STORM RESOURCES

2015 REPORT Q3

# Highlights

| Thousands of Cdn$, except volumetric and per-share amounts | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| **FINANCIAL** | | | | |
| Revenue from product sales(1) | 16,283 | 24,902 | 53,256 | 67,410 |
| Funds from operations(2) | 7,982 | 11,784 | 29,864 | 31,520 |
| Per share - basic ($) | 0.07 | 0.11 | 0.26 | 0.29 |
| Per share - diluted ($) | 0.07 | 0.11 | 0.26 | 0.29 |
| Net income (loss) | (961) | 5,473 | (8,717) | 12,277 |
| Per share - basic ($) | (0.01) | 0.05 | (0.08) | 0.11 |
| Per share - diluted ($) | (0.01) | 0.05 | (0.08) | 0.11 |
| Operations capital expenditures | 19,557 | 30,426 | 64,101 | 86,385 |
| Land and property acquisitions/ (dispositions) | (23,673) | - | (23,673) | 88,075 |
| Debt including working capital deficiency | 39,994 | 56,157 | 39,994 | 56,157 |
| Common shares (000s) | | | | |
| Weighted average - basic | 119,355 | 110,954 | 114,618 | 107,116 |
| Weighted average - diluted | 119,355 | 112,526 | 114,618 | 108,828 |
| Outstanding end of period – basic | 119,355 | 111,295 | 119,355 | 111,295 |
| **OPERATIONS** | | | | |
| (Cdn$ per Boe) | | | | |
| Revenue | 18.33 | 37.80 | 20.12 | 41.82 |
| Royalties | (1.28) | (5.99) | (1.15) | (6.02) |
| Production | (7.89) | (9.53) | (8.37) | (9.87) |
| Transportation | (0.94) | (1.69) | (1.26) | (1.74) |
| Field operating netback | 8.22 | 20.59 | 9.34 | 24.19 |
| Hedging gains (losses) | 2.22 | (1.17) | 4.20 | (2.29) |
| General and administrative | (1.07) | (0.98) | (1.60) | (1.69) |
| Interest | (0.39) | (0.56) | (0.65) | (0.66) |
| Funds from operations – per Boe | 8.98 | 17.88 | 11.29 | 19.55 |
| Barrels of oil equivalent per day (6:1) | 9,654 | 7,160 | 9,695 | 5,904 |
| Gas Production | | | | |
| Thousand cubic feet per day | 47,325 | 33,674 | 47,142 | 27,667 |
| Price (Cdn$ per Mcf) | 2.46 | 4.48 | 2.62 | 5.02 |
| NGL production | | | | |
| Barrels per day | 1,697 | 1,154 | 1,598 | 882 |
| Price (Cdn$ per barrel) | 33.32 | 73.09 | 37.13 | 78.33 |
| Oil Production | | | | |
| Barrels per day | 70 | 394 | 240 | 412 |
| Price (Cdn$ per barrel) | 55.93 | 90.31 | 50.84 | 94.44 |
| Wells drilled | | | | |
| Gross | - | 3.0 | 6.0 | 15.0 |
| Net | - | 3.0 | 6.0 | 15.0 |

(1) Excludes hedging gains and losses.
(2) Funds from operations and funds from operations per share are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 26 of the attached Management's Discussion and Analysis ("MD&A") and the reconciliation of funds from operations to the most directly comparable measurement under GAAP, "Cash Flows from Operating Activities", on page 19 of the attached MD&A.

# PRESIDENT'S MESSAGE

## 2015 THIRD QUARTER HIGHLIGHTS

- Production averaged 9,654 Boe per day (18% oil plus NGL), a per-share increase of 27% from the previous year. Production was reduced by approximately 2,900 Boe per day as a result of shutting in up to half of Storm's production at Umbach several times during the quarter when the natural gas price at BC Station 2 was too low and would have resulted in an unacceptably low field netback (caused by constraints and outages on the Spectra and TransCanada sales pipeline systems).

- NGL production was 1,697 barrels per day, an increase of 47% from the previous year. The price was $33.32 per barrel which was 59% of the average Edmonton light oil price (59% of the NGL volume was higher value condensate and plant pentanes). The NGL price was reduced by the negative price for propane (-$8.18 per barrel) which affected 17% of the NGL volume.

- Activity was focused at Umbach where four horizontal wells were completed and a fifth compressor was installed at the second field compression facility to increase capacity by 10 Mmcf per day (total field compression capacity at Umbach is now 82 Mmcf per day).

- Controllable cash costs (operating, G&A, and interest) were $9.35 per Boe which is a year-over-year decline of $1.72 per Boe, or 16%, and a decline of 15% from the previous quarter. Transportation cost is not included as recent natural gas marketing arrangements deduct the pipeline tariff from revenue which artificially reduces the transportation cost.

- Funds from operations was $8.98 per Boe, a year-over-year decrease of $8.90 per Boe, or 50%. Revenue declined by $19.47 per Boe which was partially offset by a cash hedging gain of $2.22 per Boe.

- Funds from operations was $8.0 million, or $0.07 per basic share, a decrease of 32% from the prior year. Higher production and the improvement in controllable cash costs was more than offset by the realized commodity price decreasing by 52% from the previous year.

- Operations capital investment was $19.6 million with $10.0 million for completions and $8.5 million for facilities plus pipelines.

- Debt plus working capital deficiency was $40.0 million which is 1.2 times annualized third quarter cash flow. Storm's bank credit facility is currently $140.0 million.

- The previously announced disposition of certain non-core properties in the Grande Prairie area of Alberta closed on July 15 (second quarter production from these properties was 600 Boe per day) with net proceeds of $23.7 million being used to reduce bank indebtedness.

## OPERATIONS REVIEW

Storm has a focused asset base with large land positions in resource plays with multi-year drilling upside at Umbach and in the Horn River Basin.

**Umbach, Northeast British Columbia**

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 107,000 net acres (153 net sections). To date, a total of 34.4 net horizontal wells (38.0 gross) have been drilled into the Montney formation with 28.4 net being on production.

Third quarter production from Umbach was 9,332 Boe per day and represented 97% of corporate production in the quarter. NGL recovery was 37 barrels per Mmcf sales (59% of the NGL volume is higher priced field condensate plus pentanes recovered at the gas plant). Revenue was $18.14 per Boe ($2.46 per Mcf sales and $33.38 per barrel of NGL), transportation costs were $0.87 per Boe, royalties were $1.28 per Boe (7% of revenue), operating costs were $7.80 per Boe, and the operating netback was $8.19 per Boe.

Activity in the third quarter was mainly directed toward completing four horizontal wells and installing a fifth compressor at the second field compression facility. Three of the completed horizontal wells were part of a five well pad (infills) and the fourth completion was a single well pad (step-out to the south and east). In the fourth quarter, an additional five horizontal wells (two step-outs and three infills on the same pad) were completed in October, a single horizontal well will be completed in December (step-out to the west), and four horizontal wells (infills) will be drilled.

With the addition of the fifth compressor at the second facility (cost of $3.0 million), Storm's two operated field compression facilities (both 100% working interest) have current total capacity of 82 Mmcf per day raw gas. Actual throughput in the third quarter averaged 49 Mmcf per day raw gas. Timing to start up the third field compression facility is unchanged from early May 2016 with the total cost estimated to be $25.0 million for initial capacity of 35 Mmcf per day raw gas (expandable to 70 Mmcf per day raw gas by investing an additional $7.0 million). During 2015, $4.1 million will be invested to purchase major equipment for the third facility.

Raw gas from Storm's field compression facilities is sent to the McMahon and Stoddart Gas Plants where Storm has firm processing commitments totaling 65 Mmcf per day raw gas in 2016.

As shown in the following summary, performance of the 2014 horizontal wells has shown significant improvement over earlier horizontal wells. Further improvement is expected from the 2015 horizontal wells as the length and the number of frac stages have been increased; however, production data to date has been impacted by the significant downtime experienced since June.

| | Frac Stages | IP 90 Cal Day Gross Raw Mmcf Per Day | IP 180 Cal Day Gross Raw Mmcf Per Day | 1st Year Cal Day Gross Raw Mmcf Per Day |
|---|---|---|---|---|
| **2011 – 2012 hz's (7 wells)** | 7 - 14 | **1.9 Mmcf/d**<br>340 Boe/d sales<br>7 hz's | **1.4 Mmcf/d**<br>250 Boe/d sales<br>7 hz's | **1.3 Mmcf/d**<br>230 Boe/d sales<br>7 hz's |
| **2013 hz's (6 wells)** | 16 - 18 | **4.0 Mmcf/d**<br>715 Boe/d sales<br>6 hz's | **2.9 Mmcf/d**<br>520 Boe/d sales<br>6 hz's | **2.2 Mmcf/d**<br>395 Boe/d sales<br>6 hz's |
| **2014 hz's (10 wells)** | 16 - 20 | **4.7 Mmcf/d**<br>840 Boe/d sales<br>10 hz's | **4.2 Mmcf/d**<br>750 Boe/d sales<br>10 hz's | **3.8 Mmcf/d**<br>680 Boe/d sales<br>7 hz's |
| **2015 hz's (9 wells)** | 17 - 24 | **4.2 Mmcf/d**<br>750 Boe/d sales<br>5 hz's | **3.9 Mmcf/d**<br>700 Boe/d sales<br>4 hz's | |

Note: Sales volume is calculated using 10% shrinkage from raw gas to sales and 32 barrels of NGL per Mmcf sales.

To date in 2015, the cost to drill and complete a horizontal well has averaged $4.6 million for an average of 22 frac stages. This is a 14% decrease in the cost per frac stage from the average cost of $4.6 million for the 2014 horizontal wells which had an average of 19 frac stages.

Based on the performance of the 2014 horizontal wells, Storm management is using a 6.3 Bcf raw gas type curve for internal budgeting purposes (this type curve has the same decline profile as the 3.2 and 4.4 Bcf raw gas 2P type curves used by InSite in the 2014 reserve evaluation). Using a cost of $4.9 million to drill, complete and tie in a horizontal well, and a first year average rate of 3.6 Mmcf per day raw gas, the payout is approximately 22 months and the rate of return is 38% based on $3.00 per GJ at AECO, $2.65 per GJ at BC Station 2 and Cdn $62.00 per barrel for Edmonton light oil. Expected longer term commodity prices were used with pricing then held flat for the life of the well. See the presentation on Storm's website for further details.

**Horn River Basin, Northeast British Columbia**

Storm has a 100% working interest in 119 sections in the Horn River Basin (78,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. Third quarter production averaged 137 Boe per day (100% natural gas) with production being shut in at the end of July due to the low natural gas price at BC Station 2. The operating netback was ($0.16) per Boe with revenue of $11.82 per Boe, transportation costs of $0.49 per Boe, an operating cost of $11.07 per Boe and a royalty of $0.42 per Boe, or 4% of revenue.

**Grande Prairie Area, Northwest Alberta**

Production in the quarter was 185 Boe per day (45% oil plus NGL). The majority of the properties in this area were sold on July 15 and there remains only the Valhalla property which has been shut in as a result of the decline in the natural gas price (capable of producing 300 Boe per day).

## HEDGING AND MARKETING

Realized cash gains in 2015 on Storm's commodity price hedges totaled $11.1 million to the end of the third quarter. A summary of current price hedges is provided below.

| | Q4 2015 | | 2016 | |
|---|---|---|---|---|
| **Crude Oil** | | | WTI Cdn $75.00/Bbl floor<br>WTI Cdn $90.75/Bbl ceiling | 500 Bopd |
| **Natural Gas** | AECO Cdn $3.36/GJ<br>($4.20/Mcf) | 35,670 GJ/d<br>(28,500 Mcf/d) | AECO Cdn $2.98/GJ<br>($3.72/Mcf) | 21,250 GJ/d<br>(17,000 Mcf/d) |

Although Storm has no oil production, the WTI hedge protects condensate and plant pentanes revenue which are priced in reference to WTI.

The purpose of Storm's commodity price hedges is to provide greater certainty regarding future cash flows and capital investment in order to support longer term growth plans. A maximum of 50% of current production (most recent monthly or quarterly average), before royalties, will be hedged; anticipated production growth is not hedged.

