STORM RESOURCES

2019 Q1 REPORT

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
FINANCIAL		
Revenue from product sales(1)	55,766	52,102
Funds flow	16,517	23,519
Per share - basic and diluted ($)	0.14	0.19
Net income	607	8,894
Per share - basic and diluted ($)	0.00	0.07
Cash return on capital employed ("CROCE")(2)	20%	16%
Return on capital employed ("ROCE")(2)	8%	7%
Capital expenditures	16,944	22,900
Debt including working capital deficiency(2)(3)	91,585	105,585
Common shares (000s)		
Weighted average - basic	121,557	121,557
Weighted average - diluted	121,853	121,557
Outstanding end of period – basic	121,557	121,557
OPERATIONS		
(Cdn$ per Boe)		
Revenue from product sales(1)	31.26	29.37
Transportation costs	(5.72)	(5.59)
Revenue net of transportation	25.54	23.78
Royalties	(2.61)	(1.71)
Production costs	(6.09)	(5.55)
Field operating netback(2)	16.84	16.52
Realized loss on commodity price contracts	(5.38)	(1.19)
General and administrative	(1.60)	(1.42)
Interest and finance costs	(0.61)	(0.64)
Funds flow per Boe	9.25	13.27
Barrels of oil equivalent per day (6:1)	19,823	19,708
Natural gas production		
Thousand cubic feet per day	96,537	96,068
Price (Cdn$ per Mcf)(1)	4.49	3.83
Condensate production		
Barrels per day	2,199	2,062
Price (Cdn$ per barrel)(1)	62.77	76.12
NGL production		
Barrels per day	1,534	1,635
Price (Cdn$ per barrel)(1)	31.43	33.05
Wells drilled (net)	5.0	-
Wells completed (net)	-	3.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 25 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 commodity price contracts.

PRESIDENT'S MESSAGE

2019 FIRST QUARTER HIGHLIGHTS

An unplanned 17-day outage at the McMahon Gas Plant in January affected both production and funds flow while capital investment was largely equal to funds flow. Horizontal well performance continues to exceed expectations with declines to date shallower than forecast by management's type curve. Regulatory approval for the sour gas plant at Nig was received in April with site construction expected to start in May. In April, the bank credit facility was increased to $205 million.

- Production was largely unchanged year over year and was consistent with revised guidance provided January 15, 2019. The unplanned 17-day outage at the McMahon Gas Plant reduced production in the period by approximately 15%, or 3,700 Boe per day (January was 12,765 Boe per day while February and March was 23,530 Boe per day).

- Liquids production (field condensate plus gas plant NGL) totaled 3,733 barrels per day which was largely unchanged year over year and represented 19% of total production, or 30% of production revenue.

- At the end of the quarter, there was an inventory of ten Montney horizontal wells (9.5 net) that had not started producing which included two completed wells (1.5 net). During the quarter, two wells (2.0 net) started production.

- At the Nig land block, the first three wells have been producing for ten to twelve months with declines being minimal over this period. First year calendar day rates are forecast to average 7.7 Mmcf per day raw gas or approximately 1,400 Boe per day sales with 21% liquids (including liquids recovered at the gas plant).

- Diversified natural gas sales resulted in the realized price averaging $4.49 per Mcf, or $3.43 per Mcf after deducting pipeline transportation costs, which was significantly higher than Western Canadian pricing (Station 2 $1.24 per GJ and AECO $2.49 per GJ). Firm pipeline commitments required to diversify natural gas sales also result in a higher gas transportation cost which was $1.06 per Mcf in the quarter.

- Realized hedging loss increased to $9.6 million from $2.1 million in the prior year with the majority of the increase resulting from the increase in the natural gas price at Sumas after a pipeline failure in October 2018 reduced capacity by approximately 20%. For the quarter, Sumas monthly index averaged Cdn$9.06 per Mmbtu versus the hedged price of Cdn$3.35 per Mmbtu.

- Controllable cash costs, including transportation, production, general and administrative and interest, increased to $14.02 per Boe in the quarter from $13.20 per Boe in the prior year with the increase resulting from the unplanned outage at the McMahon Gas Plant.

- Funds flow was $16.5 million, or $0.14 per share, a decrease of 26% on a per-share basis year over year which was largely the result of a higher hedging loss, lower condensate prices, and costs associated with the unplanned outage at the McMahon Gas Plant which were approximately $5.3 million ($0.6 million from increased production costs, $1.2 million from unused firm pipeline transportation and $3.5 million to purchase natural gas that was pre-sold at a monthly index price).

- Capital investment was $16.9 million which included $11.3 million to drill five horizontal wells (5.0 net), including a four-well pad at Nig and $3.4 million to purchase equipment for the gas plant at Nig.

- The balance sheet remains strong with debt including working capital deficiency being $92 million or 1.4 times annualized quarterly funds flow and is a reduction from $106 million last year.

- Subsequent to quarter end, the bank credit facility was increased to $205 million from $180 million.

- Commodity price hedges currently protect approximately 40% of forecast production for the remainder of 2019.

- Return on capital employed was 8% and cash return on capital employed was 20% on a 12-month trailing basis. Cash return on capital employed is a more meaningful measure of profitability given it is not affected by non-cash mark-to-market gains and losses on hedging (non-cash hedging loss in the first quarter was $4.8 million).

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 currently totals 121,000 net acres (172 net sections). During the first quarter, five sections of land were acquired.

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 producing horizontal wells in the area have been drilled in the upper part of the Montney formation. Storm's future drilling will also test the mid and lower Montney in certain areas where higher field condensate-gas ratios are expected based on offsetting producing wells.

First quarter field activity included drilling four horizontal wells (4.0 net) on one pad at Nig and one horizontal well (1.0 net) at Umbach which was the last well on a three-well pad. Two horizontal wells (2.0 net) started production in the quarter, both at Umbach.

Field activity in the second and third quarters will be focused on the Nig area and is expected to include completion of a four-well pad, drilling and completing an acid gas injection well and starting construction of the sour gas plant. The four-well pad to be completed at Nig includes two wells in the upper Montney, one in the mid and one in the lower.

At Umbach (100% working interest), production in the quarter averaged 15,870 Boe per day with 19% liquids and is currently approximately 17,500 Boe per day. Activity during the remainder of 2019 is expected to include the completion of three horizontal wells (3.0 net) in the fourth quarter. Field compression capacity totals 150 Mmcf per day raw gas and throughput in the first quarter averaged 125 Mmcf per day raw gas excluding the 17-day period where the McMahon Gas Plant was shut in (includes 25 Mmcf per day raw from Nig). 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 are 65 Mmcf raw gas per day at McMahon (10 Mmcf per day ending 2022, 55 Mmcf per day ending 2031) and 15 Mmcf per day at Stoddart.

At Nig (100% working interest), production in the quarter averaged 3,872 Boe per day with 20% liquids and is currently approximately 4,200 Boe per day. Activity during the remainder of 2019 is expected to include the construction of a 50 Mmcf per day sour gas plant, installing gathering and sales pipelines, drilling and completing an acid gas injection well (1.0 net) and completing and equipping four horizontal wells (4.0 net). In April, regulatory approval was received for the sour gas plant and site construction is expected to start in May with start-up anticipated in early 2020. Produced raw natural gas contains approximately 0.2% H_2S. Total estimated costs associated with the sour gas plant are $81 million (gross) with $11.4 million invested in 2018 and the remainder to be invested in 2019 ($3.4 million to the end of the first quarter). 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 $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 $15 million (net) will be invested in 2019 to drill and complete three horizontal wells (1.5 net) and for equipment deposits for a field compression facility. Depending on the timing for regulatory approvals, construction is anticipated to begin in late 2019 with start-up in the second half of 2020. Total estimated costs associated with the facility are $34 million (gross) and it is designed to be expandable to 100 Mmcf per day. Preliminary planning for 2020 includes investment of approximately $50 million (net) to drill nine horizontal wells (4.5 net), complete six horizontal wells (3.0 net) and construct the field compression facility. 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).

The first horizontal well (0.5 net) at Fireweed was completed in the fourth quarter of 2018 with encouraging results. The C-74-G/94-A-13 well has a completed length of 1,520 metres and, after flowing on a six-day cleanup, rates over the last 12 hours 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. The well is expected to remain shut in until the field compression facility is completed.

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not meaningful indicators of performance as wells are initially rate restricted for several months to manage fluid rates. In addition, the 2018 horizontal wells were affected by the 17-day outage at the McMahon Gas Plant in January 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 12 hz's	34	1830 m	5.0 Mmcf/d(2) 24 Bbls/Mmcf(3) 12 hz's	4.5 Mmcf/d(2) 20 Bbls/Mmcf(3) 12 hz's	4.3 Mmcf/d(2) 14 Bbls/Mmcf(3) 12 hz's
Umbach 2018 7 hz's	35	2005 m	3.9 Mmcf/d(2) 23 Bbls/Mmcf(3) 5 hz's	3.4 Mmcf/d(2 16 Bbls/Mmcf(3) 3 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	7.8 Mmcf/d(2 24 Bbls/Mmcf(3) 1 hz

(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 an 11 Bcf raw gas type curve (internal estimate) to forecast production which represents an average of the expected result at Umbach and Nig. Future wells will be longer (2300 to 2400 metres) and have more fracture stages (41 to 47) which is expected to result in further improvement to rates and reserves. 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 target being to protect pricing on 50% of current sales in any single market 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 40% of forecast production for the remainder of 2019.

Q2 – Q4, 2019	Crude Oil	867 Bpd	WTI Cdn$71.91/Bbl floor, Cdn$85.70/Bbl ceiling
		633 Bpd	WTI Cdn$79.54/Bbl
	Propane	200 Bpd	Conway Cdn$42.87/Bbl
	Natural Gas	41,665 Mmbtu/d (35.1 Mmcf/d)	Chicago Cdn$3.26/Mmbtu
		7,830 Mmbtu/d (6.6 Mmcf/d)	Sumas Cdn$2.65/Mmbtu
		335 GJ/d (0.3 Mmcf/d)	AECO Cdn$2.00/GJ
2020	Crude Oil	100 Bpd	WTI Cdn$74.50/Bbl floor, Cdn$86.43/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.

