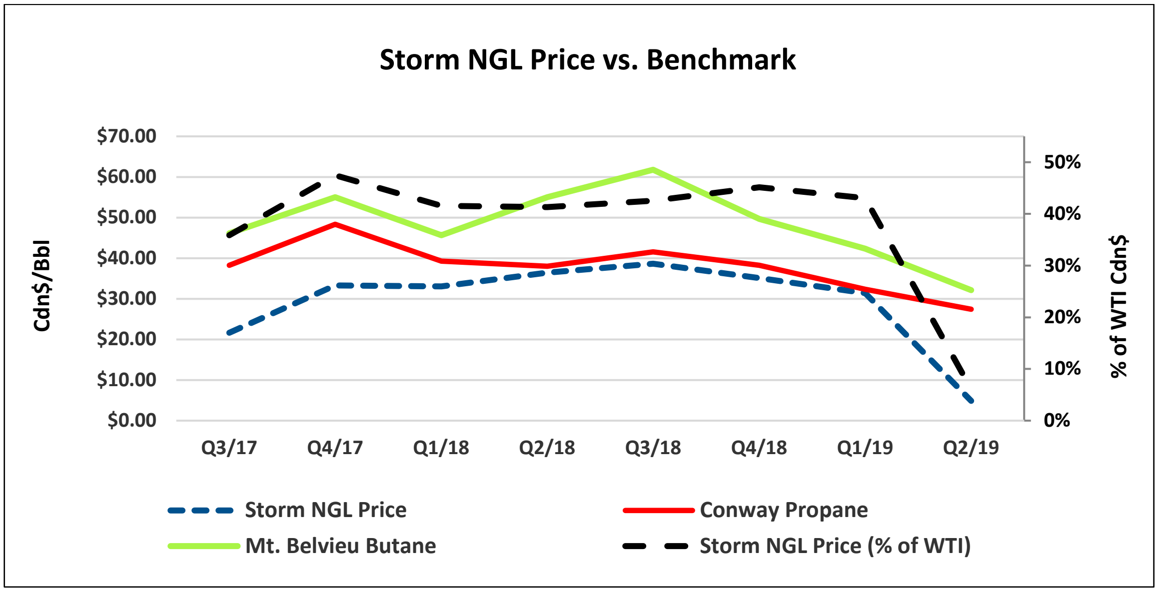
As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was approximately 350% higher than Station 2 pricing in the second quarter of 2019. A significant contributor to Storm's realized natural gas price of $2.64 per Mcf in the second quarter of 2019 was strength in Chicago and Sumas pricing, which was partially offset by low AECO and Station 2 pricing.

Approximately 70% of the Company's natural gas was sold into higher priced US markets in the second quarter of 2019.



Storm's realized condensate price for the second quarter of 2019 decreased by 18% from the second quarter of 2018 as a result of the decrease in the WTI price combined with the widening of the WTI-Edmonton condensate differential from the second quarter of 2018 to the second quarter of 2019.

The widening of the differentials was due to a combination of lower condensate prices on the US Gulf Coast and reduced demand for diluent blending as a result of pipeline constraints and refinery outages.



Storm's realized price for NGL, excluding condensate, in the second quarter of 2019 decreased by 87% relative to the same period of 2018. When comparing the first six months of 2019 to the same period of 2018, the realized price for NGL, excluding condensate, decreased by 49%. The decrease in realized NGL prices for both of the aforementioned periods was primarily due to lower contracted butane pricing as a result of elevated supply levels, lower propane pricing and weaker WTI pricing period over period.

Storm's NGL price net of transportation for the remainder of the year is anticipated to be approximately 5% to 10% of WTI in Canadian dollar terms for the contract period that commenced in April 2019 and ends in March 2020.

Revenue from Product Sales[(1)]

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Natural gas	$ 23,396	$ 27,629	$ 62,400	$ 60,743
Condensate	13,468	15,590	25,890	29,717
NGL	704	4,885	5,044	9,746
Total	$ 37,568	$ 48,104	$ 93,334	$ 100,206
% of Total Revenue by Product Type				
Natural gas	62%	57%	67%	61%
Condensate and NGL	38%	43%	33%	39%
Total	100%	100%	100%	100%

(1) Before realized gains and losses on risk management contracts and including natural gas purchased and sold to meet marketing commitments during outages.

Revenue from product sales for the second quarter of 2019 decreased by 22% when compared to the second quarter of 2018 primarily as a result of the Company's average realized price decreasing by 23%. For the six month periods, revenue from product sales decreased 7% year over year primarily due to the Company's average realized price decreasing by 8%.

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q2 2018	$ 27,629	$ 15,590	$ 4,885	$ 48,104
Effect of changes in production	311	758	389	1,458
Effect of changes in average product prices	(4,544)	(2,880)	(4,570)	(11,994)
Revenue from product sales – Q2 2019	$ 23,396	$ 13,468	$ 704	$ 37,568

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q2 2018 YTD	$ 60,743	$ 29,717	$ 9,746	$ 100,206
Effect of changes in production	491	1,712	57	2,260
Effect of changes in average product prices	1,166	(5,539)	(4,759)	(9,132)
Revenue from product sales – Q2 2019 YTD	$ 62,400	$ 25,890	$ 5,044	$ 93,334

Risk Management

	Three Months Ended June 30, 2019		Three Months Ended June 30, 2018	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (166)	$ 7,681	$ 3,133	$ (9,841)
Liquids(1)	(242)	2,042	(2,577)	(3,807)
Interest rate	1	(98)	-	-
Gain (loss) on risk management contracts	$ (407)	$ 9,625	$ 556	$ (13,648)

	Six Months Ended June 30, 2019		Six Months Ended June 30, 2018	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (10,088)	$ 9,962	$ 2,650	$ (10,461)
Liquids(1)	87	(5,047)	(4,213)	(5,285)
Interest rate	1	(98)	-	-
Gain (loss) on risk management contracts	$ (10,000)	$ 4,817	$ (1,563)	$ (15,746)

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

Although the Company has no crude oil production, condensate and a portion of the NGL stream is priced with reference to WTI and, as a result, the Company enters into crude oil risk management contracts to hedge liquids prices.

The realized gain (loss) on risk management contracts consists of the portion of contracts that have settled in cash during the reporting period. The realized loss of $10.0 million for the six months ended June 30, 2019 is due to higher pricing at Chicago and Sumas.

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

Royalties

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period	$ 577	$ 1,968	$ 5,234	$ 5,004
Percentage of revenue from product sales	1.5%	4.1%	5.6%	5.0%
Per Boe	$ 0.32	$ 1.11	$ 1.46	$ 1.41

Royalties, as a percentage of revenue from product sales, decreased in the three months ended June 30, 2019 compared to the same period in 2018 primarily due to the receipt of $1.6 million in infrastructure royalty credits in the second quarter of 2019 and lower commodity prices, partially offset by a decrease of wells benefitting from the BC Deep Well Royalty Program. Storm 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 second quarter of 2019, 27 wells qualified for the 6% royalty rate compared to 36 wells in the second quarter of 2018.

Royalties, as a percentage of revenue from product sales, increased in the six months ended June 30, 2019 compared to the same period in 2018 primarily due to a decrease in the number of wells benefitting from the BC Deep Well Royalty Program, partially offset by the receipt of infrastructure royalty credits in the second quarter of 2019.

Storm has remaining infrastructure royalty credits of $2.4 million that will reduce future royalties. Future royalty payments are dependent on commodity prices and production levels from individual wells and thus the timing to receive future royalty credits cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary as these credits are earned.

Production Costs

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period	$ 10,681	$ 9,703	$ 21,543	$ 19,553
Per Boe	$ 5.89	$ 5.46	$ 5.99	$ 5.51

Total production costs for the second quarter and first half of 2019 increased 10% when compared to the same periods of 2018 and by 8% and 9%, respectively, on a per-Boe basis. The increase in total production costs for the second quarter of 2019 compared to the second quarter of 2018 is primarily due to a gas processing credit of $0.3 million that reduced production costs in the second quarter of 2018, an increase in the BC carbon tax and higher third-party processing fees on incremental production volumes in 2019. The increase in total production costs for the six months ended June 30, 2019 compared to the same period in 2018 was primarily due to fixed costs incurred during an unplanned outage at the McMahon Gas Plant in January and an increase in the BC carbon tax.

