W&T OFFSHORE

37+ Years of Industry Leadership in the Gulf of Mexico

June 2021 Corporate Presentation

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 From 10-K for the year ended December 31, 2020 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.

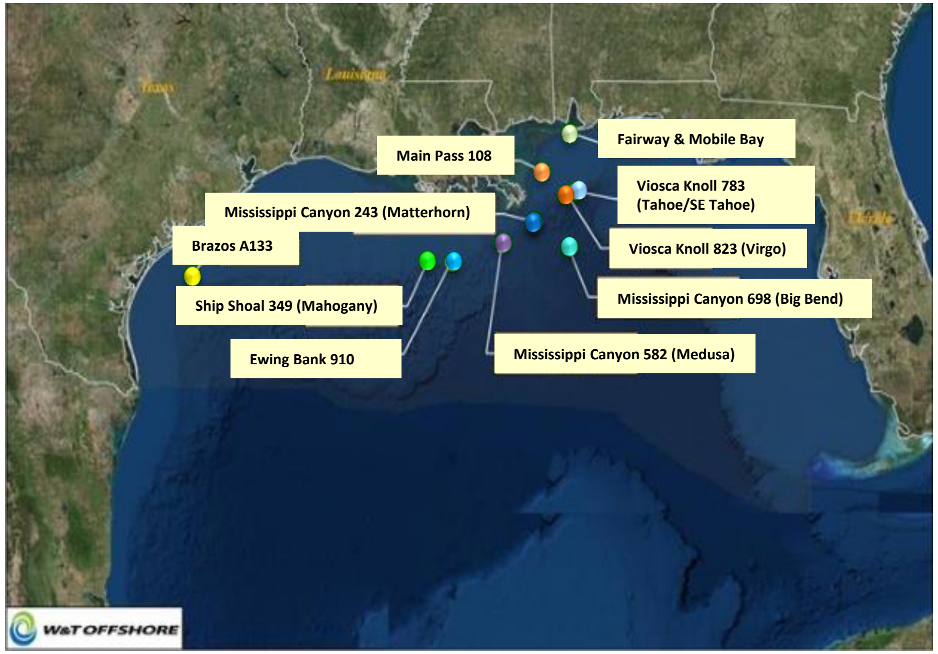
We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this presentation or as of the date of the report or document in which they are contained, and we undertake no obligation to update such information. The filings with the SEC are hereby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

Corporate Summary & Update

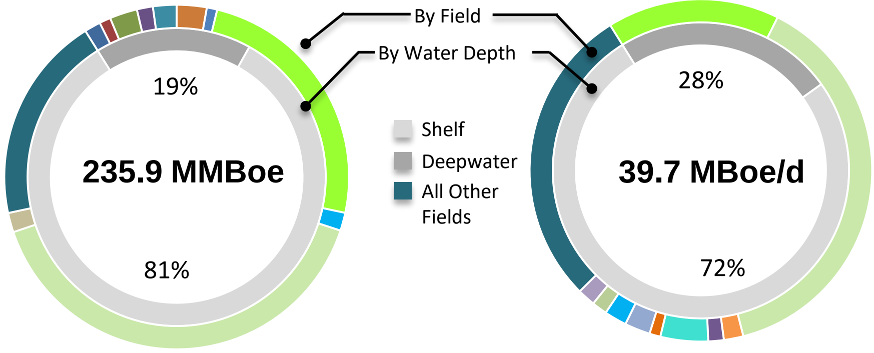
Company Snapshot



1Q'21 Average Production:	39.7 MBoe/d (50% liquids)
Producing Fields	42
1Q'21 Adjusted EBITDA[2]	$57.6 MM
1Q'21 Free Cash Flow	$40.0 MM

Net Reserves (MMBoe)	SEC Pricing[1]	NYMEX Strip[4]
1P	144.4	171.3
2P	235.9	251.9
3P	371.3	387.4

2P Reserves Mix[1] | **1Q 2021 Avg. Daily Production[3]**



Gulf of Mexico Shelf

- ~500,000 gross acres (~395,000 net)
- 72% of 1Q 2021 production of 39.7 MBoe/d
- Proved reserves of 125.2 MMBoe[1]
- 2P reserves of 190.1 MMBoe[1]
- Future growth potential from sub-salt projects

Gulf of Mexico Deepwater

- ~209,000 gross acres (~108,000 net)
- 28% of 1Q 2021 production of 39.7 MBoe/d
- Proved reserves of 19.2 MMBoe[1]
- 2P reserves of 45.8 MMBoe[1]
- Substantial upside with existing acreage

Federal vs State

- Production: Federal 60%, State 40%
- Net Acreage: Federal 82%, State 18%

Premium GOM Operator with 37+ Years of History in the Basin

Note: The outer ring of the pie charts represent contribution by field, with color indicating field location on the map
1) Based on year-end 2020 reserve report by NSAI at average realized SEC pricing of $37.78/BO and $2.05/MMbtu.
2) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see slide 44 for description of reconciling items to GAAP net income.
3) Breakout between Deepwater and Shelf reflects total Company production.
4) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu.

Recent Highlights

- ✓ ***Despite a difficult 2020, reduced total long-term debt by $130 million from 12/31/19 to 3/31/21, resulting in approximately $8.5 million of annual interest expense savings***
- ✓ ***In May 2021, announced enhancement to capital structure by transferring Mobile Bay producing assets to a Company-owned SPV in return for a $215 million non-recourse loan with a third party***
- ✓ ***Paid RBL borrowings down to $0***
- ✓ Produced 39,657 Boe/d, or 3.6 million Boe (50% liquids), in 1Q'21, a 4% increase from 4Q'20
- ✓ Reported a 1Q'21 net loss of $0.7 million or $0.01/share and Adjusted Net Income[1] of $15.9 million or $0.11/share
- ✓ Generated 1Q'21 Adjusted EBITDA[2] of $57.6 million and invested $1.6 million in capital expenditures in 1Q'21
  - ✓ **Produced Free Cash Flow[2] of $40.0 million for 1Q'21, an increase of 182% from $14.2 million in 4Q'20**
- ✓ Completed consolidation of natural gas treating facilities at Mobile Bay, with expected future cost savings of ~$5 million per year beginning in 2021
- ✓ Remained focused on controlling expenses and reported first quarter 2021 LOE and G&A costs at the low end or below guidance ranges
- ✓ Reaffirmed 2021 preliminary capital spending of $30 to $60 million to achieve stable production and maintain the ability to generate free cash flow to fund the reduction of debt and potential acquisitions
- ✓ Issued W&T's inaugural Environmental, Social and Governance ("ESG") report which is now available on the Company's web site

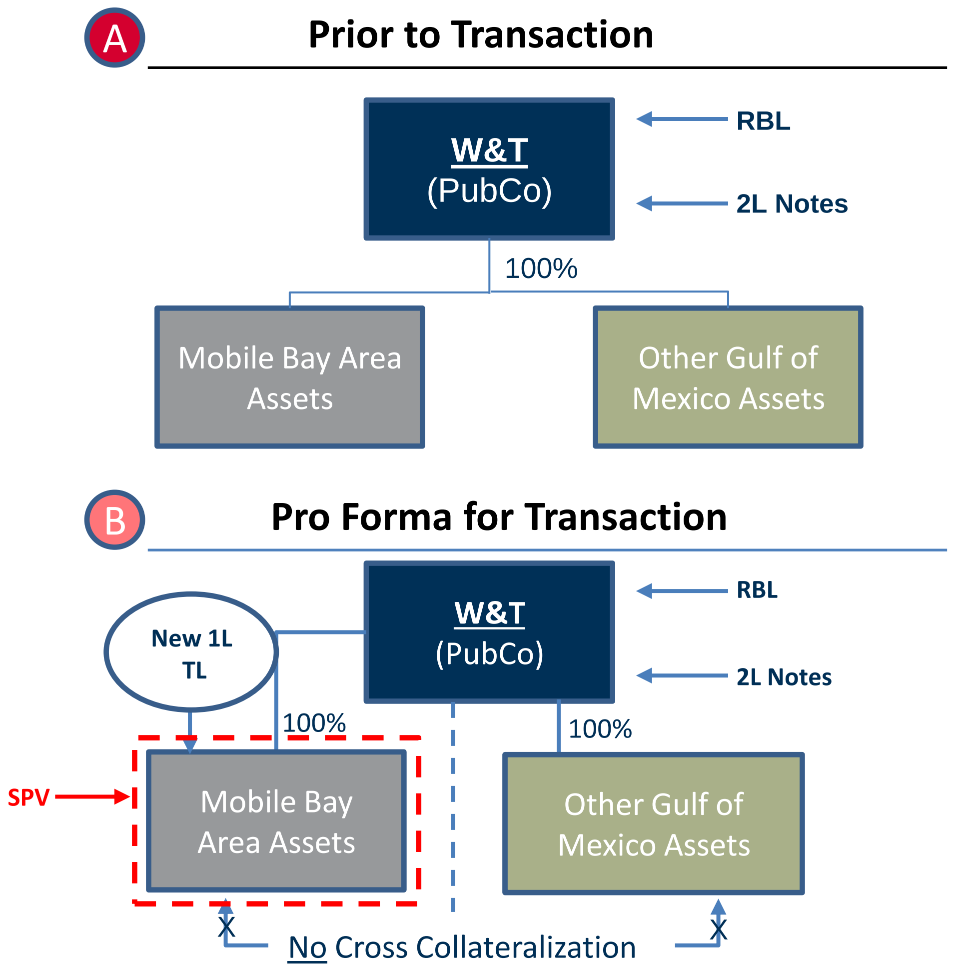
Continued Focus on Delivering Free Cash Flow and Adding Value

1) Adjusted Net Loss is a non-GAAP financial measure, see slide 42 for description of reconciling items to GAAP net loss.
2) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see slide 45 for description of reconciling items to GAAP net income.

Debt Securitization Transaction Overview

- Partnered with Munich Re, a reputable AA-rated counter-party, to fund future growth needs
  - Potential to scale over time to finance additional acquisitions
- Increased cash on hand with non-recourse financing
- Leverage-neutral transaction in non-recourse SPV structure
  - No maintenance covenants or redetermination requirements and no covenants at the parent level
- Term loan interest rate of 7% is at a substantially lower level compared to recent GOM high yield deals
  - Mandatory amortization over 7 years supports deleveraging
  - Executed natural gas derivatives contracts through term of loan to cover debt service
  - Only cash flows from the Mobile Bay area asset can be used to service the term loan debt going forward
- W&T owns 100% of the equity in the SPV
  - Keeps the upside associated with the Mobile Bay area assets
  - Adds cash to the balance sheet to reinvest in accretive acquisitions or other accretive opportunities
- On a consolidated basis, all earnings and debt are reported at the W&T level, public filings will reflect all activity for W&T and the SPV