Storm's marketing commitments are summarized below. These do not fix the price but show the price differentials and transportation cost.

| | Q4 2015 | 2016 |
|---|---|---|
| **Natural Gas** | Physical sale at McMahon Gas Plant<br>4,300 GJ/d Chicago monthly or daily price<br>minus Alliance pipeline toll Cdn$1.40/GJ | Physical sale at McMahon Gas Plant<br>18,200 GJ/d Chicago monthly or daily price<br>minus Alliance pipeline toll Cdn$1.40/GJ |
| | Physical sale at McMahon Gas Plant<br>13,400 GJ/d AECO +US$0.79/Mmbtu<br>minus Alliance pipeline toll Cdn$1.40/GJ | Physical sale at McMahon Gas Plant<br>34,800 GJ/d AECO +US$0.67/Mmbtu<br>minus Alliance pipeline toll Cdn$1.40/GJ |
| | Physical sale at BC Stn 2<br>12,800 GJ/d AECO -$0.78/GJ<br>minus Spectra T-north pipeline toll Cdn$0.17/GJ | Physical sale at BC Stn 2<br>11,000 GJ/d AECO -$0.34/GJ<br>minus Spectra T-north pipeline toll Cdn $0.17/GJ |
| | Physical sale at McMahon Gas Plant<br>11,400 GJ/d AECO -$0.22/GJ | Physical sale at McMahon Gas Plant<br>10,300 GJ/d AECO -$0.68/GJ |

## OUTLOOK

In the third quarter, production averaged 9,654 Boe per day which was lower than the forecast of 10,000 to 11,000 Boe per day provided with the release of second quarter results on August 13, 2015. Production was reduced by approximately 2,900 Boe per day as a result of shutting in production for several periods where the BC Stn 2 natural gas price was very low (the daily spot price averaged $1.22 per GJ from August 7 to 12, $0.75 per GJ from August 24 to September 4, and $0.72 per GJ from September 22 to 30). This was caused by constraints on the TransCanada and Spectra sales pipeline systems which reduced takeaway capacity from British Columbia and increased volumes being sold at BC Station 2. During periods where the natural gas price at BC Station 2 results in an unacceptably low field netback, Storm has reduced production to equal the volume of natural gas that is hedged (incremental volumes above what is hedged receive the BC Station 2 daily spot price).

Production in the fourth quarter of 2015 is forecast to be 10,000 to 12,000 Boe per day and will depend largely on constraints on the TransCanada pipeline system in Alberta and their impact on the daily spot natural gas price at BC Station 2. Production to date in the fourth quarter has averaged 8,900 Boe per day based on field estimates with approximately 3,900 Boe per day shut in during October due to the BC Station 2 natural gas price averaging $0.97 per GJ as a result of continued constraints on the TransCanada sales pipeline system.

Revised guidance for 2015 is provided below with the major revisions being reductions to forecast commodity prices and forecast production plus a reduction in capital investment due to lower service costs and the drilling of two horizontal wells being deferred to 2016.

| 2015 Guidance | Original Guidance November 13, 2014 | Revised August 13, 2015 | Revised November 11, 2015 |
|---|---|---|---|
| AECO natural gas price | $3.25 per GJ | $2.68 per GJ | $2.60 per GJ |
| BC STN 2 natural gas price | $3.00 per GJ | $2.01 per GJ | $1.87 per GJ |
| Edmonton light oil price | Cdn$83 per Bbl | Cdn$59 per Bbl | Cdn$58 per Bbl |
| Estimated average operating costs | $7.50 - $8.00 per Boe | $7.75 - $8.00 per Boe | $7.75 - $8.00 per Boe |
| Estimated average royalty rate (on production revenue before hedging) | 12% - 14% | 7% - 8% | 6% - 7% |
| Estimated operations capital (excluding acquisitions & dispositions) | $110.0 million | $106.0 million | $92.0 million |
| Estimated land and property acquisitions/(dispositions) | $0.0 million | ($23.7 million) | ($19.3 million) |
| Estimated cash G&A net of recoveries | $5.3 million | $5.3 million | $5.3 million |
| Forecast fourth quarter production | 14,000 – 14,500 Boe/d (18% oil + NGL) | 14,000 – 15,000 Boe/d (18% NGL) | 10,000 – 12,000 Boe/d (18% NGL) |
| Forecast annual production | 11,500 – 12,700 Boe/d (19% oil + NGL) | 11,000 – 12,000 Boe/d (19% oil + NGL) | 10,000 – 11,000 Boe/d (19% oil + NGL) |
| Umbach horizontal wells drilled | 9 gross (9.0 net) | 12 gross (12.0 net) | 10 gross (10.0 net) |
| Umbach horizontal wells completed | 14 gross (14.0 net) | 14 gross (14.0 net) | 13 gross (13.0 net) |
| Umbach horizontal wells starting prod'n | 16 gross (16.0 net) | 14 gross (14.0 net) | 13 gross (13.0 net) |

Capital investment in 2015 is focused entirely on the Umbach area with $50.0 million for drilling and completions plus $34.0 million to expand infrastructure (including $4.1 million to order long-lead-time equipment for the third field compression facility).

Guidance for 2016 has been finalized and is shown below.

| 2016 Guidance | November 11, 2015 |
|---|---|
| AECO natural gas price | $2.50 per GJ |
| BC STN 2 natural gas price | $1.90 per GJ |
| Edmonton light oil price | Cdn$57.00 per Bbl |
| Estimated average operating costs | $7.00 - $7.50 per Boe |
| Estimated average royalty rate (on production revenue before hedging) | 7% - 8% |

| | |
|---|---|
| Estimated operations capital<br>(excluding acquisitions & dispositions) | $105.0 million |
| Estimated cash G&A net of recoveries | $5.0 million |

| | |
|---|---|
| Forecast fourth quarter production | 20,000 – 21,000 Boe/d<br>(17% NGL) |
| Forecast annual production | 16,000 – 18,000 Boe/d<br>(17% oil + NGL) |
| Umbach horizontal wells drilled | 14 gross (14.0 net) |
| Umbach horizontal wells completed | 14 gross (14.0 net) |
| Umbach horizontal wells starting prod'n | 16 gross (16.0 net) |

Capital investment in 2016 will be directed entirely to Umbach and will include $63.0 million for drilling and completions plus $34.0 million for infrastructure (remaining $21.0 million for the third field compression facility). With this level of investment, total debt at the end of 2016 is forecast to be $105.0 million which would be approximately 1.5 times annualized funds from operations in the fourth quarter of 2016.

Note that capital investment in 2016 of $105.0 million per the above table is based on a daily spot natural gas price of $1.90 per GJ at BC Station 2. Storm's incremental growth volumes receive the BC Station 2 daily spot price and, should the price be materially below this level, capital investment in 2016 for infrastructure plus drilling and completions may be delayed which would reduce forecast production. This is consistent with what has been done since the BC Station 2 price began weakening in July 2015 which resulted in production being shut in plus drilling and completions being deferred as capital investment is contingent on achieving a minimum netback or rate of return. If necessary, Storm can reduce capital investment to $50.0 to $55.0 million which would result in forecast production being maintained at 14,000 to 15,000 Boe per day throughout 2016 (using the current forward strip, debt at the end of 2016 would be unchanged from the end of 2015). Approximately 95% of this level of production would be covered by Storm's pipeline commitments and marketing arrangements and would not be exposed to the BC Station 2 daily spot price.

Although constraints on the TransCanada sales pipeline system have continued into the fourth quarter, which has continued to depress the BC Station 2 natural gas price, the impact on Storm will be diminished going forward as a result of firm pipeline commitments and marketing agreements which cover 59 Mmcf per day sales in 2016 (67 Mmcf per day including interruptible service on the Alliance Pipeline) and increases to 88 Mmcf per day sales in 2018 (98 Mmcf per day including interruptible service on the Alliance Pipeline). For comparison, in 2015, transportation commitments totaled 22 Mmcf per day sales. Natural gas sales will also be more diversified as, using forecast natural gas production for 2016, approximately 18% will be sold in Chicago at the daily spot or monthly index price (through the Alliance Pipeline), 33% sold in Chicago at the AECO monthly index price plus $0.67 USD per Mmbtu (through the Alliance Pipeline), 11% sold at BC Station 2 at the AECO monthly index less $0.34 per GJ, 10% sold at the McMahon Gas Plant at the AECO monthly index less $0.68 per GJ, and the remaining 28% will be sold at BC Station 2 at the daily spot price. To ensure that the firm pipeline commitments and marketing arrangements can be met, there are also firm processing commitments which total 65 Mmcf per day raw gas in 2016.

Controllable cash costs (operating, G&A, and interest) have averaged $10.62 per Boe to date in 2015 which is a 7% improvement when compared to $11.43 per Boe in 2014. Previously, Storm included transportation costs in controllable cash costs; however, this is being removed because recent marketing arrangements result in pipeline tariffs being deducted from the sales price which artificially reduces transportation costs. Further improvement in controllable cash costs on a per-Boe basis is expected given that operating costs will decrease as a result of continued production growth, recent longer term processing commitments with lower associated fees, and recent investments in infrastructure at Umbach (conversion of a second well to salt water disposal and adding a fuel gas conditioning unit).

Storm's land position in the Horn River Basin continues to be a core, long-term asset with significant leverage to higher natural gas prices.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

November 11, 2015

**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.

**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 November 11, 2015 for the three and nine months ended September 30, 2015.

# MANAGEMENT'S DISCUSSION & ANALYSIS

## INTRODUCTION

Set out below is management's discussion and analysis ("MD&A") of financial and operating results for Storm Resources Ltd. ("Storm" or the "Company") for the three and nine months ended September 30, 2015. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2015, (ii) the Company's audited consolidated financial statements for the year ended December 31, 2014, and (iii) the press release issued by the Company on November 11, 2015, and other operating and financial information included in this report. All of these documents are filed on SEDAR (www.sedar.com) and appear on the Company's website (www.stormresourcesltd.com).

Readers are directed to the discussion below regarding Forward-Looking Statements, Boe Presentation and Non-GAAP Measurements.

The Company trades on the TSX Venture Exchange under the symbol "SRX".

This MD&A is dated November 11, 2015.

**See "Forward-Looking Statements", "Boe Presentation", and "Non-GAAP Measurements" beginning on page 25.**

## BASIS OF PRESENTATION

Financial data presented below have largely been derived from the Company's unaudited condensed interim consolidated financial statements (the "financial statements") for the three and nine months ended September 30, 2015, 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 year ended December 31, 2014. The reporting and the measurement currency is the Canadian dollar.

Changes to accounting policies, introduced effective January 1, 2014, are outlined in Note 2 to the Company's audited consolidated financial statements as at December 31, 2014 and for the year then ended. These changes to accounting policies have no effect on financial statements or the inter-period comparability of financial statements and financial information derived therefrom.

Unless otherwise indicated, tabular financial amounts, other than per-share amounts, are in thousands of Canadian dollars. Comparative information is provided for the three and nine month periods ended September 30, 2014.

## OPERATIONAL AND FINANCIAL RESULTS

### Overview

Production for the quarter at 9,654 Boe per day (82% natural gas and 18% NGL) fell well short of the Company's wellhead and facility production capacity, which ranged from 13,000-14,000 Boe per day for the quarter. Production for the quarter also fell short of forecast production of 10,000 to 11,000 Boe per day, and was the same as the second quarter of 2015. Reasons for the production shortfall when compared to deliverability were twofold: third party facility and pipeline closures, interruptions and curtailments: and production shut in by the Company in response to sub-economic prices, as the pricing headwinds faced by the Company in the first half of 2015 worsened in the third quarter, such that revenue per Boe for the quarter was the lowest since the Company began business in 2010. Sub-economic pricing also involved two elements, being low pricing for natural gas and NGL across all North American markets, and pipeline closures and restrictions on the TCPL system, which resulted in gas being streamed to Station 2, the Company's principal market, which is small and relatively inelastic. The redirection of natural gas to Station 2 resulted in a considerable increase in the pricing differential between Station 2 and AECO, the primary market for western Canadian gas. This widening of the differential exacerbated an already grim pricing environment and contributed to a reduction in field netback before hedging gains of 60% year over year and by 15% when compared to the second quarter of 2015.

The collapse of natural gas and NGL prices over the last several quarters is illustrated below:

| Average Quarterly Per-Unit Realized Price (Cdn$) | Natural Gas (Mcf) | | Natural Gas Liquids (Bbl) | | AECO-Station 2 Differential (GJ) | |
|---|---|---|---|---|---|---|
| Q1 – 2014 | $5.63 | 100% | $84.49 | 100% | $(0.48) | (9%) |
| Q2 – 2014 | $5.20 | 92% | $80.57 | 95% | $(0.24) | (5%) |
| Q3 – 2014 | $4.48 | 80% | $73.09 | 87% | $(0.27) | (7%) |
| Q4 – 2014 | $3.85 | 68% | $56.15 | 66% | $(0.48) | (14%) |
| Q1 – 2015 | $2.85 | 51% | $37.10 | 44% | $(0.58) | (22%) |
| Q2 – 2015 | $2.55 | 45% | $41.23 | 49% | $(0.51) | (20%) |
| Q3 – 2015 | $2.46 | 44% | $33.32 | 39% | $(1.03) | (42%) |

Cash flow for the quarter was $8.0 million, 32% less than the prior year and 2% less than the immediately prior quarter. Net debt at the end of the quarter amounted to $40.0 million resulting in a debt to annualized quarterly cash flow ratio of 1.2:1 or, using annualized year-to-date cash flow, a ratio of approximately 1:1.

