Deutsche Bank
Markets Research

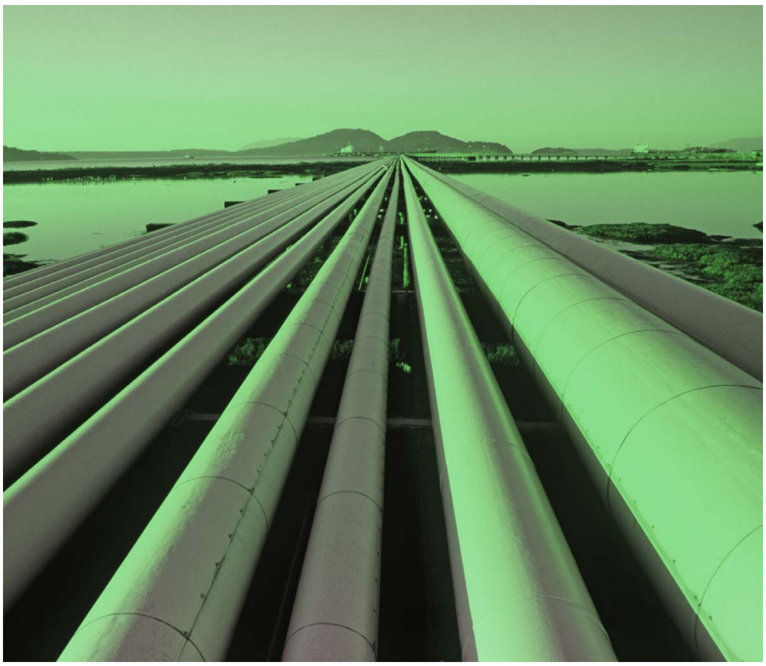
Industry

Global Oil Equities

Date
28 February 2012

North America
United States

Industrials
Integrated Oil



Paul Sankey
Research Analyst
(+1) 212 250-6137
paul.sankey@db.com

David T. Clark, CFA
Research Analyst
(+1) 212 250-8163
david-t.clark@db.com

Silvio Micheloto, CFA
Research Analyst
(+1) 212 250-1653
silvio.micheloto@db.com

Winnie Nip
Research Associate
(+1) 212 250-8529
winnie.nip@db.com

F.I.T.T. for investors

The Future of US Oil

The dynamics of the US oil market have staged a total reversal over the past five years. The impact is secular, dramatic, and challenging. In this note we outline a four stage process, integrating a North American supply forecast, infrastructure forecast, refining capacity forecast, and Atlantic Basin/global refining demand forecast. In a separately published note "The Future of North American oil equities" we recalibrate our recommendation deck.

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There are monumental secular changes occurring in North American oil

The dynamics of the US oil market have staged a total reversal over the past five years. The impact is secular, dramatic, and challenging. In this note we outline a four stage process, integrating a North American supply forecast, infrastructure forecast, refining capacity forecast, and Atlantic Basin/global refining demand forecast. In a separately published note "The Future of North American oil equities" we recalibrate our recommendation deck.

We expect a four stage process:

1) After decades of rising demand and falling supply, a u-turn: North American oil supply is growing and demand is falling, turning the US oil market inside out, challenging infrastructure designed for the opposite trend, and leading to high volatility and unprecedented price differentials. Crude imports are substituted and oil product exports grow, totally reversing US oil trade dynamics. That is the current stage.

2) Infrastructure development is rapid, through trains, barges and pipes – when not prevented by political interference. Initially inland crudes are released to the Gulf Coast, improving prices starting with the reversal of the Seaway pipeline in June '12. But as light crude imports are substituted (and they must be, due to the US crude export restriction), in due course (2013 and beyond) more supply will pressure Gulf Coast light crude (LLS) prices down towards inland prices (WTI). Continued light import substitution will narrow imported heavy differentials (Maya-LLS/WTI) and totally end US Gulf light crude imports, which only amount to around 750kb/d at this point. Stage 2012-2014.

3) With imports backed out, and stretched light crude refining capacity, US unconventional growth generates an over-supply of crude that pressures US crude prices downwards towards marginal cost of supply, which we think is around $80/bbl WTI. Stage 2013+.

4) With the Mid-Con short refined products, in the initial phase super-normal refining margins are generated from selling Brent-priced inland oil products, refined from local distressed-price crudes. With US crude prices pushed towards $80/bbl, and with OPEC/Saudi defending $100+ Brent, equilibrium is found on the Brent-WTI spread at $20-25/bbl. The situation is not dissimilar to the current extreme price differential between US and international natgas prices. US oil product exports continue to gain market share in the Atlantic Basin, until that market is filled, representing around 1.5mb/d of US distillate exports. Stage 2013+. Risk: if Atlantic Basin markets are weaker than we think for exports, such as from a huge European recession, US oil product exports could stop rising. Combined with falling US demand, that will be very bad for refiners. At that point, inter-US refining competition pressures Mid-Con margins (much less so Rockies, where supply is lower and demand stronger).

Crude spreads and corporate implications – main risk, political meddling

We cover recommendation changes in a separate note. Macro standpoint: after near term narrowing mid-2012 on Seaway startup, Brent-WTI will widen, as will Brent-LLS. Eagle Ford prices enjoy a major premium vs. Bakken. Canadian heavy WCS spreads are volatile and wide until 2014, then narrow. Gulf Heavy Maya-LLS stays narrow. Prefer international Brent-levered and Eagle Ford oil producers, Rockies refiners.

Companies Featured

ExxonMobil (XOM.N),USD87.23			Hold
	2011A	2012E	2013E
EPS (USD)	8.22	8.43	9.39
P/E (x)	9.7	10.3	9.3
EV/EBITDA (x)	5.1	5.8	5.2
Chevron (CVX.N),USD109.63			Hold
	2011A	2012E	2013E
EPS (USD)	13.19	13.05	15.33
P/E (x)	7.6	8.4	7.2
EV/EBITDA (x)	3.7	4.2	3.6

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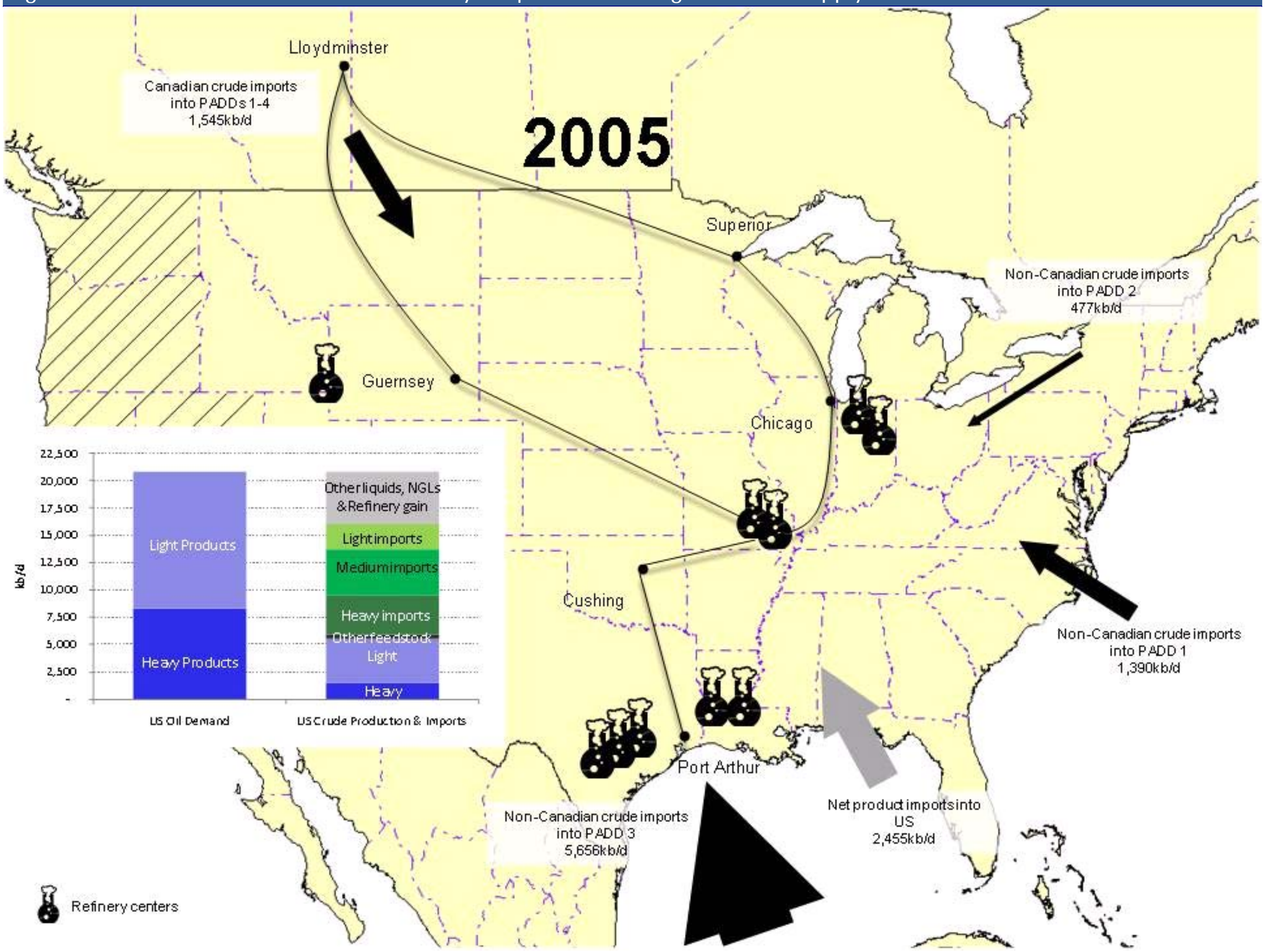
Future of US Oil

Executive Summary

Figure 1: The Peak US Oil Market – summary shape as demand growth and supply decline ended – 2005



Source: Deutsche Bank DOE, Wood Mackenzie (base map)

By 2005, the US had become a heavily oil import dependent market in both crude and oil products, after years of steadily declining domestic supply and steadily rising demand.

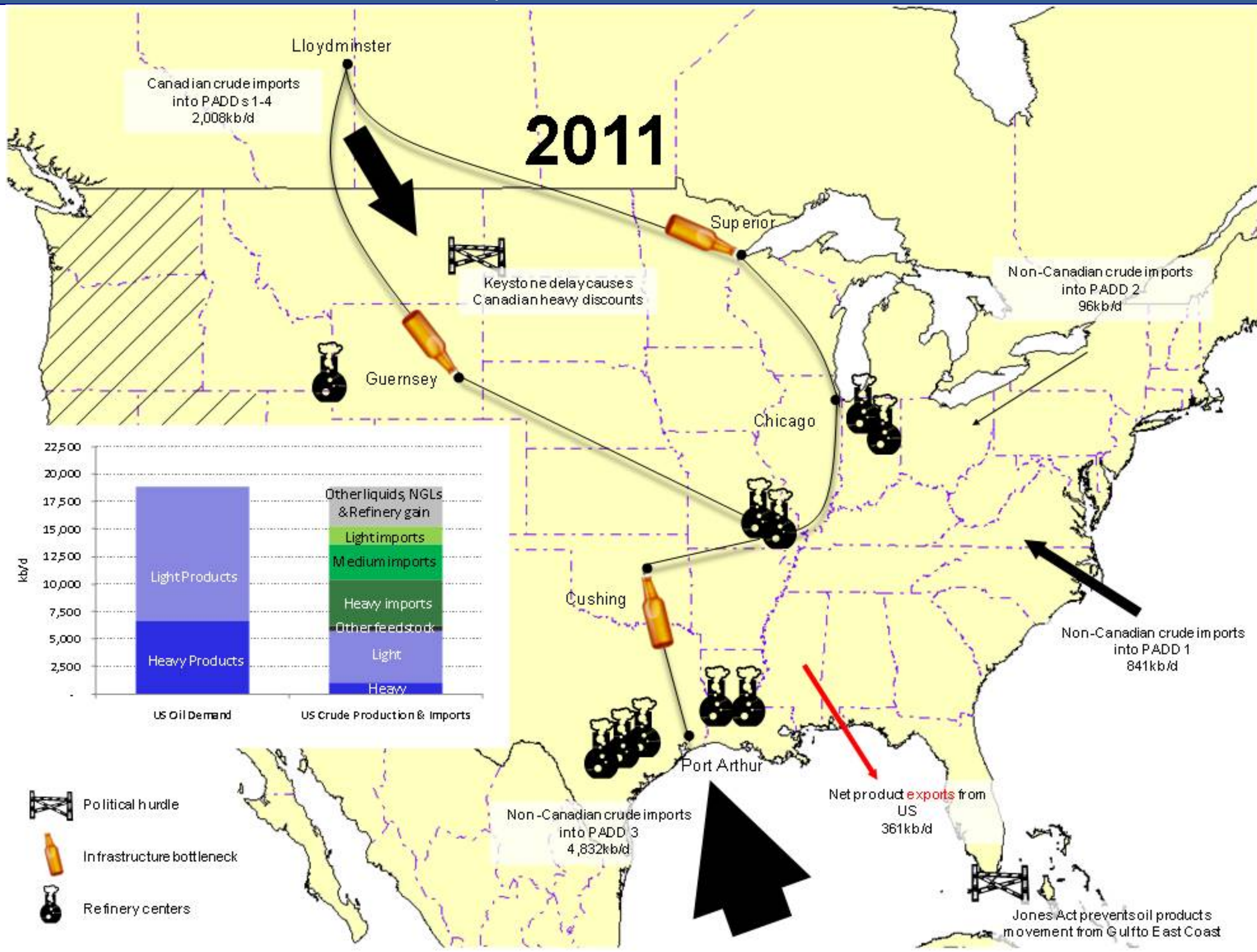
DB had identified 2007 as the peak year for US gasoline demand, because as growth finally slowed on higher gasoline prices and greater efficiency, mandated-ethanol forced-supply exceeded US gasoline demand growth. (see DB note “Food for Oil: A love-hate relationship” 13 Dec 2006).

