Barclays CEO Energy-Power Conference

New York City, NY

September 3, 2019

W&T OFFSHORE

Creating Value in the Gulf of Mexico

Forward-Looking Statement Disclosure

This presentation, contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act and Section 21E of the Exchange Act. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding our future operating and financial performance. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties, many of which are described under "Risk factors" in our Annual Report on From 10-K for the year ended December 31, 2018 available on our website and at www.sec.gov. You should understand that the following important factors, could affect our future results and could cause those results or other outcomes to differ materially from those expressed or implied in the forward-looking statements relating to: (1) amount, nature and timing of capital expenditures; (2) drilling of wells and other planned exploitation activities; (3) timing and amount of future production of oil and natural gas; (4) increases in production growth and proved reserves; (5) operating costs such as lease operating expenses, administrative costs and other expenses; (6) our future operating or financial results; (7) cash flow and anticipated liquidity; (8) our business strategy, including expansion into the deep shelf and the deepwater of the Gulf of Mexico, and the availability of acquisition opportunities; (9) hedging strategy; (10) exploration and exploitation activities and property acquisitions; (11) marketing of oil and natural gas; (12) governmental and environmental regulation of the oil and gas industry; (13) environmental liabilities relating to potential pollution arising from our operations; (14) our level of indebtedness; (15) timing and amount of future dividends; (16) industry competition, conditions, performance and consolidation; (17) natural events such as severe weather, hurricanes, floods, fire and earthquakes; and (18) availability of drilling rigs and other oil field equipment and services.

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

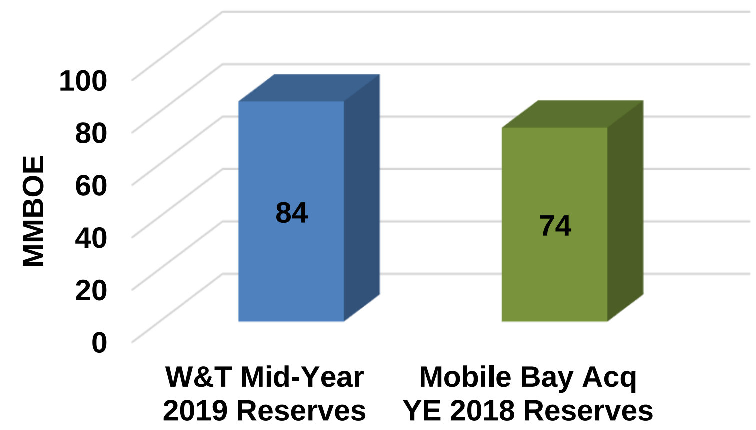
Cautionary Note Regarding Hydrocarbon Quantities.
The U.S. Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally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

Mobile Bay Acquisition

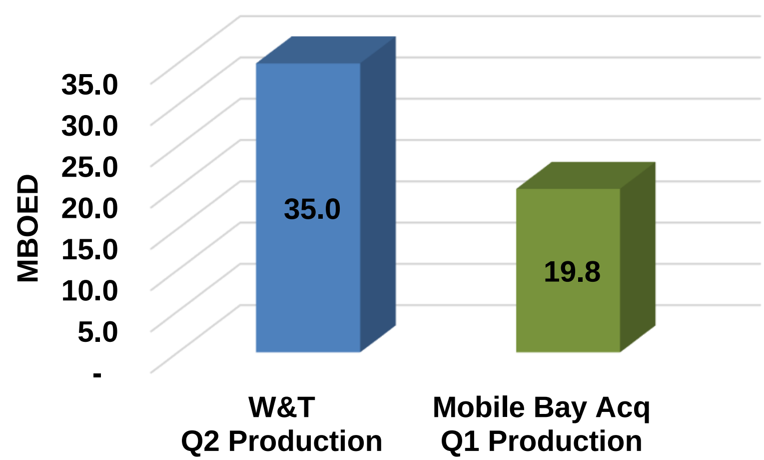
Closed Acquisition on August 30, 2019, Exactly as Planned

- Includes XOM's interests in nine GOM producing fields (eight fields previously operated by XOM) and related onshore/offshore facilities and pipelines
- Adds net proved reserves of 74 MMBOE (22% liquids)
- Produced ~19,800 Boe per day net (25% liquids) in Q1 2019
- Total cash consideration paid by W&T was $167.6 million, which includes a previously-funded $10 million deposit
- Utilized cash on hand and previously undrawn revolving credit facility to finance acquisition
- Contains future opportunities including Norphlet drilling leads and optimization of compression facilities

Nearly Doubles Proved Reserves

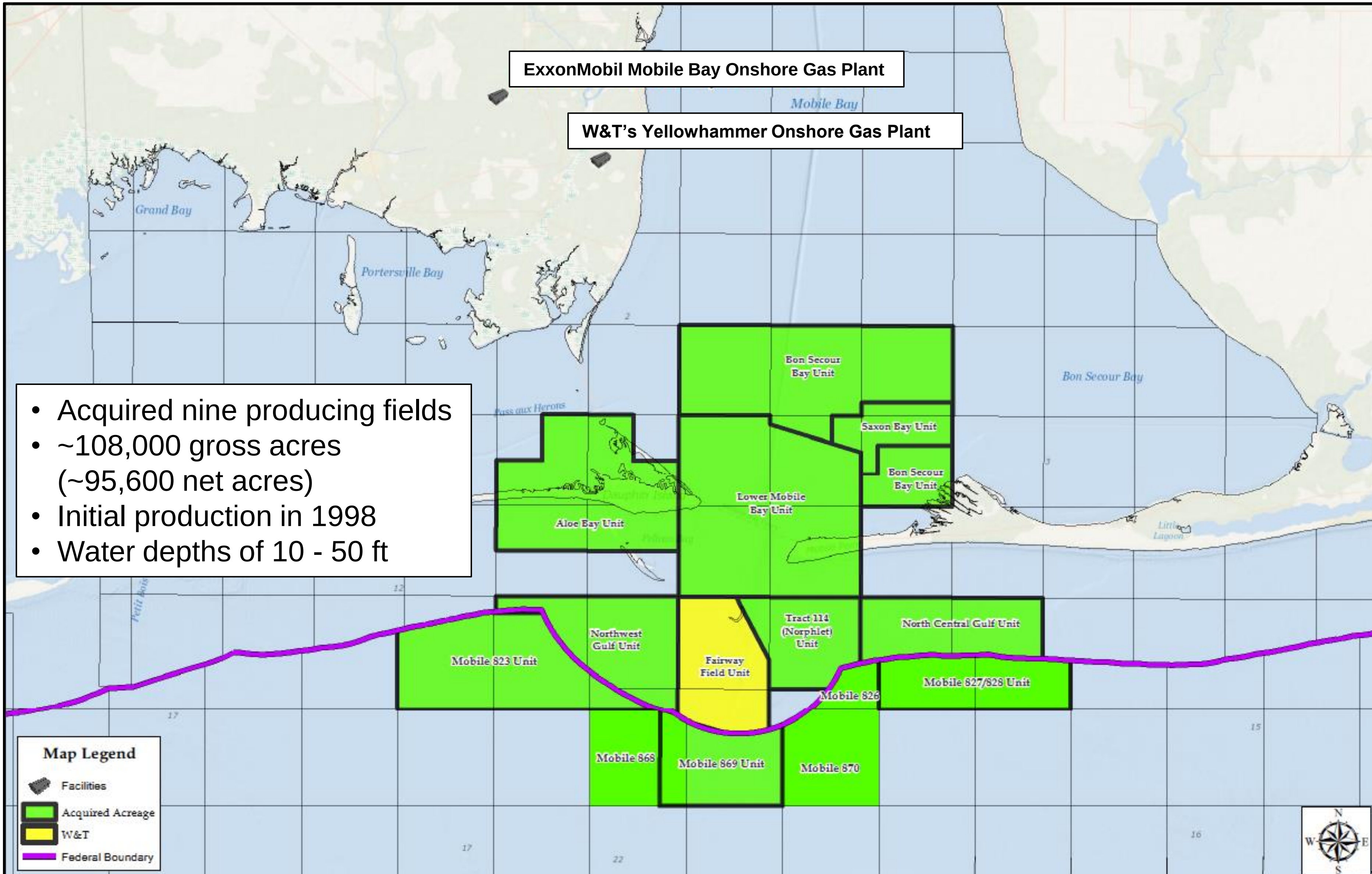


Significantly Adds Production



Allows for Significant Synergies, Consolidations and Cost Savings

Mobile Bay Acquisition – Largest Operator in the Area



- Acquired nine producing fields
- ~108,000 gross acres (~95,600 net acres)
- Initial production in 1998
- Water depths of 10 - 50 ft

Mobile Bay Acquisition – Onshore Gas Treating Facilities

- 100% XOM ownership
- Established 1993
- 420 MMcfd capacity
- 160 MMcfd gross current throughput

- 100% W&T ownership
- Established 1991
- 200 MMcfd capacity
- 50 MMcfd gross current throughput

Mobile Bay Acquisition – Excellent Bolt-on Opportunity

ACQUISITION CRITERIA

Generating Cash Flow

Strong current production rates with the opportunity to reduce operating expenses

- ✓ Q1'19 net production of 19,800 BOEPD
- ✓ Total operating cash flow for 2018 was $70 million
- ✓ Eight of nine fields operated by ExxonMobil along with the onshore treatment facility

Financeable

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

- ✓ 74 MMBoe of low decline, long life proved reserves based on October 15, 2018 strip pricing
- ✓ Vast majority of proved reserves are PDP
- ✓ Potential to add incremental reserves at little or no capital by extending field life
- ✓ Discounted P&A liability of $26 million[1]

Identified Upside

Undrilled prospects, workover or recomplete opportunities, facility upgrades, secondary recovery projects

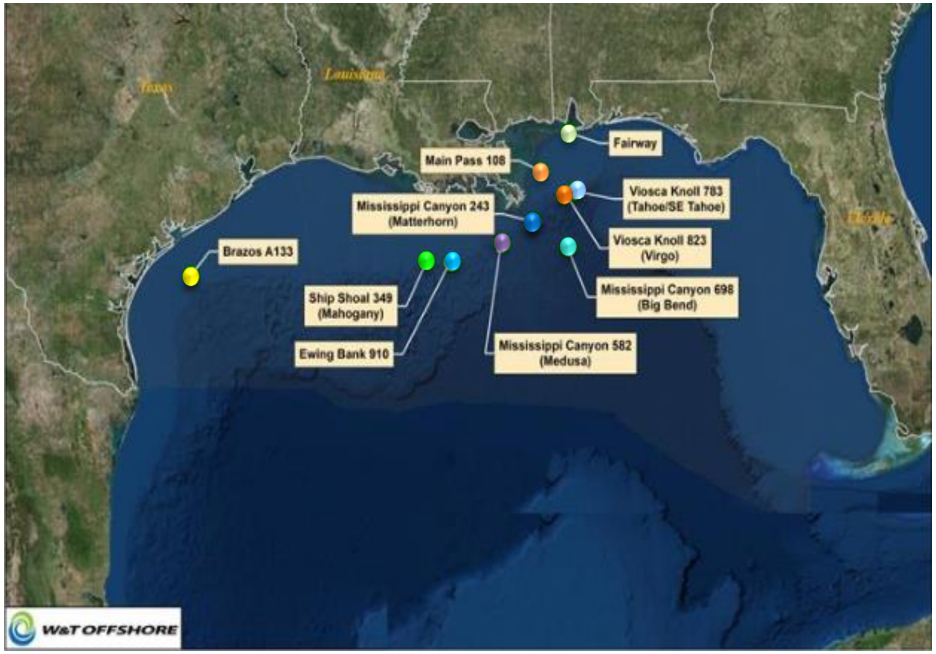
- ✓ Allows for significant synergies, consolidations and cost savings as W&T will become the largest operator in the area
- ✓ Includes 3D seismic with recent reprocessing and survey merge conducted
- ✓ Numerous drilling leads and play concepts identified
- ✓ Opportunities to optimize compression both short and long term

