

An aerial photograph of a vast, flat landscape. In the foreground, there are rolling hills with patches of green grass and yellowish-brown soil. A large, winding body of water, possibly a reservoir or a large river, stretches across the middle ground. In the center of the image, there is a small industrial site with a tall, thin structure, likely a wellhead or a flare stack. The background shows a flat expanse of land under a clear sky.

OASIS PETROLEUM
INVESTOR PRESENTATION
September 2012

Forward-Looking Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including the Company's drilling program, production, derivative instruments, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include, but are not limited to, changes in oil and natural gas prices, weather and environmental conditions, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as the Company's ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting the Company's business and other important factors that could cause actual results to differ materially from those projected as described in the Company's reports filed with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Cautionary Statement Regarding Oil and Gas Quantities

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions (using unweighted average 12-month first day of the month prices), operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The SEC also permits the disclosure of separate estimates of probable or possible reserves that meet SEC definitions for such reserves; however, we currently do not disclose probable or possible reserves in our SEC filings.

In this presentation, proved reserves attributable to the Company at December 31, 2011 are estimated utilizing SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices of \$96.23 per barrel of oil and \$4.12 per MMBtu of natural gas. The reserve estimates at December 31, 2011 and 2010 presented in this presentation are based on reports prepared by DeGolyer and MacNaughton, independent reserve engineers.

We may use the terms "unproved reserves," "EUR per well" and "upside potential" to describe estimates of potentially recoverable hydrocarbons that the SEC rules prohibit from being included in filings with the SEC. These are the Company's 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. EUR estimates and drilling locations have not been risked by Company management. Actual locations drilled and quantities that may be ultimately recovered from the Company's interests will differ substantially. There is no commitment by the Company to drill all of the drilling locations which have been attributed to these quantities. Factors affecting ultimate recovery include 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; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves, per well EUR and upside potential may change significantly as development of the Company's oil and gas assets provide additional data.

Our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Management

		Years Experience
Tommy Nusz President, Chief Executive Officer and Chairman	Former President International Division, VP Acquisitions and Divestitures, VP Strategic Planning and Engineering of Burlington Resources	30
Taylor Reid Executive Vice President, Chief Operating Officer and Director	Former Asset Manager of ConocoPhillips, GM Latin America and Asia Operations, GM Corp. Acquisitions and Divestitures with Burlington Resources	26
Michael Lou Executive Vice President, Chief Financial Officer	Former Director Global Energy IBK of Macquarie; Vice President Energy and Power Investment Banking of Bank of America Merrill Lynch	15

Oasis Highlights

Oil Focused, Pure Play Williston Basin Operator

- 88% oil weighted
- Leading leverage to the Bakken

Significant Acreage and Drilling Inventory

- Over 320,000 net acres in the Bakken / Three Forks (“TFS”) trend⁽¹⁾
- Identified drilling inventory of 1,313 gross locations (750 operated)⁽²⁾

Substantial Upside Potential ⁽²⁾

- Multiple stacked oil plays and substantial oil in place
- 941 additional gross TFS locations plus 928 additional gross locations including 4th Bakken and TFS in spacing unit

Increasing Operational Efficiency

- Continue to drive down average drilling days and average days to frac wells
- Doing more activity with less resources

Growing Production Profile

- \$912MM drilling program (\$1.06B total budget) for 2012 expected to significantly grow total production
- Increased production in 2Q12 by 158% to 20.4Mboepd over 2Q11

Experienced Management Team and Staff

- Management team has over 300 years of industry experience

(1) As of 6/30/12
(2) As of 12/31/11

Strong Foundation Drives Continued Growth

2011

Execution and Scale

- Consolidated acreage position
- Cored up acreage blocks
- Secured services to execute on development program

2012

Optimization and Delineation

- HBP acreage
- Middle Bakken delineation
- Well density and Three Forks testing
- Cost and operations optimization
- Infrastructure development

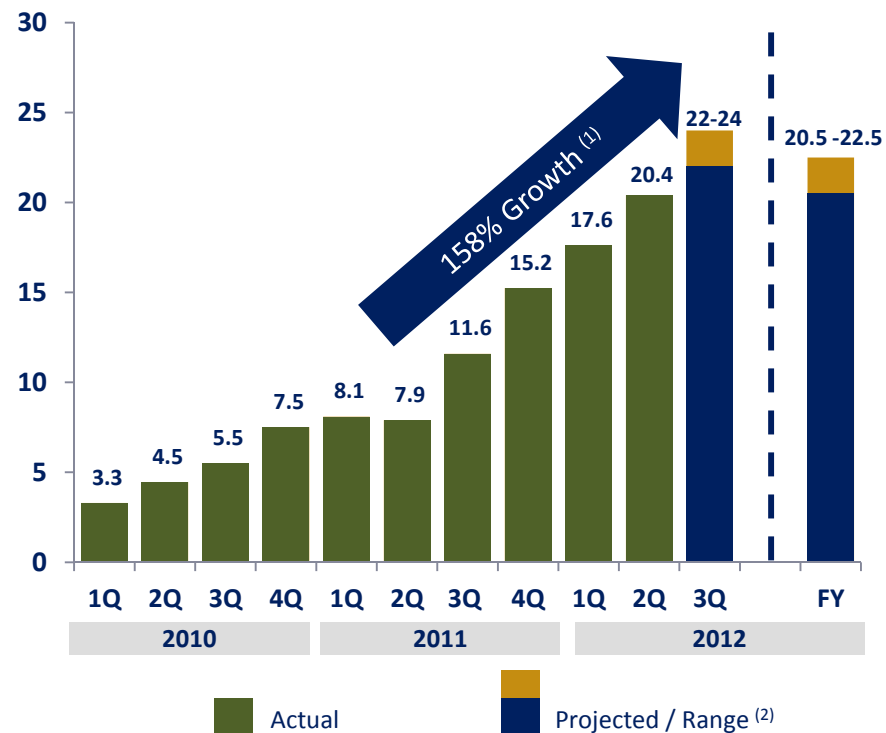
2013

Development

- Full pad development
- Capital and operating efficiencies
- Realize infrastructure benefit

Average Daily Production

(MBoe/d)

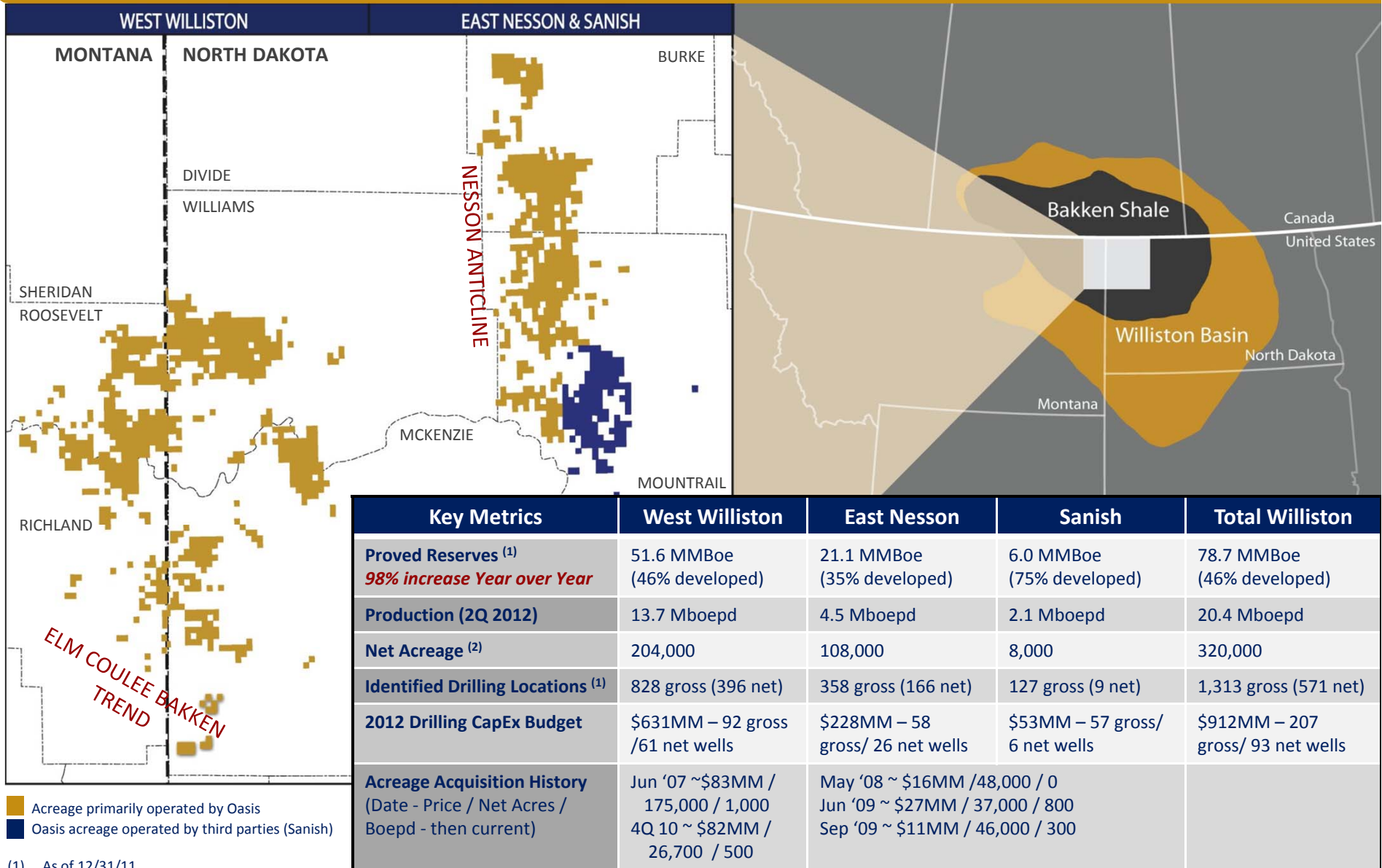


Developing a strong foundation for future success

(1) 2Q12 production over 2Q11

(2) Guidance for 3Q12 and full year was updated in press release dated 8/6/2012.