Natural gas prices were rising high in the very earliest days of US unconventional E&P, and would hit $14/mmbtu by 2007. US LNG imports were seen as highly necessary to meet demand.

High oil prices encouraged the burgeoning growth of Canadian heavy oil imports.

That was then… but this is now…

Figure 2: The Infrastructure Clash – the current picture 2011



Source: Deutsche Bank, DOE, Wood Mackenzie (base map)

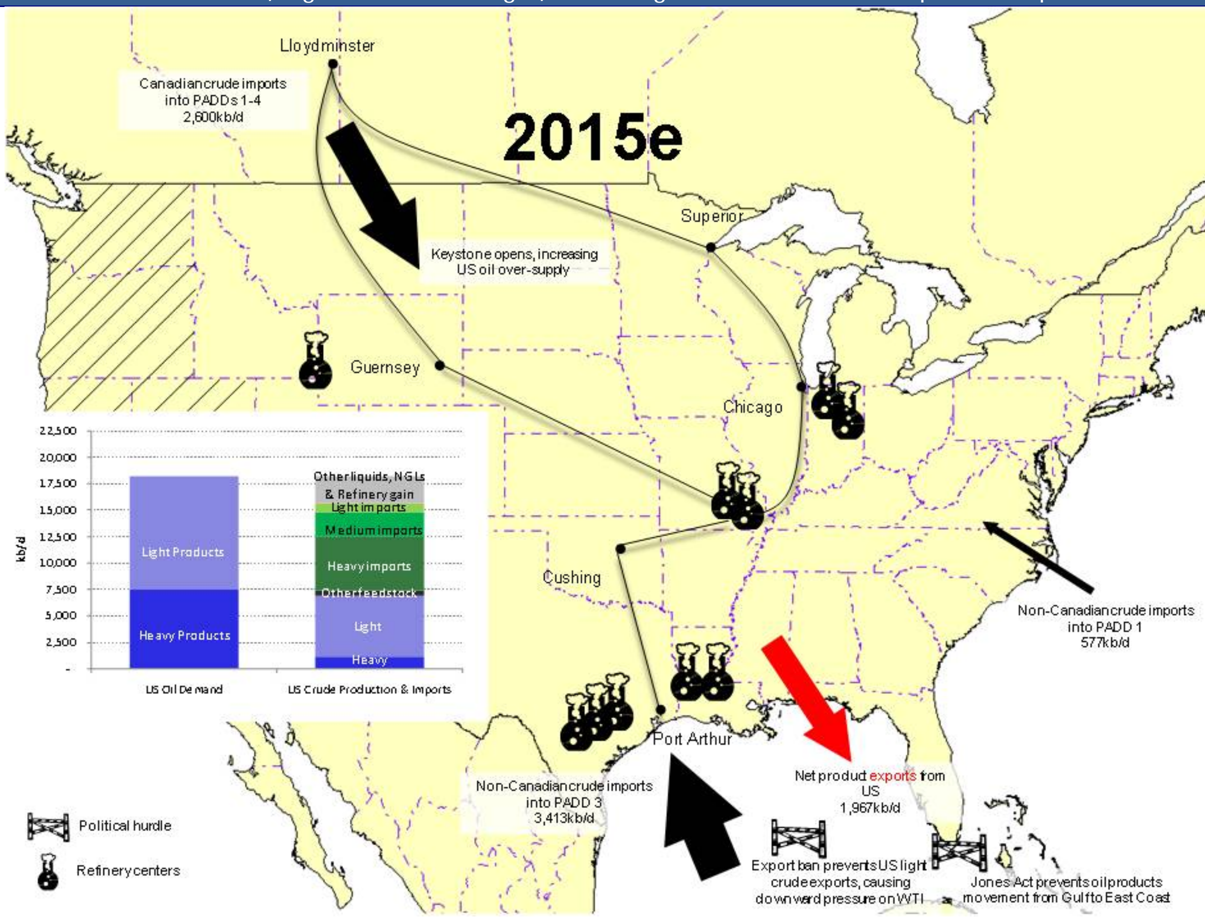
With the combination of Canadian heavy oil supply growth meeting the sudden turn in US production driven by unconventional growth, North American supply starts rising in reversal of long term trend. This meets falling domestic US demand for products, particularly gasoline, and begins to pressure US inland oil markets. At the same time, the reversal meets the "Diamond Age" of US refining, and net oil product exports commence from refiners enjoying discounted crudes and cheap natgas.

The first impact is to overwhelm infrastructure systems, with crude backing up at Nymex pricing point Cushing. The surging domestic light crude begins to back out imports of light crude.

Adding to the infrastructure problems, legacy political interference through the Jones Act prevents Gulf oil products moving to the East Coast. Divisive US politics also causes a delay to the Keystone XL pipeline project, which is increasingly needed by Gulf Coast refiners that are suffering from weak Mexican and Venezuelan heavy oil supply and are therefore running much less than optimal heavy through their highly complex systems.

This is the current infrastructure challenge phase, characterised by extreme oil price differentials.

Figure 3: Better infrastructure, a glut of domestic light, narrowing WTI-WCS and robust product exports



Source: Deutsche Bank, DOE, Wood Mackenzie (base map)

By 2015, infrastructure issues have been addressed by a well capitalized, highly efficient, and aggressive US infrastructure industry led by MLPs. We assume the Keystone pipeline has been built, but cannot second-guess environmental pressure opposing the line. Keep in mind the oil sands CO_2 emissions in their entirety are less than two major US coal-fired power plants.

US product exports have continued to rise but are reaching their maximum capacity in terms of Atlantic Basin demand appetite. Soon, competition will rise among US refiners as US and Canadian crude growth pushes up against the crude export ban, and product exports hit maximum. This will pressure US product prices and refining margins. All light and most medium crude imports have been backed out of the Gulf Coast.

With the excess of crude, and crude export restriction, US E&P and sunk cost low decline Canadian producers are over-supplying the market. Prices are pressured toward marginal cost of supply, of around $80/bbl WTI. At the same time, continued Asian demand strength, Middle East tension, weak OPEC supply growth and Saudi price policy hold Brent in excess of $100/bbl.

This market looks good for international, Brent levered plays such as Chevron and ConocoPhillips. Strong for export-oriented refiners with crude choices, such as MPC and COP/Phillips 66. And problematic for US E&Ps and mega-bulls on US oil supply growth long term. We believe price pressure will defeat the most optimistic production growth forecasts.

Introduction – the playing field & key conclusions

In this note we attempt to analyze, in depth, the future of the North American oil market. The challenge to a very bright future may well be the behavior of politicians. "The Conspiracy of Ignorance About Oil" that we highlighted in December 2008 remains a real, material risk.

Looking past that uncertainty, we project the likely scale of domestic US and Canadian oil supply. We analyze how this will impact the US refinery crude slate and oil imports. We propose a theory for future US (WTI & LLS) pricing relative to waterborne international light crude, highlight some of the shifting temporary pockets of regional price dislocations and the refiners who will benefit, and establish a framework to map our expectations for US oil supply, demand, imports/exports and prices, against which progress can be tracked year by year.

In a perfect market, the price differential for various crudes would be determined only by quality and the relative cost of transit. But a handful of factors exist in the US that have created, and will continue to create, distortions in pricing. Over the last year we have seen infrastructure bottlenecks out of the American mid-continent foment an odd $20+/bbl gap between fungible (chemically similar/interchangeable in use) WTI and LLS/Brent. Going forward a handful of other factors set the playing field –

- US production growth is overwhelmingly light, sweet crude. This is not directly fungible with all US crude oil imports; the refining system has been developed to use increasingly heavy imported crudes – quite the opposite of current crude growth dynamics.
- **By law, crude oil cannot be exported from the US without a permit**, granted in only a handful of specific and narrow situations. Due to the political sensitivity of national energy security issues, we believe it is unlikely that this restriction will be lifted over the medium-term. Meanwhile product exports are only lightly regulated.
- It is prohibitively difficult on cost to move crude from the Gulf Coast to PADD 1 (East Coast) or PADD 5 (West Coast) refiners – no crude pipelines exist and other modes of transportation, such as barge, rail and truck, are expensive. Therefore we have a permanent "triple island" situation in North America, with the largest and most important island in the middle, a massive stretch that runs from the Western Canadian basin to the US Gulf Coast. This stretch is where the vast majority of both the production and refining capacity is on the continent.
- Pipeline infrastructure in the US, originally built to move crude into the crude-short middle of the country, will now be reversed/built to move crude from emerging Inland Corridor liquids-rich unconventional plays to the core of the US refining complex on the Gulf Coast. But infrastructure in the US is not centrally planned – it is not as simple as identifying a need and building. A peculiar self-defeating game theory often applies that inhibits shippers from committing to long term oil movement contracts despite a price advantage, as that very price advantage is likely to disappear once the infrastructure is built. As a result, as we have seen with the Cushing-GC linkages, projects will tend to take longer than expected to come to fruition. A sustained period of extreme price volatility between similar crudes that should price similarly can be expected to continue. As with the Rockies Express gas pipeline, huge projects may prove largely redundant by supply and demand shifts.
- We believe US oil demand growth will be declining in the near- and medium-term, and will experience accelerating declines by mid-to-late decade, due to increasing transportation fleet efficiency.

- Once the Seaway pipeline is reversed and ramped to 400kbd by 1Q13, the US will very temporarily be a "market in balance," with most domestic crudes trading close to where they should given their quality and transportation costs to market. WTI should trade at a discount to LLS (and Brent) of roughly $3-5/bbl, equal to the ~$3/bbl pipeline toll to the Gulf Coast, and $1-3/bbl for "last mile" transit costs by barge or lateral pipeline (e.g., a reversed Ho-Ho pipeline). LLS should trade at about a $0.50-$1.00/bbl premium to similar light imported crudes due to a lower transportation cost. This is the accepted wisdom, and we think it is correct as a static consideration of where we are headed at the moment. This note is about what comes next – the post-Seaway North American oil market.

So that is the landscape going forward – no export of crude, a structurally divided continent, misaligned infrastructure, and declining demand. Given this set of distorting factors, our analysis yields the following key takeaways:

1. **Supply surges.** Relentless North American crude production growth, likely 400-500kbd per year, will push up against local and regional infrastructure constraints, and will make differentials even more volatile. Even if pipeline construction keeps up, crude export restrictions mean we are heading towards a continental oversupply of light crude. There is potential upside to the pace of growth, but it is important to note that the faster the growth, the more quickly the dynamics highlighted in this note play out – which means lower domestic crude prices, and a disincentive for marginal production, which of course means slowing growth. Always keep in mind that the system is price dynamic.

2. **Export restriction = imports pushed out**. Growth in North American light oil, with WTI/LLS as its marker crudes, will displace imports one-for-one on the Gulf Coast – it has to, because crude produced in the US, or imported into the US from Canada via pipeline, can't be exported, as mentioned. North American light crude will first displace similar imported light crudes. Once international light crudes are displaced, WTI-linked crude will continue to push out "layers" of light/medium, then medium quality crude. This will all play out on the Gulf Coast. Our refinery-by-refinery crude slate estimate suggests there is currently only about 750-900kbd of waterborne light crude coming into the GC. Further comment on the US crude export restrictions are in the appendix.

3. **An LLS discount will emerge**. Once the Gulf Coast light crude imports are backed out, we believe that ever-growing volumes of WTI/LLS-linked crudes will be forced to trade down in price to compete with cheaper imported medium. Thus a new Brent-LLS differential phenomenon will emerge. We represent this pricing dynamic in a crude import "cascade." We think LLS will relatively quickly move towards a ~$5/bbl discount. The Brent-WTI diff should be Brent-LLS + $3-5/bbl. We view this as the *minimum* for the differential.

4. **Growing oversupply won't stop until price forces the issue**. The growth in unconventional will eventually put the US into a situation of dramatic oversupply of light crude, forcing export-restricted WTI/LLS to trade at an increasing discount to Brent. Eventually the lower price will start to hit the marginal cost of supply in the least economic areas of the Bakken and other unconventional plays, compelling operators to lay down rigs. We think that happens at about $75-80/bbl. Assuming Saudi defends $100/bbl Brent, the implication is that the upper end of the differential range is about $25/bbl. So we see a roughly $8-25/bbl discount range for WTI vs Brent longer-term.

5. **Temporary regional price dislocations**. Meanwhile we foresee localized North American price distortions emerging, then fading, wherever basin supply outpaces takeaway capacity. Typically rail will step in as the swing mode of transport. The Bakken has stimulated the construction of new refining capacity

and crude handling terminal hubs, such as in St. James, LA, as well as a large fleet of new crude railcars. It is cheaper and faster to build a new crude loading terminal in a new play, and crude railcars are highly mobile. Rail will handle takeaway while pipelines are built, and the $8/bbl (with only 80% delivery reliability) marginal cost of rail to the Gulf Coast or Cushing will set the temporary differential to WTI/LLS.

6. **The North Central will be tight until 2014**. Because of shared infrastructure chokepoints, the Bakken and Western Canada need to be viewed together to get a clear picture of supply-takeaway. We have already seen blow-outs in the northern tier, and while rail and some small expansions will help, the key chokepoints (Superior and Guernsey) won't be meaningfully widened until 2014. We see a lot of volatility in differentials for North Central crudes between now and 2014.

7. **Light-heavy should be volatile for next two years.** Echoing the North Central comments, the WTI-WCS differential should remain relatively wide and very volatile until the Enbridge Gulf Access expansions are completed in 2014.

8. **Long-term light-heavy will be structurally narrow.** Refinery demand for heavy crude is growing, with 440kbd of conversion projects in the Mid-Con, a new 95kbd coker at Motiva Port Arthur, and multiple pipelines opening access to the heavy-hungry Gulf Coast. From 2014 onward, demand pull for Canadian heavy should easily stay ahead of the robust oil sands growth, and WTI-WCS should be more stable and structurally narrower.