GOM Continues to Provide Attractive Acquisition Opportunities

1) Company plugging and abandonment estimate discounted at 10%

Company Overview

Company Snapshot (Excludes Mobile Bay Acquisition)

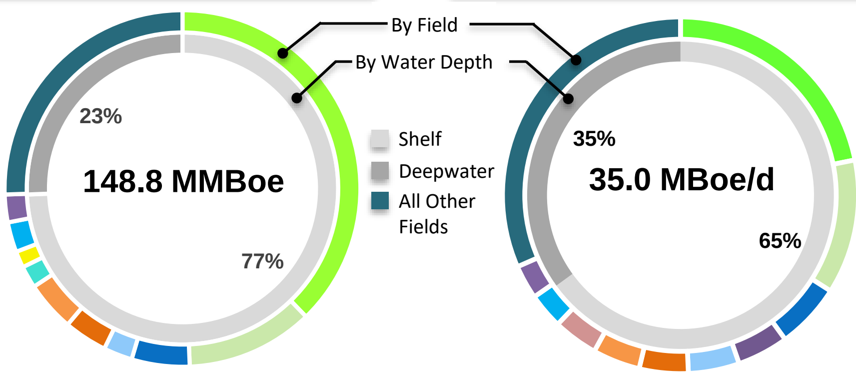


Mid-Year 2019 Net Reserves	Reserves[1] (MMBoe)	PV-10[2] $Billions
1P	84	$1.4
2P	149	$2.4
3P	259	$4.1

Liquids % of 1P Reserves:	58%
2Q 2019 Average Production:	35.0 MBoe/d (61% liquids)
2Q 2019 Adjusted EBITDA[3]	$75.0 MM
2018 Adjusted EBITDA[3]	$347.7 MM
Market Cap[4]: (NYSE:WTI)	$618 MM

SEC 2P Reserves Mix[1]

2Q 2019 Avg. Daily Production[5]



Gulf of Mexico Shelf

- 490,000 gross acres (330,000 net)
- 65% of 2Q 2019 production of 35.0 MBoe/d
- 1P SEC reserves of 63.8 MMBoe[1]
- 2P SEC reserves of 114.6 MMBoe[1]
- Future growth potential from sub-salt projects

Gulf of Mexico Deepwater

- 220,000 gross acres (110,000 net)
- 35% of 2Q 2019 production of 35.0 MBoe/d
- 1P SEC reserves of 19.8 MMBoe[1]
- 2P SEC reserves of 34.2 MMBoe[1]
- Substantial upside with existing acreage

Premium GOM Operator with 30+ Years of Operating History

Note: The outer ring of the pie charts represent contribution by field, with color indicating field location on the map.
1) Based on mid-year 2019 reserve report by NSAI at SEC pricing of $61.45/BO and $3.02/MMbtu.
2) PV-10 is a non-GAAP measure. PV-10% excluding 1P Asset Retirement Obligation, see reconciliation on slide 39.
3) EBITDA and Adjusted EBITDA are non-GAAP financial measures, see slide 38 for a reconciliation to GAAP net income.
4) Market Capitalization based on WTI's share price of $4.39 as of August 30, 2019 market close.
5) Breakout between Deepwater and Shelf reflects total Company production.

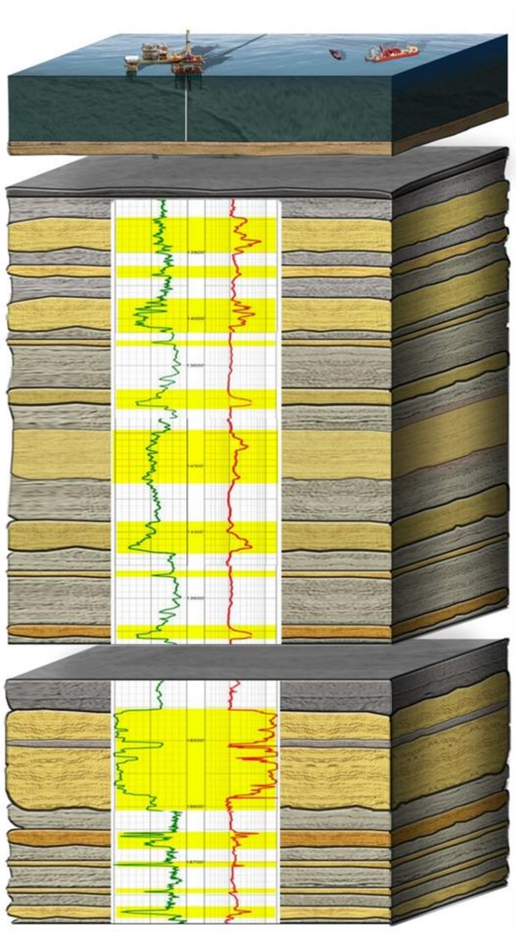
Gulf of Mexico – A Prolific & Unique Basin

Multiple stacked pay development opportunities

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

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

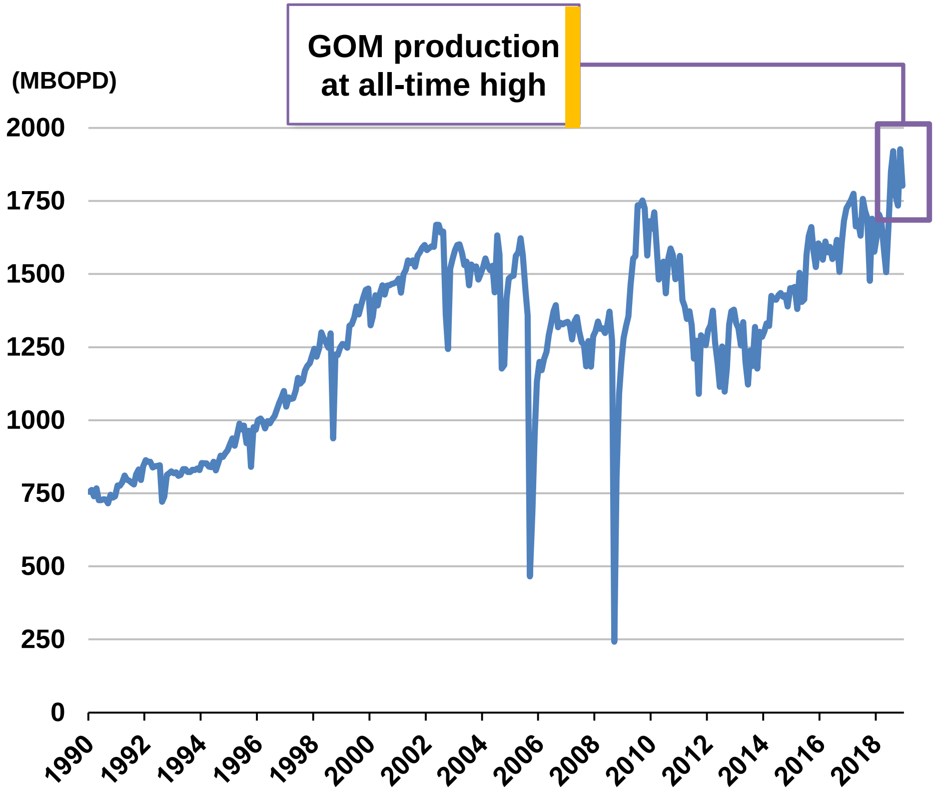
- Typical fields with high quality sands have drive mechanisms superior to primary depletion alone
- These fields enjoy incremental reserve adds annually, partly due to how reserve quantities are booked under SEC guidelines
- Fewer conventional wells required to develop fields



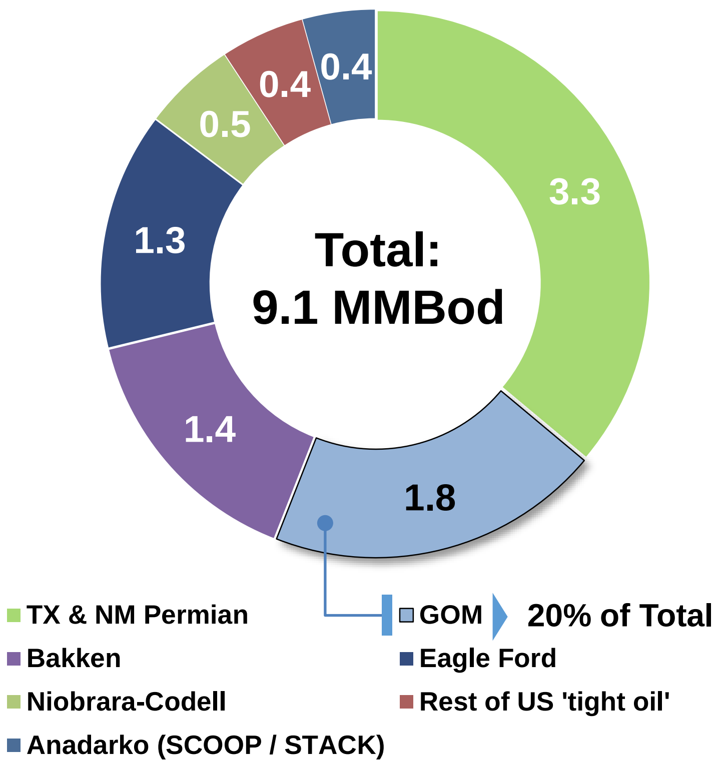
GOM Provides Better Porosity and Permeability than the Permian Basin

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

Gulf of Mexico Historical Oil Production[1]



YE 2018 US Oil Production by Key Region (MMBod)[1]

