Forward-Looking Statement Disclosure

This presentation, contains “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding our future operating and financial performance. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties, many of which are described under “Risk factors” in our Annual Report on Form 10-K for the year ended December 31, 2019 available on our website and at www.sec.gov. You should understand that the following important factors, could affect our future results and could cause those results or other outcomes to differ materially from those expressed or implied in the forward-looking statements relating to: (1) amount, nature and timing of capital expenditures; (2) drilling of wells and other planned exploitation activities; (3) timing and amount of future production of oil and natural gas; (4) increases in production growth and proved reserves; (5) operating costs such as lease operating expenses, administrative costs and other expenses; (6) our future operating or financial results; (7) cash flow and anticipated liquidity; (8) our business strategy, including expansion into the deep shelf and the deepwater of the Gulf of Mexico, and the availability of acquisition opportunities; (9) hedging strategy; (10) exploration and exploitation activities and property acquisitions; (11) marketing of oil and natural gas; (12) governmental and environmental regulation of the oil and gas industry; (13) environmental liabilities relating to potential pollution arising from our operations; (14) our level of indebtedness; (15) timing and amount of future dividends; (16) industry competition, conditions, performance and consolidation; (17) natural events such as severe weather, hurricanes, floods, fire and earthquakes; and (18) availability of drilling rigs and other oil field equipment and services.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation or as of the date of the report or document in which they are contained, and we undertake no obligation to update such information. The filings with the SEC are hereby incorporated herein by reference and qualifies the presentation in its entirety.

Cautionary Note Regarding Hydrocarbon Quantities.
The U.S. Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions, and on an optional basis, probable and possible reserves meeting SEC definitions and criteria. The company does not include probable and possible reserves in its SEC filings. This presentation includes information concerning probable and possible reserves quantities compliant with PRMS/SPE guidelines and related PV-10 values that may be different from quantities of such non-proved reserves that may be reported under SEC rules and guidelines. In addition, this presentation includes Company estimates of resources and “EURs” or “economic ultimate recoveries” that are not necessarily reserves because no specific development plan has been committed for such recoveries. Recovery of estimated probable and possible reserves, and estimates of resources and EUR’s and recoverable resources, are inherently more speculative than recovery of proved reserves.
Company Snapshot Year-end 2019

**Net Reserves** (MMBoe)

- **1P**: 157
- **2P**: 235
- **3P**: 365

**Liquids % of 1P Reserves**: 40%

**4Q19 Average Production**: 52.8 MBoe/d (45% liquids)

**4Q19 Adjusted EBITDA**

<table>
<thead>
<tr>
<th>Year</th>
<th>Adjusted EBITDA ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>282.9 MM</td>
</tr>
</tbody>
</table>

**Gulf of Mexico Shelf**
- ~595,000 gross acres (~440,000 net)
- 78% of 4Q 2019 production of 52.8 MBoe/d
- Proved reserves of 136.3 MMBoe
- 2P reserves of 197.7 MMBoe
- Future growth potential from sub-salt projects

**Gulf of Mexico Deepwater**
- ~220,000 gross acres (~110,000 net)
- 22% of 4Q 2019 production of 52.8 MBoe/d
- Proved reserves of 21.1 MMBoe
- 2P reserves of 37.2 MMBoe
- Substantial upside with existing acreage

**Production**
- 60% Federal waters
- 40% State waters
- 51 Producing Fields

**Premium GOM Operator with 36+ Years of History in the Basin**
2019 and Early 2020 Highlights

✓ Increased year-end 2019 proved reserves by 87% to 157.4 MMBoe, from 84.0 MMBoe at year-end 2018, representing a reserve replacement ratio of nearly 600% of 2019 production

✓ Closed two significant acquisitions for approximately $188 million that meaningfully increased reserves to over 157 MMBoe and grew total production to over 50,000 Boe/d.

✓ Produced 52,773 Boe/d, or 4.9 MMBoe (45% liquids), in the fourth quarter of 2019, above the midpoint of W&T’s guidance range, reflecting a 51% increase from the fourth quarter of 2018 and a 28% increase from the third quarter of 2019

✓ Reported net income for full year 2019 of $74.1 million or $0.52 per share, and net income of $9.6 million or $0.07 per share in the fourth quarter of 2019

✓ Reported Adjusted Net Income\(^2\) of $85.9 million or $0.60 per share for full year 2019, and $24.4 million or $0.17 per share in the fourth quarter of 2019

✓ Generated significant Adjusted EBITDA\(^1\) of $282.9 million for the full year 2019

✓ Recorded strong cash flow from operating activities with $232.2 million generated in full year 2019

✓ Achieved a 100% success rate on the six wells drilled in 2019 and invested $125.7 million in capital expenditures for the full year 2019, before acquisitions, which was below the low end of guidance

✓ Reduced 2020 capital expenditure estimate to $15 to $25 million due to sharply lower prices to maximize financial flexibility

✓ Added natural gas costless collars for the period April 2020 through December 2022

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1) Adjusted EBITDA is a non-GAAP financial measure, see slide 42 for description of reconciling items to GAAP net income.
2) Adjusted Net Income is a non-GAAP financial measure, see slide 43 for description of reconciling items to GAAP net income.
Magnolia Deepwater Acquisition – Key Highlights

- 75% working interest in and operatorship of the Magnolia Field in the central GOM, offshore Louisiana, in Garden Banks blocks 783 and 784
- Purchase price of $20.0 million\(^{(1)}\) as of the effective date of October 1, 2019 and assumption of P&A liability
- Added net proved reserves of 4.0 MMBoe of which 83% are proved developed producing and 72% are oil and 7% NGLs\(^{(2)}\)
- Increased W&T’s deepwater acreage by 11,500 gross acres (8,600 net acres)
- Produced approximately 2,300 net Boe per day (82% oil) to ConocoPhillips's interest in the month of October 2019
- Provides additional upside from additional pay sands in existing well bores and potential opportunities for future drilling
- Closed acquisition on December 12, 2019, funded with available cash on hand
- *In early March, announced purchase and sale agreement to acquire the remaining 25% WI with an expected close of March 31, 2020*

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1) Before normal and customary closing adjustments.  
2) As determined by Netherland Sewell & Associates as of December 31, 2019 based on SEC pricing.
Mobile Bay Acquisition – Key Highlights

- Acquired ExxonMobil’s interests and operatorship in the eastern region of the Gulf of Mexico, offshore Alabama as well as related onshore processing facilities that are adjacent to existing properties owned and operated by W&T.