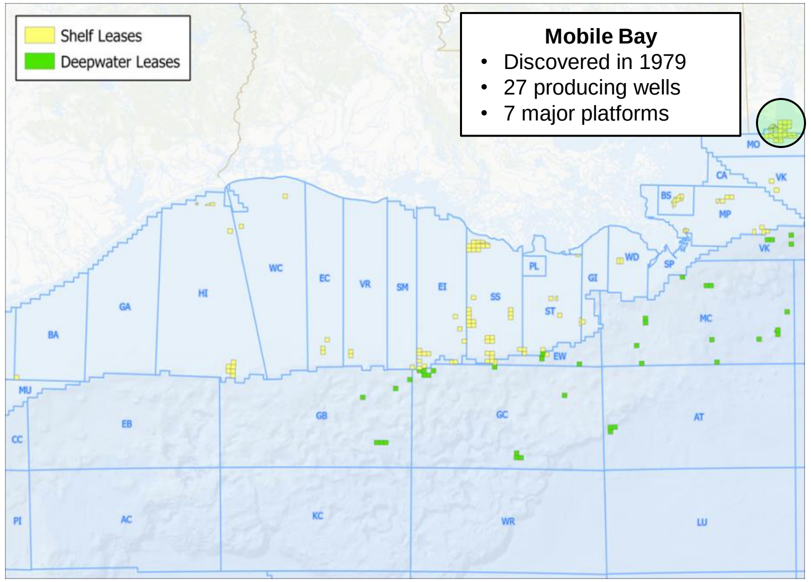
Corporate Structure



Fully Paid Down $48 Million in Outstanding RBL Borrowings and Boosted Cash

Mobile Bay Acquisition – Key Highlights

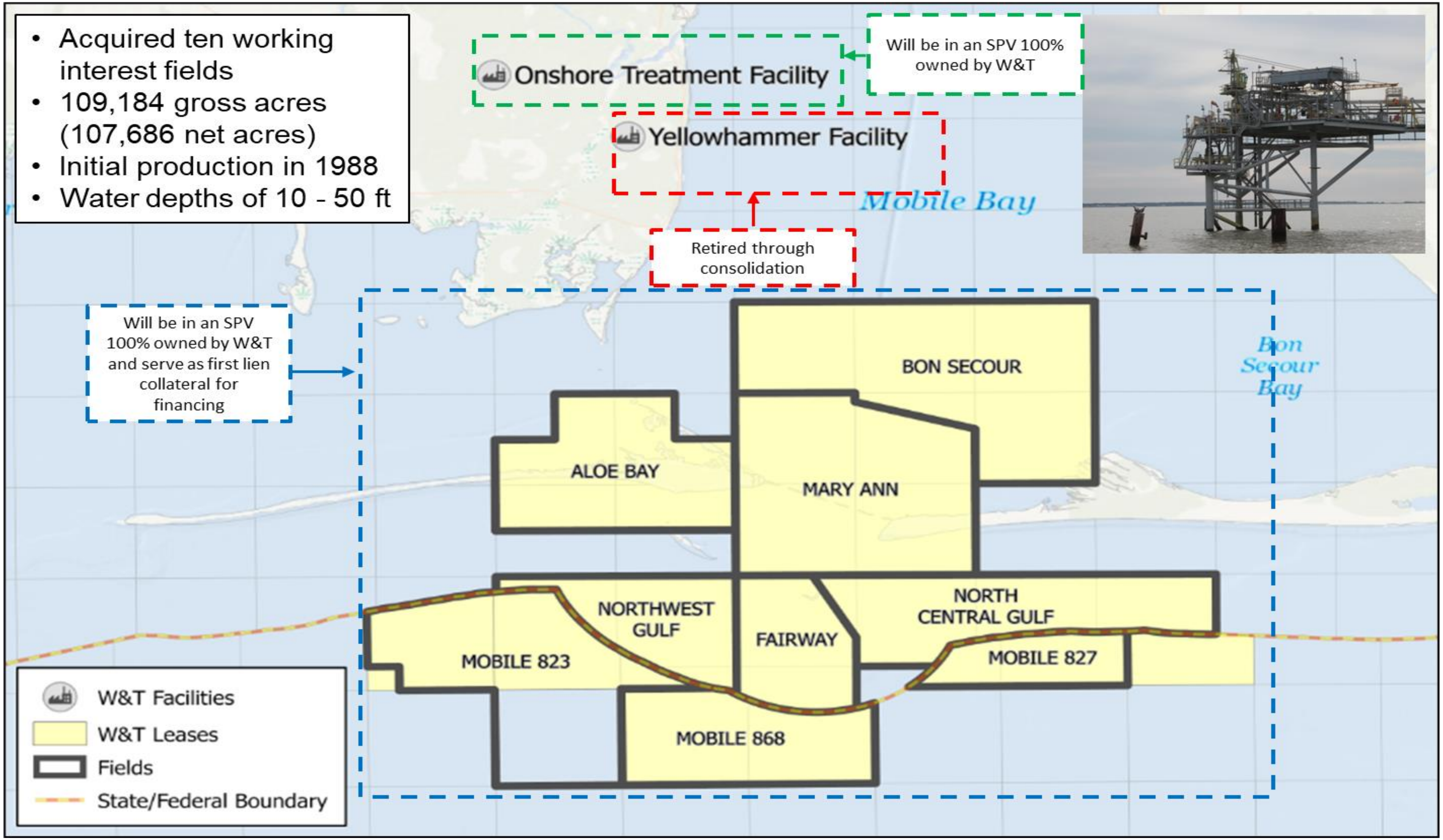
- Acquired ExxonMobil's interests and operatorship in the eastern region of the Gulf of Mexico, offshore Alabama that are adjacent to existing properties owned and operated by W&T as well as related onshore processing facilities
- Allows for significant synergies, consolidations, and cost savings as W&T is now 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 MMcf/d
- Year-end 2020 net proved reserves of ~87 MMBoe[1] of which the vast majority are proved developed producing (85% natural gas); 4Q'20 avg production 14,777 Boe/d
- Contains future opportunities including Norphlet drilling leads and optimization of compression facilities
- Identified potential drilling opportunities that are planned for permitting in 2021 and drilled thereafter
- ***Completed consolidation of natural gas treating facilities at Mobile Bay, with expected future cost savings of $5 million per year beginning in 2021***



Low Decline, Long-Life, Mostly PDP

1) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu.

Mobile Bay Area – Asset Map



Capital Structure Changes

	As of 3/31/21	Pro Forma SPV trans.
Total Cash & Equivalents	$ 53 MM	$ 186 MM
9.75% 2nd Lien Notes due Nov. 2023	$ 552 MM	$ 552 MM
RBL Borrowings[1]	$ 48 MM	$ 0 MM
7% Non-recourse Term Loan due 2028		$215 MM

- **Proven track record of navigating well through lower price environments while generating free cash flow and prudently managing the balance sheet**
- **Despite a difficult 2020 with COVID-19, negative oil prices and eight named storms that impacted production, <u>W&T reduced debt by $130 million from 12/31/19 to 3/31/21</u>**
  - $73 million of Second Lien notes were opportunistically repurchased for only $24 million in cash
  - $8 million of annualized interest expense savings
- **Recent SPV transaction substantially increased W&T's cash balance with non-recourse debt financing**
  - First-lien secured term loan is non-recourse to W&T and is amortized over seven years at a fixed interest rate of 7%
  - Provides significant source of funds for acquisitions and other growth opportunities
- **RBL balance fully paid off**
  - Redetermination currently underway and will reflect transfer of the Mobile Bay assets to the SPVs

1) RBL borrowings exclude $4.4 MM of outstanding letters of credit.

Environmental, Social and Governance

"We founded W&T nearly 40 years ago with the same core values we have today that have guided our success and provided the foundation for W&T to grow into a trusted operator in the Gulf of Mexico. From day one, we have been committed to developing and producing oil and gas resources in a safe and environmentally responsible manner, while meeting or exceeding all regulatory requirements".

Tracy Krohn, *Chairman and Chief Executive Officer*

Environmental

We are committed to protecting and preserving the environment in all aspects of our business, including production operations, well work programs, and decommissioning activities. Supporting our efforts is a robust program of policies, procedures and continuous training that meets or exceeds all regulatory requirements, and we expect our contractors to have similar programs in place.

Social

We view our people as our most valuable asset, and we strive to provide a work environment that attracts and retains the top talent in the industry. We spend considerable time and resources to advance the safety, health, and continuous professional development of our workforce. We also pride ourselves on providing an attractive compensation and benefits program that allows our employees to view working at W&T not as simply a job, but developing a career.

Governance

Our Board and its committees are responsible for our strategy and governance. Our fundamental policy is to conduct our business with honesty and integrity in accordance with the highest legal and ethical standards, which we view as critical to our long-term success and sustainability. We expect all employees across the organization to exemplify the same perspective as they carry out their work activities and appreciate their collective efforts.

Inaugural ESG Report Published on March 25th, 2021

Reserves: SEC[1] vs. 5/5/21 NYMEX Strip Pricing[2]

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Year-End 2020 Reserve Report - 05/05/21 NYMEX Strip Pricing

Reserve Category	Oil (MMBoe)	NGL (MMBoe)	Gas Bcf	Total (MMBoe)	% Liquids	Pre-Tax PV-10
Proved Developed Producing (PDP	20.5	17.3	564.4	131.8	28.7%	$1,077.7
Proved Developed Non-Producing (PDNP)	5.1	1.1	56.6	15.6	39.6%	$153.9
Proved Undeveloped (PUD)	10.0	2.5	67.8	23.8	52.5%	$224.8
Total 1P Reserves (Excluding ARO)	**35.6**	**20.9**	**688.8**	**171.3**	**33.0%**	**$1,456.4**
Probable Reserves (PROB)	41.5	6.9	193.3	80.6	60.1%	$1,039.8
Total 2P Reserves Excluding ARO)	**77.1**	**27.8**	**882.1**	**251.9**	**41.6%**	**$2,496.1**
Possible Reserves (POSS)	74.0	11.4	300.6	135.5	63.0%	$1,855.6
Total 3P Reserves Excluding ARO)	**151.1**	**39.2**	**1,182.7**	**387.4**	**49.1%**	**$4,351.8**
1P Asset Retirement Obligations (ARO)						**($205.0)**

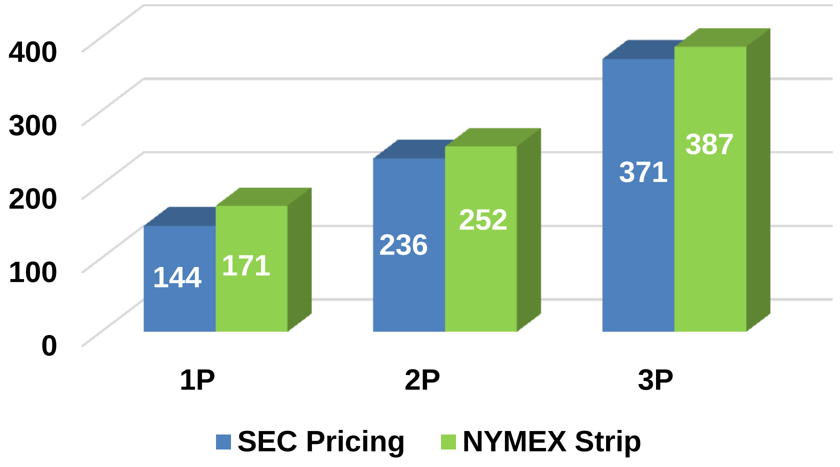
2020 Year End SEC Prices

Oil $/Bbl	Gas $/MMbtu
$37.78	$2.05

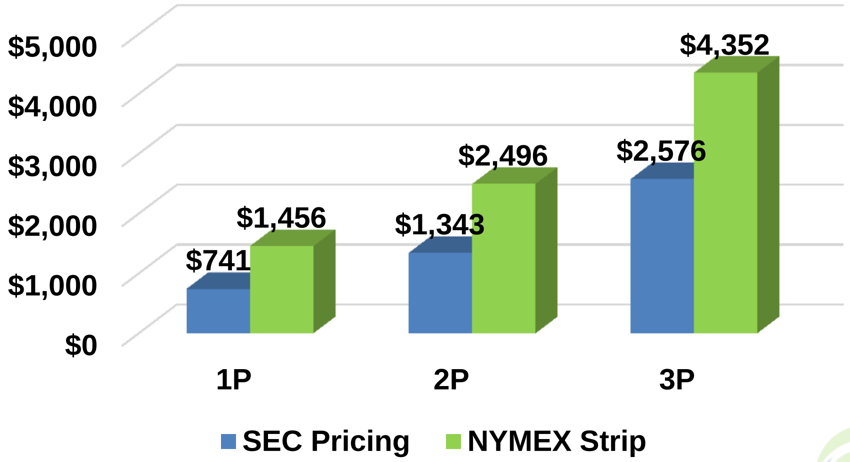
5/5/21 NYMEX Strip Prices (1P Life)

Oil $/Bbl	Gas $/MMbtu
$55.13	$2.72

Reserves MMBOE



Reserves PV-10 $MM



1) Based on year-end 2020 reserve report by NSAI at average realized SEC pricing.
2) Based on year-end 2020 reserve report at 5/05/2021 average realized NYMEX Strip pricing
3) Pre-Tax PV-10% is a non-GAAP measure; see reconciliation on slide 45.

Strategic Capital Allocation Plan

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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.

