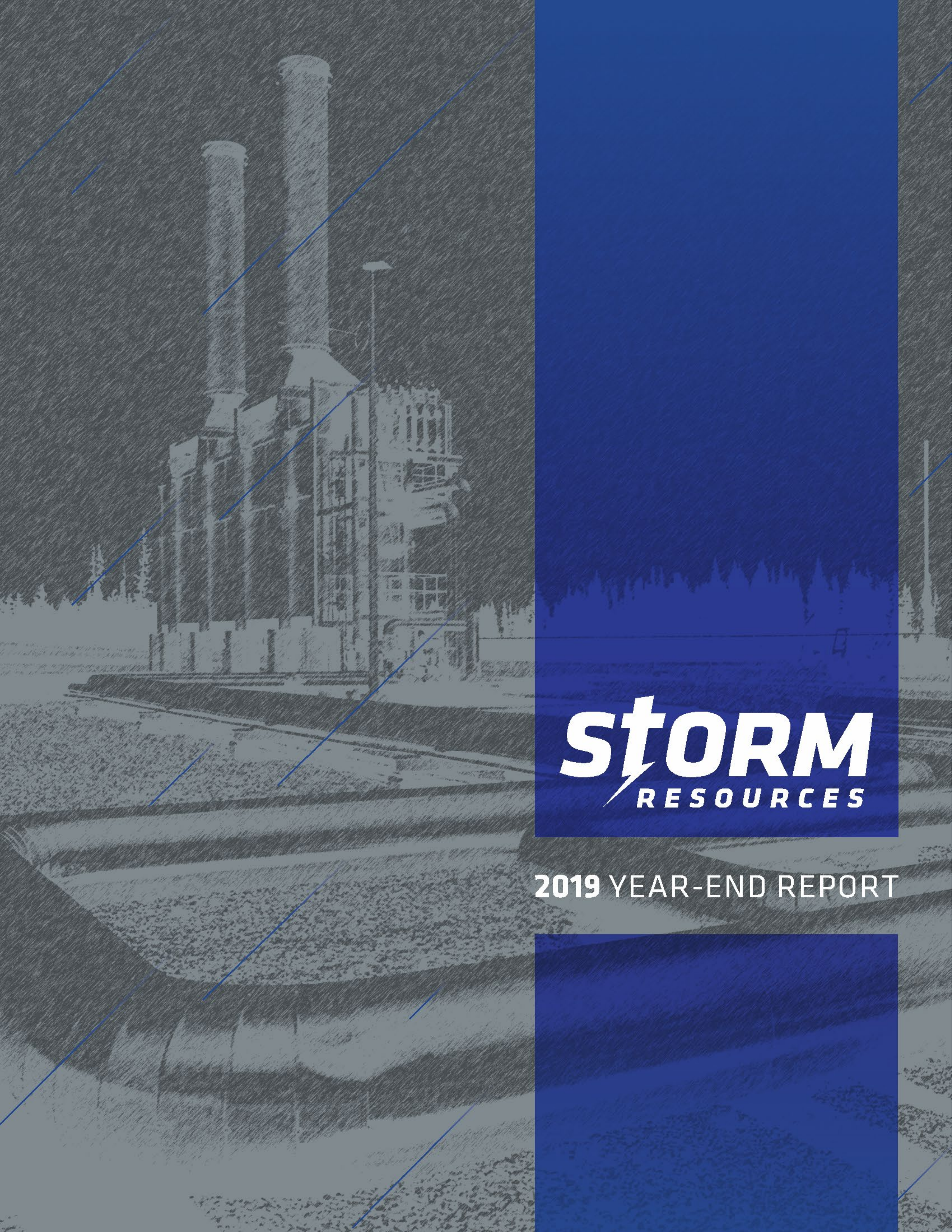


STORM RESOURCES

2019 YEAR-END REPORT

ANNUAL MEETING

The Annual General Meeting of shareholders will be held at 3:30 p.m. on Wednesday, May 13, 2020 at Calgary City Centre, +15 Level Conference Centre, 215 – 2nd Street S.W., Calgary, Alberta, Canada.

All shareholders and invited guests are encouraged to attend.

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
FINANCIAL				
Revenue from product sales(1)	48,671	74,799	173,422	226,258
Funds flow	18,469	30,941	59,549	100,092
Per share - basic and diluted ($)	0.15	0.25	0.49	0.82
Net income	2,906	26,810	11,313	40,063
Per share - basic and diluted ($)	0.02	0.22	0.09	0.33
Cash return on capital employed (“CROCE”)(2)	12%	21%	12%	21%
Return on capital employed (“ROCE”)(2)	4%	10%	4%	10%
Capital expenditures	23,913	37,100	96,843	84,763
Debt including working capital deficiency(2)(3)	128,901	91,020	128,901	91,020
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,649	121,557	121,597
Outstanding end of period - basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	23.64	36.24	23.54	30.18
Transportation costs	(5.20)	(5.57)	(5.66)	(5.84)
Revenue net of transportation	18.44	30.67	17.88	24.34
Royalties	(1.59)	(0.58)	(1.11)	(1.08)
Production costs	(5.67)	(5.46)	(5.87)	(5.50)
Field operating netback(2)	11.18	24.63	10.90	17.76
Realized gain (loss) on risk management contracts	(0.80)	(8.65)	(1.20)	(3.03)
General and administrative	(0.70)	(0.55)	(0.93)	(0.82)
Interest and finance costs	(0.71)	(0.45)	(0.68)	(0.57)
Funds flow per Boe	8.97	14.98	8.09	13.34
Barrels of oil equivalent per day (6:1)	22,375	22,432	20,182	20,538
Natural gas production				
Thousand cubic feet per day	108,679	109,520	98,458	101,019
Price (Cdn$ per Mcf)(1)	3.28	5.56	3.21	3.98
Condensate production				
Barrels per day	2,416	2,453	2,138	2,141
Price (Cdn$ per barrel)(1)	66.56	58.74	66.03	75.61
NGL production				
Barrels per day	1,846	1,726	1,634	1,561
Price (Cdn$ per barrel)(1)	6.11	35.09	10.75	35.69
Wells drilled (net)	-	4.0	6.0	4.0
Wells completed (net)	-	2.5	5.0	10.5

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 40 of the attached Management's Discussion and Analysis. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of risk management contracts, decommissioning liability and lease liability.

PRESIDENT'S MESSAGE

2019 FOURTH QUARTER HIGHLIGHTS

The start-up of a four well pad at Nig in late November increased production while funds flow benefitted from the increase in production and from an improvement in natural gas prices at AECO and Station 2. Construction continued on the Nig Gas Plant which was completed and started up February 22, 2020 (previously expected to be in January 2020).

- Production at 22,375 Boe per day was an increase of 20% from the previous quarter and was largely unchanged from the previous year. Production was reduced by approximately 500 Boe per day due to curtailments in October as a result of the low Station 2 price ($0.36 per GJ).

- Liquids production (field condensate plus gas plant NGL) increased 2% from last year to total 4,262 barrels per day, represented 19% of total production and contributed 33% of production revenue.

- A four well pad at Nig started production in late November with initial rates from the three wells in the upper/mid Montney being the same as earlier wells; however, longer-term rates are expected to be lower given tighter interwell spacing on the newest wells (400 metres versus 465 metres for earlier wells). The fourth well in the lower Montney has a higher condensate rate while the gas rate is lower (IP90 5.5 Mmcf per day raw gas plus 315 barrels per day field condensate).

- Revenue was $23.64 per Boe, a decline of $12.60 per Boe or 35% from last year, mainly from lower NGL and natural gas prices. The NGL price declined 83% as a result of lower North American propane prices and a reduction in the contracted plant gate price for propane and butane during the current marketing period from April 2019 to March 2020. The natural gas price declined 41% as a result of lower pricing in the Chicago and Sumas markets (66% of sales).

- Production, general and administrative, and interest and finance costs were $7.08 per Boe, a year-over-year increase of $0.62 per Boe with interest expense increasing $0.26 per Boe (higher debt level associated with funding construction of the Nig Gas Plant) and production cost increasing $0.21 per Boe (inflation escalator increasing third-party gas processing fees plus the scheduled increase in BC carbon tax in April 2019).

- Hedging loss of $1.6 million resulted from Sumas price hedges that were entered into before a failure on the Enbridge T-south pipeline in October 2018 which decreased throughput and increased the Sumas price (repairs completed late November 2019).

- Funds flow was $18.5 million or $0.15 per share with the year-over-year decrease of 40% per share largely the result of revenue being reduced by lower commodity prices.

- Net income was $2.9 million compared to $26.8 million in the prior year with the decline primarily attributable to lower commodity prices reducing revenue and funds flow.

- Capital investment of $24 million included $19 million for the Nig Gas Plant project plus $3 million to pipeline connect a four well pad at Nig. Investment was less than guidance ($32 to $37 million) with $9 million for the construction of the Nig Gas Plant being shifted into the first quarter of 2020 as a result of delays in equipment deliveries (damage to a bridge south of Fort St. John in late November required loads to be rerouted).

- Total debt including working capital deficiency was $129 million or 1.7 times annualized quarterly funds flow and represents 63% utilization of the $205 million bank line. The year-over-year increase in total debt is a result of the large investment in the Nig Gas Plant project in 2019 which totaled $61 million (63% of total investment).

- Commodity price hedges currently protect approximately 29% of forecast production in the first half of 2020 and 7% in the second half of 2020.

2019 YEAR-END HIGHLIGHTS

Production and funds flow were below initial guidance provided in November 2018 mainly as a result of unplanned outages, lower NGL pricing for the contract year starting April 2019, and from production curtailments due to low natural gas prices during the summer. As forecast funds flow declined during 2019, capital investment was reduced which resulted in fewer Montney horizontal wells being drilled and completed (six drills and five completions versus initial guidance for eight drills and 11 completions).

- Production averaged 20,182 Boe per day, a 2% decrease from the previous year, and was below initial guidance provided in November 2018 (21,000 to 24,000 Boe per day) mainly as a result of 31 days of unplanned outages at the McMahon Gas Plant and production curtailments during April to October due to low natural gas prices (Station 2 averaged $0.57 per GJ during this period).

- The realized natural gas price at $3.21 per Mcf was materially higher than Western Canadian pricing (AECO daily index $1.67 per GJ and Station 2 $0.96 per GJ) as a result of diversified sales.

- During 2019, seven horizontal wells started production and contributed approximately 2,600 Boe per day to average annual production and 4,700 Boe per day to fourth quarter production.

- Production, general and administrative, and interest and finance costs were $7.48 per Boe, an increase of $0.59 per Boe, largely as a result of the year-over-year decline in production caused by unplanned outages. Also contributing to the increase is higher interest expense associated with higher debt levels to fund construction of the Nig Gas Plant and higher production cost with the inflation escalator increasing third-party gas processing fees.

- Funds flow of $60 million ($8.09 per Boe) declined 40% from the previous year mainly from lower commodity prices reducing revenue per Boe by 22%.

- Net income of $11 million ($1.55 per Boe) declined 72% from the previous year primarily as a result of the decline in funds flow.

- Return on capital employed (ROCE) was 4% and cash return on capital employed (CROCE) was 12%. Non-cash hedging gains or losses will affect ROCE which is based on net income but does not affect CROCE which is based on funds flow.

- Capital investment was $97 million with approximately $61 million, or 63%, directed to the Nig Gas Plant project (gas plant, sales pipeline and acid gas injection well) which is expected to increase liquids production and reduce production cost after start-up in the first quarter of 2020.

RESERVE EVALUATION HIGHLIGHTS

Reserves increased modestly in 2019 as a result of positive technical revisions and additional future drilling locations being recognized in the Nig area.

Reserves

(Mboe)		YOY Increase	2019	2018	2017
Proved Developed Producing ("PDP")		+3%	43,322	42,204	33,729
Total Proved ("1P")		+4%	156,118	149,905	97,617
Total Proved plus Probable ("2P")		+7%	195,483	182,370	128,963
PDP as % of 2P			22%	23%	26%
1P as a % of 2P			80%	82%	76%
Reserve Life Index using fourth quarter production (years)		PDP	5.3	5.2	5.2
		1P	19.1	18.3	14.9
		2P	23.9	22.3	19.7

All-in Finding, Development & Acquisition ("FD&A") Cost Including Change in Future Development Capital ("FDC")

($/Boe)	2019	2018	2017	3-Year Total
PDP	$11.43	$5.24	$5.76	$6.79
1P	$3.90	$6.01	$3.06	$4.94
2P	$3.16	$5.10	$1.27	$3.70

Recycle Ratio Using All-in FD&A Cost

	2019	2018	2017	3-Year Total
Funds Flow (000s)	$59,549	$100,092	$64,080	$223,604
Funds Flow Netback ($/Boe)	$8.09	$13.34	$10.96	$10.80
PDP Recycle	0.7	2.5	1.9	1.6
1P Recycle	2.1	2.2	3.6	2.2
2P Recycle	2.6	2.6	8.6	2.9

- PDP FD&A was higher in 2019 as a result of $61 million invested in the Nig Gas Plant project.
- There are no reserves or financial benefit included for the Nig Gas Plant in PDP, however, incremental reserves and the lower production cost is recognized in 1P (adds 4,873 Mboe) and 2P (adds 6,771 Mboe).
- There are no PDP, 1P or 2P reserves assigned to the Fireweed area.
- PDP additions totaled 8,469 Mboe from four new wells at Nig plus positive technical revisions and replaced 115% of annual production (185% for 1P and 278% for 2P).
- On a per-share basis, PDP reserves increased by 3%, 1P increased by 4% and 2P increased by 7%.
- Material future upside remains given that 2P reserves are recognized in only the upper Montney on 44 net sections which is approximately 25% of the total Montney land position (172 net sections).
- Future drilling locations included in 2P reserves total 92.6 net horizontal wells with 13.0 net at Nig and 79.6 net at Umbach.

OPERATIONS REVIEW

Umbach, Nig and Fireweed Areas of Northeast British Columbia

Storm's land position is prospective for liquids-rich natural gas from the Montney formation and totals 121,000 net acres (172 net sections) with 79 horizontal wells (74.4 net) drilled to date.

Fourth quarter field activity was mainly focused on the Nig Gas Plant project which included delivery of major equipment to the site along with on-site construction activities and starting construction of the sales gas and NGL pipelines. In addition, the pipeline tie-in of a four well (4.0 net) pad at Nig was completed in late November after being delayed by rain and wet field conditions.

During the quarter, four new wells started production leaving an inventory at the end of the quarter of five (4.5 net) drilled Montney horizontal wells that had not started producing which included one (0.5 net) completed well.

Field activity in the first quarter will include completing construction of the Nig Gas Plant and associated sales gas and NGL pipelines plus the completion and tie-in of a three well pad at West Umbach.

At Umbach (100% working interest), produced raw natural gas contains 1.2% H_2S with approximately 85% directed to the McMahon Gas Plant and 15% to the Stoddart Gas Plant where firm processing commitments total 80 Mmcf raw gas per day (65 Mmcf per day at McMahon plus 15 Mmcf per day at Stoddart). Field compression capacity totals 150 Mmcf per day raw gas with throughput in the fourth quarter averaging 112 Mmcf per day (including 29 Mmcf per day from Nig which has been redirected to the recently commissioned Nig Gas Plant). Activity in 2020 will include completing and connecting a three well (3.0 net) pad at West Umbach in the first quarter. There remains significant capacity for future growth which is contingent on the Station 2 natural gas price.

At Nig (100% working interest), produced raw natural gas contains 0.1% H_2S and is directed to the recently constructed 50 Mmcf per day sour gas plant that started up in late February 2020. Total estimated cost of the Nig Gas Plant project remains at $86 million which includes the facility, an eight-kilometre sales gas pipeline and drilling/completing a horizontal well for acid gas injection ($11 million in 2018, $61 million in 2019, $14 million in 2020). The estimated cost was increased to $86 million in November 2019 (from $81 million) as a result of the cost for site construction being higher than forecast and design changes. At full capacity, incremental production from the gas plant versus processing at the McMahon Gas Plant is expected to be 1,500 Boe per day (70% liquids) given the higher NGL recovery and reduced gas shrinkage. In addition, eliminating third-party processing fees will result in an operating cost of less than $2.00 per Boe which will reduce the corporate operating cost. Incremental liquids are expected to include approximately 93% NGL (propane/butane) and 7% condensate with the majority of the propane being sold at the Far East Asia Index price via the Altagas Ridley Island Export Terminal (‘RIPET’). Activity in 2020 is expected to include completing the Nig Gas Plant plus drilling and completing two to four wells (2.0 to 4.0 net).

At Fireweed (50% working interest), construction of a 50 Mmcf per day field compression facility (expandable to 100 Mmcf per day) is anticipated to begin in mid-2020 with start-up in late 2020 or early 2021. The estimated cost for the facility, a 16-kilometre access road and sales pipeline is $38 million gross. There is currently one standing well (0.5 net) that has been completed which averaged 10.9 Mmcf per day raw gas, 660 barrels per day of field condensate and 1,140 barrels per day of frac water over the last 12 hours of a six-day clean-up (final flowing casing pressure of 4,800 kPa). 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. Investment in 2020 is expected to total $36 million which will include the construction of the facility and related pipelines and roads plus drilling four wells (2.0 net) and completing three wells (1.5 net).

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not reliable indicators of relative longer-term performance since wells are initially rate restricted to manage fluid rates. Note that the 2019 wells at Nig in the upper/mid Montney were drilled on tighter interwell spacing versus the 2018 wells (400 metres versus 465 metres) which is expected to reduce longer-term rates and ultimate recovery.

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Umbach 2017 - 2018 19 hz's	34	1895 m	4.6 Mmcf/d(1) 24 Bbls/Mmcf(2) 19 hz's	4.4 Mmcf/d(1) 20 Bbls/Mmcf(2) 19 hz's	4.0 Mmcf/d(1) 15 Bbls/Mmcf(2) 17 hz's
Nig 2018 upper 3 hz's	37	2180 m	8.1 Mmcf/d(1) 29 Bbls/Mmcf(2) 3 hz's	8.2 Mmcf/d(1) 25 Bbls/Mmcf(2) 3 hz's	7.5 Mmcf/d(1) 21 Bbls/Mmcf(2) 3 hz's
Nig 2019 upper/mid 3 hz's	42	2240 m	8.1 Mmcf/d(1) 20 Bbls/Mmcf(2) 3 hz's		
Nig 2019 lower 1 hz	42	2280 m	5.5 Mmcf/d(1) 57 Bbls/Mmcf(2) 1 hz		

(1) Raw gas rate.
(2) Bbls/Mmcf is the condensate-gas ratio or barrels of field condensate per Mmcf raw.

Based on results from the 2017 and 2018 wells, Storm management is using 8 Bcf and 14 Bcf raw gas type curves (internal estimates) to forecast production at Umbach and Nig respectively. More detail on well performance and management's type curve is available in the presentation on Storm's website at www.stormresourcesltd.com.

HEDGING

Commodity price hedges are used to support longer-term growth by protecting pricing on up to 50% of current production for the next 12 months and up to 25% for 13 to 24 months forward (future production growth is not hedged). The current hedge position is shown below (excludes price differential contracts which are shown in the financial statements) and protects approximately 16% of forecast production for 2020.

H1 2020	Crude Oil	900 Bpd	WTI Cdn$70.89/Bbl floor, Cdn$80.89 ceiling
		750 Bpd	WTI Cdn$71.92/Bbl
	Natural Gas	20,000 Mmbtu/d (17.2 Mmcf/d)	Chicago Cdn$3.32/Mmbtu
		1,000 Mmbtu/d (0.9 Mmcf/d)	NYMEX US$2.60/Mmbtu floor, $3.11 ceiling
		1,000 Mmbtu/d (0.9 Mmcf/d)	NYMEX US$2.41/Mmbtu
		3,500 Mmbtu/d (3.0 Mmcf/d)	Sumas Cdn$3.94/Mmbtu
		750 GJ/d (0.6 Mmcf/d)	AECO Cdn$2.00/GJ
		2,500 GJ/d (2.0 Mmcf/d)	AECO Cdn$1.77/GJ floor, $2.28 ceiling
		10,000 GJ/d (8.2 Mmcf/d)	Station 2 Cdn$1.77/GJ
H2 2020	Crude Oil	400 Bpd	WTI Cdn$68.38/Bbl floor, Cdn$79.01 ceiling
		400 Bpd	WTI Cdn$71.16/Bbl
	Natural Gas	1,500 Mmbtu/d (1.3 Mmcf/d)	Chicago Cdn$3.34/Mmbtu
		2,000 Mmbtu/d (1.7 Mmcf/d)	NYMEX US$2.47/Mmbtu
		2,300 GJ/d (1.9 Mmcf/d)	Station 2 Cdn$1.48/GJ

OUTLOOK

Production in the first quarter of 2020 is forecast to average 24,000 to 25,000 Boe per day with capital investment estimated to be $30 million (approximately 40% allocated to the Nig Gas Plant project).

Updated guidance for 2020 is provided below. Forecast production includes incremental production from the Nig gas Plant which started up in late February 2020 and the effect of a planned 25-day maintenance outage at the McMahon Gas Plant in September 2020. First production from the Fireweed area is expected in late 2020 or early 2021 depending on the timing to construct infrastructure. Forecast pricing reflects actual prices to date plus the approximate forward strip for the remainder of the year. Capital investment is intended to be approximately equal to funds flow. Investment in the first half of the year is expected to be approximately $31 million and is largely committed at this point. Capital investment for the second half of the year will be reviewed mid-year and may be adjusted depending on commodity prices and forecast funds flow.

2020 Guidance

	Initial November 12, 2019	Current February 27, 2020
Cdn$/US$ exchange rate	0.76	0.76
Chicago daily natural gas - US$/Mmbtu	$2.45	$1.90
Sumas monthly natural gas - US$/Mmbtu	not provided	$1.90
AECO daily natural gas - Cdn$/GJ	$1.85	$1.75
Station 2 daily natural gas - Cdn$/GJ	$1.60	$1.65
WTI - US$/Bbl	$54.00	$50.50
Edmonton condensate diff - US$/Bbl	($5.00)	($4.00)
Est revenue net of transport (excl hedges) - $/Boe	not provided	$13.50 - $13.75
Est operating costs - $/Boe	not provided	$4.50 - $4.75
Est royalty rate (% revenue net transportation)	not provided	5% - 7%
Est mid-point field operating netback - $/Boe	not provided	$8.20
Est hedging gains or (losses) - $ million	not provided	$5.0 - $6.0
Est cash G&A - $ million	not provided	$6.0 - $7.0
Est interest expense - $ million	not provided	$7.0 - $8.0
Est capital investment (excluding A&D) - $ million	$75.0 - $90.0 (Nig GP $5.0 million)	$75.0 - $85.0 (Nig GP $14.0 million)
Forecast fourth quarter Boe/d	27,000 - 30,000	25,000 - 30,000
Forecast fourth quarter liquids Bbls/d	5,700 - 6,300	5,300 - 6,300
Forecast annual Boe/d	24,000 - 26,000	23,500 - 26,000
Forecast annual liquids Bbls/d	not provided	4,900 - 5,500
Est annual funds flow - $ million	not provided	$62 - $69(1)
Horizontal wells drilled - gross	8 - 12 (6.0 - 8.0 net)	6 - 10 (4.0 - 8.5 net)
Horizontal wells completed - gross	6 - 14 (4.5 - 10.5 net)	8 - 10 (6.5 - 8.5 net)
Horizontal wells starting production - gross	not provided	5 - 10 (5.0 net - 8.5 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.