Large, Concentrated Acreage Blocks



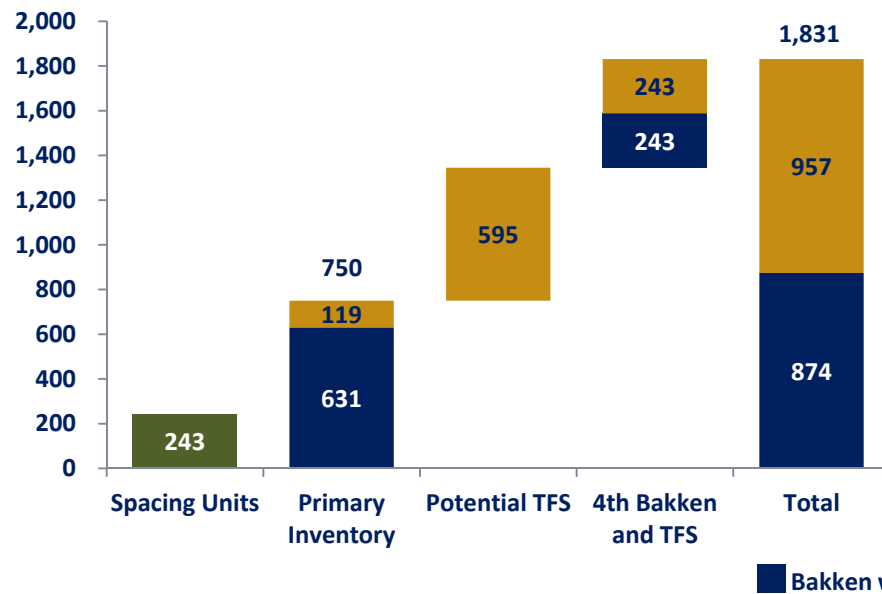
Key Metrics	West Williston	East Nesson	Sanish	Total Williston
Proved Reserves ⁽¹⁾ <i>98% increase Year over Year</i>	51.6 MMBoe (46% developed)	21.1 MMBoe (35% developed)	6.0 MMBoe (75% developed)	78.7 MMBoe (46% developed)
Production (2Q 2012)	13.7 Mboepd	4.5 Mboepd	2.1 Mboepd	20.4 Mboepd
Net Acreage ⁽²⁾	204,000	108,000	8,000	320,000
Identified Drilling Locations ⁽¹⁾	828 gross (396 net)	358 gross (166 net)	127 gross (9 net)	1,313 gross (571 net)
2012 Drilling CapEx Budget	\$631MM – 92 gross / 61 net wells	\$228MM – 58 gross / 26 net wells	\$53MM – 57 gross / 6 net wells	\$912MM – 207 gross / 93 net wells
Acreage Acquisition History (Date - Price / Net Acres / Boepd - then current)	Jun '07 ~\$83MM / 175,000 / 1,000 4Q 10 ~\$82MM / 26,700 / 500	May '08 ~\$16MM / 48,000 / 0 Jun '09 ~\$27MM / 37,000 / 800 Sep '09 ~\$11MM / 46,000 / 300		

■ Acreage primarily operated by Oasis
■ Oasis acreage operated by third parties (Sanish)

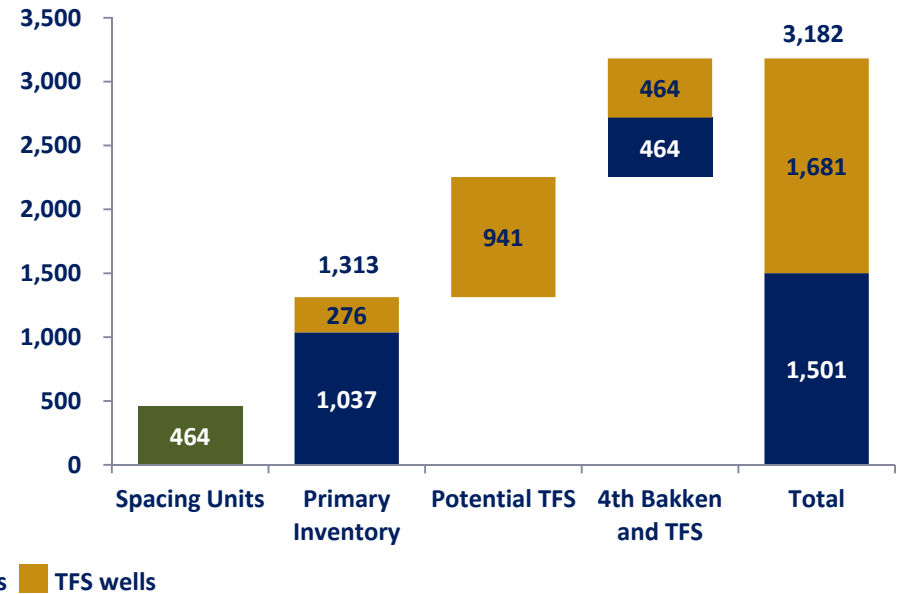
(1) As of 12/31/11
 (2) As of 6/30/12

Multi-Year Remaining Potential Drilling Inventory (1)

Gross Operated Drilling Locations



Gross Op and Non-Op Drilling Locations



- Primary Inventory includes remaining locations, assuming 3 Bakken wells and 3 TFS wells (in delineated areas)
- Potential TFS inventory reflects 3 TFS wells in acreage not yet delineated
- 1,043 total net potential locations assuming 3 Bakken and 3 TFS wells per spacing unit (1,432 if 1 additional Bakken and TFS included)
 - ~90% operated
 - >70% average working interest in operated locations
- ~8% total net potential locations included in proved reserves (PUD) as of 12/31/11
- ~11 years of inventory drilling ~120 wells/year (1 additional Bakken and TFS well adds 4 years of inventory and 36% additional locations)

(1) As of 12/31/11

Inventory Management

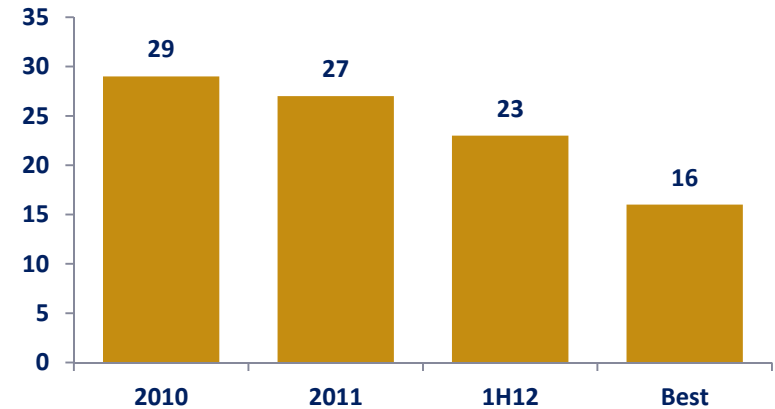
Increasing Drilling & Completion Efficiencies

- Drilling days continue to improve
- Pad Drilling
 - ~35% of wells in 2012 scheduled for pad drilling
 - Moving to full pad development in 2013
 - Drives incremental drilling efficiencies and cost savings
- Completion
 - Days to frac per well down 50% to ~5 days
 - Stimulation design
 - Oasis Well Services currently running 24 hour operations

Contracting services

- Running 9 to 10 operated rigs
 - Upgrading rig fleet
- Pressure Pumping Services
 - 2 to 3 dedicated external frac crews
 - Oasis Well Service – internal frac crew
- Laddered contracts provide flexibility

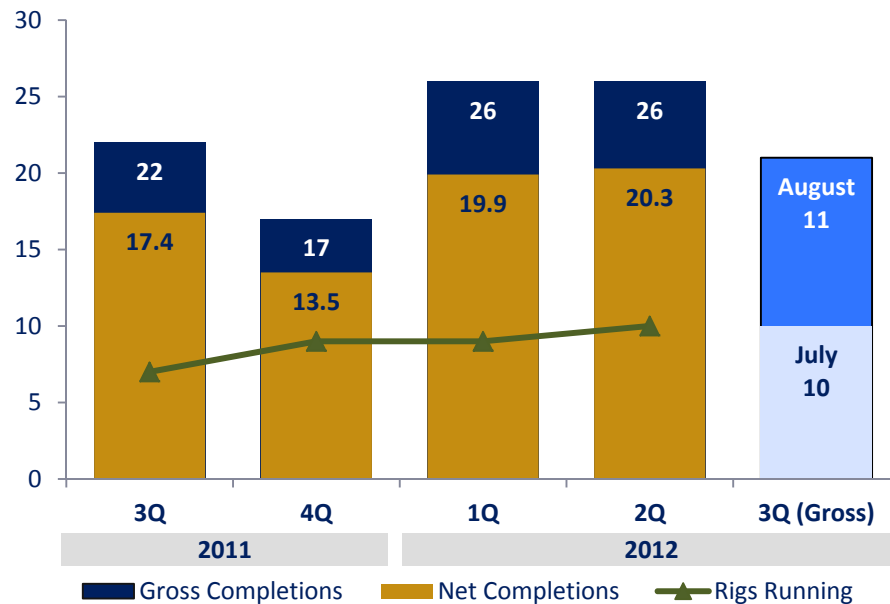
Drilling Days Improving



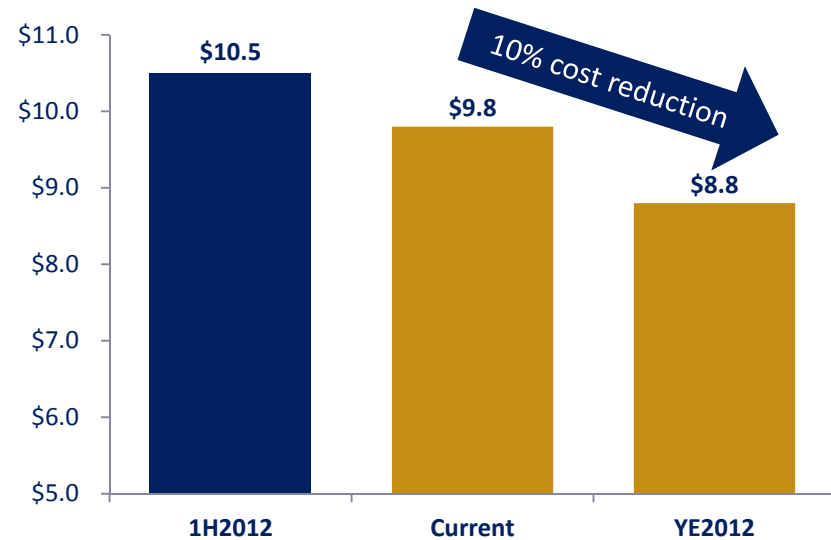
Doing more activity with less resources

Increasing Activity While Driving Down Costs

Operated Completion and Rig Activity



Well Cost Trends (\$MM)



