STORM RESOURCES

2015 REPORT Q1

Highlights

Thousands of Cdn$, except volumetric and per-share amounts	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
FINANCIAL		
Revenue from product sales	18,512	20,807
Funds from operations(1)	13,712	8,660
Per share - basic ($)	0.12	0.09
Per share - diluted ($)	0.12	0.08
Net income (loss)	(3,565)	206
Per share - basic ($)	(0.03)	0.00
Per share - diluted ($)	(0.03)	0.00
Operations capital expenditures	35,680	22,343
Land and property acquisitions	-	88,051
Debt including working capital deficiency	85,098	22,176
Common shares (000s)		
Weighted average - basic	111,322	100,668
Weighted average - diluted	111,322	102,413
Outstanding end of period – basic	111,322	109,612
OPERATIONS		
(Cdn$ per Boe)		
Revenue	21.04	45.62
Royalties	(0.54)	(7.56)
Production	(8.67)	(10.88)
Transportation	(1.68)	(1.71)
Field operating netback	10.15	25.47
Hedging gains (losses)	8.36	(3.10)
General and administrative	(2.24)	(2.91)
Interest	(0.70)	(0.47)
Funds from operations netback	15.57	18.99
Barrels of oil equivalent per day (6:1)	9,776	5,068
Gas Production		
Thousand cubic feet per day	47,713	23,711
Price (Cdn$ per Mcf)	2.85	5.63
NGL production		
Barrels per day	1,493	725
Price (Cdn$ per barrel)	37.10	84.49
Oil Production		
Barrels per day	330	391
Price (Cdn$ per barrel)	43.08	93.08
Wells drilled		
Gross	6.0	5.0
Net	6.0	5.0

(1) Funds from operations, funds from operations per share and funds from operations netback are non-GAAP measurements. See discussion of Non-GAAP Measurements on page 19 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 20 of the attached MD&A.

PRESIDENT'S MESSAGE

FIRST QUARTER 2015 HIGHLIGHTS

- Operational success at Umbach continued in the first quarter with horizontal well performance continuing to improve and with the expansion of the second Umbach field compression facility being completed on time and on budget.

- Production averaged 9,776 Boe per day (19% oil plus NGL), an increase of 91% on a per-share basis from the previous year. The increase was the result of growth at Umbach where first quarter production was 8,579 Boe per day, a year-over-year increase of 141%.

- NGL production was 1,493 barrels per day, an increase of 106% from the previous year which was the result of production growth from the liquids-rich Montney formation at Umbach where NGL recovery was 33 barrels per Mmcf sales in the quarter. With approximately 60% of the NGL mix being condensate plus pentanes, the NGL price of $37.10 per barrel was 71% of the average Edmonton light oil price.

- Activity in the quarter was focused at Umbach, where six Montney horizontal wells (6.0 net) were drilled, two horizontal wells (2.0 net) were completed, three horizontal wells (3.0 net) began producing, a 15-kilometre pipeline connecting the first field compression facility to the Stoddart Gas Plant was completed, and the second field compression facility was expanded from 27 to 54 Mmcf per day raw gas.

- Horizontal well performance at Umbach continues to improve. The first 2015 horizontal well having enough production history averaged 5.6 Mmcf per day gross raw gas over the first 90 calendar days, an improvement of 19% from the average 2014 horizontal well. Field condensate from this well averaged 32 barrels per Mmcf raw gas over the same period, an increase of 60% from the average of all horizontal wells drilled to date (an additional 18 to 42 barrels of NGL per Mmcf sales is also recovered after processing at a gas plant).

- There is currently an inventory of 10 horizontal wells (10.0 net), which includes one completed horizontal well, that have not started producing at Umbach.

- Funds from operations was $13.7 million, or $0.12 per basic share, which is an increase of 33% from the prior year.

- The funds from operations netback was $15.57 per Boe, a year-over-year decrease of 18% which was primarily the result of revenue per Boe declining by $24.58 per Boe, or 54%. This was partially offset by a hedging gain of $8.36 per Boe and by controllable cash costs declining by 17%, or $2.68 per Boe. Controllable cash costs includes operating, transportation, interest and cash general and administrative costs.

- Net loss was $3.6 million, or $0.03 per share, compared to net income of $0.2 million in the previous year. The net loss was caused in part by the reversal of prior period unrealized hedging gains amounting to $6.8 million (the realized hedging gain of $7.4 million in the first quarter reduced the prior period unrealized hedging gain).

- Capital investment was focused on the Umbach area and totaled $35.7 million which included $15.4 million for infrastructure and $19.1 million for drilling and completions.

- For the remainder of 2015, Storm has hedged approximately 40% of forecast natural gas production at an AECO price of $4.17 per Mcf ($3.33 per GJ).

- Debt plus working capital deficiency was $85.1 million which is 1.6 times annualized first quarter cash flow. In April 2015, Storm's bank credit line was increased to $150.0 million from $130.0 million.

OPERATIONS REVIEW

Storm has a focused asset base with large land positions in resource plays at Umbach and in the Horn River Basin ("HRB") which have multi-year drilling inventories while the Grande Prairie area, with its shallow decline, provides cash flow available for investment.

Umbach, Northeast British Columbia

Storm's land position at Umbach is prospective for liquids-rich natural gas from the Montney formation and currently totals 141 net sections (167 gross sections), or 100,000 net acres. To date, a total of 33.4 net horizontal wells (37.0 gross) have been drilled into the Montney formation with 23.4 net being on production.

First quarter production from Umbach was 8,579 Boe per day, a year-over-year increase of 141%. NGL production was 1,431 barrels per day, an increase of 118% and represents a recovery of 33 barrels per Mmcf sales (approximately 60% of NGL is higher priced field condensate plus pentanes recovered at the gas plant). Revenue from Umbach was $20.64 per Boe ($2.88 per Mcf sales and $37.38 per barrel of NGL), transportation costs were $1.58 per Boe, royalties were $0.46 per Boe (2% of revenue), operating costs were $7.88 per Boe, and the operating netback was $10.73 per Boe.

Activity in the first quarter included drilling six Montney horizontal wells (6.0 net) and completing two Montney horizontal wells (2.0 net) with three horizontal wells (3.0 net) starting production. There remains an inventory of 10 horizontal wells (10.0 net) that have not started producing which includes one completed horizontal well and nine standing horizontal wells awaiting completion.

Storm operates two field compression facilities (both 100% working interest) that have total capacity of 72 Mmcf per day raw gas with throughput in the first quarter averaging 42 Mmcf per day raw gas. The first field compression facility with capacity of 18 Mmcf per day raw gas had average throughput of 17 Mmcf per day raw gas in the first quarter. A 15-kilometre pipeline was constructed in the first quarter to connect the first facility to the Stoddart Gas Plant which is expected to reduce operating costs and increase NGL recovery to 55 barrels per Mmcf sales beginning in April. The second field compression facility was expanded from 27 to 54 Mmcf per day of capacity at the end of March with throughput averaging 25 Mmcf per day of raw gas during the first quarter. Investment to expand infrastructure at Umbach in the first quarter totaled $13.5 million. In the second quarter of 2015, a condensate stabilizer and other equipment will be installed at the second facility with the estimated cost being $6.4 million. These additions will improve condensate pricing and also reduce operating costs.

The operating cost at Umbach is expected to decline to $6.50 to $6.75 per Boe by the fourth quarter of 2015 as a result of continued production growth, recent longer term processing commitments which have a lower associated fee, wells recently converted to salt water disposal, and equipment additions at the second field compression facility.

Engineering design has been completed for a third field compression facility and $4.0 million will be invested to purchase major equipment in 2015 ($2.0 million in the first quarter). This facility is expected to be operational in mid-2016 with the total cost estimated to be $24.0 million for 35 Mmcf per day raw gas capacity which will be expandable to 70 Mmcf per day for an additional investment of $7.0 million.

