W&T OFFSHORE

Four Decades of Industry Leadership in the Gulf of Mexico

ENERCOM
ENERGY INVESTMENT CONFERENCE

August 2024

www.wtoffshore.com

NYSE: WTI

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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.

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 EBITDA and (iii) 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

PREMIER GULF OF MEXICO (“GOM”) OPERATOR WITH FOUR DECADES OF HISTORY IN THE BASIN

2Q24| FY 2023 **Production**	Total **Fields**	2Q24| FY 2023 **Adjusted EBITDA**[1]	2Q24| FY 2023 **Free Cash Flow**[1]
34.9 MBoe/d (55% liquids) **34.9 MBoe/d (51% liquids)**	**63**	**$45.9 MM** **$183.2 MM**	**$18.7 MM** **$63.3 MM**

Reserve Category	MY 2024 Reserves at SEC Pricing[2] (MMBoe)	MY 2024 PV-10 at SEC Pricing[2] ($MM)
1P	141.9	$1,388
2P	258.6	$3,165
3P	377.8	$5,402

Gulf of Mexico Shelf

- ~525,000 gross acres (~458,000 net)
- 80% of 2Q24 production
- Proved SEC reserves of 113.7 MMBoe[2]
- 2P SEC reserves of 204.8 MMBoe[2]
- Future growth potential from sub-salt projects

Gulf of Mexico Deepwater

- ~153,000 gross acres (~62,000 net)
- 20% of 2Q24 production
- Proved SEC reserves of 28.2 MMBoe[2]
- 2P SEC reserves of 53.8 MMBoe[2]
- Substantial upside with existing acreage

Federal vs State

Production: Federal 69%, State 31%

Net Acreage: Federal 84%, State 16%

2Q24 Highlights

- Produced 34.9 MBoe/d (55% liquids)
- Reported Adjusted EBITDA[1] of $45.9 MM
- Produced Free Cash Flow[1] of $18.7 MM
  - 2Q24 marked 26 consecutive quarters of positive Free Cash Flow
- Ended the quarter with $123.4 MM of cash on the balance sheet
- Continued to maintain a low leverage profile with Net Debt to trailing twelve months (“TTM”) Adjusted EBITDA of 1.4 times
- Paid third consecutive quarterly dividend of $0.01 per common share in May 2024
  - Declared 3Q24 dividend of $0.01 per share which will be payable on August 27, 2024 to stockholders of record on August 20, 2024
- Reported mid-year SEC proved reserves[2] of 141.9 MMBoe and a present value discounted at 10% (“PV-10”) of $1.4 B, an increase of 15% and 28%, respectively, compared to year-end 2023

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
2) Based on mid-year 2024 reserve report by NSAI at SEC pricing of $79.45/Bbl and $2.32/MMBtu. PV-10 excludes ARO and is a non-GAAP financial measure

W&T GULF OF MEXICO OPERATIONS

W&T Deepwater SPARs

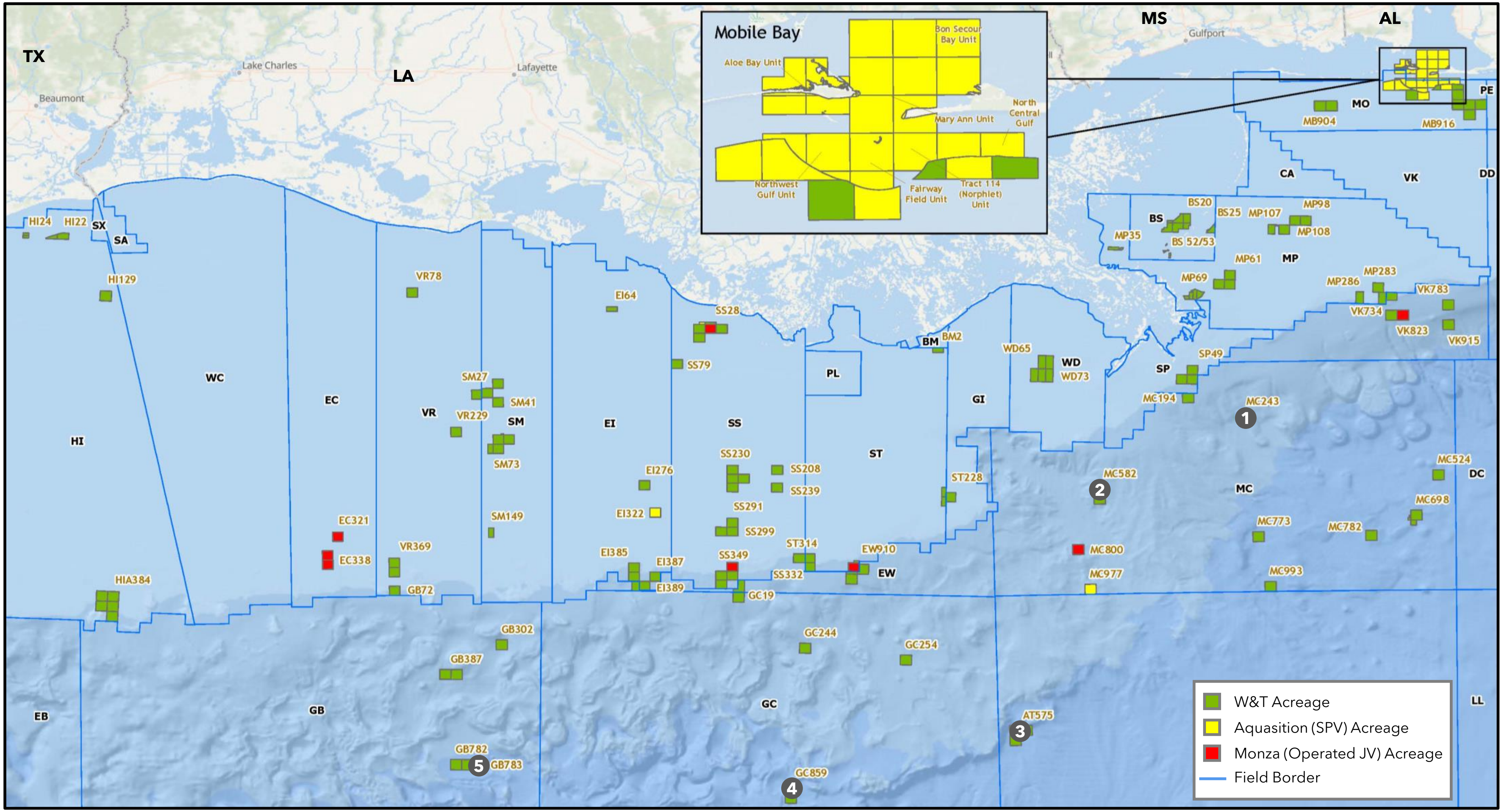
1 Matterhorn

2 Medusa

3 Neptune

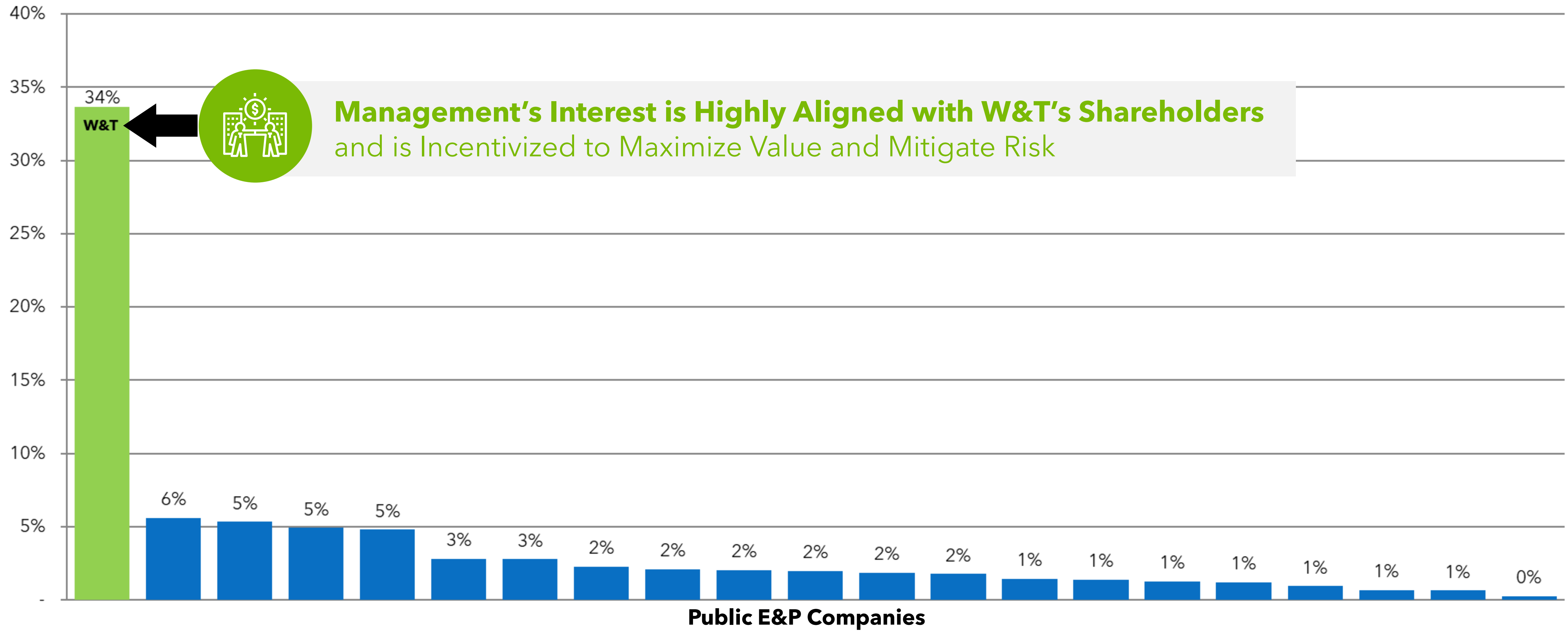
4 Heidelberg

5 Magnolia



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 7/30/2024
2) Peers comprised of the following companies: MUR, MTDR, AR, CRGY, BRY, NOG, CNX,, KOS, CRK, RRC, SM, SWN, MGY, SD, VTLE, PR, TALO, BTE, VRN, MRO

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

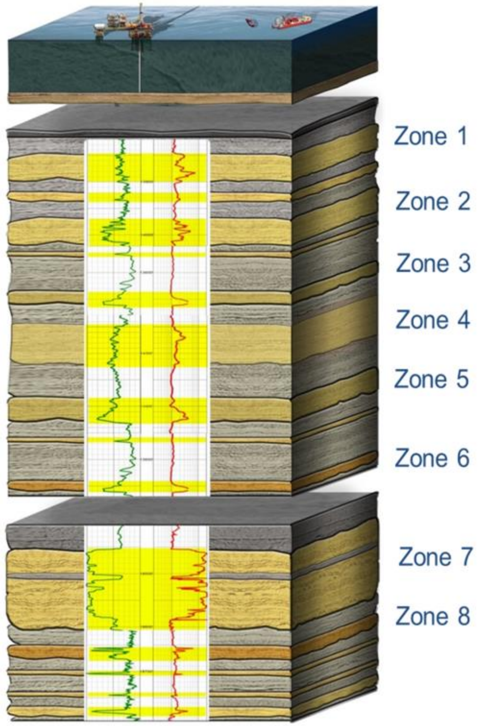
GOM Provides Better Porosity and Permeability than the Unconventionals

