U.S. Oil Production Outlook

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Energy Independence Day

Energy Independence Day: Growth in U.S. shale oil production and 100 years of natural gas resources are driving hopes for U.S. Energy Independence and fears of a correction in medium-term oil prices. In this note, we focus on the outlook for U.S. oil production as a companion to our work on U.S. gas production (*The Natural Gas Reservoir*). As with any new technology, our assumptions could prove optimistic or conservative—time will tell. We will update our basin excel model for oil production and mid-continent balances (WTI-Brent spreads) quarterly as more information becomes available. In this report, we consider the following 10 key questions, but more will likely emerge:

- **(1) How fast can U.S. production grow?** Based on high oil prices and a set of improving assumptions—i.e., a 27% higher oil well count by 2016 versus 2012, (58% higher than 2011) and a 25% improvement in 30-day initial production (IP) rates per well, we calculate that U.S. oil production could reach just over 10MBD by 2020 and maintain this level for a number of years. Although the well count increases by 27%, we note that our oil rig count only increases by 11% owing to improvements in drilling efficiency—i.e., the number of days to drill a well. Key shale plays to watch include the Eagle Ford, Bakken, and Permian. After recent exploration success, the offshore Gulf of Mexico and potentially Alaska should contribute some growth also.
- **(2) What cash flow and hence oil price is required to fund this growth?** Single well economics suggest breakevens in the $60-75/bbl range for US shales today. However, driving growth at forecast rates requires substantial capital—access to capital could be a greater constraint. In a simple calculation, we estimate that the U.S. oil industry needs around $95/bbl Brent near term to fund the capex required to deliver this growth, based on self-generated cash flow alone. This could be lowered by external funding, but we are already seeing some companies reduce capex when WTI recently fell through $90/bbl. As US oil production volumes rise, this breakeven could fall toward $80/bbl. It is important to note that the average recovery of a gas well is 3-5x the recovery of a typical oil well on a BTU basis. The shale oil revolution should help meet rising global demand but looks less likely to lead to a collapse in domestic pricing similar to U.S. gas markets.

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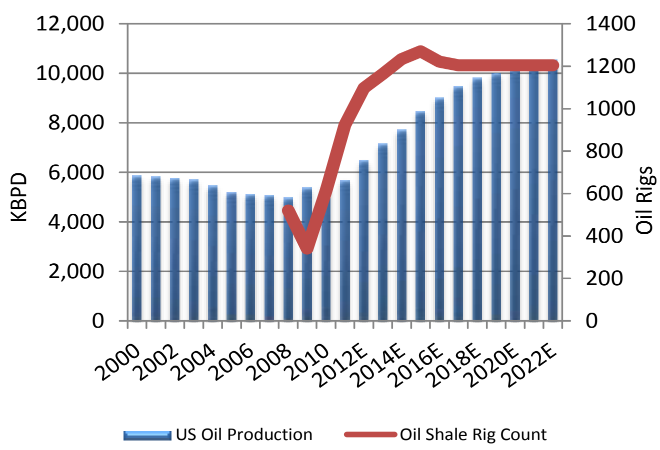
- **(3) How long can the underlying rocks maintain this rate of growth?** In the short term, growth can be maintained or even accelerate (depending on rig counts—i.e., oil prices). However, there are 2 key challenges for oil production growth vs natural gas. (1) Each individual shale oil well is less productive than gas wells from the Haynesville/Marcellus that have lowered the cost of natural gas. (2) We don't yet know the terminal decline rates from new oil shale plays (given the limited history). Physics would suggest oil decline could be higher than natural gas shales. This decline treadmill will likely lead to a plateau in US production. We forecast a 10MBD plateau for US oil production by 2020-22. At that time, we would need to add 1-1.5 current Bakken's every year *just* to offset decline in existing production. Inside we have compared our drilling program to the core acreage in each play to cross check our assumptions, (e.g., Bakken rig counts would need to fall unless acre spacing improves—otherwise the acreage would be fully drilled out by 2030). Downspacing tests are important to watch across the key plays as an indicator of longer-term production.
- **(4) Downstream Implications:** Accommodating 600kbd pa of oil growth from the U.S. and 300kbd pa of Canadian growth through 2017 will require new trunkline pipes and gathering systems. Our short term model suggests WTI-LLS will remain wide through 2H12 but narrow as Seaway, southern Keystone XL and Permian pipes are built through 2013. Even as WTI-LLS spreads narrow, it is likely that a wider discount will remain for Bakken and Canadian Heavy crude through 2014.
- **(5) Service Implications:** Growing US production will require a significant increase in the number of wells drilled from 9,200 in 2011 to 16,000 pa in 2022. This will require a higher rig count (our assumed oil rig count rises by 112 rigs by 2017). Each rig will also need to drill more wells each year. Although the near term outlook for onshore services remains challenged from weak natural gas prices, North America oil shale potential and rising gas demand should require substantial investment, people and service activity.
- **(6) US Energy Independence?:** The gap between US oil production and consumption is large and may not close in the forecast period (2022). However, North American oil independence (US, Canada, Mexico) looks more achievable with appropriate policies to promote safe drilling, energy efficiency, regional coordination and gas substitution. However, we don't hold out high hopes of the same low cost dividend to the US economy provided by natural gas due to the relatively higher cost of oil shales and Canadian oil sands. Natural gas appears the best low cost energy policy bet.
- **(7) And If There Is Another Recession**? In the event of a double dip recession, with industry balance sheets unable to absorb further deterioration in revenues, we would expect a contraction in oil activity. We flex the model to show that US production could be lower by 1.5MBD in 2017. This would also ease congestion on WTI markets, though Canadian oil growth would still need new pipes to reach markets making refiners in the north mid-con region more defensive.
- **(8) Implications for Global Shale:** North America shale success is leading a wave of entrepreneurial animal spirits. Thus far, we are most impressed with shale results in Argentina and Germany but above ground politics need to be resolved. In the medium term, the Russian Bazhenov oil shale needs watching, so too the gas shale potential of China and some excitement over Australian potential. International shale will take time to delineate and develop but could be a meaningful source of energy later this decade and in the 2020's.
- **(9) Implications for the U.S. Economy**: Our U.S. industry capex model suggests around $1.3 Trillion dollars of spend between now and 2020. Low U.S. gas prices should encourage some $35Bn of petrochemical capex and a manufacturing renaissance. The logistics to bring shale hydrocarbons to market could total an additional $80Bn this decade.

- **(10) Implications for the Oil Price**: Supply from the U.S. and Canada is visibly growing. However, outside North America non-OPEC supply growth is negative in 2012. In our base case, spare capacity increases towards 3% by 2015 (from 2% today) better but markets may still reflect some risk premium over marginal costs. Risks to this view seem balanced. Spare capacity could rise faster if curtailments in Nigeria, Iran, Venezuela, Sudan were resolved. Spare capacity could fall, if a global economic recovery takes hold.

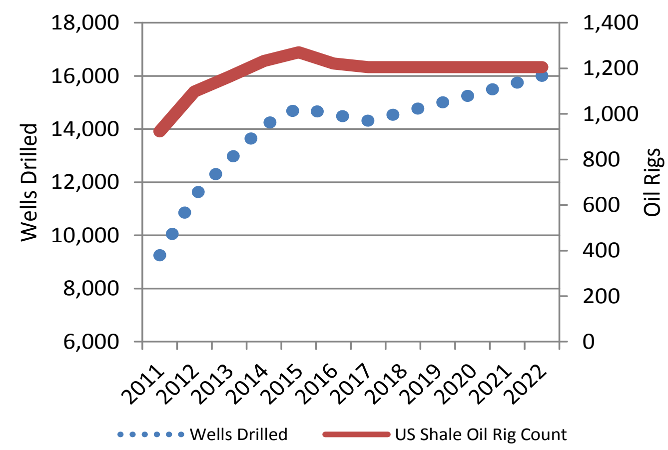
Focus Charts

Exhibit 1: U.S. Oil Production Potential, KBD



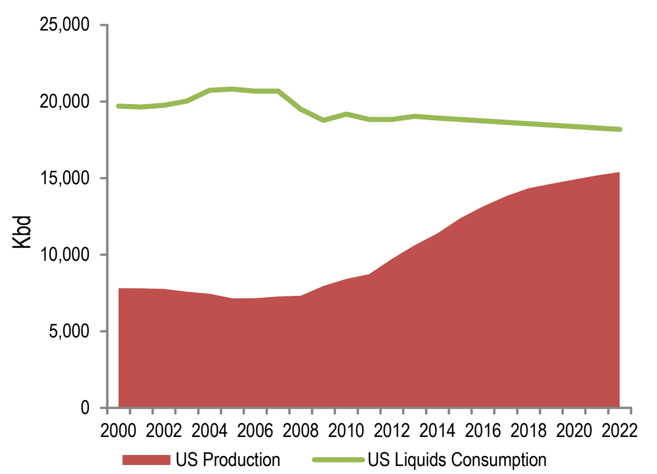
Source: EIA, Credit Suisse estimates, Baker Hughes, RigData, Smith Bits

Exhibit 2: Shale Oil Rig Count, Wells Drilled Assumptions



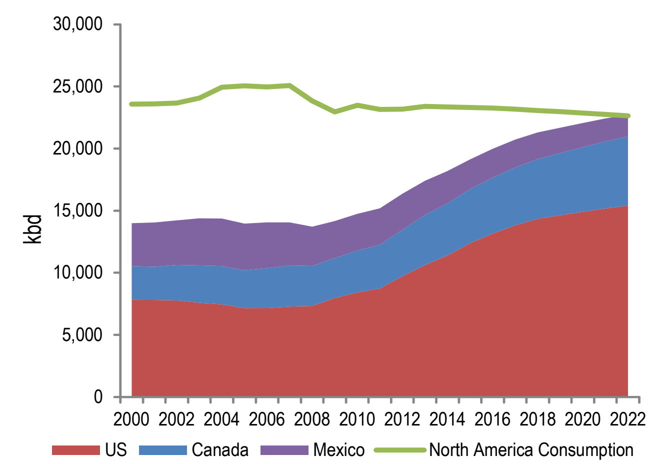
Source: Smith Bits, RigData, Baker Hughes, Credit Suisse Estimates

Exhibit 3: U.S. Liquids Independence (with NGL, Biofuels)



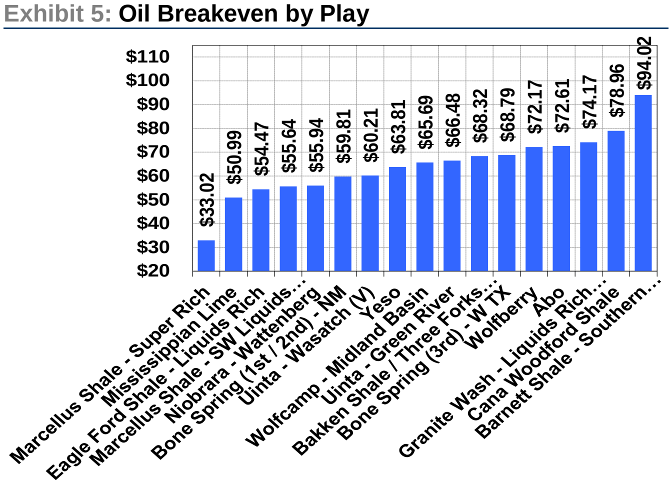
Source: IEA,BP, Credit Suisse estimates

Exhibit 4: North America Liquids Independence



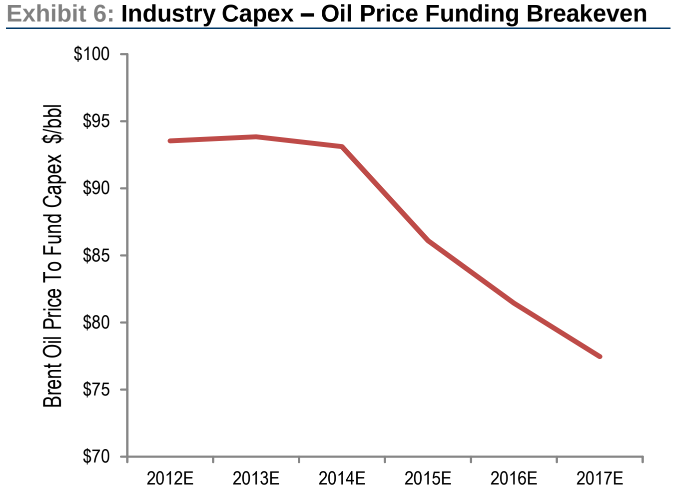
Source: IEA, BP, Credit Suisse estimates

Exhibit 5: Oil Breakeven by Play



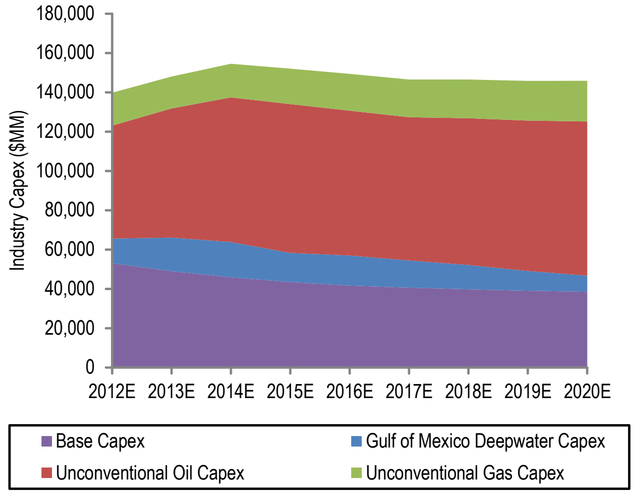
Source: Credit Suisse estimates

Exhibit 6: Industry Capex – Oil Price Funding Breakeven



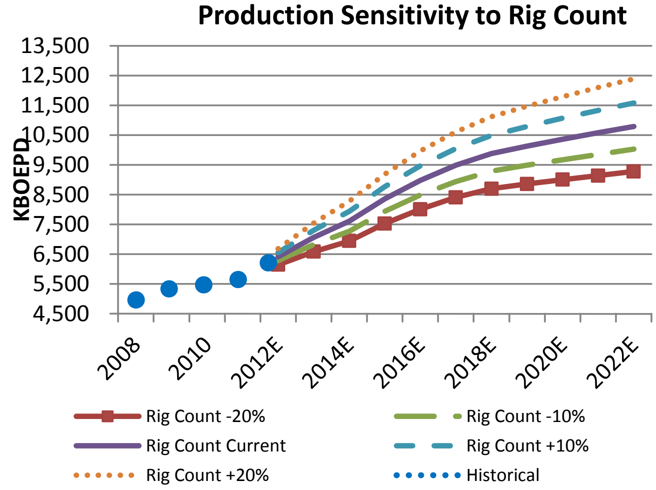
Source: Credit Suisse estimates

Exhibit 7: Overall Industry Capex of $150bn pa



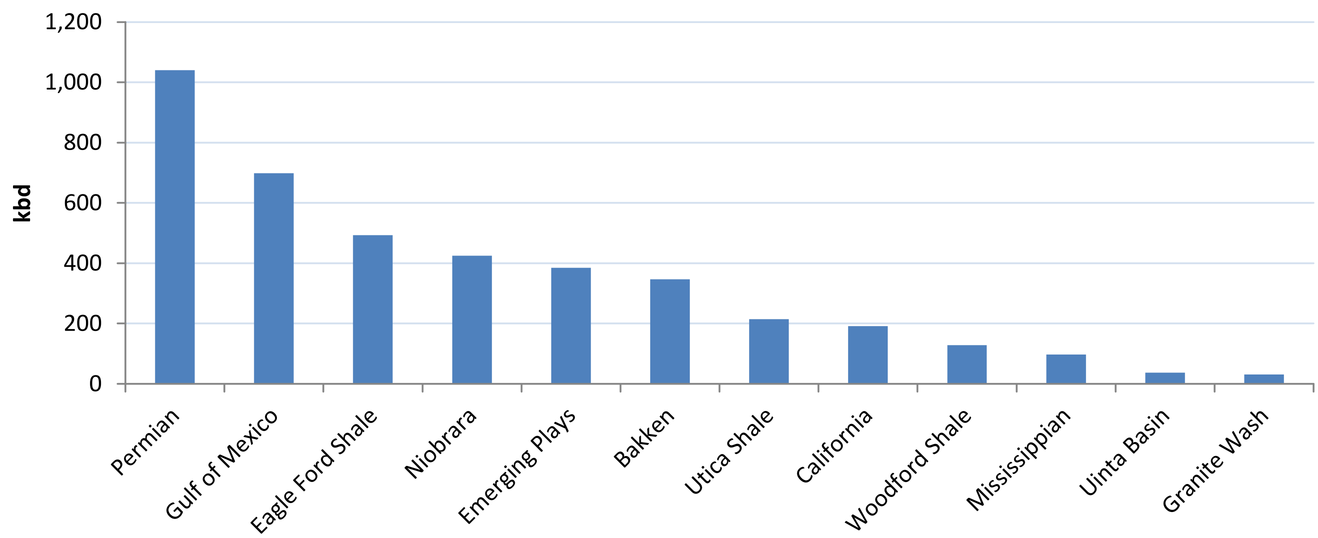
Source: Credit Suisse estimates

Exhibit 8: Oil Production Sensitivity to Rig Count



Source: Credit Suisse estimates

Exhibit 9: Oil Production Growth by Play 2012-2018 (excluding NGLs and gas). Note: (1) the U.S. Gulf of Mexico makes a decent contribution and (2) Emerging plays is a "catch-all" in the model for plays that are not fully delineated today.



Source: Credit Suisse estimates

Exhibit 10: Summary Table: U.S. Oil Production By State

Total US Production by State

	Location	2010	2011	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
U.S. Field Production of Crude Oil (Thousand Barrels)	**US**	**5482**	**5676**	**6456**	**7137**	**7692**	**8452**	**8998**	**9457**	**9792**	**9992**	**10179**	**10357**	**10532**
East Coast (PADD 1) Field Production of Crude Oil (Thousand Barrels)	**PADD 1**	**20**	**22**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**
Florida Field Production of Crude Oil (Thousand Barrels)	Florida	5	6	6	6	6	6	6	6	6	6	6	6	6
New York Field Production of Crude Oil (Thousand Barrels)	New York	1	1	1	1	1	1	1	1	1	1	1	1	1
Pennsylvania Field Production of Crude Oil (Thousand Barrels)	Pennsylvania	10	10	12	12	12	12	12	12	12	12	12	12	12
Virginia Field Production of Crude Oil (Thousand Barrels)	Virginia	0	0	0	0	0	0	0	0	0	0	0	0	0
West Virginia Field Production of Crude Oil (Thousand Barrels)	West Virginia	4	5	5	5	5	5	5	5	5	5	5	5	5
Midwest (PADD 2) Field Production of Crude Oil (Thousand Barrels)	**PADD 2**	**686**	**817**	**1178**	**1384**	**1575**	**1667**	**1687**	**1707**	**1755**	**1812**	**1868**	**1925**	**1981**
Illinois Field Production of Crude Oil (Thousand Barrels)	Illinois	25	25	27	28	29	30	31	32	32	32	32	32	32
Indiana Field Production of Crude Oil (Thousand Barrels)	Indiana	5	5	5	5	5	5	5	5	5	5	5	5	5
Kansas Field Production of Crude Oil (Thousand Barrels)	Kansas	111	114	124	133	139	142	131	119	112	107	103	100	98
Kentucky Field Production of Crude Oil (Thousand Barrels)	Kentucky	7	6	6	6	6	6	6	6	6	6	6	6	6
Michigan Field Production of Crude Oil (Thousand Barrels)	Michigan	19	18	18	18	18	18	18	18	18	18	18	18	18
Missouri Field Production of Crude Oil (Thousand Barrels)	Missouri	0	0	0	0	0	0	0	0	0	0	0	0	0
Nebraska Field Production of Crude Oil (Thousand Barrels)	Nebraska	6	7	7	7	7	7	7	7	7	7	7	7	7
North Dakota Field Production of Crude Oil (Thousand Barrels)	North Dakota	310	419	726	896	1035	1081	1082	1061	1068	1089	1114	1139	1166
Ohio Field Production of Crude Oil (Thousand Barrels)	Ohio	13	13	19	39	68	104	146	195	233	265	294	321	347
Oklahoma Field Production of Crude Oil (Thousand Barrels)	Oklahoma	186	204	240	246	262	268	255	258	268	277	284	290	296
South Dakota Field Production of Crude Oil (Thousand Barrels)	South Dakota	4	4	4	4	4	4	4	4	4	4	4	4	4
Tennessee Field Production of Crude Oil (Thousand Barrels)	Tennessee	1	1	1	1	1	1	1	1	1	1	1	1	1
Gulf Coast (PADD 3) Field Production of Crude Oil (Thousand Barrels)	**PADD 3**	**3190**	**3277**	**3708**	**4136**	**4444**	**5064**	**5548**	**5970**	**6248**	**6390**	**6520**	**6645**	**6768**
Alabama Field Production of Crude Oil (Thousand Barrels)	Alabama	19	23	25	30	35	40	45	50	55	60	65	70	75
Arkansas Field Production of Crude Oil (Thousand Barrels)	Arkansas	16	16	19	24	29	34	39	44	49	54	59	64	69
Louisiana Field Production of Crude Oil (Thousand Barrels)	Louisiana	185	189	184	189	198	231	289	429	508	561	600	633	664
Mississippi Field Production of Crude Oil (Thousand Barrels)	Mississippi	65	64	64	66	68	70	72	74	76	78	80	82	84
New Mexico Field Production of Crude Oil (Thousand Barrels)	New Mexico	179	196	216	252	284	317	343	372	396	417	438	458	478
Texas Field Production of Crude Oil (Thousand Barrels)	Texas	1176	1474	1864	2201	2507	2762	2918	3018	3128	3245	3363	3479	3595
Federal Offshore--Gulf of Mexico Field Production of Crude Oil (Thousand Barrels)	GoM - Offshore	1551	1316	1337	1374	1323	1609	1842	1982	2036	1975	1916	1858	1802
Rocky Mountain (PADD 4) Field Production of Crude Oil (Thousand Barrels)	**PADD 4**	**372**	**395**	**438**	**511**	**601**	**681**	**753**	**800**	**838**	**867**	**891**	**911**	**928**
Colorado Field Production of Crude Oil (Thousand Barrels)	Colorado	89	107	130	196	280	358	433	485	526	557	583	604	621
Montana Field Production of Crude Oil (Thousand Barrels)	Montana	69	66	69	70	72	72	72	72	72	72	73	73	73
Utah Field Production of Crude Oil (Thousand Barrels)	Utah	68	72	80	91	101	108	111	114	117	120	124	128	133
Wyoming Field Production of Crude Oil (Thousand Barrels)	Wyoming	146	150	160	153	147	143	136	130	123	117	112	106	102
West Coast (PADD 5) Field Production of Crude Oil (Thousand Barrels)	**PADD 5**	**1214**	**1165**	**1109**	**1081**	**1048**	**1016**	**986**	**957**	**927**	**900**	**875**	**852**	**832**
Alaska Field Production of Crude Oil (Thousand Barrels)	**Alaska**	**601**	**572**	**526**	**510**	**483**	**457**	**432**	**409**	**385**	**363**	**342**	**322**	**303**
Alaska South Field Production of Crude Oil (Thousand Barrels)	Alaska South	10	10	10	10	10	10	10	10	10	10	10	10	10
Alaska North Slope Crude Oil Production (Thousand Barrels)	Alaska North Slope	591	562	516	500	472	446	422	399	375	353	332	312	293
Arizona Field Production of Crude Oil (Thousand Barrels)	Arizona	0	0	0	0	0	0	0	0	0	0	0	0	0
California Field Production of Crude Oil (Thousand Barrels)	California	552	537	539	535	537	536	535	532	529	527	525	523	523
Nevada Field Production of Crude Oil (Thousand Barrels)	Nevada	1	1	1	1	1	1	1	1	1	1	1	1	1
Federal Offshore California Field Production of Crude Oil (Thousand Barrels)	California - Offshore	54	54	43	35	28	22	18	14	11	9	7	6	5
Total US Field Production		**5,482**	**5,676**	**6,456**	**7,137**	**7,692**	**8,452**	**8,998**	**9,457**	**9,792**	**9,992**	**10,179**	**10,357**	**10,532**
Yoy Growth, KBD		121	194	781	680	555	760	546	459	335	200	187	178	176

Source: EIA, Credit Suisse estimates

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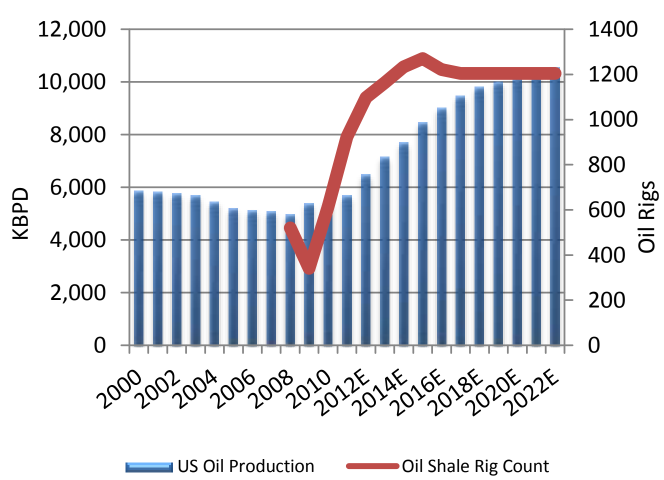
Energy Independence Day

Growth in U.S. and Canadian production is driving hopes for U.S. Energy Independence and fears of a correction in medium term oil prices. In this note we introduce an updated basin excel model for U.S. production. Some initial thoughts:

At the right oil price, strong growth in U.S. production is likely

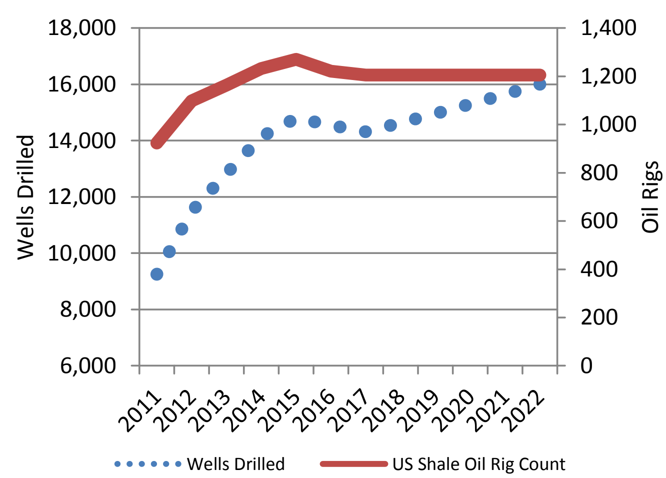
- U.S. oil production growth can be maintained (June 2012 +647 kbd yoy) given the shale revolution, offshore Gulf of Mexico resources (and potentially the Arctic). This assumes that oil prices/access to capital remains robust enough to fund investment.
- However, U.S. oil production will likely plateau at some point as the treadmill of decline increases. Oil shale decline rates are a key uncertainty (we don't have as much operational data) and a potential key constraint on the oil shale revolution. Another constraint is activity—the reserve recovery from oil wells is lower than natural gas wells suggesting that many more wells will need to be drilled relative to natural gas. Indeed, our model suggests oil well counts need to rise by a further 27% by 2016—great for longer-term onshore service demand. Demographics and ageing infrastructure could be greater constraints than funding.
- Our model assumes 30 day IP flow rates that are 25% above current observed averages, a higher rig count and a 40% reduction in the days to drill & complete a well.
- We look at resources and acreage associated with an assumed 39% increase in wells drilled pa by 2022. Under our assumptions, the industry should drill a substantial part of the Bakken and Eagle Ford by 2030. However, other plays may have further running room, notably in the back end of our forecast.
- We present volume sensitivities inside – for rig counts, for IP rates, for drilling and completion efficiency per rig. We believe $95/bbl Brent is required to fund this growth outlook in the near term. If oil prices were lower, we can flex the model to drop rigs and look at downside scenarios for U.S. production.
- Accommodating 600kbd pa of oil growth from the U.S. and 300kbd pa of Canadian growth by 2017 will require new trunkline pipes and gathering systems. Our short term model suggests WTI-LLS will remain wide through 1H13. Even as WTI-LLS spreads narrow, it is likely that a discount will remain for Bakken and Canadian Heavy through 2H14 given a lack of pipes to connect down to Cushing and the Gulf.

Exhibit 11: U.S. Oil Production Potential, KBD (excludes NGL's)



Source: EIA, Credit Suisse estimates, RigData, Baker Hughes, Smith

Exhibit 12: Shale Oil Rig Count and Wells Drilled Assumptions



Source: Smith Bits, RigData, Baker Hughes, Credit Suisse estimates

Bits

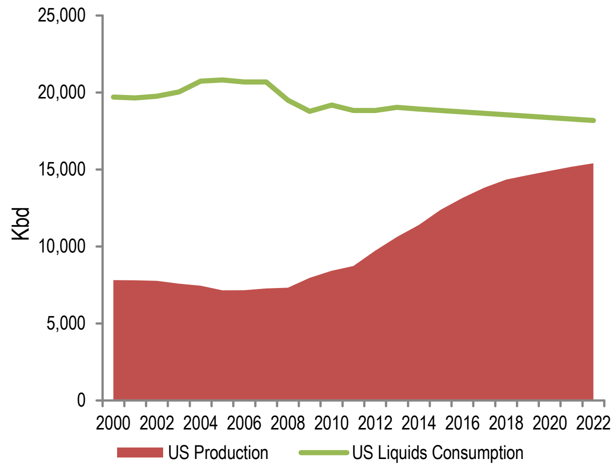
Oil Less Likely than Natural Gas to Lead to a Cheap Energy Payoff

U.S. production can grow but unlikely to match consumption anytime soon

The revolutionary change in shale gas drilling has driven U.S. natural gas prices to $2-$3/mmbtu in 2012, below even the marginal cost of some of the gas shales that contributed to this supply growth. These prices are substantially lower than international gas prices. This is providing a boon to U.S. energy consumers, notably the chemical/fertilizer industry that convert gas into products which compete with international oil markets and energy intensive manufacturing industries e.g., U.S. refining, steel. A natural hope would be that growth in U.S. oil and NGL production could allow a similar payoff for oil consumers, notably for gasoline prices at the pump. However, there are several differences between shale oil and shale gas that should be borne in mind:

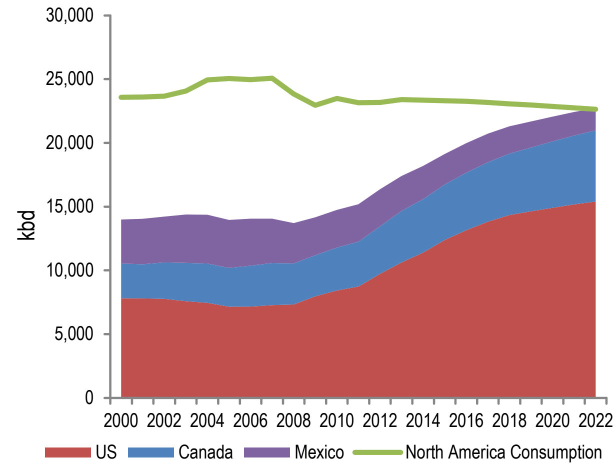
- Even with growth in U.S. liquids production and efficiency measures to reduce U.S. oil consumption, it is unlikely that the U.S. can meet its domestic oil consumption requirements anytime soon.
- It will take high near term oil prices, perhaps $95/bbl Brent, in order to fund this onshore production growth. Over time, as oil production ramps, this could fall to $80/bbl Brent. There is an element of circularity in the breakeven assumptions – prices lead to cashflow which leads to production. We have limited the well count in our model by the overall effective liquids rich acreage in each play and the likely well spacing per acre. Downspacing tests will be important to watch.
- Today, the amount of gas that can be recovered from a Marcellus or Haynesville shale gas well is 3x the amount that is recovered from a liquids well. Indeed, the Oily wells that we show in this report typically also come with associated gas. On a liquids only basis the EURs of gas wells are up to 5x better than oil wells. This suggests many more oil wells will need to be drilled than for natural gas.
- Promoting natural gas usage will likely provide the best value payoff for the economy - particularly if it can replace higher priced oil consumption. For oil markets, a policy promoting domestic oil production growth and closer integration across North America could improve domestic energy security – the goal of North American Oil Independence looks more attainable (see right hand chart), particularly if oil consumption can be reduced through the use of natural gas vehicles.

Exhibit 13: **U.S. Production and Consumption (Liquids)**



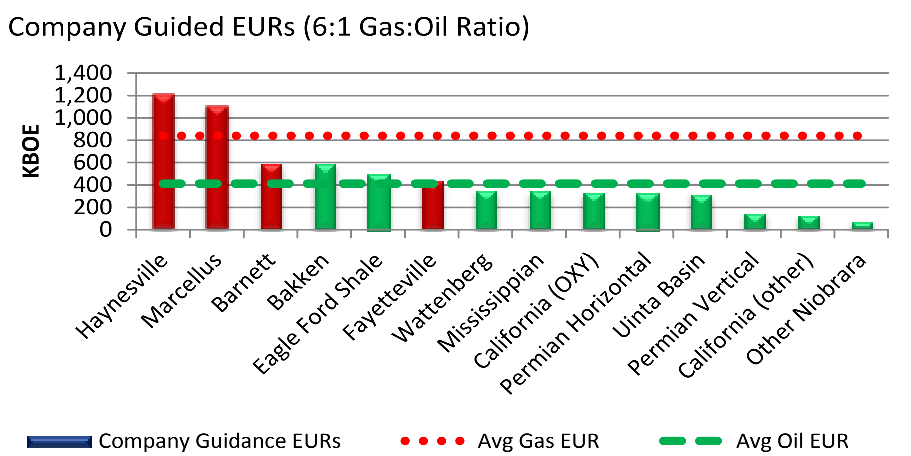
Source: BP,EIA, Credit Suisse estimates

Exhibit 14: **North America Production and Consumption (U.S., Canada+Mexico) Liquids**



Source: BP,EIA, Credit Suisse estimates

Exhibit 15: **EUR's in Oil vs Gas Plays (Company Guidance). Note that the "Oily Well" EUR will typically also include some gas. 6:1 Oil:Gas Ratio**



Source: Company data, Credit Suisse estimates

Gas wells typically recover 3x more volume than oil wells on average. If we compare the prolific shale gas plays to the oil only ratio for liquids rich wells this ratio is 5x.

