The information presented herein may contain predictions, estimates and other forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved.

Important factors that could cause actual results to differ materially from those included in the forward-looking statements include the timing and extent of changes in commodity prices for oil and gas, availability of capital, the need to develop and replace reserves, environmental risks, competition, government regulation and the ability of the Company to meet its stated business goals.

**Oil and Gas Reserves.** The SEC permits oil and natural gas companies, in their SEC filings, to disclose only reserves anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. We use certain terms in this presentation, such as total potential, de-risked, and EUR (expected ultimate recovery), that the SEC’s guidelines strictly prohibit us from using in our SEC filings. These terms represent our internal estimates of volumes of oil and natural gas that are not proved reserves but are potentially recoverable through exploratory drilling or additional drilling or recovery techniques and are not intended to correspond to probable or possible reserves as defined by SEC regulations. By their nature these estimates are more speculative than proved, probable or possible reserves and subject to greater risk they will not be realized.

**Non-GAAP Measures.** Included in this presentation are certain non-GAAP financial measures as defined under SEC Regulation G. Investors are urged to consider closely the disclosure in the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and its subsequently filed Quarterly Reports on Form 10-Q and Current Reports on Form 8-K and the reconciliation to GAAP measures provided in this presentation.

**Initial production, or IP, rates,** for both our wells and for those wells that are located near our properties, are limited data points in each well’s productive history. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, expected ultimate recovery, or EUR, or economic rates of return from such wells and should not be relied upon for such purpose. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease-line offsets. Standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.
Corporate Profile

NASDAQ: AXAS

Headquarters.................... San Antonio

Shares outstanding(1)............. 167mm

Market cap(1).......................... $43mm

Net debt .............................. $192mm
  (RBL)................................. $92mm)
  (2nd Lien)........................... $100mm)

RBL Borrowing Base $135mm → $43mm Liquidity

2019E CAPEX ......................... $89 mm

EV/BOE(2)............................... $3.44

Proved Reserves(3)............... 68.3 mmboe

NBV Non-Oil & Gas Assets(4)...... $20.1 mm

Production(5)......................... 6,519 bopd
  (9899 boepd)

PV-10(6)................................. $635mm

---

(2) Enterprise value net debt plus market cap as of December 1, 2019.
(3) Internally estimated Proved reserves as of November 1, 2019.
(5) Q3 2019
(6) PV-10 calculated using SEC pricing at midyear of $61.67 BO and $2.95 gas.
### Prelim 2020 Capex Budget Allocation

<table>
<thead>
<tr>
<th>Area</th>
<th>Capital ($MM)</th>
<th>% of Total</th>
<th>Gross Wells</th>
<th>Net Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permian - Delaware</td>
<td>$21</td>
<td>26-44%</td>
<td>3</td>
<td>2.4</td>
</tr>
<tr>
<td>Bakken/Three Forks</td>
<td>$27-58</td>
<td>56-74%</td>
<td>6-20</td>
<td>5.4-15.5</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$48-79</strong></td>
<td><strong>100%</strong></td>
<td><strong>7-23.0</strong></td>
<td><strong>7.8-18.0</strong></td>
</tr>
</tbody>
</table>

### Prelim 2020 Operating Guidance

<table>
<thead>
<tr>
<th>Operating Costs</th>
<th>Low Case</th>
<th>High Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOE ($/BO)</td>
<td>$9.00</td>
<td>$12.00</td>
</tr>
<tr>
<td>Production Tax (% Rev)</td>
<td>8.0%</td>
<td>9.0%</td>
</tr>
<tr>
<td>Cash G&amp;A ($mm)</td>
<td>$9.0</td>
<td>$13.0</td>
</tr>
<tr>
<td>Production (BOPD)</td>
<td>6,700</td>
<td>7,700</td>
</tr>
</tbody>
</table>

---

Revised Guidance 2019
Switching to barrels oil from barrels of oil equivalent format

- Gas & NGL have become insignificant revenue generators compared to percent of production
- Gas & NGL are tied to 3rd party gathering and processing, subject to unpredictable shut-ins, thus significant source of overall production variations
- Oil is a better predictor of future cash flow and more reliable