No wells were drilled during the third quarter. However, of the inventory of nine standing wells at the beginning of the quarter, four wells were completed and tied in, leaving an inventory of five wells going into the final quarter of the year all of which remain to be completed.

The Company has taken steps to diversify the markets in which its natural gas is sold. In the third quarter, approximately 53% of natural gas production was sold at the Station 2 daily spot price: 46% at the AECO monthly price adjusted for the Station 2 differential: and 1% at the AECO daily spot price. During the fourth quarter, the Company expects that Station 2 daily spot pricing will apply to 40% of production: AECO monthly price less a fixed price differential will apply to 55% of production: the Chicago index (converted to Canadian dollars) will apply to 5% of production.

Gains from hedges realized during the quarter amounted to $1.8 million, or 21% of total field netback.

Cash costs per Boe for the quarter totaled $10.29, down 19% from the third quarter of 2014 and down 15% from the second quarter of 2015. Cost control was a contributor, as was the sale of certain higher cost properties effective July 15, 2015. Capital costs also fell; however, the limited field program in the third quarter makes it difficult to assess what capital cost reductions may be sustainable through the winter and into 2016.

## Production and Revenue

### Production by Area

The Company reported production from the following areas:

| Three Months to September 30, 2015 | | | | |
|---|---|---|---|---|
| Producing Area | Natural Gas (Mcf/d) | Natural Gas Liquids (Bbls/d) | Crude Oil (Bbls/d) | Boe/d |
| Umbach – NE BC | 45,888 | 1,684 | - | 9,332 |
| Horn River Basin – NE BC | 819 | - | - | 137 |
| Grande Prairie – AB | 618 | 13 | 70 | 185 |
| Total | 47,325 | 1,697 | 70 | 9,654 |

| Three Months to September 30, 2014 | | | | |
|---|---|---|---|---|
| Producing Area | Natural Gas (Mcf/d) | Natural Gas Liquids (Bbls/d) | Crude Oil (Bbls/d) | Boe/d |
| Umbach – NE BC | 28,344 | 1,099 | - | 5,823 |
| Horn River Basin – NE BC | 1,907 | - | - | 318 |
| Grande Prairie – AB | 3,423 | 55 | 394 | 1,019 |
| Total | 33,674 | 1,154 | 394 | 7,160 |

| Nine Months to September 30, 2015 | | | | |
|---|---|---|---|---|
| Producing Area | Natural Gas (Mcf/d) | Natural Gas Liquids (Bbls/d) | Crude Oil (Bbls/d) | Boe/d |
| Umbach – NE BC | 43,705 | 1,561 | - | 8,845 |
| Horn River Basin – NE BC | 1,395 | - | - | 232 |
| Grande Prairie – AB | 2,042 | 37 | 240 | 618 |
| Total | 47,142 | 1,598 | 240 | 9,695 |

| Nine Months to September 30, 2014 | | | | |
|---|---|---|---|---|
| Producing Area | Natural Gas (Mcf/d) | Natural Gas Liquids (Bbls/d) | Crude Oil (Bbls/d) | Boe/d |
| Umbach – NE BC | 21,860 | 818 | - | 4,461 |
| Horn River Basin – NE BC | 2,088 | - | - | 348 |
| Grande Prairie - AB | 3,719 | 64 | 412 | 1,095 |
| Total | 27,667 | 882 | 412 | 5,904 |

In the third quarter of 2015, average Boe-per-day volumes increased by 35% when compared to the third quarter of 2014 and volumes were flat when compared to the second quarter of 2015. For the nine month period ended September 30, 2015, average Boe production increased by 64% year over year. In the third quarter, approximately 2,900 Boe per day of production was shut in largely due to uneconomical gas pricing.

Production increases for natural gas and NGL, when compared to the same periods in 2014, are a consequence of growth at Umbach where the Company produced from 33 wells (29.4 net) during the third quarter. Crude oil production decreased due to the sale of largely all of the Company's Alberta properties in July 2015.

Daily production per million shares outstanding for the third quarter of 2015 averaged 81 Boe per day, compared to 64 Boe per day for the third quarter of 2014 and 85 Boe per day for the immediately preceding quarter. The reduction in production per share corresponds to the dilutive effect of an equity issue in the second quarter.

HRB produces dry natural gas, while Umbach produces natural gas and associated NGL. Production for the third quarter of 2015 approximated 82% natural gas, 17% NGL and 1% light oil. In mid-July, the Company sold largely all of its Alberta properties for proceeds of approximately $23.7 million. Production for the third quarter of 2015 from the remaining properties in Alberta was 50 Boe per day.

**Average Daily Production**

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Natural gas (Mcf/d) | 47,325 | 33,674 | 47,142 | 27,667 |
| Natural gas liquids (Bbls/d) | 1,697 | 1,154 | 1,598 | 882 |
| Crude oil (Bbls/d) | 70 | 394 | 240 | 412 |
| Total (Boe/d) | 9,654 | 7,160 | 9,695 | 5,904 |

**Production Profile and Per-Unit Prices(1)**

| | Three Months to Sept. 30, 2015 | | Three Months to Sept. 30, 2014 | | Nine Months to Sept. 30, 2015 | | Nine Months to Sept. 30, 2014 | |
|---|---|---|---|---|---|---|---|---|
| | Percentage of Total Boe Production | Average Selling Price Before Transportation Costs | Percentage of Total Boe Production | Average Selling Price Before Transportation Costs | Percentage of Total Boe Production | Average Selling Price Before Transportation Costs | Percentage of Total Boe Production | Average Selling Price Before Transportation Costs |
| Natural gas - Mcf | 82% | $ 2.46 | 78% | $ 4.48 | 81% | $ 2.62 | 78% | $ 5.02 |
| Natural gas liquids - Bbl | 17% | 33.32 | 16% | 73.09 | 16% | 37.13 | 15% | 78.33 |
| Crude oil - Bbl | 1% | 55.93 | 6% | 90.31 | 3% | 50.84 | 7% | 94.44 |
| Per Boe | 100% | $ 18.33 | 100% | $ 37.80 | 100% | $ 20.12 | 100% | $ 41.82 |

(1) Before realized hedging gains of $2.22 per Boe for the three months ended September 30, 2015 and $4.20 per Boe for the nine months ended September 30, 2015. In 2014, hedging losses amounted to $1.17 and $2.29 per Boe for the three and nine months ended September 30, 2014.

Approximately 53% of Storm's natural gas production in the third quarter was sold at the Station 2 daily spot price, 46% at the AECO monthly index price less $0.34 per GJ, and 1% at the AECO daily index price. During the third quarter, as a result of continuing pipeline capacity curtailments in Alberta, increasing volumes of natural gas were directed to Station 2.

Average quarterly index prices in gigajoules are as follows:

| (Cdn$/GJ) | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| AECO Monrhly Index | $ 2.65 | $ 4.00 | $ 2.66 | $ 4.31 |
| AECO Daily Index (spot) | $ 2.75 | $ 3.81 | $ 2.62 | $ 4.56 |
| BC Station 2 Daily Index (spot) | $ 1.72 | $ 3.54 | $ 1.92 | $ 4.23 |

The portion of Storm's natural gas sold at the AECO monthly index price aligns production with the Company's natural gas hedges.

Station 2 is a smaller and less liquid market than AECO and usually Station 2 trades at a modest discount to the AECO price (equal to the pipeline transportation tariff between both markets). However, in the first nine months of 2015, transmission interruptions and curtailments in Alberta resulted in increased natural gas volumes moving to the Station 2 market. Further, natural gas production also grew in geographic areas where production is normally directed to Station 2. The consequence was a considerable widening in the AECO – Station 2 differential with average Station 2 prices for the third quarter at an unprecedented discount to AECO of $1.03 compared to $0.27 for the third quarter of 2014. It should be recognized that the widening AECO – Station 2 differential has emerged in a period of collapsing natural gas prices. It is expected the pipeline restrictions that contributed to the widening differential will be reduced or end late this year which should lead to a lower differential.

Storm's realized price for the third quarter was $2.46 per Mcf, with the price higher than index prices as a result of sales gas at Umbach having a higher heat content.

The realized price for NGL in the third quarter of 2015 fell 54% relative to the third quarter of 2014 and fell 19% compared to the second quarter of 2015 as liquids prices fell along with crude oil prices. The NGL stream in the quarter contained 58% condensate and pentanes which are generally priced with reference to crude oil prices and received an average price of $49.40 per barrel. However, the price for propane collapsed with Storm's realized plantgate price being a negative $8.18 per barrel during the quarter. For the third quarter, WTI averaged US$46.43 per barrel and Edmonton light oil was Cdn$56.23 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$4.56 per barrel, compared to Cdn$8.67 per barrel in the third quarter of 2014. Production of crude oil is now an insignificant part of the Company's operations.

As Storm continues to increase natural gas production at Umbach, higher value condensate and pentane production will also increase.

On a per-Boe basis, the realized price for the third quarter of 2015 declined by 52% relative to the third quarter of 2014 and declined by 13% relative to the second quarter of 2015.

**Revenue from Product Sales[(1)]**

| (000s) | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Natural gas (Mcf/d) | $ 10,723 | $ 13,869 | $ 33,727 | $ 37,946 |
| Natural gas liquids (Bbls/d) | 5,202 | 7,758 | 16,199 | 18,852 |
| Crude oil (Bbls/d) | 358 | 3,275 | 3,330 | 10,612 |
| Total | $ 16,283 | $ 24,902 | $ 53,256 | $ 67,410 |

(1) Excludes hedging gains and losses.

Revenue from product sales for the third quarter of 2015 decreased by 35% when compared to the third quarter of 2014, with an average price per Boe for the third quarter of 2015 of $18.33, a year-over-year decrease of 52%. Production did grow by 35%; however, this only partially offset the calamitous fall in commodity prices. Compared to the second quarter of 2015, revenue from product sales fell by 12% with production being flat quarter over quarter.

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

| (000s) | Natural Gas | Natural Gas Liquids | Crude Oil | Total |
|---|---|---|---|---|
| Revenue from product sales – Q3 2014 | $ 13,869 | $ 7,758 | $ 3,275 | $ 24,902 |
| Effect of increased (decreased) production | 5,626 | 3,651 | (2,692) | 6,585 |
| Effect of change in product prices | (8,772) | (6,207) | (225) | (15,204) |
| Revenue from product sales – Q3 2015 | $ 10,723 | $ 5,202 | $ 358 | $ 16,283 |

The importance of a high value NGL stream merits emphasis. For the third quarter, NGL comprised 18% of total Boe production, but amounted to 32% of revenue from product sales.

## Hedging

The Company had in place the following hedging arrangements at the date of this report:

| Period Hedged | Daily Volume | Average Price |
|---|---|---|
| Crude Oil Collar | | |
| Jan – Dec 2016 | 500 Bbls | $75.00 - $90.75 Cdn$/Bbl |
| Natural Gas Swaps | | |
| Q4 – 2015 | 35,667 GJ | AECO Cdn$3.36/GJ |
| Q1 – 2016 | 5,000 GJ | AECO Cdn$3.06/GJ |
| Jan – Dec 2016 | 20,000 GJ | AECO Cdn$2.98/GJ |
| Natural Gas Differential Swaps | | |
| Jan – Dec 2016 | 11,000 GJ | Price at Stn 2 = AECO minus Cdn$0.3375/GJ |
| Jan – Dec 2017 | 5,000 GJ | Price at Stn 2 = AECO minus Cdn$0.445/GJ |
| Jan - Dec 2016 | 33,000 Mmbtu | Price at Chicago = AECO plus US$0.672/Mmbtu |
| Jan – Dec 2017 | 35,000 Mmbtu | Price at Chicago = AECO plus US$0.577/Mmbtu |

During the third quarter of 2015, the Company realized gains from hedges in the amount of $2.0 million, compared to losses of approximately $0.8 million in the third quarter of 2014. During the first nine months of 2015, the Company realized gains from hedges in the amount of $11.1 million compared to losses of $3.7 million in the same period in 2014. In January 2015 the Company terminated all of the Company's then existing crude oil contracts in exchange for $5.1 million. This amount is recognized as part of the realized gain on commodity price contracts in the consolidated statement of loss for the nine months to September 30, 2015. Details by commodity of realized gains and losses are provided on page 18. The fair market value of hedges in place at September 30, 2015 was $5.9 million.

Natural gas volumes are hedged at the AECO monthly index price and the Company targets selling equal physical volumes of natural gas at the same price.

The Company's hedging program is not based on a speculative assessment of the direction of commodity prices. The program's purpose is to reduce the effect of commodity price volatility on cash flow to enable the Company to maintain a disciplined and sustainable development program. This is of particular importance at Umbach, where exploitation of the resource is at an early stage and capital investment programs necessary to delineate the scope and scale of a potentially decades-long project have to be insulated from the effects of near-term price movements.