This is a Bullish Assessment But Not Highest in Market

Our forecast for U.S. oil production is above the high case presented by the EIA in their June 2012 annual update and above the expectations of some senior industry executives. However, it is below some recent estimates. The largest variance is in shale. Our Gulf of Mexico forecasts are a couple of hundred thousand barrels a day above the EIA and we also assume decline in Alaska (Chukchi sea would be an upside wildcard). Within shale, the higher estimates in the market appear more bullish on the Bakken and the Eagle Ford. Generally, our shale optimism is driven by a combination of factors.

- Industry discussion of downspacing tests in the Eagle Ford (i.e. drilling more wells per acre) and even in the Bakken where new improved recovery techniques are being trialed. If more wells can be drilled per acre, production can grow further.

- Our reserve per well (EUR) assumptions are higher than the EIA. By necessity for a simple model, we need to use a single EUR for a play. In practice, well results vary significantly and we have shown charts inside to demonstrate this variability. One could argue that current EURs are also flattered by cherry picking of sweet spots in each play. We have attempted to compensate for this single assumption by using narrow definitions of "effective core acreage" per play. Over time, technological improvement should also provide an offset.

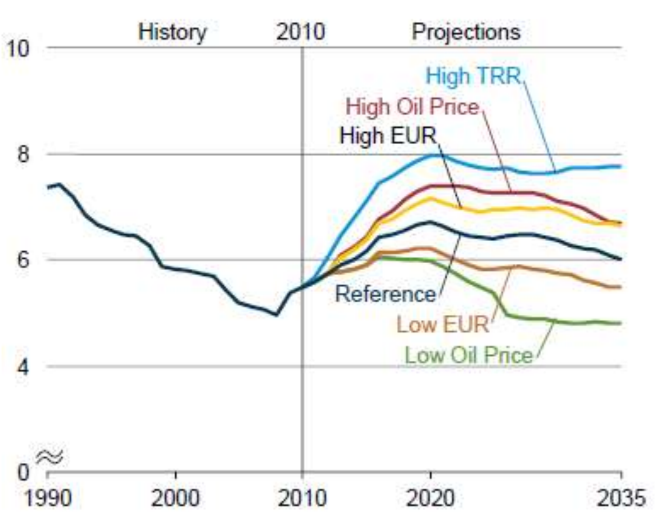
- We include an Emerging Play category which contributes 400kbd of growth by 2018. This is to reflect the industry wide R&D currently ongoing to delineate new shale plays across the Lower 48. The timing of the ramp up in this Emerging Play category may prove slower.

- We model hyperbolic decline rates across the shales but have limited data for oil shales (just 5 years). Decline could be higher than expected for oil molecules and tight rocks.

- Finally, as we parse the sources of production growth, the Permian horizontal play stands out as the largest contributor in absolute terms. The Permian is a large mature resource with deep thickness and many layers. Thus far, industry results in the Delaware Basin (Texas and New Mexico) appear to be relatively exciting across a large area. The challenge for the Delaware might be NGL offtake capacity given a higher NGL cut. In the Midland Basin, observed results have been oilier but not as consistent, i.e. sweet spots are emerging but not across the whole horizontal play fairway thus far. We note that there is 800kbd of additional oil pipeline export capacity and 200kbd of rail, indicating the Permian is viewed by the industry as a source of volume growth.

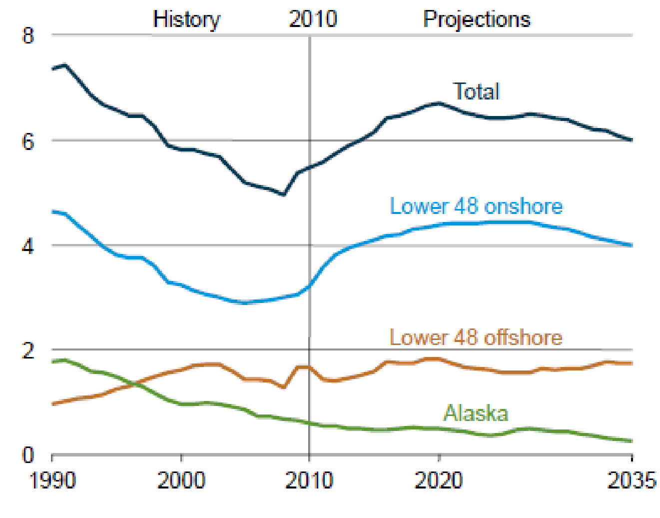
Clearly our assessment of oil production potential requires access to capital (i.e. high oil prices and open capital markets), requires improvements in IP rates, downspacing success, the delineation of new plays, supportive policy, safe operations and a sustained high level of industry activity. We are wary of being too optimistic but equally need to reflect the industry's progress. Hence, we will provide regular model updates, as rig counts, well results and downspacing results come in.

Exhibit 16: U.S. Crude Production, EIA 2012 Annual Outlook



Source: EIA

Exhibit 17: U.S. Crude Production by Type



Source: EIA

U.S. Production Growth - Impact on Global Oil Balances

In our base case, U.S. oil production growth would account for nearly 80% of the global net-gain in oil production capacity that we foresee by 2015. But, in that same base case spare capacity only grows from 2% to 3% by 2015. That would be lower than in 2009 and 2010 and on a par with the 2004-08 time frame of rapid oil price increases. It would take away a prop under fundamentals and allow for prices to gravitate down toward more sustainable long-run levels nearer $90/b. What's more, without relatively high prices ($90/b Brent or more see below) U.S. and other non-conventional growth would be less.

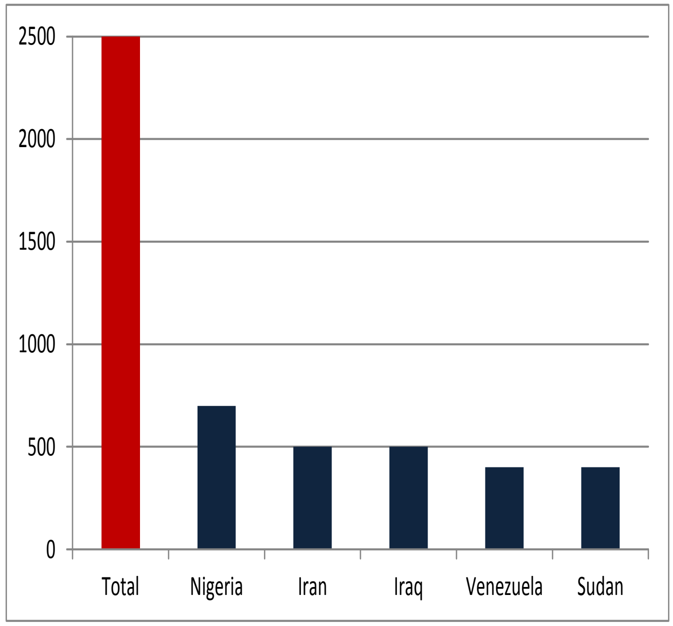
That said, in our long range model, there is the prospect of still more production growth to come in the 2015-2020 time frame from other non-Opec producers (e.g. pre-salt Brazil, pre-salt Angola, Russian shale). This could put a brake on the rising price trend that's been in place since 2003, absent stronger than expected demand growth.

Exhibit 18: Global oil s/d balance stays relatively tight a few more years, begins to loosen in 2015

Demand	2011	2012E	2013E	2014E	2015E
Global	89.5	90.6	92.0	93.1	94.0
YoY Growth, %	1.0%	1.2%	1.5%	1.3%	1.0%
OECD	45.8	45.6	45.5	45.3	44.7
YoY Growth, %	-1.0%	-0.3%	-0.3%	-0.4%	-1.3%
Non-OECD	43.7	45.0	46.4	47.8	49.3
YoY Growth, %	3.3%	2.9%	3.3%	3.0%	3.1%
Supply	**2011**	**2012E**	**2013E**	**2014E**	**2015E**
Global	88.6	90.5	92.0	93.2	94.1
YoY Growth, net mb/d	0.8	1.8	1.5	1.2	0.9
Non OPEC	50.6	50.9	51.7	53.0	54.6
YoY Growth, net mb/d	0.1	0.3	0.8	1.3	1.5
North America	15.5	16.7	17.5	18.3	19.3
YoY Growth, net mb/d	0.5	1.2	0.8	0.9	0.9
Non-Opec less NA	35.1	34.2	34.2	34.7	35.3
YoY Growth, net mb/d	-0.5	-0.9	0.0	0.5	0.6
Processing gain	2.4	2.5	2.5	2.6	2.6
OPEC	35.7	37.1	37.8	37.6	36.9
YoY Growth, net mb/d	0.6	1.5	0.7	-0.2	-0.7
Opec Crude Oil	30.2	31.5	32.3	32.0	31.3
YoY Growth, net mb/d	0.3	1.3	0.7	-0.3	-0.7
Balance, stocks					
Implied inventory change	-0.8	-0.1	0.1	0.0	0.1
Spare capacity					
All Saudi Arabia	2.4	1.9	2.0	2.5	3.0
% of total supply	2.7%	2.1%	2.1%	2.7%	3.2%

Source: Credit Suisse Commodity Research. All data in millions of barrels per day (mb/d)

Exhibit 19: Things could get much looser, quicker if any of a string of sovereign producers "normalize"



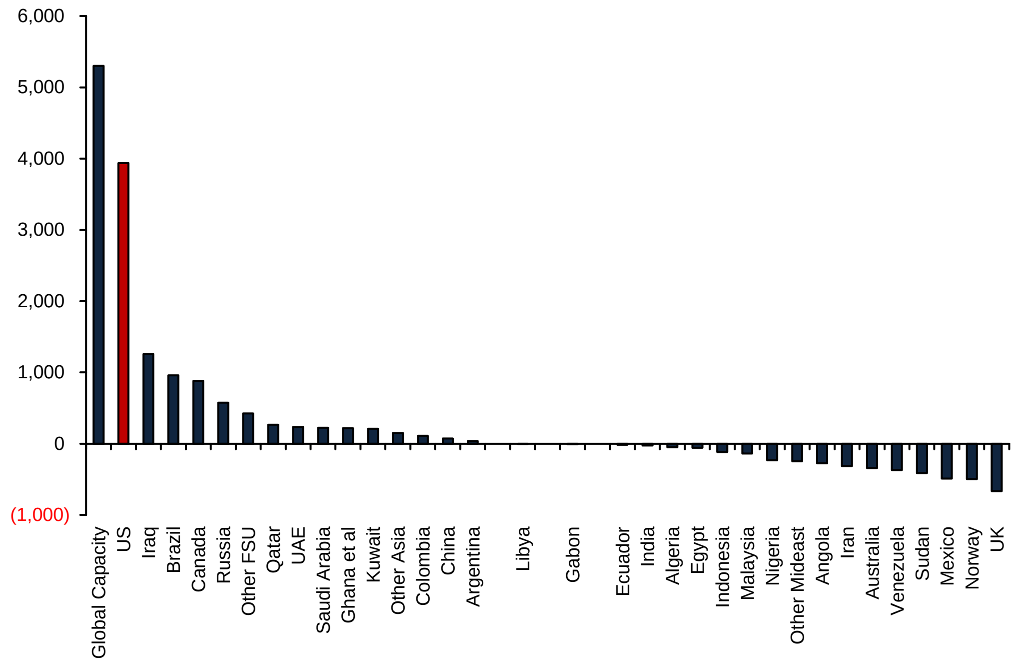
Source: Credit Suisse Commodity Research. Difference in "risked" and "normal" oil production in 2015 (kb/d)

Oil market fundamentals could deteriorate faster still, if before too long, conditions in any of a number of sovereign oil producers were to "normalize" (for lack of a better term), then capacity could grow by another 2.5mb/d by 2015. "Normal" would involve:

- shut in production were brought back on line (e.g. Nigeria, Sudan);
- sanctions were lifted soon (Iran)
- Government policy were to become much more investment friendly (Iraq, Venezuela)

Our base case tries to steer a central course through a corridor bounded on the downside by the potential return into the market of barrels from these countries and/or economic weakness and to the upside by faster than expected near term economic growth and/or greater than expected production disruptions.

Exhibit 20: CS estimated growth/decline in capacity by 2015 (base is 2010) (kbd)



Source: Credit Suisse Commodity Research

Four Important Assumptions: IP Rates, EURs, Drilling and Completion Days and Rig Counts

The bulk of this report runs through the key assumptions that we make in our interactive excel model and reviews the progress in key plays. Note that our SMID Cap E&P analyst Mark Lear publishes a shale review each quarter – *The E&P Play Book*. Our large cap E&P analyst, Arun Jayaram, has a similar model for U.S. Natural Gas supply and demand.

Key assumptions include:

- **The rig count in each play**: This is a function of relative economics across plays, overall industry cashflows, the progress of play scientific evaluation and the recoverable resource from each play.
- **Industry behavior**: We have tried to limit the well count to something that can plausibly be funded by our macro deck but that also does not outdrill the play inventory in the key plays (Bakken, Permian and Eagle Ford). As the number of days to drill a play have decreased, operators have indeed dropped rigs. Of course it is possible that "NPV maximisers" beat our rig counts – which is why we will publish regular updates for the flex model. An offsetting thought – roughly 38% of industry U.S. capex is being spent by Majors who should be more disciplined. Debt-cap ratios for smaller companies are also quite high.
- **Drilling and Completion Days**: As plays develop, the industry is getting more efficient and increasing the number of wells drilled by each rig per year. Increased efficiency is a key reason that the oil rig count might not need to rise more than 10% from here while still drilling a decent chunk of acreage by 2030.
- **Initial Production Rates and Recoverable Reserves (EUR)**: 24 hour and 30 day initial production rates are watched closely to determine production potential from each play. We apply an improvement factor to recent actual well performance which

can be flexed in the model for sensitivities. Note the assumptions made on IP will affect the recovery from every well drilled across the entire play.

- **Decline Rates**: 30 day IP's are a good proxy for performance. However, decline is also important and another key driver of recoverable reserves.

30 Day IP Rates

Producers give expected type curves by play (i.e. the production for a single well over time). These typically are based on an initial production (IP) rate and a decline curve. They are useful proxies when attempting to forecast production from shale wells, many of which have not been drilled yet. We use actual data from the respective state commissions (downloaded via HPDI) to observe IP rates. The industry has generally been optimistic in terms of the IP rate for a play type curve. This can be for a number of reasons:

We use 4Q11 IP rates as a base for the model and then a targeted improvement which clients can flex in the model.

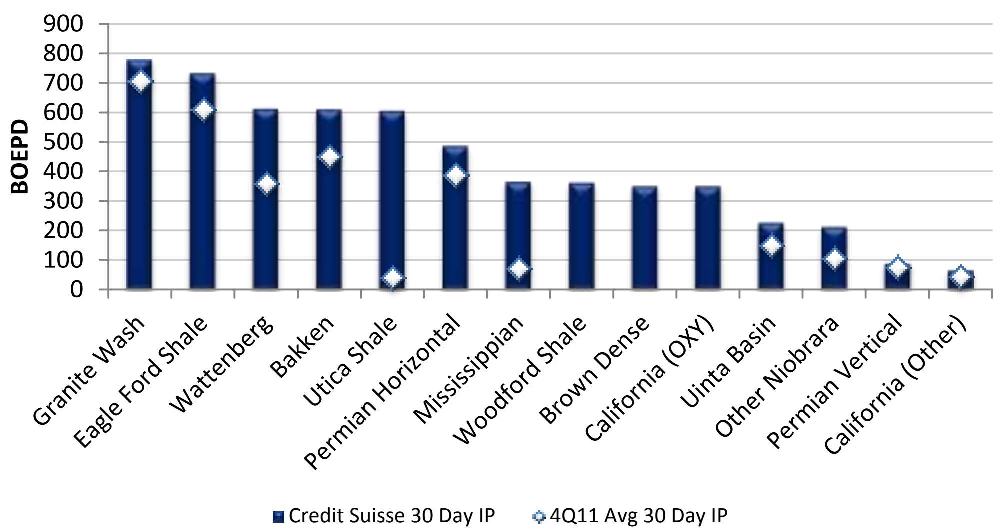
- In the early phases of a play, there are a greater amount of science wells which don't meet the type curve for future development wells.
- While drilling to hold leases by production there can be inefficiencies.
- Sufficient offtake infrastructure may not be in place.

As with natural gas IP rates, this suggests there will be improvement over time. We have chosen to drive our base forecast using 4Q11 actual IP rates and then apply a percentage improvement which we can flex.

In the chart below we show how our assumed IP's stack up against observed data. Our assumed IP rates for the key oily plays (Eagle Ford, Bakken) embed on average 21% more optimism than 4Q11 actuals.

Although there will be sweet spots in different plays, the model is run off play average IP rates which tie more closely to production.

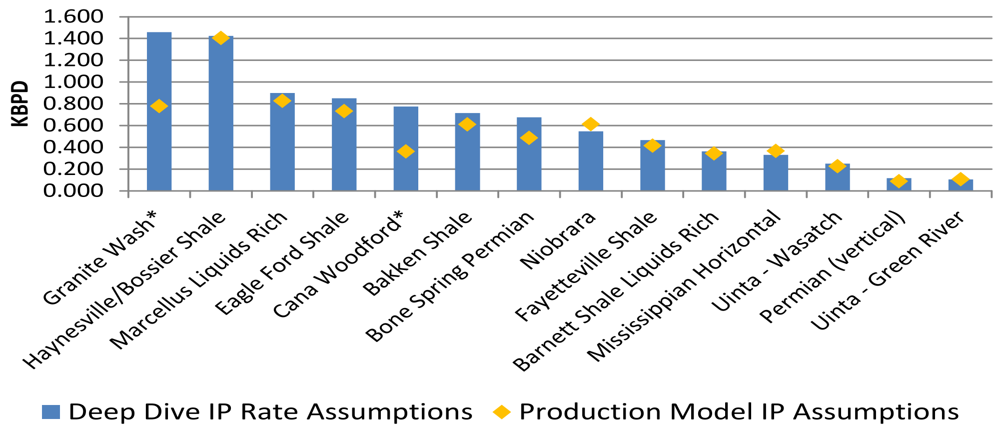
Exhibit 21: **Observed 4Q11 Play Average 30 Day IP Rates vs CS IP Assumptions (BOEPD) at 6:1 Oil:Gas Ratio ***(Plays with no 4Q11 actual data did not have any wells drilled during the sample period according to HPDI)



Source: HPDI, Credit Suisse estimates

We also show how our IP's stack up against the rates used by our E&P team to calculate well IRR's and the breakevens per well that are used in this report. They are broadly aligned. The exceptions are the Granite Wash, Woodford where we have focused on liquids rich wells only.

Exhibit 22: Credit Suisse SMID Cap 30 Day IP Assumptions vs Our Production Model Assumptions at 6:1 Oil:Gas Ratio

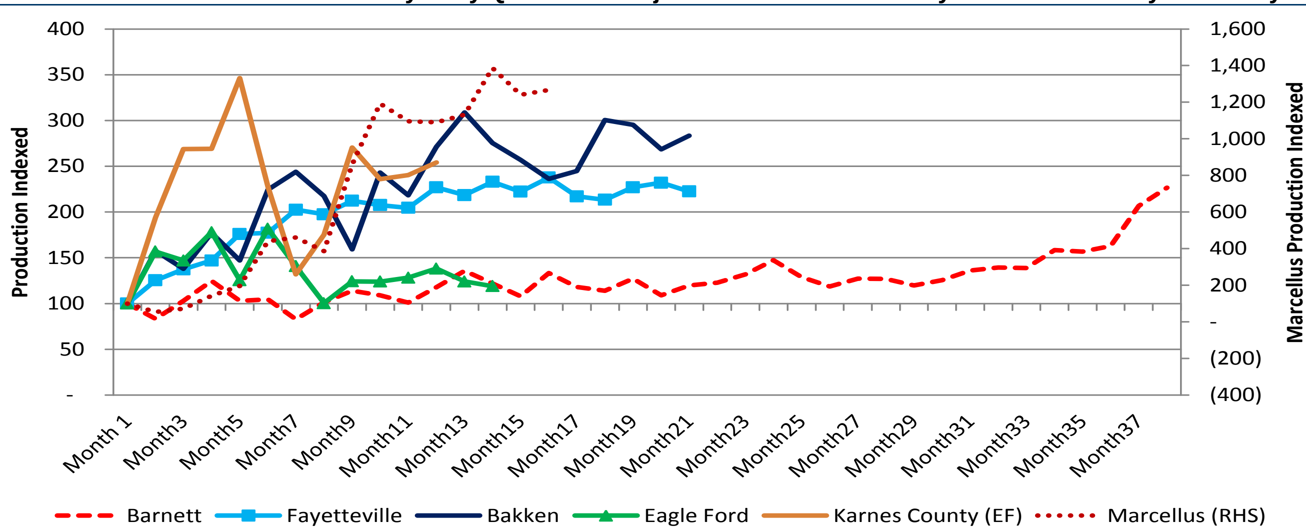


*Source: Credit Suisse estimates *Cana Woodford and Granite Wash model assumptions are based on oil well results while assumed IP rates are based on Gas well results.*

In practice, IP rates tend to improve over time. The indexed chart below follows the actual peak 30 day IP rates by quarter for both Oil and Gas plays over time. We see that in general IP rates improve significantly from the first delineation of a play to maturity. Operators gain play knowledge during early drilling campaigns (sometimes necessitated by drilling to hold acreage) and are able to focus rigs on core acreage as time goes on, leading to better well results as a play matures. The Eagle Ford seems an exception to the rule with strong 30 day IP rates from the beginning of the play history in 2009. We believe this is due to initial play average results including gas. As the industry has shifted to liquids rich wells, the IP has reduced but the economics have improved. Focusing purely on liquids rich Karnes county, observed IP's have shown improvement over time.

IP rates tend to improve over time in gas and liquid rich shales

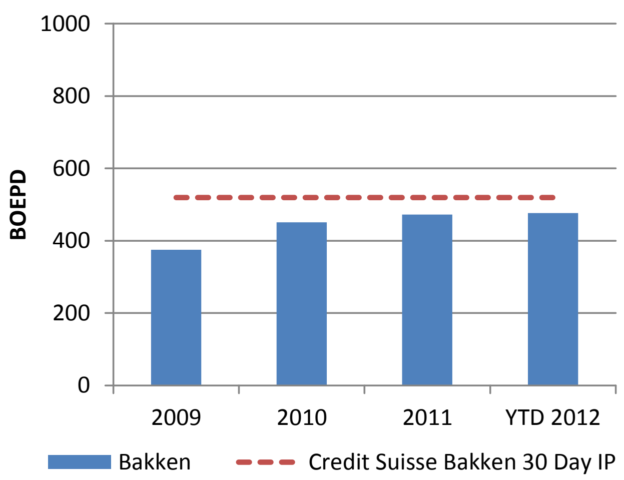
Exhibit 23: Indexed Actual Peak 30 Day IP by Quarter for Major Oil and Gas Shale Plays Since Initial Play Discovery



Source: HPDI, Credit Suisse Estimates

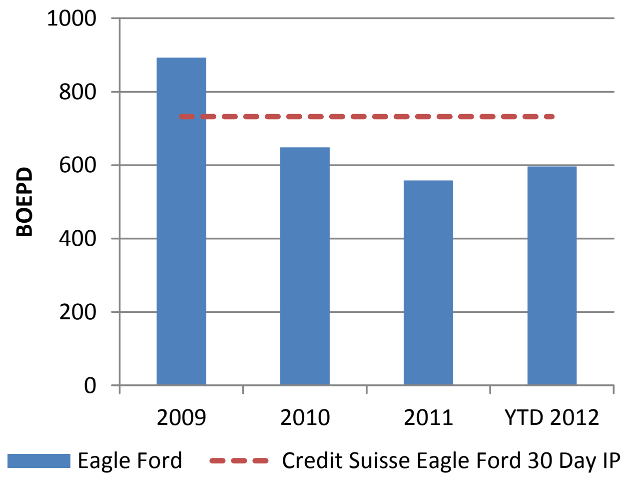
We show in the following 3 charts the observed (actual) IP rates for the industry average well in the Bakken, Eagle Ford and Permian horizontal shale plays. Note that the IP rates assumed in our production model show improvement relative to the recent history. IP rates for emerging plays can be particularly volatile. Early results in the eastern portion of the Utica were gassier than expected. However a recent well had a 24hr IP of 4,650 boed (50% liquids cut) which if repeated would suggest upside to our production forecasts across the liquids window of the play, assuming NGL and gas offtake constraints are solved.

Exhibit 24: Bakken Actual 30 Day IP over time vs Credit Suisse Assumptions



Source: HPDI, Credit Suisse estimates

Exhibit 25: Eagle Ford Actual 30 Day IP over time vs Credit Suisse Assumptions

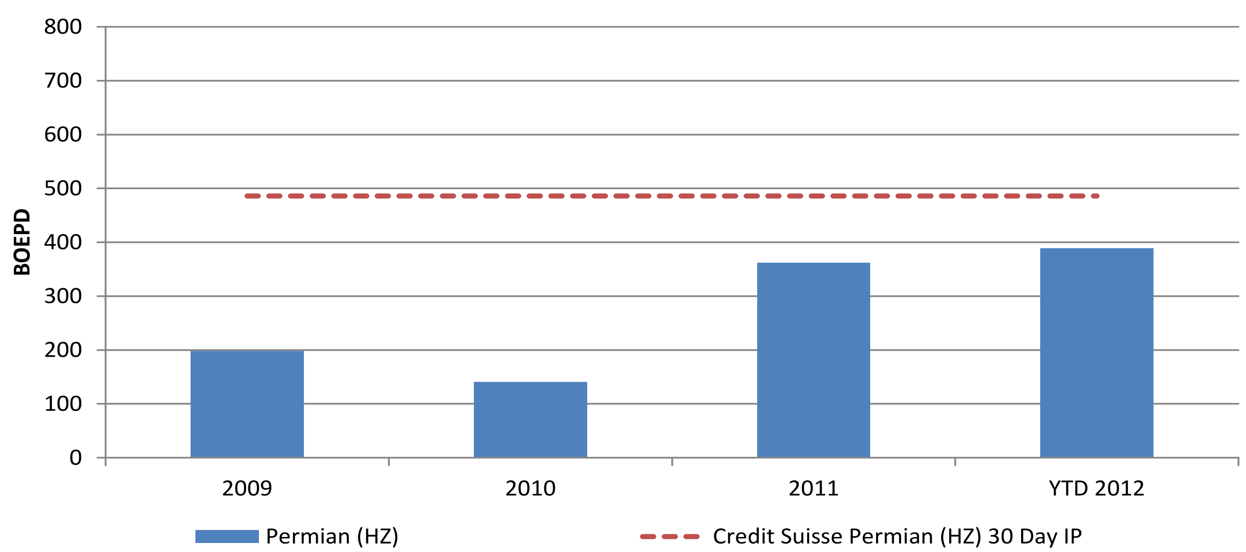


Source: HPDI, Credit Suisse estimates

It seems plausible to assume that IP rates will improve.

- The industry will learn what works across geologies
- A shift to PAD drilling can improve well uptime. The average Bakken well is only onstream 70-80% of the first 30 days.

Exhibit 26: Permian Horizontal Actual 30 Day IP vs Credit Suisse Assumptions



Source: HPDI, Credit Suisse estimates

While our assumed IP's already leave room for the industry to improve its actual performance, we will watch IP's closely and report on quarterly industry improvement. Given industry variability in well performance, we are wary of taking best in class individual well results and applying them across the whole industry or play though it is possible to flex all the assumptions in our interactive excel for which we will provide updated reports quarterly.

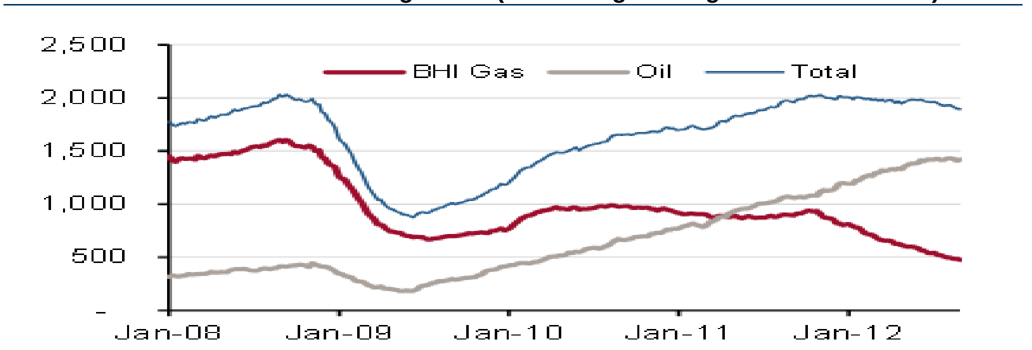
Rig Count

We only assume a 10% rise in oil rig count by 2017 vs current levels. This is primarily due to our assumptions around drilling efficiency gains over time. If the industry can drill more wells per rig, the number of rigs may not need to rise as high as the number of well locations would suggest. Our well count assumptions are linked to the aerial extent of each play and the latest thoughts on well spacing per acre. Watching downspacing tests will be important.

Barring an economic collapse, the U.S. rig count should remain high justified by shale resources. The well count should rise as U.S. rigs drill more wells per year.

Although, we have tried to limit the well count to something that does not outdrill the play inventory in the key plays (Bakken, Permian and Eagle Ford), it is possible that “NPV maximisers” beat our rig counts – which is why we will publish regular updates for the flex model. An offsetting thought – roughly 38% of industry U.S. capex is being spent by the Majors who should be more disciplined. Debt-cap ratios for smaller companies are also quite high.

Exhibit 27: Oil and Gas Directed Rig Count (note oil rig count growth due to shale)



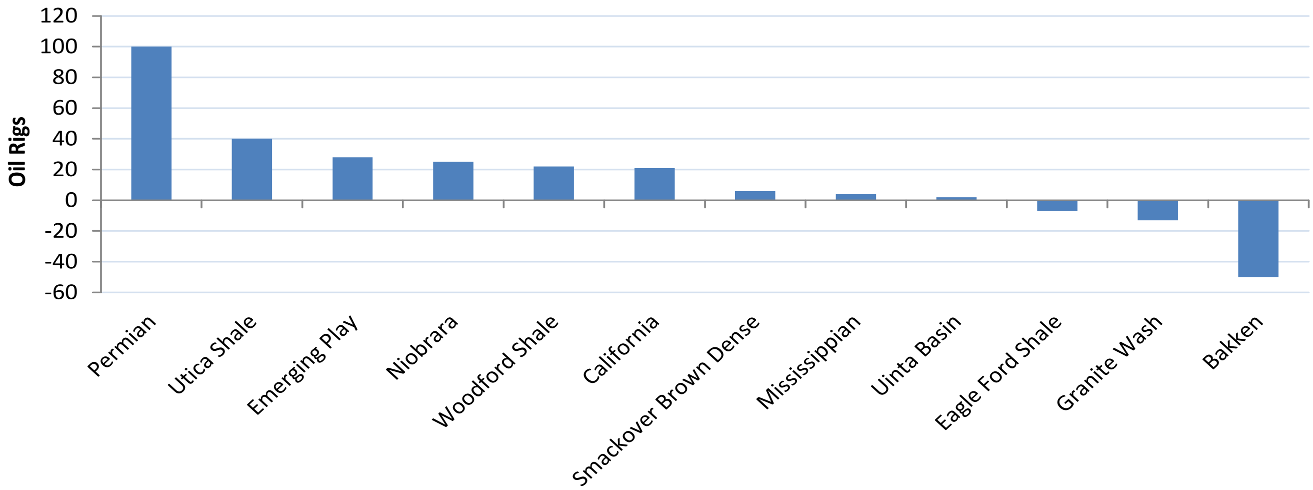
Source: Baker Hughes

Some observations on rig counts in each basin

- **Permian horizontal play is the largest source of growth**: The rig count in the Permian has risen rapidly yoy. We assume around 30 rigs per annum migrate to the Permian over time. The actual outcome will clearly depend on further delineation of the Permian’s horizontal potential.
- **Recent Utica oil wells support higher rig count expectation**: Given recent well results, we are more confident that Utica rig counts should rise. The challenge could be offtake for associated gas and NGLs.
- **Reduced Rig Counts in the Bakken / Eagle Ford**: Interestingly we reduce the rig count in the Bakken and Eagle Ford. This is due to the industry success in drilling more wells per rig per year. If downspacing tests are successful, our assumptions could prove conservative.
- **Mississippian**: Like the Utica, rig counts are rising rapidly in this mid-continent play. We have modeled flat rig counts from here because of the early stage nature of the play.

- **Niobrara**: As the Wattenberg and other Niobrara sweet spots are delineated, we would expect rig counts to rise.
- **Woodford**: Recent industry commentary suggests continued interest in the Woodford liquids rich window, though this is mainly an NGL play.
- **California**: In line with company guidance, we increase rig counts by 5 rigs each 6months for the next 2 years.
- **Emerging Plays:** We allocate an incremental 28 rigs to new emerging plays that have not yet been fully delineated.