2012 Budgeted Drilling Activity

- Drilling 112 gross operated wells spud in 2012
- 84 net operated wells
- 93 net wells (operated and non-operated)
- Running 9 to 10 rig program in 2012

Well Cost Reduction

- Driving down well costs 10% by YE12
 - Service and input costs
 - Efficiency gains
 - Completion and well design optimization
- 2013: 5% to 10% additional cost savings from pad development
- OWS frac'd wells result in additional \$500 - \$700k/well incremental savings (not reflected above)

West Williston – Overview

Key Statistics

Net Acreage ⁽¹⁾	204,000
Operated Rigs ⁽²⁾	6

Key Highlights

- Essentially 100% of the acreage is delineated in the Middle Bakken
- Target wells in Montana encouraging
- Indian Hills acreage is the deepest part of the Basin
- Extensive pad drilling and optimization
- 10 to 15 extensional Bakken tests in 2012 expected to further delineate acreage in Target, Mondak, and Missouri
- Infill testing – at least 3 wells / spacing unit, which yield ~10 to 15% of the oil in place
- Well design and completion optimization in Hebron and Red Bank have yielded encouraging results at significantly lower well costs

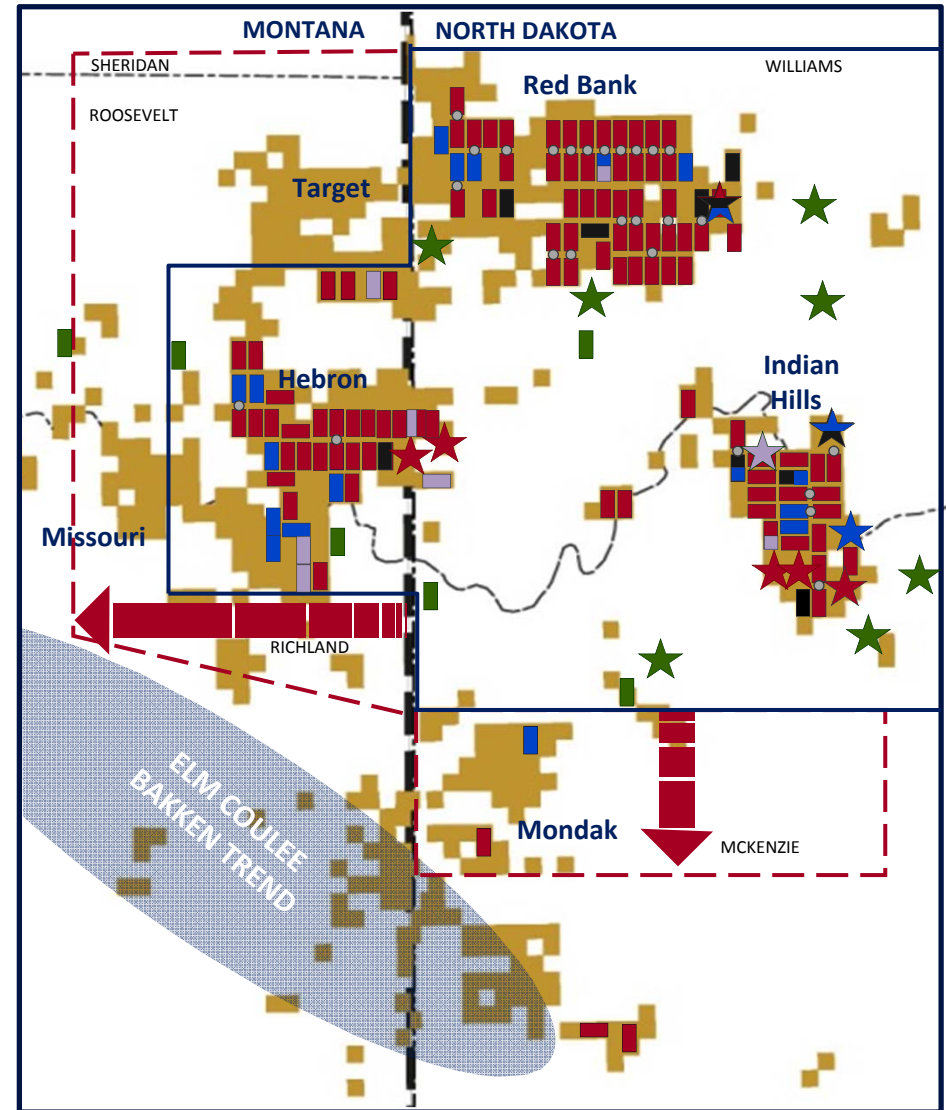
Legend ⁽²⁾

■ Operated Producing (122)	★ TFS Wells	 Delineated Acreage
■ Op – Waiting on Completion (25)	 Extensional tests	 Extensional Acreage
■ Operated Drilling (7)	■ Other Select Wells	 Pad site with 2 wells
■ Infill Sites (10)		

(1) As of 6/30/12

(2) As of 9/03/12

Note: Increase in WOC inventory largely due to shift to pad drilling



East Nesson and Sanish – Overview

Key Statistics	East Nesson	Sanish
Net Acreage ⁽¹⁾	108,000	8,000
Operated Rigs ⁽²⁾	4	Non Op

Key Highlights

- 100% of acreage in East Nesson is delineated in the Middle Bakken, with performance improving across the block
- All sand completions lowers well cost in north half
- Land group continues to high grade acreage position
- Sanish is non-op for Oasis and has solid well performance
- Completion optimization in North Cottonwood has resulted in 30% increase in production with 20% decrease in proppant used

Bakken ⁽²⁾

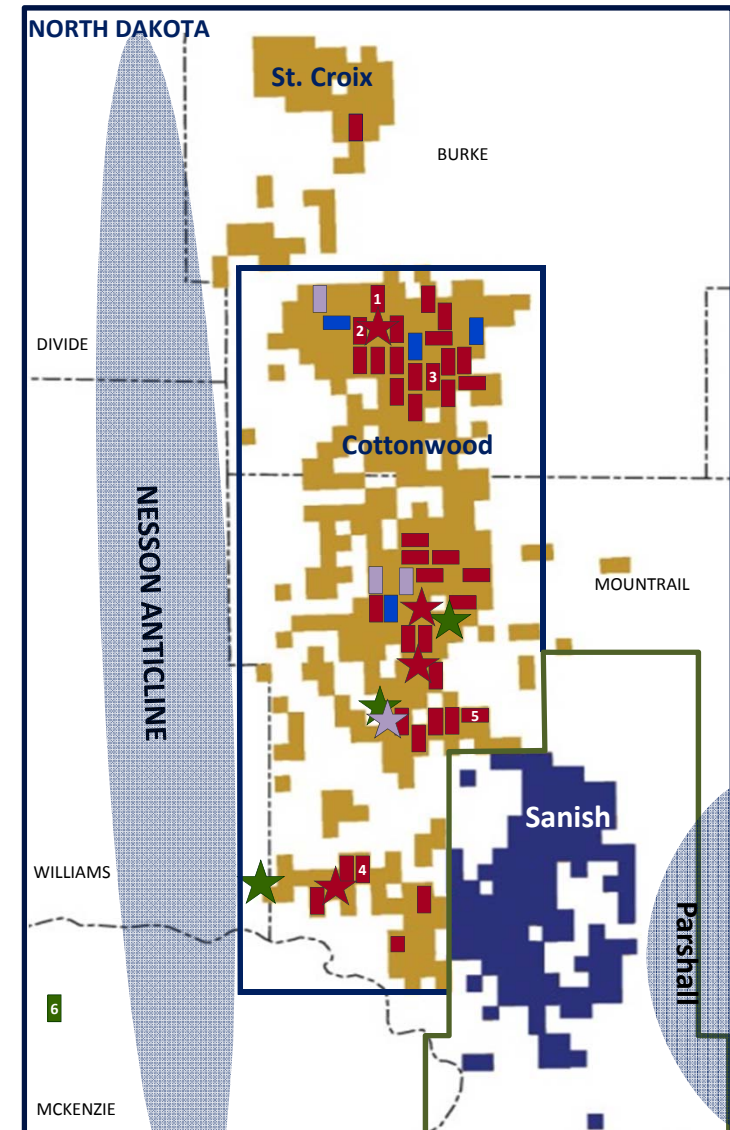
Oasis Selected Operated	Other Selected Wells
(1) Peters 11-1H	(6) Tarpon Federal 21-4H (Whiting)
(2) Rowley 6093 43-23H	
(3) Marsh 609 11-33H	
(4) Berry 5493 11-6H	
(5) Mallard 5692 21-20H	

Legend ⁽²⁾

■ Operated Producing (42)	★ TFS Wells	 Delineated Acreage
■ Op – Waiting on Completion (4)	■ Other Select Wells	 Non Op / Delineated
■ Operated Drilling (4)		

(1) As of 6/30/12

(2) As of 9/03/12



Three Forks (TFS) Overview ⁽¹⁾

TFS in Primary Inventory

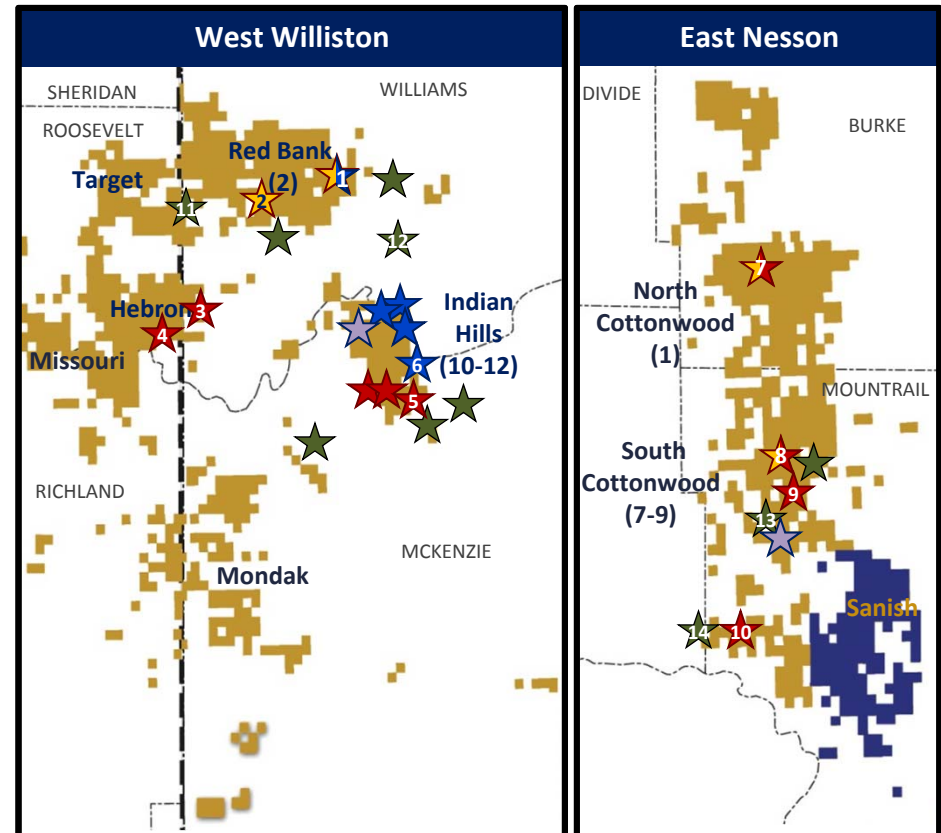
- South Cottonwood
 - Spratley produced over 1,300 boepd in first 60 days
 - TFS wells look similar (if not better) than nearby Bakken wells
 - Indian Hills
 - Solid performing operated and non-operated wells
 - Interference test with JO Anderson (TFS)
 - Performance at or below nearby Bakken wells
 - Appears TFS is producing independently
 - Birdhead – spud to rig release 22 days
 - 23,500' MD