- Allows for significant synergies, consolidations, and cost savings as W&T will become the largest operator in the area.

- Closed on August 30, 2019, exactly as expected, with total cash consideration paid of $167.6 million which includes a previously-funded $10 million deposit.

- Utilized cash on hand and previously undrawn revolving credit facility to finance acquisition.

- Includes working interests in nine GOM offshore producing fields (eight operated) and onshore gas treatment facility capable of treating 420 MMcfd.

- Adds net proved reserves of 77 MMBoe\(^1\) of which the vast majority are proved developed producing (20% liquids).

- Contains future opportunities including Norphlet drilling leads and optimization of compression facilities.

- Identified potential drilling opportunities that are planned for permitting in 2020 and drilled thereafter.

\(^1\) As determined by Netherland Sewell & Associates as of December 31, 2019 based on SEC pricing.

Low Decline, Long-Life, Mostly PDP Shelf Acquisition
Year-End 2019 Reserves Summary

- 235.0 MMBoe Net Proved + Probable (2P) Reserves
- Includes Mobile Bay and Magnolia 75% interest acquisitions
- All-in Reserve Replacement Cost: 2019: $4.18 per Boe; 3 year average: $5.05 per Boe
- Extends reserve life index from 6.2 years to 8.7 years

Replaced ~600% of Production with Acquisitions, Net Positive Revisions and Additions

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1) Based on Year-End 2019 reserve report by NSAI at SEC pricing of $55.85/BO and $2.58/Mmbtu; Computation may not foot due to rounding.
2) Does not include recently announced purchase and sale agreement for remaining 25% of Magnolia field expected to close March 31, 2020.
3) Excludes the impact of revisions due to SEC base price change related to assets acquired in 2019.
4) Includes the impact of revisions due to SEC base price change related to assets acquired in 2019.
## Current Reserve Report Overview

<table>
<thead>
<tr>
<th>Reserve Category</th>
<th>Total (MMBoe)</th>
<th>% Liquids</th>
<th>Pre-Tax PV-10%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Developed Producing (PDP)</td>
<td>122.3</td>
<td>36.1%</td>
<td>$992.0</td>
</tr>
<tr>
<td>Proved Developed Non-Producing (PDNP)</td>
<td>11.5</td>
<td>48.2%</td>
<td>95.0</td>
</tr>
<tr>
<td>Proved Undeveloped (PUD)</td>
<td>23.6</td>
<td>53.2%</td>
<td>215.5</td>
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<tr>
<td><strong>Total 1P Reserves (Excluding ARO)</strong></td>
<td>157.4</td>
<td>39.5%</td>
<td><strong>$1,302.5</strong></td>
</tr>
<tr>
<td><strong>Total 2P Reserves (Excluding ARO)</strong></td>
<td>235.0</td>
<td>43.7%</td>
<td><strong>$2,161.3</strong></td>
</tr>
<tr>
<td>1P Asset Retirement Obligations (ARO)</td>
<td></td>
<td></td>
<td>(184.9)</td>
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<tr>
<td><strong>Total 1P Reserves (Reduced By 1P ARO)</strong></td>
<td>157.4</td>
<td>39.5%</td>
<td><strong>$1,117.6</strong></td>
</tr>
<tr>
<td><strong>Total 2P Reserves (Reduced By 1P ARO)</strong></td>
<td>235.0</td>
<td>43.7%</td>
<td><strong>$1,976.4</strong></td>
</tr>
</tbody>
</table>

1) Year-end 2019 Reserve Report prepared by NSAI at SEC pricing.
2) Pre-Tax PV-10% is a non-GAAP measure; see reconciliation on slide 44.
3) Pre-Tax PV-10% excluding 1P Asset Retirement Obligation.
Corporate Responsibility

“At W&T, we fully acknowledge our responsibility to our employees and contractors and the communities where we operate, and the importance of the ongoing protection of the environment”.

Tracy Krohn, Chairman and Chief Executive Officer

Our Commitment

• We are committed to developing and producing oil and gas resources in a safe and environmentally responsible manner, while meeting or exceeding all regulatory requirements
• Our management allocates resources and tools necessary to meet expectations and performance objectives and strives to create a working environment that encourages open communication about HSE issues and concerns.

Safety & Environmental

• Reduced the number of reportable spills by 61% from 2017 to 2019
• Our Incidence of Non-Compliance/Component Ratio (as per BSEE standards) reduced by 60% from 2017 to 2019 and in 2019 was 29% lower than the industry average
• Our Incidence of Non-Compliance/Inspection Ration (as per BSEE standards) fell 70% from 2018 to 2019
• Recently purchased an infrared camera to survey all production facilities for fugitive hydrocarbon emissions
• Currently employ two certified safety professional to manage HSE programs at our facilities
• Four employee compliance technicians work across the Gulf of Mexico to conduct internal audits with respect to HSE compliance

Social

• We actively support charitable organizations in the communities where we operate
• We focus on helping children and families most in need, while aiding in the protection of the environment
• We support our employees who volunteer their time with these organizations
Operational Overview
Multiple stacked pay development opportunities

- Stacked reservoirs offer attractive primary production and recompletion opportunities
- Advanced seismic and geoscience greatly improve ability to identify drilling opportunities and enhance success