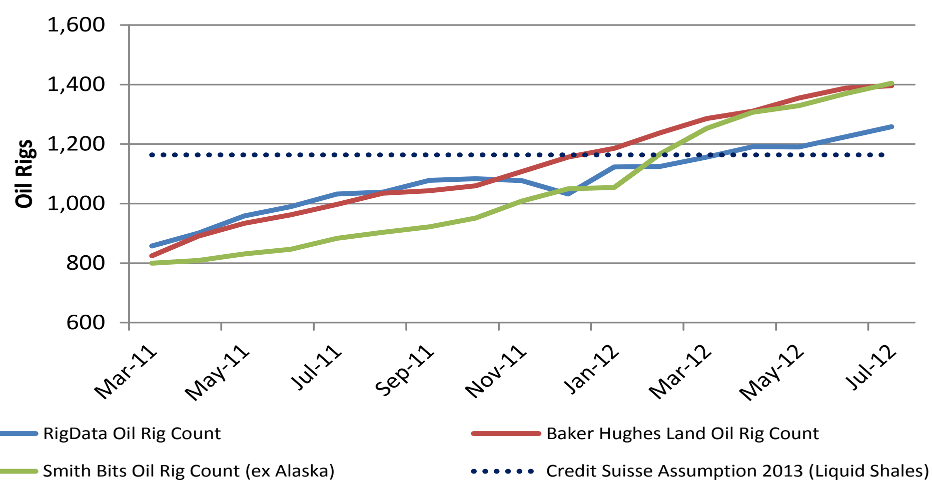
Exhibit 28: **Change in Rig Count Across Plays Through 2015**



Source: Credit Suisse estimates

We use RigData for our shale oil rig counts by play. The rig count that we present throughout the report is for shale oil rigs only. There are oil rigs operating vertically in shallower plays that we assume are mitigating decline on existing fields. This means our rig count will not be fully like for like with the Baker Hughes or Smith Bits oil rig count data.

Exhibit 29: **2013 Oil Rig Count Assumption vs Current Oil Rig Count by Source *(Industry rig counts include rigs drilling less than 5k ft which we exclude in our rig count)**



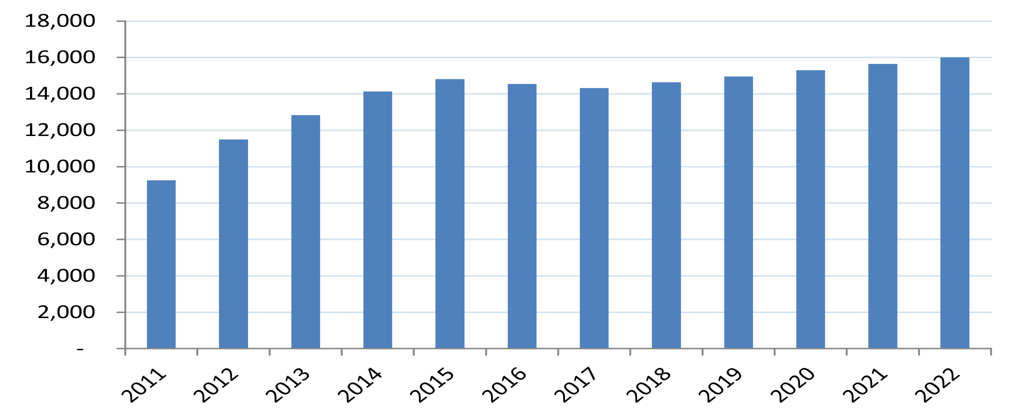
Source: Credit Suisse estimates, Baker Hughes, Smith Bits, RigData

Our "shale oil" rig count will not be fully like for like with Baker Hughes or Smith Bits "all oil" rig count data.

Drilling and Completion Days and Well Count

We assume a substantial improvement in the time it takes to drill and complete a well. This improvement in drilling and completion days results in the industry drilling substantially more oil wells than today. Indeed our base case envisages the shale well count increasing by 33% from 11,500 wells p.a. in 2012 to 15,300 wells by 2020. No doubt there will be improvements in frac efficiency also.

Exhibit 30: Wells Drilled in The Model's Oil Shale Plays by Year

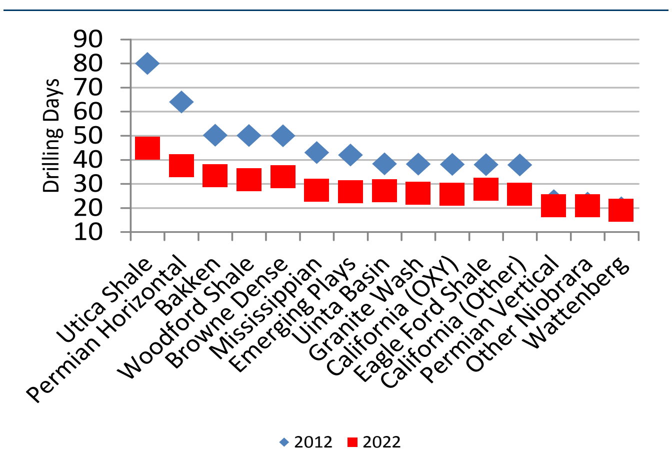


Source: Company data, Credit Suisse estimates

A 39% increase in the number of wells drilled per year (2012-2022) to grow and then sustain higher oil production

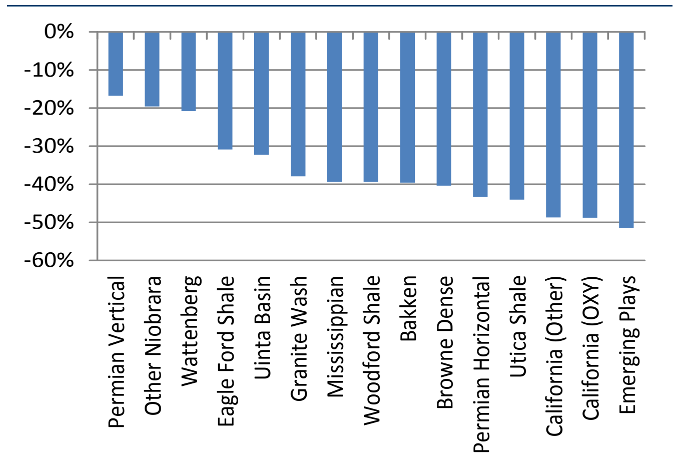
We have stress tested our forecast to determine which variable's the production model is most sensitive to and found oil production is particularly affected by the rig count, followed by D&C days, and to a lesser extent IP rates and long term decline rates (much of which happens after the 2022 cutoff). Though D&C days have less of an impact on overall future production than Rig Counts, they are still important in determining potential production out of any basin. We are assuming an average 40% improvement in the time it takes to drill and complete a well over the next 10 years which we do not feel is aggressive when looking at the improvement already seen in plays such as the Eagle Ford and Bakken in just the last 24-36 months. Spud to rig release times have come down 40-50% in the Eagle Ford since 2009 with leading edge drilling days under 10 from more than 30 in 2009. Below we present a chart of our D&C assumptions for 2012 and 2022 and the percentage improvement we are assuming longer term.

Exhibit 31: Drilling and Completion Days 2012 vs 2022



Source: Company data, Credit Suisse estimates

Exhibit 32: % Decrease in Drilling and Completion Days 2022 over 2011

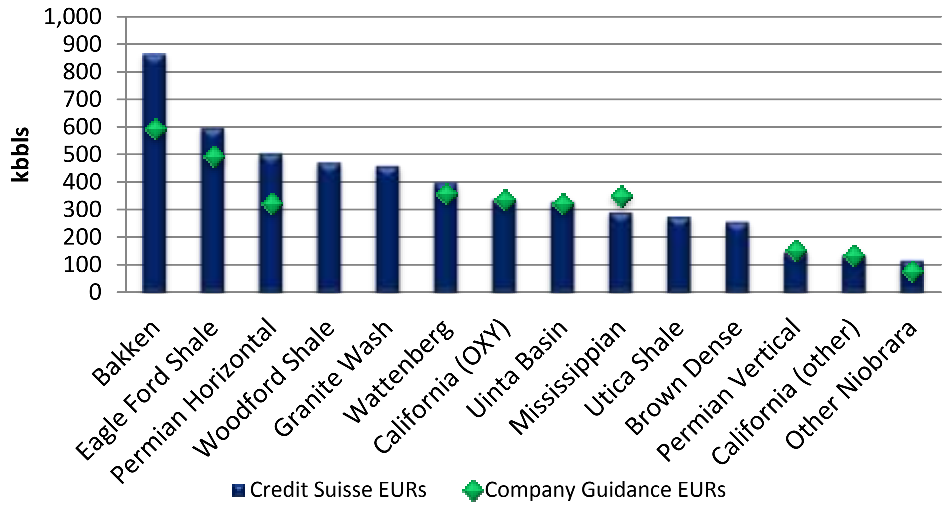


Source: Company data, Credit Suisse estimates

Expected Ultimate Recovery (EUR's)

On the basis of the above IP rates and assumed decline curves we arrive at the following EUR by play in BOE. We note that the EUR's for liquid rich plays are lower than the EUR's for low cost gas plays such as the Haynesville, Marcellus and Barnett, a key reason why the U.S. shale oil revolution may not generate as large a payoff for U.S. consumers as the natural gas boom.

Exhibit 33: EUR by Play (Company Guidance vs Credit Suisse Assumptions), BOE at 6:1 Oil:Gas Ratio *(Plays with no company guidance lack sufficient oil EUR forecasts by operators)



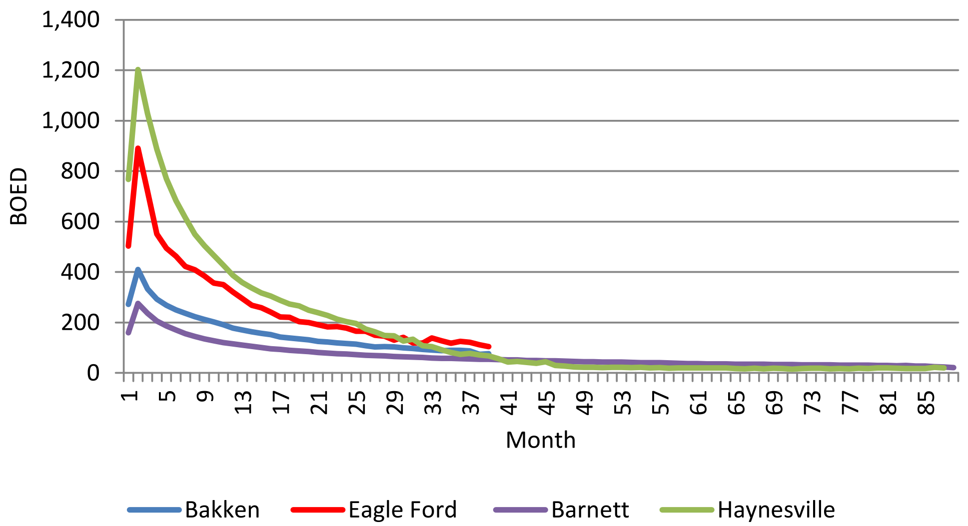
*Source: Company data, Credit Suisse estimates *Plays with no company guidance lack sufficient oil EUR forecasts by operators*

A Key Forecasting Issue: We Don't Know Oil Decline Rates for Shale

Given the success of shale gas production growth, hopes have been raised for a similar renaissance in U.S. oil production. Indeed, U.S. oil production has been growing strongly. The challenge for any prediction is that we don't have as much evidence for oil shales versus gas shales to base terminal decline rate forecasts on. We have 3-4 years of shale oil data but 6-7 years for gas.

Importantly, the rate of decline on a Bakken or Eagle Ford well in the early years of production can range from 50-70%. Logically, the greatest growth of a play is in its early years. As plays build up to higher overall production, decline can be a big hurdle to overcome. The chart below demonstrates production curves of prominent gas and oil plays using historical data. As the Bakken and Eagle Ford are still relatively new plays, historical data does not extend past 4 years, preventing assessment of decline rates in later years when production declines are more muted and long life production is established.

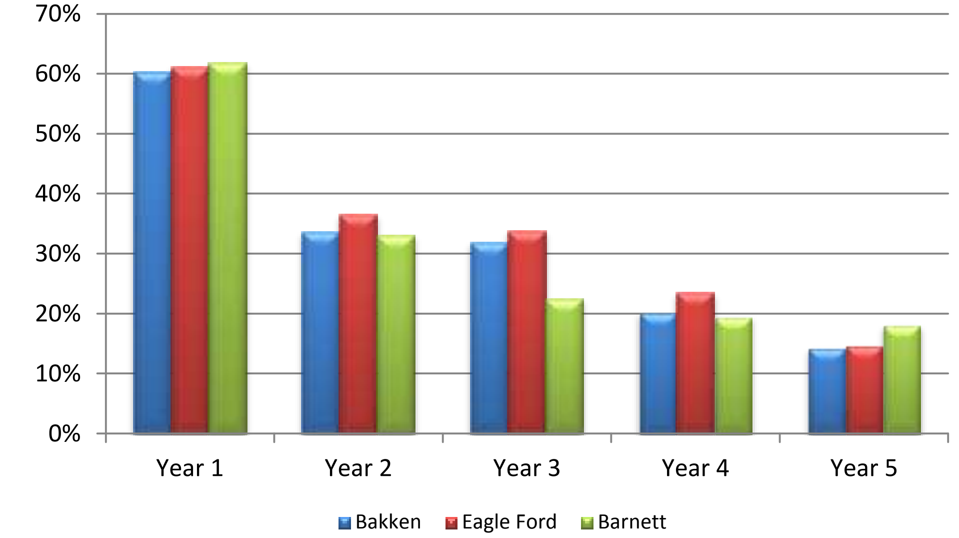
Exhibit 34: Type Curve for Key Oil Plays versus the Barnett and Haynesville



Source: HPDI, Credit Suisse Estimates

In the long run, using hyperbolic decline assumptions based on initial actual well performance, we arrive at an average terminal decline rate of around 8% with some variance from play to play. There are those who worry that shale oil wells may even halt production at some point rather than deliver a long tail due to squeezing oil molecules through tight shales. Clearly, there is much uncertainty.

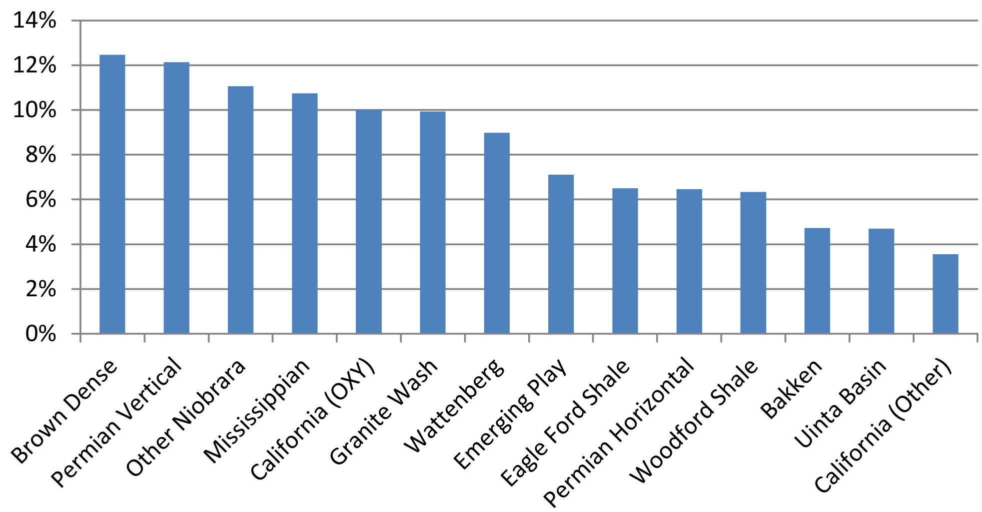
Exhibit 35: Decline Rate By Year, 1-5 yrs Eagle Ford, Bakken and Barnett (Actual)



Source: HPDI, Credit Suisse estimates

We only have 5 years of history for key liquid plays. We use this data to approximate a hyperbolic decline curve.

Exhibit 36:Terminal Decline Rate Assumptions by Play (Year 20 onwards)



*Source: HPDI, Credit Suisse estimate, *Predicted by hyperbolic decline curves*

These terminal assumptions have limited impact on 2022 production but will be important to the duration of the shale revolution.

Sensitivity Tables

In our sensitivity excel model, it is possible to flex rig counts, IP rates, drilling and completion days and longer term type curve decline rates to get a sense of the key drivers of production potential. We also include sense checks e.g. % acreage drilled, EUR/well and even recovery factor (though this is more uncertain) to gauge whether the input assumptions match the realm of possibility. Finally we include an "Emerging Plays" category to capture the industry's ambition to define new liquids rich plays over time (e.g. the Tuscaloosa, the Mancos). In this category we assume slightly higher D&C days (the industry will need to learn) but decent IP's (the industry will need to make money).

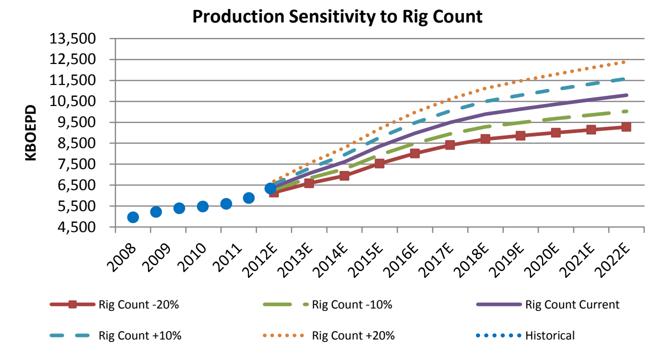
Exhibit 37: Latest Rig Count and Client Flex Forecast (2012-2017)

				Annual Forecasts					
Play	**2011**	**Current Weekly**	**vs 2011 Avg**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017-2030**
Eagle Ford Shale	161	227	66	224	230	230	220	190	150
Permian Total	**320**	**405**	**85**	**406**	**435**	**465**	**505**	**505**	**500**
Permian Horizontal	69	129	60	130	160	190	220	220	250
Permian Vertical	251	276	25	276	275	275	285	285	250
Granite Wash	104	88	-16	88	85	85	75	65	55
Woodford Shale	19	8	-11	13	20	30	30	30	30
Uinta Basin	24	24	0	26	30	28	26	24	22
Utica Shale	9	20	11	15	30	45	60	75	90
Bakken	138	155	17	167	145	130	105	85	70
Mississippian	33	78	45	70	80	82	82	55	45
Smackover Brown Dense	1	2	1	3	4	6	8	8	8
Niobrara Total	**43**	**40**	**-3**	**40**	**45**	**57**	**65**	**70**	**70**
Wattenberg	9	18	9	18	25	35	40	45	45
Other Niobarara	34	22	-12	22	20	22	25	25	25
California	30	44	14	44	50	60	65	65	65
Emerging Plays	N/A	2	N/A	2	10	15	30	50	100
Rigcount (in covered oil plays)	883	1093	208	1098	1164	1233	1271	1222	1205
Growth vs 2011				215	281	350	388	339	322
Growth vs 2012					71	140	178	129	112
% Increase vs 2012					6%	12%	16%	11%	10%

Source: Rig Data, Smith Bits and Baker Hughes

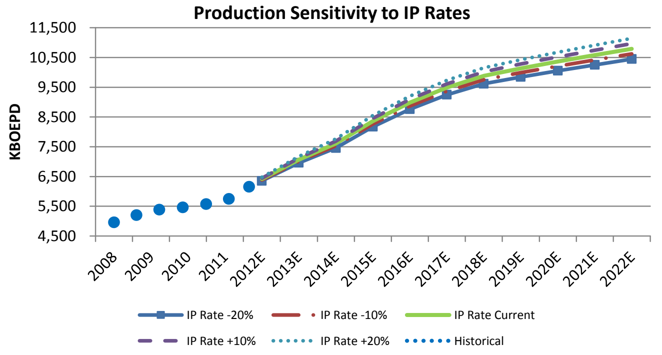
In the charts below, we show the outlook for U.S. oil production based on different sensitivities.

Exhibit 38: U.S. Oil Production Outlook vs Rig Count



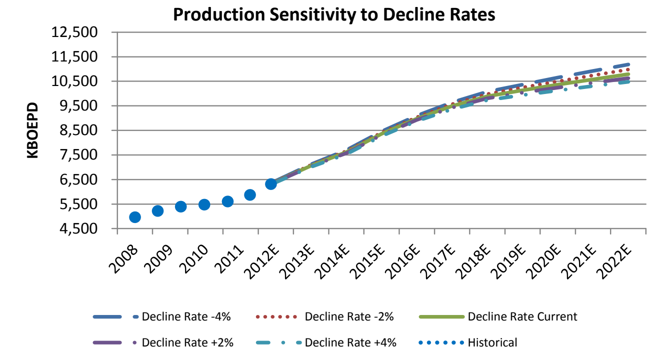
Source: EIA, Credit Suisse estimates

Exhibit 39: U.S. Oil Production Outlook vs 30 Day IP Rate % Improvement



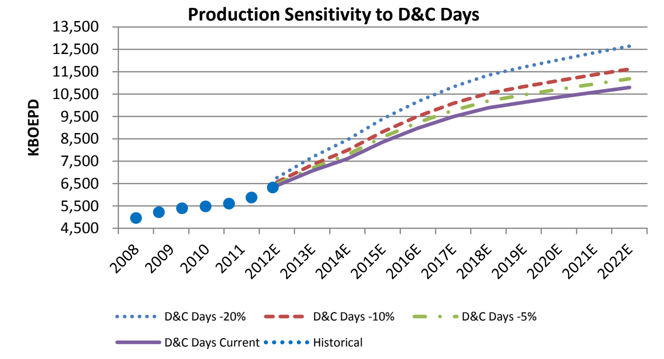
Source: EIA, Credit Suisse estimates

Exhibit 40: U.S. Oil Production Outlook vs Decline Rate



Source: EIA, Credit Suisse estimates

Exhibit 41: U.S. Oil Production Outlook vs Drilling and Completion Days Improvement

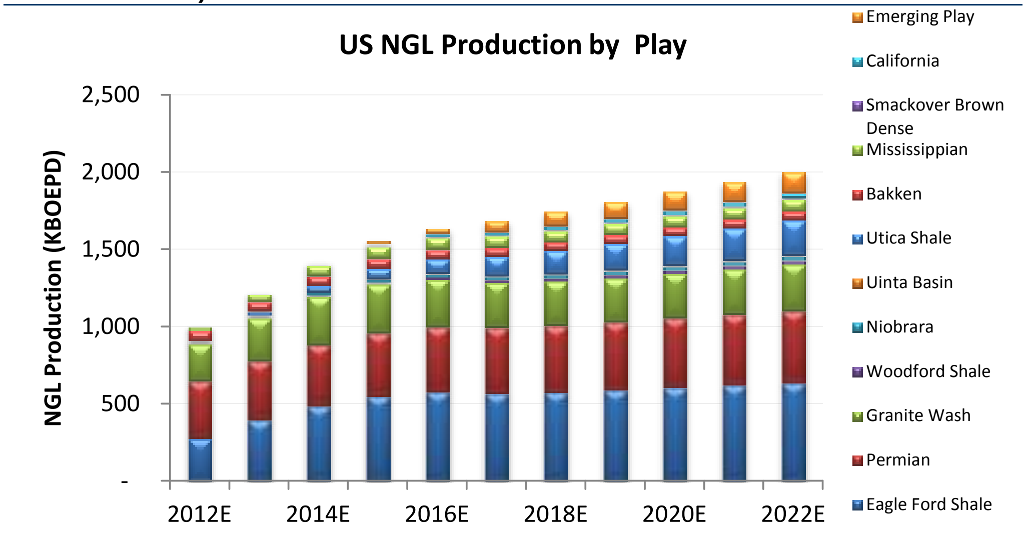


Source: EIA, Credit Suisse estimates

NGL's should also contribute to the liquid growth mix

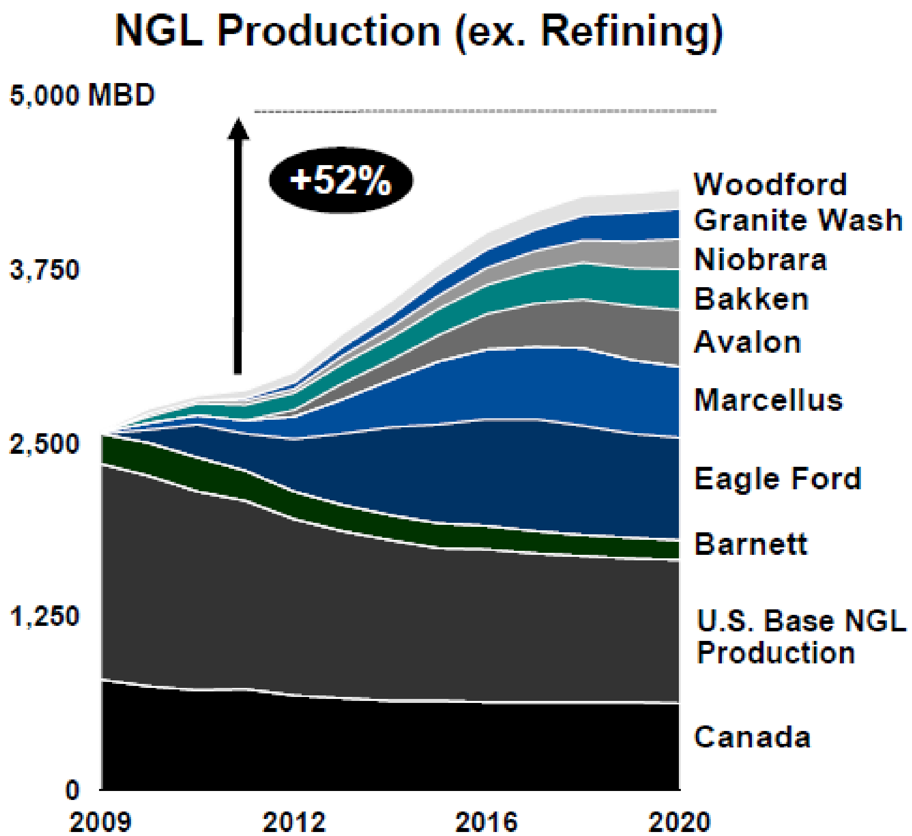
This report focuses on the potential for U.S. oil production. Total liquids production in the U.S. includes contributions from NGL's and biofuels also. Biofuel growth in the U.S. is likely to be limited given the already strong contribution from corn ethanol and the timeline to develop 2nd generation biofuels, though we note the progress companies such as KiOR have made. NGL production is a key focus of the industry. We show an industry estimate below, suggesting an additional 1.5MBD of NGL production from 2012 to 2018 or growth of around 200kbd per annum.

Exhibit 42: NGL Production Outlook From the Liquid Rich Plays in our Model (Note this is not exhaustive)



Source: Credit Suisse Estimates

Exhibit 43: NGL Production Outlook from PSX



Source: PSX

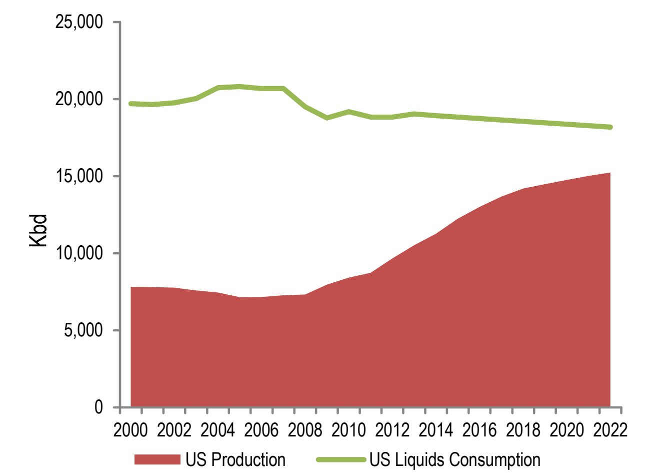
1.5MBD of additional NGL growth from 2012 to 2018

North America Oil Independence by 2022?

The U.S. consumed around 19.2mbd of liquid fuels in 2011 compared with domestic production of 5.5mbd of crude, 2.07mbd of NGLs and around 0.89mbd of biofuels (mainly ethanol) implying a gap of some 10.7mbd of domestic production for the U.S. to match supply and demand. Closing this gap would require (1) substitution of liquids demand by natural gas given 100yrs of gas resource, (2) transport and energy efficiency, (3) behavioral change (notably miles driven), (4) rising shale oil/NGL production and (5) rising contribution from the Gulf of Mexico (and possibly Alaska offshore if Chukchi Sea drilling is a success).

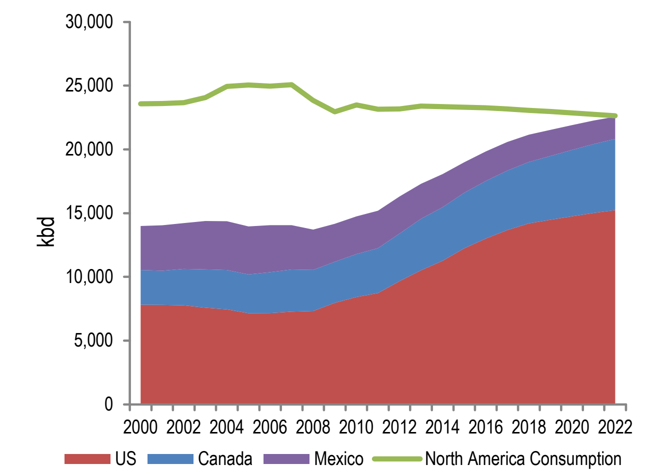
The gap is a smaller 9.5mbd for the U.S. and Canada in 2011 and 8.8mbd if Mexico is also included.

Exhibit 44: U.S. Production and Consumption (Liquids)



Source: BP, EIA, Credit Suisse Estimates

Exhibit 45: North America Production and Consumption (Liquids)



Source:BP, EIA, Credit Suisse estimates

But It Won't Come Cheap

Clearly our outlook for North America production is a function of the rocks' technical reserves, drilling efficiency and capital.

On paper, shale wells in North America should have breakeven WTI oil prices in the $50-75/bbl range (see chart).

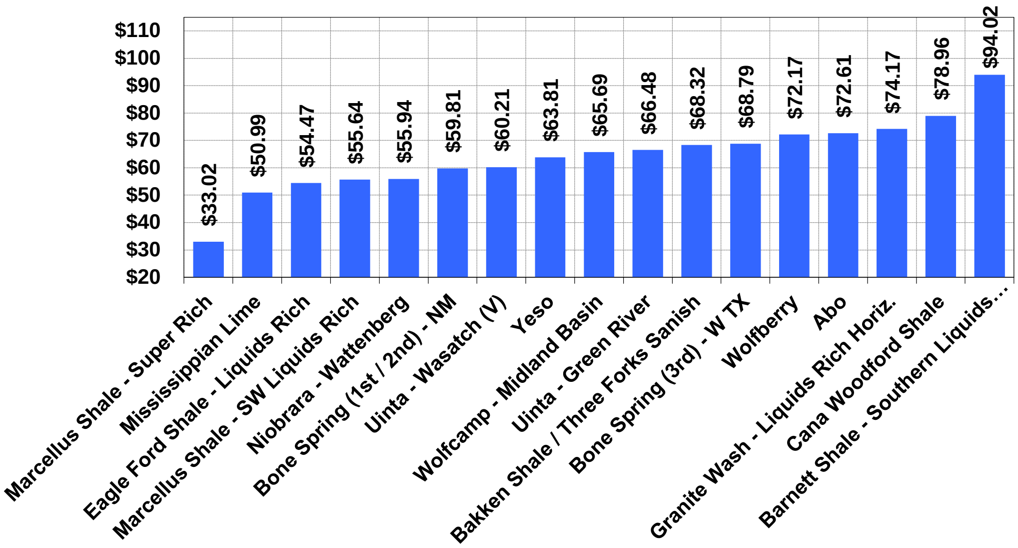
The challenge is not the returns on these theoretical wells. It is funding the upfront capital costs to hold acreage, to add infrastructure into plays, to do the science required to delineate sweet spots/completion etc and to drive growth. Eventually the challenge will also be to offset decline in the base.

As we note in the individual play focus later in this note, even for the good operators there is substantial variability in well results (likely a result of science).

On our current production model, the shale oil would require around $80bn pa. On top of this, there would be capex for shale gas, for conventional oil and gas, for the Gulf of Mexico and for exploration (we assume 10%). In total the industry would need to spend $160bn pa to deliver our growth projections for the U.S.

This is 30% of the overall global upstream capex in the industry currently for less than 15% of global production.