Carbon Tax

With the majority of the Company's operations located in British Columbia, the Company is subject to the British Columbia Carbon Tax Act. Storm pays carbon tax on fuel used in the Company's own facilities as well as on natural gas volumes processed at third-party facilities. The following table outlines the total carbon taxes (direct and indirect) that are included as a component of the aforementioned production costs.

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period	$ 1,476	$ 1,323	$ 2,827	$ 2,530
Per Boe	$ 0.81	$ 0.74	$ 0.79	$ 0.71

Transportation Costs

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period	$ 10,808	$ 11,108	$ 21,014	$ 21,020
Per Boe	$ 5.96	$ 6.25	$ 5.84	$ 5.92

Transportation costs include pipeline tariffs for natural gas sold at various price points, as well as trucking costs and pipeline tariffs for wellhead condensate. Natural gas sales volumes destined for Chicago and markets across North America have higher per-unit transportation costs, but obtain higher sales prices which offsets the higher pipeline tariffs. Transportation costs for the second quarter of 2019 decreased by 3%, and by 5% per Boe, when compared to the second quarter of 2018 due to selling less natural gas to Chicago using interruptible capacity on the Alliance Pipeline (56% of natural gas sales in Chicago in the second quarter of 2019 versus 69% in the previous year). This decrease was partially offset by incurring fixed costs of $1.2 million for unused firm transportation during the planned outages in the second quarter of 2019. Transportation costs for the first six months of 2019 were consistent with the same period in 2018 as fixed transportation costs during outages was almost completely offset by selling less natural gas to Chicago.

Field Netbacks

Details of field netbacks, measured per commodity unit sold, are as follows:

	Three Months to June 30, 2019			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 2.64	$ 71.12	$ 4.87	$ 20.72
Royalties	0.13	(8.55)	(0.70)	(0.32)
Production costs	(1.20)	-	-	(5.89)
Transportation costs	(1.10)	(5.42)	(0.24)	(5.96)
Field operating netback	$ 0.47	$ 57.15	$ 3.93	$ 8.55
Realized (loss) gain on risk management contracts	(0.02)	(2.76)	1.94	(0.22)
Field operating netback including hedging	$ 0.45	$ 54.39	$ 5.87	$ 8.33

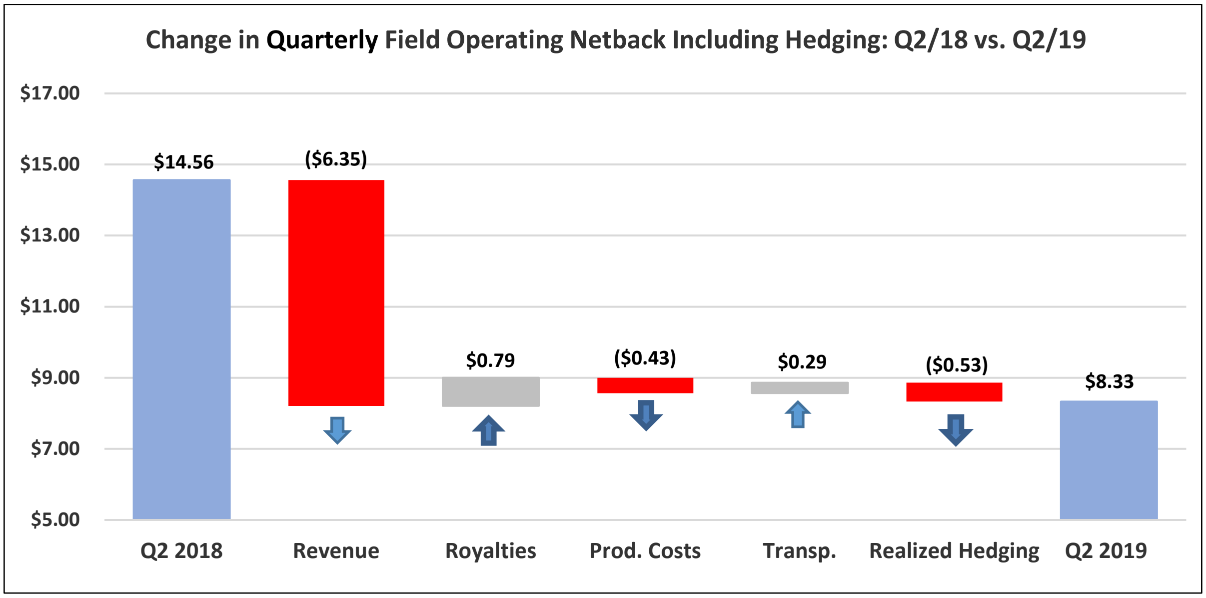
	Three Months to June 30, 2018			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.15	$ 86.33	$ 36.43	$ 27.07
Royalties	(0.02)	(7.83)	(3.06)	(1.11)
Production costs	(1.11)	-	-	(5.46)
Transportation costs	(1.16)	(5.04)	-	(6.25)
Field operating netback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

	Six Months to June 30, 2019			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.55	$ 66.85	$ 17.83	$ 25.95
Royalties	(0.08)	(8.17)	(2.51)	(1.46)
Production costs	(1.23)	-	-	(5.99)
Transportation costs	(1.08)	(5.25)	(0.12)	(5.84)
Field operating netback	$ 1.16	$ 53.43	$ 15.20	$ 12.66
Realized (loss) gain on risk management contracts	(0.57)	(0.99)	1.67	(2.78)
Field operating netback including hedging	$ 0.59	$ 52.44	$ 16.87	$ 9.88

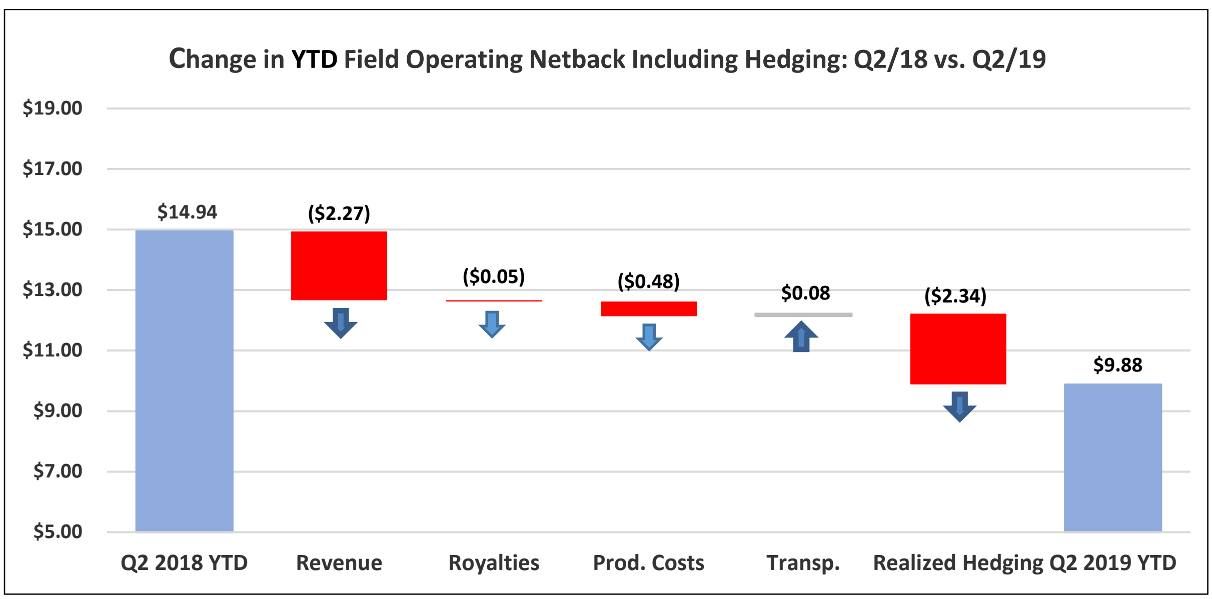
	Six Months to June 30, 2018			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.49	$ 81.15	$ 34.66	$ 28.22
Royalties	(0.08)	(7.24)	(3.13)	(1.41)
Production costs	(1.12)	-	-	(5.51)
Transportation costs	(1.11)	(4.82)	-	(5.92)
Field operating netback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

(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 field operating netback for the second quarter of 2019 decreased by 40% (43% decrease after hedging) compared to the second quarter of 2018.



The field operating netback for the first six months of 2019 decreased by 18% (34% decrease after hedging) compared to the first six months of 2018.