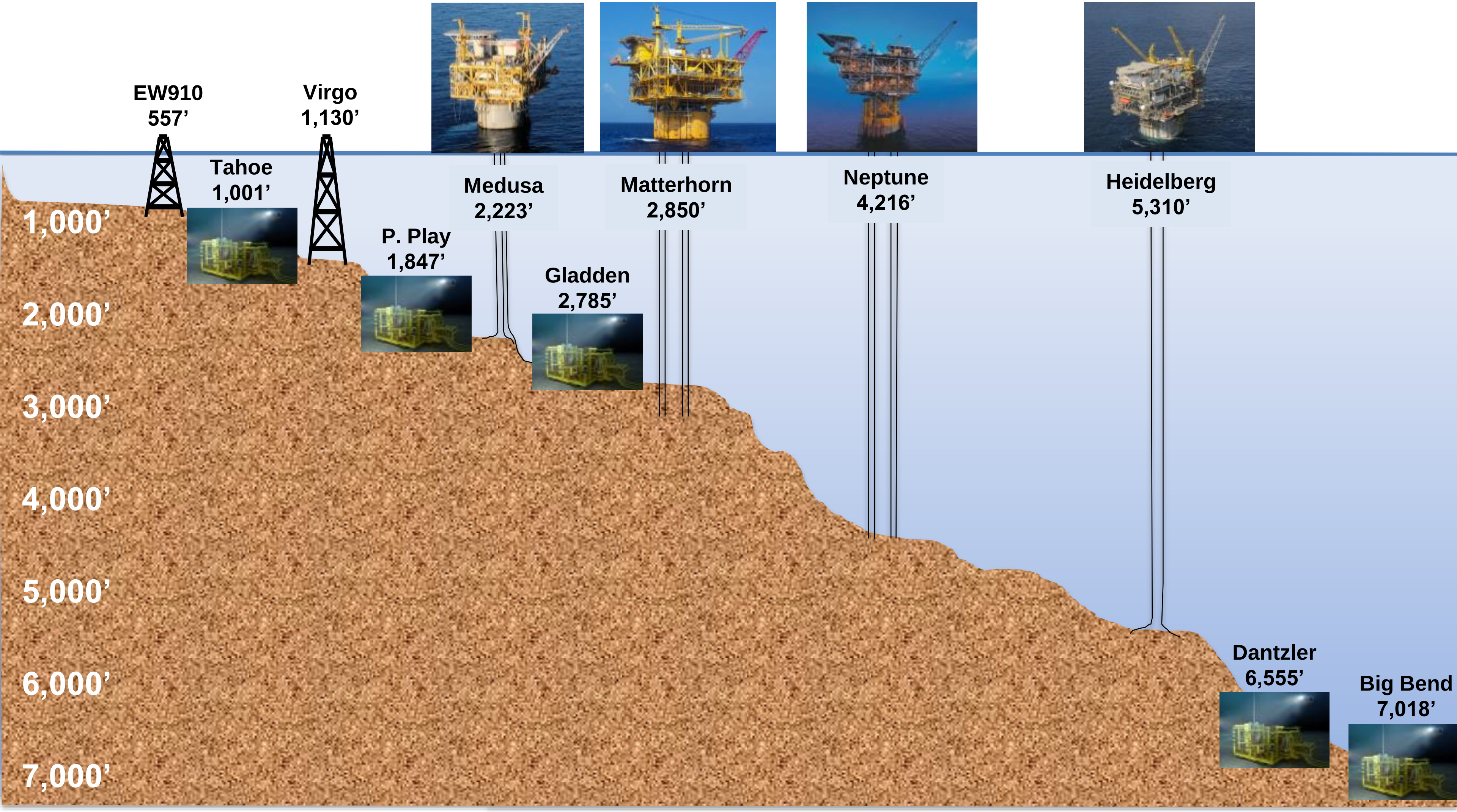


GOM Provides Unique Advantages: Low Decline Rates, World Class Porosity/Permeability and Significant Untapped Reserve Potential

1) Based on U.S. Energy Information Administration (EIA) data as of December 31, 2018.

Successful Diversification in Valuable Deepwater Projects

- WTI's Deepwater portfolio is expanding and diversifying with the Heidelberg Asset (2018) as its latest addition
- WTI operates and participates in various Deepwater Production Facilities, including TLPs, E-TLPs, SPARs, Deepwater fixed structures, and sub-sea tiebacks



Rigorous Technical Evaluation Resulting in High Drilling Success

Process

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

1. **Leads high graded for review; once approved, project team assigned and deadlines set**
2. **Cursory technical evaluation with management and land review with scoping cost and business and technical planning**
3. **Full technical evaluation with probabilistic risk analysis, AFE costing and economic evaluation**
4. **Presentation to Executive management for AFE approval**
5. **Project turned over to execution team and deadlines set**

Track Record of Drilling Success[1]

Over 400 leads evaluated since 2011

Success Rate

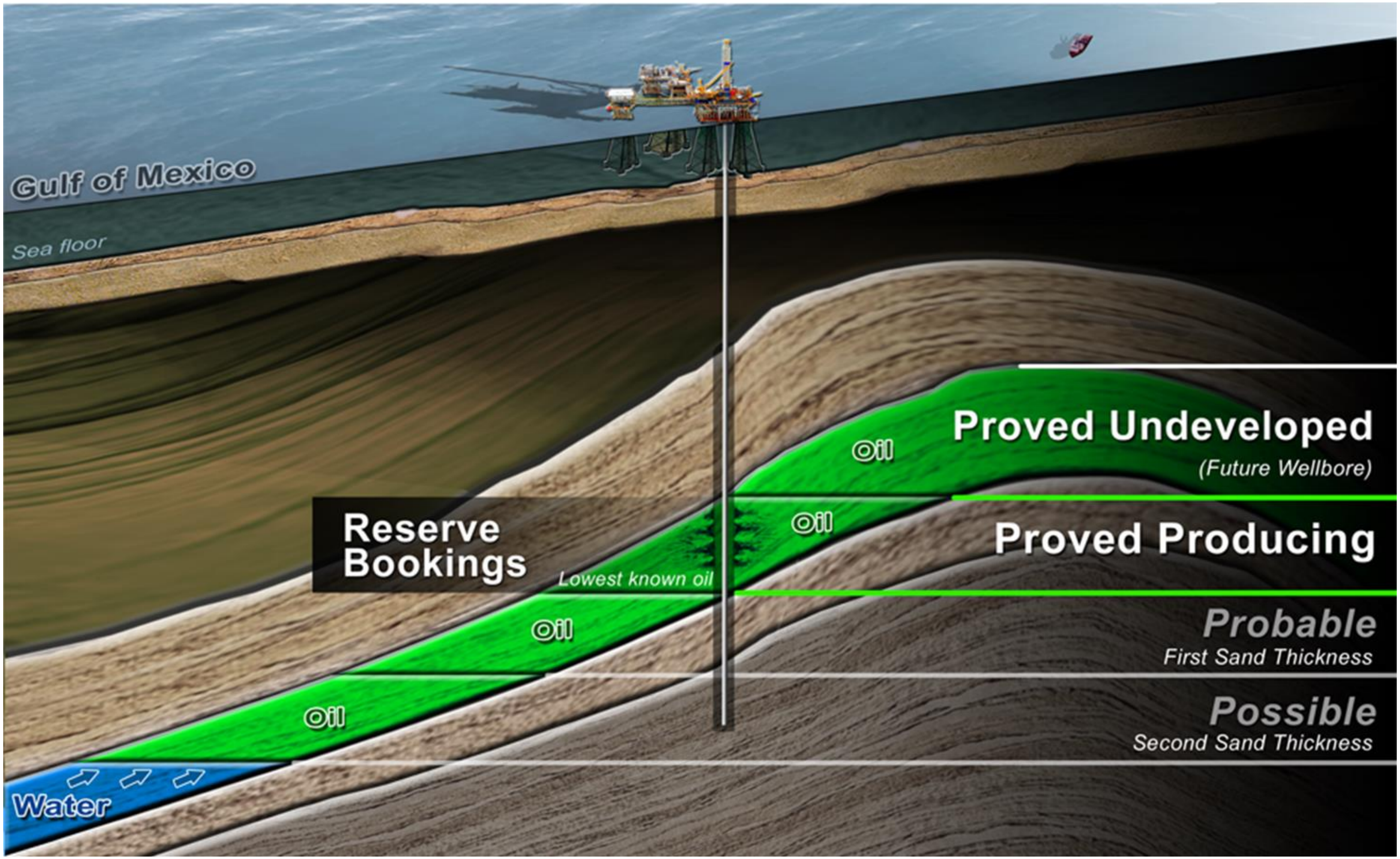
2011 - 2018	1H 2019
~ 93%	100%

47 successful offshore wells drilled since 2011

Rigorous Evaluation Process Has Led to ~94% Success Rate Since 2011

1) Excludes two successful wells that were drilled but uncompleted

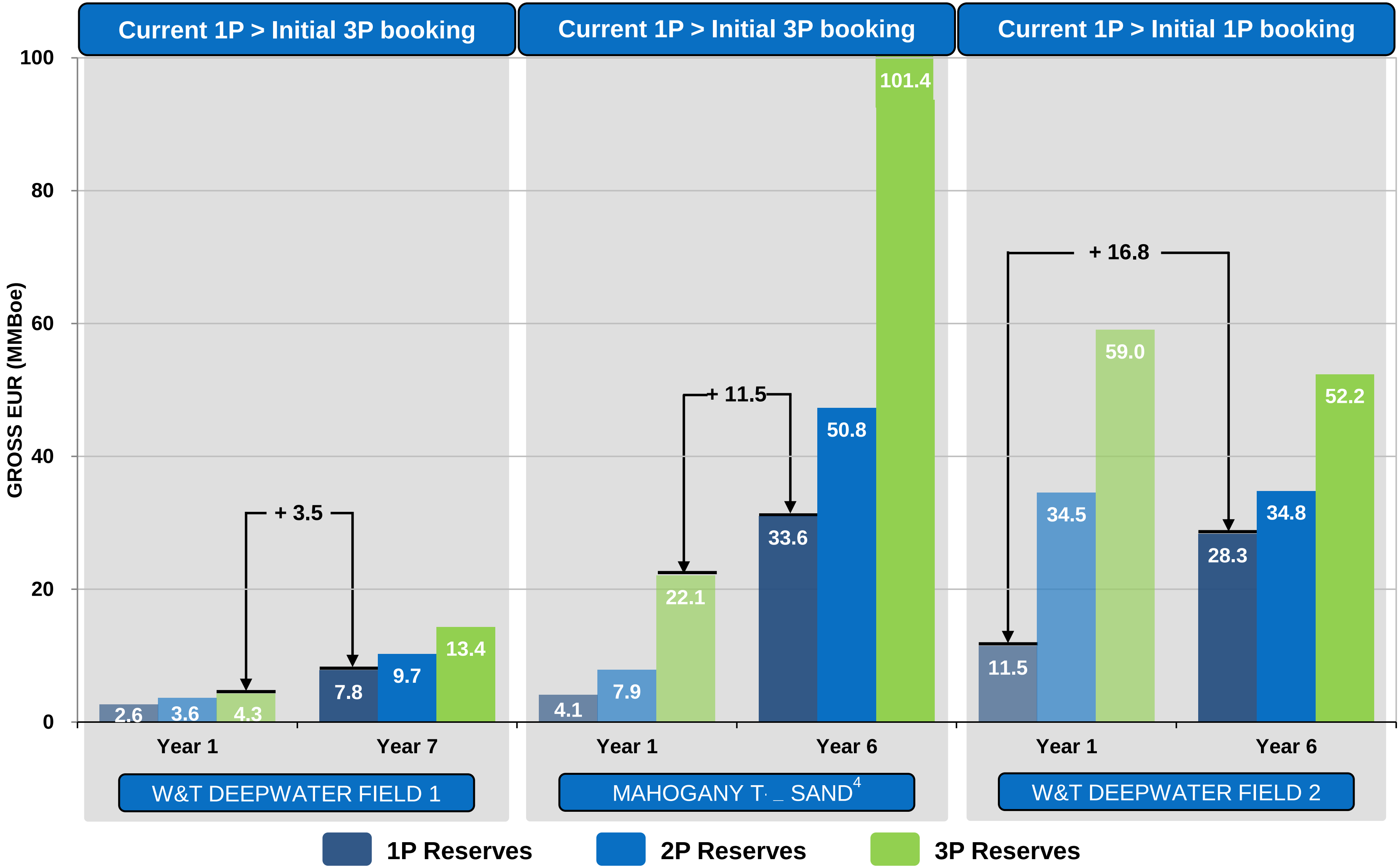
Probable and Possible Reserves May Be Produced at No Cost



Strong Drive Mechanisms Allow Reserve Production From Fewer Wellbores

Significant W&T Reserve Appreciation From Initial Bookings

Actual Results [1,2,3]



1) Mid-Year 2019 Reserve Report prepared by NSAI at SEC 2019 Mid-Year pricing of $61.45/BO and $3.02/MMBtu.
2) 1P = Proved, 2P = Proved + Probable, 3P = Proved + Probable + Possible.
3) Current proved producing reserve growth based on 2019 Mid-Year production.
4) Initial 1P booking includes A-14 well only; 2019 Mid-Year 1P booking includes A-14, A-18, A19 & 2 PUDs; 2P & 3P includes additional development wells.