Natural drive mechanisms generate incremental production from 2P and 3P reserves

- Typical fields with high quality sands have drive mechanisms superior to primary depletion alone
- These fields enjoy incremental reserve adds annually, partly due to how reserve quantities are booked under SEC guidelines
- Fewer conventional wells required to develop fields
Gulf of Mexico – 2nd Largest U.S. Producing Basin

Gulf of Mexico Historical Oil Production

YE 2019 US Oil Production by Key Region (MMBod)

GOM Provides Unique Advantages: Low Decline Rates, World Class Porosity/Permeability and Significant Untapped Reserve Potential

1) Based on U.S. Energy Information Administration (EIA) data as of December 31, 2019.
Successful Diversification in Valuable Deepwater Projects

- WTI’s Deepwater portfolio is expanding and diversifying with Magnolia (2019) as its latest addition
- WTI operates and participates in various deepwater production facilities, including TLPs, E-TLPs, SPARs, deepwater fixed structures, and sub-sea tiebacks
Rigorous Technical Evaluation Resulting in High Drilling Success

1. Leads high graded for review; once approved, project team assigned and deadlines set

2. Cursory technical evaluation with management and land review with scoping cost and business and technical planning

3. Full technical evaluation with probabilistic risk analysis, AFE costing and economic evaluation

4. Presentation to Executive management for AFE approval

5. Project turned over to execution team and deadlines set

Track Record of Drilling Success

- Over 400 leads evaluated since 2011
- 2011 - 2019 Success Rate: ~94%
- 49 successful offshore wells drilled since 2011

Rigorous Evaluation Process Has Led to ~94% Success Rate Since 2011
Probable and Possible Reserves May Be Produced at No Cost

Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores
Significant W&T Reserve Appreciation From Initial Bookings

Actual Results \(^1,2\)

**W&T DEEPWATER FIELD**

Current 1P > Initial 1P booking

**MAHOGANY T SAND**

Current 1P > Initial 3P booking

**W&T FAIRWAY FIELD**

Current 1P > Initial 3P booking

Current 1P > Initial 1P booking

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1) Year-End 2019 Reserve Report prepared by NSAI at SEC pricing of $55.85/BO and $2.58/MMBtu.
2) 1P = Proved, 2P = Proved + Probable, 3P = Proved + Probable + Possible.
3) Initial 1P booking includes A-14 well only; Year-End 2019 1P booking includes A-14, A-18, A-19 & 1 PUD; 2P & 3P includes additional development wells.
Realizing Incremental Probable and Possible Reserve Upside

WTI focused on realizing the reserves upside and adding economic value across three categories:

1) **Prob + Poss Related to PDP**
   - No additional capex required
   - Achievable because of WTI’s demonstrated understanding of the fields

2) **Prob + Poss Related to PDNP + PUD**
   - Contingent on execution of field development plans
   - No incremental direct capex required
   - Immediately moves to PDP upside (1) following proved capex spend

3) **Prob + Poss Unrelated to 1P Reserves**
   - Additional capex required
   - Limited step-out risk

<table>
<thead>
<tr>
<th>Category</th>
<th>Capex</th>
<th>Prob + Poss Related to PDP</th>
<th>Prob + Poss Related to PDNP + PUD</th>
<th>Prob + Poss Unrelated to 1P Reserves</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0^3</td>
<td>$333</td>
<td>$375</td>
<td>$266</td>
<td>$296 MM</td>
<td>$296 MM</td>
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<tr>
<td>$0 MM^4</td>
<td>$389</td>
<td>$883</td>
<td>$218</td>
<td>$1,605</td>
<td>$2,464 PV-10</td>
</tr>
<tr>
<td>$375</td>
<td>$859</td>
<td>$1,605</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**High Upside Potential Compared to Capital Employed**

1) Figures reflect Year-End 2019 Reserve Report prepared by NSAI at SEC pricing of $55.85/BO and $2.58/Mmbtu.
2) Excludes Asset Retirement Obligation.
3) Probable and possible cases that are largely associated with producing wellbores and require no additional future CAPEX requirements.
4) Probable and possible reserves with no direct CAPEX requirements that are largely associated with PNP and PUD reserves and therefore have associated future indirect CAPEX requirements.
History of Creating Long-Term Value From GOM Acquisitions

TOTAL
$115 MM
Paid out in Aug. 2011
Net average production\(^1\) of 1,700 Boe/d from Matterhorn and Virgo.

- Reserves\(^2\): 1P – 5.8 MMBoe
- 2P – 11.1 MMBoe
- 3P – 18.3 MMBoe

NEWFIELD
$206 MM
Paid out in Nov. 2014
Net average production\(^1\) of 1,800 Boe/d from 78 offshore blocks, 65 of which are in deepwater.

- Reserves\(^2\): 1P – 2.9 MMBoe
- 2P – 5.1 MMBoe
- 3P – 8.4 MMBoe

WOODSIDE
$55 MM
Net average production\(^1\) of 700 Boe/d from Neptune and 24 add'\(\)l blocks. One exploration well brought on production in 2014.

- Reserves\(^2\): 1P – 1.4 MMBoe
- 2P – 1.6 MMBoe
- 3P – 1.9 MMBoe

COBALT
$31 MM
Paid out in Aug. 2018
Net average production\(^1\) of 1,700 Boe/d from Matterhorn and Virgo.

- Reserves\(^2\): 1P – 0.5 MMBoe
- 2P – 1.0 MMBoe
- 3P – 1.6 MMBoe

CONOCOPHILLIPS\(^4\)
$20 MM
Closed December 12, 2019
Net average production\(^1\) of 2,000 Boe/d from Garden Banks 783 & 784 (Magnolia Field).

- Reserves\(^2\): 1P – 4.0 MMBoe
- 2P – 7.2 MMBoe
- 3P – 13.6 MMBoe

SHELL
$116 MM
Paid out in Nov. 2012
Net average production\(^1\) of 700 Boe/d from Tahoe and 6 other fields.