<table>
<thead>
<tr>
<th></th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Q3 2019 ACTUAL</th>
<th>REVISED GUIDANCE 2019</th>
<th>MIDPOINT YOY</th>
<th>ORIGINAL 2019 GUIDANCE WITH BO CONVERSION</th>
</tr>
</thead>
<tbody>
<tr>
<td>OIL PRODUCTION, BOPD</td>
<td>3,760</td>
<td>4,311</td>
<td>6,322</td>
<td>6,519</td>
<td>6,700-7,100¹</td>
<td>UP 9%</td>
<td>7,245-7,935²</td>
</tr>
<tr>
<td>GAS PRODUCTION, MMCFPD³</td>
<td>8.7</td>
<td>10.7</td>
<td>12.6</td>
<td>10.9</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NGL PRODUCTION, BNGLPD³</td>
<td>995</td>
<td>1,304</td>
<td>1,392</td>
<td>1,565</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BOEPD</td>
<td>6,198</td>
<td>7,391</td>
<td>9,809</td>
<td>9,899</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>% GAS &amp; NGL</td>
<td>39.3</td>
<td>41.7</td>
<td>35.5</td>
<td>34</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>% GAS &amp; NGL REVENUE</td>
<td>9.8</td>
<td>14.6</td>
<td>10.8</td>
<td>0.9</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LOE $/BO</td>
<td>10.88</td>
<td>9.45</td>
<td>10.65</td>
<td>6.20</td>
<td>10.50-11.50</td>
<td>UP 3%</td>
<td>6.07-8.32</td>
</tr>
<tr>
<td>G&amp;A $/BO (CASH ONLY)</td>
<td>7.55</td>
<td>8.29</td>
<td>4.19</td>
<td>2.45</td>
<td>3.60-4.90</td>
<td>UP 1%</td>
<td>3.21-4.32</td>
</tr>
</tbody>
</table>

¹ Includes reduction for 350 BPOD Non-Op Bakken Sale
² Previous BOED Guidance: 10,500-11,500 times previous guidance of 69% oil
³ Will consider adding gas and ngl back to production guidance when they become a material component of cash flow
Historical Reserve & Production Growth

- YE18 total proved reserves up 3% YoY
  - 55% increase over last 3 years
  - 14% CAGR since 2013
- YE18 production up 33% YoY
  - 64% increase over last 3 years
  - 16% CAGR since 2013
- Oil contribution up 40% since 2013
- ~19 year reserve life at current drilling pace

---

### Proved Reserves Summary

<table>
<thead>
<tr>
<th></th>
<th>Oil (MBbl)</th>
<th>Gas (MMcf)</th>
<th>NGL (MMBbl)</th>
<th>Total (MMBoe)</th>
<th>PV10 (M$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>YE 2018 PDP</td>
<td>12,788</td>
<td>39,177</td>
<td>3,679</td>
<td>22,996</td>
<td>$359,192</td>
</tr>
<tr>
<td>YE 2018 PNP</td>
<td>798</td>
<td>4,094</td>
<td>125</td>
<td>1,606</td>
<td>$22,687</td>
</tr>
<tr>
<td>YE 2018 PUD</td>
<td>28,650</td>
<td>46,473</td>
<td>6,230</td>
<td>42,626</td>
<td>$307,418</td>
</tr>
<tr>
<td>Total Proved</td>
<td>42,237</td>
<td>89,744</td>
<td>10,034</td>
<td>67,228</td>
<td>$689,297</td>
</tr>
<tr>
<td>WTX PRUD</td>
<td>72,109</td>
<td>84,534</td>
<td>12,257</td>
<td>98,455</td>
<td>$372,116</td>
</tr>
</tbody>
</table>

1P % Oil: 63%
1P % Liquids: 78%
1P R/P (years): 18.8x

---

{1} Reserve Summary as of 12/31/2018 and audited by LaRoche Petroleum Consultants, Inc.
The Abraxas Advantage

- **Basin / Geologic Benefit**
  - Core acreage positions in the Bakken and WTX (Delaware Basin)
  - ~ 11,500 net mineral acres in WTX (95% Operated, HBP)
  - Deep inventory of high quality locations in WTX providing 20 years of development with 2 rigs