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 first quarter, 53% of natural gas sales were at a Chicago price, 37% at Western Canadian pricing and 10% 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 April was approximately 21,800 Boe per day based on field estimates with approximately 2,500 Boe per day shut in as a result of low natural gas prices. Production in the second and third quarters of 2019 is expected to average 20,000 to 22,000 Boe per day which includes the impact of a five-day planned maintenance outage at the McMahon Gas Plant in May and a five-day planned maintenance outage on the Alliance Pipeline in June. As a result of the decline in Western Canadian natural gas prices since the end of the winter heating season (April averaged $0.70 per GJ at Station 2 and $0.80 per GJ at AECO), production has been reduced to the minimum level required to fill firm processing and transportation commitments. Prices are not expected to improve until the winter heating season starts in the fourth quarter given numerous maintenance outages scheduled on the NGTL, Alliance and Spectra T-south pipeline systems that will reduce export capacity between May and August. Capital investment in the second quarter is estimated to be $15 to $20 million with approximately 70% allocated to the sour gas plant at Nig.

The failure on the Enbridge T-south natural gas pipeline system in October 2018 has reduced capacity by approximately 20% which has depressed the Station 2 price in relation to AECO while increasing the price at Sumas. To fully restore capacity, inspections are required on various segments and these are expected to be completed by August 2019, however, additional time will also be required for the National Energy Board to complete its review of the results. Until capacity on the T-south pipeline is restored or until the NGTL North Montney extension into northeast British Columbia is in service (possibly early in the fourth quarter of 2019), the Station 2 price is expected to remain depressed in relation to AECO. The financial impact on Storm has not been material given that firm transportation commitments result in less than 15% of produced natural gas being sold at Station 2.

Updated guidance for 2019 is provided below. Pricing has been updated to reflect actual year-to-date prices with pricing for the remainder of 2019 being unchanged.

2019 Guidance

	Previous February 28, 2019	Current May 14, 2019
Cdn$/US$ exchange rate	0.76	0.76
Chicago daily natural gas - US$/Mmbtu	$2.60	$2.65
Sumas monthly natural gas - US$/Mmbtu	$3.10	$3.40
AECO daily natural gas - Cdn$/GJ	$1.60	$1.65
Station 2 daily natural gas - Cdn$/GJ	$1.25	$1.20
WTI - US$/Bbl	$55.00	$55.00
Edmonton condensate differential - US$/Bbl	-$5.50	-$5.50
Est revenue net of transport (excl hedges) - $/Boe	$17.75 - $18.25	$17.75 - $18.25
Est operating costs - $/Boe	$5.50 - $5.75	$5.50 - $5.75
Est royalty rate (% revenue before hedging)	5% - 7%	5% - 7%
Est mid-point field operating netback - $/Boe	$11.30	$11.30
Est hedging loss - $ million	$7.0 - $8.0	$8.0 - $10.0
Est cash G&A - $ million	$6.0 - $7.0	$6.0 - $7.0
- $/Boe	$0.66 - $0.91	$0.66 - $0.91
Est interest expense - $ million	$5.5 - $6.5	$5.5 - $6.5
Est capital investment (excl A&D) - $ million	$128.0	$128.0
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	21,000 - 24,000
% liquids	18%	18%

2019 Guidance

	Previous February 28, 2019	Current May 14, 2019
Est annual funds flow - $ million	$67.0 - $79.0[1]	$65.0 - $77.0[1]
Horizontal wells drilled - gross	9 (7.5 net)	9 (7.5 net)
Horizontal wells completed - gross	11 (9.5 net)	11 (9.5 net)
Horizontal wells starting production - gross	9 (9.0 net)	9 (9.0 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$/bbl)	Estimated Operations Capital ($ 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

With the corporate average decline rate estimated to be 20% in 2019, approximately three new horizontal wells at Nig would be required to offset the decline and maintain 20,000 to 22,000 Boe per day. Wells at Nig are averaging more than 1,400 Boe per day sales in the first year. As a result, at current forward strip commodity prices, funds flow is expected to materially exceed capital investment required to maintain production in 2019.

Capital investment in 2019 remains at $128 million with a significant portion (88%) being directed towards future growth including $70 million for the sour gas plant at Nig, $28 million to drill, complete, and pipeline connect a four-well pad at Nig, and $15 million to advance development at Fireweed. Attractive full-cycle rates of return are expected to be achieved assuming WTI US$55 per barrel, Cdn$/US$ exchange rate 0.76 and Station 2 $1.25 per GJ. Debt including working capital deficiency is forecast to increase by $50 to $60 million by the end of 2019 in order to fund planned growth. This may result in debt including working capital deficiency exceeding the targeted level of 1.0 to 1.5 times annualized funds flow on a short-term basis during construction of the sour gas plant as the full project cost of $81 million must be invested before incremental funds flow is realized. Maintaining a strong balance sheet remains a priority and capital investment and activity are designed to be flexible and can be accelerated or reduced depending on commodity prices.

The near-term plan remains focused on growing funds flow by advancing development of the Nig and Fireweed areas which will be financed using funds flow and available capacity on the bank line. Growth from both areas is expected to reduce per-Boe operating costs while increasing liquids as a proportion of total production with corporate production forecast to increase to approximately 25,000 Boe per day by the end of 2019 (4,600 barrels per day of liquids) and to more than 30,000 Boe per day by the end of 2020 (6,600 barrels per day of liquids). Additional growth from Umbach, where there is under-utilized field compression capacity, is contingent on a higher natural gas price.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

May 14, 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 gas to one barrel of oil. Mboe means 1,000 Boe.

Oil and Gas Metrics - Oil and gas metrics, including FD&A, recycle ratio, FDC, and reserves life index or RLI, do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods.

Initial Production Rates - References to initial production rates, and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered to be preliminary.

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 May 14, 2019 for the three months ended March 31, 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 months ended March 31, 2019. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, 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 May 14, 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 May 14, 2019.

See "Forward Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" on pages 23 to 25.

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 months ended March 31, 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 months ended March 31, 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 immediately prior three month period ended December 31, 2018 and for the three month period ended March 31, 2018.

OPERATIONAL AND FINANCIAL RESULTS

Overview

The strength in natural gas prices experienced in the fourth quarter of 2018 continued into the first quarter of 2019 supported by depressed storage levels and bitterly cold weather in February. Unfortunately for Storm, production levels in January were impacted by the McMahon Gas Plant outage which lasted for 17 days and reduced Storm's corporate production to approximately 4,500 Boe per day resulting in January 2019 average production of 12,765 Boe per day. Given the aforementioned market dynamics, natural gas prices in the first quarter of 2019 were better than this time last year, with Storm's realized price up 17% from the first quarter of 2018. With the decline in demand since the end of the winter heating season and record production levels leading to robust natural gas injections in the US, natural gas prices are under pressure yet again. In response to lower natural gas prices, over the near term Storm expects to maintain production at a level that meets firm processing and transportation commitments. As previously noted, Storm remains well positioned in regards to market access with firm transportation agreements totaling 102 Mmcf per day in 2019, the bulk of which receives US based pricing (65% to 79%).

While representing only 19% of the Company's total production base, condensate (includes field condensate and plant pentanes) and NGL (includes butane and propane) contributed 30% to the Company's top line revenue in the first quarter, buoyed by a US$10.00 per barrel recovery in WTI in the period and a material tightening of the condensate differential relative to December 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.

In the first quarter of 2019, Storm's Boe-per-day production was flat year over year and decreased by 12% when compared to the immediately preceding quarter due to the effect of the McMahon Gas Plant outage in January. Production was ramped up to just over 24,000 Boe per day in February in response to relatively strong natural gas pricing, however, was reduced in March due to weakness in Station 2 pricing. Storm's current production is approximately 21,500 Boe per day based on field estimates. Total existing field compression capacity of 150 Mmcf per day will facilitate growth in production to approximately 27,000 Boe per day, currently dependent on natural gas prices at Station 2.

Field operating netback per Boe for the first quarter of 2019 amounted to $16.84 a slight increase compared to $16.52 in the same period of 2018, while funds flow per Boe decreased to $9.25 from $13.27 in the same period in 2018. The relatively flat field operating netback versus the comparative period was primarily a result of higher realized pricing that was offset by higher royalties and operating costs. Higher natural gas pricing in the first quarter of 2019 was the main driver of the realized loss on commodity price contracts, reducing per-Boe funds flow by $5.38 in the quarter, just over half of which was related to Sumas price hedges. This was the result of a failure on the Enbridge T-south pipeline system on October 9th which materially reduced flows and increased the Sumas price to Cdn$9.06 per Mmbtu in the quarter versus the average hedged price of Cdn$3.35 per Mmbtu. Despite what was a challenging first quarter, the Company still generated a respectable recycle ratio based on the most recent measurement of finding and development cost for proved developed producing reserves ("PDP"), which for Storm amounted to $5.24 per Boe for the year ended December 31, 2018. Using Storm's first quarter funds flow of $9.25 per Boe results in a PDP recycle ratio of approximately 1.8 times, highlighting the ability to turn a profit even when faced with adverse circumstances.

Capital expenditures for the first quarter of 2019 totaled $16.9 million and included $11.3 million for the drilling of five horizontal wells, including a four-well pad at Nig, $4.0 million for facilities (primarily the Nig gas plant), and $1.0 million for equipping and pipelines. During the quarter no wells were completed and two wells were brought on stream. At quarter end the Company had an inventory of ten (9.5 net) standing horizontal wells, of which eight (8.0 net) awaited completion, with the remaining two (1.5 net) wells completed but not yet producing. Based on the current capital program, four (2.5 net) wells will be drilled in the second half of the year, and an additional eleven (9.5 net) wells will be completed over the remainder of the year. 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 first quarter of 2019 approximated funds flow, with this outlay representing approximately 13% of the total capital budget for 2019. It is anticipated that for the remainder of the year planned capital expenditures will be in excess of funds flow with the difference expected to be financed with the Company's recently expanded credit facility.

Subsequent to quarter end, 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, 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.