Storm recently contracted for transportation of up to 31.8 Mmcf per day of natural gas on the Alliance Pipeline for delivery to the Chicago market starting December 2015. The actual capacity allocated to Storm is expected to be finalized by August. Based on the current forward strip for natural gas sold at Chicago, plantgate pricing after deducting applicable pipeline tariffs is expected to be comparable to the price at AECO. Shipping on the Alliance Pipeline diversifies market access for Storm and will mitigate any future weakness in the AECO – BC Station 2 price differential which was -$0.59 per GJ in the first quarter (approximately 44% of Storm's natural gas production was sold at the BC Station 2 daily spot price in the first quarter). For reference, the differential averaged -$0.21 per GJ from 2011 to 2014. The increase in the price differential in the first quarter is expected to be temporary and was caused by continued growth of natural gas production from northeast British Columbia and unplanned maintenance reducing flows onto the TransCanada NGTL Pipeline system in Alberta. This resulted in additional volumes being sold into the smaller BC Station 2 market and widened the differential to AECO.

Performance of the 2014 and 2015 horizontal wells shows significant improvement over earlier wells when rates are compared over the first 90 and 180 calendar days (includes downtime).

	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** 345 Boe/d sales 7 hz's	**1.4 Mmcf/d** 255 Boe/d sales 7 hz's	**1.3 Mmcf/d** 235 Boe/d sales 7 hz's
2013 hz's (6 wells)	16 - 18	**4.0 Mmcf/d** 725 Boe/d sales 6 hz's	**2.9 Mmcf/d** 525 Boe/d sales 6 hz's	**2.2 Mmcf/d** 400 Boe/d sales 6 hz's
2014 hz's (10 wells)	16 - 20	**4.7 Mmcf/d** 850 Boe/d sales 10 hz's	**4.9 Mmcf/d** 885 Boe/d sales 7 hz's	**4.3 Mmcf/d** 780 Boe/d sales 1 hz
2015 hz's (3 wells)	18 - 22	**5.6 Mmcf/d** 1,015 Boe/d sales 1 hz		

Note: Sales volume is calculated using 8% shrinkage from raw gas to sales and 30 barrels of NGL per Mmcf sales.

Based on the performance of the 2014 horizontal wells with 16 to 20 frac stages, Storm management is using a 6.3 Bcf raw gas type curve for internal budgeting purposes (this type curve has same decline profile as the 3.2 and 4.4 Bcf raw gas 2P type curves used by InSite in the 2014 reserve evaluation). With a 6.3 Bcf raw gas type curve, the first year average rate is 3.6 Mmcf per day gross raw gas or 650 Boe per day sales (8% shrinkage from raw gas to sales and 30 barrels of NGL per Mmcf sales). Based on a cost of $5.4 million to drill, complete and tie in a horizontal well with 20 to 24 frac stages, the payout is approximately 25 months and the rate of return is 31% using $2.80 per GJ at AECO and Cdn $68.00 per barrel for Edmonton light oil (approximate 2016 forward strip pricing held flat for the life of the well). See the presentation on Storm's website for further details. In 2014, the actual cost to drill, complete, and tie-in a horizontal well with 16 to 20 frac stages averaged $4.9 million. Drilling times averaged approximately 14 days. The average tie-in cost was $0.3 million per horizontal well which doesn't include the cost of longer gathering pipelines to connect multi-well pads to field compression facilities. With the 2015 horizontal wells having an increased number of frac stages (20 to 24), the cost to drill, complete, and tie in a horizontal well has increased to $5.4 million. These results do not recognize any improvement in service costs in 2015.

Horn River Basin, Northeast British Columbia

Storm has a 100% working interest in 119 sections in the HRB (78,000 net acres) which are prospective for natural gas from the Muskwa, Otter Park and Evie/Klua shales. First quarter production averaged 281 Boe per day (100% natural gas), a year-over-year decline of 26%. The operating netback was $0.40 per Boe with revenue of $12.56 per Boe, transportation costs of $0.63 per Boe, an operating cost of $11.09 per Boe and a royalty of $0.44 per Boe, or 3% of revenue.

Grande Prairie Area, Northwest Alberta

Production in the first quarter was 916 Boe per day (43% oil plus NGL), a year-over-year decline of 19%. In mid-January 2015, approximately 150 Boe per day of natural gas burdened with higher third party processing fees was shut in as a result of the recent decline in the natural gas price. The operating netback was $8.36 per Boe with revenue of $28.14 per Boe, a transportation cost of $2.93 per Boe, an operating cost of $15.52 per Boe and a royalty of $1.32 per Boe, or 5% of revenue. Cash flow from this area continues to be re-invested to grow production at Umbach.

HEDGING UPDATE

For April to December of 2015, 23,900 Mcf per day (29,900 GJ per day) of natural gas is hedged at an average AECO price of approximately $4.17 per Mcf (AECO monthly index $3.33 per GJ).

During January 2015, Storm's oil hedges for 2015 were unwound for net proceeds of $5.1 million.

For 2016, 8,000 Mcf per day (10,000 GJ per day) of natural gas is hedged at an average AECO price of approximately $3.75 per Mcf (AECO monthly index $3.00 per GJ). Storm plans to continue adding to the 2016 hedge position during the remainder of 2015.

The purpose of Storm's commodity price hedges is to reduce the effect of commodity price fluctuations on capital investment and growth over the next 12 months. A maximum of 50% of current production (most recent monthly or quarterly average), before royalties, will be hedged; anticipated production growth is not hedged.

OUTLOOK

Production in April 2015 averaged 11,900 Boe per day based on field estimates and production in the second quarter of 2015 is forecast to be 10,000 to 10,500 Boe per day which includes the effect of a 21-day maintenance turnaround at the McMahon Gas Plant in June which is expected to reduce second quarter production by 1,700 Boe per day. Capital investment in the second quarter is expected to total $9.0 to $11.5 million which includes completing one horizontal well (1.0 net) and $6.4 million to add equipment at the second field compression facility at Umbach.

Guidance for 2015 remains unchanged from that provided on February 26, 2015.

2015 Guidance	November 13, 2014 Original Guidance	February 26, 2015 Revised Guidance
AECO natural gas price	$3.25 per GJ	$2.35 - $2.90 per GJ
BC STN 2 natural gas price	$3.00 per GJ	$2.05 - $2.60 per GJ
Edmonton light oil price	Cdn$83 per Bbl	Cdn$53 - $62 per Bbl
Estimated average operating costs	$7.50 - $8.00 per Boe	$8.00 - $8.50 per Boe
Estimated average royalty rate (on production revenue before hedging)	12% - 14%	6% - 10%
Estimated operations capital (excluding acquisitions & dispositions)	$110.0 million	$80.0 million
Estimated cash G&A net of recoveries	$5.3 million	$5.3 million
Forecast fourth quarter production	14,000 – 14,500 Boe/d (18% oil + NGL)	14,000 – 14,500 Boe/d (19% oil + NGL)
Forecast annual production	11,500 – 12,700 Boe/d (19% oil + NGL)	11,000 – 12,000 Boe/d (20% oil + NGL)
Umbach horizontal wells drilled Umbach horizontal wells completed Umbach horizontal wells starting production	9 gross (9.0 net) 14 gross (14.0 net) 16 gross (16.0 net)	6 gross (6.0 net) 11 gross (11.0 net) 14 gross (14.0 net)

Capital investment in 2015 includes:

- $47.8 million at Umbach for drilling and completions;
- $23.4 million to expand infrastructure at Umbach, including expansion of the second field compression facility from 27 Mmcf per day to 54 Mmcf per day in the first quarter, plus $4.0 million to order major equipment for a third field compression facility.

Total debt at the end of 2015 is forecast to be $91.0 million assuming average 2015 pricing of AECO Cdn$2.58 per GJ and Edmonton light oil Cdn$61.50 per barrel which represent actual prices to date plus current forward strip pricing for the remainder of 2015. This would be approximately 1.6 times annualized funds from operations in the fourth quarter of 2015.

If the natural gas price increases from current levels during 2015 and provides an incentive for doing so, Storm can accelerate the timing for completing the nine standing horizontal wells which would increase production in the second half of 2015. There is currently approximately 16 Mmcf per day of unused raw gas compression capacity at Umbach.