- Reserves\(^2\): 1P – 0.8 MMBoe
- 2P – 1.2 MMBoe
- 3P – 1.4 MMBoe

SHELL/ MARUBENI\(^3\)
$61 MM
Paid out in Oct. 2014
Net average production\(^1\) of 3,100 Boe/d from Fairway Field.

- Reserves\(^2\): 1P – 11.6 MMBoe
- 2P – 16.4 MMBoe
- 3P – 17.5 MMBoe

CALLON
$83 MM
Investments Post Acquisition
Net average production\(^1\) of 800 Boe/d from Medusa and 12 other fields. Two exploration wells brought on production in June 2015.

- Reserves\(^2\): 1P – 2.0 MMBoe
- 2P – 3.5 MMBoe
- 3P – 5.8 MMBoe

EXXONMOBIL
$168 MM
Closed August 30, 2019
Potential to add incremental reserves with minimal capital by consolidating operations with additional upside from potential future drilling locations and facility modifications.

- Reserves\(^2\): 1P – 77.0 MMBoe
- 2P – 90.0 MMBoe
- 3P – 106.9 MMBoe

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1) 4th Quarter 2019 net average production.
2) Year-End 2019 Reserve Report prepared by NSAI at SEC pricing at $55.85/BO and $2.58/Mmbtu.
3) Fairway Field: acquired from Shell 8.9MMBoe 1P (12.8 MMBoe 2P) in 2011 for $43MM, acquired from Marubeni 5.2MMBoe 1P (5.8 MMBoe 2P) in 2014 for $18MM.
4) Magnolia Field: acquired from ConocoPhillips 4.0MMBoe 1P (7.2 MMBoe 2P) in 2019 for $20MM, does not include announced purchase and sale agreement for remaining 25% working interest in field, expected to close 3/31/20.
Continued Sub-Salt Exploration and Development Success

SS 349 “Mahogany” (WI: 100%, NRI 83.3%)¹

- Substantially expanded the size and depth of the field since 2011 by drilling/sidetracking 13 new producing locations

- Stacked pay sands: At least six pay zones proven to be productive in field
  - Historically, main pay has been the P-Sand
  - In 2013, A-14 well logged over 370’ of net oil pay in five zones & discovered the deep T-Sand
  - In 2016, A-18 well logged oil pay beneath the T-Sand in the ‘U’ Sand
  - In 2018, A-17 well, A-5 sidetrack and A-19 wells placed on production
  - In 1Q 2019, recompleted A-6 and acid stimulated A-18 wells
  - Successfully completed the A-6 S/T targeting the P-Sand and placed online in 4Q2019

- Significantly increased field production rate since 2011

- Quality inventory of future drilling projects
  - Exploiting reservoirs in P, Q, and T thru V - Sands
  - Extending reservoir limits both in depth and aerially
  - Seismic reprocessing underway in 2020
  - Rig demobed in 2019 to save cost while evaluating seismic

Additional Benefits:
- Proven success in the field
- Low risk projects
- Spread rig costs over more projects
- Add production from low-cost recompletion projects

¹ Except A-5 sidetrack: 30% WI currently.
Key Field Activities as of March 2020

1) Daily production rates presented are gross, and all assets highlighted are part of Monza JV or eligible to be included in Monza JV.

**MC 800 Gladden Deep**
- Water depth ~ 3,000 feet
- Reached TD in 2Q’19, commercial success with 201’ of net oil pay
- Completed and brought online in September 2019; currently producing 4,360 Boe/d (89% oil)

**MC 582 (R/C)**
- MC 582 A-6, Online December 2019; currently producing 1,290 Boe/d

**SS 30 & 28**
- SS 28 #41 completed and placed online December 2019; currently producing 1,700 Boe/d

**EC 321 Field**
- EC 321 B-8 S/T, successfully drilled, completed and online December 2019; currently producing 870 Boe/d

**ST 311**
- ST 311 A-3, Online July 2019; currently producing 4,850 Boe/d
Attractive Current Inventory

Selected Growth Prospects

Prospects related to lease sales 252 & 253 not listed on the map.
GOM Drilling Joint Venture

- Secured $361.4 MM commitment for the development of 14 pre-identified projects in the GOM with potential to upsize program over time with additional projects
  - Covers the total estimated cost of the 14 wells of $336 MM, plus contingency
  - Drilled and completed nine wells through December 31, 2019

- W&T initially receives 30% of the net revenues from the drilling program wells for contributing 20% of the capital expenditures plus associated leases and providing access to available infrastructure
- HarbourVest Partners and Baker Hughes/GE are the two largest JV interest owners
- JV leverages BHGE’s unique and flexible offering to potentially consolidate engineering, products and services and lower costs
- Upon private investors achieving certain return thresholds, W&T’s share of well net revenue increases to 38.4%
- Allows W&T to develop its high return drilling inventory at a faster pace with a greatly reduced capital outlay and maintain flexibility to make acquisitions and pay down debt
- JV structure expands W&T’s access to well capitalized investors

Accelerates Development of High Return Inventory, Leverages Capital Dollars and Maintains Financial Flexibility
Strategic Capital Allocation Plan

**Maintain a Prudent Balance Sheet and Use Free Cash Flow to Grow Opportunistically and Reduce Debt**

**Organic Projects**
Focus on high rate of return projects and fields with multiple drilling opportunities that can generate cash flow quickly. Utilize GOM expertise and new technologies to identify and develop projects. Evaluate potential for joint venture funding.

**Debt Pay Down**
Use free cash flow to reduce debt to protect our balance sheet and maintain financial flexibility.

**Asset Acquisitions**
Pursue compelling producing assets generating cash flow at attractive valuations with upside potential and optimization opportunities.