9. **Refiners will only benefit from cheap crudes if the export story works**. The key question for US refiners is whether North American oil product prices can hold international parity. Our view is that they will generally be priced to Brent-levels, as long as the US Mid-Con is short product and needs to pull from the Coasts. However, Gulf Coast refiners will no longer be paying Brent prices for the marginal light barrel going forward. The key will be product exports – if highly efficient US Gulf Coast refiners can steal market share across the Atlantic Basin, they won't need to flood the Mid-Con with product. There is going to be a "bankruptcy battle" among refiners for market share, the question is whether it happens in the US or across the Atlantic Basin markets. Major sustained European recession is a threat.

10. **Conclusions in a nutshell.** Bearish US light oil prices; bullish selected refiners; inland heavy-light wide and volatile near-term, narrower long-term; export story is the linchpin for long-term product pricing. Prefer Eagle Ford producers of US oil, even with US crude discounted. Prefer Brent leveraged oil plays in general. Prefer Rockies refiners above all; expect volatile differentials leading to major excess profits for key refiners at certain, unpredictable, times.

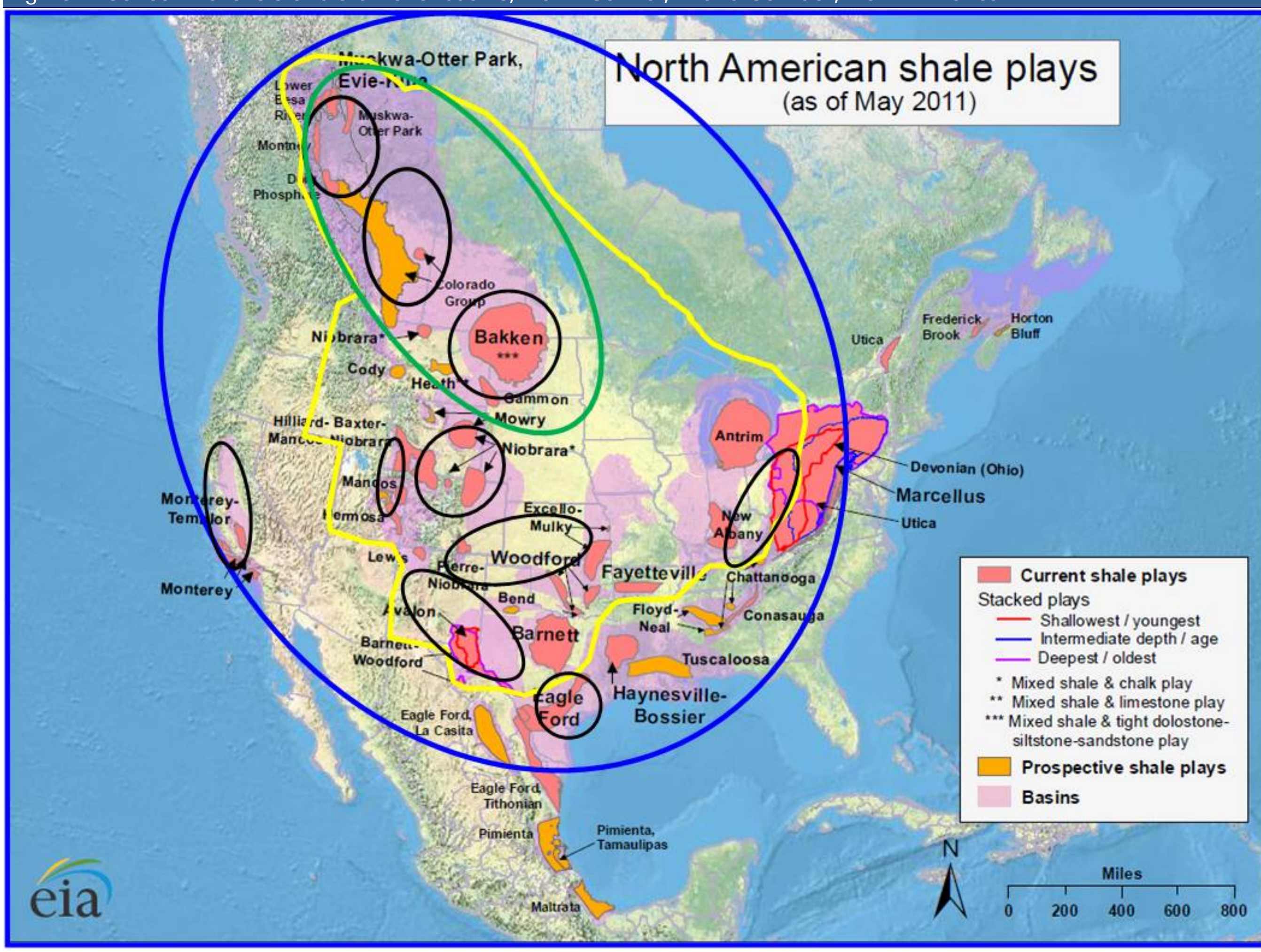
11. **Risk: fear the politicians.** Their agenda is set by US oil consumers. It should be, but with responsibility, not pandering and partisanship. Someone must have the courage to raise US gasoline taxes if they really seek to reflect the cost of oil – environmental, geopolitical, economic. At this time it seems that partisanship dictates that one side argues the direct opposite of the other purely for political capital. US unconventional oil production and refining has the potential to be the most exciting, fast-growing, export-generating, employment creating part of the US economy. Politicians have the potential to totally distort, upset and even prevent that. We are not oil apologists. We support long-term economic alternatives to oil. By far the most attractive is efficiency of use. By far the worst is distortion of markets, especially if for confused, self serving, or blindly nationalistic reasons. Basic economic law shows that trade is good. The US economy built itself on free trade. Ending that will end US economic growth.

Differentials and distortions

Conceptually we think about the dynamics of US crude oil pricing on three interrelated geographic levels, each with its own set of potentially distorting factors. One can think of them as concentric circles, the smallest is the basin level, the intermediate is the giant landlocked Inland Corridor, the broadest is the North American continent.

The basin level distortion is typically fairly simple – production growth outstrips takeaway capacity, crude backs up in the basin, the price differential widens. Infrastructure isn't always the distortion, however – for example black and yellow wax in the Uinta basin can't be shipped by pipeline before processing, and therefore will sell at a structural discount. Basin distortions tend to be temporary, with infrastructure eventually catching up with volume growth.

Figure 4: Concentric levels of distortions: basins, North Central, Inland Corridor, North America



Source: EIA, Deutsche Bank

The intermediate tier, the Inland Corridor level, has driven the US crude pricing and refining margin dynamics for last 15 months, and the distortion has been insufficient infrastructure (coupled with surging Canadian and US unconventional production), specifically a pipeline outlet from Cushing to the Gulf Coast.

Our initial focus was on the timing of the construction of Keystone XL, but as that controversial pipeline has been indefinitely delayed, the Seaway pipeline reversal has stepped into the breach. That pipeline is expected to begin shipments to the Gulf Coast in June, and ramp to its full 400kbd capacity by 1Q13.

With Seaway reversal now set to at least temporarily resolve the current distortion by 1Q13, the third and largest "circle," the North American market as a whole, will soon come into focus.

There are at least three distortions that shape what we see unfolding on a continental level.

- The first is **infrastructure**, similar to the basin and inland corridor levels. A quick look at any pipeline map (see the CAPP map in a later section) shows that the US and North America are divided into three north-south strips, with the largest section in the middle, disconnected from the East and West Coasts. A lack of east-west crude pipelines means PADD 1 and PADD 5 can't easily access production from Alberta, North Dakota or Texas. Rail and truck can move crude to the coasts, but those modes at those distances are cost prohibitive.
- The other two distortions are **regulatory/legal**, with a strong political element. The most important is the **restriction on the export of crude** from the US (see the appendix for a brief history and description of crude export restrictions). The analysis in this note is contingent on federal short supply control restrictions staying in place. We think American concern regarding "energy security," which exists as strange bedfellows on both sides of the Congressional aisle, will likely keep the restriction in place for the foreseeable future. Having said that, public and political priorities and fears ebb and flow. Everyone once thought that Iowa presidential politics had locked in corn ethanol subsidies for good, but support for those fell away quickly over the last two years. So we acknowledge that support for the crude export restriction could erode over time.
- The third distortion that will shape future domestic crude pricing is **the Jones Act** (see appendix for more detail), which mandates that any intra-US shipping by water be done using vessels under US flag, built in the US, and manned primarily by US crews. This greatly increases the costs of shipping, for example, from Houston to Philadelphia. Thanks to the Jones Act, shippers can't pull a 2Mbbl capacity VLCC into the Houston Ship Channel, load up with cheap Eagle Ford crude, and zip around to Delaware City at a $3/bbl shipping cost.

The analysis that follows is an attempt to understand what is likely to happen to crude oil prices in North America, post-Seaway, given the "playing field" set by these distorting factors.

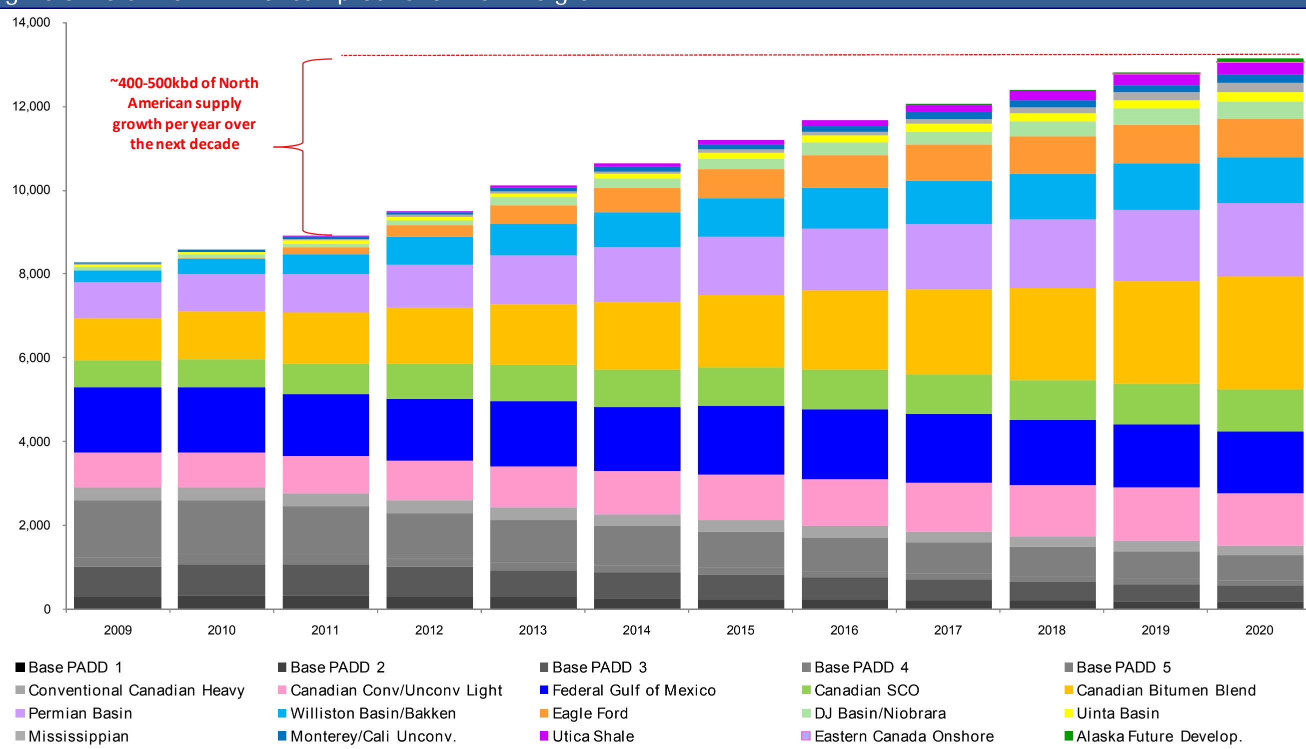
North American production growth

In order to understand and model future North American oil price and supply-demand trends we need a comprehensive view of North American production, imports and demand. We start with our production model.

We have modeled out oil production from eight US unconventional plays using an "average" type curve and a rig count estimate – assumptions for those basins are included in the appendix. For Canada we start with the Canadian Association of Petroleum Producers' (CAPP) estimates and tweak the unconventional light crude forecast upward to reflect likely growth from a few key plays. Our Gulf of Mexico forecast is based largely on Wood Mackenzie's estimates. We have applied a conservative 7-9% annual decline rate to everything else in North America. We adjusted for some incremental production from Eastern Canada onshore and Alaska future development near the end of the decade.

The resulting forecast, which we consider a base case with more upside over the medium-term than downside (in fact, given the Canadian oil sands project queue and the tendency for unconventional plays to surprise, we think there could be considerable upside, though we think it is important to understand the limitations of dynamic prices and infrastructure, which keeps our estimates relatively modest compared to a few recent bombastic predictions), suggests that North American production will add, on average, 400-500kbd of oil production growth per year over the next decade, with annual peaks as high as 650kbd.

Figure 5: Total North American production volume growth



Source: EIA, Wood Mackenzie, Company data, IEA, Bloomberg Finance LP, Deutsche Bank estimates

A few thoughts on our production forecast:

- The projected growth breaks down roughly **50/50 between Canada and the US**, and about **60/40 between light and heavy**, though the year-to-year mix varies widely depending on project start up schedules and the pace of unconventional play development.
- It is worth noting that almost all of the growth is **driven by "frontier" modes** of oil extraction opened up by technology and a high oil price: deepwater and ultra deepwater, unconventional, oil sands.
- Again, we acknowledge **some potential for upside to the forecast, but highlight several reasons for restraint** –

  1) As we will argue later in the note, we are heading towards a continental oversupply in light crude, which will push prices down and eventually disincentivize growth,

  2) Infrastructure and a strained skilled labor pool both constrain growth and will take time to develop,

  3) While it is easy to be bullish on any individual play in isolation, analysts must be careful not to simply add up plays and conclude we will see 1Mbd+ of growth a year – activity will migrate away from the margins towards the best opportunities, so growth will likely slow in one play as another heats up,

  4) The comparison of unconventional oil production to natural gas production (i.e., operators will continue to produce beyond rational economics, create a massive glut, and therefore destroy pricing) makes some sense, but we think it is unlikely to play out in the same extreme way. Two key drivers for nat gas oversupply were (a) the shift towards liquids-rich nat gas plays and (b) associated gas from unconventional oil production. There is no analog for unconventional oil production on either count – associated gas undermines rather than subsidizes economics.