Asset Acquisitions

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

Debt Pay Down

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

Generate Shareholder Value

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

Operational Overview

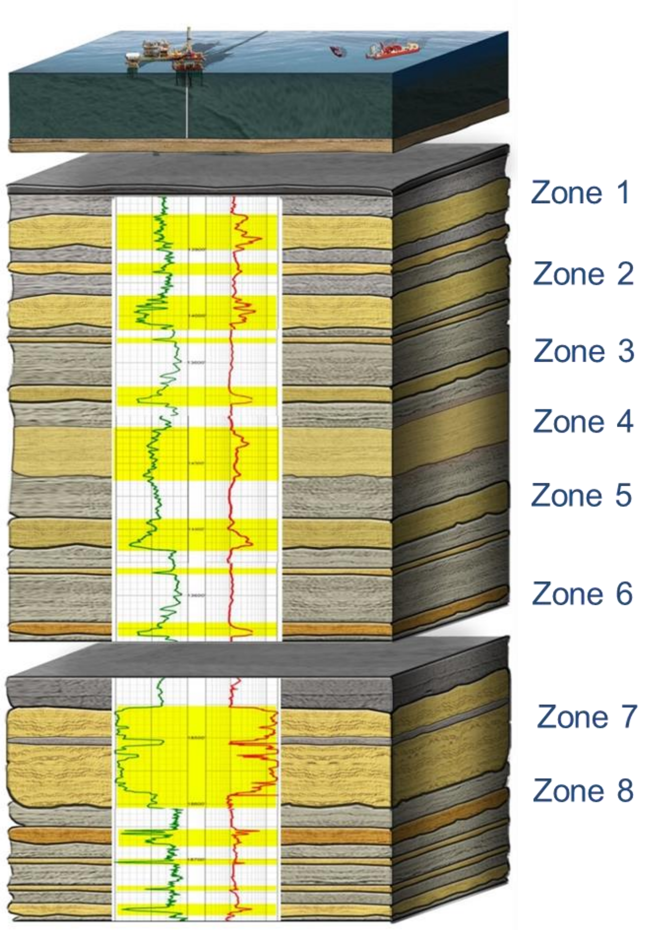
Gulf of Mexico – A Prolific & Unique Basin

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

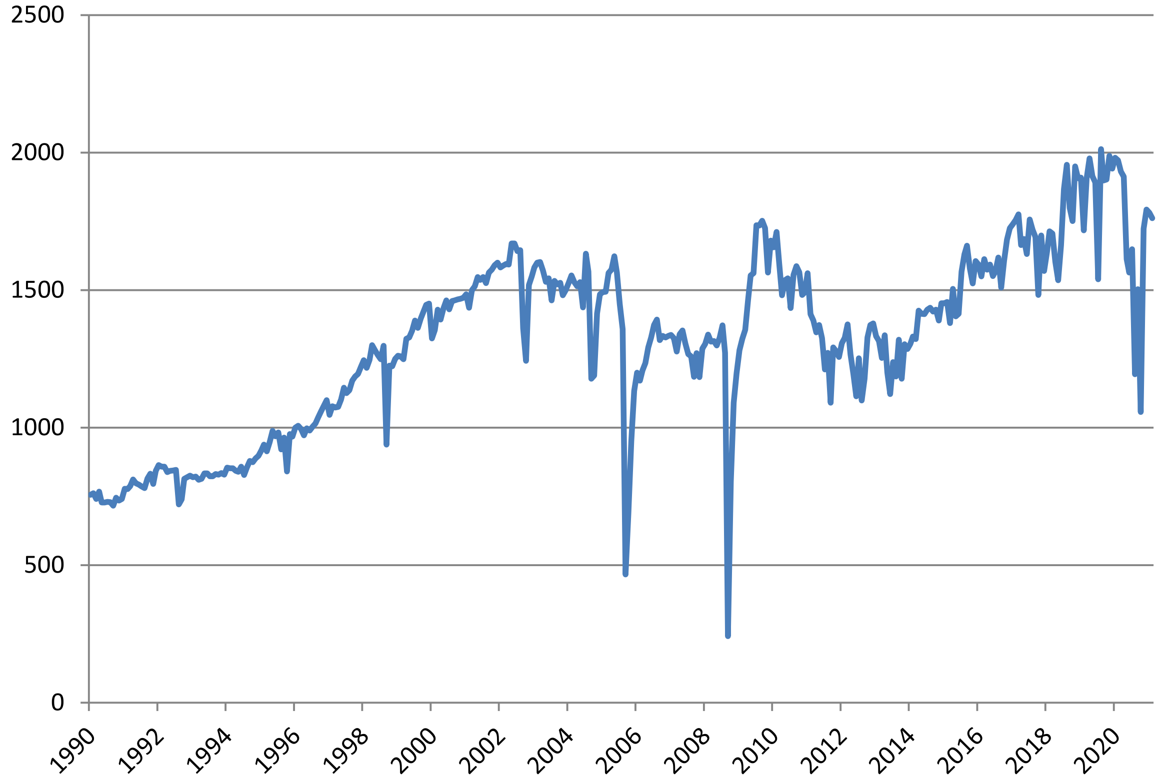
- Typical fields with high quality sands have drive mechanisms superior to primary depletion alone
- These fields enjoy incremental reserve adds annually, partly due to how reserve quantities are booked under SEC guidelines
- Fewer conventional wells required to develop fields



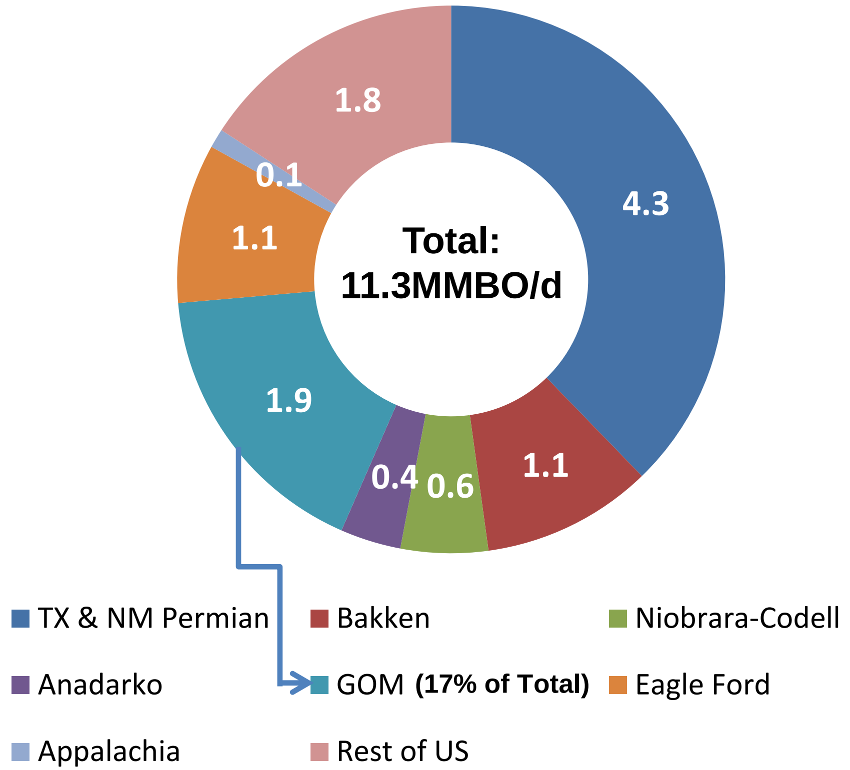
GOM Provides Better Porosity and Permeability than the Permian Basin

Gulf of Mexico – 2nd Largest U.S. Producing Basin

Gulf of Mexico Historical Oil Production[1]



US Oil Production by Key Region (MMBO/d)[1]

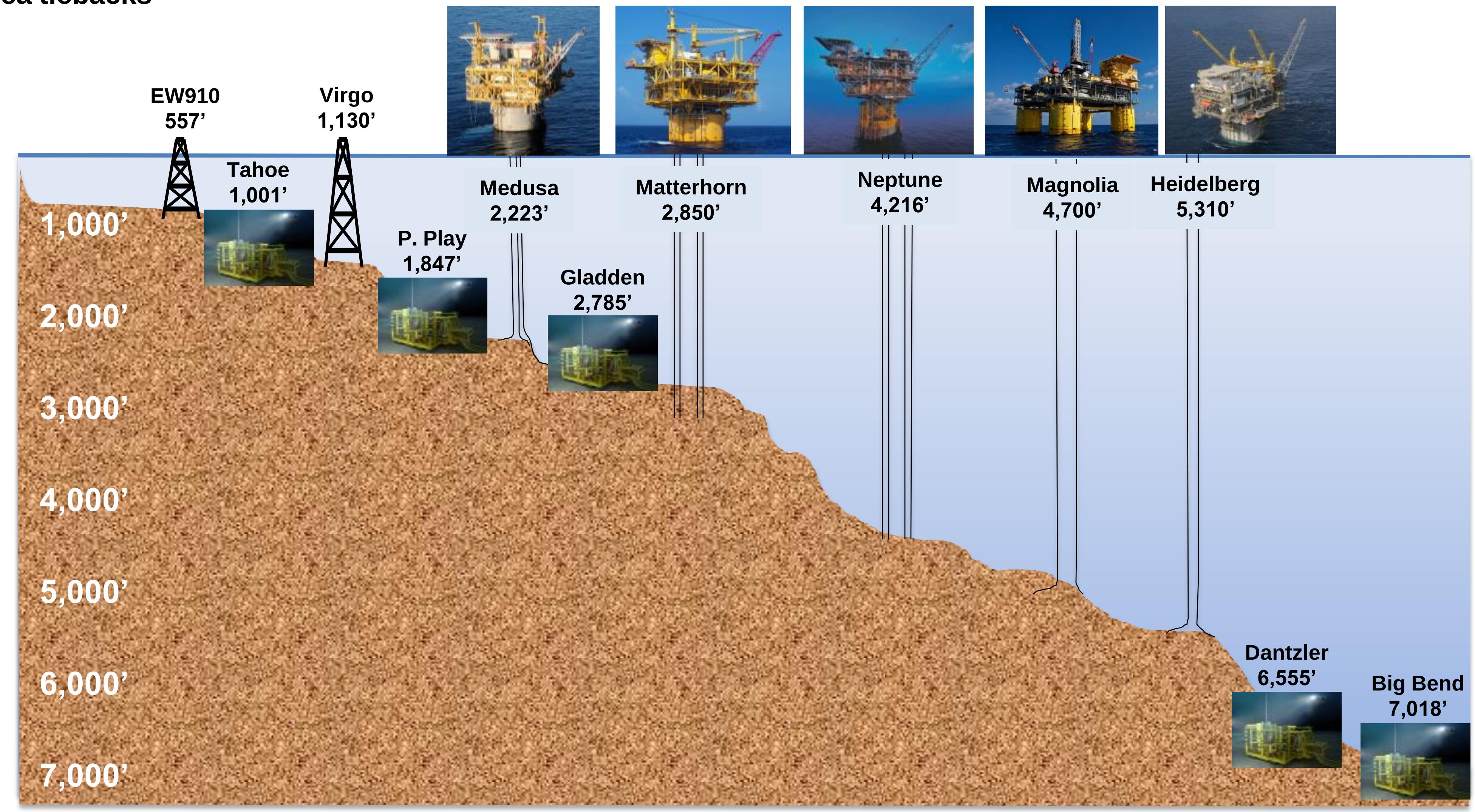


GOM Provides Unique Advantages: Low Decline Rates, World Class Porosity/Permeability and Significant Untapped Reserve Potential

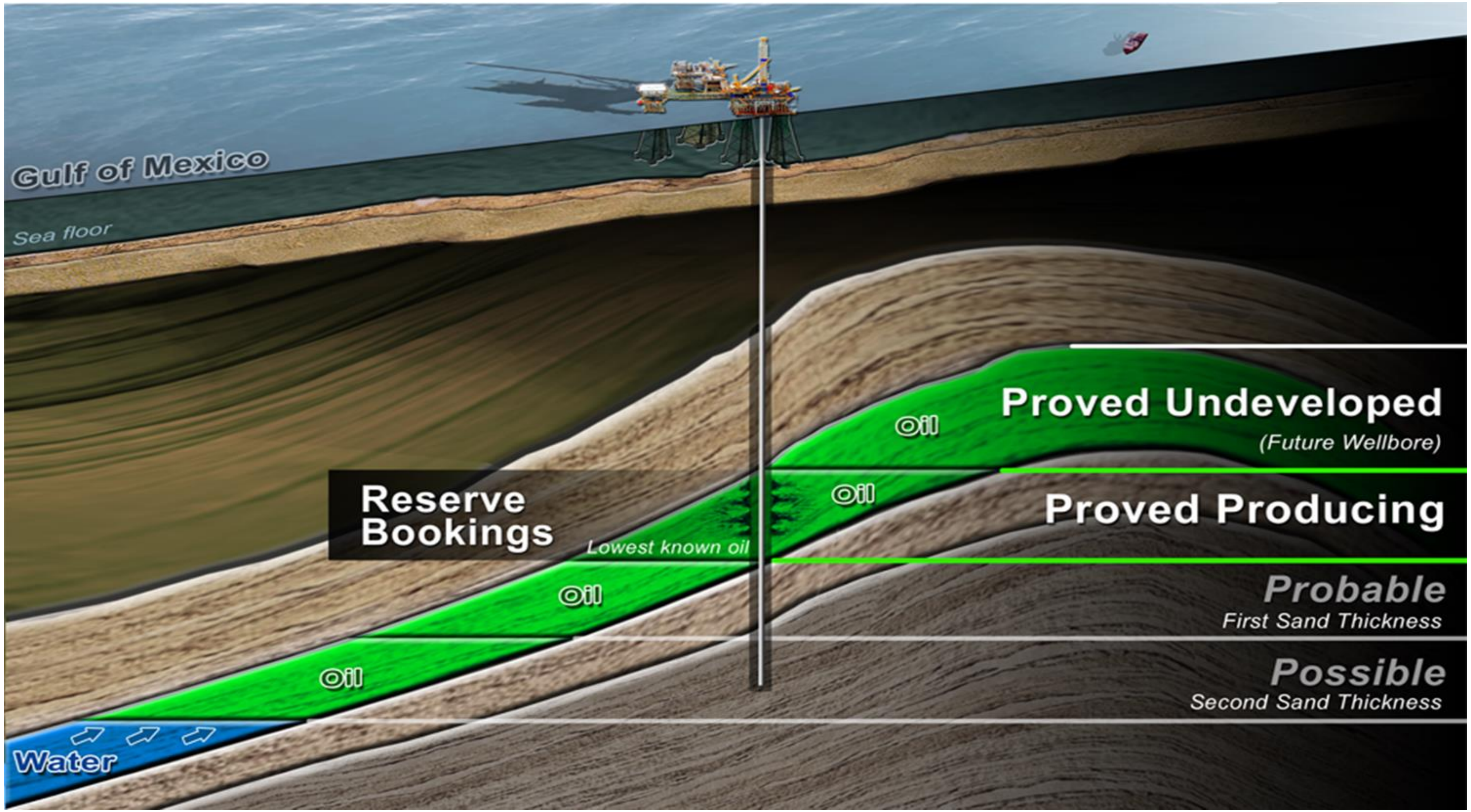
1) Based on U.S. Energy Information Administration (EIA) data as of March 31, 2021.