**Generate Shareholder Value**
Leveraging 36+ Years of GOM Acquisition Expertise

**ACQUISITION OPPORTUNITIES**

- **GOM Exits**
  Companies exiting the GOM provide a large inventory of accretive assets

- **Asset Sales**
  Majors moving to ultra-deepwater and companies monetizing GOM assets to fund onshore projects

- **Consolidation Opportunities**
  Under capitalized independents with sizeable undeveloped reserves

**ACQUISITION CRITERIA**

- **Generating Cash Flow**
  Strong current production rates with the opportunity to reduce operating expenses

- **Financeable**
  Large portion of reserve base is proved developed with solid probable/possible reserves

- **Identified Upside**
  Undrilled prospects, workover or recomplete opportunities, facility upgrades, secondary recovery projects

**Gulf of Mexico Provides an Attractive, Large Acquisition Opportunity Set**
Financial Overview
Management Ownership$^1$ – Among the Highest of Public E&P Companies$^2$

W&T Management Team has highest stock ownership

1) Ownership percentage of Named Executive Officers from 2019 company proxies. Data sources include IR Insights, Bloomberg & Company filings
2) Companies sorted alphabetically: AMPY, AMRQQ, AR, ARXOQ, AXAS, BCEI, BRY, BTE, CDEV, CHAP, CHK, CNX, COG, CPE, CPQ, CRC, CRK, CXO, DNR, DVN, EPEG, ERT, ESTE, GDP, GPOR, HPR, KOS, LLEX, LONE, LPI, MCEP, MCF, MGY, MR, MRO, MTDR, MUR, NOG, OAS, PDCE, PE, PHX, PVAC, QEP, REI, ROSE, RRC, RVRA, SBOW, SD, SM, SNDE, SRCI, SWN, TALO, UNT, UPLC, WLL, WPX, XEC, XOG
Significantly Improved Capital Structure

<table>
<thead>
<tr>
<th>Liquidity as of 02/29/20</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>9.75% 2nd Lien Notes due 2023</td>
<td>$625 MM</td>
</tr>
<tr>
<td>RBL Borrowings¹</td>
<td>$80MM</td>
</tr>
<tr>
<td><strong>Total Debt</strong>²</td>
<td>$705 MM</td>
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<tr>
<td>Total Cash &amp; Equivalents</td>
<td>$40 MM</td>
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<tr>
<td>Available Under RBL³</td>
<td>$164MM</td>
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<tr>
<td><strong>Total Liquidity as of 02/29/20</strong></td>
<td><strong>$204 MM</strong></td>
</tr>
</tbody>
</table>

- On October 18, 2018 closed a major debt refinancing
  - Simplified capital structure
  - Reduced debt principal outstanding from $903 MM to $625 MM
  - Extended the maturities of RBL and debt principal
  - Increased borrowing base from $150 MM to $250 MM

- $250 MM borrowing base reaffirmed in November 2019

- In 1Q20 reduced RBL by $25MM to $80MM as of 2/29/20

**Strong Balance Sheet Provides Flexibility for Future Growth**

1) RBL borrowings exclude $5.8 MM of outstanding letters of credit. The RBL borrowings of $105 million were utilized towards the recent purchase of Mobile Bay and GB 783 assets.
2) Excludes reduction of $10.5MM related to debt issuance costs.
3) RBL availability reduced by $5.8 MM of outstanding letters of credit.
Generating Steady and Significant Unlevered Free Cash Flow

- Strong production base and cost optimization delivers steady Adjusted EBITDA
- Adjusted EBITDA materially outpacing CAPEX and ARO spending (excluding acquisitions)
- Utilized portion of cash generated in 1Q 2020 to reduce debt by $25 MM

- Currently estimate free cash flow positive at or above $25 per barrel of oil and $1.50 per Mcf of natural gas

Substantial Cash Flow Generation Provides Optionality

1) Adjusted EBITDA is a non-GAAP financial measure, see slide 42 for description of reconciling items to GAAP net income.
2) Excludes Acquisitions.
3) Using 2020 CAPEX Mid-point guidance of $20 MM
Updated 2020 CAPEX guidance:
- $15 - $25 MM

2020 updated CAPEX mid-point is ~85% less than the $126 MM spent in 2019

Reduction of CAPEX guidance has not changed the 2020 production guidance

2020 production guidance of 47,100 to 52,100 Boe/d is 16% to 28% higher than full year 2019

2020 updated P&A guidance:
- $10 - $20 MM

CAPEX Allocation

- Drilling: 25%
- Facilities: 28%
- Seismic, Leasehold & Other: 19%
- Completions: 15%
- Recompletions: 14%

Based on midpoint of 2020 FY guidance range.
**Strong Cash Margins From Operational Excellence**

- Despite falling commodity prices in 2015 and 2016 putting pressure on realized price, WTI was able to take advantage of a favorable services environment to renegotiate long-term service contracts and reduce fixed costs, offsetting top-line margin pressure.

- As commodity prices rise from downturn lows, WTI continues to realize benefits from these continued lower service costs in the Gulf of Mexico.

---

### Mid-point of 2020 Guidance for Lifting Cost Declines to $16.49 per BOE

<table>
<thead>
<tr>
<th>Year</th>
<th>Total Lifting Costs: $/Boe</th>
<th>Cash Margin: $/Boe</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$16.18</td>
<td>$13.16</td>
</tr>
<tr>
<td>2016</td>
<td>$14.70</td>
<td>$11.06</td>
</tr>
<tr>
<td>2017</td>
<td>$14.99</td>
<td>$18.03</td>
</tr>
<tr>
<td>2018</td>
<td>$17.57</td>
<td>$25.62</td>
</tr>
<tr>
<td>2019</td>
<td>$17.82</td>
<td>$17.81</td>
</tr>
</tbody>
</table>

---

1) Lifting costs defined as cash G&A (excluding share-based compensation), LOE & Production Tax, and Transportation Costs.
2) Cash Margin represents average realized sales price per Boe less total lifting costs.
Proactive Management of Asset Retirement Obligations