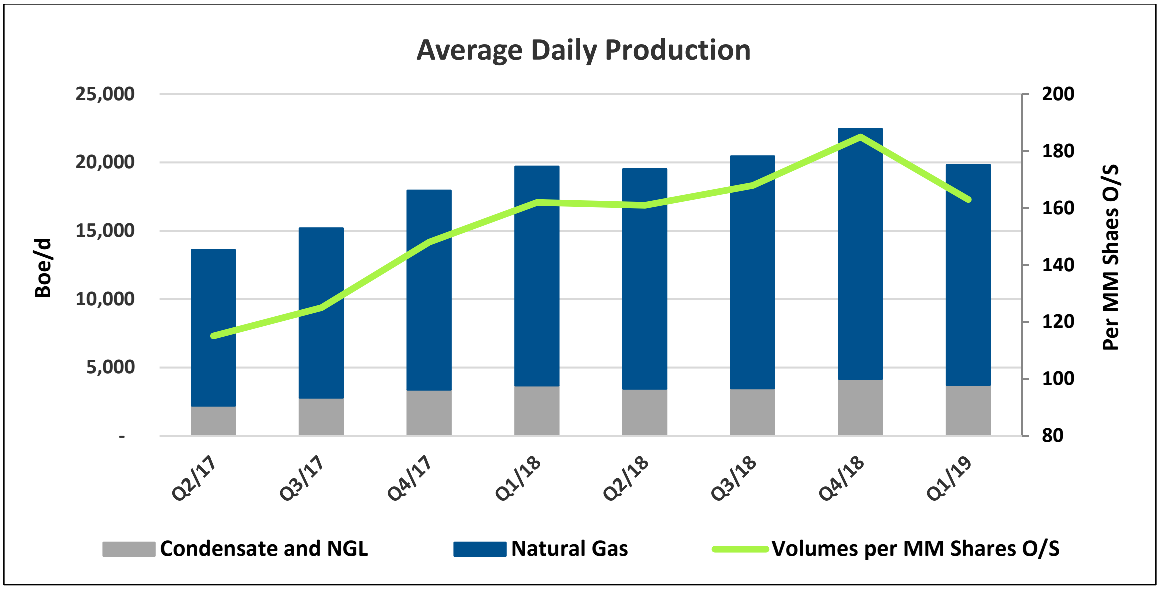
Production and Revenue

Average Daily Production

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Quarter-Over-Quarter Change	Three Months Ended December 31, 2018
Natural gas (Mcf/d)	96,537	96,068	0%	109,520
Condensate (Bbls/d)	2,199	2,062	7%	2,453
NGL (Bbls/d)	1,534	1,635	(6%)	1,726
Total (Boe/d)	19,823	19,708	1%	22,432
Natural gas weighting	81%	81%		81%
Condensate weighting	11%	11%		11%
NGL weighting	8%	8%		8%

Production for natural gas, condensate and NGL in the first quarter of 2019 was comparable to the first quarter of 2018.

Production in the first quarter of 2019 was negatively affected by the unplanned outage at the McMahon Gas Plant for 17 days in January of 2019. The outage resulted in the shut-in of approximately 19,500 Boe per day. At Umbach, the Company started production from two new 100% working interest horizontal wells during the first quarter of 2019. In the fourth quarter of 2018, the Company started production from three new 100% working interest horizontal wells at Umbach.



Daily production per million shares outstanding at the end of the first quarter of 2019 averaged 163 Boe per day, compared to 162 Boe per day for the first quarter of 2018, an increase of 1%, and 185 Boe per day for the fourth quarter of 2018, a decrease of 12%.

Average Selling Prices[(1)]

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Natural gas – Mcf	$ 4.49	$ 3.83	$ 5.56
Condensate – Bbl	$ 62.77	$ 76.12	$ 58.74
NGL – Bbl	$ 31.43	$ 33.05	$ 35.09
Per Boe	$ 31.26	$ 29.37	$ 36.24

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

On a per-Boe basis, the Company's average realized price for the first quarter of 2019 increased by 6% compared to the same period of 2018, with the increase driven by an increase in natural gas pricing, particularly from Sumas and Chicago which averaged US$6.81 per Mmbtu and US$3.32 per Mmbtu, respectively. This increase was partially offset by decreases in condensate and NGL prices.

On a per-Boe basis, the Company's average realized price for the first quarter of 2019 decreased by 14% when compared to the fourth quarter of 2018, primarily driven by decreases in natural gas and NGL pricing, partially offset by an increase in condensate prices.

Benchmark Prices

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Natural gas			
Chicago monthly index (US$/Mmbtu)	3.32	3.27	3.62
Chicago daily index (US$/Mmbtu)	3.04	2.95	3.69
Sumas (US$/Mmbtu)	6.81	2.46	11.09
AECO monthly index (Cdn$/GJ)	1.84	1.76	1.80
AECO daily index (Cdn$/GJ)	2.49	1.97	1.48
Station 2 (Cdn$/GJ)	1.24	1.81	0.64
Crude Oil			
WTI (US$/Bbl)	54.90	62.87	58.81
WTI (Cdn$/Bbl)	72.98	79.53	77.59
Edmonton C5+ (Cdn$/Bbl)	67.20	79.74	59.66
Exchange rate (US$/Cdn$)	0.75	0.79	0.76

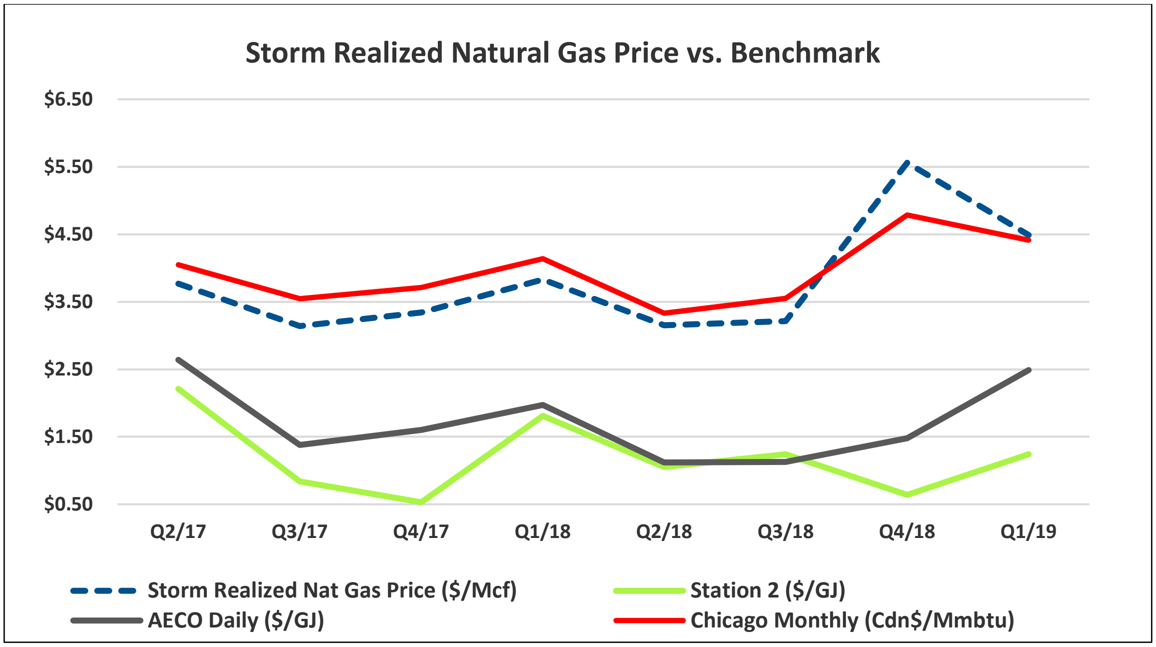
Storm's realized prices differ from market indices due to fluctuations in the foreign exchange rate and the higher heat content of the Company's natural gas will increase the per-Mcf price.

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 quarter of 2019, the monthly Sumas index price fluctuated as low as US$3.78 per Mmbtu in February 2019 to a high of US$10.46 per Mmbtu in March 2019 driving increased revenue for Storm which was offset by increased hedging losses on 70% of Storm's sales at Sumas. Sumas pricing in April normalized to US$2.66 per Mmbtu with decreased demand in the Pacific Northwest.

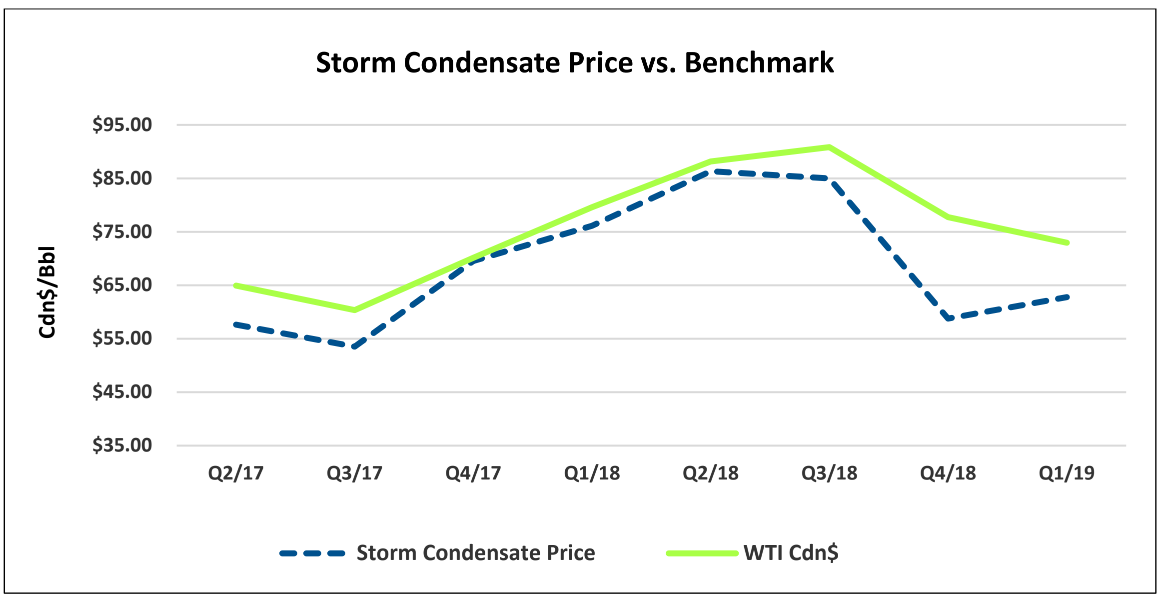
WTI crude oil pricing, on which a large part of the Company's condensate and NGL revenue is based, declined 13% from US$62.87 per barrel during the first quarter of 2018 to US$54.90 per barrel for the first quarter of 2019 due to continued market concerns over supply outpacing demand. In addition to the decrease in the WTI price was the widening of the condensate differential from a premium of US$0.17 per barrel in the first quarter of 2018 to a discount of US$4.35 per barrel for the first quarter of 2019. The condensate differential for the second quarter of 2019 is expected to settle at an approximate US$4.00 per barrel discount to WTI.