## Royalties

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period | $ 1,136 | $ 3,943 | $ 3,035 | $ 9,696 |
| Percentage of revenue from product sales | 7.0% | 15.8% | 5.7% | 14.4% |
| Per Boe | $ 1.28 | $ 5.99 | $ 1.15 | $ 6.02 |

Royalties in the third quarter of 2015 decreased by 71% when compared to the same quarter of 2014 and decreased by 60% when comparing the first nine months of 2015 to the first nine months of 2014. Decreased production revenue as a result of lower commodity pricing and the resulting lower royalty rates were the primary drivers of decreased royalties; however, royalties also decreased as a result of the receipt in January 2015 of an infrastructure royalty credit at Umbach of $1.0 million.

At Umbach, future production will further benefit from British Columbia's Infrastructure Royalty Credit Program. During 2012 and 2013, Storm received approval for $4.3 million of royalty credits ($3.4 million, net) for three pipeline projects. In late 2013, $0.8 million of this amount was applied in reduction of royalties with approximately $1.6 million being recovered in the second quarter of 2014. The remaining amount of $1.0 million was received in the first quarter of 2015. During 2014, approval was received for an additional net amount of $4.7 million of royalty credits for a facility and related gathering pipelines and, in 2015, the Company received approval for a further $5.5 million. Future royalties will thus be reduced by $10.2 million. The timing of receipt of future credits is dependent on commodity prices and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary.

In HRB, the Company received approval for an infrastructure royalty credit of $1.0 million in 2012 and received $0.3 million in 2014. Timing of receipt of the remaining $0.7 million is dependent on natural gas prices.

In March 2014, the British Columbia provincial government announced the expansion of the Deep Well Royalty Credit Program by extending royalty credits to all horizontal wells. Hitherto, wells with a vertical depth of less than 1,900 metres were not eligible for the program. Horizontal wells at Umbach, drilled after April 1, 2014, will receive a royalty credit of $0.5 million to $0.7 million per well, depending on the total measured vertical depth of the well. In conjunction with this change, wells that are eligible for this expanded credit program will bear a minimum royalty at a rate of 6%. Again, the timing of receipt of royalty credits under the program cannot be readily predicted: correspondingly, the royalty rate reported in future quarters may vary considerably.

No accounting recognition has been given to future benefits potentially accruing to Storm from the Infrastructure Royalty Credit and the Deep Well Royalty Credit programs.

Production of NGL is subject to a base royalty rate of 20% in British Columbia and approximately 25% to 30% in Alberta. This rate may be reduced if the royalty credit programs above have application.

### Production Costs

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period | $ 7,009 | $ 6,279 | $ 22,156 | $ 15,917 |
| Percentage of revenue from product sales | 43.0% | 25.2% | 41.6% | 23.6% |
| Per Boe | $ 7.89 | $ 9.53 | $ 8.37 | $ 9.87 |

Total production costs for the third quarter increased by 12% when compared to the third quarter of 2014 and decreased by 7% when compared to the second quarter of 2015. The year-over-year increase in total production costs is largely aligned with increased production at Umbach as per-Boe charges have continued to decline.

Production costs per Mcf of natural gas for the third quarter averaged $1.59 with total production costs averaging $7.89 per Boe, a year-over-year reduction of 17%. Production costs of natural gas liquids are included with natural gas costs. The equivalent charges for the third quarter of 2014 were $1.72 per Mcf of natural gas, with total production costs averaging $9.53 per Boe. For the nine month periods to September 30, per-Boe production costs averaged $8.37 in 2015 and $9.87 in 2014, a reduction of 15%. Contributing to the reduction in production costs was the July disposal of certain higher cost properties in Alberta.

Production costs per Boe have fallen due to production growth as well as lower cost natural gas growing as a percentage of the Company's production base.

Although per-unit production costs have fallen year over year, total production costs are 70% higher as a percentage of production revenue, a striking illustration of the effect falling commodity prices have on the profitability of the Company's business.

### Transportation Costs

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period | $ 836 | $ 1,111 | $ 3,335 | $ 2,802 |
| Percentage of revenue from product sales | 5.1% | 4.5% | 6.3% | 4.2% |
| Per Boe | $ 0.94 | $ 1.69 | $ 1.26 | $ 1.74 |

Transportation costs largely comprise pipeline tariffs from the sales point at the processing facility for natural gas, and trucking costs for wellhead condensate in British Columbia. Total transportation costs for the third quarter of 2015 fell by 25% over the same quarter of 2014. For the nine month periods to September 30, total transportation costs increased 19% due to higher production volumes while per-Boe transportation costs for both periods declined 44% and 28%, respectively, due to lower oil and NGL trucking charges as part of the overall transportation cost structure. The disposal of Alberta properties in the quarter should result in a sustainable reduction in transportation costs in future periods.

## Field Netbacks

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

| Three Months to September 30, 2015 | Natural Gas ($/Mcf) | Natural Gas Liquids ($/Bbl) | Crude Oil ($/Bbl) | Total ($/Boe) |
|---|---|---|---|---|
| Production revenue | $ 2.46 | $ 33.32 | $ 55.93 | $ 18.33 |
| Royalties | (0.09) | (4.52) | (2.81) | (1.28) |
| Production costs | (1.59) | - | (14.14) | (7.89) |
| Transportation costs | (0.12) | (1.87) | (3.98) | (0.94) |
| Field operating income before hedging | $ 0.66 | $ 26.93 | $ 35.00 | $ 8.22 |
| Realized hedging gains (losses) | 0.45 | - | - | 2.22 |
| Total operating income per commodity unit | $ 1.11 | $ 26.93 | $ 35.00 | $ 10.44 |
| Total operating income (000s) | $ 4,845 | $ 4,205 | $ 224 | $ 9,275 |

| Three Months to September 30, 2014 | Natural Gas ($/Mcf) | Natural Gas Liquids ($/Bbl) | Crude Oil ($/Bbl) | Total ($/Boe) |
|---|---|---|---|---|
| Production revenue | $ 4.48 | $ 73.09 | $ 90.31 | $ 37.80 |
| Royalties | (0.52) | (14.24) | (22.79) | (5.99) |
| Production costs | (1.72) | - | (25.91) | (9.53) |
| Transportation costs | (0.19) | (3.18) | (4.87) | (1.69) |
| Field operating income before hedging | $ 2.05 | $ 55.67 | $ 36.74 | $ 20.59 |
| Realized hedging gains (losses) | (0.19) | - | (4.95) | (1.17) |
| Total operating income per commodity unit | $ 1.86 | $ 55.67 | $ 31.79 | $ 19.42 |
| Total operating income (000s) | $ 5,736 | $ 5,909 | $ 1,153 | $ 12,798 |

| Nine Months to September 30, 2015 | Natural Gas ($/Mcf) | Natural Gas Liquids ($/Bbl) | Crude Oil ($/Bbl) | Total ($/Boe) |
|---|---|---|---|---|
| Production revenue | $ 2.62 | $ 37.13 | $ 50.84 | $ 20.12 |
| Royalties | (0.04) | (5.54) | (2.45) | (1.15) |
| Production costs | (1.63) | - | (18.22) | (8.37) |
| Transportation costs | (0.16) | (2.38) | (4.56) | (1.26) |
| Field operating income before hedging | $ 0.79 | $ 29.21 | $ 25.61 | $ 9.34 |
| Realized hedging gains (losses) | 0.46 | - | 78.42 | 4.20 |
| Total operating income per commodity unit | $ 1.25 | $ 29.21 | $ 104.03 | $ 13.54 |
| Total operating income (000s) | $ 16,278 | $ 12,744 | $ 6,814 | $ 35,837 |

| Nine Months to September 30, 2014 | Natural Gas ($/Mcf) | Natural Gas Liquids ($/Bbl) | Crude Oil ($/Bbl) | Total ($/Boe) |
|---|---|---|---|---|
| Production revenue | $ 5.02 | $ 78.33 | $ 94.44 | $ 41.82 |
| Royalties | (0.45) | (15.57) | (22.92) | (6.02) |
| Production costs | (1.79) | - | (21.37) | (9.87) |
| Transportation costs | (0.19) | (2.97) | (5.60) | (1.74) |
| Field operating income before hedging | $ 2.59 | $ 59.79 | $ 44.55 | $ 24.19 |
| Realized hedging gains (losses) | (0.37) | - | (7.81) | (2.29) |
| Total operating income per commodity unit | $ 2.22 | $ 59.79 | $ 36.74 | $ 21.90 |
| Total operating income (000s) | $ 16,793 | $ 14,387 | $ 4,130 | $ 35,311 |

Note: Production costs of natural gas liquids are included with natural gas costs.

Total operating income in the third quarter of 2015 declined by 28% when compared to the same quarter of 2014. Per Boe, excluding hedging gains and losses, field operating income fell by 60% in the third quarter of 2015 in comparison to the same quarter of 2014, and by 15% compared to the second quarter of 2015. For the third quarter, year-over-year royalties, production and transportation costs per Boe each fell considerably, but these gains were insufficient to counter the effect of reduced commodity prices which saw the per-Boe realization fall by $19.47, or, an unprecedented 52%. Compared to the second quarter of 2015, all field cost categories fell.

Controllable cash costs per Boe, comprising production costs, general and administrative costs and interest, amounted to $9.35 for the third quarter of 2015, $11.07 for the equivalent quarter of 2014 and $10.94 for the second quarter of 2015. Comparing the third quarter of 2015 to the same quarter in 2014, all components of cash costs decreased on a per-Boe basis except for a small increase in general and administrative costs as recoveries fell due to lower capital spending in the current quarter. Compared to the second quarter of 2015, all per-Boe cash costs declined.

## General and Administrative Costs

| Total Costs | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period – before recoveries | $ 1,411 | $ 1,278 | $ 5,947 | $ 4,375 |
| Overhead recoveries | (463) | (634) | (1,701) | (1,646) |
| Charge for period – net of recoveries | $ 948 | $ 644 | $ 4,246 | $ 2,729 |
| Per Boe | $ 1.07 | $ 0.98 | $ 1.60 | $ 1.69 |

Gross general and administrative costs for the third quarter and first nine months of 2015 increased by 10% and 36%, respectively, when compared to the same periods of 2014. The year-on-year increase in total general and administrative costs is largely attributable to increased personnel costs. Overhead recoveries fell in the third quarter of 2015 compared to the prior year due to lower field activity.

## Share-Based Compensation

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period | $ 821 | $ 611 | $ 2,589 | $ 1,436 |
| Per Boe | $ 0.92 | $ 0.93 | $ 0.98 | $ 0.89 |

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 increased by 34% in the third quarter of 2015 compared to the same quarter of 2014. The year-over-year increase in share-based compensation in both the three and nine month periods of 2015 is attributable to stock options granted in March and December of 2014.

## Depletion and Depreciation

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Depletion | $ 7,336 | $ 6,587 | $ 22,834 | $ 16,904 |
| Depreciation | 1,043 | 1,021 | 3,442 | 2,468 |
| Charge for period | $ 8,379 | $ 7,608 | $ 26,276 | $ 19,372 |
| Per Boe | $ 9.43 | $ 11.55 | $ 9.93 | $ 12.02 |

Property and equipment assets are subject to depletion and depreciation charges. Depletion is calculated using unit-of-production methodology under which intangible drilling and completion costs plus future development costs associated with individual cash generating units are depleted using a factor calculated by dividing production for the reporting period by proved plus probable reserves at the beginning of the period.

The charge for depreciation for the period relates to facility and tangible equipment costs and office equipment included with property and equipment costs. Such costs are depreciated over the useful life of the asset on a straight line basis.

Higher production volumes for the third quarter of 2015 resulted in the total charge for depletion increasing year over year by 11% in the third quarter of 2015, less than the 35% increase in production in the same periods. The year-over-year per-Boe charge for depletion fell by 17%, as the finding and development cost for proved plus probable reserves has declined, reflecting Storm's successful development program as well as the sale of Alberta properties in July 2015. Increased depreciation charges year over year for the nine month periods corresponds to increased investment in facilities.

Management reviewed the carrying amounts of exploration and evaluation and property and equipment assets for indicators of impairment at September 30, 2015 and determined that no impairment adjustment was required.

### Exploration and Evaluation Costs Expensed

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period | $ 51 | $ 7 | $ 154 | $ 275 |
| Per Boe | $ 0.06 | $ 0.01 | $ 0.06 | $ 0.17 |

Exploration and evaluation costs is a non-cash charge representing the cost of undeveloped lands with lease terms expiring in the quarter.

### Accretion

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period | $ 84 | $ 91 | $ 354 | $ 241 |

Accretion represents the time value increase for the period of the Company's decommissioning liability. The increased charge for accretion for the nine month period of 2015 compared to the same period of 2014 is due to continuing field investment and to changes in estimates of future costs and discount rates. The decreased charge in the third quarter of 2015 compared to 2014 is due to the reduction in the decommissioning liability as a result of the sale, in July, of Alberta properties.