General and Administrative Costs

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period – before recoveries	$ 1,860	$ 1,538	$ 5,104	$ 4,356
Overhead recoveries	(632)	(318)	(1,025)	(612)
Charge for period – net of recoveries	$ 1,228	$ 1,220	$ 4,079	$ 3,744
Per Boe	$ 0.68	$ 0.69	$ 1.13	$ 1.05

General and administrative costs before recoveries for the second quarter of 2019 increased by 21% when compared to the second quarter of 2018 due to higher compensation costs. General and administrative costs before recoveries for the six months ended June 30, 2019 increased by 17% compared to the same period of 2018 primarily due to the payout of the annual employee performance bonus after year-end results were finalized and higher compensation costs.

As a result of the change in lease accounting effective January 1, 2019, general and administrative costs in the second quarter of 2019 are lower by $0.1 million related to the office lease.

Fluctuations in overhead recoveries are in response to the amount and type of field capital expenditures incurred.

Net general and administrative costs on a per-Boe measure for the second quarter of 2019 were comparable to the second quarter of 2018, and increased by 8% when comparing the first six months of 2019 to the same period of 2018. Generally, the Company's general and administrative cost structure is predictable year to year and variability in per-Boe metrics is due to changes in production volumes.

Interest and Finance Costs

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period[1]	$ 1,315	$ 1,256	$ 2,433	$ 2,398
Average interest rate[2]	5.7%	5.4%	5.1%	4.8%
Per Boe	$ 0.73	$ 0.71	$ 0.68	$ 0.68

(1) Includes lease interest.
(2) Includes financing and standby fees; excludes lease interest.

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

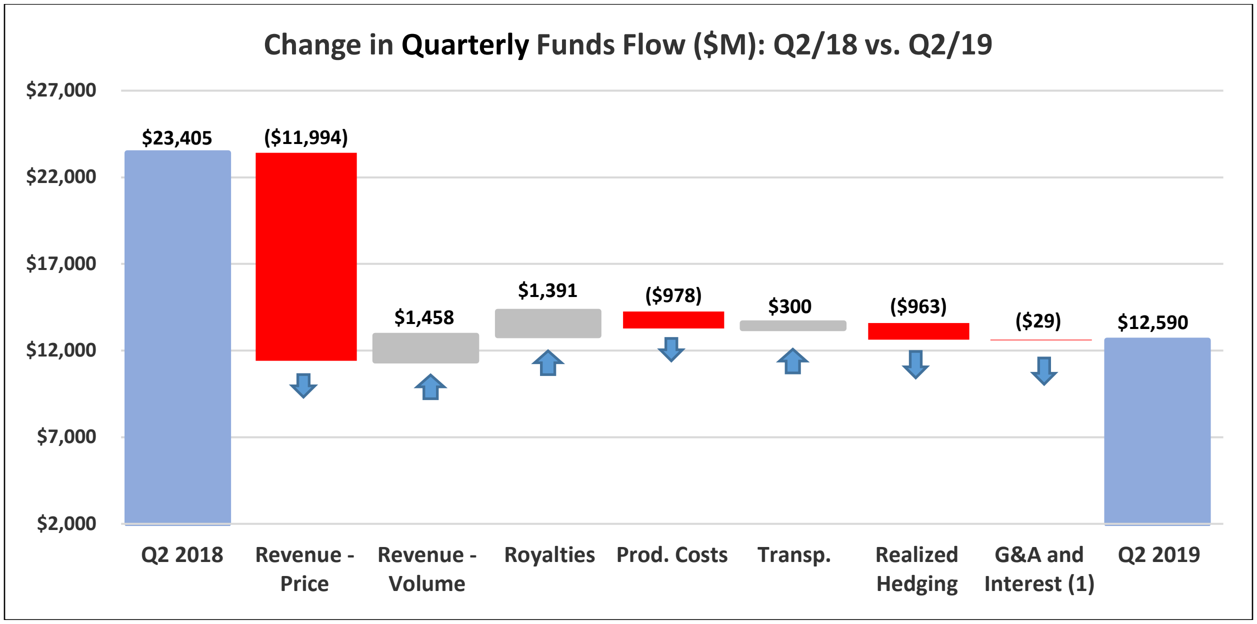
Interest costs for the second quarter and first half of 2019 increased by 5% and 1%, respectively, compared to the same periods of 2018 as a result of higher market interest rates, partially offset by lower average bank borrowings.

The average interest rate is typically higher in the second quarter due to incurring annual fees relating to the renewal of the Company's bank facility.

Funds Flow

	Three Months to June 30, 2019		Three Months to June 30, 2018		Six Months to June 30, 2019		Six Months to June 30, 2018	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$12,590	$0.10	$23,405	$0.19	$29,107	$0.24	$46,924	$0.39

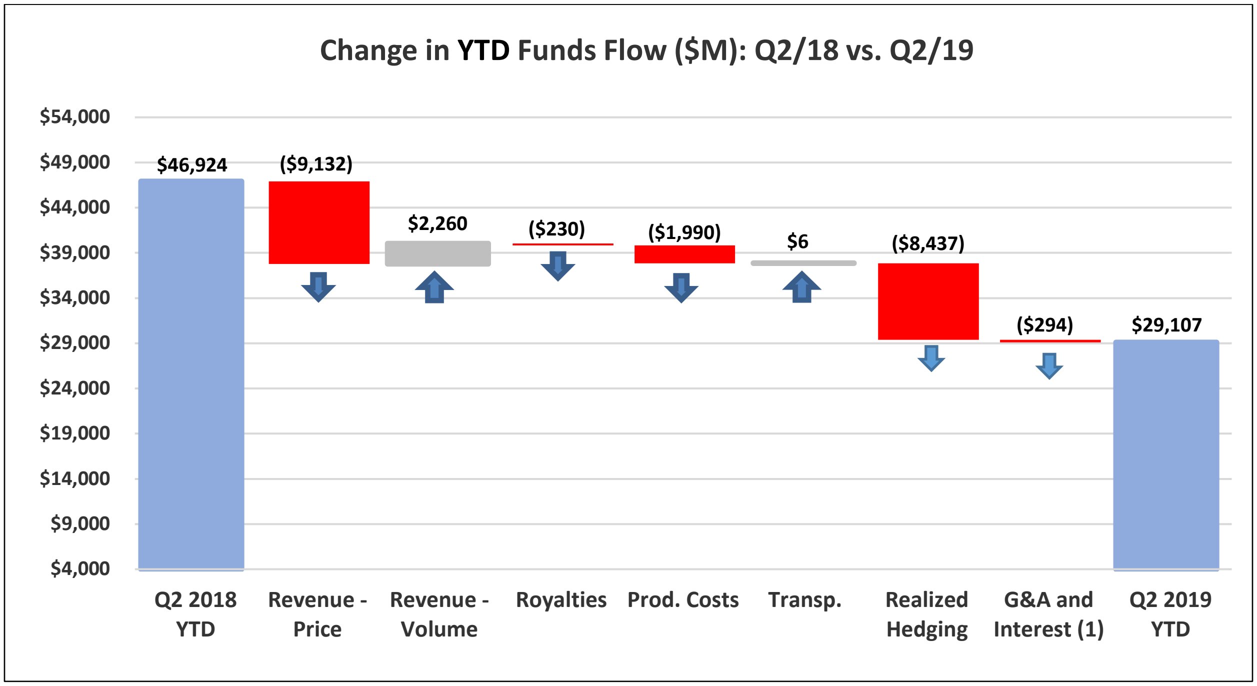
Funds flow, a measure that is not defined under IFRS, is cash generated from operating activities before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies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



(1) Excludes lease interest.

Lower realized prices was the predominant factor in the decrease in funds flow in the second quarter of 2019 versus the second quarter of 2018.

The cash return on capital employed ("CROCE") over the last 12 months, which is a measurement of the Company's cash profitability as a proportion of the funding utilized to generate it (shareholders' equity plus debt including working capital deficiency), was 18% in the second quarter of 2019 which was broadly in line with the second quarter of 2018.



(1) Excludes lease interest.

Funds flow for the first six months of 2019 decreased by 38% from the first six months of 2018. Funds flow was negatively affected by weaker realized liquids pricing, realized hedging losses on natural gas hedges and higher costs mostly related to third-party outages.

Share-Based Compensation

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period	$ 564	$ 772	$ 1,160	$ 1,466
Per Boe	$ 0.31	$ 0.43	$ 0.32	$ 0.41

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 27% in the second quarter of 2019 compared to the second quarter of 2018 and decreased by 21% when comparing the six month periods. The decrease in share-based compensation in both the three and six month periods is primarily attributable to a lower option fair valuation associated with options granted in 2018.