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Chicago monthly index price	34%	41%	35%
Chicago daily index price	19%	23%	28%
AECO daily index price	13%	0%	11%
Station 2 daily spot price	20%	17%	10%
Sumas index price	10%	13%	11%
Alliance Transfer Point ("ATP")	4%	6%	5%
Total	100%	100%	100%

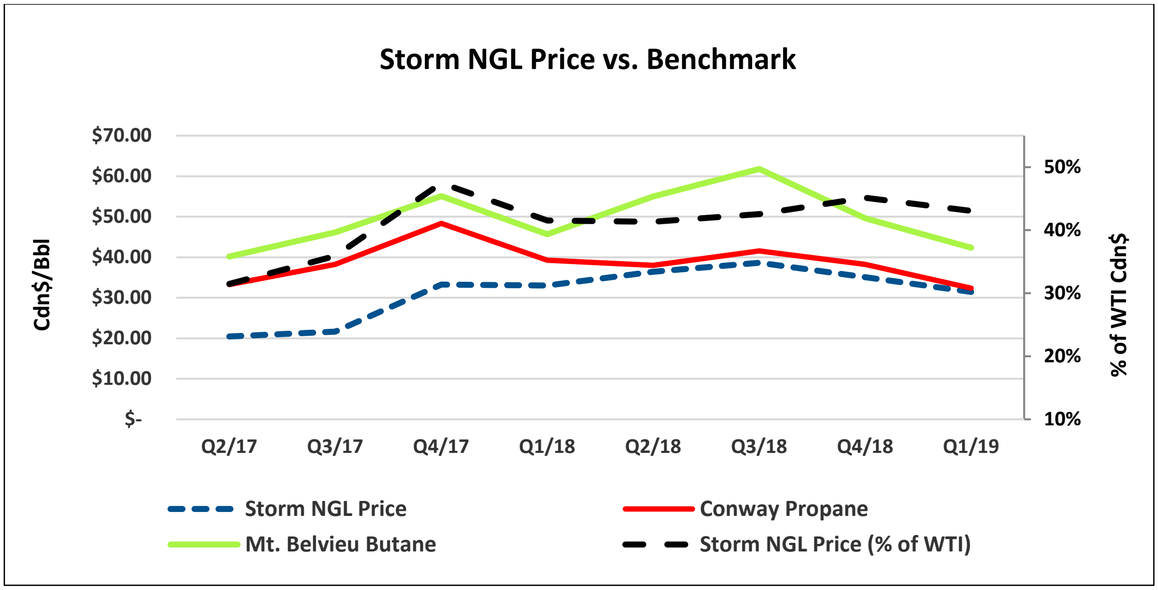


As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was approximately 242% higher than Station 2 pricing in the first quarter of 2019. A significant contributor to the increase in Storm's realized natural gas price to $4.49 per Mcf in the first quarter of 2019 was an increase in Sumas and Chicago pricing, which conversely led to increased hedging losses of $1.14 per Mcf. Including the hedging loss, the realized natural gas price of $3.35 per Mcf was a premium to Western Canadian natural gas benchmark pricing.



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

When comparing the first quarter of 2019 to the previous quarter, Storm's condensate price increased 7% as a result of the narrowing of the WTI-condensate differential from -US$13.52 per barrel in the fourth quarter of 2018 to -US$4.35 per barrel in the first quarter of 2019, partially offset by a decrease in the WTI price. The widening of the differentials in the fourth quarter of 2018 was primarily due to pipeline constraints and refinery outages reducing demand for diluent blending.



Storm's realized price for NGL, excluding condensate, in the first quarter of 2019 decreased by 5% relative to the same period of 2018. When comparing the first quarter of 2019 to the previous quarter, the realized price for NGL, excluding condensate, decreased by 10%. The decrease in realized NGL prices for both of the aforementioned periods was primarily due to weaker WTI pricing period over period.

Given elevated supply levels in 2019 for NGL in Western Canada (primarily butane), Storm's NGL price net of transportation is anticipated to be approximately 10% to 15% of WTI in Canadian dollar terms for the contract period that commenced in April 2019 and ends in March 2020. This compares to an average realization of approximately 43% in the first quarter of 2019.

Revenue from Product Sales[(1)]

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Natural gas	$ 39,005	$ 33,113	$ 55,973
Condensate	12,422	14,127	13,256
NGL	4,339	4,862	5,570
Total	$ 55,766	$ 52,102	$ 74,799
% of Total Revenue by Product Type			
Natural gas	70%	64%	75%
Condensate and NGL	30%	36%	25%
Total	100%	100%	100%

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

Revenue from product sales for the first quarter of 2019 increased by 7% when compared to the first quarter of 2018 primarily as a result of the Company's average realized price increasing by 6% and production volumes increasing by 1%. This was partially offset by revenue for natural gas being reduced by $3.5 million to purchase natural gas during the outage at the McMahon Gas Plant to meet firm delivery commitments for natural gas that was pre-sold at a monthly index price for hedging. Compared to the prior quarter, revenue from product sales decreased by 25% due to production volumes decreasing 12% and the Company's average realized price decreasing by 14%. Production in the first quarter of 2019 was lower due to the unplanned outage at the McMahon Gas Plant.

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

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q1 2018	$ 33,113	$ 14,127	$ 4,862	$ 52,102
Effect of changes in production	162	938	(299)	801
Effect of changes in average product prices	5,730	(2,643)	(224)	2,863
Revenue from product sales – Q1 2019	$ 39,005	$ 12,422	$ 4,339	$ 55,766

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q4 2018	$ 55,973	$ 13,256	$ 5,570	$ 74,799
Effect of changes in production	(7,708)	(1,631)	(725)	(10,064)
Effect of changes in average product prices	(9,260)	797	(506)	(8,969)
Revenue from product sales – Q1 2019	$ 39,005	$ 12,422	$ 4,339	$ 55,766

Commodity Price Risk Management

	Three Months Ended March 31, 2019		Three Months Ended March 31, 2018		Three Months Ended December 31, 2018	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (9,922)	$ 2,282	$ (483)	$ (620)	$ (16,774)	$ (4,212)
Liquids[(1)]	329	(7,090)	(1,636)	(1,478)	(1,087)	16,497
Gain (loss) on commodity price contracts	$ (9,593)	$ (4,808)	$ (2,119)	$ (2,098)	$ (17,861)	$ 12,285

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

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

The realized gain (loss) on commodity price contracts consists of the portion of contracts that have settled in cash during the reporting period. The realized loss during the first quarter of 2019 of $9.6 million was primarily due to stronger Chicago and Sumas market index pricing received by the Company in the period compared to natural gas fixed price swap contracts which averaged Cdn$3.28 per Mmbtu for Chicago and Cdn$3.35 per Mmbtu for Sumas. After considering the effect of hedging, Storm's realized natural gas price in the first quarter of 2019 was $3.35 per Mcf, compared to $3.77 per Mcf in the first quarter of 2018. The realized loss of $2.1 million during the first quarter of 2018 was primarily related to losses on crude oil commodity price contracts resulting from the improvement in crude oil benchmark pricing which also led to higher liquids revenue in the period.

The unrealized gain (loss) on commodity price 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 Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Charge for period	$ 4,657	$ 3,036	$ 1,189
Percentage of revenue from product sales	8.4%	5.8%	1.6%
Per Boe	$ 2.61	$ 1.71	$ 0.58

Royalties, as a percentage of revenue from product sales, in the first quarter of 2019, increased compared to the same period in 2018 due to a reduction of wells benefitting from the BC Deep Well Royalty Program as higher realized pricing has accelerated usage of the royalty credit as well as a one-time adjustment of $0.5 million. 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 first quarter of 2019, 30 wells qualified for the 6% royalty rate compared to 36 wells in the first quarter of 2018 and 37 wells in the fourth quarter of 2018.

Royalties, as a percentage of revenue from product sales, increased in the first quarter of 2019 from the fourth quarter of 2018 due to the receipt of an infrastructure royalty credit in the fourth quarter of 2018 ($3.9 million), in addition to fewer wells qualifying for the BC Deep Well Royalty Program.

Storm has remaining infrastructure royalty credits of $4.3 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 Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Charge for period	$ 10,862	$ 9,850	$ 11,270
Per Boe	$ 6.09	$ 5.55	$ 5.46

Total production costs for the first quarter of 2019 increased 10% when compared to the first quarter of 2018 and decreased 4% when compared to the fourth quarter of 2018. The increase in total production costs compared to the same period in 2018 was primarily due to fixed costs incurred during the McMahon Gas Plant outage (approximately $0.6 million). The decrease in total production costs relative to the prior quarter is largely due to lower production volumes offset to a degree by fixed costs incurred during the McMahon Gas Plant outage.

Production costs per Boe for the first quarter of 2019 increased by 10% when compared to the first quarter of 2018 and by 12% when compared to the fourth quarter of 2018 due to reduced production during the unplanned McMahon Gas Plant outage.

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 Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Charge for period	$ 1,351	$ 1,207	$ 1,368
Per Boe	$ 0.76	$ 0.68	$ 0.66

Transportation Costs

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Charge for period	$ 10,206	$ 9,912	$ 11,487
Per Boe	$ 5.72	$ 5.59	$ 5.57

Transportation costs include pipeline tariffs for natural gas sold at various points, as well as trucking costs and pipeline tariffs for condensate. Natural gas sales volumes destined for Chicago and markets across North America require additional transportation costs, but obtain higher sales prices to offset the additional pipeline tariffs to move natural gas from producing areas to consuming regions. Transportation costs for the first quarter of 2019, increased by 3%, and by 2% per Boe, when compared to the first quarter of 2018. Higher total transportation costs reflect approximately $1.2 million for costs on firm contracted capacity that was under-utilized during the McMahon Gas Plant outage, partially offset by a lower proportion of natural gas volumes sold in Chicago (pipeline capacity to Chicago has the highest transportation cost).

Transportation costs for the first quarter of 2019 were 11% lower compared to the fourth quarter of 2018 while per-Boe transportation costs increased by 3%. Transportation costs decreased due to lower production levels and a lower proportion of natural gas volumes sold in Chicago. The increase in transportation costs on a per-Boe basis is largely the result of incurring transportation costs on under-utilized firm contracted capacity during the McMahon Gas Plant outage during the first quarter of 2019.

