STORM RESOURCES

2018 YEAR-END REPORT

ANNUAL MEETING

The Annual General and Special Meeting of shareholders will be held at 3:30 p.m. on Wednesday, May 15, 2019 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$, except volumetric and per-share amounts	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
FINANCIAL				
Revenue from product sales(1)	74,799	43,507	226,258	152,880
Funds flow	30,941	21,323	100,092	64,080
Per share – basic and diluted ($)	0.25	0.18	0.82	0.53
Net income	26,810	8,624	40,063	39,689
Per share – basic and diluted ($)	0.22	0.07	0.33	0.33
Cash return on capital employed (“CROCE”)(2)	21%	15%	21%	15%
Return on capital employed (“ROCE”)(2)	10%	10%	10%	10%
Capital expenditures	37,100	26,126	84,763	81,685
Debt including working capital deficiency(2)(3)	91,020	106,124	91,020	106,124
Common shares (000s)				
Weighted average - basic	121,557	121,557	121,557	121,531
Weighted average - diluted	121,649	121,557	121,597	121,616
Outstanding end of period – basic	121,557	121,557	121,557	121,557
OPERATIONS				
(Cdn$ per Boe)				
Revenue from product sales(1)	36.24	26.37	30.18	26.15
Transportation costs	(5.57)	(5.94)	(5.84)	(5.82)
Revenue net of transportation	30.67	20.43	24.34	20.33
Royalties	(0.58)	(0.63)	(1.08)	(1.19)
Production costs	(5.46)	(5.68)	(5.50)	(6.04)
Field operating netback(2)	24.63	14.12	17.76	13.10
Realized (loss) gain on hedging	(8.65)	0.41	(3.03)	(0.40)
General and administrative	(0.55)	(0.94)	(0.82)	(1.05)
Interest and finance costs	(0.45)	(0.67)	(0.57)	(0.69)
Funds flow per Boe	14.98	12.92	13.34	10.96
Barrels of oil equivalent per day (6:1)	22,432	17,936	20,538	16,017
Natural gas production				
Thousand cubic feet per day	109,520	87,375	101,019	78,521
Price (Cdn$ per Mcf)(1)	5.56	3.34	3.98	3.61
Condensate production				
Barrels per day	2,453	1,914	2,141	1,685
Price (Cdn$ per barrel)(1)	58.74	69.53	75.61	61.80
NGL production				
Barrels per day	1,726	1,460	1,561	1,245
Price (Cdn$ per barrel)(1)	35.09	33.29	35.69	25.15
Wells drilled (net)	4.0	7.0	4.0	16.0
Wells completed (net)	2.5	3.0	10.5	12.0

(1) Excludes gains and losses on commodity price contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 39 of the attached Management’s Discussion and Analysis. CROCE and ROCE are presented on a 12-month trailing basis.
(3) Excludes the fair value of commodity price contracts.

PRESIDENT'S MESSAGE

2018 FOURTH QUARTER HIGHLIGHTS

Production and funds flow reached record highs in the quarter as a result of diversified natural gas sales along with the performance of recent horizontal wells continuing to exceed expectations at both Nig and Umbach.

- Production increased to a record of 22,432 Boe per day which represents growth of 25% on a per-share basis from the prior year and also exceeded guidance of 19,000 to 21,000 Boe per day (production was rapidly increased in mid-November in response to a strengthening natural gas price at Chicago).
- Liquids production (field condensate plus gas plant NGL) grew by 24% year over year with liquids representing 19% of total production and 25% of production revenue.
- At the end of the quarter, there was an inventory of seven Montney horizontal wells (6.5 net) that had not started producing which included four completed wells (3.5 net). During the quarter, three wells (3.0 net) started production.
- At the Nig land block, the three wells completed in early 2018 have been producing for eight to eleven months with no decline to date and averaged 8.2 Mmcf per day raw gas in February which is approximately 1,520 Boe per day sales (20% liquids including liquids recovered at the gas plant).
- Diversified natural gas sales resulted in the realized price averaging $5.56 per Mcf which was significantly higher than Western Canadian pricing (AECO $1.48 per GJ and Station 2 $0.64 per GJ). Firm pipeline commitments required to diversify sales also result in a higher natural gas transportation cost which was $1.02 per Mcf (only 18% of the realized price).
- Hedging loss totaled $17.9 million with 69%, or $12.3 million, from Sumas price hedges. This was the result of a failure on the Enbridge T-south pipeline system on October 9th which materially reduced flows and increased the Sumas price to Cdn$14.67 per Mmbtu in the quarter versus the average hedged price of Cdn$2.92 per Mmbtu.
- Production costs, general and administrative, and interest and finance costs averaged $6.46 per Boe, a decrease of 11% year over year.
- Funds flow was a record $30.9 million, or $0.25 per share, a 39% increase on a per-share basis from last year which was largely from a higher natural gas price and higher production volumes.
- Capital investment was $37.1 million which included drilling four horizontal wells (4.0 net), completing three horizontal wells (2.5 net), and initial equipment deposits of $8.9 million for the gas plant at Nig.
- The balance sheet remains strong with debt including working capital deficiency being $91 million which represents 0.7 times annualized quarterly funds flow and 50% of the bank credit facility of $180 million.
- Commodity price hedges currently protect approximately 43% of forecast production for 2019.

2018 YEAR-END HIGHLIGHTS

Financial and operational results were consistent with or better than guidance for production, funds flow, operating costs per Boe and capital investment. Notably, year-over-year production growth per share of 28% was achieved while reducing debt including the working capital deficiency by $15 million.

- Production averaged 20,538 Boe per day which was consistent with guidance and represents growth of 28% on a per-share basis from last year.
- This was the eighth consecutive year that production per share has grown with growth averaging 28% per year over the last five years.

- Liquids production grew by 26% (condensate by 27%) with liquids representing 18% of total production and 35% of production revenue.

- Due to diversified natural gas sales, the realized natural gas price was $3.98 per Mcf which was materially higher than Western Canadian pricing (AECO $1.42 per GJ and Station 2 $1.19 per GJ).

- The corporate decline rate in 2018 was approximately 26% (December 2017 corporate production was 19,220 Boe per day with the same wells producing 14,160 Boe per day in December 2018 based on field estimates). This is a reduction from the 32% decline rate in 2017.

- Cost structure continues to decrease with production, general and administrative, and interest and finance expense averaging $6.89 per Boe, a decline of 11% from the previous year.

- Funds flow was a record $100.1 million ($0.82 per share), a year-over-year increase of 56% on a per-share basis with the improvement coming from production growth (+28%) and a higher funds flow netback (+22%) which resulted from higher commodity prices and a decrease in costs on a per-Boe basis.

- Return on capital employed was 10% and cash return on capital employed was 21%. Cash return on capital employed is based on funds flow which is a more meaningful measure of profitability given that return on capital employed is based on net income which can be significantly affected by non-cash mark-to-market gains and losses on hedging (for example, 2018 was a non-cash hedging loss of $5.8 million while 2017 was a non-cash hedging gain of $24.6 million).

- Capital investment totaled $85 million and included $14 million of investment into longer-term growth projects that will not contribute to production and funds flow until 2020 ($11 million in equipment deposits for the Nig gas plant and $3 million at Fireweed).

YEAR-END RESERVE EVALUATION HIGHLIGHTS

Reserve growth was consistent with production growth while capital efficiency continued to improve with the all-in PDP FD&A setting a record low at $5.24 per Boe while PDP recycle ratio using the funds flow netback set a record high at 2.5 times.

Reserves

(Mboe)	**Increase From Last Year**	**2018**	**2017**	**2016**
Proved Developed Producing (“PDP”)	+25%	42,204	33,729	25,395
Total Proved (“1P”)	+54%	149,905	97,617	77,097
Total Proved plus Probable (“2P”)	+41%	182,370	128,963	104,192
PDP as % of 2P		23%	26%	24%
1P as a % of 2P		82%	76%	74%
Reserve Life Index using fourth quarter production	PDP	5.2	5.2	5.2
(years)	1P	18.3	14.9	15.9
	2P	22.3	19.7	21.4

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

($/Boe)	**2018**	**2017**	**2016**	**3-Year Total**
PDP	$5.24	$5.76	$6.89	$5.82
1P	$6.01	$3.06	$4.97	$5.10
2P	$5.10	$1.27	$5.48	$3.96

Recycle Ratio Using All-in FD&A Cost

	2018	2017	2016	3-Year Total
Funds Flow (000s)	$100,092	$64,080	$34,380	$198,552
Funds Flow netback ($/Boe)	$13.34	$10.96	$7.10	$10.92
PDP Recycle	2.5	1.9	1.0	1.9
1P Recycle	2.2	3.6	1.4	2.1
2P Recycle	2.6	8.6	1.3	2.8

- Reserve additions for PDP replaced 113% of annual production (698% for 1P and 712% for 2P).
- On a per-share basis, PDP reserves increased by 25%, 1P increased by 54% and 2P increased by 41%.
- Liquids reserves increased by 31% for PDP, 69% for 1P and 56% for 2P.
- Material future upside remains given that 2P reserves are recognized in only the upper Montney on 41.7 net sections which is 24% of the total Montney land position (172 net sections).
- Actual results achieved in 2018 were better than what was predicted in last year's evaluation with new wells completed in 2018 assigned estimated ultimate recoverable reserves averaging 8.9 Bcf gross raw gas which is 44% higher than the 2P estimate of 6.2 Bcf gross raw gas for future drilling locations in last year's evaluation. As a result of drilling longer horizontal wells with more frac stages, the actual cost to drill and complete a horizontal well in 2018 averaged $6.2 million which was higher than the estimated cost of $4.8 million used in last year's reserve evaluation.
- The before-tax PDP net present value ("NPV") discounted at 10% was $477 million, or $3.17 per share, after deducting debt including working capital deficiency, a year-over-year increase of 68% when the same price forecast is used (this year's price forecast used in last year's evaluation).

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

Most of the land position is delineated with existing vertical wells, the 75 horizontal wells (70.9 net) drilled to date by Storm, and multiple producing horizontal wells on adjacent lands. The majority of the producing horizontal wells have been drilled in the upper part of the Montney formation. Storm's future drilling will also test the mid and lower Montney in certain areas where higher field condensate-gas ratios are expected based on offsetting well control.

Fourth quarter 2018 field activity included drilling four horizontal wells (4.0 net) and completing three horizontal wells (2.5 net), all at Umbach. Three horizontal wells (3.0 net) started production in October and November and there remains an inventory of seven horizontal wells (6.5 net) that had not started producing at the end of the quarter which includes four completed wells (3.5 net).

First quarter 2019 field activity is expected to include drilling five horizontal wells (5.0 net). Four wells will be drilled from a single pad at Nig (licensed for a total of eight wells) with two wells in the upper Montney, one in the mid and one in the lower. Higher field condensate-gas ratios are expected from the wells in the mid and lower Montney.

At Umbach (100% working interest), investment of approximately $18 million is planned in 2019 with activity including the drilling of one well (1.0 net), the tie-in of a two-well pad (2.0 net) and the completion of a three-well pad (3.0 net). Current field compression capacity totals 150 Mmcf per day raw gas and throughput in the fourth quarter averaged 124 Mmcf per day raw gas (includes 24 Mmcf per day raw from three wells at Nig). Growth is largely contingent on the Station 2 price as incremental natural gas production would be directed to Station 2. Produced raw natural gas is sour (1.2% H_2S) with approximately 85% directed to the McMahon Gas Plant and 15% to the Stoddart Gas Plant. Firm processing commitments are 65 Mmcf raw gas per day at McMahon (10 Mmcf per day ending 2022, 55 Mmcf per day ending 2031) and 15 Mmcf per day at Stoddart (1-year term).

At Nig (100% working interest), approximately $95 million will be invested in 2019 for construction of a sour gas plant, pipelines, drilling and completing an acid gas injection well (1.0 net), and drilling, completing, and equipping four horizontal wells (4.0 net). The license application for the planned 50 Mmcf per day sour gas plant was submitted in September 2018 and, depending on when approvals are received, construction is expected to start in mid-2019 with start-up anticipated in late 2019 or early 2020. Produced raw natural gas contains approximately 0.2% H_2S. Total cost for the sour gas plant is estimated to be $81 million ($11.4 million invested in 2018, remainder in 2019) which includes $73 million for the gas plant, $4 million for an acid gas injection well and $4 million for a sales pipeline. The gas plant has a forecast operating cost of $2.00 per Boe which will reduce corporate operating costs to approximately $4.25 per Boe and is expected to add incremental production of approximately 1,500 Boe per day which primarily comes from improved liquids recovery (adds 1,100 barrels per day with 90% NGL while reducing process shrinkage by 5%).

The first three horizontal wells producing at Nig were completed in early 2018 and, to date, natural gas rates plus field condensate-gas ratios have been materially higher than at Umbach. Calendar day rates over the first 180 days have averaged 8.2 Mmcf per day raw gas plus 205 barrels per day of field condensate (approximately 1,570 Boe per day with 23% liquids including liquids recovered at the gas plant). The condensate-gas ratio during this period was approximately 50% higher than the average well at Umbach. There has been very little decline to date with rates in February averaging 8.2 Mmcf per day raw gas plus 150 barrels per day of field condensate based on field estimates.

At Fireweed (50% working interest), approximately $15 million net will be invested in 2019 to drill and complete three horizontal wells (1.5 net) and for deposits to order longer lead time equipment for a field compression facility. The license application for the 50 Mmcf per day field compression facility was submitted in January 2019 and, depending on when approvals are received, construction is expected to begin between late 2019 and early 2020 with start-up in the second half of 2020. Total costs associated with the facility are $34 million gross and it is designed to be expandable to 100 Mmcf per day. Preliminary planning for 2020 includes net investment of approximately $50 million to drill nine horizontal wells (4.5 net), complete six horizontal wells (3.0 net) and construct the field compression facility. Development at Fireweed is expected to increase condensate as a proportion of total production based on production history from several offsetting horizontal wells where first year average field condensate-gas ratios were 30 to 70 barrels per Mmcf raw which is 100% to 400% higher than at Umbach.

The first horizontal well (0.5 net) at Fireweed was completed in the fourth quarter of 2018 with encouraging results. The C-74-G/94-A-13 well has a completed length of 1,520 metres and, after flowing on a six-day cleanup, rates over the last 12 hours averaged 10.9 Mmcf per day raw gas, 660 barrels per day of field condensate, and 1,140 barrels per day of frac water with a final flowing casing pressure of 4,800 kPa. The well is expected to remain shut in until the field compression facility is completed.

The licensing process was recently changed (July 2018) and applications for wells, facilities, roads and pipelines at Nig, Umbach and Fireweed are subject to the BC Oil and Gas Commission's 'New Interim Measures Applied to Oil and Gas Applications'. Storm's lands are within Area 2 where the objective is restricted new surface disturbance. Some of Storm's license applications will result in new disturbance and have been referred for additional review which is extending the time required to obtain licenses. This would include pipelines and the gas plant at Nig plus pipelines, the facility and drilling at Fireweed. The additional time required for review is not currently quantifiable (the licensing process generally required five to six months before the new measures were implemented).

A summary of horizontal well results at Nig and Umbach is provided below. Note that IP90 and IP180 rates are not meaningful indicators of relative performance as wells after 2016 are initially rate restricted to manage fluid rates (for as long as nine months). In addition, the 2018 horizontal wells were affected by the 17 day outage at the McMahon Gas Plant in January 2019.

Year of Completion	Frac Stages	Completed Length	IP90 Cal Day	IP180 Cal Day	IP365 Cal Day
Umbach 2014 - 2016 33 hz's[(1)]	22	1350 m	4.9 Mmcf/d[(2)] 19 Bbls/Mmcf[(3)] 33 hz's	4.3 Mmcf/d[(2)] 16 Bbls/Mmcf[(3)] 33 hz's	3.4 Mmcf/d[(2)] 13 Bbls/Mmcf[(3)] 33 hz's
Umbach 2017 12 hz's	34	1830 m	5.0 Mmcf/d[(2)] 24 Bbls/Mmcf[(3)] 12 hz's	4.5 Mmcf/d[(2)] 20 Bbls/Mmcf[(3)] 12 hz's	4.3 Mmcf/d[(2)] 14 Bbls/Mmcf[(3)] 12 hz's
Umbach 2018 5 hz's	31	1850 m	3.5 Mmcf/d[(2)] 23 Bbls/Mmcf[(3)] 4 hz's		
Nig 2018 3 hz's	37	2180 m	8.1 Mmcf/d[(2)] 29 Bbls/Mmcf[(3)] 3 hz's	8.2 Mmcf/d[(2)] 25 Bbls/Mmcf[(3)] 3 hz's	

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

Based on results from the 2017 and 2018 wells, Storm management is using an 11 Bcf raw gas type curve (internal estimate) to forecast production which represents an average of the expected result at Umbach and Nig. Future wells will be longer (2300 to 2400 metres) and have more fracture stages (41 to 47) which is expected to result in further improvement to rates and reserves. More detail on well performance and management's type curve is available in the presentation on Storm's website at www.stormresourcesltd.com.