### Interest and Finance Costs

| (000's) | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Charge for period | $ 345 | $ 370 | $ 1,727 | $ 1,062 |
| Percentage of revenue from product sales | 2.1% | 1.0% | 3.2% | 1.6% |
| Per Boe | $ 0.39 | $ 0.56 | $ 0.65 | $ 0.66 |

Interest costs for the third quarter fell by 55% year over year and were largely the same when compared to the second quarter of 2015.

For the nine month period, interest costs in 2015 increased year over year as a result of expanded bank borrowings corresponding to an expanding production and asset base. The equity issue closing in June 2015, and the sale of the Alberta properties in July 2015, reduced interest costs in the third quarter.

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-from-operations ratio.

## Gain on Disposal of Investments

In the first quarter of 2014, the Company sold 1.0 million common shares of Chinook Energy Inc. ("Chinook") for proceeds of $1.5 million recognizing a gain of $0.3 million. In the second quarter of 2014, the Company sold 1.0 million common shares of Chinook for proceeds of $2.3 million for a gain of $1.2 million. There have been no further sales of Chinook common shares.

## Realized and Unrealized Gain (Loss) on Commodity Price Contracts

The realized gain (loss) on commodity price contracts comprises cash settlements on contracts which, in whole or in part, have come to term during the period, plus cash settlements relating to contracts which the Company terminated prior to the expiry date.

The unrealized gain (loss) on commodity price contracts results from the mark-to-market valuation of the unexpired portion of hedging contracts outstanding at the end of the reporting period. The change in fair value recognizes not only the mark-to-market change in the value of contracts outstanding both at the beginning and end of the reporting period, but includes the opening value of contracts which have come to term during the reporting period.

| | Three Months to Sept. 30, 2015 | | | | | Three Months to Sept. 30, 2014 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Realized gain (loss) | | | | | | | | | | |
| Crude oil | $ | - | $ | - | /Bbl | $ | (180) | $ | (4.95) | /Bbl |
| Natural gas | | 1,973 | $ | 0.45 | /Mcf | | (591) | $ | (0.19) | /Mcf |
| Total realized gain (loss) – cash | $ | 1,973 | $ | 2.22 | /Boe | $ | (771) | $ | (1.17) | /Boe |

| | Nine Months to Sept. 30, 2015 | | | | | Nine Months to Sept. 30, 2014 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Realized gain (loss) | | | | | | | | | | |
| Crude oil | $ | 5,137 | $ | 78.42 | /Bbl | $ | (877) | $ | (7.81) | /Bbl |
| Natural gas | | 5,970 | $ | 0.46 | /Mcf | | (2,807) | $ | (0.37) | /Mcf |
| Total realized gain (loss) – cash | $ | 11,107 | $ | 4.20 | /Boe | $ | (3,684) | $ | (2.29) | /Boe |

| | Three Months to Sept. 30, 2015 | | | | | Three Months to Sept. 30, 2014 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Unrealized gain (loss) | | | | | | | | | | |
| Crude oil – change in fair value | $ | 2,234 | $ | 13.75 | /Bbl | $ | 1,016 | $ | 28.02 | /Bbl |
| Natural gas – change in fair value | | (1,486) | $ | (0.34) | /Mcf | | 1,010 | $ | 0.33 | /Mcf |
| Total unrealized gain (loss) – non-cash | $ | 748 | $ | 0..84 | /Boe | $ | 2,026 | $ | 3.08 | /Boe |

| | Nine Months to Sept. 30, 2015 | | | | | Nine Months to Sept. 30, 2014 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Unrealized gain (loss) | | | | | | | | | | |
| Crude oil – change in fair value | $ | (2,726) | $ | (41.61) | /Bbl | $ | 490 | $ | 4.36 | /Bbl |
| Natural gas – change in fair value | | (4,262) | $ | (0.33) | /Mcf | | 151 | $ | 0.02 | /Mcf |
| Total unrealized gain (loss) – non-cash | $ | (6,988) | $ | (2.64) | /Boe | $ | 641 | $ | 0.40 | /Boe |

## Income Taxes

Due to uncertainty of realization, no deferred income tax asset has been set up in respect of potential future income tax reductions resulting from the use of accumulated tax losses. Details of Storm's tax pools are as follows:

| Tax Pool | As at September 30, 2015 | | Maximum Annual Deduction |
|---|---|---|---|
| Canadian oil and gas property expense | $ | 42,000 | 10% |
| Canadian development expense | | 98,000 | 30% |
| Canadian exploration expense | | 22,000 | 100% |
| Undepreciated capital cost | | 85,000 | 20 - 100% |
| Operating losses | | 156,000 | 100% |
| Other | | 5,000 | 20 - 100% |
| Total | $ | 408,000 | |

## Net Income (Loss)

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Net income (loss) | $ (961) | $ 5,473 | $ (8,717) | $ 12,277 |
| Per basic and diluted share | $ (0.01) | $ 0.05 | $ (0.08) | $ 0.11 |

## Other Comprehensive Income (Loss)

Other comprehensive income comprises net income (loss) for the period plus unrealized gains and losses resulting from the mark-to-market valuation of certain assets and liabilities. For the nine months ended September 30, 2015, a loss of $110,000 was recognized in other comprehensive income representing the reversal of prior mark- to-market gains in value of the investment in Chinook.

| Listed Securities | Holding | Number of Shares[(1)] | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|---|---|
| Chinook Energy Inc. | Common Shares | 1,000,000 | $ - | $ (170) | $ (110) | $ 890 |
| Other comprehensive income (loss) for period | | | $ - | $ (170) | $ (110) | $ 890 |

(1) Shares owned at September 30, 2015.

## Non-GAAP Funds from Operations and Funds from Operations Per Share

| | Three Months to Sept. 30, 2015 | | Three Months to Sept. 30, 2014 | | Nine Months to Sept. 30, 2015 | | Nine Months to Sept. 30, 2014 | |
|---|---|---|---|---|---|---|---|---|
| | | Per diluted share | | Per diluted share | | Per diluted share | | Per diluted share |
| Funds from operations | $ 7,982 | $0.07 | $11,784 | $0.11 | $29,864 | $0.26 | $31,520 | $0.29 |

Non-GAAP funds from operations for the third quarter of 2015 decreased by 32% year over year and, for the nine month period, decreased by 5% when comparing 2015 to 2014. Compared to the immediately prior quarter, non-GAAP funds from operations for the quarter ended September 30, 2015 fell by 2%.

Non-GAAP funds from operations is not a measure recognized by GAAP, although it is widely used by investors, analysts and other financial statement users. It is also used by the Company's banking syndicate to determine debt-to-cash-flow ratios and other measures of credit worthiness and thus determines interest rates on borrowings. The most directly comparable measure under GAAP is cash flows from operating activities, as set out below.

## Cash Flows from Operating Activities

| | Three Months to Sept. 30, 2015 | | Three Months to Sept. 30, 2014 | | Nine Months to Sept. 30, 2015 | | Nine Months to Sept. 30, 2014 | |
|---|---|---|---|---|---|---|---|---|
| | | Per diluted share | | Per diluted share | | Per diluted share | | Per diluted share |
| Non-GAAP funds from operations | $ 7,982 | $0.07 | $11,784 | $0.11 | $29,864 | $0.26 | $31,520 | $0.29 |
| Net change in non-cash working capital items | (2,295) | (0.02) | (1,081) | (0.01) | (1,447) | (0.01) | (662) | (0.01) |
| Cash from operating activities | $ 5,687 | $0.05 | $10,703 | $0.10 | $28,417 | $0.25 | $30,858 | $0.28 |

The reconciling item between funds from operations and cash flows from operating activities is the change in non-cash operating working capital items.

## Corporate Netbacks

| ($/Boe) | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Revenue from product sales | 18.33 | 37.80 | 20.12 | 41.82 |
| Realized hedging gains (losses) | 2.22 | (1.17) | 4.20 | (2.29) |
| Royalties | (1.28) | (5.99) | (1.15) | (6.02) |
| Production | (7.89) | (9.53) | (8.37) | (9.87) |
| Transportation | (0.94) | (1.69) | (1.26) | (1.74) |
| General and administrative | (1.07) | (0.98) | (1.60) | (1.69) |
| Interest | (0.39) | (0.56) | (0.65) | (0.66) |
| Funds from operations | 8.98 | 17.88 | 11.29 | 19.55 |
| Share-based compensation | (0.92) | (0.93) | (0.98) | (0.89) |
| Depletion, depreciation and accretion | (9.52) | (11.69) | (10.06) | (12.17) |
| Exploration and evaluation costs expensed | (0.06) | (0.01) | (0.06) | (0.17) |
| Gain on disposal of investments | - | - | - | 0.92 |
| Unrealized revaluation gain (loss) on investments | (0.37) | - | (0.21) | - |
| Loss on sale of oil and gas properties | (0.03) | (0.03) | (0.63) | (0.03) |
| Unrealized gain (loss) on commodity price contracts | 0.84 | 3.08 | (2.64) | 0.40 |
| Net income (loss) per Boe | (1.08) | 8.30 | (3.29) | 7.61 |

# INVESTMENT AND FINANCING

## Financial Resources and Liquidity

At the beginning of 2014, Storm's bank facility amounted to $65.0 million. In May and November 2014, the facility was increased to $90.0 million and $130.0 million respectively, in recognition of production and reserve growth at Umbach. In April 2015, the facility was again increased to $150.0 million. In July 2015, subsequent to the disposal of certain non-core assets in Alberta, the facility was reduced to $140.0 million, of which amount 24% was drawn at September 30, 2015. The facility is currently under mid-year review.

The Company is in compliance with all covenants under the credit facility, the sole financial covenant being that net debt, including working capital deficiency, cannot exceed the facility credit limit.

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 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 reports to the Board at least four times a year.

## Investments

The Company owns listed shares as set out below, which are valued at the closing price on the TSX at September 30, 2015.

| | Holding | Number of Shares | Exchange | Closing Price Sept.30, 2015 | Value at Sept.30, 2015 |
|---|---|---|---|---|---|
| Chinook Energy Inc. | Common Shares | 1,000,000 | TSX | $ 0.61 | $ 610 |

In the first quarter of 2014, the Company sold 1.0 million shares of Chinook for net proceeds of $1.5 million and recognized a gain of $0.3 million. In the second quarter of 2014, the Company sold an additional 1.0 million shares for net proceeds of $2.3 million and recognized a gain of $1.2 million. There have been no further sales of Chinook common shares. Ownership of Chinook shares is a legacy asset from a prior Storm company and is not a core asset.

## Capital Expenditures

For the quarter to September 30, 2015, the Company's capital expenditures totaled $19.6 million (2014 - $30.4 million), almost all of which was spent at Umbach completing four horizontal wells, expanding field facilities and laying pipelines. In July 2015 the Company completed the disposition of certain non-core properties in the Grande Prairie area of Alberta for net proceeds of approximately $23.7 million.

In the nine months of 2015, the Company drilled six 100% working interest horizontal wells, completed six horizontal wells and one salt water disposal well, tied in eight horizontal wells and completed expansions of a compressor station at Umbach which added compression capacity of 37 Mmcf per day, a condensate stabilizer and a fuel gas conditioning unit. A 15-kilometre pipeline was built to a third party natural gas processing plant. Major field capital outlays in the nine months of 2015 include $30.1 million on drilling and completions and $32.1 million on facilities, equipping and tie-ins, all in the Umbach area.

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Land and lease | $ 234 | $ 567 | $ 754 | $ 1,421 |
| Drilling | 619 | 6,644 | 12,992 | 33,380 |
| Completions | 10,118 | 4,844 | 17,084 | 22,320 |
| Facilities and pipelines | 8,474 | 17,479 | 32,106 | 26,835 |
| Recompletions and workovers | 106 | 867 | 1,138 | 2,369 |
| Property and facility acquisitions | - | - | - | 88,075 |
| Property acquisition, adjustments, and administrative assets | 6 | 25 | 27 | 60 |
| Total expenditures | $ 19,557 | $ 30,426 | $ 64,101 | $ 174,460 |
| Proceeds on disposition of oil and gas properties | (23,673) | - | (23,673) | - |
| Net capital expenditures | $ (4,116) | $ 30,426 | $ 40,428 | $ 174,460 |

Capital expenditures in the reporting periods were allocated as follows:

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Exploration and evaluation | $ (1,665) | $ 245 | $ (1,165) | $ 80,585 |
| Property and equipment | (2,451) | 30,181 | 41,593 | 93,875 |
| Total – net of dispositions | $ (4,116) | $ 30,426 | $ 40,428 | $ 174,460 |

## 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 September 30, 2015 corresponds to the active field program at Umbach.

## Decommissioning Liability

The Company's decommissioning liability 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 amount of the liability at September 30, 2015 reflects (i) liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, (iii) changes in the amount of future costs and timing of incurrence of such costs, (iv) less decommissioning obligations associated with dispositions of oil and gas properties, (v) less actual decommissioning costs incurred, (vi) plus the time-related increase in the present value of the liability. The risk-free discount rate used to establish the present value is 2.3%. Future costs to abandon and reclaim the Company's properties are based on a continuous internal evaluation including monitoring actual abandonment and reclamation costs which is also supported by external information from industry sources and has regard to industry best practices, provincial and other regulation and evolution of same.