Field Operating Netbacks

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

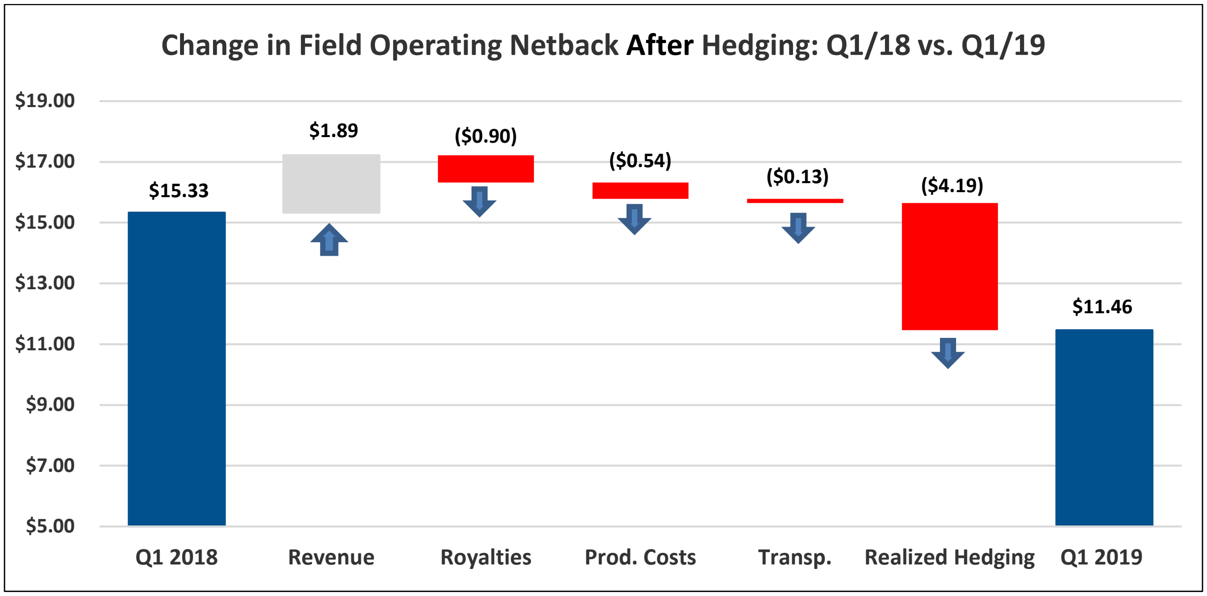
Three Months Ended March 31, 2019	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 4.49	$ 62.77	$ 31.43	$ 31.26
Royalties	(0.29)	(7.81)	(4.41)	(2.61)
Production costs	(1.25)	-	-	(6.09)
Transportation costs	(1.06)	(5.08)	-	(5.72)
Field operating netback	$ 1.89	$ 49.88	$ 27.02	$ 16.84
Realized gain (loss) on commodity price contracts	(1.14)	0.70	1.38	(5.38)
Field operating netback including hedging	$ 0.75	$ 50.58	$ 28.40	$ 11.46

Three Months Ended March 31, 2018	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.83	$ 76.12	$ 33.05	$ 29.37
Royalties	(0.15)	(6.67)	(3.20)	(1.71)
Production costs	(1.14)	-	-	(5.55)
Transportation costs	(1.05)	(4.60)	-	(5.59)
Field operating netback	$ 1.49	$ 64.85	$ 29.85	$ 16.52
Realized gain (loss) on commodity price contracts	(0.06)	(8.84)	0.04	(1.19)
Field operating netback including hedging	$ 1.43	$ 56.01	$ 29.89	$ 15.33

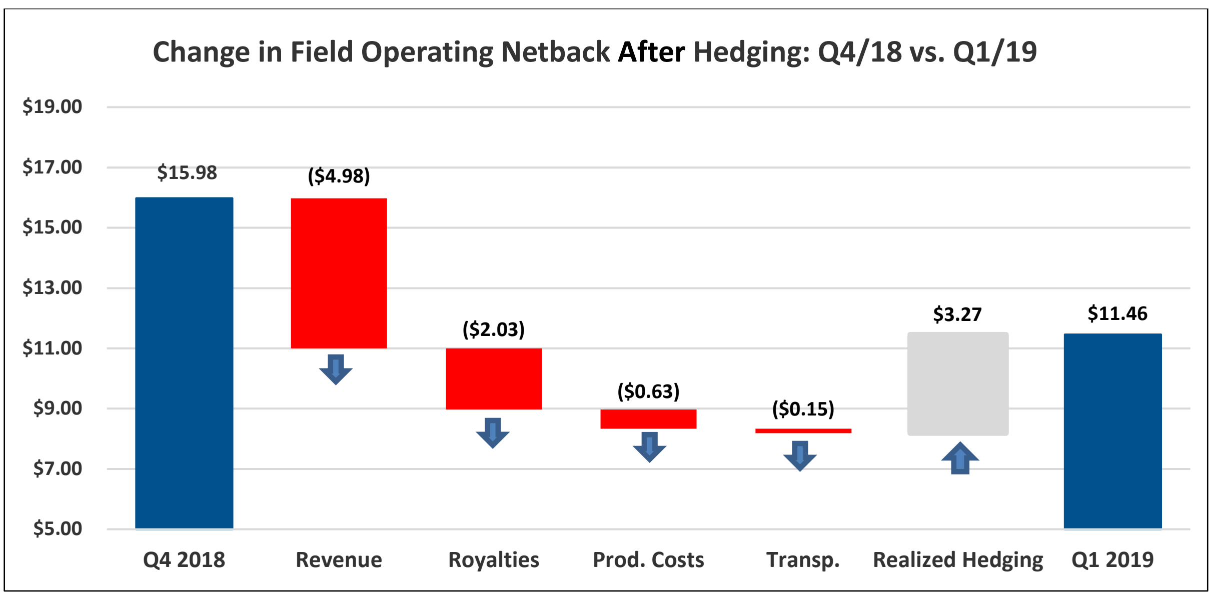
Three Months Ended December 31, 2018	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 5.56	$ 58.74	$ 35.09	$ 36.24
Royalties	0.03	(4.52)	(3.24)	(0.58)
Production costs	(1.12)	-	-	(5.46)
Transportation costs	(1.02)	(5.49)	-	(5.57)
Field operating netback	$ 3.45	$ 48.73	$ 31.85	$ 24.63
Realized gain (loss) on commodity price contracts	(1.66)	(4.98)	0.23	(8.65)
Field operating netback including hedging	$ 1.79	$ 43.75	$ 32.08	$ 15.98

(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 first quarter of 2019 increased by 2% (25% decrease after hedging) compared to the first quarter of 2018.



The field operating netback for the first quarter of 2019 decreased by 32% (28% decrease after hedging) compared to the fourth quarter of 2018.



General and Administrative Costs

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Charge for period – before recoveries	$ 3,246	$ 2,818	$ 2,061
Overhead recoveries	(395)	(294)	(933)
Charge for period – net of recoveries	$ 2,851	$ 2,524	$ 1,128
Per Boe	$ 1.60	$ 1.42	$ 0.55

General and administrative costs before recoveries for the first quarter of 2019 increased by 15% when compared to the first quarter of 2018 and increased by 57% compared to the fourth quarter of 2018. The increase in general and administrative costs for the first quarter of 2019 relative to the same period in 2018 and the immediately preceding quarter is primarily attributable to the payout of the annual employee performance bonus after year-end results were finalized.

As a result of IFRS 16 effective January 1, 2019, general and administrative costs in the first quarter of 2019 are lower by $0.1 million of office lease payments.

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 first quarter of 2019 increased by 13% compared to the first quarter of 2018, and increased by 191% compared to the fourth quarter of 2018. General and administrative costs for the first quarter tend to be higher due to the annual employee performance bonus payout, if earned. 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 Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Charge for period(1)	$ 1,118	$ 1,142	$ 923
Average interest rate(2)	4.6%	4.5%	4.6%
Per Boe	$ 0.63	$ 0.64	$ 0.45

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

The interest rate on the Company's credit 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.

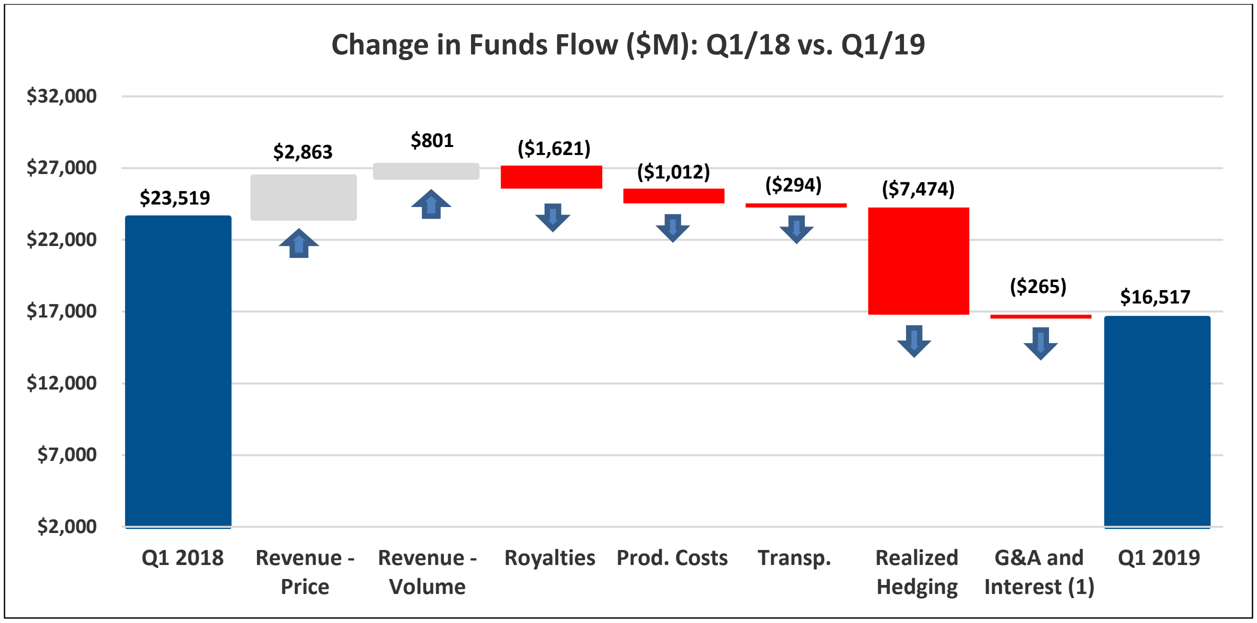
Interest costs for the first quarter of 2019 decreased by 2% compared to the same quarter of 2018 as a result of a reduction in bank borrowings and lower stamping fees, partially offset by an increase in market interest rates.

Interest costs for the first quarter of 2019 increased by 21% compared to the fourth quarter of 2018 as a result of an increase in bank borrowings.