HEDGING AND TRANSPORTATION

Commodity price hedges are used to support longer-term growth with the objective being to protect pricing on 50% of current production for the next 12 months and 25% for 13 to 24 months forward. Anticipated production growth is not hedged. Note that approximately 80% of Storm's liquids production (condensate and butane) is priced in reference to WTI. The current hedge position protects approximately 43% of forecast production for 2019.

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

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

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

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

(1) Preferential interruptible adds up to 14 Mmcf/d
(2) Sumas price less US$0.69/Mmbtu

In the fourth quarter, 63% of natural gas sales were at a Chicago price, 26% at Western Canadian pricing, and 11% at a Sumas price less a marketing adjustment. Production exceeding firm capacity is directed to Chicago and/or Station 2 on an interruptible basis depending on which sales point offers a higher net price.

OUTLOOK

For the first quarter of 2019, production is forecast to be 17,500 to 20,000 Boe per day. As was previously communicated in a press release dated January 15, 2019, the McMahon Gas Plant was shut in for 17 days starting January 2nd to repair a failure on the flare system piping. During this time, production was reduced to 4,500 Boe per day. Production to date has averaged 18,000 Boe per day based on field estimates.

Production in the second and third quarters of 2019 is expected to be approximately 20,000 to 21,000 Boe per day based on current indications for Western Canadian natural gas prices during this period ($0.75 per GJ at Station 2 and $1.25 per GJ at AECO). This level of production is the minimum that would fulfill firm transportation commitments and assumes interruptible service on the Alliance Pipeline is not available.

Updated guidance for 2019 is summarized below:

- forecast commodity prices updated to reflect pricing to date in 2019 plus the approximate current forward strip for the remainder of the year;
- estimated annual funds flow decreased primarily as a result of weaker Western Canadian propane and butane prices (primarily butane) which decreases the NGL price net of transportation to approximately 10% to 15% of WTI in Cdn$ for the next NGL contract period from April 2019 to March 2020 (versus an average of 42% in 2018); and
- the number of horizontal wells starting production decreased to 9.0 gross from 11.0 gross with the start-up of two horizontal wells accelerated into the fourth quarter of 2018 to take advantage of stronger natural gas prices.

2019 Guidance

	Initial November 13, 2018	February 28, 2019
Cdn$/US$ exchange rate	0.78	0.76
Chicago daily natural gas - US$/Mmbtu	$2.50	$2.60
Sumas monthly natural gas - US$/Mmbtu	$2.50	$3.10
AECO daily natural gas - Cdn$/GJ	$1.50	$1.60
Station 2 daily natural gas - Cdn$/GJ	$1.25	$1.25
WTI - US$/Bbl	$60.00	$55.00
Edmonton condensate diff - US$/Bbl	-$8.00	-$5.50
Est revenue net of transport (excl hedges) - $/Boe	$17.50 - $18.00	$17.75 - $18.25
Est operating costs - $/Boe	$5.50 - $5.75	$5.50 - $5.75
Est royalty rate (% revenue before hedging)	5% - 7%	5% - 7%
Est mid-point field operating netback - $/Boe	$11.05	$11.30
Est hedging loss - $ million		$7.0 - $8.0
Est cash G&A - $ million	$6.0 - $7.0	$6.0 - $7.0
- $/Boe	$0.66 - $0.91	$0.66 - $0.91
Est interest expense - $ million	$5.5 - $6.5	$5.5 - $6.5
Est capital investment (excl A&D) - $ million	$128.0	$128.0
Forecast fourth quarter production - Boe/d % liquids	23,000 – 25,000 18%	23,000 - 25,000 18%
Forecast annual production - Boe/d % liquids	21,000 – 24,000 18%	21,000 - 24,000 18%
Est annual funds flow - $ million	$72.0 - $88.0	$67.0 - $79.0(1)
Horizontal wells drilled - gross Horizontal wells completed - gross Horizontal wells starting production - gross	8 (6.5 net) 11 (9.5 net) 11 (11.0 net)	9 (7.5 net) 11 (9.5 net) 9 (9.0 net)

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

A failure on the Enbridge T-south pipeline system on October 9, 2018 affected the natural gas price at Station 2 which averaged $0.64 per GJ in the fourth quarter of 2018, a differential to AECO of -$0.84 per GJ (compared to an average price of $1.37 per GJ and differential of -$0.04 per GJ in the nine months before the failure). Flow has been restored to approximately 80% to 85% of the flow prior to the failure and the timing to fully restore capacity is not currently known although is unlikely to be before August 2019 (requires completion of engineering assessments on various segments along with review and approval from the National Energy Board). The Station 2 price is expected to remain depressed until capacity is restored or until the NGTL North Montney extension into northeast British Columbia is in service which is anticipated to be in the fourth quarter of 2019 (contracted capacity 1.5 Bcf per day). The financial effect on Storm has not been material given that less than 15% of natural gas sales are at Station 2 pricing.

Since 2015, financial results have improved materially with funds flow reaching a record $100 million in 2018, an increase of 141% on a per-share basis. Importantly, debt including working capital deficiency has increased by only 47% during this period (from $62 million at the end of 2015 to $91 million at the end of 2018). This has been a result of production growth (+103% per share), increased revenue per Boe net of transportation (+39%), and a per-Boe decrease in production, general and administrative, and interest and finance expense (-32%).

In 2019, estimated capital investment to maintain production at 2018 levels of 20,000 to 21,000 Boe per day is less than $10 million which includes connection and start-up of three horizontal wells that were completed in 2018 plus expenditures for various minor projects. The remaining investment of $118 million will be directed to growth opportunities that offer attractive full-cycle rates of return at current commodity prices. At Nig, a 50 Mmcf per day sour gas plant will be constructed in the second half of 2019 which will significantly reduce per-Boe operating costs and increase liquids recovery. At Fireweed, a 50 Mmcf per day field compression facility will be constructed in mid-2020 where higher field condensate rates are expected from horizontal wells. At Umbach, activity and production can and will be increased relatively quickly if supported by the Station 2 natural gas price given existing unused field compression capacity.

Growth has been accomplished while improving the cash return on average capital employed to 21% in 2018 from 10% in 2015. Generating a strong return on invested capital will continue to be a focus of Storm's business plan.

The Company's near-term growth plan is expected to increase the proportion of liquids and decrease per-Boe operating costs which reduces exposure to current low Western Canadian natural gas prices. Production is expected to grow to approximately 25,000 Boe per day by the end of 2019 (18% liquids) and to more than 30,000 Boe per day by the end of 2020 (21% liquids). Growth will be financed with funds flow and debt. Maintaining a strong balance sheet remains a priority and, as a result, capital investment and activity will continue to be flexible and may be accelerated or reduced depending on commodity prices.

With horizontal well results continuing to improve as length is increased and with 2P reserves recognized in only the upper Montney on less than 25% of the total land position at Umbach, Nig and Fireweed, material future upside remains. This leaves Storm well positioned to continue growing funds flow and asset value on a per-share basis and is a consideration when evaluating acquisition or diversification opportunities.

The growth and significant improvement in financial results over the last several years would not have happened without the successful efforts of Storm's employees and I would like to thank them for their hard work and also thank Storm's Board of Directors for their invaluable advice, guidance and support.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

February 28, 2019

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

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

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

Forward-Looking Statements – Such statements made in this report are subject to the limitations set out in Storm's Management's Discussion and Analysis dated February 28, 2019 for the three months and year ended December 31, 2018.

RESERVES AT DECEMBER 31, 2018

Storm's year-end reserve evaluation effective December 31, 2018 was prepared by InSite Petroleum Consultants Ltd. ("InSite") in a report dated February 20, 2018. InSite has evaluated all of Storm's natural gas and NGL reserves. The InSite price forecast at December 31, 2018 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, 2018 (the "AIF").

Summary

- Proved developed producing reserves ("PDP") increased to 42,204 Mboe during 2018, a 25% increase over the 2017 year-end PDP reserves of 33,729 Mboe. Total proved reserves ("1P") increased to 149,905 Mboe, a 54% increase over 2017 year-end 1P reserves of 97,617 Mboe. Total proved plus probable reserves ("2P") increased to 182,370 Mboe, a 41% increase over 2017 year-end 2P reserves of 128,963 Mboe.

- Reserve additions in 2018 replaced 113% of production for PDP reserves, 698% for 1P reserves and 712% for 2P reserves.

- 2P reserves include 889 Bcf of natural gas and 34 Mmbbl of NGL at year-end 2018. The NGL component includes 56% condensate (19 Mmbbl), 23% butane (8 Mmbbl) and 21% propane (7 Mmbbl).

- The all-in finding, development, and acquisition ("FD&A") cost(1) to add reserves was $5.24 per Boe for PDP, $6.01 per Boe for 1P and $5.10 per Boe for 2P.

- Technical revisions increased PDP reserves by 2,574 Mboe (7.6%), 1P reserves by 16,432 Mboe (16.8%) and 2P reserves by 21,291 Mboe (16.5%). PDP revisions were primarily due to well performance exceeding the InSite forecast from the previous year, while 1P and 2P revisions were the result of increased reserve assignments due to using longer horizontal wells.

- Breaking down 2P reserves by area, 81.9% is at Umbach, 17.7% is at Nig, 0.2% is at the Horn River Basin ("HRB") and 0.2% is at Grande Prairie.

- Future development costs ("FDC") were $686 million on a 1P basis and $707 million on a 2P basis and are fully financed from forecast cash flow within four years which complies with the Canadian Oil and Gas Evaluation ("COGE") Handbook.

- FDC increased from 2017 predominantly due to three factors: investment associated with the Nig Gas Plant in 2019; a modest increase in future drilling locations; and increased cost to drill and complete a horizontal well given longer well lengths and additional completion stages.

- At Umbach and Nig there are 88.6 net 2P future horizontal drills assigned an average of 7.9 Bcf gross raw gas (last year was 78.6 net 2P locations with 6.2 Bcf gross raw gas). There are no future drilling locations recognized at Fireweed.

- Wells drilled in 2018 were assigned an average of 8.9 Bcf gross raw gas on a 2P basis.

- At Umbach and Nig, 2P reserves were recognized in the upper Montney on 41.7 net sections (an increase of 8.0 net sections from last year), 1P on 26.2 net sections and PDP on 14.5 net sections. DPIIP averages 48 Bcf gross raw gas per section in the upper Montney (total net DPIIP 2.0 Tcf on 41.7 net sections). Forecast recovery of DPIIP totals 55% for 2P reserves.

- FDC includes $166 million net on a 2P basis for future infrastructure expansion at Umbach (last year was $55 million net for future infrastructure expansion). $71 million is allocated to the Nig area gas plant and $92 million is allocated to infrastructure expansion at Umbach South and Umbach North.

- The estimated cost to drill and complete a future Montney horizontal well at Umbach increased to $5.5 million compared to $4.8 million used in the previous year's reserve evaluation as a result of using longer horizontal wells with more frac stages.

(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, 2018, 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, 2018
(Before deduction of royalties payable, not including royalties receivable)

	Sales Gas (Mmcf)	NGL (Mbbls)	6:1 Oil Equivalent (Mboe)
Proved producing	207,828	7,566	42,204
Proved non-producing	5,132	91	947
Total proved developed	212,960	7,657	43,151
Proved undeveloped	518,405	20,354	106,755
Total proved	731,365	28,011	149,905
Probable additional	158,126	6,110	32,464
Total proved plus probable	889,492	34,121	182,370

Numbers in this table may not add due to rounding.

Gross Company Reserve Reconciliation for 2018
(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, 2017 – opening balance	33,729	97,617	31,346	128,963
Acquisitions	-	-	-	-
Discoveries	-	-	-	-
Extensions	13,393	43,347	(3,739)	39,608
Dispositions	-	-	-	-
Technical revisions	2,626	16,516	4,861	21,377
Economic factors	(52)	(84)	(2)	(86)
Production	(7,492)	(7,492)	-	(7,492)
December 31, 2018 – closing balance	42,204	149,905	32,464	182,370

Numbers in this table may not add due to rounding.

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

(Years)	2018	2017	2016
PDP	5.2	5.2	5.2
1P	18.3	14.9	15.9
2P	22.3	19.7	21.4

Future Development Costs ("FDC")

	Proved ($M)	Proved Plus Probable ($M)
2019	107,300	107,300
2020	228,939	228,939
2021	233,362	233,362
2022	116,860	137,575
2023	-	-
Total FDC - undiscounted	686,461	707,176
Total FDC - discounted at 10%	618,923	635,441

($million)	2018	2017	2016
1P FDC	$ 686	$ 412	$ 413
2P FDC	$ 707	$ 481	$ 524

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)	2018	2017	2016	3 Year Total
Net capital investment (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Total capital including change in FDC (000s)	$ 83,641	$ 81,685	$ 64,938	$ 230,264
Total reserve additions (Mboe)	15,967	14,180	9,424	39,571
All-in PDP FD&A cost (per Boe)	$ 5.24	$ 5.76	$ 6.89	$ 5.82

Total Proved FD&A Cost (All-in)	2018	2017	2016	3 Year Total
Net capital investment (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	274,814	(1,127)	(22,669)	251,018
Total capital including change in FDC (000s)	$ 359,577	$ 80,558	$ 42,269	$ 482,404
Total reserve additions (Mboe)	59,780	26,366	8,501	94,647
All-in 1P FD&A cost (per Boe)	$ 6.01	$ 3.06	$ 4.97	$ 5.10

Total Proved Plus Probable FD&A Cost (All-in)	2018	2017	2016	3 Year Total
Net capital investment (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	226,058	(42,755)	(19,395)	163,908
Total capital including change in FDC (000s)	$ 310,821	$ 38,930	$ 45,543	$ 395,294
Total reserve additions (Mboe)	60,899	30,617	8,308	99,824
All-in 2P FD&A cost (per Boe)	$ 5.10	$ 1.27	$ 5.48	$ 3.96

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

Total Proved F&D Cost	2018	2017	2016	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	274,814	(1,127)	(22,669)	251,018
Total capital including change in FDC (000s)	$ 359,577	$ 80,558	$ 42,269	$ 482,404
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	43,347	16,669	5,182	65,199
1P F&D cost (per Boe)	$ 8.30	$ 4.83	$ 8.16	$ 7.40

Total Proved Plus Probable F&D Cost	2018	2017	2016	3 Year Total
Capital expenditures excluding acquisitions and dispositions (000s)	$ 84,763	$ 81,685	$ 64,938	$ 231,386
Change in FDC (000s)	226,058	(42,755)	(19,395)	163,908
Total capital including change in FDC (000s)	$ 310,821	$ 38,930	$ 45,543	$ 395,294
Reserve additions excluding acquisitions, dispositions, and revisions (Mboe)	39,608	19,615	4,890	64,112
2P F&D cost (per Boe)	$ 7.85	$ 1.98	$ 9.31	$ 6.17

Net Present Value Summary (before tax) as at December 31, 2018

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	693,974	561,063	476,842	419,619	378,559
Proved non-producing	6,795	4,763	3,506	2,673	2,088
Total proved developed	700,769	565,826	480,348	422,292	380,647
Proved undeveloped	1,609,850	976,620	634,522	426,964	290,364
Total proved	2,310,619	1,542,446	1,114,870	849,257	671,011
Probable additional	781,393	384,353	230,041	156,288	115,536
Total proved plus probable	3,092,013	1,926,799	1,344,911	1,005,544	786,547

Numbers in this table may not add due to rounding.

Net Present Value Summary (after tax) as at December 31, 2018

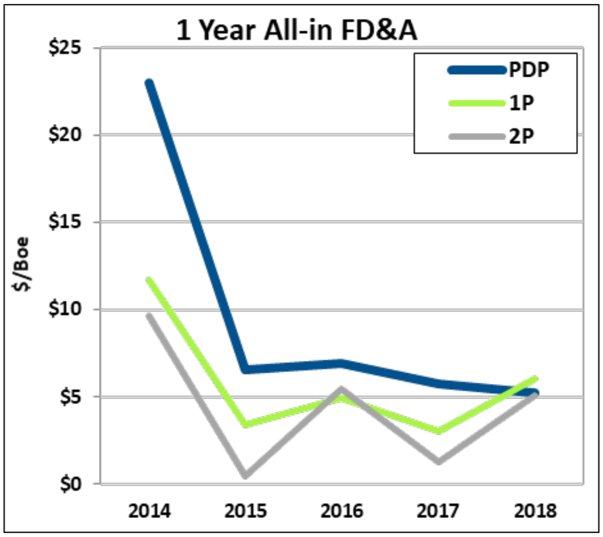
Benchmark oil and NGL prices used are adjusted for quality of oil or NGL produced and for transportation costs. The calculated NPV each include a deduction for estimated future well abandonment costs. The NPV disclosed does not represent fair market value of reserves.

