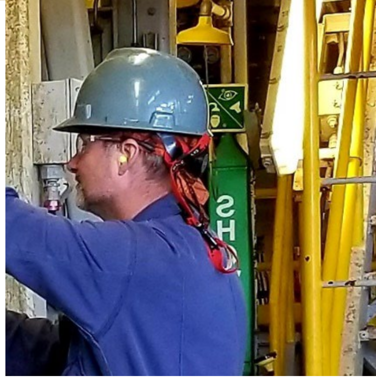
W&T OFFSHORE



Four Decades of Industry Leadership in the Gulf of Mexico

LOUISIANA ENERGY CONFERENCE

May 30, 2023

www.wtoffshore.com

NYSE: WTI

DISCLAIMER

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Cautionary Note Regarding Hydrocarbon Quantities

The SEC 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 reserves quantities compliant with PRMS/SPE guidelines and related PV-10 values that are 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 reserves and estimates of resources and EUR’s and recoverable resources, are inherently more speculative than recovery of proved reserves.

PV-10 of reserves includes projected revenues, estimated production costs and estimated future development costs. Unless otherwise stated, PV-10 excludes cash flows for asset retirement obligations, general and administrative expenses, derivatives, debt service and income taxes.

Standardized measure or the PV-10 from our proved or 2P oil and natural gas reserves should not be viewed as representative of the current market value of our estimated oil and natural gas reserves.

See Appendix for more information.

DISCLAIMER (CONT'D)

Non-GAAP Measures

This presentation includes certain financial measures that are not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). These measures include (i) Net Debt, (ii) Adjusted Net Income (Loss), (iii) Adjusted EBITDA and (iv) Free Cash Flow. These non-GAAP financial measures are not measures of financial performance prepared or presented in accordance with GAAP and may exclude items that are significant in understanding and assessing our financial results. Therefore, these measures should not be considered in isolation, and users of any such information should not place undue reliance thereon. Please refer to the slides titled "Non-GAAP Reconciliations" under the Appendix to this presentation for a reconciliation of these measures to the most directly comparable GAAP measures and WTI's definitions (which may be materially different than similarly titled measures used by other companies) of these measures as well as certain additional information regarding these measures. WTI believes the presentation of these metrics may be useful to investors because it supplements investors' understanding of its operating performance by providing information regarding its ongoing performance that excludes items it believes do not directly affect its core operations.

CORPORATE OVERVIEW

W&T – SEASONED GULF OF MEXICO ("GOM") PLAYER

FY 2022 | 1Q23 Avg.[1] **Production**	Total **Fields**	FY 2022 | 1Q23 **Adjusted EBITDA**[2]	FY 2022 | 1Q23 **Free Cash Flow**[2]
40.1 Mboe/d (49% liquids) **32.5 MBoe/d (56% liquids)**	**47**	**$563.7 MM** **$43.1 MM**	**$376.4 MM** **$12.4 MM**

Reserve Category	YE 2022 Reserves at SEC Pricing[4] (MMBoe)	YE 2022 PV-10 at SEC Pricing[4] ($MM)
1P	165.3	$3,129
2P	245.8	$4,908
3P	345.3	$7,286

Gulf of Mexico Shelf

- ~466,000 gross acres (~389,000 net)
- 75% of 1Q23 production of 32.5 MBoe/d[1]
- Proved SEC reserves of 138.1 MMBoe[4]
- 2P SEC reserves of 195.9 MMBoe[4]
- Future growth potential from sub-salt projects

Gulf of Mexico Deepwater

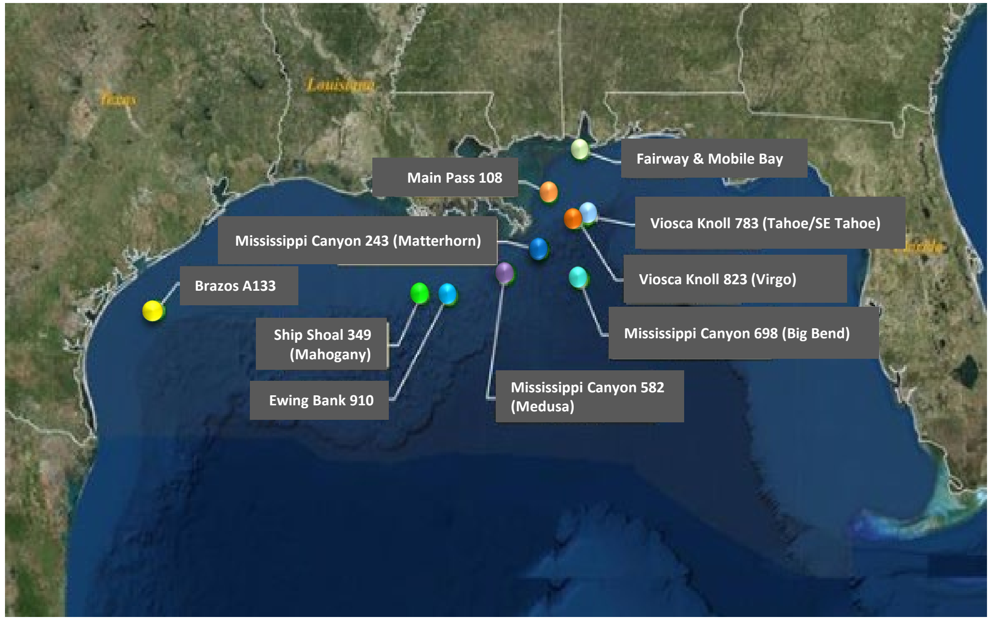
- ~159,000 gross acres (~68,000 net)
- 25% of 1Q23 production of 32.5 MBoe/d[1]
- Proved SEC reserves of 27.2 MMBoe[4]
- 2P SEC reserves of 49.9 MMBoe[4]
- Substantial upside with existing acreage

Federal vs State

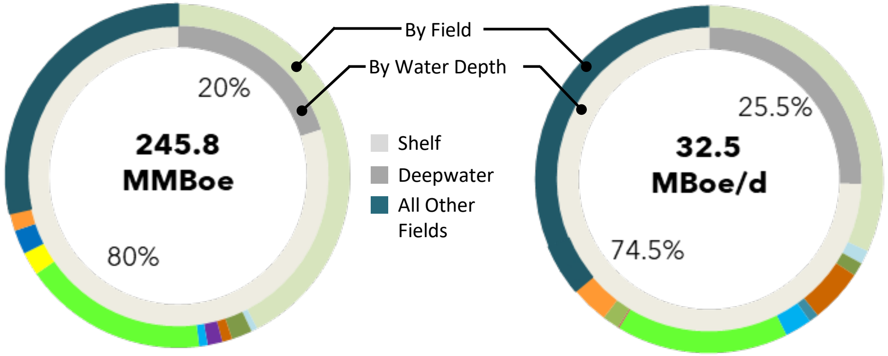
Production: Federal 74%, State 26%

Net Acreage: Federal 79%, State 21%

Premier GOM Operator with Four Decades of History in the Basin



2P Reserves Mix[3,4] **1Q23 Avg. Daily Production**[1,3]



Note: The outer ring of the pie charts represent contribution by field, with color indicating field location on the map

1) Production temporarily impacted by planned maintenance at Mobile Bay and unplanned downtime at non-operated fields
2) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see Appendix for description of reconciling items to GAAP net income and operating cash flow
3) Breakout between Deepwater and Shelf reflects total Company production
4) Based on year-end 2022 reserve report by NSAI at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu; before differentials and excluding ARO. PV-10 is a non-GAAP financial measure, see Appendix

1Q 2023 HIGHLIGHTS

- Produced 32.5 MBoe/d (56% liquids)
  - Production temporarily impacted by planned maintenance at Mobile Bay and unplanned downtime at non-operated fields
- Generated Net Income of $26.0 MM or $0.17 per diluted share
- Reported Adjusted EBITDA[1] of $43.1 MM
- Produced Free Cash Flow[1] of $12.4 MM, the 21st consecutive quarter of positive Free Cash Flow
- Ended quarter with a $177.4 MM cash balance
- Continued significant improvement in the Company's leverage profile with Net Debt to last twelve months ("LTM") Adjusted EBITDA of 0.4 times compared to over 2.0 times one year ago
- Closed the offering of $275.0 MM, 11.75% Senior Second Lien Notes due 2026 (the "2026 Senior Second Lien Notes") on January 30, 2023
  - Net proceeds of the offering, along with cash on hand, used to fund the total redemption of the Company's $552.5 MM, 9.75% Senior Second Lien Notes due 2023 (the "2023 Senior Second Lien Notes")
- Appointed a new independent director to the Board
- Named apparent high bidder in the most recent Gulf of Mexico ("GOM") lease sale on two shallow water blocks

1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures, see Appendix for description of reconciling items to GAAP net income and operating cash flow

Continued Focus on Delivering Free Cash Flow and Adding Value

PRODUCTION

Full Year 2022 Production
40.1 MBoe/d
(49% liquids)

1Q23 Production
32.5 Boe/d
(56% liquids)

ADJUSTED EBITDA

Full Year 2022 Adjusted EBITDA[1]
$564 MM

1Q23 Adjusted EBITDA[1]
$43 MM

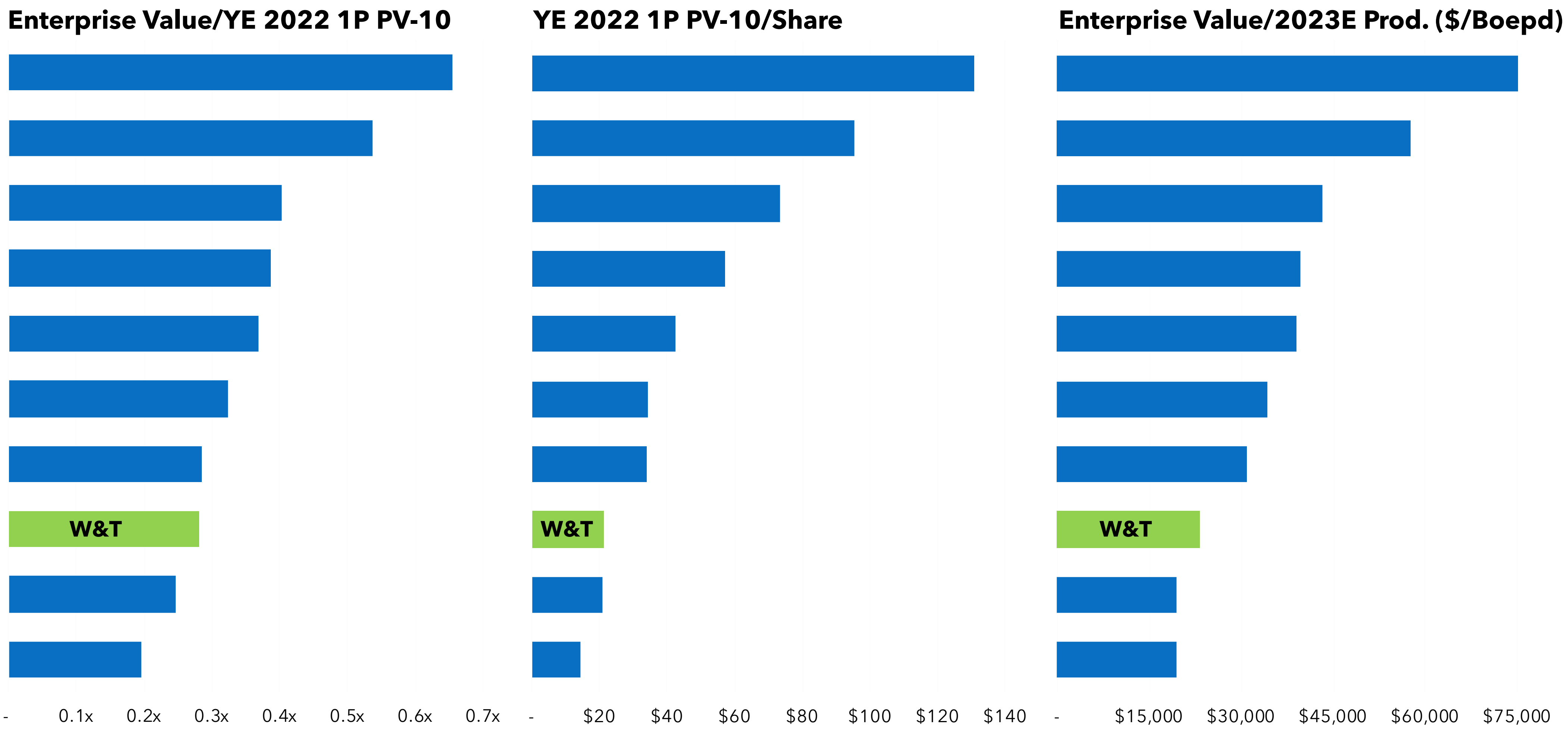
FREE CASH FLOW

Full Year 2022 Free Cash Flow[1]
$376 MM

1Q23 Free Cash Flow[1]
$12 MM

ATTRACTIVE INVESTMENT OPPORTUNITY[1]

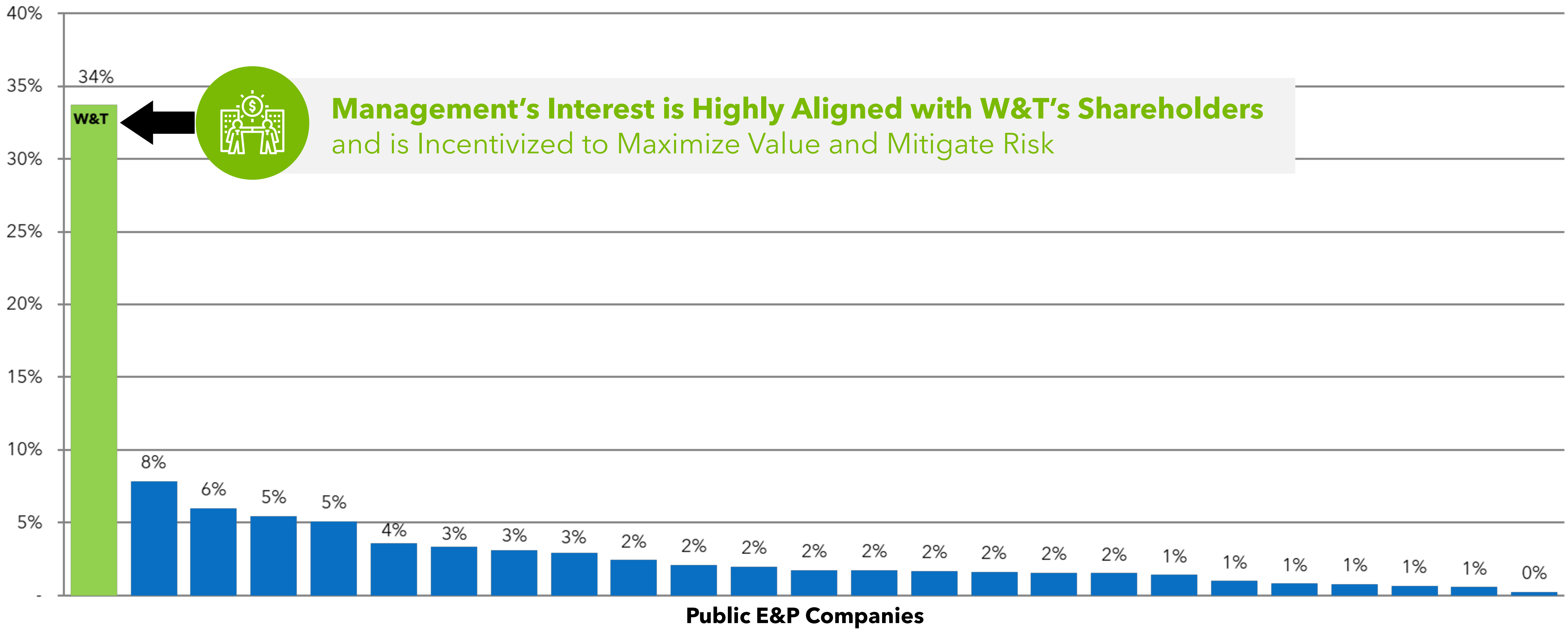
- Despite strong performance and an improved financial position, W&T trades at a discounted valuation relative to its small-cap peer group[2]
- Compelling LTM Free Cash Flow yield of 34%
- Project inventory and existing infrastructure provide paths for both organic growth and acquisitions
- Significant insider ownership aligns executive management with shareholders



1) Data as of 5/22/2023. Consensus estimates sourced from Capital IQ
2) Peer group comprised of AMPY, BATL, BRY, CRC, ESTE, HPK, KOS, REI, TALO