The majority of estimated capital investment in 2020 is being directed to growth from the Nig and Fireweed areas:

- $36 million at Fireweed includes constructing a 50 Mmcf per day field compression facility (50% working interest), drilling four horizontal wells (2.0 net) and completing three wells (1.5 net);

- $28 to $38 million at Nig includes $14 million to complete the gas plant (100% working interest), drilling two to four horizontal wells (2.0 to 4.0 net) and completing and pipeline connecting two to four wells (2.0 to 4.0 net); and
- $11 million at Umbach includes completing and pipeline connecting three horizontal wells (3.0 net).

Firm pipeline transportation contracts in 2020 total approximately 115 Mmcf per day with 50% directed to Chicago, 16% to BC Station 2, 12% to AECO, 12% to Alliance ATP and 10% to Sumas. Production exceeding firm contracts will generally be sold at Station 2 using interruptible capacity. Approximately 60% of forecast natural gas production in 2020 will be sold into US markets and the remaining 40% in Western Canadian markets.

Natural gas prices at AECO and Station 2 have improved since last September as a result of declining supply and low storage levels. In addition, the AECO – Station 2 price differential has improved to average -$0.09 per GJ to date in 2020 (versus -$0.70 per GJ in 2019) as a result of restoring capacity on the Enbridge T-south pipeline in late November 2019 after the completion of repairs and inspections following a failure in October 2018. Also helping the differential is the start-up of the TC Energy North Montney extension on January 31st which will ultimately increase exports from NE BC by up to 1.5 Bcf per day (contracted capacity). Although the pricing outlook has become more optimistic, that could reverse if supply growth restarts given the loss of market share in eastern markets (lower AECO price is required to incentivise higher exports from Western Canada to eastern markets).

Storm's NGL price is expected to improve in 2020 based on indications for contracted plant gate pricing for butane and propane for the next contract year which starts in April. The NGL price during the current contract period (April 2019 to March 2020) has averaged approximately 7% of WTI versus 42% of WTI in the previous contract period (April 2018 to March 2019). This reduced 2019 funds flow by approximately $10 million. Using the current forward strip, the price is expected to improve to approximately 20% of WTI for the next contract period (April 2020 to March 2021). Also contributing to the lower NGL price in 2019 was weaker North American propane prices (Conway averaged US$0.47 per gallon in 2019 versus US$0.72 in 2018 and is currently approximately US$0.40).

The near-term growth plan is expected to increase liquids as a proportion of total production and decrease per-Boe operating costs. Depending on capital investment and the number of wells drilled and completed in 2020, production is forecast to grow to 25,000 to 30,000 Boe per day by the fourth quarter of 2020. At the mid-point, the year-over-year increase in fourth quarter total production is forecast to be 23% with liquids production increasing by 36%. The start of production from Fireweed in late 2020 or early 2021 will further increase liquids production as a proportion of total production. With capital investment intended to be approximately equal to funds flow, investment may be adjusted depending on commodity prices which would change the timing for growth.

Over the last three years, funds flow per share has been largely unchanged as a result of declining commodity prices, however, production has grown by 26% per share, PDP reserves have grown by 28% per share, the PDP recycle ratio has averaged 1.6 using the funds flow netback, and annual return on capital employed has been between 4% and 10%. Capital investment decisions will continue to emphasize both per-share growth along with a return on invested capital.

The business plan continues to focus on increasing asset value per share by converting resource into per-share growth of funds flow and reserves value. This has been challenging in the current price environment where commodity prices have been volatile and have trended lower over the last several years. Success in this environment is expected to continue being dependent on improving capital efficiencies (better wells for the same or lower cost) and finding ways to offset the effect of declining commodity prices (reducing production costs and/or increasing liquids production to increase revenue). With 2P reserves recognized only in the upper Montney on approximately 25% of the total land position, there remains significant longer-term upside.

I appreciate the considerable and relentless efforts of Storm's employees and the advice, guidance and support of the Board of Directors which have both been invaluable to Storm's success to date.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

February 27, 2020

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 February 27, 2020 for the three months and year ended December 31, 2019.

RESERVES AT DECEMBER 31, 2019

Storm's year-end reserve evaluation effective December 31, 2019 was prepared by InSite Petroleum Consultants Ltd. ("InSite") in a report dated February 20, 2020. InSite has evaluated all of Storm's natural gas and NGL reserves. The InSite price forecast at December 31, 2019 was used to determine estimates of net present value ("NPV"). Storm's Reserves Committee, which is made up of independent and appropriately qualified directors, has reviewed and approved the evaluation prepared by InSite, and the report of the Reserves Committee has been accepted by the Company's Board of Directors.

Reserves included herein are stated on a company gross basis (working interest before deduction of royalties without including any royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). In addition to the information disclosed in this report, more detailed information will be included in Storm's Annual Information Form for the year ended December 31, 2019 (the "AIF").

Summary

- Proved developed producing reserves ("PDP") increased to 43,322 Mboe during 2019, a 3% increase over the 2018 year-end PDP reserves of 42,204 Mboe. Total proved reserves ("1P") increased to 156,118 Mboe, a 4% increase over 2018 year-end 1P reserves of 149,905 Mboe. Total proved plus probable reserves ("2P") increased to 195,482 Mboe, a 7% increase over 2018 year-end 2P reserves of 182,370 Mboe.

- Reserve additions in 2019 replaced 115% of production for PDP reserves, 185% for 1P reserves and 278% for 2P reserves.

- Technical revisions increased PDP reserves by 1,768 Mboe (4%), 1P reserves by 981 Mboe (1%) and reduced 2P reserves by 771 Mboe (0%). Revisions were primarily due to well performance exceeding the InSite forecast from the previous year.

- 2P reserves include 937 Bcf of natural gas and 39 Mmbbl of NGL at year-end 2019. The NGL component includes 52% condensate (20 Mmbbl), 24% butane (9 Mmbbl) and 24% propane (9 Mmbbl).

- Breaking down 2P reserves by area, 74% is at Umbach and 26% is at Nig. There were no reserves assigned to the Fireweed area (all categories).

- The all-in finding, development and acquisition ("FD&A") cost[1] to add reserves was $11.43 per Boe for PDP, $3.90 per Boe for 1P and $3.16 per Boe for 2P.

- Future development costs ("FDC") were $642 million for 1P and $675 million for 2P and are fully financed from forecast cash flow within four years which complies with the Canadian Oil and Gas Evaluation ("COGE") Handbook.

- FDC includes $114 million net on a 2P basis for future infrastructure expansion at Umbach (last year was $166 million net) with $13 million to finish construction of the Nig Gas Plant and $101 million allocated to future infrastructure expansion at Nig and Umbach.

- FDC decreased from 2018 mainly as a result of investing $61 million in the Nig Gas Plant in 2019 (1P and 2P at the end of 2019 includes the remaining $13 million to finish construction of the Nig Gas Plant).

- The estimated cost to drill, complete and tie in a future Montney horizontal well at Umbach is $5.9 million which is unchanged from the previous year (versus actual cost in 2019 averaging $5.7 million).

- Wells drilled in 2019 were assigned an average of 10.5 Bcf gross raw gas on a 2P basis.

- At Umbach and Nig there are 92.6 net 2P future horizontal drills assigned an average of 8.1 Bcf gross raw gas (last year was 88.6 net 2P locations with 7.9 Bcf gross raw gas).

- At Umbach and Nig, 2P reserves were recognized in the upper Montney on 44 net sections (an increase of 2.3 net sections from last year), 1P on 42.3 net sections and PDP on 15.4 net sections. DPIIP averages 51

Bcf gross raw gas per section in the upper Montney (total net DPIIP 2.24 Tcf on 44 net sections). Forecast recovery of DPIIP totals 54% for 2P reserves.

- The full corporate decommissioning liability for all wells and facilities was included in this year's evaluation and totaled $38.3 million on an undiscounted basis. Compared to last year, this reduced the PDP Net Present Value ("NPV") by $27 million on an undiscounted basis and by $8 million when discounted at 10%. Previously, only the decommissioning liability associated with currently active wells was included (did not include inactive wells or the cost of decommissioning facilities).

- The PDP NPV discounted at 10% decreased by 16% to $399.5 million mainly as a result of lower forecast natural gas prices (approximate decrease of 15% over the first five years) plus the effect of including the full corporate decommissioning liability for all wells and facilities. Using this year's price forecast in last year's evaluation, the NPV discounted at 10% was flat year over year.

(1) The all-in calculation reflects the result of Storm's entire capital investment program as it takes into account the effect of acquisitions, dispositions and revisions, as well as the change in FDC.

INFORMATION REGARDING DISCLOSURE ON OIL AND GAS RESERVES AND RESOURCES

All amounts are stated in Canadian dollars unless otherwise specified. Where applicable, natural gas has been converted to barrels of oil equivalent ("Boe") based on 6 Mcf:1 Boe. The Boe rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not recognize a value equivalent at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value. Production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties, unless otherwise stated. Unless otherwise specified, all reserves volumes are based on "company gross reserves" using forecast prices and costs. The oil and gas reserves statement for the year ended December 31, 2019, which will include complete disclosure of oil and gas reserves and other information in accordance with NI 51-101, will be contained within the AIF which will be available on SEDAR.

References to estimates of oil and gas classified as DPIIP are not, and should not be confused with, oil and gas reserves.

Gross Company Interest Reserves as at December 31, 2019
(Before deduction of royalties payable, not including royalties receivable)

	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	210,418	8,253	43,322
Proved non-producing	4,076	91	771
Total proved developed	214,494	8,344	44,093
Proved undeveloped	536,365	22,630	112,025
Total proved	750,859	30,974	156,118
Probable additional	186,573	8,270	39,365
Total proved plus probable	937,432	39,244	195,482

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2019
(Gross company interest reserves before deduction of royalties payable)

	6:1 Oil Equivalent (Mboe)			
	Proved Developed Producing	Total Proved	Probable	Proved plus Probable
December 31, 2018 – opening balance	42,204	149,905	32,464	182,370
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	6,702	12,582	8,653	21,235
Dispositions	-	-	-	-
Technical revisions	1,768	1,225	(1,642)	(417)
Economic factors	-	(244)	(110)	(354)
Production	(7,351)	(7,351)	-	(7,351)
December 31, 2019 – closing balance	43,322	156,118	39,365	195,482

Numbers in this table may not add due to rounding.

Reserve Life Index ("RLI") Using Fourth Quarter Production

(Years)	2019	2018	2017
PDP	5.3	5.2	5.2
1P	19.1	18.3	14.9
2P	23.9	22.3	19.7

Future Development Costs ("FDC")

	Proved ($M)	Proved Plus Probable ($M)
2020	85,600	85,600
2021	169,575	169,575
2022	268,735	289,044
2023	118,558	130,868
2024	-	-
Total FDC - undiscounted	642,469	675,087
Total FDC - discounted at 10%	521,619	546,292

($million)	2019	2018	2017
1P FDC	$ 642	$ 686	$ 412
2P FDC	$ 675	$ 707	$ 481

Note: InSite escalates capital costs at 2% per year after 2019.

All-in Finding, Development and Acquisition Costs ("FD&A") (including acquisitions, dispositions and revisions)

Proved Developed Producing FD&A Cost (All-in)	2019	2018	2017	3 Year Total
Net capital investment (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,921
Total capital including change in FDC (000s)	$ 96,843	$ 83,641	$ 81,685	$ 262,169
Total reserve additions (Mboe)	8,469	15,967	14,180	38,616
All-in PDP FD&A cost (per Boe)	$ 11.43	$ 5.24	$ 5.76	$ 6.79

Total Proved FD&A Cost (All-in)	2019	2018	2017	3 Year Total
Net capital investment (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(43,992)	274,814	(1,127)	229,695
Total capital including change in FDC (000s)	$ 52,851	$ 359,577	$ 80,558	$ 492,986
Total reserve additions (Mboe)	13,563	59,780	26,366	99,709
All-in 1P FD&A cost (per Boe)	$ 3.90	$ 6.01	$ 3.06	$ 4.94

Total Proved Plus Probable FD&A Cost (All-in)	2019	2018	2017	3 Year Total
Net capital investment (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(32,089)	226,058	(42,755)	151,214
Total capital including change in FDC (000s)	$ 64,754	$ 310,821	$ 38,930	$ 414,505
Total reserve additions (Mboe)	20,464	60,899	30,617	111,980
All-in 2P FD&A cost (per Boe)	$ 3.16	$ 5.10	$ 1.27	$ 3.70

Finding and Development Costs ("F&D") (excluding acquisitions, dispositions and revisions)

Total Proved F&D Cost	2019	2018	2017	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(43,992)	274,814	(1,127)	229,695
Total capital including change in FDC (000s)	$ 52,851	$ 359,577	$ 80,558	$ 492,986
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	12,582	43,347	16,669	72,598
1P F&D cost (per Boe)	$ 4.20	$ 8.30	$ 4.83	$ 6.79

Total Proved Plus Probable F&D Cost	2019	2018	2017	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 96,843	$ 84,763	$ 81,685	$ 263,291
Change in FDC (000s)	(32,089)	226,058	(42,755)	151,214
Total capital including change in FDC (000s)	$ 64,754	$ 310,821	$ 38,930	$ 414,505
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	21,235	39,608	19,615	80,458
2P F&D cost (per Boe)	$ 3.05	$ 7.85	$ 1.98	$ 5.16

Net Present Value Summary (before tax) as at December 31, 2019

Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	612,052	485,065	399,523	340,434	297,875
Proved non-producing	5,204	3,350	2,247	1,547	1,079
Total proved developed	617,256	488,415	401,770	341,981	298,954
Proved undeveloped	1,476,538	937,831	628,601	436,660	310,307
Total proved	2,093,794	1,426,246	1,030,371	778,641	609,261
Probable additional	825,098	425,209	248,771	159,563	109,366
Total proved plus probable	2,918,892	1,851,455	1,279,142	938,204	718,627

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2019

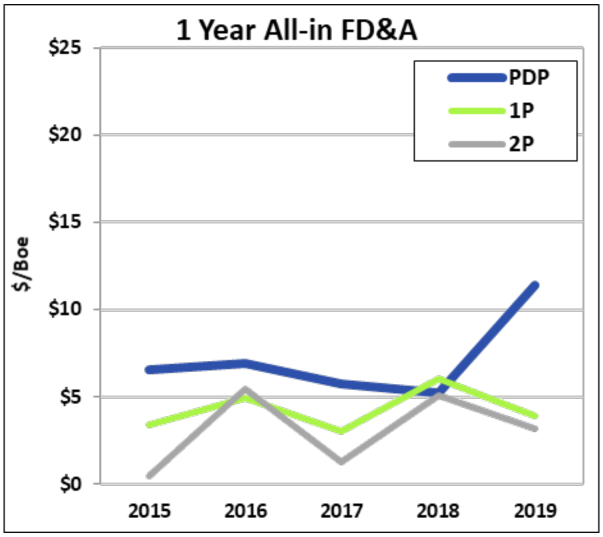
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV each include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

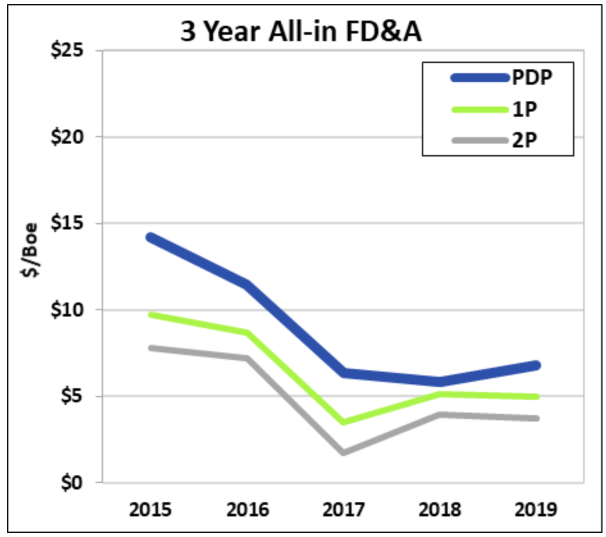
(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	578,137	466,464	388,827	334,031	293,907
Proved non-producing	3,845	2,524	1,724	1,206	851
Total proved developed	581,982	468,988	390,551	335,237	294,758
Proved undeveloped	1,093,533	682,789	447,459	301,897	206,551
Total proved	1,675,515	1,151,776	838,010	637,134	501,309
Probable additional	611,458	314,275	183,243	117,062	79,880
Total proved plus probable	2,286,973	1,466,052	1,021,253	754,195	581,189

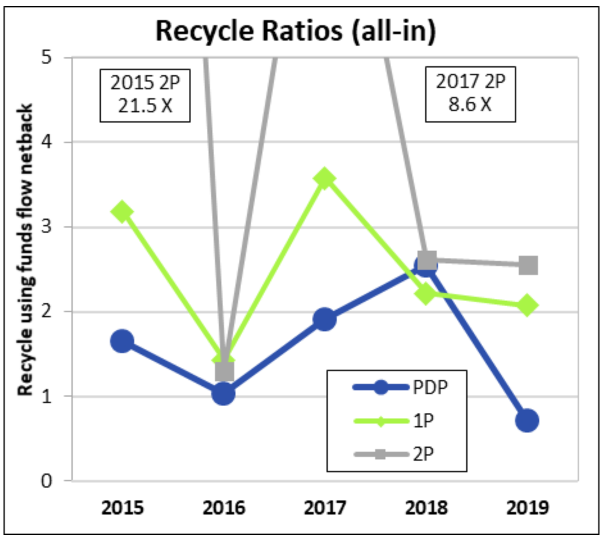
Numbers in this table may not add due to rounding.

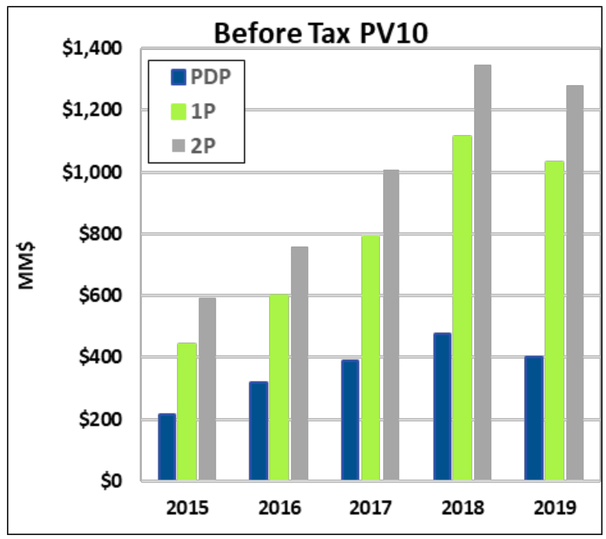
InSite Escalating Price Forecast as at December 31, 2019

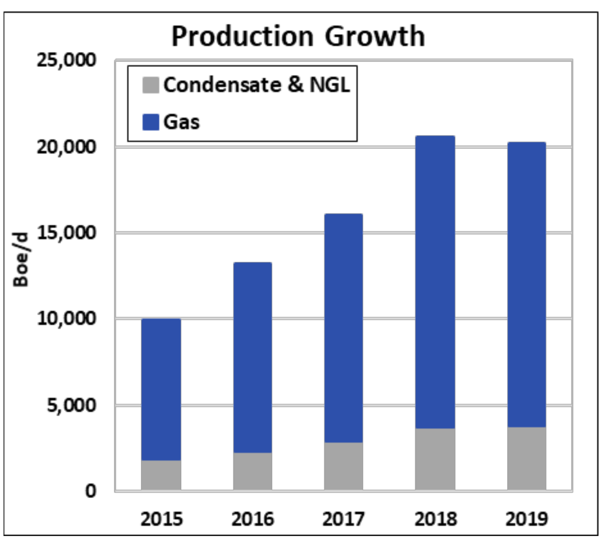
	Exchange Rate (US$/Cdn$)	WTI Crude Oil (US$/Bbl)	Condensate (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)	BC Station 2 (Cdn$/Mmbtu)
2020	0.76	61.00	76.93	2.50	2.05	1.70
2021	0.77	64.50	80.22	2.75	2.32	2.02
2022	0.78	66.50	82.30	3.00	2.60	2.30
2023	0.80	68.20	84.40	3.15	2.69	2.44
2024	0.80	69.90	86.91	3.25	2.81	2.59

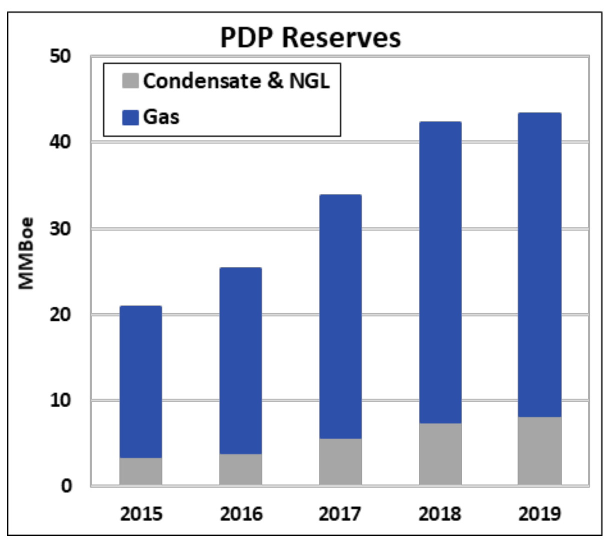

1 Year All-in FD&A
$/Boe
$25
$20
$15
$10
$5
$0
PDP
1P
2P
2015
2016
2017
2018
2019

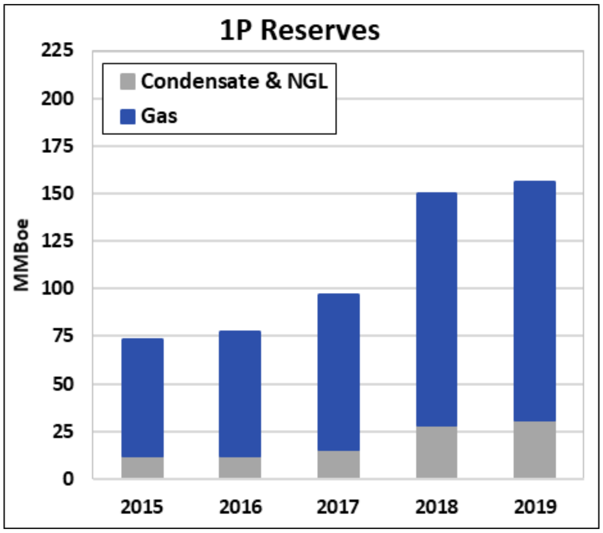

3 Year All-in FD&A
$/Boe
$25
$20
$15
$10
$5
$0
PDP
1P
2P
2015
2016
2017
2018
2019

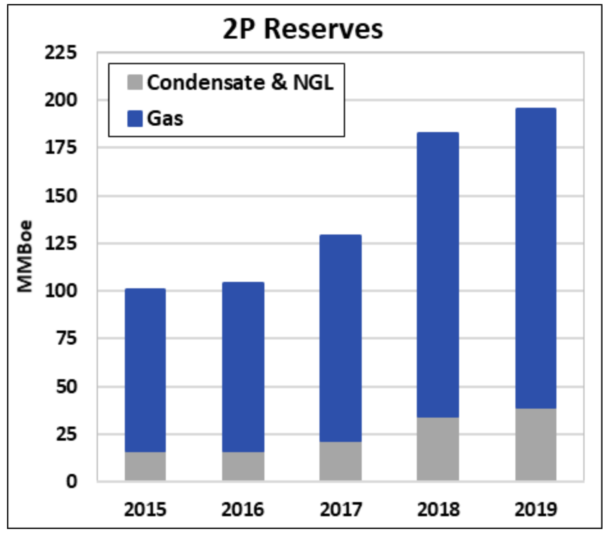

Recycle Ratios (all-in)
Recycle using funds flow netback
2015 2P
21.5 X
2017 2P
8.6 X
PDP
1P
2P
5
4
3
2
1
0
2015
2016
2017
2018
2019