Multiple stacked pay opportunities

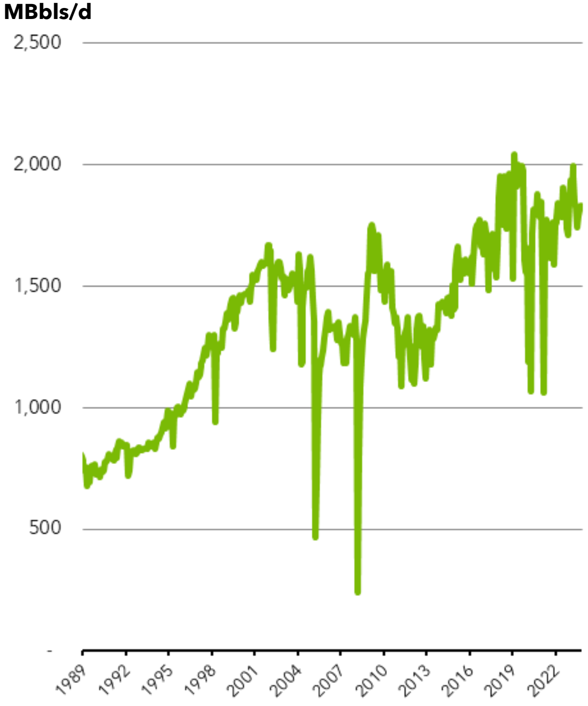
- Offer attractive primary production and recompletion opportunities
- Provide multiple targets improving chance of success when drilling

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

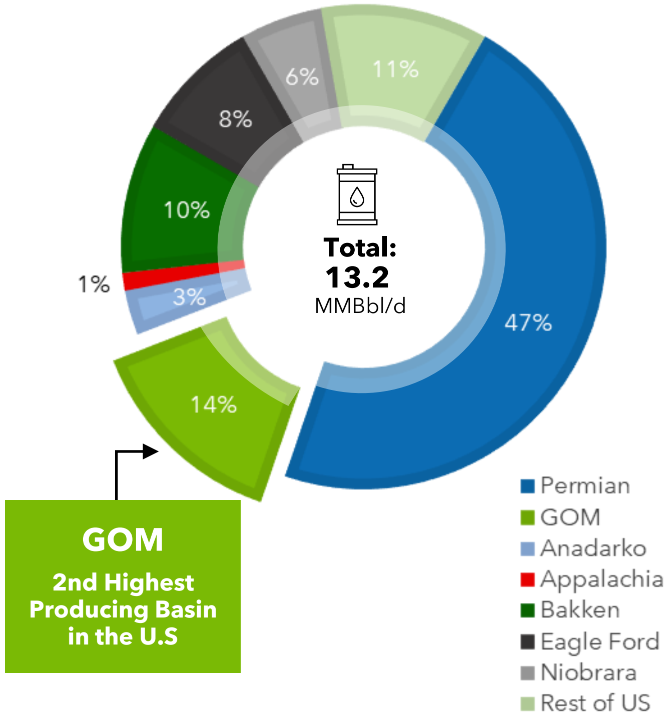


GOM Historical Oil Production[1]



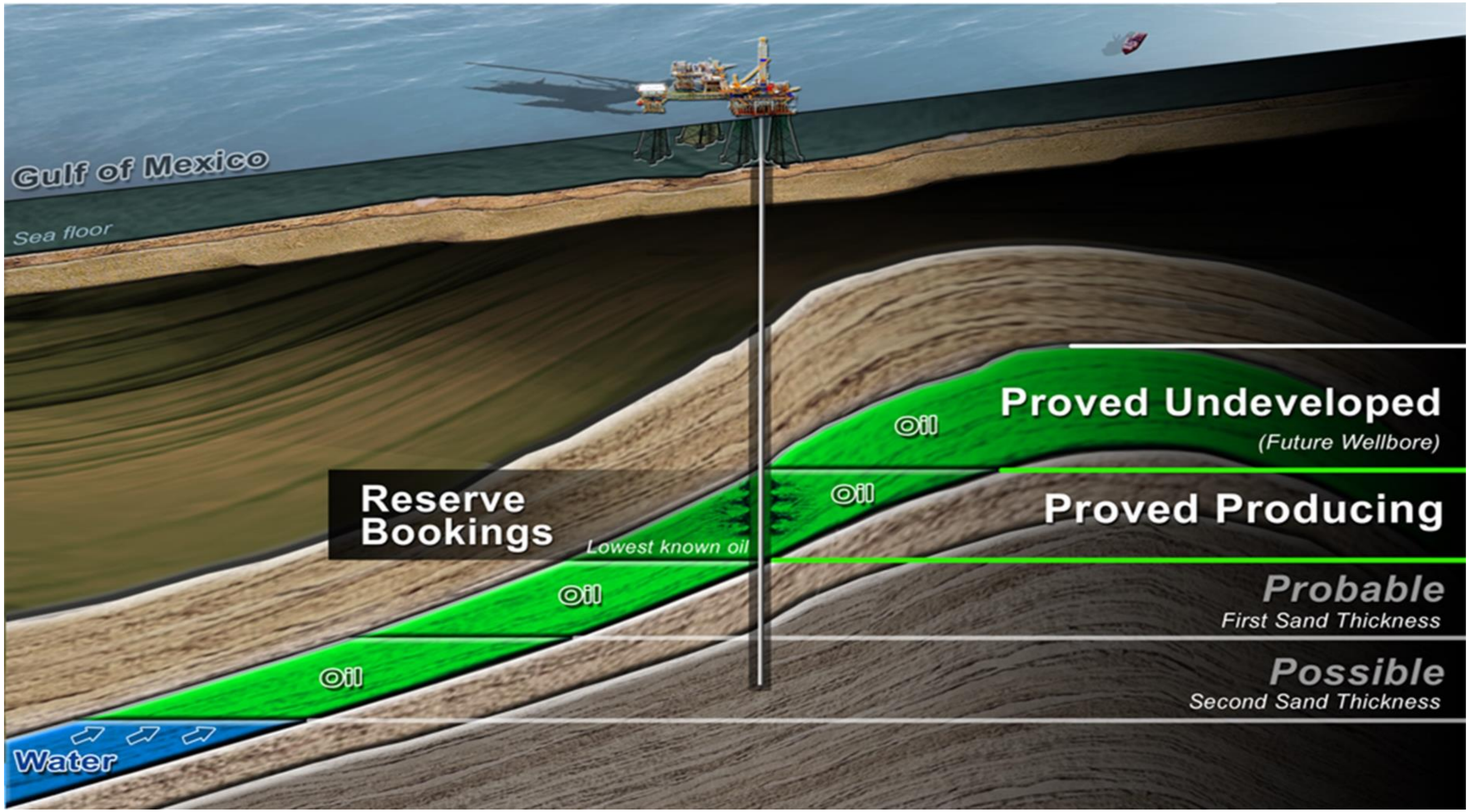
1) Based on U.S. Energy Information Administration (EIA) data as of April 2024

US Oil Production by Key Region[1]



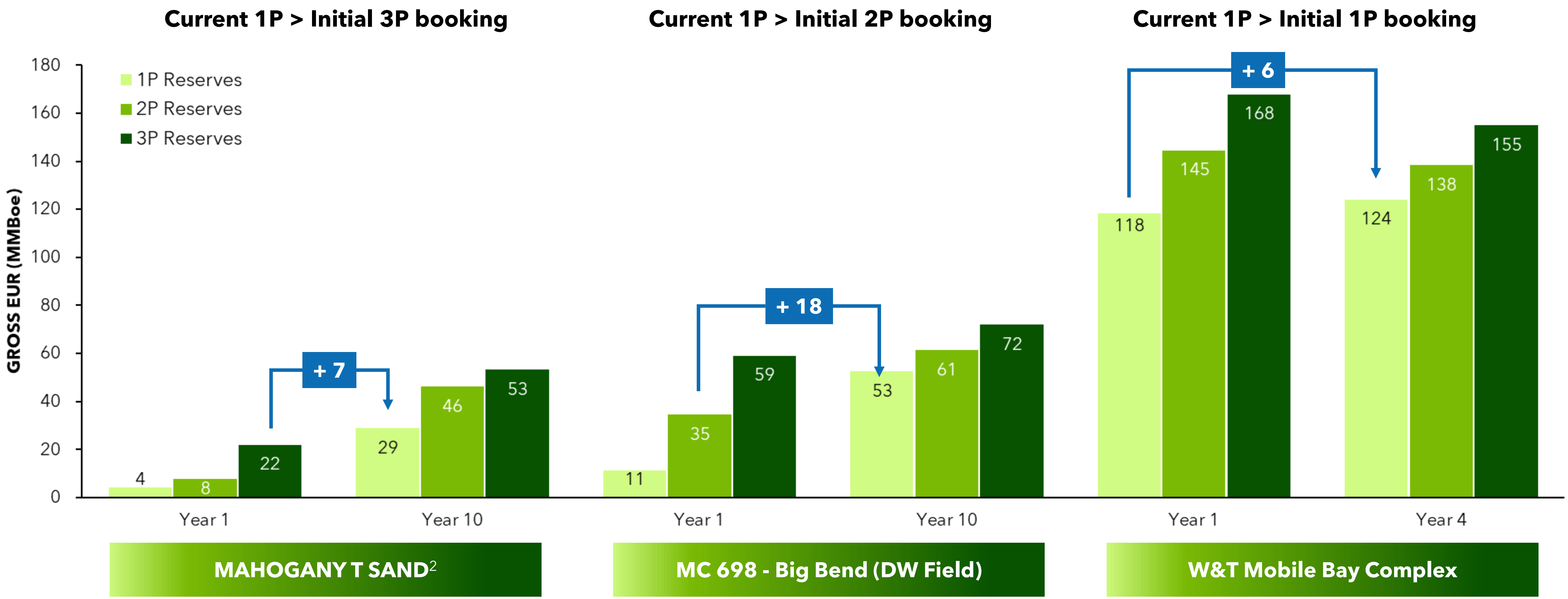
GOM Provides Unique Advantages:
Low Decline Rates, Superior Porosity/Permeability and Significant Untapped Reserve Potential