Funds Flow

	Three Months Ended March 31, 2019		Three Months Ended March 31, 2018		Three Months Ended December 31, 2018	
		Per diluted share		Per diluted share		Per diluted share
Funds flow	$ 16,517	$ 0.14	$ 23,519	$ 0.19	$ 30,941	$ 0.25

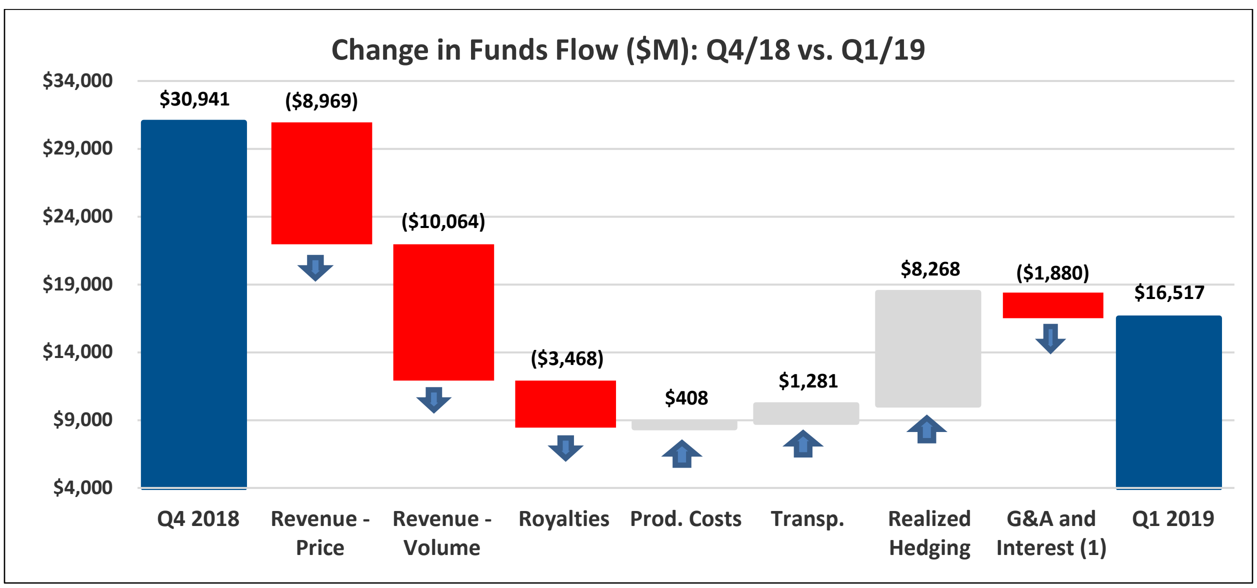
Funds flow, a measure that is not defined under IFRS, is cash from operations before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies and is used by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



(1) Excludes lease interest.

Higher realized hedging losses and higher costs associated with the outage at the McMahon Gas Plant were partially offset by higher realized prices and were the primary factors in funds flow decline of 30% in the first quarter of 2019 versus the first 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), increased from 16% in the first quarter of 2018 to 20% in the first quarter of 2019.



(1) Excludes lease interest.

Funds flow for the first quarter of 2019 decreased by 47% from the fourth quarter of 2018. Funds flow was negatively affected by lower production volumes, higher costs related to the McMahon Gas Plant outage and weaker realized pricing relative to the fourth quarter of 2018, partially offset by lower realized hedging losses.

Share-Based Compensation

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Charge for period	$ 596	$ 694	$ 838
Per Boe	$ 0.33	$ 0.39	$ 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 14% in the first quarter of 2019 compared to the same quarter of 2018 and decreased by 29% when compared to the immediately prior quarter. The decrease in share-based compensation is primarily attributable to a lower option fair valuation associated with options granted in 2018.

Depletion and Depreciation

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Depletion	$ 7,852	$ 9,835	$ 9,027
Depreciation	1,894	1,612	1,772
Charge for period	$ 9,746	$ 11,447	$ 10,799
Per Boe	$ 5.46	$ 6.45	$ 5.23

Depletion and depreciation decreased by 15% in the first quarter of 2019 compared to the same quarter of 2018 due to lower finding and development costs. The quarterly per-Boe decrease in depletion corresponds to lower finding and development costs at Umbach.

Comparing the first quarter of 2019 with the fourth quarter of 2018, production volumes declined by 12% with a corresponding decrease in the depletion and depreciation charge of 10%. The increase on a per-Boe basis in the first quarter of 2019 compared to the prior quarter corresponds to depreciation costs on facilities that are depreciated evenly in the period despite reduced production during the unplanned McMahon Gas Plant outage.

Income Taxes

The Company did not incur any cash tax expense in the three months ended March 31, 2019, nor does it expect to pay any cash tax in 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 our assets and liabilities. For the three months ended March 31, 2019, the Company recognized a deferred income tax expense of $0.6 million as a result of $1.2 million of net income before taxes. As at March 31, 2019, the Corporation had a deferred income tax liability of $5.0 million.

Tax Pools	As at March 31, 2019	Maximum Annual Deduction
Canadian oil and gas property expense	$ 46,000	10%
Canadian development expense	127,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	104,000	20% - 100%
Operating losses	165,000	100%
Other	1,000	20% - 100%
Total	$ 466,000	

Net Income

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Net income	$ 607	$ 8,894	$ 26,810
Per basic and diluted share	$ 0.00	$ 0.07	$ 0.22

The mark-to-market valuation of commodity price contracts resulted in a considerable distortion on reported net income for both the first quarter of 2019 relative to the same period in 2018 and to the fourth quarter of 2018. For the first quarter of 2019, the unrealized loss on commodity price contracts amounted to $4.8 million compared to an unrealized loss in the first quarter of 2018 of $2.1 million and an unrealized gain of $12.3 million in the fourth quarter of 2018.

Excluding unrealized gains and losses on commodity price contracts, the decrease in net income in the first quarter of 2019 compared to the same period in 2018 is primarily attributable to increased realized hedging losses, partially offset by an improved pricing environment driving increased 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 8% in the first quarter of 2019 compared to 7% in the first quarter of 2018, although as mentioned above is distorted by unrealized gains and losses on the Company's commodity price contracts.

Corporate Netbacks

($/Boe)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Revenue from product sales	31.26	29.37	36.24
Realized loss on commodity price contracts	(5.38)	(1.19)	(8.65)
Royalties	(2.61)	(1.71)	(0.58)
Production	(6.09)	(5.55)	(5.46)
Transportation	(5.72)	(5.59)	(5.57)
General and administrative	(1.60)	(1.42)	(0.55)
Interest and finance costs	(0.61)	(0.64)	(0.45)
Funds flow	9.25	13.27	14.98
Share-based compensation	(0.33)	(0.39)	(0.41)
Depletion, depreciation and accretion	(5.54)	(6.52)	(5.29)
Lease interest	(0.02)	-	-
Exploration and evaluation costs expensed	-	(0.10)	-
Unrealized revaluation loss on investments	(0.01)	(0.05)	(0.11)
Unrealized gain (loss) on commodity price contracts	(2.69)	(1.18)	5.96
Deferred income tax expense	(0.33)	-	(2.15)
Net income	0.33	5.03	12.98

INVESTMENT AND FINANCING

Financial Resources and Liquidity

As at March 31, 2019, the Company had an extendible revolving credit facility in the amount of $180 million (December 31, 2018 – $180 million) based on a bank determined borrowing base related to the Company's producing reserves. At March 31, 2019, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that debt including working capital deficiency should not exceed the credit facility amount. At March 31, 2019, debt including working capital deficiency amounted to $91.6 million, representing 51% of the available credit facility.

As at March 31, 2019, the Company had issued letters of credit in the amount of $9.9 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.

Subsequent to March 31, 2019, the Company's annual borrowing base review was completed which resulted in the Company's credit facility being increased to $205 million. No additional financial covenants were imposed and the sole financial covenant relating to debt including working capital deficiency not exceeding the credit facility amount has been removed. 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 credit facility at bankers' acceptance rates, plus a stamping fee. Collateral comprises a floating charge demand debenture on the assets of the Company.

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 first quarter of 2019, the Company incurred capital expenditures of $16.9 million compared to $22.9 million in the first quarter of 2018. Capital expenditures in the first quarter of 2019 were primarily related to drilling five horizontal wells, which included a four-well pad at Nig, and for deposits on long-lead-time equipment for the sour gas plant at Nig.

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Land and seismic	$ 583	$ 574	$ 1,043
Drilling	11,308	-	14,613
Completions	23	8,884	10,664
Facilities	3,981	5,339	8,859
Equipping and pipelines	958	7,443	1,766
Recompletions and workovers	45	653	131
Property acquisition and administrative assets	46	7	24
Total capital expenditures	$ 16,944	$ 22,900	$ 37,100

Net capital investment was allocated as follows:

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	Three Months Ended December 31, 2018
Exploration and evaluation	$ 583	$ 574	$ 1,043
Property and equipment	16,361	22,326	36,057
Total capital expenditures	$ 16,944	$ 22,900	$ 37,100

Decommissioning Liability

The Company's decommissioning liability of $29.0 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 March 31, 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
- commodity price 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 $377.7 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended March 31, 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.

	2019			2018				2017
($000s unless otherwise stated)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenue from product sales	55,766	74,799	51,253	48,104	52,102	43,506	31,719	33,262
Funds flow	16,517	30,941	22,227	23,405	23,519	21,323	13,170	11,629
Per share – basic and diluted ($)	0.14	0.25	0.18	0.19	0.19	0.18	0.11	0.10
Net income (loss)	607	26,810	7,174	(2,815)	8,894	8,624	682	9,752
Per share – basic and diluted ($)	0.00	0.22	0.06	(0.02)	0.07	0.07	0.01	0.08
Net capital expenditures	16,944	37,100	21,845	2,918	22,900	26,126	23,895	4,307
Average daily production (Boe)	19,823	22,432	20,455	19,529	19,708	17,936	15,193	13,991
Debt including working capital deficiency(1)	91,585	91,020	84,648	85,073	105,585	106,124	101,297	90,582