Realizing Incremental Probable and Possible Reserve Upside[1]

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

1 Prob + Poss Related to PDP

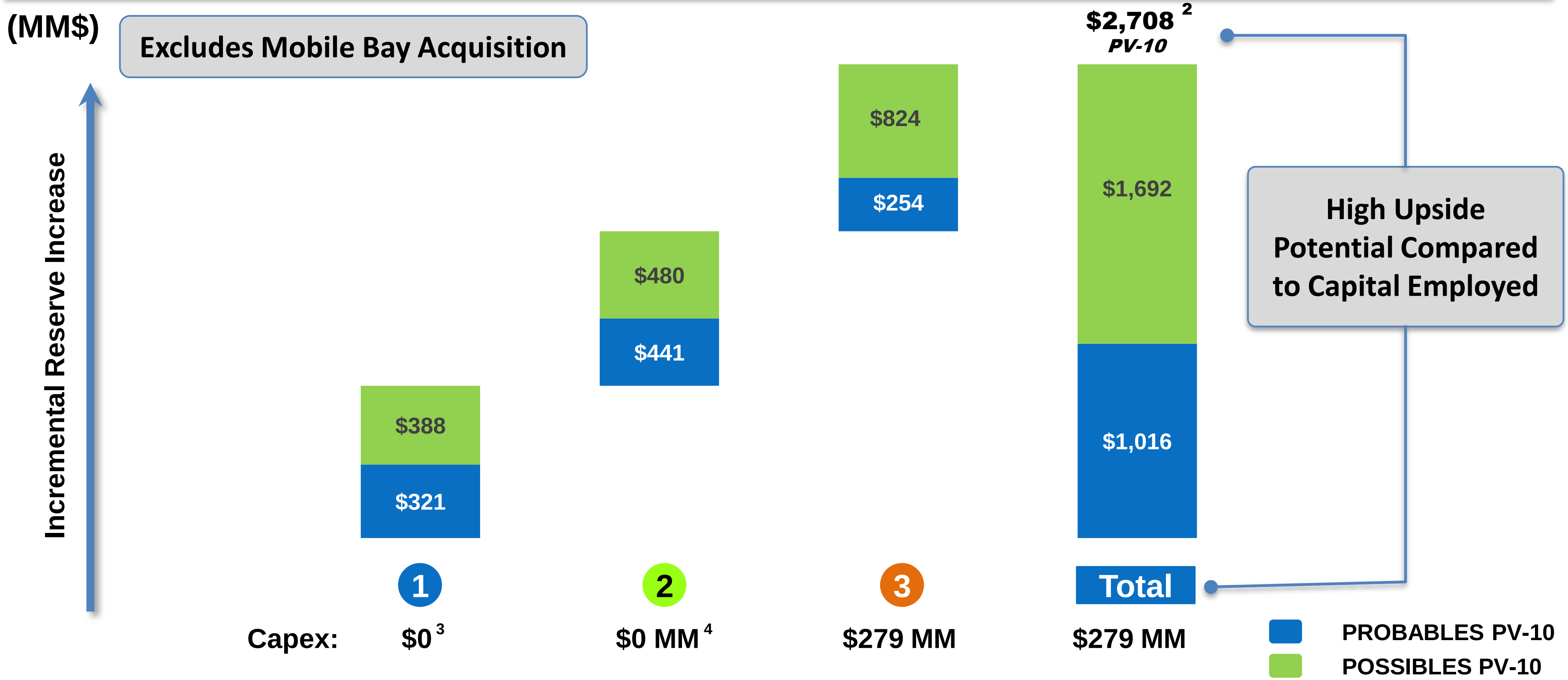
- No additional capex required
- Achievable because of WTI's demonstrated understanding of the fields

2 Prob + Poss Related to PDNP + PUD

- Some additional capex required
- Lower-risk combination of behind pipe recompletions, sidetracks and development wells

3 Prob + Poss Unrelated to 1P Reserves

- Additional capex required
- Limited step-out risk



1) Figures reflect Mid-Year 2019 Reserve Report prepared by NSAI at SEC pricing of $61.45/BO and $3.02/MMbtu.
2) Excludes Asset Retirement Obligation.
3) Probable and possible cases that are largely associated with producing wellbores and require no additional future CAPEX requirements.
4) Probable and possible reserves with no direct CAPEX requirements that are largely associated with PNP and PUD reserves and therefore have associated future indirect CAPEX requirements.

Continued Sub-Salt Exploration and Development Success

SS 349 "Mahogany" (WI: 100%, NRI 83.3%)[1]

- Substantially expanded the size and depth of the field since 2011 by drilling/sidetracking 13 new producing locations
- Stacked pay sands: At least six pay zones proven to be productive in field
  - *Historically, main pay has been the P-Sand*
  - *In 2013, A-14 well logged over 370' of net oil pay in five zones & discovered the deep T-Sand*
  - *In 2016, A-18 well logged oil pay beneath the T-Sand in the 'U' Sand*
  - *In 2018, A-17 well, A-5 sidetrack and A-19 wells placed on production*
  - *In 1Q 2019, recompleted A-6 and acid stimulated A-18 wells*
  - *A-19 well producing >7,000 Boe/d from T-sand in early July 2019*
  - *Currently drilling the A-6ST targeting another sand*
  - *Following the A-6ST, the A-12ST is scheduled, targeting the T-Sand*
- Quality inventory of future drilling projects
  - *Exploiting reservoirs in P, Q, and T thru V - Sands*
  - *Extending Reservoir limits both in depth and aerially*
- Significantly increased field production rate (gross):
  - *3Q2011 rate[2]: ~1,290 Boe/d*
  - *Current rate[3]: ~15,550 Boe/d (76% liquids)*
  - *~12.2x growth since 3Q2011*

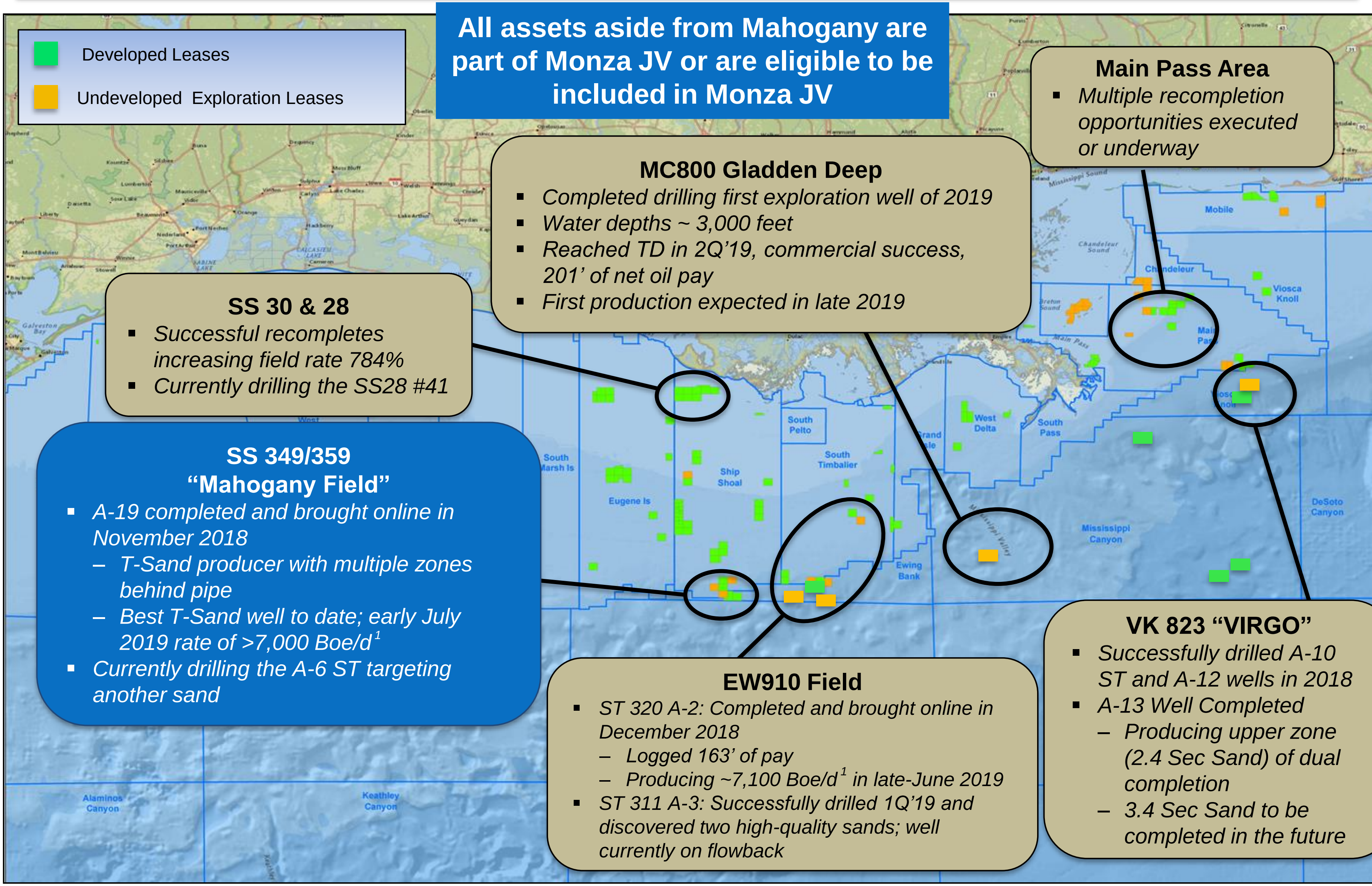
Mahogany Platform

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

1) Except A-5 sidetrack: 30% WI currently.
2) 90-day average daily production, July 1, 2011 – Sept. 30, 2011.
3) 3-day average daily production, Aug 2, 2019 to Aug 4, 2019.

Key Recent Field Activities

Three Rigs Running as of July 31, 2019



All assets aside from Mahogany are part of Monza JV or are eligible to be included in Monza JV

Main Pass Area

- *Multiple recompletion opportunities executed or underway*

MC800 Gladden Deep

- *Completed drilling first exploration well of 2019*
- *Water depths ~ 3,000 feet*
- *Reached TD in 2Q'19, commercial success, 201' of net oil pay*
- *First production expected in late 2019*

SS 30 & 28

- *Successful recompletes increasing field rate 784%*
- *Currently drilling the SS28 #41*

SS 349/359 "Mahogany Field"

- *A-19 completed and brought online in November 2018*
  - *T-Sand producer with multiple zones behind pipe*
  - *Best T-Sand well to date; early July 2019 rate of >7,000 Boe/d*[1]
- *Currently drilling the A-6 ST targeting another sand*

EW910 Field

- *ST 320 A-2: Completed and brought online in December 2018*
  - *Logged 163' of pay*
  - *Producing ~7,100 Boe/d*[1] *in late-June 2019*
- *ST 311 A-3: Successfully drilled 1Q'19 and discovered two high-quality sands; well currently on flowback*