With approximately 35% of Storm's first quarter revenue coming from oil and NGL sales (excluding hedging gains), the recent improvement in the price of oil will also increase Storm's revenue and cash flow. The Edmonton light oil price is currently approximately Cdn$66.00 per barrel (WTI US$58 per barrel) which is $14.00 per barrel higher than the price in the first quarter and would increase Storm's first quarter oil price by approximately 33% and the NGL price by approximately 23% which adds $1.50 per Boe to the operations netback.

The corporate operating cost is expected to decline from $8.67 per Boe in the first quarter to below $7.50 per Boe in the fourth quarter as a result of operating costs at Umbach declining below $6.75 per Boe in the fourth quarter of 2015.

At Umbach, Montney horizontal wells continue to offer attractive rates of return at current forward strip pricing for oil and natural gas given that NGL recovery increases revenue while the relatively shallow depth of the Montney (1,400 to 1,600 metres) results in a lower drilling and completion cost. With a strong balance sheet, an evolving plan to expand infrastructure at Umbach, and improving capital efficiencies, Storm expects to meet or exceed 2015 production guidance and remains well positioned for continued rapid growth into 2016.

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

EXECUTIVE APPOINTMENTS

Effective May 1, 2015, Jamie Conboy was appointed Vice President, Geology, Darren Evans was appointed Vice President, Exploitation and Bret Kimpton was appointed Vice President, Production. All three joined Storm predecessor companies between 1999 and 2005 and have made meaningful contributions towards the success of Storm.

Respectfully,

B. Lavergne

Brian Lavergne,
President and Chief Executive Officer

May 13, 2015

Discovered-Petroleum-Initially-in-Place (“DPIIP”) - is defined in the Canadian Oil and Gas Evaluation Handbook (“COGEH”) as the quantity of hydrocarbons that are estimated to be in place within a known accumulation. DPIIP is divided into recoverable and unrecoverable portions, with the estimated future recoverable portion classified as reserves and contingent resources. There is no certainty that it will be economically viable or technically feasible to produce any portion of this DPIIP except for those portions identified as proved or probable reserves.

Contingent Resources - are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project at an early stage of development. Estimates of contingent resources are estimates only; the actual resources may be higher or lower than those calculated in the independent evaluation. There is no certainty that the resources described in the evaluation will be commercially produced.

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 May 13, 2015 for the three months ended March 31, 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 months ended March 31, 2015. It should be read in conjunction with (i) the Company's unaudited condensed interim consolidated financial statements for the three months ended March 31, 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 May 13, 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 was incorporated on June 8, 2010 as 1541229 Alberta Ltd. with nominal share capital. On August 17, 2010 it participated in a plan of arrangement (the "Arrangement") along with Storm Exploration Inc. ("SEO") and ARC Energy Trust ("ARC"). The Arrangement resulted in the sale of SEO to ARC and the spin out of the Company as a junior exploration and development company. The Company trades on the TSX Venture Exchange under the symbol "SRX".

This MD&A is dated May 13, 2015.

LIMITATIONS

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 months ended March 31, 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. Comparative information is provided for the immediately prior three month period ended December 31, 2014 and for the three month period ended March 31, 2014.

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 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;
- future decommissioning costs and discount rates used to determine the net present value of such costs;
- 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 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;
- future royalties, operating costs, interest and general and administrative costs;
- future effect of regulatory regimes and tax and royalty laws, including incentive programs;
- 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 geographical areas developed; 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" and the material assumptions described under the headings "Overview"; "Production and Revenue"; "Hedging"; "Royalties"; "Production Costs"; "Field Netbacks"; "General and Administrative Costs"; "Share-Based Compensation"; "Depletion and Depreciation"; "Accretion"; "Interest and Finance Costs"; "Gain (Loss) on Commodity Price Contracts"; "Income Taxes"; "Other Comprehensive 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 market for production, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and related costs including future royalties, production 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 acquired assets and corporations. 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 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 similar 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. These measurements are 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".

OPERATIONAL AND FINANCIAL RESULTS

Overview

During the first quarter of 2015 Storm's operational focus was exclusively on continued development of the Montney natural gas and NGL property at Umbach. The Company began the year with an inventory of eight standing wells, of which five awaited completion. Two of these wells were completed in the quarter and six additional wells were drilled. At March 31, 2015 the Company had a total of nine standing wells awaiting completion and one additional well completed and tied in but not yet producing. Wells in inventory will be completed and tied in as producing wells begin to decline and if justified by commodity prices. Towards the end of the quarter, Storm completed the expansion of the second 100% working interest compression facility increasing capacity at that facility to 54 Mmcf per day. In addition, a 15-kilometre pipeline was built to connect the first field compression facility to the Stoddart Gas Plant, providing the Company with additional gas processing access and alternatives. Given cash flow constraints imposed by a bleak commodity price outlook, no further drilling and only limited facility investment is planned for the remainder of 2015. Nevertheless, Storm considers that the inventory of standing wells is sufficient to keep facilities full and to achieve guidance for the year. Capital spent in the first quarter totaled 45% of the amount currently budgeted for 2015.

No capital was spent in the first quarter of 2015 on either the Horn River Basin or the Company's Alberta properties, each of which is producing to expectations.

Storm's per-Boe production increased 93% year over year and fell 4% when compared to the immediately preceding quarter. The year-over-year increase reflects facility investment in the third quarter of 2014. The quarter-over-quarter reduction in production is due to the shut-in for several days of the second field compression facility to interconnect piping installed as part of the expansion. In addition, there were unscheduled interruptions at the McMahon gas plant.

On a macro level the quarter was dominated by the collapse of commodity prices which began in the middle of 2014 and has accelerated each quarter since. Below are amounts realized by Storm per commodity unit over the last five quarters: they illustrate the depth and severity of the pricing collapse. It merits emphasis that pricing for all of Storm's products has been affected, approximately equally: price declines in prior periods tended to be commodity specific.

Average Quarterly Per-Unit Realized Price (Cdn$)	Natural Gas		Natural Gas Liquids		Crude Oil		Boe	
Q1 – 2014	$5.63	100%	$84.49	100%	$93.08	100%	$45.62	100%
Q2 – 2014	$5.20	92%	$80.57	95%	$99.27	107%	$43.66	96%
Q3 – 2014	$4.48	80%	$73.09	87%	$90.31	97%	$37.80	83%
Q4 – 2014	$3.85	68%	$56.15	66%	$68.01	73%	$29.99	66%
Q1 – 2015	$2.85	51%	$37.10	44%	$43.08	46%	$21.04	46%

The fall of 54% year over year and 30% quarter over preceding quarter in per-Boe revenue had the potential to severely affect cash flow. However, this effect was muted by a BC royalty credit of $1.0 million received in the quarter, as well as the Company's hedging program which delivered hedging gains of $7.4 million. Included in this amount was a one-time gain of $5.1 million received on the termination of Storm's crude oil contracts.

Nevertheless, funds flow from operations increased by 58% year over year and was largely the same as the final quarter of 2014. Overall, cash costs were down 17% year over year and up 9% compared to the final quarter of 2014, principally due to increased general and administrative costs associated with the payment in the first quarter of 2015 of employee performance bonus amounts.

Although it is desirable that corporate momentum be maintained, protection of the Company's balance sheet is paramount in current circumstances. The Company's hedging program will be supportive, although it only covers part of the Company's production. Generally, cash costs are trending downwards and there is a reasonable expectation that service costs will fall somewhat for the balance of 2015. As announced earlier, Storm's capital program for 2015 has been reduced by close to 30%. Higher-cost production has been shut in. Although the Company's approach is essentially defensive, there may emerge opportunities to execute on strategically valuable and favourably priced land or equipment acquisitions. In this regard, a recent $20 million increase in the Company's bank line increases financial capacity. It is also a strong endorsement by the lending group of the quality of the Company's business plan and asset base.