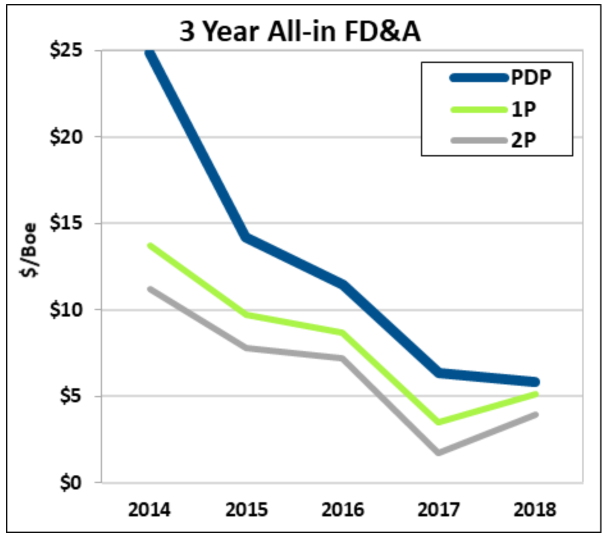
(000s)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved producing	633,691	522,539	450,976	401,549	365,520
Proved non-producing	5,026	3,522	2,594	1,979	1,545
Total proved developed	638,717	526,061	453,570	403,528	367,065
Proved undeveloped	1,191,494	705,732	441,551	280,585	174,436
Total proved	1,830,211	1,231,792	895,120	684,113	541,501
Probable additional	578,230	284,148	169,854	115,289	85,207
Total proved plus probable	2,408,440	1,515,940	1,064,974	799,401	626,708

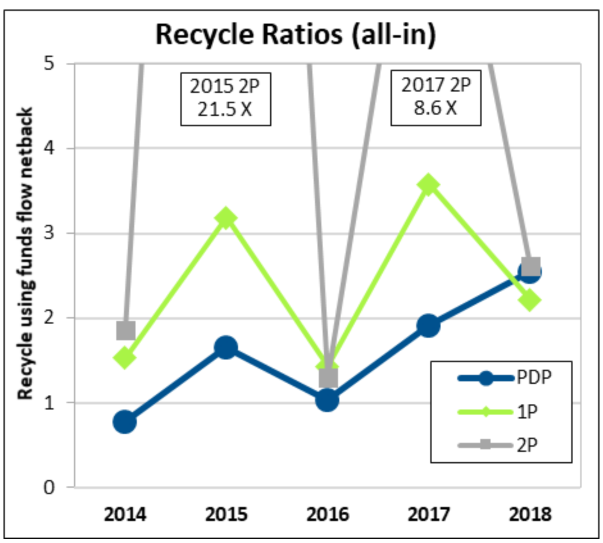
Numbers in this table may not add due to rounding.

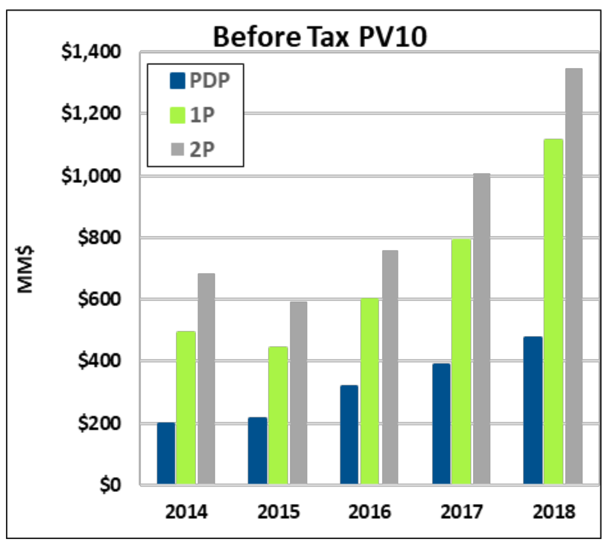
InSite Escalating Price Forecast as at December 31, 2018

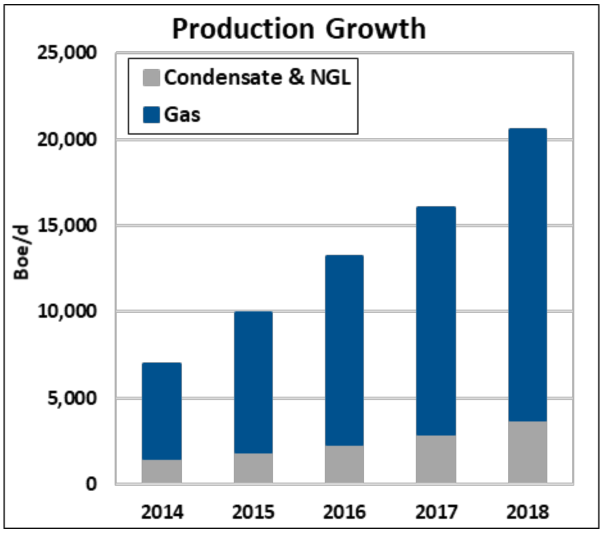
	Exchange Rate (US$/Cdn$)	WTI Crude Oil (US$/Bbl)	Condensate (Cdn$/Bbl)	Henry Hub Natural Gas (US$/Mmbtu)	AECO Natural Gas (Cdn$/Mmbtu)	BC Station 2 (Cdn$/Mmbtu)
2019	0.76	57.00	67.95	3.00	1.90	1.43
2020	0.78	64.00	78.95	3.15	2.29	1.97
2021	0.80	68.00	83.72	3.35	2.71	2.46
2022	0.80	71.00	86.58	3.50	3.03	2.78
2023	0.80	72.80	88.60	3.62	3.21	2.96

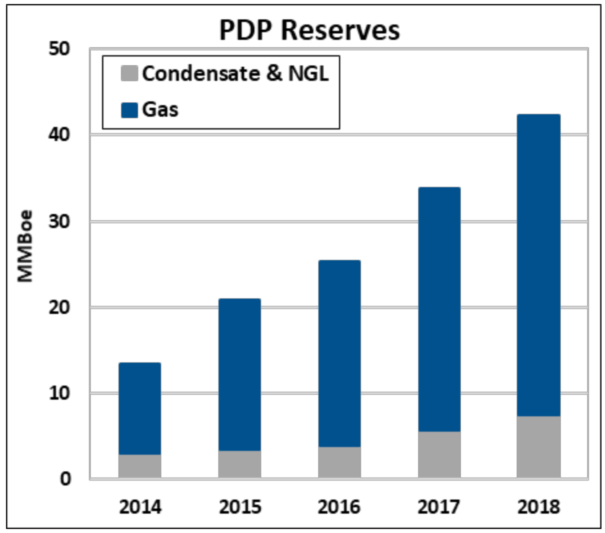


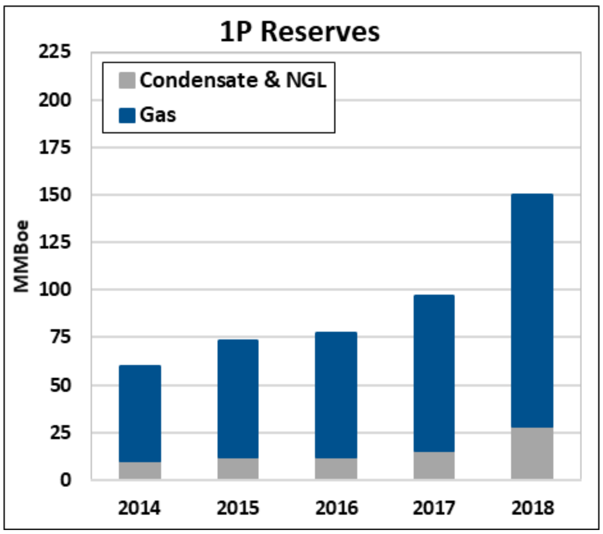


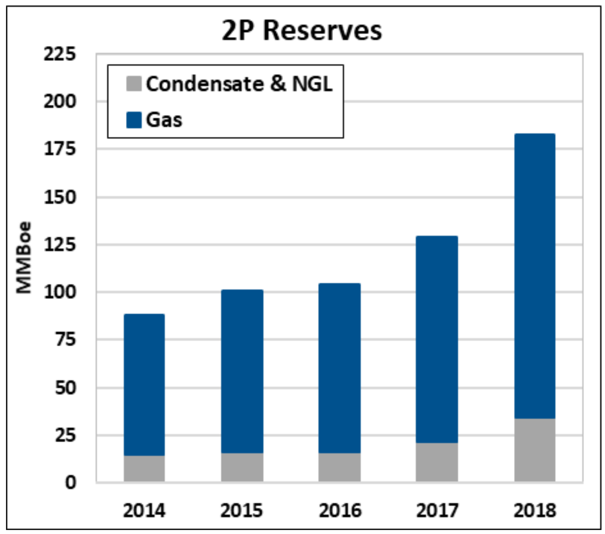


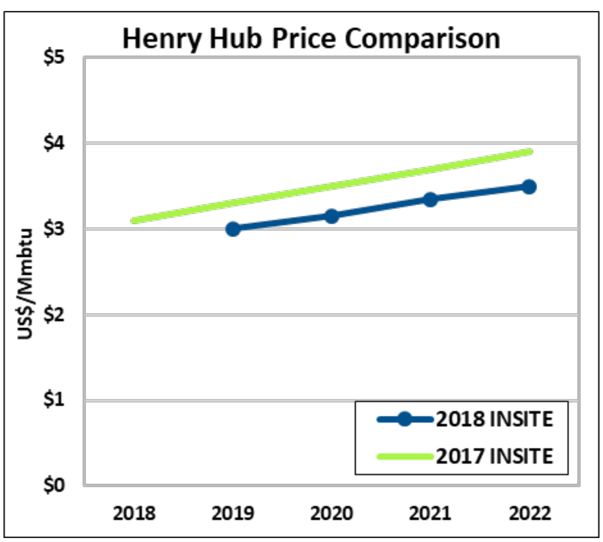


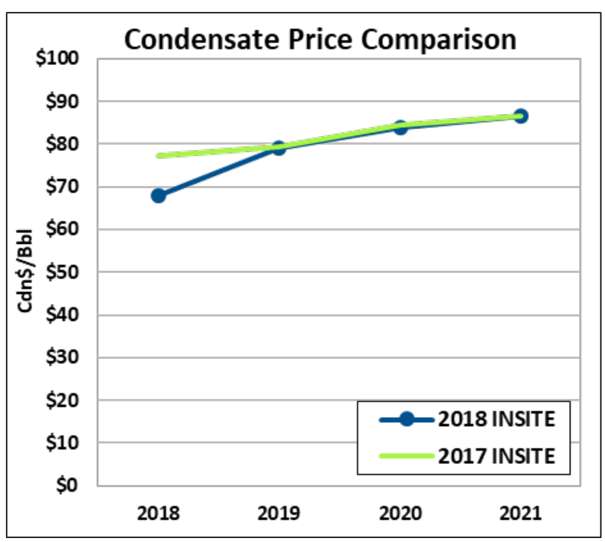

Production Growth
Condensate & NGL
Gas
Boe/d
25,000
20,000
15,000
10,000
5,000
0
2014
2015
2016
2017
2018

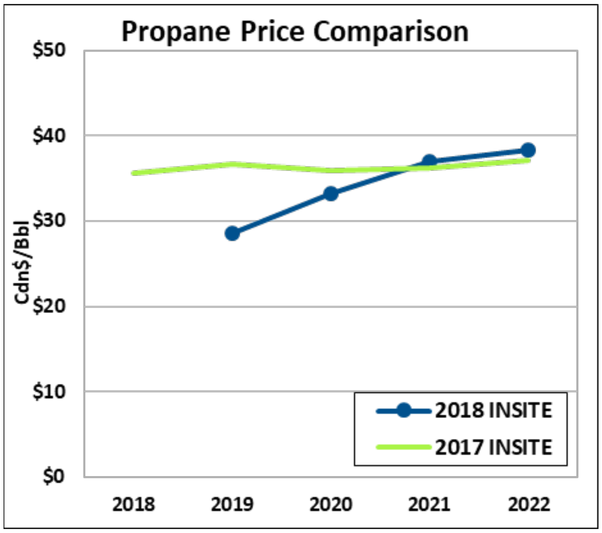

PDP Reserves
Condensate & NGL
Gas
MMBoe
50
40
30
20
10
0
2014
2015
2016
2017
2018

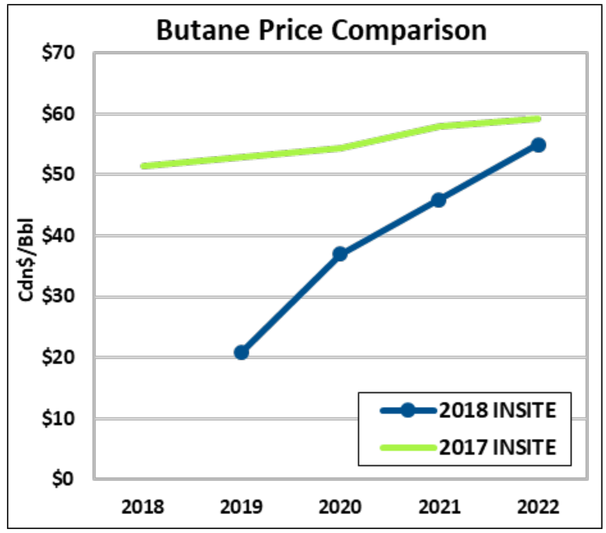

1P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2014
2015
2016
2017
2018


2P Reserves
Condensate & NGL
Gas
MMBoe
225
200
175
150
125
100
75
50
25
0
2014
2015
2016
2017
2018


Henry Hub Price Comparison
US$/Mmbtu
$5
$4
$3
$2
$1
$0
2018
2019
2020
2021
2022
2018 INSITE
2017 INSITE


Condensate Price Comparison
Cdn$/Bbl
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
2018
2019
2020
2021
2018 INSITE
2017 INSITE


Propane Price Comparison
$50
$40
$30
$20
$10
$0
Cdn$/Bbl
2018
2019
2020
2021
2022
2018 INSITE
2017 INSITE


Butane Price Comparison
$70
$60
$50
$40
$30
$20
$10
$0
Cdn$/Bbl
2018
2019
2020
2021
2022
2018 INSITE
2017 INSITE

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, 2018. It should be read in conjunction with (i) the Company's audited consolidated financial statements for the years ended December 31, 2018 and 2017, (ii) each of the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, June 30 and September 30, 2018, and (iii) the press release issued by the Company on February 28, 2019, and other operating and financial information included in this report. All of these documents as well as the Company's Annual Information Form dated March 29, 2018 are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

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

This MD&A is dated February 28, 2019.

See "Forward-Looking Statements", "Boe Presentation" and "Non-GAAP Measurements" on pages 37 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, 2018 and the unaudited interim consolidated financial information for the three months ended December 31, 2018 (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, 2018 and 2017. 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, 2017.

OPERATIONAL AND FINANCIAL RESULTS

Overview

Year Ended December 31, 2018

Despite a challenging business environment for Canadian energy companies, Storm remains steadfast in executing on the Company's strategic plan, which continues to be focused on capital discipline and growing asset value on a per-share basis. In this regard, 2018 was a defining year in Storm's evolution marked by significant improvements in well results and record funds flow. Storm exited the year in a position of strength allowing the Company considerable flexibility to navigate ongoing challenges facing the industry, including extreme volatility in commodity prices. In response to weakness in Western Canadian natural gas prices, Storm maintained relatively flat production for the first ten months of the year before ramping up production to record levels through November and December in response to strength in US based pricing. Storm benefitted from its diversification strategy in the fourth quarter with approximately 75% of production volumes sold at US based pricing (Chicago and Sumas). Despite the AECO daily price averaging $1.42 per GJ and Station 2 averaging $1.19 per GJ in 2018, Storm's realized natural gas price was $3.98 per Mcf for the year, highlighting the benefit of the Company's ability to sell natural gas south of the border into the Chicago and Sumas markets. As noted in the past, weakness in Western Canadian natural gas prices comes down to record supply levels, further exacerbated for Canadian producers by a lack of growth in egress to other markets. With pricing at historically low levels, capital spending should be reduced industry wide, which would invariably lead to reduced supply followed by higher prices in due course.

While representing only 18% of the Company's total production base, condensate (includes field condensate and plant pentanes) and NGL (includes butane and propane) contributed 35% to the Company's top line revenue, with strength in condensate and NGL 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, participation in the crude oil market remains an important part of Storm's business plan, particularly in light of the ability to focus drilling on areas where higher liquids recoveries are expected.