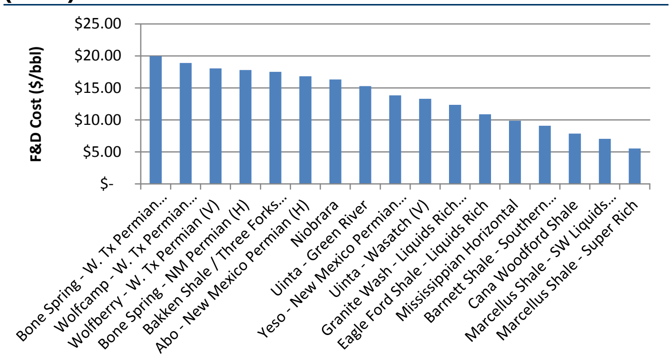
Exhibit 46: WTI Oil Price Breakeven, $/bbl



$50-$75/bbl for individual shale wells to breakeven

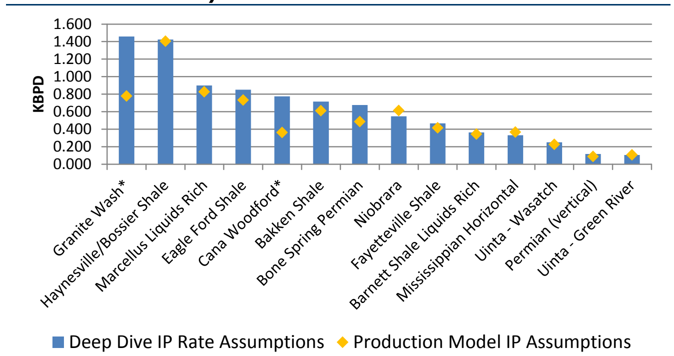
Source: Company data, Credit Suisse estimates

Exhibit 47: Liquids Rich F&D Cost Assumed in Above ($/bbl)



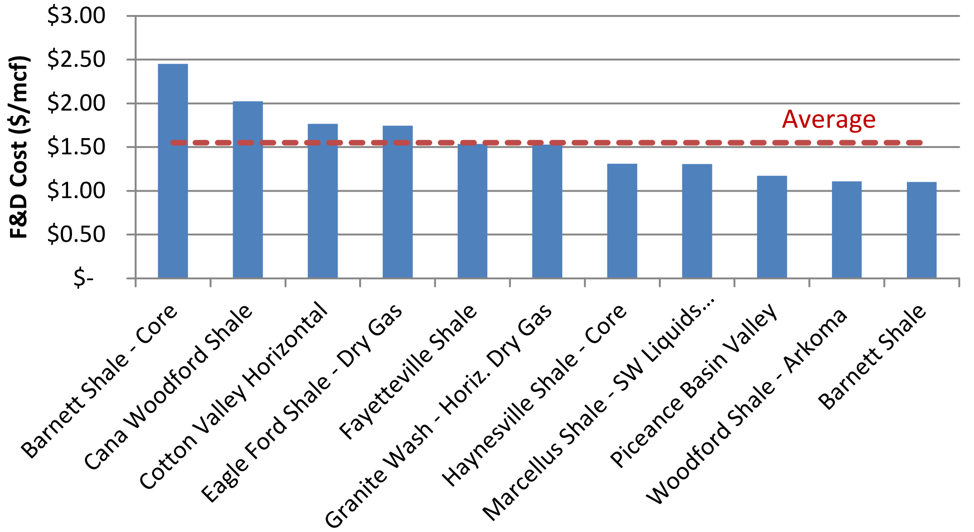
Source: Company data, Credit Suisse estimates

Exhibit 48: 30 Day IP Rate (assumed in above and in Production Model) at 6:1 Oil:Gas Ratio



*Source: Company data, Credit Suisse estimates *Granite Wash and Cana Woodford IP Rates in model are based on oil well results while Deep Dive assumed rates include Gas wells.*

Exhibit 49: Gas Play F&D Cost Used in SMID Cap Deep Dive

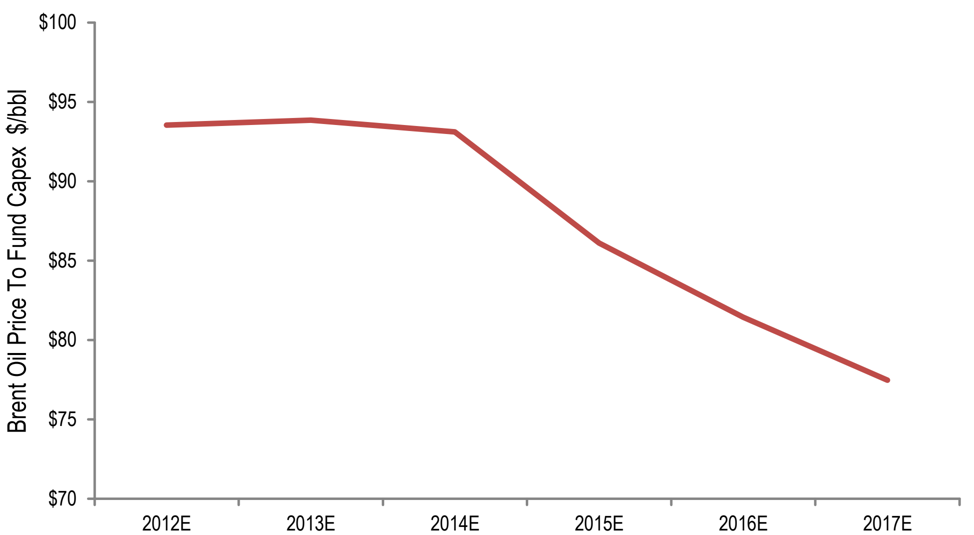


Source: Company data, Credit Suisse estimates

Although an inexact science, we looked at the U.S. as a closed system to gauge the type of oil price which would provide sufficient cashflow to fund this capex. Our conclusion is that the rate of investment needs a Brent oil price of $95/bbl today. Indeed we have seen companies pull back on capex in order to manage their cashflows in the latest oil price pullback. Over time as U.S. oil production ramps up, this breakeven would fall towards $80/bbl. This raises an interesting behavioral question. Although, we have tried to limit the well count to something that does not outdrill the play inventory in the key plays (Bakken, Permian and Eagle Ford), it is possible that “NPV maximisers” beat our rig counts – which is why we will publish regular updates for the flex model. An offsetting thought – roughly 38% of industry U.S. capex is being spent by the Majors who should be more disciplined. Debt-cap ratios for smaller companies are also quite high.

In the near term $95/bbl Brent looks required for funding – this would drop over time as oil production grew.

Exhibit 50: Brent Oil Price Required to Fund Industry at $4.5/mmbtu Henry Hub



Source: Credit Suisse estimates

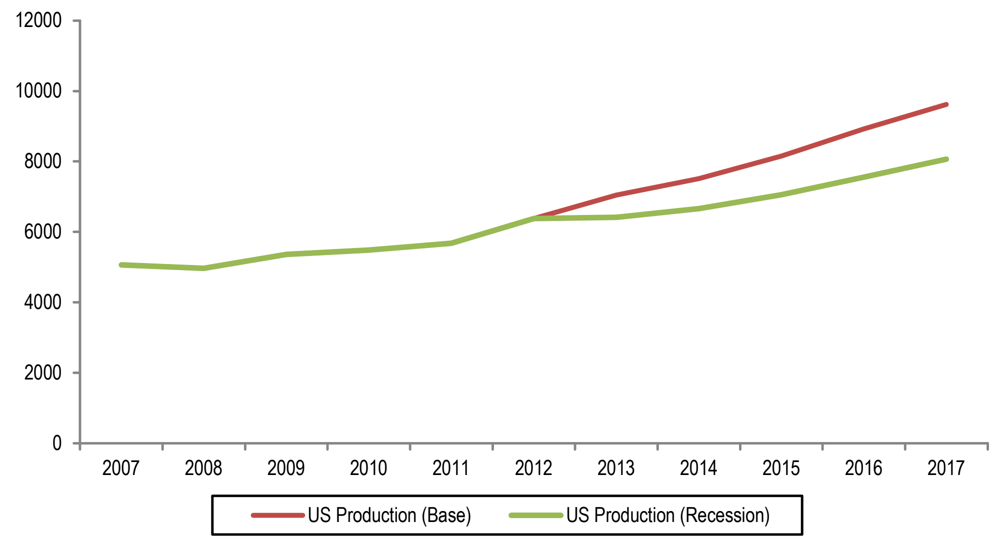
And If There Was A Recession

We calculate that a $95/bbl Brent oil price would be required to generate enough cashflow to match U.S. capex spend. In a recession with oil prices falling to $60/bbl Brent and then recovering to $80/bbl Brent some $60bn would be taken out of the system in 2013 and 2014. This is around one full year of capex in unconventional oil across the U.S.

Instead of rising, we would expect the non-conventional rig count in this scenario to fall 180 rigs and for there to be a reduction in base industry capex also.

Instead of growing, overall U.S. production could be flatter in 2013. As oil markets absorb the price shock and rise towards marginal cost in a recovery, then drilling would resume. In the recession case, we assumed $80/bbl Brent for a number of years. Balancing industry cashflows in this case would suggest a lower rate of production recovery. Overall, we would end 2017 with 8MBD, some 1.5MBD lower than our base case.

Exhibit 51: Outlook for U.S. Production (Base Case and Recession), kbd



Source: Company data, Credit Suisse estimates

Infrastructure: Rising to the Challenge

More Pipes Required

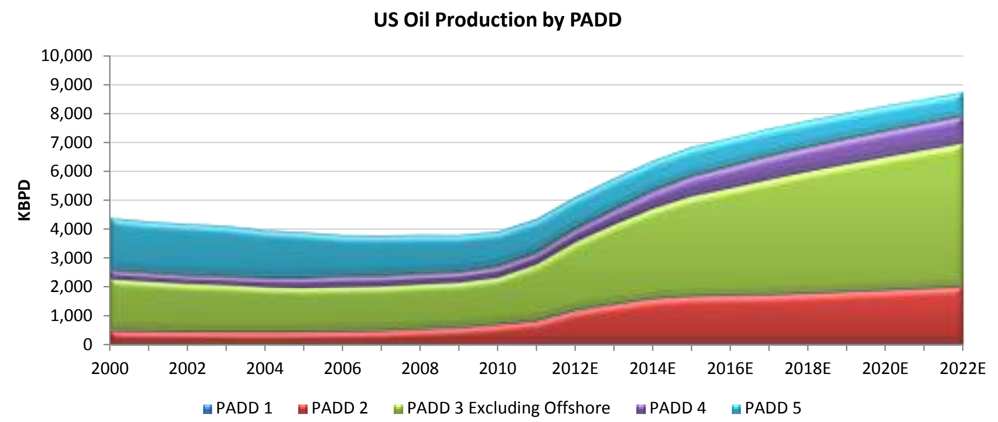
With our forecast of onshore growth and rising Canadian imports, more infrastructure looks required (we lay out a table of key projects in the Appendix). Incremental trunklines include

- Seaway 400kbd from Cushing to the Gulf (fully operational 1Q13)
- Seaway expansion and Flanagan South (mid-2014). Expands Seaway from Cushing to the Gulf by 450kbd and adds capacity to take crude that is currently bottlenecked in the Chicago area down to Cushing
- Keystone XL – we await sanctioning of the cross border section of this pipeline. Should add capacity of 500-800mbd from Cushing down to the Gulf by late 2013/early 2014 and then from Canada to Cushing by late 2014.
- Line 9 reversal – 240kbd of capacity to take crude to Eastern Canada.
- Rail and barge – in our forecasts we continue to see a need for rail and barge. Notably our forecasts suggest the Bakken will continue to be rail constrained at least until

Flanagan South is built out suggesting weak differentials for Bakken and WCS over time.

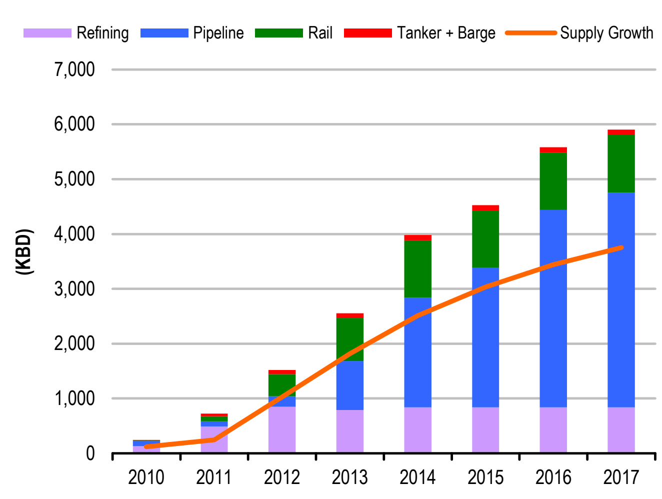
- We note that much of the growth in production is happening in PADD3 (Gulf Coast), particularly if we add in the offshore Gulf. Thus far, the "mid-con" exposed names have been able to generate super normal returns which should fade (but remain healthy) as infrastructure is built out. Over time, it seems more likely that the Gulf Coast will become a more advantaged region, given supply trends.

Exhibit 52: Growth in Oil Production by PADD (excluding the Offshore)



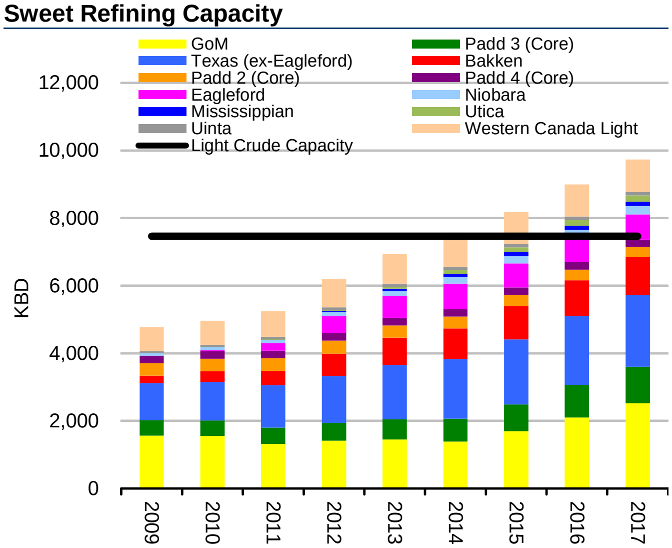
Source: Company data, Credit Suisse estimates

Exhibit 53: Padd 2+4 Export Infrastructure vs Supply



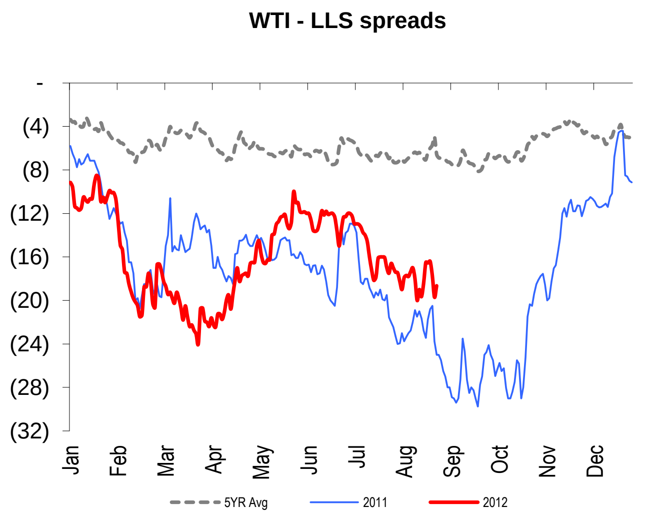
Source: Company data, Credit Suisse estimates

Exhibit 54: Light Sweet Crude Supply vs Padd 2,3,4 Light Sweet Refining Capacity



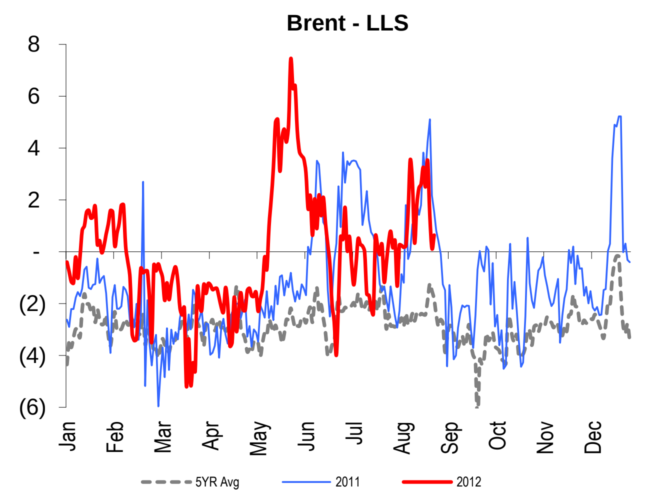
Source: Company data, Credit Suisse estimates

Exhibit 55: WTI vs LLS ($/bbl)



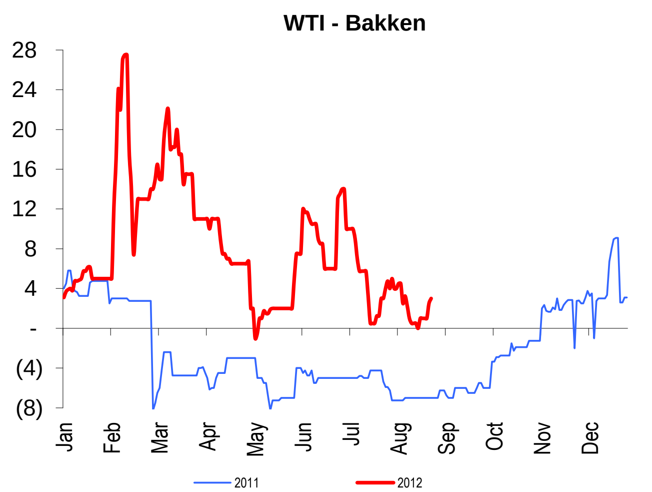
Source: EIA

Exhibit 56: LLS vs Brent ($/bbl)



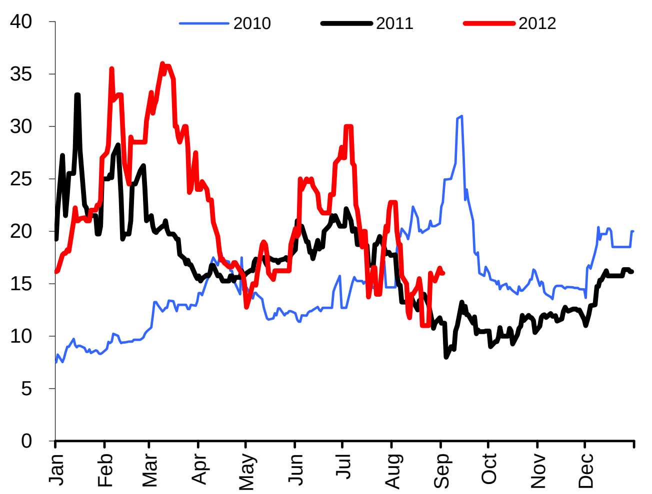
Source: EIA

Exhibit 57: Bakken vs WTI ($/bbl)



Source: EIA

Exhibit 58: WTI vs WCS ($/bbl)



Source: EIA

Exhibit 59: Credit Suisse Commodity Differentials Forecasts

	1Q12A	2Q12A	3Q12E	4Q12E	2012E	2013E	2014E	LT
WTI - LLS	-$16.53	-$15.08	-$12.00	-$14.00	-$14.40	-$6.50	-$5.00	-$4.50
WTI - Brent	-$15.69	-$15.52	-$11.00	-$13.00	-$13.80	-$5.50	-$4.00	-$6.00
WTI - WTS	$3.62	$5.32	$4.00	$4.00	$4.24	$3.00	$2.50	$2.50
Brent - LLS	-$0.84	$0.44	-$1.00	-$1.00	-$0.60	-$1.00	-$1.00	$1.50
WTI - WCS	$26.97	$19.87	$26.00	$26.00	$24.71	$22.50	$21.38	$19.00
WTI - Bakken	$12.14	$6.55	$8.00	$8.00	$8.67	$8.00	$7.50	$7.00
LLS - MAYA	$10.58	$9.36	$11.00	$11.00	$10.48	$11.50	$12.25	$13.00
LLS - MARS	$4.16	$4.17	$5.00	$5.00	$4.58	$5.00	$5.00	$5.00

Source: Company data, Credit Suisse estimates

Exhibit 60: Pipeline and Rail Capacity for Export from the Mid-Con Region. Please note this EXCLUDES pipes that are "intra-regional" e.g. pipes from the Bakken to Cushing, and from Chicago to Cushing.

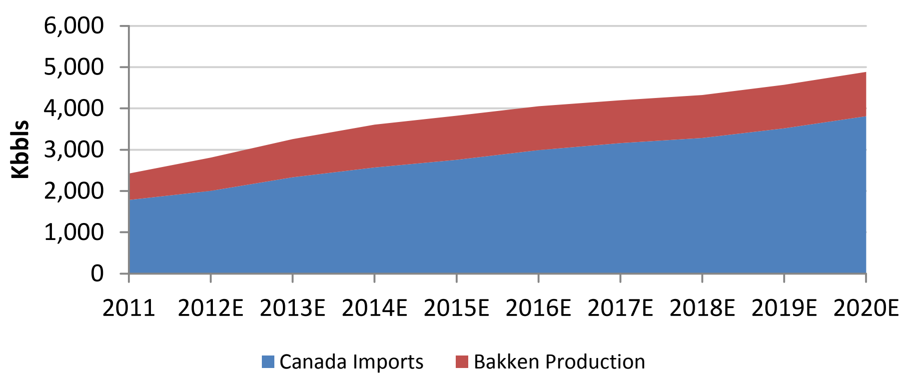
	2009	2010	2011	2012E	2013E	2014E	2015E	2016E	2017E
Pipeline Exports									
- Enbridge Monarch									
- Keystone XL						470	500	500	500
- Kinder Morgan TMX 3 (Southern Expansion)								80	400
- Kinder Morgan Northern Leg (Northern Expansion)							100	400	400
- Longhorn					146	235	235	235	235
- Enbridge Northern Gateway								525	525
- Pettus South Reactivation									
- N. Eagle Ford Pipeline Expansion									
- Line 9 reversal to Canada East Coast					50	240	240	240	240
- Arrowhead Expansion									
- Magellan/M3 JV									
- West Texas Gulf					100	100	100	100	100
- Koch Eagle Ford Pipeline									
- NuStar & TexStar Midstream Services									
- Seaway Expansion (Enbridge/EPD) Flanagan South						225	450	600	600
- Seaway reversal				100	400	400	400	400	400
- Pegasus		93	93	93	93	93	93	93	93
- Permian Express					101	150	150	150	150
- Oneok									
- Bridge Tex						87	278	278	278
Tanker/Barge/Truck (PADD 2 to Other Regions)	18	24	69	96	106	116	116	116	116
Rail Off-loading									
- EOG (via Nustar at St James)	0	0	20	73	100	100	100	100	100
HESS - US Development Group (St. James) - 1	0	15	65	65	65	65	65	65	65
HESS - US Development Group (St. James) - 2	0	0	0	16	65	65	65	65	65
- 'Rangeland TSO		0	0	15	30	30	30	30	30
- Additional Terminal in Gulf (Lario Logistics)	0	0	9	110	140	250	250	250	250
- Additional Terminal in Gulf		0	0	0	0	140	140	140	140
- Savage Companies/Kansas City Southern	0	0	0	0	70	70	70	70	70
- Enbridge - Berthold		0	0	10	70	80	80	80	80
- To East Coast	0	0	0	13	25	25	25	25	25
- To West Coast (non TSO)		0	0	0	20	20	20	20	20
- Other		0	0	0	0	0	0	0	0
- Permian Rail Offtake		0	0	100	203	203	203	203	203
Sub Total Pipelines			**93**	**193**	**891**	**2,000**	**2,546**	**3,601**	**3,921**
Sub Total Rail			**94**	**401**	**788**	**1,048**	**1,048**	**1,048**	**1,048**
Sub Total Barge/Truck/Tanker			**69**	**96**	**106**	**116**	**116**	**116**	**116**
Total Export Infrastructure			**256**	**690**	**1,784**	**3,164**	**3,710**	**4,765**	**5,085**

Source: Company data, Credit Suisse estimates

Chicago Could be the Greatest Bottleneck

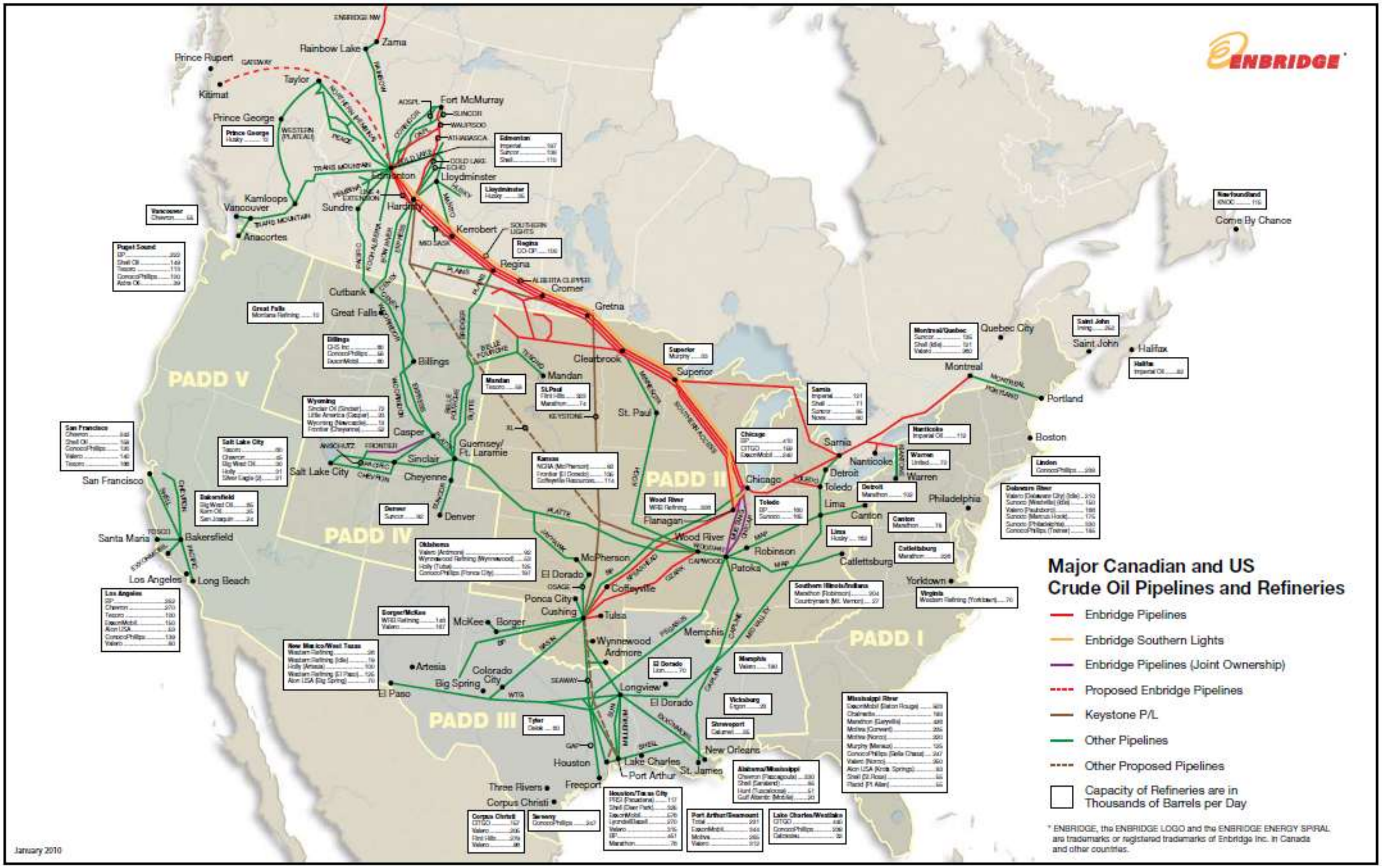
Between now and 2016, Bakken production and Canadian imports could grow by 1500kbd. However, the next major pipes to be built to bring this crude to market are Flanagan South (on-stream 2H14) and Keystone XL which has not yet been approved. Rail capacity will need to fill in the gap in the interim and rail is not cheap. This suggests Bakken and WCS crudes will be discounted relative to Brent for some time.

Exhibit 61: Bakken Production + Canada Imports



Source: CAPP, Credit Suisse estimates

Exhibit 62: North American Pipeline Infrastructure

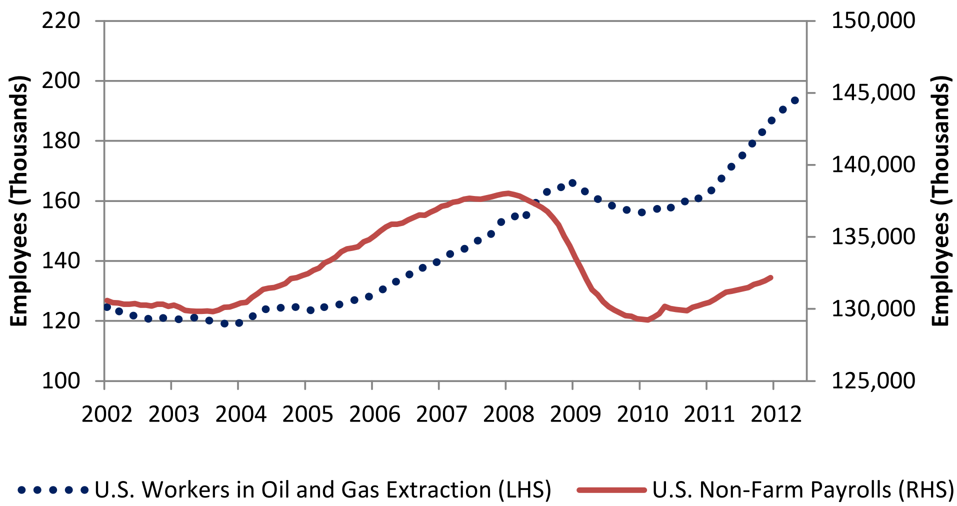


Source: Enbridge

Other Challenges – People are Important

One of the most imminent constraints on the oil and gas industry is people. What some describe as the "graying" of the industry is decreasing the pool of experienced employees at the same time the industry is experiencing robust growth due to the explosion in shale drilling. The number of employees working in oil and gas extraction was relatively resilient throughout 2008-10 compared to overall non-farm payrolls and is up almost 66% over the last 10 years. The failure of operators to plan for future labor demand can lead to unnecessarily high compensation expenses and slow management's ability to take advantage of rising commodity prices.

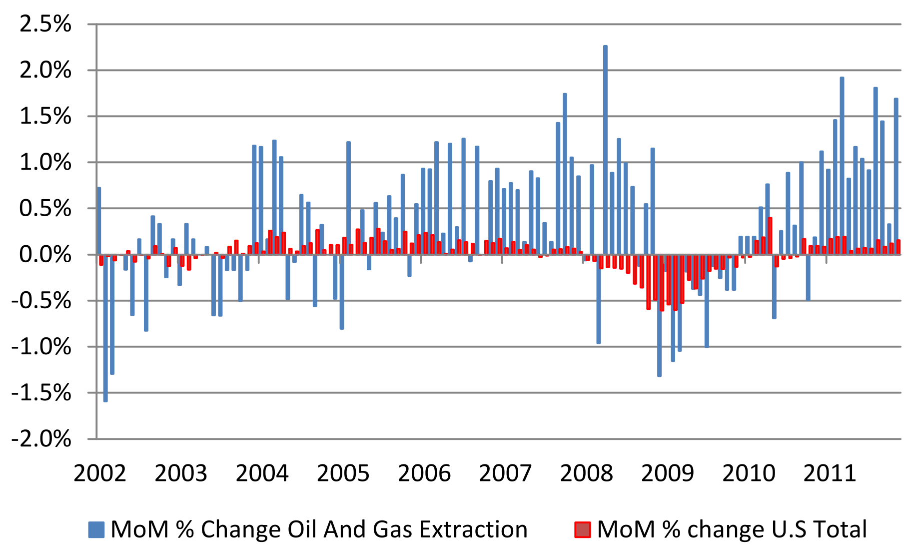
Exhibit 63: U.S. Workers in Oil and Gas Extraction and Total U.S. Non-Farm Payrolls 2002-Present



Source: BLS

Oil and Gas payrolls are up 20% since the beginning of 2008 compared to total U.S. Non-Farm payrolls which are down .4% over the same period.

Exhibit 64: MoM % Change in Payrolls: Oil and Gas vs U.S. Non-Farm Total



Source: BLS

Increased Regulation could Slow Current Production Growth.

The invention of fracing technology has allowed the U.S. to produce shale deposits that were previously thought to be uneconomic. Though this new technological has transformed the U.S. energy supply outlook, it also increased public scrutiny of the practice and concerns over the pollution of water supplies has state governments taking a hard look at increasing regulations on the industry to ensure the safe application of fracing. The two most important issues facing an operator is the need to effectively case and segregate the well from any fresh water aquifers nearby, and the safe disposal of flowback water collected after fracing operations are complete.

Water: When a well is cased and cemented correctly there is very little risk of fracing fluids contaminating water tables which are usually 5,000ft or more above the production casing. The larger issue is how to deal with the large amount of flowback water that is produced during the fracing process. A 2007 study by the U.S. Department of Energy estimated that 2.3 billion gallons of produced water is generated every day. This number is likely much higher now after the explosion in the use of horizontal fracturing which requires up to 5 million gallons of water per well. Recent accidental discharges of brine into nearby water reservoirs in Pennsylvania have brought this issue into the spotlight. The industry needs to develop consistent water management methods and disposal options if it wants to avoid potentially onerous regulation by states, which could curtail the rapid growth in horizontal drilling.

Other risks could include gas flaring, notably in the Bakken.

OCTG Availability

The envisaged growth in wells drilled, and rig count over the next 10 years should translate favourably into increased demand for oil country tubular goods OCTG (pipes and casings). In aggregate (assuming that Chinese players remain out of the high end market for the next 10 years) we see a premium OCTG capacity from 2.06mt in 2011 to 4.2mt in 2018/19. With all the global capacity coming online, a global growth rate CAGR in demand for premium OCTG products of c9% will be necessary to balance the market for the first 5 years, slowing to c4% thereafter. We therefore see limited risk of shortage over the next 4 years, but beyond 2017, there could be potential shortages if premium OCTG globally grows above 3-4% (absent further capacity increases) i.e. if North America remains strong and global shale takes off.

A Word on Recovery Factors, A Key Longer Term Uncertainty

This section comes with many caveats. We have used data sources from the USGS, from EIA, from the IPAA and a number of other sources to build up a consensus on the original oil in place in new shale plays so that we can have a stab at the recovery factors implied in our model. We have also taken a stab at the percentage of acreage that will be drilled under our assumptions (perhaps a more reliable comparison). Some definitions:

Original Oil in Place: The amount of oil estimated to be in a volume of rock. Oil in place is a function of following variables:

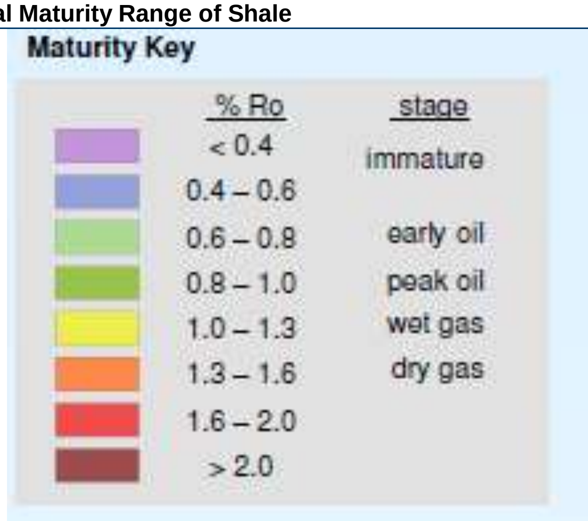
1) The total organic carbon contained in rock (% weight),

2) the vitrinite reflectance (%Ro) or the thermal maturity of the organic material

3) Thickness of the rock that contains this organic matter and total horizontal acreage of the play.