INSIDE OWNERSHIP[1]

AMONG THE HIGHEST OF PUBLIC E&P COMPANIES[2]



1) Ownership percentage of insiders sourced from S&P Capital IQ as of 5/2/2023
2) Peers comprised of the following companies: AR, BRY, BTE, CNX, CPE, CPG, CRK, ESTE, KOS, MGY, MRO, MTDR, MUR, NOG, PDCE, PR, ROCC, RRC, SBOW, SD, SM, SWN, VTLE, TALO

PROVEN AND CONSISTENT STRATEGY

Focus on Free Cash Flow Generation

Prioritize Environmental, Social & Governance Matters

Maintain High Quality Conventional Asset Base with Low Decline

Reduce Costs to Improve Margins and Increase ROCE

Preserve Ample Liquidity and Financial Flexibility

Capitalize on Unique & Accretive Acquisition Opportunities

WHY WE HAVE LIKED THE GULF OF MEXICO FOR 40 YEARS

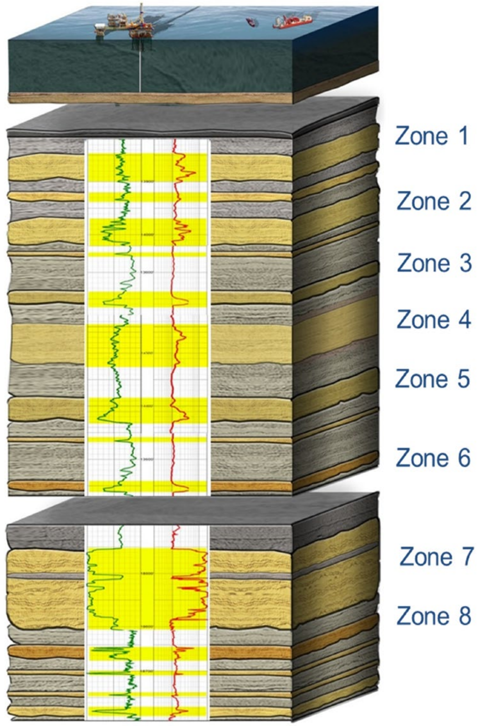
GOM Provides Better Porosity and Permeability than the Unconventionals

Multiple stacked pay opportunities

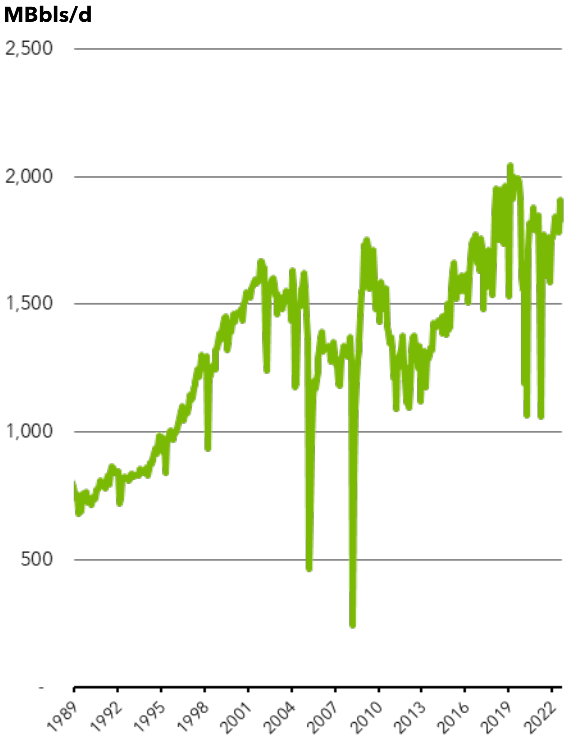
- Offer attractive primary production and recompletion opportunities
- Provide multiple targets improving chance of success when drilling

Natural drive mechanisms generate incremental production from 2P reserves

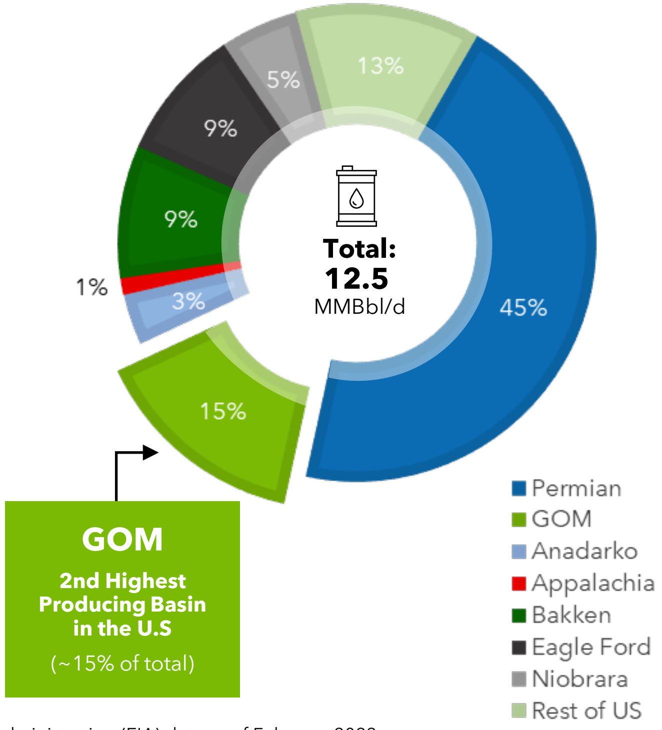
- High quality sandstones have drive mechanisms superior to depletion drive alone
- Enjoy incremental reserve adds, partly due to how reserve quantities are booked or categorized under SEC guidelines



GOM Historical Oil Production[1]



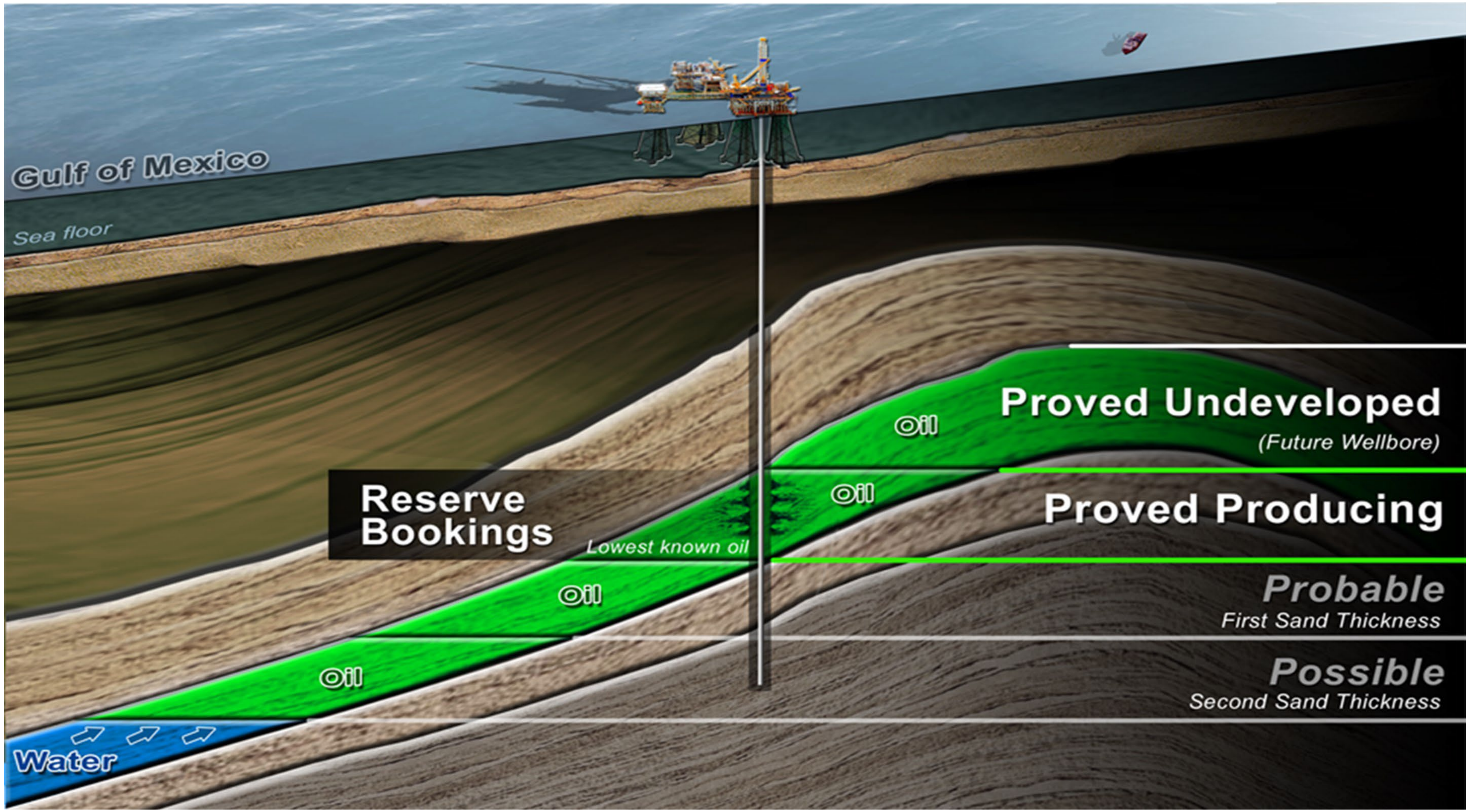
US Oil Production by Key Region[1]



1) Based on U.S. Energy Information Administration (EIA) data as of February 2023

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

INCREMENTAL RESERVES MAY BE PRODUCED WITH MARGINAL INCREMENTAL CAPEX



Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores

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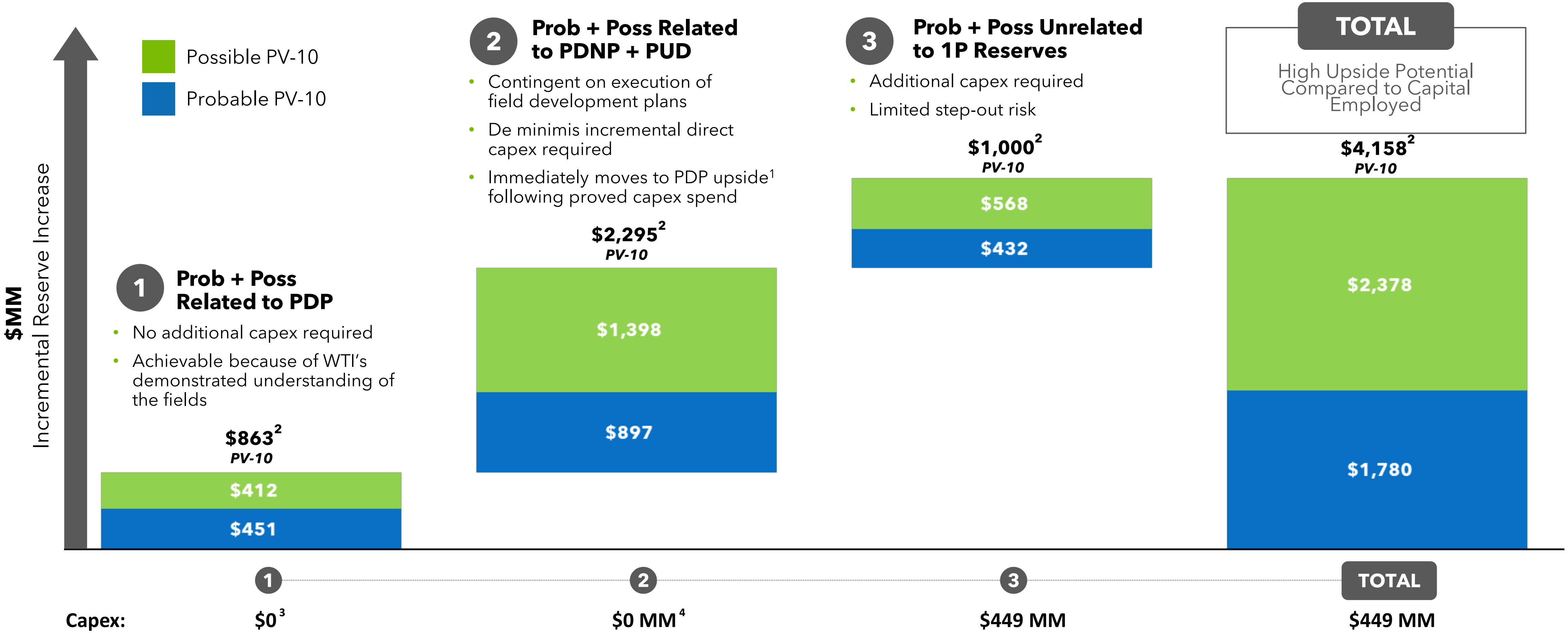
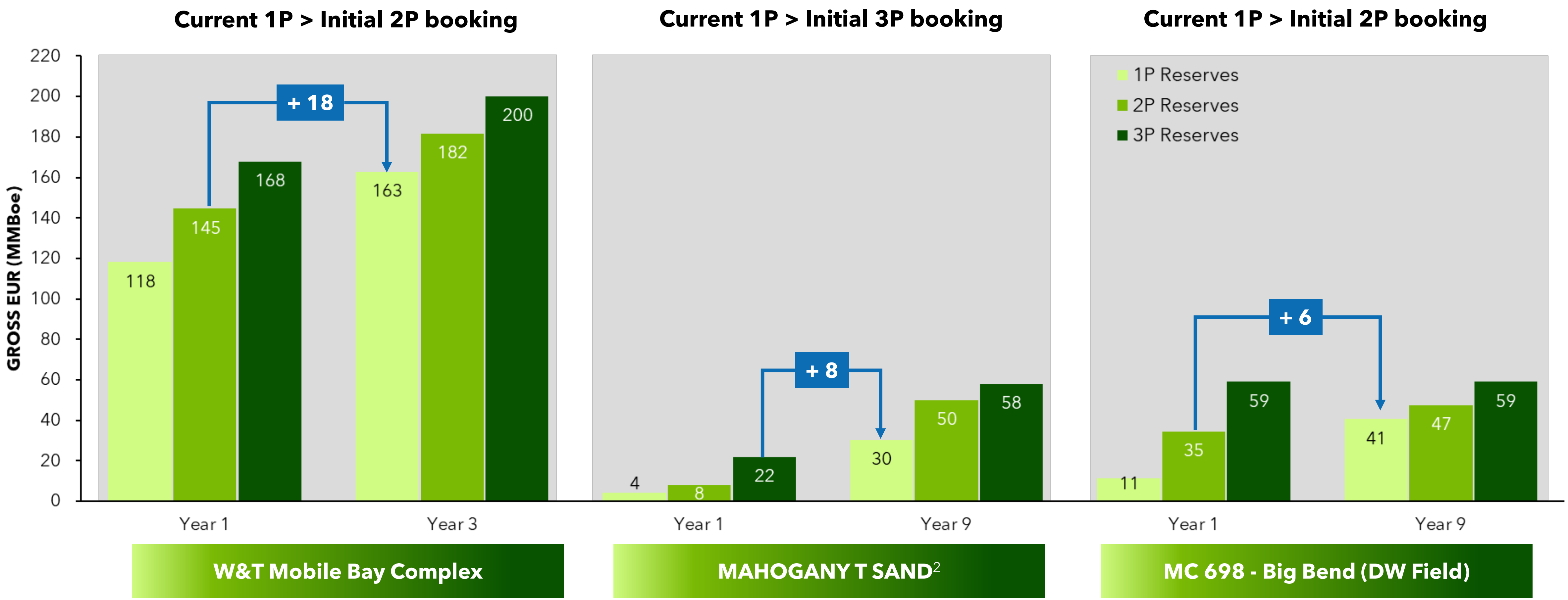
INCREMENTAL RESERVE UPSIDE POTENTIAL[1]



1) Based on year-end 2022 reserve report at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu
2) Excludes Asset Retirement Obligation
3) Probable and possible cases that are largely associated with producing wellbores and require no material future capex requirements
4) Probable and possible reserves with immaterial direct capex requirements that are largely associated with PDNP and PUD reserves and therefore have associated future indirect capex requirements

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

SIGNIFICANT RESERVE APPRECIATION FROM INITIAL BOOKINGS[1]



1) Based on year-end 2022 reserve report at SEC pricing (1P Life) $94.14/Bbl and $6.36/MMBtu
2) Initial 1P booking includes A-14 well only; YE 2021 1P booking includes A-14, A-18 and A-19 wells; 2P & 3P includes additional development wells

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LEVERAGING FOUR DECADES 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 Free 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 GOM ACQUISITIONS