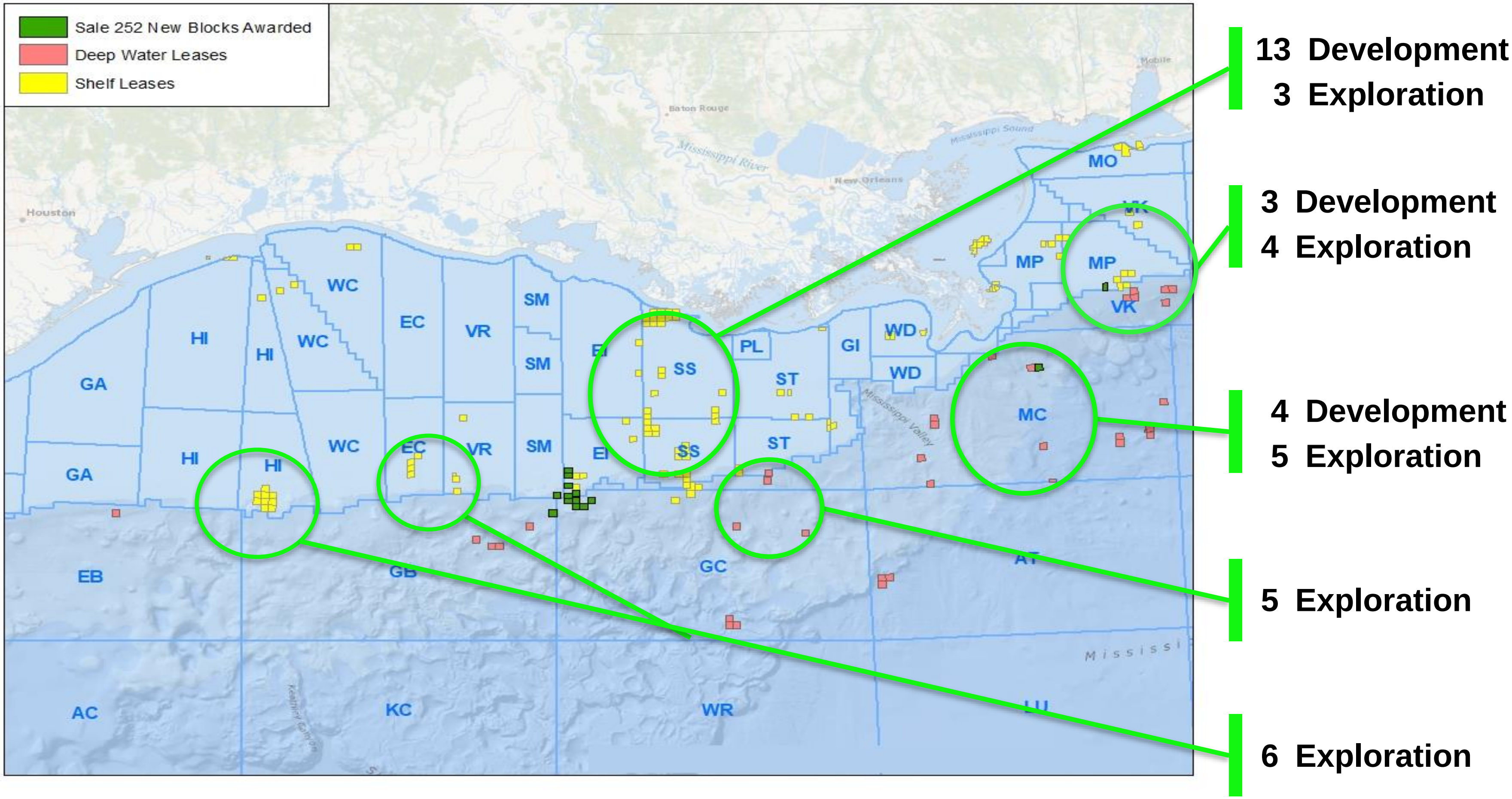
VK 823 "VIRGO"

- *Successfully drilled A-10 ST and A-12 wells in 2018*
- *A-13 Well Completed*
  - *Producing upper zone (2.4 Sec Sand) of dual completion*
  - *3.4 Sec Sand to be completed in the future*

1) Daily production rates presented are gross.

Attractive Current Inventory

Selected Growth Prospects[1]



~50 Near Term Prospects with 39 Platform Wells and 11 Subsea Tiebacks (all < 5 miles) and an estimated P10/3P Resource Potential of ~170 MMBoe

1) Seven growth prospects and additional prospects related to Lease Sale 252 acreage are not listed on the map.

GOM Drilling Joint Venture

- Secured $361.4 MM commitment for the development of 14 pre-identified projects in the GOM with potential to upsize program over time with additional projects
  - Covers the total estimated cost of the 14 wells of $336 MM, plus contingency
  - Drilled 9 wells through 1H 2019
- W&T initially receives 30% of the net revenues from the drilling program wells for contributing 20% of the capital expenditures plus associated leases and providing access to available infrastructure
- HarbourVest Partners and Baker Hughes/GE are the two largest JV interest owners
- JV leverages BHGE's unique and flexible offering to potentially consolidate engineering, products and services and lower costs
- Upon private investors achieving certain return thresholds, W&T's share of well net revenue increases to 38.4%
- Allows W&T to develop its high return drilling inventory at a faster pace with a greatly reduced capital outlay and maintain flexibility to make acquisitions and pay down debt
- JV structure expands W&T's access to well capitalized investors

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

Strategic Capital Allocation Plan

Maintain a prudent balance sheet and use free cash flow to grow opportunistically

Organic Projects

Focus on high rate of return projects and fields with multiple drilling opportunities that can generate cash flow quickly.

Asset Acquisitions

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

Inventory Expansion

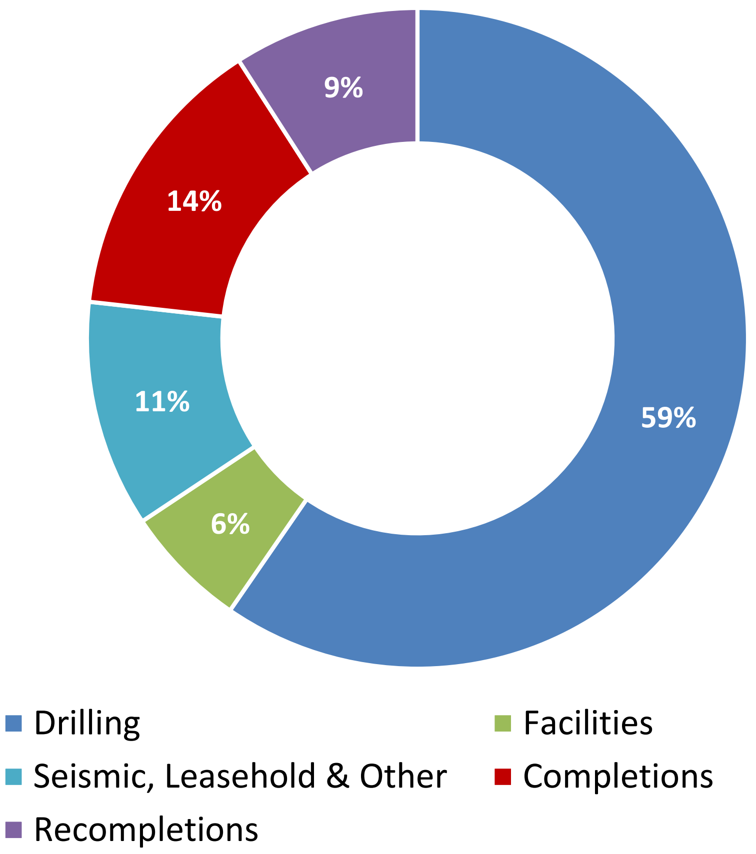
Utilize GOM expertise and new technologies to identify and develop projects. Evaluate potential for joint venture funding.

Generate Shareholder Value

2019 Estimated Capital

- 2019 CAPEX guidance: $125 - $155 MM
- 1H 2019 total capital expenditures of ~$63 MM plus $10 MM deposit for GOM Mobile Bay acquisition
- Approximately six exploration & six development wells planned
- ~26% of 2019 capital devoted to Monza projects
- 2019 ARO forecast ~$23 MM

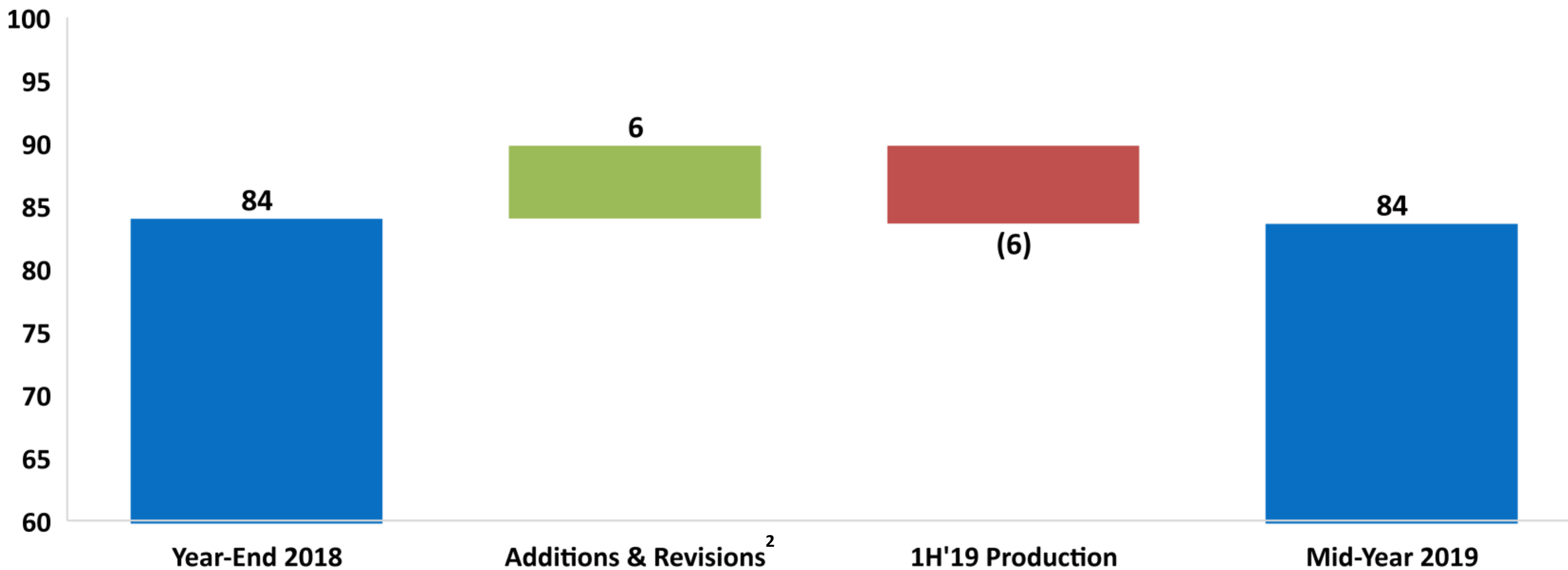
CAPEX Allocation[1]



2019 Capital Expected to be Funded by Cash From Operations

1) Based on midpoint of 2019 FY guidance range.

Mid-Year 2019 Reserves Summary[1]



- **Excludes reserves related to Mobile Bay acquisition**
- PV-10[3] of 1P Reserves at SEC Pricing = $1.4 Billion
- 148.8 MMBoe Net Proved + Probable (2P) Reserves
- PV-10[3] of 2P Reserves at SEC Pricing = $2.4 Billion

YTD Positive Revisions and Additions Replaced 1H 2019 Production

1) Mid-Year 2019 Reserve Report prepared by NSAI at SEC pricing at $61.45/BO and $3.02/MMbtu.
2) Includes (0.5) MMBOE of downward revisions due to price
3) Pre-Tax PV-10 is a non-GAAP measure Pre-Tax PV-10% excluding 1P Asset Retirement Obligation, see reconciliation on slide 39.