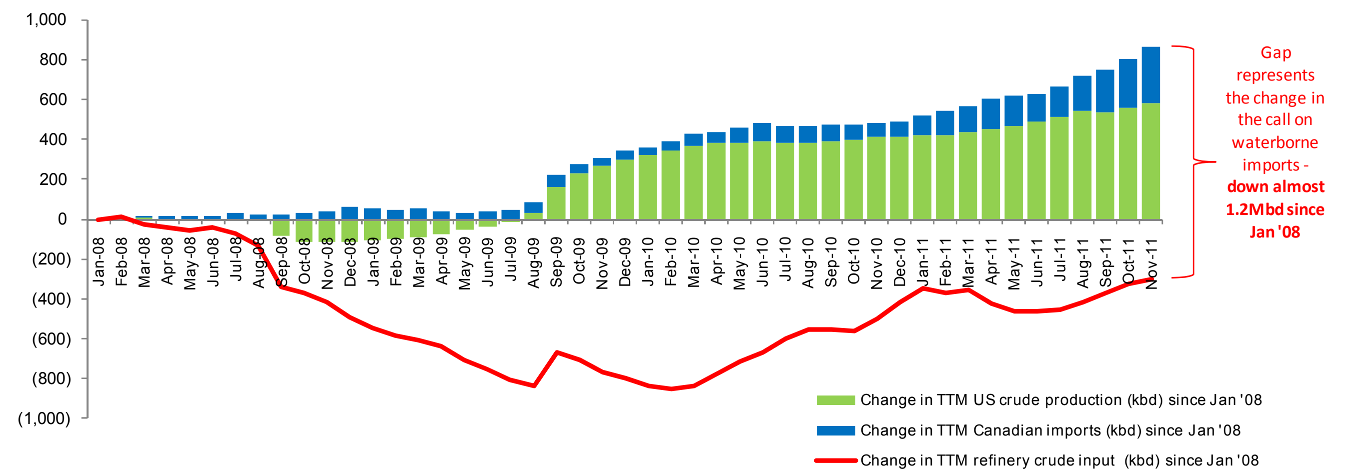
- **Canadian unconventional light production** has the potential to be much greater than either CAPP's subdued forecast or our own somewhat higher expectation. We acknowledge growing potential and enthusiasm for a number of unconventional oil and liquids-rich nat gas plays in Canada – Cardium, Duvernay, Southern Saskatchewan/Alberta (Bakken, Exshaw, etc.), liquids-rich Montney, Horn River. However, we model this growth cautiously for a number of reasons. As mentioned, we believe by mid-decade North America will be in a light crude oversupply situation. In our view geographic remoteness will be a major competitive disadvantage in terms of both costs and realizations. Even if well economics are excellent, remote plays will have major logistical hurdles to get to a (US refining) market that won't need the light oil. The Duvernay may be the "Canadian Eagle Ford" (more than twice as big, similar subsurface potential and early well performance, etc.), but the real Eagle Ford is just a hundred miles from Gulf Coast refineries, with a surplus of cheap pipeline capacity to facilitate. Canadian light will have to travel longer distances, through as yet un-built gathering systems, into trunk-lines already reserved for other supply, through numerous chokepoints that have already prompted major differential blow-outs, to get to US refineries that have a desire for more heavy sour crude. This does not strike us as a good environment for realizations. The West Coast export route, developed later in the decade, could change that.

- In our view, to a certain degree, the production growth expectation, a big focus of media and oil analysts right now, misses the more important point. **It is the looming light over-supply and the infrastructure that matters most.** If we DO experience a 1Mbd+ surge, it can only last for a short while, and will accelerate the dynamics we will talk about shortly. In the end our decade-long average can't be dramatically too low, because there just isn't enough room in the US refining crude slate for that much light. The US crude export restriction will need to removed or revised for the light oversupply calculus to change.

The US import picture – light imports in free fall

Rapid growth in US and Canadian production over the last several years has dramatically changed the US crude import picture.

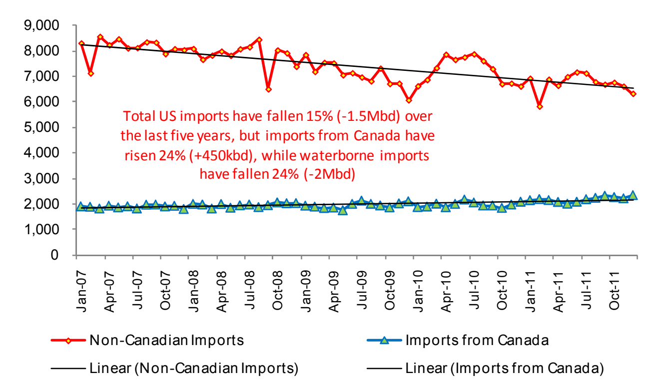
Figure 6: Change since 2008 in rolling 12 month refinery crude demand vs. US production & Canadian imports



Source: EIA, Deutsche Bank

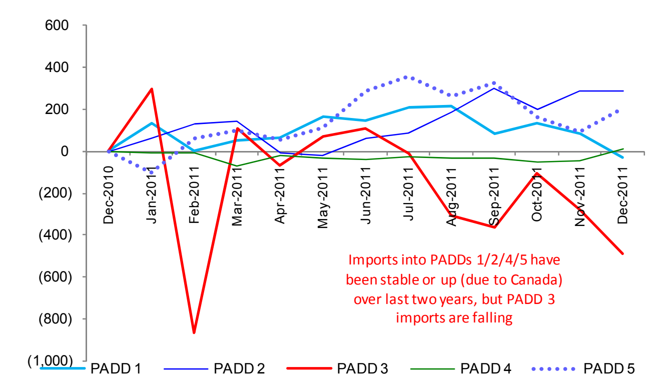
While total refinery crude throughput has recovered somewhat from 2009 lows, it is still well below 2007 & 1H08 levels. The production ramp coupled with lackluster demand means the call on waterborne crude imports is down meaningfully over the four year period. Figure 7 below illustrates the structural decline in US non-Canadian imports.

Figure 7: Non-Canadian imports falling quickly



Source: EIA, Deutsche Bank

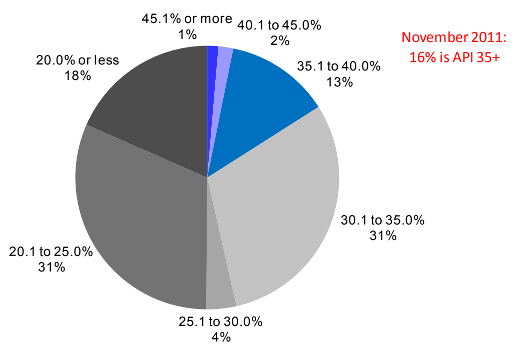
Figure 8: Change in imports by PADD since Dec 2010



Source: EIA, Deutsche Bank

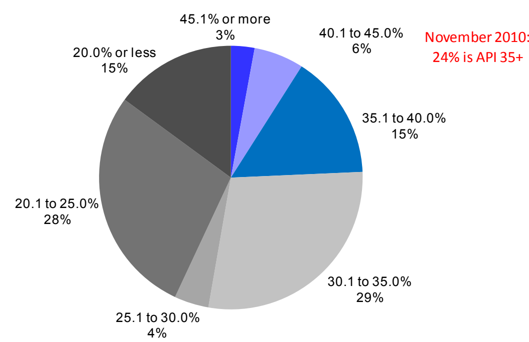
As you would expect, most of the decline in crude imports into the US has occurred in PADD 3, along the Gulf Coast, where domestic and Canadian production is forcing out waterborne imports (Figure 8 above). Imports are up YoY in PADD 2 (Canadian surge) and PADD 5 (growing demand, switch-out of South American for ANS), flat in PADD 1 (refinery idling offset by higher runs) and PADD 4 (local production keeping Canadian at bay). But PADD 3 imports are down by nearly 500kbd YoY through December.

Figure 9: US import mix by quality, November 2011



Source: EIA, Deutsche Bank

Figure 10: US import mix by quality, November 2010

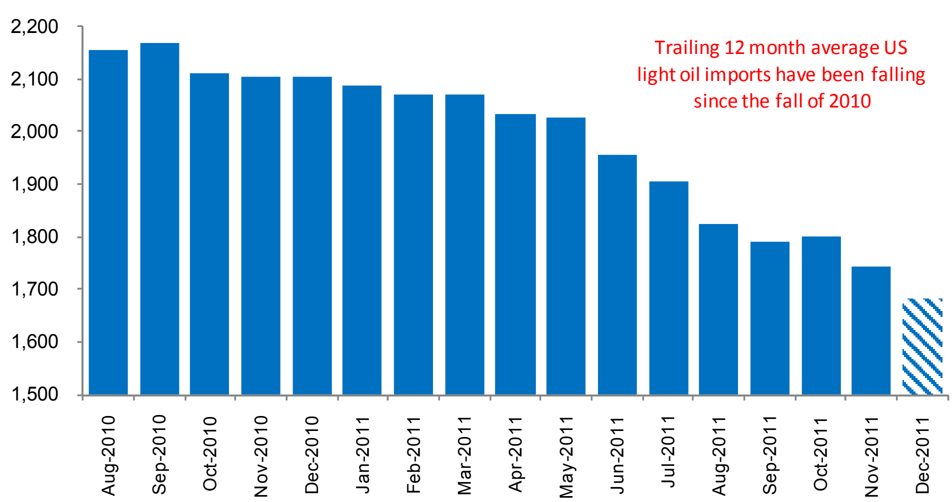


Source: EIA, Deutsche Bank

Since much of the production growth reaching the coast is light (Eagle Ford, Bakken by rail, etc.), it is **light imports that are being pushed out of the import slate**. The pie charts above illustrate the changing US import mix – a year ago about a quarter of US crude imports were of light oil, while as of November 2011 the portion had fallen to 16% and we believe it has fallen further in the 2-3 months since.

The trailing twelve month view of US light crude imports below shows how rapid the decline has been over the last year.

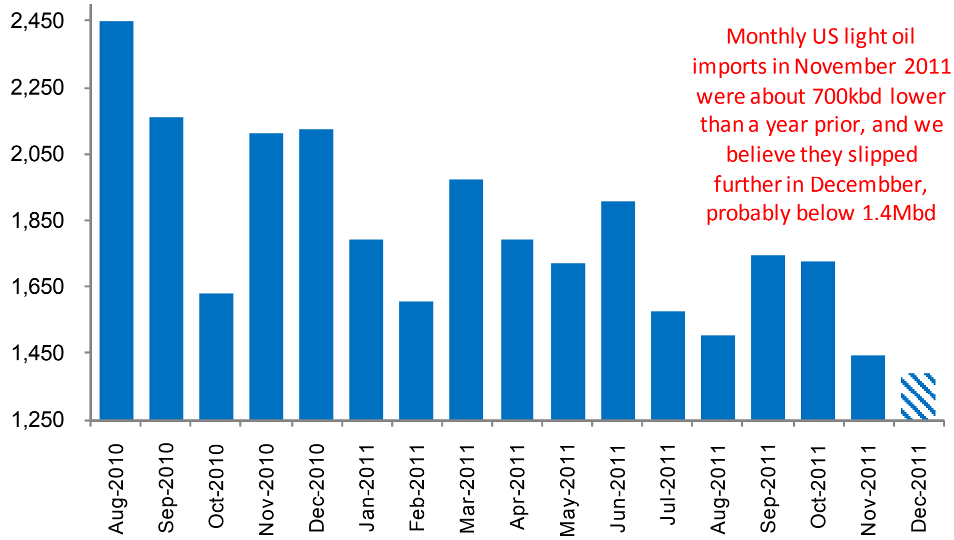
Figure 11: Trailing 12-month average US imports of light (API 35+) crude



Source: EIA, Deutsche Bank estimates

While the trailing twelve month average gives a cleaner view of the trend by removing month-to-month volatility, it also doesn't fully capture the very near-term decline we have seen as accelerating volumes of Eagle Ford crude have moved to the Gulf Coast via a new pipeline.

Figure 12: Monthly US light (API 35+) crude imports, with DB estimate for Sep-Nov



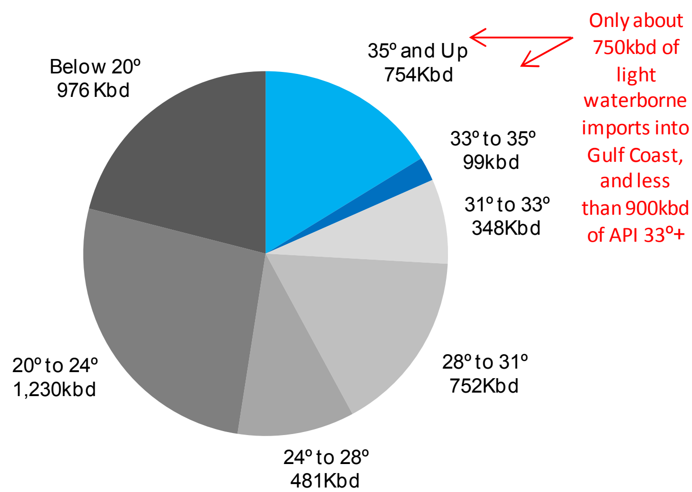
Source: EIA, Deutsche Bank estimates

EIA import data by crude quality is published with a couple month delay, so we haven't seen numbers yet for December and January, but there was a ~300kbd decline in total imports from September to November, and so we believe that the light import number has continued to decline as Eagle Ford volumes surge and Bakken oil arrives by rail to St. James.