INCREMENTAL RESERVES MAY BE PRODUCED WITH MARGINAL INCREMENTAL CAPEX



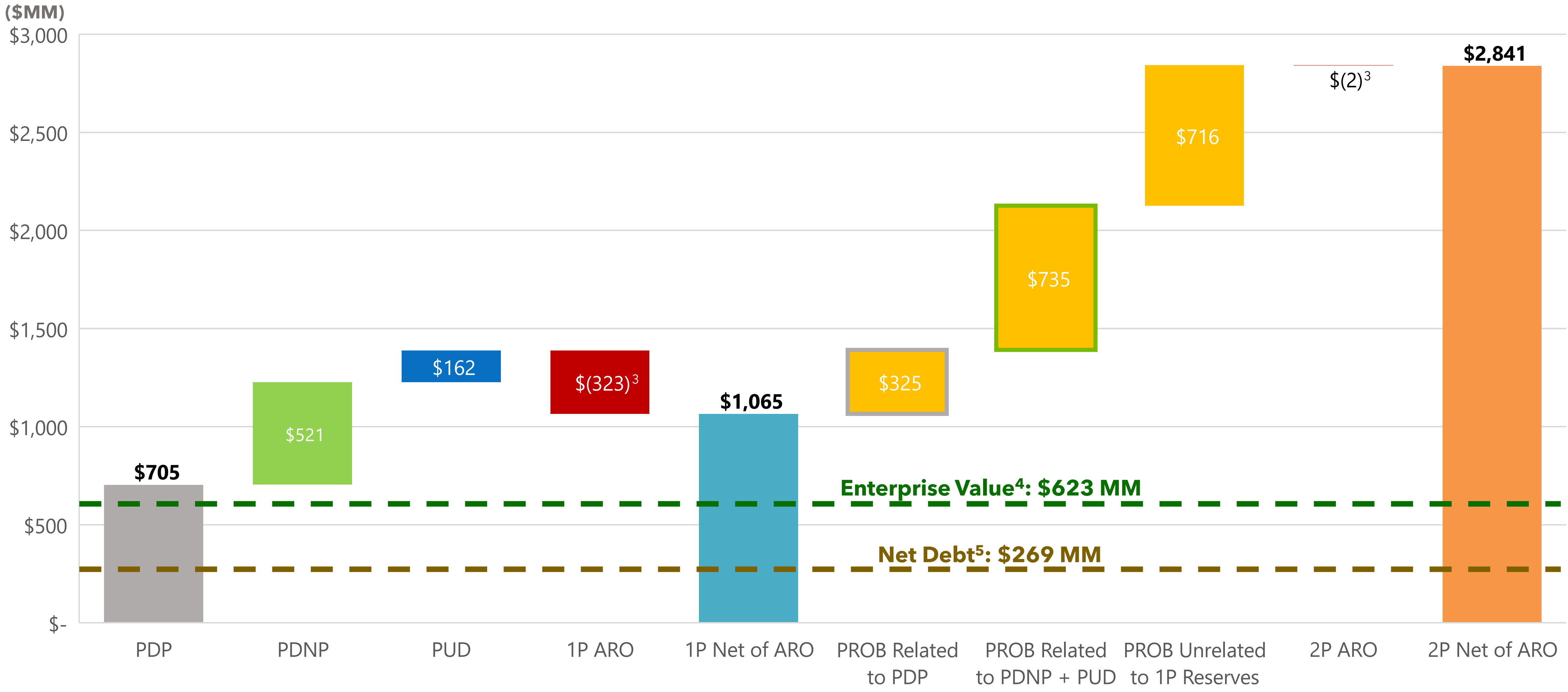
Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores

SIGNIFICANT RESERVE APPRECIATION FROM INITIAL BOOKINGS[1]



1) Based on mid-year 2024 reserve report by NSAI at SEC pricing of $79.45/Bbl and $2.32/MMBtu
2) Initial 1P booking includes A-14 well only; MY 2024 1P booking includes A-14, A-18 and A-19 wells; 2P & 3P includes additional development wells

PRO FORMA RESERVES PV-10[1,2]



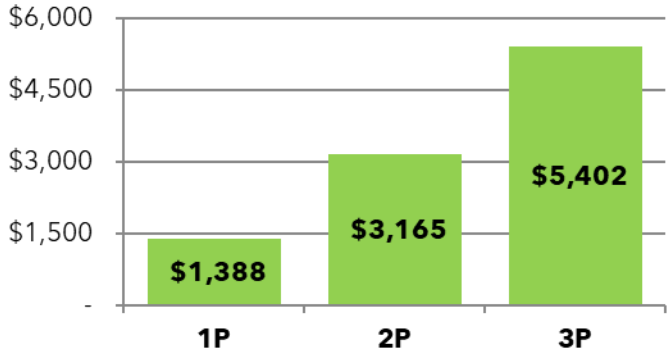
1) Based on mid-year 2024 reserve report by NSAI at SEC pricing of $79.45/Bbl and $2.32/MMBtu
2) PV-10 is a non-GAAP financial measure
3) ARO is based on the Company's latest internal estimates. This amount differs from the ARO calculated in accordance with GAAP and reported in W&T's financial statements
4) Enterprise value calculated as 147,182,248 outstanding shares (as of 8/7/24) multiplied by $2.22 share price (as of 8/14/24) plus net debt
5) Net debt is defined as current and long-term debt, net of unamortized debt discounts, less cash and cash equivalents.

PRO FORMA RESERVE PROFILE WITH ~$1.4B OF 1P PV-10

Reserve Category	Oil (MMBbl)	NGL (MMBbl)	Gas (Bcf)	Total (MMBoe)	% Liquids	PV-10 ($MM)
Proved Developed Producing (PDP)	22.6	8.4	275.5	76.9	40%	$ 705
Proved Developed Non-Producing (PDNP)	17.3	3.6	117.4	40.5	52%	521
Proved Undeveloped (PUD)	13.8	1.0	57.8	24.5	61%	162
Total 1P Reserves (Excluding ARO)	**53.7**	**13.0**	**450.7**	**141.9**	**47%**	**$ 1,388**
Probable Reserves (PROB)	76.6	5.3	208.6	116.7	70%	1,777
Total 2P Reserves (Excluding ARO)	**130.3**	**18.4**	**659.3**	**258.6**	**58%**	**$ 3,165**
Possible Reserves (POSS)	72.3	7.2	238.4	119.2	67%	2,237
Total 3P Reserves (Excluding ARO)	**202.5**	**25.6**	**897.7**	**377.8**	**60%**	**$ 5,402**
Est. PV-10 of 1P ARO[3]						(323)

Mid-Year 2024 Reserves PV-10[1,2]

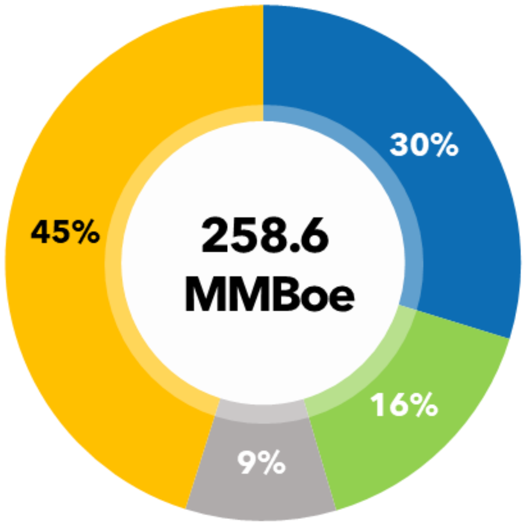
$ in MM



Mid-Year 2024 Reserves[1]

MMBoe

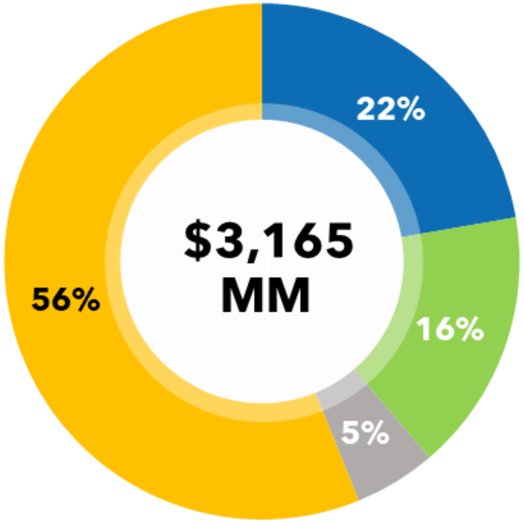
2P SEC Reserves[1]



PDP
PDNP
PUD
PROB

Natural Gas **45.7%** | Liquids **54.3%**

2P SEC PV-10[1,2]



1) Based on mid-year 2024 reserve report by NSAI at SEC pricing of $79.45/Bbl and $2.32/MMBtu
2) PV-10 excludes Asset Retirement Obligations and is a non-GAAP financial measure
3) ARO is based on the Company's latest internal estimates. This amount differs from the ARO calculated in accordance with GAAP and reported in W&T's financial statements

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

2012 – NEWFIELD

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

Net average production[2] of 952 Boe/d from 78 offshore blocks, 65 of which are in deepwater

Reserves[3]**:** **1P** – 1.5 MMBoe; **2P** – 2.8 MMBoe

2012 – Shell / Marubeni

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

Net average production[2] of 2,730 Boe/d from Fairway Field

Reserves[3]**:** **1P** – 9.3 MMBoe; **2P** – 10.8 MMBoe

2013 – CALLON PETROLEUM

$83 MM[1]
Investments Post-Acquisition

Net average production[2] of 281 Boe/d from Medusa and 12 other fields. Two exploration wells brought on production in 6/2015

Reserves[3]**:** **1P** – 1.5 MMBoe; **2P** – 3.0 MMBoe

2014 – woodside

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

Net average production[2] of 757 Boe/d from Neptune and 24 add'l blocks. One exploration well brought online in 2014

Reserves[3]**:** **1P** – 1.4 MMBoe; **2P** – 1.6 MMBoe

2019 – ExxonMobil / Chevron

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

Net average production[2] of 8,983 Boe/d. Potential to add incremental reserves with minimal capital by consolidating operations

Reserves[3]**:** **1P** – 46.9 MMBoe; **2P** – 55.0 MMBoe

2022 – ANKOR ENERGY / Undisclosed Private Seller

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

Net average production[2] of 2,379 Boe/d. Acquired 100% working interest of operated assets, including over 50 producing wells

Reserves[3]**:** **1P** – 2.1 MMBoe; **2P** – 4.5 MMBoe

2023 – Undisclosed Private Seller

$32 MM[1]
Closed Sep. 2023

Net average production[2] of 2,049 Boe/d from eight fields located in the GOM Shelf

Reserves[3]**:** **1P** – 2.3 MMBoe; **2P** – 3.5 MMBoe

2024 – COX OPERATING

$72 MM[1]
Closed Jan. 2024

Acquired six producing fields located in the GOM Shelf

Reserves[3]**:** **1P** – 23.8 MMBoe; **2P** – 68.9 MMBoe

2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024

1) Purchase prices as of closing dates, which are often adjusted for normal and customary post-effective date adjustments
2) 2Q 2024 net average production
3) Based on mid-year 2024 reserve report at SEC pricing of $79.45/Bbl and $2.32/MMBtu

SS 349 FIELD ("MAHOGANY") CASE STUDY

Mahogany Gross Production

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]	$947 MM
MY 2024 2P PV10[2] including ARO	$600 MM
Total Project Value[3]	**$1,547 MM**