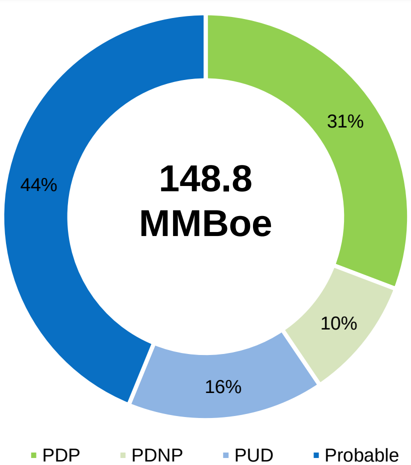
Reserves Summary: Mid-Year 2019 Reserve Report 1

Excludes Mobile Bay Acquisition

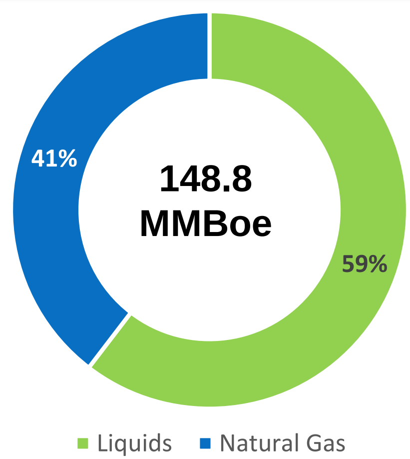
Current Reserve Report (SEC Pricing) Overview[1]

Reserve Category	Total (MMboe)	% Liquids	Pre-Tax PV-10% [2]
Proved Developed Producing (PDP)	45.8	53.9%	$804.7
Proved Developed Non-Producing (PDNP)	14.5	65.9%	251.2
Proved Undeveloped (PUD)	23.3	60.2%	347.4
Total 1P Reserves (Excluding ARO)	**83.6**	**57.7%**	**$1,403.3**
Total 2P Reserves (Excluding ARO)	**148.8**	**58.5%**	**$2,419.2**
1P Asset Retirement Obligations (ARO)			(179.3)[4]
Total 1P Reserves (Including 1P ARO)	**83.6**	**57.7%**	**$1,224.0**
Total 2P Reserves (Including 1P ARO)	**148.8**	**58.5%**	**$2,239.9**

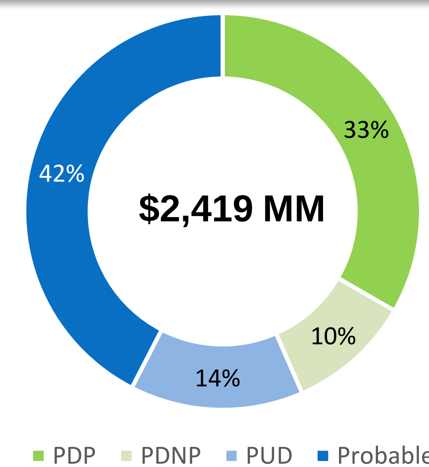
2P Reserves[1]



2P Reserves[1]



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



1) Mid-Year 2019 Reserve Report prepared by NSAI at SEC pricing of $61.45/BO and $3.02/MMbtu.
2) Pre-Tax PV-10% is a non-GAAP measure; see reconciliation on slide 39.
3) Pre-Tax PV-10% excluding 1P Asset Retirement Obligation.
4) Year-end 2018 amount

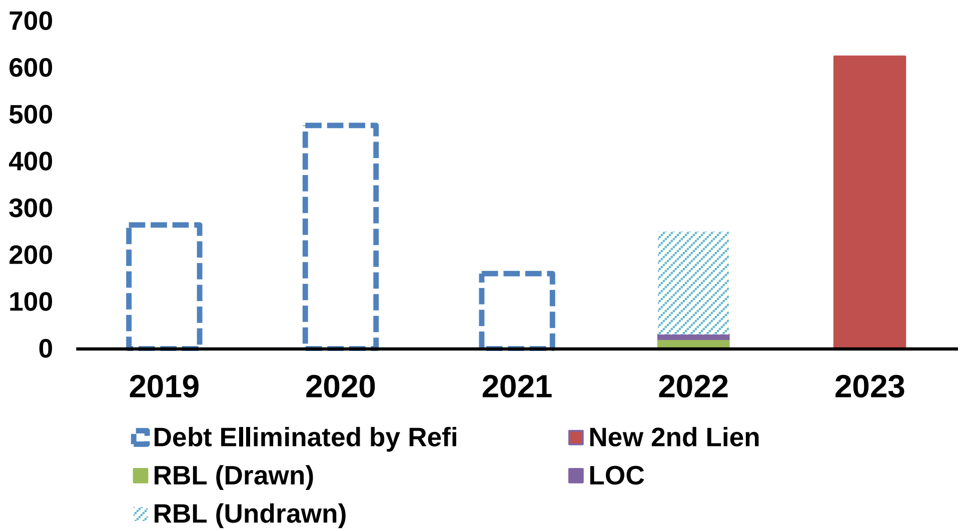
Financial Overview

Significantly Improved Capital Structure

Liquidity as of 06/30/19 (Excludes Mobile Bay Acquisition)

9.75% 2nd Lien Notes due 2023	$625 MM
RBL Borrowings[1]	$ 21 MM
Total Debt	**$646 MM**[2]
Total Cash & Equivalents	$ 66 MM
Available Under RBL[3]	$222 MM
Total Liquidity	**$288 MM**

Debt Maturity Schedule ($MM)

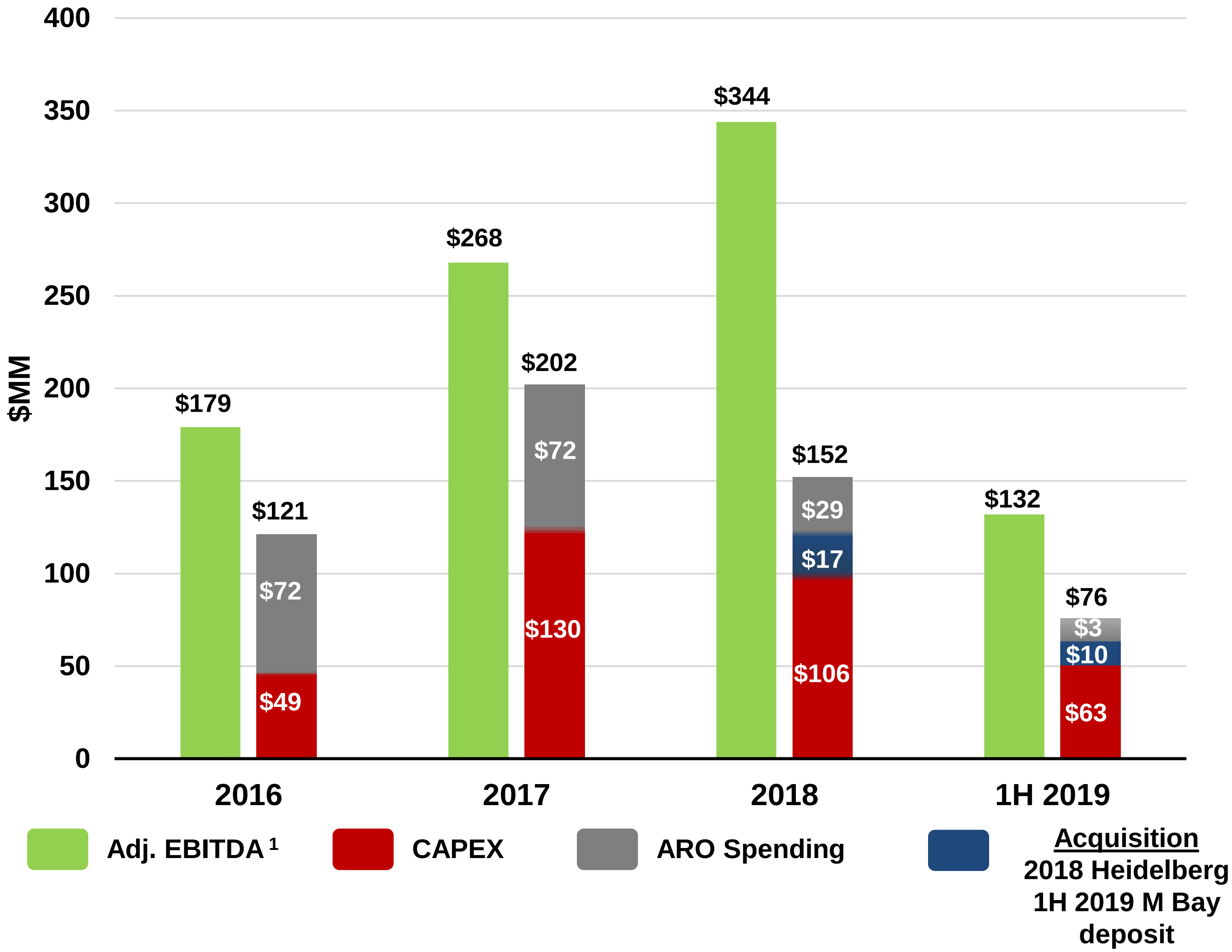


- On October 18, 2018 closed a major debt refinancing
  - Simplified capital structure
  - Reduced debt principal outstanding from $903 MM to $625 MM
  - Extended the maturities of RBL and debt principal
  - Increased borrowing base from $150 MM to $250 MM
- Strong liquidity position provides optionality
- Paid down remaining RBL balance in July 2019

Improved Balance Sheet Provides Flexibility for Future Growth

1) RBL borrowings exclude $7.2MM of outstanding letters of credit.
2) Excludes reduction of $12 MM related to debt issuance costs.
3) RBL availability reduced by $7.2 MM of outstanding letters of credit.

Generating Steady and Significant Free Cash Flow



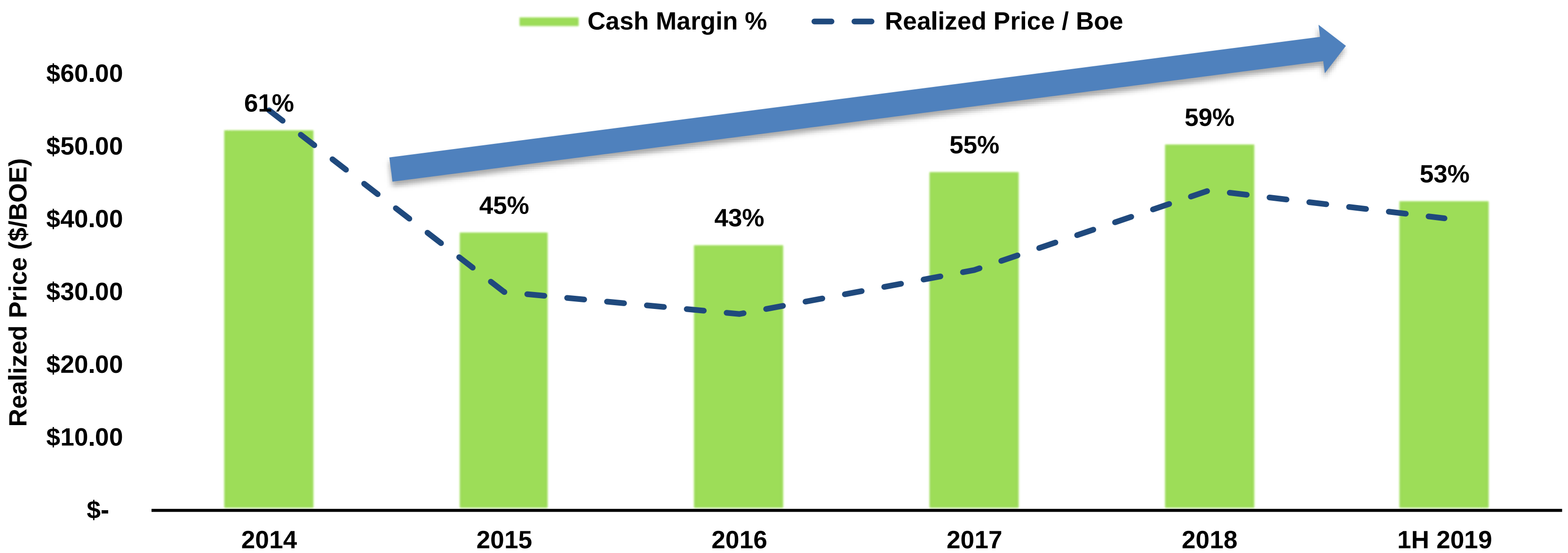
- Strong production base and cost optimization delivers steady Adjusted EBITDA[1]
- Adjusted EBITDA materially outpacing CAPEX and ARO spending
- Utilized growing cash balance to reduce debt in Q4 2018

Substantial Cash Flow Generation Provides Optionality

1) Adjusted EBITDA is a non-GAAP financial measures, see slide 38 for a reconciliation to GAAP net income.

