W&T OFFSHORE

Johnson Rice 2014 Energy Conference

October 1, 2014 – New Orleans, LA

Disclaimer

The Securities and Exchange Commission ("SEC") requires oil and gas companies, in their filings with the SEC, to disclose 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. The SEC permits the optional disclosure of probable and possible reserves; however, we have not disclosed our probable and possible reserves in our filings with the SEC. We may use the terms "potential reserves," "targeted reserves," "unrisked anticipated recovery", "ultimate recovery" and "EUR" to describe estimates of potentially recoverable hydrocarbons that the SEC rules strictly prohibit us from including in filings with the SEC. These are our internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These quantities may not constitute "reserves" within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or SEC rules and do not include any proved reserves unless the well was included in previously disclosed proved undeveloped reserve estimates. Drilling locations have not been risked by Company management except where indicated. We also use the term "NAV" or "net asset value" that are based on assumptions about pricing we could receive for future quantities of hydrocarbon production, which pricing assumptions may not be representative of current or future market conditions. Actual locations drilled and quantities that may be ultimately recovered from our interests could differ substantially from our estimates and targets. We make no commitment to drill all of the drilling locations which have been attributed to these quantities and our drilling plans are subject to revision. Factors affecting ultimate recovery and reserve estimates and targets include actual drilling results, including geological and mechanical factors affecting recovery rates, which will vary from well to well; and the scope of our ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors. Estimates of targeted reserves, potential reserves and average well data may change significantly as development of our oil and gas assets provide additional data.

Our production forecasts, estimated and targeted initial production rates and expectations for future periods are similarly dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity. These may be affected by significant commodity price declines or drilling cost increases. Actual production will vary from well to well.

W&T Offshore Overview *(NYSE: WTI)*

Financial Summary

Financial Overview

Twelve Months Ended		***6/30/14***		*12/31/13*
Revenue	**$**	**1,007.0**	$	984.1
Adjusted EBITA (1)	**$**	**637.0**	$	606.7
Dividend Yield		**4.9%**		4.9%

1) See the slide titled "Reconciliation of Net Income to Adjusted EBITDA" for an analysis of the change between Net Income and Adjusted EBITDA

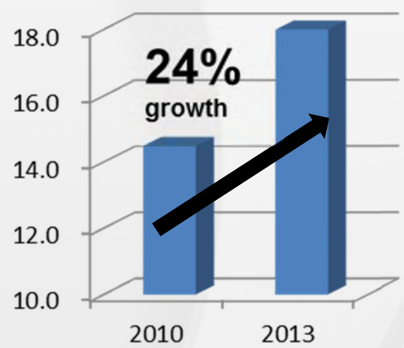
Reserves and Production

Reserves		***As of 12/31/13***
Proved Reserves *(MMBOE)*		**117.7**
Oil and Liquids Percentage *(oil proved reserves/total proved reserves)*		**63.2%**
PV-10 *($ in billions)*	**$**	**2.5**
Drilling Success Rate *(YTD 2014)*		**100%**
R/P *(YE 2013 Proved Reserves / 2013 Production)*		**6.55**

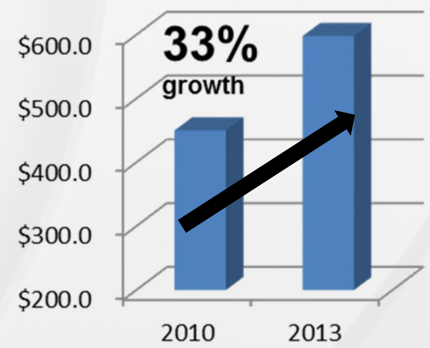
Daily Production	***Six Months Ended 6/30/14***
Oil *(MBbls/d)*	**19.8**
NGLs *(MBbls/d)*	**5.7**
Natural Gas *(MMcf/d)*	**136.8**
Total *(Mboe/d)*	**48.4**
Total *(MMcfe/d)*	**290.2**

Track Record of Growth

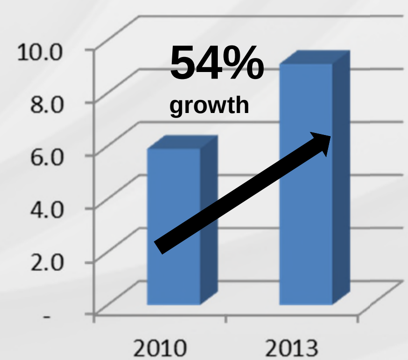
Production
(MMboe)



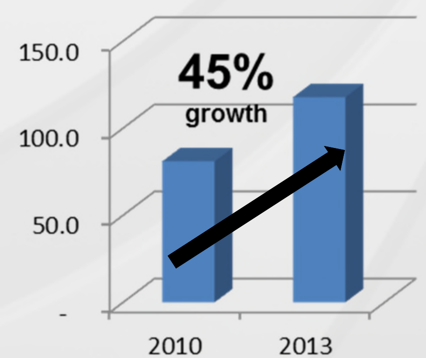
Adjusted EBITDA
($ in millions)



Oil Production
(MMBoe)



Proved Reserves
(MMBoe)



Premium Assets in Three Prolific Basins

Deepwater Gulf of Mexico

- ~ 575,000 gross acres (~287,000 net acres)
- ~ 38% of daily production
- 1P reserves of 25.2 MMBoe + 1.9 MMBoe of 1P reserves for Neptune (from Woodside)
- 2P reserves of 41.5 MMBoe + 3.0 MMBoe of 2P reserves for Neptune (from Woodside)
- Substantial upside from planned projects (Big Bend, Dantzler, Medusa, Neptune and others)

Gulf of Mexico Shelf

- ~ 613,000 gross acres (~423,000 net acres)
- ~ 55% of daily production
- 1P reserves – 54.3 MMBoe
- 2P reserves of 78.1 MMBoe
- Future growth potential from sub-salt prospects identified with WAZ Seismic

Permian Basin

- ~ 43,300 gross acres (~32,400 net acres)
- ~ 7% of Daily Production
- 1P reserves – 38.2 MMBoe
- 2P reserves of 47.0 MMBoe
- Over 85% of acreage is HBP from vertical program with horizontal program expanding to test multiple benches

Notes: *Reserves are as of 12/31/2013. Deepwater gross acres include ~ 151,000 acres acquired from Woodside*

High Impact Projects Drive Long-Term Growth

Deepwater success will add significant value over next several years

- *Recent large discoveries yield multi-year reserve additions*
- *Provides increased visibility of future growth*
- *Planned deepwater projects provide potential for production additions as soon as the first half of 2015.*

Recent success on GOM Shelf is creating further opportunities

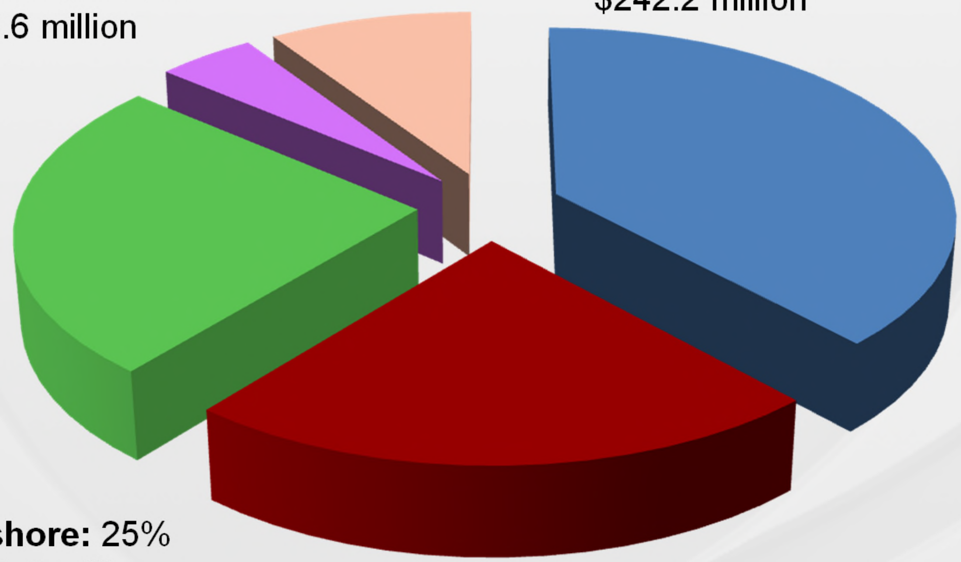
- *Mahogany average daily net sales are up ~400% since 2011 and the field size continues to grow*
- *Drilling success and advanced seismic data improves understanding of sub-salt targets on the shelf*

Expanded horizontal drilling program in the Permian Basin targeting the Wolfcamp "B" and Spraberry

- *Continued success in multiple benches will grow both the inventory of drilling locations and increase the overall value of the field*

2014 Capital Expenditures Budget Increased to $635 million

Revised Capital Budget Allocation

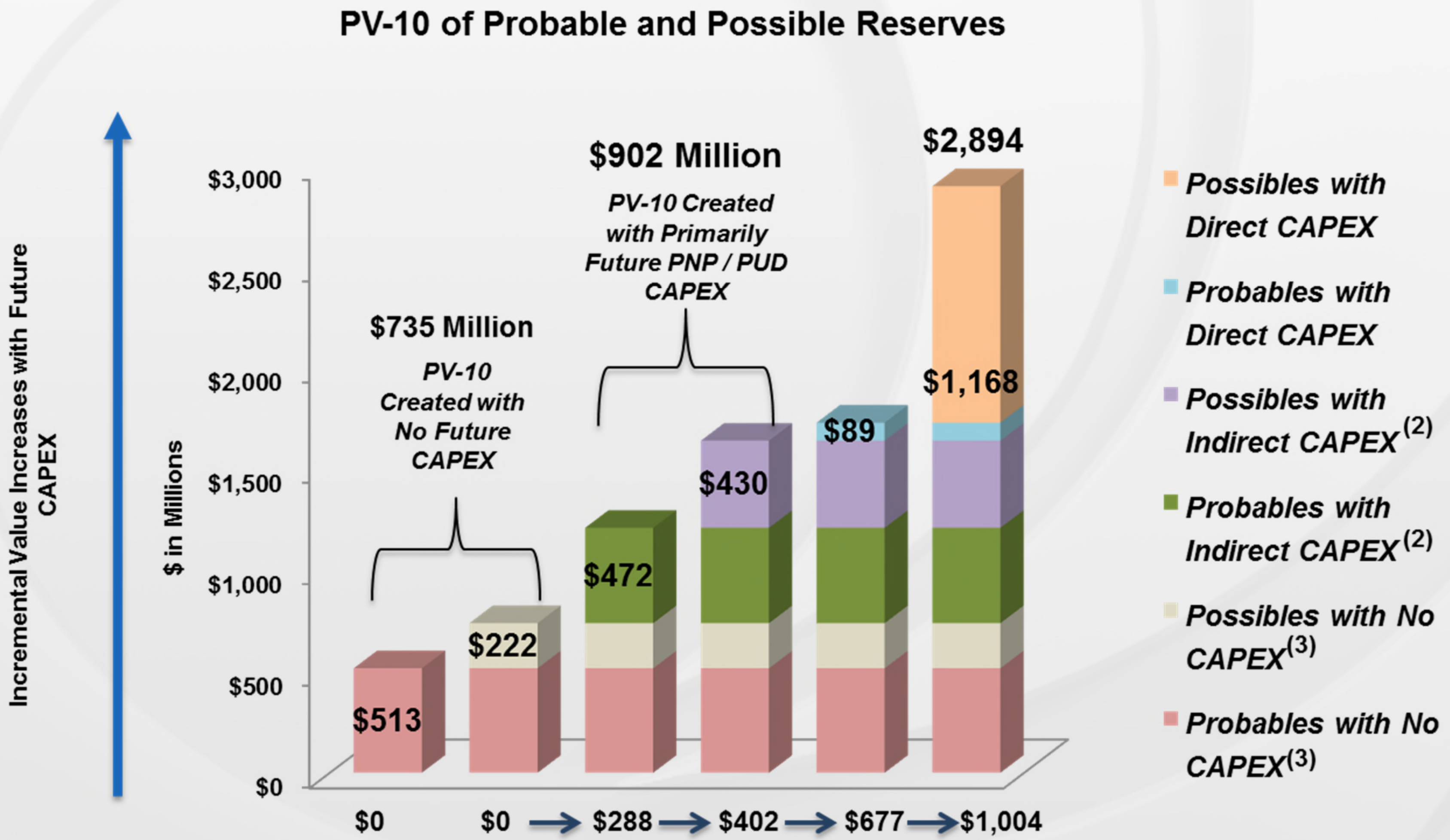


Increased Budget For Quality, High Impact Projects

- *Deepwater GOM development at Big Bend and Dantzler. Revised budget increase of ~$37MM includes 2nd Dantzler well*
- *Acquired properties (Neptune Field + 24 deepwater blocks) from Woodside for $50MM*
- *Added ~$48MM for new exploration activity at Neptune, Medusa and EW 910 in the deepwater GOM*
- *~$20MM increase for mostly 3 add'l horizontal wells raises our 2014 Permian Basin drill wells to 10 horizontal and 32 vertical wells*
- *Mahogany exploration and acceleration wells bring more oil online (3 wells). Drilling will extend into 2015 & beyond*