Undiscounted P&A Schedule\(^1,2\)

<table>
<thead>
<tr>
<th>Year</th>
<th>ARO (MM$)</th>
<th>ARO as % of Total Capex</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>$60.0</td>
<td>18%</td>
</tr>
<tr>
<td>2012</td>
<td>$112.8</td>
<td>19%</td>
</tr>
<tr>
<td>2013</td>
<td>$81.5</td>
<td>13%</td>
</tr>
<tr>
<td>2014</td>
<td>$74.3</td>
<td>12%</td>
</tr>
<tr>
<td>2015</td>
<td>$32.6</td>
<td>12%</td>
</tr>
<tr>
<td>2016</td>
<td>$72.3</td>
<td>60%</td>
</tr>
<tr>
<td>2017</td>
<td>$72.4</td>
<td>36%</td>
</tr>
<tr>
<td>2018</td>
<td>$28.6</td>
<td>21%</td>
</tr>
<tr>
<td>2019</td>
<td>$11.4</td>
<td>9%</td>
</tr>
<tr>
<td>2020</td>
<td>$15.0</td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td>$19.7</td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td>$29.6</td>
<td></td>
</tr>
<tr>
<td>2023+</td>
<td>$17.3</td>
<td>Average</td>
</tr>
</tbody>
</table>

**Accelerating P&A To Capture Low Costs…**

WTI took advantage of low service cost environments in 2016 and 2017 by bringing forward upcoming P&A liabilities

**Resulting in Low ARO Burden Over Next 3 Years**

Average annual ARO liability of ~$21MM over 2020-2022

---

1) Net of amounts held in escrow (total of $15.8 MM); Additional P&A liability estimate of $414 MM from 2023-2046, with an average annual burden of ~$17 MM; $15.1 MM of estimated total P&A liability after 2046.

2) As of year-end 2019 and includes Mobile Bay and Magnolia acquisitions.
## Investment Highlights

### Solid Margins and Capital Discipline Lead to Free Cash Flow
- Capital allocation to high return, quick payback projects allowed W&T to generate $232 MM of operating cash flow in 2019
- 2019 Adjusted EBITDA\(^1\) of $282.9 MM
- Reduced 2020 Budget to ~$20 million due to lower prices to maximize financial flexibility
- Inventory of lower risk/higher return projects, plus upside opportunities

### High Quality Asset Base with Substantial Low-Risk Upside
- Leveraging expertise of technical teams, combined with innovations to add value to existing assets
- Captured ~$700 MM of probable and possible reserve upside with no additional capital required
- Better seismic data is leading to better decisions and enhanced recoveries
- Projects include high rate of return stacked-pay development with exploration components in very large known reservoirs

### Strong Returns
- Optimizing operations has reduced LOE per Boe and D&C costs
- Attractive acquisitions, platform drilling, subsea tiebacks to existing infrastructure and high-quality assets led to 3-year reserve replacement costs of $5.05/Boe
- Surplus equipment and services in GOM allows for improved terms that significantly lowers drilling, development and asset retirement costs

### Maintaining Good Liquidity and Paying Down Debt
- ~$204 MM in liquidity as of February 29, 2020
- Reduced RBL by $25MM to $80MM as of 2/29/20
- No long-term debt maturities until 2023
- Strong balance sheet provides flexibility for the future

---

1) Adjusted EBITDA is a non-GAAP financial measures, see slide 42 for a reconciliation to GAAP net income.
Appendix
## 2020 Guidance (As of March 17, 2020)

<table>
<thead>
<tr>
<th></th>
<th>1st Quarter</th>
<th>Full Year</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil (MMBbls)</strong></td>
<td>1.7 - 1.9</td>
<td>6.5 - 7.1</td>
</tr>
<tr>
<td><strong>NGL's (MMBbls)</strong></td>
<td>0.50 - 0.56</td>
<td>2.05 - 2.27</td>
</tr>
<tr>
<td><strong>Natural Gas (BCF)</strong></td>
<td>13.8 - 15.3</td>
<td>52.4 - 57.9</td>
</tr>
<tr>
<td><strong>Total (MMBoe)</strong></td>
<td>4.5 - 5.0</td>
<td>17.3 - 19.2</td>
</tr>
<tr>
<td><strong>Total (Boed/d)</strong></td>
<td>49,600 - 54,800</td>
<td>47,100 - 52,100</td>
</tr>
<tr>
<td><strong>Lease Operating Expenses</strong></td>
<td>$51.0 - $56.0 MM</td>
<td>$200 - $220 MM</td>
</tr>
<tr>
<td><strong>G &amp; T and Production Taxes</strong></td>
<td>$8.3 - $9.2 MM</td>
<td>$33 - $37 MM</td>
</tr>
<tr>
<td><strong>G &amp; A</strong></td>
<td>$15.5 - $17.0 MM</td>
<td>$56 - $62 MM</td>
</tr>
<tr>
<td><strong>CAPEX</strong></td>
<td></td>
<td>$15 - $25 MM</td>
</tr>
<tr>
<td><strong>Cash Income Tax Rate</strong></td>
<td></td>
<td>~0%</td>
</tr>
</tbody>
</table>
Hedging Strategy Protects Cash Flow Without Limiting Upside