4) Porosity and permeability of the rock. The measure of the empty space in a material and the ability of the material to transmit fluids.

Exhibit 65: Thermal Maturity Range of Shale



Source: Utah Department of Natural Resources

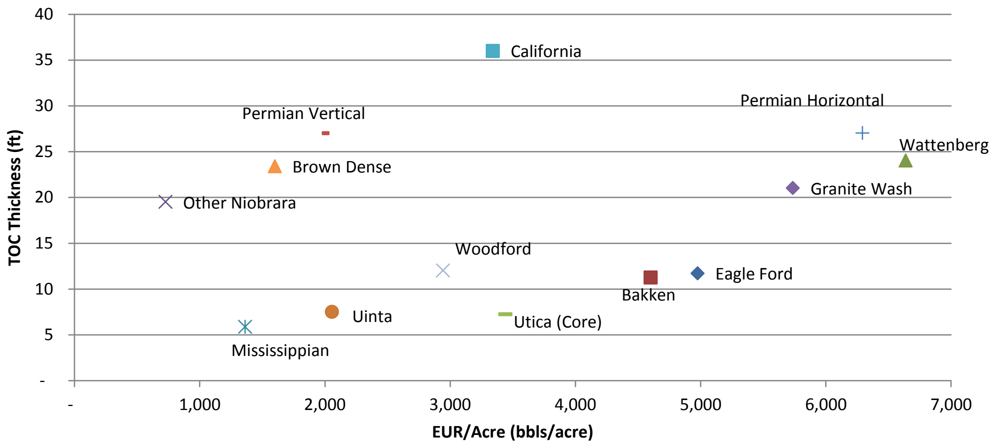
Technically Recoverable Reserves: The amount of oil that can be recovered with current technology. This is a moving target as technology advances and is often revised upwards over time.

Recovery Factor: Technically Recoverable Reserves / Original Oil in Place.

An example – the Eagle Ford: The Eagle Ford shale is one of the most prolific shale plays in the U.S. with over 200 rigs working, and IRR's estimated to be 50-100% depending on the window being drilled. The USGS estimates a pay zone of between 60-300ft thick across the play with a total organic carbon content of between 6%-7% which is considered excellent. The last USGS study on the Eagle Ford in 2008 estimates technically recoverable reserves at close to 12Bn barrels of oil equivalent. Based on producer estimates of oil in place there could be close to 200Bn barrels trapped in Eagle Ford rocks. In our model, 28.5Bn barrels are recovered by 2032 which while significant, would only be a 15% recovery factor, leading us to believe our number could be in the right ballpark.

In the following chart we show estimates of the oil in place by play from various sources against a theoretical calculation based on total oil content and play thickness. This highlights the Permian and California as potential outliers where more resources could be developed over time versus our models, if the source code is cracked.

Exhibit 66: A Proxy for Oil in Place versus Potential EUR



Source: USGS, Credit Suisse estimates

High "TOC x Thickness" in California and the Permian suggests resource upside over time with technological progress.

We include the following table of Original Oil in Place, mainly for reference purposes. In our opinion, available liquids rich acreage and acre spacing provide a more reliable determinant of production, which we discuss below.

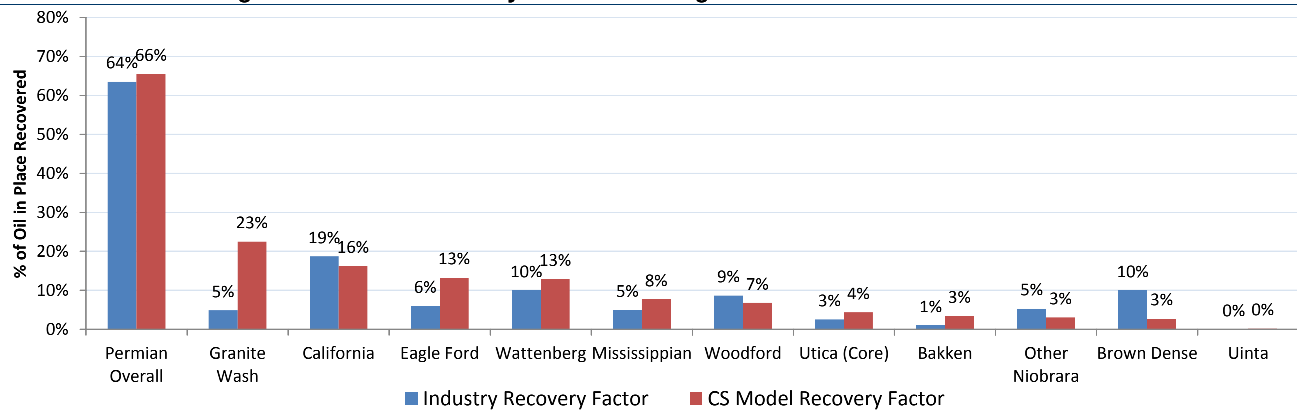
Exhibit 67: Summary Table: Play Depth, TOC, Play Thickness

Play	Average Play Depth (ft)	Average Pay Zone Thickness (ft)	Total Organic Content (TOC%)	Estimated Oil In Place (MMBOE)	Comment
Eagle Ford	9,000	180	7%	193,967	EIA and Global Geophysical Services
Bakken	9,500	75	15%	400,000	USGS
Wattenberg	9,000	800	3%	29,340	USGS
Other Niobrara	9,000	650	3%	104,000	USGS
Mississippian	5,500	300	2%	50,781	USGS
Uinta	14,500	300	3%	1,318,964	Utah Department of Natural Resources
Permian Horizontal	8,500	450	6%	95,000	Advanced Resources Int., Oil and Gas Journal
Permian Vertical	8,500	450	6%	95,000	Advanced Resources Int., Oil and Gas Journal
Utica (Core)	6,500	300	3%	18,000	EIA and Global Geophysical Services
Granite Wash	12,000	300	7%	36,000	EIA
California (Other)	10,300	800	5%	34,625	EIA, OXY
California (OXY)	10,300	800	5%	34,625	EIA, OXY
Brown Dense	9,800	425	6%	30,000	AAPG
Woodford	9,000	200	6%	53,880	EIA

Source:USGS,EIA, Global Geophysical Services, OXY, American Association of Petroleum Geologists, Credit Suisse Estimates. For the Permian OOIP we use the same figure for vertical as horizontal. (**) Although the whole Uinta basin is estimated to have a large oil in place, the challenge is the waxy nature of the crude which makes processing and logistics expensive.

We compare our estimates of produced recovered resource from each play with the USGS estimates of Original Oil in Place (OOIP) in the following chart. This is not a reliable scientific chart, but for indicative purposes. It shows the recovery factors from shale are generally less than 15%. The Permian is an exception given the long history of production from the region and multi layered thickness. Our recovery factors are generally above industry estimates but the industry data, like this report, represents a fast moving target given technological change.

Exhibit 68: Recovery Factor by Play According to Industry Estimates. Note the Industry Recovery factor is Industry Recovered Resource / Industry Original Oil in Place (OOIP). The Credit Suisse Recovery Factor is based on our produced resources against the same industry estimate of Original Oil in Place



Source: Company data, Credit Suisse estimates, USGS,consumer energy report, HIS Energy, Rose Exploration, US Department of Energy.

Core Acreage May Be a Better Proxy For Resource Depth

On an acreage basis, by 2030, our model is drilling 72-85% of the Eagle Ford and Bakken, and a lower but significant share of remaining basins overall - the Uinta, Other Niobrara, Permian (Horizontal), California (permitting/geology), Brown Dense and Utica (both early plays). The following table and maps show:

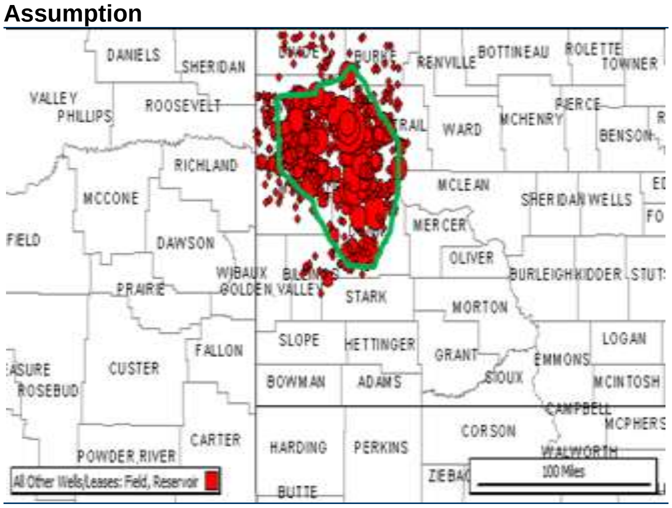
- The acres that our rig count drills out based on the acre spacing shown. Note we assume improvement in acre spacing per well for most plays to give credit for “downspacing”. There could be upside to our Bakken forecasts if downspacing is successful.
- Effective acreage is our estimate for the liquids rich sweetspot in each play where current IP rates can be sustained over time.
- Ultimately the rig count will depend on cashflow availability (i.e. Oil price and capital markets), animal spirits and technical success. Constraining our model to a 2030 drill out could prove conservative for NPV maximizing entrepreneurs.

Exhibit 69: Summary Table: Play Acreage, Spacing and Percentage Drilled

Play	Acres Drilled Through 2030	Acre Spacing	Effective Acreage	Total Acreage	% of Effective Acreage Drilled
Eagle Ford	3,244,431	80	3,813,750	12,800,000	85%
Bakken	2,200,152	130	3,072,000	12,654,000	72%
Wattenberg	920,985	60	1,191,357	1,191,357	77%
Other Niobrara	1,367,935	160	2,552,909	2,552,909	54%
Mississippian	1,456,736	120	3,188,927	6,500,000	46%
Uinta	901,982	160	1,935,728	10,786,202	47%
Permian Horizontal	3,172,157	80	5,138,441	5,138,441	62%
Permian Vertical	3,492,768	40	9,210,958	42,861,559	38%
Utica (Core)	899,449	80	1,758,678	108,800,000	51%
Granite Wash	1,248,640	80	1,422,222	1,536,000	88%
California (Other)	284,188	40	544,712	544,712	52%
California (OXY)	698,939	80	1,600,000	1,600,000	44%
Brown Dense	236,437	160	1,666,116	2,560,000	14%
Woodford	948,906	160	1,580,247	3,448,320	60%

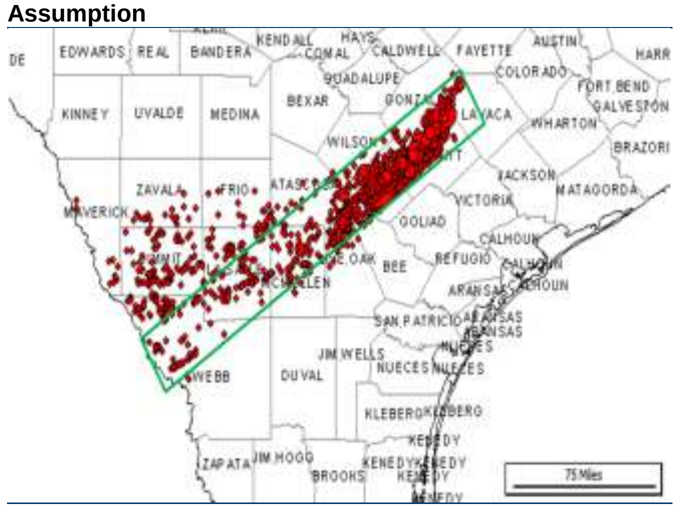
Source: USGS, EIA, company data, Credit Suisse Estimates

Exhibit 70: Bakken Liquids Rich Effective Acreage Assumption



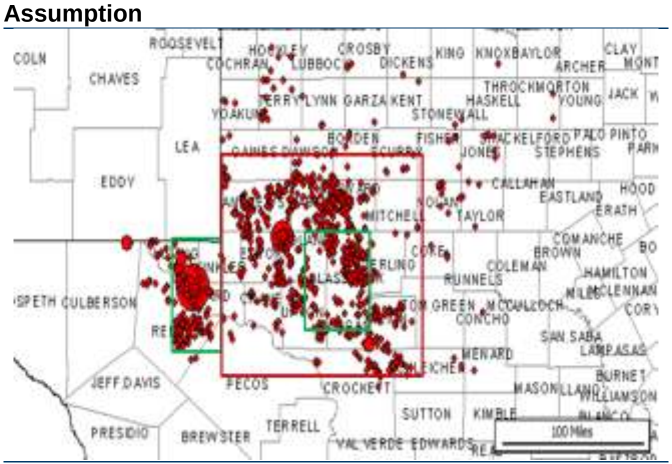
Source: HPDI, Credit Suisse estimates

Exhibit 71: Eagle Ford Liquids Rich Effective Acreage Assumption



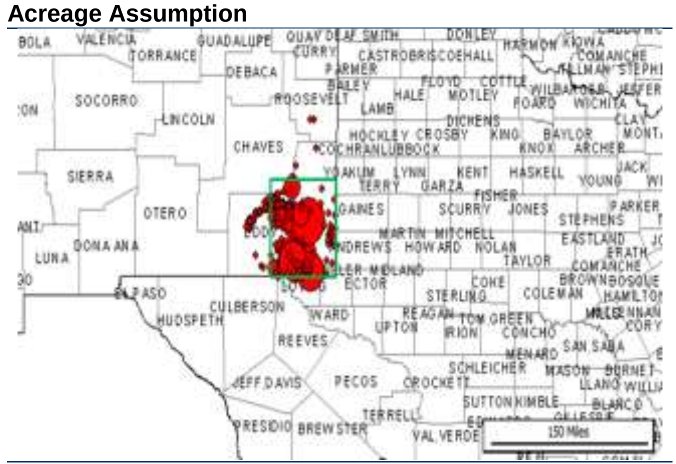
Source: HPDI, Credit Suisse estimates

Exhibit 72: Permian Liquids Rich Effective Acreage Assumption



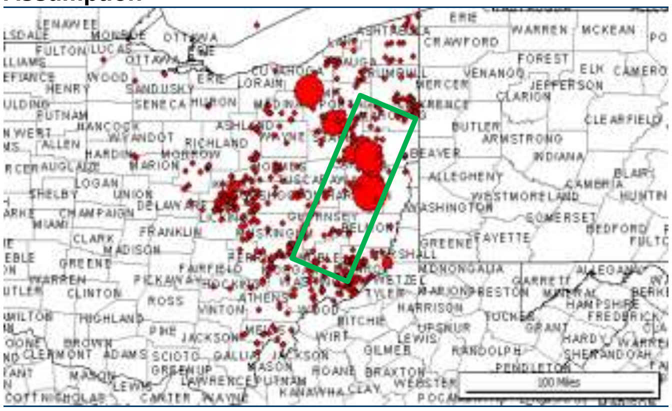
*Source: HPDI, Credit Suisse estimates *Red box is Vertical Acreage and Green Boxes are Horizontal Acreage*

Exhibit 73: New Mexico Permian Liquids Rich Effective Acreage Assumption



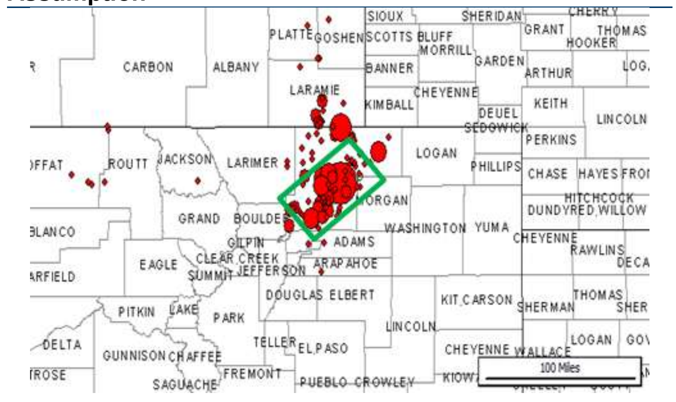
Source: HPDI, Credit Suisse estimates

Exhibit 74: Utica Liquids Rich Effective Acreage Assumption



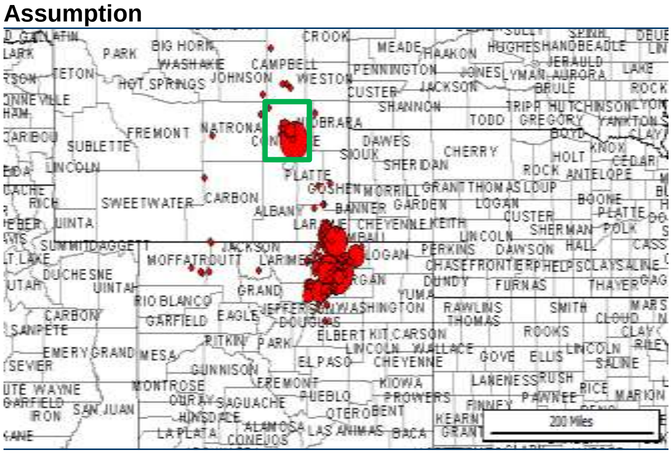
Source: HPDI, Credit Suisse estimates

Exhibit 75: Wattenberg Liquids Rich Effective Acreage Assumption



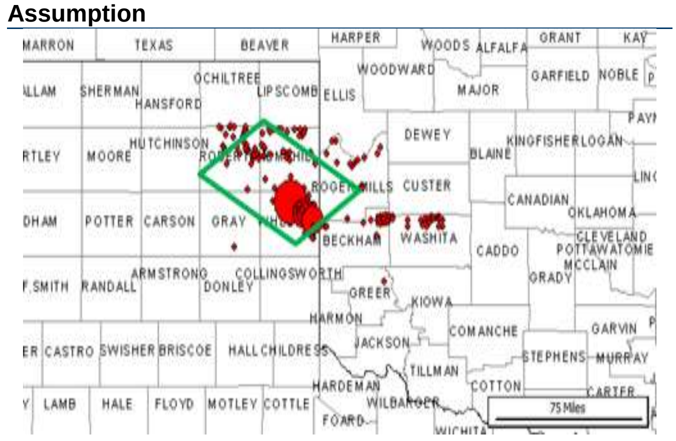
Source: HPDI, Credit Suisse estimates

Exhibit 76: Other Niobrara Liquids Rich Effective Acreage Assumption



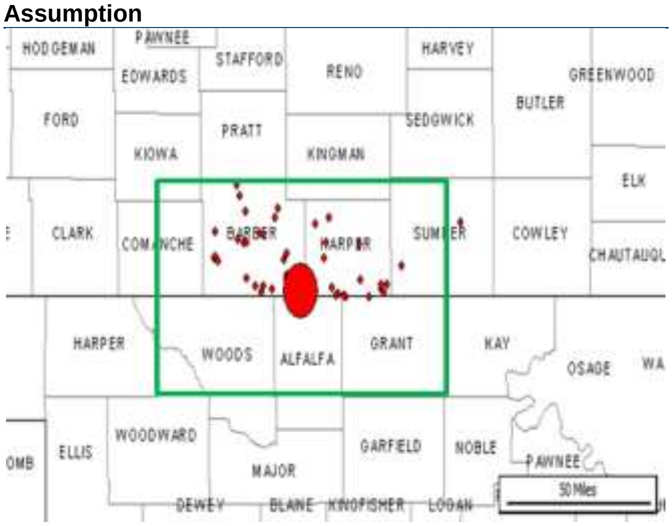
Source: HPDI, Credit Suisse estimates

Exhibit 77: Granite Wash Liquids Rich Effective Acreage Assumption



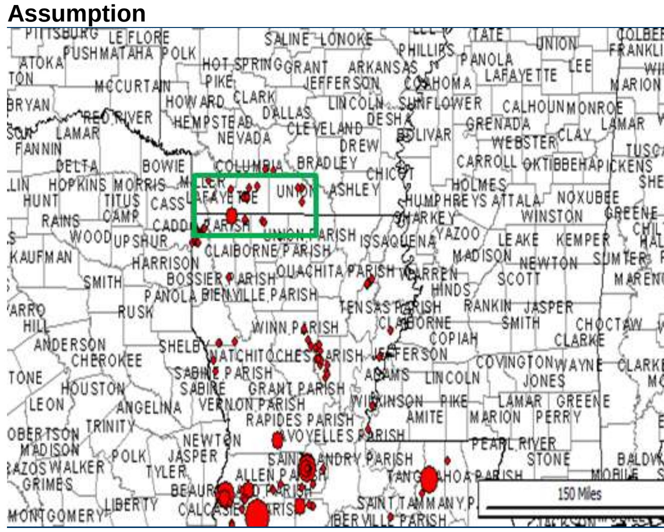
Source: HPDI, Credit Suisse estimates

Exhibit 78: Mississippian Liquids Rich Effective Acreage Assumption



Source: HPDI, Credit Suisse estimates

Exhibit 79: Browne Dense Liquids Rich Effective Acreage Assumption

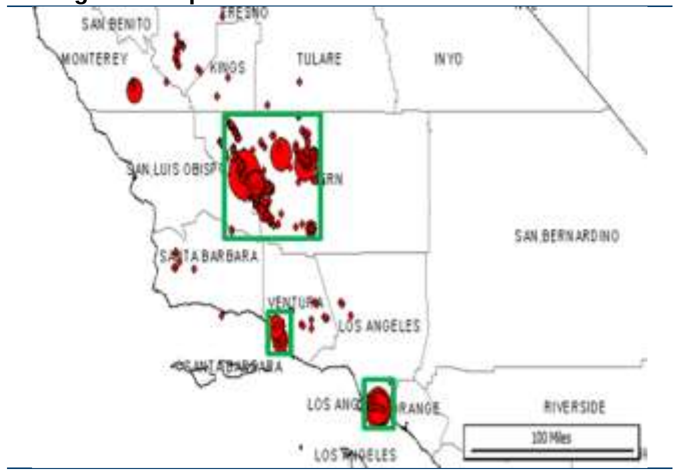


Source: HPDI, Credit Suisse estimates

Exhibit 80: California HZ Liquids Rich Effective Acreage Assumption

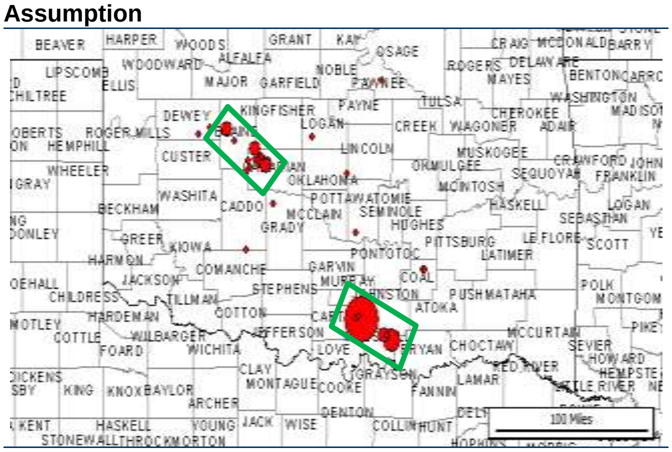
Source: HPDI, Credit Suisse estimates

Exhibit 81: California Vertical Liquids Rich Effective Acreage Assumption



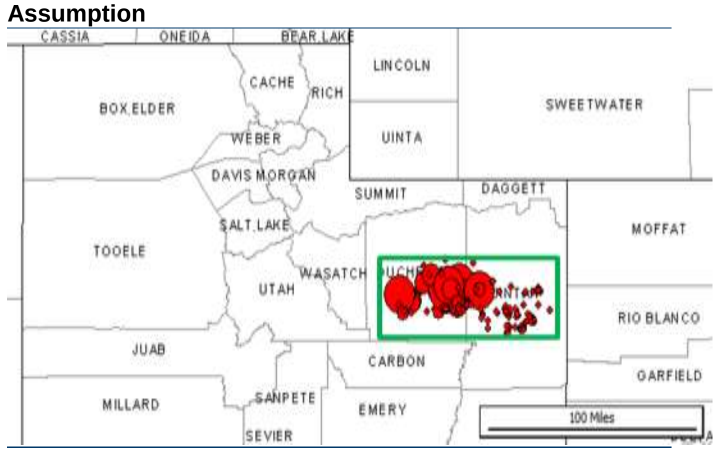
Source: HPDI, Credit Suisse estimates

Exhibit 82: Woodford Liquids Rich Effective Acreage Assumption



Source: HPDI, Credit Suisse estimates

Exhibit 83: Uinta Liquids Rich Effective Acreage Assumption



Source: HPDI, Credit Suisse estimates

Exhibit 84: Summary Table: U.S. Oil Production Potential By State

Total US Production by State

	Location	2010	2011	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
U.S. Field Production of Crude Oil (Thousand Barrels)	**US**	**5482**	**5676**	**6456**	**7137**	**7692**	**8452**	**8998**	**9457**	**9792**	**9992**	**10179**	**10357**	**10532**
East Coast (PADD 1) Field Production of Crude Oil (Thousand Barrels)	**PADD 1**	**20**	**22**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**
Florida Field Production of Crude Oil (Thousand Barrels)	Florida	5	6	6	6	6	6	6	6	6	6	6	6	6
New York Field Production of Crude Oil (Thousand Barrels)	New York	1	1	1	1	1	1	1	1	1	1	1	1	1
Pennsylvania Field Production of Crude Oil (Thousand Barrels)	Pennsylvania	10	10	12	12	12	12	12	12	12	12	12	12	12
Virginia Field Production of Crude Oil (Thousand Barrels)	Virginia	0	0	0	0	0	0	0	0	0	0	0	0	0
West Virginia Field Production of Crude Oil (Thousand Barrels)	West Virginia	4	5	5	5	5	5	5	5	5	5	5	5	5
Midwest (PADD 2) Field Production of Crude Oil (Thousand Barrels)	**PADD 2**	**686**	**817**	**1178**	**1384**	**1575**	**1667**	**1687**	**1707**	**1755**	**1812**	**1868**	**1925**	**1981**
Illinois Field Production of Crude Oil (Thousand Barrels)	Illinois	25	25	27	28	29	30	31	32	32	32	32	32	32
Indiana Field Production of Crude Oil (Thousand Barrels)	Indiana	5	5	5	5	5	5	5	5	5	5	5	5	5
Kansas Field Production of Crude Oil (Thousand Barrels)	Kansas	111	114	124	133	139	142	131	119	112	107	103	100	98
Kentucky Field Production of Crude Oil (Thousand Barrels)	Kentucky	7	6	6	6	6	6	6	6	6	6	6	6	6
Michigan Field Production of Crude Oil (Thousand Barrels)	Michigan	19	18	18	18	18	18	18	18	18	18	18	18	18
Missouri Field Production of Crude Oil (Thousand Barrels)	Missouri	0	0	0	0	0	0	0	0	0	0	0	0	0
Nebraska Field Production of Crude Oil (Thousand Barrels)	Nebraska	6	7	7	7	7	7	7	7	7	7	7	7	7
North Dakota Field Production of Crude Oil (Thousand Barrels)	North Dakota	310	419	726	896	1035	1081	1082	1061	1068	1089	1114	1139	1166
Ohio Field Production of Crude Oil (Thousand Barrels)	Ohio	13	13	19	39	68	104	146	195	233	265	294	321	347
Oklahoma Field Production of Crude Oil (Thousand Barrels)	Oklahoma	186	204	240	246	262	268	255	258	268	277	284	290	296
South Dakota Field Production of Crude Oil (Thousand Barrels)	South Dakota	4	4	4	4	4	4	4	4	4	4	4	4	4
Tennessee Field Production of Crude Oil (Thousand Barrels)	Tennessee	1	1	1	1	1	1	1	1	1	1	1	1	1
Gulf Coast (PADD 3) Field Production of Crude Oil (Thousand Barrels)	**PADD 3**	**3190**	**3277**	**3708**	**4136**	**4444**	**5064**	**5548**	**5970**	**6248**	**6390**	**6520**	**6645**	**6768**
Alabama Field Production of Crude Oil (Thousand Barrels)	Alabama	19	23	25	30	35	40	45	50	55	60	65	70	75
Arkansas Field Production of Crude Oil (Thousand Barrels)	Arkansas	16	16	19	24	29	34	39	44	49	54	59	64	69
Louisiana Field Production of Crude Oil (Thousand Barrels)	Louisiana	185	189	184	189	198	231	289	429	508	561	600	633	664
Mississippi Field Production of Crude Oil (Thousand Barrels)	Mississippi	65	64	64	66	68	70	72	74	76	78	80	82	84
New Mexico Field Production of Crude Oil (Thousand Barrels)	New Mexico	179	196	216	252	284	317	343	372	396	417	438	458	478
Texas Field Production of Crude Oil (Thousand Barrels)	Texas	1176	1474	1864	2201	2507	2762	2918	3018	3128	3245	3363	3479	3595
Federal Offshore--Gulf of Mexico Field Production of Crude Oil (Thousand Barrels)	GoM - Offshore	1551	1316	1337	1374	1323	1609	1842	1982	2036	1975	1916	1858	1802
Rocky Mountain (PADD 4) Field Production of Crude Oil (Thousand Barrels)	**PADD 4**	**372**	**395**	**438**	**511**	**601**	**681**	**753**	**800**	**838**	**867**	**891**	**911**	**928**
Colorado Field Production of Crude Oil (Thousand Barrels)	Colorado	89	107	130	196	280	358	433	485	526	557	583	604	621
Montana Field Production of Crude Oil (Thousand Barrels)	Montana	69	66	69	70	72	72	72	72	72	72	73	73	73
Utah Field Production of Crude Oil (Thousand Barrels)	Utah	68	72	80	91	101	108	111	114	117	120	124	128	133
Wyoming Field Production of Crude Oil (Thousand Barrels)	Wyoming	146	150	160	153	147	143	136	130	123	117	112	106	102
West Coast (PADD 5) Field Production of Crude Oil (Thousand Barrels)	**PADD 5**	**1214**	**1165**	**1109**	**1081**	**1048**	**1016**	**986**	**957**	**927**	**900**	**875**	**852**	**832**
Alaska Field Production of Crude Oil (Thousand Barrels)	**Alaska**	**601**	**572**	**526**	**510**	**483**	**457**	**432**	**409**	**385**	**363**	**342**	**322**	**303**
Alaska South Field Production of Crude Oil (Thousand Barrels)	Alaska South	10	10	10	10	10	10	10	10	10	10	10	10	10
Alaska North Slope Crude Oil Production (Thousand Barrels)	Alaska North Slope	591	562	516	500	472	446	422	399	375	353	332	312	293
Arizona Field Production of Crude Oil (Thousand Barrels)	Arizona	0	0	0	0	0	0	0	0	0	0	0	0	0
California Field Production of Crude Oil (Thousand Barrels)	California	552	537	539	535	537	536	535	532	529	527	525	523	523
Nevada Field Production of Crude Oil (Thousand Barrels)	Nevada	1	1	1	1	1	1	1	1	1	1	1	1	1
Federal Offshore California Field Production of Crude Oil (Thousand Barrels)	California - Offshore	54	54	43	35	28	22	18	14	11	9	7	6	5
Total US Field Production		**5,482**	**5,676**	**6,456**	**7,137**	**7,692**	**8,452**	**8,998**	**9,457**	**9,792**	**9,992**	**10,179**	**10,357**	**10,532**
Yoy Growth, KBD		121	194	781	680	555	760	546	459	335	200	187	178	176

Source: EIA, Credit Suisse estimates

For fixed income- and macro-related disclosures, please see page 71.

Equity Research

Focus on Texas

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Texas has been the source of the bulk of near-term onshore oil production growth. Much of this is from the Eagle Ford and Permian where rig counts have rapidly increased.

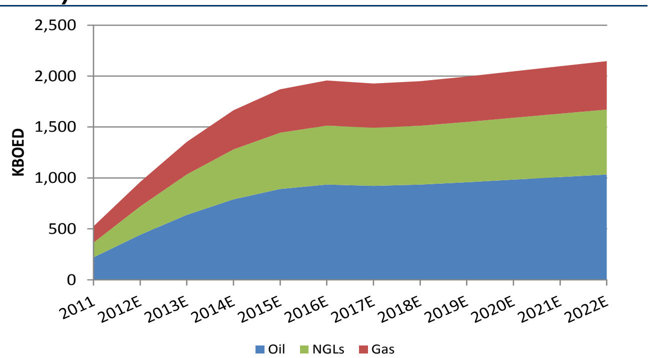
Eagle Ford

The Eagle Ford shale trend covers roughly 20,000 square miles in south Texas, where operators have primarily targeted up dip volatile oil and gas/condensate zones of the play. The Eagle Ford is on average 60'-300' thick at depths of 4,000' (*black oil window*) to 14,000' (*dry gas*) and has a high carbonate content which makes the formation more brittle and ideal for hydraulic fracturing. Operators continue to delineate the play with core areas emerging in the Black Hawk area in Karnes and Dewitt Counties, Texas, in the northeast part of the trend, as well as in Webb County in the southwest.

Sweet spots in the Eagle Ford provide some of the best economics in U.S. onshore E&P, whether its BHP's Black Hawk or ROSE's Gates Ranch area. This point is supported by A&D activity, with the Eagle Ford attracting the best $/acre metrics in the U.S. E&P in 2011, from MRO paying $21k per acre for Hilcorp in June 2011 and APC getting roughly $14k per acre for its JV with KNOC in March 2011. This compares to deals in the Marcellus and Bakken that have valued leasehold in a range of $7-8k per acre (*NBL JV with CNX in the Marcellus and STO/BEXP*). With the build-out of infrastructure in the Eagle Ford, operators are able to get oil and NGLs to Gulf Coast markets where they receive premium pricing relative to WTI and what they have received historically.