Current Activity in the TFS

- 9 gross operated wells on production
 - 3 in Indian Hills, 2 in Hebron, 4 in Cottonwood
- Over 20 TFS wells planned in 2012, 4 of which are extensional tests in Cottonwood and Red Bank

TFS Wells ⁽²⁾

Oasis Selected Operated		Other Selected Wells
West Williston	East Nesson	Other Operators
(1) Arlyss	(7) Zdnok	(11) Obert (CLR)
(2) Mercedes	(8) Orion	(12) State (Brigham)
(3) Moore	(9) Caspian	(13) Liffrig (Brigham)
(4) Wilson	(10) Spratley	(14) Krieger (XTO)
(5) JO Anderson		
(6) Birdhead		



Legend ⁽¹⁾

- ★ Operated Producing TFS (9)
- ★ 2012 Extensional Operated TFS Tests
- ★ Op – Waiting on Completion (5)
- ★ Other Selected TFS Wells
- ★ Operated Drilling (2)
- (#) Range of wells planned for 2012

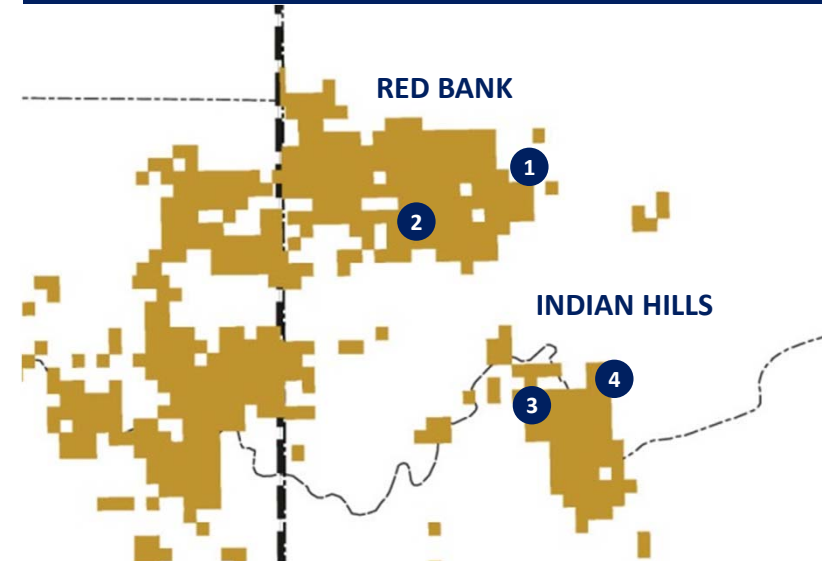
(1) As of 9/03/12

2012 Infill Program

Infill Program

- Foundation for development plan
- Over 35 new gross operated wells included in tests for well patterns and density in 2012
- Micro-seismic analysis on pilot areas
- Tests will provide additional data on interaction between wells

Full Infill Pilots in 2012



Red Bank

- (1) 3 Bakken well test (~1,700 feet inter-well spacing)
- (2) 4 Bakken well test (~1,400 feet inter-well spacing)

Indian Hills

- (3) 4 Bakken well test
- (4) 3 Bakken and 3 TFS test

Oasis Well Services (“OWS”)

Timing

- First frac job in late March 2012
- 9 frac jobs completed as of end of June 2012
- 105 stages pumped in July
- Currently running 24 hour operations
- \$10-12MM estimated of CapEx savings in calendar year 2012
- Neutral EBITDA in calendar year 2012 as operations ramp

Annualized Economics for One Frac Spread

- Save ~\$500 -700k/ gross well on up to 50% of operated wells
- Incremental EBITDA from non-op partners ~ \$200k per gross well
- Annual savings:
 - \$16 - \$20MM of CapEx savings per year
 - \$7 - 9MM of incremental EBITDA
 - Total impact of \$23 - 29MM
- \$24MM investment in equipment with ~ 1 year payback

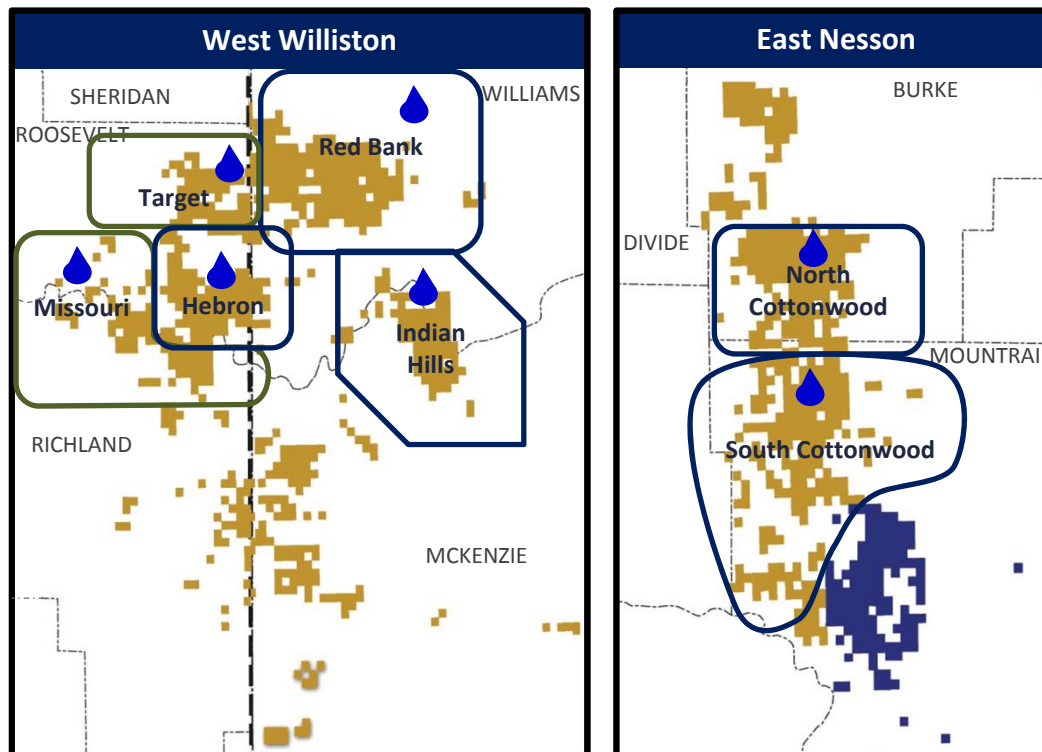
OWS Hydraulic Pumping Unit



OWS Blender on Location



Salt Water Disposal ("SWD") Update



Salt Water Disposal (SWD)

Focus Area	Red Bank, Indian Hills, Hebron, North Cottonwood, and South Cottonwood
Capital Cost	\$74MM 2012 infrastructure budget, mainly for SWD
Oasis Benefit	LOE - Expect \$2.00 to \$3.00/Boe reduction from Q3 2011 levels → 2Q LOE = \$6.49/Boe Eliminates trucking and commercial disposal costs
Timing for 2011 and 2012 SWD Systems	At end of 6/12, ~32% of operated water production flowed through 2011 and 2012 pipeline systems → expect to flow 80% by EOY 12 At end of 6/12, ~63% of operated water production disposed in Company operated disposal wells

Gas Marketing & Infrastructure

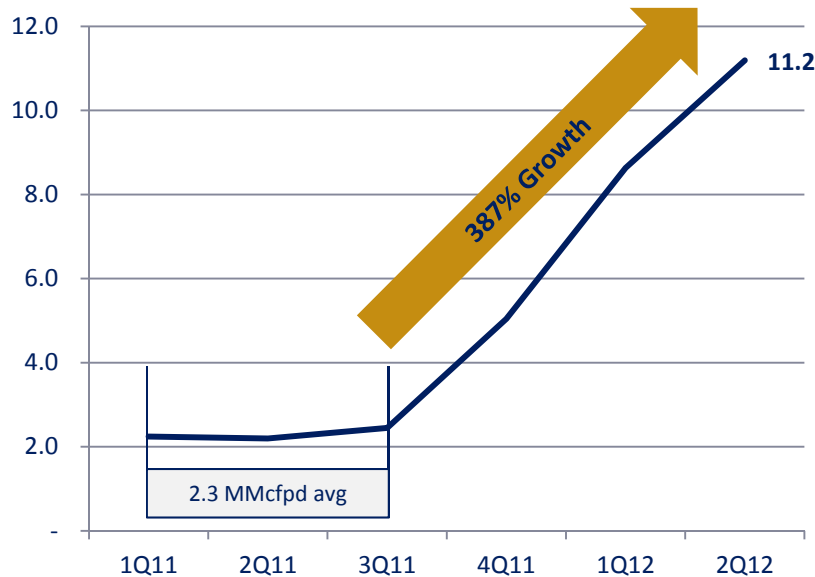
Gas Infrastructure Highlights

- 118 of the 144⁽¹⁾, or 82%, were connected to natural gas infrastructure on 6/30/12
- Gas infrastructure is across all Oasis project areas
- Hiland, Bear Tracker, Bear Paw and Whiting