Depletion and Depreciation

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Depletion	$ 8,040	$ 9,926	$ 15,892	$ 19,761
Depreciation	1,914	1,673	3,808	3,285
Charge for period	$ 9,954	$ 11,599	$ 19,700	$ 23,046
Per Boe	$ 5.49	$ 6.53	$ 5.48	$ 6.49

Depletion and depreciation decreased by 14% in the second quarter of 2019 compared to the same quarter of 2018 due to lower finding and development costs. Comparing the first six months of 2019 with the same period in 2018, depletion and depreciation decreased by 15% as a result of 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.

Exploration and Evaluation Costs Expensed

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Charge for period	$ 1,119	$ 98	$ 1,119	$ 277
Per Boe	$ 0.62	$ 0.06	$ 0.31	$ 0.08

Exploration and evaluation costs expensed in the three and six months ended June 30, 2019 represent costs associated with the expiry of non-core lands.

Income Taxes

In May 2019, the Government of Alberta substantively enacted a reduction in the provincial corporate tax rate from 12% to 8% over a four-year period.

The Company did not incur any cash tax expense in the three and six months ended June 30, 2019, nor does it expect to pay any cash tax in the remainder of 2019 or 2020 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

Deferred income taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities. For the three and six months ended June 30, 2019, the Company recognized a deferred income tax expense of $2.5 million and $3.1 million, respectively, as a result of $10.4 million and $11.6 million of net income before taxes, respectively. As at June 30, 2019, the Corporation had a deferred income tax liability of $7.6 million.

Tax Pools	As at June 30, 2019	Maximum Annual Deduction
Canadian oil and gas property expense	$ 46,000	10%
Canadian development expense	125,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	110,000	20% - 100%
Operating losses	172,000	100%
Other	1,000	20% - 100%
Total	$ 477,000	

Net Income (Loss)

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Net income (loss)	$ 7,864	$ (2,815)	$ 8,471	$ 6,079
Per basic and diluted share	$ 0.06	$ (0.02)	$ 0.07	$ 0.05

The mark-to-market valuation of risk management contracts resulted in a considerable distortion on reported net income (loss) for the three and six months ended June 30, 2019 relative to the comparable periods in 2018. For the three and six months ended June 30, 2019, the unrealized gain on risk management contracts amounted to $9.6 million and $4.8 million, respectively, compared to an unrealized loss for the three and six months ended June 30, 2018 of $13.6 million and $15.7 million, respectively.

Excluding unrealized gains and losses on risk management contracts, the decrease in net income in the three and six months ended June 30, 2019 compared to the same periods of 2018 is primarily attributable to the weakened commodity pricing environment driving decreased revenue.

The return on capital employed ("ROCE") over the last 12 months, which is a measurement of the Company's income profitability as a proportion of the funding utilized to generate it (shareholders' equity plus debt including working capital deficiency), was 11% in the second quarter of 2019 compared to 4% in the second quarter of 2018, although as mentioned above is distorted by unrealized gains and losses on the Company's risk management contracts.

Corporate Netbacks

($/Boe)	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Revenue from product sales	20.72	27.07	25.95	28.22
Realized gain (loss) on risk management contracts	(0.22)	0.31	(2.78)	(0.44)
Royalties	(0.32)	(1.11)	(1.46)	(1.41)
Production	(5.89)	(5.46)	(5.99)	(5.51)
Transportation	(5.96)	(6.25)	(5.84)	(5.92)
General and administrative	(0.68)	(0.69)	(1.13)	(1.05)
Interest and finance costs	(0.71)	(0.71)	(0.66)	(0.68)
Funds flow	6.94	13.16	8.09	13.21
Share-based compensation	(0.31)	(0.43)	(0.32)	(0.41)
Depletion, depreciation and accretion	(5.56)	(6.60)	(5.55)	(6.56)
Lease interest	(0.02)	-	(0.02)	-
Exploration and evaluation costs expensed	(0.62)	(0.06)	(0.31)	(0.08)
Unrealized revaluation gain (loss) on investments	-	0.01	-	(0.02)
Unrealized gain (loss) on risk management contracts	5.31	(7.68)	1.34	(4.43)
Deferred income tax expense	(1.41)	-	(0.87)	-
Net income (loss)	4.33	(1.60)	2.36	1.71

INVESTMENT AND FINANCING

Financial Resources and Liquidity

As at June 30, 2019, the Company had an extendible revolving credit facility in the amount of $205 million (December 31, 2018 – $180 million) based on a bank determined borrowing base related to the Company's producing reserves. The credit facility is available to the Company until May 29, 2020, 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 in full one year later. In the event that the lenders reduce the borrowing base below the amount drawn, the Company would have 90 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount. Interest is paid on the utilized portion of the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company.

At June 30, 2019, debt including working capital deficiency amounted to $102.3 million, representing approximately 50% of the available credit facility.

As at June 30, 2019, the Company had issued letters of credit in the amount of $10.2 million (December 31, 2018 - $7.6 million) in support of future natural gas transportation and processing obligations. Availability under the Company's credit facility is reduced by a like amount.

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

Capital Expenditures

In the second quarter of 2019, the Company incurred capital expenditures of $23.1 million compared to $2.9 million in the second quarter of 2018.

In the first six months of 2019, the Company incurred capital expenditures of $40.1 million (first six months of 2018 - $25.8 million) primarily related to costs incurred in constructing the sour gas plant at Nig, as well as drilling and commencing completion activities on a four-well pad at Nig.

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Land and seismic	$ 952	$ 351	$ 1,535	$ 925
Drilling	-	-	11,308	-
Completions	7,931	171	7,954	9,055
Facilities	13,886	664	17,867	6,003
Equipping and pipelines	371	1,150	1,329	8,593
Recompletions and workovers	4	84	49	737
Property acquisition and administrative assets	1	498	47	505
Total capital expenditures	$ 23,145	$ 2,918	$ 40,089	$ 25,818

Net capital investment was allocated as follows:

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Exploration and evaluation	$ 952	$ 539	$ 1,535	$ 1,113
Property and equipment	22,193	2,379	38,554	24,705
Total capital expenditures	$ 23,145	$ 2,918	$ 40,089	$ 25,818

Decommissioning Liability

The Company's decommissioning liability of $29.9 million 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 and inflated amount of the liability at June 30, 2019 was $43.8 million (December 31, 2018 - $43.2 million).

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 office space and field equipment;
- rental obligations for accommodation, office equipment and automotive equipment;
- banking agreements; and
- risk management contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The remaining aggregate commitment approximates $6.5 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 $383.1 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended June 30, 2019 appears below. While the fourth quarter 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 first and third quarter results for 2018 were relatively consistent in terms of capital expenditures, production and funds flow, supported by stable Chicago natural gas prices and materially stronger liquids pricing. Capital expenditures were increased in the fourth quarter of 2018 primarily to include deposits on long-lead-time equipment for the sour gas plant at Nig. In response to strong US based pricing, production was increased in the fourth quarter leading to strong funds flow generation in the period. With funds flow outpacing capital expenditures, debt including working capital was reduced by approximately $15 million over the course of the year.

An unplanned outage in the first quarter of 2019 resulted in approximately 19,500 Boe per day of the Company's production being shut in for 17 days. This had a notable effect on revenue, costs, funds flow and net income for the period. Capital expenditures in the first quarter of 2019 approximated funds flow resulting in marginal movement in debt including working capital deficiency.

In the second quarter of 2019, weaker pricing across all products resulted in lower revenue, while a planned Alliance Pipeline outage resulted in increased costs as fixed transportation tolls were incurred without associated revenue. Debt including working capital deficiency increased to $102.3 million as spending on the Nig gas plant progressed.