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

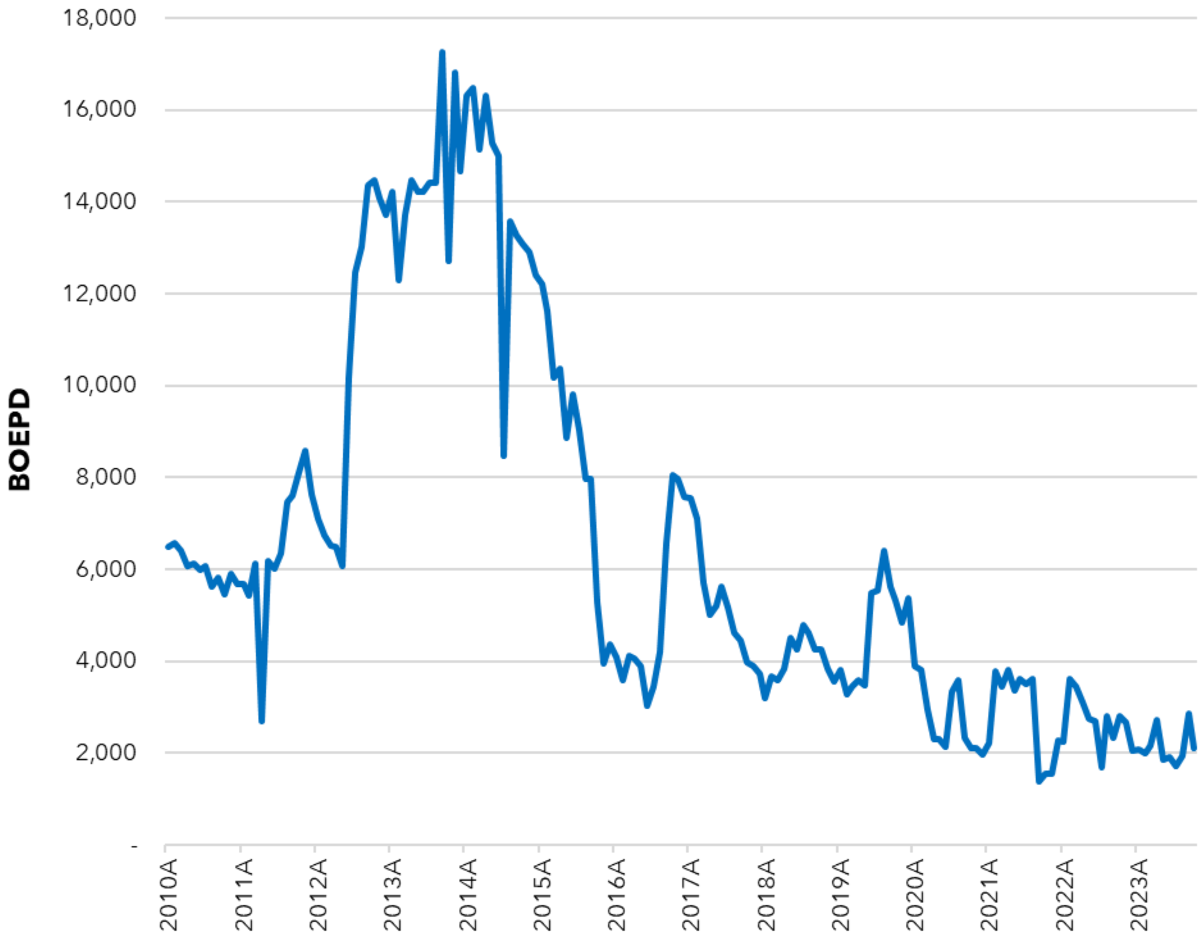
Current Reserves[2]

1P Reserves:	14.3 MMBoe
2P Reserves:	32.5 MMBoe
3P Reserves:	47.3 MMBoe

1) From closing date including capex to June 30, 2024
2) Based on mid-year 2024 reserve report at SEC pricing of $79.45/Bbl and $2.32/MMBtu
3) Total Net Cash Flow as of June 30, 2024, plus mid-year 2024 2P SEC PV10 value (including ARO)

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]	$506 MM
MY 2024 2P PV10[2] including ARO	$120 MM
Total Project Value[3]	**$626 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:	5.4 MMBoe
2P Reserves:	9.5 MMBoe
3P Reserves:	16.0 MMBoe

1) From closing date including capex to June 30, 2024
2) Based on mid-year 2024 reserve report at SEC pricing of $79.45/Bbl and $2.32/MMBtu
3) Total Net Cash Flow as of June 30, 2024, plus mid-year 2024 2P SEC PV10 value (including ARO)

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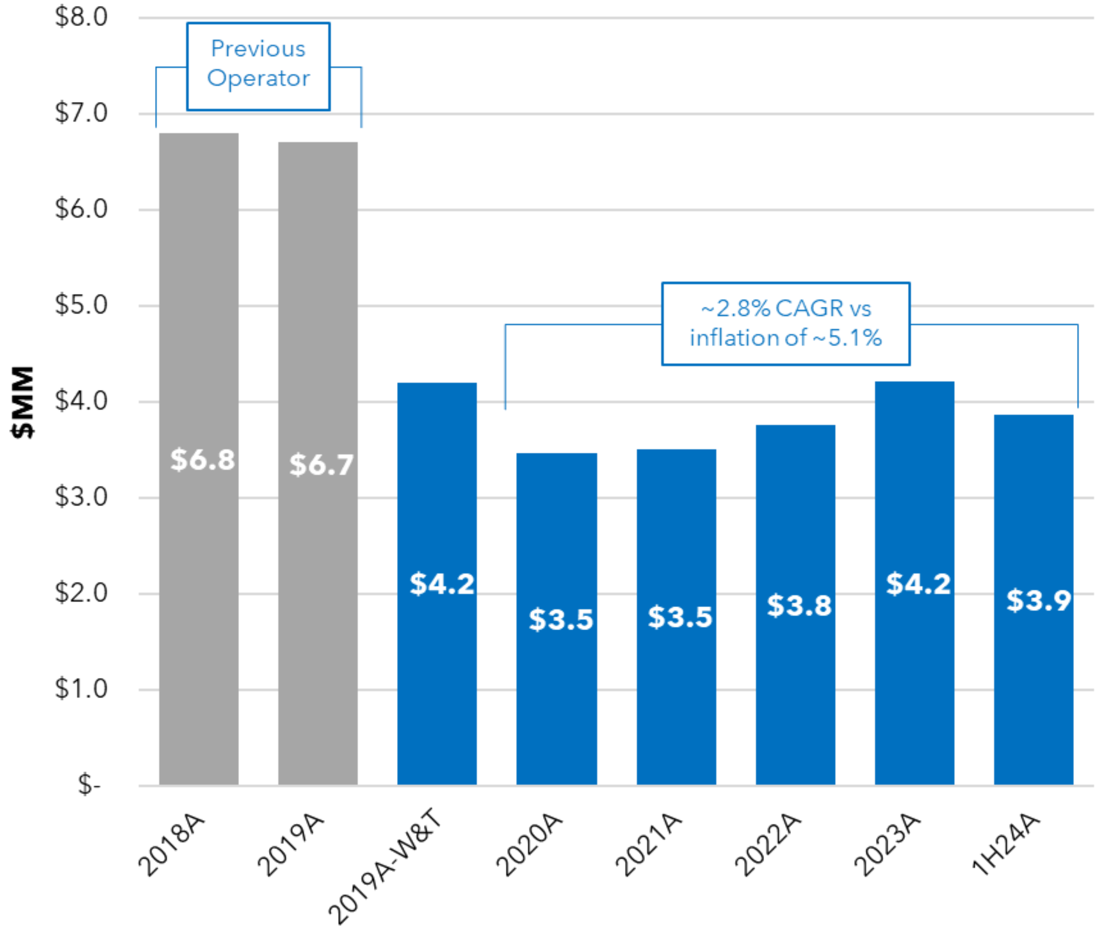
EXXON/CHEVRON MOBILE BAY CASE STUDY

Base LOE/Monthly Average



1) From closing date including capex to June 30, 2024
2) Based on mid-year 2024 reserve report at SEC pricing of $79.45/Bbl and $2.32/MMBtu
3) Total Net Cash Flow as of June 30, 2024, plus mid-year 2024 2P SEC PV10 value (including ARO)

"XOM/CVX Mobile Bay" Fields

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

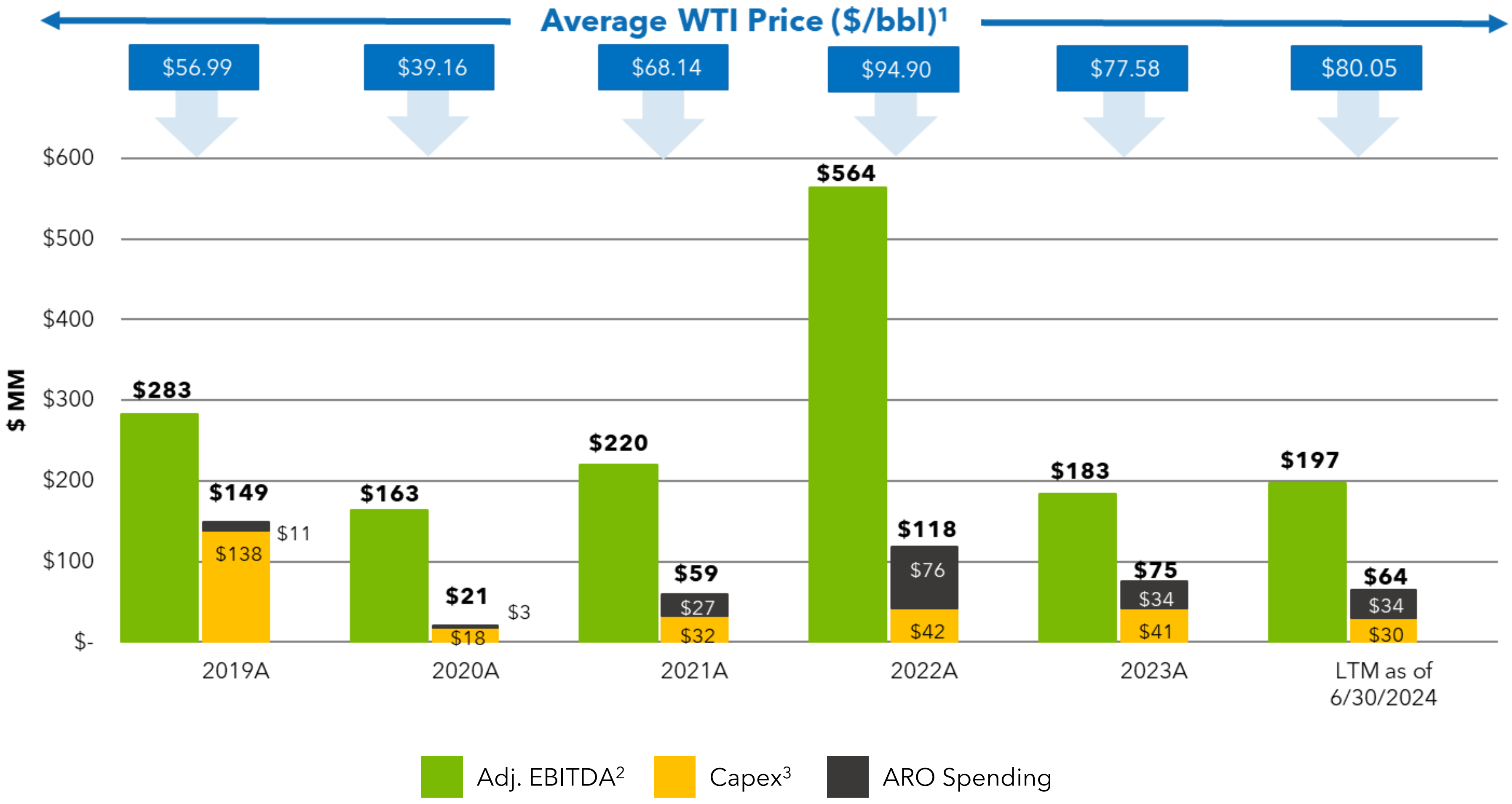
Total Net Cash Flow[1]	$327 MM
MY 2024 2P PV10[2] including ARO	$203 MM
Total Project Value[3]	**$530 MM**

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

Current Reserves[2]

