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This presentation contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historical fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements may include projections and estimates concerning Bonanza Creek Energy, Inc.’s (the “Company”) capital expenditures, liquidity and capital resources, estimated revenues and losses, timing and success of specific projects, outcomes and effects of litigation, claims and disputes, business strategy and other statements concerning the Company’s operations, economic performance and financial condition. When used in this presentation, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “forecast,” “may,” “continue,” “predict,” “potential,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. The Company has based these forward-looking statements on certain assumptions and analyses it has made in light of its experiences and perceptions of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. The actual results or developments anticipated by these forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond the Company’s control, and may not be realized or, even if substantially realized, may not have the expected consequences. Factors that could cause actual results to differ materially include, but are not limited to, the: the Company’s ability to replace oil and natural gas reserves; declines or volatility in prices it receives for its oil and natural gas, including any impact on the Company’s asset carrying values or reserves arising from the price declines; its financial position; its cash flow and liquidity; general economic conditions, whether internationally, nationally or in the regional and local market areas in which the Company does business; development and completion expectations and strategy; impact of the Company’s reorganization; 2020 guidance, the Company’s ability to generate sufficient cash flow from operations, borrowings or other sources to enable it to fully develop its undeveloped acreage positions; the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs; uncertainties associated with estimates of proved oil and gas reserves and, in particular, probable and possible resources; the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulation); environmental risks; drilling and operating risks, including risks related to horizontal drilling; exploration and development risks; competition in the oil and natural gas industry; management’s ability to execute the Company’s plans to meet its goals, uncertainties of negotiations to result in an agreement or a completed transaction; the Company’s ability to retain key members of its senior management and key technical employees; infrastructure challenges; access to adequate gathering systems and pipeline take-away capacity to execute the Company’s drilling program; the Company’s ability to secure firm transportation for oil and natural gas it produces and to sell the oil and natural gas at market prices; costs associated with perfecting title for mineral rights in some of the Company’s properties; the Company’s ability to realize estimated well cost reductions; continued hostilities in the Middle East; other sustained military campaigns or acts of terrorism or sabotage; and other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact the Company’s businesses, operations or pricing; and other important factors that could cause actual results to differ materially from those projected in this presentation and in the Company’s filings with the U.S. Securities and Exchange Commission (the “SEC”). For further detail on these and other risks and uncertainties, the Company refers you to the information under “Risk Factors” in the Company’s Annual Report on Form 10-K for the year ended December 31, 2019 and in comparable sections of our Quarterly Reports on Form 10-Q, as filed with the SEC. All of the forward-looking statements made in this presentation are qualified by these cautionary statements and are made only as of the date hereof. The Company does not undertake, and specifically declines, any obligation to update any such statements or references to you announce the results of any revisions to any such statements to reflect future events or developments. Although the Company believes that its plans, intentions and expectations reflected in or suggested by the forward-looking statements it makes in this presentation are reasonable, the Company can give no assurance that these plans, intentions or expectations will be achieved.

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Bonanza Creek – Pure-Play Wattenberg Operator

- Highly contiguous, oily acreage in rural Weld County
- Over 1,000 future economic drilling locations (1)
- Strong financial position
  - Leverage of 0.2x Net Debt / LTM EBITDAX at 3/31/20
  - ~$300 million of liquidity as of 3/31/20
- Year-end 2019 Total Proved PV-10 of $858 million (SEC Prices) (2)
  - 1Q 2020 PDP PV-10 at strip of $388 million (3)
- 2019 production growth of 48% over 2018 on capex of $222 million
- 2020 production approximately flat with 2019 on capex of $65 million (4)
  - 2019 average production of 23.5 Mboe/d

---

(1) Gross, SRL equivalent
(2) PV-10 based on NSAI reserves as of 12/31/19 using SEC pricing of $55.85 WTI and $2.58 Henry Hub. See Appendix for a reconciliation of year-end 2019 PV-10 to year-end 2019 standardized measure
(3) PV-10 based on 1Q 2020 internal reserves as of 3/31/20 using 3/31/20 strip pricing:
  - WTI = $29.02, $36.22, $39.19, $41.19, $42.98 (2020-2024)
  - HH = $2.03, $2.48, $2.40, $2.42, $2.44 (ROY 2020-2024)
(4) Based on mid-point of Company’s most recent 2020 guidance
Track Record of Performance & Managing Commodity Cycle