TOTAL

$115 MM[1]
Paid out in Aug. 2011

Net average production[2] of 984 Boe/d from Matterhorn and Virgo

Reserves[3]: **1P** – 5.6 Mmboe; **2P** – 10.3 Mmboe

NEWFIELD

$206 MM[1]
Paid out in Nov. 2014

Net average production[2] of 1,400 Boe/d from 78 offshore blocks, 65 of which are in deepwater

Reserves[3]: **1P** – 1.8 Mmboe; **2P** – 5.1 Mmboe

woodside

$55 MM[1]
Investments Post Acquisition
Paid out in Sep. 2019

Net average production[2] of 251 Boe/d from Neptune and 24 add'l blocks. One exploration well brought online in 2014

Reserves[3]: **1P** – 2.1 Mmboe; **2P** – 2.5 Mmboe

Cobalt International Energy

$17 MM[1]
Paid out in Aug. 2018

Net average production[2] of 206 Boe/d from Green Canyon 859, 903, & 904

Reserves[3]: **1P** – 0.2 Mmboe; **2P** – 0.3 Mmboe

Marubeni / ConocoPhillips

$18 MM[1]
Paid out in Apr. 2021

Net average production[2] of 1,836 Boe/d from Garden Banks 783 & 784 (Magnolia Field)

Reserves[3]: **1P** – 12.0 Mmboe; **2P** – 20.8 Mmboe

2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022

Shell

$116 MM[1]
Paid out in Nov. 2012

Net average production[2] of 474 Boe/d from Tahoe and 6 other fields

Reserves[3]: **1P** – 0.8 Mmboe; **2P** – 1.4 Mmboe

Shell / Marubeni

$61 MM[1]
Paid out in Oct. 2014

Net average production[2] of 1,155 Boe/d from Fairway Field

Reserves[3]: **1P** – 14.5 Mmboe; **2P** – 15.8 Mmboe

CALLON PETROLEUM

$83 MM[1]
Investments Post-Acquisition

Net average production[2] of 269 Boe/d from Medusa and 12 other fields. Two exploration wells brought on production in 6/2015

Reserves[3]: **1P** – 2.1 Mmboe; **2P** – 3.7 Mmboe

ExxonMobil / Chevron

$171 MM[1]
Paid out in Jan. 2022

Net average production[2] of 10,099 Boe/d. Potential to add incremental reserves with minimal capital by consolidating operations

Reserves[3]: **1P** – 76.1 Mmboe; **2P** – 87.4 Mmboe

ANKOR ENERGY / Undisclosed Private Seller

$48 MM[1]
Paid out in Aug. 2022

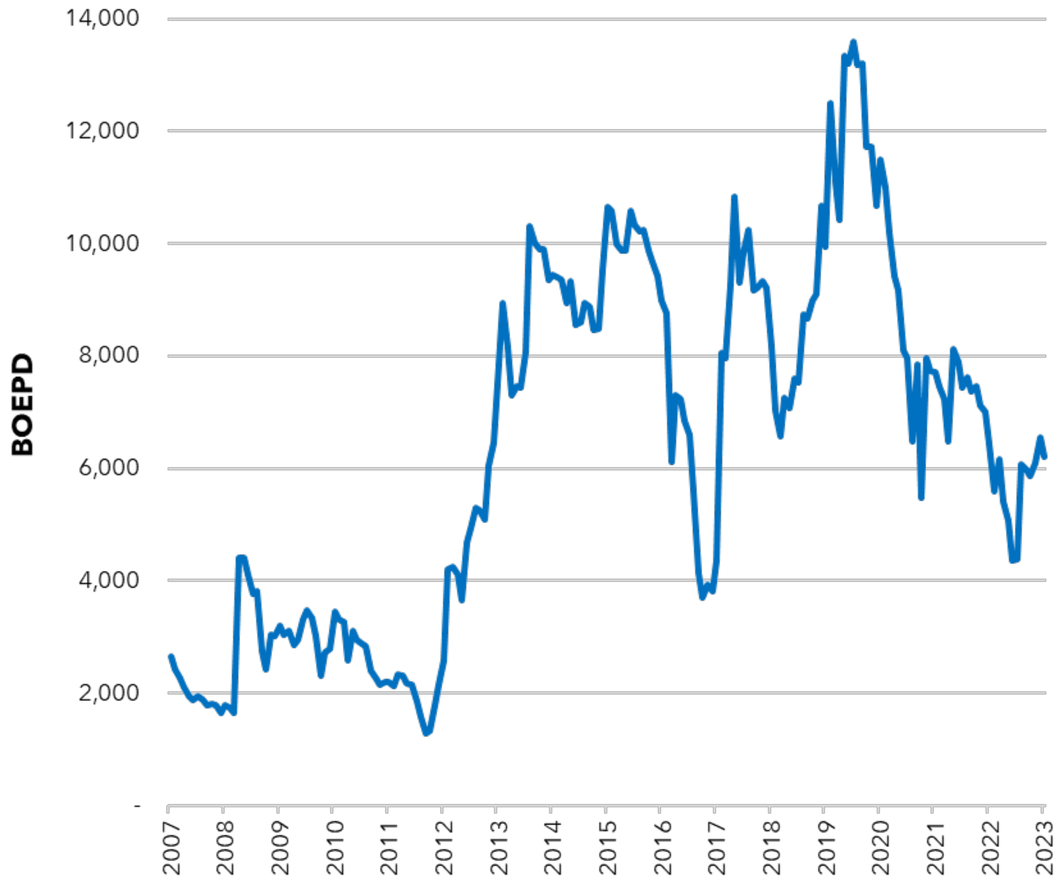
Net average production[2] of 3,158 Boe/d. Acquired 100% working interest of operated assets, including over 50 producing wells

Reserves[3]: **1P** – 4.8 Mmboe; **2P** – 8.9 Mmboe

1) Purchase prices as of closing dates, which are often adjusted for normal and customary post-effective date adjustments
2) 1Q 2023 net average production
3) Based on year-end 2022 reserve report at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu

SS 349 FIELD ("MAHOGANY") CASE STUDY

Mahogany Gross Production



1) From closing date including capex to December 31, 2022
2) Based on year-end 2022 reserve report at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu
3) Total Net Cash Flow as of December 31, 2022, plus year-end 2022 2P SEC PV10 value (including ARO)

SS 349 Field ("Mahogany")

- WI: 100%, 360' Water Depth
- 1st commercially successful subsalt development in the Gulf of Mexico (initial production in 1997)
- Purchased interest in 2000, 2004 & 2008
- Cumulative purchase price of $175 MM
- Valuation

Total Net Cash Flow[1]	$826 MM
YE 2022 2P PV10[2] including ARO	$1,041 MM
Total Project Value[3]	**$1,867 MM**

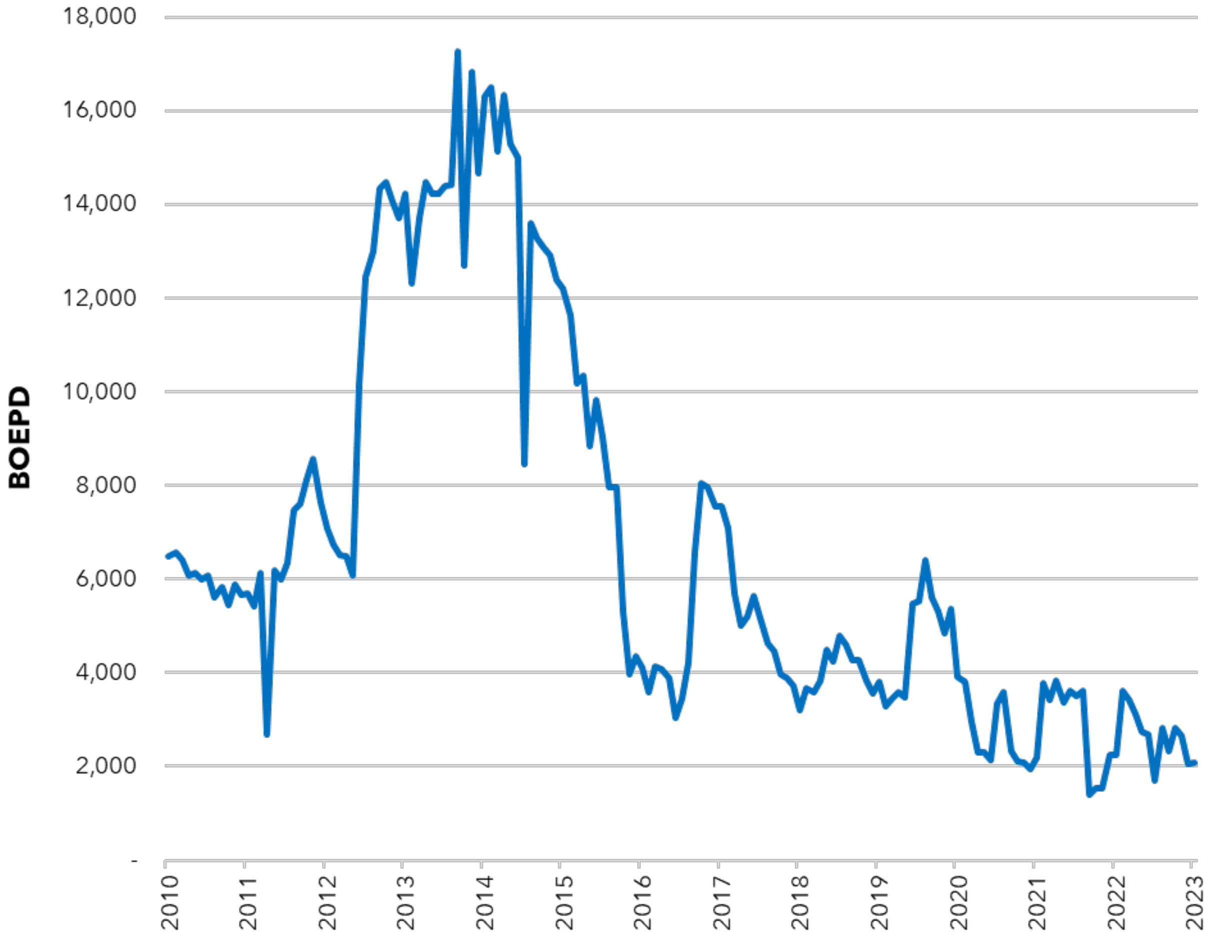
- Have increased value by:
  - Development and exploration drilling
  - Performing recompletes
  - Reworks and performance optimization

Current Reserves[2]

1P Reserves:	19.0 MMBoe
2P Reserves:	42.6 MMBoe
3P Reserves:	62.4 MMBoe

TOTAL E&P DEEPWATER ACQUISITION CASE STUDY

Matterhorn and Virgo Gross Production



"Matterhorn" & "Virgo" Fields

- WI: 64% – 100%, 1,130' – 2,400' water depth
- Purchased from Total E&P, USA in 2010
- Cumulative purchase price of $115 MM
- Valuation

Total Net Cash Flow[1]	$511 MM
YE 2022 2P PV10[2] including ARO	$275 MM
Total Project Value[3]	**$787 MM**

- Have increased value by:
  - Drilling sidetracks
  - Performing recompletes
  - Instituting waterflood
  - Entering processing arrangement (~$60 million in processing revenues received to date)

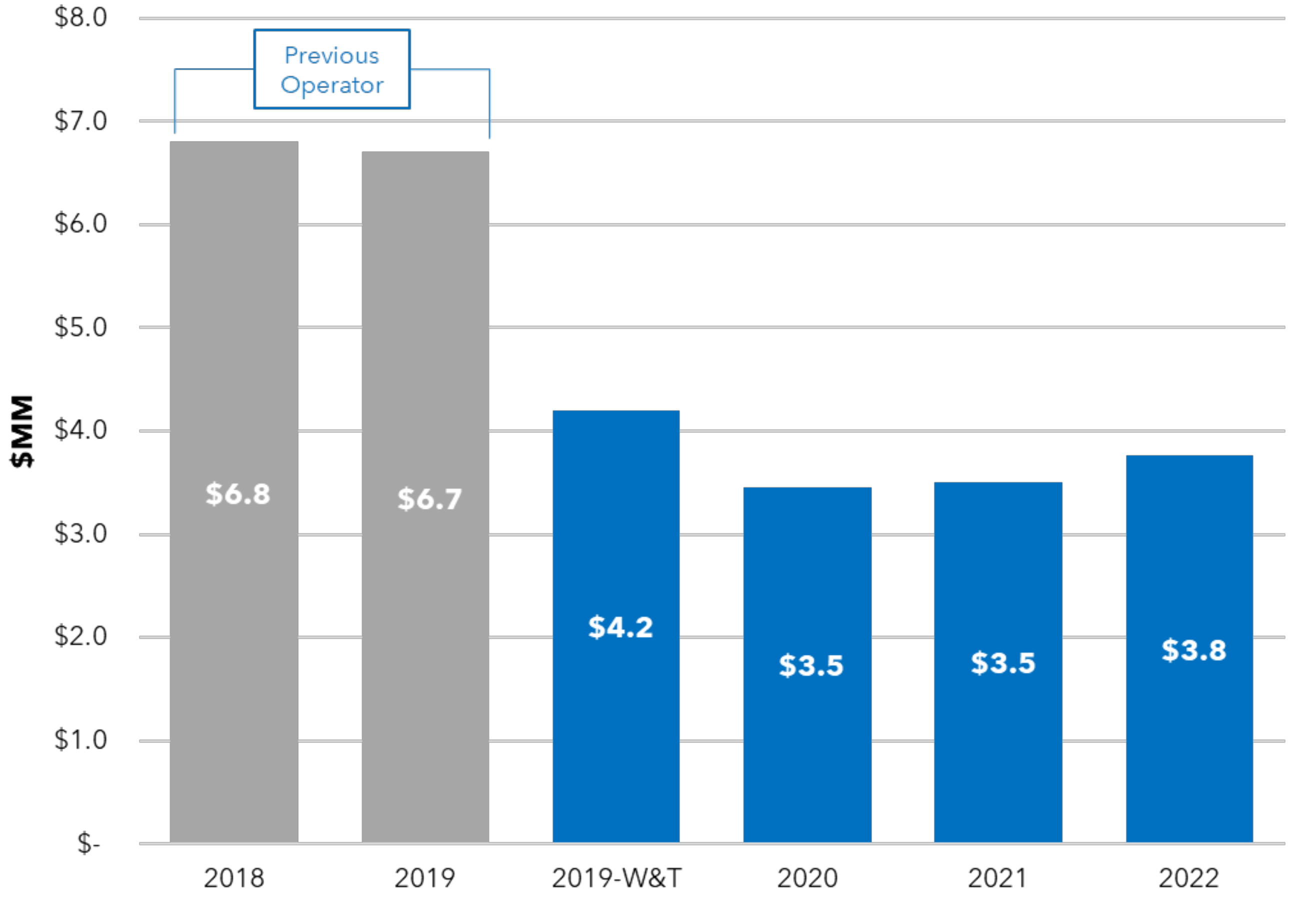
Current Reserves[2]

1P Reserves:	5.6 MMBoe
2P Reserves:	10.3 MMBoe
3P Reserves:	18.6 MMBoe

1) From closing date including capex to December 31, 2022
2) Based on year-end 2022 reserve report at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu
3) Total Net Cash Flow as of December 31, 2022, plus year-end 2022 2P SEC PV10 value (including ARO)

EXXON/CHEVRON MOBILE BAY CASE STUDY

Base LOE/Monthly Average



"XOM/CVX Mobile Bay" Fields

- WI: 25% – 100%, 10' – 50' water depth
- Purchased in 2019
- $171 MM acquisition cost
- Valuation

Total Net Cash Flow[1]	$312 MM
YE 2022 2P PV10[2] including ARO	$1,385 MM
Total Project Value[3]	**$1,697 MM**

- Have increased value by:
  - Consolidation of treatment facilities in the area
  - Modify treatment of waste oil
  - Reducing downtime

Current Reserves[2]

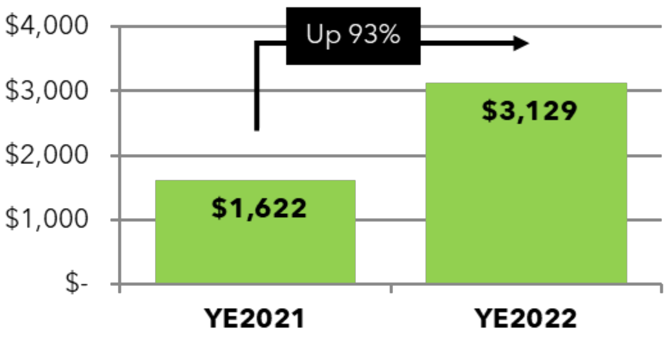
1P Reserves:	91.3 MMBoe
2P Reserves:	104.2 MMBoe
3P Reserves:	115.9 MMBoe