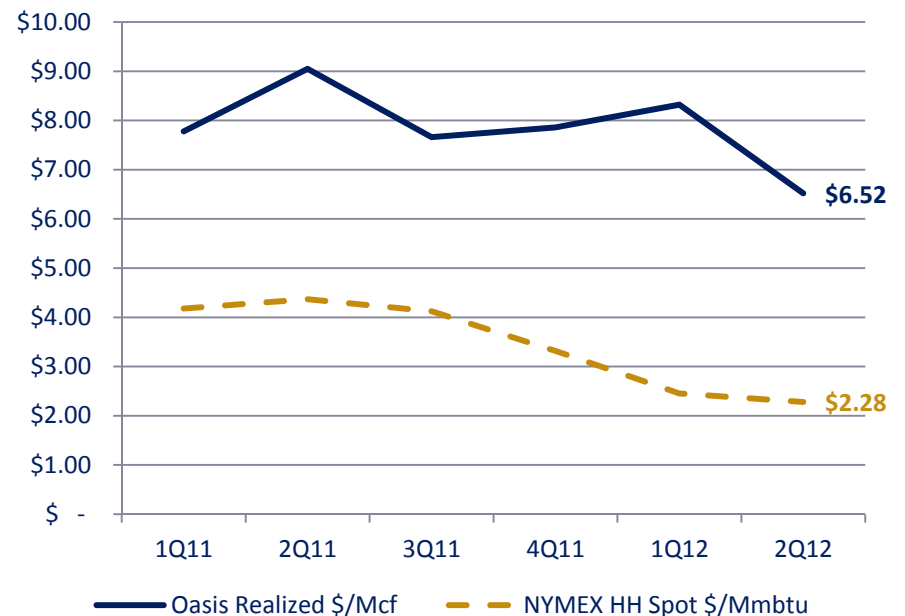
Gas Marketing Highlights

- High BTU gas with high liquids content results in premium price realization over Henry Hub
- \$6.52/Mcf average realized price in 2Q
- \$4.24/Mcf average realized premium in 2Q

Net Gas Volumes (MMcf per day)



Realized Gas Price (\$ per Mcf)

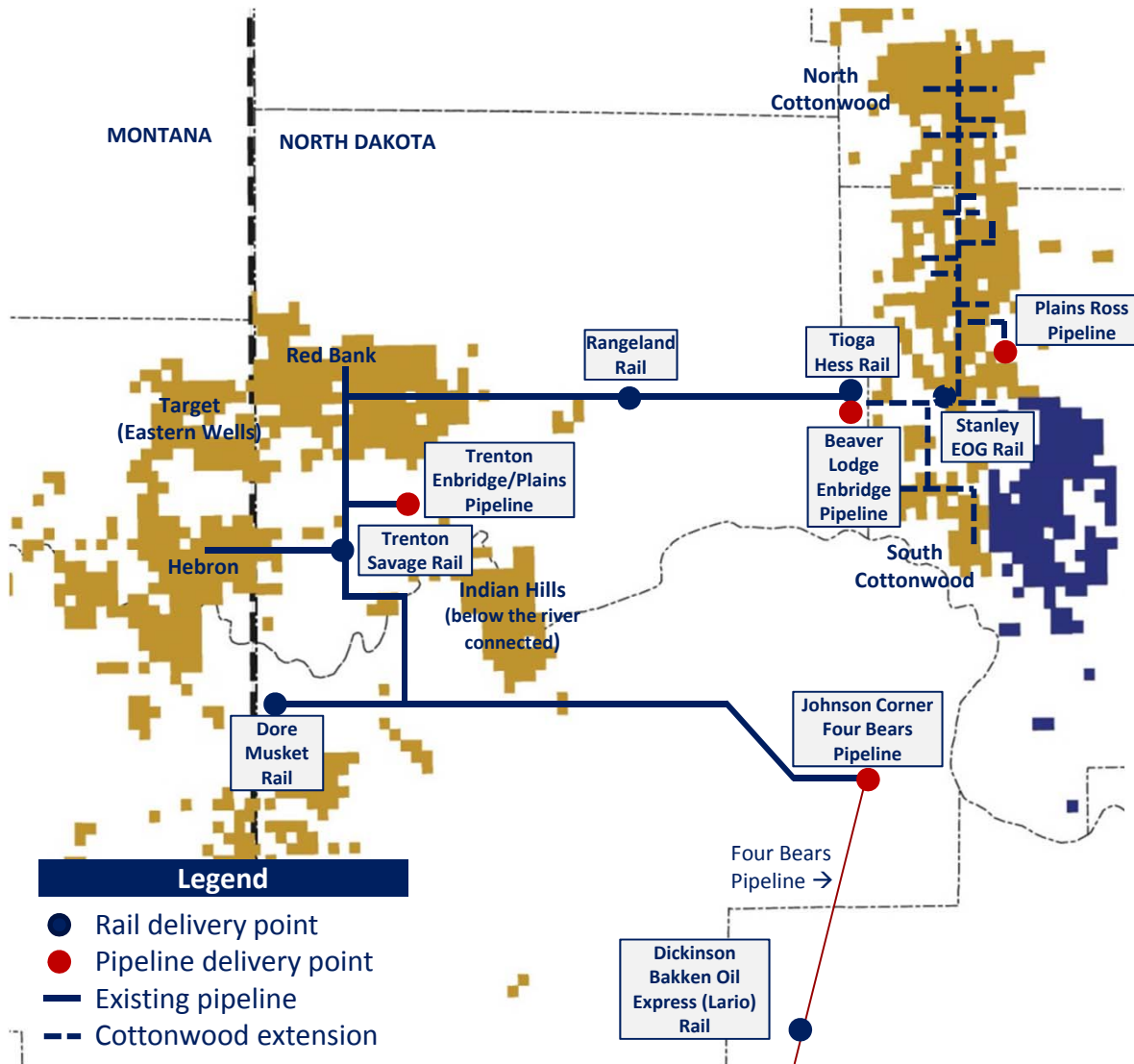


(1) This well count includes wells before Oasis ramped up its drilling program in late 2009. Prior to this new program, Oasis had 4 gross operated wells in West Williston and 19 gross operated wells in East Nesson in the Bakken/TFS.

Oasis Petroleum Marketing ("OPM")

Banner Oil Gathering System and Cottonwood Extension

Oil Infrastructure & Marketing

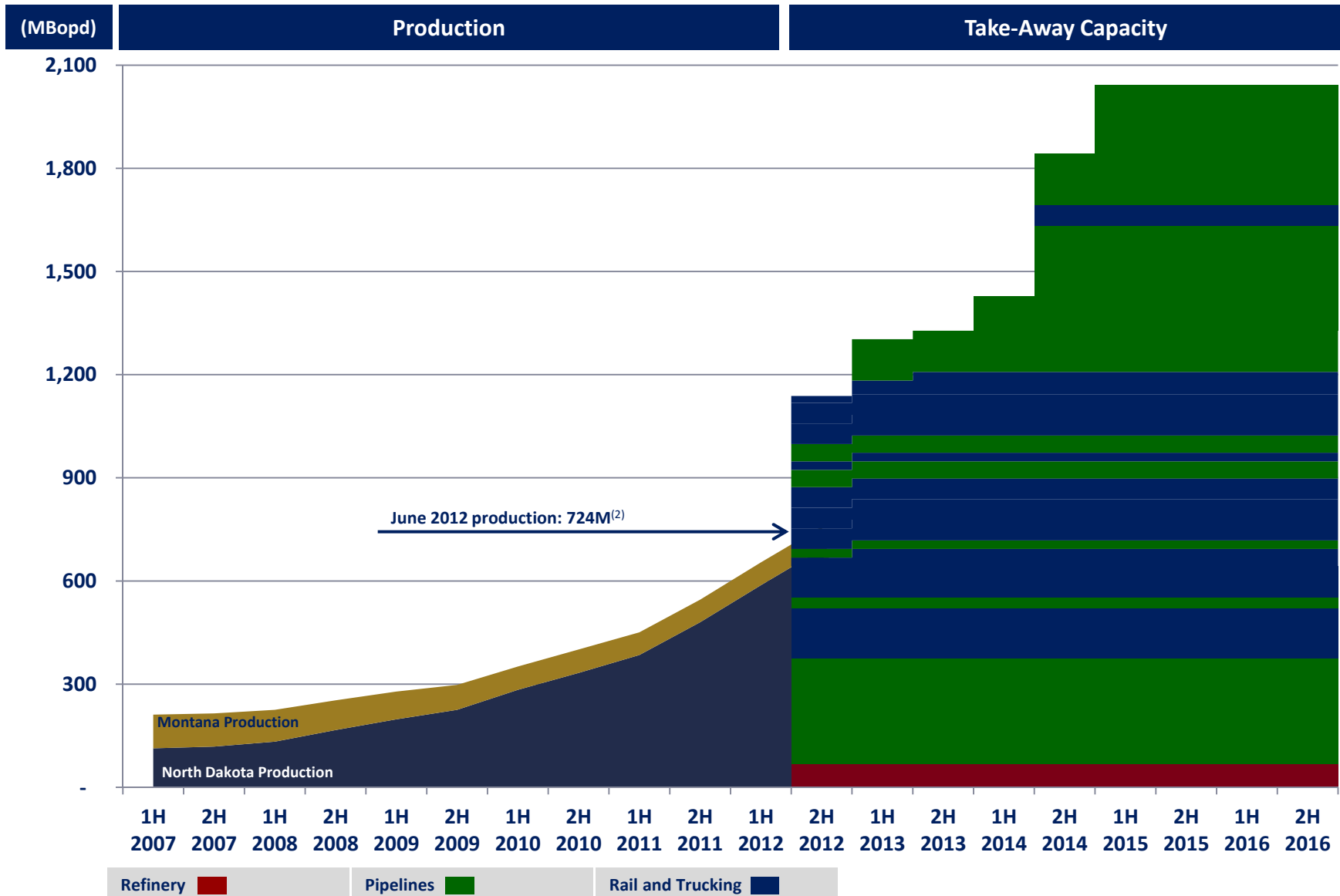


Legend

- Rail delivery point
- Pipeline delivery point
- Existing pipeline
- - Cottonwood extension

- Market with > 25 different counterparties
- Multiple delivery points to nominate oil:
 - Rail
 - Pipeline
- Expands sales to refineries and downstream markets
- Approximately 60% of oil volumes on pipeline, ramping to ~80%+ in 1H13 due to Cottonwood extension
 - 94 wells connected at end of June
- Eliminates cost to truck from well-head ~\$3-5 per barrel
- Add \$2 fee per barrel for pipeline
- Transportation and Gathering expected to range between \$1.00 to \$1.50 per boe across all barrels in 2012