1P Reserves:	56.9 MMBoe
2P Reserves:	66.6 MMBoe
3P Reserves:	77.5 MMBoe

SIGNIFICANT FREE CASH FLOW GENERATION

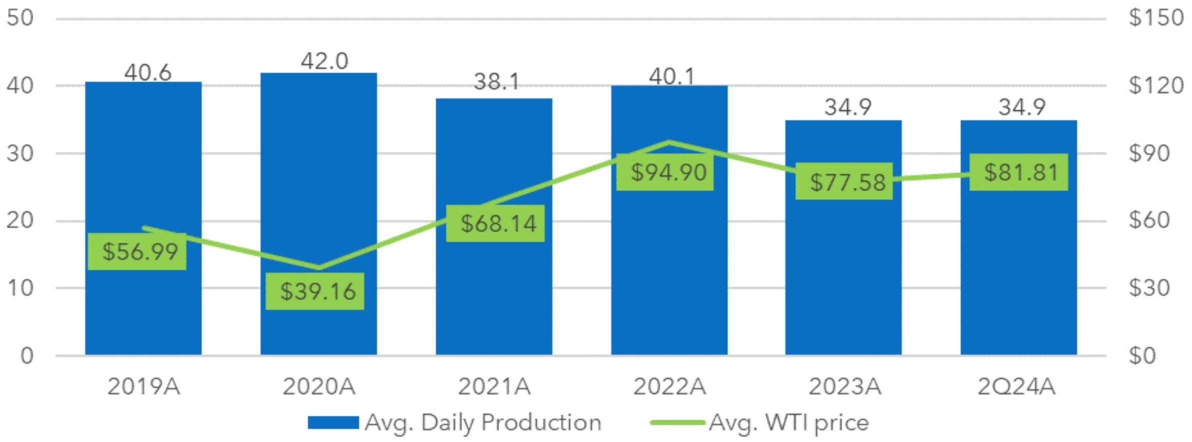


- Strong production base and cost optimization delivers steady Adjusted EBITDA[2]
- Adjusted EBITDA[2] has materially outpaced capex and ARO spending (before acquisitions)
- Free cash flow allowed W&T to reduce Total Debt by **$303 MM** in 2023

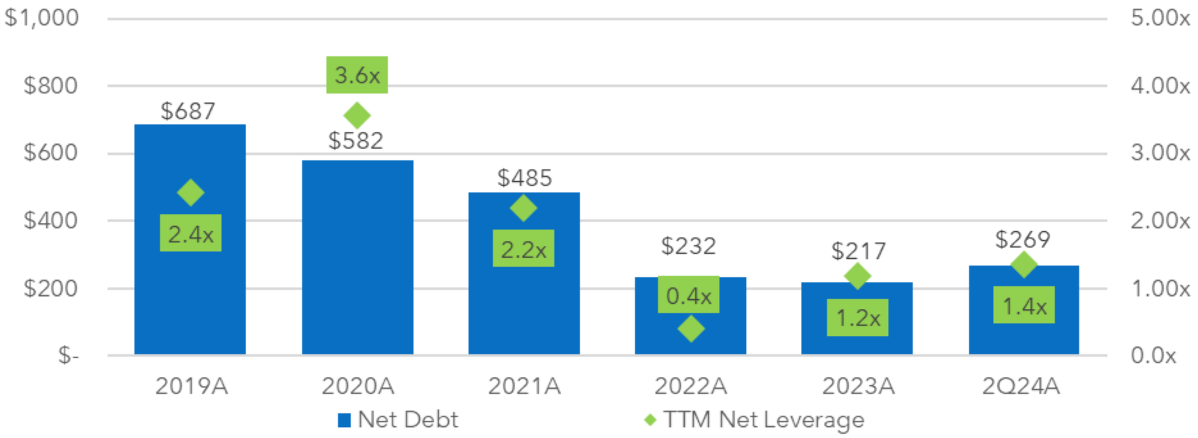
1) Source: EIA
2) Adjusted EBITDA is a non-GAAP financial measure, see Appendix for description of reconciling items to GAAP net income
3) Capex excludes acquisitions; includes only accrual basis capital expenditures

W&T HAS MATERIALLY TRANSFORMED SINCE 2019

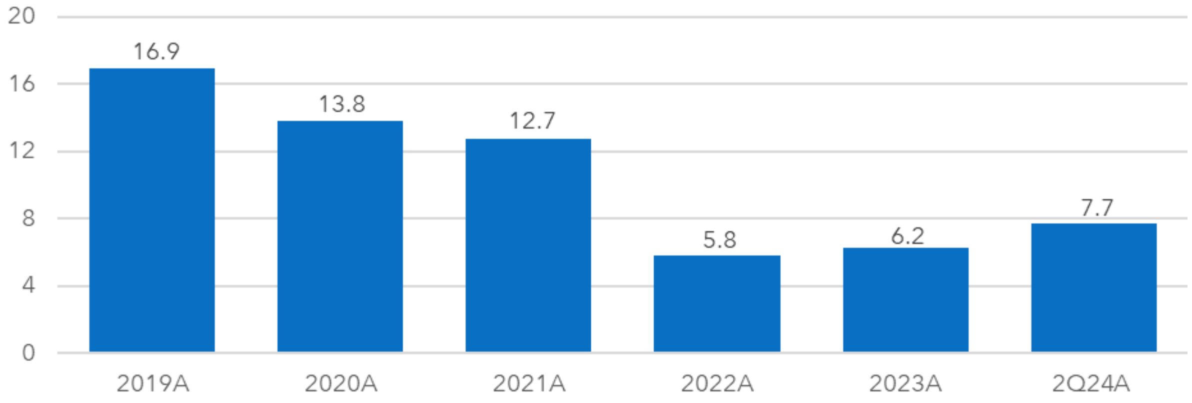
Production and WTI Price (MBoe/d)



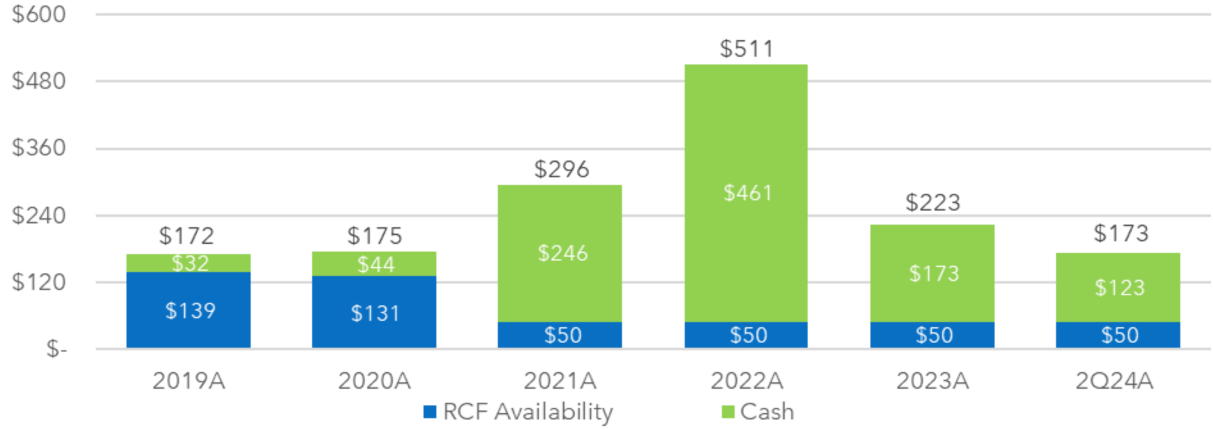
Net Debt and Net Leverage[1] ($MM)



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



Liquidity[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) Liquidity defined as cash balance + available RCF capacity; Cash balance shown includes restricted cash

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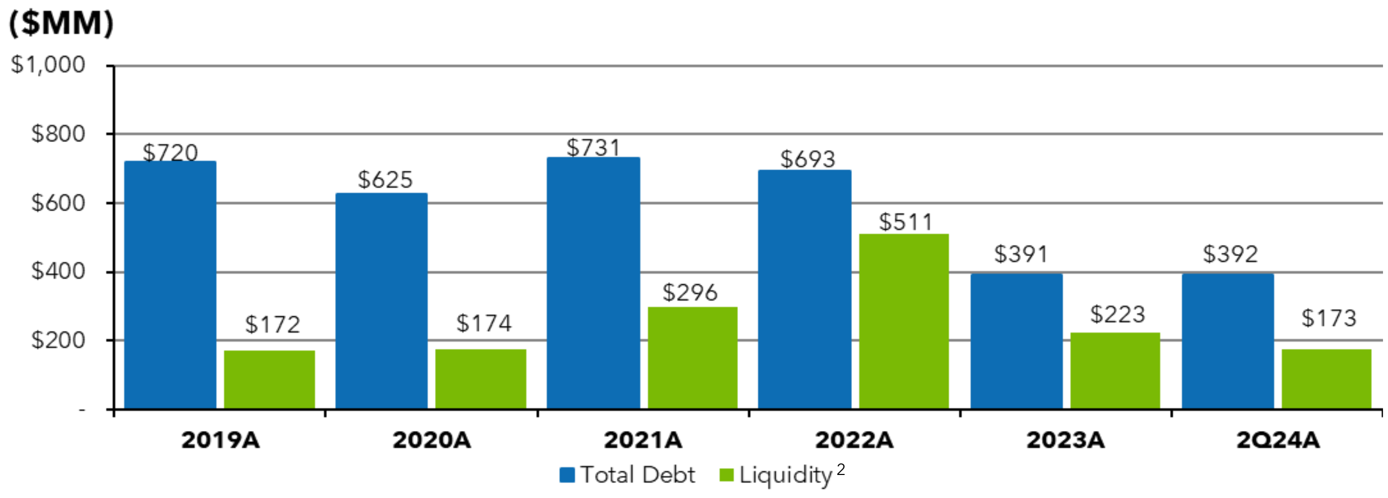
CAPITAL STRUCTURE AS OF JUNE 30, 2024

Net Debt[1] as of 6/30/24 ($MM)

Total Cash & Equivalents (excluding $4.4MM restricted cash)	**$123.4**
11.75% 2nd Lien Notes due Feb. 2026	$271.0
RBL Borrowings	-
7% Non-recourse Term Loan due 2028	111.7
TVPX Loan	9.3
Total Debt	**$391.9**
Net Debt[1]	**$268.5**



- **In 2023 W&T reduced Total Debt by $303 MM**
- 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 was originally due to be amortized over seven years at a fixed interest rate of 7%
  - W&T recently announced liquidity-enhancing modifications to the term loan that include deferring principal repayments of $30.1 MM that would have been due in 2024
  - Mandatory principal repayments to restart in the first quarter of 2025 with the option, but not obligation, to catch up on cumulative amortization through excess cash flow sweep
- 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

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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

Q3 & FY 2024 GUIDANCE

	Third Quarter 2024	Full Year 2024
Production		
Oil (MBbl)	1,175 - 1,325	5,000 – 5,500
NGLs (MBbl)	250 – 300	1,150 – 1,350
Natural Gas (MMcf)	8,500 – 9,500	34,500 – 38,500
Total Equivalents (MBoe)	2,842 – 3,208	11,900 – 13,267
Average Daily Equivalents (MBoe/d)	30.9 – 34.9	32.5 – 36.2
Expenses		
Lease Operating Expense ($MM)	$77.0 – $85.0	$280.0 – $315.0
Gathering, Transportation & Production Taxes ($MM)	7.5 – 8.5	31.0 – 34.0
General & Administrative – Cash ($MM)	16.0 – 17.5	66.0 – 74.0
General & Administrative – Non-Cash ($MM)	3.7 – 4.1	11.5 – 13.5
DD&A ($ per Boe)[1]		13.00 – 14.00
Capital Investment Program		
Capital Expenditures[1]		$35.0 – $45.0
Plugging & Abandonment[1]		30.0 – 40.0

1) Quarterly guidance not provided for select items

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
- Added additional environmental policies and trainings to existing robust program
- Focused on best practices and strategies to reduce emissions
- **Formed a new ESG Committee of the board to develop ESG strategies and initiatives**
- **Spill Ratio[1]: W&T's ratio in 1H24 was 0.004 compared to 1.2 GOM average in 2022**

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
- Continued commitment to shareholder outreach to solicit feedback and respond to concerns
- **Employee and Executive Compensation tied to ESG performance metrics**