Production and Revenue

Production by Area

The Company reported production from the following areas:

				Three Months Ended March 31, 2015
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	42,888	1,431	-	8,579
Horn River Basin – NE BC	1,684	-	-	281
Grande Prairie – AB	3,141	62	330	916
Total	47,713	1,493	330	9,776

				Three Months Ended March 31, 2014
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	17,413	656	-	3,559
Horn River Basin – NE BC	2,278	-	-	380
Grande Prairie – AB	4,020	69	391	1,129
Total	23,711	725	391	5,068

				Three Months Ended December 31, 2014
Producing Area	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	Crude Oil (Bbls/d)	Boe/d
Umbach – NE BC	43,409	1,540	-	8,775
Horn River Basin – NE BC	1,843	-	-	307
Grande Prairie – AB	3,842	65	385	1,091
Total	49,094	1,605	385	10,173

In the first quarter of 2015, average Boe-per-day volumes increased by 93% when compared to the first quarter of 2014, and decreased by 4% when compared to the immediately preceding quarter. Production increases for natural gas and NGL, when compared to the same quarter in 2014, are attributed to growth at Umbach where the Company produced from 27 wells (23.4 net) during the quarter. Production declines relative to the last quarter of 2014 are primarily due to the shutdown for several days of a Company owned compressor station which was being expanded, and also due to downtime at a third party natural gas processing facility. Crude oil production decreased as a result of natural declines. Production to date in the second quarter of 2015 is averaging approximately 11,900 Boe per day based on field estimates.

Daily production per million shares outstanding at the end of the quarter averaged 88 Boe per day, compared to 46 Boe per day for the first quarter of 2014 and 91 Boe per day for the final quarter of 2014.

HRB produces dry natural gas, while Umbach produces natural gas and associated NGL. Production in Alberta for the first quarter of 2015 approximated 36% light oil, with an average API of 37 degrees, 57% natural gas and 7% NGL.

Average Daily Production

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Natural gas (Mcf/d)	47,713	23,711	49,094
Natural gas liquids (Bbls/d)	1,493	725	1,605
Crude oil (Bbls/d)	330	391	385
Total (Boe/d)	9,776	5,068	10,173

Production Profile and Per-Unit Prices(1)

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014		Three Months Ended December 31, 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
Natural gas - Mcf	81%	$ 2.85	78%	$ 5.63	80%	$ 3.85
Natural gas liquids - Bbl	15%	37.10	14%	84.49	16%	56.15
Crude oil - Bbl	4%	43.08	8%	93.08	4%	68.01
Per Boe	100%	$ 21.04	100%	$ 45.62	100%	$ 29.99

(1) Before realized hedging gains of $8.36 per Boe for the three months ended March 31, 2015 (Q1 2014 – losses of $3.10 per Boe, Q4 2014 – gains of $0.52 per Boe).

The Company's natural gas is produced in both British Columbia and Alberta and, generally, is sold at a price based on the Station 2 price in British Columbia and the AECO index in Alberta. In the first quarter of 2015, approximately 50% of natural gas sales were priced at the AECO monthly index price less the Station 2 – AECO differential, 6% at the AECO daily index price and 44% was sold at the Station 2 daily index price. Average quarterly index prices are as follows:

(Cdn$/GJ)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
AECO Monthly Index	$ 2.80	$ 4.51	$ 3.80
AECO Daily Index (spot)	$ 2.60	$ 5.42	$ 3.41
BC Station 2 Daily Index (spot)	$ 2.02	$ 4.94	$ 2.93

A portion of Storm's natural gas is sold at the AECO monthly index price to align with the Company's natural gas hedges which are based on the monthly index.

Station 2 is a less liquid market from AECO and usually Station 2 prices trade at a modest discount to the equivalent AECO prices. However, in the first quarter of 2015, transmission interruptions in Alberta resulted in increased natural gas volumes moving to the Station 2 market. There was also growth in natural gas production in areas where production is normally directed to Station 2. The consequence was a considerable widening in the Station 2 - AECO differential, from Station 2 being 9% below the AECO price in the first quarter of 2014, rising to 14% in the final quarter of 2014 and to 23% in the first quarter of 2015. It is uncertain when the circumstances that led to the widening differential will change and thus lead to a lower differential.

Storm's realized price for the first quarter was $2.85 per Mcf, with the price higher than index prices as a result of sales gas at Umbach and Grande Prairie having a higher heat content.

The realized price for NGL in the first quarter of 2015 fell by 56% and 34% relative to the first and fourth quarters of 2014 as liquids prices continued to collapse in 2015. The NGL stream contains a high proportion of condensate and pentanes which are generally priced with reference to crude oil prices. Correspondingly, realized prices in the fourth quarter of 2014 and 2015 fell in alignment with lower crude oil prices. As Storm continues to increase natural gas production at Umbach, higher value condensate and pentane production will also increase.

For the first quarter, WTI averaged US$48.63 per barrel and Edmonton light oil was Cdn$51.94 per barrel, resulting in an exchange rate adjusted differential between WTI and Edmonton light oil of Cdn$8.41 per barrel, compared to Cdn$9.10 per barrel in the first quarter of 2014. Due to quality and gravity differentials, Storm's average crude oil sales price for the first quarter of 2015, prior to the inclusion of hedging gains, was $8.85 per barrel lower than the Edmonton light oil reference price.

On a per-Boe basis, the realized price for the first quarter of 2015 declined by 54% and 30% relative to the first and fourth quarters of 2014.

Revenue from Product Sales(1)

(000s)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Natural gas (Mcf/d)	$ 12,245	$ 12,017	$ 17,369
Natural gas liquids (Bbls/d)	4,985	5,511	8,292
Crude oil (Bbls/d)	1,282	3,279	2,409
Total	$ 18,512	$ 20,807	$ 28,070

(1) Excludes hedging gains and losses.

Revenue from product sales for the first quarter of 2015 decreased by 11% when compared to the first quarter of 2014 and decreased by 34% when compared to the immediately preceding quarter. However, quarterly production volumes grew 93% year over year and decreased by 4% when compared to the immediately preceding quarter. The disparity between growth in production and in revenue corresponds to price declines, as follows:

Realized Prices per Commodity Unit	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Natural gas (Mcf/d)	$ 2.85	$ 5.63	$ 3.85
Natural gas liquids (Bbls/d)	$ 37.10	$ 84.49	$ 56.15
Crude oil (Bbls/d)	$ 43.08	$ 93.08	$ 68.01
Total (Boe/d)	$ 21.04	$ 45.62	$ 29.99

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

(000s)	Natural Gas	Natural Gas Liquids	Crude Oil	Total
Revenue from product sales – Q1 2014	$ 12,017	$ 5,511	$ 3,279	$ 20,807
Effect of increased (decreased) production	12,161	5,842	(513)	17,490
Effect of change in product prices	(11,933)	(6,368)	(1,484)	(19,785)
Revenue from product sales – Q1 2015	$ 12,245	$ 4,985	$ 1,282	$ 18,512

Hedging

The Company had in place the following hedging arrangements at March 31, 2015:

Fixed Price	Volume	AECO Natural Gas Average Price (Cdn$/GJ)
Q2 – 2015	25,700 GJ/day	$3.22
Q3 – 2015	34,000 GJ/day	$3.27
Q4 – 2015	30,000 GJ/day	$3.47
Jan – Dec 2016	10,000 GJ/day	$3.00

During the first quarter of 2015, the Company realized gains from hedges in the amount of $7.4 million, compared to losses of $1.4 million in the first quarter of 2014 and gains of $0.5 million in the fourth quarter of 2014. Details by commodity of realized gains and losses are provided on page 18. The fair market value of hedges in place at March 31, 2015 was $6.1 million.

In January 2015 the Company terminated all of the Company's 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 income for the period.

Natural gas volumes are hedged at the AECO monthly index and the Company sells an equal volume of natural gas at the same index.