	2019		2018				2017	
($000s unless otherwise stated)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenue from product sales	37,568	55,766	74,799	51,253	48,104	52,102	43,506	31,719
Funds flow	12,590	16,517	30,941	22,227	23,405	23,519	21,323	13,170
Per share – basic and diluted ($)	0.10	0.14	0.25	0.18	0.19	0.19	0.18	0.11
Net income (loss)	7,864	607	26,810	7,174	(2,815)	8,894	8,624	682
Per share – basic and diluted ($)	0.06	0.00	0.22	0.06	(0.02)	0.07	0.07	0.01
Net capital expenditures	23,145	16,944	37,100	21,845	2,918	22,900	26,126	23,895
Average daily production (Boe)	19,923	19,823	22,432	20,455	19,529	19,708	17,936	15,193
Debt including working capital deficiency(1)	102,268	91,585	91,020	84,648	85,073	105,585	106,124	101,297

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

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, as outlined in Storm's August 13, 2019 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 2019 guidance;
- future average production volumes in the fourth quarter of 2019 and annual production for 2019, along with production volumes by commodity and production declines including the estimated corporate average decline rate of 20% in 2019;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2019 guidance;
- future reduction to corporate operating costs to approximately $4.25 per Boe with the start-up of the Nig sour gas plant, along with the forecast operating cost for the Nig gas plant of less than $2.00 per Boe and total sales from the Nig gas plant of approximately 10,500 Boe per day (27% liquids);
- future value of unrealized risk management contracts including the estimated hedging loss as outlined in 2019 guidance;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2019 capital expenditure program including 2019 capital investment of $110 million and total cost of approximately $81 million for the Nig sour gas plant;
- preliminary estimated capital investment for 2020 of $80 million and that this is expected to be approximately equal to funds flow;
- forecasted maintenance capital in 2019 of approximately $18 million to maintain production levels of 20,000 to 22,000 Boe per day;
- third quarter 2019 production of 18,000 to 20,000 Boe per day and third quarter capital investment of $45 million;
- future expansion plans at Fireweed including expansion of the compression facility to 100 Mmcf per day, and preliminary planning for 2020 net capital expenditures of $50 million to $55 million with 2020 exit production of over 4,000 Boe per day net to Storm with 25% liquids;
- 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 along with field condensate-gas ratios that are forecast to be significantly higher than Umbach;
- future production levels of 24,000 Boe per day (4,300 barrels per day of liquids) in the fourth quarter of 2019 and 28,000 Boe per day (6,500 barrels per day of liquids) in the fourth quarter 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 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 including the 2019 increase exceeding and the target of remaining within 1.0 to 1.5 times annualized funds flow;
- availability and use of credit facilities including approximately $90 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 along with the expectation to not pay any cash tax in 2019 or 2020;
- 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 8.5 and 14 Bcf raw gas type curves for 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 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 2019 to Chicago, Sumas, Station 2 and AECO markets and the forecasted NGL price net of transport being approximately 5% to 10% of WTI in Cdn$ for the next contract period from April 2019 to March 2020;
- 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"; "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"; "Exploration and Evaluation Costs Expensed"; "Income Taxes"; "Net Income (Loss)"; "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", "CROCE", "ROCE" 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

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

Debt including working capital deficiency is defined as bank indebtedness plus working capital surplus or deficiency excluding the mark-to-market value of risk management 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.

($000s unless otherwise stated)	As at June 30, 2019	As at June 30, 2018	As at June 30, 2017
Accounts receivable	10,982	11,490	3,032
Prepaids and deposits	387	688	702
Accounts payable and accrued liabilities	(29,065)	(9,944)	(10,157)
Working capital deficiency (surplus)	17,696	(2,234)	6,423
Bank indebtedness	84,572	87,307	84,159
Debt including working capital deficiency	102,268	85,073	90,582

CROCE & ROCE

CROCE is non-GAAP financial measure and does not have a standardized meaning under IFRS. CROCE is determined by taking funds flow plus interest and finance costs on a 12-month trailing basis, and dividing it by the average capital employed (shareholders' equity plus debt including working capital deficiency) as presented in the following table.

($000s unless otherwise stated)	Twelve Months Ended June 30, 2019	Twelve Months Ended June 30, 2018
Average debt including working capital deficiency(1)	93,671	87,828
Average shareholders' equity(1)	394,924	362,904
Average capital employed	488,595	450,732
Funds flow	82,275	81,417
Interest and finance costs	4,279	4,355
Funds flow plus interest and finance costs	86,554	85,772
CROCE	18%	19%

(1) The average debt including working capital deficiency and shareholders' equity represent the average of the opening and ending balances as presented on the statement of financial position for the respective period.

ROCE is non-GAAP financial measure and does not have a standardized meaning under IFRS. ROCE is determined by taking net income plus interest and finance costs and deferred income tax expense on a 12-month trailing basis, and dividing it by the average capital employed (shareholders' equity plus debt including working capital deficiency) as presented in the table below.

($000s unless otherwise stated)	Twelve Months Ended June 30, 2019	Twelve Months Ended June 30, 2018
Average debt including working capital deficiency(1)	93,671	87,828
Average shareholders' equity(1)	394,924	362,904
Average capital employed	488,595	450,732
Net income	42,455	15,385
Interest and finance costs	4,279	4,355
Deferred income tax expense	7,562	-
	54,296	19,740
ROCE	11%	4%

(1) The average debt including working capital deficiency and shareholders' equity represent the average of the opening and ending balances as presented on the statement of financial position for the respective period.

The CROCE and ROCE measures allow management and others to evaluate the Company's capital efficiency and ability to generate profitable returns by measuring the Company's earnings (funds flow and net income) relative to the capital employed in the business.

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, 2019 for the year ended December 31, 2018 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2018 under the heading "Business Risks".

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

IFRS 16 Leases

In January 2016, the IASB issued IFRS 16 *Leases* which is effective January 1, 2019 and replaces IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which requires lessees to recognize assets and liabilities for essentially all leases previously classified as operating leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases.

Effective January 1, 2019, the Company adopted IFRS 16 *Leases* using the modified retrospective approach, whereby the cumulative effect of initially applying the standard resulted in the initial recognition of a $3.1 million "Right-of-use asset" with a corresponding increase to "Lease liability" primarily relating to the Company's corporate office lease in Calgary. The modified retrospective approach does not require restatement of prior period comparative financial information and is applied prospectively.

The lease liability was measured at the present value of the remaining lease payments, discounted using the Company's weighted average incremental borrowing rate of approximately 5% on January 1, 2019. The right-of-use asset was measured at amounts equal to the lease liability.

On adoption, the Company used the following practical expedients permitted by the standard:

- Accounted for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases; and
- Accounted for lease payments as an expense for leases for low-value assets.

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Company's lease liability as at January 1, 2019:

		Total
Transportation and processing commitments	$	384,707
Office lease		5,773
Commitments as at December 31, 2018		390,480
Less:		
Agreements that do not contain a lease		(384,707)
Non-lease components		(2,082)
Lease liability commitments as at December 31, 2018		3,691
Discounting at incremental borrowing rate of 5%		(597)
Lease liability as at January 1, 2019	$	3,094

Update to Significant Accounting Policies

Lease Liabilities and Right-of-Use Assets

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the lease commencement date, a lease liability is recognized at the present value of future lease payments, using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. A corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received and initial direct costs. The Company has elected not to recognize leases for short-term leases with a lease term of twelve months or less, or leases for low-value assets. Payments are applied against the lease liability and interest expense is recognized on the lease liability using the effective interest rate method. Depreciation is recognized on the right-of-use asset over the lease term.

Disclosure Controls and Internal Controls Over Financial Reporting

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

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

No material changes in the Company's DCP and its ICFR were identified during the quarter ended June 30, 2019 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.