Improving Cash Margins From Operational Cost Cutting

- Despite falling commodity prices in 2015 and 2016 putting pressure on realized price, WTI was able to take advantage of a favorable services environment to renegotiate long-term service contracts and reduce fixed costs, offsetting top-line margin pressure
- As commodity prices rise from downturn lows, WTI continues to realize benefits from these continued lower service costs in the Gulf of Mexico

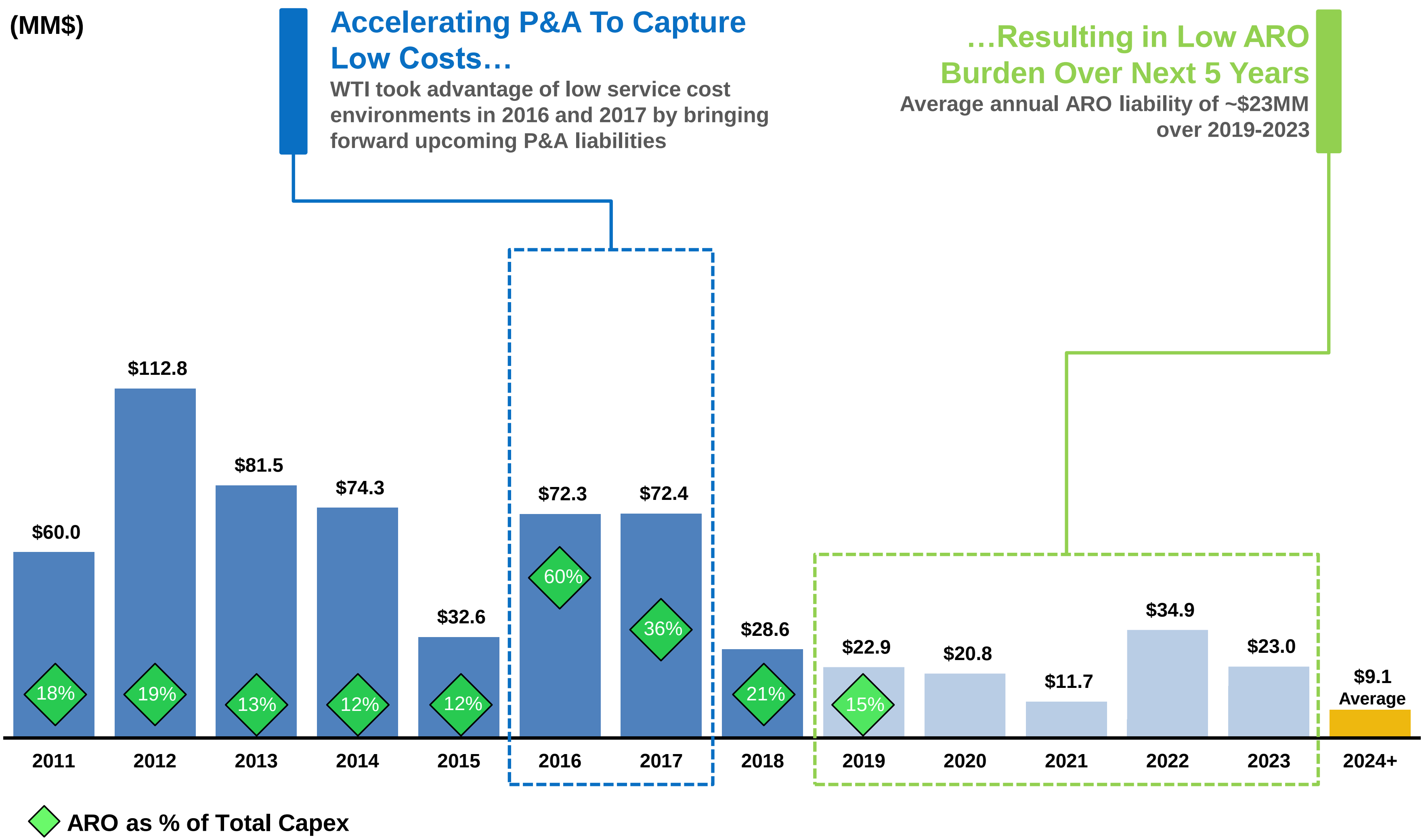


	2014	2015	2016	2017	2018	1H 2019
Total Lifting Costs: $/Boe [1]	$20.68	$16.18	$14.70	$14.99	$17.57	$20.09
Cash Margin: $/Boe [2]	$32.81	$13.16	$11.06	$18.03	$25.62	$20.04

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

Proactive Management of Asset Retirement Obligations

Undiscounted P&A Schedule[1,2] (Excludes Mobile Bay Acquisition)



1) Net of amounts held in escrow (total of $15.7 MM); Additional P&A liability estimate of $213.8 MM from 2024-2046, with an average annual burden of ~$9.3 MM; $12.6 MM of estimated total P&A liability after 2046.
2) As of year-end 2018.

Investment Highlights

Generating Significant Free Cash Flow and High Profit Margins

- Capital allocation to high return, quick payback projects allowed W&T to generate $322 MM of operating cash flow in 2018
- 1H 2019 Adjusted EBITDA[1] of $132 MM
- Inventory of lower risk/higher return projects, plus upside opportunities

High Quality Asset Base with Substantial Low-Risk Upside

- Leveraging expertise of technical teams, combined with innovations to add value to existing assets
- Captured $800 MM of probable and possible reserve upside with no additional capital required
- Better seismic data is leading to better decisions and enhanced recoveries
- Projects include high rate of return stacked-pay development with exploration components in very large known reservoirs

Strong Returns

- Optimizing operations has reduced LOE per Boe and D&C costs
- Platform drilling, subsea tiebacks to existing infrastructure and high-quality assets led to 3-year F&D costs < $6.50/Boe
- Surplus equipment and services in GOM allows for improved contract terms that significantly lowers drilling, development and asset retirement costs

Restructured Balance Sheet and Good Liquidity

- In October 2018, closed debt refinance reducing debt by $217 MM, increased borrowing base facility by $100 MM and extended maturities
- Established a drilling joint venture that allows us to drill and exploit assets on a promoted basis with reduced capital outlay
- Leveraged low cost service environment to reduce P&A liabilities
- ~$288 MM in liquidity as of June 30, 2019

1) EBITDA and Adjusted EBITDA are non-GAAP financial measures, see slide 38 for a reconciliation to GAAP net income.

W&T OFFSHORE

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Appendix

2019 Guidance (As of July 31, 2019)

	Full Year	3rd Quarter
Production[1]	38,900 – 42,200 Boe/d	38,600 – 42,500 Boe/d
Lease Operating Expenses	$192 - $204 MM	$56 - $62 MM
G & T and Production Taxes	$32 - $35 MM	$9 - $10 MM
G & A	$59 - $62 MM	$16 - $18 MM
CAPEX	$125 - $155 MM	
Cash Income Tax Rate	0%[2]	

1) Includes impact of GOM Mobile Bay acquisition with FY 2019 ~57% liquids and 3rd quarter 2019 ~59% liquids.
2) This excludes the second quarter 2019 non-cash tax benefit.

Hedging Strategy Protects Cash Flow Without Limiting Upside[1]

Crude Oil

Quarter	Instrument	Volume Bbl/d	Average Floor	Average Ceiling
3Q19	WTI Swaps	10,000	$60.92	$60.92
	WTI Calls (long)	10,000	$61.00	
4Q19	WTI Swaps	10,000	$60.92	$60.92
	WTI Calls (long)	10,000	$61.00	
1Q20	WTI Swaps	10,000	$60.92	$60.92
	WTI Calls (long)	10,000	$61.00	
Apr-May'20	WTI Swaps	10,000	$60.92	$60.92
	WTI Calls (long)	10,000	$61.00	

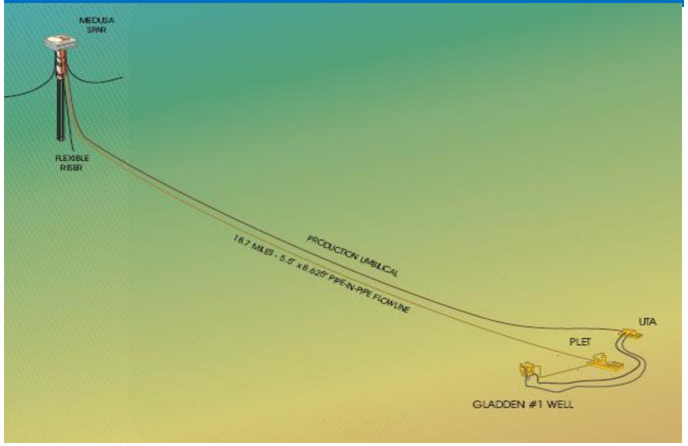
W&T's Hedging Positions Lock in Floor Price, Protect Future Cash Flows And Allow Opportunity to Capture Potential Oil Price Increases

1) Commodity Derivative positions as of July 31, 2019.

Significant Infrastructure Advantage

Platform Rig on infield production facility (EW 910 Area)

Subsea tieback to existing infrastructure (MC 800 Gladden)



- **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)*

W&T Owns Infrastructure with an Estimated Replacement Value of ~$570 MM[1]

1) Management Estimates.

History of Creating Long-Term Value From GOM Acquisitions

TOTAL

$115 MM

Paid out in Aug. 2011

Current net average production[1] of 2,055 Boe/d from Matterhorn and Virgo

Reserves[2]:	1P –	6.5 MMBoe
	2P –	12.3 MMBoe
	3P –	21.0 MMBoe

NEWFIELD

$206 MM

Paid out in Nov. 2014

Current net average production[1] of 480 Boe/d from 78 offshore blocks, 65 of which are in deepwater

Reserves[2]:	1P –	2.5 MMBoe
	2P –	4.5 MMBoe
	3P –	8.8 MMBoe

WOODSIDE

$55 MM

Investments Post Acquisition

Current net average production[1] of 840 Boe/d from Neptune and 24 add'l blocks

One exploration well brought on production in 2014. Exploration could double field size

Reserves[2]:	1P –	1.5 MMBoe
	2P –	1.8 MMBoe
	3P –	2.1 MMBoe

COBALT

$31 MM[3]

Current net average production[1] of 1,280 Boe/d from Green Canyon 859, 903, & 904