Successful Diversification in Valuable Deepwater Projects

- W&T's deepwater portfolio was expanded and diversified with Magnolia (2019) as its latest addition
- W&T operates and participates in various deepwater production facilities, including TLPs, E-TLPs, SPARs, deepwater fixed structures, and sub-sea tiebacks



Incremental Reserves May Be Produced at No Cost



Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores

Significant W&T Reserve Appreciation From Initial Bookings

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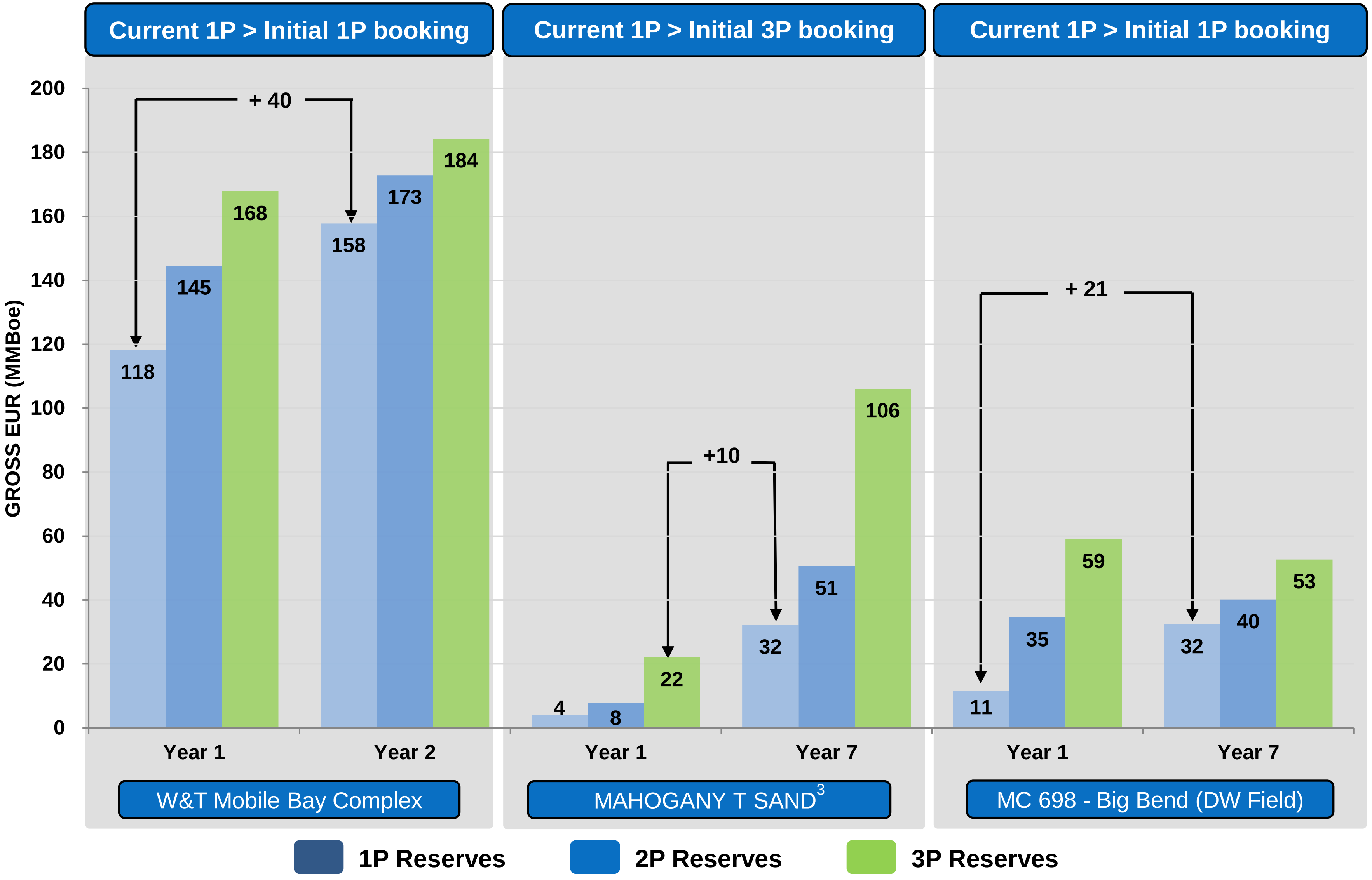


NYSE: WTI

1) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu.
2) 1P = Proved, 2P = Proved + Probable, 3P = Proved + Probable + Possible.
3) Initial 1P booking includes A-14 well only; Year-end 2020 1P booking includes A-14, A-18, A-19 & 1 PUD; 2P & 3P includes additional development wells.

Realizing Incremental Reserve Upside[1]

Focused on Realizing the Reserves Upside and Adding Economic Value Across 3 Categories:

1 Prob + Poss Related to PDP

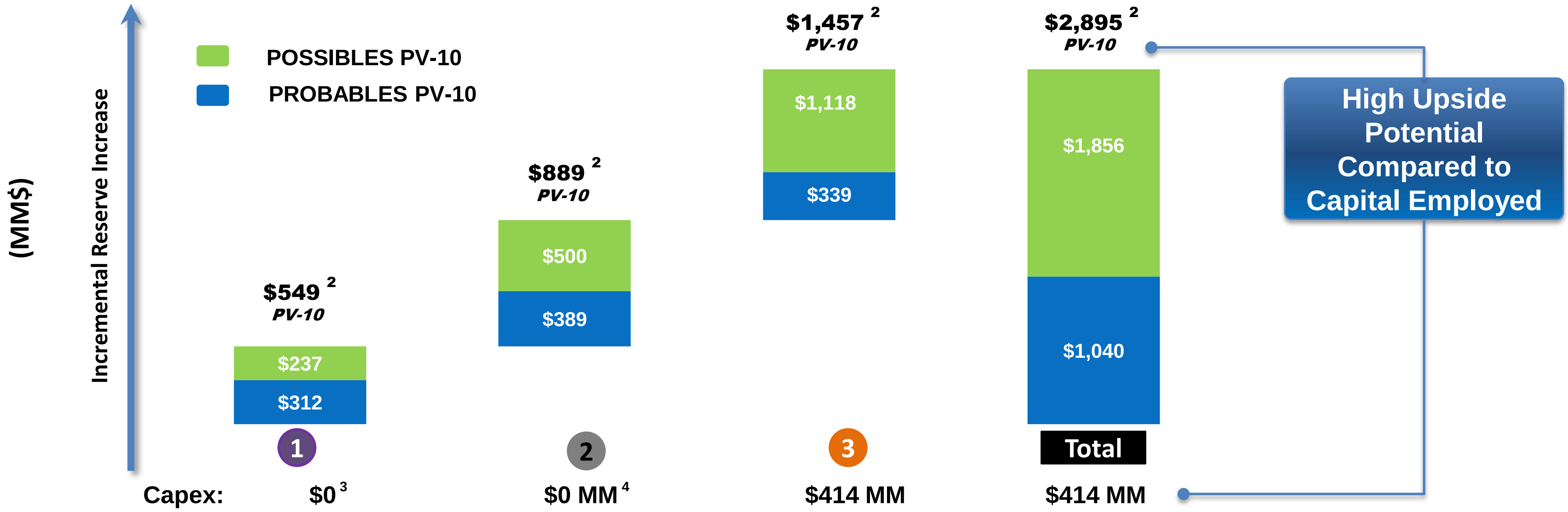
- No additional capex required
- Achievable because of WTI's demonstrated understanding of the fields

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



1) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/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.

Significant Declines in All-In Reserve Replacement Cost[1] (RRC)

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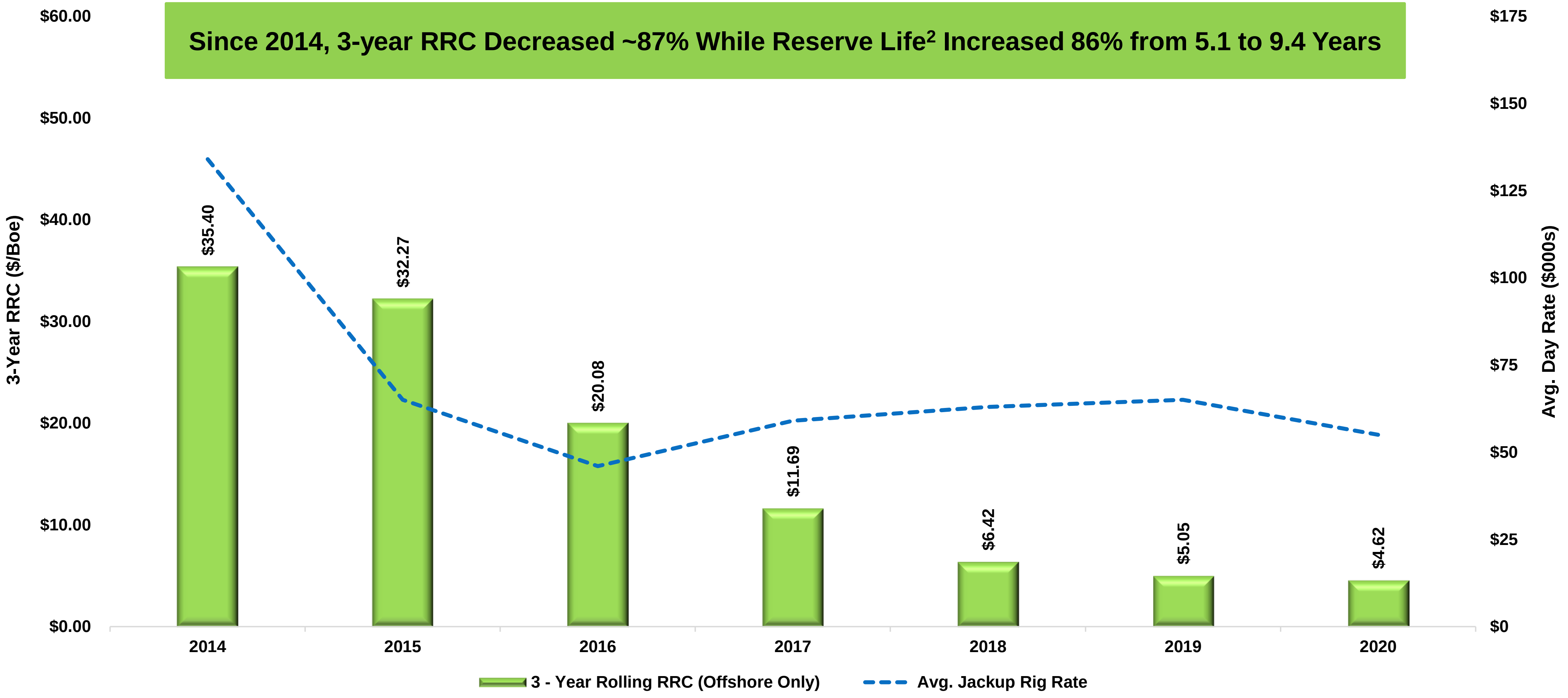
Since 2014, 3-year RRC Decreased ~87% While Reserve Life[2] Increased 86% from 5.1 to 9.4 Years