**Wattenberg Production & Capex**

- 38% CAGR from 4Q17 to 1Q20
- Capex: 6.11, 6.00, 6.01, 4.26, 4.54, 6.05, 4.54, 3.61, 3.53, 3.41, 3.44
- Net Debt: 5.65, 4.72, 5.44, 6.05, 4.54, 3.61, 3.53, 3.41, 3.44, 3.44
- 2020 Guidance: 25.0

**Wattenberg LOE + Recurring Cash G&A**

- ~56% Decline from 4Q17 to 1Q20
- LOE: 7.61, 5.65, 4.72, 6.01, 4.26, 3.27, 2.91, 2.87, 3.00, 3.01, 2.52
- Cash G&A: 2.00, 3.00, 3.01, 3.00, 3.01, 2.52

**Pre-Hedge Adjusted EBITDAX & Margin**

- Decline of 46% from 4Q17 to 1Q20
- Adjusted EBITDAX: $35.79, $41.79, $43.02, $45.28, $40.14, $38.22, $37.88, $32.96, $34.85, $26.01
- Margin: 55%, 57%, 63%, 61%, 66%, 66%, 61%, 64%, 53%

**Wattenberg Revenues & Realized Prices**

- Revenue before impact of derivatives: $39.4, $51.7, $59.0, $69.9, $66.2, $72.6, $85.8, $75.2, $79.7, $60.4
Peer Leading Cash Cost Structure & Pre-Hedge Margin

(1) Source: Stifel Research (May 4, 2020). Peers include APA, AXAS, CDEV, CHAP, CLR, CPE, CXO, DNR, DVN, EOG, FANG, HPR, LPI, MRO, MTDR, NBL, OAS, PDCE, PE, PXD, QEP, ROSE, SM, SNDE, WPX, XEC

(2) All costs are 2020E. Total cash costs include LOE & gathering, G&A expense, production taxes, and interest expense
Attractive Valuation & Shareholder Mix

Balanced Shareholder Base

• Significant shareholder evolution over 2 years
• Pre-emergence debt holders’ equity ownership reduced from >50% to <25%
• Company’s beta has decreased from over two to less than one\(^{(1)}\)

Compelling Valuation\(^{(2)}\)

• Attractive valuation with strong balance sheet
• Discount to DJ Basin and average SMID Cap Peers
• Generating greater EBITDA per share with significantly less debt

\(^{(1)}\) 1-year BCEI raw beta to XOP per Bloomberg
\(^{(2)}\) DJ Basin Peers include HPR, PDCE, and XOG. SMID Cap Peers include AXAS, CPE, CHAP, ESTE, and MTDR and is based on Bloomberg 2020 consensus estimates as of 5/4/2020
Rural and Oily Acreage

- No municipalities / 100% unincorporated Weld County acreage
  - < 3% of acreage with Federal minerals or surface
- Actively engaged with community stakeholders to help ensure safe, thoughtful and responsible development
- Surface use agreements in place for all planned 2020 operated wells
- Receiving Weld County, COGCC, and CDPHE permits on a consistent basis
Resilient to Evolving Regulatory Landscape

• No expected impact to BCEI’s
  …development plan or existing infrastructure
  …1,000 well inventory or PUDs
  …pending permit applications

• All mineral resources remain accessible with existing development practices

• Less than 5% of surface is impacted by an increase from current 1,500’ to 2,000’ distance from occupied structures

• Lowest exposure to occupied structures among public DJ Basin operators in Colorado (2)

(1) Map shows 1,500’ and 2,000’ distance from occupied structures on undeveloped acreage
(2) Source: RS Energy Group, “Proposition 112 Playbook: Indecent Proposal” (Oct 2018)
Rocky Mountain Infrastructure

Rocky Mountain Infrastructure Assets

- 140 miles and 100 MMcf/d of gas gathering capacity
- 11 pipeline interconnects to 4 midstream gas processors
- 1 oil pipeline interconnect with 2nd expected in 3Q 2020
- 6 compressor sites, 28k total horsepower
- 4 CPFs with total 42 Mbo/d capacity
- 22 miles of water gathering connecting to 2 third-party disposal wells
- 35 miles of total oil gathering
  - Lowers diff by $1.25 - $1.50\(^{(1)}\)

RMI Benefits to Upstream Business

- Provides consistent/low wellhead pressure & flow assurance
- Operating and surface cost efficiencies
- Delivery point flexibility with greater access to third-party processing and additional oil & gas takeaway
- Minimal additional permits, rights-of-ways, and surface use agreements required