1) From closing date including capex to December 31, 2022
2) Based on year-end 2022 reserve report at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu
3) Total Net Cash Flow as of December 31, 2022, plus year-end 2022 2P SEC PV10 value (including ARO)

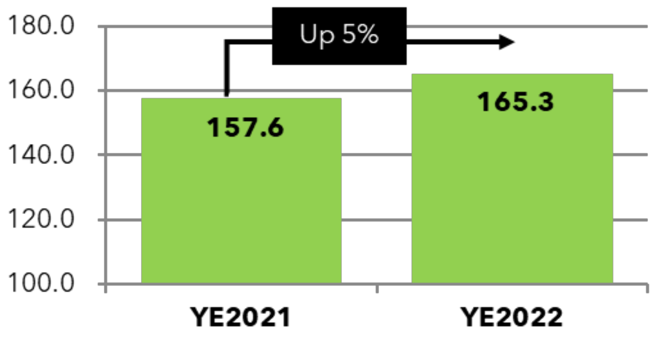
SIGNIFICANT INCREASE IN YEAR-END RESERVES AND PV-10

Reserve Category	Oil (MMBbl)	NGL (MMBbl)	Gas (Bcf)	Total (MMBoe)	% Liquids	Pre-Tax PV10 ($MM)
Proved Developed Producing (PDP)	23.7	16.1	499.2	123.0	32.3%	$ 2,280.8
Proved Developed Non-Producing (PDNP)	7.5	1.5	76.8	21.8	41.3%	$ 457.6
Proved Undeveloped (PUD)	9.5	1.3	58.6	20.5	52.4%	$ 390.2
Total 1P Reserves (Excluding ARO)	**40.6**	**18.9**	**634.6**	**165.3**	**36.0%**	**$ 3,128.6**
Probable Reserves (PROB)	38.1	7.2	211.4	80.5	56.2%	$ 1,779.8
Total 2P Reserves (Excluding ARO)	**78.7**	**26.1**	**845.9**	**245.8**	**42.6%**	**$ 4,908.4**
Possible Reserves (POSS)	52.9	7.8	233.1	99.5	61.0%	$ 2,378.2
Total 3P Reserves (Excluding ARO)	**131.6**	**33.9**	**1,079.1**	**345.3**	**47.9%**	**$ 7,286.6**
Est. PV10 of 1P ARO						$ (271.5)

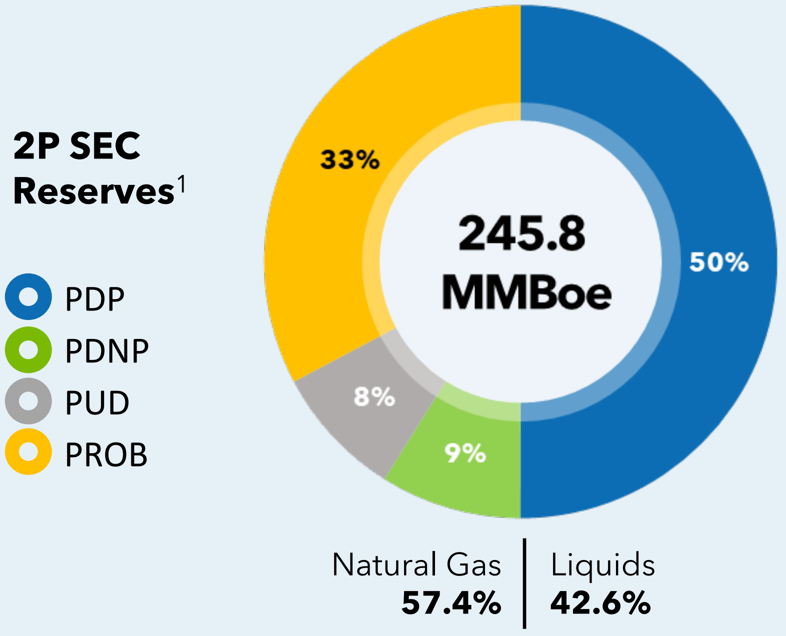
Proved Reserve PV-10[1,2]
$ in MM



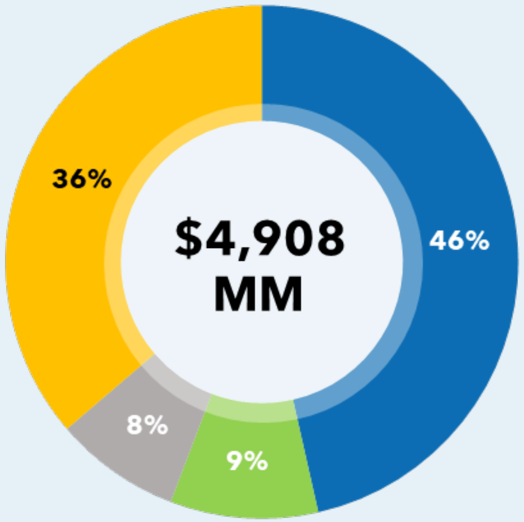
Proved Reserve[1,2]
MMBoe



2P SEC Reserves[1]



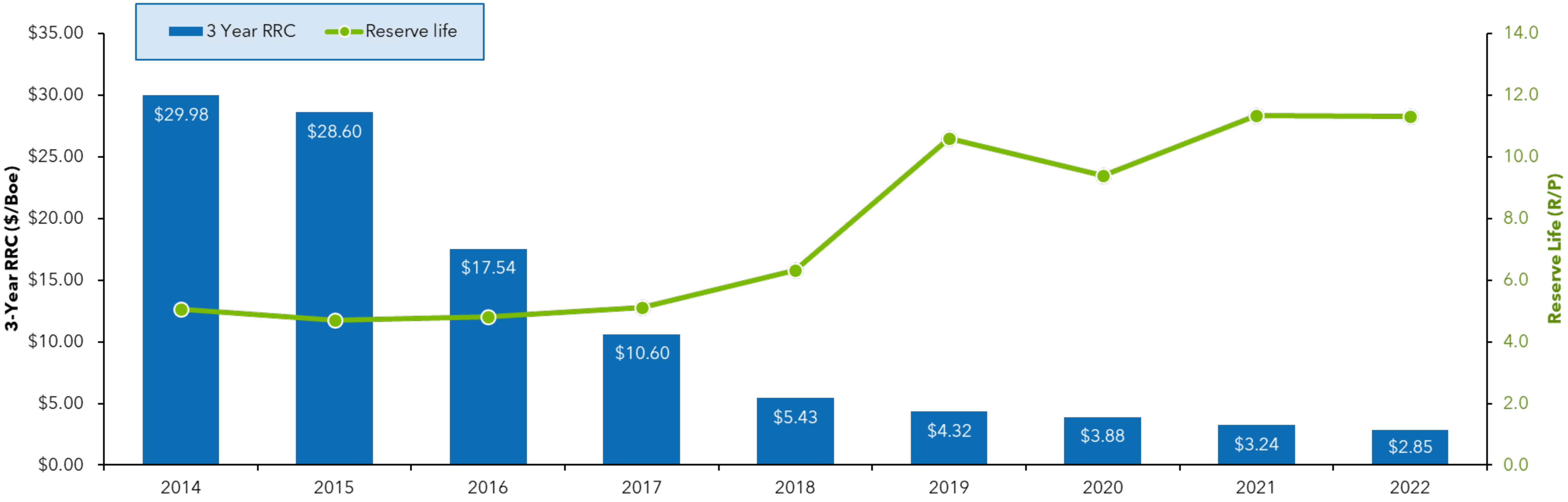
2P Pre-Tax PV-10[2,3]



1) Based on year-end 2022 reserve report at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu
2) Pre-Tax PV-10 of year-end proved reserves is a non-GAAP financial measure
3) Pre-Tax PV-10 excluding Asset Retirement Obligations

MAJOR DECLINE IN ALL-IN RESERVE REPLACEMENT COST[1] (RRC)

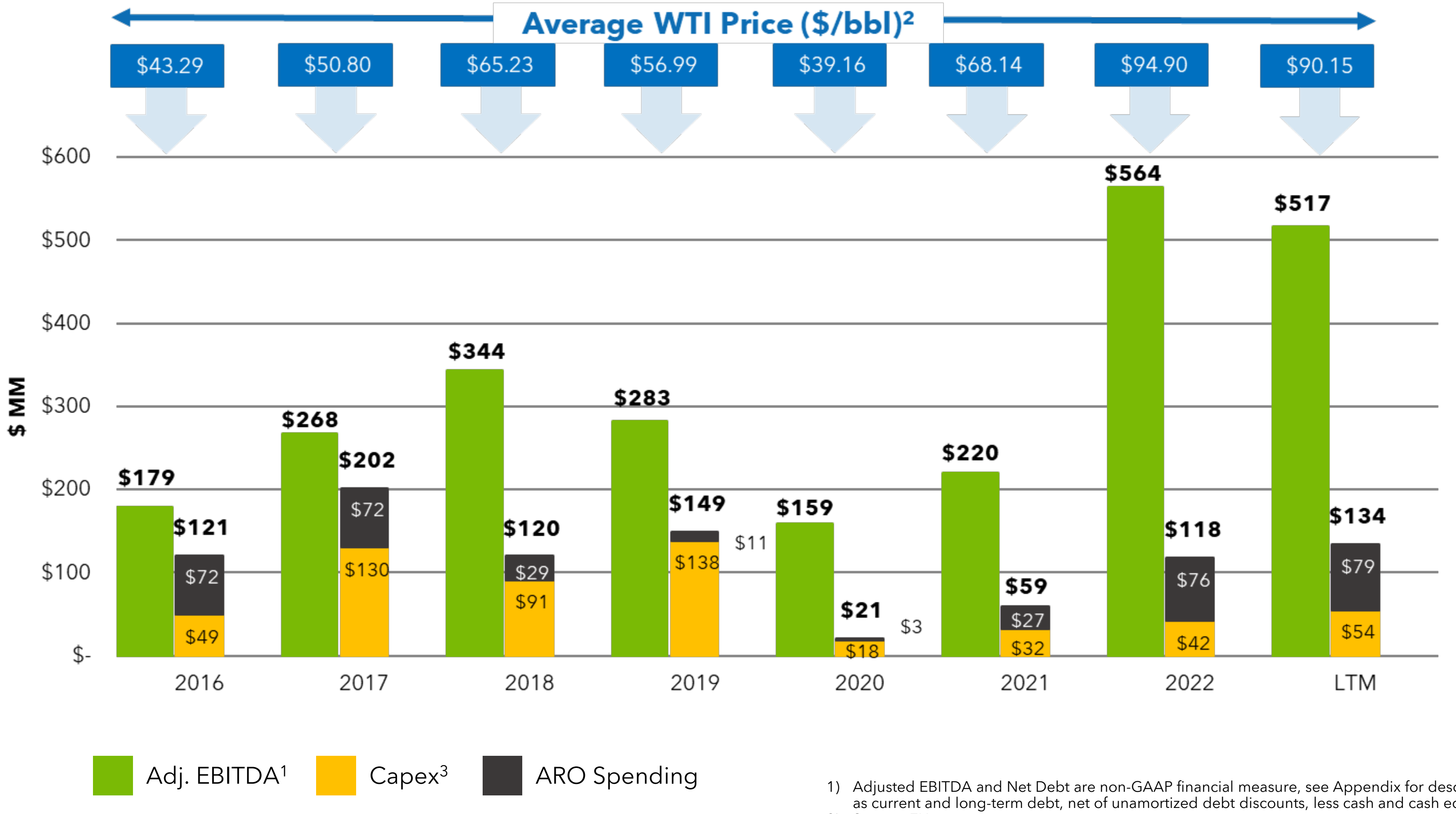
Since 2014, 3-year RRC Decreased ~91% While Reserve Life[2] Increased 123% from 5.1 to 11.3 Years



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

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

SIGNIFICANT FREE CASH FLOW GENERATION

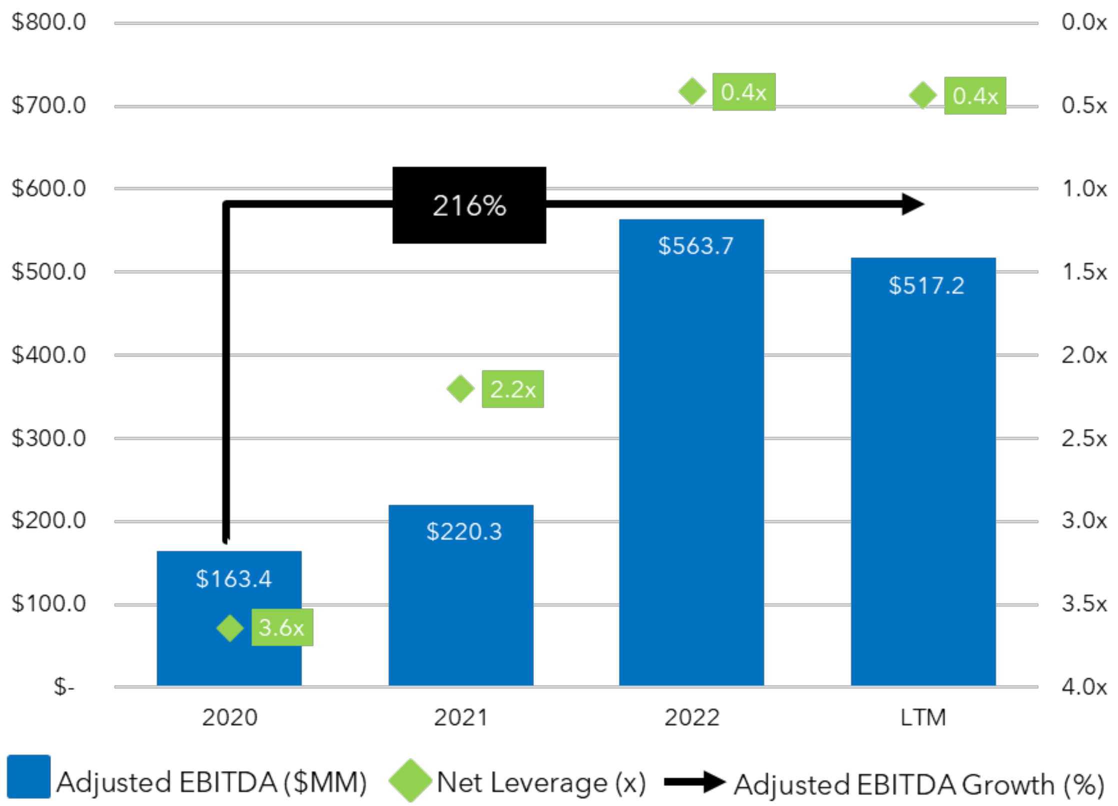


- Strong production base and cost optimization delivers steady Adjusted EBITDA[1]
- Adjusted EBITDA[1] has materially outpaced capex and ARO spending (before acquisitions) since 2016
- Over the last twelve months, free cash flow generated has allowed W&T to reduce Net Debt[1] by **~$279 MM**