Expanding Takeaway Capacity out of Bakken (1)

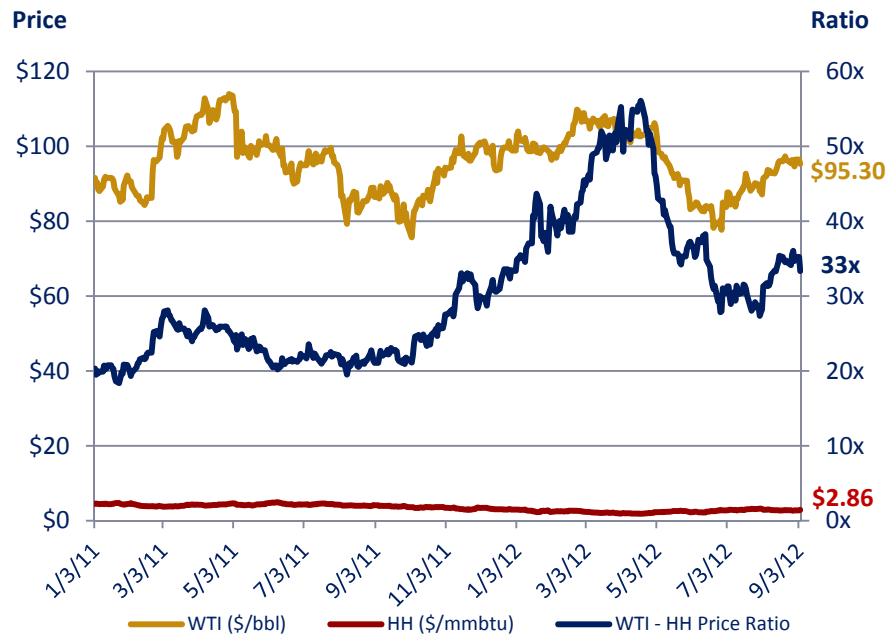


(1) Actual and announced projects. Public filings and North Dakota Pipeline Authority and includes data supplied by IHS Global Inc; Copyright 2010

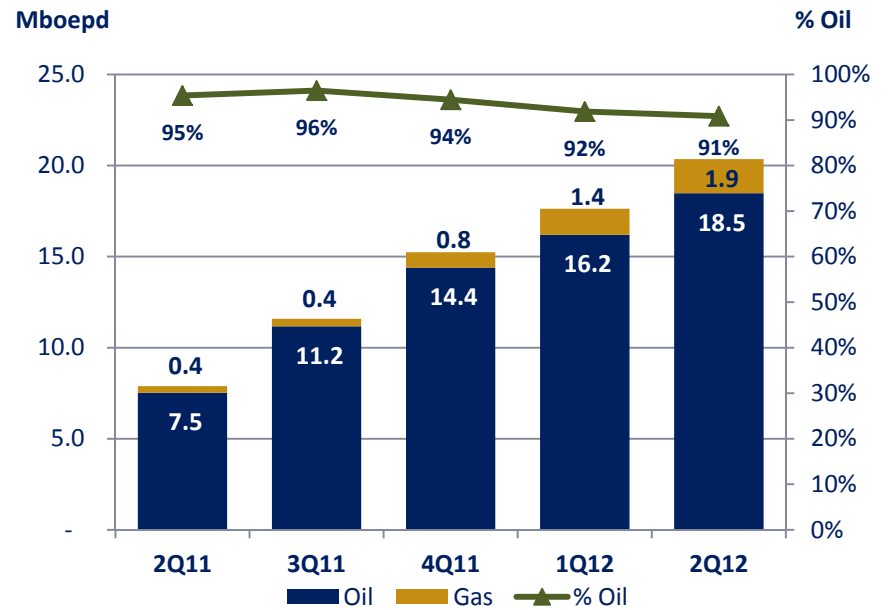
(2) EIA data for Montana production; NDIC data for North Dakota Bakken production

Oil Weighted Production

WTI – Henry Hub Price Disparity (\$/bbl to \$/Mmbtu) ⁽¹⁾



Oasis Oil and Gas Production (per Mboe)

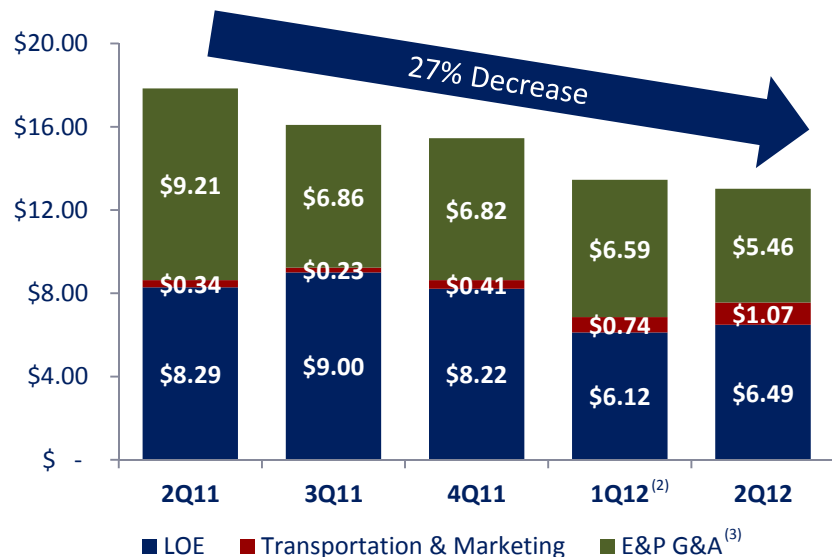


Oil weighted production drives high realized prices, especially given the disparity in pricing between WTI and Henry Hub

(1) As of 9/4/12

Improving Operating Cost Structure Drives High Cash Margins

Operating Cash Costs (\$ per Boe) ⁽¹⁾



Realized Price and Operating Cash Margins per Boe



(1) Excludes production taxes, which average ~ 10%

(2) Excludes marketing expense of \$1.4mm in 1Q12 that had associated revenue of \$1.5mm

(3) E&P G&A includes the non-cash amortization of restricted stock

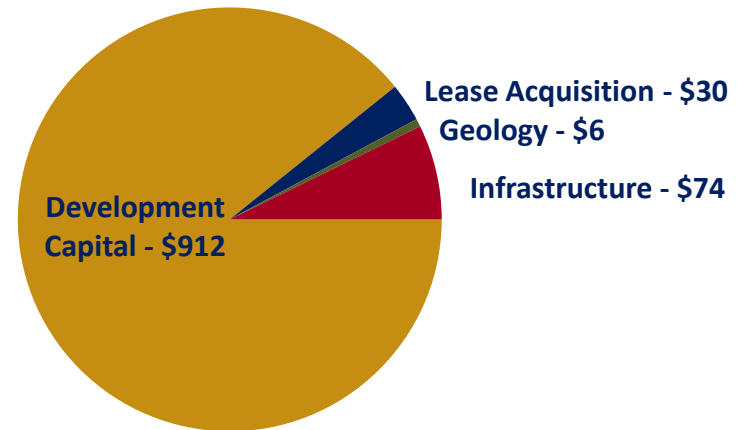
Note: excludes financing costs

Updated 2012 Capital Budget (\$1,062MM)

Updated 2012 Capital Budget

CapEx (\$MM)	Prior Budget	Updated Budget	Change
E&P Capital			
Development Capital	\$758	\$912	\$154
Lease Acquisition	25	30	5
Infrastructure	57	74	17
Geology	6	6	0
Total E&P Capital	\$846	\$1,022	\$176
OWS	\$15	\$17	\$2
Non E&P	23	23	0
Total Company CapEx ⁽¹⁾	\$884	\$1,062	\$178

2012 E&P Capital Budget (\$1,022MM)



20% increase in development capital results in 20% increase in capital production volumes

(1) Does not include \$30 million spent in the first quarter relating to 2011 activity which is not included in the revised budget

Strong Liquidity and Management Alignment

Strong Balance Sheet & Liquidity

- Proceeds from Senior Notes to pre-fund capital budget
- Growing production and cash flow from operations rapidly improves credit metrics

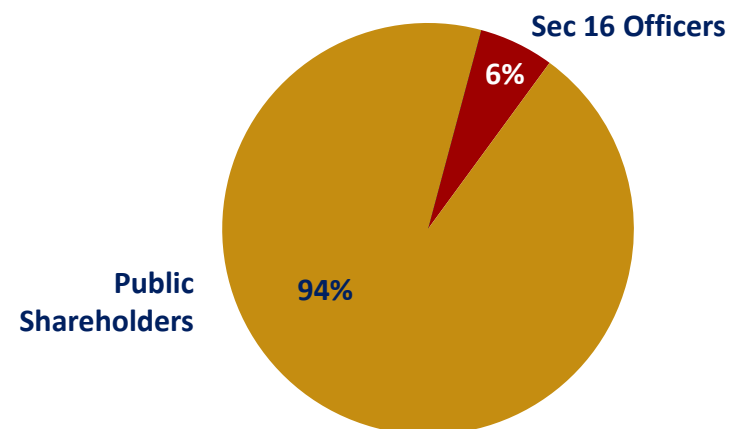
Liquidity Position ⁽¹⁾

Cash & short-term investments	\$631MM
Revolver availability	\$500MM
\$1.2B Debt Outstanding	
7.25% Senior Notes	\$400MM
6.5% Senior Notes	\$400MM
6.875% Senior Notes	\$400MM