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 Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for period	$ 473	$ 3,449	$ 3,455
Percentage of revenue from product sales	2.5%	16.6%	12.3%
Per Boe	$ 0.54	$ 7.56	$ 3.69

Royalties for the first quarter of 2015 decreased by 86% when compared to both the first quarter of 2014 and the final quarter of 2014. Decreased production revenue as a result of lower commodity pricing was the primary driver of decreased royalties; however, royalties also decreased as a result of the receipt of an infrastructure royalty credit at Umbach which reduced 2015 royalties by $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, $745,000 of this amount was applied in reduction of royalties and the Company received approximately $1.6 million 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, with this amount likely being received in late 2015 and 2016. The timing of receipt of future credits is dependent on commodity prices and cannot be readily forecasted; correspondingly, royalty rates reported in future quarters could vary considerably depending on when future credits are received.

In HRB, the Company benefited from British Columbia's Deep Well Royalty Credit program, applicable to horizontal wells with a vertical depth greater than 1,900 metres. Under this program, which is not subject to expiry, drilling credits earned are applied in reduction of future royalties levied on production. The Company has received the full entitlement of $1.1 million and HRB production, absent further drilling, no longer benefits from royalty credits under this program. In 2012 the Company received approval for an infrastructure royalty credit of $1.0 million at HRB and received $0.3 million in 2014.

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. Wells spud after April 1, 2014 benefit from this change. As a result, future horizontal wells at Umbach 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.

In Alberta, production from new wells is subject to a 5% royalty rate for the first 12 months of production, subject to a maximum volume of 50,000 Bbls of crude oil or 500 million cubic feet of natural gas. Lack of drilling activity in Alberta has resulted in the expiry of this program's benefits to Storm.

Production of NGL is subject to an effective royalty rate of 20% in British Columbia and approximately 25% to 30% in Alberta.

Production Costs

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for period	$ 7,624	$ 4,962	$ 7,864
Percentage of revenue from product sales	41.2%	23.8%	27.9%
Per Boe	$ 8.67	$ 10.88	$ 8.40

Total production costs for the first quarter increased by 54% when compared to the first quarter of 2014 and decreased by 3% when compared to the final quarter of 2014. The increase in production costs is largely aligned with increased production at Umbach.

Production costs per Mcf of natural gas for the first quarter averaged $1.64 and production costs per barrel of crude oil for the same period averaged $19.42, with total production costs averaging $8.67 per Boe. Production costs of natural gas liquids are included with natural gas costs. The equivalent charges for the first quarter of 2014 were $1.94 per Mcf of natural gas and $23.34 per barrel for crude oil, with total production costs averaging $10.88 per Boe. Per-Boe production costs for the final quarter of 2014 averaged $1.61 for natural gas and $16.94 for crude oil with total production costs averaging $8.40.

Year over year, production costs per Boe have declined due to production growth as well as lower cost natural gas growing as a percentage of the Company's production base.

Transportation Costs

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for period	$ 1,476	$ 782	$ 1,791
Percentage of revenue from product sales	8.0%	3.8%	6.4%
Per Boe	$ 1.68	$ 1.71	$ 1.91

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 and for crude oil in Alberta. Total transportation costs for the first quarter of 2015 increased by 89% over the same quarter of 2014, and decreased 18% over the immediately preceding quarter. Year over year, higher volumes of field condensate at Umbach resulted in increased NGL trucking charges. Pipeline restrictions in the fourth quarter of 2014 also contributed to higher condensate trucking charges at Umbach.

Field Netbacks

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

	Three Months Ended March 31, 2015			
	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 2.85	$ 37.10	$ 43.08	$ 21.04
Royalties	0.11	(6.26)	(3.35)	(0.54)
Production costs	(1.64)	-	(19.42)	(8.67)
Transportation costs	(0.19)	(3.80)	(4.88)	(1.68)
Field operating income before hedging	$ 1.13	$ 27.04	$ 15.43	$ 10.16
Realized hedging gains (losses)	0.52	-	172.75	8.36
Total operating income per commodity unit	$ 1.64	$ 27.04	$ 188.18	$ 18.52
Total operating income (000s)	$ 7,069	$ 3,633	$ 5,596	$ 16,298

	Three Months Ended March 31, 2014			
	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 5.63	$ 84.49	$ 93.08	$ 45.62
Royalties	(0.84)	(15.00)	(18.97)	(7.56)
Production costs	(1.94)	-	(23.34)	(10.88)
Transportation costs	(0.21)	(2.85)	(4.16)	(1.71)
Field operating income before hedging	$ 2.64	$ 66.64	$ 46.61	$ 25.47
Realized hedging gains (losses)	(0.53)	-	(8.28)	(3.10)
Total operating income per commodity unit	$ 2.11	$ 66.64	$ 38.33	$ 22.37
Total operating income (000s)	$ 4,504	$ 4,347	$ 1,349	$ 10,200

	Three Months Ended December 31, 2014			
	Natural Gas ($/Mcf)	Natural Gas Liquids ($/Bbl)	Crude Oil ($/Bbl)	Total ($/Boe)
Production revenue	$ 3.85	$ 56.15	$ 68.01	$ 29.99
Royalties	(0.30)	(10.27)	(16.81)	(3.69)
Production costs	(1.61)	-	(16.94)	(8.40)
Transportation costs	(0.20)	(4.62)	(5.51)	(1.91)
Field operating income before hedging	$ 1.74	$ 41.26	$ 28.75	$ 15.99
Realized hedging gains (losses)	(0.07)	-	22.84	0.52
Total operating income per commodity unit	$ 1.67	$ 41.26	$ 51.59	$ 16.51
Total operating income (000s)	$ 7,524	$ 6,094	$ 1,828	$ 15,446

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

Total operating income in the first quarter of 2015 increased by 60% and by 6% respectively, when compared to the first and final quarters of 2014. However, the first quarter of 2015 benefited from a gain of $5.1 million on the termination of Storm's crude oil hedging contracts. Per Boe, excluding hedging gains and losses, field operating income fell by 60% in the first quarter of 2015 in comparison to the same quarter of 2014, and by 36% compared to the final quarter of 2014. Year over year, royalties, production and transportation costs per Boe each fell, but these gains were insufficient to counter the effect of reduced commodity prices which saw the per-Boe realization fall by $24.58, or a remarkable 54%. Compared to the final quarter of 2014, royalties and transportation costs fell, with operating costs increasing marginally: however, falling commodity prices resulted in the per-Boe realization falling by 30%.

Cash costs per Boe, comprising production costs, transportation, interest and general and administrative costs, amounted to $13.29 for the first quarter of 2015, $15.97 for the equivalent quarter of 2014 and $11.97 for the final quarter of 2014. Comparing the first quarter of 2015 to the same quarter in 2014, per-Boe reductions in production, transportation and general and administrative costs more than offset interest cost increases. Compared to the immediately preceding quarter, increased bank debt and payment of employee performance bonuses resulted in higher interest and general and administrative costs. Production costs increased marginally while transportation costs fell.

General and Administrative Costs

Total Costs	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for perod – before recoveries	$ 2,852	$ 1,746	$ 1,581
Overhead recoveries	(883)	(419)	(498)
Charge for period – net of recoveries	$ 1,969	$ 1,327	$ 1,083
Per Boe	$ 2.24	$ 2.91	$ 1.16

Gross general and administrative costs for the first quarter of 2015 increased by 63% when compared to the first quarter of 2014 and increased by 80% compared to the final quarter of 2014. The increase in general and administrative costs is largely attributable to employee performance bonuses paid in March 2015. The increase in overhead recoveries in the first quarter of 2015 corresponds to the quarter's active field program.

On a per-Boe measure, net general and administrative costs fell by 23% compared to the first quarter of 2014 due to increased production.

Share-Based Compensation

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for period	$ 985	$ 257	$ 756
Per Boe	$ 1.12	$ 0.56	$ 0.81

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 283% in the first quarter of 2015 compared to the same quarter of 2014 and increased by 30% when compared to the immediately prior quarter. The increase in share-based compensation in the first quarter of 2015 is attributable to stock options granted in March and December of 2014.