The North American and PADD 3 crude slates

In the absence of EIA PADD-level import oil quality data, we have estimated the current PADD 3 waterborne imported crude slate by aggregating our refinery-by-refinery estimated crude slates, triangulating with EIA US data, refining company data and comments, producer comments, Wood Mac estimates and our own estimates. Although US oil data are the best and most timely globally, challenges remain, especially in areas such as refining input where commercial sensitivity is high.

Figure 13: Estimated PADD 3 non-Canadian crude import slate by API quality



Source: Company data, EIA, Wood Mackenzie, Deutsche Bank estimates

We believe that out of the 4.6Mbd or so of non-Canadian crude being imported into PADD 3 currently, there is only about 750-800kbd of 35 degree API or higher crude, and less than 900kbd of 33 degree API or higher crude.

Based on conversations with, and public comments from major refiners, we believe this breakdown is in the correct ball park. Estimates from the refiners put PADD 3 waterborne light crude imports in the 700kbd to 1Mbd range.

The conclusion is that the maximum potential for US crude import substitution by US unconventional growth is far lower than current perception. There is a simple confusion between total US crude imports and substitutability, and the real, far lower light, substitutable component of those imports. On the Gulf Coast alone, some 4.6mb/d of crude imports in total are only, as highlighted, around 15% replaceable before excess supply will begin to build.

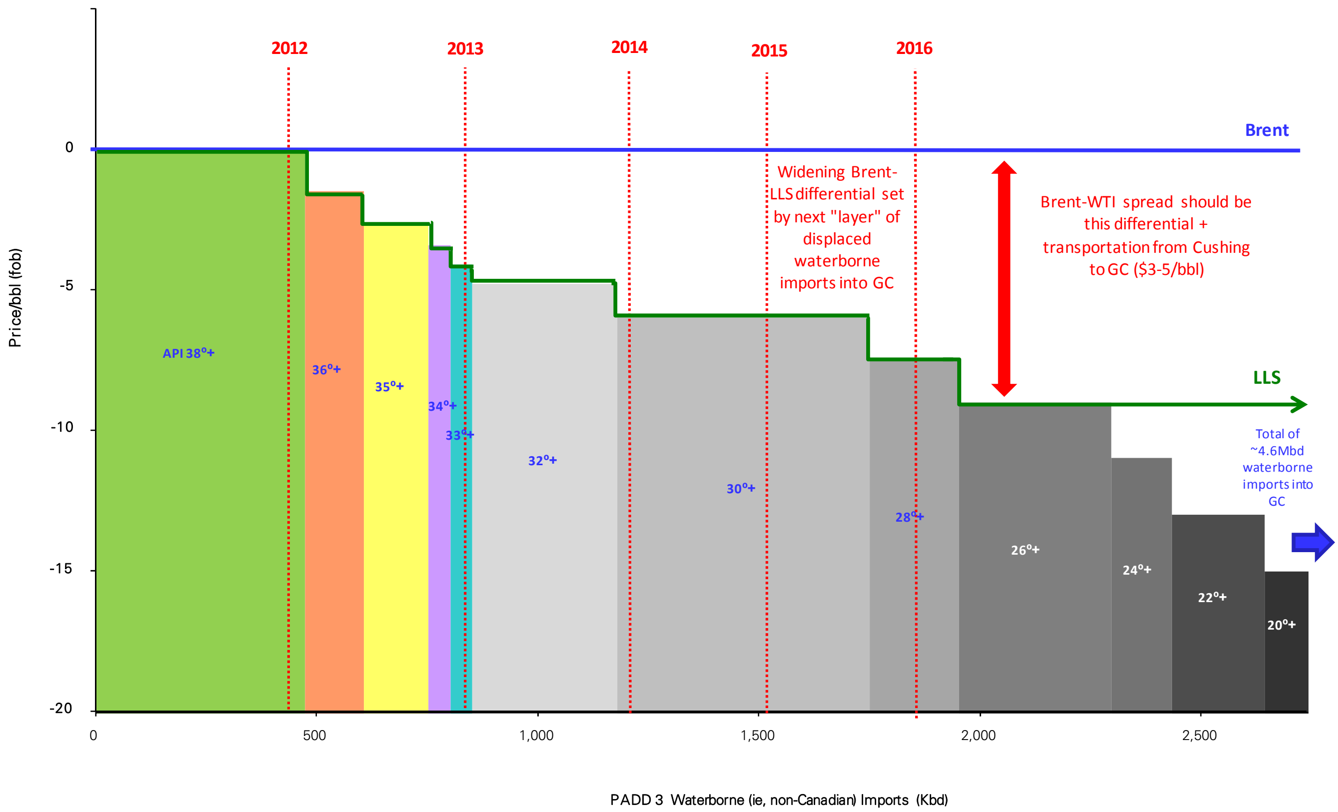
WTI and the import slate cascade

So how will the market handle the relatively fast substitution of light imports and then over-supply? **Key point: light demand from refiners is limited, and falling**.

The import slate cascade graphic below essentially consolidates our production forecast and the PADD 3 waterborne crude import pie chart, and summarizes the resulting (minimum) pricing dynamic we foresee for LLS and WTI, relative to Brent and other global light crudes, going forward.

Each column in the cascade represents a crude quality slice of the PADD 3 import mix. The width of the column is the volume of imports, the height is the average price of that quality tier, relative to Brent.

Figure 14: Our PADD 3 crude import "cascade" – gauging the scale and timing of the Brent-LLS/WTI differential



Source: Company data, EIA, Wood Mackenzie, Bloomberg Finance LP, Deutsche Bank estimates

For this exercise we've assumed that incremental North American light crude production will displace the lightest crude first, then will displace the next lightest remaining imported crude and so forth.

Conceptually, we believe that export-constrained LLS will trade down to the next quality tier of imported light or medium crude until that tier is displaced by domestic light crudes.

In general, based on both typical yield and empirically observed crude prices, our rule-of-thumb is that each API "tier" is worth about $0.50 to $0.85 in price, usually in the $0.60 to $0.65 range, holding sulfur and TAN and other factors equal.

Once LLS and WTI have displaced all of the comparably light waterborne crudes, and are competing with crudes below their own API level, we expect their prices to fall to the next quality tier in the import slate. They may capture a slightly higher price than the displaced crude due to higher yield, but in order to avoid being backed up into Cushing or elsewhere, they will need to "trade down the cascade."

We've over-layered our projected North American light crude growth forecast by year, marked by the red dotted lines, to show roughly how quickly we think a Brent-LLS differential could emerge. By the end of 2013 it looks to us like you could see a $5+/bbl structural differential for Brent-LLS, based on increasing domestic light production alone.

The Brent-WTI differential, based on this analysis, would be roughly the LLS differential plus the transportation cost from Cushing to the Gulf Coast refineries, which is roughly $3-5/bbl. As a reminder, Seaway is expected to ramp to 400kbd in early 2013, at which point the consensus is that the Brent-WTI differential should settle towards that $3-5/bbl transportation cost level. We agree with that general conclusion from now to 1Q13, but we see the potential for a re-widening of the Brent-WTI within a year post-Seaway, to $8-10/bbl.

By 2014 or 2015 the Brent-LLS minimum differential could be $5-8/bbl or more, and thus Brent-WTI could be $10-13/bbl+, close to what we see today.

Because this is a conceptual exercise we used *only* our light production growth estimate to project when the Gulf would no longer need waterborne light imports. In reality several factors suggest that light imports will be pushed out much more quickly:

1. **Mid-Continent refinery conversions** between now and the end of 2013 will add about 440kbd of heavy capacity, but only about 100kbd of total refinery capacity, and thus will reduce implied light demand by about 340kbd. That includes COP/CVE Wood River's CORE project, which started up in the last couple of months, but the effect of which hasn't showed up yet in EIA numbers. Even without Wood River, conversions at Detroit and Whiting will lower theoretical light demand in the Mid-Con by over 300kbd.

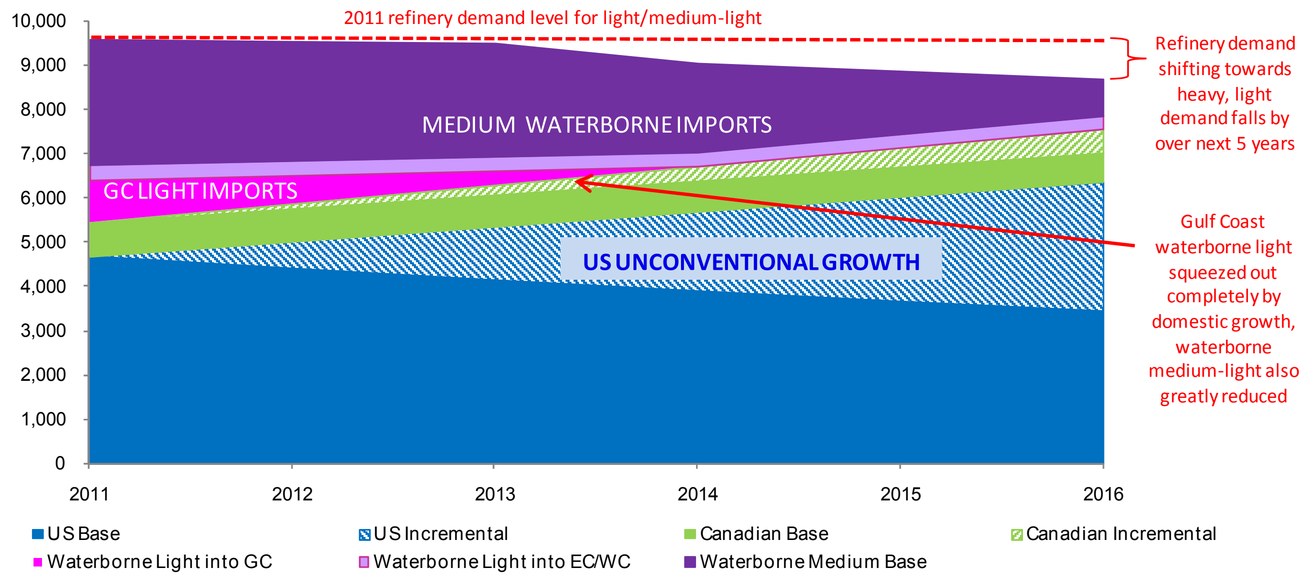
2. **Seaway reversal** may initially bring some cheap light crude to the Gulf Coast, but we expect it to largely be used to deliver even cheaper Canadian dilbit and conventional heavy. In general Gulf Coast refiners want to run much more heavy sour (discussed further in a later section). As they gain access to Canadian heavy via Seaway and **other projects** (Keystone XL, Seaway expansion, crude-by-rail from Canada), light and medium imported barrels will be backed out, and they will largely have to be imported barrels. Recall that Seaway reversal takes place in June 2012, and will ramp to 400kbd by 1Q13. So the potential for a near-term acceleration of displaced light import crude is high.

3. **Motiva's Port Arthur expansion** (Shell/Saudi Aramco JV), expected to finally startup in 1H12, will add about 325kbd of total capacity, and will include a 95kbd coker. We would expect that up to 200kbd of the new capacity would optimally be for heavy crude, likely a large portion of Saudi Heavy (API 28), but also some Canadian heavy. While 100-150kbd of light capacity will also be added to the Gulf Coast, one would expect much of the incremental capacity from Motiva to push out some less efficient/complex Gulf Coast refiners, who run primarily light crude, and who will be forced to lower utilization rates to make way. **Thus the net impact on light consumption on the Gulf Coast may actually be reduced demand once Motiva starts up.**

The call on light and heavy waterborne imports is much different

As we have described in the last several graphics, dramatic growth in North American light crude supply will force out light waterborne imports, then eat into medium waterborne imports. Refinery conversions and pipeline access to cheaper Canadian heavy crude will likely shift some US refinery demand from light/medium to heavy/medium sour. The evolving mix for refinery demand for lighter crudes is illustrated in the following chart.

Figure 15: Evolution of US refinery demand for light/medium crudes over next half decade

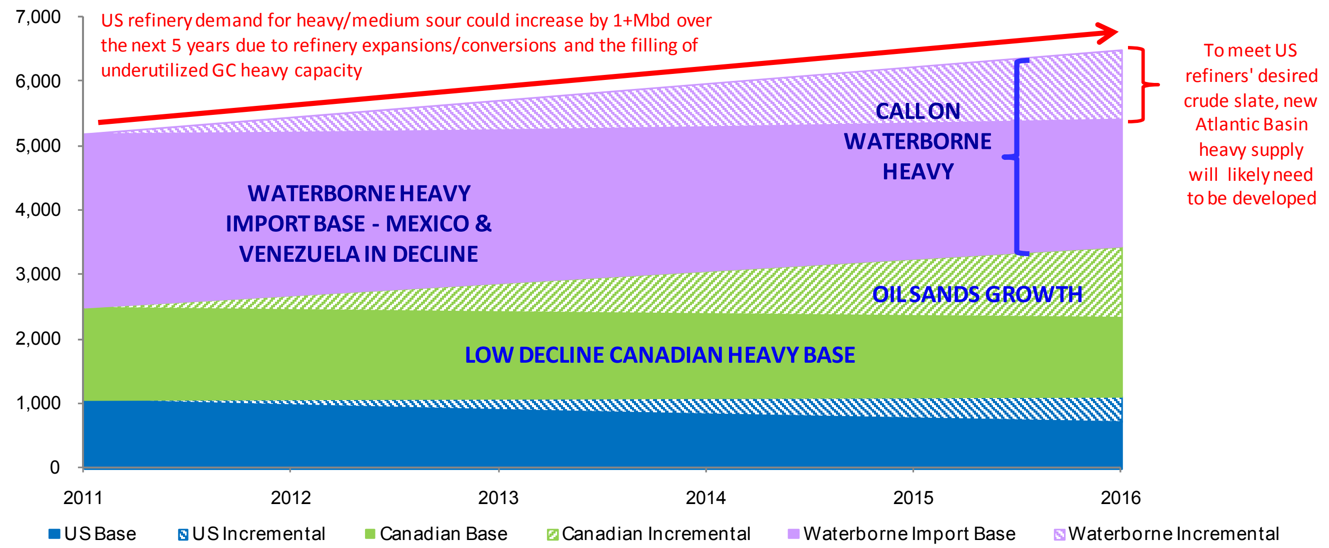


Source: EIA, CAPP, Wood Mackenzie, Company data, Deutsche Bank estimates

The story for heavy is much different. While there will be tremendous growth in North American heavy production thanks to the Canadian oil sands, US refinery demand for heavy will likely also increase meaningfully. Mid-Continent refinery conversions, including the recently started-up Wood River CORE project, will add over 400kbd of heavy capacity relative to 2011 (Detroit and Whiting are the other two major projects that will be completed over the next two years). The Motiva Port Arthur expansion will likely add ~200kbd of heavy demand to the Gulf Coast, and in general the Gulf Coast refiners will shift towards more heavy/medium sour as they gain pipeline access to Canadian heavy. We believe that the Gulf Coast currently runs 600kbd to 1.2Mbd less heavy/medium sour than it could or wants to, due to a too-narrow waterborne light-heavy differential. Access to deeply discounted Canadian heavy via the Enbridge system or Keystone XL will likely fill that underutilized Gulf Coast heavy capacity.