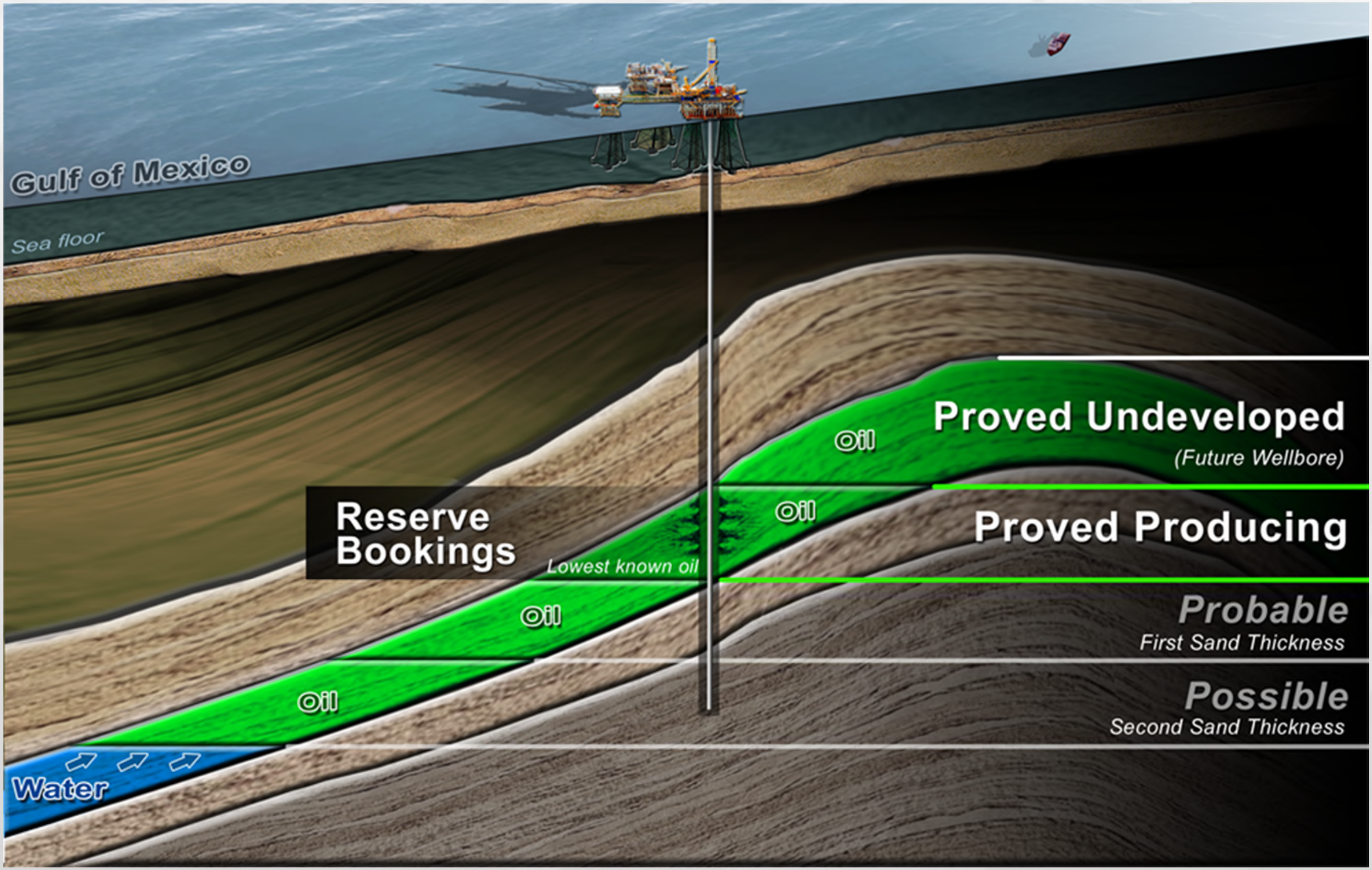
Incremental Cash Flow Associated with Probable and Possible Reserves (1)

Probables and Possibles provide hidden value and significant upside

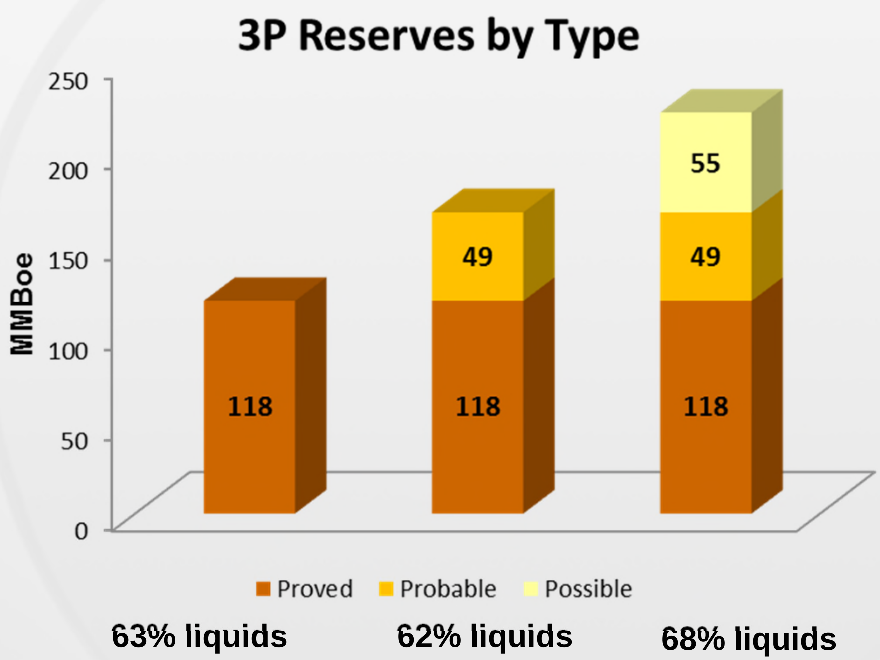


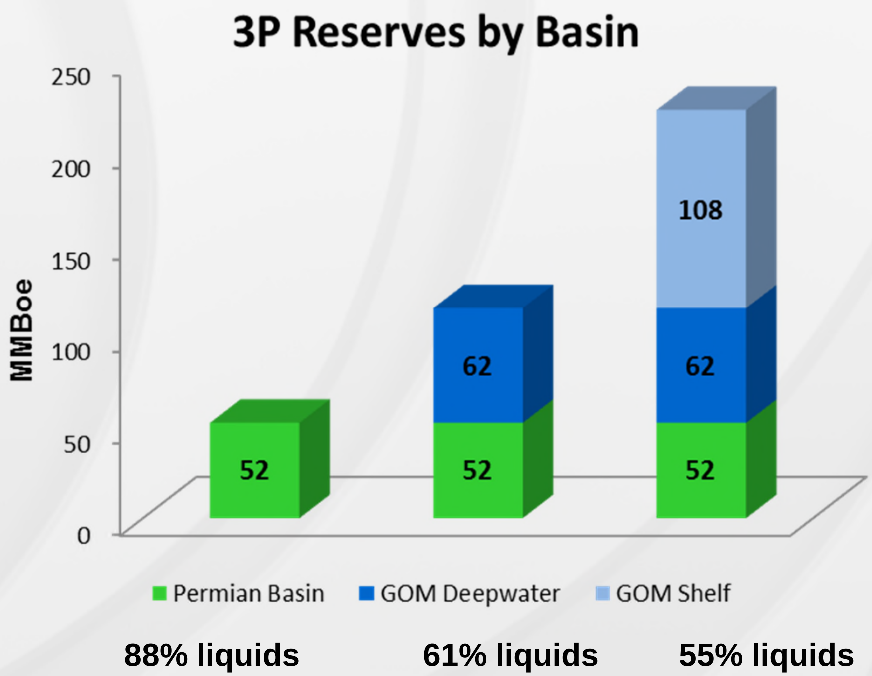
(1) *Figures reflect year-end 2013 SEC price case.*
(2) *Probable and possible reserves with no direct CAPEX requirements that are largely associated with PNP and PUD reserves and therefore have associated future indirect CAPEX requirements.*
(3) *Probable and possible cases that are largely associated with producing wellbores and require no additional future CAPEX requirements.*

Proved Reserve Bookings Example



3P Reserves of 222 MMBoe Provides Long Term Value





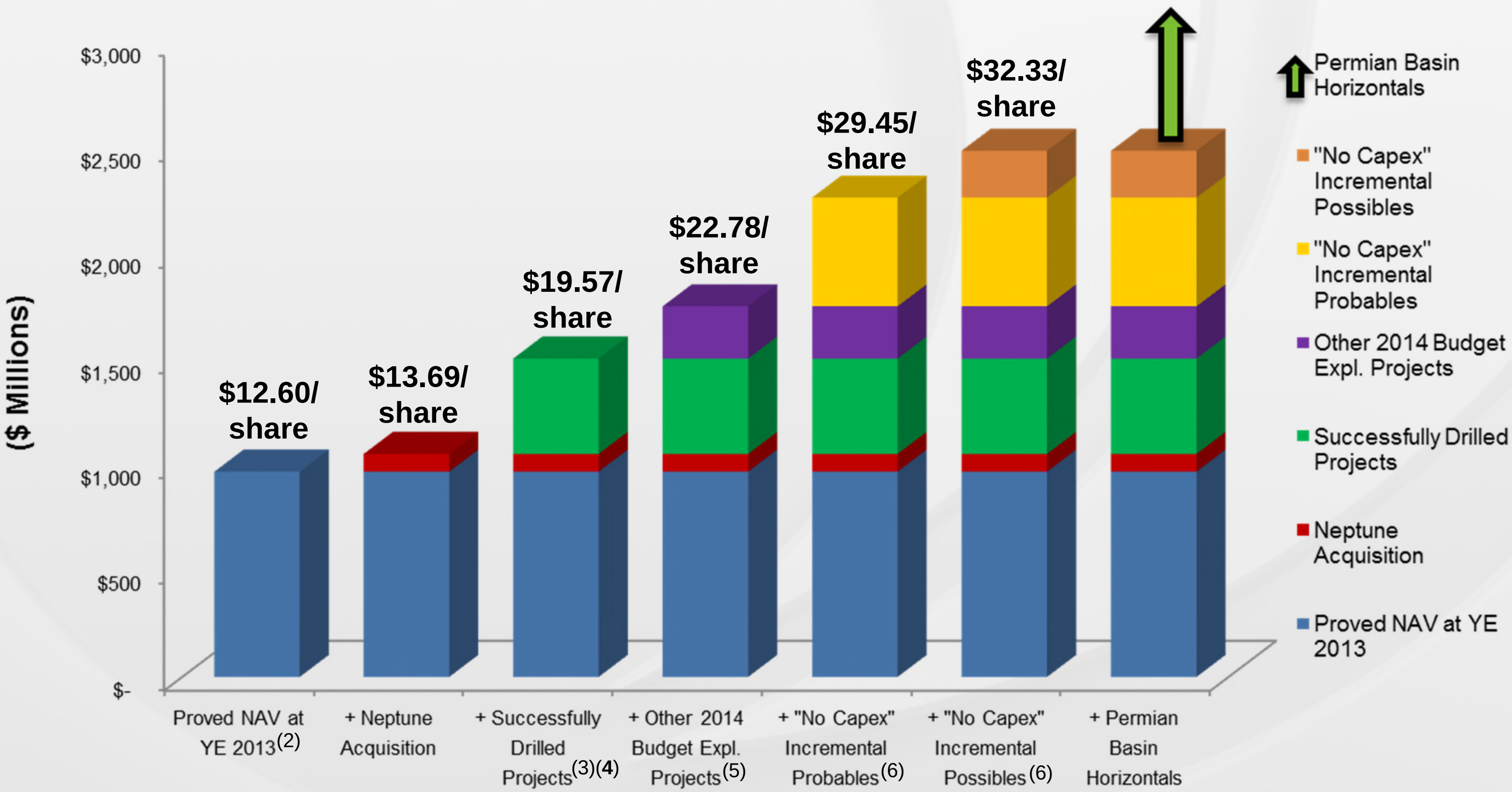
Substantial probable and possible reserves provide future growth

Yet to be included in this analysis are all of the reserves from recent discoveries such as Dantzler and Troubadour, multiple target benches for Permian acreage or the Neptune acquisition.

Note: *Figures reflect year end 2013 SEC price case*

Net Asset Value Estimate

- ***Current stock price is $13.34 (as of 9/16/14 close)***
- ***Our estimate of Net Asset Value per share [(1)] is substantially greater than the current stock price***
- ***More upside in full probable and possible value and all future exploratory projects currently under evaluation***



(1) Diluted shares of 77 million shares.
(2) Proved NAV calculated as PV-10 of proved reserves at SEC pricing at 12/31/13, less debt and ARO, plus cash as of 6/30/14.
(3) Successfully drilled projects include Big Bend and Dantzler #1 & #2.
(4) Big Bend and Dantzler #1 & #2 valuation based on operator's latest published estimates, adjusted for $2.3 million in 1P PV-10 value booked at YE2013 for Big Bend.
(5) Other 2014 Budget exploratory projects include Neptune SB03, Medusa SS6 & SS7, and EW 910 A-5ST & A-8. PV-10 of unrisked mean cases based on 7/28/14 NYMEX pricing.
(6) "No capex" probables and possibles are associated with PDP reserves and require no additional capital. As of 12/31/2013.