(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 May 14, 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 $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 commodity price 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 $128 million and total cost of approximately $81 million for the Nig sour gas plant;
- forecasted maintenance capital in 2019 to maintain production levels of 20,000 to 22,000 Boe per day;
- second and third quarter 2019 production of 20,000 to 22,000 Boe per day and second quarter capital investment of $15 to $20 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 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 25,000 Boe per day (4,600 barrels per day of liquids) by the end of 2019 and more than 30,000 Boe per day (6,600 barrels per day of liquids) by the end of 2020;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;
- future funds flow, including the amounts outlined in 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 a $50 to $60 million increase in 2019 and the target of remaining within 1.0 to 1.5 times annualized funds flow;
- availability and use of credit facilities including approximately $80 million of unused credit capacity at quarter end;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future amounts and use of tax pools and losses along with the expectation to not pay any cash tax in 2019 or 2020;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from drilling longer wells, specifically management's estimated 11 Bcf raw gas type curve for new wells and further improvements on this given future wells with lengths of 2,300 to 2,400 metres;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2019 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and NGL, specifically the anticipated sales allocation in 2019 to Chicago, Sumas, Station 2 and AECO markets and the forecasted NGL price net of transport being approximately 10% to 15% of WTI in Cdn$ 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"; "Commodity Price Risk Management"; "Royalties"; "Production Costs"; "Transportation Costs"; "Field Netbacks"; "General and Administrative Costs"; "Interest and Finance Costs"; "Funds Flow"; "Share-Based Compensation"; "Depletion and Depreciation"; "Income Taxes"; "Net Income"; "Financial Resources and Liquidity"; "Capital Expenditures"; "Decommissioning Liability"; "Contractual Obligations"; industry conditions including commodity prices, facility and pipeline capacity constraints and access to processing facilities and to market for production; currency fluctuations; imprecision of reserve estimates and related costs including future royalties, production and transportation costs and future development costs; environmental risks; competition from other industry participants; the lack of availability of qualified personnel or management; stock market volatility; ability to access sufficient capital from internal and external sources; and the ability of the Company to realize value from its properties. All of these caveats should be considered in the context of current economic conditions, in particular low, in a historical context, prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing domestic and international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Readers are advised that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Storm's actual results, performance or achievement, could differ materially from those expressed in, or implied by, these forward-looking statements. Storm disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required under securities law. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

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

Non-GAAP Measurements - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles ("GAAP"). Specifically, "debt including working capital deficiency", "field operating netbacks", "field operating netbacks including hedging", "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 commodity price contracts. Management believes this is a key measure to assess the Company's liquidity and is used by the Company's lenders to set corporate interest rates.

($000s unless otherwise stated)	As at March 31, 2019	As at March 31, 2018	As at March 31, 2017
Accounts receivable	23,221	12,251	12,514
Prepaids and deposits	588	663	901
Accounts payable and accrued liabilities	(25,788)	(19,142)	(21,345)
Working capital deficiency	1,979	6,228	7,930
Bank indebtedness	89,606	99,357	89,934
Debt including working capital deficiency	91,585	105,585	97,864

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 table below.

($000s unless otherwise stated)	Twelve Months Ended March 31, 2019	Twelve Months Ended March 31, 2018
Average debt including working capital deficiency(1)	98,585	101,725
Average shareholders' equity(1)	391,732	358,575
Average capital employed	490,317	460,300
Funds flow	93,090	69,641
Interest and finance costs	4,220	4,073
Funds flow plus interest and finance costs	97,310	73,714
CROCE	20%	16%

(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 March 31, 2019	Twelve Months Ended March 31, 2018
Average debt including working capital deficiency(1)	98,585	101,725
Average shareholders' equity (1)	391,732	358,575
Average capital employed	490,317	460,300
Net income	31,776	27,952
Interest and finance costs	4,220	4,073
Deferred income tax expense	5,013	-
	41,009	32,025
ROCE	8%	7%

(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 5.0% 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
Effect of discounting(1)		(597)
Lease liability as at January 1, 2019	$	3,094

(1) Lease liability discounted at the incremental borrowing rate of 5%.

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 March 31, 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$, except volumetric and per-share amounts	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017
FINANCIAL								
Revenue from product sales[(1)]	55,766	74,799	51,253	48,104	52,102	43,507	31,719	33,262
Funds flow	16,517	30,941	22,227	23,405	23,519	21,323	13,170	11,629
Per share - basic and diluted ($)	0.14	0.25	0.18	0.19	0.19	0.18	0.11	0.10
Net income	607	26,810	7,174	(2,815)	8,894	8,624	682	9,752
Per share - basic and diluted ($)	0.00	0.22	0.06	(0.02)	0.07	0.07	0.01	0.08
Cash return on capital employed (“CROCE”)[(2)]	20%	21%	21%	19%	16%	15%	14%	13%
Return on capital employed (“ROCE”)[(2)]	8%	10%	6%	4%	7%	10%	5%	5%
Capital expenditures	16,944	37,100	21,845	2,918	22,900	26,126	23,895	4,307
Debt including working capital deficiency[(2)(3)]	91,585	91,020	84,648	85,073	105,585	106,124	101,297	90,582
Common shares (000s)								
Weighted average - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
Weighted average - diluted	121,853	121,649	121,557	121,557	121,557	121,557	121,613	121,682
Outstanding end of period – basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
OPERATIONS								
(Cdn$ per Boe)								
Revenue from product sales[(1)]	31.26	36.24	27.24	27.07	29.37	26.37	22.68	26.12
Transportation costs	(5.72)	(5.57)	(5.98)	(6.25)	(5.59)	(5.94)	(6.09)	(5.75)
Revenue net of transportation	25.54	30.67	21.26	20.82	23.78	20.43	16.59	20.37
Royalties	(2.61)	(0.58)	(1.03)	(1.11)	(1.71)	(0.63)	(0.85)	(1.47)
Production costs	(6.09)	(5.46)	(5.54)	(5.46)	(5.55)	(5.68)	(6.03)	(6.74)
Field operating netback[(2)]	16.84	24.63	14.69	14.25	16.52	14.12	9.71	12.16
Realized (loss) gain on hedging	(5.38)	(8.65)	(1.73)	0.31	(1.19)	0.41	1.34	(1.10)
General and administrative	(1.60)	(0.55)	(0.66)	(0.69)	(1.42)	(0.94)	(1.03)	(1.17)
Interest and finance costs	(0.61)	(0.45)	(0.49)	(0.71)	(0.64)	(0.67)	(0.61)	(0.76)
Funds flow per Boe	9.25	14.98	11.81	13.16	13.27	12.92	9.41	9.13
Barrels of oil equivalent per day (6:1)	19,823	22,432	20,455	19,529	19,708	17,936	15,193	13,991
Natural gas production								
Thousand cubic feet per day	96,537	109,520	101,905	96,426	96,068	87,375	74,318	68,308
Price (Cdn$ per Mcf)[(1)]	4.49	5.56	3.21	3.15	3.83	3.34	3.13	3.77
Condensate production								
Barrels per day	2,199	2,453	2,059	1,984	2,062	1,914	1,600	1,468
Price (Cdn$ per barrel)[(1)]	62.77	58.74	84.97	86.33	76.12	69.53	53.52	57.65
NGL production								
Barrels per day	1,534	1,726	1,412	1,473	1,635	1,460	1,206	1,138
Price (Cdn$ per barrel)[(1)]	31.43	35.09	38.64	36.43	33.05	33.29	21.66	20.45
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 commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 25 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 commodity price contracts.

CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Condensed Interim Consolidated Statements of Financial Position

(Canadian $000s) (unaudited)	March 31, 2019	December 31, 2018
ASSETS		
Current		
Accounts receivable (Note 13)	$ 23,221	$ 29,262
Prepaids and deposits	588	853
Fair value of commodity price contracts (Note 13)	-	2,341
	23,809	32,456
Exploration and evaluation (Note 4)	102,882	102,277
Property and equipment (Note 5)	440,079	430,801
Right-of-use asset (Notes 3 and 8)	2,985	-
	$ 569,755	$ 565,534
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 25,788	$ 34,359
Fair value of commodity price contracts (Note 13)	5,561	3,521
	31,349	37,880
Bank indebtedness (Note 6)	89,606	86,776
Fair value of commodity price contracts (Note 13)	2,607	2,180
Lease liability (Notes 3 and 8)	3,007	-
Decommissioning liability (Note 9)	29,039	26,334
Deferred income taxes	5,013	4,433
	160,621	157,603
Shareholders' equity		
Share capital (Note 10)	391,444	391,444
Contributed surplus (Note 11)	15,737	15,141
Retained earnings	1,953	1,346
	409,134	407,931
Commitments (Note 15)		
	$ 569,755	$ 565,534

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

James K. Wi

Director

Condensed Interim Consolidated Statements of Income and Comprehensive Income

(Canadian $000s except per-share amounts) (unaudited)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Revenue		
Revenue from product sales (Note 7)	$ 55,766	$ 52,102
Royalties	(4,657)	(3,036)
Net revenue	51,109	49,066
Realized loss on commodity price contracts (Note 13)	(9,593)	(2,119)
Unrealized loss on commodity price contracts (Note 13)	(4,808)	(2,098)
Net revenue and commodity price contracts	36,708	44,849
Expenses		
Production	10,862	9,850
Transportation	10,206	9,912
General and administrative	2,851	2,524
Share-based compensation (Note 11)	596	694
Depletion and depreciation (Notes 5 and 8)	9,746	11,447
Exploration and evaluation costs expensed (Note 4)	-	179
Accretion (Note 9)	129	127
Interest and finance costs	1,118	1,142
Unrealized revaluation loss on investment	13	80
Total expenses	35,521	35,955
Net income before taxes	1,187	8,894
Deferred income tax expense	580	-
Net income and comprehensive income for the period	$ 607	$ 8,894
Net income per share (Note 12)		
- Basic and diluted	$ 0.00	$ 0.07

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)	Three Months Ended March 31, 2019			
	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	-	-	607	607
Share-based compensation (Note 11)	-	596	-	596
Balance, end of period	$ 391,444	$ 15,737	$ 1,953	$ 409,134

(Canadian $000s) (unaudited)	Three Months Ended March 31, 2018			
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of period	$ 391,444	$ 12,014	$ (38,717)	$ 364,741
Net income for the period	-	-	8,894	8,894
Share-based compensation (Note 11)	-	694	-	694
Balance, end of period	$ 391,444	$ 12,708	$ (29,823)	$ 374,329

See accompanying notes to the condensed interim consolidated financial statements.

Condensed Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Operating activities		
Net income for the period	$ 607	$ 8,894
Non-cash items:		
Unrealized loss on commodity price contracts (Note 13)	4,808	2,098
Depletion, depreciation and accretion (Notes 5, 8 and 9)	9,875	11,574
Share-based compensation (Note 11)	596	694
Lease interest (Note 8)	38	-
Exploration and evaluation costs expensed (Note 4)	-	179
Unrealized revaluation loss on investment	13	80
Deferred income tax expense	580	-
Funds flow	16,517	23,519
Net change in non-cash working capital items (Note 14)	5,943	2,188
	22,460	25,707
Financing activities		
Payment on lease liability (Note 8)	(125)	-
Increase (decrease) in bank indebtedness	2,830	(1,636)
	2,705	(1,636)
Investing activities		
Additions to property and equipment (Note 5)	(16,361)	(22,326)
Additions to exploration and evaluation assets (Note 4)	(583)	(574)
Net change in non-cash working capital items (Note 14)	(8,221)	(1,171)
	(25,165)	(24,071)
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 March 31, 2019 and December 31, 2018 and for the three months ended March 31, 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 an oil and 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 May 14, 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 5.0% 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
Effect of discounting(1)		(597)
Lease liability as at January 1, 2019	$	3,094

(1) Lease liability discounted at the incremental borrowing rate of 5%.