## Shareholders' Equity

Details of share issuances from inception to September 30, 2015 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 Dec.31/14 | Stock option exercises | 1,710 | $ 3.26 | 5,580 |
| | | 23,839 | | 98,355 |
| June 10, 2015 | Issued under private placement | 8,000 | $ 4.55 | 36,400 |
| Nine months ended Sept.30/15 | Stock option exercises | 33 | $ 1.83 | 60 |
| | | 8,033 | | 36,460 |
| Total at September 30, 2015 | | 119,355 | $ 3.28 | $ 391,714 |

(1) Before share issue costs.

On January 31, 2014, the Company issued 13,629,442 common shares at a fair value under IFRS of $4.25 per share, as partial consideration for the acquisition of two horizontal wells, producing 359 Boe net per day, and 29 sections of undeveloped land directly adjacent to Storm's 100% working interest lands in Umbach South. The total cost of the acquisition was approximately $87.9 million including $30.2 million in cash.

In February 2014, the Company issued 7,250,000 common shares pursuant to a bought deal financing at a price of $4.10 per common share for gross proceeds of $29,725,000. At the same time, the Company issued to certain directors, officers and employees of the Company 1,250,000 common shares pursuant to a non-brokered financing at a price of $4.10 per common share for gross proceeds of $5,125,000. Both of these financings closed on February 14, 2014. Net proceeds received totaled $33.0 million.

In June 2015, the Company issued 8,000,000 common shares pursuant to a bought deal financing at a price of $4.55 per common share for gross proceeds of $36,400,000. This financing closed on June 10, 2015. Net proceeds received totaled $34.2 million.

During the first nine months of 2015, stock options were exercised at an average price of $1.83 per optioned share and 33,000 common shares were issued for proceeds of $60,000.

Issued and outstanding common shares at September 30, 2015 and November 11, 2015, the date of this MD&A, totaled 119,354,978.

## 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 agreement; and
- hedging contracts.

All such contractual obligations reflect market conditions at the time of contract and do not involve related parties. At present the Company has a lease of office premises for a period of five years commencing October 1, 2013 for a base rent, not including operating costs, totaling approximately $3.0 million over the term of the lease. Current monthly operating costs amount to $28,300. In addition, the Company has gas transportation and processing commitments valued at a total of approximately $149.3 million over the period to December 31, 2020.

## QUARTERLY RESULTS

Summarized information by quarter for the two years ended September 30, 2015 appears below:

| | 2015 | | | 2014 | | | | 2013 |
|---|---|---|---|---|---|---|---|---|
| | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 |
| Production revenue ($000s)[1] | 18,256 | 20,236 | 25,871 | 28,556 | 24,131 | 20,202 | 19,393 | 15,420 |
| Non-GAAP funds from operations ($000s)[2] | 7,982 | 8,170 | 13,712 | 13,892 | 11,784 | 11,076 | 8,660 | 7,501 |
| Per share | | | | | | | | |
| - basic ($) | 0.07 | 0.07 | 0.12 | 0.13 | 0.11 | 0.10 | 0.09 | 0.09 |
| - diluted ($) | 0.07 | 0.07 | 0.12 | 0.12 | 0.11 | 0.10 | 0.08 | 0.09 |
| Net income (loss) ($000s) | (961) | (4,191) | (3,565) | (7,422) | 5,473 | 6,598 | 206 | (25,174) |
| Per share | | | | | | | | |
| - basic ($) | (0.01) | (0.04) | (0.03) | (0.07) | 0.05 | 0.06 | 0.00 | (0.34) |
| - diluted ($) | (0.01) | (0.04) | (0.03) | (0.07) | 0.05 | 0.06 | 0.00 | (0.34) |
| Net capital expenditures ($000s) | (4,116)[4] | 8,864 | 35,680 | 20,095 | 30,426 | 33,640 | 110,394 | 11,380 |
| Average daily production - Boe | 9,654 | 9,657 | 9,776 | 10,173 | 7,160 | 5,462 | 5,068 | 4,773 |
| Net debt ($000s)[3] | 39,994 | 28,051 | 85,098 | 63,080 | 56,157 | 41,837 | 22,176 | 12,059 |

(1) Includes realized hedging gains and losses.
(2) See Non-GAAP Measurements on page 26 of this MD&A.
(3) Includes investments and working capital deficiency and excludes the fair value of commodity price contracts.
(4) Net of property disposition for proceeds of $23.7 million.

## CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the period ended September 30, 2015 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 using information which may involve an element of measurement uncertainty. Variations between amounts estimated and included in the financial statements and actual results subsequently realized could have a material effect on Storm's operating results and financial position.

## Accounting for Acquisitions

Acquisitions completed in earlier reporting periods necessitated the allocation of fair values to the assets acquired and the liabilities assumed. The determination of fair values was made by management of Storm and involved measurements, estimations and judgments which could differ from similar determinations made by other parties. Further, fair values were set using management's knowledge of the assets and liabilities of the acquired assets or companies at the time of acquisition or subsequently, and information and circumstances may emerge that could result in changes to the fair values set by management. The allocation of fair values thus involves measurement uncertainty and changes thereto could have a material effect on operating results and financial position.

## Accounts Payable and Accrued Liabilities

At the end of each reporting period, the Company estimates the cost of services and materials provided during the reporting period if these costs have not been invoiced to the Company by the reporting date. The Company estimates and recognizes the cost of such unbilled services and materials using well established measurement procedures. Nonetheless, such procedures may reflect judgment by management and are thus subject to measurement uncertainty. In addition, estimates of services and materials not invoiced relate in large part to the Company's capital programs, the level of which can vary considerably between reporting periods. As a result, the amount of 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 obligation.

## 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. 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.

## 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. Accordingly, the amounts of tax pools available for future use may differ significantly from the amounts estimated in the financial statements.

## 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.

## Exploration and Evaluation Assets

Costs incurred by the Company in the initial 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 are expensed if the Company 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 residual balance of exploration and evaluation assets at the end of each reporting period represents an asset whose value can only be established in future periods.

### Property and Equipment and Depletion and Depreciation

Generally, upon commencement of production, the Company transfers from exploration and evaluation assets to property and equipment assets an amount representing the accumulated net costs associated with the property. 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.

Property and equipment assets are 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 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 such reserves. Further, for non-reserve assets such as facilities and pipelines, estimates of the useful life of these assets must be made. 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 and adjustments to the carrying amount may be made. All of these involve assumptions regarding future events and circumstances and involve a high degree of uncertainty.

## LIMITATIONS

**Forward-Looking Statements** – Certain information set forth in this document, including management's assessment of Storm's future plans and operations, 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. Without limitation, any statements regarding the following are forward-looking statements:

- future commodity prices;
- future production volumes, production volumes by commodity and production declines;
- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- future capital expenditures and their allocation to specific projects, activities or periods;
- future drilling, completion and tie-in of wells;
- future facility access, acquisition, construction and entry in service;
- future earnings or losses, including per-share amounts;
- future non-GAAP funds from operations and future cash flows, including per-share amounts;
- future availability of financing;
- future asset acquisitions or dispositions;
- intentions with respect to investments;
- future sources of funding for capital programs and future availability of such sources;
- development plans;
- estimates regarding the carrying amount of exploration and evaluation costs;
- estimates regarding the carrying amount of property and equipment;
- future debt levels;
- availability of credit facilities;
- future decommissioning costs, inflation rates and discount rates used to determine the net present value of such costs;
- future tax liabilities and future use of tax pools and losses;
- measurement and recoverability of reserves or contingent resources including estimates of DPIIP and timing of such recoverability;
- estimates of ultimate recovery from wells;
- future finding and development costs;
- estimates of the future life of depreciable assets;
- future royalties, transportation costs, operating costs, interest and general and administrative costs;
- effect of existing and future agreements with respect to processing, transportation and marketing of natural gas;
- future provisions for depletion and depreciation and accretion;
- expected 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;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs; and
- changes to any of the foregoing.

Statements relating to “reserves” or “resources” 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”; “Risk Assessment”; “Financial Reporting Update”; and the material assumptions described under the headings “Overview”; “Production and Revenue”; “Hedging”; “Royalties”; “Production Costs”; “Transportation Costs”; “Field Netbacks”; “General and Administrative Costs”; “Share-Based Compensation”; “Depletion and Depreciation”; “Exploration and Evaluation Costs Expensed”; “Accretion”; “Interest and Finance Costs”; “Gain on Disposal of Investments”; “Realized and Unrealized Gain (Loss) on Commodity Price Contracts”; “Income Taxes”; “Net Income (Loss)”; “Other Comprehensive Income (Loss)”; “Financial Resources and Liquidity”; “Investments”; “Accounts Payable and Accrued Liabilities”; “Decommissioning Liability”; “Shareholders’ Equity”; “Contractual Obligations”; industry conditions including commodity prices, capacity constraints and access to processing facilities and to market for production, volatility of commodity prices, 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 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. 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 oil in the ratio of six thousand cubic feet of gas to one barrel of oil.

**Non-GAAP Measurements** - Within this MD&A, references are made to terms which are not recognized under Generally Accepted Accounting Principles (“GAAP”). Specifically, “funds from operations”, “funds from operations per share”, “netbacks”, “field netbacks”, “field operating income”, “total operating income”, “cash costs”, and measurements “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. In particular, funds from operations is not intended to represent, or be equivalent to, cash flow from operating activities calculated in accordance with GAAP, which is measured on the Company’s consolidated statements of cash flows. Funds from operations and other 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. Funds from operations is also used by lenders to measure compliance with debt covenants and thus set interest costs. Reference is made to the discussion in this MD&A under “Non-GAAP Funds from Operations and Funds from Operations per Share” and to “Cash Flows from Operating Activities”.

# RISK ASSESSMENT

There are a number of risks facing participants in the Canadian oil and gas industry. Some risks are common to all businesses while others are specific to the industry. Information with respect to such risks is set out in Storm's Annual Information Form dated March 31, 2015 for the year ended December 31, 2014 under the heading "Risk Factors" and in Storm's MD&A for the period ended December 31, 2014 under the heading "Risk Assessment".

# FINANCIAL REPORTING UPDATE

### Accounting Changes

*Future Accounting Policies*

Financial Instruments

IFRS 9 Financial Instruments is intended to replace IAS 39 Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and also requires a single impairment method to be used, replacing the multiple rules of IAS 39. Although new hedge accounting requirements have been introduced, Storm does not employ hedge accounting for risk management contracts currently in place. This standard is effective for annual periods beginning on or after January 1, 2018.

Revenue

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers which replaces IAS18 and IAS11. The standard is required to be adopted for fiscal years beginning on or after January 1, 2018.

The Company is currently evaluating the effect of these standards on Storm's financial statements.

# 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 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4.

# CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

## Interim Consolidated Statements of Financial Position

| (Canadian $000s) (unaudited) | September 30, 2015 | December 31, 2014 |
|---|---|---|
| **ASSETS** | | |
| **Current** | | |
| Accounts receivable (Note 11) | $ 6,596 | $ 8,205 |
| Prepaids and deposits | 849 | 905 |
| Investments (Note 3) | 610 | 1,270 |
| Fair value of commodity price contracts (Note 11) | 5,932 | 12,920 |
| | 13,987 | 23,300 |
| Exploration and evaluation (Note 4) | 123,603 | 126,805 |
| Property and equipment (Note 5) | 275,478 | 268,463 |
| | $ 413,068 | $ 418,568 |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current** | | |
| Accounts payable and accrued liabilities | $ 14,904 | $ 27,430 |
| | 14,904 | 27,430 |
| Bank indebtedness (Note 6) | 33,145 | 46,030 |
| Decommissioning liability (Note 7) | 15,391 | 23,553 |
| | 63,440 | 97,013 |
| **Shareholders' equity** | | |
| Share capital (Note 8) | 385,491 | 351,161 |
| Contributed surplus (Note 9) | 5,933 | 3,363 |
| Deficit | (41,796) | (33,079) |
| Accumulated other comprehensive income | - | 110 |
| | 349,628 | 321,555 |
| Commitments (Note 13) | | |
| | $ 413,068 | $ 418,568 |

See accompanying notes to the condensed interim consolidated financial statements.