Company growth not impacted by basin-wide gas constraints

\(^{(1)}\) For Company's oil moving through gathering line to Riverside only. The Company’s 2020 oil differential guidance includes this benefit.
Consistent and Low Gathering Pressure and Flow Assurance

Production vs Line Pressure

Pre-Gathering System
Inconsistent Line Pressure, Low Production and Erratic Flowrates

Post-Gathering System
Consistent Line Pressure, Higher Production and Predictable Flowrates

Connected to Gathering

Gathering System Pressure Outside RMI

BCEI/RMI Field Pressure

(1) Represents actual line pressure and well performance from group of wells that were completed, produced, and later connected into Rocky Mountain Infrastructure.
Engineering Better Well Performance

Higher-Intensity Completions

**Driving value creation through:**
- Tighter stage and perf cluster architecture
- Optimized proppant intensity
- Increased slickwater volumes and rates
- Extreme limited-entry hydraulics
- Enhanced fracture complexity
- Value-maximizing reservoir management

Optimizing Spacing
- K-22 pad performing in-line with lower-density type curve
- I-21 pad (~16 WPS density) exceeding type curve

Note: Well performance represent Niobrara B and C results in Legacy West
Encouraging Legacy East and Northern Performance

- BCEI and offset operators continue to expand core Wattenberg to the north and east with modern completions
- Future BCEI delineation wells planned in northern and eastern acreage
Technical & Operating Teams Driving Better Performance

**Legacy West Type Curves**

- **1,030 Mboe EUR**
- **580 Mboe EUR**

**Days on Production**

**Cumulative Boe**

XRL Type Curve | SRL Type Curve

**Legacy Central Type Curves**

- **930 Mboe EUR**
- **520 Mboe EUR**

**Days on Production**

**Cumulative Boe**

XRL Type Curve | SRL Type Curve

**Legacy East Type Curves**

- **830 Mboe EUR**
- **470 Mboe EUR**

**Days on Production**

**Cumulative Boe**

XRL Type Curve | SRL Type Curve

**French Lake Type Curves**

- **940 Mboe EUR**

**Days on Production**

**Cumulative Boe**

XRL Delineation Type Curve | XRL Development Type Curve

---

(1) 3-stream type curves predicated on 8-12 wells per section depending on area, stimulated lateral length, and intensity

(2) Delineation type curve represents French Lake actuals constrained by incomplete infrastructure buildout. Development type curve represents the Company’s best estimate with infrastructure buildout
Technical & Operating Performance Driving Oil Efficiency & ROCE

2019-2021 Estimated Return on Capital Employed (ROCE)\(^{(1)}\)

<table>
<thead>
<tr>
<th>Year</th>
<th>BCEI</th>
<th>Peer 1</th>
<th>Peer 2</th>
<th>Peer 3</th>
<th>Peer 4</th>
<th>Peer 5</th>
<th>Peer 6</th>
<th>Peer 7</th>
</tr>
</thead>
<tbody>
<tr>
<td>2021</td>
<td>12%</td>
<td>10%</td>
<td>8%</td>
<td>6%</td>
<td>4%</td>
<td>2%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td>2020</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

12-Month Cumulative Oil Production per 1,000 Lateral Feet\(^{(2)}\) (2Q 2018 to Present)

<table>
<thead>
<tr>
<th>Operator</th>
<th>12-Month Production per 1,000'</th>
</tr>
</thead>
<tbody>
<tr>
<td>BCEI</td>
<td>18,000</td>
</tr>
<tr>
<td>Peer 1</td>
<td>16,000</td>
</tr>
<tr>
<td>Peer 2</td>
<td>14,000</td>
</tr>
<tr>
<td>Peer 3</td>
<td>12,000</td>
</tr>
<tr>
<td>Peer 4</td>
<td>10,000</td>
</tr>
<tr>
<td>Peer 5</td>
<td>8,000</td>
</tr>
<tr>
<td>Peer 6</td>
<td>6,000</td>
</tr>
<tr>
<td>Peer 7</td>
<td>4,000</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Source: SunTrust Robinson Humphrey Research (December 2019). SMID Cap Peers include MTDR, PDCE, CPE, WLL, ESTE, HPR, XOG

\(^{(2)}\) Source: RS Energy. DJ Basin peer group includes OXY (120 wells), COP (17 wells), Crestone (61 wells), EOG (45 wells), Great Western (45 wells), HPR (37 wells), NBL (60 wells), PDC (53 wells), SRC (66 wells), XOG (97 wells), Petroshare (14 wells), BCEI (19 wells), For operators with 10 wells or greater.
Relative Peer Well Performance