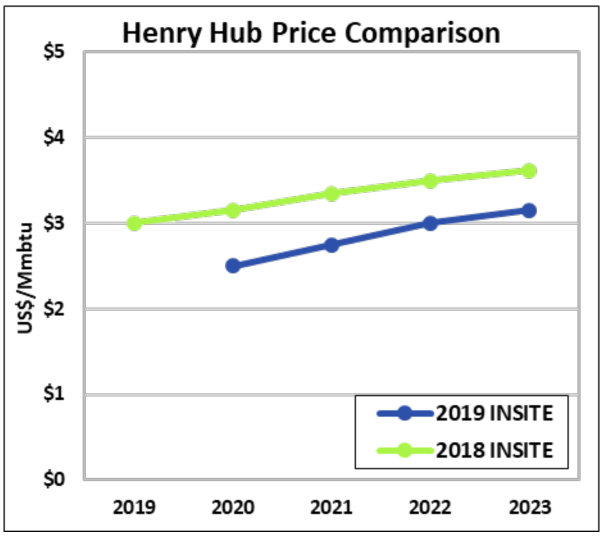

Before Tax PV10
MM$
$1,400
$1,200
$1,000
$800
$600
$400
$200
$0
PDP
1P
2P
2015
2016
2017
2018
2019

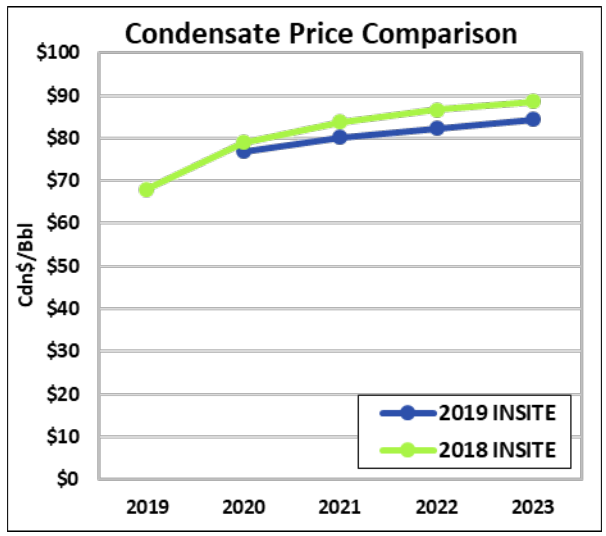

Production Growth
Boe/d
25,000
20,000
15,000
10,000
5,000
0
Condensate & NGL
Gas
2015
2016
2017
2018
2019

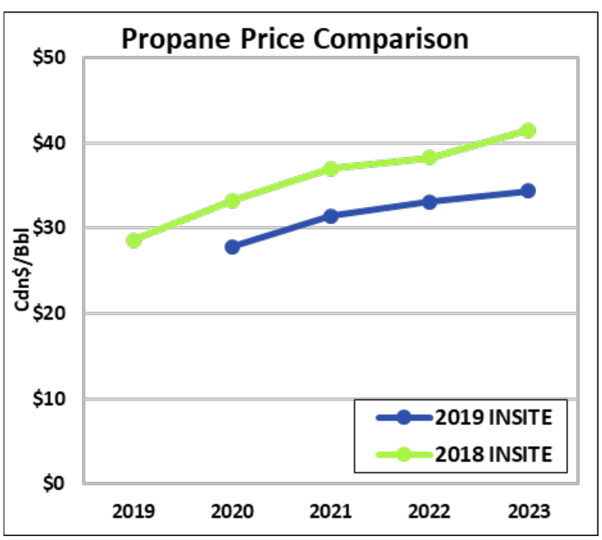

PDP Reserves
MMBoe
50
40
30
20
10
0
Condensate & NGL
Gas
2015
2016
2017
2018
2019

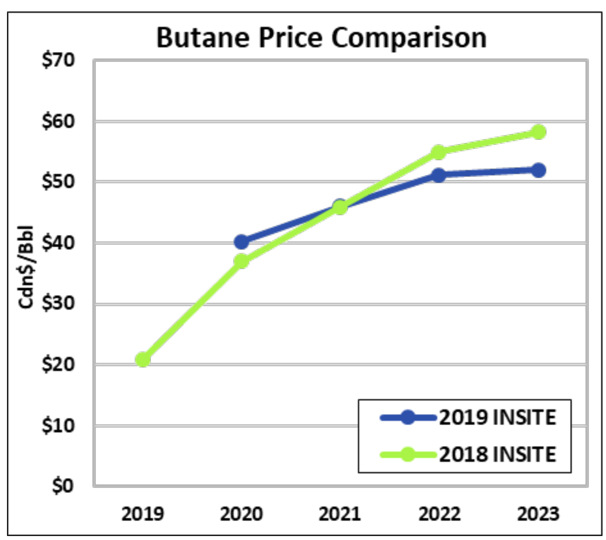

1P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2015
2016
2017
2018
2019


2P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2015
2016
2017
2018
2019


Henry Hub Price Comparison
US$/Mmbtu
$5
$4
$3
$2
$1
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023


Condensate Price Comparison
Cdn$/Bbl
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023


Propane Price Comparison
Cdn$/Bbl
$50
$40
$30
$20
$10
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023


Butane Price Comparison
Cdn$/Bbl
$70
$60
$50
$40
$30
$20
$10
$0
2019 INSITE
2018 INSITE
2019
2020
2021
2022
2023

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 and year ended December 31, 2019. It should be read in conjunction with (i) the Company's audited consolidated financial statements for the years ended December 31, 2019 and 2018, (ii) each of the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, June 30 and September 30, 2019, and (iii) the press release issued by the Company on February 27, 2020, 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 February 27, 2020.

See discussion related to "Forward-Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" on pages 38 to 40.

BASIS OF PRESENTATION

Financial data presented below have largely been derived from the Company's audited consolidated financial statements for the year ended December 31, 2019 and the unaudited interim consolidated financial information for the three months ended December 31, 2019 (the "financial statements"), prepared in accordance with International Financial Reporting Standards ("IFRS"). Accounting policies adopted by the Company are referred to in Note 3 to the audited consolidated financial statements for the years ended December 31, 2019 and 2018. The reporting and the functional currency is the Canadian dollar.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands. Comparative information is provided for the three months and year ended December 31, 2018.

OPERATIONAL AND FINANCIAL RESULTS

Overview

Year Ended December 31, 2019

Fiscal 2019 was defined by third-party outages (total of 43 days) and low commodity prices that reduced Storm's production and funds flow. As previously disclosed, the McMahon gas plant, which processed the bulk of Storm's natural gas production in 2019, was subject to six days of planned and 31 days of unplanned outages, for a total of 37 days during the year. In addition, production was restricted at times during the year in response to ongoing weakness in Western Canadian natural gas prices. As a result, production remained relatively flat for the first eleven months of the year before ramping up in December. Despite the AECO daily price averaging $1.67 per GJ and Station 2 averaging $0.96 per GJ in 2019, Storm's realized natural gas price was $3.21 per Mcf for the year. This highlights the benefit of the Company's diversified marketing strategy whereby 68% of the Company's natural gas was sold into higher priced Chicago and Sumas markets which offset weaker pricing at Station 2 and AECO. As noted in the past, weakness in Western Canadian natural gas prices has been due to record supply levels, further exacerbated for Canadian producers by a lack of growth in egress to other markets, although showed improvement in the fourth quarter due to low storage levels and slowing supply growth.

When comparing to 2018, condensate and NGL prices were down 13% and 70%, respectively. Benchmark crude oil pricing decreased in 2019 compared to 2018 as a result of a lower oil demand forecast due to trade tensions between China and the US which continued to affect the global economy, tempered by supply levels that were reduced by output cuts and US sanctions on Iran and Venezuela. Elevated supply levels for NGL in Western Canada and constrained take-away capacity materially reduced Storm's realized NGL price for the contract period that commenced in April 2019 and ends in March 2020. Storm's NGL price averaged 14% of WTI in Canadian dollars in 2019, materially lower than the average of 43% of WTI in Canadian dollars that was realized in 2018.

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 33% to the Company's top line revenue compared to 35% in the prior year, with relative strength in condensate prices helping to offset the weakness in natural gas prices over the course of the year. As the majority of Storm's condensate and NGL revenue streams are based on crude oil reference prices, 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.

Adjustments to the near-term growth plan in the second half of 2019 resulted in capital expenditure guidance being amended by the Company as set out in the table below:

2019 Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	WTI (US$/Bbl)	Capital Investment ($ million)	Forecast Annual Funds Flow ($ million)	Forecast Annual Production (Boe/d)
Nov 13, 2018	$2.50	$1.25	$60.00	$128.0	$72.0 - $88.0	21,000 - 24,000
Feb 28, 2019	$2.60	$1.25	$55.00	$128.0	$67.0 - $79.0	21,000 - 24,000
May 14, 2019	$2.65	$1.20	$55.00	$128.0	$65.0 - $77.0	21,000 - 24,000
Aug 13, 2019	$2.45	$1.00	$55.00	$110.0	$55.0 - $61.0	20,000 - 22,000
Nov 12, 2019	$2.45	$0.90	$56.00	$105.0 - $110.0	$58.7 - $64.5	20,000 - 22,000
Actual 2019 Results	**$2.42**	**$0.96**	**$57.03**	**$96.8**	**$59.5**	**20,182**

Despite remaining at depressed levels, natural gas prices were relatively stable for the first half of the year as was the Company's capital expenditure and production guidance. Storm continued to execute on construction of a 50 Mmcf per day sour gas plant to develop the Nig land block, which accounted for 63% of the capital expenditures in 2019. In August 2019, capital expenditure and production guidance were reduced in response to the ongoing decline in natural gas prices and the multiple outages experienced at the McMahon Gas Plant which reduced both production and forecasted funds flow. Capital expenditures in 2019 came in further below budget due to timing of expenditures for the Nig Gas Plant, with approximately $9.0 million of expenditures moving from the fourth quarter of 2019 to the first quarter of 2020 due to minor delays relating to equipment deliveries.

Year over year, total production was within previously updated guidance of 20,000 to 22,000 Boe per day and largely flat with 2018 levels as growth was inhibited by the aforementioned third party outages coupled with low commodity prices. Storm's production increased to approximately 26,000 Boe per day in December 2019 following the tie-in of a new four well pad at Nig and has averaged approximately 24,000 Boe per day to date in 2020 based on field estimates. As always, Storm continues to manage its production base in response to ongoing volatility in crude oil and natural gas prices, while ensuring firm transportation and processing commitments are being met.

Debt including working capital deficiency at year end amounted to $129 million, or 1.7 times annualized fourth quarter 2019 funds flow, with $122 million drawn on the Company's $205 million credit facility.

Year-over-year funds flow per Boe decreased 39% primarily due to a 22% decrease in realized pricing. Given the reduction in prices relative to 2018, Storm's hedging program realized a hedging loss of $8.8 million compared to a hedging loss of $22.7 million in the prior year. Recall, a large component of the hedging loss in both 2019 and 2018 was due to hedges at Sumas that were added before the Enbridge T-south pipeline failure in October 2018 which resulted in materially higher pricing in the Sumas market.

Storm's 2019 capital program was focused on the Nig property, with construction of the Nig Gas Plant along with drilling and completing an acid gas injection well and drilling and completing a four well pad that is evaluating different intervals in the Montney with two wells in the upper, one well in the mid and one well in the lower. The Company incurred net capital expenditures of $96.8 million, 70% of which was spent on infrastructure initiatives ($67.3 million) while 29% was spent on drilling and completions ($28.1 million). Six wells (100% working interest) were drilled in the year and five (5.0 net) wells were completed. Storm had an inventory of five horizontal wells (4.5 net) that had not started producing at the end of 2019, one (0.5 net) of which was completed.

Commodity prices and funds flow will continue to drive the Company's capital program at Umbach, Nig and Fireweed in 2020. With strong well performance to date and moderating declines through 2019, Storm continues to project modest levels of maintenance capital on a go-forward basis. The capital program for 2020 of $75 million to $85 million is expected to largely be funded through estimated funds flow of $62 million to $69 million and unused capacity on the Company's credit facility. The Company's capital program is flexible and can be amended throughout the year as required. Storm's longer-term business plan to continue growing funds flow and asset value per share will not change; what may change is timing of execution.

Quarter Ended December 31, 2019

Production was within previously updated guidance of 22,000 to 24,000 Boe per day, flat compared to the fourth quarter of 2018 and 20% higher compared to the third quarter of 2019. Revenue from product sales for the quarter was 35% lower than the prior year due to lower pricing or, alternatively, down 17% after factoring in realized hedging losses. Revenue per Boe decreased 35% compared to the fourth quarter of 2018 as lower natural gas and NGL prices were only partially offset by higher condensate prices. Revenue per Boe was 29% higher than the immediately preceding quarter. Production increased from just over 20,000 Boe per day for the month of October to just under 26,000 Boe per day for the month of December. Increased production in December 2019 was supported by strong natural gas prices in Western Canada along with strong condensate prices.

Funds flow for the quarter totaled $18.5 million, approximately 40% lower than the same period in the prior year and 54% higher than the third quarter of 2019. Increased funds flow over the preceding quarter resulted primarily from higher production levels and improved pricing. The improvement in pricing was partially offset by realized hedging losses of $1.6 million in the fourth quarter primarily due to losses on Sumas and Chicago positions. Using annualized funds flow for the fourth quarter, the ratio of year-end debt including working capital deficiency to funds flow amounted to 1.7 times.

Capital expenditures for the quarter totaled $23.9 million and were lower than previously announced guidance of $32.0 million to $37.0 million primarily due to timing of expenditures related to the Nig Gas Plant ($9.0 million moved from the fourth quarter of 2019 to the first quarter of 2020). Included in the $23.9 million are facility, equipping and gathering costs of $22.1 million which was predominantly related to the Nig gas plant and the associated sales pipeline plus the tie-in of the four well pad at Nig.

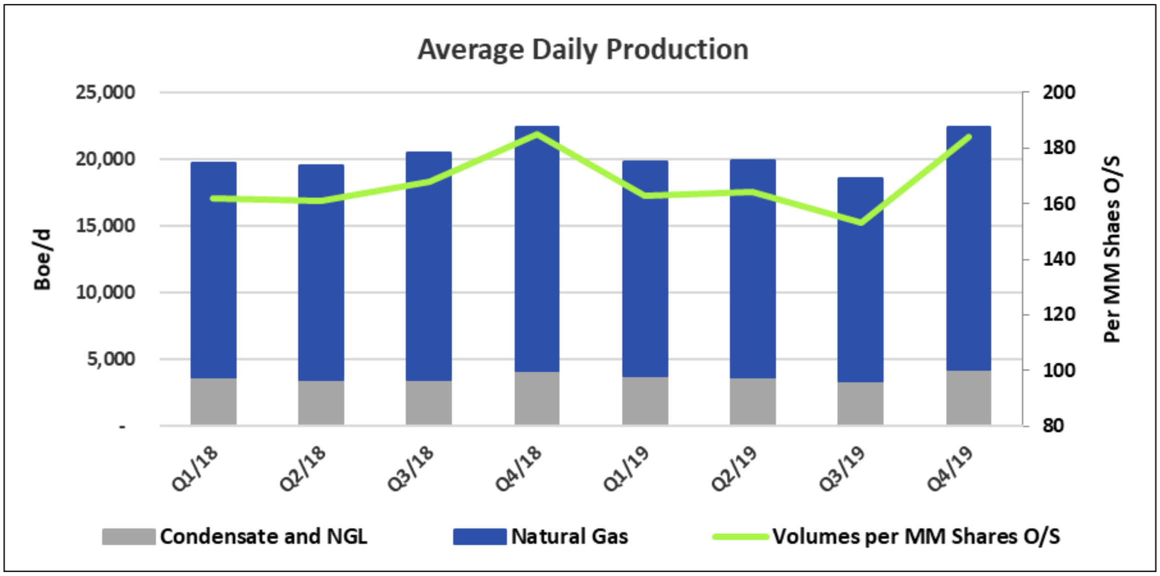
During the fourth quarter of 2019, the Company's bank syndicate confirmed Storm's credit facility at $205 million during the mid-year review, which was approximately 64% drawn at the end of the fourth quarter (including $10 million for letters of credit). The next annual review will take place prior to May 29, 2020.

Production and Revenue

Average Daily Production

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year-Over-Year Change	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018	Year-Over-Year Change
Natural gas (Mcf/d)	108,679	109,520	(1%)	98,458	101,019	(3%)
Condensate (Bbls/d)	2,416	2,453	(1%)	2,138	2,141	-
NGL (Bbls/d)	1,846	1,726	7%	1,634	1,561	5%
Total (Boe/d)	22,375	22,432	-	20,182	20,538	(2%)
Natural gas weighting	81%	81%		81%	82%	
Condensate weighting	11%	11%		11%	10%	
NGL weighting	8%	8%		8%	8%	

Production for natural gas, condensate and NGL for the fourth quarter of 2019 was comparable to the fourth quarter of 2018 and 2% lower when comparing the year ended December 31, 2019 to the same period of 2018, primarily due to 2019 being negatively affected by third-party outages which offset production increases in the year. Of the 43 days of outages, 12 days related to planned outages while the remaining 31 days of outages were unplanned. These outages reduced production by approximately 2,000 Boe per day for the year ended December 31, 2019. In addition to the unplanned outages, production was voluntarily curtailed at times in response to weak natural gas pricing at Station 2.



Daily production per million shares outstanding for the fourth quarter of 2019 averaged 184 Boe per day compared to 185 Boe per day for the fourth quarter of 2018. Daily production per million shares outstanding in 2019 averaged 166 Boe per day, compared to 169 Boe per day in 2018.

Revenue from Product Sales[(1)]

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Natural gas	$ 32,836	$ 55,973	$ 115,488	$ 146,852
Condensate	14,796	13,256	51,522	59,071
NGL	1,039	5,570	6,412	20,335
Total	$ 48,671	$ 74,799	$ 173,422	$ 226,258
% of Total Revenue by Product Type				
Natural gas	67%	75%	67%	65%
Condensate and NGL	33%	25%	33%	35%
Total	100%	100%	100%	100%

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

Revenue from product sales for the fourth quarter of 2019 decreased by 35% when compared to the fourth quarter of 2018 as a result of the Company's average realized price decreasing by 35% as production volumes stayed flat. For the year ended December 31, 2019, revenue from product sales decreased 23% year over year due to the Company's average realized price decreasing by 22%.

The contribution of condensate and NGL to total revenue from product sales was 33% for both the three months and year ended December 31, 2019 (three months and year ended December 31, 2018 – 25% and 35%, respectively). For the three months ended December 31, 2019, condensate and NGL revenue from product sales made up a larger proportion of total revenue versus the same period in 2018 as natural gas prices were 70% higher in the fourth quarter of 2018 and contributed a higher percentage of total revenue given Storm's 81% natural gas weighting. For the year ended December 31, 2019 there was a more normalized distribution of revenue by product type as pricing was down across all revenue streams and averaged out over a full twelve months, reducing the effect of the significant increase in natural gas prices in the fourth quarter of 2018.

A reconciliation of year-over-year revenue changes for the three month period ending December 31, 2019 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q4 2018	$ 55,973	$ 13,256	$ 5,570	$ 74,799
Effect of changes in production	(430)	(199)	387	(242)
Effect of changes in average product prices	(22,707)	1,739	(4,918)	(25,886)
Revenue from product sales – Q4 2019	$ 32,836	$ 14,796	$ 1,039	$ 48,671

A reconciliation of year-over-year revenue changes for the year ended December 31, 2019 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – 2018	$ 146,852	$ 59,071	$ 20,335	$ 226,258
Effect of changes in production	(3,723)	(72)	953	(2,842)
Effect of changes in average product prices	(27,641)	(7,477)	(14,876)	(49,994)
Revenue from product sales – 2019	$ 115,488	$ 51,522	$ 6,412	$ 173,422

Average Selling Prices(1)

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Natural gas – Mcf	$ 3.28	$ 5.56	$ 3.21	$ 3.98
Condensate – Bbl	$ 66.56	$ 58.74	$ 66.03	$ 75.61
NGL – Bbl	$ 6.11	$ 35.09	$ 10.75	$ 35.69
Per Boe	$ 23.64	$ 36.24	$ 23.54	$ 30.18

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

On a per-Boe basis, the Company's average realized price for the three months ended December 31, 2019 decreased by 35% compared to the same period of 2018, with the decrease driven by lower natural gas and NGL pricing, partially offset by higher condensate pricing. As previously communicated, Storm's NGL price for the April 2019 to March 2020 contract year was expected to be approximately 5% to 10% of WTI. The Company's NGL price for the fourth quarter of 2019 was 8% of WTI which was in line with expectations. The decrease in natural gas pricing is primarily due to a reduction in prices at Chicago and Sumas.

On a per-Boe basis, the Company's average realized price for the year ended December 31, 2019 decreased by 22% when compared to the same period of 2018, primarily driven by decreases in NGL, natural gas and condensate pricing.

Benchmark Prices

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year ended Dec. 31, 2019	Year ended Dec. 31, 2018
Natural gas				
Chicago monthly index (US$/Mmbtu)	2.44	3.62	2.56	3.06
Chicago daily index (US$/Mmbtu)	2.21	3.69	2.42	3.02
Sumas (US$/Mmbtu)	4.20	11.09	3.80	4.30
AECO monthly index (Cdn$/GJ)	2.21	1.80	1.54	1.45
AECO daily index (Cdn$/GJ)	2.35	1.48	1.67	1.42
Station 2 (Cdn$/GJ)	1.41	0.64	0.96	1.19
Crude Oil				
WTI (US$/Bbl)	56.96	58.81	57.03	64.77
WTI (Cdn$/Bbl)	75.27	77.76	75.70	83.94
Edmonton condensate (Cdn$/Bbl)	70.05	59.66	70.17	78.90
Exchange rate (US$/Cdn$)	0.76	0.76	0.75	0.77

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

In October 2018, a pipeline rupture occurred on the Enbridge T-south line which reduced pipeline capacity. This had increased volatility in pricing for both Station 2 (lower) and Sumas (higher). During the fourth quarter of 2018, the monthly Sumas index price averaged US$11.09 per Mmbtu resulting in increased revenue for Storm which was offset by increased hedging losses on Storm's sales at Sumas. In November 2019, the Enbridge T-south line returned to full capacity. Sumas pricing in the fourth quarter of 2019 averaged US$4.20 per Mmbtu with increased demand in the Pacific Northwest.