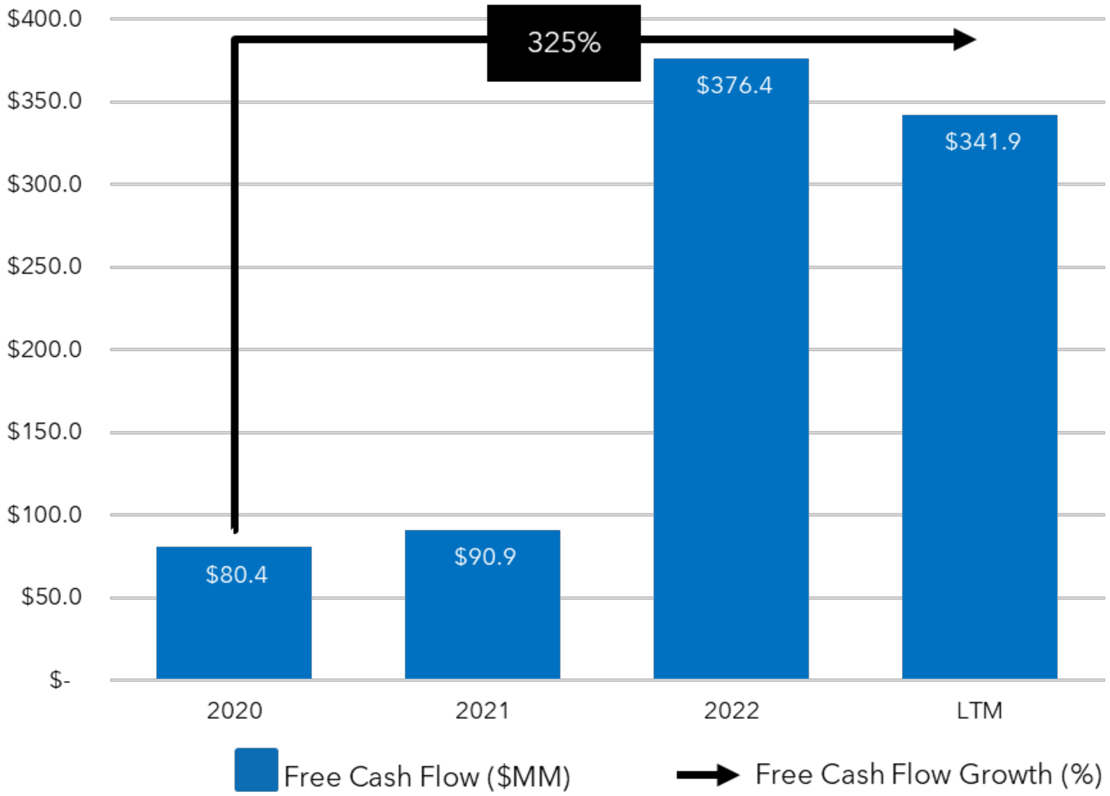
1) Adjusted EBITDA and Net Debt are non-GAAP financial measure, see Appendix for description of reconciling items to GAAP net income, Net Debt defined as current and long-term debt, net of unamortized debt discounts, less cash and cash equivalents
2) Source: EIA
3) Capex excludes acquisitions; includes only accrual basis capital expenditures

W&T HAS GROWN ITS CASH FLOW YEAR-OVER-YEAR AND REDUCED LEVERAGE

Adjusted EBITDA and Net Leverage[1]
($MM)



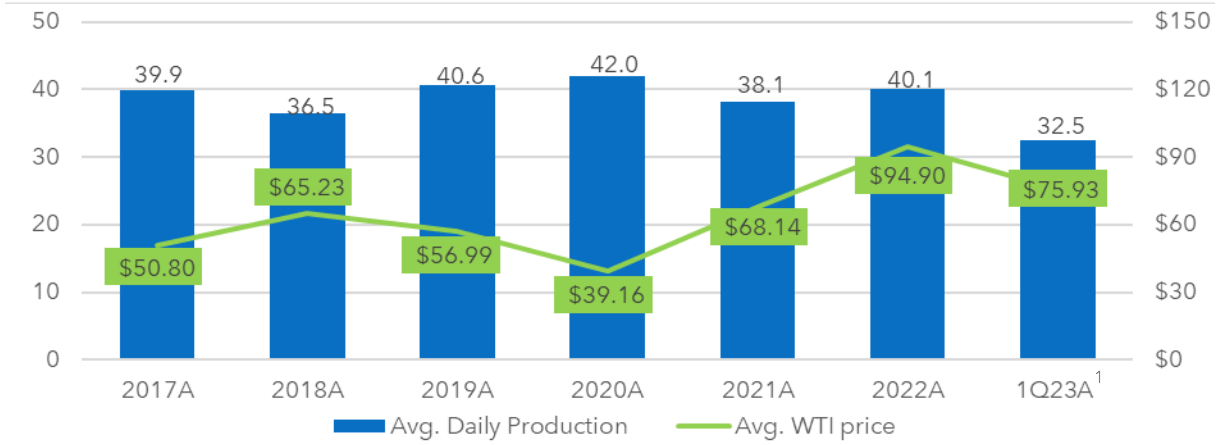
Free Cash Flow[2]
($MM)



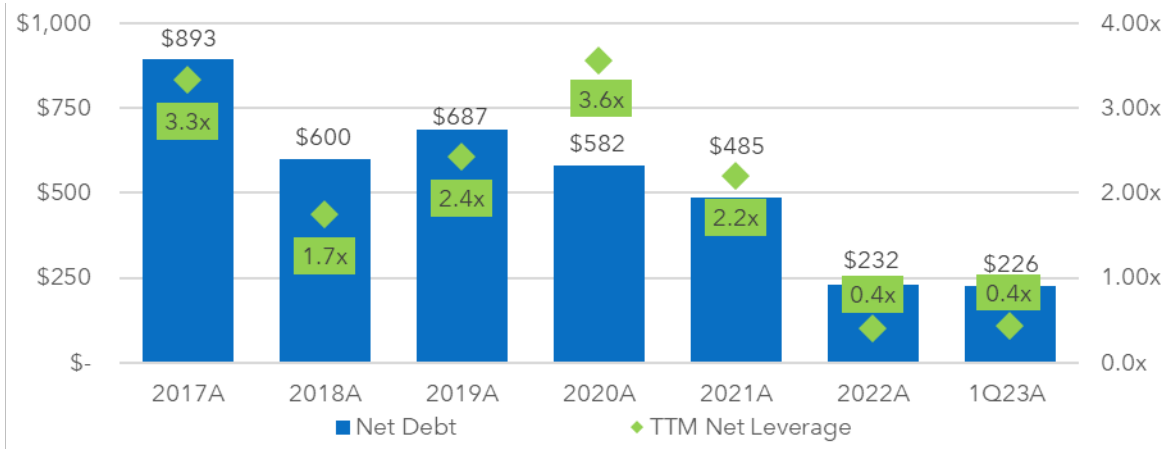
1) Net Leverage defined as Net Debt / Adjusted EBITDA, Net Debt defined as current and long-term debt, net of unamortized debt discounts, less cash and cash equivalents; see Appendix for description of reconciling items to GAAP net income
2) Free Cash Flow defined as Adjusted EBITDA, less capital expenditures (excluding acquisitions), plugging and abandonment costs and interest expense; see Appendix for description of reconciling items to GAAP operating cash flow

W&T HAS MATERIALLY TRANSFORMED SINCE 2017

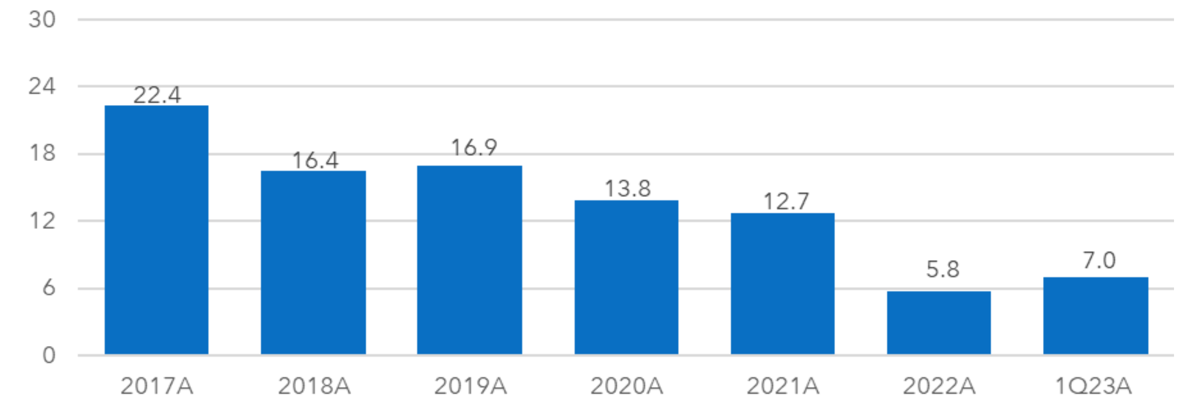
Production and WTI Price
(Mboe/d)



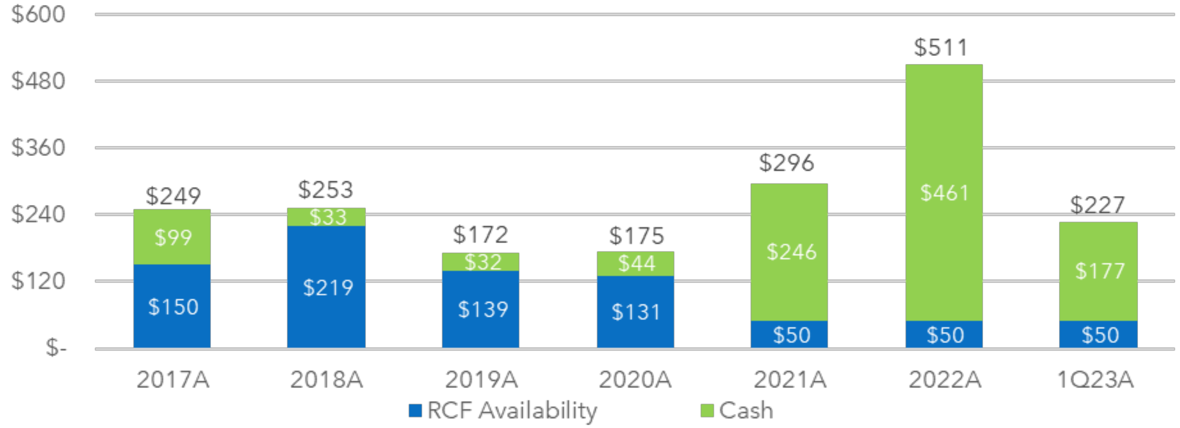
Net Debt and Net Leverage[2]
($MM)



Net Debt/Daily Production
($000s/Boe/d)



Liquidity[3]
($MM)

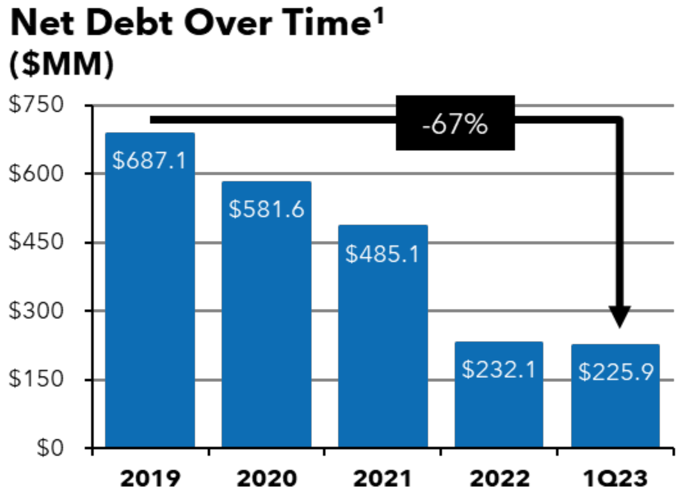


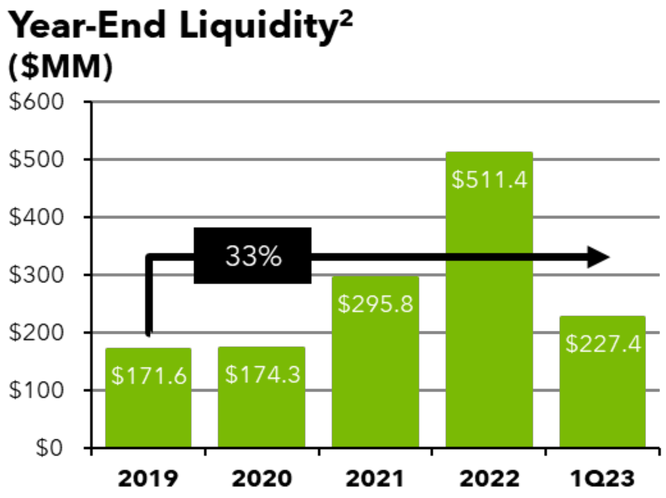
1) Production temporarily impacted by planned maintenance at Mobile Bay and unplanned downtime at non-operated fields
2) Net Leverage defined as Net Debt / Adjusted EBITDA, Net Debt, defined as current and long-term debt, net of unamortized debt discounts, less cash and cash equivalents; see Appendix for description of reconciling items to GAAP net income
3) Liquidity defined as cash balance + available RCF capacity; Cash balance shown includes restricted cash

CAPITAL STRUCTURE AS OF MARCH 31, 2023

Net Debt[1] as of 03/31/23 ($MM)

Total Cash & Equivalents (excluding $4.4MM restricted cash)	**$177.4**
11.75% 2nd Lien Notes due Feb. 2026	$269.1
RBL Borrowings	-
7% Non-recourse Term Loan due 2028	$134.2
Total Debt	**$403.3**
Net Debt[1]	**$225.9**





- Proven track record of generating free cash flow and prudently managing the balance sheet through multiple price environments
- Despite a difficult couple of years with COVID-19, negative oil prices, and hurricane impacts, **W&T reduced Net Debt by $461.2 MM from December 31, 2019 to March 31, 2023**
- On 1/30/2023, issued New Senior Notes of $275.0 MM at 11.75% interest due 2/1/2026. The proceeds, along with cash on hand, were used to repay the Existing Senior Notes of $552.5 MM in February 2023
- First Lien secured term loan is non-recourse to W&T at the parent level and is amortized over seven years at a fixed interest rate of 7%
- **Calculus Lending, LLC facility**
  - $100.0 MM revolving credit facility with $50.0 MM borrowing base provides opportunistic liquidity
- $83.5 MM remaining on ATM Equity Program provides additional equity for debt repayment or asset acquisitions

1) Net Debt is defined as current and long-term debt, net of unamortized debt discounts, less cash and cash equivalents
2) Liquidity is defined as cash and cash equivalents plus availability under RBL, excludes restricted cash

STRATEGIC CAPITAL ALLOCATION PLAN

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, optimize the balance sheet and maintain financial flexibility

Generate Shareholder Value

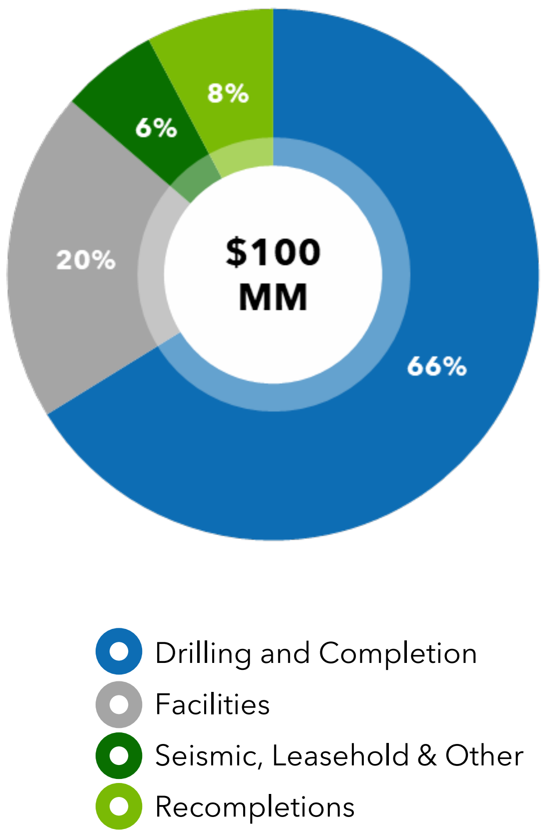
Maintain a Prudent Balance Sheet and
Use Free Cash Flow to Grow Opportunistically and Reduce Debt

2023 CAPITAL EXPENDITURE AND P&A BUDGET

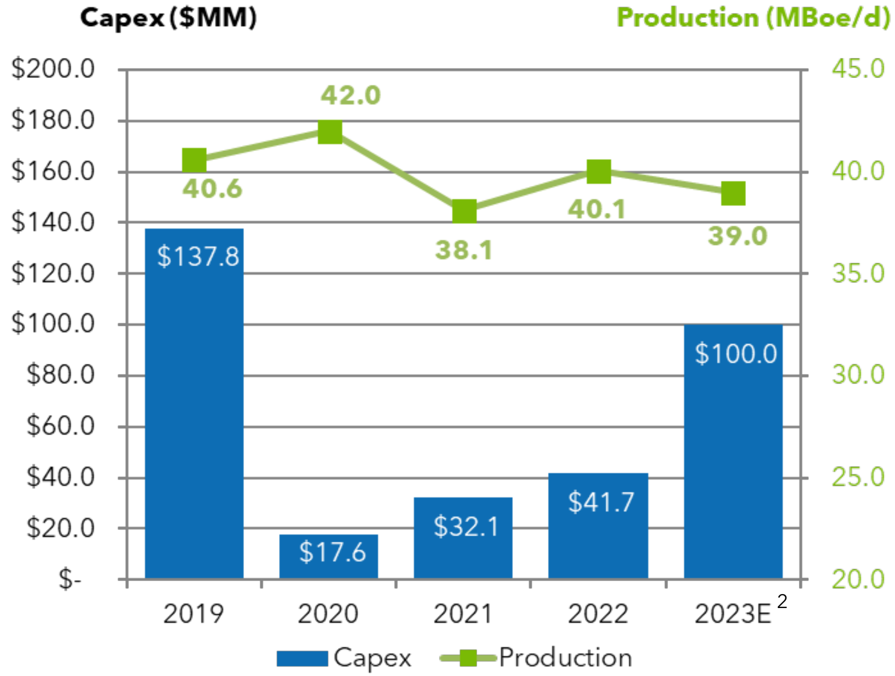
2023 Capex[1] guidance:
- $90 - $110 MM
- Included in this range are planned expenditures related to one deepwater well and three shelf wells, as wells as facilities, seismic, and recompletions