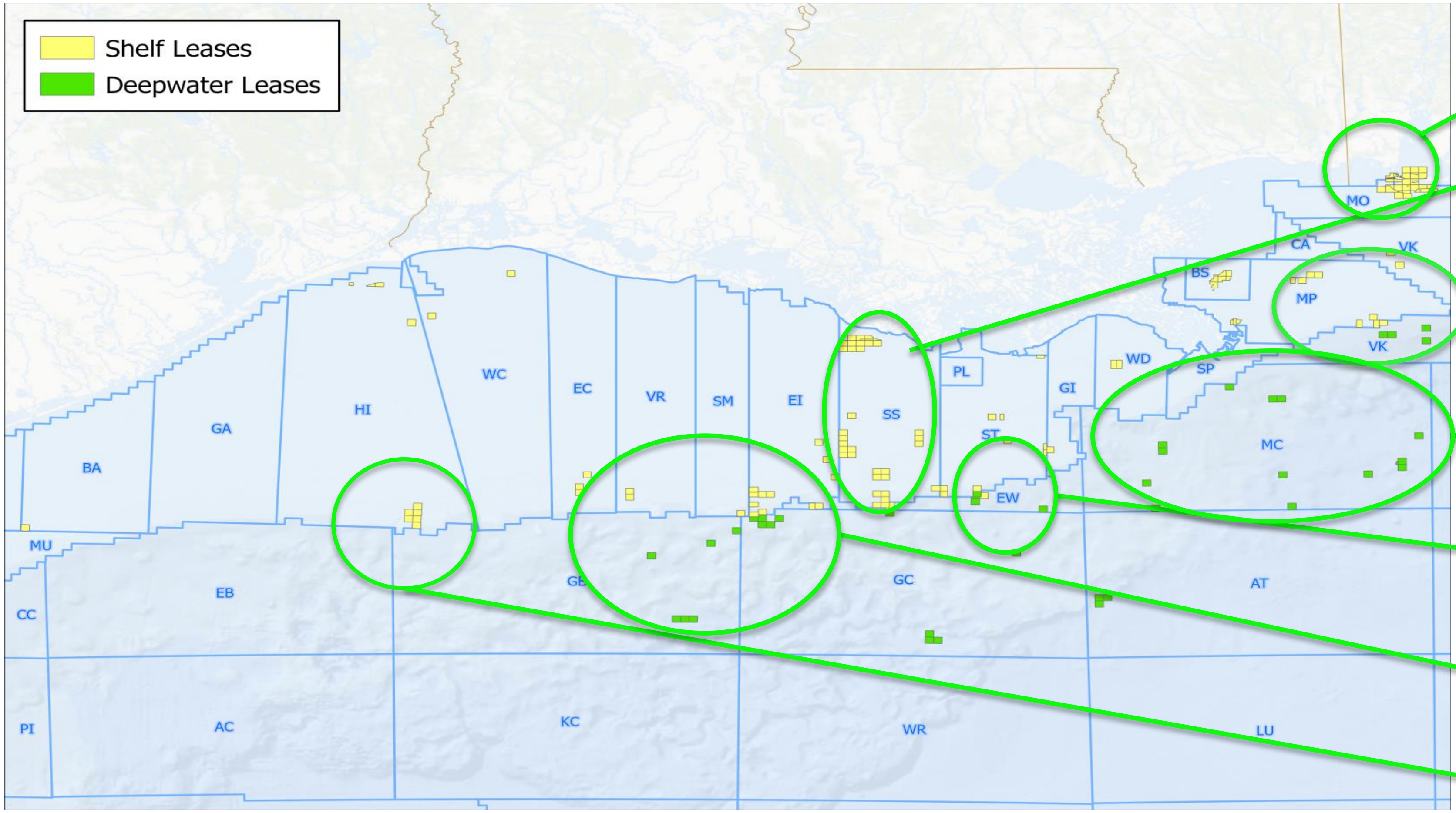


High Grading Projects, Sustainable Lower Service Costs, and Utilizing Existing Infrastructure Has Led to Lower RRC

1) Calculated as total capex divided by total reserve additions. Includes capital costs and reserves associated with revisions, extensions, discoveries and acquisitions.
2) Year-end Proved Reserves divided by production for the year.

Attractive Drilling Inventory[1]

Selected Growth Opportunities



1 Exploration

9 Development
4 Exploration

2 Development

5 Development
6 Exploration

1 Development
3 Exploration

4 Development
8 Exploration

1 Exploration

~44 Opportunities with 19 Platform Wells and 25 Subsea Tiebacks (all < 15 miles) with an Estimated 3P Resource Potential of ~200 MMBoe

1) Inventory as of November 2020.

Leveraging 37+ Years of GOM Acquisition Expertise

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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

History of Creating Long-Term Value From Acquisitions

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TOTAL
$115 MM
Paid out in Aug. 2011

Net average production[1] of 940 Boe/d from Matterhorn and Virgo.

Reserves[2]:		
	1P –	5.4 MMBoe
	2P –	10.0 MMBoe
	3P –	17.9 MMBoe

NEWFIELD
$206 MM
Paid out in Nov. 2014

Net average production[1] of 1,295 Boe/d from 78 offshore blocks, 65 of which are in deepwater.

Reserves[2]:		
	1P –	1.8 MMBoe
	2P –	4.1 MMBoe
	3P –	8.6 MMBoe

WOODSIDE
$55 MM
Paid out in Sep. 2019
Investments Post Acq.

Net average production[1] of 770 Boe/d from Neptune and 24 add'l blocks. One exploration well brought on production in 2014.

Reserves[2]:		
	1P –	1.5 MMBoe
	2P –	1.7 MMBoe
	3P –	2.4 MMBoe

COBALT
$17 MM
Paid out in Aug. 2018

Net average production[1] of 460 Boe/d from Green Canyon 859, 903, & 904.

Reserves[2]:		
	1P –	0.2 MMBoe
	2P –	0.4 MMBoe
	3P –	0.7 MMBoe

CONOCOPHILLIPS/ MARUBENI[4]
$18 MM
Paid out in Apr. 2021

Net average production[1] of 3,460 Boe/d from Garden Banks 783 & 784 (Magnolia Field).

Reserves[2]:		
	1P –	6.8 MMBoe
	2P –	21.3 MMBoe
	3P –	40.9 MMBoe

2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020

SHELL
$116 MM
Paid out in Nov. 2012

Net average production[1] of 430 Boe/d from Tahoe and 6 other fields.

Reserves[2]:		
	1P –	0.6 MMBoe
	2P –	0.9 MMBoe
	3P –	1.0 MMBoe

SHELL/ MARUBENI[3]
$61 MM
Paid out in Oct. 2014

Net average production[1] of 2,920 Boe/d from Fairway Field.

Reserves[2]:		
	1P –	16.6 MMBoe
	2P –	17.7 MMBoe
	3P –	17.9 MMBoe

CALLON
$83 MM
Investments Post Acquisition

Net average production[1] of 410 Boe/d from Medusa and 12 other fields.

Two exploration wells brought on production in June 2015.

Reserves[2]:		
	1P –	2.1 MMBoe
	2P –	3.8 MMBoe
	3P –	6.2 MMBoe

EXXONMOBIL
$168 MM
Closed August 30, 2019

Net average production[1] of 14,777 Boe/d. Potential to add incremental reserves with minimal capital by consolidating operations with additional upside from potential future drilling locations and facility modifications.

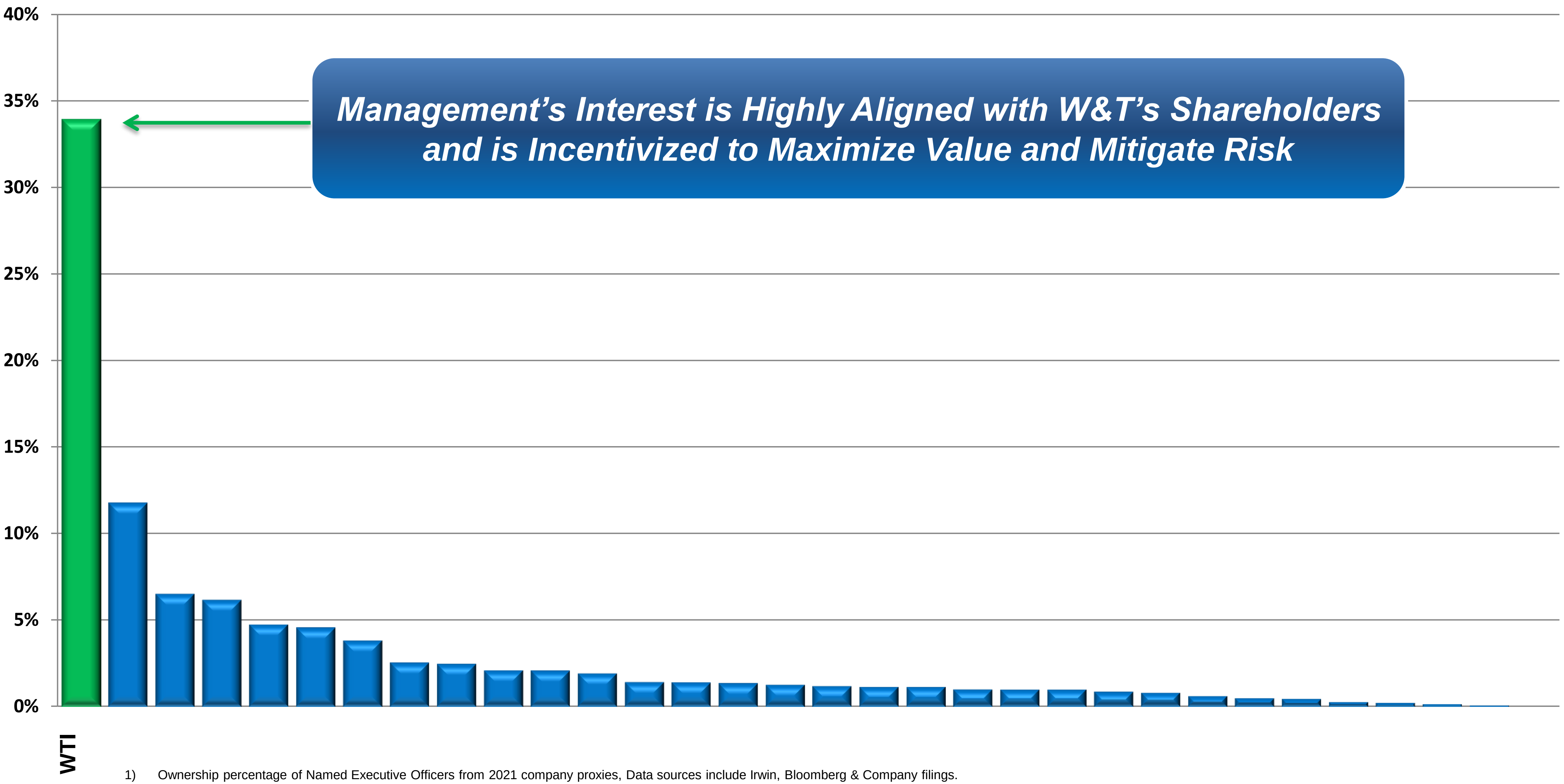
Reserves[2]:		
	1P –	86.9 MMBoe
	2P –	96.0 MMBoe
	3P –	103.6 MMBoe

1) Reflects 4Q'20 net average production except ConocoPhillips/Marubeni (Magnolia) which reflects December 2020 as 4Q '20 included extended field shut-in.
2) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu.
3) Fairway Field: 8.9MMBoe(1P Reserves),12.8MMBoe(2P Reserves) acquired from Shell in 2011 for $43MM, 5.2MMBoe(1P Reserves), 5.8MMBoe(2P Reserves) acquired from Marubeni in 2014 for $18MM.
4) Magnolia Field: 4.0MMBoe (1P Reserves), 7.2MMBoe(2P Reserves) acquired from ConocoPhillips in December 2019 for $20MM, and 1.4MMBoe(1P Reserves), 2.5MMBoe (2P Reserves acquired from Marubeni in March 2020 for $5.8MM, as of the effective date.

Financial Overview

Management Ownership[1]

Among the Highest of Public E&P Companies[2]



1) Ownership percentage of Named Executive Officers from 2021 company proxies, Data sources include Irwin, Bloomberg & Company filings.
2) Companies sorted alphabetically: AR, BCEI, BRY, BTE, CDEV, CNX, COG, CPE, CPG, CRK, ESTE, GDP, KOS, LPI, MCF, MGY, MRO, MTDR, MUR, NOG, PDCE, PVAC, REI, RRC, SBOW, SD, SM, SWN, TALO.

