Storm Resources Ltd. (“Storm” or the “Company”) is Pleased to Announce Its Financial and Operating Results for the Three and Six Months Ended June 30, 2019

CALGARY, Alberta, Aug. 13, 2019 (GLOBE NEWSWIRE) -- Storm Resources Ltd. (TSX:SRX)

Storm has also filed its unaudited condensed interim consolidated financial statements as at June 30, 2019 and for the three and six months then ended along with Management’s Discussion and Analysis (“MD&A”) for the same period. This information appears on SEDAR at www.sedar.com and on Storm’s website at www.stormresourcesltd.com.

Selected financial and operating information for the three and six months ended June 30, 2019 appears below and should be read in conjunction with the related financial statements and MD&A.

Highlights

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

(1) Excludes gains and losses on risk management contracts.
(2) Certain financial amounts shown above are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 26 of the

MD&A. CROCE and ROCE are presented on a 12-month trailing basis.
(2) Excludes the fair value of risk management contracts and lease liability.

PRESIDENT'S MESSAGE

2019 SECOND QUARTER HIGHLIGHTS

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

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

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

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

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

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

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

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

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

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

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

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

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

OPERATIONS REVIEW

Umbach, Nig and Fireweed Areas, Northeast British Columbia

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

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

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

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

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

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

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

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

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

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

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

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

HEDGING AND TRANSPORTATION

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

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

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

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

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

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

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

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

In the second quarter, 56% of natural gas sales were at a Chicago price, 32% at Western Canadian pricing and 12% at the Sumas price less a marketing adjustment. Production exceeding firm capacity is directed to Chicago and/or Station 2 on an interruptible basis depending on which sales point offers a higher net price.

OUTLOOK

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

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

2019 Guidance

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

2019 Guidance

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

Horizontal wells starting production - gross	9 (9.0 net)	7 (7.0 net)

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

Guidance History

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

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

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

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

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

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

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

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

Respectfully,

Brian Lavergne,
President and Chief Executive Officer

August 13, 2019

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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.

Non-GAAP Measures - This document may refer to the terms “debt including working capital deficiency”, “field operating netbacks”, “field operating netbacks including hedging”, “CROCE”, “ROCE”, the terms “cash” and “non-cash”, “cash costs”, and measurements “per commodity unit” and “per Boe” which are not recognized under Generally Accepted Accounting Principles ("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, analysts and other parties. Additional information relating to certain of these non-GAAP measures can be found in Storm’s MD&A dated August 13, 2019 for the period ended June 30, 2019 which is available on Storm’s SEDAR profile at www.sedar.com and on Storm’s website at www.stormresourcesltd.com.

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

Forward-Looking Information - This press release contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "will", “would”, "expect", “anticipate”, “intend”, "believe", "plan", "potential", “outlook”, “forecast”, “estimate”, “budget” and similar expressions are intended to identify forward-looking statements or information. More particularly, and without limitation, this press release contains forward-looking statements and information concerning: current and future years’ guidance in respect of certain operational and financial metrics, including, but not limited to, commodity pricing, estimated average operating costs, estimated average royalty rate, estimated operations capital, estimated general and administrative costs, estimated quarterly and annual production and estimated number of horizontal wells drilled, completed and connected, capital investment plans, infrastructure plans, anticipated United States exports, pipeline capacity, price volatility mitigation strategy and cost reductions. Statements of “reserves” are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking statements and information in this press release are based on certain key expectations and assumptions made by Storm, including: prevailing commodity prices and exchange rates; applicable royalty rates and tax laws; future well production rates; reserve and resource volumes; the performance of existing wells; success to be expected in drilling new wells; the adequacy of budgeted capital expenditures to carrying out planned activities; the availability and cost of services; and the receipt, in a timely manner, of regulatory and other required approvals. Although the Company believes that the expectations and assumptions on which such forward-looking statements and information are based are reasonable, undue reliance should not be placed on these forward-looking statements and information because of their inherent uncertainty. In particular, there is no assurance that exploitation of the Company’s undeveloped lands and prospects will result in the emergence of profitable operations.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to the risks associated with the oil and gas industry in general such as: general economic conditions in Canada, the United States and internationally; operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to reserves, production, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; marketing and transportation of petroleum and natural gas and loss of markets; competition; ability to access sufficient capital from internal and external sources; geopolitical risk; stock market volatility; and changes in legislation, including but not limited to tax laws, royalty rates and environmental regulations.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect the operations or financial results of the Company are included or are incorporated by reference in the Company’s Annual Information Form dated March 29, 2019 and the MD&A dated August 13, 2019 for the period ended June 30, 2019 which are available on Storm’s SEDAR profile at www.sedar.com and on Storm’s website at www.stormresourcesltd.com.

The forward-looking statements and information contained in this press release are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

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