On behalf of the Board:

Director

Director

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

| (Canadian $000s except per-share amounts) (unaudited) | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| **Revenue** | | | | |
| Revenue from product sales | $ 16,283 | $ 24,902 | $ 53,256 | $ 67,410 |
| Royalties | (1,136) | (3,943) | (3,035) | (9,696) |
| | $ 15,147 | $ 20,959 | $ 50,221 | $ 57,714 |
| Realized gain (loss) on commodity price contracts (Note 11) | 1,973 | (771) | 11,107 | (3,684) |
| Unrealized gain (loss) on commodity price contracts (Note 11) | 748 | 2,026 | (6,988) | 641 |
| | 2,721 | 1,255 | 4,119 | (3,043) |
| **Expenses** | | | | |
| Production | 7,009 | 6,279 | 22,156 | 15,917 |
| Transportation | 836 | 1,111 | 3,335 | 2,802 |
| General and administrative (Note 13) | 948 | 644 | 4,246 | 2,729 |
| Share-based compensation (Note 9) | 821 | 611 | 2,589 | 1,436 |
| Depletion and depreciation (Note 5) | 8,379 | 7,608 | 26,276 | 19,372 |
| Exploration and evaluation costs expensed (Note 4) | 51 | 7 | 154 | 275 |
| Accretion (Note 7) | 84 | 91 | 354 | 241 |
| | 18,128 | 16,351 | 59,110 | 42,772 |
| **Income (loss) before the following:** | (260) | 5,863 | (4,770) | 11,899 |
| Interest and finance costs | (345) | (370) | (1,727) | (1,062) |
| Gain on disposal of investments (Note 3) | - | - | - | 1,486 |
| Unrealized loss on investments (Note 3) | (330) | - | (550) | - |
| Loss on sale of oil and gas properties (Note 5) | (26) | (20) | (1,670) | (46) |
| **Net income (loss) for the period** | (961) | 5,473 | (8,717) | 12,277 |
| Other comprehensive income (loss) | | | | |
| Reversal of prior period unrealized (gain) loss on investments (Note 3) | - | (170) | (110) | 890 |
| **Comprehensive income (loss) for the period** | $ (961) | $ 5,303 | $ (8,827) | $ 13,167 |
| **Net income (loss) per share (Note 10)** | | | | |
| **- basic** | $ (0.01) | $ 0.05 | $ (0.08) | $ 0.11 |
| **- diluted** | $ (0.01) | $ 0.05 | $ (0.08) | $ 0.11 |

See accompanying notes to the condensed interim consolidated financial statements.

## Interim Consolidated Statements of Changes in Shareholders' Equity

| (Canadian $000s) (unaudited) | | | | Nine Months to September 30, 2015 | |
|---|---|---|---|---|---|
| | Share Capital | Contributed Surplus | Deficit | Accumulated Other Comprehensive Income | Total Equity |
| Balance, beginning of period | $351,161 | $ 3,363 | $ (33,079) | $ 110 | $321,555 |
| Net loss for the period | - | - | (8,717) | - | (8,717) |
| Issue of common shares (Note 8) | 36,460 | - | - | - | 36,460 |
| Share issue costs (Note 8) | (2,149) | - | - | - | (2,149) |
| Share-based compensation (Note 9) | - | 2,589 | - | - | 2,589 |
| Share based compensation on options exercised (Note 8) | 19 | (19) | - | - | - |
| Reversal of prior period unrealized gain on investments (Note 3) | - | - | - | (110) | (110) |
| Balance, end of period | $385,491 | $ 5,933 | $ (41,796) | $ - | $349,628 |

| (Canadian $000s) (unaudited) | | | | Nine Months to September 30, 2014 | |
|---|---|---|---|---|---|
| | Share Capital | Contributed Surplus | Deficit | Accumulated Other Comprehensive Income | Total Equity |
| Balance, beginning of period | $252,837 | $ 2,969 | $ (37,934) | $ - | $217,872 |
| Net income for the period | - | - | 12,277 | - | 12,277 |
| Issue of common shares (Note 9) | 98,295 | - | - | - | 98,295 |
| Share issue costs (Note 9) | (1,829) | - | - | - | (1,829) |
| Share-based compensation (Note 10) | - | 1,436 | - | - | 1,436 |
| Transfer of share-based compensation on options exercised (Note 10) | 1,745 | (1,745) | - | - | - |
| Reversal of prior period unrealized loss on investments (Note 3) | - | - | - | 890 | 890 |
| Balance, end of period | $351,048 | $ 2,660 | $ (25,657) | $ 890 | $328,941 |

See accompanying notes to the condensed interim consolidated financial statements.

## Interim Consolidated Statements of Cash Flows

| (Canadian $000s) (unaudited) | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| **Operating activities** | | | | |
| Net income (loss) for the period | $ (961) | $ 5,473 | $ (8,717) | $ 12,277 |
| Non-cash items: | | | | |
| Share-based compensation (Note 9) | 821 | 611 | 2,589 | 1,436 |
| Depletion, depreciation and accretion (Note 5) | 8,463 | 7,699 | 26,630 | 19,613 |
| Exploration and evaluation costs expensed (Note 4) | 51 | 7 | 154 | 275 |
| Gain on disposal of investments (Note 3) | - | - | - | (1,486) |
| Unrealized loss on investments (Note 3) | 330 | - | 550 | - |
| Loss on sale of oil and gas properties (Note 5) | 26 | 20 | 1,670 | 46 |
| Unrealized loss (gain) on commodity price contracts (Note 11) | (748) | (2,026) | 6,988 | (641) |
| | 7,982 | 11,784 | 29,864 | 31,520 |
| Net change in non-cash working capital items (Note 12) | (2,295) | (1,081) | (1,450) | (662) |
| | 5,687 | 10,703 | 28,414 | 30,858 |
| **Financing activities** | | | | |
| Proceeds from issue of common shares - net of expenses (Note 8) | - | 4,493 | 34,311 | 38,541 |
| Increase (decrease) in bank indebtedness | (12,258) | 20,425 | (12,885) | 28,278 |
| | (12,258) | 24,918 | 21,426 | 66,819 |
| **Investing activities** | | | | |
| Additions to exploration and evaluation assets (Note 4) | (234) | (245) | (734) | (1,633) |
| Additions to property and equipment (Note 5) | (19,323) | (30,181) | (63,367) | (84,752) |
| Cash portion of acquisitions of property and equipment and exploration and evaluation assets (Notes 4 and 5) | - | - | - | (30,150) |
| Proceeds on disposal of investments (Note 3) | - | - | - | 3,806 |
| Proceeds on disposal of oil and gas properties (Notes 4 and 5) | 23,673 | - | 23,673 | - |
| Net change in non-cash working capital items (Note 12) | 2,455 | (5,195) | (9,412) | 15,052 |
| | 6,571 | (35,621) | (49,840) | (97,677) |
| Change in cash during the period | - | - | - | - |
| Cash, beginning of period | - | - | - | - |
| Cash, end of period | $ - | $ - | $ - | $ - |

See accompanying notes to the condensed interim consolidated financial statements.

# NOTES TO THE CONDENSED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Three and nine months ended September 30, 2015 and 2014

Tabular amounts in thousands of Canadian dollars, except per-share amounts
(unaudited)

## 1. REPORTING ENTITY

Storm Resources Ltd. (the "Company" or "Storm"), is an oil and gas exploration and development company incorporated in the province of Alberta, Canada on June 8, 2010 and is listed on the TSX Venture Exchange under the symbol "SRX". The Company operates in the provinces of Alberta and British Columbia and its head office is located at Suite 200, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4. The Company became a reporting issuer in August 2010.

These unaudited condensed interim consolidated financial statements (the "financial statements") include the accounts of Storm and its wholly owned subsidiary.

## 2. BASIS OF PRESENTATION

*Statement of Compliance*

The financial statements have been prepared in accordance with IAS 34 Interim Financial Reporting, based on International Financial Reporting Standards ("IFRS") as issued and amended from time to time by the International Accounting Standards Board ("IASB"). The financial statements follow the same accounting policies and methods of computation as used in the audited consolidated financial statements for the years ended December 31, 2014 and 2013. The note disclosures do not include all disclosures applicable to annual audited consolidated financial statements. Accordingly, the financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto as at and for the years ended December 31, 2014 and 2013.

These financial statements were authorized for issue by the Board of Directors on November 11, 2015.

*Basis of Measurement*

The Company's financial statements have been prepared on a going concern basis consistent with prior periods, under the historical cost convention, except for certain financial assets and financial liabilities, which are measured at fair value, as explained in Note 11.

*Use of Estimates and Judgments*

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, income 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 period changes to estimates are made.

Judgments applied by management to accounting policies that have the most significant effect on the amounts in the financial statements are described in Note 3 to the Company's audited consolidated financial satements for the year ended December 31, 2014.

## 3. INVESTMENTS

| | September 30, 2015 | December 31, 2014 |
|---|---|---|
| Chinook Energy Inc. ("Chinook") | $ 610 | $ 1,270 |

The investment in Chinook was transferred to Storm from a predecessor company in August 2010 and at September 30, 2015 the Company held a total of 1.0 million common shares (December 31, 2014 – 1.0 million). Chinook is listed on the TSX.

The reversal of unrealized revaluation gains in the amount of nil and $0.1 million, respectively, for the three and nine months ended September 30, 2015, was recognized in other comprehensive income. In the same periods of 2014, the reversal of an unrealized revaluation gain of $0.2 million and unrealized loss of $0.9 million was also recognized in other comprehensive income. Further erosion of the Chinook share price resulted in unrealized losses of $0.3 million and $0.6 million for the three and nine months ended September 30, 2015, recognized on the consolidated statement of loss.

In 2014, the Company sold 2.0 million common shares of Chinook for net proceeds of $3.8 million and recognized a gain of $1.5 million for the nine months ended September 30, 2014 which was recognized in the consolidated statement of income.

## 4. EXPLORATION AND EVALUATION

| | Nine Months Ended September 30, 2015 | Year ended December 31, 2014 |
|---|---|---|
| Balance, beginning of period | $ 126,805 | $ 87,396 |
| Acquisitions | - | 78,930 |
| Additions | 734 | 1,754 |
| Exploration and evaluation expenditures expensed | (154) | (1,427) |
| Future decommissioning costs | 321 | 3,476 |
| Disposals | (2,842) | - |
| Transfer to property and equipment | (1,261) | (43,324) |
| Balance, end of period | $ 123,603 | $ 126,805 |

## 5. PROPERTY AND EQUIPMENT

| | Nine Months Ended September 30, 2015 | Year ended December 31, 2014 |
|---|---|---|
| Net book value, beginning of period | $ 268,463 | $ 152,472 |
| Cost | | |
| Balance, beginning of period | $ 379,207 | $ 211,024 |
| Acquisitions | - | 8,972 |
| Additions | 63,367 | 104,850 |
| Future decommissioning costs | 1,277 | 11,037 |
| Disposals | (91,115) | - |
| Transfer from exploration and evaluation assets | 1,261 | 43,324 |
| Balance, end of period | $ 353,997 | $ 379,207 |
| Accumulated depletion and depreciation | | |
| Balance, beginning of period | $ (110,744) | $ (58,552) |
| Depletion and depreciation | (26,276) | (29,492) |
| Disposals | 58,501 | - |
| Reduction in carrying amount of property and equipment | - | (22,700) |
| Balance, end of period | $ (78,519) | $ (110,744) |
| Net book value, end of period | $ 275,478 | $ 268,463 |

In July 2015, the Company sold its Grande Prairie oil properties for net proceeds of approximately $23.7 million. The resulting loss of $1.7 million was recorded on the statement of loss and comprehensive loss. Management reviewed the carrying amounts of exploration and evaluation and property and equipment assets for indicators of impairment at September 30, 2015 and determined no impairment adjustment was required.

## 6. BANK INDEBTEDNESS

As at September 30, 2015, the Company had an extendible revolving bank facility in the amount of $140.0 million (December 31, 2014 – $130.0 million) based on the Company's producing reserves. The revolving facility is available to the Company until April 29, 2016. At that time the Company has the option to extend the facility for an additional year. At September 30, 2015, the Company is in compliance with all covenants under the credit facility. The only financial covenant is that net debt including working capital deficiency not exceed the facility amount. The facility is subject to mid-year review by the Company's banking syndicate by the end of November 2015.

## 7. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning of oil and gas production assets, including well sites, gathering systems and facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The total estimated undiscounted amount required to settle the Company's continuing decommissioning obligation is approximately $25.0 million (December 31, 2014 - $37.3 million), which is expected to be paid over the next 25 years. A risk-free discount rate of 2.3% (2014 – 2.6%) and an inflation rate of 2.0% (2014 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $15.4 million.