DEEPWATER

Gulf of Mexico

Deepwater Acquisitions Drive Growth

Through acquisitions and lease sales, W&T now holds interests in ~ 575,000 gross / 287,000 net acres in the deepwater of the Gulf of Mexico - 40% of total net offshore acres

2010 – Total
$115 million

- *Matterhorn*
- *Virgo*
- *1P – 11 MMBoe (64% liquids)*
- *Increased reserves*
- ***Paid out in August 2011***

2010 – Shell Deepwater
$116 million

- *Tahoe*
- *Droshky*
- *1P – 13 MMBoe (8% oil)*
- *Increased reserves*
- ***Paid out in November 2012***

2012 – Newfield
$206 million

- *78 lease blocks*
- *65 deepwater blocks*
- *1P – 7 MMBoe (39% liquids)*
- *Wrigley (MC 506) back online in Sept. 2014*

2013 – Callon
$82 million

- *Medusa (prod. is 88% oil)*
- *1P - 2 MMBoe*
- *3P – 7 MMBoe*
- *Drilling 1-2 expl. wells in late 2014/early 2015; multiple add'l wells under evaluation*

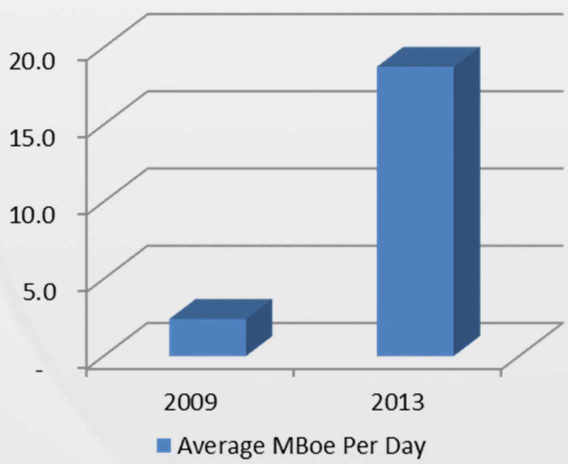
2014 – Woodside
$51 million

- *Neptune (prod. is 87% oil)*
- *27 deepwater blocks*
- *1P – 2 MMBoe*
- *2P – 3 MMBoe*
- *Currently completing exploratory well at Neptune (AT 618)*

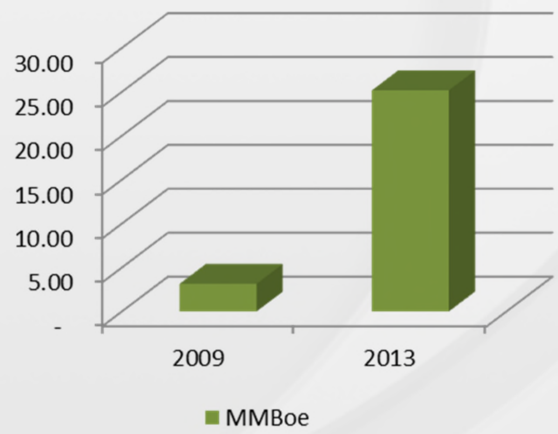
Significant Growth in the Deepwater GOM

Between 2009 and 2013, average deepwater production has grown nearly 700% and proved reserves[(1)] are up 320%. Gross Acres have increased 378% from 2009 to now.

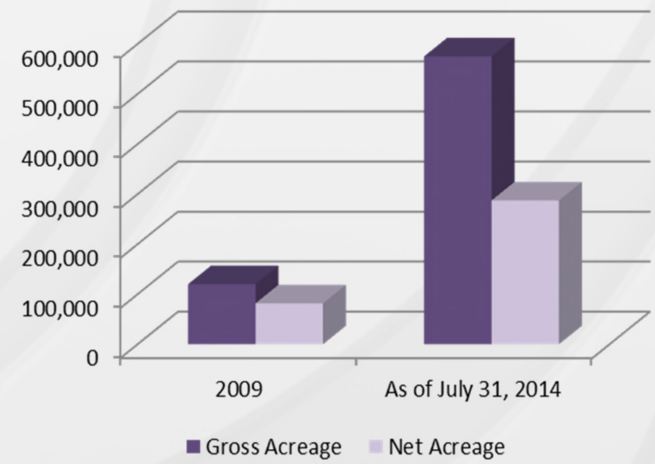
Deepwater Net Daily Production



Deepwater Net Reserves

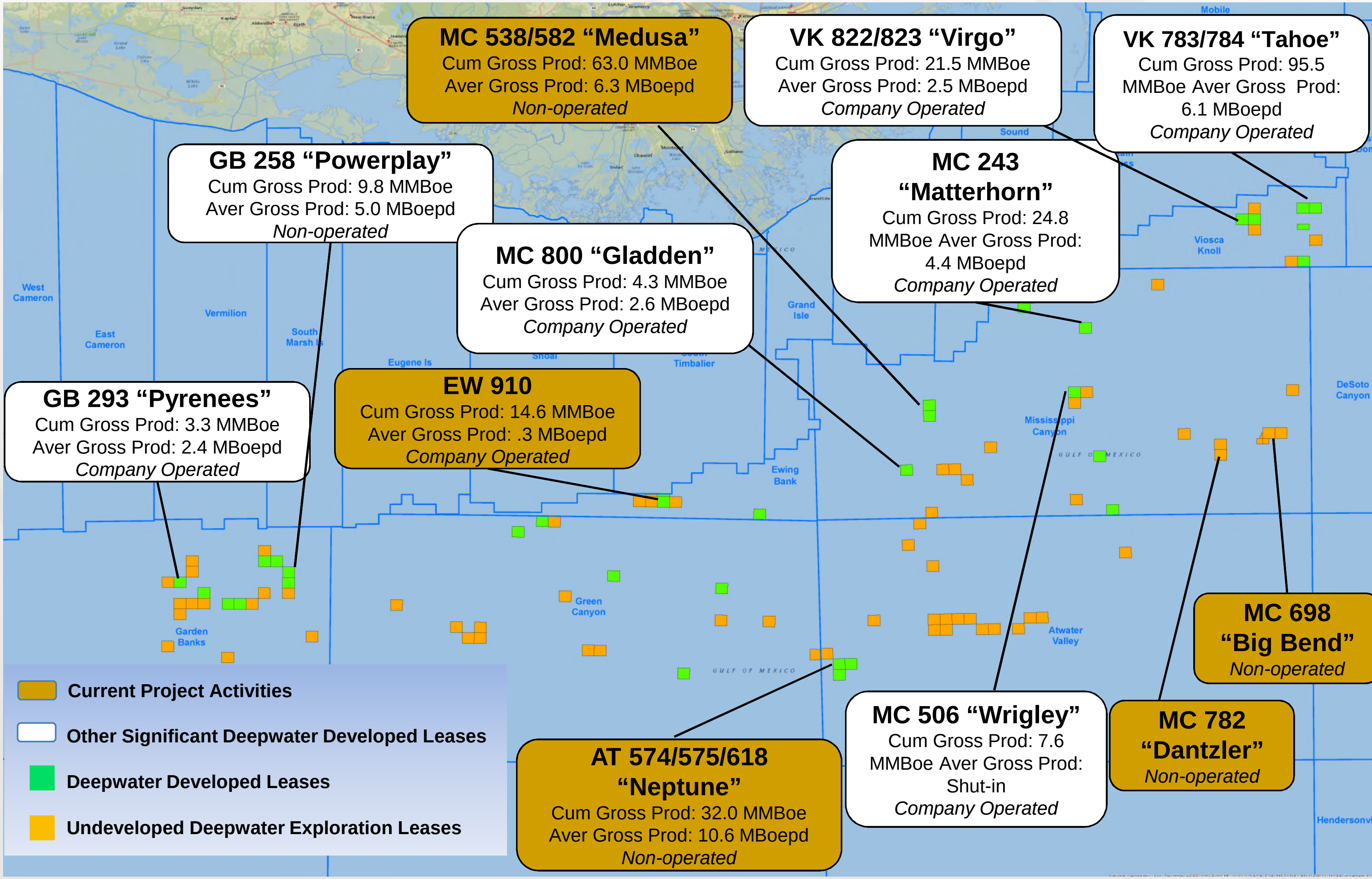


Deepwater Acreage



(1) 2013 year-end proved reserve figures have yet to include unbooked potential reserves associated with the successful exploration wells at MC 699 'Troubadour' or MC 782 'Dantzler' and are only partial bookings for MC 698 'Big Bend'.

Well Positioned in the Deepwater GOM

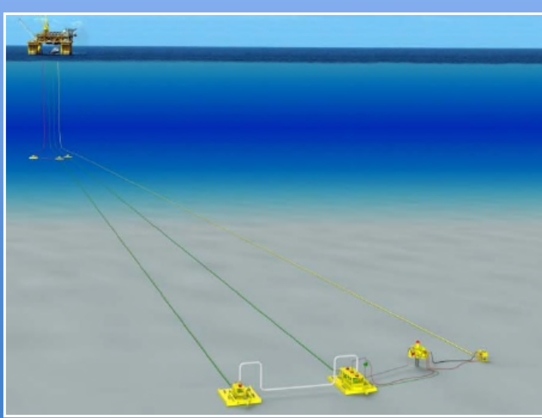


Except for the Neptune Field, “Aver Gross Prod” is the estimated daily average for the month of June 2014. That for Neptune is May 2014.
MC 506 “Wrigley Field” was recently returned to production.

Deepwater Success – MC 698 "Big Bend"

MC 698 "Big Bend"

- *Sub-sea tie back*
- *~7,000' water depth*
- *Can accommodate Dantzler and other potential development*

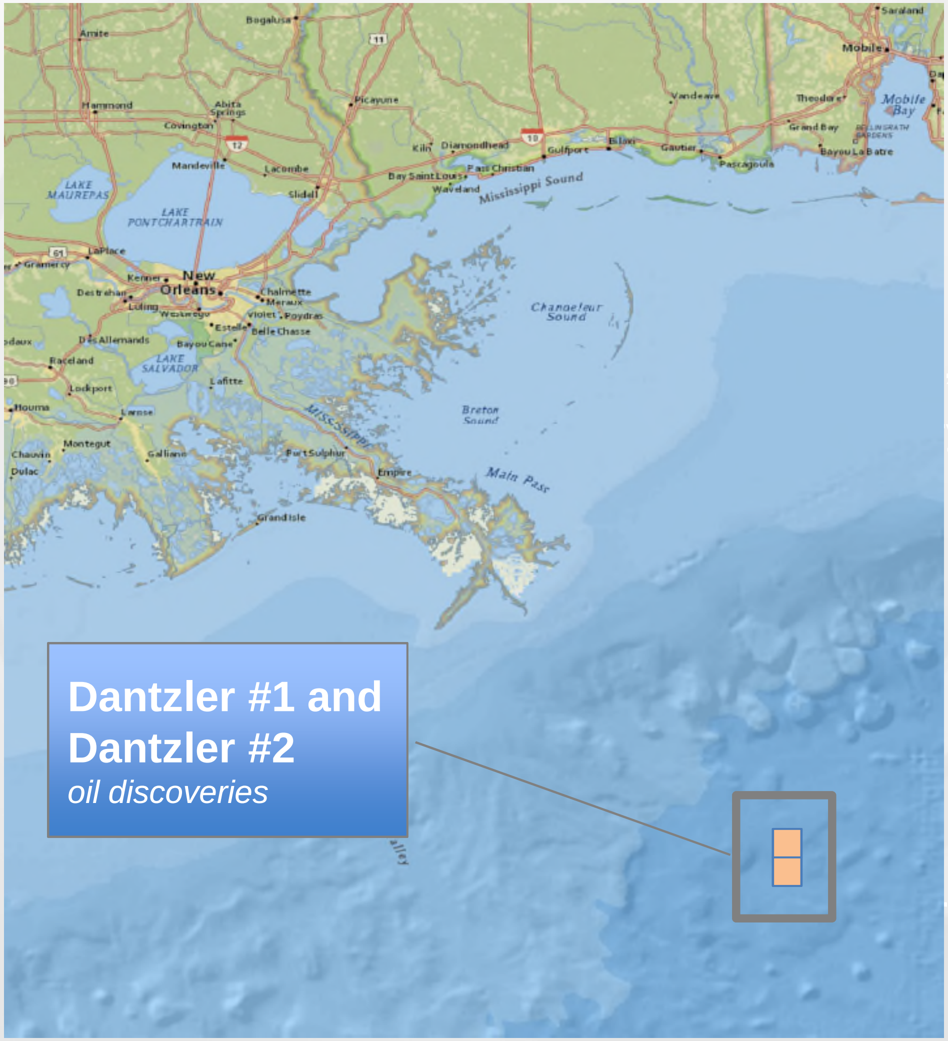


MC 698 Big Bend
(working interest – 20%)

- Located about 165 miles SSE of New Orleans, LA
- Gross resource estimate of 30 to 65 MMBoe with potential additional 30 – 50 MMBoe *(P75 – P25)*[(1)]
- Targeting first production in late 2015 *(est. peak rate of 22,000 Boepd)* [(1)]
- Sub-sea development with tie-back to host facility. Can accommodate Dantzler development

(1) Represents operator's latest published gross production and reserve assumptions.

Deepwater Success – MC 782 “Dantzler”



MC 782 “Dantzler”
(working interest – 20%)

- *Located about 160 miles SSE of New Orleans, LA*
- *Two oil discovery wells*
  - o *The Dantzler #2 appraisal well encountered 122 net feet of crude oil pay in two high-quality Miocene reservoirs. Completion operations have recently started after drilling to a TD of 18,210’ in 6,600’ of water. Completion of the Dantzler #1 will then follow*
- *Gross resource estimate of 65 to 100 MMBoe (P75 – P25 case)(1)*
  - o ***Peak rate est. 36,000 Boe per day**(1) (gross)*
- *Planned tie-in with Big Bend to potential nearby host facilities*
  - o ***Tie-in and 1st production anticipated in 1st Qtr 2016***

(1) Represents operator’s latest published gross production and reserve assumptions.