Reserves[2]:	1P –	0.4 MMBoe
	2P –	1.3 MMBoe
	3P –	2.0 MMBoe

2010 2011 2012 2013 2014 2015 2016 2017 2018 2019

SHELL

$116 MM

Paid out in Nov. 2012

Current net average production[1] of 970 Boe/d from Tahoe and 6 other fields

Reserves[2]:	1P –	2.7 MMBoe
	2P –	3.4 MMBoe
	3P –	3.9 MMBoe

CALLON

$83 MM

Investments Post Acquisition

Current net average production[1] of 730 Boe/d from Medusa and 12 other fields

Two exploration wells brought on production in June 2015

Reserves[2]:	1P –	2.1 MMBoe
	2P –	3.7 MMBoe
	3P –	6.0 MMBoe

EXXONMOBIL

$168 MM

Closed August 30, 2019

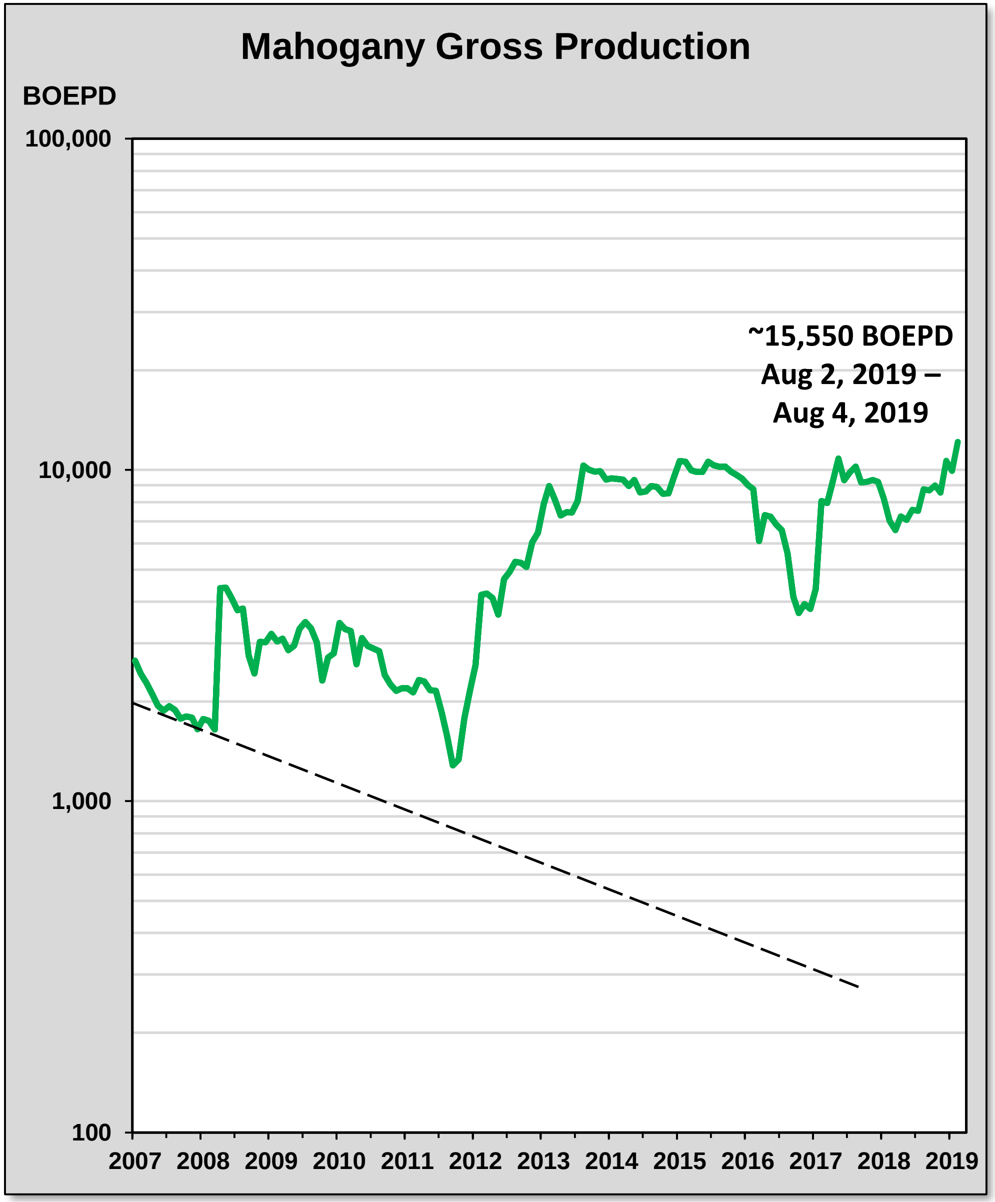
Q1 2019 net average production of 19,800 Boe/d

YE 2018 net proved reserves ~ 74 MMBoe

Potential to add incremental reserves with minimal capital by consolidating operations with additional upside from potential future drilling locations and facility modifications

1) June 2019 net average production.
2) Mid-Year 2019 Reserve Report prepared by NSAI at SEC pricing at $61.45/BO and $3.02/MMbtu.
3) Based on effective date of January 1, 2018.

SS 349 Field ("Mahogany") Case Study



SS 349 Field ("Mahogany")

- WI: 100.0%, 360' Water Depth
- 1st commercially successful subsalt development in the Gulf of Mexico (initial production in 1997)
- Originally purchased Amoco's interest in 2000
- Purchased additional interest in 2004 & 2008
- **Cumulative purchase price of $175MM**
- **Total Net Cash Flow (including capex) from final purchase date[1] = $460 MM**

Have increased value by:

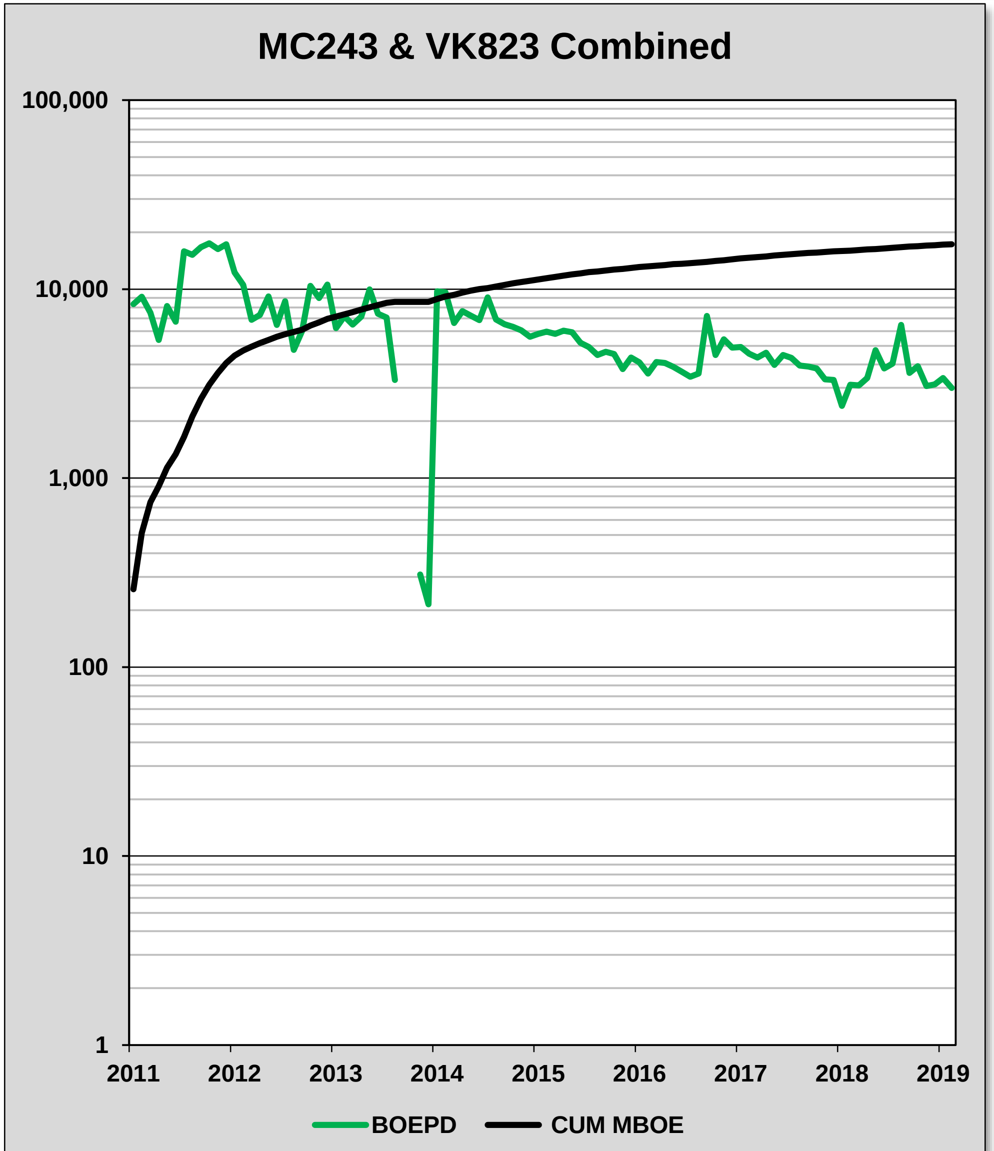
- Development and exploration drilling
- Performing recompletes
- Reworks and performance optimization

Current Reserves[2]

1P Reserves:	32.6	MMBOE
2P Reserves:	55.7	MMBOE
3P Reserves:	111.0	MMBOE

1) As of February 28, 2019.
2) Mid-Year 2019 SEC reserves at $61.45/BO and $3.02/MMbtu.

Total E&P Deepwater Acquisition Case Study



"Matterhorn" & "Virgo" Fields

- WI: 64% - 100%, 1,130' - 2,400' water depth
- Purchased from Total E&P, USA in 2010
- **$115MM acquisition cost**
- **Total Net Cash Flow (including capex) from final purchase date[1] = $509 MM**

Have increased value by:

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

Current Reserves[2]

1P Reserves:	6.8	MMBOE
2P Reserves:	13.5	MMBOE
3P Reserves:	22.3	MMBOE

1) As of February 28, 2019.
2) Mid-Year 2019 SEC reserves at $61.45/BO and $3.02/MMbtu.

Non-GAAP Reconciliations

We define EBITDA as net income plus income tax expense (benefit), net interest expense, and depreciation, depletion, amortization and accretion. Adjusted EBITDA excludes the unrealized commodity derivative (gain) loss, bad debt reserve, gain on debt transactions, lawsuits and settlements, and civil penalties and other litigation. We believe the presentation of EBITDA and Adjusted EBITDA provides useful information regarding our ability to service debt and to fund capital expenditures. We believe this presentation is relevant and useful because it helps our investors understand our operating performance and makes it easier to compare our results with those of other companies that have different financing, capital and tax structures. EBITDA and 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. EBITDA and Adjusted EBITDA, as we calculate them, may not be comparable to EBITDA and Adjusted EBITDA measures reported by other companies. In addition, EBITDA and Adjusted EBITDA do not represent funds available for discretionary use. Adjusted EBITDA margin represents the ratio of Adjusted EBITDA to total revenues.

The following table presents a reconciliation of our net income to EBITDA and Adjusted EBITDA along with our Adjusted EBITDA margin.

	Three Months Ended			Six Months Ended	
	June 30,	March 31,	June 30,	June 30,	
	2019	2019	2018	2019	2018
			(In thousands) (Unaudited)		
Net income (loss)……	$ 36,389	$ (47,761)	$ 36,083	$ (11,372)	$ 63,723
Income tax (benefit) expense ……	(11,695)	172	112	(11,523)	221
Net interest expense ……	12,207	16,282	12,272	28,489	23,262
Depreciation, depletion, amortization and accretion ……	38,073	33,766	39,757	71,839	77,838
EBITDA ……	74,974	2,459	88,224	77,433	165,044
Adjustments:					
Unrealized commodity derivative (gain) loss ……	(3,839)	50,459	5,070	46,621	5,070
Amortization of derivative premium ……	3,888	3,845	-	7,733	-
Bad debt reserve ……	18	120	201	138	543
Civil penalties and other litigation ……	-	-	(194)	-	(194)
Adjusted EBITDA ……	$ 75,041	$ 56,883	$ 93,301	$ 131,925	$ 170,463
Adjusted EBITDA Margin ……	56%	49%	62%	53%	60%

Non-GAAP Reconciliations

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

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

	December 31, 2018
Present value of estimated future net revenues (PV-10)	$ 1,439.8
Present value of estimated ARO, discounted at 10%	(179.3)
PV-10 after ARO	$ 1,260.5
Future income taxes, discounted at 10%	$ (193.5)
Standardized measure of discounted future net cash flows[1]	$ 1,067.0

	June 30, 2019
Present value of estimated future net revenues (PV-10)	$ 1,403.3
Present value of estimated ARO, discounted at 10%[2]	(179.3)
PV-10 after ARO	$ 1,224.0

1) Company calculates Standardized measure of discounted future net cash flows annually for 10-K filing.
2) As of year-end 2018.

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