Adjustments to the near-term growth plan in the second half of 2018 resulted in capital expenditure guidance being amended by the Company as set out in the table below:

2018 Guidance History

	Chicago Daily (US$/Mmbtu)	Station 2 Daily (Cdn$/GJ)	WTI (US$/bbl)	Estimated Capital Expenditures ($ million)	Forecast Annual Funds Flow ($ million)	Forecast Annual Production (Boe/d)
November 14, 2017	$2.80	$1.30 - $1.70	$52.00	$55.0 - $90.0	$73.0 - $90.0	20,000 - 23,000
March 1, 2018	$2.60	$1.05	$56.00	$55.0 - $90.0	$70.0 - $78.0	20,000 - 23,000
May 15, 2018	$2.60	$1.20	$64.00	$55.0 - $65.0	$76.0 - $80.0	20,000 - 21,000
August 14, 2018	$2.70	$1.35	$66.00	$80.0	$85.0 - $90.0	20,000 – 20,500
November 13, 2018	$2.90	$1.30	$66.00	$85.0	$90.0 - $96.0	19,500 – 20,500
Actual 2018 Results	**$3.02**	**$1.19**	**$64.77**	**$84.8**	**$100.1**	**20,538**

Despite remaining at depressed levels, natural gas prices were relatively stable for most of the year as was the Company's capital expenditure and production guidance. In August 2018, Storm finalized a two-year growth plan that will see the construction of a 50 Mmcf per day sour gas plant to develop the Nig land block and the construction of a 50 Mmcf per day field compression facility to develop the Fireweed land block. As a result, capital expenditures were increased in August primarily to incorporate deposits on long-lead-time equipment for the sour gas plant at Nig. In addition, the strength in US based natural gas pricing resulted in actual funds flow exceeding guidance.

Storm continues to manage its production base between 20,000 and 25,000 Boe per day in response to ongoing volatility in crude oil and natural gas prices, while ensuring firm transportation and processing commitments are being met. Storm can react quickly and accelerate production growth in response to improved pricing as evidenced by December production reaching record levels at approximately 24,500 Boe per day.

Debt including working capital deficiency at year end amounted to $91 million, or 0.7 times annualized fourth quarter 2018 funds flow, with $87 million drawn on the Company's $180 million credit facility.

Year over year, total production grew by 28%, all from the Umbach area in northeast British Columbia, although production between the two periods is not directly comparable given 2017 was affected by the McMahon Gas Plant turnaround that lasted for 39 days. Production growth in 2018 is more impressive in the context of the reduction in the Company's debt including working capital deficiency, which was reduced by $15 million during the year.

Year-over-year production costs per Boe fell by 9%, while the total of general and administrative and interest and finance costs per Boe fell by 20%. These cost reductions, coupled with a 15% increase in realized pricing and the aforementioned increase in production volumes, drove a year-over-year funds flow per Boe increase of 22%. Given the improved pricing scenario relative to 2017, Storm's hedging program resulted in a realized hedging loss of $22.7 million compared to a realized hedging loss of $2.4 million in the prior year. A large component of the hedging loss was due to the Enbridge T-south pipeline failure on October 9th which resulted in materially higher pricing in the Sumas market.

Storm's 2018 capital program was focused on the Umbach property, with the program pushing development to the northwest (West Umbach and Nig) and southern parts of the Company's lands (South Umbach and Fireweed) in areas where condensate content is expected to be higher. The Company incurred net capital expenditures of $84.8 million, 54% of which was spent on drilling and completions ($45.4 million) while 40% was spent on infrastructure initiatives ($33.9 million). Four wells (100% working interest) were drilled in the year and 11 (10.5 net) wells were completed. Storm had an inventory of seven horizontal wells (6.5 net) that had not started producing at the end of 2018, four (3.5 net) of which were completed.

Commodity prices and funds flow will continue to drive the Company's capital program at Umbach in 2019. In order to maintain 20,000 to 21,000 Boe per day of production in 2019, Storm estimates maintenance capital of only $10 million. The capital program for 2019 of $128 million is expected to be funded through estimated funds flow of $67 million to $79 million and approximately $80 million of unused credit 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 will not change; what may change is timing of execution.

As previously communicated, Storm's third compression facility was twinned late in the third quarter which supports growth in corporate production to approximately 27,000 Boe per day.

Quarter Ended December 31, 2018

Not only was the fourth quarter of 2018 the Company's strongest quarter, financially, of 2018 but also the strongest quarter in the Company's history. Production was 25% higher than the fourth quarter of 2017 and 10% higher compared to the third quarter of 2018. Revenue from product sales for the quarter was 72% higher than the prior year due to higher production levels and higher pricing or, alternatively, up 29% after factoring in realized hedging gains and losses. Revenue per Boe increased 37% compared to the fourth quarter of 2017 as higher natural gas prices were partially offset by lower condensate prices. Revenue per Boe was 33% higher than the immediately preceding quarter. Production increased from just over 20,000 Boe per day for the month of October to just under 24,500 Boe per day for the month of December. Production to date in 2019 has averaged approximately 18,000 Boe per day based on field estimates (after taking into account the 17 days of downtime in January at the McMahon gas plant due to a failure on flare system piping). Increased production in December 2018 was supported by strong natural gas prices in US markets coupled with the Company's hedge portfolio that includes protection for volumes sold at both AECO and Station 2.

Funds flow for the quarter totaled $30.9 million, approximately 45% higher than the same period in the prior year and 39% higher than the third quarter of 2018. Increased funds flow over the preceding quarter resulted primarily from improved pricing, higher production levels and infrastructure royalty credits in the current period. Funds flow was affected by a realized hedging loss of $17.9 million in the fourth quarter due to strong pricing in the Chicago and Sumas market, with materially higher Sumas pricing from the Enbridge T-south pipeline failure the main driver of the hedging loss. Using annualized funds flow for the fourth quarter, the ratio of year-end debt including working capital deficiency to funds flow amounted to 0.7 times.

Capital expenditures for the quarter were in line with previously announced guidance and totaled $37.1 million. Included in this amount are drilling and completion costs of $25.3 million, corresponding to the drilling of four wells along with the completion of three (2.5 net) wells in the quarter. Facility, equipping and gathering costs totaled $10.6 million which was predominantly related to the Nig gas plant.

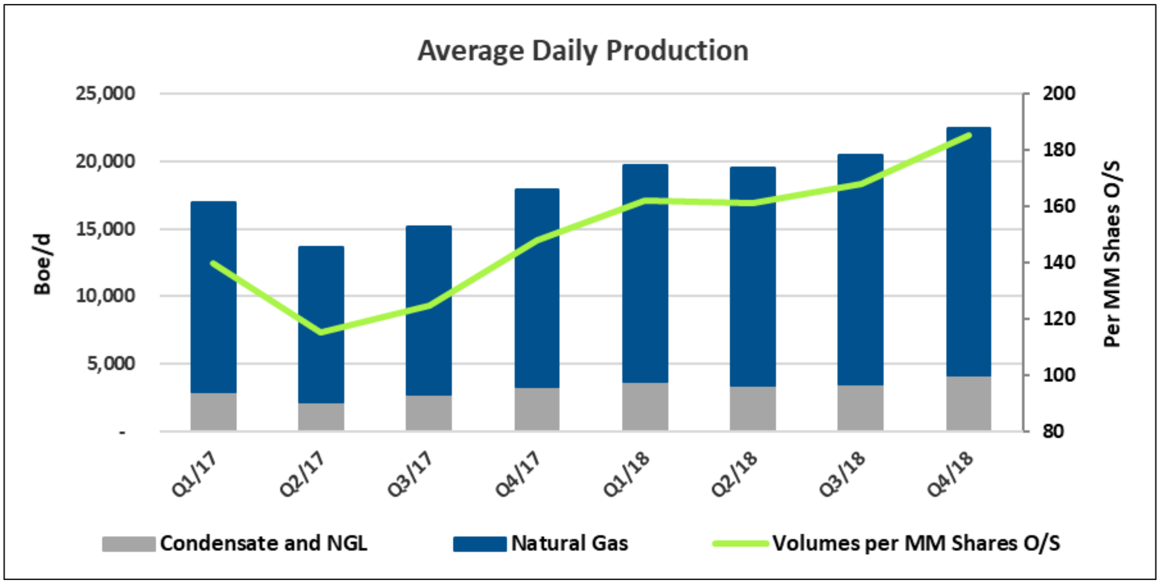
During the fourth quarter of 2018, the Company's bank syndicate confirmed Storm's credit facility at $180 million, which was approximately 50% drawn at the end of the fourth quarter. The annual review will take place prior to April 26, 2019.

Production and Revenue

Average Daily Production

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year-Over-Year Change	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017	Year-Over-Year Change
Natural gas (Mcf/d)	109,520	87,375	25%	101,019	78,521	29%
Condensate (Bbls/d)	2,453	1,914	28%	2,141	1,685	27%
NGL (Bbls/d)	1,726	1,460	18%	1,561	1,245	25%
Total (Boe/d)	22,432	17,936	25%	20,538	16,017	28%
Natural gas weighting	81%	81%		82%	82%	
Condensate weighting	11%	11%		10%	10%	
NGL weighting	8%	8%		8%	8%	

Production increases for natural gas, condensate and NGL, when compared to both periods in 2017, came from growth at Umbach where the Company started production from three new 100% working interest wells during the fourth quarter of 2018 and nine new 100% working interest wells during the year ended December 31, 2018. Comparability on an annual basis was affected by the McMahon Gas Plant turnaround in 2017 which reduced volumes during the comparative period.



Daily production per million shares outstanding for the fourth quarter of 2018 averaged 185 Boe per day compared to 148 Boe per day for the fourth quarter of 2017, an increase of 25%. Daily production per million shares outstanding in 2018 averaged 169 Boe per day, compared to 132 Boe per day in 2017, an increase of 28%.

Average Selling Prices(1)

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Natural gas – Mcf	$ 5.56	$ 3.34	$ 3.98	$ 3.61
Condensate – Bbl	$ 58.74	$ 69.53	$ 75.61	$ 61.80
NGL – Bbl	$ 35.09	$ 33.29	$ 35.69	$ 25.15
Per Boe	$ 36.24	$ 26.37	$ 30.18	$ 26.15

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

On a per-Boe basis, the Company's average realized price for the three months and year ended December 31, 2018 increased by 37% and 15%, respectively, compared to the same periods of 2017.

The increase in average realized price in the fourth quarter of 2018 was primarily driven by an increase in natural gas pricing, most notably from Sumas and Chicago which averaged US$11.09 per Mmbtu and US$3.62 per Mmbtu, respectively, in the fourth quarter of 2018. This increase was partially offset by a decrease in condensate prices. For the year, the increase in Storm's average realized price was driven by gains across all three product streams, most notably condensate and NGL pricing.

Benchmark Prices

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year ended Dec. 31, 2018	Year ended Dec. 31, 2017
Natural gas				
Chicago monthly index (US$/Mmbtu)	3.62	2.92	3.06	3.04
Chicago daily index (US$/Mmbtu)	3.69	2.83	3.02	2.88
Sumas (US$/Mmbtu)	11.09	2.67	4.30	2.62
AECO monthly index (Cdn$/GJ)	1.80	1.85	1.45	2.30
AECO daily index (Cdn$/GJ)	1.48	1.60	1.42	2.04
Station 2 (Cdn$/GJ)	0.64	0.53	1.19	1.48
Crude Oil				
WTI (US$/Bbl)	58.81	55.40	64.77	50.95
Edmonton light oil (Cdn$/Bbl)	42.69	69.02	69.31	62.91
Exchange rate (US$/Cdn$)	0.76	0.79	0.77	0.77

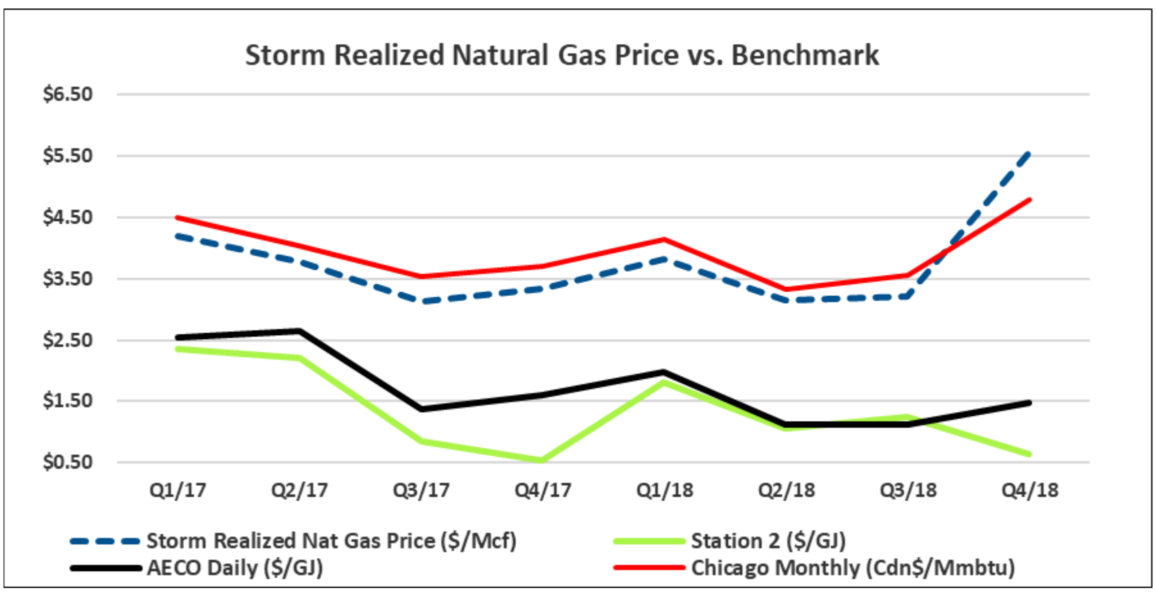
Storm's realized prices differ from market indices due to fluctuations in the foreign exchange rate and the higher heat content of the Company's natural gas will increase the per-Mcf price.

In October 2018, a pipeline rupture occurred on the Enbridge T-south line which reduced pipeline capacity. As a result of the constraints there was, and continues to be, increased volatility in pricing for both Station 2 (lower) and Sumas (higher). The monthly Sumas index price spiked from US$2.25 per Mmbtu in October 2018 to US$17.69 per Mmbtu in December 2018 driving both increased revenue for Storm and increased hedging losses given that approximately 85% of fourth quarter sales at Sumas were previously hedged. Chicago natural gas pricing also improved in the fourth quarter due to weather-related demand.

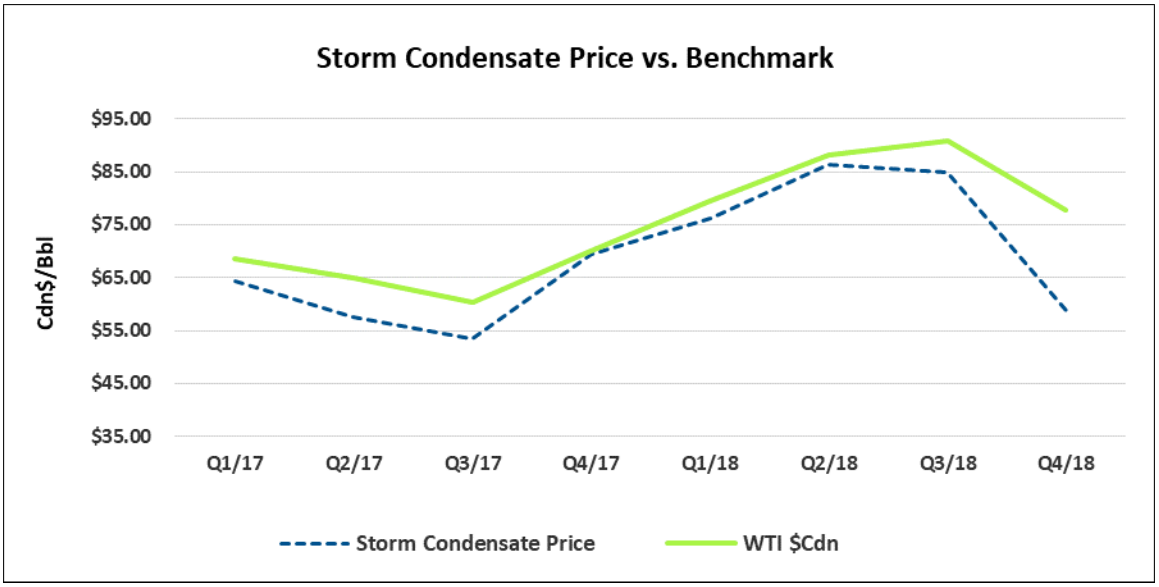
Crude oil pricing, on which a large part of the Company's condensate and NGL revenue is based, declined 15% from US$69.50 per barrel during the third quarter of 2018 to US$58.81 per barrel for the fourth quarter of 2018 due to market concerns over supply outpacing demand. Compounding the decrease in WTI was widening of the condensate differentials, which increased from -US$2.68 per barrel in the third quarter of 2018 to -US$13.52 per barrel for the fourth quarter of 2018.