- **Royalty / Leasehold Benefit**
  - Legacy high value acreage with favorable NRI’s
  - Recent Permian and Bakken precedent M&A transactions carry a 25% royalty burden (75% Effective NRI)
  - AXAS Bakken Effective NRI’s average ~82.5%, WTX ~80% providing meaningful minerals optionality

- **Commodity Benefit**
  - 66% of production from black oil, 82% from liquids in Q3
  - 66% of net reserves from black oil, 79% from liquids

- **Infrastructure Benefit**
  - Delaware
    - Expanding network of in-field SWD’s, frac-ponds, 2 water supply wells (additional can be put in service)
    - 72,000 BWPD Permitted Disposal
    - 9257 BWPD Actual August average disposal
    - 50,000 BWPD Permits Pending
  - Bakken
    - 2 in-field SWD’s, a third available if needed
  - Company owned & operated Ravin #1 Drilling Rig well suited and targeted for future WTX development
  - Provides significant infrastructure optionality

---

(1) Assumes 880' spacing per 640 acre DSU
Asset Base Overview
Delaware Basin
Permian Basin – Wolfcamp & Bone Spring

Map Source: Investor presentations, Drilling Info and management estimates.
Abaxas has identified 404 net potential drilling locations assuming 880 ft spacing between wells in the same zone. Approximately 33% of these locations could be combined in the future for long lateral development should conditions warrant. Abaxas believes this location count is conservative as no locations have been assigned to benches that AXAS has not commercially proven.
Down-spacing Observations

Caprito 99 Down-Space Wells

**RATE vs TIME**

- 302H Parent Well

**CUM BOE vs TIME**

- Distance from 302H Parent:
  - 202H - 350’
  - 311H - 650’
  - 211H - 980’
  - 301H - 1,320’

- 302H Parent Well
Delaware Basin – 3rd Bone Spring

3rd Bone Spring Average vs. Type

Caprito 82-101H  Dec 17
Mesquite 102H    Oct 18
Mesquite U103H   Oct 18
Woodberry 101H   Jul 19
Delaware Basin – Wolfcamp A1

Wolfcamp A1 Average vs. Type

Caprito 98-201H  Jul 17
Caprito 82-202H  Dec 17
Caprito 99 202H   Jun 18
Caprito 99 211H   Jun 18
Greasewood 201H  Aug 18
Pecan 47 201H    Dec 18
Creosote 201H    Mar 19
Hackberry 201H   May 19
Woodberry 201H   Jul 19
Wolfcamp A2 Average vs. Type

- Caprito 99-302H Nov 16
- Caprito 98-301H Jul 17
- Caprito 83-304H Oct 17
- Caprito 99-301H Jun 18
- Caprito 99-311H Jun 18
- Greasewood 301H Aug 18
- Creosote 302H Mar 19
Wolfcamp B Average vs. Type

Caprito 83-404H  Dec 17
## Delaware Basin Economics by Zone - EOY18 Model

### Abraxas EOY18 Assumptions
#### Third Bone Spring
- 630 MBOE gross type curve
  - 86% Oil
  - Initial rate: 1,100 boepd
  - di: 99.9%
  - dm: 6.0%
  - b-factor: 1.4
- Assumed CWC: $7.6 million

#### Wolfcamp A1
- 640 MBOE gross type curve
  - 88% Oil
  - Initial rate: 809 boepd
  - di: 97.4%
  - dm: 7.0%
  - b-factor: 1.4
- Assumed CWC: $7.6 million

#### Wolfcamp A2
- 580 MBOE gross type curve
  - 87% Oil
  - Initial rate: 843 boepd
  - di: 98.6%
  - dm: 7.0%
  - b-factor: 1.4
- Assumed CWC: $7.6 million

#### Wolfcamp B
- 525 MBOE gross type curve
  - 87% Oil
  - Initial rate: 634 boepd
  - di: 95.79%
  - dm: 7.0%
  - b-factor: 1.4
- Assumed CWC: $7.6 million

---

![ROR vs. WTI](chart1)

![ROR vs. WTI](chart2)

![ROR vs. WTI](chart3)

![ROR vs. WTI](chart4)
Asset Highlights:

- ~ 3,500 net acres in the heart of McKenzie Cty.
- 69 wells drilled by Abraxas (37MB / 31TF1, 1TF2)
- 63 completions, 6 DUC’s (Jore Federal extension pad)
- Cum Production ~ 11 MMbo / 17 MMboe
- Current Net Production ~ 5,500 boepd
- Remaining Locations:
  - 33 (13MB & TF, 20TF2)
- Refrac Candidates ~ 20

2019 Activity:

- Drill 6 gross (5.4 net) wells – Drilled
- Complete 4 gross (1.3 net) wells – On production
**Bakken/Three Forks**

**Remaining Inventory**

**Remaining Locations**
(19 Total - 8 MB, 11 TF1, includes 6 DUC’s)

- Jore Federal WI ~ 98% (3MB, 7TF1) (includes 6 DUC’s)
- Yellowstone WI ~ 75% (4MB, 4TF1)
- Ravin WI ~ 48.6% (1MB)

**Three Forks 2nd Bench**
(20 TF2 PRUD’s booked)

- AXAS book type curve = 555 MBOE
- CLR results > 1,000 MBOE
- AXAS spacing = 1,320’; CLR spacing = 990’
Bakken Completion Evolution: 2010 - 2019

Highlights –
- Increase in prop mass and fluid volume
- Increase in stages and adding diverters to drive cluster efficiency
- Using thinner fluids to promote complexity

<table>
<thead>
<tr>
<th>GEN 1</th>
<th>GEN 2</th>
<th>GEN 3</th>
<th>GEN 4</th>
<th>GEN 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>PIPE EXIT METHOD</td>
<td>SLEEVES</td>
<td>PERF/SLEEVE HYBRID</td>
<td>PERFS</td>
<td>PERFS</td>
</tr>
<tr>
<td>ISOLATION</td>
<td>SWELL PACKERS</td>
<td>SWELL PACKERS</td>
<td>CEMENTED</td>
<td>CEMENTED</td>
</tr>
<tr>
<td>STAGES</td>
<td>27</td>
<td>33</td>
<td>41</td>
<td>41</td>
</tr>
<tr>
<td>PROP MASS (PPF)</td>
<td>400</td>
<td>600</td>
<td>750</td>
<td>800</td>
</tr>
<tr>
<td>PROP SIZE</td>
<td>100M 30/50 20/40</td>
<td>100M 30/50 20/40</td>
<td>100M 30/50 20/40</td>
<td>100M 30/50 20/40</td>
</tr>
<tr>
<td>PROP TYPE</td>
<td>50/50 WHITE, CERAMIC</td>
<td>80/20 WHITE, CERAMIC</td>
<td>100% WHITE</td>
<td>100% WHITE</td>
</tr>
<tr>
<td>FLUID USE (BPF)</td>
<td>7</td>
<td>11</td>
<td>15</td>
<td>17</td>
</tr>
<tr>
<td>FLUID TYPE</td>
<td>SW/XLINK</td>
<td>SW/XLINK</td>
<td>HVFR</td>
<td>HVFR</td>
</tr>
<tr>
<td>AVG PROP CONC (PPA)</td>
<td>1.4</td>
<td>1.3</td>
<td>1.2</td>
<td>1.1</td>
</tr>
<tr>
<td>RATE (BPM)</td>
<td>30</td>
<td>30</td>
<td>30</td>
<td>50</td>
</tr>
<tr>
<td>DIVERSION</td>
<td>NO</td>
<td>NO</td>
<td>PLA GRANULAR</td>
<td>PLA GRANULAR</td>
</tr>
<tr>
<td>LIMITED ENTRY</td>
<td>NO</td>
<td>NO</td>
<td>NO</td>
<td>YES</td>
</tr>
</tbody>
</table>

SPE #184851 “Re-designing from Scratch and Defending Offset Wells: Case Study of a Six-Well Bakken Zipper Project”
World Oil, June 2017 “From Scratch Redesign Yields Uplift in Legacy Bakken Field”
Middle Bakken Completion Generations vs. Type

Middle Bakken Completion Generations vs. Type

Rav-Wiley 2H; Ravin13H ~200Mboe Cum/Well First 180 days
Generational Uplift – Three Forks

North Fork Field

Three Forks Completion Generations vs. Type

Rav-Wiley 1H; Ravin 14H ~187Mboe Cum/Well First 180 days
**Bakken System Economics**