Depletion and Depreciation

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Depletion	$ 7,825	$ 5,018	$ 8,965
Depreciation	1,394	681	1,155
Charge for period	$ 9,219	$ 5,699	$ 10,120
Per Boe	$ 10.48	$ 12.49	$ 10.81

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 resulted in the total charge for depletion and depreciation increasing year over year in the first quarter of 2015. The quarterly year-over-year per-Boe charge fell by 16%, as the finding and development cost for proved plus probable reserves has declined, reflecting Storm's successful drilling program.

Management reviewed the carrying amounts of exploration and evaluation and property and equipment assets for indicators of impairment at March 31, 2015 and determined that no impairment adjustment was required.

Exploration and Evaluation Costs Expensed

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for period	$ 103	$ 152	$ 1,152
Per Boe	$ 0.12	$ 0.33	$ 1.23

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

Accretion

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for period	$ 133	$ 67	$ 110

Accretion represents the time value increase for the period of the Company's decommissioning liability. The increased year-over-year charge for accretion is due to changes in estimates of future costs and discount rates. The increase in accretion expense between the final quarter of 2014 and the first quarter of 2015 was due to additional liabilities assumed due to drilling and facility construction in the first quarter of 2015.

Interest and Finance Costs

(000s)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Charge for period	$ 617	$ 213	$ 470
Percentage of revenue from product sales	3.3%	1.0%	1.7%
Per Boe	$ 0.70	$ 0.47	$ 0.50

Interest costs for the first quarter of 2015 increased by 190% compared to the equivalent period in 2014, and increased by 31% compared to the final quarter of 2014, as a result of increased bank borrowings corresponding to an expanding production and asset base. Expanded use of the Company's credit facility in future quarters will result in increased interest costs.

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 has 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 current reporting period.

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014		Three Months Ended December 31, 2014	
Realized gain (loss)						
Crude oil	$ 5,137	$ 172.75/Bbl	$ (292)	$ (8.28)/Bbl	$ 809	$ 22.84/Bbl
Natural gas	2,222	$ 0.52/Mcf	(1,122)	$ (0.53)/Mcf	(323)	$ (0.07)/Mcf
Total realized gain/(loss) - cash	$ 7,359	$ 8.36/Boe	$(1,414)	$ (3.10)/Boe	$ 486	$ 0.52/Boe

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014		Three Months Ended December 31, 2014	
Unrealized gain (loss)						
Crude oil – change in fair value	$(4,861)	$(163.46)/Bbl	$ (467)	$(13.26)/Bbl	$ 4,570	$129.02/Bbl
Natural gas – change in fair value	(1,976)	$ (0.46)/Mcf	(2,470)	$ (1.16)/Mcf	8,957	$ 1.98/Mcf
Total unrealized gain/(loss) - non-cash	$(6,837)	$ (7.77)/Boe	$(2,937)	$ (6.44)/Boe	$13,527	$ 14.45/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 March 31, 2015	Maximum Annual Deduction
Canadian oil and gas property expense	$ 63,000	10%
Canadian development expense	107,000	30%
Canadian exploration expense	23,000	100%
Undepreciated capital cost	84,000	20 - 100%
Operating losses	138,000	100%
Other	3,000	20 - 100%
Total	$ 418,000	

Net Income (Loss)

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Net income (loss)	$ (3,565)	$ 206	$ (7,422)
Per basic and diluted share	$ (0.03)	$ 0.00	$ (0.07)

Other Comprehensive 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 three months ended March 31, 2015, a loss of $50,000 was recognized in other comprehensive income, representing the mark-to-market decrease in value of the investment in Chinook measured against the value at the end of the final quarter of 2014.

Listed Securities	Holding	Number of Shares(1)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Chinook Energy Inc.	Common Shares	1,000,000	$ 50	$ -	$ 780
Other comprehensive loss for period			$ 50	$ -	$ 780

(1) Shares owned at March 31, 2015.

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

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014		Three Months Ended December 31, 2014	
		Per diluted share		Per diluted share		Per diluted share
Funds from operations	$ 13,712	$ 0.12	$ 8,660	$ 0.08	$ 13,892	$ 0.12

Non-GAAP funds from operations for the first quarter of 2015 increased by 58% from the first quarter of 2014, and decreased by 1% compared to the final quarter of 2014.

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 Ended March 31, 2015		Three Months Ended March 31, 2014		Three Months Ended December 31, 2014	
		Per diluted share		Per diluted share		Per diluted share
Non-GAAP funds from operations	$ 13,712	$ 0.12	$ 8,660	$ 0.08	$ 13,892	$ 0.12
Net change in non-cash working capital items	225	-	(855)	0.00	3,579	0.03
Cash from operating activities	$ 13,937	$ 0.12	$ 7,805	$ 0.08	$ 17,471	$ 0.15

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 Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Revenue from product sales	21.04	45.62	29.99
Realized hedging gains (losses)	8.36	(3.10)	0.52
Royalties	(0.54)	(7.56)	(3.69)
Production	(8.67)	(10.88)	(8.40)
Transportation	(1.68)	(1.71)	(1.91)
General and administrative	(2.24)	(2.91)	(1.16)
Interest	(0.70)	(0.47)	(0.50)
Funds from operations netback	15.57	18.99	14.85
Share-based compensation	(1.12)	(0.56)	(0.81)
Depletion, depreciation and accretion	(10.63)	(12.64)	(10.93)
Exploration and evaluation costs expensed	(0.12)	(0.33)	(1.23)
Gain on disposal of investments	-	0.64	-
Unrealized revaluation gain (loss) on investments	-	0.83	-
Reduction of carrying amount of property and equipment	-	-	(24.26)
Gain (loss) on disposal of oil and gas properties	-	(0.03)	-
Unrealized gain (loss) on commodity price contracts	(7.77)	(6.44)	14.45
Net income (loss) per Boe	(4.07)	0.46	(7.93)

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 increased to $150.0 million.

The Company is in compliance with all covenants under the credit facility, the sole financial covenant being that net debt including working capital deficiency not 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 March 31, 2015.

	Holding	Number of Shares	Exchange	Closing Price Mar. 31, 2015	Value at Mar. 31, 2015
Chinook Energy Inc.	Common Shares	1,000,000	TSX	$ 1.22	$ 1,220

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 were no shares sold in the second half of 2014 or the first quarter of 2015.

Capital Expenditures

In the first quarter of 2015, the Company spent $35.7 million (2014 - $22.3 million), all of which was spent on field operations almost exclusively to develop the high liquids content natural gas play at Umbach.

During the quarter, the Company drilled six 100% working interest horizontal wells, completed two horizontal wells and one salt water disposal well, tied in four horizontal wells and completed an expansion of a compressor station at Umbach which added compression capacity of 27 Mmcf per day. A 15-kilometre pipeline was built to a third party natural gas processing plant. Major field capital outlays in the first quarter include $19.1 million on drilling and completions and $15.4 million on facilities, equipping and tie-ins, all in the Umbach area.

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Land and lease	$ 336	$ 295	$ 342
Drilling	12,253	12,327	4,240
Completions	6,887	5,467	8,149
Facilities	15,378	3,378	7,488
Recompletions and workovers	806	876	-
Proceeds on disposition of oil and gas properties	-	-	-
Property acquisition, adjustments and administrative assets	20	88,051	(124)
Total	$ 35,680	$ 110,394	$ 20,095

Capital expenditures in the reporting periods were allocated as follows:

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014	Three Months Ended December 31, 2014
Exploration and evaluation	$ 316	$ 79,527	$ 637
Property and equipment	35,364	30,867	19,458
Total – net of dispositions	$ 35,680	$ 110,394	$ 20,095

Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities include operating, administrative and capital costs payable. 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 March 31, 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. Changes in the amount of the liability during the period ended March 31, 2015 reflect (i) additional liabilities accruing to the Company as a result of field activity and acquisitions, (ii) revisions of estimates of inflation and discount rates, iii) assessment of the amount of future costs and timing of incurrence of such costs, (iv) less the decommissioning obligations associated with dispositions of oil and gas properties, (v) 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 March 31, 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
Total at March 31, 2015 and December 31, 2014		111,322	$ 3.19	$ 355,254

(1) Before share issue costs.