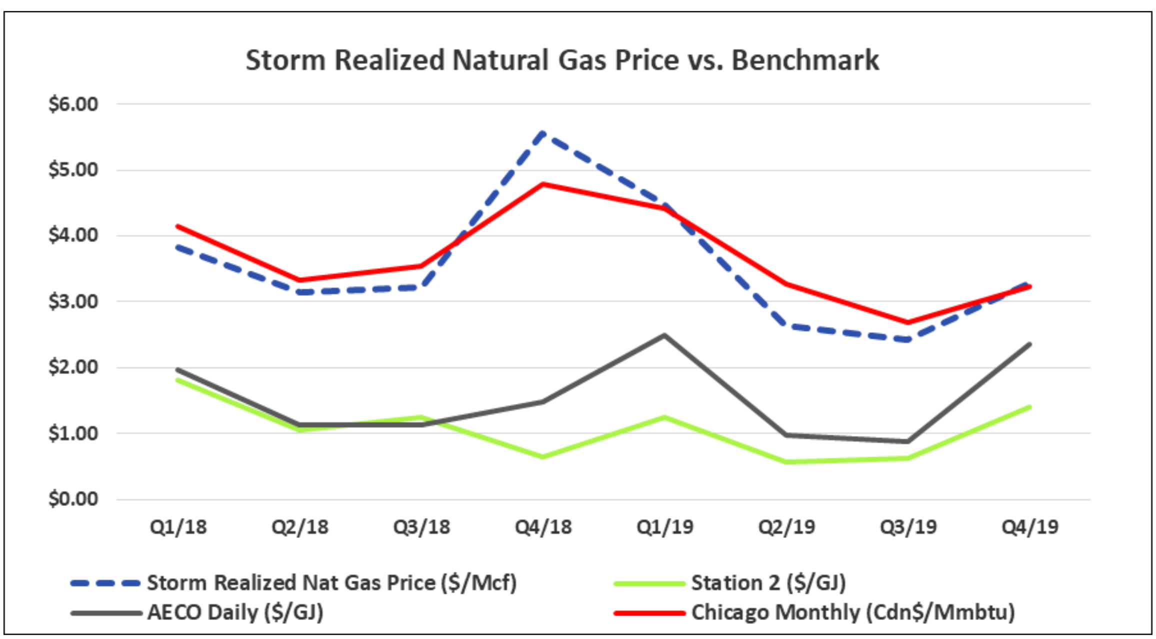
US natural gas prices trended lower in 2019, particularly in the latter half of the year, due to increasing supply and reduced demand through the summer and into shoulder season. With moderate winter weather through the fourth quarter and into 2020, US natural gas prices have been under further pressure in 2020.

Western Canadian natural gas pricing (AECO and Station 2) increased in the fourth quarter compared to the fourth quarter of 2018 due to increased demand combined with low storage levels.

WTI crude oil pricing, on which a large part of the Company's condensate and NGL revenue is based, declined 3% from US$58.81 per barrel during the fourth quarter of 2018 to US$56.96 per barrel for the fourth quarter of 2019 due to global trade tensions continuing to affect international economies and lower oil demand forecasts, partially offset by geopolitical tensions in the Middle East affecting the stability of oil supplies. Condensate pricing in the fourth quarter of 2019 increased as the decrease in WTI was more than offset by the narrowing of the Edmonton condensate differential from a discount of US$13.52 per barrel in the fourth quarter of 2018 to a discount of US$3.95 per barrel for the fourth quarter of 2019. The condensate differential continued to narrow in the first quarter of 2020 relative to 2019 and condensate prices are expected to settle at close to parity with WTI in US dollar terms in the first quarter of 2020.

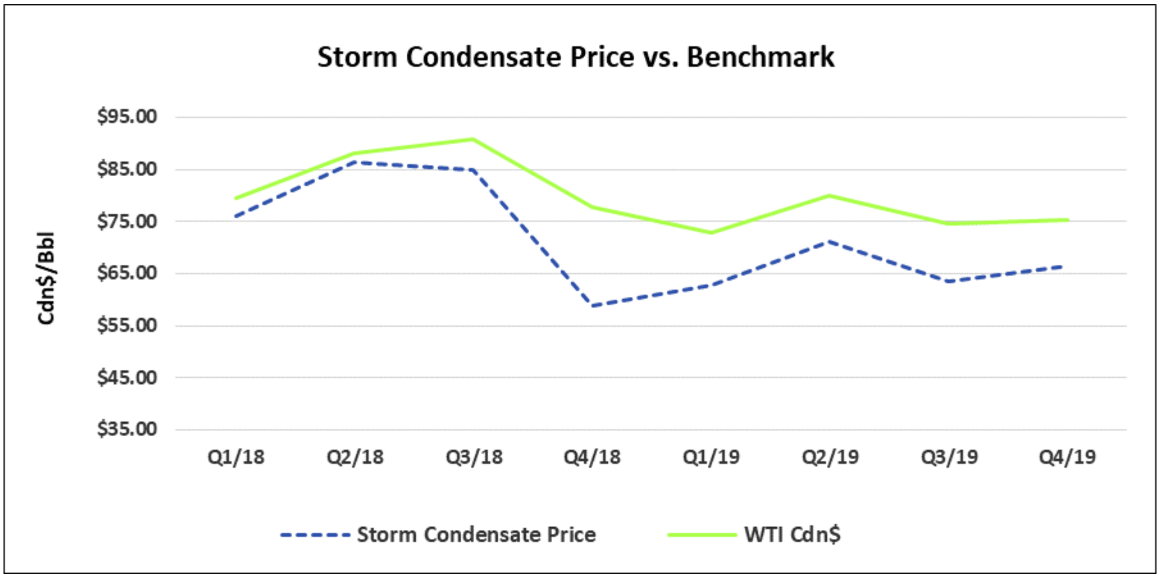
The Company's production during the fourth quarter and year ended December 31, 2019 was sold as follows:

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year ended Dec. 31, 2019	Year ended Dec. 31, 2018
Chicago monthly index price	30%	35%	33%	38%
Chicago daily index price	25%	28%	24%	25%
AECO index price	11%	11%	11%	6%
Station 2 index price	20%	10%	19%	14%
Sumas index price	11%	11%	11%	12%
Alliance Transfer Point ("ATP")	3%	5%	2%	5%
Total	100%	100%	100%	100%



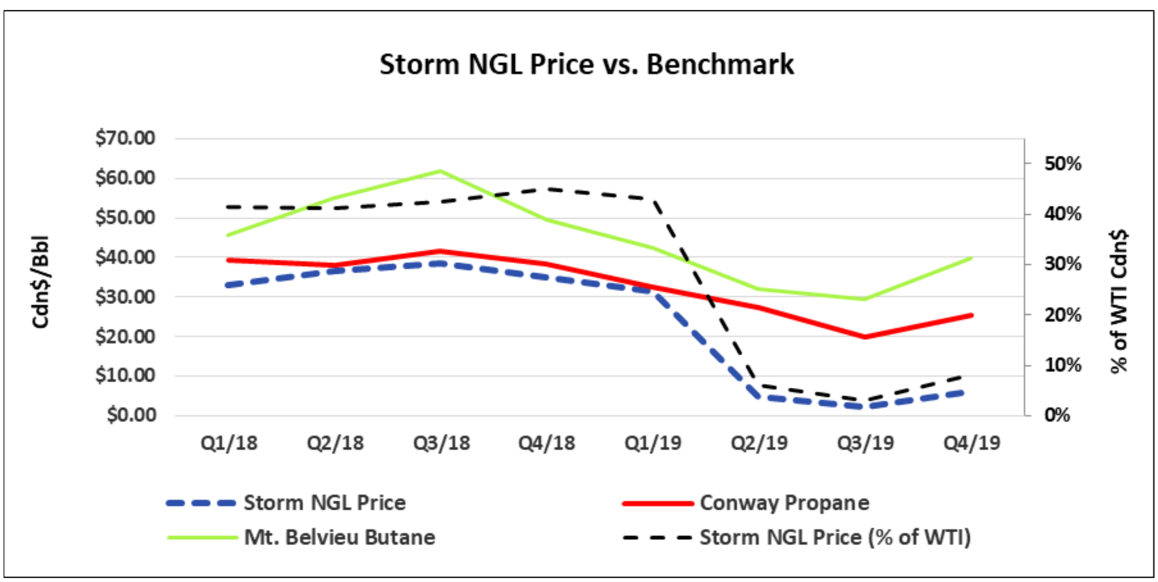
As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was approximately 120% higher than Station 2 pricing in the fourth quarter of 2019 and approximately 220% higher for the year ended December 31, 2019. A significant contributor to the increase in Storm's realized natural gas price to $3.28 per Mcf in the fourth quarter of 2019 was selling approximately 66% of the Company's natural gas into the Chicago and Sumas markets, which had higher relative pricing than AECO and Station 2.

The effect of the higher realized natural gas price on the Company's funds flow is partially offset by higher transportation costs.



Storm's realized condensate price for the fourth quarter of 2019 increased by 13% from the fourth quarter of 2018 as a result of a narrowing of the WTI-Edmonton condensate differential from the fourth quarter of 2018 to the fourth quarter of 2019, offset by a slight decrease in the WTI price. The fourth quarter of 2018 was significantly affected by pipeline constraints and refinery outages which reduced demand for diluent blending.

In 2019, Storm's condensate price decreased 13% compared to 2018 primarily as a result of a decrease in the WTI price while the WTI-Edmonton condensate differential was relatively stable year over year.



Storm's realized price for NGL, excluding condensate, in the fourth quarter of 2019 decreased by 83% relative to the same period of 2018. For the year ended December 31, 2019, the realized price for NGL, excluding condensate, decreased by 70% year over year. The decrease in realized NGL prices for both of the aforementioned periods was primarily due to lower contracted butane pricing as a result of elevated supply levels, lower propane pricing and weaker WTI pricing period over period.

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

Risk Management

	Three Months to Dec. 31, 2019		Three Months to Dec. 31, 2018	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (2,358)	$ 2,439	$ (16,774)	$ (4,212)
Liquids(1)	714	(4,574)	(1,087)	16,497
Interest rate	-	122	-	-
Gain (loss) on risk management contracts	$ (1,644)	$ (2,013)	$ (17,861)	$ 12,285

	Year Ended Dec. 31, 2019		Year Ended Dec. 31, 2018	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (10,532)	$ 10,742	$ (14,687)	$ (16,741)
Liquids(1)	1,698	(9,226)	(7,990)	10,908
Interest rate	1	11	-	-
Gain (loss) on risk management contracts	$ (8,833)	$ 1,527	$ (22,677)	$ (5,833)

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

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

The realized gains and losses on risk management contracts consists of the portion of contracts that have settled in cash during the reporting period. The realized loss of $8.8 million for the year ended December 31, 2019 is primarily due to higher pricing at Chicago and Sumas which also benefitted the Company's natural gas revenues during the first quarter of 2019.

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

Royalties

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Charge for period	$ 3,267	$ 1,189	$ 8,169	$ 8,127
Percentage of revenue from product sales	6.7%	1.6%	4.7%	3.6%
Per Boe	$ 1.59	$ 0.58	$ 1.11	$ 1.08

Royalties, as a percentage of revenue from product sales, increased in the fourth quarter of 2019 compared to the same period in 2018 primarily due to receipt of $0.2 million in infrastructure royalty credits in the fourth quarter of 2019 compared to $3.9 million received in the fourth quarter of 2018 and a decrease in wells benefitting from the BC Deep Well Royalty Program, partially offset by lower commodity prices. 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 fourth quarter of 2019, 28 wells qualified for the 6% royalty rate compared to 37 wells in the fourth quarter of 2018.

Royalties, as a percentage of revenue from product sales, increased in 2019 compared to 2018 primarily due to receipt of infrastructure royalty credits of $3.7 million in 2019 compared to credits of $5.3 million received in 2018 and a decrease in the number of wells benefitting from the BC Deep Well Royalty Program, partially offset by a decrease in commodity prices.

Storm has remaining infrastructure royalty credits of $7.0 million that will reduce future royalties, which includes credits of $6.2 million relating to the construction of the Nig Gas Plant which came online in February 2020. 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 realized.

Production Costs

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Charge for period	$ 11,663	$ 11,270	$ 43,274	$ 41,242
Per Boe	$ 5.67	$ 5.46	$ 5.87	$ 5.50

Total production costs for the fourth quarter of 2019 increased 3% when compared to the fourth quarter of 2018. Total production costs increased by 5% for the year ended December 31, 2019 when compared to the same period of 2018. The increase in total production costs for the fourth quarter of 2019 compared to the fourth quarter of 2018 is due to higher third-party gas processing costs as a result of an annual inflation escalator and an increase in BC carbon tax effective April 1, 2019. The increase in total production costs for the year ended December 31, 2019 compared to the same period of 2018 was primarily due to fixed costs incurred during unplanned outages at the McMahon Gas Plant and an increase in the BC carbon tax.

On a per-Boe basis, production costs increased by 4% and 7% in the three months and year ended December 31, 2019 compared to the same periods of 2018, primarily due to incurring fixed costs and lower production during unplanned outages at the McMahon Gas Plant.

Carbon Tax

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

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Charge for period	$ 1,521	$ 1,368	$ 5,716	$ 5,217
Per Boe	$ 0.74	$ 0.66	$ 0.78	$ 0.70

Transportation Costs

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Charge for period	$ 10,708	$ 11,487	$ 41,703	$ 43,764
Per Boe	$ 5.20	$ 5.57	$ 5.66	$ 5.84

Transportation costs include pipeline tariffs for natural gas sold at various points, as well as trucking costs and pipeline tariffs for wellhead condensate. Natural gas sales volumes destined for Chicago and markets across North America have higher per-unit transportation costs, but obtain higher sales prices which offsets the higher pipeline tariffs.

Transportation costs for the fourth quarter of 2019 and on a per-Boe basis decreased by 7% when compared to the fourth quarter of 2018, primarily due to a lower proportion of natural gas sales volumes transported on the Alliance Pipeline and sold at Chicago. Transportation costs for the year ended December 31, 2019 decreased by 5% and by 3% on a per-Boe basis when compared to the same period of 2018 due to selling less natural gas to Chicago, partially offset by incurring fixed costs for unused firm transportation during outages.

Field Netbacks

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

	Three Months Ended December 31, 2019			
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.28	$ 66.56	$ 6.11	$ 23.64
Royalties	(0.13)	(8.44)	(0.79)	(1.59)
Production costs	(1.17)	-	-	(5.67)
Transportation costs	(0.97)	(4.62)	-	(5.20)
Field operating netback	$ 1.01	$ 53.50	$ 5.32	$ 11.18
Realized gain (loss) on risk management contracts	(0.24)	1.81	1.83	(0.80)
Field operating netback including hedging	$ 0.77	$ 55.31	$ 7.15	$ 10.38

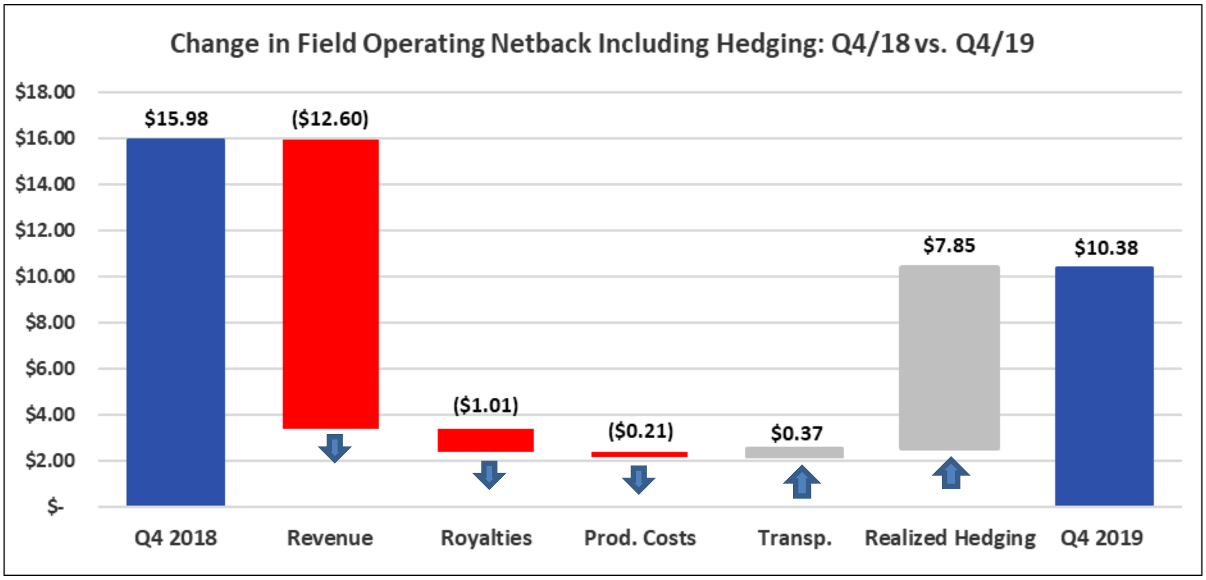
	Three Months Ended December 31, 2018			
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 5.56	$ 58.74	$ 35.09	$ 36.24
Royalties	0.03	(4.52)	(3.24)	(0.58)
Production costs	(1.12)	-	-	(5.46)
Transportation costs	(1.02)	(5.49)	-	(5.57)
Field operating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

	Year Ended December 31, 2019			
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.21	$ 66.03	$ 10.75	$ 23.54
Royalties	(0.03)	(8.02)	(1.44)	(1.11)
Production costs	(1.20)	-	-	(5.87)
Transportation costs	(1.05)	(4.90)	(0.06)	(5.66)
Field operating netback	$ 0.93	$ 53.11	$ 9.25	$ 10.90
Realized gain (loss) on risk management contracts	(0.29)	0.63	2.02	(1.20)
Field operating netback including hedging	$ 0.64	$ 53.74	$ 11.27	$ 9.70

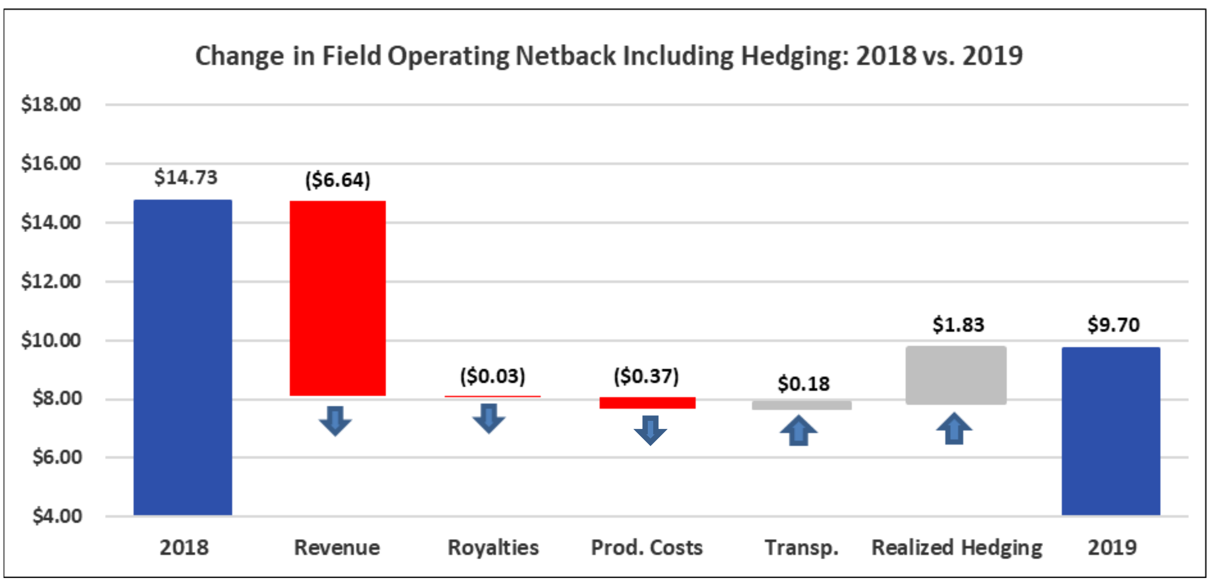
	Year Ended December 31, 2018			
	Natural Gas(1) ($/Mcf)	Condensate(2) ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.98	$ 75.61	$ 35.69	$ 30.18
Royalties	(0.03)	(6.50)	(3.29)	(1.08)
Production costs	(1.12)	-	-	(5.50)
Transportation costs	(1.08)	(5.24)	-	(5.84)
Field operating netback	$ 1.75	$ 63.87	$ 32.40	$ 17.76
Realized gain (loss) on risk management contracts	(0.40)	(10.27)	0.05	(3.03)
Field operating netback including hedging	$ 1.35	$ 53.60	$ 32.45	$ 14.73

(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 fourth quarter of 2019 decreased by 55% (35% decrease after hedging) compared to the fourth quarter of 2018.



The 2019 field operating netback decreased by 39% (34% decrease after hedging) compared to 2018.



General and Administrative Costs

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Charge for period – before recoveries	$ 2,039	$ 2,061	$ 8,870	$ 8,155
Overhead recoveries	(594)	(933)	(1,987)	(2,043)
Charge for period – net of recoveries	$ 1,445	$ 1,128	$ 6,883	$ 6,112
Per Boe	$ 0.70	$ 0.55	$ 0.93	$ 0.82

General and administrative costs before recoveries for the fourth quarter of 2019 were broadly in line with the fourth quarter of 2018. General and administrative costs before recoveries for the year ended December 31, 2019 increased by 9% compared to 2018 due to higher compensation costs and the payout of the employee annual performance bonus after year-end results were finalized.

As a result of the change in lease accounting effective January 1, 2019, general and administrative costs are lower by $0.1 million in the fourth quarter of 2019 and lower by $0.5 for the year ended December 31, 2019 related to the office lease.

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

Net general and administrative costs on a per-Boe measure for the fourth quarter of 2019 were 27% higher than the fourth quarter of 2018 due to lower overhead recoveries as a result of lower capital expenditures in the fourth quarter of 2019. Net general and administrative costs on a per-Boe basis for 2019 were 13% higher when compared to 2018. Generally, the Company's general and administrative cost structure is predictable year to year and variability in per-Boe metrics is due to changes in production volumes.

Interest and Finance Costs

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Charge for period(1)	$ 1,510	$ 923	$ 5,158	$ 4,244
Average interest rate(2)	5.0%	4.6%	5.1%	4.8%
Per Boe	$ 0.73	$ 0.45	$ 0.70	$ 0.57

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

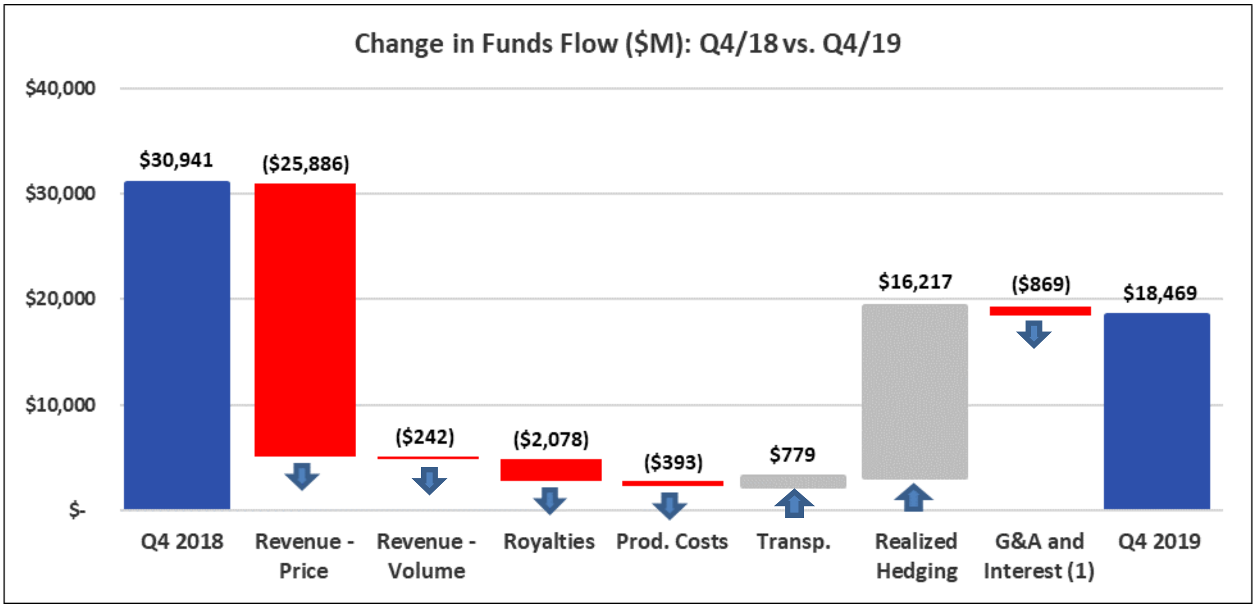
The interest rate on the Company's bank facility is based on bankers' acceptance rates plus a stamping fee which is amended each quarter in response to changes in the Company's debt to funds flow ratio.