Exploration Opportunities at MC 538 “Medusa”

Medusa (MC 538/582) acquired in 2013

(WI: 15%; NRI: 15%*)

- *Current daily production of roughly 1,100 Boepd net to W&T (~85% oil)*
- *Medusa spar is also the host facility for the W&T owned “Gladden” production at MC 800*

Expansion activity planned at Medusa

- *Currently planning to drill one to two new exploratory wells in late 2014 / early 2015*
  - *Drilling and completion cost estimate of $122 million to $137 million gross per well and about $18 million to $21 million net to W&T*
  - *We expect these exploratory wells to move probable reserves into the proved category*
- *Additional wells are currently under evaluation*

** This provides for royalty suspension*

Neptune Field

Neptune Field

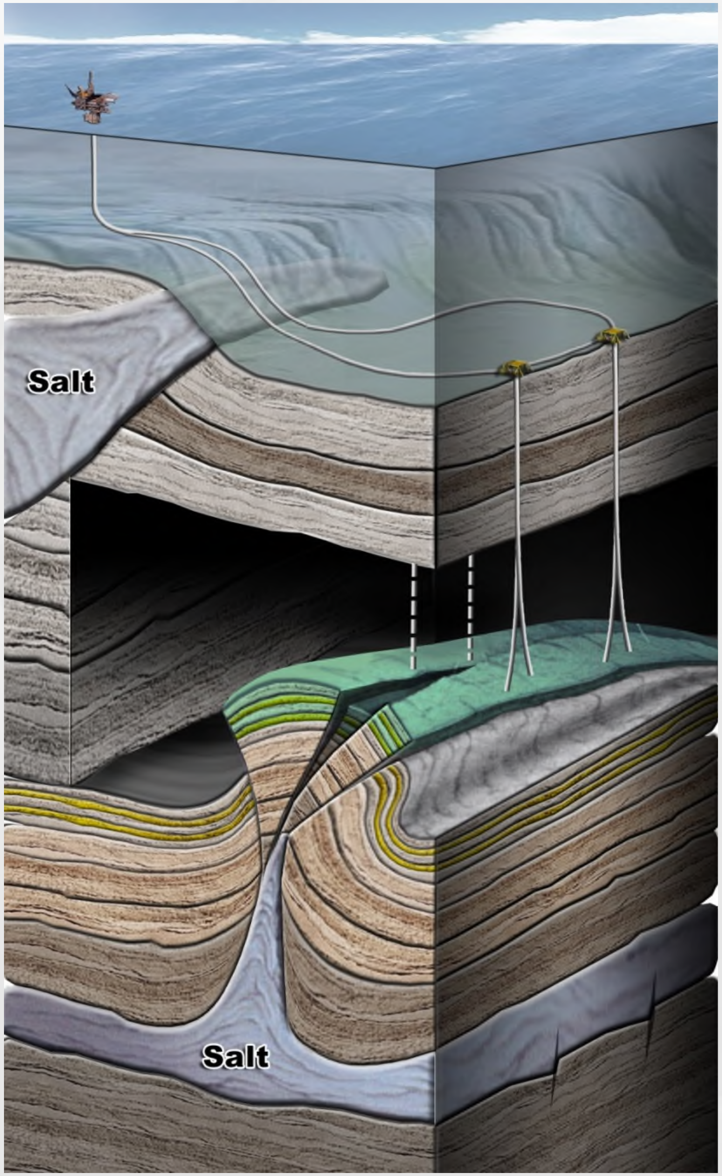
(WI: 20.0%, NRI: 17.5%)

- *Atwater Valley 574, 575 and 618*
- *Current estimated daily production rate of 1,700 Boe, net to W&T's interest*
- *Water depth of 6,200'; TLP is situated on Block 574 where the water depth is about 5,500'*
- *Additional exploration and development could substantially increase field size*

Currently Completing Well – AT 618 SB 03

- *Targeting two main field pays*
- *Target well depth - ~20,800' TVD*
- *Estimated total well cost to drill is ~$160 million gross, ~$32 million net*
- *Estimated initial rate of 5,400 Boe per day (gross), 930 Boe per day (net). Anticipated first production in 2014 Fourth Quarter*

Neptune Field and Other Woodside Acquisition Upside



Neptune Upside

- *Drilling – Northern half of field has never been tested due to salt overhang. Significant upside exists to potentially double the size of the field.*
- *Gas-lift – Operator is considering plans to install gas-lift in production riser to increase production and recovery of existing reservoir.*

Additional Woodside Acquisition Upside

- *Additional drilling potential exists on other exploration leases (a total of 24 additional deepwater blocks acquired)*
- *Arcadius Prospect, located one block south of producing Power Play, can utilize existing infrastructure*

Multi Well Potential at Ewing Bank 910

EW 910 Field

- *Water depth of 560 feet*
- *Cumulative field production of 15 MMBoe (80% oil)*

Current Drilling Plans

- *Initial two well drilling program in a 50% / 50% JV, with potential for third well thereafter, in 2015*

Well	Cost ($MM)	IP Rate (Boe p/d) (1)	NPV ($MM) (1)	Estimated Reserves (MMBoe) (1)
A-5 ST	$ 20.7	1,375	$ 48.0	1.2
A-8	22.1	1,540	145.4	3.8
	$ 42.8	2,915	$193.4	5.0

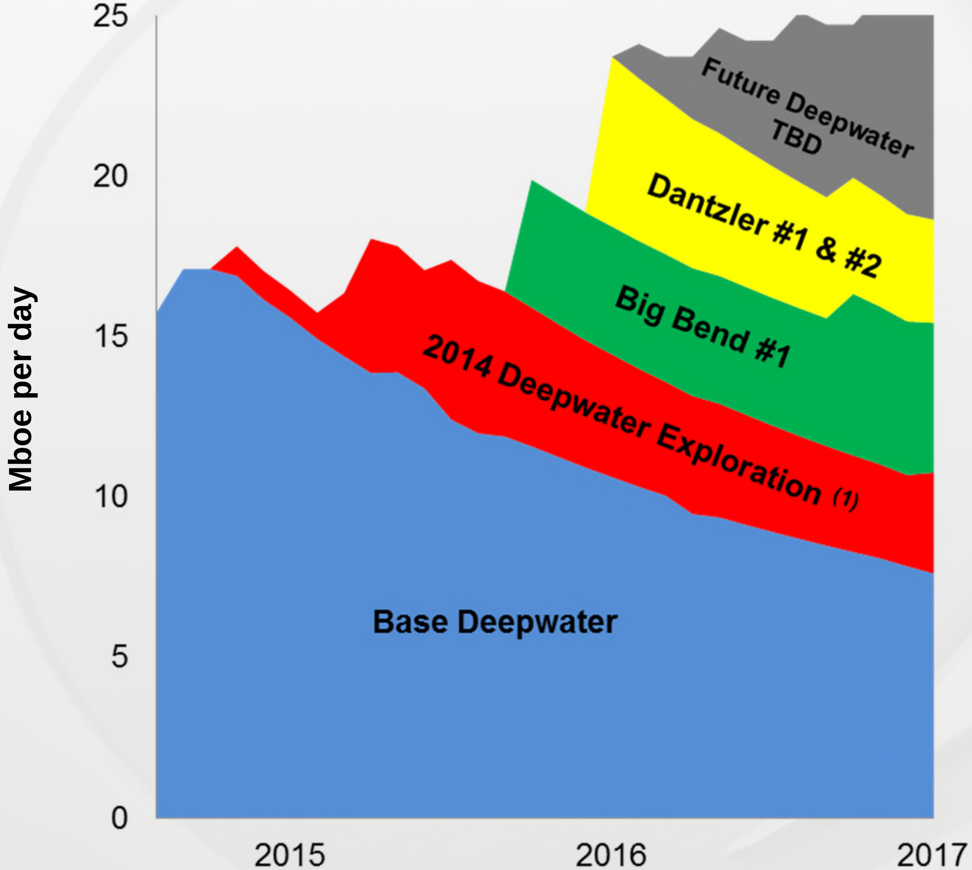
(1) Net mean success rate and value. Based on 7/28/2014 NYMEX Strip.

- *First production expected in Second Quarter of 2015 for A-5 ST and Third Quarter of 2015 for A-8.*

Additional Upside with Improved Seismic

- *Seven additional wells in inventory*
- *Prospective 35-70 MMBoe (net)*
- *Additional drilling locations could be determined*

Deepwater GOM – Production Growth Outlook



(1) Includes Neptune SB03, Medusa SS6 & SS7, and EW 910 A-5ST & A-8 wells.
(2) Based on latest known timing estimates and W&T estimates on initial production volumes.

Deepwater production, predominantly oil, is expected to grow over 50% to a rate of ~23,500 Boe per day in January 2016[(2)]

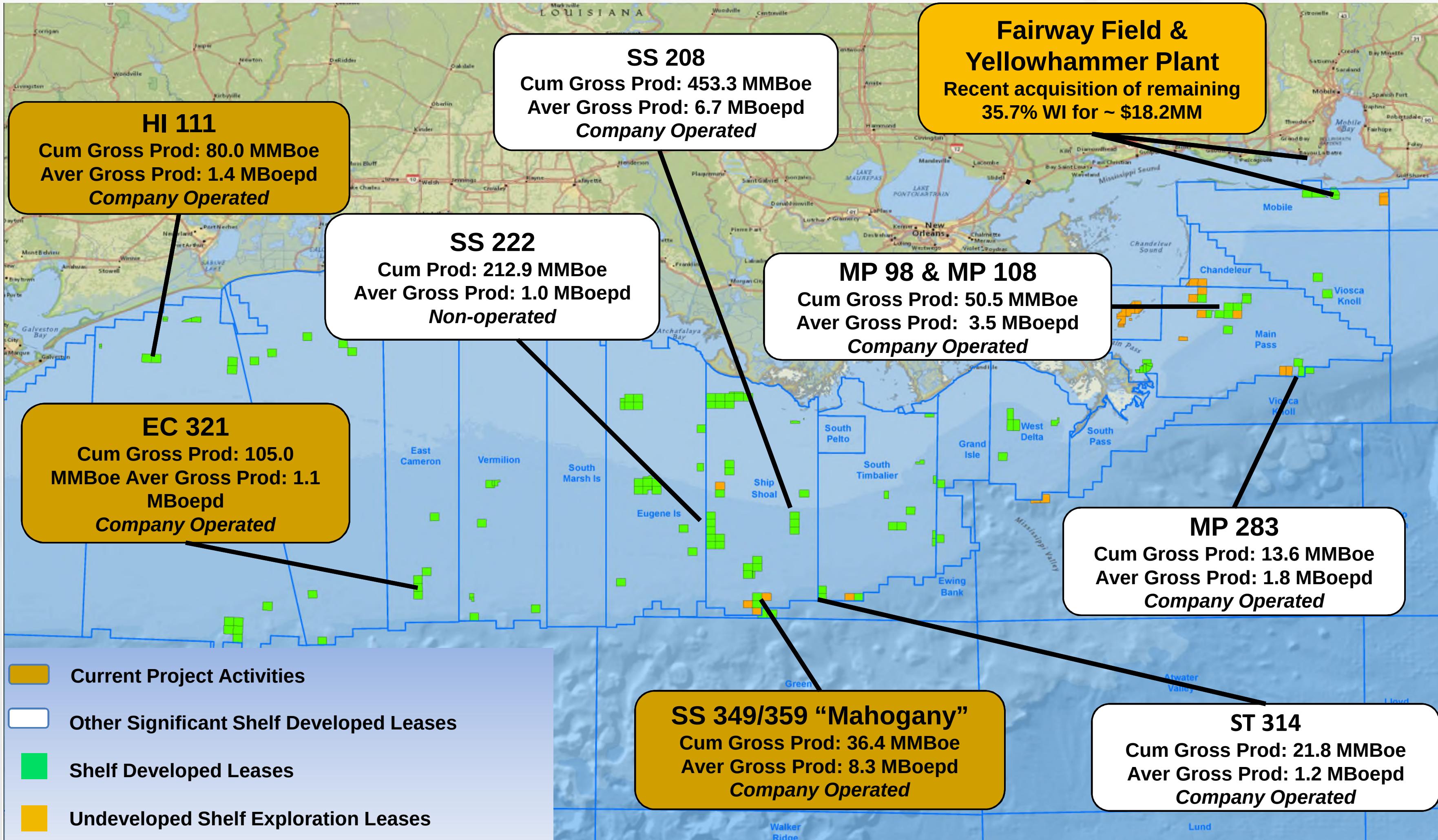
Repeatable deepwater growth

- *We anticipate 1 - 2 additional deepwater exploration wells per year*
- *Deepwater production acquisitions*
- *Evaluating other drilling opportunities at Neptune, Medusa, EW 910, Dantzler, Virgo, Matterhorn, Power Play and others*