The Company's production during the fourth quarter and year ended December 31, 2018 was sold as follows:

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year ended Dec. 31, 2018	Year ended Dec. 31, 2017
Chicago monthly index price	35%	45%	38%	45%
Chicago daily index price	28%	25%	25%	21%
AECO daily index price	11%	-	6%	1%
Station 2 daily spot price	10%	24%	14%	28%
Sumas index price	11%	-	12%	-
Alliance Transfer Point ("ATP")	5%	6%	5%	5%
Total	100%	100%	100%	100%



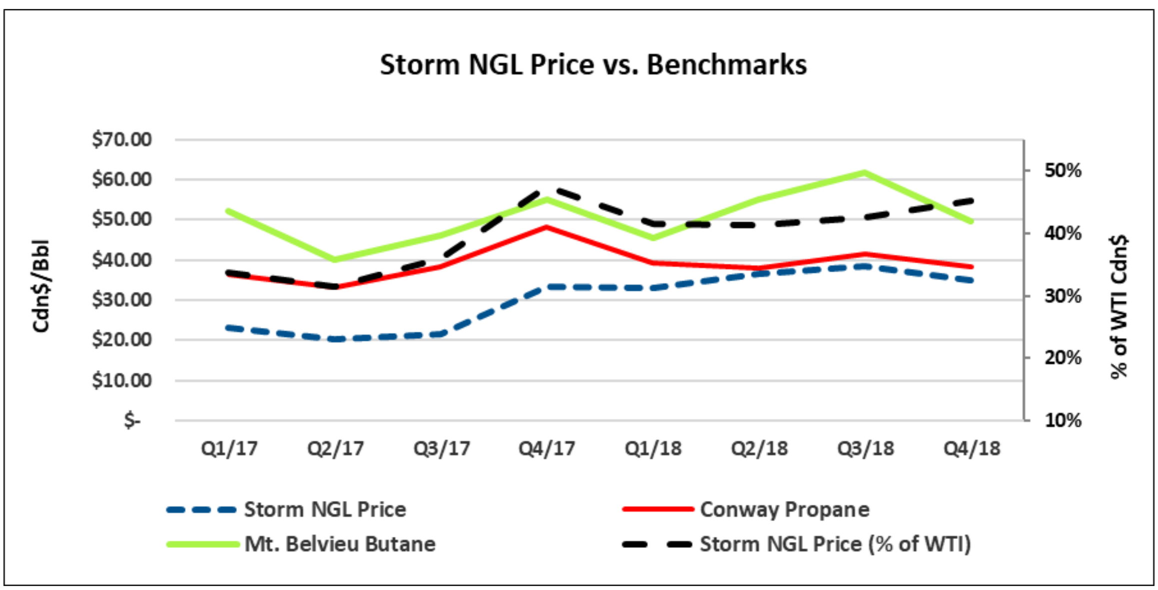
As a result of the Company's diversified marketing strategy, Storm's realized natural gas price was approximately 720% higher than Station 2 pricing in the fourth quarter of 2018 and 220% higher for the year ended December 31, 2018. A significant contributor to the increase in Storm's realized natural gas price to $5.56 per Mcf in the fourth quarter of 2018 was an increase in Sumas and Chicago pricing, which conversely led to increased hedging losses of $1.66 per Mcf as the majority of the Company's hedged volumes are in those markets.



Storm's realized condensate price for the fourth quarter of 2018 decreased by 16% from the fourth quarter of 2017 as a result of the widening of the WTI-condensate differential from -US$2.57 per barrel in the fourth quarter of 2017 to -US$13.52 per barrel in the fourth quarter of 2018.

The widening of the differential was primarily due to pipeline constraints and refinery outages reducing demand for diluent blending, although differentials have since narrowed from the fourth quarter of 2018 with the February 2019 WTI-condensate differential settling at -US$2.39 per barrel.

In 2018, Storm's condensate price increased 22% compared to 2017, as a result of the increase in WTI, partially offset by the widening of the WTI-condensate differential in the fourth quarter of 2018.



Storm's realized price for NGL, excluding condensate, in the fourth quarter of 2018 increased by 5% relative to the same period of 2017. For the year ended December 31, 2018, the realized price for NGL, excluding condensate, increased by 42% year over year. The increase in realized NGL prices for both of the aforementioned periods was primarily due to stronger WTI pricing year over year.

Given elevated supply levels in 2019 for NGL in Western Canada (primarily butane), Storm's NGL price net of transportation is anticipated to be approximately 10% to 15% of WTI in Canadian dollar terms for the next contract period that commences in April 2019 and ends in March 2020. This compares to an average realization of approximately 42% in 2018.

Revenue from Product Sales[1]

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Natural gas	$ 55,973	$ 26,793	$ 146,852	$ 103,434
Condensate	13,256	12,243	59,071	38,015
NGL	5,570	4,471	20,335	11,431
Total	$ 74,799	$ 43,507	$ 226,258	$ 152,880
% of Total Revenue by Product Type				
Natural gas	75%	62%	65%	68%
Condensate and NGL	25%	38%	35%	32%
Total	100%	100%	100%	100%

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

Revenue from product sales for the fourth quarter of 2018 increased by 72% when compared to the fourth quarter of 2017 as a result of the Company's average realized price increasing by 37% and production volumes increasing by 25%. For the year ended December 31, 2018, revenue from product sales increased 48% year over year due to production volumes increasing 28% and the Company's average realized price increasing by 15%.

A reconciliation of year-over-year revenue changes for the three month period ending December 31, 2018 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – Q4 2017	$ 26,793	$ 12,243	$ 4,471	$ 43,507
Effect of changes in production	6,791	3,447	813	11,051
Effect of changes in average product prices	22,389	(2,434)	286	20,241
Revenue from product sales – Q4 2018	$ 55,973	$ 13,256	$ 5,570	$ 74,799

A reconciliation of year-over-year revenue changes for the year ended December 31, 2018 is as follows:

	Natural Gas	Condensate	NGL	Total
Revenue from product sales – 2017	$ 103,434	$ 38,015	$ 11,431	$ 152,880
Effect of changes in production	29,637	10,268	3,782	43,687
Effect of changes in average product prices	13,781	10,788	5,122	29,691
Revenue from product sales – 2018	$ 146,852	$ 59,071	$ 20,335	$ 226,258

Commodity Price Risk Management

	Three Months to Dec. 31, 2018		Three Months to Dec. 31, 2017	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (16,774)	$ (4,212)	$ 1,014	$ 3,744
Liquids[1]	(1,087)	16,497	(329)	(4,551)
Gain (loss) on commodity price contracts	$ (17,861)	$ 12,285	$ 685	$ (807)

	Year Ended Dec. 31, 2018		Year Ended Dec. 31, 2017	
	Realized Gain (Loss)	Unrealized Gain (Loss)	Realized Gain (Loss)	Unrealized Gain (Loss)
Natural gas	$ (14,687)	$ (16,741)	$ (2,597)	$ 25,814
Liquids[1]	(7,990)	10,908	239	(1,187)
Gain (loss) on commodity price contracts	$ (22,677)	$ (5,833)	$ (2,358)	$ 24,627

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

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

The realized gain (loss) on commodity price contracts consists of the portion of contracts that have settled in cash during the reporting period. The realized loss on liquids was largely incurred evenly throughout 2018 given the gradual rise in WTI prices whereas the realized loss on natural gas contracts was primarily isolated to the fourth quarter of 2018 given the significant increase in both Chicago and Sumas pricing in the period.

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

Royalties

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period	$ 1,189	$ 1,046	$ 8,127	$ 6,974
Percentage of revenue from product sales	1.6%	2.4%	3.6%	4.6%
Per Boe	$ 0.58	$ 0.63	$ 1.08	$ 1.19

Royalties, as a percentage of revenue from product sales, in the three months ended December 31, 2018, decreased compared to the same period in 2017 due to applying BC Deep Well Royalty credits and receiving higher infrastructure royalty credits in the fourth quarter of 2018 ($3.9 million in the fourth quarter of 2018 versus $1.2 million in the fourth quarter of 2017) which offset higher royalties due to an increase in natural gas pricing.

Royalties, as a percentage of revenue from product sales, decreased in 2018 compared to 2017 due to higher infrastructure royalty credits received in 2018 ($5.3 million in 2018 versus $1.5 million in 2017). In addition to infrastructure royalty credits, Storm also receives royalty credits on qualifying wells through the BC Deep Well Royalty Credit Program which reduces the royalty rate on new horizontal wells to 6% for approximately two years. In 2018, 37 wells qualified for the 6% royalty rate compared to 35 wells in 2017.

Storm has remaining infrastructure royalty credits of $4.3 million that will reduce future royalties. Future royalty payments are dependent on commodity prices and production levels from individual wells and thus the timing to receive future royalty credits cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary as these credits are earned.

Production Costs

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period	$ 11,270	$ 9,376	$ 41,242	$ 35,283
Per Boe	$ 5.46	$ 5.68	$ 5.50	$ 6.04

The increase in total production costs for the three months and year ended December 31, 2018 when compared to the same periods of 2017 is primarily due to increased production. The percentage increase in production costs is considerably less than the percentage increase in production volumes, indicative of the Company's efforts to reduce per-Boe costs.

Production costs per Boe for the fourth quarter of 2018 decreased by 4% compared to the fourth quarter of 2017 and decreased by 9% when comparing the year ended December 31, 2018 periods. The decreases were due in part to continued production growth thereby reducing the effect of the fixed cost component on per-Boe costs, while on an annual basis the decrease was also affected by the McMahon Gas Plant turnaround in 2017.

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, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period	$ 1,368	$ 1,107	$ 5,217	$ 3,872
Per Boe	$ 0.66	$ 0.67	$ 0.70	$ 0.66

Transportation Costs

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period	$ 11,487	$ 9,797	$ 43,764	$ 34,020
Per Boe	$ 5.57	$ 5.94	$ 5.84	$ 5.82

Transportation costs include pipeline tariffs for natural gas sold at various points, as well as trucking costs and pipeline tariffs for condensate. Transportation costs for the fourth quarter of 2018 increased by 17%, and decreased by 6% per Boe, when compared to the fourth quarter of 2017. Total transportation costs for 2018 increased by 29%, and were flat on a per-Boe basis, when compared to 2017. Higher total transportation costs reflect higher production volumes (year-over-year increase of 25% for the fourth quarter and 28% for the year ended December 31, 2018).

On a per-Boe basis, lower transportation costs for the fourth quarter of 2018 are largely the result of a lower proportion of natural gas sales in Chicago via the Alliance Pipeline which has a higher tariff versus sales at AECO or Station 2 (63% of natural gas sales in Chicago in the fourth quarter of 2018 versus 70% in the fourth quarter of 2017). This was partially offset by higher costs for moving condensate to further sales points.

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

Field Netbacks

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

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

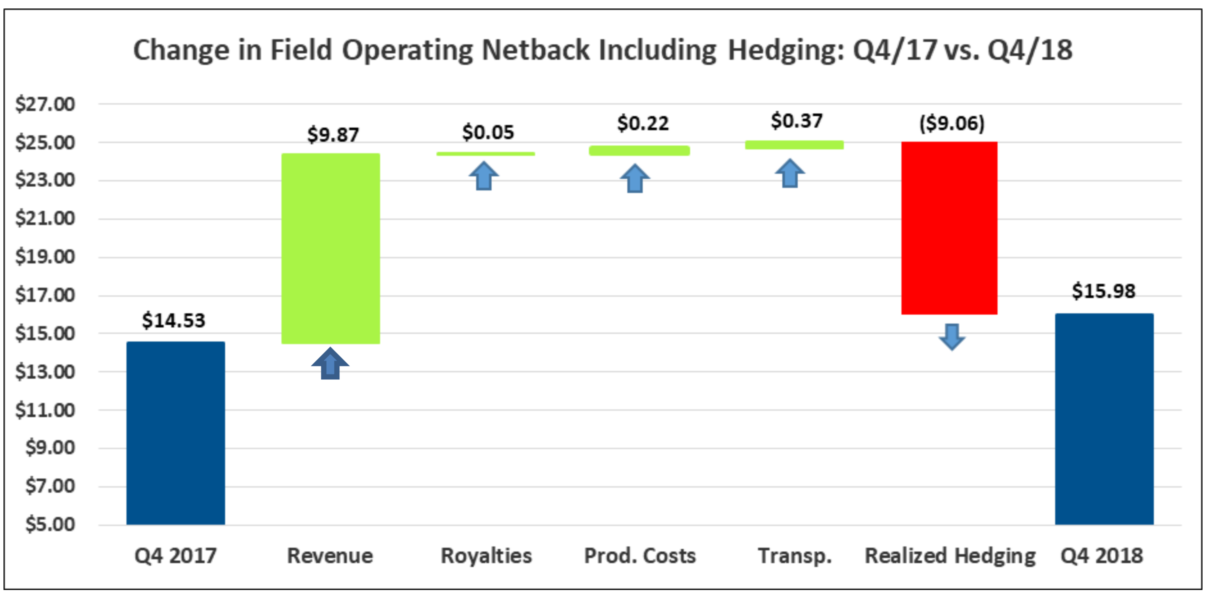
				Three Months Ended December 31, 2017
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.34	$ 69.53	$ 33.29	$ 26.37
Royalties	0.05	(5.96)	(2.99)	(0.63)
Production costs	(1.17)	-	-	(5.68)
Transportation costs	(1.13)	(4.09)	-	(5.94)
Field operating netback	$ 1.09	$ 59.48	$ 30.30	$ 14.12
Realized gain (loss) on commodity price contracts	0.13	(1.87)	-	0.41
Field operating netback including hedging	$ 1.22	$ 57.61	$ 30.30	$ 14.53

	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 commodity price contracts	(0.40)	(10.27)	0.05	(3.03)
Field operating netback including hedging	$ 1.35	$ 53.60	$ 32.45	$ 14.73

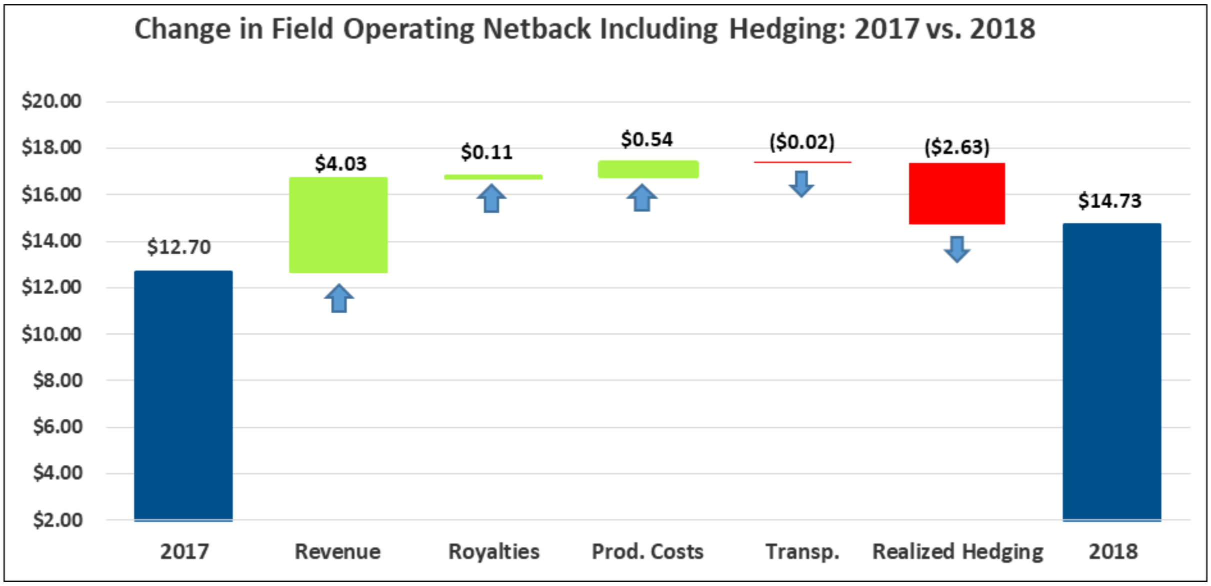
	Year Ended December 31, 2017			
	Natural Gas[1] ($/Mcf)	Condensate[2] ($/Bbl)	NGL ($/Bbl)	Total ($/Boe)
Revenue from product sales	$ 3.61	$ 61.80	$ 25.15	$ 26.15
Royalties	(0.09)	(5.59)	(2.31)	(1.19)
Production costs	(1.23)	-	-	(6.04)
Transportation costs	(1.10)	(4.16)	-	(5.82)
Field operating netback	$ 1.19	$ 52.05	$ 22.84	$ 13.10
Realized gain (loss) on commodity price contracts	(0.09)	0.39	-	(0.40)
Field operating netback including hedging	$ 1.10	$ 52.44	$ 22.84	$ 12.70

(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 2018 increased by 74% (10% increase including hedging) compared to the fourth quarter of 2017.



The 2018 field operating netback increased by 36% (16% increase including hedging) compared to 2017.



General and Administrative Costs

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period – before recoveries	$ 2,061	$ 1,879	$ 8,155	$ 7,442
Overhead recoveries	(933)	(335)	(2,043)	(1,284)
Charge for period – net of recoveries	$ 1,128	$ 1,544	$ 6,112	$ 6,158
Per Boe	$ 0.55	$ 0.94	$ 0.82	$ 1.05

General and administrative costs before recoveries for the three months and year ended December 31, 2018 increased by 10% when compared to the same periods of 2017. The increase in general and administrative costs in 2018 compared to 2017 is largely due to a higher annual performance bonus that was paid in the first quarter of 2018.