Generating Steady and Significant Free Cash Flow[1]

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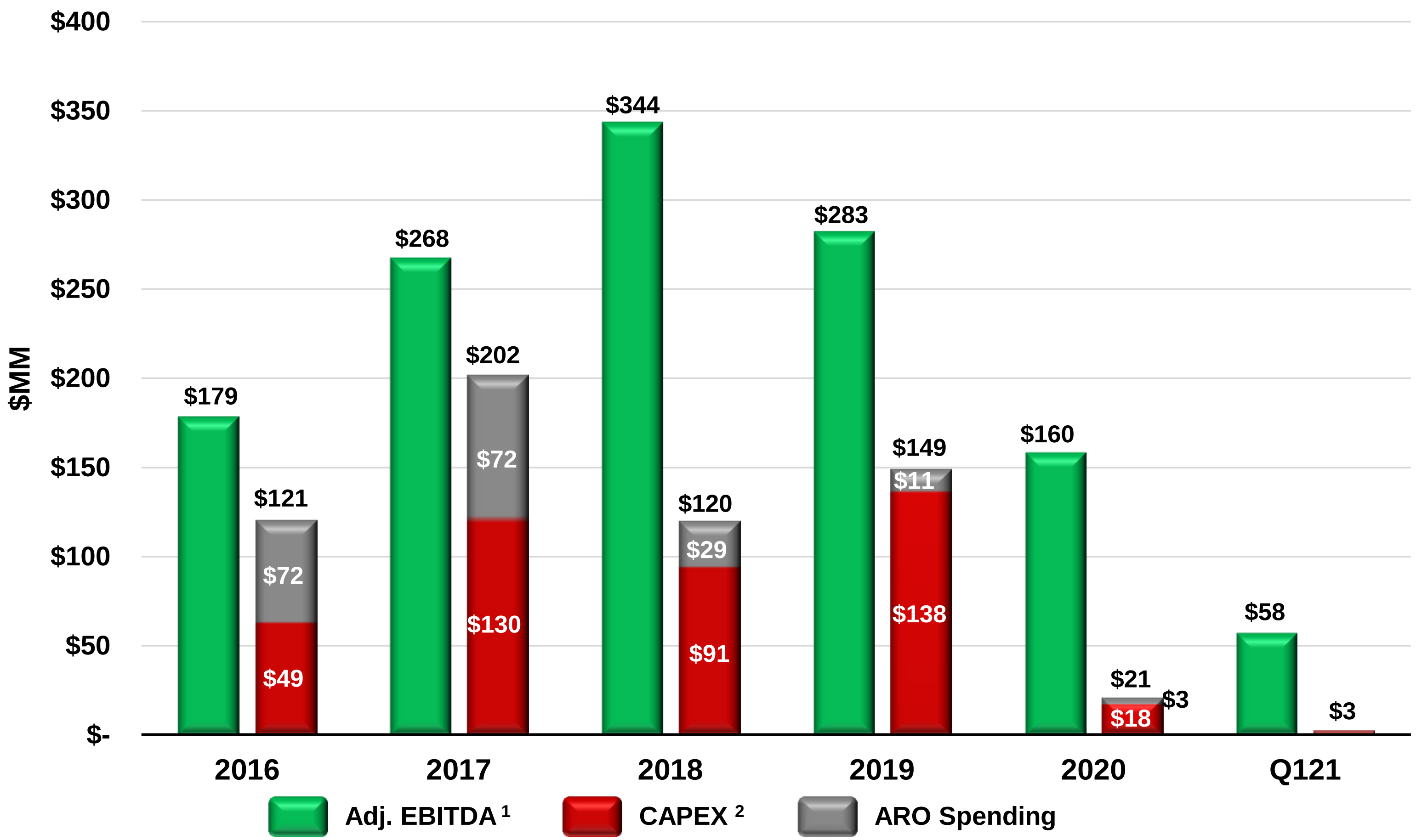


- Strong production base and cost optimization delivers steady Adjusted EBITDA[1]
- Adjusted EBITDA[1] materially outpaced CAPEX and ARO spending (excluding acquisitions) since 2016
- In 2020, utilized portion of cash generated to reduce 2nd Lien debt by $72.5 MM through bond repurchases at ~33% of par value

Each $1 improvement in oil price increases annual Adjusted EBITDA[1] by ~$6 MM[3]
Each $0.10 improvement in gas price increases annual Adjusted EBITDA[1] by ~$5 MM[3]

Substantial Unlevered Free Cash Flow[1] Generation Provides Optionality

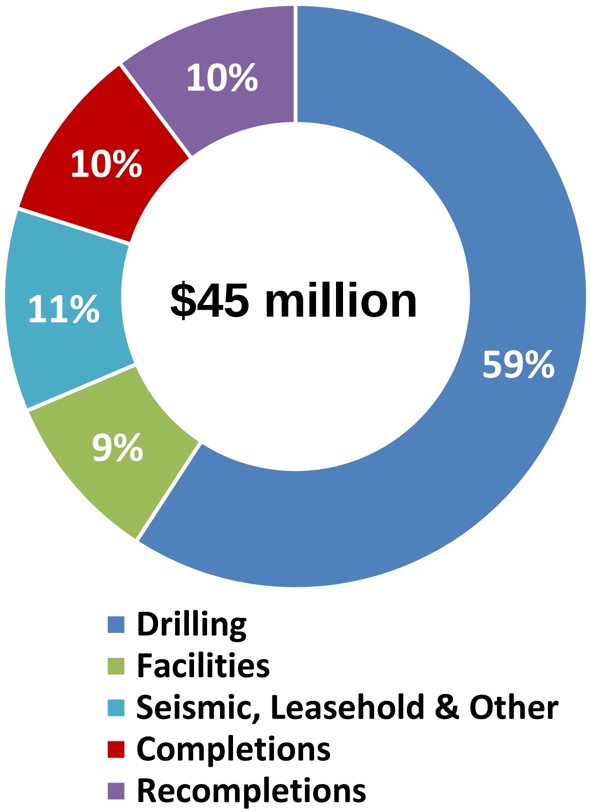
1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see slide 44 in appendix for description of reconciling items to GAAP net income.
2) Excludes acquisitions; includes only accrual basis capital expenditures.
3) Before impact of hedging.

2021 Capital Expenditure Budget

- 2021 CAPEX[1] guidance:
  - $30 - $60 MM
    - 2019 actuals ~$138 million
    - 2020 actuals ~$18 million
    - Q1 2021 actuals - $1.6 million
  - 2021 spending weighted to 2H'21

- 2021 P&A guidance:
  - $17 - $21 MM
    - 2019 actuals ~$11 million
    - 2020 actuals ~$3 million
    - Q1 2021 actuals - ~$1 million

CAPEX Allocation[1,2]



Managing 2021 CAPEX to Enhance Financial Flexibility

1) Accrual basis capital expenditures only.
2) Based on midpoint of 2021 forecast.

2021 and Beyond

Consistent Strategy Positions W&T To Thrive Through Multiple Pricing Cycles

Focused on Free Cash Flow Generation

Prioritize Environmental, Social and Governance Matters

High Quality Conventional Asset Base with Low Decline

Reducing Costs to Improve Margins and Increase ROCE

Maintaining Good Liquidity and Financial Flexibility

Capitalize on Unique and Accretive Opportunities

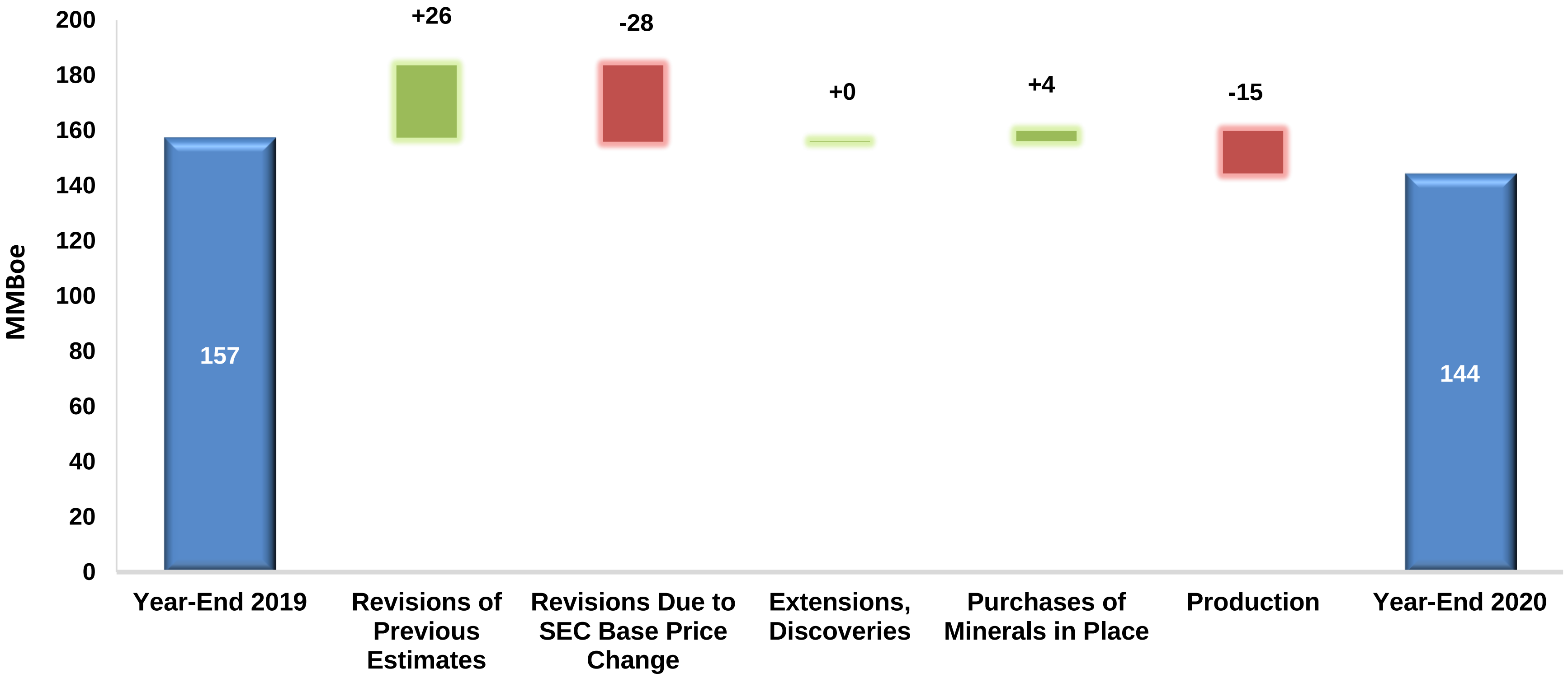
Appendix

2021 Guidance

Guidance as of May 4, 2021

	Full Year	2nd Quarter
Oil (MMBbls)	4.97 – 5.57	1.26 – 1.39
NGL's (MMBbls)	1.47 – 1.63	0.37 – 0.41
Natural Gas (BCF)	44.4 – 49.0	11.0 – 12.2
Total (MMBoe)	13.8 – 15.4	3.5 – 3.8
Total (Boed/d)	38,000 – 42,000	38,500 – 42,500
Lease Operating Expenses	$158 - $174 MM	$44 - $48 MM
G & T and Production Taxes	$23 - $25 MM	$5.4 - $5.9 MM
G & A	$49 - $54 MM	$13.9 - $15.4 MM
Current Income Tax Expense Rate	0%	0%

SEC Year-End 2020 Reserves[1]



- 235.9 MMBoe Net Proved + Probable (2P) Reserves
- All-in Reserve Replacement Cost 3-year average: $4.62 per Boe
- Reserve life index[2] 9.4 years at SEC pricing and 11.0 at NYMEX strip pricing

Strong Year of Positive Technical Revisions Offset by Significant Decrease in SEC Reference Pricing

1) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu; Computation may not foot due to rounding.
2) Year-end 2020 Proved Reserves divided by 2020 production

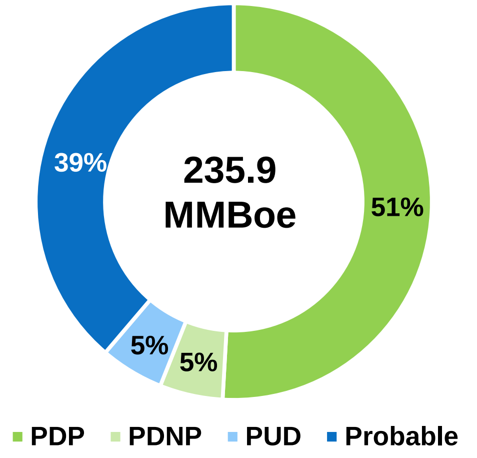
SEC Year-End 2020 Reserve Report[1]

SEC Year-end 2020 Reserves

Reserve Category	Oil (MMBoe)	NGL (MMBoe)	Gas Bcf	Total (MMBoe)	% Liquids	Pre-Tax PV-10[2]
Proved Developed Producing (PDP)	19.4	15.6	510.4	120.1	29.2%	$573.0
Proved Developed Non-Producing (PDNP)	4.6	0.9	39.8	12.1	45.4%	$73.7
Proved Undeveloped (PUD)	8.2	0.8	19.1	12.2	73.9%	$94.2
Total 1P Reserves (Excluding ARO)	**32.2**	**17.4**	**569.3**	**144.4**	**34.3%**	**$740.9**
Probable Reserves (PROB)	41.7	8.8	246.0	91.5	55.2%	$602.4
Total 2P Reserves (Excluding ARO)	**73.9**	**26.2**	**815.2**	**235.9**	**42.4%**	**$1,343.3**
Possible Reserves (POSS)	73.7	11.4	301.9	135.4	62.8%	$1,233.2
Total 3P Reserves (Excluding ARO)	**147.6**	**37.5**	**1,117.2**	**371.3**	**49.9%**	**$2,576.4**

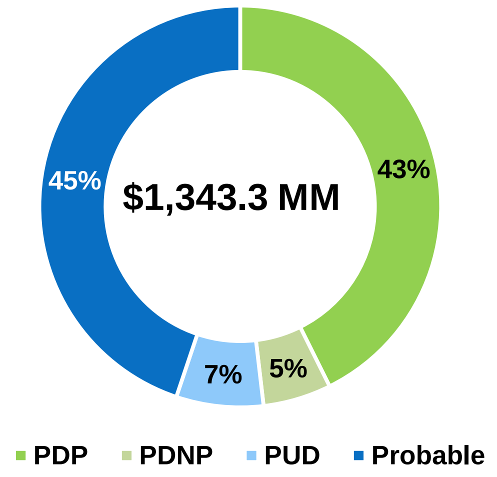
1P Asset Retirement Obligations (ARO)	**($205.0)**

2P Reserves[1]



Natural Gas 57.6%
Liquids 42.4%

2P Pre-Tax PV-10% [2,3]



1) Based on year-end 2020 reserve report by NSAI at average realized SEC pricing of $37.78/BO and $2.05/MMbtu.
2) Pre-Tax PV-10% is a non-GAAP measure; see reconciliation on slide 45.
3) Pre-Tax PV-10% excluding 1P Asset Retirement Obligation.