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

| | Nine Months Ended September 30, 2015 | Year Ended December 31, 2014 |
|---|---|---|
| Balance, beginning of period | $ 23,553 | $ 8,689 |
| Obligations incurred | 1,202 | 3,797 |
| Obligations acquired | - | 710 |
| Obligations disposed | (10,117) | - |
| Obligations settled | - | (34) |
| Change in rate estimate | - | 6,029 |
| Change in cost estimates | 398 | 4,011 |
| Accretion expense | 354 | 351 |
| Balance, end of period | $ 15,390 | $ 23,553 |

## 8. 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, 2013 | 87,483 | $ 252,837 |
| Shares issued pursuant to Umbach acquisition(1) | 13,629 | 57,925 |
| Shares issued pursuant to private placement(2) | 8,500 | 34,850 |
| Share issue costs(2) | - | (1,829) |
| Shares issued on stock option exercises(3) | 1,710 | 7,378 |
| Balance as at December 31, 2014 | 111,322 | $ 351,161 |
| Shares issued pursuant to private placement(4) | 8,000 | 36,400 |
| Share issue costs(4) | - | (2,149) |
| Shares issued on stock option exercises (5) | 33 | 79 |
| Balance as at September 30, 2015 | 119,355 | $ 385,491 |

(1) On January 31, 2014 the Company issued 13,629,442 common shares, with a deemed value of $4.25 per common share, for a total amount of $57.9 million, and paid cash of approximately $30.0 million to acquire undeveloped land and natural gas wells in the Umbach area of northeast British Columbia. (See Note 4)

(2) On February 14, 2014 the Company issued, under private placement agreements, 8,500,000 common shares at a price of $4.10 per common share for proceeds of approximately $34.9 million before issue costs of approximately $1.8 million.

(3) During 2014, 1,709,666 common shares were issued upon the exercise of a like amount of stock options for proceeds of approximately $5.5 million. Related prior period share-based compensation of $1.8 million was transferred to share capital from contributed surplus. Of this amount, $1.7 million applied to the nine months ended September 30, 2014.

(4) On June 10, 2015 the Company issued 8,000,000 common shares, pursuant to a bought deal financing, at a price of $4.55 per common share for gross proceeds of $36,400,000 before issue costs of approximately $2.1 million.

(5) During the first nine months of 2015, 33,000 common shares were issued upon the exercise of stock options for proceeds of $60,000 and related prior period share-based compensation of $19,000 was transferred to share capital from contributed surplus.

## 9. 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, employees and consultants. Options are granted at the market price of the shares on the last business day prior to the date of grant, have a four-year term and vest in tranches of one third over three years. Under the stock option plan, a total of 11,935,497 common shares are available for issuance. At September 30, 2015, and at the date of this quarterly report, options in respect of 5,963,834 common shares had been issued, all of which are unexercised, and options remain in respect of 5,971,663 common shares which are available for further grants under the stock option plan.

Details of the options outstanding at September 30, 2015 are as follows:

| | Number of Options (000s) | Weighted Average Exercise Price |
|---|---|---|
| Outstanding at December 31, 2013 | 3,897 | $ 2.47 |
| Granted during the period | 3,770 | $ 4.52 |
| Exercised during the period | (1,710) | $ 3.26 |
| Outstanding at December 31, 2014 | 5,957 | $ 3.54 |
| Granted during the period | 40 | $ 4.71 |
| Exercised during the period | (33) | $ 1.83 |
| Outstanding at September 30, 2015 | 5,964 | $ 3.55 |
| Number exercisable at September 30, 2015 | 2,270 | $ 2.64 |

| 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 |
| $1.75 - $2.63 | 2,114 | 1.1 | $ 1.83 | 1,619 | $ 1.85 |
| $2.64 - $3.95 | 40 | 0.4 | $ 3.04 | 40 | $ 3.04 |
| $3.96 - $5.20 | 3,810 | 2.8 | $ 4.52 | 611 | $ 4.70 |
| Total | 5,964 | 2.2 | $ 3.55 | 2,270 | $ 2.64 |

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 nine months ended September 30, 2015 of $1.86 per share (2014 - $1.99) include the following:

| | 2015 | 2014 |
|---|---|---|
| Share price | $ 4.71 | $ 4.70 |
| Exercise price | $ 4.71 | $ 4.70 |
| Volatility | 53% | 56% |
| Forfeiture rate | 10% | 10% |
| Expected option life (years) | 3.7 | 3.7 |
| Dividends | - | - |
| Risk-free interest rate | 0.5% | 1.4% |

Share-based compensation expense of $0.8 million and $2.6 million was charged to the consolidated statement of income (loss) during the three and nine months to September 30, 2015 (2014 - $0.6 million and $1.4 million) with an equivalent offset to contributed surplus. Volatility is based on the historical price variances of the Company's share price using market data.

## 10. NET INCOME (LOSS) PER SHARE

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

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept. 30, 2014 |
|---|---|---|---|---|
| Net income (loss) for the period | $ (961) | $ 5,473 | $ (8,717) | $ 12,277 |
| Weighted average number of common shares outstanding – basic: | | | | |
| Common shares outstanding at beginning of period | 119,355 | 109,925 | 111,322 | 87,483 |
| Effect of shares issued | - | 1,029 | 3,296 | 19,633 |
| Weighted average number of common shares outstanding – basic | 119,355 | 110,954 | 114,618 | 107,116 |
| Effect of outstanding options | - | 1,572 | - | 1,712 |
| Weighted average number of common shares outstanding - diluted | 119,355 | 112,526 | 114,618 | 108,828 |
| Net income (loss) per share | | | | |
| - basic | $ (0.01) | $ 0.05 | $ 0.08) | $ 0.11 |
| - diluted | $ (0.01) | $ 0.05 | $ (0.08) | $ 0.11 |

At September 30, 2015, all outstanding stock options were considered anti-dilutive as the Company was in a loss position. For the three and nine months ended September 30, 2014, 1.8 million and 1.3 million stock options were excluded from the calculation of dilutive shares as they were anti-dilutive to those periods.

## 11. FINANCIAL INSTRUMENTS

The fair value of the Company's investment in Chinook is determined with reference to published share prices and is therefore classified as a Level 1 financial instrument. At September 30, 2015, the Company's investment in Chinook is carried at the fair value of $0.6 million (December 31, 2014 - $1.3 million).

The fair value of the Company's commodity 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 has no Level 3 financial instruments.

### Risk Management

#### 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. The maximum exposure to credit risk at September 30, 2015 is as follows:

| | Carrying Amount as at September 30, 2015 |
|---|---|
| Accounts receivable | $ 6,596 |
| Fair value of commodity price contracts | 5,932 |
| Total | $ 12,528 |

*Derivative Contracts*

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

*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. The Company's production is sold to organizations whose credit worthiness is assessable from publicly available information. 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. The Company does not typically obtain collateral security from joint venture partners.

No default on outstanding receivables is anticipated and less than 0.2% of the Company's outstanding receivable balance is considered past due at September 30, 2015.

**Market risk**

*Commodity Prices*

As at the date of this report, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts of $5.9 million (December 31, 2014 – $12.9 million) is included in current assets. For the three and nine months ended September 30, 2015, this resulted in an unrealized mark-to-market gain of $0.7 million (2014 – gain of $2.0 million) and loss of $7.0 million (2014 – gain of $0.6 million) when measured against the fair market value at the end of the preceding period. In January 2015, the Company terminated all of its crude oil contracts in exchange for $5.1 million which is included as a realized gain in the calculation of net income for the three and nine months ended September 30, 2015.

| Period Hedged | Daily Volume | Average Price |
|---|---|---|
| Crude Oil Collar | | |
| Jan – Dec 2016 | 500 Bbls | $75.00 - $90.75 Cdn$/Bbl |
| Natural Gas Swaps | | |
| Q4 – 2015 | 35,667 GJ | AECO Cdn$3.36/GJ |
| Q1 – 2016 | 5,000 GJ | AECO Cdn$3.06/GJ |
| Jan – Dec 2016 | 20,000 GJ | AECO Cdn$2.98/GJ |
| Natural Gas Differential Swaps | | |
| Jan – Dec 2016 | 11,000 GJ | Price at Stn 2 = AECO minus Cdn$0.3375/GJ |
| Jan – Dec 2017 | 5,000 GJ | Price at Stn 2 = AECO minus Cdn$0.445/GJ |
| Jan - Dec 2016 | 33,000 Mmbtu | Price at Chicago = AECO plus US$0.672/Mmbtu |
| Jan – Dec 2017 | 35,000 Mmbtu | Price at Chicago = AECO plus US$0.577/Mmbtu |

During the three and nine months ended September 30, 2015, the Company realized gains from commodity price contracts in place or terminated in the amount of $2.0 million and $11.1 million, respectively (2014 – losses of $0.8 million and $3.7 million, respectively).

*Sensitivities*

Using the Company's actual production volumes, royalty rates and debt levels for the first nine months of 2015, the estimated after-tax effect that changes in certain factors would have on net income and net income per share is set out below:

| | | 2015 |
|---|---|---|
| Factor | Change in Net Income | Change in Net Income Per Share |
| US$1.00/Bbl change in the price of WTI[(1)] | $ 550,000 | $ - |
| $0.10/Mcf change in the price of natural gas | $ 1,270,000 | $ 0.01 |
| 1% change in the interest rate | $ 470,000 | $ - |

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

The Company's income tax assets are sufficient to eliminate taxes payable on any increases to income resulting from above; accordingly, before and after tax amounts are the same.

## 12. SUPPLEMENTAL CASH FLOW INFORMATION

### Changes in non-cash working capital

| | Three Months to Sept. 30, 2015 | Three Months to Sept. 30, 2014 | Nine Months to Sept. 30, 2015 | Nine Months to Sept.30, 2014 |
|---|---|---|---|---|
| Accounts receivable | $ (3,045) | $ (3,468) | $ 1,609 | $ (5,276) |
| Prepaids and deposits | (144) | 2,628 | 56 | 286 |
| Accounts payable and accrued liabilities | 3,349 | (5,436) | (12,527) | 19,380 |
| Change in non-cash working capital | $ 160 | $ (6,276) | $ (10,862) | $ 14,390 |
| Relating to: | | | | |
| Operating activities | $ (2,295) | $ (1,081) | $(1,450) | $ (662) |
| Investing activities | 2,455 | (5,195) | (9,412) | 15,052 |
| | $ 160 | $ (6,276) | $ (10,862) | $ 14,390 |
| Interest paid during the period | $ 356 | $ 321 | $ 1,554 | $ 691 |
| Income taxes paid during the period | $ - | $ - | $ - | $ - |

## 13. COMMITMENTS

The Company has the following long-term commitments over the next five years:

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|---|
| Office lease | $ 235 | $ 940 | $ 940 | $ 705 | $ - | $ - | $ 2,820 |
| Gas transportation and processing commitments | 6,179 | 39,502 | 37,395 | 32,366 | 18,225 | 15,672 | 149,339 |
| Total | $ 6,414 | $ 40,442 | $ 38,335 | $ 33,071 | $ 18,225 | $ 15,672 | $ 152,159 |

In the first nine months of 2015, office lease payments of $693,000 (2014 - $684,000) were included in general and administrative expense.

# CORPORATE INFORMATION

## Officers

Brian Lavergne
President & CEO

Robert S. Tiberio
Chief Operating Officer

Donald G. McLean
Chief Financial Officer

John Devlin
Vice President, Finance

Jamie Conboy
Vice President, Geology

H. Darren Evans
Vice President, Exploitation

Bret A. Kimpton
Vice President, Production

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## Directors

Matthew J. Brister (2)(3)

John A. Brussa

Mark A. Butler (1)(3)

Stuart G. Clark (1)
Chairman

Brian Lavergne
CEO

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

TSX Venture 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
Bank of Montreal
Royal Bank of Canada
Calgary, Alberta

## Executive Offices

Suite 200, 640 – 5th Avenue S.W.
Calgary, Alberta, T2P 3G4 Canada
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www.stormresourcesltd.com

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## Commonly Used Abbreviations

| | |
|---|---|
| 3-D | Three-dimensional |
| API | American Petroleum Institute |
| Bbls | Barrels of oil or natural gas liquids |
| Bbls/d | Barrels per day |
| Bcf | Billions of cubic feet |
| Bcfe | Billions of cubic feet equivalent |
| 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 |
| DPIIP | Discovered Petroleum Initially in Place |
| GJ | Gigajoules |
| GJ/d | Gigajoules per day |
| kPa | One thousand pascals |
| LNG | Liquefied natural gas |
| Mbbls | Thousands of barrels |
| Mboe | Thousands of barrels of oil equivalent |
| Mcf | Thousands of cubic feet |
| Mcf/d | Thousands of cubic feet per day |
| Mmbbls | Millions of barrels |
| Mmboe | Millions of barrels of oil equivalent |
| 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 |
| Mstb | Thousand stock tank barrels |
| NAV | Net Asset Value |
| NGL | Natural gas liquids |
| NPV | Net present value |
| OGIP | Original Gas in Place |
| OPEC | Organization of Petroleum Exporting Countries |
| psig | pounds per square inch gage pressure |
| Scf/ton | Standard cubic foot per ton |
| SRX | Storm Resources Ltd. |
| STOOIP | Stock Tank Original Oil in Place |
| Tcf | Trillions of cubic feet |
| TSX | Toronto Stock Exchange |
| TSXV | TSX Venture Exchange |
| US$ | United States dollar |
| WTI | West Texas Intermediate |

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