**Economics by Zone - EOY18 Model**

---

**Middle Bakken**

**Abraxas EOY18 Assumptions**
- 975 MBOE gross type curve
  - 88% Oil
  - Initial rate: 1,302 boepd
  - $i$: 95.90%
  - $dm$: 8.0%
  - $b$-factor: 1.3
- Assumed CWC: $7.6 million

---

**Three Forks**

**Abraxas EOY18 Assumptions**
- 791 MBOE gross type curve
  - 87% Oil
  - Initial rate: 1,066 boepd
  - $i$: 95.78%
  - $dm$: 8.0%
  - $b$-factor: 1.3
- Assumed CWC: $7.6 million

---

**ROR vs. WTI**

![Graph showing ROR vs. WTI for Middle Bakken](image1)

![Graph showing ROR vs. WTI for Three Forks](image2)
### Oil and Gas Marketing & Takeaway

**Delaware Basin**

**Oil Marketing and Takeaway**
- **Caprito Area:**
  - Caprito oil production on pipe in May/June 2018
  - Agreement with third party on long term contract
  - Rate of $0.65/bbl to Wink
  - Wink trades at a slight discount to Midland
  - Abraxas will likely add other units to the third party system as development progresses across the Company's Ward and Winkler County assets
  - Multiple new crude lines to Gulf Coast in service 2019
    - Cactus 2
    - Epic
    - Gray Oak

**Gas Marketing and Takeaway**
- **Delaware Basin:**
  - Majority of acreage dedicated on long term contract
  - Contract pays 100% of residue gas and 100% of NGLs with deductions for compression, gathering and processing
  - Majority sells/prices at Waha
  - Third party controls numerous processing facilities with additional facility projects under construction
  - Third party has adequate capacity from Waha to Katy
  - Operational downtime improving
  - Multiple sales outlets with ample capacity expected
    - Gulf Coast express in service September 2019 (2BCFPD)
    - 2 more pipelines Waha to Gulf Coast
      - Permian Highway (Oct 2020)
      - Whistler (Q3 2021)

**Bakken/Three Forks**
- **North Fork/Pershing Area:**
  - All oil production on pipe
  - Agreement with third parties on long term contract
  - Locked discount (including all tariff) of $5.18-$5.87 off NYMEX through August 2019
  - Do not anticipate any issues with takeaway
  - DAPL expansion

**Hedging**
- Actively hedging basis as and when advantageous from a cost perspective
- Difficult from a liquidity and contract standpoint to hedge basis in the area
### Abraxas Hedging Profile

#### Current Hedge Book

<table>
<thead>
<tr>
<th></th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil Swaps (bbls/day)</strong></td>
<td>5,438</td>
<td>3,779</td>
<td>2,809</td>
</tr>
<tr>
<td><strong>Swap Price ($/Bbl)</strong> (1)</td>
<td>$56.69</td>
<td>$55.23</td>
<td>$57.83</td>
</tr>
<tr>
<td><strong>Mid-Cush Basis Swaps (bbls/day)</strong></td>
<td>4,000</td>
<td>4,000</td>
<td>-</td>
</tr>
<tr>
<td><strong>Swap Price ($/Bbl)</strong> (2)</td>
<td>$(3.00)</td>
<td>$(3.00)</td>
<td>$-</td>
</tr>
</tbody>
</table>

---

(1) WTI - straight line average price. Includes 3,993 Bopd and 1,941 Bopd of WTI swaps in 2018 and 2019, respectively.

(2) Argus Midland – NYM WTI CMA Differential.
Adjusted EBITDA is defined as net income plus interest expense, depreciation, depletion and amortization expenses, deferred income taxes and other non-cash items. The following table provides a reconciliation of Adjusted EBITDA to net income for the periods presented.