Interest costs for the fourth quarter of 2019 increased by 64% compared to the fourth quarter of 2018 as a result of higher average bank borrowings. Interest costs for 2019 increased by 22% compared to 2018 as a result of higher market interest rates combined with higher average bank borrowings which are used to fund capital expenditures.

Funds Flow

	Three Months to Dec. 31, 2019		Three Months to Dec. 31, 2018		Year Ended Dec. 31, 2019		Year Ended Dec. 31, 2018	
		Per diluted share		Per diluted share		Per diluted share		Per diluted share
Funds flow	$18,469	$0.15	$30,941	$0.25	$59,549	$0.49	$100,092	$0.82

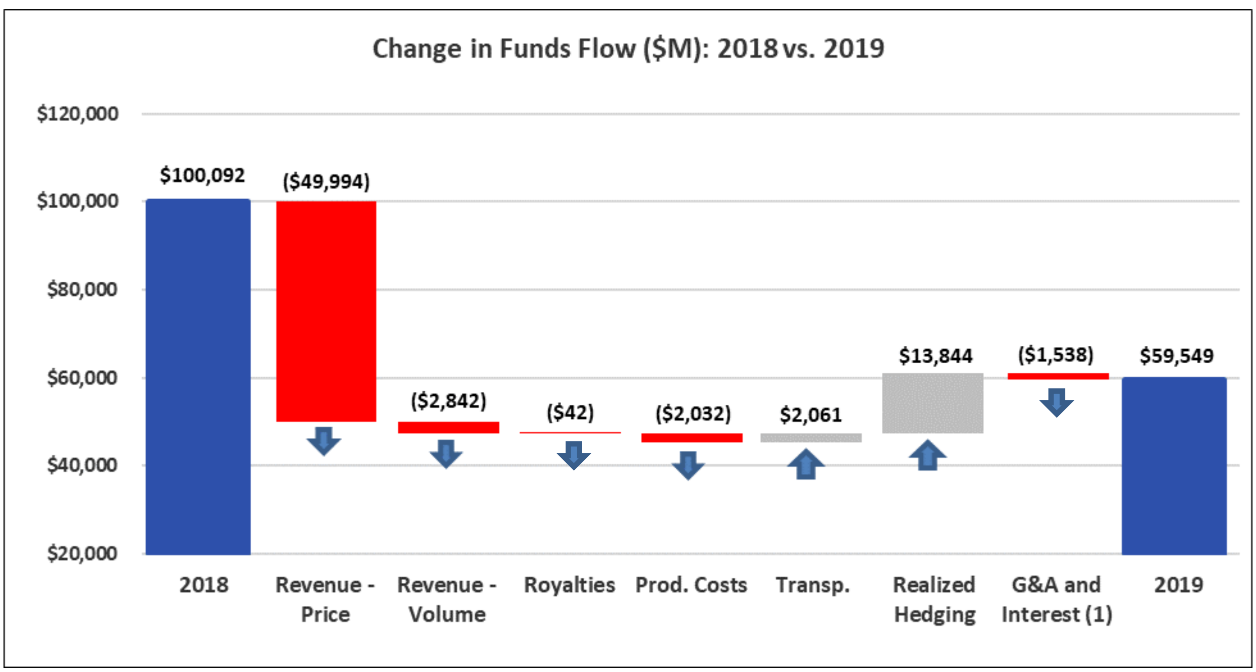
Funds flow, a measure that is not defined under IFRS, is cash generated from operating activities before changes in non-cash working capital, as presented on the statement of cash flows. The measurement of funds flow is used to benchmark operations against prior and future periods and peer group companies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



(1) Excludes lease interest.

Lower realized prices was the predominant factor in the 40% decrease in funds flow in the fourth quarter of 2019 versus the fourth quarter of 2018.

The cash return on capital employed ("CROCE") over the last 12 months, which is a measurement of the Company's cash profitability as a proportion of the funding utilized to generate it (shareholders' equity plus debt including working capital deficiency), was 12% in the fourth quarter of 2019 compared to 21% in the fourth quarter of 2018.



(1) Excludes lease interest.

Funds flow for 2019 decreased by 41% from 2018. Funds flow was negatively affected by weaker realized pricing.

Share-Based Compensation

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Charge for period	$ 656	$ 838	$ 2,464	$ 3,127
Per Boe	$ 0.32	$ 0.41	$ 0.33	$ 0.42

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 22% in the fourth quarter of 2019 compared to the fourth quarter in 2018 and by 21% in the year ended December 31, 2019 compared to the same period of 2018. The decrease in share-based compensation in both periods is primarily attributable to a lower option fair valuation associated with options granted during 2018.

Depletion and Depreciation

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Depletion	$ 9,246	$ 9,027	$ 32,742	$ 38,845
Depreciation	2,010	1,772	7,764	6,772
Charge for period	$ 11,256	$ 10,799	$ 40,506	$ 45,617
Per Boe	$ 5.46	$ 5.23	$ 5.50	$ 6.09

Depletion and depreciation increased by 4% in the fourth quarter of 2019 compared to the same quarter of 2018. Comparing the year ended December 31, 2019 with the same period in 2018, depletion and depreciation decreased by 11%. The year-to-date per-Boe decrease in depletion corresponds to lower finding and development costs.

Income Taxes

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

The Company did not incur any cash tax expense in the three months and year ended December 31, 2019, nor does it expect to pay any cash tax in 2020 or 2021 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

Deferred income taxes arise from differences between the accounting and tax bases of the Company's assets and liabilities. For the three months and year ended December 31, 2019, the Company recognized a deferred income tax expense of $1.5 million and $4.9 million, respectively, as a result of $4.4 million and $16.2 million of net income before taxes, respectively. As at December 31, 2019, the Corporation had a deferred income tax liability of $9.4 million.

Tax Pools	As at December 31, 2019	Maximum Annual Deduction
Canadian oil and gas property expense	$ 43,000	10%
Canadian development expense	110,000	30%
Canadian exploration expense	14,000	100%
Undepreciated capital cost	137,000	20% – 100%
Operating losses	199,000	100%
Total	$ 503,000	

Net Income

The mark-to-market valuation of risk management contracts resulted in a considerable distortion on reported net income for the three months and year ended December 31, 2019 relative to the comparable periods in 2018. The mark-to-market valuation of risk management contracts amounted to an unrealized loss of $2.0 million for the three months ended December 31, 2019 and an unrealized gain of $1.5 million for the year ended December 31, 2019. This compares to an unrealized gain of $12.3 million for the three months ended December 31, 2018 and an unrealized loss of $5.8 million for the year ended December 31, 2018.

Excluding unrealized gains and losses on risk management contracts, the decrease in net income in the three months and year ended December 31, 2019 compared to the same periods of 2018 is primarily attributable to the weakened commodity pricing environment driving decreased revenue.

The return on capital employed ("ROCE") over the last 12 months, which is a measurement of the Company's income profitability as a proportion of the funding utilized to generate it (shareholders' equity plus debt including working capital deficiency), was 4% in the fourth quarter of 2019 compared to 10% in the fourth quarter of 2018, although as mentioned above is distorted by unrealized gains and losses on the Company's risk management contracts.

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Net income	$ 2,906	$ 26,810	$ 11,313	$ 40,063
Per basic and diluted share	$ 0.02	$ 0.22	$ 0.09	$ 0.33

Corporate Netbacks

($/Boe)	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Revenue from product sales	23.64	36.24	23.54	30.18
Realized gain (loss) on risk management contracts	(0.80)	(8.65)	(1.20)	(3.03)
Royalties	(1.59)	(0.58)	(1.11)	(1.08)
Production	(5.67)	(5.46)	(5.87)	(5.50)
Transportation	(5.20)	(5.57)	(5.66)	(5.84)
General and administrative	(0.70)	(0.55)	(0.93)	(0.82)
Interest and finance costs	(0.71)	(0.45)	(0.68)	(0.57)
Funds flow	8.97	14.98	8.09	13.34
Share-based compensation	(0.32)	(0.41)	(0.33)	(0.42)
Depletion, depreciation and accretion	(5.52)	(5.29)	(5.57)	(6.16)
Lease interest	(0.02)	-	(0.02)	-
Exploration and evaluation costs expensed	(0.01)	-	(0.15)	(0.04)
Unrealized revaluation gain (loss) on investments	0.01	(0.11)	(0.01)	(0.03)
Unrealized gain (loss) on risk management contracts	(0.98)	5.96	0.21	(0.78)
Deferred income tax expense	(0.72)	(2.15)	(0.67)	(0.59)
Net income	1.41	12.98	1.55	5.32

INVESTMENT AND FINANCING

Financial Resources and Liquidity

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

At December 31, 2019, debt including working capital deficiency amounted to $128.9 million, representing approximately 63% of the available credit facility.

As at December 31, 2019, the Company had issued letters of credit in the amount of $10.0 million (December 31, 2018 - $7.6 million) in support of future natural gas transportation and processing obligations. Availability under the Company's credit facility is reduced by a like amount.

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

Capital Expenditures

In the fourth quarter of 2019, the Company incurred capital expenditures of $23.9 million compared to $37.1 million in the fourth quarter of 2018.

During 2019, the Company incurred capital expenditures of $96.8 million (2018 - $84.8 million) primarily related to costs incurred in constructing the Nig Gas Plant, as well as drilling and completion activities on a four well pad at Nig.

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Land and seismic	$ 370	$ 1,043	$ 2,155	$ 3,846
Drilling	208	14,613	14,639	14,902
Completions	991	10,664	13,474	30,517
Facilities	16,543	8,859	56,830	19,552
Equipping and pipelines	5,585	1,766	10,499	14,365
Recompletions and workovers	194	131	249	903
Property acquisition and administrative assets	22	24	80	678
Total field capital expenditures	$ 23,913	$ 37,100	$ 97,926	$ 84,763
Proceeds on disposition of undeveloped land	-	-	(1,083)	-
Total capital expenditures	$ 23,913	$ 37,100	$ 96,843	$ 84,763

Net capital investment was allocated as follows:

	Three Months to Dec. 31, 2019	Three Months to Dec. 31, 2018	Year Ended Dec. 31, 2019	Year Ended Dec. 31, 2018
Exploration and evaluation	$ 370	$ 1,043	$ 1,086	$ 4,034
Property and equipment	23,543	36,057	95,757	80,729
Total capital expenditures	$ 23,913	$ 37,100	$ 96,843	$ 84,763

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, general and administrative and capital costs payable. When appropriate, net payables in respect of cash calls issued to partners regarding capital projects and estimates of amounts owing but not yet invoiced to the Company are included in accounts payable. The level of accounts payable and accrued liabilities at December 31, 2019 corresponds to the active field program at Umbach.

Decommissioning Liability

The Company's decommissioning liability of $28.1 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 December 31, 2019 was $38.3 million (December 31, 2018 - $43.2 million).

Share Capital

Details of share issuances from inception to December 31, 2019 are as follows:

		Number of Shares (000s)	Price per Share	Gross Proceeds[1] ($000s)
June 8, 2010	Issued upon incorporation		$ 1.00	$ -
August 17, 2010	Issued under the Arrangement	17,515	$ 3.28	57,600
August 17, 2010	Issued under private placement	2,300	$ 3.28	7,544
September 22, 2010	Issued upon exercise of warrants	6,562	$ 3.28	21,522
		26,377		86,666
January 12, 2012	Issued on acquisition of SGR	11,761	$ 3.73	43,869
March 23, 2012	Issued under private placement	6,946	$ 3.40	23,615
March 23, 2012	Issued on acquisition of Bellamont	16,740	$ 2.37	39,674
		35,447		107,158
May 1, 2013	Issued under private placement	12,580	$ 1.88	23,650
May 1, 2013	Issued under insider private placement	3,000	$ 1.88	5,640
June 30, 2013	Shares cancelled	(21)	$ 2.37	(50)
November 19, 2013	Issued under private placement	9,000	$ 3.35	30,150
November 19, 2013	Issued under insider private placement	1,100	$ 3.35	3,685
		25,659		63,075
January 31, 2014	Issued pursuant to Umbach acquisition	13,629	$ 4.25	57,925
February 14, 2014	Issued under private placement	7,250	$ 4.10	29,725
February 14, 2014	Issued under insider private placement	1,250	$ 4.10	5,125
Year ended December 31, 2014	Stock option exercises	1,710	$ 3.26	5,580
		23,839		98,355
June 10, 2015	Issued under private placement	8,000	$ 4.55	36,400
Year ended December 31, 2015	Stock option exercises	145	$ 1.81	262
		8,145		36,662
Year ended December 31, 2016	Stock option exercises	1,297	$ 1.97	2,558
Year ended December 31, 2017	Stock option exercises	793	$ 1.83	1,456
Total at December 31, 2018 and 2019		121,557	$ 3.26	$ 395,930

(1) Before share issue costs and transfers from contributed surplus.

There were no stock options exercised in 2018 or 2019.

Issued and outstanding common shares at December 31, 2019 and at February 27, 2020, the date of this MD&A, totaled 121,556,812.

CONTRACTUAL OBLIGATIONS

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

- purchase of services;
- royalty agreements;
- operating agreements;
- processing and transportation agreements;
- right of way agreements;
- lease obligations for office space and field equipment;
- rental obligations for accommodation, office equipment and automotive equipment;
- banking agreements; and
- risk management contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The remaining aggregate commitment approximates $4.9 million over six years. In addition, as at the date of this report, the Company has transportation and processing commitments valued at a total of approximately $473 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended December 31, 2019 appears below.

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

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

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

The third quarter of 2019 was affected negatively by an unplanned 14-day outage at the McMahon Gas Plant resulting in lower revenues. The debt including working capital deficiency rose to $123.3 million as construction of the Nig Gas Plant continued as planned.

During the fourth quarter of 2019, the Company continued with construction of the Nig Gas Plant and ramped up production in December in response to improved commodity prices for all product streams, generating funds flow for the quarter of $18.5 million. Debt including working capital deficiency increased to $128.9 million.

				2019				2018
($000s unless otherwise stated)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue from product sales	48,671	31,417	37,568	55,766	74,799	51,253	48,104	52,102
Funds flow	18,469	11,973	12,590	16,517	30,941	22,227	23,405	23,519
Per share – basic and diluted ($)	0.15	0.10	0.10	0.14	0.25	0.18	0.19	0.19
Net income (loss)	2,906	(64)	7,864	607	26,810	7,174	(2,815)	8,894
Per share – basic and diluted ($)	0.02	(0.00)	0.06	0.00	0.22	0.06	(0.02)	0.07
Net capital expenditures	23,913	32,841	23,145	16,944	37,100	21,845	2,918	22,900
Average daily production (Boe)	22,375	18,596	19,923	19,823	22,432	20,455	19,529	19,708
Debt including working capital deficiency(1)	128,901	123,342	102,268	91,585	91,020	84,648	85,073	105,585

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

SELECTED ANNUAL FINANCIAL INFORMATION

($000s unless otherwise stated)	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2017
Revenue from product sales	173,422	226,258	152,880
Funds flow	59,549	100,092	64,080
Per share – basic and diluted ($)	0.49	0.82	0.53
Net income	11,313	40,063	39,689
Per share – basic and diluted ($)	0.09	0.33	0.33
Total assets	616,496	565,534	515,563
Debt including working capital deficiency(1)	128,901	91,020	106,124
Average daily production (Boe)	20,182	20,538	16,017
Funds flow ($/Boe)	8.09	13.34	10.96

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

The trend in annual results represents execution of the Company's strategic plan in the face of a volatile commodity price environment. The cornerstone of the strategic plan is capital investment discipline and growing asset value on a per-share basis. Storm achieved positive production and funds flow growth in 2018 relative to 2017 on the back of improved commodity prices, although funds flow generation was down in 2019 due to third party outages and a decrease in commodity prices. Over the last three years, the Company has benefitted from a diversified marketing strategy whereby a significant portion of the Company's production receives US based pricing. Prudent capital spending enabled the Company to increase funds flow 56% in 2018 from 2017 while debt decreased by 14% over the same period. This trend reversed in 2019 due to the aforementioned third-party outages and lower commodity prices, while debt increased due to the build out of the Nig Gas Plant project, which will benefit 2020 results. Net income has also been affected by volatile commodity prices, although is also subject to a high degree of variability due to unrealized gains and losses on risk management contracts. The Company reported a $1.5 million unrealized gain on risk management contracts for the year ended December 31, 2019, an unrealized loss on risk management contracts of $5.8 million for the year ended December 31, 2018 and an unrealized gain on risk management contracts of $24.6 million for the year ended December 31, 2017.

The increase in the Company's total assets reflects the ongoing development of the Company's Montney play at Umbach, Nig and Fireweed. Capital expenditures in 2019 were primarily directed towards construction of the 50 Mmcf per day Nig Gas Plant and drilling and completion activities at Nig. Capital expenditures in 2018 included drilling, completions and infrastructure expenditures including twinning of a third field compression facility at Umbach at a cost of approximately $7 million, which supports growth of corporate production from Umbach alone to approximately 27,000 Boe per day. While 2017 capital expenditures were largely directed to drilling and completions, the Company commissioned the first phase of the aforementioned third field compression facility, which increased Storm's compression capacity by one-third and resulted in a considerable increase in production in 2017.

Share Trading

Set out below is share trading activity for Storm for 2019 and 2018.

	2019					2018				
	Q1	Q2	Q3	Q4	Year	Q1	Q2	Q3	Q4	Year
High ($)	2.46	2.56	1.79	1.68	2.56	2.86	3.30	3.24	3.16	3.30
Low ($)	1.51	1.63	1.14	1.16	1.14	1.75	1.99	2.30	1.43	1.43
Close ($)	2.38	1.81	1.32	1.64	1.64	2.10	3.12	2.74	1.74	1.74
Volume traded (000s)	8,405	4,930	10,035	17,012	40,383	5,971	8,077	3,464	5,666	23,178
Value traded ($000s)	16,883	9,292	13,417	24,244	63,836	12,727	22,612	9,891	11,930	57,160
Weighted average trading price ($)	2.01	1.88	1.34	1.43	1.58	2.13	2.80	2.86	2.11	2.47

Note: Data obtained from the TMX website.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the audited consolidated financial statements for the years ended December 31, 2019 and 2018 are based on accounting policies, estimates and judgments which reflect information available to management at the time of preparation. Certain amounts in the financial statements are derived from a fully completed transaction cycle, or are validated by events subsequent to the end of the reporting date, or are based on established and effective measurement and control systems. However, certain other amounts, as described below, are based on estimations made by management using information which involves an element of measurement uncertainty. The degree of uncertainty related to each of the following items will vary; further, it may change between reporting periods. Variations between amounts estimated and actual results could have a material effect on Storm's operating results and financial position.

Oil and Gas Reserves

Estimates of quantities of proven and probable reserves of natural gas and NGL (which includes condensate) are not a financial measurement. However, estimated future cash flows associated with reserves are used in impairment assessments for exploration and evaluation assets and property and equipment, the measurement of decommissioning obligations and depletion and depreciation of property and equipment. Such estimates of cash flows involve assumptions regarding future commodity prices, exchange rates, discount rates, inflation rates and future production and transportation costs and, of necessity, involve uncertainty. Reserve estimates are prepared annually by independent qualified reserve evaluators in accordance with independently established industry standards using, in part, data supplied by the Company. The results of the independent reserve evaluation are reviewed by the Reserves Committee of the Company's Board of Directors. In certain circumstances the Company will prepare internal estimates of reserves which may be used in accounting measurements applicable to interim reporting periods.

Accounts Receivable, Accounts Payable and Accrued Liabilities

At the end of each reporting period the Company estimates the amount receivable from product sales and from joint venture partners to the extent that these amounts are not determinable from purchaser statements or amounts invoiced to partners. In addition, the Company estimates the cost of services and materials provided by suppliers during the reporting period if these costs have not been invoiced to the Company by the reporting date. The Company estimates and recognizes such revenues and costs using well established measurement procedures. Nonetheless, such procedures reflect judgment by management and are thus subject to measurement uncertainty. In addition, estimates of services and materials not invoiced, either to or by the Company, relate in large part to the Company's capital expenditure programs, the level of which can vary considerably between reporting periods. As a result, the amount of accounts receivable, accounts payable and accrued liabilities subject to estimation will vary and in periods of high field activity the amount subject to estimation may be a large part of the total amount.

Risk Management Contracts

The Company periodically enters into contracts which fix a price or a price range for future periods for natural gas and crude oil. Each such contract is valued at the end of each reporting period, with the change in value of outstanding contracts being included in the measurement of income for the period. The period end value is based on option pricing models using estimates for future circumstances and is correspondingly subject to both mathematical and input uncertainty. Crude oil contracts are used as a proxy for condensate and NGL contracts, as part of the Company's condensate and NGL stream is priced with reference to crude oil index prices.

Exploration and Evaluation Assets

Costs incurred by the Company in the assessment phase of a property offering development potential are categorized as exploration and evaluation assets. Such costs are transferred to CGUs, generally when production commences or reserves are assigned, or are expensed if management determines that the costs incurred will yield no future economic benefit or if the lease associated with the property expires. The amounts transferred to property and equipment, or expensed, and the timing of the decisions relative to each, are subject to measurement uncertainty. Furthermore, the carrying amount of exploration and evaluation assets at the end of each reporting period represents an asset whose value can only be established in future periods. The carrying amount of exploration and evaluation assets is reviewed at the end of each reporting period for indicators of impairment. If such indicators exist the carrying amount will be measured against the estimated recoverable amount and, if necessary, reduced. This review involves estimates and judgments by management and thus involves a high degree of uncertainty.

Property and Equipment, and Depletion and Depreciation

Amounts transferred from exploration and evaluation assets to property and equipment represent the accumulated net costs associated with the property transferred. The timing and the measure of the amount to be transferred involves estimation and judgment by management and the estimates used could differ from similar estimates developed by other parties. In addition, acquired property and equipment is initially recorded at fair value as determined by management. Measurement of fair value includes estimation and judgment and is inherently subjective and uncertain.

Property and equipment is subject to depletion and depreciation, and charges for depletion and depreciation are based on estimates which may only be validated in future periods, if ever. Such charges involve estimates by management of the useful economic life for assets subject to depletion and depreciation, the quantities of oil and gas reserves used in the depletion calculation, the future prices at which such reserves may be sold, and future costs to develop and produce such reserves.