SHELF

Gulf of Mexico

Well Positioned on Shelf

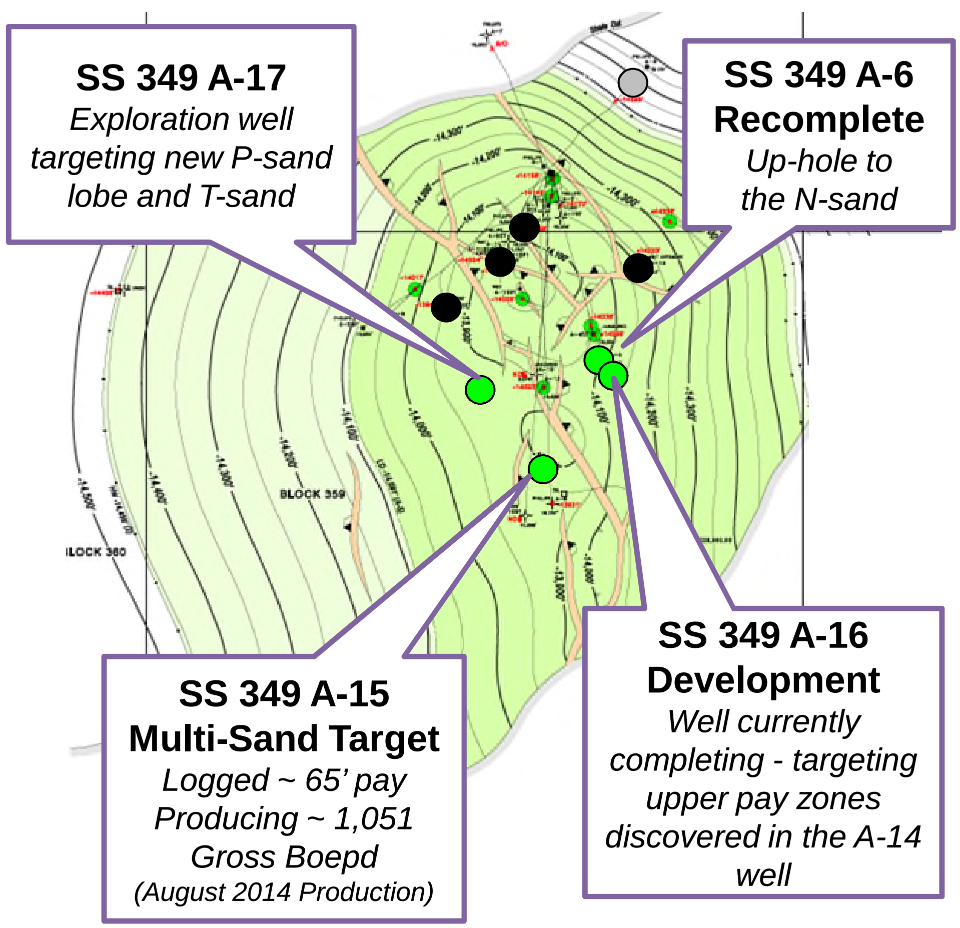


Seismic data (including WAZ) is expected to identify more prospective sub-salt drilling projects

“Aver Gross Prod” is the estimated daily average for the month of June 2014

GOM Shelf – Exploration at Ship Shoal 349

2014 Activity at SS 349



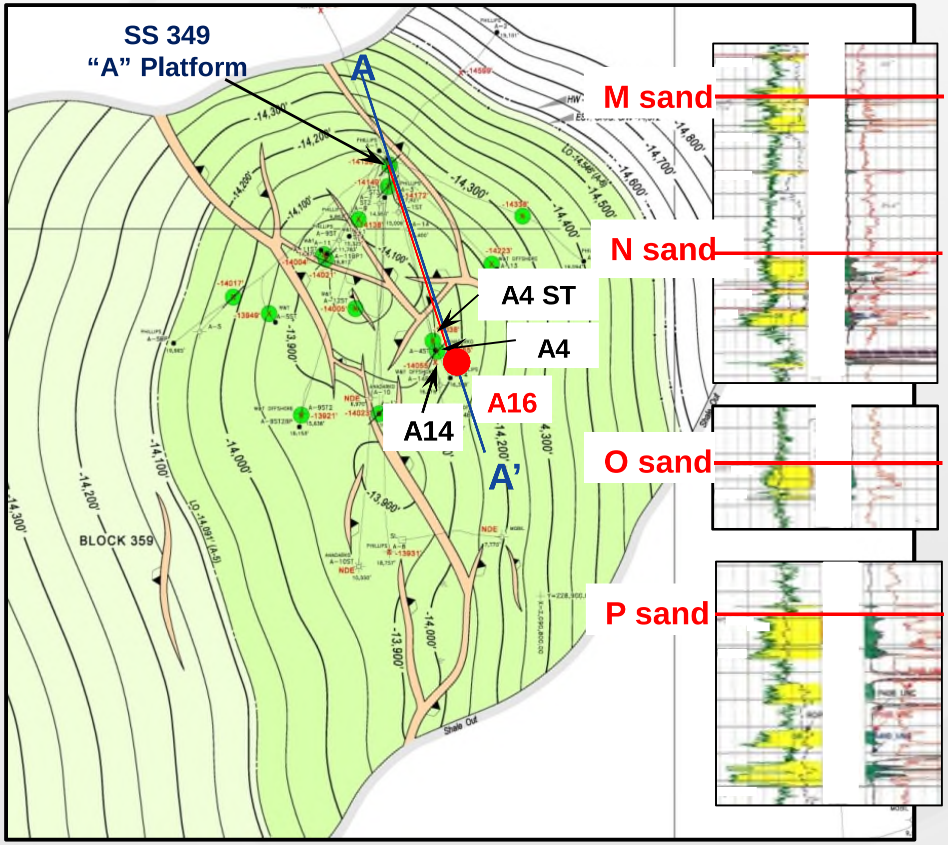
SS 349 "Mahogany"
Continued Sub-Salt Exploration & Development Success

(WI: 100%, NRI: 83.3%)

- *Mahogany production ~ 76% oil*
- *Multi-horizon production*
  - *Primary Field Pay is P-Sand*
  - *New T-Sand discovery 3,000' deeper from P-Sand extends the "known depth" of the oil column*
  - *Multiple new producing horizons recently discovered*
- *Average production rate during August:*
  - *7,454 Boepd net (8,948 gross)*
- *WAZ seismic data being acquired to potentially create additional drilling locations, and / or to identify deeper targets*

Development – GOM Shelf

SS 359 A14 Log



SS 349 "Mahogany" A-16 Well *Bring forward production from zones identified above the T-sand in the A-14 well*

(WI: 100%, NRI: 83.3%)

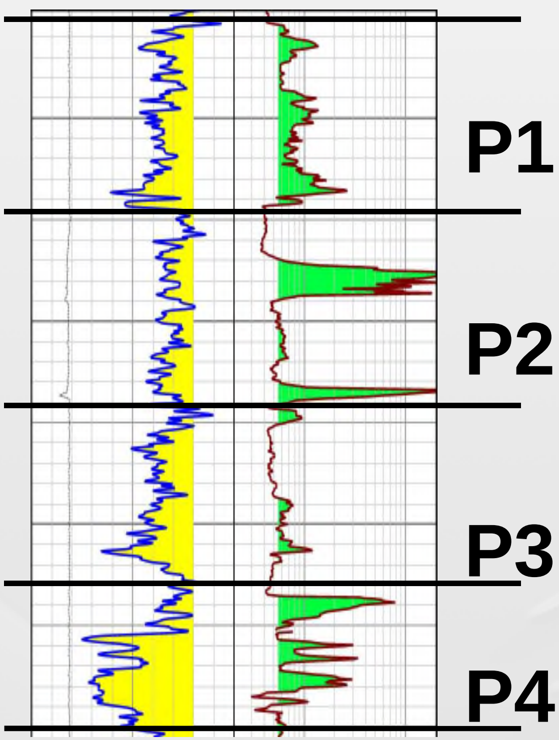
- *Targets the M, N, O, and P sand reservoirs logged during the drilling of the A-14*
- *Initial Est. Cost - $32.0 million*
- *Well is currently in completion*
- *Target well depth - 15,000' TVD*
- *Target IP – 1,800 Boepd*
- *Est. 1st production – Q4 2014*
- ***Project NPV - $50 million***

The A-16 well is the 8th consecutive well at "Mahogany" as part of a multi-year continuous drilling program.

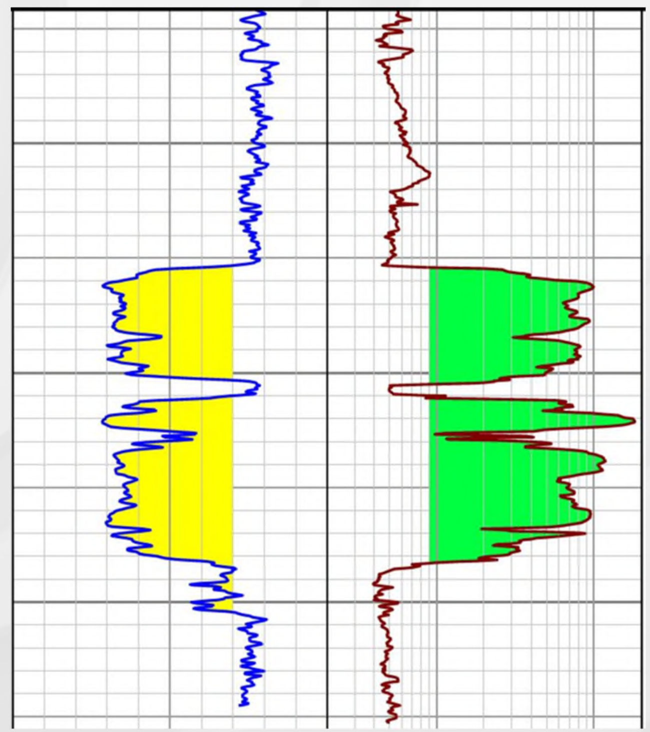
Mahogany’s prolific “P” & “T” Sand

- *Mahogany's primary field pay “P” Sand has cumulatively produced 22.5 MMBO since 1997 from multiple wells*
- *“T” Sand is 3,000 feet deeper and better quality than “P” Sand*
- *Upside potential up-dip from incremental probable reserves for the “T” Sand*
- *WAZ data may identify additional productive sands or expand potential size of T-Sand*

SS 349 A-14 “P” Sand Log

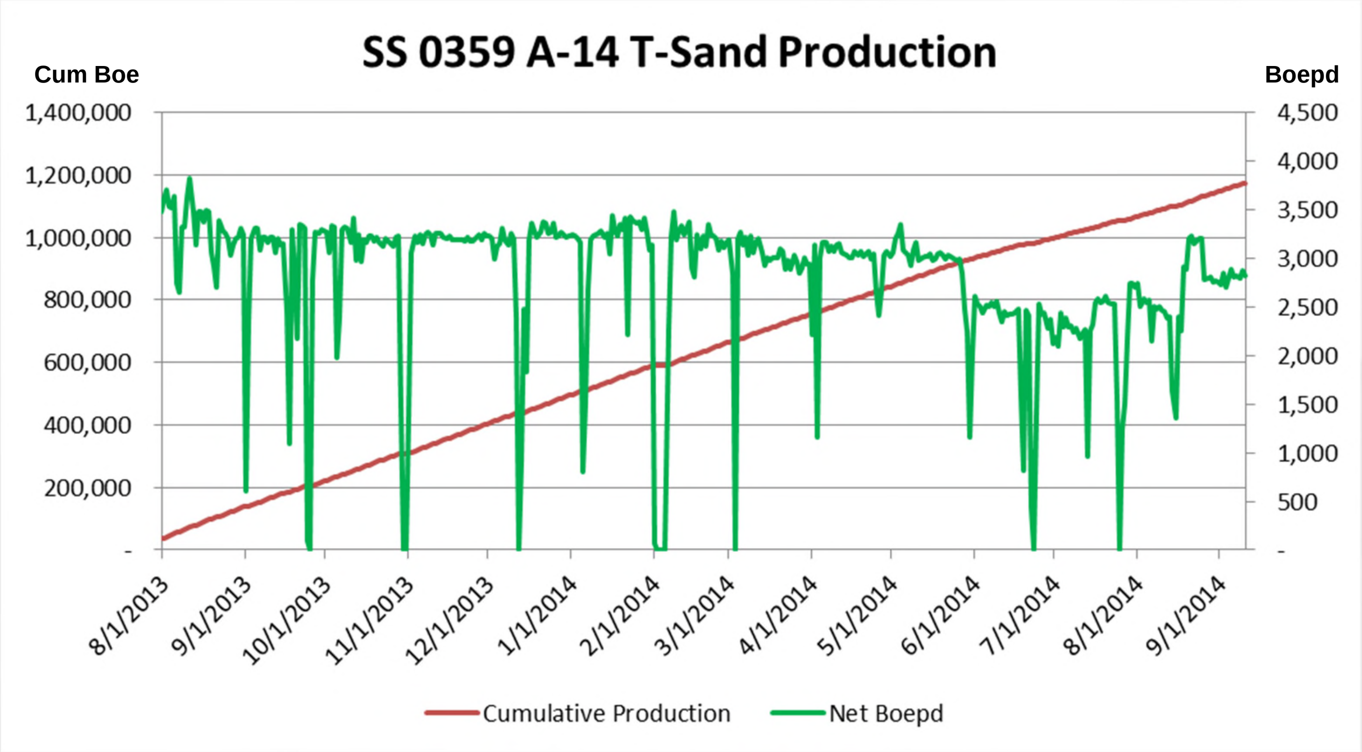


SS 349 A-14 “T” Sand Log



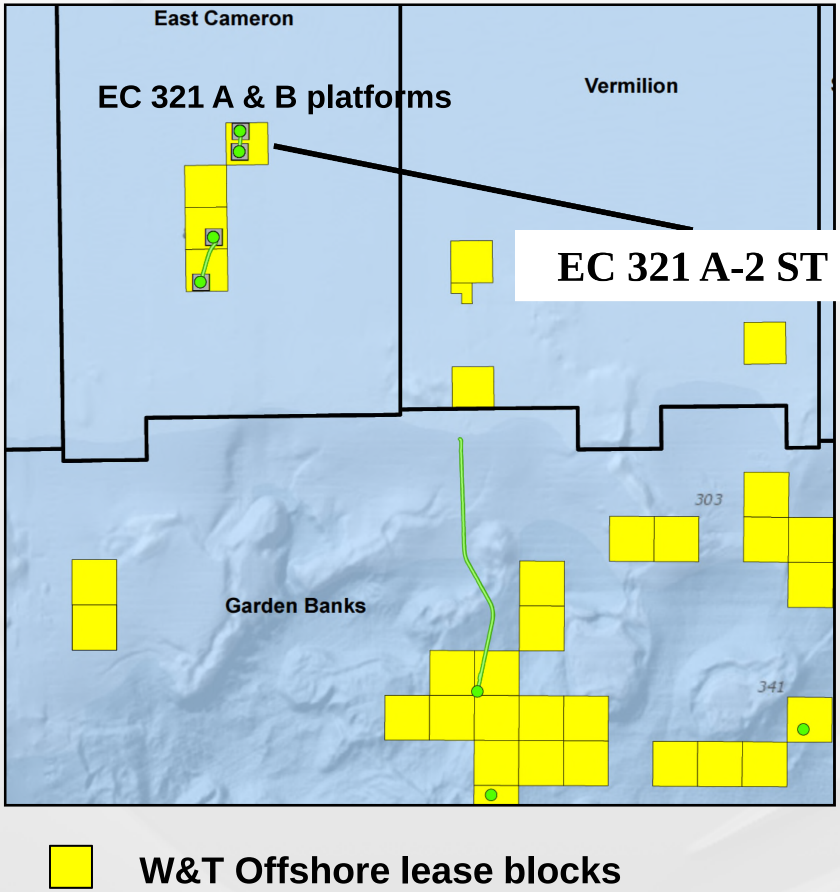
Mahogany A-14 “T-Sand” – Strong Production