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

Note: Additional details on our 2022 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 26 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 0.004 in 1H24 vs. 1.2 average in the GOM for 2022**
- 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

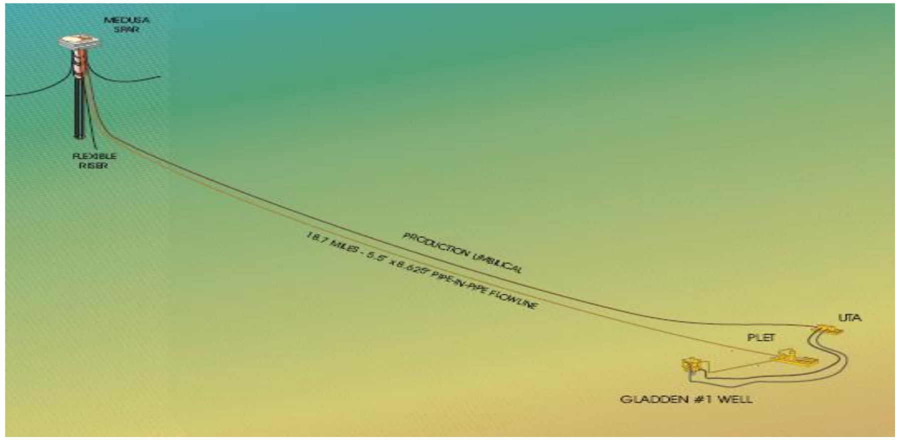
Success Rate
2011 – 2023
89%

50
Successful offshore wells drilled since 2011

SIGNIFICANT INFRASTRUCTURE ADVANTAGE

Platform Rig on infield production facility (EW 910 Area)

Subsea tieback to existing infrastructure (MC 800 Gladden)



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

Economic Advantage

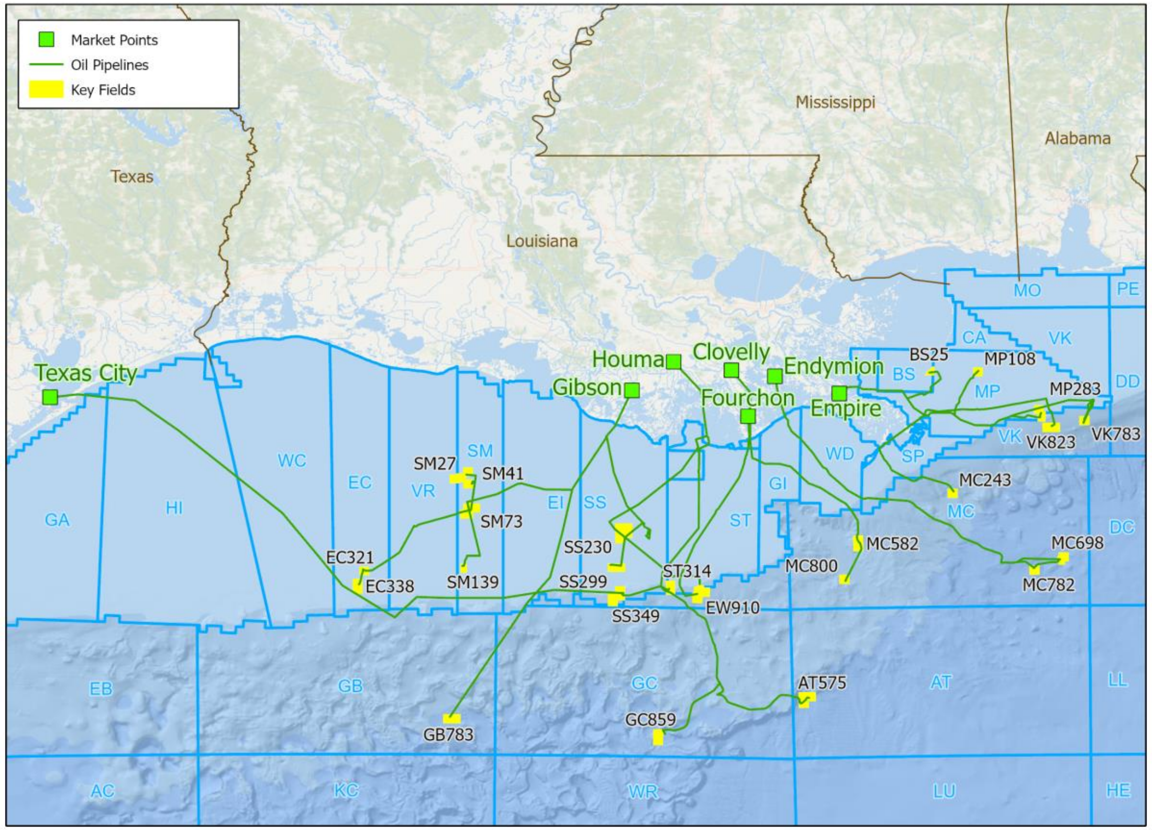
- Reduces capital expenditures
- Increases returns by generating cashflow quicker
- Marketing contracts already in place
- Provides revenue upside in potential Production Handling Agreements (PHA)
  - 2019 $15.3 MM
  - 2020 $7.5 MM
  - 2021 $12.2 MM
  - 2022 $15.4 MM
  - 2023 $13.2 MM

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

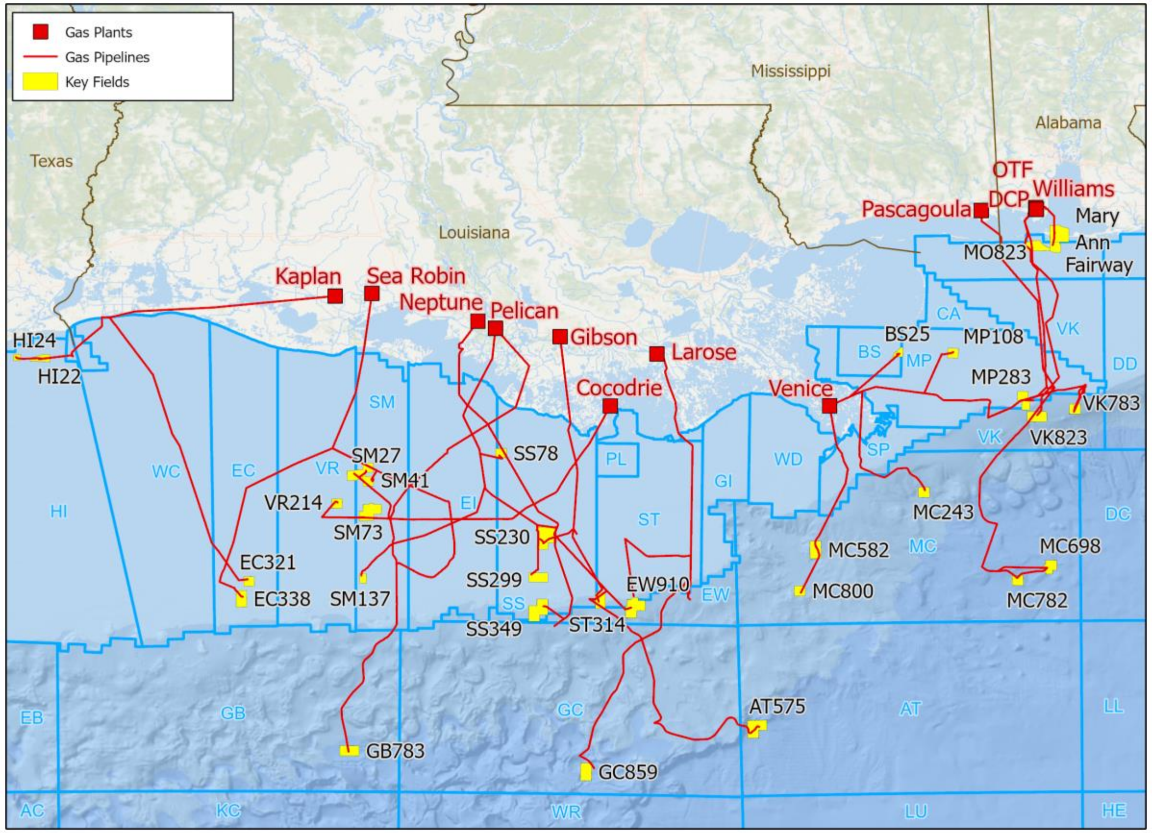
MULTIPLE TAKEAWAY OPTIONS HELP MITIGATE HURRICANE RISK

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

W&T Access to Crude Takeaway Lines

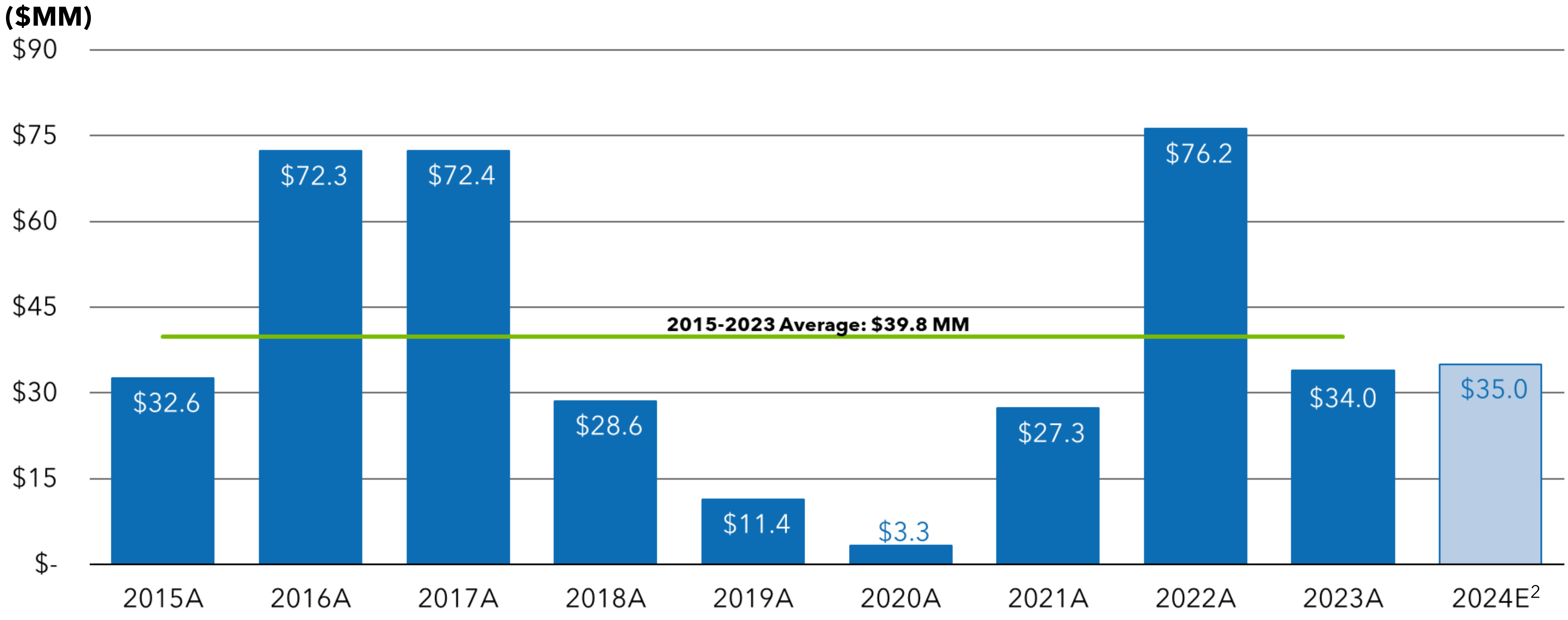


W&T Access to Natural Gas Takeaway Lines



W&T OFFSHORE

P&A EXPENDITURES[1]