The carrying amounts of property and equipment are reviewed each reporting period to determine whether there are indicators of impairment. If there are such indicators, an impairment test per CGU is completed involving the calculation of an estimated recoverable amount; as a result adjustments to the carrying amount may be made. All of these involve assumptions regarding uncertain future events and circumstances.

Decommissioning Liability

Storm records as a liability the discounted estimated fair value of obligations associated with the decommissioning of field assets. The carrying amount of exploration and evaluation assets and property and equipment is increased by an amount equivalent to the liability. In summary, the decommissioning liability reflects the present value of estimated costs to complete the abandonment and reclamation of field assets as well as the estimated timing of incurrence of these costs. The liability is increased each reporting period to reflect the passage of time, with the charge for accretion included in earnings. The liability is also adjusted to reflect changes in the amount and timing of future retirement obligations as well as asset dispositions and is reduced by the amount of any costs incurred in the period. Adjustments are also made to the liability in response to changes in discount and inflation rates. The amount of future decommissioning costs, the timing of incurrence of such costs, the discount rate and, correspondingly, the charge for accretion, are subject to uncertainty of estimation. In addition, the decommissioning activities to which the estimates relate are likely to take place many years, potentially decades, in the future. The long timeline between incurrence and eventual satisfaction of the obligation will inevitably affect the accuracy of the estimation process.

Share-Based Compensation

To determine the charge for share-based compensation, the Company estimates the fair value of stock options at the time of issue using assumptions regarding the life of the option, dividend yields, interest rates and the volatility of the security under option. Although the assumptions used to value a specific option remain unchanged throughout the life of the option, assumptions may change with respect to subsequent option grants. In addition, the assumptions used may not properly represent the fair value of stock options at any time; as no alternative valuation model is applied, the difference between the Company’s estimation of fair value and the actual value of the option is not measurable. Although the methodology used to measure the charge for share-based compensation is largely uniform across Storm’s peers, inputs to the calculation, and thus the charge, may vary considerably.

Income Taxes

The measurement of Storm’s tax pools, losses and deferred tax assets and liabilities requires interpretation of complex laws and regulations. All tax filings and compliance with tax regulations are subject to audit and reassessment, potentially several years after the initial filing. In addition, the amount and timing of use of tax pools may be affected by future legislation. Accordingly, the amounts of tax pools available for future use may differ significantly from the amounts estimated in the financial statements.

LIMITATIONS

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, as outlined in Storm's February 27, 2020 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 2020 guidance;
- future average production volumes in the fourth quarter of 2020 and annual production for 2020, along with production volumes by commodity;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2020 guidance;
- future reduction to corporate operating costs with the start-up of the Nig Gas Plant, along with the forecast operating cost for the Nig Gas Plant of less than $2.00 per Boe and incremental production from the Nig Gas Plant of approximately 1,500 Boe per day (70% liquids);
- future value of unrealized risk management contracts including the estimated hedging gain as outlined in 2020 guidance;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2020 capital expenditure program including 2020 capital investment of $75 to $85 million and total cost of approximately $86 million for the Nig Gas Plant;
- first quarter 2020 production of 24,000 to 25,000 Boe per day, first quarter capital investment of $30 million and capital investment of $31 million for the first half of the year;
- future expansion plans at Fireweed including expansion of the compression facility to 100 Mmcf per day, and 2020 net capital expenditures of $36 million;
- future growth plans through 2020 and 2021 including timing for the start-up of the Fireweed field compression facility;
- future cost of the Fireweed compression facility, including access road and sales pipeline, of $38 million gross along with field condensate-gas ratios that are forecast to be significantly higher than Umbach;
- future production levels of 25,000 to 30,000 Boe per day (5,300 to 6,300 barrels per day of liquids) in the fourth quarter of 2020, representing a year-over-year increase of 23% (using the mid-point) with liquids production increasing approximately 36%;
- 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 2020 guidance and per-share amounts;
- 2020 capital investment being approximately equal to funds flow;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital expenditure programs and future availability of such sources;
- drilling rigs, field service providers and completion and tie-in equipment being available as required, with costs of securing these services not materially exceeding expectations;
- development plans for Storm's properties;
- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency;
- availability and use of credit facilities including approximately $70 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 2020 or 2021;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from drilling longer wells, specifically management's estimated 8 and 14 Bcf raw gas type curves for wells;

- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2020 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 2020 to Chicago, Sumas, Station 2 and AECO markets and the forecasted NGL price net of transport being approximately 20% of WTI in Cdn$ for the next contract period starting in April 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 "Critical Accounting Estimates"; "Business Risks"; "Financial Reporting Update"; and the material assumptions and observations described under the headings "Overview"; "Production and Revenue"; "Risk Management"; "Royalties"; "Production Costs"; "Transportation Costs"; "Field Netbacks"; "General and Administrative Costs"; "Interest and Finance Costs"; "Funds Flow"; "Share-Based Compensation"; "Depletion and Depreciation"; "Accretion"; Income Taxes"; "Net Income"; "Financial Resources and Liquidity"; "Capital Expenditures"; "Accounts Payable and Accrued Liabilities"; "Decommissioning Liability"; "Share Capital"; "Contractual Obligations"; industry conditions including commodity prices, facility and pipeline capacity constraints and access to processing facilities and to market for production; the occurrence of an extended operational outage, a major safety or environmental incident, or unexpected events such as fires (including forest fires); currency fluctuations; imprecision of reserve estimates and related costs including future royalties, production and transportation costs and future development costs; environmental risks; increased competition from other industry participants or from companies that provide alternative sources of energy; the lack of availability of qualified personnel or management; the potential for security breaches of Storm's information technology and infrastructure by malicious persons or entities, and the unavailability or failure of such systems to perform as anticipated as a result of such breaches; stock market volatility; ability to access sufficient capital from internal and external sources; the risk that competing business objectives may exceed Storm's capacity to adapt and implement change; risks and uncertainties associated with obtaining regulatory, third party and stakeholder approvals outside of Storm's control for the Company's operations, projects, initiatives and exploration and development activities and the satisfaction of any conditions to approvals; 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 (including climate change) 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, the cost of compliance with current and future environmental laws, including climate change laws, and risks relating to increased activism and public opposition to fossil fuels. 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. Readers are cautioned that the foregoing list of factors is not exhaustive. **The forward-looking statements contained therein are expressly qualified by this cautionary statement.**

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

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

Field Operating Netbacks

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

Debt Including Working Capital Deficiency

Debt including working capital deficiency is defined as bank indebtedness plus working capital surplus or deficiency excluding the mark-to-market value of risk management contracts, decommissioning liability and lease liability. 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 December 31, 2019	As At December 31, 2018	As At December 31, 2017
Accounts receivable	21,961	29,262	15,104
Prepaids and deposits	764	853	4,542
Less: Accounts payable and accrued liabilities	(30,018)	(34,359)	(24,777)
Working capital deficiency	7,293	4,244	5,131
Bank indebtedness	121,608	86,776	100,993
Debt including working capital deficiency	128,901	91,020	106,124

CROCE & ROCE

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

($000s unless otherwise stated)	Year Ended December 31, 2019	Year Ended December 31, 2018
Average debt including working capital deficiency(1)	109,960	98,572
Average shareholders' equity(1)	414,820	386,336
Average capital employed	524,780	484,908
Funds flow	59,549	100,092
Interest and finance costs	5,158	4,244
Funds flow plus interest and finance costs	64,707	104,336
CROCE	12%	21%

(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)	Year Ended December 31, 2019	Year Ended December 31, 2018
Average debt including working capital deficiency[(1)]	109,960	98,572
Average shareholders' equity [(1)]	414,820	386,336
Average capital employed	524,780	484,908
Net income	11,313	40,063
Interest and finance costs	5,158	4,244
Deferred income tax expense	4,927	4,433
	21,398	48,740
ROCE	4%	10%

(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. The following reviews a number of the identifiable business risks faced by the Company. Business risks evolve constantly and additional risks emerge periodically. The risks below are those identified by management at the date of completion of this report, and may not describe all of the material business risks, identifiable or otherwise, faced by the Company.

Property Exploitation

Storm's exploitation programs require sophisticated and scarce technical skills as well as capital and access to land and oilfield service equipment. Storm endeavours to minimize the associated risks by ensuring that:

- activity is focused in core regions where internal expertise and experience can be applied;
- prospects are internally generated;
- development drilling is in areas where there is immediate or near-term access to facilities, pipelines and markets or where construction of necessary infrastructure is within the Company's financial capacity;
- the Company seeks to act as operator and to maintain a 100% or high working interest. The Company can thus control the timing, cost and technical content of its exploration and development programs.

Nevertheless, drilling and completing a well may not result in the discovery of economic reserves, or a well may be rendered uneconomic by commodity price declines or an increasing cost structure.

In addition, the Company's investment program is currently focused on development of the Umbach, Nig and Fireweed properties, resulting in asset concentration risk.

Commodity Price Fluctuations

When the Company identifies hydrocarbons of sufficient quantity and quality and successfully brings them on stream, it faces a pricing environment which is volatile and subject to a myriad of factors, largely out of the Company's control. Low prices for the Company's expected primary products will have a material effect on the Company's funds flow and profitability and thus re-investment capacity, and hence ultimate growth potential. Low prices also limit access to capital, both equity and debt. The Company in part mitigates the risk of pricing volatility through the use of risk management contracts, such as fixed priced sales, swaps, collars and similar contracts. However, access to such commodity price protection instruments may not be available in future periods, or available only at a cost considered to be uneconomic. Such risk management contracts tend to be for short periods and the pricing protection this provides has limited effect against medium and long term pricing trends. The Company may shut in production rather than sell it at prices considered by management to be unacceptably low. The Company's production base is almost entirely natural gas and associated liquids, a trend unlikely to change in future years, resulting in commodity concentration risk.

Adverse Well or Reservoir Performance

Changes in productivity in wells and areas developed by the Company could result in termination or limitation of production, or acceleration of decline rates, resulting in reduced overall corporate volumes and revenues. In addition, wells drilled by the Company tend to produce at high initial rates followed by rapid declines until a flattening decline profile emerges. There is a risk that the decline profile which eventually emerges for newly drilled wells is sub-economic. In addition, the Company's property in northeastern British Columbia is in the early stage of development and there is a risk that unforeseeable circumstances may emerge which will adversely affect reservoir performance.

Field Operations

Storm's current and future exploration, development and production activities involve the use of heavy equipment and the handling of volatile liquids and gases. Catastrophic events, regardless of cause or responsibility, such as well blowouts, explosions and fires within pipeline, gathering, or facility infrastructure, as well as failure of gathering systems or mechanical equipment, could lead to releases of liquids or gases, spills of contaminants, personal injuries and death, damage to the environment, as well as uncontrolled cost escalation. With support from suitably qualified external parties, the Company has developed and implemented policies and procedures to mitigate environmental, health and safety risks. These policies and procedures include the use of formal corporate policies, emergency response plans, and other policies and procedures reflecting what management considers to be best oilfield practices. These policies and procedures are subject to periodic review. Storm also manages environmental and safety risks by maintaining its operations to a high standard and complying with all provincial and federal environmental and safety regulations. Nevertheless, application of best practices to field operations serves only to mitigate, not eliminate, risk.

The Company's areas of activity are relatively undeveloped. In any new area of activity, property access and production require considerable early stage investment, for example, road construction, access to processing facilities, pipelines and other transportation arrangements, which is not necessarily applicable to more mature producing areas. In addition, supervision and maintenance of production facilities is likely to be more expensive than in existing and more accessible producing areas. In addition, the Company's property at HRB in northeast British Columbia, is in an area which is climatically and geographically hostile.

Storm maintains industry-specific insurance policies, including environmental damage and business interruption, on important owned and non-owned production and processing facilities. Although the Company believes its current insurance coverage corresponds to industry standards, there is no guarantee that such coverage will be available in the future, and if it is, at a cost acceptable to the Company, or that existing coverage will necessarily extend to all circumstances or incidents resulting in loss or liability.

Retention of Key Personnel

A loss in key personnel of Storm could delay the completion of certain projects or otherwise have a material adverse effect on the Company. Shareholders are dependent on Storm's management and staff in respect of the administration and management of all matters relating to the Company's assets.

Environmental

The Company's operations are subject to extensive environmental regulations which are addressed through formal policies and procedures and application of best field practices. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change initiatives ultimately put in place. Given the evolving nature of climate change discussions, the regulation of emissions of greenhouse gases ("GHG") and potential federal and provincial GHG commitments, the Company is unable to predict the effect on its operations and financial condition at this time. It is possible that the Company could face increases in operating and capital costs in order to comply with increased GHG emissions legislation.

The Company's development program in northeastern British Columbia involves horizontal drilling and fracturing applications. Fracturing involves the use of large quantities of liquids and chemicals, whose use and subsequent disposal has resulted in the emergence of environmental concerns, primarily in more heavily populated areas elsewhere in North America. In particular, much of the natural gas produced by the Company contains hydrogen sulfide, which is potentially lethal and has to be removed from the natural gas stream. This requires access to specialized processing facilities. Although the Company considers that access to such facilities is adequate for current and near-term production levels, this may not be the case in the future. In addition, future exploitation of shale gas in the HRB may cause management of carbon dioxide volumes produced concurrently with natural gas to become an operational issue.

The evolution of environmental regulation, in particular as it relates to fracturing applications, cannot be predicted at this stage. Nevertheless, it is reasonable to expect that management of environmental issues and related societal expectations will become an increasingly important part of the Company's business, with a corresponding effect on costs and economic returns.

Since the majority of the Company's operations are located British Columbia, the Company is subject to the British Columbia Carbon Tax Act, which initially set a carbon price of $30 per tonne. Beginning on April 1, 2018, the provincial carbon tax was increased by $5 per tonne, increased again by $5 per tonne on April 1, 2019, and additional $5 per tonne increases are expected per year reaching the federal target carbon price of $50 per tonne on April 1, 2021. This will, of course, have a corresponding effect on costs and economic returns.

In addition to Company-specific environmental concerns, increasing public and political focus on climate change and its possible amelioration, may cause changes in demand for the Company's products and the introduction of regulations which may result in changes to the Company's operating practices as well as additional and unforeseeable costs and the incurrence of future liabilities, real or contingent. Changes in public policy in response to changes in government at federal and provincial levels over the next several years cannot be determined at this stage, but given that the Company is a producer of primary hydrocarbons it is likely that its business will be subject to increased regulation and potentially subject to additional taxes, costs and obligations.

Industry Capacity Constraints

The collapse in prices for crude oil and natural gas, in a historical context, has reduced field activity and thus concerns over access to equipment and services. Further, service costs have fallen in recent years and remain relatively stable. Nevertheless, periods of high field activity can result in shortages of services, products, equipment, or manpower in many or all of the components of the development cycle. Increased demand leads to higher land and service costs during peak activity periods. In addition, access to transportation and processing facilities may be difficult or expensive to secure. Storm's competitors include companies with far greater resources, including access to capital and the ability to secure oilfield services at more favourable prices and to build out operations on a scale which lowers the economic threshold for exploitation of a resource. Storm competes by maintaining a large inventory of self-generated exploration and development locations, by acting as operator where possible, and through facility access and ownership. Storm also seeks to carefully manage key supplier relationships. Declines in commodity prices should, in principle, result in lower service costs; however, this may be offset by service providers choosing to retire equipment rather than operate at sub-optimum prices, or ceasing business altogether.

Capital Programs

Capital expenditures are designed to accomplish two main objectives, being the generation of short and medium term funds flow from development activities, and expansion of future funds flow from the identification of or further development of reserves. The Company focuses its activity in core areas, which allows it to leverage its experience and knowledge, and acts as operator wherever possible. The Company may use farm-outs to minimize risk on plays it considers higher risk or where total capital invested exceeds an acceptable level. In addition, Storm may enter into risk management contracts in support of capital programs, and to manage future debt levels. Generally, capital programs are financed from funds flow and disciplined use of debt, and occasionally, equity. Failure to develop producing wells or to sell production at a reasonable price and thus maintain an acceptable level of funds flow, will result in the exhaustion of available financial resources and will require the Company to seek additional capital which may not be available, or only available on unacceptable terms, or terms highly dilutive to existing shareholders. In addition, credit availability from the Company's bankers is also necessary to support capital programs and any changes to credit arrangements may have an effect on both the size of the Company's future capital programs and the timing of expenditures. As the banking facility available to the Company is based on future funds flows from existing production, falling commodity prices will likely have an effect on borrowing availability.

Reserve Estimates

Estimates of economically recoverable oil and natural gas reserves and natural gas liquids, and related future net cash flows, are based upon a number of variable factors and assumptions. These include commodity prices, production, future operating, transportation, development and facility as well as decommissioning costs, access to market, and potential changes to the Company's operations or to reserve measurement protocols arising from regulatory or fiscal changes. All of these estimates may vary from actual circumstances, with the result that estimates of recoverable oil and natural gas reserves attributable to any property are subject to revision. In future, the Company's actual production, revenues, royalties, transportation, operating expenditures, finding, development, facility and decommissioning costs associated with its reserves may vary from such estimates, and such variances may be material.

Production

Production of oil and natural gas reserves at an acceptable level of profitability may not be possible during periods of low commodity prices. The Company will attempt to mitigate this risk by focusing on higher netback opportunities and will act as operator where possible, thus allowing the Company to manage costs, timing, method and marketing of production. Production risk is also addressed by concentrating field activity in regions where infrastructure is or will be Storm owned, or readily accessible at an acceptable cost. In periods of low commodity prices the Company will shut in production, either temporarily or permanently, if netbacks are sub-economic.

Production is also dependent in part on access to third-party facilities and pipelines with the result that production may be reduced by outages, accidents, maintenance programs, prorationing and similar interruptions outside of the Company's control. For example, a gas processing facility, to which a majority of the Company's gas production is directed, was closed for maintenance in the second and third quarters of 2017 for a period of 39 days. In addition, this same facility was shut down for a total of 37 days in 2019 due to a combination of planned and unplanned outages. Generally, this facility is closed for significant maintenance every three years.

Storm's contracted gas processing capacity at third-party facilities was approximately 60% of total raw gas production during December 2019 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in if capacity available to Storm is allocated to other parties. Transportation of gas to processing facilities and to market is similarly exposed to the extent that the required capacity is not covered by contract. In addition, contracts for processing or pipeline access are for a fixed term and may not be renewed or may be renewed under more onerous terms.

Financial and Liquidity Risks

The Company faces a number of financial risks over which it has no control, such as commodity prices, exchange rates, interest rates, access to credit and capital markets, as well as changes to government regulations and tax and royalty policies. The Company uses the guidelines below to address financial exposure. Although these guidelines result in conservative management of the Company's finances, they cannot eliminate the financial risks the Company faces.

- Internal funds flow provides the initial source of funding on which the Company's capital expenditure program is based.
- Debt, if available, may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled. The Company measures debt levels against current or near-term funds flow. If the debt-to-cash-flow ratio becomes unacceptably high, capital programs will be postponed, assets sold or farmed out or other measures taken to bring debt levels down.
- Interest rate contracts, if available, may be used to manage fluctuations in interest rate.
- Equity, if available on acceptable terms, may be raised to fund acquisitions and capital programs.
- Farm-outs of projects may be arranged if management considers that the capital requirements of a project are excessive in the context of the Company's resources, or where the project affects the Company's risk profile, or where the project is of lower priority.
- Risk management contracts, if available, may be used to manage commodity price volatility when the Company has capital programs, including acquisitions, whose cost exceeds near-term projected funds flow and where capital programs involve longer-term commitments.
- The Company will also sell assets at an acceptable price if the proceeds can be redeployed in properties offering a higher netback or greater development potential.

Marketing Risks

Markets for future production of crude oil and natural gas are outside the Company's capacity to control or influence and can be affected by events such as weather, climate change, regulation, regional, national and international supply and demand imbalances, facility and pipeline access, geopolitical events, currency fluctuation, introduction of new or termination of existing supply arrangements, as well as downtime due to maintenance or damage, either to owned or third-party facilities and pipelines. The Company will attempt to mitigate these risks as follows:

- Properties are developed in areas where there is access to processing and pipeline or other transportation infrastructure, and, where possible, owned by the Company.
- The Company will delay drilling or tie-in of new wells or shut in production if acceptable pricing cannot be realized.
- The Company constantly assesses the various markets into which production can be sold and if possible will direct production to markets offering the most attractive returns.
- The Company endeavours to secure access to facilities and pipelines under contracts setting volumes, prices and term.

Storm has contracted pipeline transportation capacity for approximately 111 Mmcf per day of natural gas sales volumes in the first quarter of 2020 with the remaining portion relying on access to interruptible capacity. There is a risk that the uncontracted, interruptible portion could be reduced or shut in during partial outages or if capacity is allocated to other parties.

The Company's product profile comprises a large and growing percentage of natural gas. Pricing and access to markets has been affected by the growth of domestic gas production in North America. When, if ever, access to historical markets in North America may improve, is not predictable. Further, development of certain natural gas reserves in Canada is to a degree underwritten by the expectation that new Pacific Rim export markets will be accessed through the establishment of LNG liquefaction facilities on Canada's west coast. While development of one such facility is underway, whether additional facilities will be completed, if ever, cannot be predicted.

Access to Debt and Equity

The Company's funds flow and borrowing capacity is sufficient to fund its existing capital budget. Nevertheless, funding is finite and investment must result in production being brought on stream, followed by the generation of funds flow and the identification of proved plus probable reserves. Bank financing, which for junior oil and gas companies like Storm, is conventionally a loan, renewable annually but subject to semi-annual review, is based on anticipated future funds flows. Thus, bank financing is short term only and availability is likely to be reduced in response to lower production or lower commodity prices. Banking arrangements are renewed in May each year and are subject to mid-year review.

Although equity is another source of financing, the Company is exposed to changes in the equity markets, which could result in equity not being available, or only available under conditions which are unacceptably dilutive to existing shareholders. The inability of the Company to develop profitable operations, with the consequent exclusion from debt and equity markets, may result in the Company curtailing or suspending operations.

Changes in Government Regulations, Royalties and Policies

In both Canada and the United States the energy industry is subject to scrutiny, frequently hostile, by political and environmental groups. This may lead to increased regulation and increased compliance costs. In particular, there is a risk that existing royalty incentive programs could be terminated or amended, royalty or income tax rates could be increased, rules and regulations around well licensing or surface access could be changed, horizontal drilling and hydraulic fracturing could be subject to increased oversight or regulation, First Nations consultation requirements may be changed and GHG emissions targets may be changed which could affect carbon taxes. In 2018, the governments of Canada, the United States and Mexico entered into the Canada-United States-Mexico Agreement ("CUSMA"). CUSMA will become effective in 90 days upon ratification by the legislature of each country. To date the United States and Mexico have ratified CUSMA while Canada has recently begun the process of ratifying the new trade agreement. The United States remains a primary market for the Company's products and the pending adoption of CUSMA has created uncertainty with regard to market access, commodity prices, exchange rates and other factors, each of which may have an effect on the Company's ability to profitably grow its production.

Cyber-Security

The Company is dependent on information technology, such as computer hardware and software systems, in order to properly operate its business. These systems have the potential for information security risks, which could include potential breakdown, virus, invasion, cyber-attack, cyber-fraud, security breach and destruction or interruption of information technology systems by third parties or insiders. Unauthorized access to these systems could result in interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse effect on the protection of intellectual property and confidential and proprietary information, and on the Company's business, financial condition, results of operations and fund flow.