2023 P&A guidance:
- $25 - $35 MM
- Current year activity driven by obligations and prior deferrals on terminated leases with BSEE

Capex Allocation[1,2]



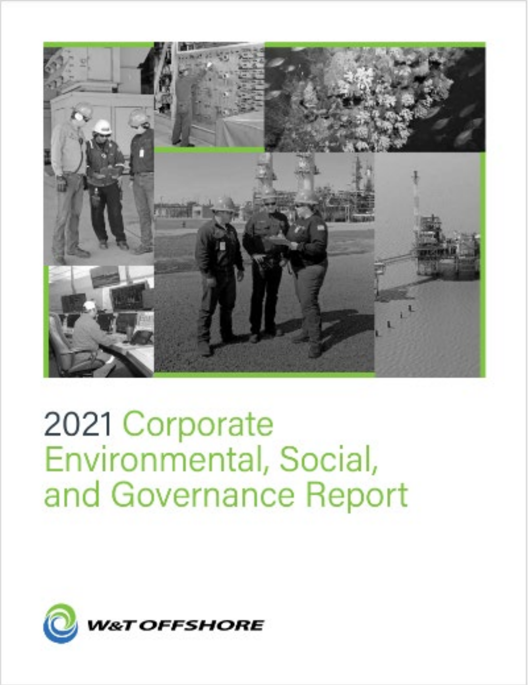
Production vs Capex



1) Accrual basis capital expenditures only
2) Based on midpoint of annual guidance range

2023 Capex Includes More Capital for Recompletions

ENVIRONMENTAL, SOCIAL, AND GOVERNANCE



Disclosure & Reporting Framework
- SASB (Sustainability Accounting Standards Board)
- TCFD (Task Force on Climate-related Financials Disclosures)
- SDG (Sustainable Development Goals)

Environmental

- Committed to protecting and preserving the environment
- Robust program of policies and continuous training
- Focused on best practices and strategies to reduce emissions
- **In 2022 consolidated two Mobile Bay treating facilities into one plant, reducing emissions**
- **Spill Ratio[1]: W&T's ratio in 2022 was 0.057 compared to 1.83 GOM average in 2021**

Social

- Focused on our organization and our communities
- Organization focused on open communication and trust to build a strong culture
- Continuous professional development of our workforce and safety performance
- **50% of our executive officers and board members are women or minorities**
- **Required diversity training throughout organization**

Governance

- Strong Board oversight responsible for strategy, governance and creating long-term value
- Highest legal and ethical standards expected across entire organization
- Focused on being a responsible corporate citizen with policies and procedures
- **Employee and Executive Compensation tied to ESG performance metrics**

1) Spill Ratio: Barrels spilled / millions of barrels produced

Note: Additional details on our 2021 ESG report and initiatives can be found on the W&T website: https://www.wtoffshore.com/corporate-responsibility

WHY INVEST IN W&T OFFSHORE?

1. Four Decades of Safe Operations in the Gulf of Mexico
2. Proven Track Record of Delivering Positive Cash Flows with 21 Consecutive Quarters of Positive Free Cash Flow
3. Experienced Management Team With Industry-Leading Inside Ownership Ensuring Alignment of Incentives
4. Strong and Robust Liquidity and Leverage Metrics
5. Low Organic Finding and Discovery Costs Driven by Existing Infrastructure
6. Proven History of Realizing Probable and Possible Upside
7. Extensive Track Record of Creating Long-Term Value from Accretive, Low-Risk Acquisitions
8. Rigorous Technical Evaluation Resulting in High Drilling Success

APPENDIX

40 YEARS OF SAFE OPERATIONS IN THE GULF OF MEXICO

HSE&R Philosophy

- HSE&R performance is a key pillar for WTI Operations
- Specific HSE&R department reports directly to the COO

Robust and Developed Safety and Environmental Management System (S.E.M.S.)

- Instituted corporate wide S.E.M.S. program in 2011
- Well developed, documented, articulated, and robust system used to drive and support company safety procedures
- Covers 17 key elements which form the cornerstone of safety and operations
- 3rd party audits conducted to strengthen and evolve this program

HSE&R Performance

- **No employee fatalities since inception**
- Outstanding environmental record compared to any GOM operator
- **Environmental Spill ratio averaged 0.057 in 2022 vs. 1.83 average in the GOM for 2021**
- Consistently outperform peer group on BSEE benchmark tracking index (BSEE spill ratio for operators)[1]
- Deeply engrained culture to prevent and contain environmental exposure with exceptional performance levels for years

1) BSEE spill ratio is defined as volume discharged/million bbls produced

RIGOROUS TECHNICAL EVALUATION RESULTS IN DRILLING SUCCESS

PROCESS

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

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

3 **TECHNICAL EVALUATION**
Full technical evaluation with probabilistic risk analysis, AFE costing and economic evaluation

4 **AFE REVIEW**
Presentation to Executive management for AFE approval

5 **EXECUTE**
Project turned over to execution team and deadlines set

Track Record of Drilling Success

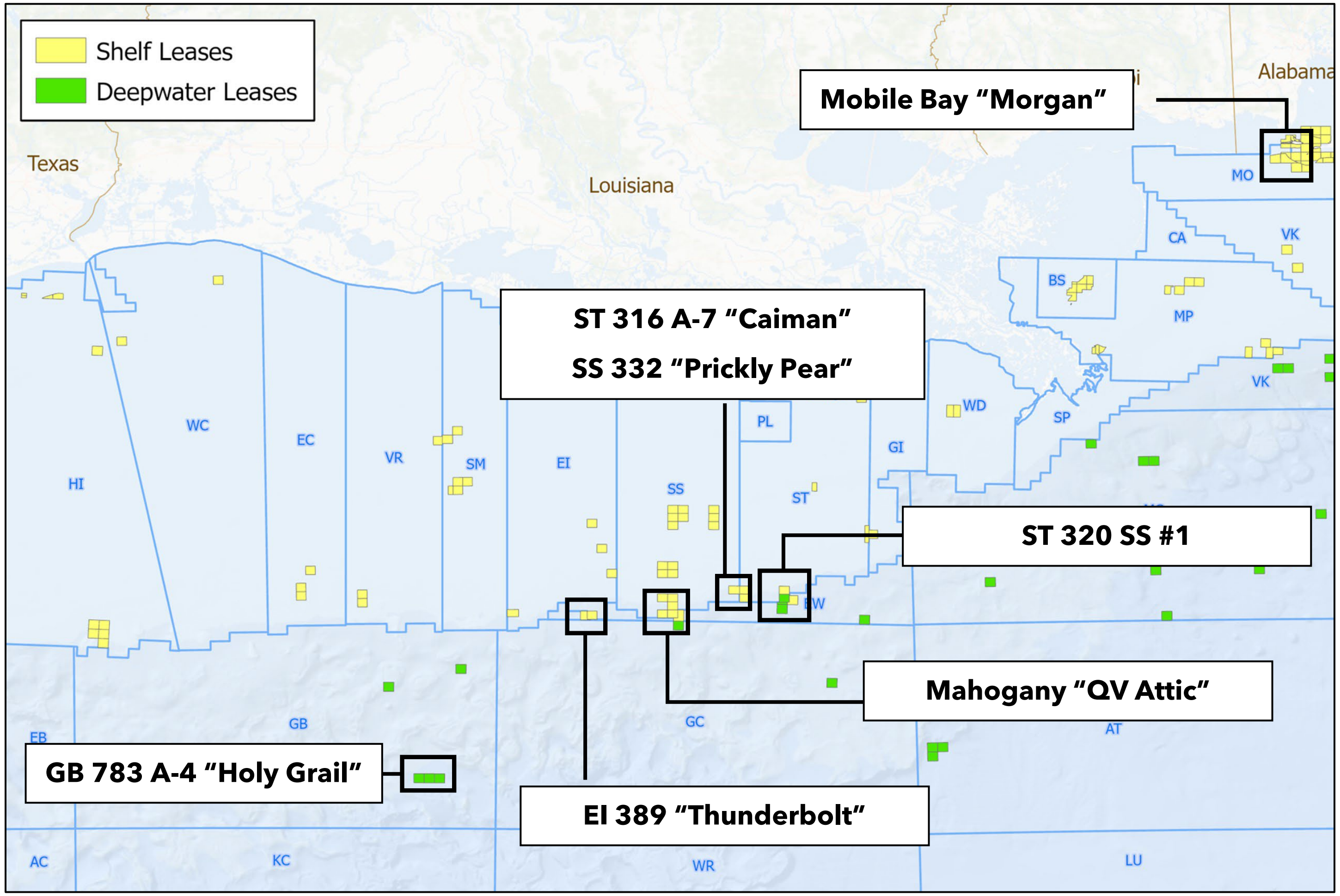
Over 400
Leads evaluated since 2011

Success Rate
2011 – 2022
>90%

50
Successful offshore wells drilled since 2011

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

SELECT OPPORTUNITIES



Inventory Highlights

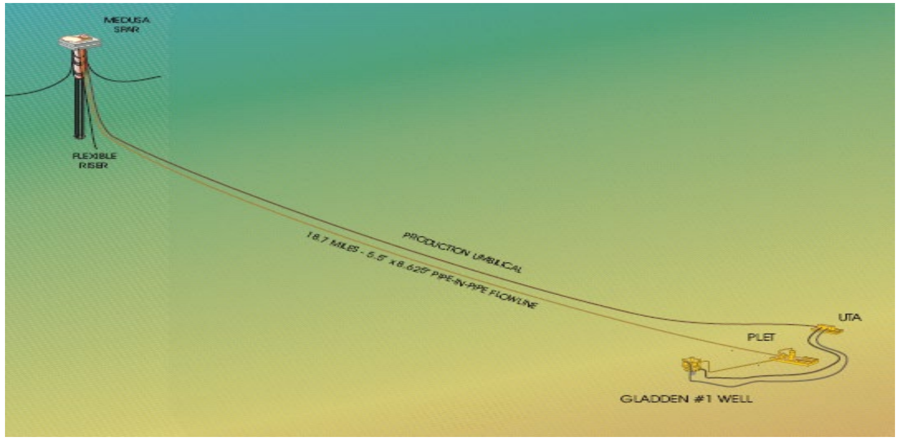
38	E&P Opportunities
79%	Avg Working Interest
87%	Operated
74%	HBP

38 Opportunities with 16 Platform Wells and 22 Subsea Tiebacks (all < 15 miles)

SIGNIFICANT INFRASTRUCTURE ADVANTAGE

Platform Rig on infield production facility (EW 910 Area)

Subsea tieback to existing infrastructure (MC 800 Gladden)



155 Existing structures provide a key advantage when evaluating/ developing prospect opportunities

Economic Advantage

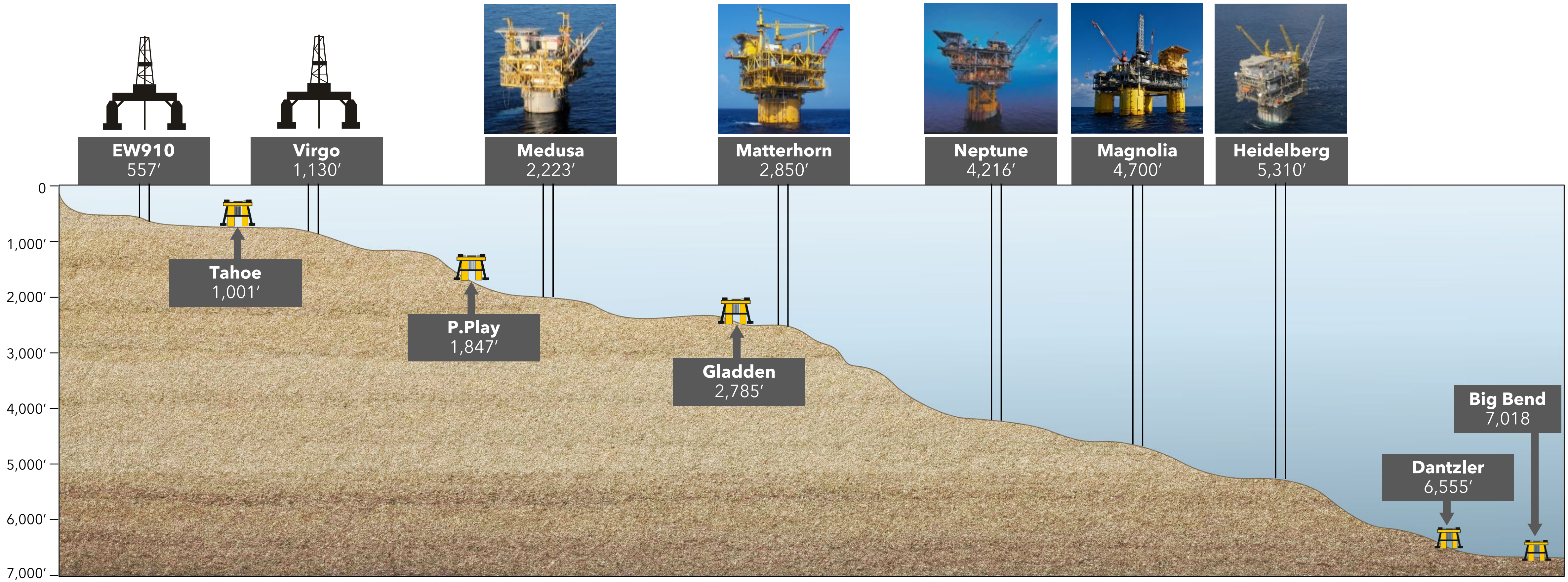
- Reduces capital expenditures
- Increases returns by generating cashflow quicker
- Marketing contracts already in place
- Provides revenue upside in potential Production Handling Agreements (PHA)
  - 2019 $15.3 MM
  - 2020 $7.5 MM
  - 2021 $12.2 MM
  - 2022 $15.4 MM
  - 1Q23 $2.9 MM

W&T Owns Infrastructure with an Estimated Replacement Value >$1.0B

W&T OFFSHORE

SUCCESSFUL PARTICIPATION IN VALUABLE DEEPWATER PROJECTS

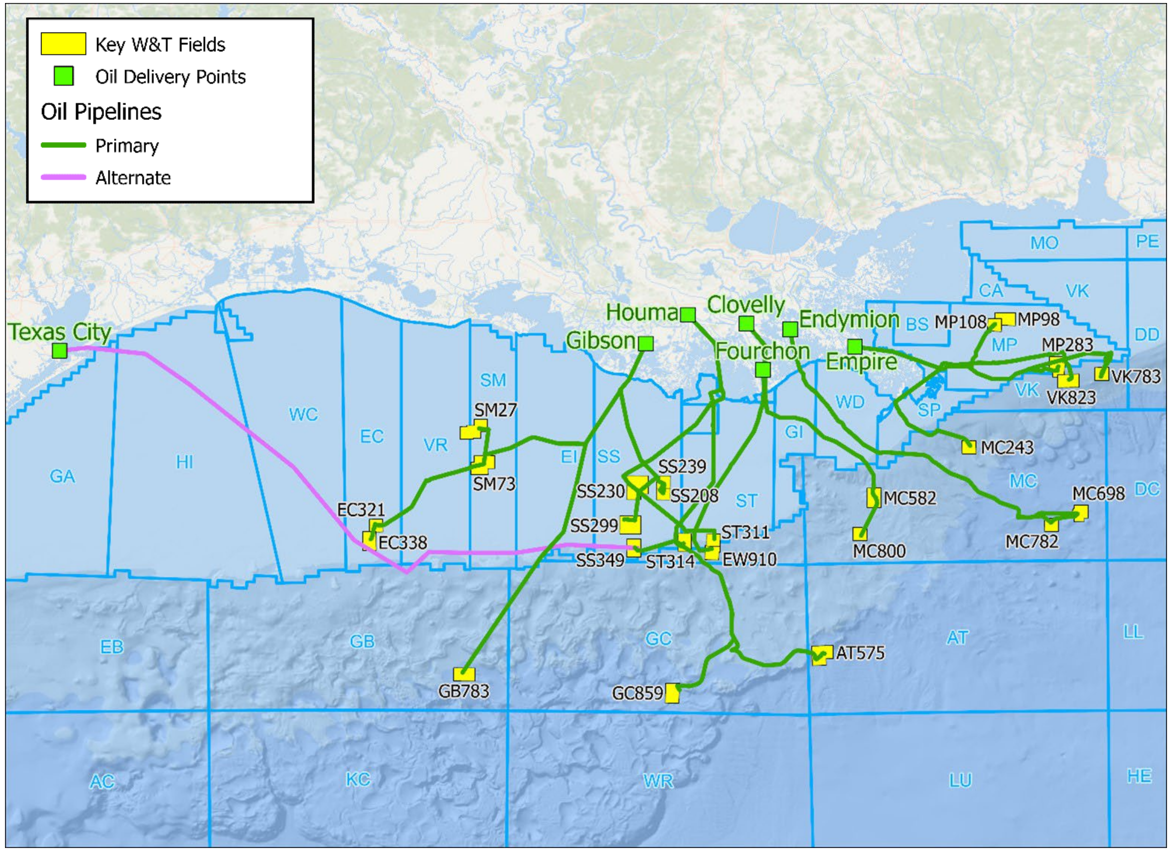
- W&T's deepwater portfolio was expanded and diversified with Magnolia (2019) as its latest addition
- W&T operates and participates in various deepwater production facilities, including TLPs, E-TLPs, SPARs, deepwater fixed structures, and sub-sea tiebacks