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

	Three Months Ended March 31, 2019	Year ended December 31, 2018
Balance, beginning of period	$ 102,277	$ 103,907
Additions	583	4,034
Expiries - exploration and evaluation costs expensed	-	(277)
Future decommissioning costs	22	370
Transfer to property and equipment	-	(5,757)
Balance, end of period	$ 102,882	$ 102,277

As at March 31, 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

	Three Months Ended March 31, 2019	Year ended December 31, 2018
Cost		
Balance, beginning of period	$ 646,983	$ 559,524
Additions	16,361	80,729
Future decommissioning costs	2,554	973
Transfer from exploration and evaluation assets	-	5,757
Balance, end of period	$ 665,898	$ 646,983
Accumulated depletion and depreciation		
Balance, beginning of period	$ (216,182)	$ (170,565)
Depletion and depreciation	(9,637)	(45,617)
Balance, end of period	$ (225,819)	$ (216,182)
Net book value, beginning of period	$ 430,801	$ 388,959
Net book value, end of period	$ 440,079	$ 430,801

As at March 31, 2019, the Company determined that there were no indicators of impairment to property and equipment.

As at March 31, 2019, the balance of assets under construction not subject to depreciation or depletion was $14.8 million (December 31, 2018 - $11.4 million) and relate to the construction of a sour gas plant at Nig.

6. BANK INDEBTEDNESS

As at March 31, 2019, the Company had an extendible revolving credit facility in the amount of $180 million (December 31, 2018 – $180 million) based on a bank determined borrowing base related to the Company's producing reserves. At March 31, 2019, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that debt including working capital deficiency should not exceed the credit facility amount.

As at March 31, 2019, the Company had issued letters of credit in the amount of $9.9 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.

Subsequent to March 31, 2019, the Company's annual borrowing base review was completed which resulted in the Company's credit facility being increased to $205 million. No additional financial covenants were imposed and the sole financial covenant relating to debt including working capital deficiency not exceeding the credit facility amount has been removed. 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.

7. REVENUE FROM PRODUCT SALES

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Natural gas	$ 39,005	$ 33,113
Condensate	12,422	14,127
NGL	4,339	4,862
Total	$ 55,766	$ 52,102

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 81% of the Company's total revenue from product sales for the three months ended March 31, 2019 (March 31, 2018 – 44% 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 three months ended March 31, 2019, 53% received Chicago index based pricing, 20% received Station 2 pricing, 13% received AECO pricing, 10% received Sumas pricing and the remaining 4% 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:

	Three Months Ended March 31, 2019
Cost	
Balance, beginning of period (Note 3)	$ 3,094
Additions	-
Balance, end of period	$ 3,094
Accumulated depreciation	
Balance, beginning of period	$ -
Depreciation	(109)
Balance, end of period	$ (109)
Net book value, beginning of period	$ 3,094
Net book value, end of period	$ 2,985

As at March 31, 2019, the net book value of the right-of-use asset for the Company's corporate office lease in Calgary is $3.0 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:

	Three Months Ended March 31, 2019
Balance, beginning of period (Note 3)	$ 3,094
Lease payments	(125)
Lease interest	38
Balance, end of period	$ 3,007

As at March 31, 2019, the total undiscounted amount of the estimated future cash flows to settle the Company's lease liability over the remaining lease term is $3.6 million.

Short-term leases are leases with a lease term of twelve months or less. During the three months ended March 31, 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.

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 1.8% (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 $29.0 million at March 31, 2019. There are currently 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:

	Three Months Ended March 31, 2019	Year Ended December 31, 2018
Balance, beginning of period	$ 26,334	$ 24,474
Obligations incurred	651	1,406
Obligations settled	(37)	(242)
Change in estimates(1)	1,962	179
Accretion expense	129	517
Balance, end of period	$ 29,039	$ 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 March 31, 2019	121,557	$ 391,444

For the period from January 1, 2019 to May 14, 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 March 31, 2019, a total of 12,155,681 common shares were available for issuance. At March 31, 2019, options in respect of 9,178,400 common shares were issued and outstanding and options in respect of 2,977,281 common shares were available for future issue.

At May 14, 2019, the date of this quarterly report, options in respect of 9,100,600 common shares were issued and outstanding and options in respect of 3,055,081 common shares are available for future issue.

Details of the options outstanding at March 31, 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	90	$ 2.32
Outstanding at March 31, 2019	9,178	$ 3.28
Number exercisable at March 31, 2019	4,065	$ 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	4,975	3.3	$ 2.32	793	$ 2.86
$2.87 - $4.50	2,104	1.0	$ 3.44	1,859	$ 3.40
$4.51 - $5.50	2,099	1.7	$ 5.37	1,413	$ 5.37
Total	9,178	2.4	$ 3.28	4,065	$ 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 three months ended March 31, 2019 of $0.81 per share include the following:

	2019
Share price	$2.32
Exercise price	$2.32
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 was charged to the consolidated statement of income during the three months ended March 31, 2019 (March 31, 2018 - $0.7 million) with an equivalent offset to contributed surplus.

12. NET INCOME PER SHARE

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Net income for the period	$ 607	$ 8,894
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of period	121,557	121,557
Effect of shares issued	-	-
Weighted average number of common shares outstanding – basic	121,557	121,557
Dilutive effect of outstanding options[1]	296	-
Weighted average number of common shares outstanding - diluted	121,853	121,557
Net income per share		
Basic and diluted	$ 0.00	$ 0.07

(1) Excludes effect of 6.6 million weighted average common shares related to stock options that were anti-dilutive for the three months ended March 31, 2019 (9.6 million weighted average common shares related to stock options for the three months ended March 31, 2018).

13. FINANCIAL INSTRUMENTS

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

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

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

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's commodity price contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the three months ended March 31, 2019.

The Company's commodity price contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at March 31, 2019:

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Commodity price contracts			
Current asset	$ 2,017	$ (2,017)	$ -
Long-term asset	4,230	(4,230)	-
Current liability	(7,578)	2,017	(5,561)
Long-term liability	(6,837)	4,230	(2,607)
Net position	$ (8,168)	$ -	$ (8,168)

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)
Commodity price 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 March 31, 2019, the Company's two major energy customers with investment grade credit ratings, accounted for $19.0 million (March 31, 2018 - $5.9 million from one major customer) of total receivables and 81% of total revenues (March 31, 2018 – 44% from one major customer). 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 March 31, 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 March 31, 2019.

The maximum exposure to credit risk at March 31, 2019 was the carrying amount of accounts receivable of $23.2 million. No receivables were impaired at March 31, 2019.

Commodity Price Contracts

At the date of this report, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts at March 31, 2019, a net liability position of $8.2 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 months ended March 31, 2019, this resulted in an unrealized mark-to-market loss of $4.8 million (March 31, 2018 – unrealized mark-to-market loss of $2.1 million) when measured against the fair market value at the end of the preceding reporting period. These amounts are recognized in the consolidated statement of income and comprehensive income.

Period Hedged	Daily Volume	Average Price
Natural Gas Swaps		
Apr – Jun 2019	22,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Jul – Dec 2019	11,500 Mmbtu	Chicago Cdn$3.27/Mmbtu
Jul – Dec 2019	2,000 Mmbtu	Sumas Cdn$2.90/Mmbtu
Apr – Dec 2019	26,500 Mmbtu	Chicago Cdn$3.23/Mmbtu
Apr – Dec 2019	6,500 Mmbtu	Sumas Cdn$2.60/Mmbtu
Nov 2019 – Mar 2020	1,500 GJ	AECO Cdn$2.00/GJ
Jan – Jun 2020	20,000 Mmbtu	Chicago Cdn$3.33/Mmbtu
Jun – 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		
Apr – Jun 2019	650 Bbls	$68.83 - $80.74 Cdn$/Bbl
Jul – Dec 2019	600 Bbls	$74.39 - $89.91 Cdn$/Bbl
Apr – Dec 2019	250 Bbls	$70.60 - $83.26 Cdn$/Bbl
Jan – Jun 2020	200 Bbls	$74.50 - $86.43 Cdn$/Bbl
Crude Oil Swaps		
Apr – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Jul – Dec 2019	400 Bbls	$80.90 Cdn$/Bbl
Apr – Dec 2019	250 Bbls	$82.49 Cdn$/Bbl
Propane Swaps		
Apr – Dec 2019	200 Bbls	$42.87 Cdn$/Bbl

The Company realized a loss from commodity price contracts in place in the amount of $9.6 million for the three months ended March 31, 2019 (March 31, 2018 – realized loss of $2.1 million).

Physical Delivery Sales Contract

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

Period Hedged	Daily Volume	Contract Price
Natural Gas		
Apr 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 due to changes in the fair value of commodity price contracts in place at March 31, 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	Three Months Ended March 31, 2019
Increase of US$10.00/Bbl in the price of WTI[1]	$ (4,125)
Decrease of US$10.00/Bbl in the price of WTI[1]	$ 4,125
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$ (1,646)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$ 1,646

(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 Ended March 31, 2019	Three Months Ended March 31, 2018
Accounts receivable	$ 6,028	$ 2,773
Prepaids and deposits	265	3,879
Accounts payable and accrued liabilities	(8,571)	(5,635)
Change in non-cash working capital	$ (2,278)	$ 1,017
Relating to:		
Operating activities	$ 5,943	$ 2,188
Investing activities	(8,221)	(1,171)
Change in non-cash working capital	$ (2,278)	$ 1,017
Interest paid during the period	$ 1,037	$ 1,127
Income taxes paid during the period	$ -	$ -

15. COMMITMENTS

At March 31, 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	$ 42,502	$ 38,656	$ 27,788	$ 28,048	$ 25,541	$ 215,212	$ 377,747
Office lease[1]	284	376	376	376	376	1,129	2,917
Total	$ 42,786	$ 39,032	$ 28,164	$ 28,424	$ 25,917	$ 216,341	$ 380,664

(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
TSX	Toronto Stock Exchange
US	United States
US$	United States dollar
WTI	West Texas Intermediate

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