- *Current Rate is 2,825 Boe net (~3,391 gross)*
- *Production is > 76% crude oil*
- *Cumulative production ~ 1,175,000 Boe net*
- *Steady production indicates strong water drive and/or large reservoir*
- *Bottom hole pressure has been very constant*



Note: *During the period June to mid-August, platform work and other well operations impacted SS 359 A-14 production*

Exploration – GOM Shelf



EC 321 A-2 ST

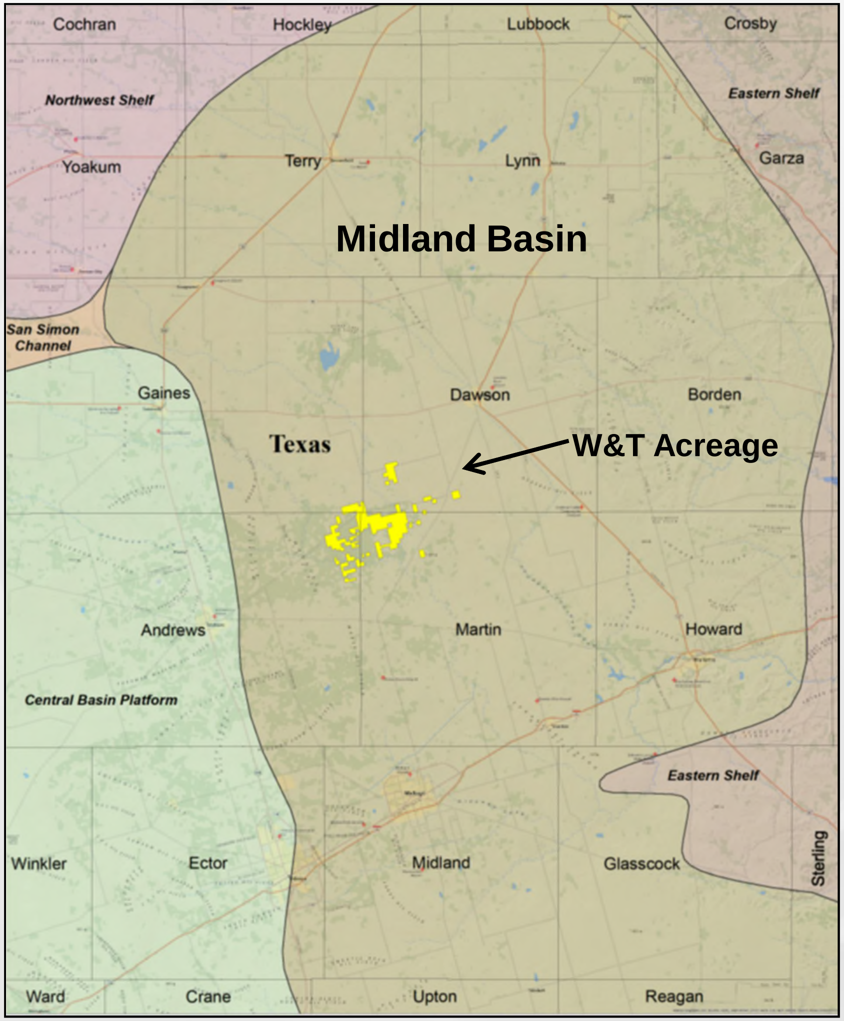
(WI: 100%, NRI: 83.3%)

- *Summary* – Targeting new reserves in the Lentic 1 sand by drilling a side-track from the existing A-2 well bore
- Target well depth – ~8,500' TVD
- ***Status – Well is in completion and should commence production in fourth quarter of 2014***
- Target IP – 850 Boepd (60% oil)
- Unrisked potential – 1.1 MMBoe

East Cameron 321 field is situated 97 miles off the coast of Louisiana in 225' of water. Average July production of ~ 1,150 Boepd (~ 87% oil)

PERMIAN BASIN

Permian Basin: Overview of Asset and Activity



*Rates normalized for 7500' effective lateral length

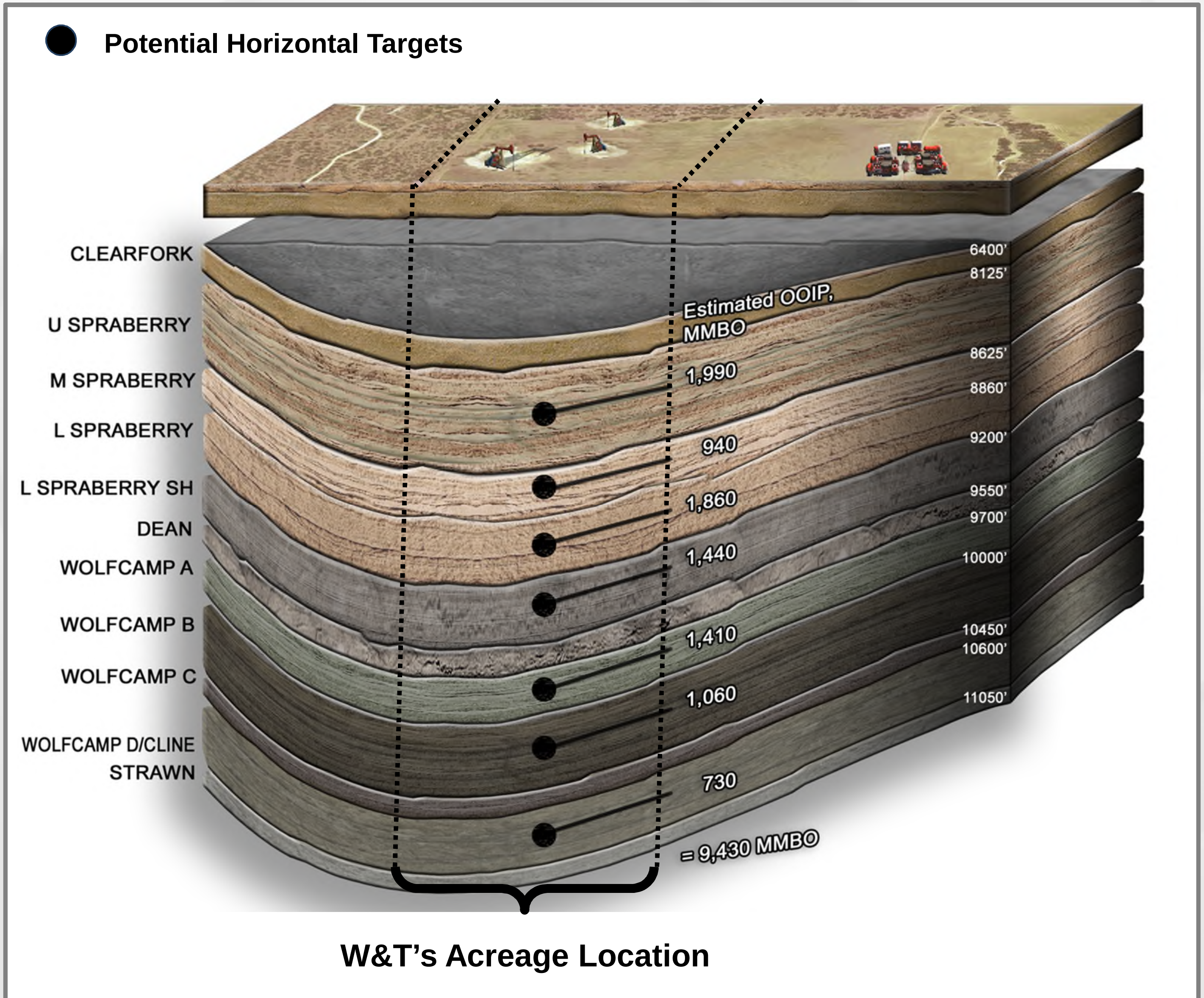
Permian Basin (WI: 100%, NRI: ~78%)

- *~32,000 net acres with 26,000 highly contiguous net acres in the heart of the Northern Midland Basin portion of the Permian Basin*
- *2014 Capital Budget allocation of ~$157 million*
- *Current drilling program reflects 2 to 3 rigs throughout the year drilling vertical (~30) and horizontal (~10) wells*
- *Our Permian acreage is ~85% "held by production"*

Key Points for Permian Basin

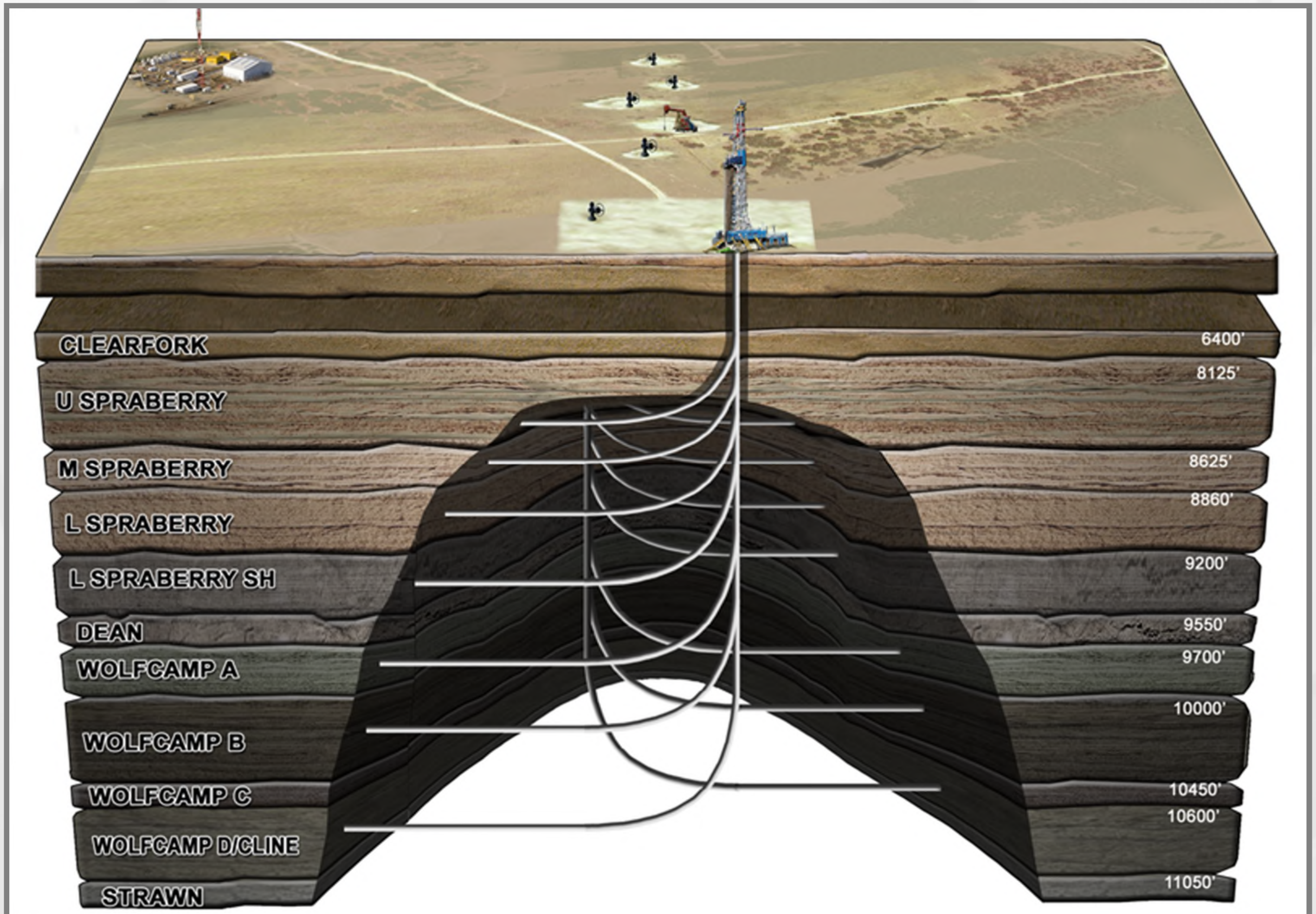
- *First horizontal Wolfcamp B well, Chablis 9H, reached a 24 hr peak rate of 697* Boepd (73% oil) and 30 day average rate of 434* Boepd*
- *Joint operated Wolfcamp B well reached a 24 hour peak rate of 692* Boepd and 30 day average rate of 426* Boepd (83% oil)*
- *Next two Wolfcamp B wells, the Chablis 10H and Chablis 13H (drilled from a common pad) reached 24 hr peak test rates of 968* Boepd (80% oil) and 1,125* Boepd (89% oil), respectively*
- *First horizontal Lower Spraberry Shale well, Pinot 65 15H, recently reached a 24 hr test rate of 965* Boepd (86% oil)*

Permian Basin – Northern Midland Basin Portion



W&T's approximately 28,000 gross acre leasehold in the Yellow Rose Field is located in the Northern Midland Basin, slightly east of the basin axis. Deep position allows for higher thermal maturity and higher pressures to increase potential for hydrocarbon recovery, and potential for stacked horizontal targets multiplies the effective acreage. Currently seven potential horizontal targets have been identified.