Rigorous Technical Evaluation Results in Drilling Success

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Process

1. Leads
2. Screening
3. Technical Evaluation
4. AFE Review
5. Execute

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

Success Rate[1]
2011 – 2020
> 90%

50 successful offshore wells drilled since 2011

Rigorous Evaluation Process Has Led to >90% Success Rate Since 2011

GOM Drilling Joint Venture

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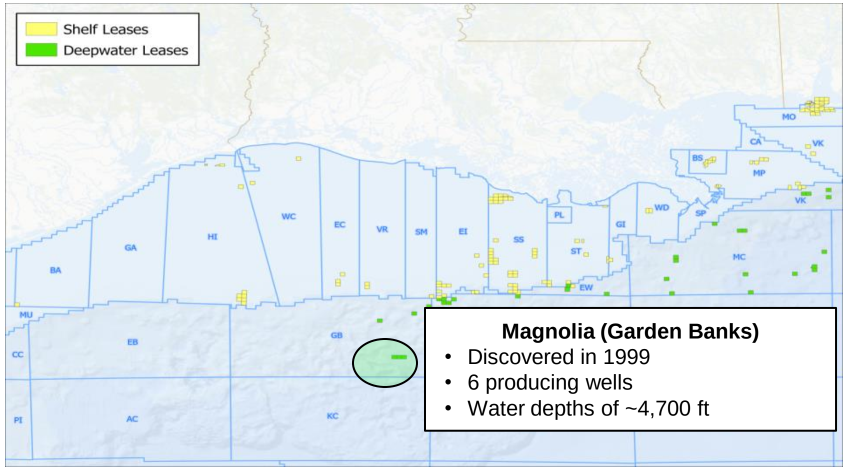
- Secured $361.4 MM commitment for the development of 14 pre-identified projects in the GOM with potential to upsize program over time with additional projects
  - Covers the total estimated cost of the 14 wells of $336 MM, plus contingency
  - Drilled and completed nine wells through December 31, 2019
  - Successfully drilled one well in 2020 in the East Cameron 338/349 Field (Cota well). Initial production is planned for late 2021, subject to completion of certain infrastructure projects
- 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
- 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

Magnolia Deepwater Acquisition – Key Highlights

- Acquired 100% working interest in and operatorship of the Magnolia Field in the central GOM, offshore Louisiana, in Garden Banks blocks 783 and 784 through two transactions
- Combined purchase price of $25.8 million[1] as of the effective date of October 1, 2019 and assumption of P&A liability
  - Net purchase price of $18.1 million as of the closing dates
  - **Acquisition paid out in April 2021**
- Sellers were ConocoPhillips (75% WI) and Marubeni Oil & Gas (25% WI)
- Year-end 2020 combined net proved reserves of 6.8 MMBoe of which 76% are oil and 6% NGLs[2]
- Increased W&T's deepwater acreage by 11,520 gross and net acres
- Produced approximately 3,460 net Boe/d (80% oil) in December 2020
- Decreased Lease Operating Expenses ~30% since acquiring working interest
- Provides additional upside from additional pay sands in existing wellbores and potential opportunities for future drilling
- Closed acquisition of 75% WI with ConocoPhillips on December 12, 2019; acquisition of remaining 25% WI from Marubeni closed on March 31, 2020; both acquisitions were funded with available cash on hand



Oil-Weighted Deepwater GOM Acquisition

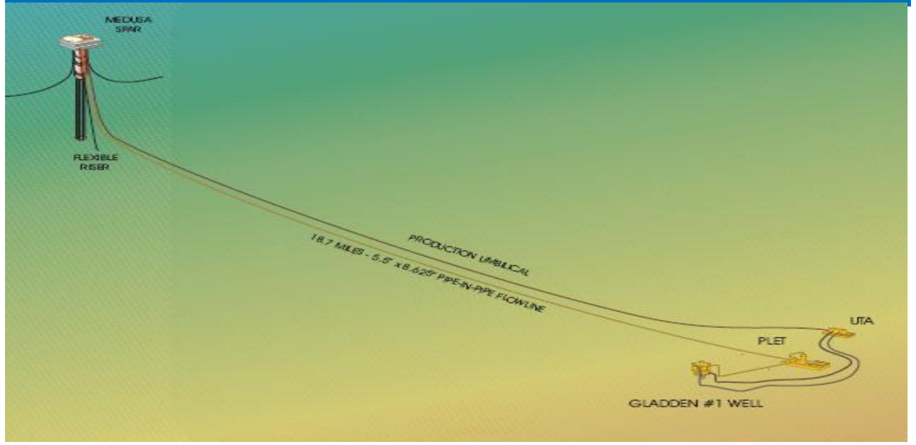
1) Before normal and customary closing adjustments.
2) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu.

Significant Infrastructure Advantage

W&T Owns Substantial Infrastructure in the Gulf of Mexico

Platform Rig on infield production facility (EW 910 Area)

Subsea tieback to existing infrastructure (MC 800 Gladden)

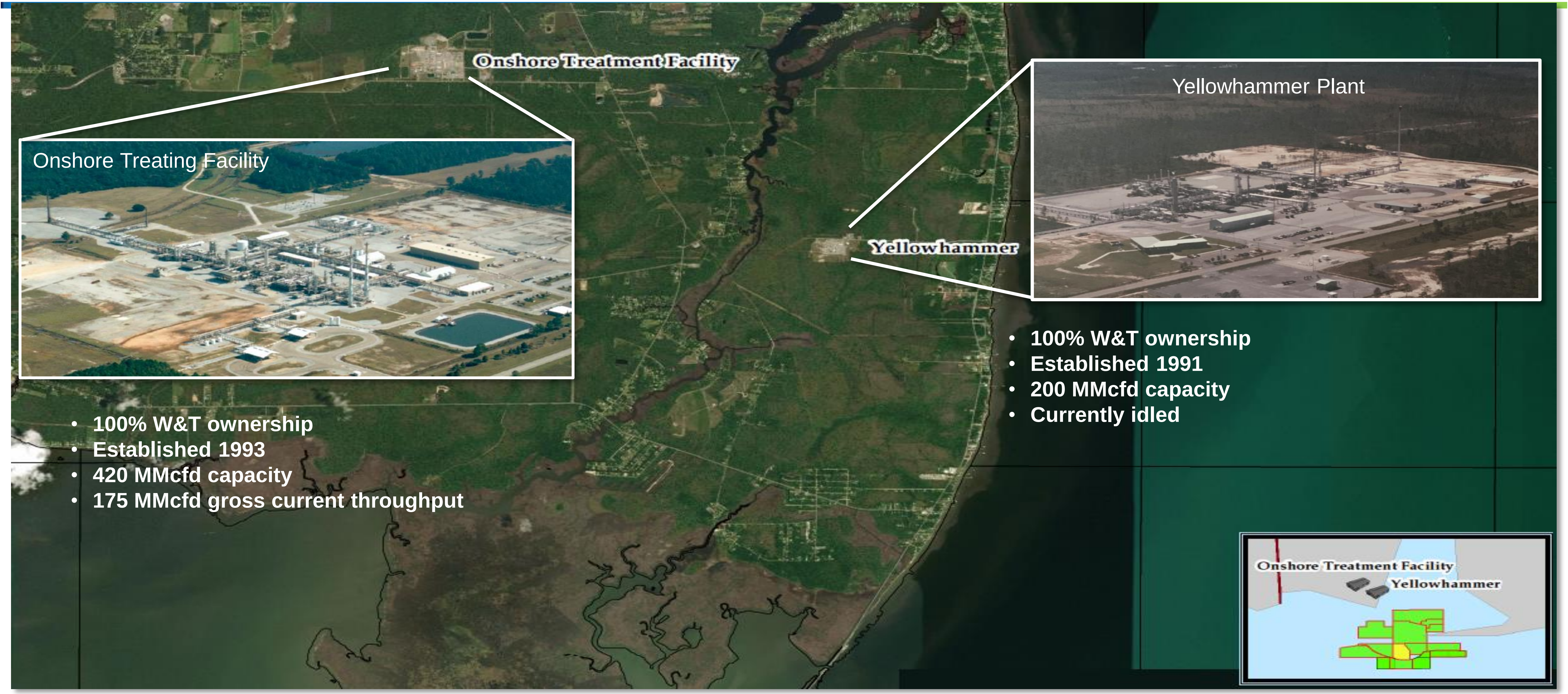


- **146 existing structures provide a key advantage when evaluating/developing prospect opportunities**
- **Economic Advantage**
  - *Reduces capital expenditures*
  - *Increases returns by generating cashflow quicker*
  - *Marketing contracts already in place*
  - *Provides revenue upside in potential Production Handling Agreements (PHA)*
    - *2018 $13.4 MM, 2019 $15.3 MM, 2020 $9.1 MM, Q121 $2.4 MM*

Asset Retirement Obligations[1]

1) Projected undiscounted P&A costs are net of escrows (total of $29.9 MM); Undiscounted P&A estimate of $438 MM from 2023 to 2050.
2) Midpoint of 2021 guidance.

Mobile Bay Area – Onshore Gas Treating Facilities



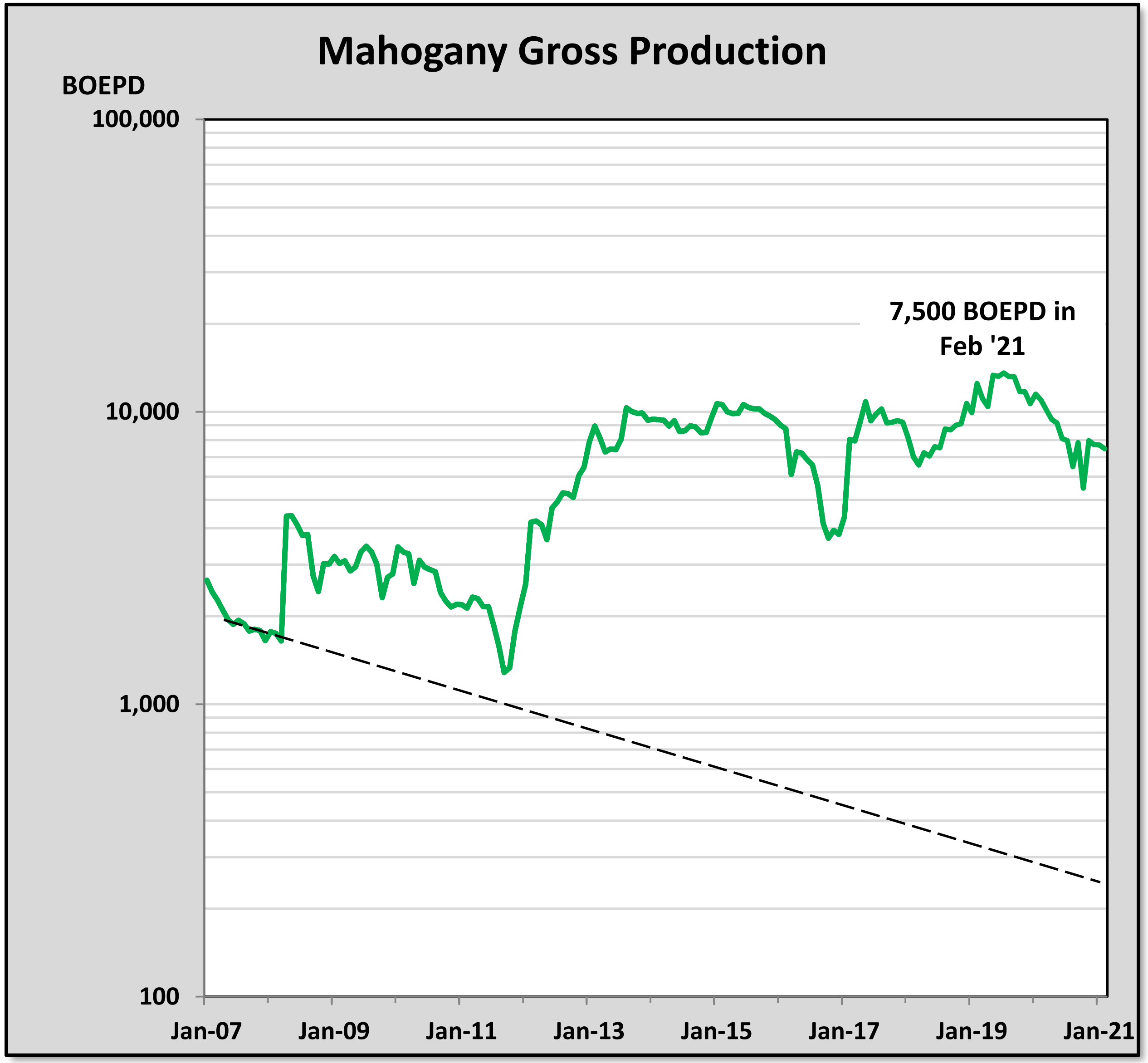
Onshore Treating Facility

- **100% W&T ownership**
- **Established 1993**
- **420 MMcfd capacity**
- **175 MMcfd gross current throughput**