QUARTERY SUMMARIES

Thousands of Cdn$, except volumetric and per-share amounts	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017
FINANCIAL								
Revenue from product sales[1]	37,568	55,766	74,799	51,253	48,104	52,102	43,507	31,719
Funds flow	12,590	16,517	30,941	22,227	23,405	23,519	21,323	13,170
Per share - basic and diluted ($)	0.10	0.14	0.25	0.18	0.19	0.19	0.18	0.11
Net income (loss)	7,864	607	26,810	7,174	(2,815)	8,894	8,624	682
Per share - basic and diluted ($)	0.06	0.00	0.22	0.06	(0.02)	0.07	0.07	0.01
Cash return on capital employed (“CROCE”)[2]	18%	20%	21%	21%	19%	16%	15%	14%
Return on capital employed (“ROCE”)[2]	11%	8%	10%	6%	4%	7%	10%	5%
Capital expenditures	23,145	16,944	37,100	21,845	2,918	22,900	26,126	23,895
Debt including working capital deficiency[2][3]	102,268	91,585	91,020	84,648	85,073	105,585	106,124	101,297
Common shares (000s)								
Weighted average - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,853	121,649	121,557	121,557	121,557	121,557	121,613
Outstanding end of period – basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
OPERATIONS								
(Cdn$ per Boe)								
Revenue from product sales[1]	20.72	31.26	36.24	27.24	27.07	29.37	26.37	22.68
Transportation costs	(5.96)	(5.72)	(5.57)	(5.98)	(6.25)	(5.59)	(5.94)	(6.09)
Revenue net of transportation	14.76	25.54	30.67	21.26	20.82	23.78	20.43	16.59
Royalties	(0.32)	(2.61)	(0.58)	(1.03)	(1.11)	(1.71)	(0.63)	(0.85)
Production costs	(5.89)	(6.09)	(5.46)	(5.54)	(5.46)	(5.55)	(5.68)	(6.03)
Field operating netback[2]	8.55	16.84	24.63	14.69	14.25	16.52	14.12	9.71
Realized (loss) gain on risk management contracts	(0.22)	(5.38)	(8.65)	(1.73)	0.31	(1.19)	0.41	1.34
General and administrative	(0.68)	(1.60)	(0.55)	(0.66)	(0.69)	(1.42)	(0.94)	(1.03)
Interest and finance costs	(0.71)	(0.61)	(0.45)	(0.49)	(0.71)	(0.64)	(0.67)	(0.61)
Funds flow per Boe	6.94	9.25	14.98	11.81	13.16	13.27	12.92	9.41
Barrels of oil equivalent per day (6:1)	19,923	19,823	22,432	20,455	19,529	19,708	17,936	15,193
Natural gas production								
Thousand cubic feet per day	97,510	96,537	109,520	101,905	96,426	96,068	87,375	74,318
Price (Cdn$ per Mcf)[1]	2.64	4.49	5.56	3.21	3.15	3.83	3.34	3.13
Condensate production								
Barrels per day	2,081	2,199	2,453	2,059	1,984	2,062	1,914	1,600
Price (Cdn$ per barrel)[1]	71.12	62.77	58.74	84.97	86.33	76.12	69.53	53.52
NGL production								
Barrels per day	1,591	1,534	1,726	1,412	1,473	1,635	1,460	1,206
Price (Cdn$ per barrel)[1]	4.87	31.43	35.09	38.64	36.43	33.05	33.29	21.66
Wells drilled (net)	-	5.0	4.0	-	-	-	7.0	3.0
Wells completed (net)	-	-	2.5	5.0	-	3.0	3.0	5.0

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 26 of the attached Management’s Discussion and Analysis. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of risk management contracts and lease liability.

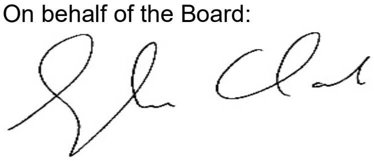
CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

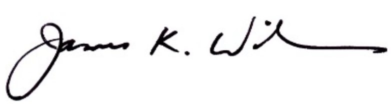
(Canadian $000s) (unaudited)	Notes	June 30, 2019	December 31, 2018
ASSETS			
Current			
Accounts receivable	13	$ 10,982	$ 29,262
Prepaids and deposits		387	853
Risk management contracts	13	3,082	2,341
		14,451	32,456
Exploration and evaluation	4	102,737	102,277
Property and equipment	5	453,164	430,801
Right-of-use asset	3, 8	2,876	-
		$ 573,228	$ 565,534
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current			
Accounts payable and accrued liabilities		$ 29,065	$ 34,359
Risk management contracts	13	-	3,521
		29,065	37,880
Bank indebtedness	6	84,572	86,776
Risk management contracts	13	1,625	2,180
Lease liability	3, 8	2,921	-
Decommissioning liability	9	29,921	26,334
Deferred income taxes		7,562	4,433
		155,666	157,603
Shareholders' equity			
Share capital	10	391,444	391,444
Contributed surplus	11	16,301	15,141
Retained earnings		9,817	1,346
		417,562	407,931
Commitments	15		
		$ 573,228	$ 565,534

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:



Director



Director

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

(Canadian $000s except per-share amounts) (unaudited)	Notes	Three Months Ended June 30 2019	Three Months Ended June 30 2018	Six Months Ended June 30 2019	Six Months Ended June 30 2018
Revenue					
Revenue from product sales	7	$ 37,568	$ 48,104	$ 93,334	$ 100,206
Royalties		(577)	(1,968)	(5,234)	(5,004)
		36,991	46,136	88,100	95,202
Realized gain (loss) on risk management contracts	13	(407)	556	(10,000)	(1,563)
		36,584	46,692	78,100	93,639
Expenses					
Production		10,681	9,703	21,543	19,553
Transportation		10,808	11,108	21,014	21,020
General and administrative		1,228	1,220	4,079	3,744
Share-based compensation	11	564	772	1,160	1,466
Depletion and depreciation	5, 8	9,954	11,599	19,700	23,046
Exploration and evaluation costs expensed	4	1,119	98	1,119	277
Accretion	9	123	128	252	255
Interest and finance costs		1,315	1,256	2,433	2,398
Unrealized (gain) loss on risk management contracts	13	(9,625)	13,648	(4,817)	15,746
Unrealized revaluation (gain) loss on investment		4	(25)	17	55
		26,171	49,507	66,500	87,560
Net income (loss) and comprehensive income (loss)		10,413	(2,815)	11,600	6,079
Deferred income tax expense		2,549	-	3,129	-
Net income (loss) and comprehensive income (loss)		$ 7,864	$ (2,815)	$ 8,471	$ 6,079
Net income (loss) per share					
- Basic and diluted	12	$ 0.06	$ (0.02)	$ 0.07	$ 0.05

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)					Six Months to June 30, 2019
	Notes	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance, beginning of period		$ 391,444	$ 15,141	$ 1,346	$ 407,931
Net income for the period		-	-	8,471	8,471
Share-based compensation	11	-	1,160	-	1,160
Balance, end of period		$ 391,444	$ 16,301	$ 9,817	$ 417,562

(Canadian $000s) (unaudited)					Six Months to June 30, 2018
	Notes	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period		$ 391,444	$ 12,014	$ (38,717)	$ 364,741
Net income for the period		-	-	6,079	6,079
Share-based compensation	11	-	1,466	-	1,466
Balance, end of period		$ 391,444	$ 13,480	$ (32,638)	$ 372,286

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

		Three Months Ended June 30		Six Months Ended June 30	
(Canadian $000s) (unaudited)	Notes	2019	2018	2019	2018
Operating activities					
Net income (loss) for the period		$ 7,864	$ (2,815)	$ 8,471	$ 6,079
Non-cash items:					
Unrealized (gain) loss on risk management	13	(9,625)	13,648	(4,817)	15,746
Depletion, depreciation and accretion	5, 8, 9	10,077	11,727	19,952	23,301
Share-based compensation	11	564	772	1,160	1,466
Lease interest	8	38	-	76	-
Exploration and evaluation costs expensed	4	1,119	98	1,119	277
Unrealized revaluation (gain) loss on investment		4	(25)	17	55
Deferred income tax expense		2,549	-	3,129	-
Funds flow		12,590	23,405	29,107	46,924
Net change in non-cash working capital items	14	6,960	(2,687)	12,904	(499)
		19,550	20,718	42,011	46,425
Financing activities					
Payment on lease liability	8	(124)	-	(249)	-
Decrease in bank indebtedness		(5,034)	(12,050)	(2,204)	(13,686)
		(5,158)	(12,050)	(2,453)	(13,686)
Investing activities					
Additions to property and equipment	5	(22,193)	(2,379)	(38,554)	(24,705)
Additions to exploration and evaluation assets	4	(952)	(539)	(1,535)	(1,113)
Net change in non-cash working capital items	14	8,753	(5,750)	531	(6,921)
		(14,392)	(8,668)	(39,558)	(32,739)
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 June 30, 2019 and December 31, 2018 and for the three and six months ended June 30, 2019 and 2018

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”). Certain information and disclosures normally included in the notes to the consolidated financial statements have been condensed or have been disclosed on an annual basis only. Accordingly, these condensed interim consolidated financial statements should be read in conjunction with the Company’s audited consolidated financial statements as at and for the year ended December 31, 2018. All financial information is reported in thousands of Canadian dollars, which is the functional currency of the Company.

These financial statements were authorized for issue by the Board of Directors on August 13, 2019.

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 13.

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, 2018.

3. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

IFRS 16 Leases

In January 2016, the IASB issued IFRS 16 *Leases* which is effective January 1, 2019 and replaces IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which requires lessees to recognize assets and liabilities for essentially all leases previously classified as operating leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases.