High Management Ownership

- Section 16 Officers own 6% of Company
- Strongly aligned management team

Ownership ⁽²⁾



(1) Cash balance as of 6/30/12 adjusted for the 6.875% Senior Notes offering

(2) As of 9/03/12

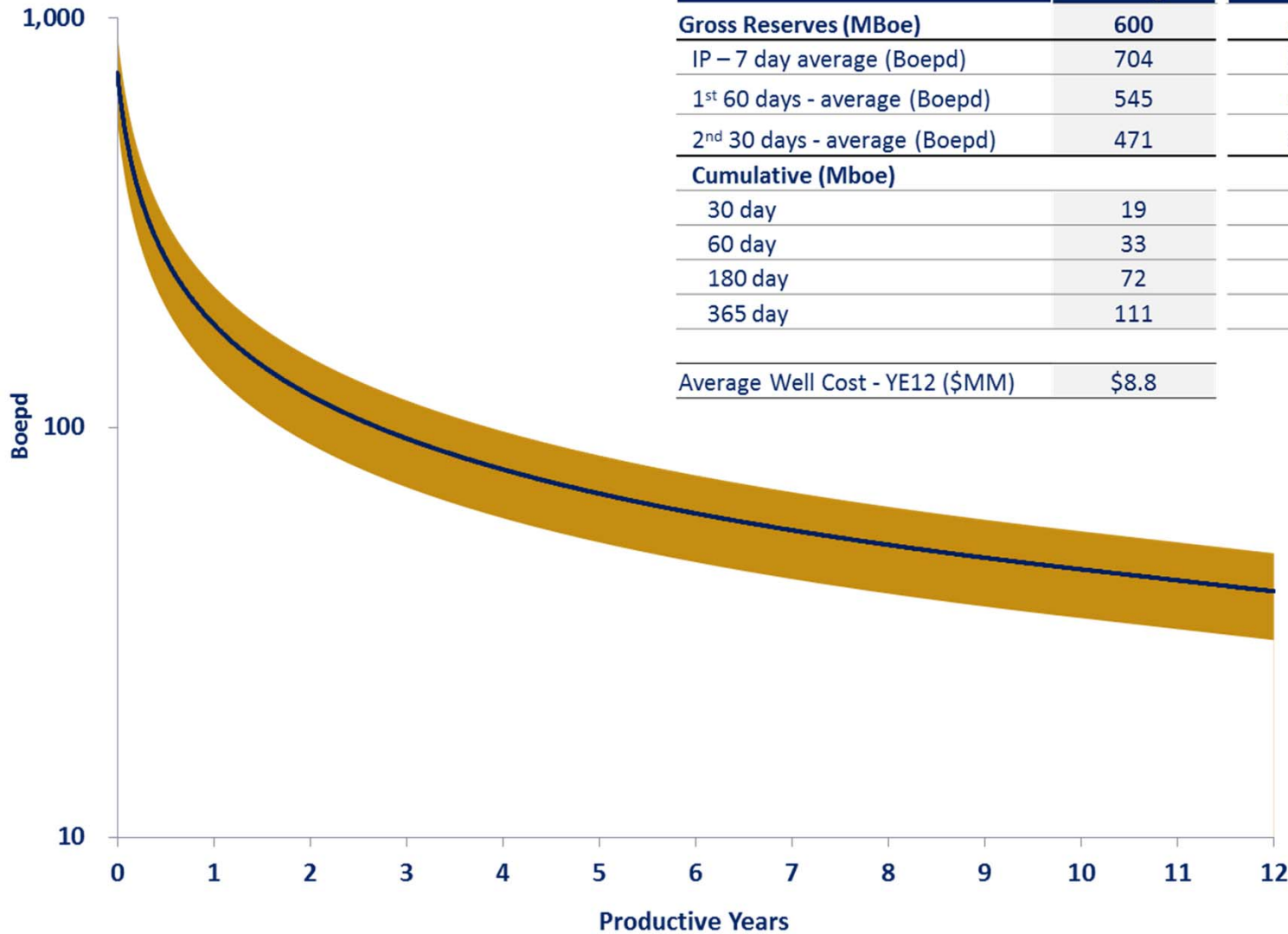
Investment Highlights

- Oil focused, pure play in the Williston Basin
- Large, concentrated acreage position with identified drilling inventory
- Substantial upside potential with known catalysts
- Increasing operational efficiencies
- Growing production profile with capital going towards increasing reserves and lowering costs
- Management with resource play execution experience



APPENDIX

Middle Bakken Type Curve and Economics



	Average	Low End	High End
Gross Reserves (MBoe)	600	450	750
IP – 7 day average (Boepd)	704	536	873
1 st 60 days - average (Boepd)	545	415	675
2 nd 30 days - average (Boepd)	471	359	584
Cumulative (Mboe)			
30 day	19	14	23
60 day	33	25	41
180 day	72	55	89
365 day	111	85	138
Average Well Cost - YE12 (\$MM)	\$8.8		

High: 750 Mboe
 Average: 600 Mboe
 Low: 450 Mboe

Key Metrics by Project Area

	Delineated Blocks					Extensional Areas			
	West Williston			East Nesson		West Williston			East Nesson
	Red Bank	Indian Hills	Hebron	North Cottonwood	South Cottonwood	Target	Missouri	Mondak/Other	St. Croix
Net Acreage (000s) from '10 to '11	63 to 67	23 to 25	45 flat	40 to 41	43 to 42	21 flat	13 to 16	26 to 27	19 to 14
Operated Rigs ⁽¹⁾	1	2	1	1	3	0	2	0	0

Metric	West Williston	East Nesson	Sanish	Total Williston
Net Acreage ⁽²⁾	204,000	108,000	8,000	320,000
Estimated PDP - MMBoe ⁽³⁾	24.0	7.3	4.5	35.8
Estimated PUD - MMBoe ⁽³⁾	27.7	13.7	1.5	42.9
Estimated Proved Reserves - MMBoe ⁽³⁾	51.6	21.1	6.0	78.7
2Q12 Production (Mboe/d)	13.7	4.5	2.1	20.4
Operated Rigs Running – Current ⁽¹⁾	6	4	-	10
Bakken / TFS Wells ⁽¹⁾⁽⁴⁾				
Waiting on Completion	25	4	-	29
Producing	122	42	-	164
2012 Budgeted Spud Wells				
Gross Operated	79	33	-	112
Total Gross Wells	92	58	57	207
Net Operated	59.2	24.5	-	83.7
Working Interest in Operated Wells	75%	74%	-	75%
Net Non Operated	1.7	1.5	6.0	9.1
Total Net Wells	60.9	25.9	6.0	92.8
2012 CapEx Budget (\$MM)				
Drilling Capital	\$631	\$228	\$53	\$912
Leasehold				\$30
Infrastructure				\$74
Geologic and Geophysical				\$6
Total E&P CapEx				\$1,022
Oasis Well Services				\$17
Non E&P				\$23
Total Company CapEx⁽⁵⁾				\$1,062

(1) As of 9/03/12

(2) As of 6/30/12

(3) As of 12/31/11

(4) This well count is based on wells that began when Oasis ramped up its drilling program in late 2009. Prior to this new program, Oasis had 4 gross operated wells in West Williston and 19 gross operated wells in East Nesson in the Bakken/TFS.

(5) Does not include \$30 million spent in the first quarter relating to 2011 activity which is not included in the revised budget

Williston Inventory (1)

Identified Primary Locations	PUD		Non-Proved		Total Primary Inventory		
	Gross	Net	Gross	Net	Gross	Net	WI %
Operated							
Williston West	78	56.5	442	305.6	520	362.2	69.6%
East Nesson	42	27.2	188	125.1	230	152.2	66.2%
Sanish	0	0.0	0	0.0	0	0.0	0
Total Operated	120	83.7	630	430.7	750	514.4	68.6%
Non-Operated							
Williston West	2	0.3	306	33.8	308	34.1	11.1%
East Nesson	2	0.1	126	13.5	128	13.6	10.6%
Sanish	36	3.0	91	6.0	127	9.0	7.1%
Total Non-Operated Inventory	40	3.4	523	53.3	563	56.7	10.1%
Company Total Inventory							
Williston West	80	56.8	748	339.4	828	396.3	47.9%
East Nesson	44	27.3	314	138.6	358	165.8	46.3%
Sanish	36	3.0	91	6.0	127	9.0	7.1%
Total Primary Inventory	160	87.1	1,153	484.0	1,313	571.1	43.5%

	Primary Bakken		Primary TFS		Potential TFS		4th Bakken and TFS		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston West	731	345.0	97	51.2	714	342.8	546	266.8	2,088	1,005.8
East Nesson	263	137.4	95	28.5	202	124.2	212	105.2	772	395.3
Sanish	43	4.1	84	4.9	25	5.3	170	16.4	322	30.7
Total	1,037	486.5	276	84.6	941	472.3	928	388.4	3,182	1,431.8

	Total Locations		Operated Locations		Percent Operated	
	Gross	Net	Gross	Net	Gross	Net
Primary Bakken Drilling Locations	1,037	486.5	631	438.8	60.8%	90.2%
Primary TFS Drilling Locations	276	84.6	119	75.6	43.1%	89.3%
Total Primary Locations	1,313	571.1	750	514.4	57.1%	90.1%
Potential TFS Locations	941	472.3	595	424.7	63.2%	89.9%
4th Bakken and TFS Locations	928	388.4	486	341.2	52.4%	87.8%
Total Locations	3,182	1,431.8	1,831	1,280.3	57.5%	89.4%

(1) Identified primary gross and net drilling locations in our West Williston and East Nesson project areas are based on 1,280 acre spacing with three wells targeting the Bakken formation in each identified spacing unit (excluding previously drilled wells). Primary TFS drilling locations include areas, Indian Hills and parts of South Cottonwood, where initial TFS wells were considered economic. Identified gross and net drilling locations in our Sanish project area include up to three wells targeting the Bakken formation and two wells targeting the TFS formation per spacing unit (excluding previously drilled wells). As of 12/31/11.

Bakken / TFS Drilling Program by Project Area⁽¹⁾

Project Areas	West Williston		East Nesson		Sanish		Total	
	Bakken / TFS Wells							
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Producing on or before 12/31/10:								
Operated	20	17.0	31	25.8	-	-	51	42.8
Non-Operated	33	3.0	35	3.5	123	9.6	191	16.1
<i>Production started in 2011:</i>								
Operated	53	42.2	10	6.9	-	-	63	49.2
Non-Operated	4	(0.4)	15	0.9	51	3.4	69	3.9
Total Producing Wells on 12/31/11:								
Operated	73	59.2	41	32.7	-	-	114	92.0
Non-Operated	37	2.6	51	4.4	174	13.1	262	20.1
<i>Production started in 1Q 2012:</i>								
Operated	19	14.9	7	5.0	-	-	26	19.9
Non-Operated	3	0.5	-	-	21	1.6	24	2.0
<i>Production started in Q2 2012</i>								
Gross Operated	19	14.6	7	5.7	-	-	26	20.3
Gross Non-Operated	3	0.2	2	0.0	17	1.7	22	2.0
Total Producing Wells on 6/30/12:								
Operated	111	88.1	55	44.2	-	-	166	132.3
Non-Operated	43	3.3	53	4.4	212	16.4	308	24.1
Wells Waiting on Completion on 6/30/12:								
Gross Operated	24	19.5	6	4.6	-	-	30	24.1
Gross Non-Operated	5	0.6	6	0.4	8	0.5	19	1.5
Wells Drilling on on 6/30/12⁽²⁾:								
Gross Operated	8	6.7	1	0.7	-	-	9	7.4
Gross Non-Operated	1	0.2	1	0.1	8	0.7	10	1.0

(1) West Williston includes 4 gross operated wells and East Nesson includes 19 gross operated wells in the Bakken/TFS that were producing prior to our ramping up our drilling program in late 2009.