(In thousands)

<table>
<thead>
<tr>
<th>Description</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net (loss) income</td>
<td>$16,006</td>
<td>$57,821</td>
</tr>
<tr>
<td>Net interest expense</td>
<td>$2,496</td>
<td>$7,052</td>
</tr>
<tr>
<td>Depreciation, depletion and amortization</td>
<td>$26,226</td>
<td>$42,759</td>
</tr>
<tr>
<td>Amortization of deferred financing fees</td>
<td>$423</td>
<td>$440</td>
</tr>
<tr>
<td>Stock-based compensation</td>
<td>$3,238</td>
<td>$2,366</td>
</tr>
<tr>
<td>Impairment</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Unrealized (gain) loss on derivative contracts</td>
<td>$4,299</td>
<td>($27,099)</td>
</tr>
<tr>
<td>Realized (gain) loss on monetized derivative contracts</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Expenses incurred with offerings and execution of loan agreement</td>
<td>$4,856</td>
<td>$325</td>
</tr>
<tr>
<td>Other non-cash items</td>
<td>$451</td>
<td>$516</td>
</tr>
<tr>
<td>Bank EBITDA</td>
<td>$57,994</td>
<td>$84,181</td>
</tr>
<tr>
<td>Credit facility borrowings</td>
<td>$84,250</td>
<td>$180,000</td>
</tr>
<tr>
<td>Debt/Bank EBITDA</td>
<td>1.45x</td>
<td>2.14x</td>
</tr>
</tbody>
</table>
Adjusted EBITDA is defined as net income plus interest expense, depreciation, depletion and amortization expenses, deferred income taxes and other non-cash items. The following table provides a reconciliation of Adjusted EBITDA to net income for the periods presented.

(In thousands)

<table>
<thead>
<tr>
<th></th>
<th>30-Sep-18</th>
<th>31-Dec-18</th>
<th>31-Mar-19</th>
<th>30-Jun-19</th>
<th>TTM</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net (loss) income</td>
<td>$1,778</td>
<td>$55,819</td>
<td>($18,324)</td>
<td>$11,678</td>
<td>$50,950</td>
</tr>
<tr>
<td>Net interest expense</td>
<td>$1,952</td>
<td>$2,409</td>
<td>$2,967</td>
<td>$2,765</td>
<td>10,092</td>
</tr>
<tr>
<td>Depreciation, depletion and amortization</td>
<td>$11,011</td>
<td>$12,913</td>
<td>$13,463</td>
<td>$12,079</td>
<td>49,466</td>
</tr>
<tr>
<td>Amortization of deferred financing fees</td>
<td>$113</td>
<td>$121</td>
<td>$121</td>
<td>$128</td>
<td>483</td>
</tr>
<tr>
<td>Stock-based compensation</td>
<td>428</td>
<td>472</td>
<td>768</td>
<td>522</td>
<td>2,190</td>
</tr>
<tr>
<td>Impairment</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Unrealized (gain) loss on derivative contracts</td>
<td>6,840</td>
<td>(51,738)</td>
<td>20,576</td>
<td>(7,526)</td>
<td>(31,847)</td>
</tr>
<tr>
<td>Realized (gain) loss on monetized derivative contracts</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Expenses incurred with offerings and execution of loan agreement</td>
<td>105</td>
<td>8</td>
<td>56</td>
<td>8</td>
<td>178</td>
</tr>
<tr>
<td>Other non-cash items</td>
<td>131</td>
<td>121</td>
<td>111</td>
<td>110</td>
<td>472</td>
</tr>
<tr>
<td>Bank EBITDA</td>
<td>$22,358</td>
<td>$20,124</td>
<td>$19,739</td>
<td>$19,764</td>
<td>$81,984</td>
</tr>
</tbody>
</table>

Credit facility borrowings $183,000

Debt/Bank EBITDA 2.23x
PV-10 is the estimated present value of the future net revenues from our proved oil and gas reserves before income taxes discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2018:

<table>
<thead>
<tr>
<th>Total Proved</th>
<th>31-Dec-18 ($000)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Future cash inflows</td>
<td>$2,876,976</td>
</tr>
<tr>
<td>Future production costs</td>
<td>(849,063)</td>
</tr>
<tr>
<td>Future development costs</td>
<td>(547,163)</td>
</tr>
<tr>
<td>Future income tax expense</td>
<td>(181,224)</td>
</tr>
<tr>
<td>Present Worth at 10 Percent</td>
<td>$1,299,526</td>
</tr>
<tr>
<td>Discount</td>
<td>(647,642)</td>
</tr>
<tr>
<td>Standardized measure of discounted future net cash flows</td>
<td>$651,884</td>
</tr>
</tbody>
</table>