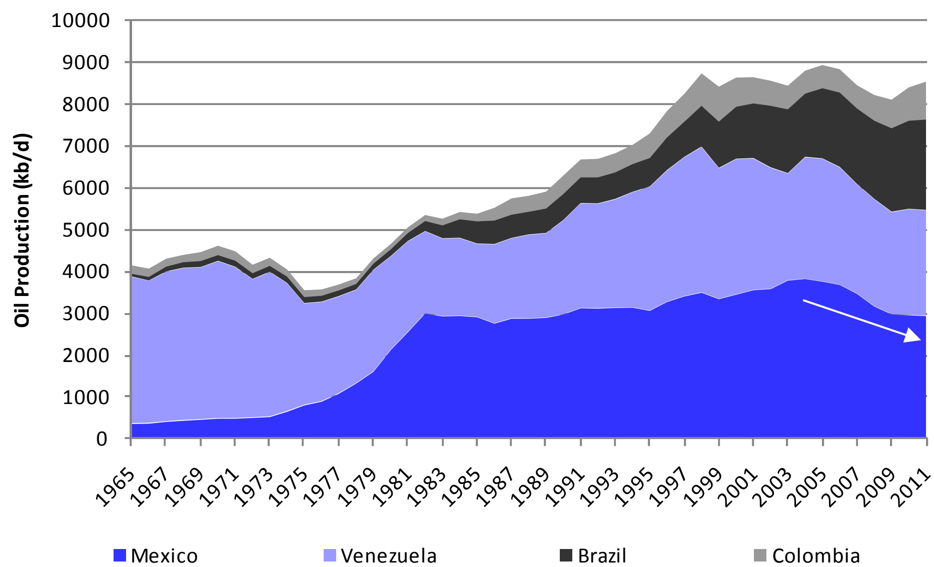
The US refinery demand chart below illustrates the dynamic for heavy over the next five years. Canadian heavy production growth should be roughly 150-200kbd per year, with potential for upside given the current announced project queue (see later sections for more detail). Even with that growth, the call on waterborne heavy is substantial. One conclusion is that the Gulf Coast refiners will take all of the Canadian heavy production they can get their hands on. Another is that both the inland and coastal light-heavy will probably be structurally narrow (though for infrastructure reasons we think WTI-WCS will be volatile and wider until 2014, more on that later in the note).

Figure 16: Evolution of US refinery demand for heavy/medium sour crudes over next half decade



Source: EIA, CAPP, Wood Mackenzie, Company data, Deutsche Bank estimates

Figure 17: Oil Production – Mexico, Venezuela, Brazil and Colombia



Source: BP, IEA

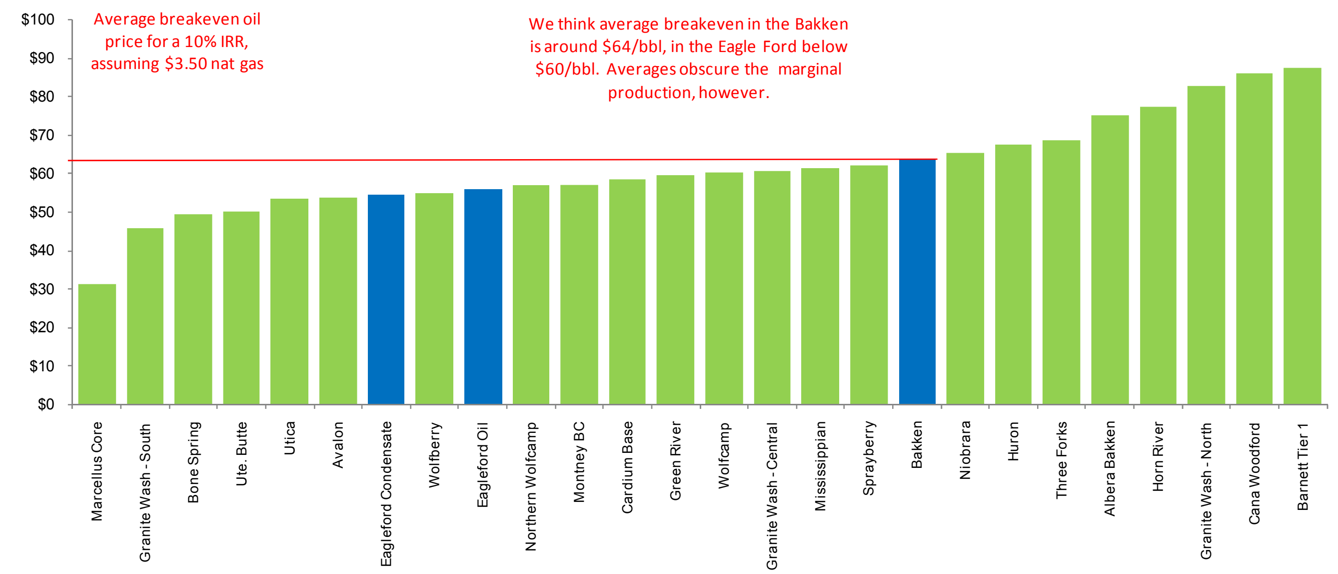
Having said that, a shift in refinery demand of ~1Mbd towards heavy means the call on imported waterborne heavy crude will remain flat or even rise, despite the growth in Canadian heavy. Given the structural decline of Mexican heavy, and persistently disappointing Venezuelan production, the market may be challenged to supply a heavy-hungry Gulf Coast refining complex, as it is today. Saudi will supply the Motiva Port Arthur expansion, but we do wonder if growth from Brazil and other emerging heavy producers will be enough to offset the Mexican decline and Venezuela's choppy development. **This is a key rationale for our view that Gulf Coast imported heavy, priced under Maya, will trade close and even at a premium to US domestic light crude.**

How wide can the light differential go?

We view the incremental displacement of medium/intermediate crude as the mechanism that will set the *minimum* differential between LLS/WTI and Brent. However surging production of light crude in North America may eventually cause the differential to blow out to much wider levels. How wide can the Brent-LLS and Brent-WTI go? Obviously we have already seen Brent-WTI blow out to nearly $30/bbl (summer 2011), and Brent-Bakken to over $40/bbl (winter 2012).

The light crude oversupply will likely continue until price strongly incentivizes enough operators to lay down rigs on the margin. Most of the major US unconventional plays have average economic breakevens below $70/bbl, and average breakevens in the Eagle Ford liquid windows appear to be $60/bbl or below. In the Bakken we think the average is around $65/bbl.

Figure 18: Average breakevens for the major North American liquids-rich unconventional plays-



Source: Company data, Wood Mackenzie, Deutsche Bank E&P Equity Research Team, DB estimates

Averages obscure the fact that most plays have a sweet spot and marginal areas, and during the high oil price-driven booms there is plenty of drilling activity in counties and sub-regions with marginal economics. The Bakken in particular has a wide variability between top quartile areas and bottom quartile marginal areas. Furthermore, Bakken type curves tend to have steep declines, thus a fall off in drilling will hit basin production more quickly than many other basins. The Bakken also has the scale to make a difference to oversupply should drilling activity pull back.

We therefore think the economics of the marginal Bakken is the best “shorthand” way of determining the price at which North American light supply will rationalize. Obviously volatility spikes could push the differential beyond the range this rationalization sets for short periods, as we have seen a couple of times over the last year. Using the low-end of public company ranges for Bakken well results to represent the marginal regions within the Bakken, we think $75-80/bbl WTI is the level where we see meaningful reduction in activity in US unconventional oil drilling on the margin, likely in the Bakken. This estimate is supported by reductions in Bakken activity seen in Q3 2011 when WTI prices touched $80/bbl and operators laid down rigs.

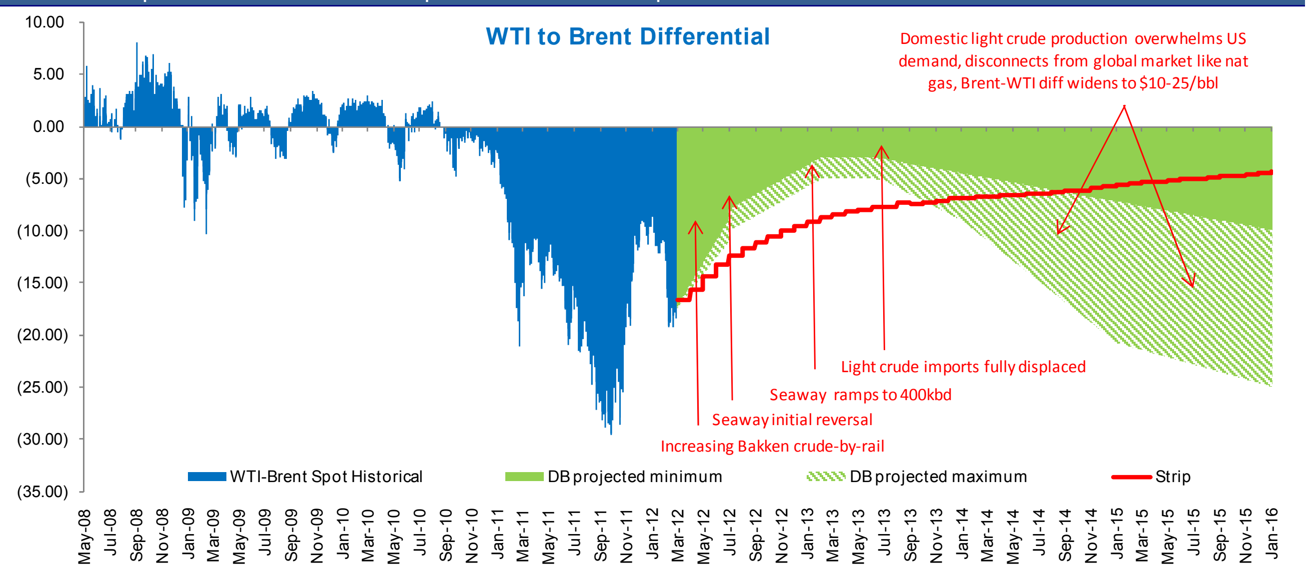
Figure 19: Estimated well economics for marginal Bakken acreage vs. play average

	Average	Marginal Area
EUR	525	350
IP Rate (30 day)	900	400
% Oil	87%	86%
Gross Well Cost	$9.5M	$10.0M
Assumed IRR	10%	0%
Breakeven	**$64**	**$80**

Note: Average well metrics for the Bakken from the DB E&P Research Team's estimates, based on reported company well performance data. For the marginal Bakken acreage we use the low-end of published company well metric ranges as a proxy. We based these approximate metrics on the data offered by the top 25 acreage holders in the Bakken, though each company reports different sets of data, some offering up a range themselves, others publishing the results from a set of specific wells. The estimate we use here is not an average of the low-end of the range, but rather a rounded approximation of where the low-end appears to be, excluding the extremes. The calculated IRR is after-tax, and assumes $3.50/mcf for gas, Y grade NGL pricing at 50% of WTI, and a 25 year life for wells. We use a b factor of 1.3, an initial month-to-month decline rate of 40% from the 30 day IP rate, and a terminal decline of 7% yoy for the Bakken.
Source: Company data, Wood Mackenzie, Deutsche Bank estimates

As we have highlighted in other notes (e.g., 12/12/11 FITT note – "The Pressures on OPEC"), due to a post-Arab Spring national budget that requires ~$92/bbl oil to balance, Saudi has stated it will defend ~$100/bbl to the upside. Capacity growth in OPEC already trails demand growth, and is 70% dependent on Iraq over the next 5 years. So we view $100/bbl with upside to demand destruction ($130/bbl) as our Brent scenario. If unconventional production volume growth flattens when WTI falls to around $75-80/bbl, that would suggest a sustainable high-end to our expected differential range of about $20-25/bbl.