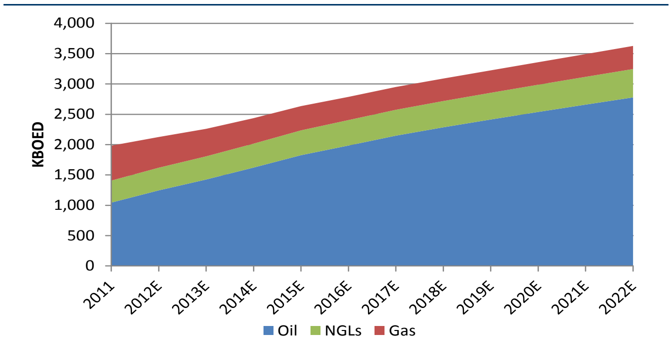
More recently the focus has been on infill spacing opportunities in the Eagle Ford. EOG's 4Q results were highlighted by 8 infill pilot programs (*including 33 wells*) which indicated that 65-90 acre spacing is optimal to maximize resource recovery compared to its prior 130-acre well spacing assumption. ROSE is also encourage by initial down spacing results in Gates Ranch, where it has not encountered any well interference to date on 65-acre spacing but needs more well performance history to determine to what extent infill drilling is accelerating recovery if at all.

Exhibit 85: Eagle Ford Production Outlook by Type (kboed) 6:1 Oil:Gas Ratio



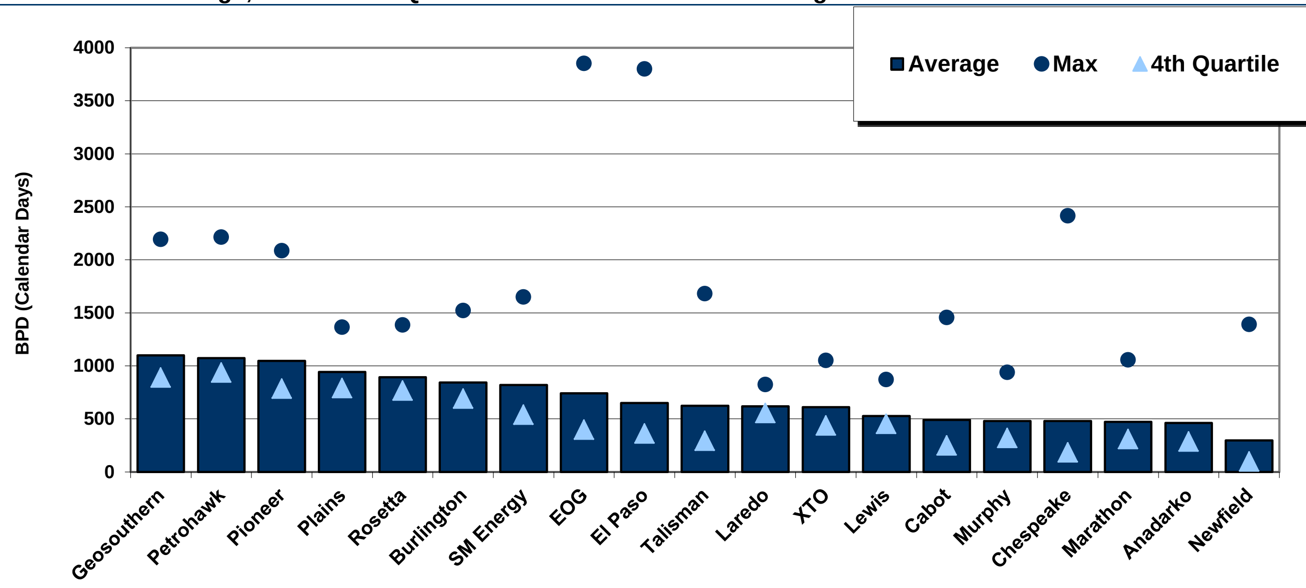
Source: HPDI, EIA, Credit Suisse estimates

Exhibit 86: Permian Production Outlook by Type (kboed), 6:1 Oil:Gas Ratio



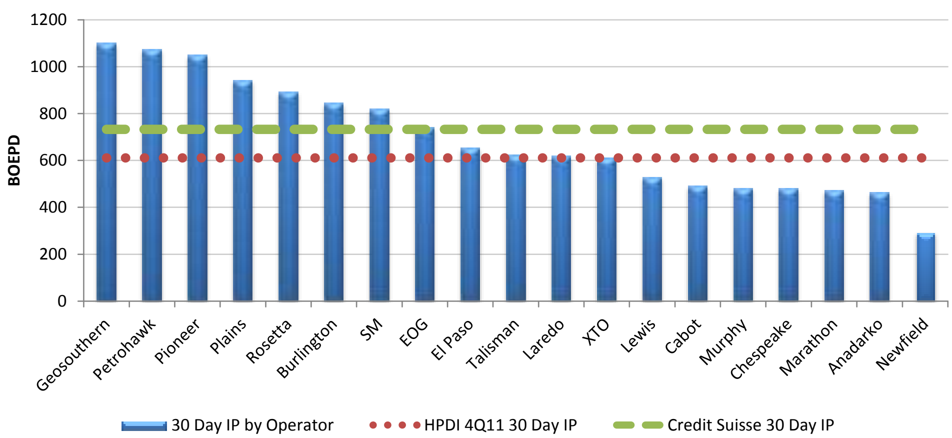
Source: HPDI, EIA, Credit Suisse estimates

Exhibit 87: 2011 Average, Best and 4th Quartile Peak Month Rates in the Eagle Ford at 6:1 Oil:Gas Ratio



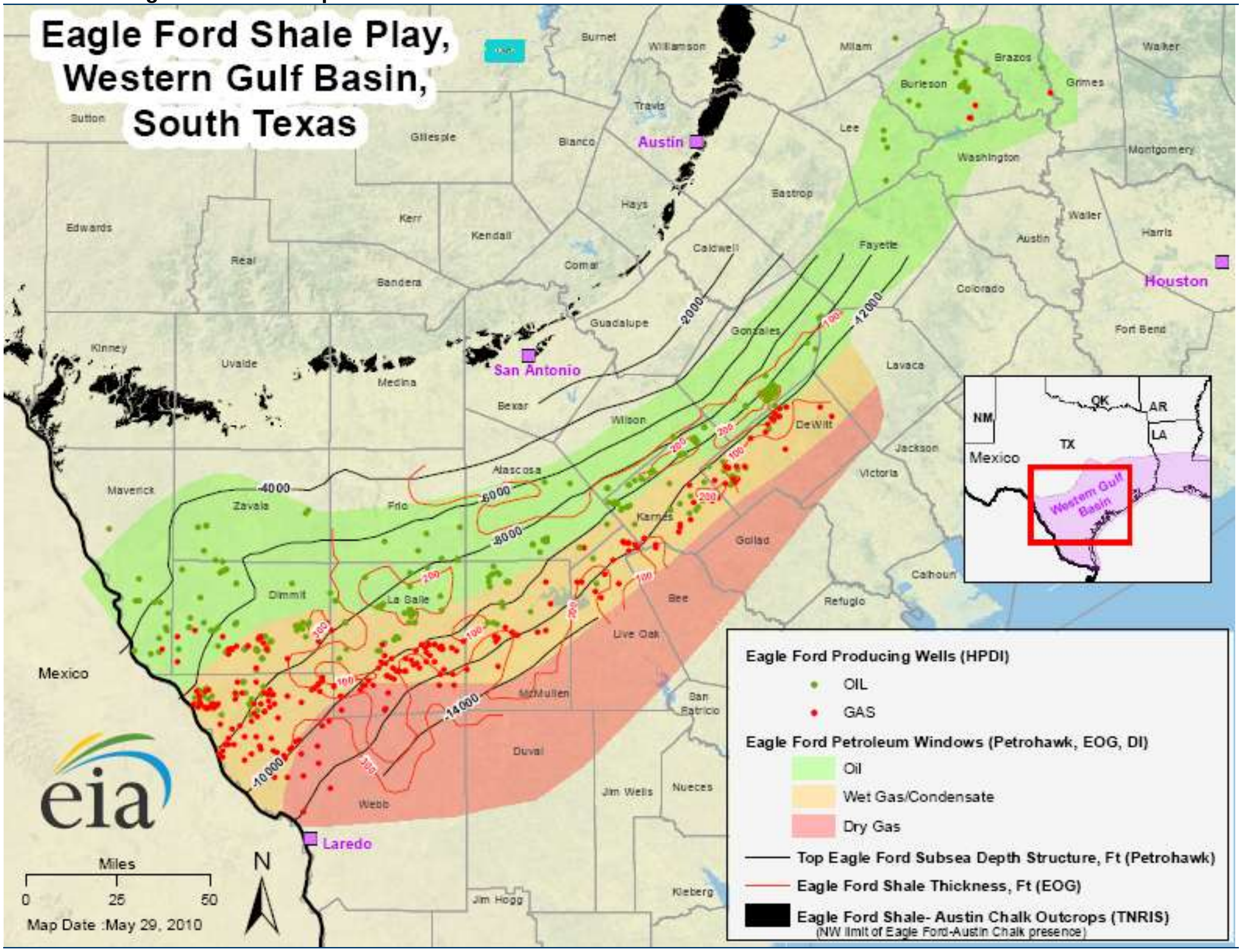
Source: HPDI

Exhibit 88: Eagle Ford: 30 Day IP guidance by Operator, vs 4Q11 HPDI Average 30 Day IP's and Credit Suisse IP Assumption at 6:1 Oil:Gas Ratio



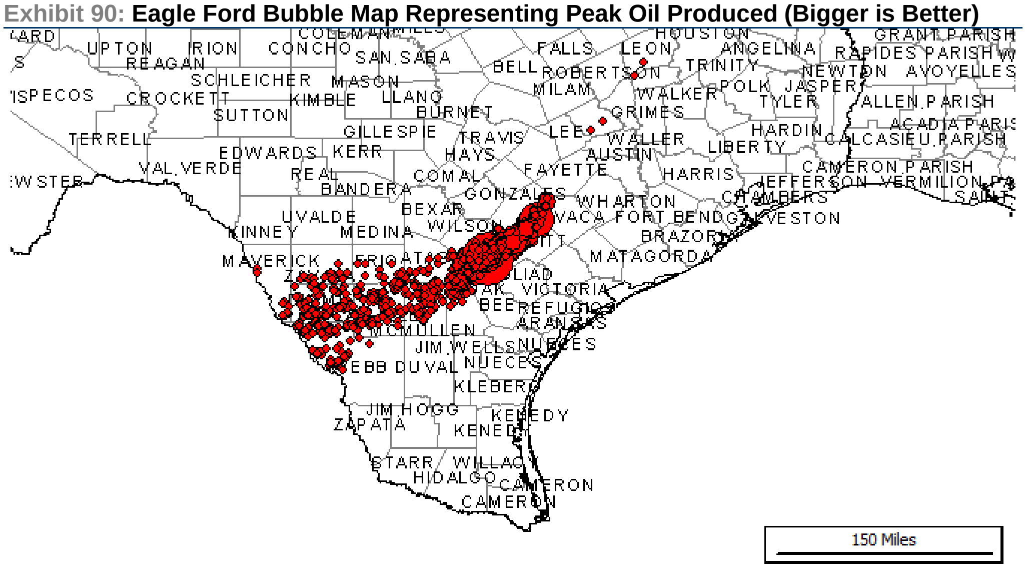
Source: Company data, Credit Suisse estimate, HPDI

Exhibit 89: Eagle Ford Area Map



Source: EIA.

Exhibit 90: Eagle Ford Bubble Map Representing Peak Oil Produced (Bigger is Better)

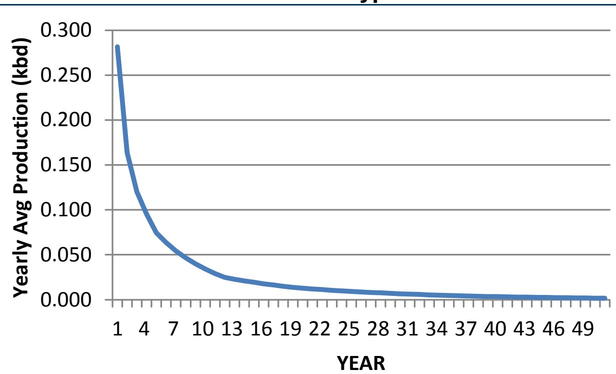


Source: HPDI.

Permian

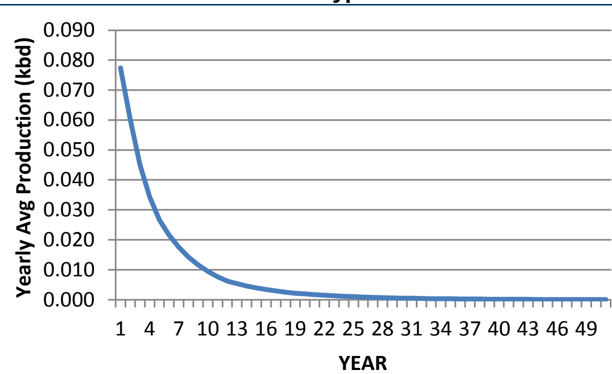
Activity in the Permian Basin is accelerating with the emergence of new unconventional oil and liquids-rich plays. There are ~475 rigs (*100+ horizontal rigs*) from just ~400 rigs in the middle of 2011. The Permian should remain an area of focus in 2012 with a number of new horizontal oil and vertical combination projects being tested. The recent focus in the Permian has been on a number of stacked horizons in the Delaware Basin in southeastern New Mexico and West Texas, as well as in the Midland Basin where operators are targeting the horizontal Cline (*Lower Wolfcamp*) and Wolfcamp.

Exhibit 91: Assumed Horizontal Type Curve



Source: Credit Suisse estimates

Exhibit 92: Assumed Vertical Type Curve



Source: Credit Suisse estimates

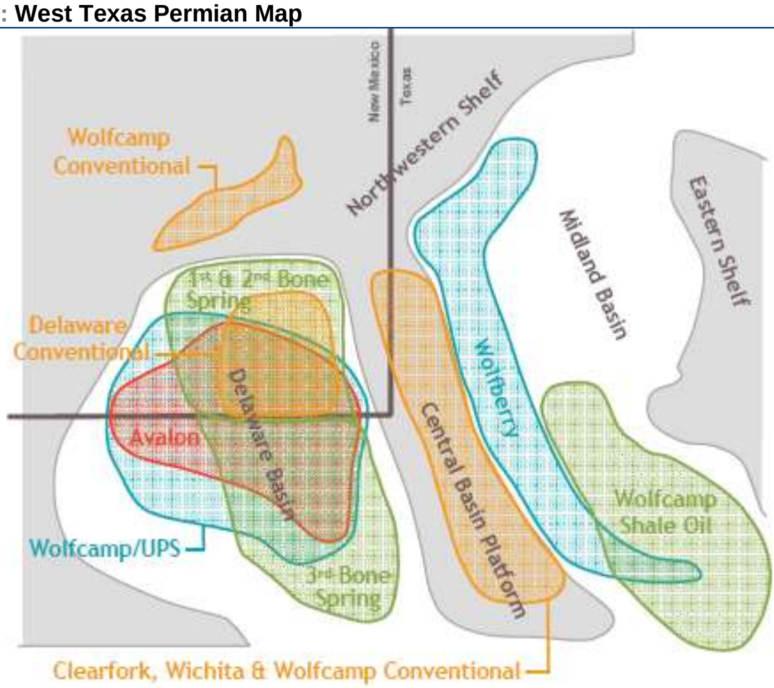
In the Midland Basin, the Wolfcamp shale has been receiving increased attention on the back of improving well results out of EOG and AREX. EOG reported peak initial production of 1,141 Boe/d from five recent Wolfcamp horizontal wells and bumped EUR expectations to 320 MBoe from 270 MBoe in 4Q11. Given strong results in the play EOG is increasing activity from a two-rig operated program in 2011 to four rigs in 2012. AREX, also in the southern Midland Basin, is targeting the vertical Wolffork play as well as the horizontal Wolfcamp. AREX recently delivered its strongest three Wolfcamp horizontal wells to date with average initial production rates of 884 Boe/d and is currently estimating EURs of 450 MBoe.

With recent deals in the Delaware Basin, activity could be on the upswing in the Bone Spring and Wolfcamp as well. In November 2011 CXO paid $330 million for 114k net acres (*primarily in Pecos County, TX*), and in December 2011 CRK bought 44k net acres in Reeves County, TX for $333 million. CXO expects vertical Wolfbone wells costing $4-6 million to recover 200-400 MBoe. At its April 2012 analyst day, DVN highlighted its 1.5 MM acre Permian position with the bulk of 2012 rig activity in the Delaware Basin where 17 hz Bone Spring wells are outperforming the company's 550 MBoe type curve.

The Permian Basin is a conglomerate of stacked conventional and unconventional oil plays spanning 250 by 300 miles throughout West Texas and southeastern New Mexico. It contains 1,339 identified reservoirs, or roughly 29% of the estimated future oil reserve growth in the U.S. The Wolfcamp is one objective within the Permian located in the Delaware Basin that has seen increased activity in recent quarters with EOG, DVN, EP, AREX and BHP/HK acquiring sizeable positions. Most recently, COP made its entry into the Wolfcamp by acquiring leases for approximately $5,600/acre.

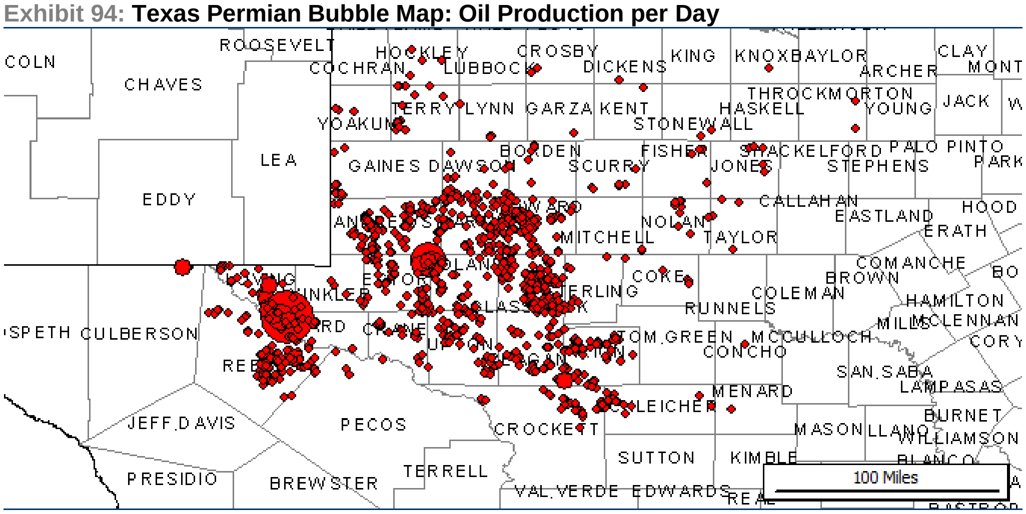
The Permian is poised to remain an area of focus in 2012 with a number of new horizontal oil and vertical combination projects being tested. The recent focus in the Permian has been on a number of stacked horizons in the Delaware Basin in southeastern New Mexico and West Texas, as well as in the Midland Basin where operators are targeting the horizontal Cline (Lower Wolfcamp) and Wolfcamp.

Exhibit 93: West Texas Permian Map



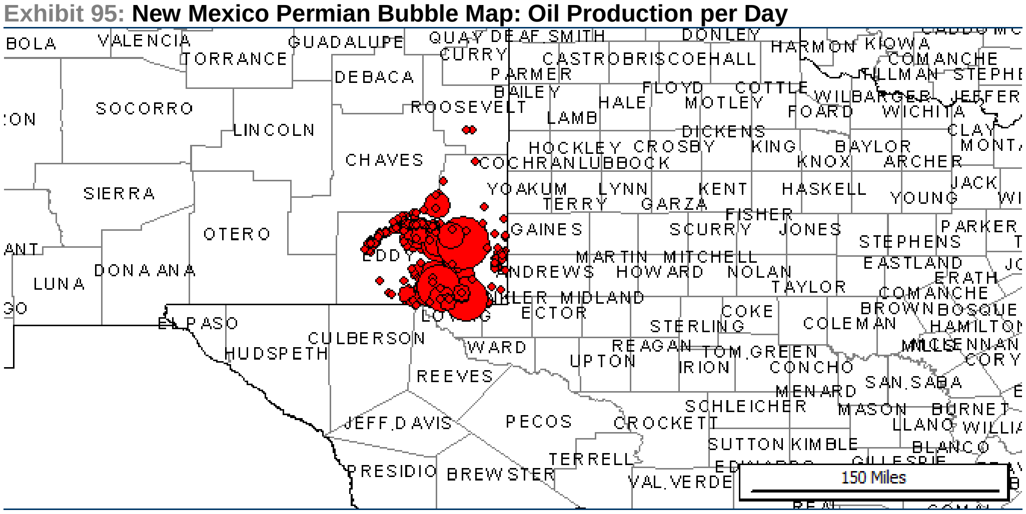
Source: Devon Energy

Exhibit 94: Texas Permian Bubble Map: Oil Production per Day



Source: HPDI

Exhibit 95: New Mexico Permian Bubble Map: Oil Production per Day

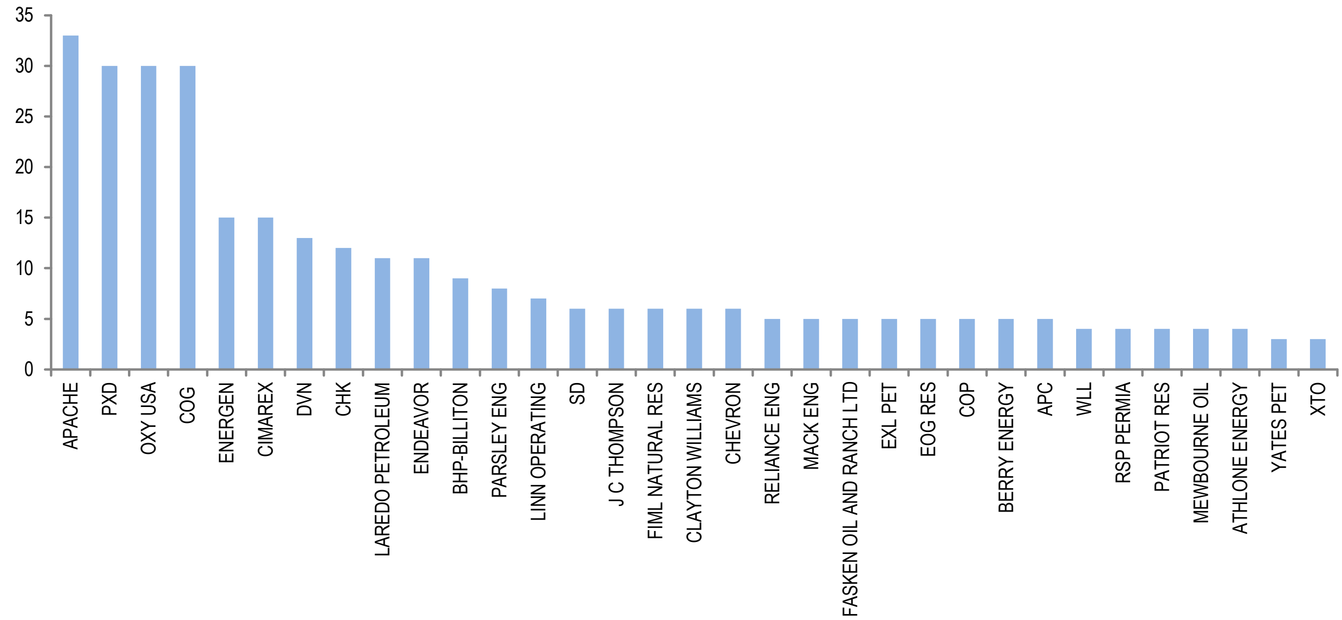


Source: HPDI

The Permian horizontal play stands out as the largest contributor to growth in absolute terms. We note that there is 800kbd of additional oil pipeline export capacity and 200kbd of rail, indicating the Permian is viewed by the industry as a source of volume growth.

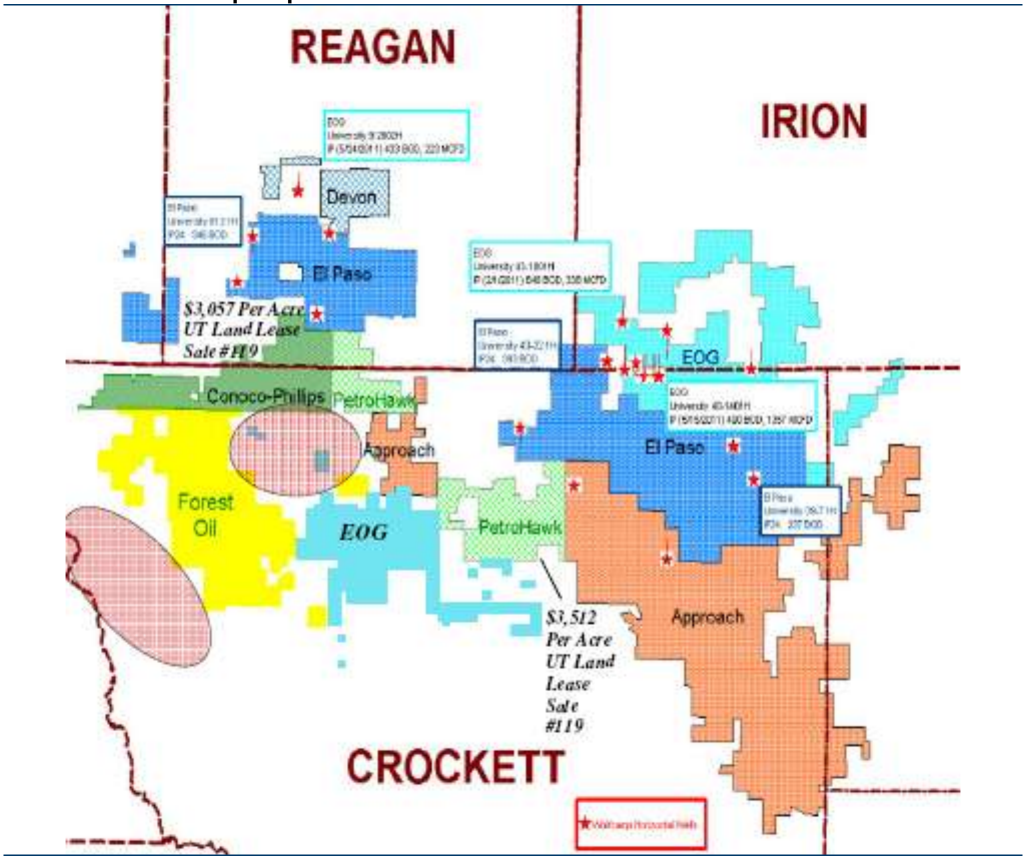
Assuming the rocks support the rig count, there is room to increase when we look at the current list of operators. US majors such as COP, XOM and CVX for example with decent positions are operating with less than 10 rigs apiece.

Exhibit 96: Current Permian Rig Count by Operator



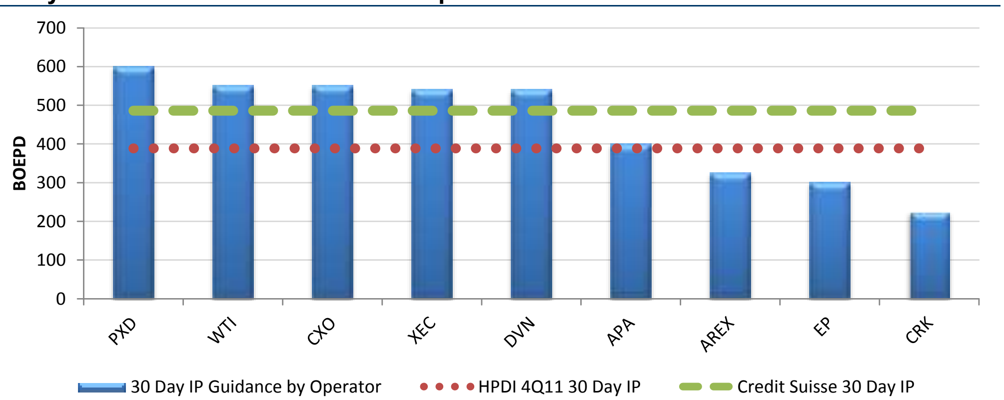
Source: Smith Bits

Exhibit 97: Wolfcamp Map



Source: Forest Oil

Exhibit 98: Permian Horizontal: 30 Day IP Guidance by Operator, vs 4Q11 HPDI Average 30 Day IP's And Credit Suisse IP Assumption at 6:1 Oil:Gas Ratio



Source: Company Data, HPDI, Credit Suisse estimates

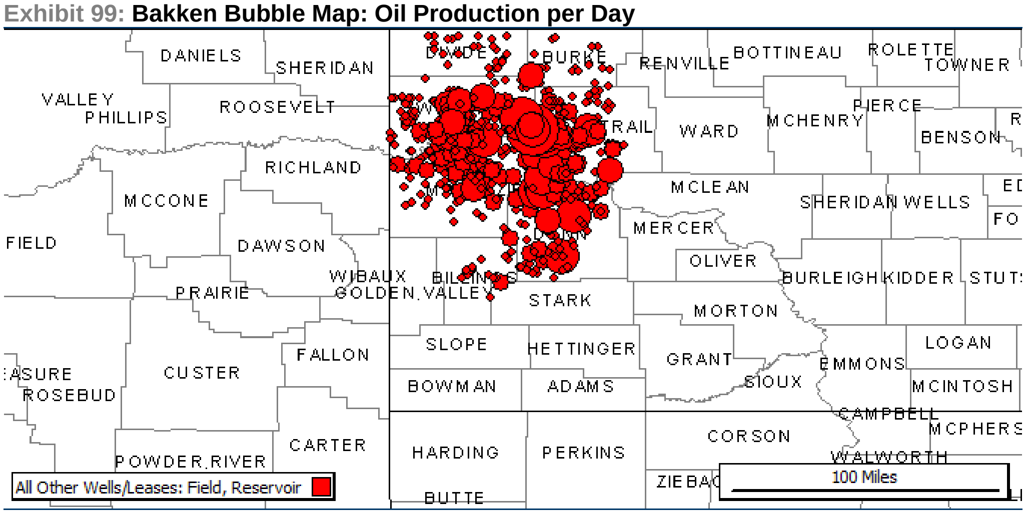
Focus on the Bakken

Bakken / Three Forks

The Bakken is an unconventional oil play spanning over 200,000 square miles through parts of Montana, North Dakota and Saskatchewan. The basin consists of lower shale, middle dolomite and upper shale. Both shale types are organic-rich marine shale. With thickness up to 130 ft, relatively shallow compared to other shale plays, the Bakken is an excellent candidate for horizontal drilling. The Bakken overlies the Devonian-aged Three Forks/Sanish formation, which is prevalent along the Nesson anticline and to the east, and is being increasingly derisked to the west. CLR estimates that there is 24 Billion boe of recoverable resource in the Williston, well ahead of the USGS estimate of 3-4.3 Bboe.

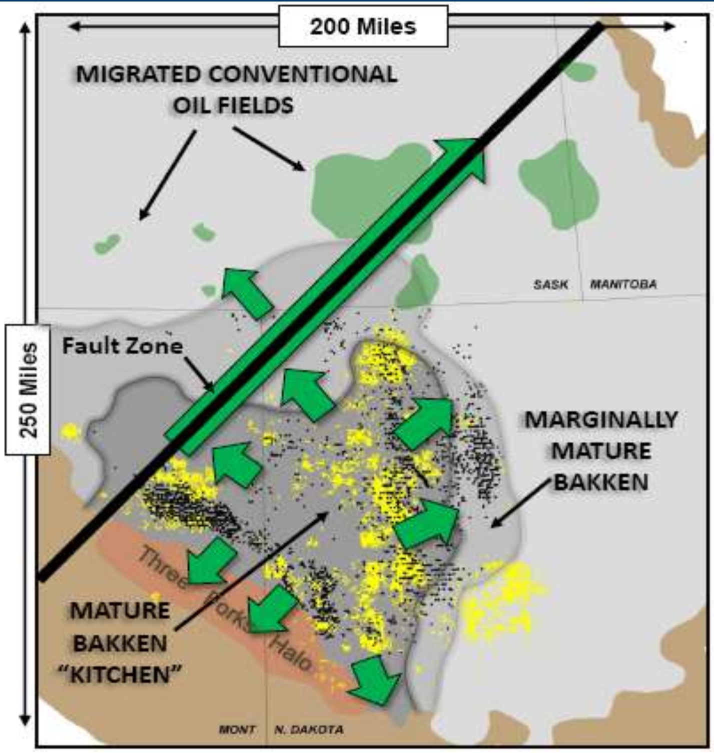
While sentiment in the Bakken has weakened relative to other oil basins over the past year due to cost inflation, operators have signaled that upward cost pressure is abating. Rail infrastructure is also volumetrically improving export options (albeit at relatively high cost). The operating environment in the Bakken is clearly improved over 2011 and all indications from the operators in the basin are that oil growth is ahead of initial earlier expectations. As operators start moving into more full pad drilling operations, production should continue to climb.