Yellowhammer Plant

- **100% W&T ownership**
- **Established 1991**
- **200 MMcfd capacity**
- **Currently idled**

SS 349 Field (“Mahogany”) Case Study



SS 349 Field (“Mahogany”)

- 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] = $602 MM

Have increased value by:

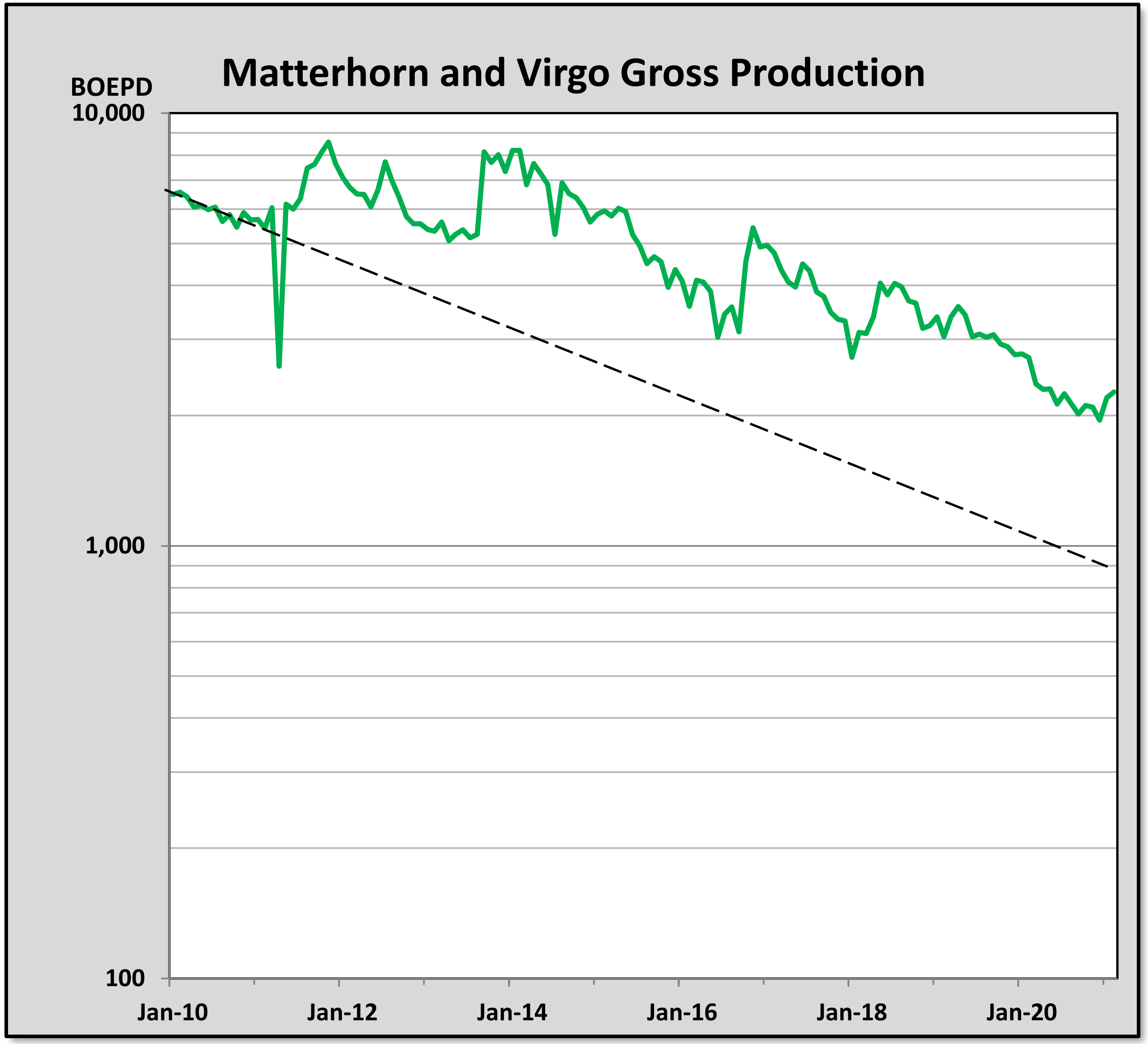
- Development and exploration drilling
- Performing recompletes
- Reworks and performance optimization

Current Reserves[2]

1P Reserves:	24.9	MMBoe
2P Reserves:	49.9	MMBoe
3P Reserves:	112.1	MMBoe

1) As of December 31, 2020.
2) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu.

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[1] = $500 MM

Have increased value by:

- Drilling sidetracks
- Performing recompletes
- Instituting waterflood
- Entering processing arrangement ($61 million in processing revenues received to date)

Current Reserves[2]

1P Reserves:	5.4	MMBoe
2P Reserves:	10.0	MMBoe
3P Reserves:	17.9	MMBoe

1) As of December 31, 2020.
2) Based on year-end 2020 reserve report at 5/5/2021 average realized NYMEX Strip pricing (1P Life) of $55.13/BO and $2.72/MMbtu.

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. The T-Sand has currently produced over 9 MMBO and 17 BCF from 3 wells.*
  - *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*
  - *Legacy 3D seismic reprocessing completed in Q2 2020 and new 3D survey obtained in Q3 2020, field re-interpretation underway*
  - *Rig demobed in 2019 to save cost while evaluating seismic*

Mahogany Platform

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.

Non-GAAP Reconciliations

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 (Loss) Income", "Adjusted EBITDA" and "Free Cash Flow". Management uses these non-GAAP financial measures in its analysis of performance. 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 (Loss) Income to Adjusted Net (Loss) Income

Adjusted Net (Loss) Income does not include the unrealized commodity derivative loss (gain), amortization of derivative premium, bad debt reserve, deferred tax benefit, gain on debt transactions, and 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.

	Three Months Ended		
	March 31, 2021	December 31, 2020	March 31, 2020
	(In thousands, except per share amounts) (Unaudited)		
Net (loss) income	$ (746)	$ (8,947)	$ 65,980
Unrealized commodity derivative loss (gain)	16,334	11,456	(52,520)
Amortization of derivative premium	456	1,483	4,349
Bad debt reserve	-	(1,063)	36
Deferred tax (benefit) expense	(203)	(6,880)	6,499
Gain on debt transactions	-	-	(18,501)
Litigation and other	40	(2,708)	-
Adjusted Net Income (Loss)	$ 15,881	$ (6,659)	$ 5,843
Basic and diluted adjusted (loss) earnings per common share	$ 0.11	$ (0.05)	$ 0.04
Weighted Average Shares Outstanding	142,151	141,721	141,546

Non-GAAP Reconciliations

Adjusted EBITDA/ Free Cash Flow Reconciliations

The Company also presents the non-GAAP financial measures Adjusted EBITDA and Free Cash Flow. The Company defines Adjusted EBITDA as net (loss) 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, gain on debt transactions, and litigation and other. Company management 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 Company defines Free Cash Flow as Adjusted EBITDA (defined above), less capital expenditures, plugging and abandonment costs and interest expense (all on an accrual basis). For this purpose, the Company's definition of capital expenditures includes costs incurred related to oil and natural gas properties (such as drilling and infrastructure costs and the lease maintenance costs) and equipment, furniture and fixtures, but excludes acquisition costs of oil and gas properties from third parties that are not included in the Company's capital expenditures guidance provided to investors. Company management believes that Free Cash Flow is an important financial performance measure for use in evaluating the performance and efficiency of its current operating activities after the impact of accrued capital expenditures, plugging and abandonment costs and interest expense and without being impacted by items such as changes associated with working capital, which can vary substantially from one period to another. There is no commonly accepted definition Free Cash Flow within the industry. Accordingly, Free Cash Flow, as defined and calculated by the Company, may not be comparable to Free Cash Flow or other similarly named non-GAAP measures reported by other companies. While the Company includes interest expense in the calculation of Free Cash Flow, other mandatory debt service requirements of future payments of principal at maturity (if such debt is not refinanced) are excluded from the calculation of Free Cash Flow. These and other non-discretionary expenditures that are not deducted from Free Cash Flow would reduce cash available for other uses.

The following tables present (i) a reconciliation of cash flow from operating activities, a GAAP measure, to Free Cash Flow, as defined by the Company and (ii) a reconciliation of the Company's net (loss) income, a GAAP measure, to Adjusted EBITDA and Free Cash Flow, as such terms are defined by the Company.

Non-GAAP Reconciliations

	Three Months Ended		
	March 31, 2021	December 31, 2020	March 31, 2020
	(In thousands) (Unaudited)		
Net (loss) income	$ (746)	$ (8,947)	$ 65,980
Interest expense, net	15,034	15,402	17,110
Income tax benefit	(203)	(6,858)	6,499
Depreciation, depletion, amortization and accretion	26,637	26,547	39,126
Unrealized commodity derivative loss (gain)	16,334	11,456	(52,520)
Amortization of derivative premium	456	1,483	4,349
Bad debt reserve	-	(1,063)	36
Gain on debt transactions	-	-	(18,501)
Litigation and other	40	(2,708)	-
Adjusted EBITDA	$ 57,552	$ 35,312	$ 62,079
Investment in oil and natural gas properties and equipment	(1,575)	(4,678)	(9,542)
Purchases of furniture, fixtures and other	2	(460)	(70)
Asset retirement obligation settlements	(962)	(551)	(249)
Interest expense, net	(15,034)	(15,402)	(17,110)
Free Cash Flow	$ 39,983	$ 14,221	$ 35,108

	Three Months Ended		
	March 31, 2021	December 31, 2020	March 31, 2020
	(In thousands) (Unaudited)		
Net cash provided by (used in) operating activities	$ 44,964	$ (6,229)	$ 84,324
Bad debt reserve	-	(1,063)	36
Litigation and other	40	(2,708)	-
Amortization of debt items and other items	(2,019)	(1,583)	(1,625)
Share-based compensation	(454)	(817)	(1,048)
Current tax benefit (expense) (1)	-	22	-
Changes in derivatives receivable (payable) (1)	(3,184)	(1,758)	9,337
Changes in operating assets and liabilities, excluding asset retirement obligation settlements	2,209	33,495	(46,304)
Investment in oil and natural gas properties and equipment	(1,575)	(4,678)	(9,542)
Purchases of furniture, fixtures and other	2	(460)	(70)
Free Cash Flow	$ 39,983	$ 14,221	$ 35,108

(1) A reconciliation of the adjustment used to calculate Free Cash Flow to the Condensed Consolidated Financial Statements is included below:

<u>Current tax benefit:</u>			
Income tax (benefit) expense	$ (203)	$ (6,858)	$ 6,499
Less: Deferred income taxes	(203)	(6,880)	6,499
Current tax benefit (expense)	$ -	$ 22	$ -
<u>Changes in derivatives receivable:</u>			
Derivatives receivable (payable), end of period	$ (3,465)	$ (281)	$ 9,682
Derivatives receivable (payable), beginning of period	281	(1,477)	(345)
Change in derivatives receivable (payable)	$ (3,184)	$ (1,758)	$ 9,337

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):

	December 31, 2020	
Present value of estimated future net revenues (PV-10)[1] ………………………………………………………	$	740.9
Present value of estimated ARO, discounted at 10% …………………………………………………………….	$	(204.2)
PV-10 after ARO …………………………………………………………………………………………………….	$	536.7
Future income taxes, discounted at 10% ……………………………………………………………………….	$	(43.0)
Standardized measure of discounted future net cash flows[2]…………………………………………………..	$	493.7

1) Based on year-end 2020 reserve report by NSAI at average realized SEC pricing of $37.78/BO and $2.05/MMbtu.
2) Company calculates Standardized measure of discounted future net cash flows annually for 10-K filing.

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