### W&T OFFSHORE, INC. AND SUBSIDIARIES

**Financial Commodity Derivative Positions**

**As of March 17, 2020**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Crude Oil - WTI NYMEX:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan 2020 - May 2020</td>
<td>Swaps</td>
<td>10,000</td>
<td>$60.92</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jan 2020 - May 2020</td>
<td>Calls (long)</td>
<td>10,000</td>
<td>$61.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jun 2020 - Dec 2020</td>
<td>Costless Collars</td>
<td>1,000</td>
<td>$45.00</td>
<td>$63.60</td>
<td></td>
</tr>
<tr>
<td>Jun 2020 - Dec 2020</td>
<td>Costless Collars</td>
<td>9,000</td>
<td>$45.00</td>
<td>$63.50</td>
<td></td>
</tr>
<tr>
<td>Jun 2020 - Dec 2020</td>
<td>Calls (long)</td>
<td>10,000</td>
<td></td>
<td></td>
<td>$67.50</td>
</tr>
<tr>
<td><strong>Natural Gas - Henry Hub NYMEX:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dec 2019 - Dec 2022</td>
<td>Calls (long)</td>
<td>40,000</td>
<td>$3.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Apr 2020 - Dec 2022</td>
<td>Costless Collars</td>
<td>40,000</td>
<td>$1.83</td>
<td>$3.00</td>
<td></td>
</tr>
</tbody>
</table>

W&T’s Hedging Positions Lock in Floor Price, Protect Future Cash Flows And Allow Opportunity to Capture Potential Oil Price Increases
147 existing structures provide a key advantage when evaluating/developing prospect opportunities

**Economic Advantage**

- *Reduces capital expenditures*
- *Increases returns by generating cashflow quicker*
- *Marketing contracts already in place*
- *Provides revenue upside in potential Production Handling Agreements (PHA)*
  - 2018 $13.4 MM, 2019 $15.3 MM
Mobile Bay Acquisition – XOM Producing Fields

- Acquired nine working interest fields
- 108,000 gross acres (95,600 net acres)
- Initial production in 1988
- Water depths of 10 - 50 ft
Mobile Bay Acquisition – Onshore Gas Treating Facilities

- **ExxonMobil - Onshore Treating Facility**
  - 100% XOM ownership
  - Established 1993
  - 420 MMcfd capacity
  - 160 MMcfd gross current throughput

- **W&T - Yellowhammer Plant**
  - 100% W&T ownership
  - Established 1991
  - 200 MMcfd capacity
  - 50 MMcfd gross current throughput
SS 349 Field ("Mahogany") Case Study

- WI: 100.0%, 360’ Water Depth
- 1st commercially successful subsalt development in the Gulf of Mexico (initial production in 1997)
- Originally purchased Amoco’s interest in 2000
- Purchased additional interest in 2004 & 2008
- Cumulative purchase price of $175MM
- Total Net Cash Flow (including capex) from final purchase date\(^1\) = $540 MM

Have increased value by:
- Development and exploration drilling
- Performing recompletes
- Reworks and performance optimization

Current Reserves\(^2\)

<table>
<thead>
<tr>
<th>Type</th>
<th>Reserves</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1P Reserves</td>
<td>28.0</td>
<td>MMBoe</td>
</tr>
<tr>
<td>2P Reserves</td>
<td>50.3</td>
<td>MMBoe</td>
</tr>
<tr>
<td>3P Reserves</td>
<td>110.2</td>
<td>MMBoe</td>
</tr>
</tbody>
</table>

1) As of December 31, 2019.
2) As determined by Netherland Sewell & Associates as of December 31, 2019 based on SEC pricing.
Total E&P Deepwater Acquisition Case Study

“Matterhorn” & “Virgo” Fields

- WI: 64% - 100%, 1,130’ - 2,400’ water depth
- Purchased from Total E&P, USA in 2010
- $115MM acquisition cost
- Total Net Cash Flow (including capex) from final purchase date = $503 MM

Have increased value by:
- Drilling sidetracks
- Performing recompletes
- Instituting waterflood
- Entering processing arrangement ($58 million in processing revenues received to date)

Current Reserves

<table>
<thead>
<tr>
<th>Reserves Type</th>
<th>Quantity</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1P Reserves</td>
<td>5.8</td>
<td>MMBoe</td>
</tr>
<tr>
<td>2P Reserves</td>
<td>11.1</td>
<td>MMBoe</td>
</tr>
<tr>
<td>3P Reserves</td>
<td>18.3</td>
<td>MMBoe</td>
</tr>
</tbody>
</table>

1) As of December 31, 2019.
2) As determined by Netherland Sewell & Associates as of December 31, 2019 based on SEC pricing.
Certain financial information included in W&T’s financial results are not measures of financial performance recognized by accounting principles generally accepted in the United States, or GAAP. These non-GAAP financial measures are “Adjusted Net Income” and “Adjusted EBITDA.” Management uses these non-GAAP financial measures in its analysis of performance. In addition, Adjusted EBITDA is a key metric used to determine the Company’s incentive compensation awards. These disclosures may not be viewed as a substitute for results determined in accordance with GAAP and are not necessarily comparable to non-GAAP performance measures which may be reported by other companies.

Reconciliation of Net Income to Adjusted EBITDA

The Company defines Adjusted EBITDA as net income plus income tax (benefit) expense, net interest expense, and depreciation, depletion, amortization and accretion, excluding the unrealized commodity derivative gain or loss, amortization of derivative premium, bad debt reserve, litigation and other. W&T believes the presentation of Adjusted EBITDA provides useful information regarding its ability to service debt and to fund capital expenditures. The Company believes this presentation is relevant and useful because it helps investors understand W&T’s operating performance and makes it easier to compare its results with those of other companies that have different financing, capital and tax structures. Adjusted EBITDA should not be considered in isolation from or as a substitute for net income, as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. Adjusted EBITDA, as W&T calculates it, may not be comparable to Adjusted EBITDA measures reported by other companies. In addition, Adjusted EBITDA does not represent funds available for discretionary use.

The following table presents a reconciliation of our net income to Adjusted EBITDA.