Exhibit 99: Bakken Bubble Map: Oil Production per Day



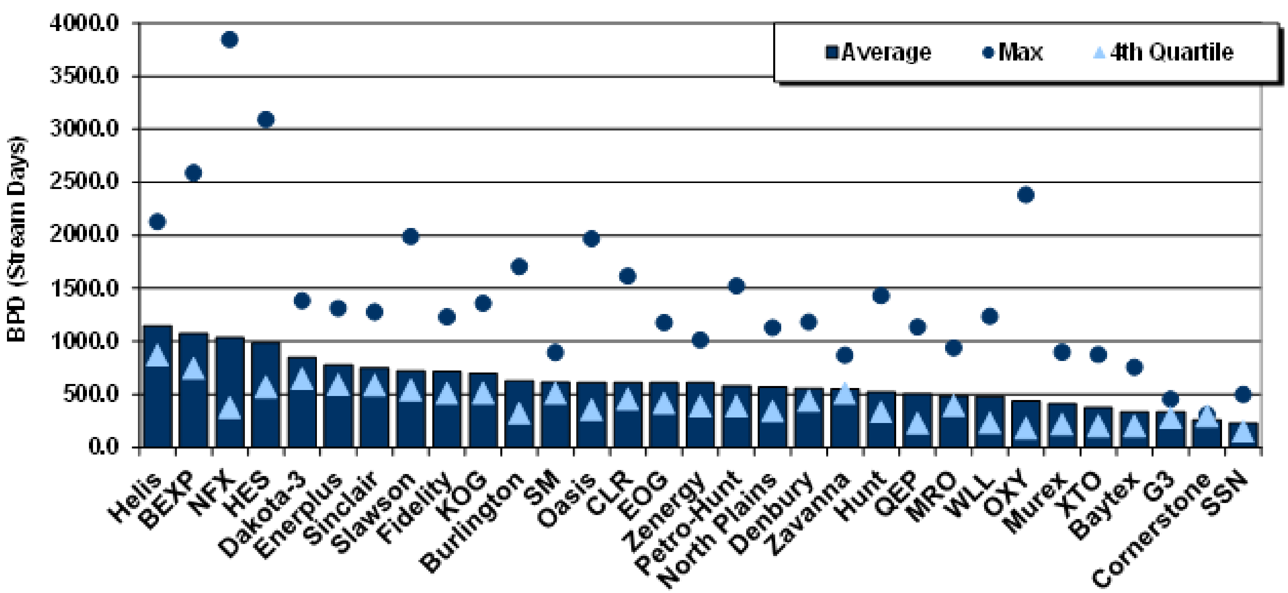
Source: HPDI

Exhibit 100: **Bakken / Williston Basin Map**



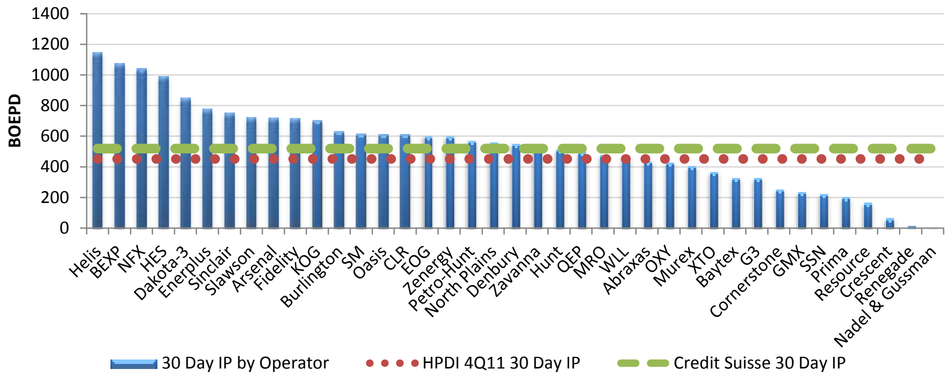
Source: Continental Resources

Exhibit 101: **2011 Average, Best and 4th Quartile Peak Month Rates in the Bakken at 6:1 Oil:Gas Ratio**



Source: HBDI

Exhibit 102: Bakken Horizontal: 30 Day IP Guidance by Operator, vs HPDI 4Q11 30 Day IP and Credit Suisse IP Assumption at 6:1 Oil:Gas Ratio



Source: Company data,HPDI, Credit Suisse estimates,

Focus on the Niobrara

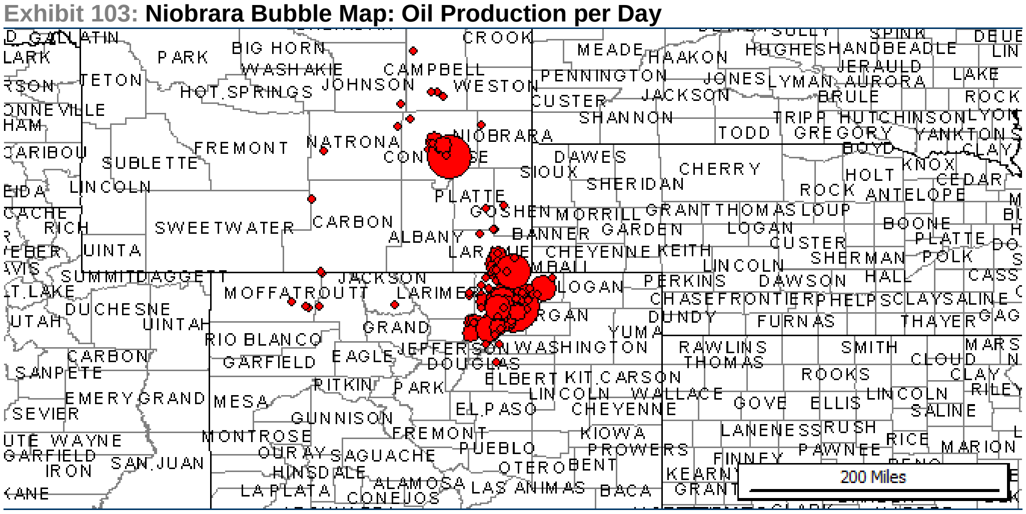
The Niobrara shale is an unconventional oil play in Colorado and Wyoming, with the bulk of early activity focused in the DJ Basin in northeastern Colorado. The play got off to a fast start with excitement centered around EOG's Jake discovery well in late 2009, while subsequent activity has proven the play less repeatable than initially thought. The core of the play has been established in the Wattenberg field in Colorado while operators have had mixed success stretching north into Wyoming. Recent discussion on the core-Wattenberg has centered on horizontal potential in the Codell, down spacing potential and enhanced project returns with longer lateral lengths. Operators are also testing the play in the Powder River, North Park, Piceance and Sandwash Basins.

Momentum in the Niobrara took a turn for the better in 2H11, with APC, NBL and PETD all increasing recovery estimates in the core Wattenberg field. While results outside of Wattenberg in the DJ have been spotty, operators such as WLL, DVN and APC remain optimistic about the oil opportunity in the Niobrara outside of Wattenberg. At its March 2012 analyst day PETD suggested well recoveries in Wattenberg were tracking closer to the high-end of the company's 300-500 Mboe range estimate. PETD reported initial average initial production and 30-day average rates of 629 Boe/d and 476 Boe/d, respectively in Wattenberg. Three wells drilled in PETD's Krieger prospect, which is northeast of Wattenberg, have underperformed the 290 MBoe type curve.

In November, APC unveiled its expectations in the Niobrara where it holds 350k net acres in the Wattenberg field holding an estimated 0.5-1.5 BBoe of net resources. APC estimates it has 1,200-2,700 locations and expects well recoveries in a range of 300-600 MBoe. The company's first 11 Niobrara and Codell horizontals had average initial production rates of 600 Bbl/d and 1.5 MMcf/d. APC is optimistic about the opportunity in the Niobrara outside of Wattenberg where the company holds another 910k net acres in the DJ and Powder River Basins. Results have not been as robust as they have been in the Wattenberg with disparities in reservoir energy being the important differentiating variable.

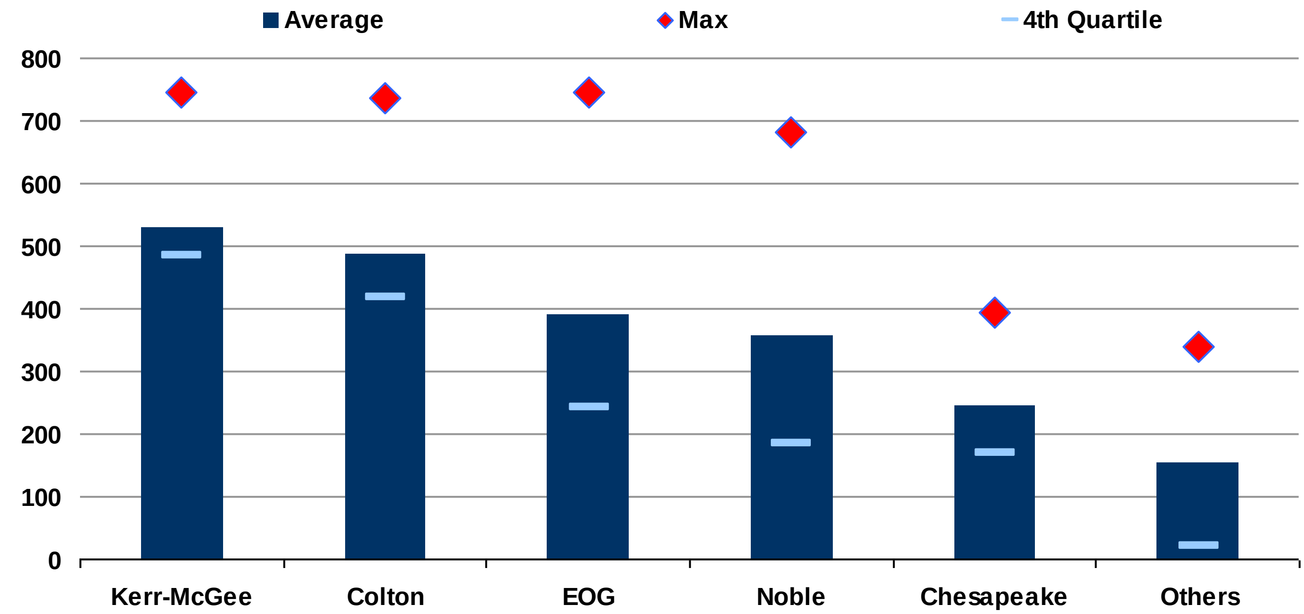
At its November analyst day NBL demonstrated improving results in the Niobrara where the latest 18 horizontal wells are have expected recoveries of 355 MBoe, or 22% above the initial 23 wells drilled. NBL estimates 1.3 BBoe of net risked resource on 840k net acres, and expects EURs of over 310 MBoe on ~400k net acres in the Wattenberg field.

Exhibit 103: Niobrara Bubble Map: Oil Production per Day



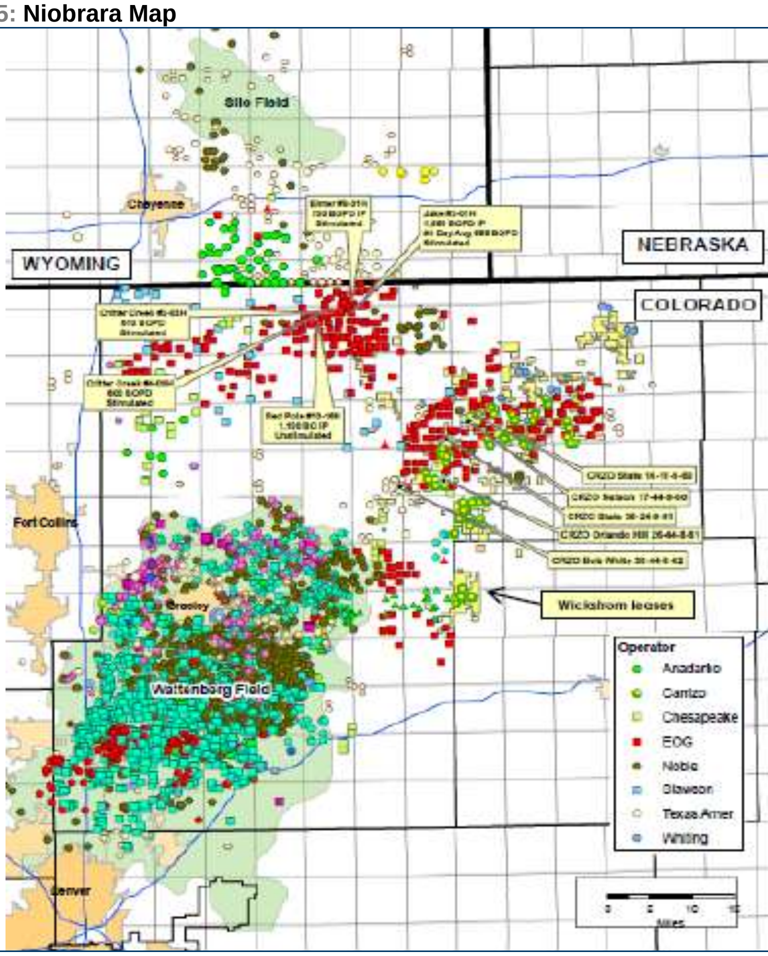
Source: HPDI

Exhibit 104: 2011 Average, Best and 4th Quartile Peak Month Rates in the Niobrara at 6:1 Oil:Gas Ratio



Source: HPDI

Exhibit 105: Niobrara Map



Source: Carrizo Oil and Gas

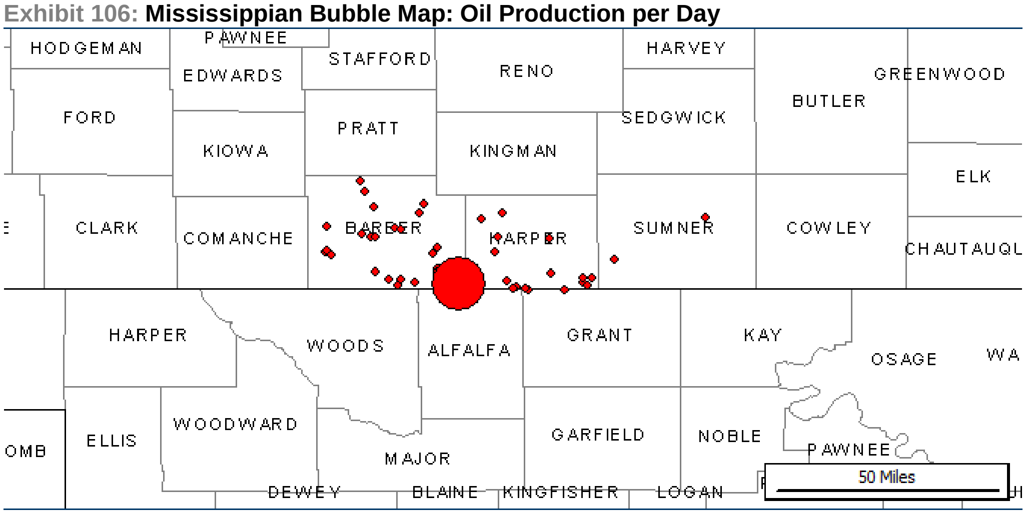
Other Plays

Mississippian Lime

The Mississippian is an unconventional oil play stretching under roughly 6.5 million acres in northern Oklahoma and southern Kansas. The play is relatively shallow at 6,000' average vertical depth and is characterized as an oil in matrix and fractured carbonate target. SD and CHK have been the early movers in the play, while RRC has been building a position. DVN and RDS/A have also been increasing their presence in the area. Activity in the Mississippian located on the northern Oklahoma/southern Kansas border is limited to a few operators including SD, RRC, DVN, UNT and CHK. SD is the primary operator having drilled 195 horizontal wells to date (*approximately half of the 400 horizontal wells drilled overall*). Development of the play should ramp in 2012 as more capital is diverted to the play in light of recent updates. SD currently estimates 350-500 MBoe EURs with a ~60% oil cut and noted that it plans to ramp to 45 rigs in the play by the end of 2013 (*plans to add a rig a month*) from 20 rigs currently. RRC recently provided a 485 MBoe EUR estimate with a ~70% liquids cut and noted that it plans to initiate development of the play with a 'couple of rigs' in 2012.

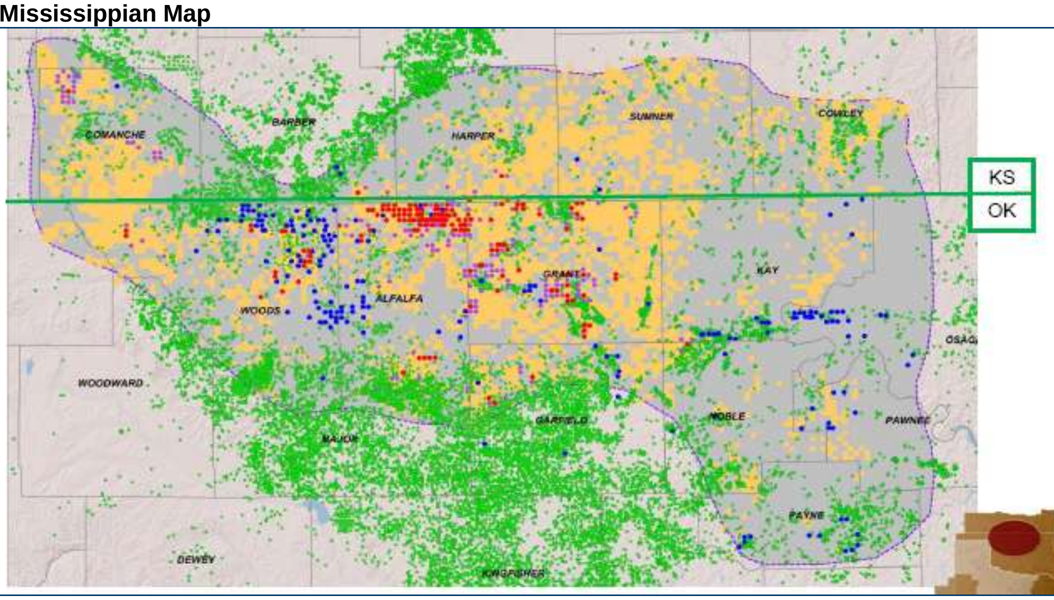
Recent JV deals have helped to affirm the resource potential of the play. On December 23, 2011, SD announced that it entered into a JV with Repsol for a non-operated interest in 363,636 net acres in the Mississippian and Extension Mississippian for $1 billion (*$250MM up front and $750MM in drilling carry over 3 years*), which equates to ~$2,400/acre when discounting the carry. Assuming the Extension Mississippian acres received a nominal $1,000/acre consideration, would imply the core acreage (*113,636 net acres*) is worth ~$5,500/acre. SD also recently completed a $500MM (*$250MM up front and $250MM in drilling carry over three years*) JV in August 2011 with Atinum partners for 113,000 net acres in the core Mississippian, which equates to ~$4,000/acre (*discounting carry*). We note that although the economics the play appear to be display one of the best returns in onshore E&P, acreage values are still lower than those being recorded in the Eagle Ford and the Utica (*still early in the exploration phase*) where recent deals have valued acreage at +$10,000/acre. We would expect further evidence of repeatability of well results will drive other operators into the basin and give current acreage holders leverage moving forward. Recent results have been extremely encouraging particularly in Logan County, OK where DVN reported a 30-day IP of 590 boed from the Matthew 1-33H well, and Osage Exploration and Development reported a 72-hr and 30-day IP rate of 1185 boed and 876 boed, respectively from the Slawson-operated Wolf 1-29 well.

Exhibit 106: Mississippian Bubble Map: Oil Production per Day



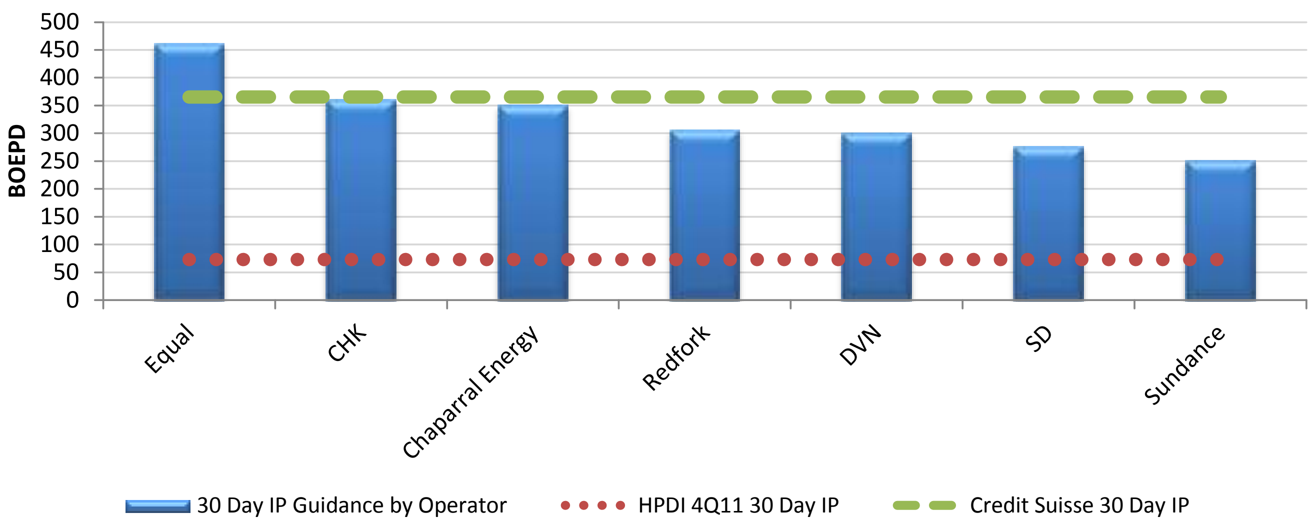
Source: HPDI

Exhibit 107: **Mississippian Map**



Source: SandRidge Energy

Exhibit 108: **Mississippian: 30 Day IP Guidance by Operator, vs HPDI 4Q11 30 Day IP and Credit Suisse Model Forecast at 6:1 Oil:Gas Ratio**



Source: Company data, HPDI, Credit Suisse estimates

Uinta

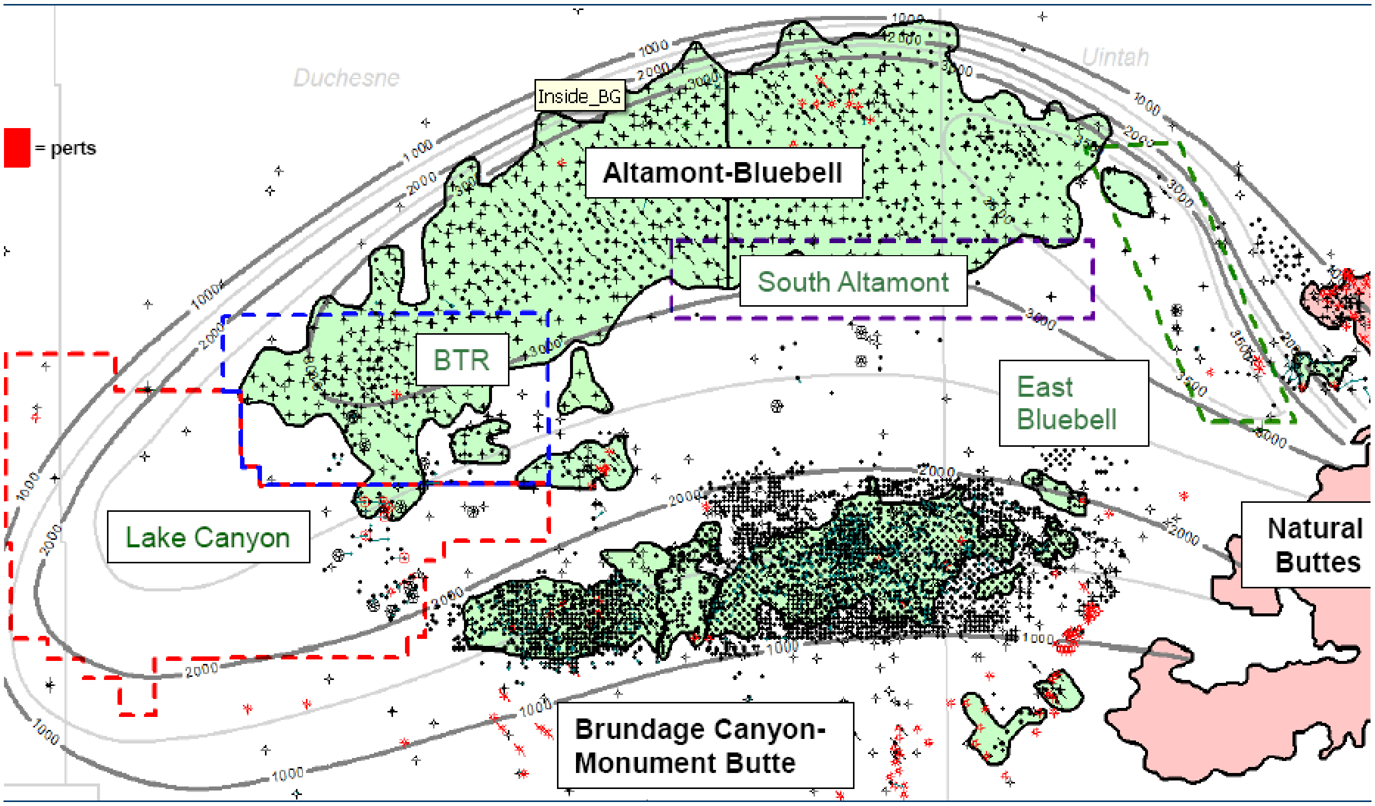
NFX offered a comprehensive update on the Uinta in July 2011 after completing the acquisition of HNR that brought the company's position in the basin to 250k net acres. NFX estimates it has 700 MMBoe of resource potential in the Uinta coming from shallow vertical development in the Green River, deep vertical development in the Wasatch and horizontal development in the Uteland Butte formation. Operators have also discussed the potential for additional horizontal oil shale targets in the Mahogany and Black Shale, which both lie at shallower depths than the Uteland Butte.

In Monument Butte, eight Uteland Butte hz wells drilled by NFX in 2011 had initial production rates of ~380 Boe/d and 30-day average rates of 180 Boe/d. West of Monument Butte in Lake Canyon, BBG and BRY are also testing the Uteland Butte horizontally. While costs are higher in Lake Canyon *($4.5 million drill and complete vs. $2.8 million for NFX*) initial production and 30-day rates have been more robust at `900 Boe/d and `500 Boe/d, respectively from BBG's first seven hz Uteland Butte wells. Despite early initial success, BBG is only planning to drill eight Uteland Butte hz wells in 2012.

NFX's focus in the basin has shifted to the Central Basin in 2012 which lies just north of Monument Butte. The company recently reported a deep Wasatch vertical well that IP'd at 2,500 boed and had a 10-day initial rate of 2,100 boed. The company reported an average IP of 900 boed from 7 other deep Wasatch vertical wells and is expects to deliver results from its first two horizontal Wasatch wells by mid-year.

While the economics appear to stack up well in the Uinta, there are concerns about the capacity of refiners to take additional black and yellow wax crude. Wax refining capacity is estimated at 60 Mbbls/d with current production out of the basin estimated at ~50 MBbls/d. Notably, wax crude has historically traded at a 10-15% discount to WTI, but recent work by our refining team suggests that the recent supply agreement for wax crude would lock in a differential closer to a ~25% discount and any further greenfield refining expansions would require differentials in the range of 25-30%. While project economics would likely withstand the wider differentials, the timing of any further capacity additions could potentially put a lid on growth near/intermediate-term.

Exhibit 109: Uinta Basin



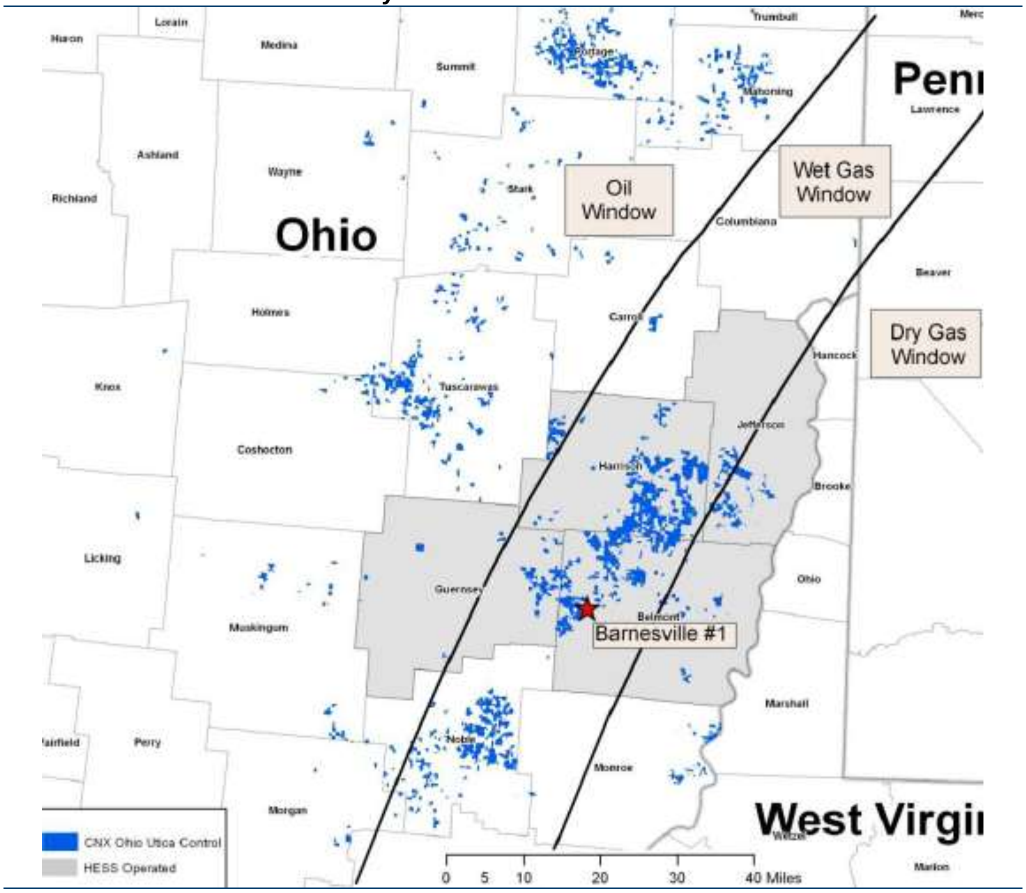
Source: Bill Barrett Corp.

Utica

Progress is being made in the Utica play. Operators continue to delineate the play while also trying to find the right frac and completion techniques ("*shake & bake"*) in order to optimize well results. Good recent 24hr IP rates provide some excitement for the play. The liquids cut has been 70pct but with only 35-40pct crude. NGL and gas offtake may be a near term constraint on the pace of rig count increase. APC posted three Utica well results (*located in Noble and Guernsey Counties, OH*), which posted high oil cuts. PETD drilled a vertical test well in Belmont County, OH that was dry gas. GPOR announced a very strong 24-hour initial production rate recently (4,650boed) with a decent liquids cut (50% liquids) from its Wagner well on the border of Belmont and Harrison counties. Enervest (EVEP) also announced a significant well with a 24-hr IP of 1,690boed and a 78% liquids cut further west than the Wagner well in Harrison County.

However, relative to the Utica map that we show below, recent well results suggest that the dry gas – liquids transition could occur to the West of the line shown.

Exhibit 110: Old Utica Area Map – Recent Results Suggest Dry Gas Window Extends Further West into Belmont County



Source: CONSOL Energy

Other Unconventional Liquids Plays on the Horizon

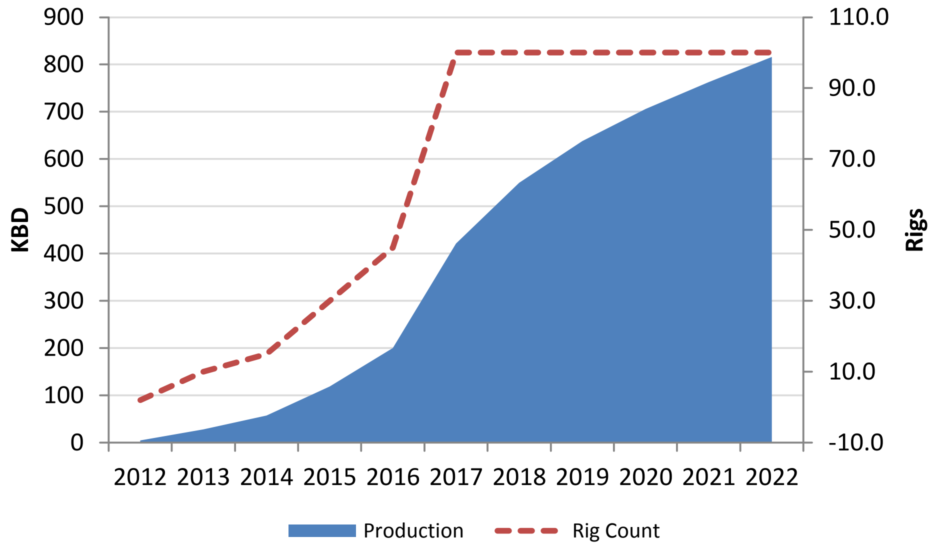
We also highlight a number of other plays have seen recent activity by early movers, but not detailed in this report given that they are still in the early stages of exploration. These notable plays include the Utica Shale in northwest PA, Upper Devonian, Brown Dense/Smackover, Tuscaloosa Marine Shale, the Woodbine, the Wilcox conventional oil, the Austin Chalk and the Southern Alberta Bakken.

Notably, some early data points have started trickling out with ECA reporting two initial Tuscaloosa well results that had an average 30-day IP rate of 690 Boe/d, while DVN's first two Tuscaloosa wells had 30-day IPs of less than 200 Boe/d. SWN released results for its initial Brown Dense well, which exhibited a peak rate of 104 Boe/d. SWN is currently completing its second Brown Dense well and has started drilling its third well in the play.

Capturing New Plays in the Model

In our production model, we have devoted 100 rigs to these emerging plays. As more data becomes available, we will shift these plays into named play models. This translates into 500 kbd of oil production by 2020 from sources with less technical knowledge today.