Stacked Lateral Drilling



W&T is moving towards multi-well pad drilling with stacked laterals to efficiently unlock the value of the stacked pay resource potential.

Significant Activity Near W&T Acreage

WELLS DRILLED AND TESTED

SM Energy Tatonka #1H
549 Boepd (6,400' Wolfcamp B lateral)

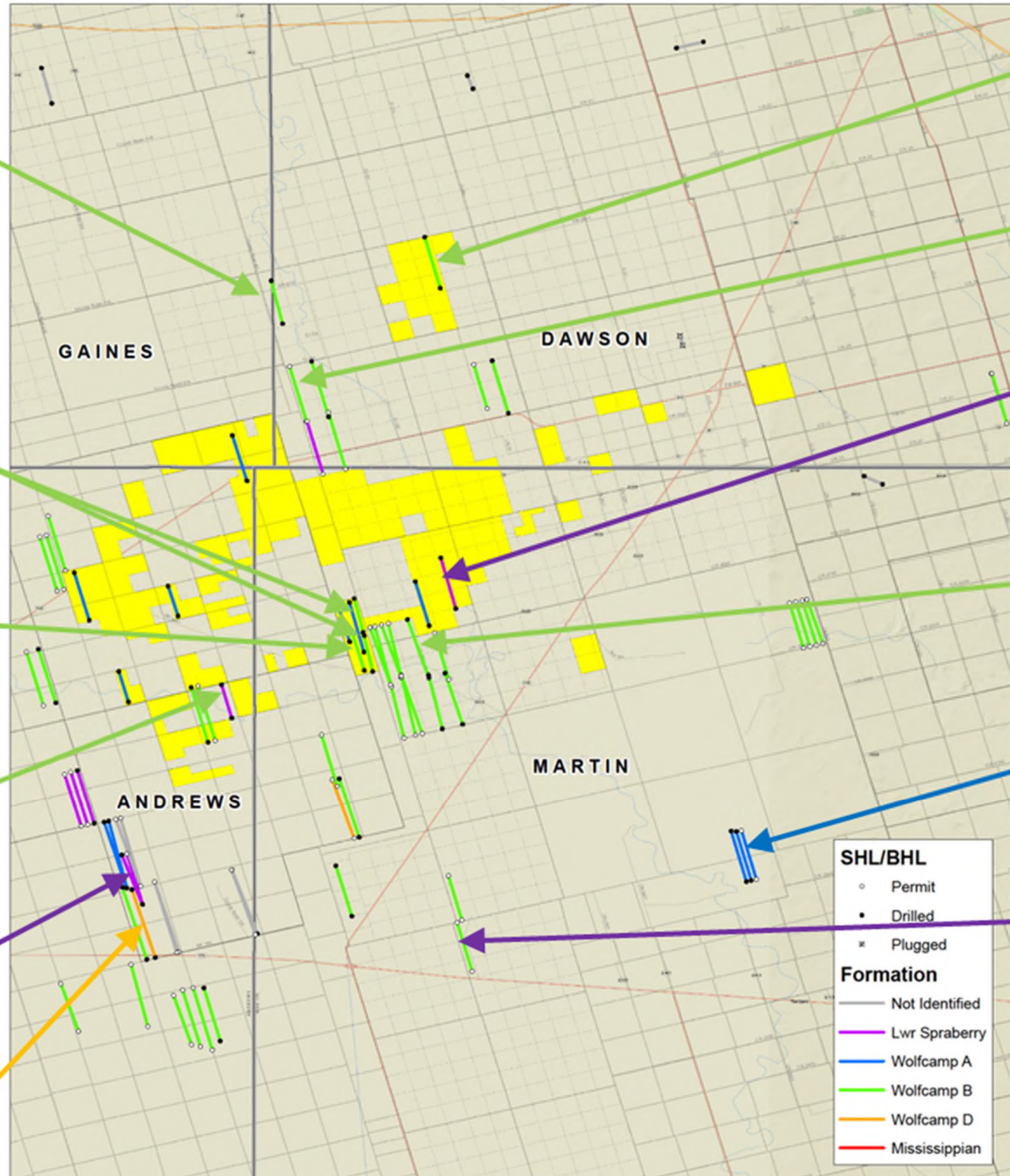
W&T Chablis #10H & #13H
(common pad)
10H—24 hr IP: 643 Boepd (4,982' Wolfcamp B lateral)
13H—24 hr IP: 738 Boepd (4,922' Wolfcamp B lateral)

W&T Chablis #9H
24 hr IP: 549 Boepd
(5,905' Wolfcamp B lateral)

Diamondback Energy UL III 4 #1H
24hr IP: 613 Boepd
(4,051' Wolfcamp B lateral)

Pioneer Resources University 7-43 #16H
24hr IP: 1,660 Boepd
(7,502' Lower Spraberry lateral)

Pioneer Resources University 7-43 #10H
24hr IP: 3,605 Boepd
(7,382' Wolfcamp D/Cline lateral)



W&T Beaujolais A 1302H
Currently drilling
(Wolfcamp B lateral)

Diamondback Energy Kent County School #1701H
541 Boepd
(8,543' Wolfcamp B lateral)

W&T Pinot 65 #15H
24 hr IP: 871 Boepd (6,769' Lower Spraberry lateral)

Diamondback Energy Mabee Breedlove #2201H
24 hr IP: 1,029 / 30 day avg: 788 Boepd
(8,296' Wolfcamp B lateral)

Energen Resources Jones Holten #101H
24 hr IP: 1,171 / 30 day avg: 843 Boepd
(6,675' Wolfcamp A lateral)

Athlon Dorothy Faye #2H
24 hr IP: 1,279 / 30 day avg: 1,076 Boepd
(Lower Spraberry lateral)

Permian Basin Horizontal Well Fracture Stimulation

- *Currently evaluating both hybrid and slickwater fracture stimulation treatments to stimulate our horizontal wells*
- *On the last five horizontal wells we have performed two slickwater treatments and three hybrid treatments*
- *Results are still under evaluation as three of these treatments have been performed since early July*

Summary Stimulation Parameters for Last 5 Horizontal Wells

	Slickwater (2 wells)	**Hybrid** (3 wells)
Effective lateral length*	avg. 6,300’	avg. 5,900’
Target spacing between stages	260’	240’
Target stages	24	24
Target volume per stage (MGals)	450	350
Proppant type	Sand	Sand
Target proppant per stage (lbs)	300,000	320,000
Target proppant per lateral foot (lbs)	1,200	1,300

**Effective Lateral Length is the distance from the deepest perforation to the shallowest perforation within the target horizontal bench.*

Untapped Reserve and Inventory Growth Potential

Target / Bench	Booked Proved Locations (PUDs)	Preliminary Unbooked Locations	Unbooked Net Potential (MMBoe)
80 acre vertical	110	66	6
40 acre vertical	52	246	21
20 acre vertical	0	673	57
TOTAL VERTICALS	**162**	**985**	**84**
Upper Spraberry Horizontal	0	170	60
Middle Spraberry Horizontal	0	170	60
Lower Spraberry Horizontal	0	170	60
Lower Spraberry Shale Horizontal	0	170	60
Wolfcamp A Horizontal	21	30	10
Wolfcamp B Horizontal	21	158	55
Wolfcamp D/Cline Horizontal	0	49	17
TOTAL HORIZONTALS	**42**	**917**	**322**
TOTAL ALL WELLS	**204**	**1,902**	**406**

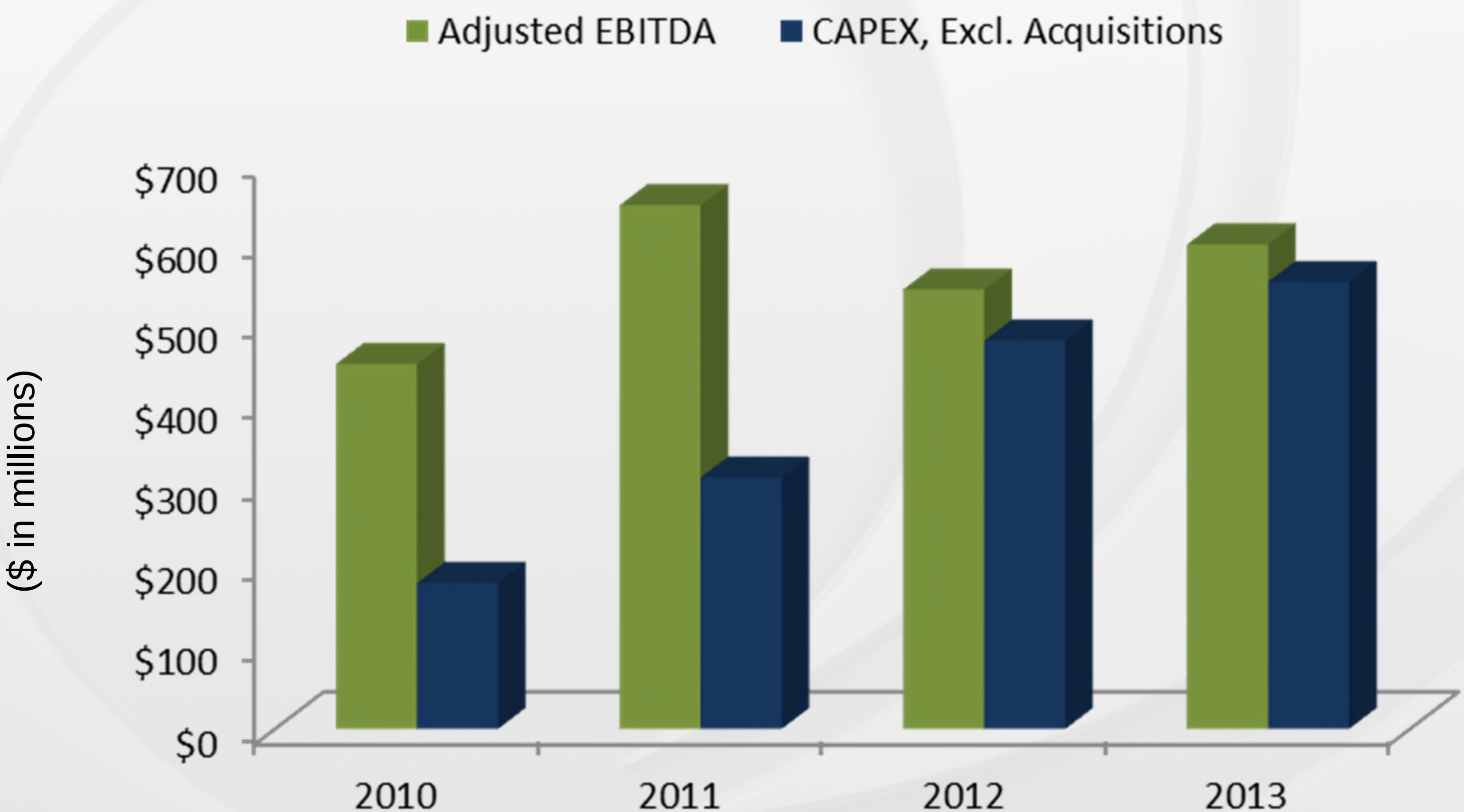
Liquidity Available for Further Growth

- **Revolving bank credit facility of $1.2 billion with an $750 million borrowing base**
  - *Borrowing base[1] at $750 million with facility maturity of Nov. 2018*
  - *Improved terms on the credit facility agreement[2]*
  - *As of August 1, 2014, cash on hand (~ $22 million) and amount available under credit facility (~ $452.0 million) totaled $474.2 million*
  - *20 banks in our current credit facility with additional capacity*
- **Adjusted EBITDA for Twelve Months Ended June 30, 2014 - $637 million**
  (see appendix for full disclosure)
- **Senior notes mature in 2019**
  - *Bonds recently trading[3] at $107.00 with a yield-to-worst of 4.72%*
- **Oil hedges to protect the budget** (see appendix for full disclosure)
  - *Average swap price[4] for 2014: Brent - $97.37 & LLS - $97.96*
- **Access to capital markets**