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 fell by 41% in the fourth quarter of 2018 compared to the fourth quarter of 2017 and by 22% in 2018 compared to 2017. Generally, the Company's general and administrative cost structure is predictable year to year and per-Boe declines are due to increased production volumes.

Interest and Finance Costs

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period	$ 923	$ 1,105	$ 4,244	$ 4,007
Average interest rate[(1)]	4.6%	4.4%	4.8%	4.4%
Per Boe	$ 0.45	$ 0.67	$ 0.57	$ 0.69

(1) Includes financing and standby fees.

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

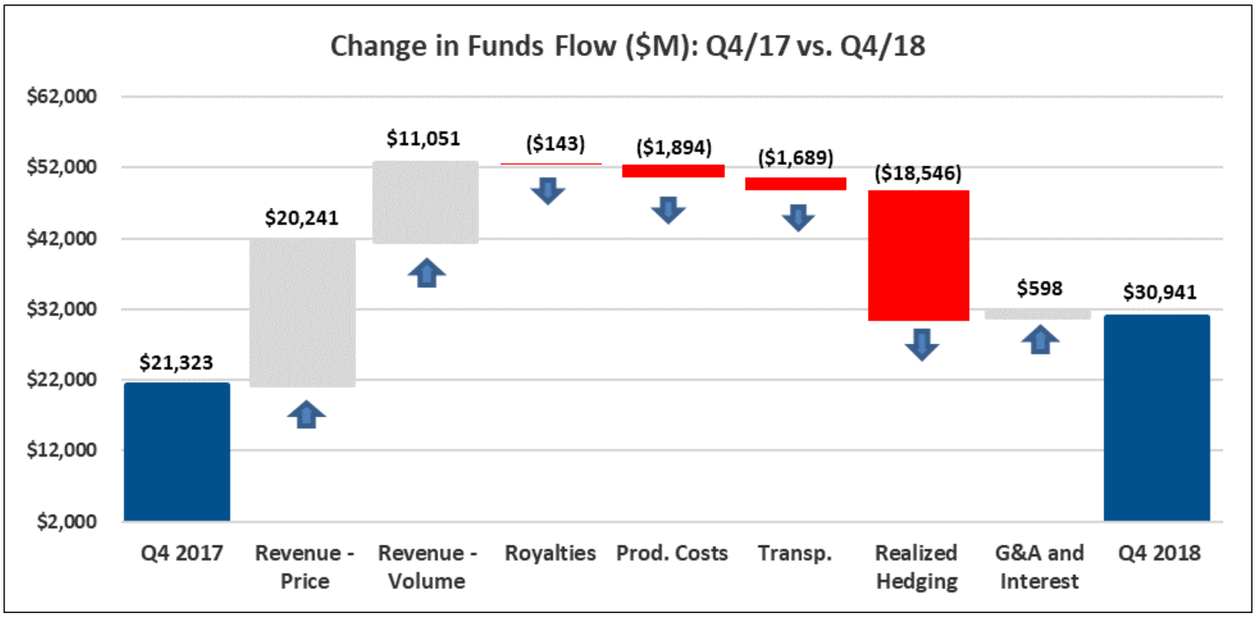
Interest and finance costs in the fourth quarter of 2018 decreased by 16% compared to the fourth quarter of 2017 as a result of a reduction in bank borrowings.

Interest and finance costs in 2018 increased by 6% annually, due to higher interest driven by interest rate increases from the Bank of Canada.

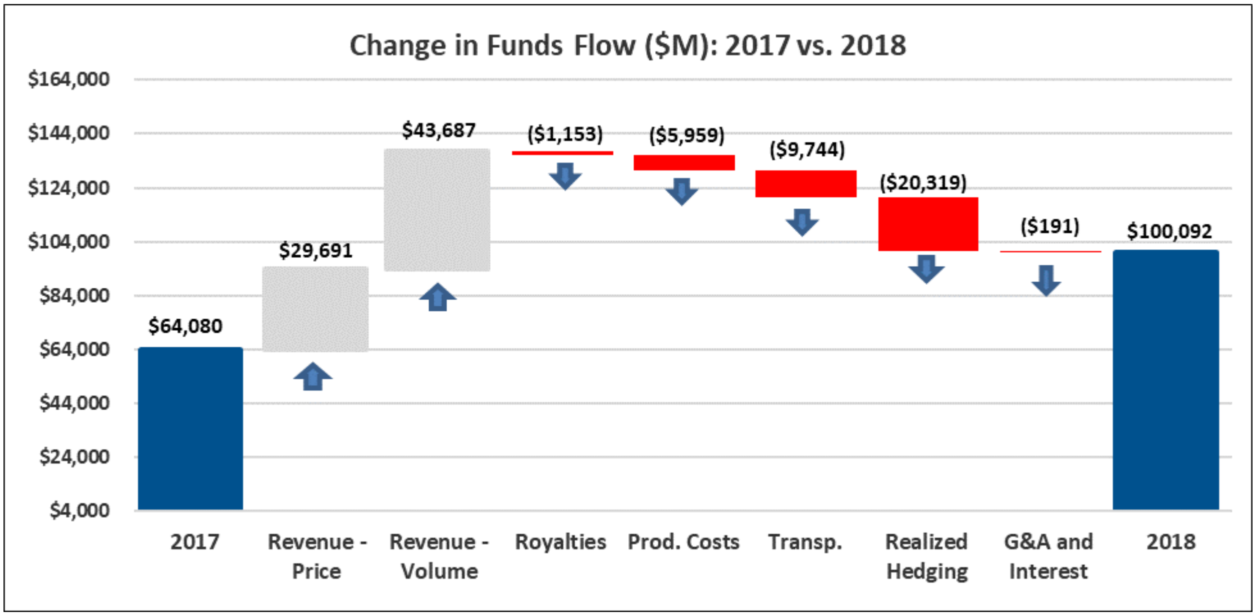
Funds Flow

	Three Months to Dec. 31, 2018	Per diluted share	Three Months to Dec. 31, 2017	Per diluted share	Year Ended Dec. 31, 2018	Per diluted share	Year Ended Dec. 31, 2017	Per diluted share
Funds flow	$30,941	$0.25	$21,323	$0.18	$100,092	$0.82	$64,080	$0.53

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



Production growth and higher realized prices partially offset by a higher realized hedging loss were the predominant factors in funds flow growth of 45% in the fourth quarter of 2018 versus the fourth quarter of 2017.



Funds flow for 2018 increased 56% from 2017. In 2018, funds flow benefitted from both production growth and stronger realized pricing relative to 2017, partially offset by a higher realized hedging loss. The cash return on capital employed ("CROCE"), which is a measurement of the Company's cash profitability as a proportion of the funding utilized to generate it (shareholders' equity plus debt including working capital deficiency), increased from 15% in 2017 to 21% in 2018.

Share-Based Compensation

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period	$ 838	$ 902	$ 3,127	$ 3,816
Per Boe	$ 0.41	$ 0.55	$ 0.42	$ 0.65

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 7% in the fourth quarter of 2018 compared to the same quarter in 2017 and by 18% in 2018 compared to 2017. The decrease in share-based compensation is primarily attributable to a lower option valuation associated with options granted in 2018.

Depletion and Depreciation

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Depletion	$ 9,027	$ 9,285	$ 38,845	$ 38,325
Depreciation	1,772	1,541	6,772	5,904
Charge for period	$ 10,799	$ 10,826	$ 45,617	$ 44,229
Per Boe	$ 5.23	$ 6.56	$ 6.09	$ 7.57

Depletion and depreciation in the fourth quarter of 2018 was in line with the same quarter of 2017 due to a 25% increase in production volumes being offset by lower finding and development costs. Comparing 2018 to 2017, depletion and depreciation increased by 3% as a result of a 28% increase in production volumes which was partially offset by lower finding and development costs. The quarterly and year ended December 31, 2018 per-Boe decreases in depletion correspond to lower finding and development costs at Umbach.

Accretion

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Charge for period	$ 133	$ 128	$ 517	$ 454
Per Boe	$ 0.06	$ 0.08	$ 0.07	$ 0.08

Accretion represents the time value increase for each reporting period for the Company's decommissioning liability. The higher charge for accretion in 2018 compared to 2017 is due to obligations incurred in the year and changes in estimates over the course of the year, including changes to inflation rates, discount rates and estimated settlement dates.

Income Taxes

The Company did not incur any cash tax expense in the three months and year ended December 31, 2018, nor does it expect to pay any cash tax in 2019 or 2020 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

Deferred income taxes arise from differences between the accounting and tax bases of our assets and liabilities. For the three months and year ended December 31, 2018, the Company recognized a deferred income tax expense of $4.4 million as a result of $44.5 million of net income before taxes. As at December 31, 2018, the Corporation had a deferred income tax liability of $4.4 million.

For the year-end December 31, 2017, Storm was in a net deferred tax asset position. Due to uncertainty of realization, no deferred income tax asset was recognized/recorded in the prior year.

Tax Pools	As at December 31, 2018	Maximum Annual Deduction
Canadian oil and gas property expense	$ 46,000	10%
Canadian development expense	124,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	106,000	20% – 100%
Operating losses	164,000	100%
Other	1,000	20% – 100%
Total	$ 464,000	

Net Income

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Net income	$ 26,810	$ 8,624	$ 40,063	$ 39,689
Per basic and diluted share	$ 0.22	$ 0.07	$ 0.33	$ 0.33

The mark-to-market valuation of commodity price contracts resulted in a considerable distortion to the reported net income for both the three months and year ended December 31, 2018 relative to the same periods in 2017. The unrealized gain on commodity price contracts for the three months ended December 31, 2018 was $12.3 million compared to an unrealized loss of $0.8 million for the three months ended December 31, 2017. The unrealized loss on commodity price contracts for 2018 was $5.8 million compared to an unrealized gain of $24.6 million for 2017.

Excluding unrealized gains and losses on commodity price contracts, the increase in net income in the three months and year ended December 31, 2018 compared to the same periods of 2017 is primarily attributable to increased production levels and an improved pricing environment driving increased revenue.

The return on capital employed ("ROCE"), 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 flat year over year at 10% in both 2018 and 2017, although as mentioned above is distorted by unrealized gains and losses on the Company's commodity price contracts.

Corporate Netbacks

($/Boe)	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Revenue from product sales	36.24	26.37	30.18	26.15
Realized gain (loss) on commodity price contracts	(8.65)	0.41	(3.03)	(0.40)
Royalties	(0.58)	(0.63)	(1.08)	(1.19)
Production	(5.46)	(5.68)	(5.50)	(6.04)
Transportation	(5.57)	(5.94)	(5.84)	(5.82)
General and administrative	(0.55)	(0.94)	(0.82)	(1.05)
Interest and finance costs	(0.45)	(0.67)	(0.57)	(0.69)
Funds flow	14.98	12.92	13.34	10.96
Share-based compensation	(0.41)	(0.55)	(0.42)	(0.65)
Depletion, depreciation and accretion	(5.29)	(6.64)	(6.16)	(7.65)
Exploration and evaluation costs expensed	-	(0.01)	(0.04)	(0.07)
Unrealized revaluation gain (loss) on investments	(0.11)	(0.01)	(0.03)	(0.02)
Unrealized gain (loss) on commodity price contracts	5.96	(0.49)	(0.78)	4.21
Deferred income tax expense	(2.15)	-	(0.59)	-
Net income	12.98	5.22	5.32	6.78

INVESTMENT AND FINANCING

Financial Resources and Liquidity

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

At December 31, 2018, the Company was in compliance with all covenants under the credit facility; the sole financial covenant is that debt including working capital deficiency cannot exceed the credit facility limit. At December 31, 2018, debt including working capital deficiency amounted to $91.0 million, representing 53% of the available credit facility.

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

Capital Expenditures

In the fourth quarter of 2018, the Company incurred capital expenditures of $37.1 million compared to $26.1 million in the fourth quarter of 2017.

During 2018, the Company incurred capital expenditures of $84.8 million (2017 - $81.7 million) primarily related to drilling 4.0 horizontal wells, completing 11.0 (10.5 net) horizontal wells, building a pipeline to the Nig land block, installing additional compression at Umbach and for deposits on long-lead-time equipment for the sour gas plant at Nig.

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Land and seismic	$ 1,043	$ 765	$ 3,846	$ 1,844
Drilling	14,613	13,329	14,902	31,329
Completions	10,664	8,055	30,517	28,537
Facilities	8,859	858	19,552	6,352
Equipping and pipelines	1,766	2,943	14,365	12,175
Recompletions and workovers	131	172	903	1,434
Property acquisition and administrative assets	24	4	678	14
Total capital expenditures	$ 37,100	$ 26,126	$ 84,763	$ 81,685

Net capital investment was allocated as follows:

	Three Months to Dec. 31, 2018	Three Months to Dec. 31, 2017	Year Ended Dec. 31, 2018	Year Ended Dec. 31, 2017
Exploration and evaluation	$ 1,043	$ 765	$ 4,034	$ 1,838
Property and equipment	36,057	25,361	80,729	79,847
Total capital expenditures	$ 37,100	$ 26,126	$ 84,763	$ 81,685

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, 2018 corresponds to the active field program at Umbach.

Decommissioning Liability

The Company's decommissioning liability of $26.3 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 amount of the liability at December 31, 2018 was $43.2 million (December 31, 2017 - $36.3 million).

Share Capital

Details of share issuances from inception to December 31, 2018 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

		Number of Shares (000s)	Price per Share	Gross Proceeds[(1)] ($000s)
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		121,557	$ 3.26	$ 395,930

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

During 2017, stock options were exercised at an average price of $1.83 per optioned share and 793,000 common shares were issued for proceeds of $1,456,000. There were no stock options exercised in 2018.

Issued and outstanding common shares at December 31, 2018 and at February 28, 2019, 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 accommodation, office equipment and automotive equipment;
- banking agreements; and
- commodity price contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018. The aggregate commitment approximates $6.0 million over seven years. In addition, as at the date of this report, the Company has transportation and processing commitments valued at a total of approximately $384.7 million.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended December 31, 2018 appears below. During the second half of 2016, pricing for the Company's commodities began to improve, enabling the Company to implement a larger capital expenditure program in the fourth quarter of 2016 which increased production in the first quarter of 2017 as new wells were turned on. While the first and fourth quarters of 2017 saw a normalized level of capital expenditures, production and funds flow, the second and third quarters of 2017 were affected by a planned maintenance turnaround at the McMahon Gas Plant in June that involved an unanticipated extension into July, which affected revenue and funds flow.

Apart from minimal capital expenditures in the second quarter of 2018, the 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.

($000s unless otherwise stated)	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Revenue from product sales	74,799	51,253	48,104	52,102	43,506	31,719	33,262	44,392
Funds flow	30,941	22,227	23,405	23,519	21,323	13,170	11,629	17,958
Per share – basic and diluted ($)	0.25	0.18	0.19	0.19	0.18	0.11	0.10	0.15
Net income (loss)	26,810	7,174	(2,815)	8,894	8,624	682	9,752	20,631
Per share – basic and diluted ($)	0.22	0.06	(0.02)	0.07	0.07	0.01	0.08	0.17
Net capital expenditures	37,100	21,845	2,918	22,900	26,126	23,895	4,307	27,357
Average daily production (Boe)	22,432	20,455	19,529	19,708	17,936	15,193	13,991	16,947
Debt including working capital deficiency(1)	91,020	84,648	85,073	105,585	106,124	101,297	90,582	97,864

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

SELECTED ANNUAL FINANCIAL INFORMATION

($000s unless otherwise stated)	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Revenue from product sales	226,258	152,880	103,014
Funds flow	100,092	64,080	34,380
Per share – basic and diluted ($)	0.82	0.53	0.29
Net income (loss)	40,063	39,689	(38,460)
Per share – basic and diluted ($)	0.33	0.33	(0.32)
Total assets	565,534	515,563	465,617
Debt including working capital deficiency(1)	91,020	106,124	89,841
Average daily production (Boe)	20,538	16,017	13,219
Funds flow ($/Boe)	13.34	10.96	7.10

(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, the cornerstone of which is capital investment discipline and growing asset value on a per-share basis. Storm has achieved strong production growth over the last three years, despite a volatile commodity price environment, which has resulted in funds flow growth year over year. This is reflective of the Company's diversified marketing strategy whereby a significant portion of the Company's production base receives US based pricing. Prudent capital spending has enabled the Company to increase funds flow 191% in 2018 from 2016 while debt only increased by 1% over the same period. Net income has also been affected by higher funds flow, although is subject to a high degree of variability due to unrealized gains and losses on commodity price contracts. The Company reported a $5.8 million unrealized loss on commodity price contracts for the year ended December 31, 2018, an unrealized gain on commodity price contracts of $24.6 million for the year ended December 31, 2017 and an unrealized loss on commodity price contracts of $30.1 million for the year ended December 31, 2016.