Effective January 1, 2019, the Company adopted IFRS 16 *Leases* using the modified retrospective approach, whereby the cumulative effect of initially applying the standard resulted in the initial recognition of a $3.1 million "Right-of-use asset" with a corresponding increase to "Lease liability" primarily relating to the Company's corporate office lease in Calgary. The modified retrospective approach does not require restatement of prior period comparative financial information and is applied prospectively.

The lease liability was measured at the present value of the remaining lease payments, discounted using the Company's weighted average incremental borrowing rate of approximately 5% on January 1, 2019. The right-of-use asset was measured at amounts equal to the corresponding initial lease liability.

On adoption, the Company used the following practical expedients permitted by the standard:

- Accounted for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases; and
- Accounted for lease payments as an expense for leases for low-value assets.

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Company's lease liability as at January 1, 2019:

		Total
Transportation and processing commitments	$	384,707
Office lease		5,773
Commitments as at December 31, 2018		390,480
Less:		
Agreements that do not contain a lease		(384,707)
Non-lease components		(2,082)
Lease liability commitments as at December 31, 2018		3,691
Discounting at incremental borrowing rate of 5%		(597)
Lease liability as at January 1, 2019	$	3,094

Update to Significant Accounting Policies

Lease Liabilities and Right-of-Use Assets

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the lease commencement date, a lease liability is recognized at the present value of future lease payments, using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. A corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received and initial direct costs. The Company has elected not to recognize leases for short-term leases with a lease term of twelve months or less, or leases for low-value assets. Payments are applied against the lease liability and interest expense is recognized on the lease liability using the effective interest rate method. Depreciation is recognized on the right-of-use asset over the lease term.

4. EXPLORATION AND EVALUATION

	Six Months Ended June 30, 2019	Year ended December 31, 2018
Balance, beginning of period	$ 102,277	$ 103,907
Additions	1,535	4,034
Expiries - exploration and evaluation costs expensed	(1,119)	(277)
Future decommissioning costs	44	370
Transfer to property and equipment	-	(5,757)
Balance, end of period	$ 102,737	$ 102,277

As at June 30, 2019, management reviewed the carrying amounts of exploration and evaluation assets for indicators of impairment and concluded that there are no indicators of potential impairment.

5. PROPERTY AND EQUIPMENT

	Six Months Ended June 30, 2019	Year ended December 31, 2018
Cost		
Balance, beginning of period	$ 646,983	$ 559,524
Additions	38,554	80,729
Future decommissioning costs	3,291	973
Transfer from exploration and evaluation assets	-	5,757
Balance, end of period	$ 688,828	$ 646,983
Accumulated depletion and depreciation		
Balance, beginning of period	$ (216,182)	$ (170,565)
Depletion and depreciation	(19,482)	(45,617)
Balance, end of period	$ (235,664)	$ (216,182)
Net book value, beginning of period	$ 430,801	$ 388,959
Net book value, end of period	$ 453,164	$ 430,801

As at June 30, 2019, the Company determined that there were no indicators of impairment to property and equipment.

As at June 30, 2019, the balance of assets under construction not subject to depreciation or depletion was $26.8 million (December 31, 2018 - $11.4 million) and relates to the construction of a sour gas plant at Nig, located in northeast British Columbia.

6. BANK INDEBTEDNESS

As at June 30, 2019, the Company had an extendible revolving credit facility in the amount of $205 million (December 31, 2018 – $180 million) based on a bank determined borrowing base related to the Company's producing reserves. The credit facility is available to the Company until May 29, 2020, 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 in full one year later. In the event that the lenders reduce the borrowing base below the amount drawn, the Company would have 90 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount. Interest is paid on the utilized portion of the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral provided comprises a floating charge demand debenture on the assets of the Company.

As at June 30, 2019, the Company had issued letters of credit in the amount of $10.2 million (December 31, 2018 - $7.6 million) in support of future natural gas transportation and processing obligations. Available capacity under the Company's credit facility is reduced by a like amount.

7. REVENUE FROM PRODUCT SALES

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

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Natural gas	$ 23,396	$ 27,629	$ 62,400	$ 60,743
Condensate	13,468	15,590	25,890	29,717
NGL	704	4,885	5,044	9,746
Total	$ 37,568	$ 48,104	$ 93,334	$ 100,206

Storm's revenue was generated mostly in British Columbia where production was sold primarily to two major energy customers with investment grade credit ratings which accounted for 80% and 81% of the Company's total revenue from product sales for the three and six months ended June 30, 2019, respectively (June 30, 2018 – 44% and 49%, respectively, from one major customer). The majority of revenues are derived from variable price contracts based on index prices at each sales point. Of total natural gas revenue for the six months ended June 30, 2019, 55% received Chicago pricing, 21% received Station 2 pricing, 11% received Sumas pricing, 10% received AECO pricing and the remaining 3% received ATP pricing.

8. RIGHT-OF-USE ASSET AND LEASE LIABILITY

Right-of-Use Asset

The following table provides a reconciliation of the carrying amount of the right-of-use asset on initial adoption of the lease standard on January 1, 2019 pertaining to the Company's corporate office lease in Calgary:

	Six Months Ended June 30, 2019
Cost	
Balance, beginning of period (Note 3)	$ 3,094
Additions	-
Balance, end of period	$ 3,094
Accumulated depreciation	
Balance, beginning of period	$ -
Depreciation	(218)
Balance, end of period	$ (218)
Net book value, beginning of period	$ 3,094
Net book value, end of period	$ 2,876

As at June 30, 2019, the net book value of the right-of-use asset for the Company's corporate office lease in Calgary is $2.9 million with a remaining lease term to the year 2026.

Lease Liability

The following table provides a reconciliation of the carrying amount of the liability recognized on initial adoption of the lease standard on January 1, 2019 pertaining to the Company's corporate office lease in Calgary:

	Six Months Ended June 30, 2019
Balance, beginning of period (Note 3)	$ 3,094
Lease payments	(249)
Lease interest	76
Balance, end of period	$ 2,921

As at June 30, 2019, the total undiscounted amount of the estimated future cash flows to settle the Company's lease liability over the remaining lease term is $3.4 million.

Short-term leases are leases with a lease term of twelve months or less. During the six months ended June 30, 2019, short-term lease costs of approximately $1.7 million were incurred primarily relating to the lease of drilling equipment which was captured within property and equipment costs.

9. 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 and inflated liability required to settle the Company's decommissioning obligation is approximately $43.8 million (December 31, 2018 - $43.2 million), with the majority of payments being made in the years 2034 to 2053. A risk-free discount rate of 1.7% (December 31, 2018 – 2.2%) and an inflation rate of 2.0% (December 31, 2018 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $29.9 million at June 30, 2019. Currently there are no material decommissioning costs expected to be incurred within the next year.

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

	Six Months Ended June 30, 2019	Year Ended December 31, 2018
Balance, beginning of period	$ 26,334	$ 24,474
Obligations incurred	651	1,406
Obligations settled	(42)	(242)
Change in estimates[1]	2,726	179
Accretion expense	252	517
Balance, end of period	$ 29,921	$ 26,334

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

10. 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, 2018 and June 30, 2019	121,557	$ 391,444

For the period from January 1, 2019 to August 13, 2019 there were no common shares issued upon the exercise of stock options.

11. SHARE-BASED COMPENSATION

The Company has a stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to directors, officers and employees. Options are granted at the volume weighted average price of the shares on the TSX for the five trading days immediately preceding the date of grant, have a four-year term and vest in one-third tranches over three years. Under the stock option plan, at June 30, 2019, a total of 12,155,681 common shares were available for issuance. At June 30, 2019, options in respect of 9,042,400 common shares were issued and outstanding and options in respect of 3,113,281 common shares were available for future issue.

At August 13, 2019, the date of this report, options in respect of 9,102,400 were issued and outstanding and options in respect of 3,053,281 common shares are available for future issue.

Details of the options outstanding at June 30, 2019 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2018	9,088	$ 3.29
Granted during the period	138	$ 2.22
Forfeited during the period	(184)	$ 3.34
Outstanding at June 30, 2019	9,042	$ 3.27
Number exercisable at June 30, 2019	4,027	$ 3.98

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$1.81 - $2.86	4,922	3.0	$ 2.32	774	$ 2.86
$2.87 - $4.50	2,066	0.7	$ 3.44	1,870	$ 3.42
$4.51 - $5.50	2,054	1.4	$ 5.37	1,383	$ 5.37
Total	9,042	2.1	$ 3.27	4,027	$ 3.98

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

The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the six months ended June 30, 2019 of $0.78 per share include the following:

	2019
Share price	$2.22
Exercise price	$2.22
Volatility	45%
Forfeiture rate	2%
Expected option life (years)	3.7
Risk-free interest rate	1.5%

Share-based compensation expense of $0.6 million and $1.2 million was charged to the consolidated statement of income (loss) during the three and six months to June 30, 2019, respectively (2018 - $0.8 million and $1.5 million, respectively) with an equivalent offset to contributed surplus.