Extraordinary Circumstances

Storm's operations and its financial condition may be affected by uncontrollable, unpredictable and unforeseeable circumstances such as weather patterns, changes in contractual, regulatory or fiscal terms, actions by governments at various levels, both domestic and other, termination of access to third-party pipelines or facilities, actions by industry organizations, local communities, militant groups, exclusion from certain markets or other undeterminable events.

FINANCIAL REPORTING UPDATE

Changes in Accounting Policies

IFRS 16 Leases

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

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

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

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

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

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

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

Policy Applicable Before January 1, 2019

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term. Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. At inception, a leased asset within P&E and a corresponding lease obligation are recognized. The leased asset is depreciated over the shorter of the estimated useful life of the asset or the lease term. All of the

Company’s leases are operating leases, which are not recognized on the consolidated statement of financial position. Rather, these payments in respect of operating leases are recognized in the consolidated statement of income.

Policy Applicable From January 1, 2019

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 with a 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. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company’s disclosure controls and procedures and have concluded that the Company’s disclosure controls and procedures are effective as of December 31, 2019.

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. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company’s internal controls over financial reporting and concluded that the Company’s internal controls over financial reporting are effective as of December 31, 2019. 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 December 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$, except volumetric and per-share amounts	Q4 2019	Q3 2019	Q2 2019	Q1 2019	Q4 2018	Q3 2018	Q2 2018	Q1 2018
FINANCIAL								
Revenue from product sales[(1)]	48,671	31,417	37,568	55,766	74,799	51,253	48,104	52,102
Funds flow	18,469	11,973	12,590	16,517	30,941	22,227	23,405	23,519
Per share - basic and diluted ($)	0.15	0.10	0.10	0.14	0.25	0.18	0.19	0.19
Net income (loss)	2,906	(64)	7,864	607	26,810	7,174	(2,815)	8,894
Per share - basic and diluted ($)	0.02	(0.00)	0.06	0.00	0.22	0.06	(0.02)	0.07
Cash return on capital employed (“CROCE”)[(2)]	12%	15%	18%	20%	21%	21%	19%	16%
Return on capital employed (“ROCE”)[(2)]	4%	9%	11%	8%	10%	6%	4%	7%
Capital expenditures	23,913	32,841	23,145	16,944	37,100	21,845	2,918	22,900
Debt including working capital deficiency[(2)(3)]	128,901	123,342	102,268	91,585	91,020	84,648	85,073	105,585
Common shares (000s)								
Weighted average - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
Weighted average - diluted	121,557	121,557	121,557	121,853	121,649	121,557	121,557	121,557
Outstanding end of period - basic	121,557	121,557	121,557	121,557	121,557	121,557	121,557	121,557
OPERATIONS								
(Cdn$ per Boe)								
Revenue from product sales[(1)]	23.64	18.36	20.72	31.26	36.24	27.24	27.07	29.37
Transportation costs	(5.20)	(5.83)	(5.96)	(5.72)	(5.57)	(5.98)	(6.25)	(5.59)
Revenue net of transportation	18.44	12.53	14.76	25.54	30.67	21.26	20.82	23.78
Royalties	(1.59)	0.19	(0.32)	(2.61)	(0.58)	(1.03)	(1.11)	(1.71)
Production costs	(5.67)	(5.88)	(5.89)	(6.09)	(5.46)	(5.54)	(5.46)	(5.55)
Field operating netback[(2)]	11.18	6.84	8.55	16.84	24.63	14.69	14.25	16.52
Realized gain (loss) on risk management contracts	(0.80)	1.64	(0.22)	(5.38)	(8.65)	(1.73)	0.31	(1.19)
General and administrative	(0.70)	(0.79)	(0.68)	(1.60)	(0.55)	(0.66)	(0.69)	(1.42)
Interest and finance costs	(0.71)	(0.69)	(0.71)	(0.61)	(0.45)	(0.49)	(0.71)	(0.64)
Funds flow per Boe	8.97	7.00	6.94	9.25	14.98	11.81	13.16	13.27
Barrels of oil equivalent per day (6:1)	22,375	18,596	19,923	19,823	22,432	20,455	19,529	19,708
Natural gas production								
Thousand cubic feet per day	108,679	91,053	97,510	96,537	109,520	101,905	96,426	96,068
Price (Cdn$ per Mcf)[(1)]	3.28	2.42	2.64	4.49	5.56	3.21	3.15	3.83
Condensate production								
Barrels per day	2,416	1,856	2,081	2,199	2,453	2,059	1,984	2,062
Price (Cdn$ per barrel)[(1)]	66.56	63.45	71.12	62.77	58.74	84.97	86.33	76.12
NGL production								
Barrels per day	1,846	1,564	1,591	1,534	1,726	1,412	1,473	1,635
Price (Cdn$ per barrel)[(1)]	6.11	2.29	4.87	31.43	35.09	38.64	36.43	33.05
Wells drilled (net)	-	1.0	-	5.0	4.0	-	-	-
Wells completed (net)	-	5.0	-	-	2.5	5.0	-	3.0

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 40 of the attached Management’s Discussion and Analysis. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of risk management contracts, decommissioning liability and lease liability.

FINANCIALS

MANAGEMENT'S REPORT

To the Shareholders of Storm Resources Ltd.

The financial statements of Storm Resources Ltd. were prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Management has used estimates and careful judgment, particularly in those circumstances where transactions affecting current periods are dependent on information not known for certain until a future period. The financial and operational information contained in this year-end report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Michael J. Hearn
Chief Financial Officer

Emily Wignes
Vice President, Finance

February 27, 2020

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Storm Resources Ltd.

Opinion

We have audited the consolidated financial statements of Storm Resources Ltd. and its subsidiaries ("Storm"), which comprise the consolidated statements of financial position as at December 31, 2019 and 2018, and the consolidated statements of income and comprehensive income, consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of Storm as at December 31, 2019 and 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Consolidated Financial Statements* section of our report. We are independent of Storm in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the consolidated financial statements and our auditor's report thereon, in the Year-End Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

The Year-End Report is expected to be made available to us after the date of the auditor's report. If based on the work we will perform on this other information, we conclude there is a material misstatement of other information, we are required to report that fact to those charged with governance.

Responsibilities of Management and Those Charged with Governance for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing Storm's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate Storm or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing Storm's financial reporting process.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of Storm's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on Storm's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause Storm to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within Storm to express an opinion on the financial statements. We are responsible for the direction, supervision, and performance of Storm's audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is Ryan MacDonald.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Alberta

February 27, 2020

Consolidated Statements of Financial Position

(Canadian $000s)	Notes	December 31, 2019	December 31, 2018
ASSETS			
Current			
Accounts receivable	16	$ 21,961	$ 29,262
Prepaids and deposits		764	853
Risk management contracts	16	1,113	2,341
		23,838	32,456
Exploration and evaluation	6	99,737	102,277
Property and equipment	7	490,264	430,801
Right-of-use asset	4, 10	2,657	-
		$ 616,496	$ 565,534
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current			
Accounts payable and accrued liabilities	16	$ 30,018	$ 34,359
Risk management contracts	16	2,042	3,521
Current portion of decommissioning liability	11	448	-
Current portion of lease liability	10	507	-
		33,015	37,880
Bank indebtedness	8, 16	121,608	86,776
Risk management contracts	16	904	2,180
Decommissioning liability	11	27,667	26,334
Lease liability	4, 10	2,234	-
Deferred income taxes	12	9,360	4,433
		194,788	157,603
Shareholders' equity			
Share capital	13	391,444	391,444
Contributed surplus	14	17,605	15,141
Retained earnings		12,659	1,346
		421,708	407,931
Commitments	20		
		$ 616,496	$ 565,534

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Director

Director

Consolidated Statements of Income and Comprehensive Income

(Canadian $000s except per-share amounts)	Notes	Year Ended December 31, 2019	Year Ended December 31, 2018
Revenue			
Revenue from product sales	9	$ 173,422	$ 226,258
Royalties		(8,169)	(8,127)
		$ 165,253	$ 218,131
Realized gain (loss) on risk management contracts	16	(8,833)	(22,677)
		$ 156,420	$ 195,454
Expenses			
Production		43,274	41,242
Transportation		41,703	43,764
General and administrative		6,883	6,112
Share-based compensation	14	2,464	3,127
Depletion and depreciation	7, 10	40,506	45,617
Exploration and evaluation costs expensed	6	1,140	277
Accretion	11	492	517
Interest and finance costs		5,158	4,244
Unrealized (gain) loss on risk management contracts	16	(1,527)	5,833
Unrealized revaluation loss on investment		87	225
		140,180	150,958
Net income and comprehensive income		16,240	44,496
Deferred income tax expense	12	4,927	4,433
Net income and comprehensive income		$ 11,313	$ 40,063
Net income per share	15		
- Basic and diluted		$ 0.09	$ 0.33

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s)				Year Ended December 31, 2019	
	Notes	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance, beginning of year		$ 391,444	$ 15,141	$ 1,346	$ 407,931
Net income for the year		-	-	11,313	11,313
Share-based compensation	14	-	2,464	-	2,464
Balance, end of year		$ 391,444	$ 17,605	$ 12,659	$ 421,708

(Canadian $000s)				Year Ended December 31, 2018	
	Notes	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Total Equity
Balance, beginning of year		$ 391,444	$ 12,014	$ (38,717)	$ 364,741
Net income for the year		-	-	40,063	40,063
Share-based compensation	14	-	3,127	-	3,127
Balance, end of year		$ 391,444	$ 15,141	$ 1,346	$ 407,931

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(Canadian $000s)	Notes	Year Ended December 31, 2019	Year Ended December 31, 2018
Operating activities			
Net income for the year		$ 11,313	$ 40,063
Non-cash items:			
Unrealized (gain) loss on risk management	16	(1,527)	5,833
Depletion, depreciation and accretion	7, 10, 11	40,998	46,134
Share-based compensation	14	2,464	3,127
Lease interest	10	147	-
Exploration and evaluation costs expensed	6	1,140	277
Unrealized revaluation loss on investment		87	225
Deferred income tax expense	12	4,927	4,433
Funds flow		59,549	100,092
Net change in non-cash working capital items	19	8,957	(7,851)
		68,506	92,241
Financing activities			
Payment on lease liability	10	(500)	-
Increase (decrease) in bank indebtedness		34,832	(14,217)
		34,332	(14,217)
Investing activities			
Additions to property and equipment	7	(95,757)	(80,729)
Additions to exploration and evaluation assets	6	(2,169)	(4,034)
Disposition of exploration and evaluation assets	6	1,083	-
Net change in non-cash working capital items	19	(5,995)	6,739
		(102,838)	(78,024)
Change in cash during the year		-	-
Cash, beginning of year		-	-
Cash, end of year		$ -	$ -

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for years ended December 31, 2019 and 2018

Tabular amounts in thousands of Canadian dollars, except per share amounts

1. REPORTING ENTITY

Storm Resources Ltd. (the "Company" or "Storm"), is a crude oil and natural gas exploration and development company incorporated in the province of Alberta, Canada on June 8, 2010 and is listed on the TSX under the symbol "SRX". The Company operates primarily in the province of British Columbia and its head office is located at Suite 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4. The Company became a reporting issuer in August 2010.

These audited 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 Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). 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 February 27, 2020.

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 16.

3. SUMMARY OF ACCOUNTING POLICIES

Exploration and Evaluation Expenditures

Exploration and evaluation ("E&E") expenditures are accounted for in accordance with IFRS 6 - *Exploration for and Evaluation of Mineral Resources*, whereby costs associated with the exploration for and evaluation of oil and gas reserves are accumulated on an area-by-area basis and are capitalized as E&E assets when incurred. Future decommissioning costs relating to E&E activities are also included. Costs incurred in advance of land acquisition are charged to the consolidated statement of income in the period in which they are incurred.

E&E costs are not subject to depletion or depreciation until they are reclassified from E&E to property and equipment ("P&E"). E&E costs are accumulated by field or exploration area pending determination of technical feasibility and commercial viability. Technical feasibility and commercial viability is typically considered to be achieved when proved reserves are determined to exist. Once reserves are assigned to specific lands, the associated E&E assets are tested for impairment and the lesser of cost and the estimated recoverable amount is reclassified to P&E.

Property and Equipment

P&E represents both intangible and tangible costs incurred in developing oil and natural gas reserves and maintaining or enhancing production from such reserves. Future decommissioning costs, related to producing assets, are also capitalized. P&E is carried at cost, less accumulated depletion and depreciation and accumulated impairment losses. Gains and losses on disposal of P&E are determined as the difference between proceeds from disposal and the carrying amount of the asset sold and are recognized in the consolidated statement of income.

Depletion and Depreciation

The net carrying amount of intangible crude oil and natural gas assets, categorized as P&E, is depleted using the unit-of-production method based on estimated proved plus probable reserves, taking into account the future development costs required to produce the reserves.

Year-end proved plus probable reserves are determined by independent engineers in accordance with Canadian National Instrument 51-101. Production and reserves of natural gas are converted to equivalent barrels of crude oil on the basis of six thousand cubic feet of natural gas to one barrel of crude oil. Changes in estimates used in prior periods, such as proved plus probable reserves, that affect the unit-of-production calculations, do not give rise to prior year adjustments and are dealt with prospectively. Proved plus probable reserves at the end of each interim reporting period are based on reserves determined at the immediately prior year end, adjusted for production and internal estimates of changes to reserves since the prior year end.

Tangible costs, such as processing facilities and well equipment, are depreciated on a straight-line basis over the estimated useful life of the facilities and equipment. Where facilities and equipment includes major components having different useful lives, they are depreciated separately.

Depreciation rates, useful lives and residual values are reviewed at each reporting date.

Impairment of Non-Financial Assets

The carrying amounts of P&E and E&E assets are reviewed separately at each reporting date to determine whether there is any indication of impairment. If such an indication exists, the estimated recoverable amount is calculated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of the cash flows of other assets or group of assets (the “cash generating unit” or “CGU”). CGU’s are determined by similar geological formation and proximity, shared infrastructure, product type and similar exposure to market risks. The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs of disposal. E&E assets are assessed for impairment at the operating segment level.

In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using an after-tax discount rate and future commodity prices that reflect current market assumptions. Fair value less costs of disposal (“FVLCD”) is the amount obtainable from the sale of an asset or CGU in an arm’s length transaction between knowledgeable, willing parties, less the costs of disposal. An impairment loss is recognized in the consolidated statement of income if the carrying amount of an asset or CGU exceeds its estimated recoverable amount.

Impairment losses previously recognized are assessed at each reporting date for indications that the loss has decreased or no longer exists. If there has been an increase in the estimate of the recoverable amount an impairment loss is reversed to the extent that the asset’s new carrying amount does not exceed the original carrying amount, net of related accumulated depletion and depreciation.

Lease Liabilities and Right-of-Use Assets

Policy applicable before January 1, 2019

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term. Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. At inception, a leased asset within P&E and a corresponding lease obligation are recognized. The leased asset is depreciated over the shorter of the estimated useful life of the asset or the lease term. All of the Company’s leases are operating leases, which are not recognized on the consolidated statement of financial position. Rather, these payments in respect of operating leases are recognized in the consolidated statement of income.

Policy applicable from January 1, 2019

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 with a 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.

Decommissioning Liability

Decommissioning liabilities are measured as the present value of management's best estimate of the expenditure required to settle the future decommissioning liability at the reporting date using a risk-free discount rate. This estimate is recognized when a legal or constructive obligation arises and is capitalized as part of E&E assets or P&E as appropriate. The amount capitalized to P&E is amortized on a unit-of-production basis consistent with the measurement of depletion. The obligation is adjusted at the end of each reporting period to reflect the passage of time and changes in the estimated future costs underlying the obligation. The increase in the obligation due to the passage of time is recognized as accretion expense in the consolidated statement of income whereas increases or decreases due to changes in the estimated future costs are capitalized. Actual costs incurred upon settlement of decommissioning obligations are charged against the liability; if actual costs exceed the liability recorded, the difference is charged to the consolidated statement of income.

Revenue Recognition

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

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

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

Transportation

Transportation expenses include costs incurred by the Company to transport natural gas and condensate from the wellhead to the point of title transfer.

Share-Based Compensation

The Company has issued options to acquire common shares to directors, officers and employees of the Company. These options are accounted for using the fair-value method which estimates the value of the options at the date of the grant using the Black-Scholes option pricing model. The fair value of each tranche of options thus established is recognized as compensation expense over the vesting period of the related options, with an equivalent increase to contributed surplus. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest. The effect of any revision in forfeiture rates is recognized in the consolidated statement of income with a corresponding adjustment to contributed surplus. When options are exercised, the proceeds, together with the amounts recorded in contributed surplus, are recorded in share capital.

Government Grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to them and the grants will be received. When the conditions of a grant relate to income or expenses, it is recognized in the consolidated statement of income in the period in which the expenditures are incurred or income is earned. When the conditions of a grant relate to an underlying asset, it is recognized as a reduction to the carrying amount of the related asset and amortized into income on a systematic basis over the expected useful life of the underlying asset through reduced depletion and depreciation expense.

Financial Instruments

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

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

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

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

Any subsequent reclassification of financial assets and liabilities from their initial recognition will be reclassified on the first day of the reporting period.

Impairment of financial assets

Impairment of financial assets is determined by measuring the assets' expected credit losses ("ECLs"). Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls, which is measured as the difference between the present value of the cash flows due to the Company and the cash flows that the Company expects to receive. In making an assessment as to whether financial assets are credit-impairment, the Company considers historically realized bad debts, evidence of a deterioration of a debtor's financial condition, evidence that a debtor will enter bankruptcy, increase in the number of days the debtor is past due and change in economic condition that could correlate to increased risk of default. ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component since accounts receivable are due within one year or less.

Risk management contracts

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

Income Tax

Income tax comprises current and deferred taxes. Income tax is recognized in the consolidated statement of income except to the extent that it relates to items recognized directly in other comprehensive income or elsewhere in shareholders' equity, in which case the related income tax expense or recovery is similarly recognized in the appropriate account.

Current tax expense is the expected cash tax payable on the taxable income for the year, using tax rates enacted, or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

In general, deferred income tax expense and the related liability is recognized in respect of temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. Deferred income tax is determined on a non-discounted basis using tax rates and laws that have been enacted or substantively enacted at the reporting date and are expected to continue to apply when the deferred tax asset or liability is settled. Deferred tax assets are recognized to the extent that it is probable that the assets can be recovered. Deferred income tax assets and liabilities are presented as non-current on the consolidated statement of financial position.

Jointly Controlled Assets and Operations

Certain of the Company's exploration and production activities are regarded as joint operations and are conducted under joint operating agreements, whereby two or more parties jointly control the assets. The financial statements reflect only the Company's share of these jointly controlled assets and, once production commences, Storm's proportionate share of the relevant revenue and related costs.

Share Capital

Proceeds from the issuance of common shares are classified as shareholders' equity. Costs directly attributable to the issuance of shares are recognized as a deduction from shareholders' equity.

Net Income Per Share

Basic net income per share is calculated by dividing the net income attributable to equity owners for the reporting period by the weighted average number of common shares outstanding during the reporting period.

Diluted net income per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The Company's potentially dilutive instruments comprise stock options granted to directors, officers and employees. The number of shares included with respect to options is computed using the treasury stock method, which assumes that proceeds received from the exercise of in-the-money stock options are used to purchase common shares at average market prices during the period.

4. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

IFRS 16 Leases

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

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

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

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

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

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

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

5. 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 as follows:

Classification and Carrying Amount of Exploration and Evaluation Assets

Each reporting period, E&E assets are subject to an internally conducted impairment review. Factors brought into the consideration of impairment include the Company's future plans for the property, lease expiries, drilling and development results on proximate or analogous properties, facility and pipeline access, views as to future commodity prices, operating and development costs and availability of capital for exploration and development programs. Judgment is required to determine the level at which E&E is assessed for impairment. E&E assets are assessed for impairment at the operating segment level. An impairment assessment is also completed when the costs of E&E assets are transferred to P&E on a specific identification basis.

Carrying Amount of Property and Equipment

Each reporting period, P&E is subject to an impairment review applied at the CGU level. The impairment review gives recognition to changes in geological interpretation or development plans, drilling results, development costs, changes to reserve estimates and values, future commodity prices, facility and pipeline access, operating results, operating and future development costs, industry activity in the area, access to markets and availability of development capital.

Depletion, Impairment and Reserves

The amounts recorded for depletion and impairment testing are based on estimates of proved plus probable reserves. Significant judgment and estimates are required to calculate the recoverable amount on non-financial assets. The Company estimates the recoverable amount of non-financial assets, including P&E and E&E, based on its FVLCD, calculated using the after-tax future cash flows expected to be derived from production of proved plus probable oil and gas reserves, less estimated selling costs, discounted using market-based rates to reflect a market participant's view of the risks associated with the assets.

Assumptions that are valid at the time of reserve estimation may change materially as new information becomes available. Reserves estimates are based on engineering data, forward price estimates, production and future development costs, recovery rates or decommissioning costs, all of which may change the economic status of reserves and may ultimately result in reserves used for measurement purposes being removed from similar calculations in future reporting periods. Reserves have been evaluated at December 31, 2019 and 2018 by the Company's independent qualified reserves evaluator.

Decommissioning Liability

Measurement of the Company's decommissioning liability involves estimates as to the cost and timing of incurrence of future decommissioning programs. It also involves assessment of appropriate discount rates, rates of inflation applicable to future costs and the rate used to measure the accretion charge for each reporting period. Measurement of the liability also reflects current engineering methodologies as well as current and expected future environmental legislation and standards.

Measurement and Utilization of Tax Assets

The Company has tax pools which may be applied in reduction of future income. The amount of such pools is subject to audit by taxing authorities, possibly several years after the initial measurement. In addition, future changes to tax laws may result in the loss or limitation of use of such pools.

Measurement of Share-Based Compensation

The charge for share-based compensation involves the estimate of the fair value of stock options at time of issue. The estimate involves assumptions regarding the life of the option, dividend yields, interest rates, and volatility of the security subject to the option. The charge is measured using the Black-Scholes option pricing model, which could be replaced by a pricing model producing different results.

Carrying Amounts of Financial Instruments

Financial instruments are subject to valuation at the end of each reporting period. Generally the valuation is based on active and efficient markets. However, certain financial instruments may not be traded on an efficient market, or the market may disappear or be subject to circumstances or controls that impede the efficiency of the market.

6. EXPLORATION AND EVALUATION

	Year Ended December 31, 2019	Year Ended December 31, 2018
Balance, beginning of year	$ 102,277	$ 103,907
Additions	2,169	4,034
Dispositions	(1,083)	-
Expiries - exploration and evaluation costs expensed	(1,140)	(277)
Future decommissioning costs	178	370
Transfer to property and equipment	(2,664)	(5,757)
Balance, end of year	$ 99,737	$ 102,277

For the year ended December 31, 2019, the Company determined certain of its E&E assets to be technically feasible and commercially viable and they were, therefore, transferred to P&E. An impairment test was conducted prior to the transfer (determined using the same methodology outlined in Note 7 – Property and Equipment), but no impairment was recognized as the recoverable amount of these assets exceeded the carrying value.

As at December 31, 2019, management reviewed the carrying amounts of the remaining assets in E&E for indicators of impairment and due to continued volatility in the natural gas price environment and resulting declines in forecasted long-term natural gas prices, the Company performed an asset impairment test on its E&E assets, aggregated at the operating segment level. The impairment test was performed using recoverable amount based on the FVLCD using the same inputs described in Note 7. As at December 31, 2019, the Company determined that there was no impairment to E&E.