In April 2013 the Company entered into a bought deal financing for aggregate gross proceeds of $23,650,400. Pursuant to this financing, the Company issued 12,580,000 common shares at a price of $1.88 per share. Concurrently with the bought deal financing, the Company issued 3,000,000 common shares also at a price of $1.88 per share to certain directors, officers and employees of the Company for gross proceeds of $5,640,000. Both of these financings closed on May 1, 2013. Net proceeds received totaled $27.8 million.

In October 2013 the Company entered into a bought deal financing for aggregate gross proceeds of $30,150,000. Pursuant to this financing, the Company issued 9,000,000 common shares at a price of $3.35 per share. Concurrently with the bought deal financing, the Company issued 1,100,000 common shares, also at a price of $3.35 per share, to certain directors, officers and employees of the Company for gross proceeds of $3,685,000. Both of these financings closed on November 19, 2013. Net proceeds received totaled $31.9 million.

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 producing 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 $88.0 million including $30.0 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 2014, stock options were exercised at an average price of $3.26 per optioned share and 1,709,666 common shares were issued for proceeds of approximately $5,580,000.

Issued and outstanding common shares at March 31, 2015 and May 13, 2015, the date of this MD&A, totaled 111,321,978.

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 agreements.

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 $88.3 million over the next four years.

QUARTERLY RESULTS

Summarized information by quarter for the two years ended March 31, 2015 appears below:

	2015				2014			2013
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production revenue ($000s)(1)	25,871	28,556	24,131	20,202	19,393	15,420	13,093	11,960
Non-GAAP funds from operations ($000s)(2)	13,712	13,892	11,784	11,076	8,660	7,501	6,144	5,077
Per share								
- basic ($)	0.12	0.13	0.11	0.10	0.09	0.09	0.08	0.07
- diluted ($)	0.12	0.12	0.11	0.10	0.08	0.09	0.08	0.07
Net income (loss) ($000s)	(3,565)	(7,422)	5,473	6,598	206	(25,174)	(1,429)	661
Per share								
- basic ($)	(0.03)	(0.07)	0.05	0.06	0.00	(0.34)	(0.02)	0.01
- diluted ($)	(0.03)	(0.07)	0.05	0.06	0.00	(0.34)	(0.02)	0.01
Net capital expenditures ($000s)	35,680	20,095	30,426	33,640	110,394	11,380	23,717	16,710
Average daily production - Boe	9,776	10,173	7,160	5,462	5,068	4,773	3,800	3,460
Net debt ($000s)(3)	85,098	63,080	56,157	41,837	22,176	12,059	40,968	22,671

(1) Includes hedging gains and losses.
(2) See Non-GAAP Measurements on page 10 of this MD&A.
(3) Includes investments and working capital deficiency and excludes the fair value of commodity price contracts.

CRITICAL ACCOUNTING ESTIMATES

Financial amounts included in this MD&A and in the financial statements for the period ended March 31, 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 estimated costs to complete the abandonment and reclamation of field assets as well as the estimated timing of the costs to be incurred in future periods. 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 written off, 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 on the Company's statement of financial position an amount representing the accumulated net costs associated with the property. 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, 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 are made. All of these involve assumptions regarding future events and circumstances and involve a high degree of uncertainty.

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, 2017.

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)	March 31, 2015	December 31, 2014
ASSETS		
Current		
Accounts receivable	$ 9,494	$ 8,205
Prepaids and deposits	3,136	905
Investments (Note 3)	1,220	1,270
Fair value of commodity price contracts (Note 11)	6,083	12,920
	19,933	23,300
Exploration and evaluation (Note 4)	126,502	126,805
Property and equipment (Note 5)	295,761	268,463
	$ 442,196	$ 418,568
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 35,201	$ 27,430
	35,201	27,430
Bank indebtedness (Note 6)	63,747	46,030
Decommissioning liability (Note 7)	24,323	23,553
	123,271	97,013
Shareholders' equity		
Share capital (Note 8)	351,161	351,161
Contributed surplus (Note 9)	4,348	3,363
Deficit	(36,644)	(33,079)
Accumulated other comprehensive income	60	110
	318,925	321,555
Commitments (Note 13)		
	$ 442,196	$ 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 Ended March 31, 2015	Three Months Ended March 31, 2014
Revenue		
Revenue from product sales	$ 18,512	$ 20,807
Realized gain (loss) on commodity price contracts (Note 11)	7,359	(1,414)
Royalties	(473)	(3,449)
	$ 25,398	$ 15,944
Expenses		
Production	7,624	4,962
Transportation	1,476	782
General and administrative	1,969	1,327
Share-based compensation (Note 9)	985	257
Depletion and depreciation (Note 5)	9,219	5,699
Exploration and evaluation costs expensed (Note 4)	103	152
Accretion	133	67
	21,509	13,246
Income before the following:	3,889	2,698
Interest and finance costs	(617)	(213)
Gain on disposal of investments (Note 3)	-	291
Unrealized revaluation gain on investments (Note 3)	-	380
Loss on disposal of oil and gas properties	-	(13)
Reversal of prior period unrealized gains on commodity price contracts (Note 11)	(6,837)	(2,937)
Net income (loss) for the period	(3,565)	206
Other comprehensive loss		
Reversal of prior period unrealized gain on investments (Note 3)	(50)	-
Other comprehensive loss	(50)	-
Comprehensive income (loss) for the period	$ (3,615)	$ 206
Net income (loss) per share (Note 10)		
- basic	$ (0.03)	$ 0.00
- diluted	$ (0.03)	$ 0.00

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Changes in Shareholders' Equity

(Canadian $000s) (unaudited)				Three Months Ended March 31, 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	-	-	(3,565)	-	(3,565)
Share-based compensation (Note 9)	-	985	-	-	985
Reversal of prior period unrealized gain on investments (Note 3)	-	-	-	(50)	(50)
Balance, end of period	$ 351,161	$ 4,348	$ (36,644)	$ 60	$ 318,925

(Canadian $000s) (unaudited)				Three Months Ended March 31, 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	-	-	206	-	206
Issue of common shares (Note 8)	92,775	-	-	-	92,775
Share issue costs (Note 8)	(1,829)	-	-	-	(1,829)
Share-based compensation (Note 9)	-	257	-	-	257
Balance, end of period	$ 343,783	$ 3,226	$ (37,728)	-	$ 309,281

See accompanying notes to the condensed interim consolidated financial statements.

Interim Consolidated Statements of Cash Flows

(Canadian $000s) (unaudited)	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
Operating activities		
Net income (loss) for the period	$ (3,565)	$ 206
Non-cash items:		
Share based compensation (Note 9)	985	257
Depletion, depreciation and accretion	9,352	5,766
Exploration and evaluation costs expensed (Note 4)	103	152
Gain on disposal of investment (Note 3)	-	(291)
Unrealized revaluation gain on investments (Note 3)	-	(380)
Loss on disposal of oil and gas properties	-	13
Reversal of prior period unrealized gains on commodity price contracts (Note 11)	6,837	2,937
	13,712	8,660
Net change in non-cash working capital items (Note 12)	225	(855)
	13,937	7,805
Financing activities		
Proceeds from issue of common shares – net of expenses (Note 8)	-	33,021
Increase (decrease) in bank indebtedness	17,717	(5,353)
	17,717	27,668
Investing activities		
Additions to exploration and evaluation assets (Note 4)	(316)	(601)
Additions to property and equipment (Note 5)	(35,364)	(21,777)
Cash portion of acquisitions of property and equipment and exploration and evaluation assets (Notes 4 and 5)	-	(30,091)
Proceeds on disposal of investments (Note 3)	-	1,451
Net change in non-cash working capital items (Note 12)	4,026	15,545
	(31,654)	(35,473)
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 months ended March 31, 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 used in the audited consolidated financial statements for the years ended December 31, 2014 and 2013. The financial statement 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 May 13, 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.