Exhibit 111: **Production and Rigs in Emerging Plays**

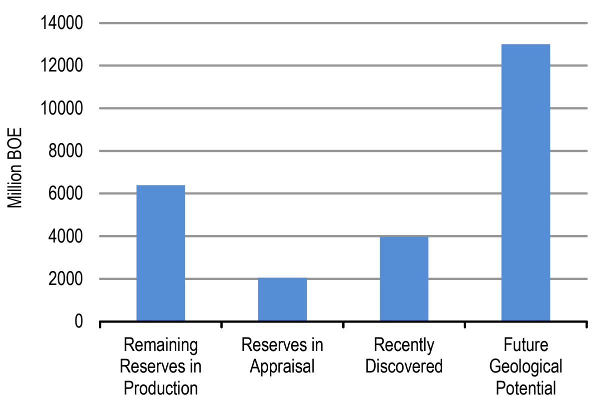


Source: Company data, Credit Suisse estimates

Shale Is Not the Only Growth: Gulf of Mexico and Arctic

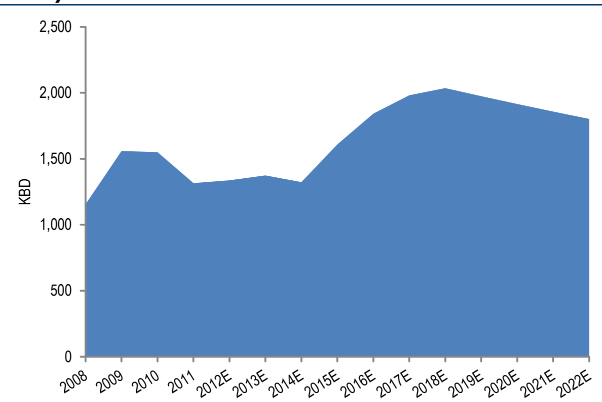
In recent years there have been a number of large discoveries made in the Gulf of Mexico both in the Miocene and the Lower Tertiary trend. After a Macondo related hiatus these are being developed and rigs are returning slowly to exploration activity. Our production model shows a hockey stick of growth in 2015-2017 as these new fields are put on production. The sustainability of the hockey stick will depend on further exploration success, limited hurricane impacts, and safe industry operations.

Exhibit 112: **Estimated Remaining Resources (bn boe)**



Source: EIA, Credit Suisse estimates

Exhibit 113: **Gulf of Mexico Oil Production Outlook (kboed)**



Source: EIA, Credit Suisse estimates

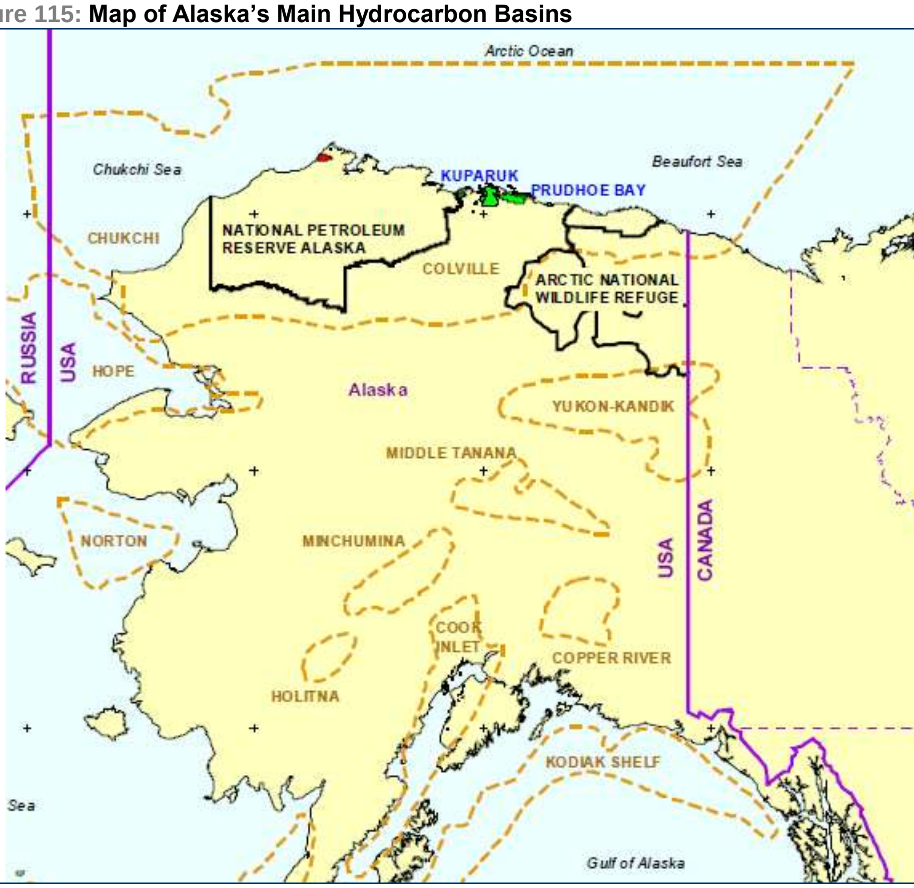
Beyond the Gulf, Shell should test its first prospect in the Artic Chukchi sea in August – see our report "Time to Focus on Alaska". This could add >500kbd to 2020 production in a success case.

Figure 114: Undiscovered resources in Alaska Federal offshore

	Technically recoverable resource			Economically recoverable resource at $80/bbl		
	Oil & Gas (boe)	**Oil (bbl)**	**Gas (tcf)**	**Oil & Gas (boe)**	**Oil (bbl)**	**Gas (tcf)**
Total Alaska offshore, of which:	**50.11**	**26.61**	**132.07**	**38.22**	**21.51**	**93.99**
1- Arctic sub-region	43.00	23.75	108.19	32.51	19.01	75.94
Chukchi Sea	29.04	15.38	76.77	**21.68**	**12.00**	54.44
Beaufort Sea	13.14	8.22	27.65	**10.47**	**6.92**	19.97
Hope basin	0.82	0.15	3.77	0.36	0.09	1.53
2- Bering Shelf sub-region	3.95	1.16	15.70	3.05	0.96	11.78
3- Pacific margin sub-region	3.16	1.70	8.18	2.66	1.54	6.27
Cook Inlet	1.23	1.01	1.20	1.18	0.97	1.16
Other	1.93	0.69	6.98	1.48	0.57	5.11

Source: "Undiscovered Oil and Gas Resources, Alaska Federal Offshore", US Minerals Management Service, 2006. Estimates of economically recoverable resource calculated on $80/bbl oil and $12.1/mcf gas.

Figure 115: Map of Alaska's Main Hydrocarbon Basins

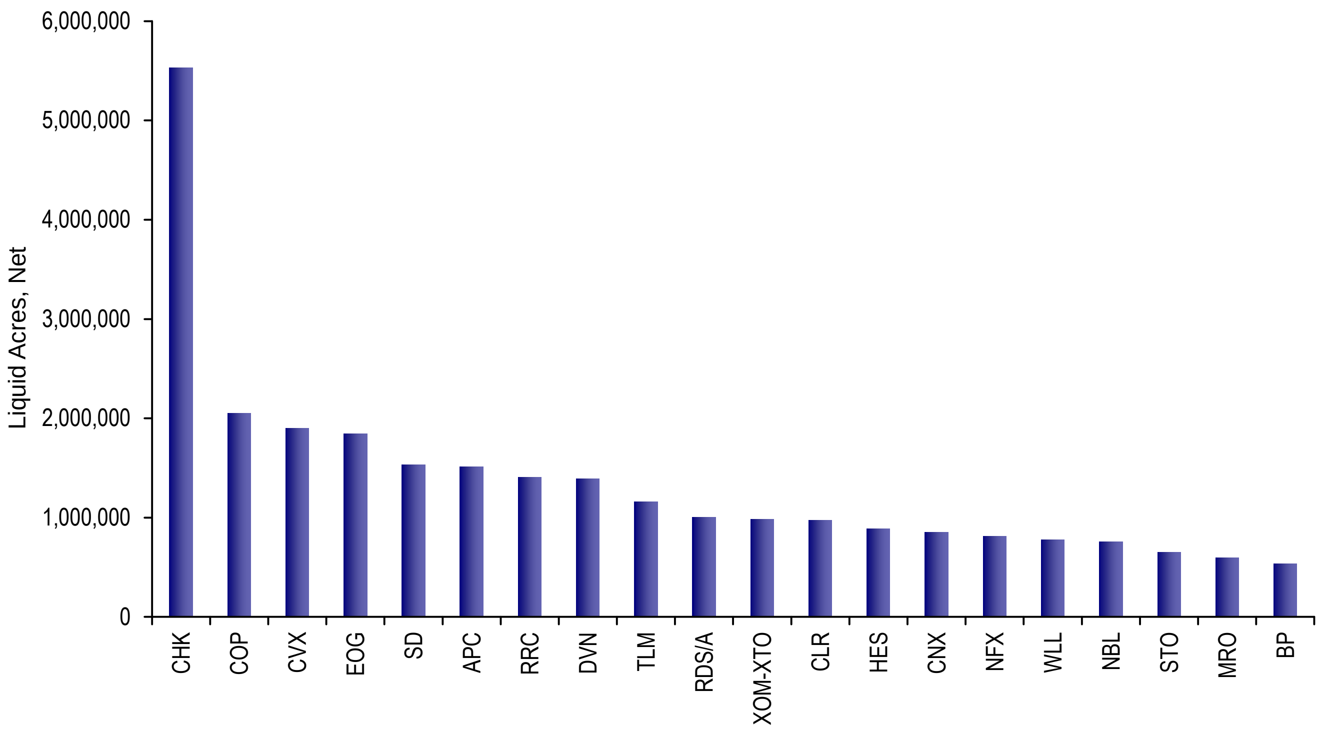


Source: Wood MacKenzie

Appendix 1: Large-Cap Acreage Holders

The good news from a capital perspective is that the supermajors, notably CVX, COP and XOM are building a larger shale footprint in the US. Capital earned on assets overseas could flow back into the US given the political stability and potential shale returns (assuming barriers are not put in place to those capital flows). With the US E&P's facing a cashflow crunch from weak natural gas prices, weak NGL prices and the high upfront capital costs on shale, M&A consolidation also seems a likely outcome.

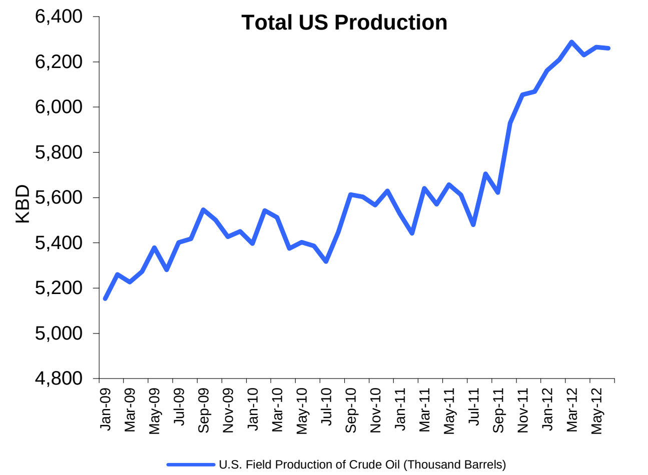
Exhibit 116: Largest "Liquids-Rich" Acreage Holders



Source: Company data, Credit Suisse estimates

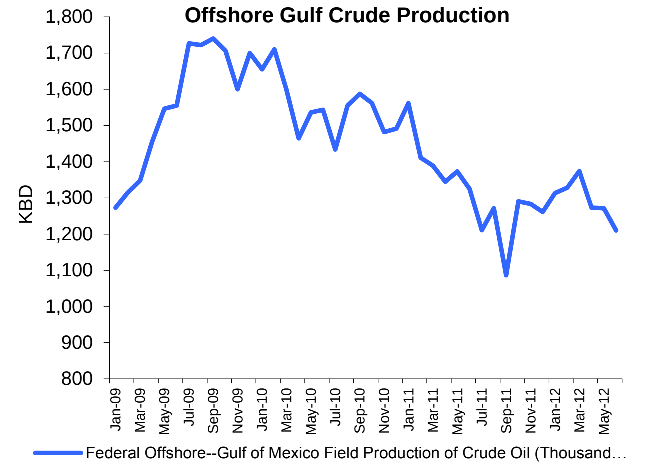
Appendix 2: Recent Production Trends

Exhibit 117: Total US Oil Production (KBD)



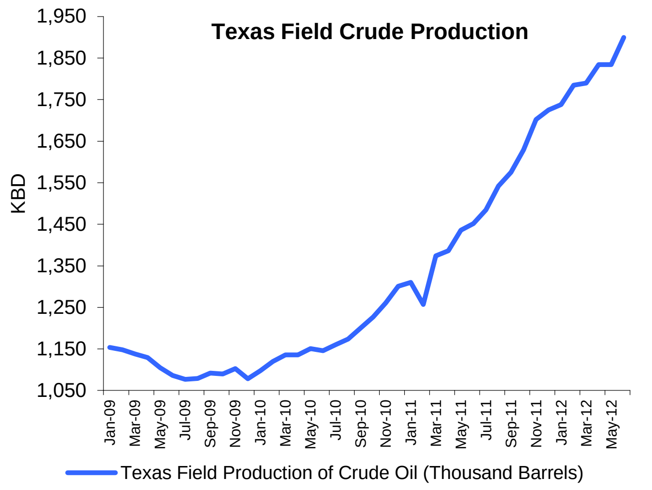
Source: EIA

Exhibit 118: Offshore GoM Crude Oil Production (KBD)



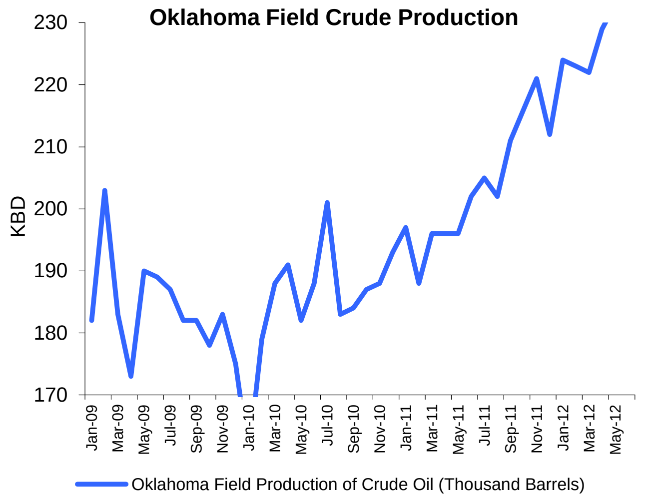
Source: EIA

Exhibit 119: Texas Crude Oil Production (KBD)



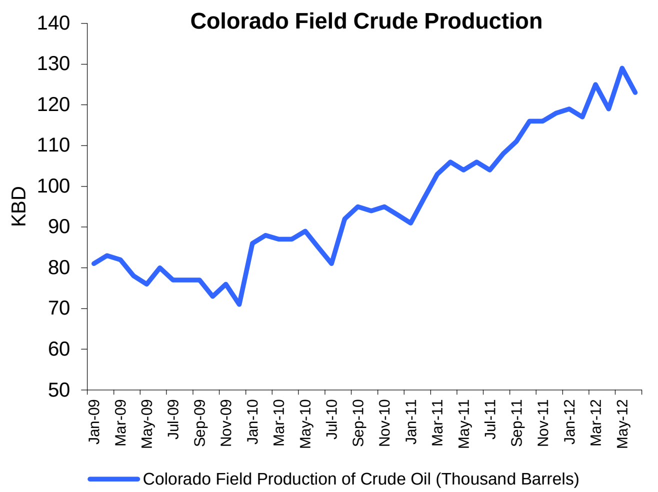
Source: EIA

Exhibit 120: Oklahoma Crude Oil Production (KBD)



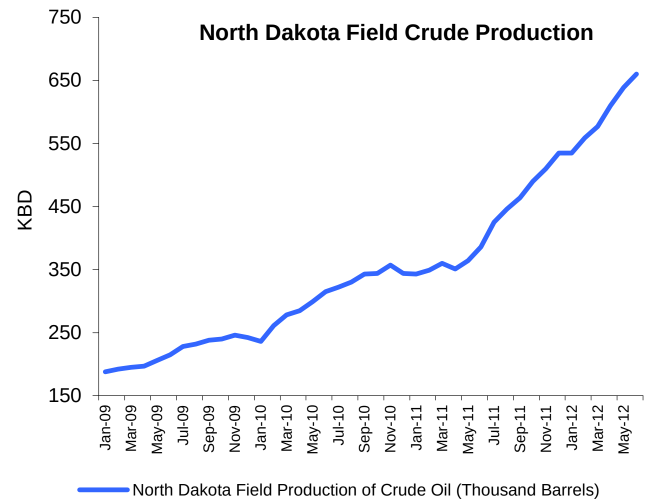
Source: EIA

Exhibit 121: Colorado Crude Oil Production (KBD)



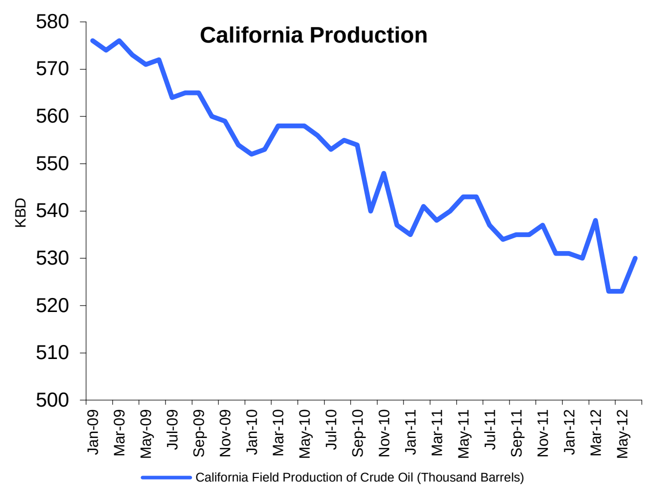
Source: EIA

Exhibit 122: North Dakota Crude Oil Production (KBD)



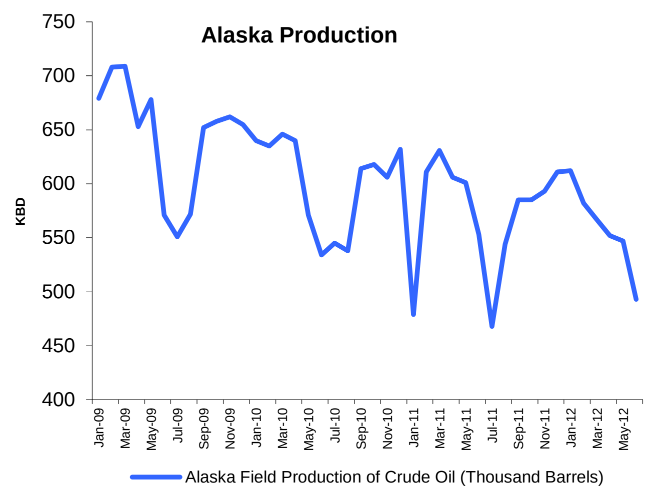
Source: EIA

Exhibit 123: California Crude Oil Production (KBD)



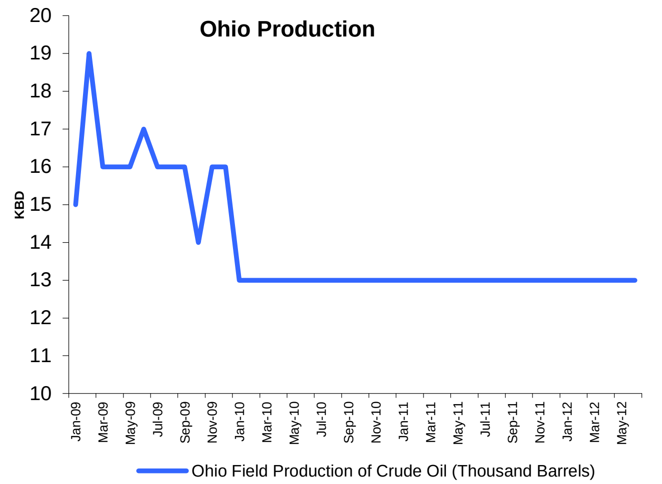
Source: EIA

Exhibit 124: Alaska Crude Oil Production (KBD)



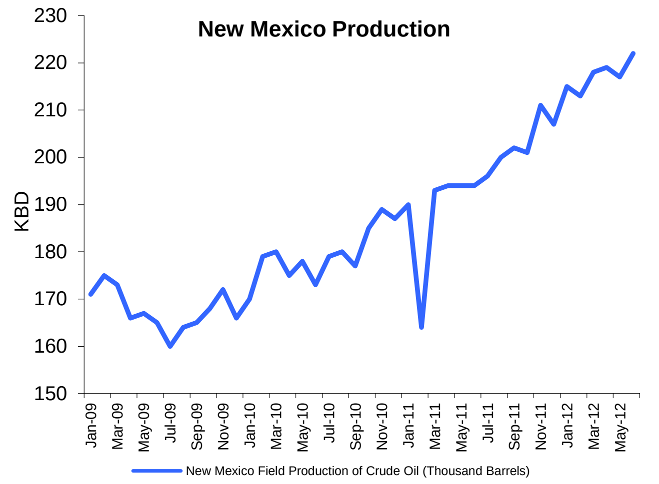
Source: EIA

Exhibit 125: Ohio Crude Oil Production (KBD)



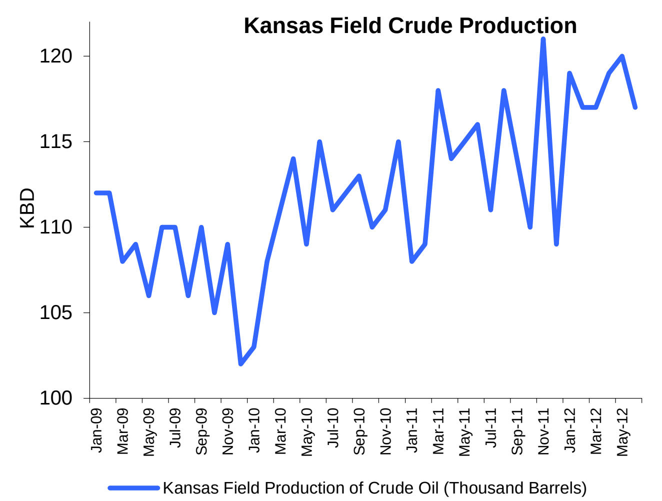
Source: EIA

Exhibit 126: New Mexico Crude Oil Production (KBD)



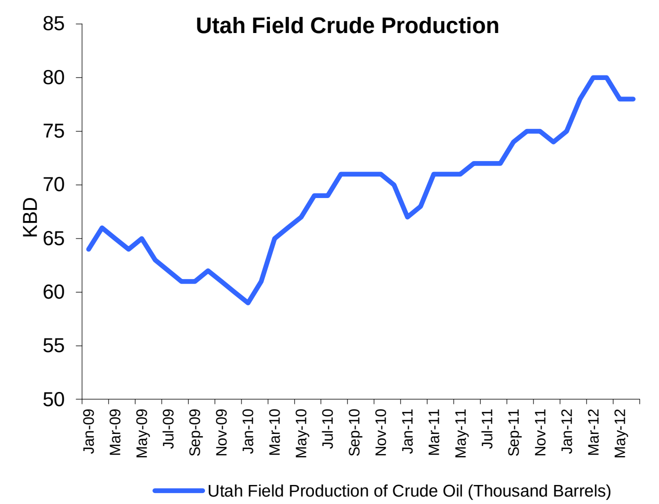
Source: EIA

Exhibit 127: Kansas Crude Oil Production (KBD)



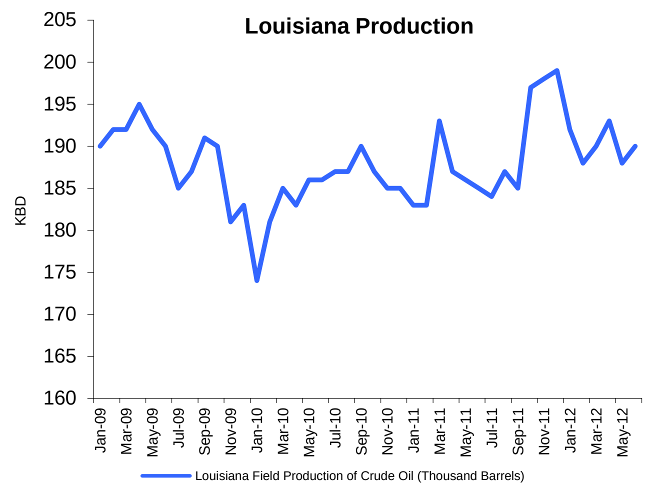
Source: EIA

Exhibit 128: Utah Crude Oil Production (KBD)



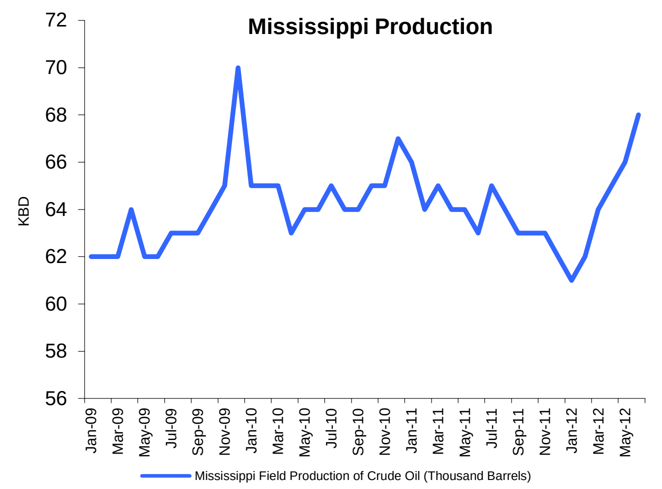
Source: EIA

Exhibit 129: Louisiana Crude Oil Production (KBD)



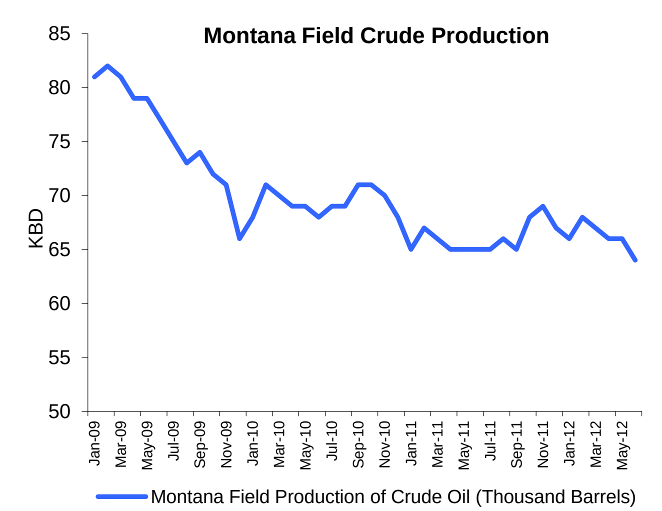
Source: EIA

Exhibit 130: Mississippi Crude Oil Production (KBD)



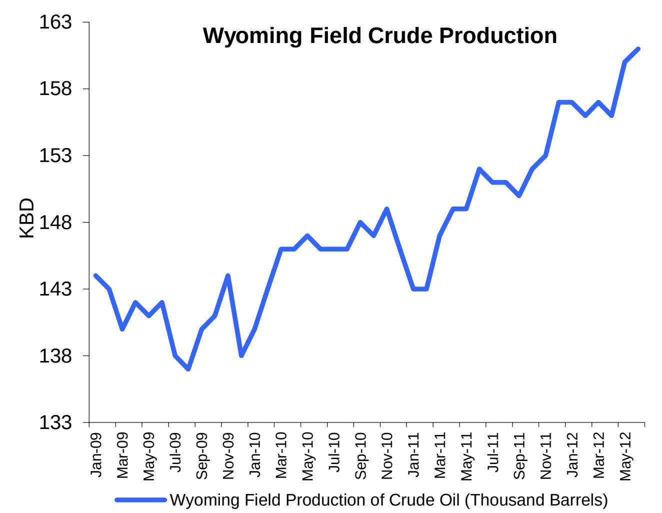
Source: EIA

Exhibit 131: Montana Crude Oil Production (KBD)



Source: EIA

Exhibit 132: Wyoming Crude Oil Production (KBD)



Source: EIA

Appendix 2: Pipeline Projects

Exhibit 133: **Capacity and Timing of Key Pipeline Projects**

	2009	2010	2011	2012E	2013E	2014E	2015E	2016E	2017E
Pipeline Exports									
- Enbridge Monarch									
- Keystone XL						470	500	500	500
- Kinder Morgan TMX 3 (Southern Expansion)								80	400
- Kinder Morgan Northern Leg (Northern Expansion)							100	400	400
- Longhorn					146	235	235	235	235
- Enbridge Northern Gateway								525	525
- Pettus South Reactivation									
- N. Eagle Ford Pipeline Expansion									
- Line 9 reversal to Canada East Coast					50	240	240	240	240
- Arrowhead Expansion									
- Magellan/M3 JV									
- West Texas Gulf					100	100	100	100	100
- Koch Eagle Ford Pipeline									
- NuStar & TexStar Midstream Services									
- Seaway Expansion (Enbridge/EPD) Flanagan South						225	450	600	600
- Seaway reversal				100	400	400	400	400	400
- Pegasus		93	93	93	93	93	93	93	93
- Permian Express					101	150	150	150	150
- Oneok									
- Bridge Tex						87	278	278	278
Tanker/Barge/Truck (PADD 2 to Other Regions)	18	24	69	96	106	116	116	116	116
Rail Off-loading									
- EOG (via Nustar at St James)	0	0	20	73	100	100	100	100	100
HESS - US Development Group (St. James) - 1	0	15	65	65	65	65	65	65	65
HESS - US Development Group (St. James) - 2	0	0	0	16	65	65	65	65	65
- 'Rangeland TSO		0	0	15	30	30	30	30	30
- Additional Terminal in Gulf (Lario Logistics)	0	0	9	110	140	250	250	250	250
- Additional Terminal in Gulf		0	0	0	0	140	140	140	140
- Savage Companies/Kansas City Southern	0	0	0	0	70	70	70	70	70
- Enbridge - Berthold		0	0	10	70	80	80	80	80
- To East Coast	0	0	0	13	25	25	25	25	25
- To West Coast (non TSO)		0	0	0	20	20	20	20	20
- Other		0	0	0	0	0	0	0	0
- Permian Rail Offtake		0	0	100	203	203	203	203	203
Sub Total Pipelines			**93**	**193**	**891**	**2,000**	**2,546**	**3,601**	**3,921**
Sub Total Rail			**94**	**401**	**788**	**1,048**	**1,048**	**1,048**	**1,048**
Sub Total Barge/Truck/Tanker			**69**	**96**	**106**	**116**	**116**	**116**	**116**
Total Export Infrastructure			**256**	**690**	**1,784**	**3,164**	**3,710**	**4,765**	**5,085**

Source: Company data, Credit Suisse estimates

Fixed Income Disclosure Appendix

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Companies Mentioned *(Price as of 05 Sep 12)*
Anadarko Petroleum Corp. (APC, $69.13, OUTPERFORM, TP $90.00)
Approach Resources, Inc. (AREX, $28.90, Not Rated)
Baytex Energy Corp. (BTE.TO, C$44.63, NEUTRAL, TP C$50.00)
BHP Billiton (BLT.L, 1779 p, NEUTRAL, TP 2,100.00 p)
BP (BP.N, $41.63, OUTPERFORM, TP $46.50)
Brigham Exploration Co. (BEXP, $36.48, Not Rated)
Burlington Resources (BRUP4, Not Rated)
Cabot Oil & Gas Corp. (COG, $41.50, Not Rated)
Chesapeake Energy Corp. (CHK, $19.19, NEUTRAL [V], TP $22.00)
Chevron Corp. (CVX, $111.22, OUTPERFORM, TP $120.00)
Cimarex Energy (XEC, $57.58, Not Rated)
Comstock Resources, Inc. (CRK, $16.25, NEUTRAL [V], TP $17.00)
CONCHO RESOURCES (CXO, $88.14, Not Rated)
ConocoPhillips (COP, $56.21, NEUTRAL, TP $60.00)
CONSOL Energy, Inc. (CNX, $28.83, NEUTRAL, TP $33.00)
Continental Resources (clr)
Denbury Resources (DNR, $15.41, Not Rated)
Devon Energy Corp. (DVN, $57.45, Not Rated)
El Paso Corp. (EP, $28.75, Not Rated)
EOG Resources, Inc. (EOG, $109.32, NEUTRAL, TP $115.00)
ExxonMobil Corp. (XOM, $87.12, NEUTRAL, TP $90.00)
Harvest Natural Resources In (HNR, $9.57)
Hess Corp. (HES, $49.65, NEUTRAL, TP $60.00)
Kerr-Mcgee (KMG, Not Rated)
Kodiak Oil & Gas Corp. (KOG, $8.95, OUTPERFORM [V], TP $11.00)
Marathon Oil Corp. (MRO, $27.45, NEUTRAL, TP $37.00)
Murphy Oil Corp. (MUR, $51.23, Not Rated)
Newfield Exploration Co. (NFX, $32.99, Not Rated)
Noble Energy, Inc. (NBL, $86.73, OUTPERFORM, TP $103.00)
Occidental Petroleum (OXY, $83.11, OUTPERFORM, TP $114.00)
PetroHawk Energy Corp. (HK, $7.80, Not Rated)
Petroleum Developement Corp (petd)
Pioneer Natural Resources (PXD, $97.26, Not Rated)
Plains Exploration & Production (PXP, $39.64)
QEP Resources, Inc. (QEP, $28.68, Not Rated)
Range Resources (RRC, $65.28, OUTPERFORM, TP $72.00)
Red Fork Energy (rfe)
Rosetta Resources, Inc. (ROSE, $42.87, OUTPERFORM [V], TP $63.00)
Royal Dutch Shell Plc. (ADR) (RDSa.N, $69.54, NEUTRAL, TP $76.00)
SM Energy Co. (SM, $47.69, Not Rated)
Southwestern Energy Co. (SWN, $31.25, NEUTRAL, TP $31.00)
Statoil (STO.N, $25.49, UNDERPERFORM, TP $26.50)
Sundance Energy Corp (sea)
Talisman Energy, Inc. (TLM, $13.95, OUTPERFORM, TP $16.00)
Unit Corp. (UNT, $39.74, Not Rated)
W&T Offshore, Inc. (WTI, $17.61, Not Rated)
Whiting Petroleum Corp. (WLL, $45.45, OUTPERFORM [V], TP $65.00)

Equity Research Disclosure Appendix

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