7. PROPERTY AND EQUIPMENT

	Year Ended December 31, 2019	Year Ended December 31, 2018
Cost		
Balance, beginning of year	$ 646,983	$ 559,524
Additions	95,757	80,729
Future decommissioning costs	1,111	973
Transfer from exploration and evaluation assets	2,664	5,757
Balance, end of year	$ 746,515	$ 646,983
Accumulated depletion and depreciation		
Balance, beginning of year	$ (216,182)	$ (170,565)
Depletion and depreciation	(40,069)	(45,617)
Balance, end of year	$ (256,251)	$ (216,182)
Net book value, beginning of year	$ 430,801	$ 388,959
Net book value, end of year	$ 490,264	$ 430,801

Future capital costs required to develop proved plus probable reserves in the amount of $566.2 million (December 31, 2018 - $538.9 million) are included in the depletion calculation.

As at December 31, 2019, the balance of assets under construction not subject to depreciation or depletion was $65.0 million (December 31, 2018 - $11.4 million) and relates to the construction of a gas plant at Nig, located in northeast British Columbia.

Impairment Assessment and Testing

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At December 31, 2019, the Company determined that an indicator of impairment existed for its material producing CGU at Umbach as the market capitalization of the Company was less than the net asset value. Although there was a decline in commodity prices, specifically related to Western Canadian natural gas prices, the Company was sheltered from this decline through its diversified marketing strategy including approximately 20% of production attracting liquids pricing (mainly WTI based).

An impairment is recognized if the carrying value of an asset exceeds the recoverable amount. The Company determines the recoverable amount by using discounted future cash flows of proved plus probable reserves using forecast prices and costs.

Forecast future prices, as prepared by an independent qualified reserve evaluator, used in the impairment evaluation as at December 31, 2019, reflect the benchmark prices set forth in the table below, adjusted for basis differentials to determine local reference prices, transportation costs and tariffs, heat content and quality.

	2020	2021	2022	2023	2024	2025	2026[(1)]
WTI Cushing Oklahoma (US$/Bbl)	61.00	64.50	66.50	68.20	69.90	71.50	73.50
NYMEX Henry Hub (US$/Mmbtu)	2.50	2.75	3.00	3.15	3.25	3.35	3.42
AECO-C Spot (Cdn$/Mmbtu)	2.05	2.32	2.60	2.69	2.81	2.94	3.00
Station 2 (Cdn$/Mmbtu)	1.70	2.02	2.30	2.44	2.59	2.71	2.82
Exchange rate (US$/Cdn$)	0.76	0.77	0.78	0.80	0.80	0.80	0.80

(1) Prices escalate at 2% thereafter.

Recoverable amounts were estimated based on a fair value less costs of disposal (“FVLCD”) methodology, using the present value of the CGUs expected future cash flows (after-tax). The cash flow information was derived from a report on the Company’s oil and gas reserves which was prepared by an independent qualified reserve evaluator. The projected cash flows used in the FVLCD calculation reflect market assessments of key assumptions as at December 31, 2019, including long-term forecasts of commodity prices, inflation rates and foreign exchange rates (Level 3 fair value inputs as described in Note 16). Future cash flow estimates are discounted using after-tax risk-adjusted discount rates. The after-tax discount rate applied in the impairment calculation as at December 31, 2019 was 10%. All else being equal, a 1% increase in the assumed discount rate or a 10% decrease in future planned funds flows would not result in an impairment for the year ended December 31, 2019.

As at December 31, 2019, the Company determined that there was no impairment to P&E.

8. BANK INDEBTEDNESS

As at December 31, 2019, the Company had an extendible revolving credit facility in the amount of $205 million (December 31, 2018 – $180 million) of which $121.6 million was drawn as at December 31, 2019. The credit facility is based on a bank determined borrowing base related to the Company's producing reserves. The credit facility is available to the Company until May 29, 2020, at which time the borrowing base amount will be reviewed and in the ordinary course of business the Company will have the option to extend the facility for an additional year. If the credit facility is not extended, the facility moves into a term phase whereby the outstanding loan amount is to be repaid in full one year later. In the event that the lenders reduce the borrowing base below the amount drawn, the Company would have 90 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount. Interest is paid on the utilized portion of the credit facility at bankers' acceptance rates, plus a stamping fee. Collateral provided comprises a floating charge demand debenture on the assets of the Company.

As at December 31, 2019, the Company had issued letters of credit in the amount of $10.0 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.

9. REVENUE FROM PRODUCT SALES

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

	Year Ended December 31, 2019	Year Ended December 31, 2018
Natural gas	$ 115,488	$ 146,852
Condensate	51,522	59,071
NGL	6,412	20,335
Total	$ 173,422	$ 226,258

Storm's revenue was generated mostly in British Columbia where production was sold primarily to two major energy customers with investment grade credit ratings which accounted for 80% and 81% of the Company's total revenue from product sales for the three months and year ended December 31, 2019, respectively (December 31, 2018 – 56% 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 year ended December 31, 2019, 57% received Chicago pricing, 19% received Station 2 pricing, 11% received Sumas pricing, 11% received AECO pricing and the remaining 2% received ATP pricing.

10. 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:

	Year Ended December 31, 2019
Cost	
Balance, beginning of year (Note 4)	$ 3,094
Additions	-
Balance, end of year	$ 3,094
Accumulated depreciation	
Balance, beginning of year	$ -
Depreciation	(437)
Balance, end of year	$ (437)
Net book value, beginning of year	$ 3,094
Net book value, end of year	$ 2,657

As at December 31, 2019, the net book value of the right-of-use asset for the Company's corporate office lease in Calgary is $2.7 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:

	Year Ended December 31, 2019
Balance, beginning of year (Note 4)	$ 3,094
Lease payments	(500)
Lease interest	147
Balance, end of year	$ 2,741
Less current portion	507
Long-term portion	$ 2,234

As at December 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 $3.2 million.

Short-term leases are leases with a lease term of twelve months or less. During the year ended December 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 costs.

11. 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 liability 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 inflated and undiscounted liability required to settle the Company's decommissioning obligation is approximately $38.3 million (December 31, 2018 - $43.2 million), with the majority of payments being made in the years 2034 to 2054. A risk-free discount rate of 1.7% (December 31, 2018 - 2.2%) and an inflation rate of 1.4% (December 31, 2018 - 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $28.1 million at December 31, 2019.

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

	Year Ended December 31, 2019	Year Ended December 31, 2018
Balance, beginning of year	$ 26,334	$ 24,474
Obligations incurred	2,706	1,406
Obligations settled	(246)	(242)
Change in estimates(1)	(1,171)	179
Accretion expense	492	517
Balance, end of year	$ 28,115	$ 26,334
Less current portion	448	-
Long-term portion	$ 27,667	$ 26,334

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

12. DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are based on the differences between the accounting amounts and the related tax bases of the Company's E&E and P&E assets, risk management contracts, decommissioning liability, share issue costs and unrealized gains and losses on investments.

Storm was not required to pay income taxes in the current or prior year as the Company had sufficient income tax deductions available to shelter taxable income. The Company has tax pools associated with E&E and P&E of approximately $304.1 million as well as non-capital losses of approximately $197.6 million. The non-capital losses begin to expire in 2027.

The provision for deferred income taxes is different from the amount computed by applying the combined statutory Canadian federal and provincial tax rates to pre-tax income for the year.

The differences are as follows:

	Year Ended December 31, 2019	Year Ended December 31, 2018
Net income before income taxes	$ 16,240	$ 44,496
Statutory combined federal and provincial income tax rate	26.8%	27.0%
Expected income tax expense	$ 4,353	$ 12,014
Add (deduct) the income tax effect of:		
Share-based compensation	660	844
Change in unrecorded deferred income tax asset	-	(11,701)
Change in enacted corporate tax rate	(471)	-
Change in estimated tax pool balances	-	3,260
Other	385	16
Deferred income tax expense	$ 4,927	$ 4,433
Effective tax rate	30.3%	10.0%

The components of the deferred income tax assets and liabilities are as follows:

	As at December 31, 2019	As at December 31, 2018
Deferred tax assets:		
Non-capital losses	$ 50,494	$ 44,632
Decommissioning liability	7,145	7,110
Fair value of risk management contracts	466	907
Share issue costs	-	116
Investments	283	289
Deferred tax liabilities:		
Property and equipment in excess of tax basis	$ (67,748)	$ (57,487)
Deferred income tax asset (liability)	$ (9,360)	$ (4,433)

13. 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 December 31, 2019	121,557	$ 391,444

For the period from January 1, 2019 to February 27, 2020, no common shares were issued upon the exercise of stock options.

14. 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 December 31, 2019, a total of 12,155,681 common shares were available for issuance, options in respect of 10,188,100 common shares were issued and outstanding and options in respect of 1,967,581 common shares were available for future issue.

At February 27, 2020, the date of this report, options in respect of 10,212,100 common shares are issued and outstanding and options in respect of 1,943,581 common shares are available for future issue.

Details of the options outstanding at December 31, 2019 and 2018 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2017	7,914	$ 4.46
Granted during the year	4,993	$ 2.34
Cancelled/forfeited during the year	(399)	$ 4.10
Expired during the year	(3,420)	$ 4.51
Outstanding at December 31, 2018	9,088	$ 3.29
Granted during the year	3,017	$ 1.52
Cancelled/forfeited during the year	(184)	$ 3.34
Expired during the year	(1,733)	$ 3.38
Outstanding at December 31, 2019	10,188	$ 2.74
Number exercisable at December 31, 2019	3,813	$ 4.02

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
$1.36 - $2.85	5,478	3.5	$ 1.65	820	$ 1.81
$2.86 - $4.50	2,696	2.0	$ 3.00	992	$ 3.10
$4.51 - $5.50	2,014	0.9	$ 5.39	2,001	$ 5.39
Total	10,188	2.6	$ 2.74	3,813	$ 4.02

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 year ended December 31, 2019 of $0.56 per share (2018 - $0.88 per share) include the following:

	2019	2018
Share price	$1.36 - $2.35	$1.81 - $3.09
Exercise price	$1.36 - $2.35	$1.81 - $3.09
Volatility	48%	49%
Forfeiture rate	2%	10%
Expected option life (years)	3.7	3.7
Risk-free interest rate	1.4% - 1.7%	1.7% - 2.1%

Share-based compensation expense of $2.5 million was charged to the consolidated statement of income during the year ended December 31, 2019 (2018 - $3.1 million) with an equivalent offset to contributed surplus.

15. NET INCOME PER SHARE

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

	Year Ended December 31, 2019	Year Ended December 31, 2018
Net income for the year	$ 11,313	$ 40,063
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of year	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)	-	40
Weighted average number of common shares outstanding - diluted	121,557	121,597
Net income per share		
Basic and diluted	$ 0.09	$ 0.33

(1) Excludes the effect of 9.2 million weighted average common shares related to stock options that were anti-dilutive for the year ended December 31, 2019 (8.5 million weighted average common shares related to stock options for the year ended December 31, 2018).

16. FINANCIAL INSTRUMENTS

The Company's financial instruments include accounts receivable, prepaids and deposits, accounts payable and accrued liabilities, bank indebtedness and risk management contracts.

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

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

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's risk management contracts described below is based on forward prices of commodities and interest rates available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the years ended December 31, 2019 and December 31, 2018.

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

	Gross Amounts Recognized as Financial Assets (Liabilities)	Gross Amounts of Financial Assets (Liabilities) Offset	Net Amounts Recognized as Financial Assets (Liabilities)
Risk management contracts			
Current asset	$ 1,805	$ (692)	$ 1,113
Long-term asset	-	-	-
Current liability	(2,734)	692	(2,042)
Long-term liability	(904)	-	(904)
Net position	$ (1,833)	$ -	$ (1,833)

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

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

Financial Risk Management

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, marketing and financing activities such as:

- credit risk;
- market risk; and
- liquidity risk.

Management has primary responsibility for monitoring and managing financial risks under direction from the Board of Directors, which has overall responsibility for establishing the Company's risk management framework.

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer, joint venture partner or counterparty to a financial instrument fails to meet its contractual obligations.

Cash

When the Company has a cash surplus, it limits its exposure to credit risk by only investing in liquid securities and only with counterparties that have an acceptable credit rating or are supported by provincial government guarantees.

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 December 31, 2019, the Company's two major energy customers with investment grade credit ratings accounted for $17.0 million of total receivables (December 31, 2018 - $22.1 million from one major customer) and 81% of total revenues (December 31, 2018 – 56%). 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 December 31, 2019 and 2018, there were no receivables outstanding for more than 60 days. No material default on outstanding receivables is anticipated as none of the Company's outstanding receivables are considered past due at December 31, 2019.

The maximum exposure to credit risk at December 31, 2019 was the carrying amount of accounts receivable of $22.0 million and risk management contract assets of $1.1 million. No receivables were impaired at December 31, 2019.

Risk Management Contracts

The Company enters into derivative risk management contracts with counterparties with an acceptable credit rating and with a demonstrated capability to execute such contracts. The contracts, individually and in aggregate, are subject to controls established by the Board of Directors and limitations set out in the Company's banking agreement.

Market Risk

Market risk is the risk that changes in market prices will affect the Company's income or the value of its financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

Market risks are as follows and are largely outside the control of the Company:

- commodity prices;
- interest rates; and
- foreign currency exchange rates.

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil, natural gas, condensate and natural gas liquids are affected by many known and unknown factors such as demand and supply imbalances, market access, the relationship between the Canadian and United States dollar as well as national and international economic and geopolitical events.

The Company is exposed to the risk of declining prices for production resulting in a corresponding reduction in projected funds flow. Reduced funds flow may result in lower levels of capital being available for field activity, thus compromising the Company's capacity to grow total production while at the same time replacing continuous production declines from existing properties. Bank financing available to the Company is in the form of a reserves based loan, which is reviewed semi-annually, and is based on future funds flows and commodity price expectations. Changes to commodity prices will have an effect on credit available to the Company under its banking agreement.

The Company uses risk management contracts to manage its exposure to fluctuations in commodity prices, by fixing prices of future deliveries of crude oil and natural gas and thus providing stability of funds flow. The Company does not use these instruments for trading or speculative purposes. Although the Company had no crude oil production at December 31, 2019, part of its condensate and NGL stream is sold at a price based on crude oil. Accordingly, a financial investment based on crude oil is used as a proxy for the Company's condensate and NGL stream.

Fair values for risk management contracts are based on quotes received from financial institution counterparties and are calculated using current market rates and prices and option pricing models using forward pricing curves and implied volatility.

At the date of this report, Storm has the undernoted risk management contracts in place. The fair market value of these contracts at December 31, 2019, a net liability position of $1.8 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 year ended December 31, 2019, this resulted in an unrealized mark-to-market gain of $1.5 million (December 31, 2018 - an unrealized mark-to-market loss of $5.8 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		
Jan – Mar 2020	13,000 GJ	Station 2 Cdn$1.92/GJ
Apr – Aug 2020	7,000 GJ	Station 2 Cdn$1.48/GJ
Jan – Mar 2020	1,500 GJ	AECO Cdn$2.00/GJ
Jan – Mar 2020	7,000 Mmbtu	Sumas Cdn$3.93/Mmbtu
Jan – Jun 2020	20,000 Mmbtu	Chicago Cdn$3.33/Mmbtu
Jul – Dec 2020	1,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Apr – Dec 2020	2,000 Mmbtu	NYMEX US$2.45/Mmbtu
Natural Gas Collars		
Jan – Mar 2020	2,000 Mmbtu	NYMEX $2.60 - $3.12 US$/Mmbtu
Jan – Mar 2020	5,500 GJ	AECO $1.77 - $2.28 Cdn$/GJ
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		
Jan – Jun 2020	900 Bbls	$70.89 - $80.89 Cdn$/Bbl
Jul – Dec 2020	400 Bbls	$68.38 - $79.01 Cdn$/Bbl

Period Hedged	Daily Volume	Average Price
Crude Oil Swaps		
Jan – Jun 2020	750 Bbls	$71.92 Cdn$/Bbl
Jul – Dec 2020	400 Bbls	$71.16 Cdn$/Bbl
Crude Oil Differential Swaps		
Jan – Jun 2020	400 Bbls	WTI minus Cdn$4.25/Bbl
Jan – Dec 2020	600 Bbls	WTI minus Cdn$7.90/Bbl

The Company realized a loss from risk management contracts in place in the amount of $8.8 million for the year ended December 31, 2019 (December 31, 2018 - realized loss of $22.7 million).

Physical Delivery Sales Contracts

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.

	Daily Volume	Contract Price
Natural Gas		
Jan 2020 – Oct 2020	14,028 Mmbtu at Station 2	Sumas less US$0.69/Mmbtu
Apr 2020 – Oct 2020	6,000 GJ at Station 2	AECO 7A less Cdn$0.295/GJ
Nov 2020 – Oct 2021	5,000 GJ at Station 2	AECO 7A less Cdn$0.125/GJ
Apr 2020 – Mar 2021	6,000 GJ at ATP	AECO 5A plus Cdn$0.09/GJ

Interest Rate Risk

Interest on the Company's revolving bank facility varies with changes in market interest rates and is most commonly based on bankers acceptances issued by the Company's banks, plus a stamping fee. The stamping fee may change based on the Company's debt-to-funds-flow ratio for the previous quarter. The Company is thus exposed to increased borrowing costs during periods of increasing interest rates, with a corresponding reduction in both funds flows and project economics. In addition, a higher debt-to-cash-flow ratio will mean an increase in stamping fees, and correspondingly, interest rates.

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility. If interest rates applicable to floating rate debt were to have increased by 100 basis points (1%) it is estimated that the Company's net income for the year ended December 31, 2019 would have decreased by $0.8 million. A decrease in interest rates by 1% would result in an increase in net income by an equivalent amount.

In the second quarter of 2019, the Company entered into an interest rate swap contract to manage the uncertainty of variable interest rates by fixing the variable component of a portion of the interest paid on the Company's revolving bank facility. Interest rate swaps are classified as derivative financial assets and liabilities at fair value through profit and loss and measured at fair value, with gains and losses on re-measurement included as a component of unrealized risk management contracts in the period in which they arise. This interest rate swap is included on the balance sheet as either a risk management contract asset or liability and is classified as current or non-current based on the contractual terms specific to the instrument. As at December 31, 2019, the Company had the following interest rate contract in place to manage interest rate risk:

Index	Effective Date	Notional Principal	Remaining Term	Fixed Contract Rate
One-month bankers' acceptance – CDOR[1]	May 31, 2019	$25 million	Jan 2020 – May 2022	1.949%

(1) Canadian Dollar Offered Rate.

Risk Management

Subsequent to December 31, 2019, the Company entered into the following interest rate swap contracts to manage interest rate risk:

Index	Effective Date	Notional Principal	Remaining Term	Fixed Contract Rate
One-month bankers' acceptance – CDOR[1]	January 21, 2020	$10 million	Jan 2020 – Jan 2023	1.943%
One-month bankers' acceptance – CDOR[1]	January 31, 2020	$15 million	Jan 2020 – Jan 2021	1.985%

(1) Canadian Dollar Offered Rate.

Foreign Currency Exchange Rate Risk

Prices for crude oil are determined in global markets and generally denominated in US dollars. Natural gas prices are largely influenced by both US and Canadian supply and demand structures. Changes in the Canadian dollar relative to the US dollar affect the Company's natural gas revenue, some of which is sold at a US$ price; therefore, variation in the Canadian-US dollar exchange rate will affect Canadian dollar prices for the Company's production. In addition, costs of imported materials used in the Company's operations will be affected by the Canadian-US dollar exchange rate.

Sensitivities

The following table summarizes the effects of movement in commodity prices on net income due to changes in the fair value of risk management contracts in place at December 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		Year Ended December 31, 2019
Increase of US$10.00/Bbl in the price of WTI(1)	$	(6,510)
Decrease of US$10.00/Bbl in the price of WTI(1)	$	6,510
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$	(2,056)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$	2,056

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

Liquidity Risk

Liquidity difficulties would emerge if the Company is unable to establish or maintain a profitable production base and thus generate sufficient funds flow to cover both operating and capital requirements. This may be the consequence of insufficient funds flows resulting from low product prices, production interruptions, operating or capital cost increases, unsuccessful investment programs, limitations in the Company's access to markets, or delays in bringing on stream new wells or facilities. These risks cannot be eliminated; however, the Company uses the following guidelines to address financial exposure:

- internal funds flow provides the initial source of funding on which the Company's capital expenditure program is based;
- debt, if available, may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled;
- equity, if available on acceptable terms, may be raised to fund acquisitions and exploration expenditures;
- farm-outs of projects may be arranged if management concludes that a project requires too much capital or where the project affects the Company's investment risk profile.

The timing of cash flows related to financial liabilities as at December 31, 2019 is as follows:

	Less than 1 year	2-3 years	Total
Accounts payable and accrued liabilities	$ 30,018	$ -	$ 30,018
Risk management contracts	2,042	904	2,946
Bank indebtedness(1)	-	121,608	121,608
Total financial liabilities	$ 32,060	$ 122,512	$ 154,572

(1) Bank indebtedness is based on a revolving credit facility, which is reviewed annually. At renewal, the Company has the option to extend the facility for an additional year. If the revolving facility is not extended, the facility converts to a non-revolving facility payable in one year.

17. CAPITAL MANAGEMENT

The Company's capital structure comprises shareholders' equity and bank indebtedness. The Company's objective when managing capital is to maintain financial flexibility to support capital programs that will replace production sold as well as production declines and provide a base for future growth in production. Capital management involves the preparation of an annual budget, which is implemented after approval by the Company's Board of Directors. As the Company's business evolves throughout the year, the budget will be amended; however, any changes are again subject to approval by the Board of Directors.

Funds flow, bank financing and potential proceeds from the issue of equity and the sale of assets will be invested in exploration and development operations with the intent of growing short and medium term operating funds flow. Growing funds flow enables the Company to increase bank or other debt financing, thus expanding capital available for investment. It may be that capital currently available to the Company is insufficient to adequately grow funds flow, thus requiring additional capital which may be available only on terms dilutive to existing shareholders, if available at all.

18. RELATED PARTY TRANSACTIONS

The remuneration of the key management personnel of the Company, which includes directors and officers, is set out below in aggregate:

	Year Ended December 31, 2019	Year Ended December 31, 2018
Salaries and short-term benefits	$ 3,293	$ 3,001
Share-based compensation	1,381	1,697
Total compensation	$ 4,674	$ 4,698

19. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Year Ended December 31, 2019	Year Ended December 31, 2018
Accounts receivable	$ 7,214	$ (14,305)
Prepaids and deposits	89	3,611
Accounts payable and accrued liabilities	(4,341)	9,582
Change in non-cash working capital	$ 2,962	$ (1,112)
Relating to:		
Operating activities	$ 8,957	$ (7,851)
Investing activities	(5,995)	6,739
Change in non-cash working capital	$ 2,962	$ (1,112)
Interest paid during the year	$ 5,087	$ 4,207
Income taxes paid during the year	$ -	$ -

20. COMMITMENTS

At December 31, 2019, the Company has the following long-term commitments over the next five years and thereafter:

	2020	2021	2022	2023	2024	Thereafter	Total
Transportation and processing commitments	$ 65,155	$ 68,406	$ 52,855	$ 30,073	$ 30,203	$ 226,277	$ 472,969
Office lease[1]	356	356	356	356	356	385	2,165
Total	$ 65,511	$ 68,762	$ 53,211	$ 30,429	$ 30,559	$ 226,662	$ 475,134

(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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