(2) Excludes one rig between locations on 6/30/12

Financial and Operational Results / 2012 Guidance

Select Operating Metrics	Actual											Guidance ⁽¹⁾		
	1Q 10	2Q 10	3Q 10	4Q 10	FY 10	1Q 11	2Q 11	3Q 11	4Q 11	FY11	1Q 12	2Q 12	3Q 12	FY12
Production (Boepd)	3,295	4,461	5,507	7,511	5,206	8,090	7,893	11,583	15,243	10,724	17,633	20,353	22,000-24,000	20,500 -22,500
Production (Bopd)	2,998	4,189	5,248	7,148	4,908	7,716	7,527	11,175	14,402	10,226	16,196	18,487		
% Oil	91%	94%	95%	95%	94%	95%	95%	96%	94%	95%	92%	91%		
WTI (\$/Bbl)	\$78.85	\$77.70	\$76.11	\$85.17	\$80.19	\$94.26	\$102.46	\$89.18	\$94.78	\$94.55	\$103.03	\$93.23		
Realized Oil Prices (\$/Bbl)	\$70.21	\$67.19	\$66.42	\$73.05	\$69.60	\$82.33	\$95.48	\$83.52	\$85.46	\$86.18	\$88.10	\$82.36		
Differential to WTI	11%	14%	13%	14%	13%	13%	7%	6%	10%	9%	14%	12%		
Realized Natural Gas Price (\$/Mcf)	\$7.02	\$7.53	\$6.29	\$5.53	\$6.52	\$7.78	\$9.05	\$7.66	\$7.86	\$8.02	\$8.32	\$6.52		
LOE (\$/Boe) ⁽¹⁾	\$9.70	\$6.94	\$6.12	\$7.71	\$7.43	\$7.73	\$8.29	\$9.00	\$8.22	\$8.36	\$6.12	\$6.49	\$5.75 - \$7.00	
Transportation & Gathering (\$/Boe) ⁽²⁾	\$0.34	\$0.27	\$0.21	\$0.21	\$0.24	0.43	0.34	\$0.23	0.41	\$0.34	\$0.74	\$1.06	\$1.00 - \$1.50	
G&A (\$/Boe) ⁽³⁾	\$11.86	\$9.22	\$9.57	\$11.05	\$10.39	\$8.17	\$9.21	\$6.86	\$6.82	\$7.52	\$7.60	\$7.31		
Production Taxes (% of revenue)	9.5%	10.1%	10.7%	11.5%	10.7%	10.4%	10.5%	10.1%	10.1%	10.2%	9.6%	9.5%	9.5% - 10.5%	
DD&A Costs (\$/Boe)	\$19.73	\$21.63	\$19.25	\$19.46	\$19.91	\$18.97	\$18.24	\$19.57	\$19.40	\$19.16	\$24.23	\$23.87		
Select Financial Metrics (\$ MM)														
Oil Revenue	\$18.9	\$25.6	\$32.1	\$48.0	\$124.7	\$57.2	\$65.4	\$85.9	\$113.2	\$321.7	\$129.9	\$138.6		
Gas Revenue	\$1.1	\$1.1	\$0.9	\$1.1	\$4.2	\$1.6	\$1.8	\$1.7	\$3.7	\$8.8	\$6.5	\$6.6		
Bulk Purchase of Oil Revenue	-	-	-	-	-	-	-	-	-	-	\$1.5	-		
Well Services Revenue	-	-	-	-	-	-	-	-	-	-	\$0.7	\$3.9		
Total Revenue	\$20.1	\$26.7	\$33.0	\$49.1	\$128.9	\$58.7	\$67.2	\$87.6	\$116.9	\$330.4	\$138.6	\$149.1		
LOE	\$2.9	\$2.8	\$3.1	\$5.3	\$13.8	\$5.6	\$6.0	\$9.6	\$11.5	\$32.7	\$9.8	\$12.0		
Transportation & Gathering ⁽²⁾	\$0.1	\$0.1	\$0.1	\$0.1	\$0.5	\$0.3	\$0.2	\$0.2	\$0.6	\$1.4	\$1.2	\$2.0		
Production Taxes	\$1.9	\$2.7	\$3.5	\$5.6	\$13.8	\$6.1	\$7.1	\$8.9	\$11.8	\$33.9	\$13.3	\$13.7		
Exploration Costs	-	-	-	-	-	-	\$0.3	-	\$1.3	\$1.7	\$2.8	-		
Bulk Purchase of Oil Cost ⁽²⁾	-	-	-	-	-	-	-	-	-	-	\$1.4	-		
Well Services Expenses	-	-	-	-	-	-	-	-	-	-	\$0.5	\$1.2		
G&A ⁽³⁾	\$3.5	\$3.7	\$4.8	\$7.6	\$19.7	\$6.0	\$6.6	\$7.3	\$9.6	\$29.4	\$12.2	\$13.5	\$55 - \$62	
Adjusted EBITDA ⁽⁴⁾	\$11.6	\$17.4	\$22.0	\$31.2	\$82.2	\$41.1	\$44.6	\$62.9	\$85.9	\$234.5	\$101.1	\$108.5		
DD&A Costs	\$5.8	\$8.8	\$9.8	\$13.4	\$37.8	\$13.8	\$13.1	\$20.9	\$27.2	\$75.0	\$38.9	\$44.2		
Interest Expense	\$0.3	\$0.5	\$0.2	\$0.3	\$1.4	\$5.2	\$6.8	\$6.8	\$10.9	\$29.6	\$13.9	\$14.1		
E&P CapEx	\$36.9	\$71.6	\$74.8	\$162.3	\$345.6	\$75.5	\$125.0	\$198.9	\$237.9	\$637.3	\$267.0	\$263.2	\$1,022	
Non E&P CapEx	-	\$0.2	\$4.7	\$1.9	\$6.8	\$0.5	\$7.9	\$8.6	\$11.7	\$28.7	\$21.3	\$4.1	\$40	
Total CapEx ⁽⁵⁾	\$36.9	\$71.8	\$79.5	\$164.2	\$352.4	\$76.0	\$132.9	\$207.5	\$249.6	\$666.0	\$288.3	\$267.3	\$1,062	
Select Non-Cash Expense Items (\$ MM)														
Impairment of oil and gas properties	\$3.1	\$7.9	\$0.8	\$0.2	\$12.0	\$1.4	\$1.5	\$0.4	\$0.3	\$3.6	\$0.4	\$2.2		
Amortization of Restricted Stock ⁽⁶⁾	-	\$0.0	\$0.6	\$0.6	\$1.2	\$0.5	\$1.0	\$1.0	\$1.1	\$3.7	\$1.6	\$2.3		
Amortization of Restricted Stock (\$/boe) ⁽⁶⁾	-	\$0.12	\$1.11	\$0.89	\$0.65	\$0.72	\$1.45	\$0.96	\$0.76	\$0.93	\$0.99	\$1.25		

(1) Guidance for full year and 3Q12 was included in press release dated 8/6/12.

(2) Excludes marketing expense of \$1.4MM in 1Q12 associated with the bulk oil purchase. Cost is included below under "Bulk Purchase of Oil Cost."

(3) G&A includes \$1.6MM (\$1.01 per Boe) in 1Q12 and \$1.1MM (\$0.60 per Boe) in 2Q12 of expenses associated with running OWS.

(4) Non GAAP Adjusted EBITDA Reconciliation can be found on the Oasis website at www.oasispetroleum.com.

(5) 1Q12 CapEx include approximately \$30 million related to 2011 that was carried into 2012. The FY12 guidance/budget does not include this \$30 million.

(6) Non-Cash Amortization of Restricted Stock is included in G&A.

Risk Management⁽¹⁾

Type	Remaining Term	Weighted Average Prices (\$/Bbl)			BOPD	Total Barrels
		Sub-Floor	Floor	Cap		
2012						
<i>Partial Year</i>						
Swaps	4 Months (Sep-Dec)		\$94.61	\$94.61	1,000	122,000
<i>Full Year</i>						
Two-Way Collar	4 Months (Sep-Dec)		\$88.61	\$105.59	9,000	1,098,000
Three-Way Collar (net)	4 Months (Sep-Dec)	\$66.25	\$90.25	\$110.04	10,000	1,220,000
Total 2012 Hedges (Weighted Average)			\$89.73	\$107.26		2,440,000
<i>Implied total volume hedged (BOPD) for 2012</i>						<i>20,000</i>
2013						
<i>Partial Year</i>						
Put Spread (No Ceiling)	6 Months (Jan-Jun)	\$65.00	\$95.00		500	90,500
<i>Full Year</i>						
Swaps	12 Months (Jan-Dec)		\$96.49	\$96.49	2,000	730,000
Two-Way Collar	12 Months (Jan-Dec)		\$86.11	\$97.69	4,500	1,642,500
Three-Way Collar	12 Months (Jan-Dec)	\$65.13	\$92.92	\$113.09	5,130	1,872,450
Put Spread (No Ceiling)	12 Months (Jan-Dec)	\$71.03	\$91.03		4,870	1,777,550
Total 2013 Hedges (Weighted Average)			\$67.93	\$91.00	\$104.28	6,113,000
<i>Implied total volume hedged (BOPD) for 2013</i>						<i>16,748</i>
2014						
<i>Full Year</i>						
Three-Way Collar	12 Months (Jan-Dec)	\$71.25	\$91.25	\$109.96	4,000	1,460,000
Total 2014 Hedges (Weighted Average)			\$71.25	\$91.25	\$109.96	1,460,000
<i>Implied total volume hedged (BOPD) for 2014</i>						<i>4,000</i>

(1) As of 9/03/12

Key Company Facts / External Support

Oasis Petroleum Inc.

Exchange / Ticker	NYSE / OAS
Shares Outstanding	93.3 MM
Share Price (close on 9/04/12)	\$30.09 per share
Approx. Market Capitalization	\$2.8 BN

External Support

Independent Financial/Tax Auditor	PricewaterhouseCoopers
Legal Advisors	DLA Piper LLP / Vinson & Elkins, LLP
Reserve Auditors	DeGolyer and MacNaughton