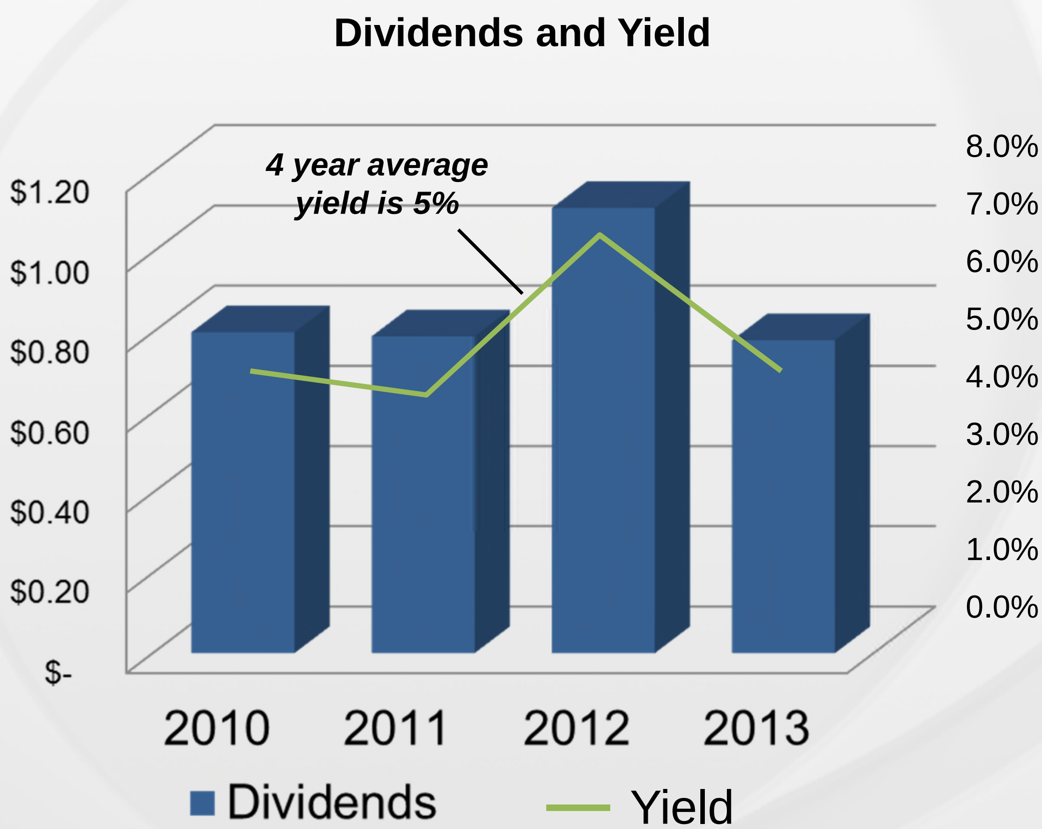
(1) *Effective April 17, 2014, our borrowing base was changed to $750 million from $800 million upon completion of the semi-annual redetermination in accordance with the terms of our revolving bank credit facility agreement.*
(2) *One financial covenant concerning the maximum leverage ratio of total debt to EBITDA, as defined in the New Credit Agreement, was increased from 3.0 to 1.0 to 3.5 to 1.0, and interest rates were decreased for certain borrowings depending on our facility utilization ratio.*
(3) *Bond pricing and YTW are quotes as of August 26, 2014*
(4) *Prices reflect weighted averages for Brent and LLS based swaps*

Drilling Within Cash Flow

Historically, we have not borrowed money for drilling



Returning Cash to Investors



W&T has paid three normal quarterly dividends of $0.10 per share in 2014

(Paid in March, June 2014 and September 2014)

- *Four year average yield* of 5%*
- *Quarterly dividend has been increased five times since going public*
- *Have paid a special dividend six of the last seven years*

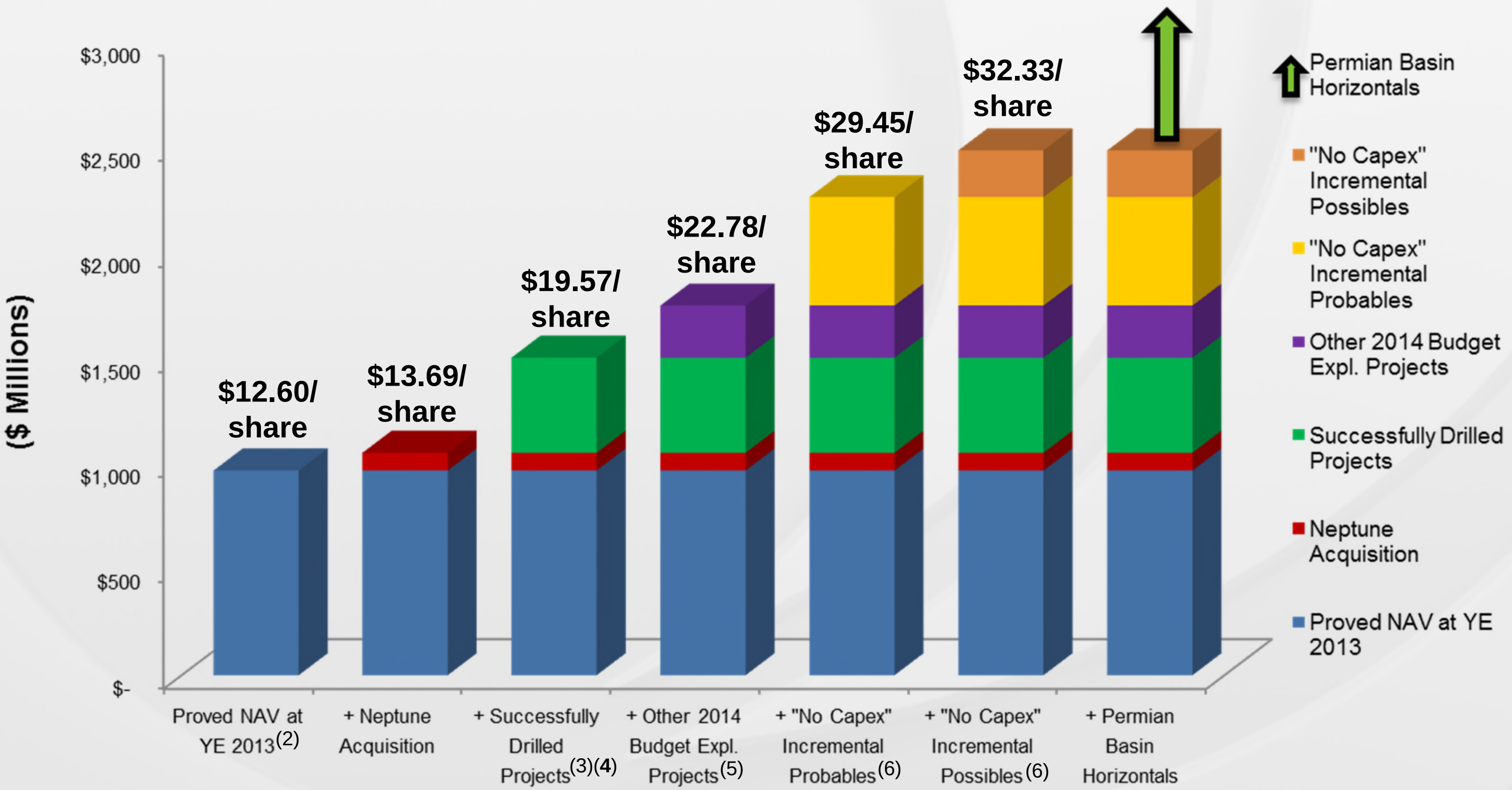
** Yield is calculated as total dividends for the year, divided by the closing stock price on the last day of the respective year.*

How We Provide Value to Our Investors

- **Continued focus on organic growth activity**
  - *Active exploration program providing significant potential for reserve additions*
  - *Disciplined approach: drill within cash flow*
- **Balanced Asset Development**
  - *2014 Budget that is allocated between each of our primary operating basins: Permian, Gulf of Mexico shelf, GOM Deepwater*
- **Company focused on free cash flow generation**
  - *Adjusted EBITDA for last 12 months at 6/30/14 - $637 million*
- **Continued strong liquidity for acquisition opportunities**
  - *Cash and borrowing availability as of August 1, 2014 still reflects roughly $474.2 million in available capacity*
- **Returning cash to shareholders via consistent dividends**
  - *Four year average dividend yield of 5%*
- **Management Team**
  - *Incentivized and experienced*

Net Asset Value Estimate

- ***Current stock price is $13.34 (as of 9/16/14 close)***
- ***Our estimate of Net Asset Value per share (1) is substantially greater than the current stock price***
- ***More upside in full probable and possible value and all future exploratory projects currently under evaluation***



(1) Diluted shares of 77 million shares.
(2) Proved NAV calculated as PV-10 of proved reserves at SEC pricing at 12/31/13, less debt and ARO, plus cash as of 6/30/14.
(3) Successfully drilled projects include Big Bend and Dantzler #1 & #2.
(4) Big Bend and Dantzler #1 & #2 valuation based on operator's latest published estimates, adjusted for $2.3 million in 1P PV-10 value booked at YE2013 for Big Bend.
(5) Other 2014 Budget exploratory projects include Neptune SB03, Medusa SS6 & SS7, and EW 910 A-5ST & A-8. PV-10 of unrisked mean cases based on 7/28/14 NYMEX pricing.
(6) "No capex" probables and possibles are associated with PDP reserves and require no additional capital. As of 12/31/2013.

APPENDIX

Reconciliation of Net Income to Adjusted EBITDA

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

($ in thousands)	Twelve Months Ended June 30, 2014	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Net income (loss)	$ 23,334	$ 21,026	$ 49,014	$ 51,322	$ 71,984	$ 172,817	$ 117,892
Income tax expense (benefit)	13,370	11,921	27,325	28,774	47,547	91,517	11,901
Net interest expense	76,442	38,685	37,815	75,572	49,979	42,432	36,996
Depreciation, depletion, amortization and accretion	494,304	251,542	208,767	451,529	356,232	328,786	294,100
EBITDA	607,450	323,174	322,921	607,197	525,742	635,552	460,889
Adjustments:							
Derivatives loss (gain)	38,514	20,571	(9,473)	8,470	13,954	(1,896)	4,256
Royalty relief recoupment	-	-	-	-	-	-	(24,881)
Transportation allowance for deepwater production	-	-	-	-	-	-	4,687
Loss on extinguishment of debt	128	-	-	128	-	22,694	-
Contract Option Fee	(9,062)	-	-	(9,062)	-	-	-
Litigation Accrual	-	-	-	-	10,250	-	-
Adjusted EBITDA	$ 637,030	$ 343,745	$ 313,448	$ 606,733	$ 549,946	$ 656,350	$ 444,951

We define EBITDA as net income (loss) plus income tax expense (benefit), net interest expense (which includes interest income), depreciation, depletion, amortization and accretion and impairment of oil and natural gas properties. Adjusted EBITDA excludes the loss on extinguishment of debt and the gain or loss related to our derivative contracts. Although not prescribed under GAAP, we believe the presentation of EBITDA and Adjusted EBITDA provide useful information regarding our ability to service debt and fund capital expenditures and they help our investors understand our operating performance and make 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 flow 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.

2014 Guidance *($ in millions)*

	Third Quarter 2014			Full Year 2014		
Estimated Production						
Oil and NGLs (MMBbls)	1.9	-	2.1	8.7	-	8.9
Natural Gas (Bcf)	9.4	-	10.4	47.0	-	48.4
Total (Bcfe)	21.1	-	23.3	99.0	-	102.0
Total (MMBoe)	3.5	-	3.9	16.5	-	17.0
Operating Expenses						
Lease operating expenses	$ 78	-	$ 86	$ 254	-	$282
Gathering, transportation, & production taxes	$ 7	-	$ 8	$ 27	-	$ 30
General & administrative	$ 23	-	$ 25	$ 87	-	$ 95
Income tax rate (1)	36.5%			36.5%		

(1) Reflects the statutory federal and state tax rate

2013 Year End Proved Reserves

Classification of Proved Reserves

	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Oil Equivalent (MMBoe)	Natural Gas Equivalent (Bcfe)	% of total reserves	PV-10 (1) (Millions)
Proved developed producing	27.8	8.1	148.5	60.6	363.8	51%	$ 1,895.0
Proved developed non-producing	8.4	3.0	84.2	25.5	152.3	22%	482.0
Total proved developed	36.2	11.1	232.7	86.1	516.1	73%	2,377.0
Proved undeveloped	22.3	4.8	27.2	31.6	189.8	27%	151.0
Total proved	58.5	15.9	259.9	117.7	705.9	100%	$ 2,528.0

1) In accordance with guidelines established by the SEC, our proved reserves as of December 31, 2013 were determined to be economically producible under existing economic conditions, which requires the use of the unweighted arithmetic average of the first-day-of-the-month price for oil and gas for the period January 2013 through December 2013. Also note that the PV-10 value is a non-GAAP financial measure. We refer to PV-10 as the present value of estimated future net revenues of estimated 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. For 2013, proved reserves and PV-10 were calculated using average prices of $99.65 per barrel for oil, $35.21 per barrel for natural gas liquids and $3.80 per Mcf for natural gas, as adjusted for energy content for natural gas, quality, transportation fees and regional price differentials.

Financial Commodity Derivatives [1]

2014 Swaps	Brent Swaps		WTI Swaps		LLS Swaps	
Month	Barrels Per Day	Avg Swap Price	Barrels Per Day	Avg Swap Price	Barrels Per Day	Avg Swap Price
September	1,800	$ 97.38	-	-	9,000	$ 97.69
October	1,700	$ 97.37	-	-	5,000	$ 98.12
November	1,700	$ 97.37	-	-	5,000	$ 98.12
December	1,700	$ 97.37	-	-	5,000	$ 98.12

(1) All figures reflect weighted averages for the specified period

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. 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 to U.S. Investors

The United States 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. U.S. Investors are urged to consider closely the disclosure in our Form 10-K for the year ended December 31, 2013, available from us at Nine Greenway Plaza, Suite 300, Houston, Texas 77046. You can obtain these forms from the SEC by calling 1-800-SEC-0330.

W&T OFFSHORE

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