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended</th>
<th>Twelve Months Ended</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>December 31,</td>
<td>December 31,</td>
</tr>
<tr>
<td></td>
<td>2019</td>
<td>2018</td>
</tr>
<tr>
<td></td>
<td>September 30,</td>
<td>December 31,</td>
</tr>
<tr>
<td></td>
<td>2019</td>
<td>2018</td>
</tr>
<tr>
<td></td>
<td>(In thousands)</td>
<td>(In thousands)</td>
</tr>
<tr>
<td>Net income</td>
<td>$ 9,559</td>
<td>$ 138,844</td>
</tr>
<tr>
<td>Income tax (benefit) expense</td>
<td>(8,171)</td>
<td>172</td>
</tr>
<tr>
<td>Net interest expense</td>
<td>16,635</td>
<td>15,170</td>
</tr>
<tr>
<td>Depreciation, depletion, amortization and accretion</td>
<td>37,818</td>
<td>35,047</td>
</tr>
<tr>
<td>Unrealized commodity derivative loss (gain)</td>
<td>18,052</td>
<td>59,002</td>
</tr>
<tr>
<td>Amortization of derivative premium</td>
<td>4,248</td>
<td>(5,531)</td>
</tr>
<tr>
<td>Bad debt reserve</td>
<td>13</td>
<td>2,116 (l)</td>
</tr>
<tr>
<td>Gain on debt transactions</td>
<td>55</td>
<td>15,912</td>
</tr>
<tr>
<td>Write-off contingent liability</td>
<td>-</td>
<td>206</td>
</tr>
<tr>
<td>Litigation and other</td>
<td>816</td>
<td>69</td>
</tr>
<tr>
<td>Adjusted EBITDA</td>
<td>$ 78,970</td>
<td>$ 282,985</td>
</tr>
<tr>
<td></td>
<td>$ 72,001</td>
<td>$ 347,125</td>
</tr>
</tbody>
</table>

1) Prior year reconciliation has been reclassified to conform to current year presentation.
Reconciliation of Net Income to Adjusted Net Income

Adjusted Net Income does not include the unrealized commodity derivative loss (gain), amortization of derivative premium, bad debt reserve, deferred tax benefit, gain on debt transactions, write-off contingent liability, litigation and other. Adjusted Net Income is presented because the timing and amount of these items cannot be reasonably estimated and affect the comparability of operating results from period to period, and current periods to prior periods.

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended</th>
<th></th>
<th>Twelve Months Ended</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>December 31,</td>
<td>September 30,</td>
<td>December 31,</td>
<td>December 31,</td>
</tr>
<tr>
<td></td>
<td>2019</td>
<td>2019</td>
<td>2018</td>
<td>2019</td>
</tr>
<tr>
<td><strong>Net income</strong></td>
<td>$ 9,559</td>
<td>$ 75,899</td>
<td>$ 138,844</td>
<td>$ 74,086</td>
</tr>
<tr>
<td>Unrealized commodity derivative loss (gain)</td>
<td>18,052</td>
<td>(5,670)</td>
<td>(55,331)</td>
<td>59,002</td>
</tr>
<tr>
<td>Amortization of derivative premium</td>
<td>4,248</td>
<td>3,931</td>
<td>2,116†</td>
<td>15,912</td>
</tr>
<tr>
<td>Bad debt reserve</td>
<td>13</td>
<td>55</td>
<td>76</td>
<td>206</td>
</tr>
<tr>
<td>Deferred tax benefit</td>
<td>(8,338)</td>
<td>(55,764)</td>
<td>137</td>
<td>(64,102)</td>
</tr>
<tr>
<td>Gain on debt transactions</td>
<td>-</td>
<td>-</td>
<td>(47,109)</td>
<td>-</td>
</tr>
<tr>
<td>Write-off contingent liability</td>
<td>-</td>
<td>-</td>
<td>(4,630)</td>
<td>-</td>
</tr>
<tr>
<td>Litigation and other</td>
<td>816</td>
<td>-</td>
<td>69</td>
<td>816</td>
</tr>
<tr>
<td><strong>Adjusted Net Income</strong></td>
<td>$ 24,350</td>
<td>$ 18,451</td>
<td>$ 34,172</td>
<td>$ 85,920</td>
</tr>
</tbody>
</table>

Basic and diluted adjusted earnings per common share

|                                |         |         |         |         |
|                                | $ 0.17  | $ 0.13  | $ 0.24  | $ 0.60  |

1) Prior year reconciliation has been reclassified to conform to current year presentation.
Non-GAAP Reconciliations

We refer to PV-10 as the present value of estimated future net revenues of proved reserves as calculated by our independent petroleum consultant using a discount rate of 10%. This amount includes projected revenues, estimated production costs and estimated future development costs and excludes ARO. We have also included PV-10 after ARO below. PV-10 after ARO includes the present value of ARO related to proved reserves using a 10% discount rate and no inflation of current costs. Neither PV-10 nor PV-10 after ARO are financial measures defined under GAAP; therefore, the following table reconciles these amounts to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that the non-GAAP financial measures of PV-10 and PV-10 after ARO are relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 and PV-10 after ARO are used internally when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. We believe the use of pre-tax measures is valuable because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid. Management believes that the presentation of PV-10 and PV-10 after ARO provide useful information to investors because they are widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. PV-10 and PV-10 after ARO are not measures of financial or operating performance under GAAP, nor are they intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 and PV-10 after ARO should not be considered in isolation or as substitutes for the standardized measure of discounted future net cash flows as defined under GAAP. Investors should not assume that PV-10, or PV-10 after ARO, from our proved oil and natural gas reserves shown above represent a current market value of our estimated oil and natural gas reserves.

The reconciliation of PV-10 and PV-10 after ARO to the standardized measure of discounted future net cash flows relating to our estimated proved oil and natural gas reserves is as follows (in millions):

<table>
<thead>
<tr>
<th>December 31, 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ 1,303</td>
</tr>
<tr>
<td>$ (184.9)</td>
</tr>
<tr>
<td>$ 1,117.6</td>
</tr>
<tr>
<td>$ (130.7)</td>
</tr>
<tr>
<td>$ 986.9</td>
</tr>
</tbody>
</table>

1) Company calculates Standardized measure of discounted future net cash flows annually for 10-K filing.

2) As of year-end 2019.