Figure 20: DB expectation for Brent-WTI spread vs. current strip



Source: Bloomberg Finance LP, EIA, company data, Deutsche Bank estimates

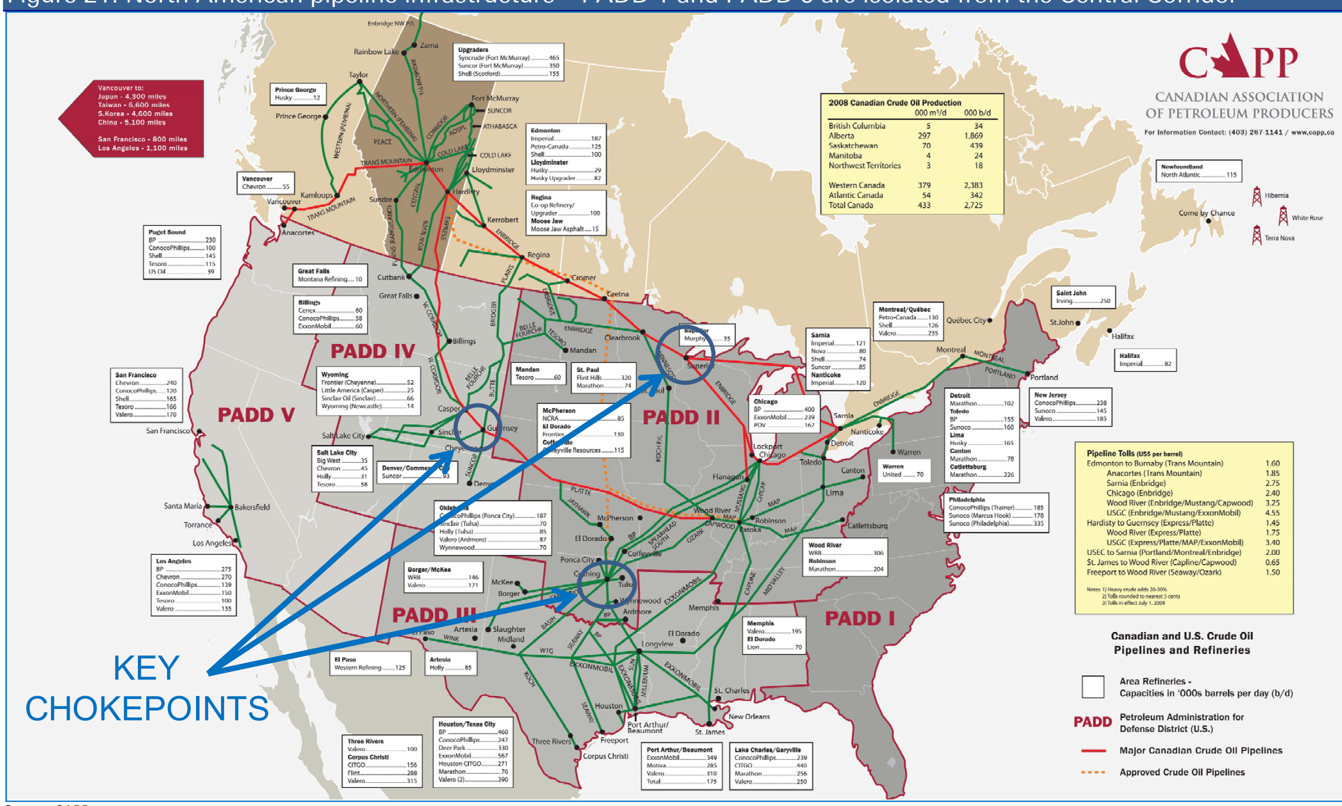
So our expected range for Brent-WTI over the medium-term (2013 to 2016) is $8/bbl to $25/bbl. Volatility is likely to be high, and we believe we will see the differential move outside those parameters for short periods, but that range is where we think it will gravitate once water-borne light crude has been fully pushed out and we move into a period of chronic over-supply. Note that the current strip is pricing a consistently narrowing differential over the same period, as illustrated above.

North American infrastructure – dead spots and price dislocations

As North American crude production growth has surged beyond expectations, midstream companies have ramped infrastructure activity. Literally dozens of major pipeline projects are now in the queue for startup between now and mid-decade. Many of these projects face political, regulatory or shipper commitment hurdles and will likely be delayed, revised or scrapped. Given the likelihood of unexpected production growth surges, the timing of many of these pipeline projects becomes critical in projecting future price locations.

As the CAPP map of major North American crude pipelines below shows, there are many regions and emerging oil basins of the US and Canada that are either not connected at all to the main pipeline networks, or have limited capacity. Indeed the US East and West Coasts are essentially disconnected from the central corridor of the continent. Within PADD 2/3/4, there are sub-regions that are pipeline dead spots or are severely underserved. When an unconventional play within those regions sees a surge in production, new pipelines and/or crude-by-rail handling infrastructure needs to be built, and there is often a lag, which causes the trapped crude to price at a discount to marker crudes.

Figure 21: North American pipeline infrastructure – PADD 1 and PADD 5 are isolated from the Central Corridor



Source: CAPP

The current major pipeline project queue:

Figure 22: Proposed major North American crude pipeline additions/expansions (in order of startup)

Pipeline	Operator	From	To	Basin	Exit?	(mi)	(kbd)	(kbd)	(in)	Date	($m)	Comments
Nustar Koch Eagle Ford	Koch	Pettus, TX	Corpus Christi, TX	Eagle Ford		66	30	50	10	3Q11	NA	Eagle Ford to local refineries in Corpus Christi, or barge terminals on coast
White Cliffs Expansion	SemGroup	Platteville, CO	Cushing, OK	Niobrara		526	40	40	12	4Q11	NA	Expanded to 70kbd from 30kbd, only current exit pipeline out of Niobrara
Koch Arrowhead Expansion	Koch	Eagle Ford, TX	Corpus Christi, TX	Eagle Ford		95	50	90	20	1Q12	NA	Eagle Ford to local refineries in Corpus Christi, or barge terminals on coast
Basin Pipeline Expansion	PAA	Colorado City, TX	Cushing, OK	Permian	√	519	50	50	NA	1Q12	NA	Capacity increasing from max. 400kbd to max. 450kbd in leg to Cushing
PAA Medford-Cushing Conversion	PAA	Medford, OK	Cushing, OK	Mississippian		110	12	25	10	1Q12	NA	Runs from Mississippi Lime to Cushing, converted LPG pipeline, will ramp to 25kbd by 2012
Valero/Harvest Eagle Ford	Harvest	Atascosa, TX	Three Rivers Refinery	Eagle Ford		190	50	70	12	2Q12	NA	Dedicated line to Valero refinery
EPD Eagle Ford Trunkline	Enterprise	Lyssy, TX	Sealy,TX (Houston)	Eagle Ford		220	250	350	24	2Q12	NA	Main pipeline from Eagle Ford to Houston refinery complex
Seaway Reversal	Enbridge/EPD	Cushing, OK	Freeport, TX	Inland Corridor	√	500	150	400	30	2Q12	1,300	ENB/EPD say reversal will startup 06/12 at 150kbd, ramp to 400kbd by 1Q13
KM EF to Houston Ship Channel	KMP	Cuero, TX	Houston, TX	Eagle Ford		273	300	300	NA	2Q12	220	Eagle Ford to Houston Ship Channel, uses both new build and converted gas pipeline
Butte Loop	True	Baker, ND	Casper, WY	Bakken		323	50	50	16	2Q12	NA	Includes gathering system, exit from Bakken to Guernsey, connect with Platte to Wood River
Koch Pipeline	Koch	Karnes County, TX	Corpus Christi, TX	Eagle Ford		95	120	250	20	2Q12	NA	Eagle Ford to Corpus Christi
Velocity/NuStar EF	NuStar	Gardendale, TX	Oakville, TX	Eagle Ford		113	100	100	12	2Q12	NA	Another small Eagle Ford exit path
West Texas - Houston Access	Sunoco	Midland, TX	Houston, TX	Permian	√	476	40	40	NA	2Q12	NA	Open season Feb-Mar 2012, would take Permian crude out of Mid-Con
TexStar/NuStar Eagle Ford	NuStar	Frio County, TX	Corpus Christi, TX	Eagle Ford		167	120	120	16	3Q12	NA	Eagle Ford to local refineries in Corpus Christi, or barge terminals on coast
Enbridge Line 5 Expansion	Enbridge	Superior, WI	Sarnia, ON	Northern tier		645	50	50	30	4Q12	95	Expands existing line from 490kbd to 540kbd
Plains Bakken North	PAA	Trenton, ND	Regina, SK	Bakken		103	50	70	12	4Q12	180	Will connect to Enbridge system in Saskatchewan
Ho-Ho Pipeline Reversal	RD Shell	Houston, TX	Houma, LA	Gulf Coast		320	300	300	22	1Q13	NA	Would take Eagle Ford and other crudes east, could move further via St. James links
Plains All American Eagle Ford	PAA	Eagle Ford, TX	Corpus Christi, TX	Eagle Ford		162	300	300	24	1Q13	300	Also building marine terminal & 1.5Mbbl of storage, delays have pushed back to 1Q13
Long Horn Reversal/Conversion	Magellan	Odessa, TX	Houston, TX	Permian	√	518	135	225	18	1Q13	345	Permian crude to coast instead of Cushing, 12-18 months from sanction, $275m project cost
Enbridge Line 79	Enbridge	Stockbridge, MI	Freedom Junction, MI	Inland Corridor		64	80	80	20	1Q13	190	Will increase amount of crude that can be moved from Line 6B to Detroit and Toledo, expandx Line 17
West Texas - Longview Access	Sunoco	Midland, TX	Longview, TX	Inland Corridor		458	30	30	NA	1Q13	NA	Open season Feb-Mar 2012, would take Permian crude to MidValley pipeline (Ohio/Detroit)
Magellan/Copano Double Eagle	Magellan	Eagle Ford, TX	Corpus Christi, TX	Eagle Ford		190	100	100	24	1Q13	150	50/50 JV, new 140 mi stretch to connect to existing 50 mi pipeline owned by Copano
Enbridge Bakken Expansion	Enbridge	Beaver Lodge, ND	Cromer, Manitoba	Bakken		124	120	325	NA	1Q13	560	$370m project to connect Bakken to Enbridge mainline
PAA Mississippian	PAA	Alva, OK	Cushing, OK	Mississippian		170	175	175	NA	2Q13	NA	LT contract with SandRidge, will use Medford-Cushing pipeline right of way
EPD EF Phase II Extension	Enterprise	Wilson, TX	Gardendale, TX	Eagle Ford		220	200	200	24	2Q13	NA	Extends existing line
Enbridge Line 9 segment-reversal	Enbridge	Sarnia, ON	North Westover, ON	Inland Corridor	√	132	50	50	30	2Q13	100	First leg of reversal, denied exemption from public hearing process, hearings in 3Q12, so delayed
Keystone XL Gulf Coast Project	TransCanada	Cushing, OK	Port Arthur, TX	Inland Corridor	√	500	500	830	36	3Q13	2,300	Split project into two, piece to GC won't require State Dept permitting
SemGroup Mississippian	SemGroup/Gavilon	Cleo Springs , OK	Cushing, OK	Mississippian		210	140	180	NA	3Q13	NA	Will feed SemGroup's 1Mbbl storage facility at Cushing
Magellan Products Reversal	Magellan	Cushing, OK	Gulf Coast	Inland Corridor	√	500	60	70	12	4Q13	NA	Company mentioned on 2Q/3Q calls they're looking at using inactive & reversed pipelines
Saddle Butte Pipeline	High Prarie	Alexander, ND	Clearbrook, MN	Bakken		450	150	150	16	4Q13	NA	Launched open season mid-February '12
Waupisoo Pipeline Expansion	Enbridge	Cheecham, AB	Edmonton, AB	WCSB		236	65	310	NA	2013	400	Two phases, 65kbd in late 2012/early 2013, then the rest in 2H13
TransCanada Heartland Extension	TransCanada	Ft Sask'wan, AB	Hardisty, AB	WCSB		130	600	600	NA	2013+	NA	Intra-WCSB pipeline
Enbridge Toledo Spur (Line 17) Exp	Enbridge	Stockbridge, MI	Toledo/Lima, OH	Inland Corridor		82	310	310	36	2013-15	900	Gets more Canadian crude further east
Pony Express	Kinder Morgan	Guernsey, WY	Cushing, OK	Niobrara		710	210	210	NA	1Q14	NA	Converts 500 mi of under-utilized gas pipeline into crude,will carry Niobrara, Bakken & Canadian
Gulf Coast Access/Flanagan South	Enbridge	Flanagan, IL	Cushing, OK	Inland Corridor		580	400	500	30	2Q14	1,900	Key pipeline add to bring Canadian heavy sour to GC in lieu of KXL, Announced successful open season
Athabasca Pipeline Expansion	Enbridge	Kirby Lake, AB	Hardisty, AB	WCSB		338	430	570	NA	3Q14	1,200	Phased project that will add as much as 570kbd by 2014
KM Cochin Pipeline Conversion	Kinder Morgan	McHenry, ND	Windsor, ON	Bakken		1,600	30	30	NA	2014	NA	Partial pipeline conversion that would use unutilized capacity on a products/propane pipeline
Line 9 reversal to Montreal	Enbridge	Sarnia, ON	Montreal, QC	Inland Corridor	√	524	50	200	30	2014	100	Will be done in phases, first from Sarnia to Westover, only 50kbd
Seaway Loop/expansion	Enterprise	Cushing, OK	Freeport, TX	Inland Corridor	√	500	400	400	36	2014	NA	In theory would be built at the same time as Enbridge's Flanagan South
Keystone XL Northern Leg	TransCanada	Hardisty, AB	Cushing, OK	WCSB/Bakken		1,667	700	830	36	2015	5,300	$7.6B project, application rejected due to forced premature decision, will reapply by early '13
Keystone XL Texas Lateral	TransCanada	Port Arthur, TX	Houston/Tex City, TX	Gulf Coast		48	500	500	NA	2015	800	Would move KXL crude to Houston area refineries
Portland Montreal Pipeline Reversa	P-M	Montreal, QC	Portland, ME	Inland Corridor	√	261	200	200	18	2015+	100	Would extend Line 9 all of the way to the Maine coast, where crude could be exported to Europe
Alberta Clipper Expansion	Enbridge	Hardisty, AB	Superior, WI	WCSB		1,000	350	350	NA	2015+	NA	Can be expanded to 800kbd, no announced plans for expansion, will likely be needed by mid-decade
TransMountain expansion - twinning	Kinder Morgan	Edmonton, AB	Vancouver, BC	WCSB	√	715	300	500	30	2016+	4,300	Simple twinning of pipeline replaced more complicated TMX2, TMX3 and Northern Leg plan
Northern Gateway Pipeline	Enbridge	Bruderheim, AB	Kitimat, BC	WCSB	√	731	500	500	36	2017+	5,500	Still trying to get reg approval, NEB hearing in Jan., opposition from First Nations/environmentalists
Norther Gateway Condensate	Enbridge	Kitimat, BC	Bruderheim, AB	WCSB		731	193	193	NA	2017+	5,500	Will take condensate from West Coast to oil sands region to be used as diluent
Keystone East	TransCanada	Patoka, IL	Lima/Toledo/Detroit	Inland Corridor	√	410	300	300	NA	2017+	NA	Would extend Keystone system into far eastern PADD 2
White Cliffs ExLoop - Tentative	SemGroup	Platteville, CO	Cushing, OK	Niobrara		526	NA	NA	NA	NA	NA	Niobrara exit capacity - has been discussed but nothing announced

Source: Company data, Reuters, Dow Jones Newswire, Pipeline & Gas Journal, Energy Intelligence, Wood Mackenzie, CAPP, Oil Sands Review, Deutsche Bank estimates

The list above captures most of the major pipeline projects currently either under construction, in an approval process, testing shipper interest or proposed as a potential route later in the decade. The pipelines are listed in approximate order of start-up, with the caveat that these dates are often in flux. We expect this list will grow as the likely scale of several of the nascent unconventional plays becomes more apparent. We include it here as a reference, as the upcoming sections, which discuss production vs. takeaway balances, will revolve to a large extent around the timing of pipeline startups.