Note: Bubbles are sized by well count and colored by oil %
Source: RSEG (2019)
2020 Guidance – Focused on Profitable Growth & Operational Flexibility

<table>
<thead>
<tr>
<th>Guidance</th>
<th>2019 Actuals</th>
<th>2020 Guidance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (Mboe/d)</td>
<td>23.5</td>
<td>23.0 - 25.0</td>
</tr>
<tr>
<td>% Oil</td>
<td>60%</td>
<td>54 - 60%</td>
</tr>
<tr>
<td>LOE ($/Boe)</td>
<td>$2.95</td>
<td>$2.50 - $2.90</td>
</tr>
<tr>
<td>RMI Opex ($/Boe)</td>
<td>$1.40</td>
<td>$1.50 - $1.85</td>
</tr>
<tr>
<td>Cash G&amp;A ($MM)(^{(1)})</td>
<td>$32</td>
<td>$27 - $29</td>
</tr>
<tr>
<td>Severance / AdValorem Tax (as a % of revenue)</td>
<td>8.3%</td>
<td>8% - 9%</td>
</tr>
<tr>
<td>Oil Differential ($/bbl)(^{(2)})</td>
<td>$5.28</td>
<td>$4.75 - $5.25</td>
</tr>
<tr>
<td>Total Capex ($MM)</td>
<td>$222</td>
<td>$60 - $70</td>
</tr>
</tbody>
</table>

- Drilling and completion activities stopped during 1Q 2020
- Expect flat YoY production in 2020
- Free cash flow generation expected to pay off debt by year end 2020
- Maintains operational flexibility to respond to market conditions
  - 30 gross DUCs in inventory that require minimal non-wellbore capex
  - French Lake development to start in 2021

\(^{(1)}\) Cash G&A is a non-GAAP measure as it excludes stock-based compensation. 2019 Cash G&A also excludes one-time cash severances paid. Please see Appendix for a reconciliation to the GAAP measure

\(^{(2)}\) Oil differential guidance based on forecasted operated volumes and 5/1/2020 Strip WTI pricing
Strong Financial Position

COMMITTED TO MAINTAINING FINANCIAL STRENGTH AND FLEXIBILITY

- Simple capital structure with low leverage allows company to be patient and opportunistic
- >$300 million of liquidity as of 3/31/2020
- Proactive hedging philosophy to protect balance sheet
  - Approximately 100% of remainder of 2020 oil hedged with an average floor of ~$40/Bbl
- Disciplined capital allocation and returns-focused production growth
Hedged Volumes*

- Protect balance sheet and reduce realized price volatility
- Combination of swaps, collars and puts

* Hedges as of 5/7/2020
Year-End 2019 PV-10 Reconciliation

PV-10 values are non-GAAP financial measures as defined by the SEC. The Company believes that the presentation of PV-10 value is relevant and useful to its investors because it presents the discounted future net cash flows attributable to reserves prior to taking into account corporate future income taxes and the Company’s current tax structure. The Company further believes investors and creditors use pre-tax PV-10 values as a basis for comparison of the relative size and value of its reserves as compared with other companies.

The GAAP financial measure most directly comparable to pre-tax PV-10 is the standardized measure of discounted future net cash flows (“Standardized Measure”). With respect to PV-10 calculated as of an interim date, GAAP does not provide for disclosure of standardized measure on an interim basis. It is not practical to calculate the taxes for the related interim period.

The following table presents a reconciliation of GAAP Standardized Measure to the non-GAAP financial measure of PV-10.

(in millions)

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount (in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Proved Reserve PV-10 at 12/31/2019 (1)</td>
<td>$ 858</td>
</tr>
<tr>
<td>Present value of future income taxes discounted at 10%</td>
<td>–</td>
</tr>
<tr>
<td>Standardized Measure at 12/31/2019 (1)</td>
<td>$ 858</td>
</tr>
</tbody>
</table>

(1) The 12-month average benchmark pricing used to estimate SEC proved reserves and PV-10 value for crude oil and natural gas as of December 31, 2019 were $55.85 per Bbl of WTI crude oil and $2.58 per MMBtu of natural gas at Henry Hub before differential adjustments. Adjustments were then made for location, grade, transportation, gravity, and Btu content, which resulted in a decrease of $4.63 per Bbl for crude oil and a decrease of $1.14 per MMBtu for natural gas.
Adjusted EBITDAX Reconciliation

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management to provide a metric of the Company’s ability to internally generate funds for exploration and development of oil and gas properties. The metric excludes items which are non-recurring in nature and/or items which are not reasonably estimable. Management believes Adjusted EBITDAX provides external users of the Company’s consolidated financial statements such as industry analysts, investors, lenders, and rating agencies with additional information to assist in their analysis of the Company. The Company defines Adjusted EBITDAX as earnings before interest expense, income taxes, depreciation, depletion, amortization, impairment, exploration expenses and other similar non-cash and non-recurring charges. Adjusted EBITDAX is not a measure of net income (loss) or cash flows as determined by GAAP.