12. NET INCOME (LOSS) PER SHARE

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

	Three Months to June 30, 2019	Three Months to June 30, 2018	Six Months to June 30, 2019	Six Months to June 30, 2018
Net income (loss) for the period	$ 7,864	$ (2,815)	$ 8,471	$ 6,079
Weighted average number of common shares outstanding – basic				
Common shares outstanding at beginning of period	121,557	121,557	121,557	121,557
Effect of shares issued	-	-	-	-
Weighted average number of common shares outstanding – basic	121,557	121,557	121,557	121,557
Dilutive effect of outstanding options(1)	-	-	-	-
Weighted average number of common shares outstanding - diluted	121,557	121,557	121,557	121,557
Net income (loss) per share				
Basic and diluted	$ 0.06	$ (0.02)	$ 0.07	$ 0.05

(1) Excludes effect of 9.1 million weighted average common shares related to stock options that were anti-dilutive for the three and six months ended June 30, 2019 (8.3 million and 8.7 million weighted average common shares related to stock options for each of the three and six months ended June 30, 2018, respectively).

13. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, deposits, accounts payable and accrued liabilities, bank indebtedness and risk management 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 and interest rates, 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 risk management contracts described below is based on forward prices of commodities and interest rates available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the three and six months ended June 30, 2019.

The Company's risk management contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at June 30, 2019:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Risk management contracts			
Current asset	$ 27,199	$ (24,117)	$ 3,082
Long-term asset	59	(59)	-
Current liability	(24,117)	24,117	-
Long-term liability	(1,684)	59	(1,625)
Net position	$ 1,457	$ -	$ 1,457

The following is a summary of the Company's financial assets and financial liabilities that were subject to offset as at December 31, 2018:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Risk management contracts			
Current asset	$ 6,900	$ (4,559)	$ 2,341
Long-term asset	-	-	-
Current liability	(8,080)	4,559	(3,521)
Long-term liability	(2,180)	-	(2,180)
Net position	$ (3,360)	$ -	$ (3,360)

Accounts Receivable

The Company's accounts receivable tend to be concentrated with a limited number of marketers of the Company's production as well as joint venture partners and are subject to normal industry credit risk. Receivables from crude oil and natural gas marketers are typically collected on or about the 25th of the following month. The Company's production is sold to organizations whose credit worthiness is in part assessable from publicly available information. As at June 30, 2019, the Company's two major energy customers with investment grade credit ratings accounted for $8.1 million of total receivables (June 30, 2018 - $5.2 million from one major customer) and 80% and 81% of total revenues for the three and six months ended June 30, 2019, respectively (three and six months ended June 30, 2018 – 44% and 49%, respectively). Where operations involve partners in a joint venture, the Company attempts to mitigate the risk from joint venture receivables by obtaining pre-approval and cash call deposits from its partners in advance of significant capital expenditures. Receivables from joint ventures are typically collected within one to three months of the joint venture bill being issued. As at June 30, 2019, there were no receivables outstanding for more than 60 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at June 30, 2019.

The maximum exposure to credit risk at June 30, 2019 was the carrying amount of accounts receivable of $11.0 million and risk management contract assets of $3.1 million. No receivables were impaired at June 30, 2019.

Risk Management

At the date of this report, Storm has the undernoted risk management contracts in place. The fair market value of these contracts at June 30, 2019, a net asset position of $1.5 million (December 31, 2018 – net liability position of $3.4 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the three and six months ended June 30, 2019, this resulted in unrealized mark-to-market gains of $9.6 million and $4.8 million, respectively (2018 – unrealized losses of $13.6 million and $15.7 million, respectively) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Jul – Dec 2019	38,000 Mmbtu	Chicago Cdn$3.24/Mmbtu
Jul – Dec 2019	8,500 Mmbtu	Sumas Cdn$2.67/Mmbtu
Nov 2019 – Mar 2020	1,500 GJ	AECO Cdn$2.00/GJ
Jan – Mar 2020	5,000 Mmbtu	Sumas Cdn$3.93/Mmbtu
Jan – Jun 2020	20,000 Mmbtu	Chicago Cdn$3.33/Mmbtu
Jul – Dec 2020	1,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Natural Gas Differential Swaps		
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		
Jul – Dec 2019	850 Bbls	$73.28 - $87.95 Cdn$/Bbl
Jan – Jun 2020	300 Bbls	$74.67 - $86.28 Cdn$/Bbl
Crude Oil Swaps		
Jul – Dec 2019	650 Bbls	$81.51 Cdn$/Bbl
Jan – Jun 2020	100 Bbls	$81.40 Cdn$/Bbl
Condensate Differential Swaps		
Sept – Dec 2019	600 Bbls	WTI minus Cdn$6.13/Bbl
Jan – Dec 2020	200 Bbls	WTI minus Cdn$8.00/Bbl
Propane Swaps		
Jul – Dec 2019	200 Bbls	$42.87 Cdn$/Bbl

In the second quarter of 2019, the Company entered into an interest rate swap contract to manage the uncertainty of variable interest rates by fixing the variable component of a portion of the interest paid on the Company's revolving bank facility. Interest rate swaps are classified as derivative financial assets and liabilities at fair value through profit and loss and measured at fair value, with gains and losses on re-measurement included as a component of unrealized risk management contracts in the period in which they arise. This interest rate swap is included on the balance sheet as either a risk management contract asset or liability and is classified as current or non-current based on the contractual terms specific to the instrument. As at June 30, 2019, the Company had the following interest rate contract in place to manage interest rate risk:

Index	Effective Date	Notional Principal	Remaining Term	Fixed Contract Rate
One-month bankers' acceptance – CDOR[1]	May 31, 2019	$25 million	July 2019 – May 2022	1.949%

(1) Canadian Dollar Offered Rate.

The Company realized a loss from risk management contracts in place in the amount of $0.4 million for the three months ended June 30, 2019 and realized a loss of $10.0 million for the six months ended June 30, 2019 (2018 – realized gain of $0.6 million and realized loss of $1.6 million, respectively).

Physical Delivery Sales Contract

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

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Jul 2019 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu

Sensitivities

The following table summarizes the effects of movement in commodity prices on net income (loss) due to changes in the fair value of risk management contracts in place at June 30, 2019. Changes in the fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Factor	Six Months Ended June 30, 2019	
Increase of US$10.00/Bbl in the price of WTI[(1)]	$	(3,484)
Decrease of US$10.00/Bbl in the price of WTI[(1)]	$	3,484
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$	(2,182)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$	2,182

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

14. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Three Months to June 30, 2019		Three Months to June 30, 2018		Six Months to June 30, 2019		Six Months to June 30, 2018	
Accounts receivable	$	12,235	$	786	$	18,263	$	3,559
Prepaids and deposits		201		(25)		466		3,854
Accounts payable and accrued liabilities		3,277		(9,198)		(5,294)		(14,833)
Change in non-cash working capital	$	15,713	$	(8,437)	$	13,435	$	(7,420)
Relating to:								
Operating activities	$	6,960	$	(2,687)	$	12,904	$	(499)
Investing activities		8,753		(5,750)		531		(6,921)
Change in non-cash working capital	$	15,713	$	(8,437)	$	13,435	$	(7,420)
Interest paid during the period	$	1,268	$	1,224	$	2,305	$	2,351
Income taxes paid during the period	$	-	$	-	$	-	$	-

15. COMMITMENTS

At June 30, 2019, the Company has the following long-term commitments over the next five years and thereafter:

	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing commitments	$ 29,211	$ 51,951	$ 31,876	$ 31,034	$ 25,259	$213,817	$383,148
Office lease[(1)]	188	376	376	376	376	784	2,476
Total	$ 29,399	$ 52,327	$ 32,252	$ 31,410	$ 25,635	$214,601	$385,624

(1) Office lease commitment includes the operating cost component of the office lease costs.

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 (2)

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

Stikeman Elliott 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
Canadian Western Bank
Calgary, Alberta

Executive Offices

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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
PDP	Proved developed producing reserves
1P	Proved reserves
2P	Proved plus probable reserves
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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