1) Net of amounts held in escrow (total of $22.3 MM)
2) Midpoint of 2024 plugging and abandonment expenditures guidance of $30-$40 million

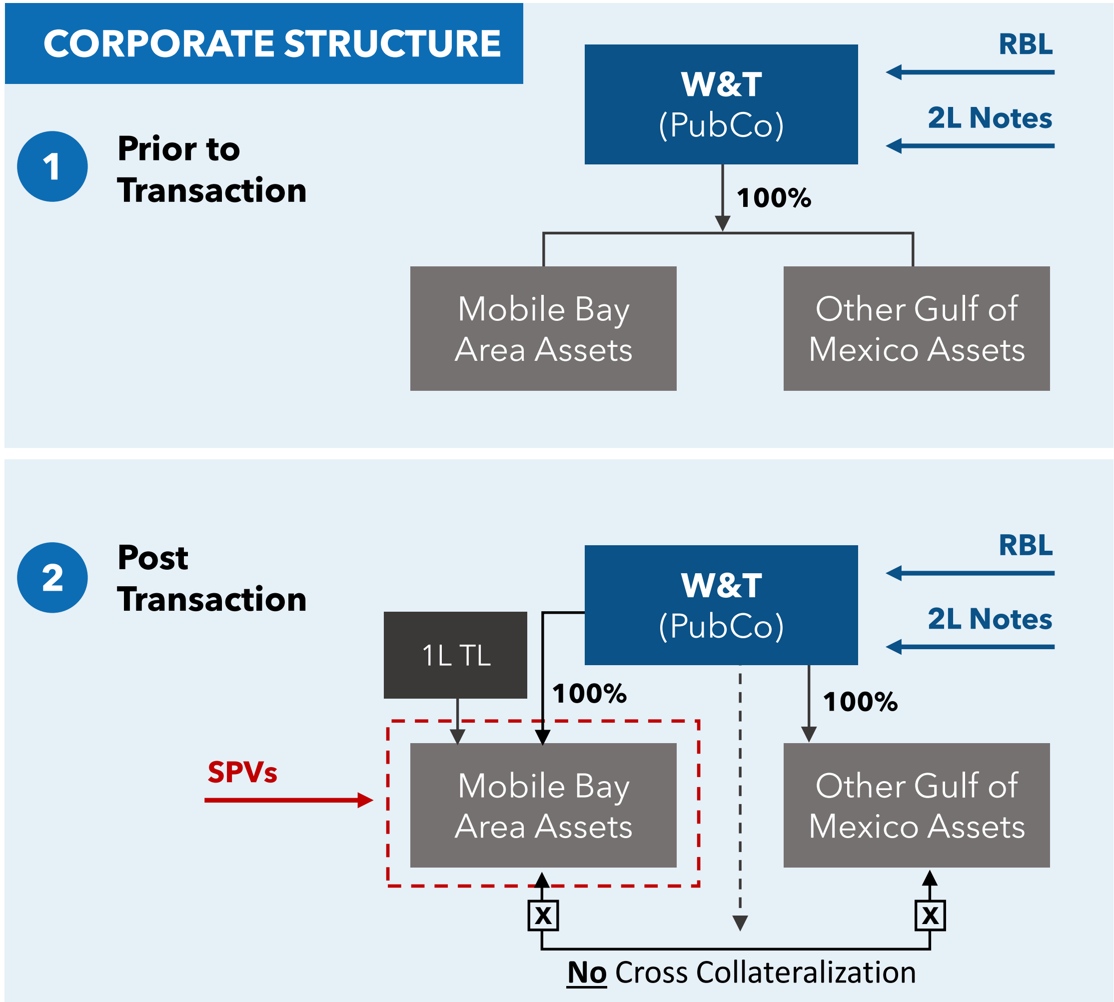
GOM DRILLING JOINT VENTURE

- 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 June 30, 2024
  - 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 substantially lower than 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
- W&T owns 100% of the equity in the SPVs
  - Keeps all cash flows associated with the Mobile Bay area assets after debt service & 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

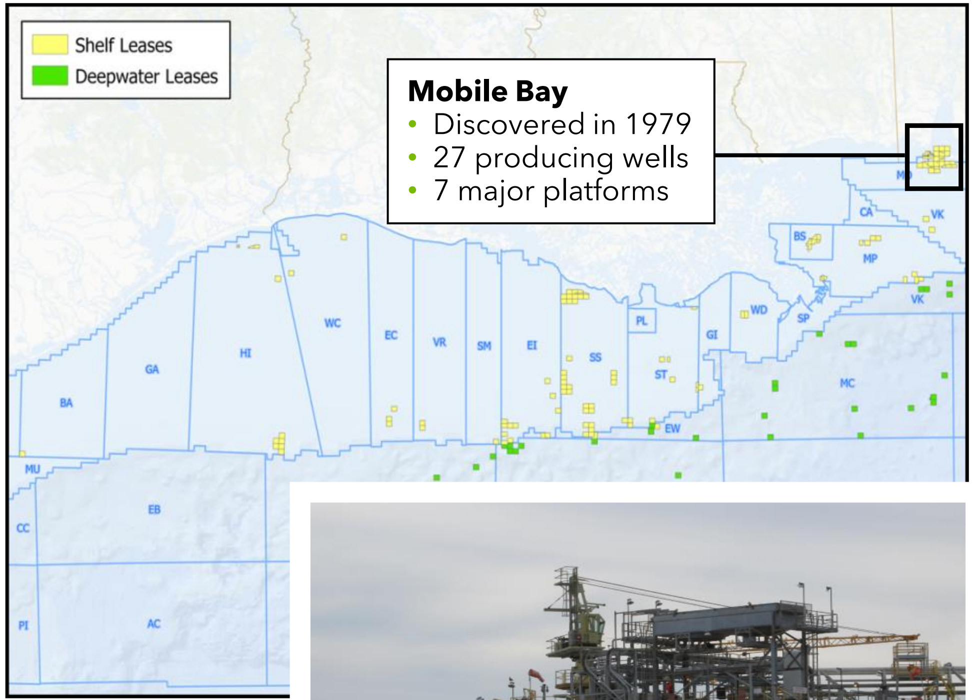


Boosted Cash and Allowed Repayment of the RBL Facility

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
- Mid-Year 2024 proved reserves of ~57 MMBoe[1] of which the vast majority are natural gas (83%) and proved developed producing; 2Q24 average production of 11.9 MBoe/d
- Contains future opportunities including Norphlet drilling leads and optimization of compression facilities



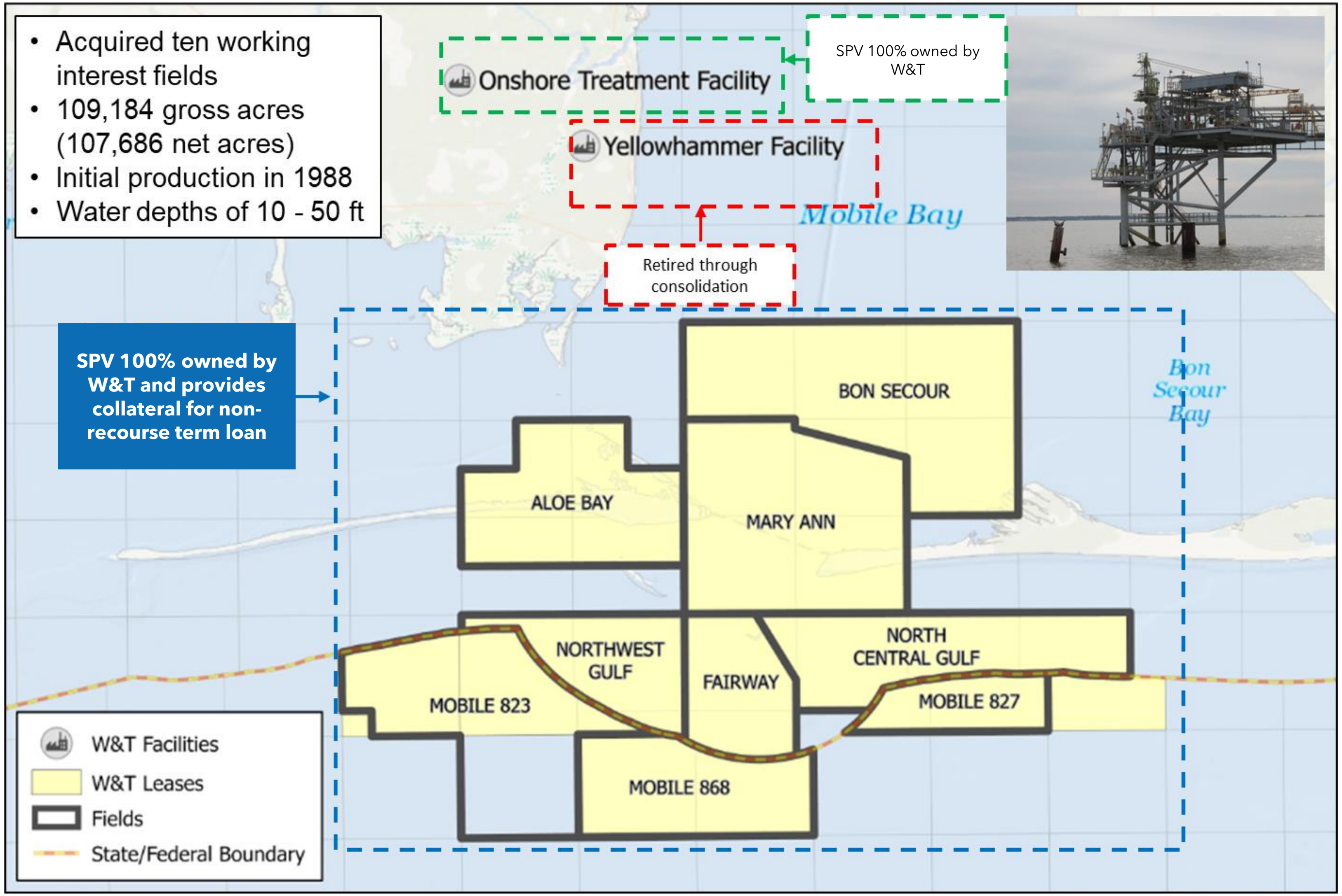
Completed consolidation of natural gas treating facilities at Mobile Bay, which resulted in cost savings beginning in 2021 and reduction of GHG emissions

1) Based on mid-year 2024 reserve report at SEC pricing of $79.45/Bbl and $2.32/MMBtu; before differentials and excluding ARO.