The following table presents a reconciliation of the GAAP financial measure of net income (loss) to the non-GAAP financial measure of Adjusted EBITDAX.

<table>
<thead>
<tr>
<th>Net income (loss)</th>
<th>4Q17</th>
<th>1Q18</th>
<th>2Q18</th>
<th>3Q18</th>
<th>4Q18</th>
<th>1Q19</th>
<th>2Q19</th>
<th>3Q19</th>
<th>4Q19</th>
<th>1Q20</th>
</tr>
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<tbody>
<tr>
<td>($5,768)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exploration</td>
<td>3,386</td>
<td>29</td>
<td>221</td>
<td>(6)</td>
<td>47</td>
<td>97</td>
<td>408</td>
<td>33</td>
<td>259</td>
<td>373</td>
</tr>
<tr>
<td>Depreciation, depletion and amortization</td>
<td>9,126</td>
<td>7,508</td>
<td>9,564</td>
<td>10,987</td>
<td>13,824</td>
<td>15,759</td>
<td>18,898</td>
<td>19,900</td>
<td>21,896</td>
<td>21,584</td>
</tr>
<tr>
<td>Abandonment and impairment of unproved properties</td>
<td>-</td>
<td>2,502</td>
<td>2,477</td>
<td>430</td>
<td>(138)</td>
<td>879</td>
<td>878</td>
<td>879</td>
<td>8,565</td>
<td>30,057</td>
</tr>
<tr>
<td>Unused commitments</td>
<td>-</td>
<td>21</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Stock-based compensation (1)</td>
<td>1,035</td>
<td>1,008</td>
<td>2,184</td>
<td>1,741</td>
<td>2,223</td>
<td>1,380</td>
<td>1,768</td>
<td>2,041</td>
<td>1,697</td>
<td>1,239</td>
</tr>
<tr>
<td>Severance costs (1)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>279</td>
<td>-</td>
<td>418</td>
<td>-</td>
<td>-</td>
<td>333</td>
<td>413</td>
</tr>
<tr>
<td>Ad valorem reimbursement</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(5,134)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Advisor fees related to CEO search and strategic alternatives (1)</td>
<td>2,774</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Interest expense</td>
<td>313</td>
<td>357</td>
<td>805</td>
<td>608</td>
<td>833</td>
<td>1,151</td>
<td>385</td>
<td>(78)</td>
<td>1,192</td>
<td>217</td>
</tr>
<tr>
<td>Derivative (gain) loss</td>
<td>12,603</td>
<td>8,742</td>
<td>22,012</td>
<td>16,078</td>
<td>(77,103)</td>
<td>36,544</td>
<td>(8,173)</td>
<td>(12,894)</td>
<td>21,668</td>
<td>(100,419)</td>
</tr>
<tr>
<td>Derivative cash settlements</td>
<td>(1,464)</td>
<td>(4,312)</td>
<td>(7,310)</td>
<td>(8,322)</td>
<td>1,784</td>
<td>936</td>
<td>(543)</td>
<td>3,373</td>
<td>(2,075)</td>
<td>11,254</td>
</tr>
<tr>
<td>Gain on sale of oil and gas properties</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>(26,720)</td>
<td>(604)</td>
<td>(1,126)</td>
<td>1,432</td>
<td>-</td>
<td>(1,483)</td>
<td>0</td>
</tr>
<tr>
<td>Income tax effect</td>
<td>(376)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Deferred financing costs amortization</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>30</td>
<td>125</td>
<td>123</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Adjusted EBITDAX</td>
<td>$21,629</td>
<td>$29,725</td>
<td>$34,812</td>
<td>$38,438</td>
<td>$41,856</td>
<td>$49,170</td>
<td>$56,198</td>
<td>$49,547</td>
<td>$48,797</td>
<td>$43,269</td>
</tr>
<tr>
<td>Pre-Hedge Adjusted EBITDAX</td>
<td>(1,464)</td>
<td>(4,312)</td>
<td>(7,310)</td>
<td>(8,322)</td>
<td>1,784</td>
<td>936</td>
<td>(543)</td>
<td>3,373</td>
<td>(2,075)</td>
<td>11,254</td>
</tr>
<tr>
<td>$23,093</td>
<td>$34,037</td>
<td>$42,122</td>
<td>$46,760</td>
<td>$40,072</td>
<td>$48,234</td>
<td>$56,741</td>
<td>$46,174</td>
<td>$50,872</td>
<td>$32,015</td>
<td></td>
</tr>
</tbody>
</table>