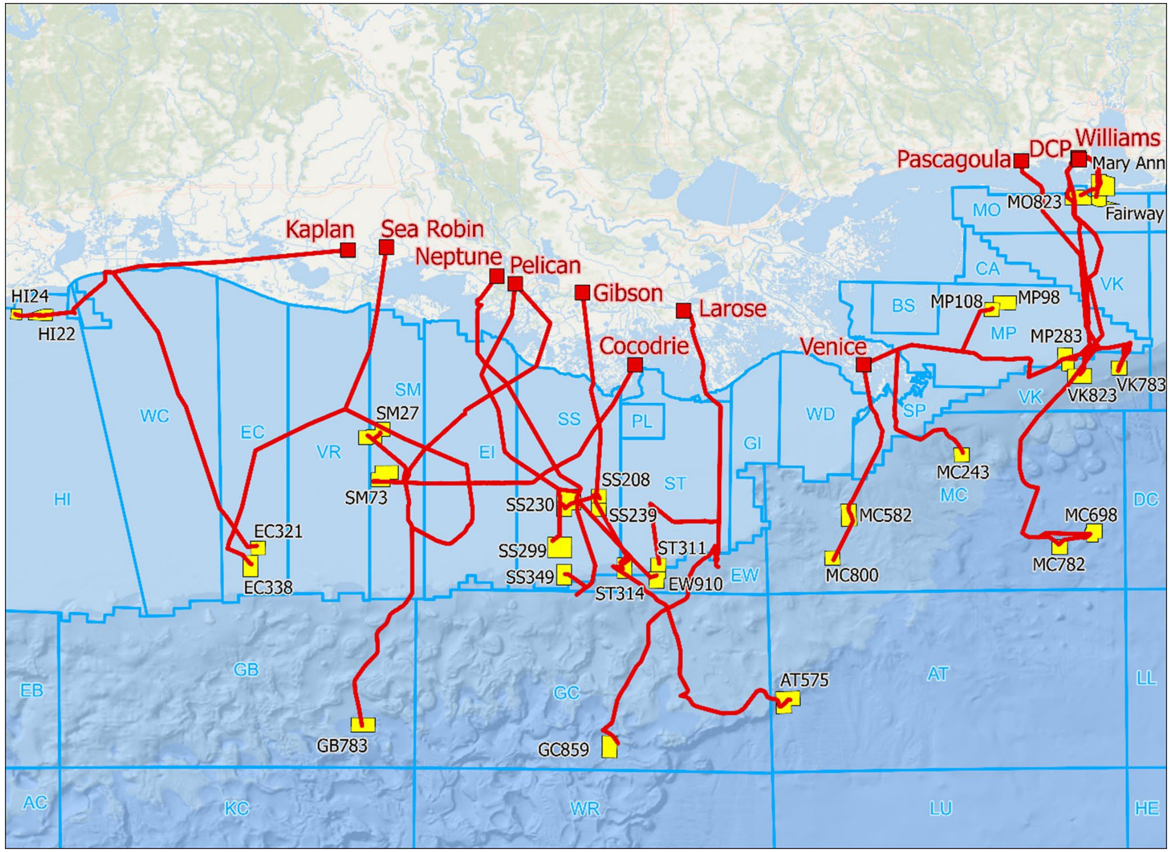
MULTIPLE TAKEAWAY OPTIONS HELP MITIGATE HURRICANE RISK

Prudent hurricane risk management through diverse production base, takeaway optionality, and adequate insurance coverage

W&T Crude Takeaway Lines

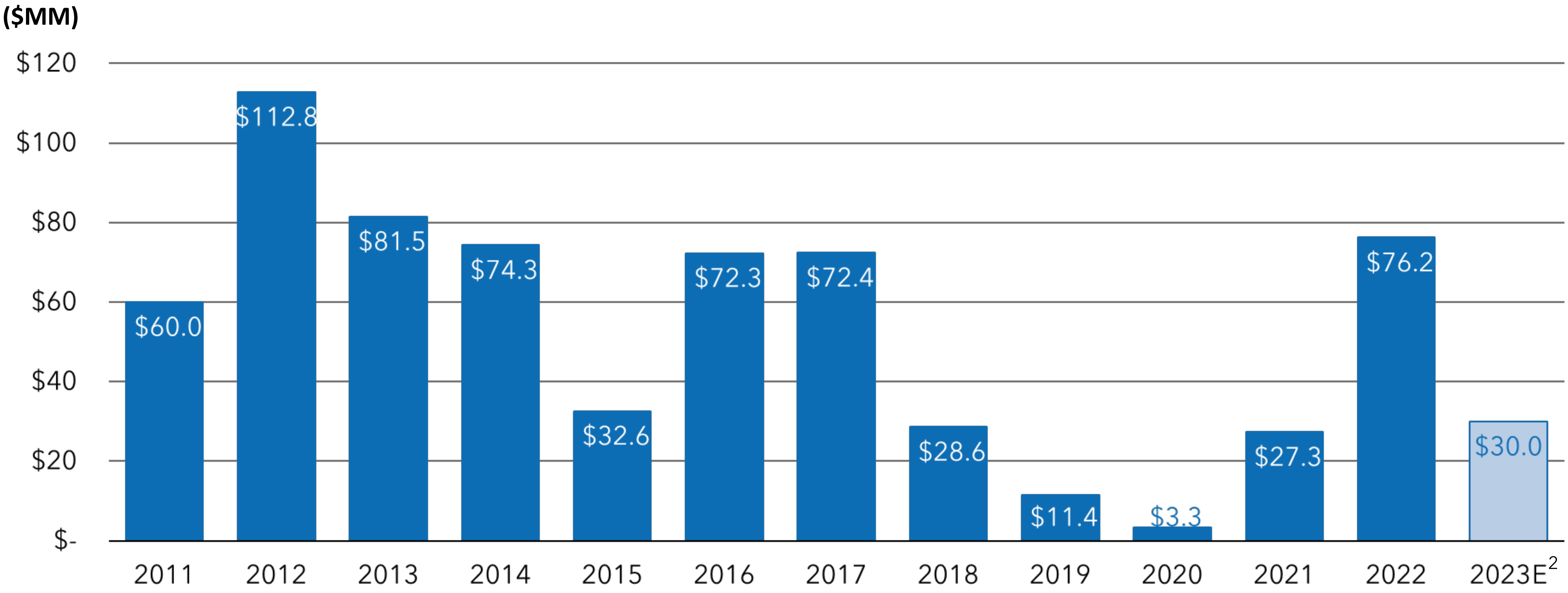


W&T Natural Gas Takeaway Lines



W&T OFFSHORE

P&A EXPENDITURES[1]



1) Net of amounts held in escrow (total of $21.6 MM)
2) Midpoint of 2023 plugging and abandonment expenditures guidance of $25-$35 million

W&T OFFSHORE

GOM DRILLING JOINT VENTURE

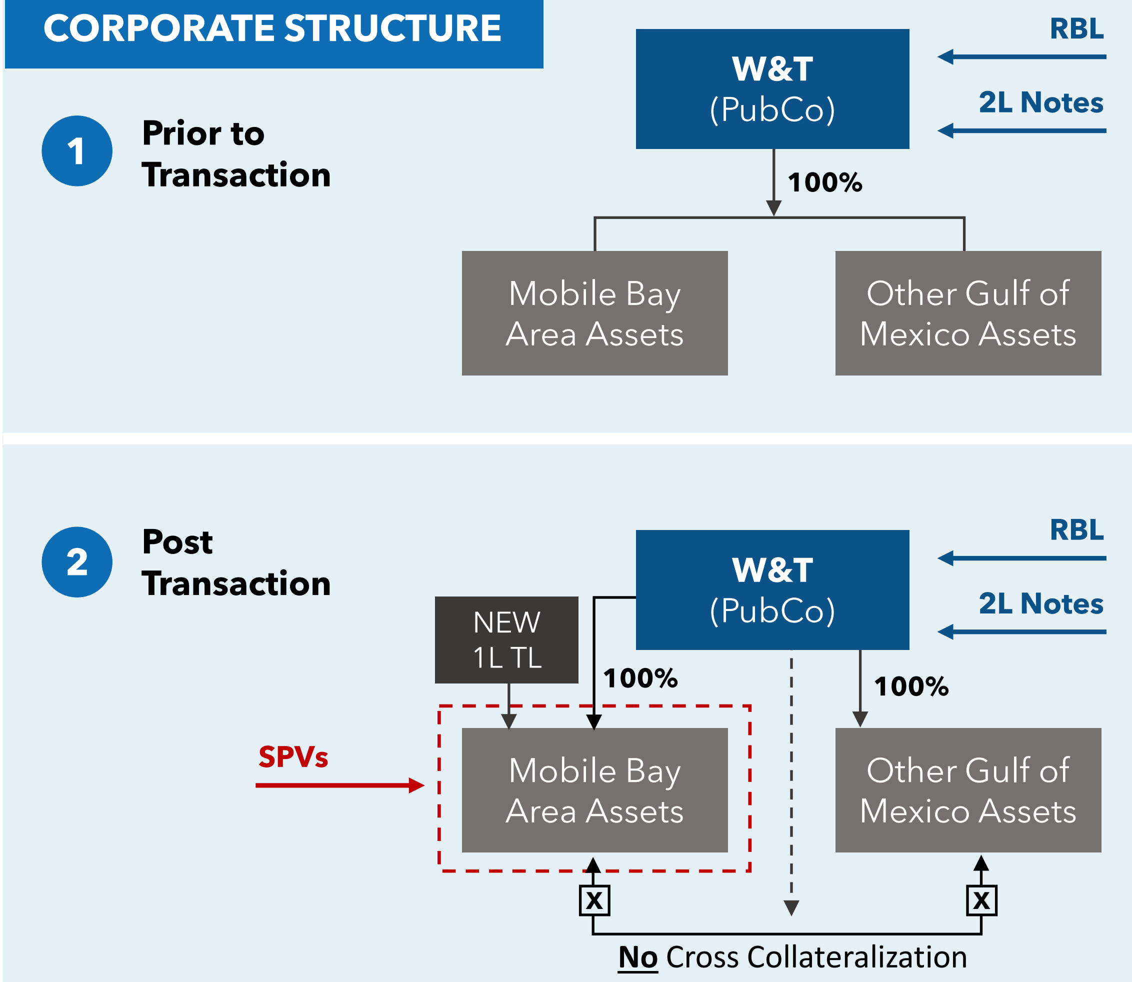
- Secured $361.4 MM commitment for the development of 14 pre-identified drill wells in the GOM with potential to upsize program over time with additional wells
  - Covers the total estimated cost of the 14 wells of $336 MM, plus contingency
  - Drilled and completed ten wells through December 31, 2022
  - The most recent completion was the East Cameron 338/349 #1 (Cota well), which came online in March 2022
- 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
- Upon private investors achieving certain return thresholds, W&T's share of each well's net revenue increases to 38.4%
- 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
- Allowed 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

MUNICH RE TRANSACTION OVERVIEW

- Partnered with Munich Re, a reputable AA-rated counter-party, to fund future growth needs
- 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 or recourse to any other assets of parent
- 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 will be used to service the term loan debt going forward
- W&T owns 100% of the equity in the SPVs
  - Keeps all cash flows associated with the Mobile Bay area assets after debt service and reserves
  - Adds cash to the balance sheet to reinvest in accretive acquisitions or other accretive drilling opportunities
  - Keeps future drilling 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 SPVs

CORPORATE STRUCTURE

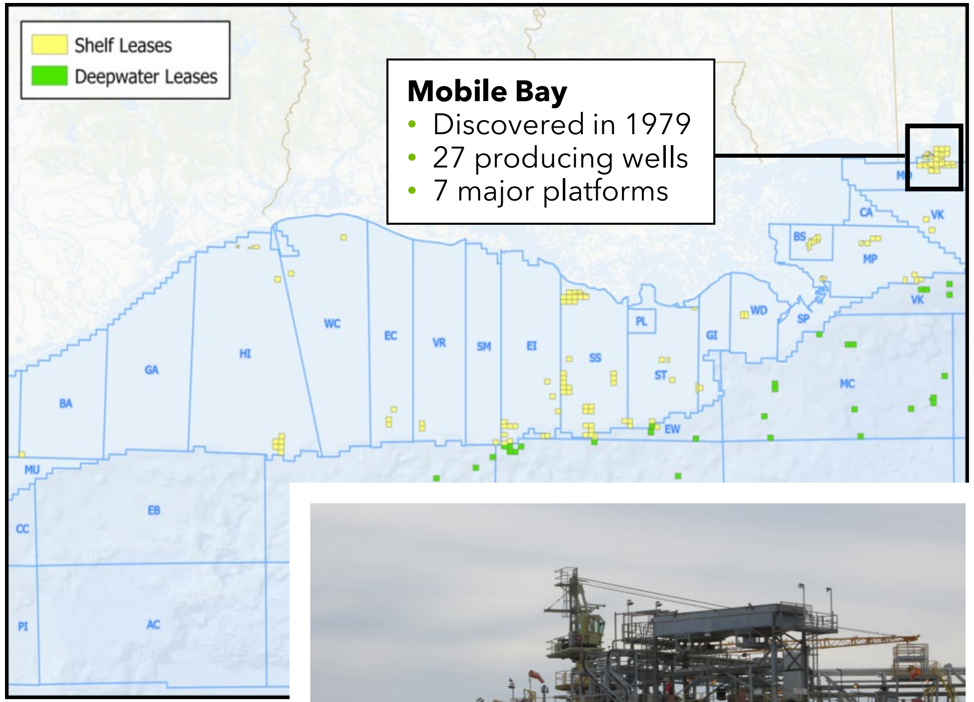


Boosted Cash and Allowed Repayment of the RBL Facility

W&T OFFSHORE

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
- Allowed for significant synergies, consolidations, and cost savings as W&T became the largest operator in the area
- Initial transaction closed on August 30, 2019, with total cash consideration paid of $167.6 MM which included a previously-funded $10 MM deposit
- Utilized cash on hand and previously undrawn revolving credit facility to finance acquisition
- Included working interests in nine GOM offshore producing fields (eight operated) and onshore natural gas treatment facility capable of treating 420 MMcf/d
- Year-end 2022 proved reserves of ~104 MMBoe[1] of which the vast majority are natural gas (84%) and proved developed producing; 1Q23 avg production of 10.1 MBoe/d
- Contains future opportunities including Norphlet drilling leads and optimization of compression facilities



Completed consolidation of natural gas treating facilities at Mobile Bay, which resulted in cost savings beginning in 2021 and reduction of GHG emissions