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

3. INVESTMENTS

	March 31, 2015	December 31, 2014
Chinook Energy Inc. (“Chinook”)	$ 1,220	$ 1,270

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

The reversal of an unrealized revaluation gain for the quarter ended March 31, 2015, in the amount of $50,000, was recognized in other comprehensive income. In 2014, the reversal of an unrealized revaluation loss of $0.4 million was recognized in the consolidated statement of income (loss).

In January 2014, the Company sold 1.0 million common shares of Chinook for net proceeds of $1.5 million and recognized a gain of $0.3 million measured against the carrying amount at December 31, 2013.

4. EXPLORATION AND EVALUATION

	Three Months Ended March 31, 2015	Year ended December 31, 2014
Balance, beginning of period	$ 126,805	$ 87,396
Acquisitions	-	78,930
Additions	316	1,754
Exploration and evaluation expenditures expensed	(103)	(1,427)
Future decommissioning costs	-	3,476
Transfer to property and equipment	(516)	(43,324)
Balance, end of period	$ 126,502	$ 126,805

In the first quarter of 2014, the Company spent approximately $88.0 million on undeveloped land and producing properties, consisting of $30.0 million in cash and 13,629,442 common shares at a deemed price of $4.25 per share. This transaction did not constitute a business combination as only assets were acquired with no related personnel or infrastructure.

5. PROPERTY AND EQUIPMENT

	Three Months Ended March 31, 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	35,364	104,850
Future decommissioning costs	637	11,037
Transfer from exploration and evaluation assets	516	43,324
Balance, end of period	$ 415,724	$ 379,207
Accumulated depletion and depreciation		
Balance, beginning of period	$ (110,744)	$ (58,552)
Depletion and depreciation	(9,219)	(29,492)
Reduction in carrying amount of property and equipment	-	(22,700)
Balance, end of period	$ (119,963)	$ (110,744)
Net book value, end of period	$ 295,761	$ 268,463

6. BANK INDEBTEDNESS

As at March 31, 2015, the Company had an extendible revolving bank facility in the amount of $130.0 million (December 31, 2014 – $130.0 million) based on the Company's producing reserves. In April 2015, the facility was increased to $150.0 million in recognition of increased production and reserve growth at Umbach. 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 March 31, 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.

7. DECOMMISSIONING LIABILITY

The Company provides for the future cost of decommissioning 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 decommissioning obligation is approximately $38.5 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 – 2.3%) and an inflation rate of 2.0% (2014 – 2.0%) was used to calculate the present value of the decommissioning obligation, amounting to $24.3 million.

The following table provides a reconciliation of the carrying amount of the obligation associated with the decommissioning of oil and gas properties:

	Three Months Ended March 31, 2015	Year Ended December 31, 2014
Balance, beginning of period	$ 23,553	$ 8,689
Obligations incurred	641	3,797
Obligations acquired	-	710
Obligations disposed	(4)	-
Obligations settled	-	(34)
Change in rate estimates[1]	-	6,029
Change in cost estimates	-	4,011
Accretion expense	133	351
Balance, end of period	$ 24,323	$ 23,553

(1) Relates to changes in the inflation rate and discount rate in 2014.

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 from stock option exercises[3]	1,710	7,378
Balance as at December 31, 2014 and March 31, 2015	111,322	$ 351,161

(1) On January 31, 2014 the Company issued 13,629,442 common shares, with a deemed value of $4.25 per common share, for proceeds 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.

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 11,132,197 common shares are available for issuance. At March 31, 2015, and at the date of this quarterly report, options in respect of 5,956,834 common shares had been issued, all of which are unexercised, and options remain in respect of 5,175,363 common shares which are available for further grants under the stock option plan.

Details of the options outstanding at March 31, 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 and March 31, 2015	5,957	$ 3.54
Number exercisable at March 31, 2015	2,063	$ 2.66

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	2,147	1.6	$ 1.83	1,442	$ 1.84
$2.64 - $3.95	40	0.9	$ 3.04	40	$ 3.04
$3.96 - $4.68	3,770	3.3	$ 4.52	581	$ 4.68
Total	5,957	2.7	$ 3.54	2,063	$ 2.66

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).

No options have been granted to date in 2015. The weighted average inputs used in the Black-Scholes pricing model to determine the fair value of the options granted during the three months ended March 31, 2014 of $1.99 per share include the following:

	2014
Share price	$ 4.68
Exercise price	$ 4.68
Volatility	56%
Forfeiture rate	10%
Expected option life (years)	3.7
Dividends	-
Risk-free interest rate	1.4%

Share-based compensation expense of $985,000 was charged to the consolidated statement of income (loss) during the three months to March 31, 2015 (2014 - $257,000) with an equivalent offset to contributed surplus. Volatility is based on the historical trading 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 Ended March 31, 2015	Three Months Ended March 31, 2014
Net income (loss) for the period	$ (3,565)	$ 206
Weighted average number of common shares outstanding – basic		
Common shares outstanding at beginning of period	111,322	87,483
Effect of shares issued	-	13,185
Weighted average number of common shares outstanding – basic	111,322	100,668
Effect of outstanding options	-	1,745
Weighted average number of common shares outstanding - diluted	111,322	102,413
Net income (loss) per share		
- basic	$ (0.03)	$ -
- diluted	$ (0.03)	$ -

At March 31, 2015, all outstanding stock options were considered anti-dilutive. In the first quarter of 2014, 1.8 million stock options were excluded from the diluted-per-share calculation.

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. The Company's investment in Chinook is carried at the March 31, 2015 fair value of $1.2 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 March 31, 2015 is as follows:

	Carrying Amount as at March 31, 2015
Accounts receivable	$ 9,494
Fair value of commodity price contracts	6,083
Total	$ 15,577

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 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 from joint venture partners.

No default on outstanding receivables is anticipated as less than 0.2% of the Company's outstanding receivable balance is considered past due at March 31, 2015.

Market risk

Commodity Prices

As at March 31, 2015, Storm has the undernoted commodity price contracts in place. The fair market value of these contracts of $6,083,000 (December 31, 2014 – $12,920,000) is included in current assets. This resulted in an unrealized mark-to-market loss of $6,837,000 (2014 – loss of $2,937,000) when measured against the fair market value at the preceding quarter end which is recognized in the consolidated statement of income (loss) for the three months ended March 31, 2015. 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 months ended March 31, 2015.

Fixed Price	Volume	AECO Natural Gas Average Price (Cdn$/GJ)
Q2 – 2015	25,700 GJ/day	$3.22
Q3 – 2015	34,000 GJ/day	$3.27
Q4 – 2015	30,000 GJ/day	$3.47
Jan – Dec 2016	10,000 GJ/day	$3.00

During the three months ended March 31, 2015, the Company realized gains from commodity price contracts in place or terminated in the amount of $7,359,000 (2014 – losses of $1,414,000).

Sensitivities

Using the Company's actual production volumes, royalty rates and debt levels for the first three 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	$	170,000	$	-
$0.10/Mcf change in the price of natural gas	$	430,000	$	-
1% change in the interest rate	$	550,000	$	-

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 Ended March 31, 2015		Three Months Ended March 31, 2014
Accounts receivable	$	(1,289)	$	(2,281)
Prepaids and deposits		(2,231)		233
Accounts payable and accrued liabilities		7,771		16,738
Change in non-cash working capital	$	4,251	$	14,690
Relating to:				
Operating activities	$	225	$	(855)
Investing activities		4,026		15,545
	$	4,251	$	14,690
Interest paid during the period	$	519	$	210
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
Office lease	$ 697	$ 940	$ 940	$ 705	$ -
Gas transportation and processing commitments	12,217	29,309	26,554	17,278	2,897
Total	$ 12,914	$ 30,249	$ 27,494	$ 17,983	$ 2,897

In the first quarter of 2015, office lease payments of $231,000 (2014 - $228,000) 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

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

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

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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
STOOIP	Stock Tank Original Oil in Place
Tcf	Trillions of cubic feet
TSX	Toronto Stock Exchange
US$	United States dollar
WTI	West Texas Intermediate

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