(1) Included as a portion of general and administrative expense in the consolidated statements of operations.
Recurring Cash G&A Reconciliation

Recurring cash G&A is a supplemental non-GAAP financial measure that is used by management and external users of the Company’s consolidated financial statements, such as industry analysts, investors, lenders, and rating agencies. The Company defines recurring cash G&A as GAAP general and administrative expense exclusive of the Company’s stock-based compensation and one-time charges, such as severance costs and advisor fees. The Company refers to recurring cash G&A to provide typical cash G&A costs that are planned for in a given period. Recurring cash G&A is not a fully inclusive measure of general and administrative expense as determined by GAAP.

The following table presents a reconciliation of GAAP financial measures of G&A expense to the non-GAAP financial measure of recurring cash G&A (in thousands):

<table>
<thead>
<tr>
<th></th>
<th>4Q17</th>
<th>1Q18</th>
<th>2Q18</th>
<th>3Q18</th>
<th>4Q18</th>
<th>1Q19</th>
<th>2Q19</th>
<th>3Q19</th>
<th>4Q19</th>
<th>1Q20</th>
</tr>
</thead>
<tbody>
<tr>
<td>General and Administrative Expense</td>
<td>$11,356</td>
<td>$9,533</td>
<td>$9,917</td>
<td>$10,899</td>
<td>$12,104</td>
<td>$10,278</td>
<td>$9,803</td>
<td>$9,920</td>
<td>$9,667</td>
<td>$9,429</td>
</tr>
<tr>
<td>Stock-Based Compensation</td>
<td>(1,035)</td>
<td>(1,008)</td>
<td>(2,184)</td>
<td>(1,741)</td>
<td>(2,223)</td>
<td>(1,380)</td>
<td>(1,768)</td>
<td>(2,041)</td>
<td>(1,697)</td>
<td>(1,239)</td>
</tr>
<tr>
<td>Severance costs</td>
<td>0</td>
<td>0</td>
<td>(279)</td>
<td>0</td>
<td>(418)</td>
<td>0</td>
<td>0</td>
<td>(333)</td>
<td>(413)</td>
<td></td>
</tr>
<tr>
<td>Recurring Cash G&amp;A</td>
<td>$10,321</td>
<td>$8,525</td>
<td>$7,733</td>
<td>$8,879</td>
<td>$9,881</td>
<td>$8,480</td>
<td>$8,035</td>
<td>$7,879</td>
<td>$7,637</td>
<td>$7,777</td>
</tr>
<tr>
<td>Crude Oil Equivalent Sales Volumes (MBoe)</td>
<td>1,357</td>
<td>1,509</td>
<td>1,640</td>
<td>1,632</td>
<td>1,633</td>
<td>1,866</td>
<td>2,223</td>
<td>2,234</td>
<td>2,239</td>
<td>2,260</td>
</tr>
<tr>
<td>Recurring Cash G&amp;A per Boe</td>
<td>$7.61</td>
<td>$5.65</td>
<td>$4.72</td>
<td>$5.44</td>
<td>$6.05</td>
<td>$4.54</td>
<td>$3.61</td>
<td>$3.53</td>
<td>$3.41</td>
<td>$3.44</td>
</tr>
</tbody>
</table>
Net Debt is a supplemental non-GAAP financial measure that is used by management and external users of the Company’s consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. The Company defines net debt as GAAP long-term debt less GAAP cash and cash equivalents. We believe net debt is an important element for assessing the Company’s liquidity.

The following table presents a reconciliation of GAAP financial measure of long term debt to the non-GAAP financial measure of net debt (in thousands):

<table>
<thead>
<tr>
<th>(in thousands)</th>
<th>As of 3/31/2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Long-Term Debt</td>
<td>$ 59,000</td>
</tr>
<tr>
<td>Cash and cash equivalents</td>
<td>(11,052)</td>
</tr>
<tr>
<td>Net Debt</td>
<td>$ 47,948</td>
</tr>
</tbody>
</table>