The increase in the Company's total assets reflects the ongoing development of the Company's Montney play at Umbach. Capital expenditures in 2018 primarily included drilling, completions and infrastructure expenditures. While 2017 capital expenditures were largely directed to drilling and completions, a significant driver of capital expenditures in 2016 was the decision to accelerate construction of a third field compression facility in the second half of the year, adding expenditures of $18.8 million in 2016. This investment increased Storm's compression capacity by more than one-third and resulted in a considerable increase in production in 2017. This third field compression facility was twinned in 2018 at a cost of approximately $7 million and will support growth of corporate production to approximately 27,000 Boe per day.

Share Trading

Set out below is share trading activity for Storm for 2018 and 2017.

	2018					2017				
	Q1	Q2	Q3	Q4	Year	Q1	Q2	Q3	Q4	Year
High ($)	2.86	3.30	3.24	3.16	3.30	5.33	4.64	4.17	3.76	5.33
Low ($)	1.75	1.99	2.30	1.43	1.43	3.60	3.60	3.25	2.41	2.41
Close ($)	2.10	3.12	2.74	1.74	1.74	4.15	4.20	3.54	2.70	2.70
Volume traded (000s)	5,971	8,077	3,464	5,666	23,178	6,461	6,576	3,539	5,030	21,606
Value traded ($000s)	12,727	22,612	9,891	11,930	57,160	27,831	26,342	12,941	14,931	82,045
Weighted average trading price ($)	2.13	2.80	2.86	2.11	2.47	4.31	4.01	3.66	2.97	3.80

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, 2018 and 2017 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.

Commodity Price 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 28, 2019 press release, contains forward-looking information (within the meaning of applicable Canadian securities legislation). Such statements or information are generally identifiable by words such as "anticipate", "believe", "intend", "plan", "expect", "estimate", "budget", "outlook", "forecast" or other similar words and include statements relating to or associated with individual or groups of wells, facilities, regions or projects as well as timing of any future event which may have an effect on the Company's operations or financial position. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices in each market in which production is sold including prices as outlined in 2019 guidance;
- future average production volumes in the fourth quarter of 2019 and annual production for 2019, along with production volumes by commodity and production declines;
- future revenues and production costs (including royalties) and revenues and production costs per commodity unit as outlined in 2019 guidance;
- future reduction to corporate operating costs to approximately $4.25 per Boe with the start-up of the Nig sour gas plant, along with the forecast operating cost for the Nig gas plant of $2.00 per Boe and incremental production of approximately 1,500 Boe per day;
- future value of unrealized commodity price contracts including the estimated hedging loss as outlined in 2019 guidance;
- future capital expenditures and their allocation to specific projects, activities or periods as outlined in the 2019 capital expenditure program including 2019 capital investment of $128 million ($18 million at Umbach, $95 million at Nig and $15 million at Fireweed) and total cost of approximately $81 million for the Nig sour gas plant;
- forecasted maintenance capital in 2019 of $10 million to maintain production levels of 20,000 to 21,000 Boe per day;
- first quarter 2019 production of 17,500 to 20,000 Boe per day and second and third quarter 2019 production of 20,000 to 21,000 Boe per day;
- future expansion plans at Fireweed including expansion of the compression facility to 100 Mmcf per day, and preliminary planning for 2020 net capital expenditures of $50 million;
- future growth plans through 2020 including timing for the start-up of the Nig sour gas plant and the Fireweed field compression facility;
- future cost of the Fireweed compression facility of $34 million along with field condensate-gas ratios that are forecast to be significantly higher than Umbach;
- future production levels of 25,000 Boe per day (18% liquids) by the end of 2019 and more than 30,000 Boe per day (21% liquids) by the end of 2020;
- future facility access, acquisition, construction and entry in service and timing thereof;
- future earnings or losses, including per-share amounts;

- future funds flow, including the amounts outlined in 2019 guidance and per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- future sources of funding for capital expenditure programs and future availability of such sources;
- drilling rigs, field service providers and completion and tie-in equipment being available as required, with costs of securing these services not materially exceeding expectations;
- development plans for Storm's properties;
- estimates regarding the carrying amount of exploration and evaluation assets;
- estimates regarding the carrying amount of property and equipment;
- considerations regarding asset impairment;
- future levels of debt including working capital deficiency;
- availability and use of credit facilities including approximately $80 million of unused credit capacity at year end;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future amounts and use of tax pools and losses along with the expectation to not pay any cash tax in 2019 or 2020;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from drilling longer wells, specifically management's estimated 11 Bcf raw gas type curve for new wells and further improvements on this given future wells with lengths of 2,300 to 2,400 metres;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future transportation, general and administrative and interest costs in total and by commodity unit as outlined in 2019 guidance;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas, condensate and NGL, specifically the anticipated sales allocation in 2019 to Chicago, Sumas, Station 2 and AECO markets and the forecasted NGL price net of transport being approximately 10% to 15% of WTI in Cdn$ for the next contract period from April 2019 to March 2020;
- future provisions for depletion and depreciation and accretion;
- future share-based compensation charges;
- future interest rates and interest and financing costs;
- estimates on a per-share basis and per-Boe basis;
- dates or time periods by which wells will be drilled, completed and tied in, facility and pipeline construction completed and brought into service, geographical areas developed, facilities and pipelines accessed;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- effect of existing or future contractual obligations;
- references to the intentions of management or the Company; and
- changes to any of the foregoing.

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

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

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

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

Field Operating Netbacks

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

Debt Including Working Capital Deficiency

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

($000s unless otherwise stated)	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
Accounts receivable	29,262	15,104	13,199
Prepaids and deposits	853	4,542	1,176
Less: Accounts payable and accrued liabilities	(34,359)	(24,777)	(25,382)
Working capital deficiency	4,244	5,131	11,007
Bank indebtedness	86,776	100,993	78,834
Debt including working capital deficiency	91,020	106,124	89,841

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 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, 2018	Year Ended December 31, 2017
Average debt including working capital deficiency[(1)]	98,572	97,983
Average shareholders' equity[(1)]	386,336	342,261
Average capital employed	484,908	440,244
Funds flow	100,092	64,080
Interest and finance costs	4,244	4,007
Funds flow plus interest and finance costs	104,336	68,087
CROCE	21%	15%

(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 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, 2018	Year Ended December 31, 2017
Average debt including working capital deficiency[(1)]	98,572	97,983
Average shareholders' equity [(1)]	386,336	342,261
Average capital employed	484,908	440,244
Net income	40,063	39,689
Interest and finance costs	4,244	4,007
Deferred income tax expense	4,433	-
	48,740	43,696
ROCE	10%	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 commodity price 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 commodity price 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 oil field 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, 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 commodity price 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 period of 17 days in January 2019 due to a failure on flare system piping. 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 2018 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.
- Commodity price 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 102 Mmcf per day of natural gas sales volumes in the first quarter of 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 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 and 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 April 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 upon ratification by the legislature of each country. 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 9 *Financial Instruments*

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

IFRS 15 Revenue from Contracts with Customers

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

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

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

The Company reviewed its various revenue streams and underlying contracts with customers and concluded that the adoption of the new standard required presentation changes in revenue and transportation that did not affect net income or funds flow. In addition, Storm has expanded the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type. Additional disclosure as required under IFRS 15 can be found in Note 9.

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

	Three Months Ended December 31, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 34,844	$ 8,663	$ 43,507
Transportation	$ 1,134	$ 8,663	$ 9,797
Net income and comprehensive income for the period	$ 8,624	-	$ 8,624

	Year Ended December 31, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 123,306	$ 29,574	$ 152,880
Transportation	$ 4,446	$ 29,574	$ 34,020
Net income and comprehensive income for the period	$ 39,689	-	$ 39,689

Future Accounting Policy Changes

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

- Certain leases with a remaining term of less than 12 months at January 1, 2019 will be recognized as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value;
- Short-term leases and leases of low-value assets that have been identified at January 1, 2019 will not be recognized in the consolidated statement of financial position. Payments for these leases will be disclosed in the notes to the financial statements.

As of December 31, 2018, the Company has completed a detailed assessment on the potential effect of the adoption of IFRS 16 on its financial statements. The Company will adopt IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard will result in the recognition of right-of-use assets with a corresponding increase to lease obligations. Based on the assessment to date, the estimated right-of-use assets to be recorded on the consolidated statement of financial position are anticipated to be less than 1% of total assets as at December 31, 2018. The right-of-use assets will be measured at amounts equal to the lease obligations. The right-of-use assets and lease obligations to be recognized primarily relate to the Company's office lease in Calgary.

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, 2018.

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, 2018. 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, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

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

ADDITIONAL INFORMATION

Additional information relating to the Company can be viewed at www.sedar.com or on the Company’s website at www.stormresourcesltd.com. Information can also be obtained by contacting the Company at Storm Resources Ltd., Suite 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4.

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 28, 2019

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 (the Company), which comprise the consolidated statements of financial position as at December 31, 2018 and 2017, 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 the Company as at December 31, 2018 and 2017, 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 the Company 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 Annual 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 and the Annual Report 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.

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 the Company'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 the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company'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 the Company'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 the Company'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 the Company 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.

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 28, 2019

Consolidated Statements of Financial Position

(Canadian $000s)	December 31, 2018	December 31, 2017
ASSETS		
Current		
Accounts receivable (Note 15)	$ 29,262	$ 15,104
Prepaids and deposits	853	4,542
Fair value of commodity price contracts (Note 15)	2,341	2,842
	32,456	22,488
Fair value of commodity price contracts (Note 15)	-	209
Exploration and evaluation (Note 6)	102,277	103,907
Property and equipment (Note 7)	430,801	388,959
	$ 565,534	$ 515,563
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 34,359	$ 24,777
Fair value of commodity price contracts (Note 15)	3,521	478
	37,880	25,255
Bank indebtedness (Note 8)	86,776	100,993
Fair value of commodity price contracts (Note 15)	2,180	100
Decommissioning liability (Note 10)	26,334	24,474
Deferred income taxes (Note 11)	4,433	-
	157,603	150,822
Shareholders' equity		
Share capital (Note 12)	391,444	391,444
Contributed surplus (Note 13)	15,141	12,014
Retained earnings (deficit)	1,346	(38,717)
	407,931	364,741
Commitments (Note 19)		
	$ 565,534	$ 515,563

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)	Year Ended December 31, 2018	Year Ended December 31, 2017
Revenue		
Revenue from product sales (Note 9)	$ 226,258	$ 152,880
Royalties	(8,127)	(6,974)
Net revenue	$ 218,131	$ 145,906
Realized gain (loss) on commodity price contracts (Note 15)	(22,677)	(2,358)
Unrealized gain (loss) on commodity price contracts (Note 15)	(5,833)	24,627
Net revenue and commodity price contracts	$ 189,621	$ 168,175
Expenses		
Production	41,242	35,283
Transportation	43,764	34,020
General and administrative	6,112	6,158
Share-based compensation (Note 13)	3,127	3,816
Depletion and depreciation (Note 7)	45,617	44,229
Exploration and evaluation costs expensed (Note 6)	277	386
Accretion (Note 10)	517	454
Interest and finance costs	4,244	4,007
Unrealized revaluation loss on investment	225	133
Total expenses	145,125	128,486
Net income before taxes	44,496	39,689
Deferred income tax expense (Note 11)	4,433	-
Net income and comprehensive income for the year	$ 40,063	$ 39,689
Net income per share (Note 14)		
- Basic and diluted	$ 0.33	$ 0.33

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s)			Year Ended December 31, 2018	
	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 (Note 13)	-	3,127	-	3,127
Balance, end of year	$ 391,444	$ 15,141	$ 1,346	$ 407,931

(Canadian $000s)			Year Ended December 31, 2017	
	Share Capital	Contributed Surplus	Deficit	Total Equity
Balance, beginning of year	$ 389,316	$ 8,870	$ (78,406)	$ 319,780
Net income for the year	-	-	39,689	39,689
Issue of common shares (Note 12)	1,456	-	-	1,456
Share-based compensation (Note 13)	-	3,816	-	3,816
Share-based compensation on options exercised (Note 12)	672	(672)	-	-
Balance, end of year	$ 391,444	$ 12,014	$ (38,717)	$ 364,741

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

(Canadian $000s)	Year Ended December 31, 2018	Year Ended December 31, 2017
Operating activities		
Net income for the year	$ 40,063	$ 39,689
Non-cash items:		
Unrealized (gain) loss on commodity price contracts (Note 15)	5,833	(24,627)
Depletion, depreciation and accretion (Notes 7 and 10)	46,134	44,683
Share-based compensation (Note 13)	3,127	3,816
Exploration and evaluation costs expensed (Note 6)	277	386
Unrealized revaluation loss on investment	225	133
Deferred income tax expense (Note 11)	4,433	-
Funds flow	100,092	64,080
Net change in non-cash working capital items (Note 18)	(7,851)	(331)
	92,241	63,749
Financing activities		
Proceeds from issue of common shares (Note 12)	-	1,456
Increase (decrease) in bank indebtedness	(14,217)	22,159
	(14,217)	23,615
Investing activities		
Additions to property and equipment (Note 7)	(80,729)	(79,847)
Additions to exploration and evaluation assets (Note 6)	(4,034)	(1,838)
Net change in non-cash working capital items (Note 18)	6,739	(5,679)
	(78,024)	(87,364)
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, 2018 and 2017

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 28, 2019.

Basis of Measurement

The Company’s financial statements have been prepared on a going concern basis consistent with prior years, and follow the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 15.

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.

At each reporting date, E&E assets are reviewed for indicators of impairment and, if circumstances suggest that the carrying amount of a particular area exceeds its recoverable amount, the associated cost is written down to its estimated recoverable amount and the difference is accounted for as impairment expense on the consolidated statement of income. If, at any time, it is determined that the Company has no future exploitation plans and commercial production cannot be achieved in relation to an area, the associated costs are written down to the estimated recoverable amount or fully de-recognized and the amount of the write-down is expensed on the consolidated statement of income.

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 and probable reserves, taking into account the future development costs required to produce the reserves.

Year-end proved and 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 and probable reserves, that affect the unit-of-production calculations, do not give rise to prior year adjustments and are dealt with prospectively. Proved and 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

The carrying amounts of P&E are reviewed 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, P&E 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"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs of disposal. 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 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.

Leases

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.

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 commodity price 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.

Commodity price contracts

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

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.

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.

4. NEW ACCOUNTING POLICIES

Changes in Accounting Policies

IFRS 9 *Financial Instruments*

On January 1, 2018, the Company retrospectively adopted IFRS 9 *Financial Instruments*, which replaces IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard uses a principle-based approach for the classification and measurement of financial assets: amortized cost and fair value. Additional amendments include a single "expected credit loss" impairment method and a substantially reformed approach to hedge accounting. Prior to the adoption of IFRS 9, the Company did not apply hedge accounting to its commodity price contracts and there was no change to this approach with adoption of IFRS 9. IFRS 9 contains three principal categories for financial assets: measured at amortized cost, fair value through other comprehensive income and fair value through profit and loss. The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. The adoption of IFRS 9 resulted in a change in classification of the Company's financial assets, which primarily consist of accounts receivable and commodity price contracts. The expected credit loss model applies to the Company's accounts receivable. As at December 31, 2018, 100% of the Company's accounts receivable was outstanding for less than 60 days. The adoption of IFRS 9 did not result in any material change to the valuation of the Company's financial assets.

The following table summarizes the change in classification categories for the Company's financial assets and liabilities.

	IAS 39	IFRS 9
Financial Assets		
Accounts receivable	Loans and receivables (amortized cost)	Amortized cost
Commodity price contracts	Held-for-trading (FVTPL)	FVTPL
Financial Liabilities		
Accounts payable and accrued liabilities	Other financial liabilities (amortized cost)	Amortized cost
Commodity price contracts	Held-for-trading (FVTPL)	FVTPL
Bank indebtedness	Other financial liabilities (amortized cost)	Amortized cost

IFRS 15 Revenue from Contracts with Customers

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

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

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

The Company reviewed its various revenue streams and underlying contracts with customers and concluded that the adoption of the new standard required presentation changes in revenue and transportation that did not affect net income or funds flow. In addition, Storm has expanded the disclosures in the notes to its financial statements as outlined in IFRS 15, including disclosing disaggregated revenue streams by product type. Additional disclosure as required under IFRS 15 can be found in Note 9.

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

	Year Ended December 31, 2017		
	As previously reported prior to adoption of IFRS 15	Transportation expense reclassified	Adjusted balances upon adoption of IFRS 15
Revenue from product sales	$ 123,306	$ 29,574	$ 152,880
Transportation	$ 4,446	$ 29,574	$ 34,020
Net income and comprehensive income for the period	$ 39,689	-	$ 39,689

Future Accounting Policy Changes

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

- Certain leases with a remaining term of less than 12 months at January 1, 2019 will be recognized as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a lower dollar value;
- Short-term leases and leases of low-value assets that have been identified at January 1, 2019 will not be recognized in the consolidated statement of financial position. Payments for these leases will be disclosed in the notes to the financial statements.