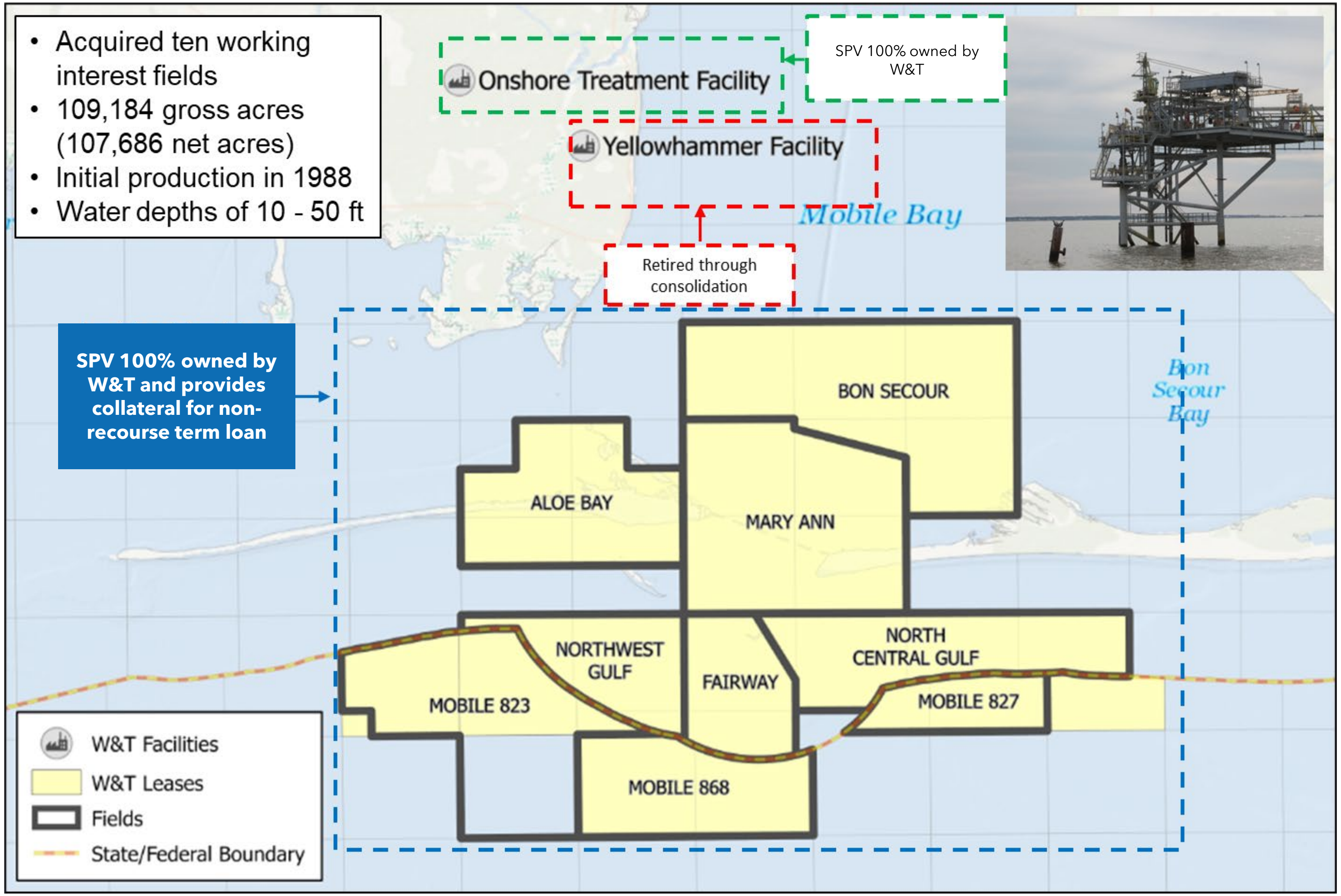
1) Based on year-end 2022 reserve report at 12/31/22 by NSAI at SEC pricing (1P Life) of $94.14/Bbl and $6.36/MMBtu

Low Decline, Long-Life, Mostly PDP

W&T OFFSHORE

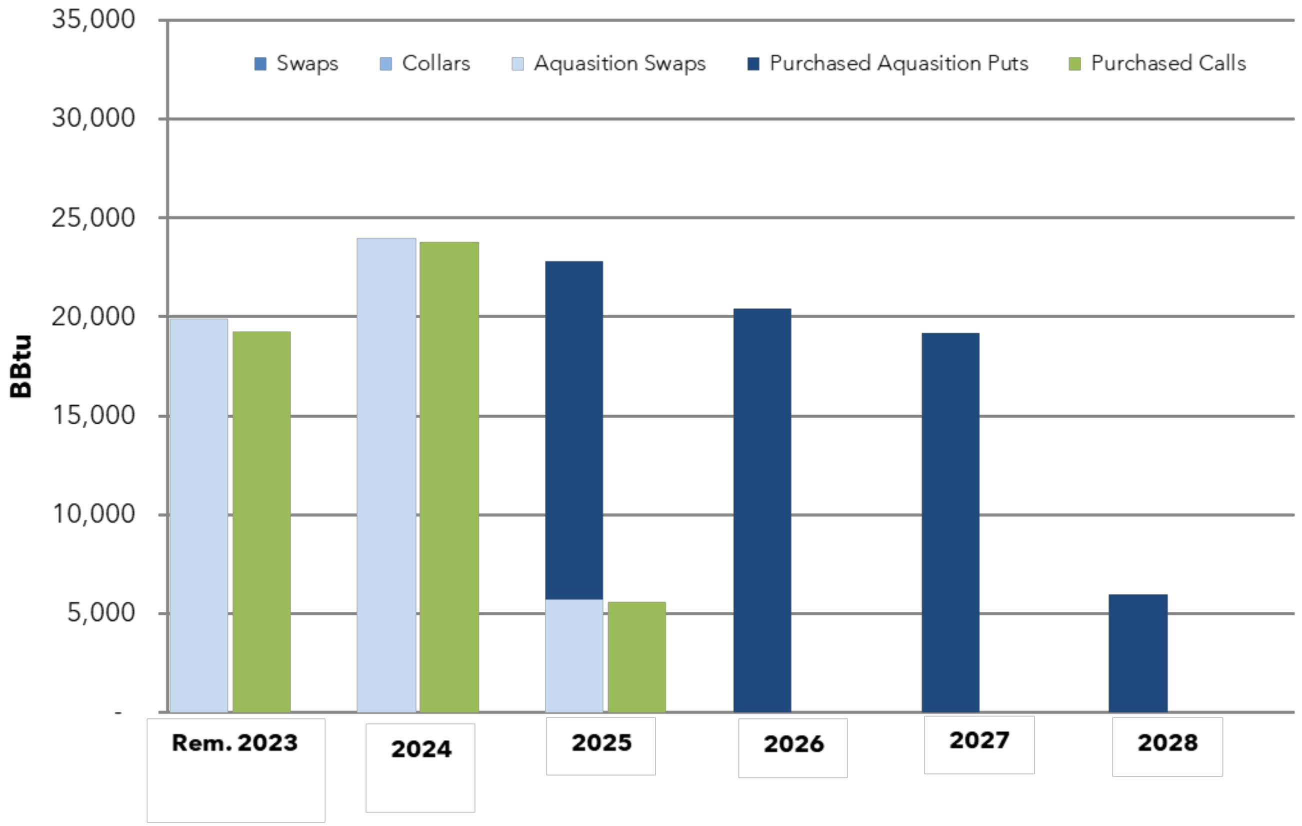
MOBILE BAY AREA – ASSET MAP

- Acquired ten working interest fields
- 109,184 gross acres (107,686 net acres)
- Initial production in 1988
- Water depths of 10 - 50 ft



HEDGE PROGRAM

Natural Gas Hedges



- Mobile Bay transaction required gas hedges at the SPV level to cover a majority of debt service
- W&T has ~60% of 2023 estimated natural gas production hedged by swaps[1]
- W&T structured "synthetic long puts" through 1Q25 using purchased calls and sold swaps that protect against low gas prices while preserving benefits of higher gas prices
  - ~95% of swaps are covered by purchased calls
- W&T is unhedged on oil, which provides considerable upside if WTI price increases throughout the year
- The Company monitors commodity prices and will opportunistically add hedges when favourable to the business plan

1) Based on the guidance range for 2023 natural gas production provided by the Company on May 9, 2023

HEDGE SUMMARY

W&T (excluding Aquasition, LLC)

Natural Gas - Henry Hub NYMEX

	PURCHASED CALLS		
	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg strike price per MMBTU
2Q23	6,370,000	70,000	$ 7.50
3Q23	6,440,000	70,000	$ 7.50
4Q23	6,440,000	70,000	$ 7.50
2024	23,790,000	65,000	$ 6.13
2025	5,580,000	62,000	$ 5.50

Aquasition, LLC

Natural Gas - Henry Hub NYMEX

PERIOD	SWAPS			PURCHASED PUTS		
	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg strike price per MMBTU	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg strike price per MMBTU
2Q23	6,600,000	72,527	$ 2.30			
3Q23	6,600,000	71,739	$ 2.35			
4Q23	6,600,000	71,739	$ 2.50			
2024	24,000,000	65,574	$ 2.46			
2025	5,700,000	63,333	$ 2.72	17,100,000	62,182	$ 2.27
2026				20,400,000	55,890	$ 2.35
2027				19,200,000	52,603	$ 2.37
2028				6,000,000	49,587	$ 2.50

NON-GAAP RECONCILIATIONS

Adjusted EBITDA/ Free Cash Flow Reconciliations

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, non-recurring IT transition costs, release of restricted funds, non-ARO P&A costs, and litigation and other. The Company defines Net Debt as current and long-term debt, net of unamortized debt discounts, less cash and cash equivalents. The Company defines Net Leverage as Net Debt divided by the last 12 month's Adjusted EBITDA. 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, asset retirement obligations 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, asset retirement obligations 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 of 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 Total Debt to Net Debt and Net Leverage (ii) a reconciliation of the Company's net (loss) income, a GAAP measure, to Adjusted EBITDA and Free Cash Flow (iii) a reconciliation of cash flow from operating activities, a GAAP measure, to Free Cash Flow, as such terms are defined by the Company.

NON-GAAP RECONCILIATIONS

($000s)	March 31, 2023		December 31, 2022	
	(Unaudited)			
Term loan				
Principal	$	138,348	$	147,899
Unamortized debt issuance costs		(4,145)		(4,592)
Total term loan	$	134,203	$	143,307
Credit agreement borrowings		–		–
11.75% Senior Second Lien Notes				
Principal	$	275,000		–
Unamortized debt issuance costs		(5,929)		–
Total 11.75% Senior Second Lien Notes	$	269,071		–
9.75% Senior Second Lien Notes				
Principal		–	$	552,460
Unamortized debt issuance costs		–		(2,330)
Total 9.75% Senior Second Lien Notes		–	$	550,130
Total Debt	$	403,274	$	693,437
Cash and cash equivalents		177,389		461,357
Net Debt	**$**	**225,885**	**$**	**232,080**
LTM Adjusted EBITDA		517,161		563,736
Net Leverage		**0.44x**		**0.41x**

NON-GAAP RECONCILIATIONS

($000s)	Three Months Ended March 31, 2023	Three Months Ended December 31, 2022	Year Ended December 31, 2022	Year Ended December 31, 2021
	(Unaudited)		(Unaudited)	
Net Income (loss)	**$ 26,005**	**$ 43,449**	**$ 231,149**	**$ (41,478)**
Interest expense, net	14,713	14,526	69,441	70,049
Income tax expense, (benefit)	8,639	6,859	53,660	(8,057)
Depreciation, depletion, amortization and accretion	30,134	34,246	133,630	113,447
Unrealized commodity derivative (gain)/loss and effect of derivative premiums, net	(39,470)	(53,132)	45,475	87,901
Allowance for credit losses	-	43	(76)	323
Write-off debt issue costs	-	-	–	1,230
Non-cash incentive compensation	1,922	2,743	7,922	3,364
Non-recurring costs related to IT services transition	785	1,844	8,237	–
Release of restricted funds	-	-	–	(11,102)
Non-ARO P&A costs	6	15,899	18,402	4,495
Other	378	(372)	(4,104)	126
Adjusted EBITDA	**$ 43,112**	**$ 66,105**	**$ 563,736**	**$ 220,298**
Investment in oil and natural gas properties, equipment and other	(7,367)	(11,666)	(41,632)	(32,062)
Asset retirement obligation settlements	(8,642)	(14,940)	(76,225)	(27,309)
Interest expense, net	(14,713)	(14,526)	(69,441)	(70,049)
Free Cash Flow	**$ 12,389**	**$ 24,973**	**$ 376,438**	**$ 90,878**

W&T OFFSHORE

NON-GAAP RECONCILIATIONS

($000s)	December 31, 2022	December 31, 2021	December 31, 2020	December 31, 2019	December 31, 2018	December 31, 2017	December 31, 2016
	Twelve Months Ended (Unaudited)						
Net Income (loss)	**$ 231,149**	**$ (41,478)**	**$ 37,790**	**$ 74,086**	**$ 248,827**	**$ 79,682**	**$ (249,020)**
Interest expense, net	69,441	70,049	61,143	59,569	48,645	45,521	92,109
Income tax expense, (benefit)	53,660	(8,057)	(30,153)	(75,194)	535	(12,569)	(43,376)
Depreciation, depletion, amortization and accretion	133,630	113,447	120,284	148,498	149,854	155,682	211,609
Unrealized commodity derivative (gain)/loss and effect of derivative premiums, net	45,475	87,901	20,762	74,914	(50,375)	–	7,672
Ceiling test write-down	–	–	–	–	–	–	279,063
Allowance for credit losses	(76)	323	(981)	206	730	888	–
Write-off debt issue costs	–	1,230	444	–	–	–	1,368
Non-cash incentive compensation	7,922	3,364	3,959	–	–	–	–
Non-recurring costs related to IT services transition	8,237	–	–	–	–	–	–
Release of restricted funds	–	(11,102)	–	–	–	–	–
Non-ARO P&A costs	18,402	4,495	–	–	–	–	–
Gain on debt transactions	–	–	(47,469)	–	(47,109)	(7,811)	(123,923)
Other	(4,104)	126	(2,708)	816	(3,982)	6,996	3,615
Adjusted EBITDA	**$ 563,736**	**$ 220,298**	**$ 163,391**	**$ 282,895**	**$ 347,125**	**$ 268,389**	**$ 179,117**
Investment in oil and natural gas properties, equipment and other[1]	(41,632)	(32,062)	(18,162)	(137,905)	(106,191)	(130,981)	(48,702)
Asset retirement obligation settlements	(76,225)	(27,309)	(3,339)	(11,443)	(28,617)	(72,409)	(72,320)
Interest expense, net	(69,441)	(70,049)	(61,463)	(59,569)	(48,645)	(45,521)	(92,109)
Free Cash Flow	**$ 376,438**	**$ 90,878**	**$ 80,427**	**$ 73,978**	**$ 163,672**	**$ 19,478**	**$ (34,014)**

1) Excludes proceeds from asset sales

NON-GAAP RECONCILIATIONS

($000s)	Three Months Ended March 31, 2023	Three Months Ended December 31, 2023	Year Ended December 31, 2022	Year Ended December 31, 2021
	(Unaudited)		(Unaudited)	
Net cash provided by operating activities	**$ 23,435**	**$ 12,679**	**$ 339,530**	**$ 133,668**
Allowance for credit losses	–	43	(76)	323
Release of restricted funds	–	–	–	(11,102)
Amortization of debt items and other items	(3,249)	(1,437)	(7,551)	(5,325)
Non-recurring costs related to IT services transition	785	1,844	8,237	–
Current tax benefit	4,243	1,846	8,476	132
Changes in derivatives receivable/(payable)	5,098	12,085	47,933	34,370
Non-ARO P&A costs	6	15,899	18,402	4,495
Changes in operating assets and liabilities, excluding ARO settlements	(10,939)	(5,948)	7,223	(33,747)
Investment in oil and natural gas properties, equipment and other	(7,367)	(11,666)	(41,632)	(32,062)
Other	378	(372)	(4,104)	126
Free Cash Flow	**$ 12,390**	**$ 24,973**	**$ 376,438**	**$ 90,878**
Current tax benefit:				
Income tax expense (benefit)	$ 8,639	$ 6,859	$ 53,660	$ (8,057)
Less: Deferred income taxes	4,396	5,013	45,184	(8,189)
Current tax benefit	$ 4,243	$ 1,846	$ 8,476	$ 132
Changes in derivatives receivable:				
Derivatives payable, end of period	$ 524	$ (4,574)	$ (4,574)	$ (6,396)
Derivatives payable, beginning of period	4,574	16,659	6,396	282
Derivative premiums paid	–	–	46,111	40,484
Change in derivatives receivable (payable)	$ 5,098	$ 12,085	$ 47,933	$ 34,370

THANK YOU

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