Low Decline, Long-Life, Mostly PDP

MOBILE BAY AREA – ASSET MAP

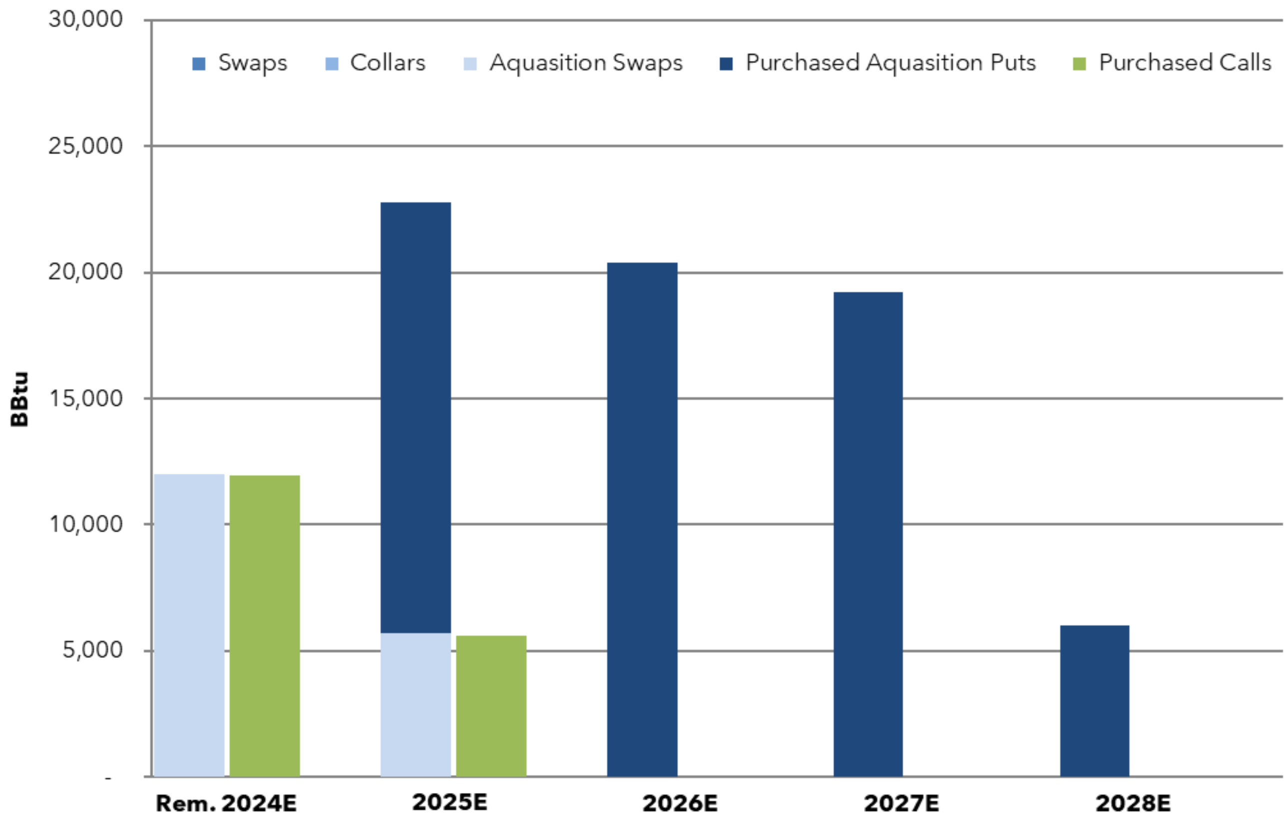
- Acquired ten working interest fields
- 109,184 gross acres (107,686 net acres)
- Initial production in 1988
- Water depths of 10 - 50 ft



W&T OFFSHORE

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 ~63% of remaining 2024 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
  - ~99% 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 2024 natural gas production provided by the Company on August 6, 2024

W&T OFFSHORE

HEDGE SUMMARY

W&T (excluding Aquasition, LLC)

PERIOD	PURCHASED CALLS		
	Total Volume (MMBTU)	Avg daily volume (MMBTU/d)	Weighted Avg strike price per MMBTU
3Q24	5,980,000	65,000	$ 6.13
4Q24	5,980,000	65,000	$ 6.13
2025	5,580,000	62,000	$ 5.50

Aquasition, LLC

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
3Q24	6,000,000	65,217	$ 2.36			
4Q24	6,000,000	65,217	$ 2.51			
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

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 "Net Debt", "Adjusted EBITDA," "Free Cash Flow" and "PV-10" or are derivable from a combination of these measures. 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. Prior period amounts have been conformed to the methodology and presentation of the current period.

We calculate Net Debt as total debt (current and long-term portions) net of unamortized debt discounts, less cash and cash equivalents. Management uses Net Debt to evaluate the Company's financial position, including its ability to service its debt obligations.

The Company defines Adjusted EBITDA as net (loss) income plus net interest expense, income tax expense, depreciation, depletion, amortization, and ARO accretion, excluding the unrealized commodity derivative (gain) loss net of derivative premiums, allowance for credit losses, non-cash incentive compensation, non-recurring IT-transition costs, non-ARO plugging and abandonment costs, 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 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)	June 30, 2024	December 31, 2023
	(Unaudited)	
11.75% Senior Second Lien Notes		
Principal	$ 275,000	$ 275,000
Unamortized debt issuance costs	(4,019)	(5,090)
Total 11.75% Senior Second Lien Notes	$ 270,981	$ 269,910
Term loan		
Principal	$ 114,159	$ 114,159
Unamortized debt issuance costs	(2,499)	(3,052)
Total term loan	$ 111,660	$ 111,107
TVPX Loan		
Principal	$ 10,475	$ 11,025
Discount	(1,027)	(1,294)
Unamortized debt issuance costs	(185)	(144)
Total term loan	$ 9,263	$ 9,587
Credit agreement borrowings	$ -	$ -
Total Debt	$ 391,904	$ 390,604
Cash and cash equivalents[1]	123,375	173,338
Net Debt	**$ 268,529**	**$ 217,266**
LTM Adjusted EBITDA	196,616	183,222
Net Leverage	**1.4x**	**1.2x**

1) Cash balance excludes restricted cash of $4.4 MM

NON-GAAP RECONCILIATIONS

($000s)	Three Months Ended June 30, 2024	Three Months Ended March 31, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
	(Unaudited)			(Unaudited)	
Net Income (loss)	**$ (15,388)**	**$ (11,474)**	**$ (12,109)**	**$ (26,862)**	**$ 13,896**
Interest expense, net	10,164	10,072	10,323	20,236	25,036
Income tax expense, (benefit)	(4,636)	1,045	2,997	(3,591)	11,636
Depreciation, depletion, amortization and accretion	45,074	41,906	35,894	86,980	66,028
Unrealized commodity derivative (gain)/loss and effect of derivative premiums,	2,738	(1,122)	(1,129)	1,616	(40,599)
Allowance for credit losses	346	84	3	430	3
Non-cash incentive compensation	1,386	3,032	2,087	4,418	4,009
Non-recurring costs related to IT services transition	4,202	758	1,078	4,960	1,863
Non-ARO P&A costs	1,709	5,352	-	7,061	6
Other	304	(214)	(312)	90	66
Adjusted EBITDA	**$ 45,899**	**$ 49,439**	**$ 38,832**	**$ 95,338**	**$ 81,944**
Investment in oil and natural gas properties, equipment and other	(8,781)	(3,156)	(15,632)	(11,937)	(22,999)
Asset retirement obligation settlements	(8,209)	(3,788)	(3,199)	(11,997)	(11,841)
Interest expense, net	(10,164)	(10,072)	(10,323)	(20,236)	(25,036)
Free Cash Flow	**$ 18,745**	**$ 32,423**	**$ 9,678**	**$ 51,168**	**$ 22,068**

NON-GAAP RECONCILIATIONS

($000s)	Twelve Months Ended December 31, 2023	December 31, 2022	December 31, 2021	December 31, 2020	December 31, 2019
	(Unaudited)				
Net Income (loss)	**$ 15,598**	**231,149**	**$ (41,478)**	**$ 37,790**	**$ 74,086**
Interest expense, net	44,689	69,441	70,049	61,463	59,569
Income tax expense, (benefit)	18,345	53,660	(8,057)	(30,153)	(75,194)
Depreciation, depletion, amortization and accretion	143,695	133,630	113,447	120,284	148,498
Unrealized commodity derivative (gain)/loss and effect of derivative premiums, net	(58,846)	45,475	87,901	20,762	74,914
Allowance for credit losses	37	(76)	323	(981)	206
Write-off debt issue costs	-	-	1,230	444	-
Non-cash incentive compensation	10,383	7,922	3,364	3,959	-
Non-recurring costs related to IT services transition	3,044	8,237	-	-	-
Release of restricted funds	-	-	(11,102)	-	-
Non-ARO P&A costs	6,246	18,402	4,495	-	-
Gain on debt transactions	-	-	-	(47,469)	-
Other	31	(4,104)	126	(2,708)	816
Adjusted EBITDA	**$ 183,222**	**$ 563,736**	**$ 220,298**	**$ 163,391**	**$ 282,895**
Investment in oil and natural gas properties, equipment and other	(41,278)	(41,632)	(32,062)	(18,162)	(137,905)
Asset retirement obligation settlements	(33,970)	(76,225)	(27,309)	(3,339)	(11,443)
Interest expense, net	(44,689)	(69,441)	(70,049)	(61,463)	(59,569)
Free Cash Flow	**$ 63,285**	**$ 376,438**	**$ 90,878**	**$ 80,427**	**$ 73,978**

NON-GAAP RECONCILIATIONS

($000s)	Three Months Ended June 30, 2024	Three Months Ended March 31, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
	(Unaudited)			(Unaudited)	
Net cash provided by operating activities	**$ 37,446**	**$ 11,642**	**$ 26,197**	**$ 49,088**	**$ 49,632**
Allowance for credit losses	346	84	3	430	3
Amortization of debt items and other items	(1,044)	(1,292)	(1,114)	(2,336)	(4,363)
Non-recurring costs related to IT services transition	4,202	758	1,078	4,960	1,863
Current tax benefit	(311)	312	(4,187)	1	56
Changes in derivatives receivable/(payable)	(1,994)	1,156	(1,201)	(838)	3,897
Non-ARO P&A costs	1,709	5,352	-	7,061	6
Changes in operating assets and liabilities, excluding ARO settlements	(13,132)	17,781	4,846	4,649	(6,093)
Investment in oil and natural gas properties, equipment and other	(8,781)	(3,156)	(15,632)	(11,937)	(22,999)
Other	304	(214)	(312)	90	66
Free Cash Flow	**$ 18,745**	**$ 32,423**	**$ 9,678**	**$ 51,168**	**$ 22,068**
<u>Current tax benefit:</u>					
Income tax expense (benefit)	$ (4,636)	$ 1,045	$ 2,997	$ (3,591)	$ 11,636
Less: Deferred income taxes	(4,325)	733	7,184	(3,592)	11,580
Current tax benefit	$ (311)	$ 312	$ (4,187)	$ 1	$ 56
<u>Changes in derivatives receivable:</u>					
Derivatives payable, end of period	$ (567)	$ 1,427	$ (677)	$ (567)	$ (677)
Derivatives payable, beginning of period	(1,427)	(271)	(524)	(271)	4,574
Change in derivatives receivable (payable)	$ (1,994)	$ 1,156	$ (1,201)	$ (838)	$ 3,897

NON-GAAP RECONCILIATIONS

Reconciliation of PV-10 to Standardized Measure

The Company also discloses PV-10, which is not a financial measure defined under GAAP. The standardized measure of discounted future net cash flows is the most directly comparable GAAP financial measure for proved reserves calculated using SEC pricing. Company management believes that the non-GAAP financial measure of PV-10 is relevant and useful for evaluating the relative monetary significance of oil and natural gas properties. PV-10 is also used internally when assessing the potential return on investment related to oil and natural gas properties and in evaluating acquisition opportunities. Company management believes that the use of PV-10 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. Additionally, Company management believes that the presentation of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. PV-10 is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the Company's estimated oil and natural gas reserves. PV-10 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 of the Company's proved oil and natural gas reserves represents a current market value of the Company's estimated oil and natural gas reserves. With respect to PV-10 calculated as of an interim date (i.e., other than year-end), it is not practical for the Company to reconcile the PV-10 of its SEC pricing proved reserves as of June 30, 2024 because GAAP does not provide for disclosure of standardized measure on an interim basis.

W&T OFFSHORE

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