As of December 31, 2018, the Company has completed a detailed assessment on the potential effect of the adoption of IFRS 16 on its financial statements. The Company will adopt IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard will result in the recognition of right-of-use assets with a corresponding increase to lease obligations. Based on the assessment to date, the estimated right-of-use assets to be recorded on the consolidated statement of financial position are anticipated to be less than 1% of total assets as at

December 31, 2018. The right-of-use assets will be measured at amounts equal to the lease obligations. The right-of-use assets and lease obligations to be recognized primarily relate to the Company's office lease in Calgary.

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. An impairment assessment is completed when the costs of E&E assets are transferred to P&E. In the event an impairment provision is identified, the carrying amount of E&E assets is reduced with the amount of the reduction being included in the consolidated statement of income.

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 and probable reserves.

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, 2018 and 2017 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, 2018	Year Ended December 31, 2017
Balance, beginning of year	$ 103,907	$ 110,395
Additions	4,034	1,838
Expiries - exploration and evaluation costs expensed	(277)	(386)
Future decommissioning costs	370	192
Transfer to property and equipment	(5,757)	(8,132)
Balance, end of year	$ 102,277	$ 103,907

For the year ended December 31, 2018, 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, 2018, management reviewed the carrying amounts of the remaining assets in E&E for indicators of impairment and concluded that there are no indicators of potential impairment.

7. PROPERTY AND EQUIPMENT

	Year Ended December 31, 2018	Year Ended December 31, 2017
Cost		
Balance, beginning of year	$ 559,524	$ 466,700
Additions	80,729	79,847
Future decommissioning costs	973	4,845
Transfer from exploration and evaluation assets	5,757	8,132
Balance, end of year	$ 646,983	$ 559,524
Accumulated depletion and depreciation		
Balance, beginning of year	$ (170,565)	$ (126,336)
Depletion and depreciation	(45,617)	(44,229)
Balance, end of year	$ (216,182)	$ (170,565)
Net book value, beginning of year	$ 388,959	$ 340,364
Net book value, end of year	$ 430,801	$ 388,959

Future capital costs required to developed proved and probable reserves in the amount of $538.9 million (December 31, 2017 - $481.1 million) are included in the depletion calculation. As at December 31, 2018, the balance of assets under construction not subject to depreciation or depletion was $11.4 million (December 31, 2017 - nil) and relate to the construction of a gas plant.

Impairment Assessment and Testing

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. At December 31, 2018, 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 whereby approximately 75% of natural gas is sold at NYMEX-based pricing (Chicago and Sumas).

An impairment is recognized if the carrying value of a CGU exceeds the recoverable amount for that CGU. 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, 2018, 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.

	2019	2020	2021	2022	2023	2024	2025(1)
WTI Cushing Oklahoma (US$/Bbl)	57.00	64.00	68.00	71.00	72.80	74.50	76.50
NYMEX Henry Hub (US$/Mmbtu)	3.00	3.15	3.35	3.50	3.62	3.70	3.78
AECO-C Spot (Cdn$/Mmbtu)	1.90	2.29	2.71	3.03	3.21	3.33	3.44
Station 2 (Cdn$/Mmbtu)	1.43	1.97	2.46	2.78	2.96	3.08	3.19
Exchange rate (US$/Cdn$)	0.76	0.78	0.80	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, 2018, including long-term forecasts of commodity prices, inflation rates and foreign exchange rates (Level 3 fair value inputs). 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, 2018 was 12%. 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, 2018.

As at December 31, 2018, the Company determined that there was no impairment to P&E.

8. BANK INDEBTEDNESS

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

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

9. REVENUE FROM PRODUCT SALES

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Natural gas	$ 146,852	$ 103,434
Condensate	59,071	38,015
NGL	20,335	11,431
Total	$ 226,258	$ 152,880

Storm’s revenue was generated mostly in British Columbia where the production was sold primarily to one major marketer, which accounted for 56% of the Company’s total revenue from product sales for the year ended December 31, 2018. The majority of revenues are derived from variable price contracts based on index prices. Of total natural gas revenue for 2018, 63% received Chicago index based pricing, 14% received Station 2 pricing, 12% received Sumas pricing, 6% received AECO pricing and the remaining 5% received ATP pricing.

10. 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 undiscounted amount required to settle the Company's decommissioning obligation is approximately $43.2 million (December 31, 2017 - $36.3 million), with the majority of payments being made in the years 2034 to 2053. A risk-free discount rate of 2.2% (December 31, 2017 – 2.2%) and an inflation rate of 2.0% (December 31, 2017 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $26.3 million at December 31, 2018. There are currently no material decommissioning costs expected to be incurred within the next five years.

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Balance, beginning of year	$ 24,474	$ 18,983
Obligations incurred	1,406	3,028
Obligations settled	(242)	-
Change in estimates[(1)]	179	2,009
Accretion expense	517	454
Balance, end of year	$ 26,334	$ 24,474

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

11. 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, commodity price 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, P&E and share-issue costs of approximately $300.1 million as well as non-capital losses of approximately $164.2 million. The non-capital losses begin to expire in 2026.

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, 2018	Year Ended December 31, 2017
Net income before income taxes	$ 44,496	$ 39,689
Statutory combined federal and provincial income tax rate	27.0%	26.4%
Expected income tax expense (recovery)	$ 12,014	$ 10,473
Add (deduct) the income tax effect of:		
Share-based compensation	844	1,007
Change in unrecorded deferred income tax asset	(11,701)	(11,777)
Change in enacted corporate tax rate	-	277
Change in estimated tax pool balances	3,260	-
Other	16	20
Deferred income tax expense	$ 4,433	$ -
Effective tax rate	10.0%	0.0%

The components of the deferred income tax assets and liabilities are as follows. The net deferred tax asset at December 31, 2017 was not recognized/recorded due to uncertainty as to future realization.

	As at December 31, 2018	As at December 31, 2017
Deferred tax assets:		
Non-capital losses	$ 44,632	$ 55,433
Decommissioning liability	7,110	6,608
Fair value of commodity price contracts	907	-
Share issue costs	116	329
Investment	289	269
Deferred tax liabilities:		
Property and equipment in excess of tax basis	$ (57,487)	$ (49,913)
Fair value of commodity price contracts	-	(667)
Deferred income tax asset (liability)	$ (4,433)	$ 12,059

12. 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, 2016	120,764	$ 389,316
Shares issued on stock option exercises(1)	793	2,128
Balance as at December 31, 2017 and December 31, 2018	121,557	$ 391,444

(1) During 2017, 793,000 common shares were issued upon the exercise of stock options for proceeds of $1,456,000 and related prior period share-based compensation of $672,000 was transferred to share capital from contributed surplus.

(2) For the period from January 1, 2018 to February 28, 2019, no common shares were issued upon the exercise of stock options.

13. 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, 2018, and at February 28, 2019, the date of this report, a total of 12,155,681 common shares were available for issuance, options in respect of 9,088,400 common shares were issued and outstanding and options in respect of 3,067,281 common shares were available for future issue.

Details of the options outstanding at December 31, 2018 and 2017 are as follows:

	Number of Options (000s)	Weighted Average Exercise Price
Outstanding at December 31, 2016	8,387	$ 4.21
Granted during the year	320	$ 4.27
Exercised during the year	(793)	$ 1.83
Outstanding at December 31, 2017	7,914	$ 4.46
Granted during the year	4,993	$ 2.34
Forfeited during the year	(399)	$ 4.10
Expired during the year	(3,420)	$ 4.51
Outstanding at December 31, 2018	9,088	$ 3.29
Number exercisable at December 31, 2018	3,224	$ 4.25

Range of Exercise Price	Outstanding Options			Exercisable Options	
	Number of Options Outstanding (000s)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number of Options Outstanding (000s)	Weighted Average Exercise Price
$1.81 - $2.86	4,885	3.5	$ 2.32	-	-
$2.87 - $4.50	2,104	1.2	$ 3.44	1,825	$ 3.39
$4.51 - $5.50	2,099	1.9	$ 5.37	1,399	$ 5.37
Total	9,088	2.6	$ 3.29	3,224	$ 4.25

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, 2018 of $0.88 per share (2017 - $1.59 per share) include the following:

	2018	2017
Share price	$1.81 - $3.09	$3.91 - $5.27
Exercise price	$1.81 - $3.09	$3.91 - $5.27
Volatility	49%	52%
Forfeiture rate	10%	10%
Expected option life (years)	3.7	3.7
Risk-free interest rate	1.7% - 2.1%	0.7% - 1.4%

Share-based compensation expense of $3.1 million was charged to the consolidated statement of income during the year ended December 31, 2018 (2017 - $3.8 million) with an equivalent offset to contributed surplus.

14. NET INCOME PER SHARE

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

	Year Ended December 31, 2018	Year Ended December 31, 2017
Net income for the year	$ 40,063	$ 39,689
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of year	121,557	120,764
Effect of shares issued	-	767
Weighted average number of common shares outstanding – basic	121,557	121,531
Dilutive effect of outstanding options(1)	40	85
Weighted average number of common shares outstanding - diluted	121,597	121,616
Net income per share		
Basic and diluted	$ 0.33	$ 0.33

(1) Excludes the effect of 8.5 million weighted average common shares related to stock options that were anti-dilutive for the year ended December 31, 2018 (6.0 million weighted average common shares related to stock options for the year ended December 31, 2017).

15. FINANCIAL INSTRUMENTS

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

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

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide continual and verifiable pricing information.

- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

The carrying value of bank indebtedness approximates its fair value as it bears interest at market rates. The fair value of the Company's commodity price contracts described below is based on forward prices of commodities available in the market place and they are therefore classified as Level 2 financial instruments. The Company does not have any financial instruments classified as Level 3 and there were no transfers between levels within the fair value hierarchy for the years ended December 31, 2018 and December 31, 2017.

The Company's commodity price contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's consolidated statements of financial position. The following is a summary of the Company's financial assets and financial liabilities that are subject to offset as at December 31, 2018:

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

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

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

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, 2018, the Company's most significant marketer accounted for $22.1 million (2017 - $6.1 million) of total receivables and 56% of total revenues (2017 – 57%). 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, 2018 and 2017, 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, 2018.

The maximum exposure to credit risk at December 31, 2018 was the carrying amount of accounts receivable of $29.3 million and commodity price contract assets of $2.3 million. No receivables were impaired at December 31, 2018.

Commodity price contracts

The Company enters into derivative commodity price 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 commodity price 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, 2018, 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 commodity price 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 commodity price contracts in place. The fair market value of these contracts at December 31, 2018, a net liability position of $3.4 million (December 31, 2017 – net asset position of $2.5 million), is included in current and non-current assets or current and non-current liabilities as appropriate. For the year ended December 31, 2018, this resulted in an unrealized mark-to-market loss of $5.8 million (2017 - an unrealized mark-to-market gain of $24.6 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 2019	9,000 GJ	AECO Cdn$1.93/GJ
Jan – Mar 2019	9,000 GJ	Stn 2 Cdn$1.73/GJ
Jan – Mar 2019	3,500 Mmbtu	Sumas Cdn$4.77/Mmbtu
Jan – Jun 2019	22,500 Mmbtu	Chicago Cdn$3.34/Mmbtu
Jul – Dec 2019	11,500 Mmbtu	Chicago Cdn$3.27/Mmbtu
Jul – Dec 2019	2,000 Mmbtu	Sumas Cdn$2.90/Mmbtu
Jan – Dec 2019	26,500 Mmbtu	Chicago Cdn$3.23/Mmbtu
Jan – Dec 2019	6,500 Mmbtu	Sumas Cdn$2.60/Mmbtu
Nov 2019 – Mar 2020	1,500 GJ	AECO Cdn$2.00/GJ
Jan – Jun 2020	18,500 Mmbtu	Chicago Cdn$3.30/Mmbtu
Natural Gas Differential Swaps		
Jan – Dec 2020	12,500 Mmbtu	Price at Chicago = NYMEX minus US$0.274/Mmbtu
Jan – Dec 2021	12,500 Mmbtu	Price at Chicago = NYMEX minus US$0.256/Mmbtu
Crude Oil Collars		
Jan – Jun 2019	650 Bbls	$68.83 - $80.74 Cdn$/Bbl
Jul – Dec 2019	600 Bbls	$74.39 - $89.91 Cdn$/Bbl
Jan – Dec 2019	250 Bbls	$70.60 - $83.26 Cdn$/Bbl
Crude Oil Swaps		
Jan – Jun 2019	350 Bbls	$70.09 Cdn$/Bbl
Jul – Dec 2019	400 Bbls	$80.90 Cdn$/Bbl
Jan – Dec 2019	250 Bbls	$82.49 Cdn$/Bbl
Propane Swaps		
Jan – Dec 2019	200 Bbls	$42.87 Cdn$/Bbl

The Company realized a loss from commodity price contracts in place in the amount of $22.7 million for the year ended December 31, 2018 (2017 – realized loss of $2.4 million).

Physical Delivery Sales Contract

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

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

Interest rate risk

Interest on the Company's revolving bank facility varies with changes in core 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. Currently, the Company has not entered into any agreements to manage this risk. 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, 2018 would have decreased by $0.9 million. A decrease in interest rates by 1% would result in an increase in net income by an equivalent amount.

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 commodity price contracts in place at December 31, 2018. Changes in the fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Factor		Year Ended December 31, 2018
Increase of US$10.00/Bbl in the price of WTI[(1)]	$	(5,475)
Decrease of US$10.00/Bbl in the price of WTI[(1)]	$	5,475
Increase of US$0.10/Mmbtu in the price of NYMEX natural gas	$	(2,227)
Decrease of US$0.10/Mmbtu in the price of NYMEX natural gas	$	2,227

(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, 2018 is as follows:

	Less than 1 year	2-3 years	Total
Accounts payable and accrued liabilities	$ 34,359	$ -	$ 34,359
Commodity price contracts	1,180	2,180	3,360
Bank indebtedness[(1)]	-	86,776	86,776
Total financial liabilities	$ 35,539	$ 88,956	$ 124,495

(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.

16. 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. 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. Growing funds flow enables the Company to increase bank or other debt financing, thus expanding capital available for investment.

17. RELATED PARTY TRANSACTIONS

Two directors of the Company are partners at law firms which have been engaged by the Company to provide legal services. During the year ended December 31, 2018, the Company incurred $0.1 million in legal fees and disbursements which was recorded at the exchange amount.

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, 2018	Year Ended December 31, 2017
Salaries and short-term benefits	$ 3,001	$ 2,446
Share-based compensation	1,697	2,281
Total compensation	$ 4,698	$ 4,727

18. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	Year Ended December 31, 2018	Year Ended December 31, 2017
Accounts receivable	$ (14,305)	$ (2,039)
Prepaids and deposits	3,611	(3,366)
Accounts payable and accrued liabilities	9,582	(605)
Change in non-cash working capital	$ (1,112)	$ (6,010)
Relating to:		
Operating activities	$ (7,851)	$ (331)
Investing activities	6,739	(5,679)
Change in non-cash working capital	$ (1,112)	$ (6,010)
Interest paid during the year	$ 4,207	$ 3,369
Income taxes paid during the year	$ -	$ -

19. COMMITMENTS

At December 31, 2018, the Company has the following long-term commitments over the next five years and thereafter:

	2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing commitments	$ 54,966	$ 37,995	$ 27,105	$ 27,368	$ 24,865	$ 212,408	$ 384,707
Office lease	794	801	806	814	822	1,736	5,773
Total	$ 55,760	$ 38,796	$ 27,911	$ 28,182	$ 25,687	$ 214,144	$ 390,480

In the first quarter of 2018, the Company entered into an office lease agreement commencing on October 1, 2018.

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

McCarthy Tétrault LLP
Burnet Duckworth & Palmer LLP
Calgary, Alberta

Auditors

Ernst & Young LLP
Calgary, Alberta

Registrar & Transfer Agent

Alliance Trust Company
Calgary, Alberta

Bankers

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

Executive Offices

Suite 600, 215 – 2nd Street S.W.
Calgary, Alberta, T2P 1M4 Canada
Tel: (403) 817-6145 Fax: (403) 817-6146
www.stormresourcesltd.com

Abbreviations

ATP	Alliance Transfer Point
Bbls	Barrels of oil or natural gas liquids
Bbls/d	Barrels per day
Bcf	Billions of cubic feet
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day
Bopd	Barrels of oil per day
Btu	British thermal unit
Cdn$	Canadian dollar
CGU	Cash generating unit
DPIIP	Discovered Petroleum Initially in Place
GJ	Gigajoules
GJ/d	Gigajoules per day

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

Storm Resources Ltd.
Suite 600, 215 – 2nd Street S.W., Calgary, Alberta T2P 1M4
Phone: (403)817-6145   Fax: (403)817-6146

www.stormresourcesltd.com