Inland Corridor redux

While the Seaway pipeline reversal temporarily solves the WTI infrastructure bottleneck in the Mid-Con, we have emphasized that it is not simply a matter of getting some WTI-linked crude out of Cushing proper and to the Gulf Coast, but of finding a destination for the growing amounts of light crude being produced in the Inland Corridor.

We believe that Inland Corridor oil production will average 400kbd of growth per annum through 2020, essentially a major pipeline's worth of crude added to the picture *every year*. Roughly half of that growth will be light sweet crude. Given flat to falling demand in the Inland Corridor, it should quickly become apparent that Seaway's 400kbd of capacity will only take care of the PADD 2 supply-demand imbalance for about a year's worth of growth. Thus it is possible that Cushing/other PADD 2 storage could again see a structural build that would encourage more pipeline capacity out of the Mid-Con.

So more Cushing to GC pipeline capacity will be needed, and the timing of construction of those pipelines will determine whether temporary LLS-WTI price distortions re-emerge.

Following President Obama/State Department's recent denial of the Keystone XL application (after being forced to prematurely make a decision on the proposed re-routed KXL plan by Congress in the payroll tax extension bill), TransCanada announced it would continue with a new application that included the Nebraska re-routing. TransCanada has since indicated the new plan would be completed by early 2013, and that the pipeline could be in service by early 2015. The following table, which we have published numerous times over the course of the Brent-WTI roller coaster ride, has been updated for recent pipeline newsflow and our updated North American production outlook.

Figure 23: Inland Corridor incremental supply and mitigating factors

Crude Production in Inland Corridor	**H/L**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Canadian											
Blended Bitumen	Heavy	1,244	1,334	1,445	1,628	1,728	1,886	2,031	2,209	2,460	2,681
Upgraded SCO	Light	723	843	869	885	922	936	942	954	973	998
Conventional Heavy	Heavy	300	289	286	281	274	265	257	246	233	219
Conv/Unconv Light/Med	Light	635	682	743	803	859	911	956	994	1,024	1,045
Bakken area	Light	472	644	737	825	903	967	1,023	1,066	1,088	1,090
Permian	Light	925	1,046	1,178	1,294	1,395	1,487	1,574	1,648	1,704	1,750
Niobrara	Light	106	135	180	217	256	293	329	361	385	398
Other PADD 2	Light	392	401	422	451	488	532	581	631	682	735
Other PADD 4	Light	225	226	230	233	236	241	248	257	267	278
Total		**5,023**	**5,600**	**6,089**	**6,617**	**7,061**	**7,518**	**7,941**	**8,367**	**8,816**	**9,194**
Incremental Supply vs 2011			577	1,066	1,594	2,037	2,495	2,917	3,344	3,793	4,170
YoY Incremental			577	489	529	443	458	422	426	449	378
Mitigating Factors			**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Refining											
Utilization +2% across Inland Corridor			89	180	180	185	185	185	185	185	185
Wood River CORE			50	50	50	50	50	50	50	50	50
Detroit HOUP			5	15	15	15	15	15	15	15	15
Mandan			5	10	10	10	10	10	10	10	10
DOP Trenton Diesel Refinery			0	0	10	20	20	20	20	20	20
Redwater Bitumen Refinery			0	0	25	50	50	75	100	125	150
McKee			0	0	0	25	25	25	25	25	25
Pipeline Additions											
Enbridge Line 6B back to capacity			25	50	50	50	50	50	50	50	50
Enbridge Line 9 reversal			13	50	50	125	200	200	200	200	200
Enbridge/Enterprise Seaway reversal			125	400	400	400	400	400	400	400	400
Sunoco West Texas - Houston Access			20	40	40	40	40	40	40	40	40
Long Horn reversal - El Paso to Houston			0	120	135	135	135	135	135	135	135
Keystone XL/Marketlink to Port Arthur			0	250	500	700	700	830	830	830	830
Magellan product pipeline reversal			0	0	50	70	70	70	70	70	70
Seaway Expansion			0	0	200	400	400	400	400	400	400
Kinder Morgan TMX Expansion			0	0	0	0	150	300	300	300	300
TransCanada Northern Gateway			0	0	0	0	0	250	500	500	500
Kinder Morgan TMX Future Expansion			0	0	0	0	0	0	100	200	200
Rail Additions											
Hess unit train(s), Bakken to St. James, LA			37	49	54	81	108	114	143	143	143
EOG unit train, Bakken to St. James, LA			35	63	63	63	63	67	67	67	67
Tesoro unit train, Bakken to Anacortes, WA			15	27	27	27	27	29	29	29	29
Other Bakken exit rail systems			272	401	405	414	432	456	456	456	456
Total Mitigating Factors			**690**	**1,704**	**2,264**	**2,860**	**3,130**	**3,720**	**4,123**	**4,248**	**4,273**
Supply surplus vs. pipelines relative to 2011, if....											
...Seaway and Long Horn reversals are only major pipeline adds			245	151	630	933	1,316	1,713	2,114	2,538	2,891
...plus KXL GC, Magellan reversal and Seaway expansion			245	(99)	(120)	(237)	146	413	814	1,238	1,591
... no Northern Gateway			245	(99)	(120)	(237)	(4)	113	514	938	1,291
...Everything gets built			245	(99)	(120)	(237)	(4)	(137)	(86)	238	591
Effective rail capacity from Bakken out of Inland Corridor			**359**	**539**	**549**	**585**	**630**	**665**	**694**	**694**	**694**
Balance including eff rail capacity, if everything gets built			**(114)**	**(638)**	**(669)**	**(822)**	**(634)**	**(802)**	**(779)**	**(455)**	**(103)**

Likely to see 400kbd+/yrear of production growth out to end of the decade, in a region with flat long-term demand

We think mid-con refiners are running near effective capacity now and are skeptical they can increase utilization much, but we here assume some increase to be conservative

Almost every proposed pipeline has either permitting or shipper commitment issues that are likely to cause delays. We've assumed here that everything starts on time.

Supply surplus will continue to get more acute over the next few months until Seaway can be reversed and ramped to capacity, though rapid crude by rail growth will relieve pressure in PADD 2 and set the transporation differential b/w LLS and WTI

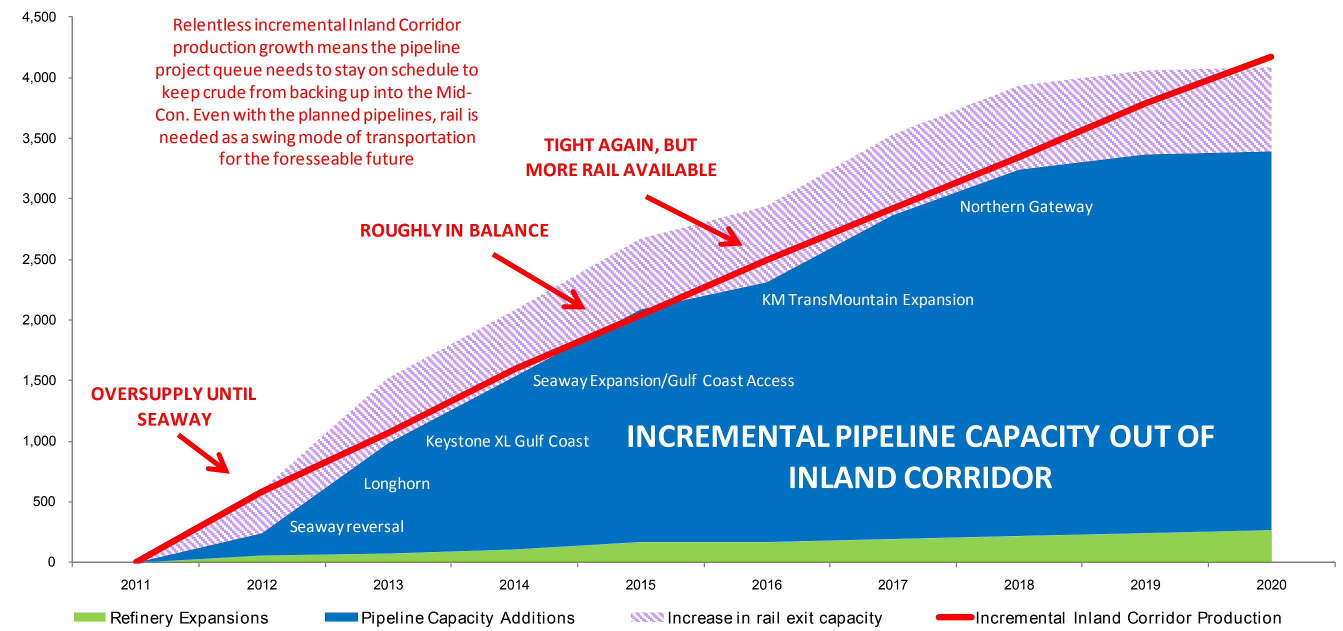
Medium and long-term imbalance will depend on whether and when other planned pipelines are built. Substantial rail may be needed for the long-term.

Source: EIA, CAPP, ND DMR, Company data, Wood Mackenzie, Texas Railroad Commission, Deutsche Bank estimates

By our estimation there will be, on average, about 400kbd per year of crude production growth from Western Canada, PADD 2, PADD 4 and northern/western PADD 3 (i.e., the Inland Corridor) over the next decade. That is enough to fill a Seaway-size pipeline in a year. Thus further pipeline capacity will need to be built from Cushing to the Gulf Coast, or we will again see WTI-linked crudes backing up into PADD 2.

The two major proposals on the table for the medium-term to handle the surging Mid-Con/Canadian production are the Seaway Expansion, which would twin the current pipeline and take capacity to 800kbd+, and the southern leg of the controversial Keystone XL project, which would add 500-700kbd+ (and expandable to 830+kbd) to the Cushing-GC route. Without those projects (or possibly even with them), crude-by-rail will be the marginal mode of transportation for landlocked WTI-linked crude, and will therefore set the transportation cost differential ($7-10/bbl) component of the Brent-WTI spread.

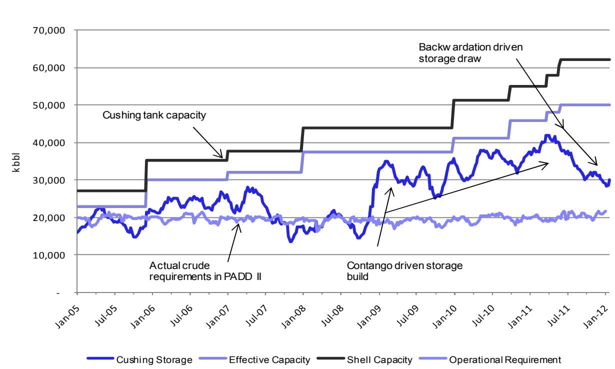
Figure 24: Inland Corridor – incremental supply and takeaway vs. 2011 – pipelines need to stay on schedule



Source: Deutsche Bank

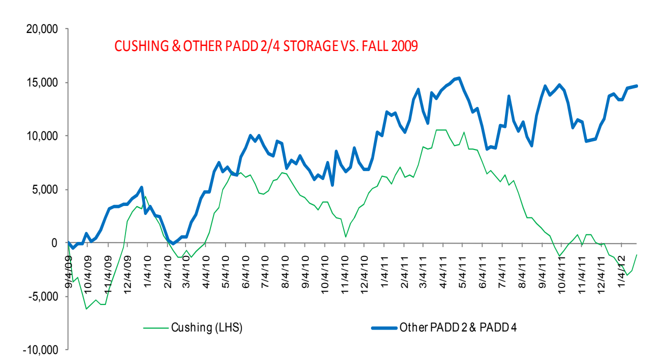
The issue of Cushing, and its status as the world's premier oil storage site, and pricing point of WTI. As the Inland Corridor has backed up with crude over the last 15-18 months, much of the surplus has been parked in storage outside of Cushing. While WTI differentials are obviously sensitive to the amount of crude in storage at Cushing, we believe it is equally sensitive to the amount in storage in the Mid-Con *outside* of Cushing. Indeed, over summer 2011 many observers were surprised that the Brent-WTI differential didn't compress as Cushing storage dropped by about 10Mbd over a six month period (see Figure 20 above). Our explanation was that storage had been built to take advantage of crude oil market contango (higher prices in future than present). When the curve flattened (future prices in line with present), speculators started selling barrels, *regardless of overall oil price levels*. Underlining that moves at Cushing can be entirely speculative, we believe that at the same time, Mid Con inventories overall were rising. As shown below, while speculative Cushing barrels were coming out of storage, the Mid-Con was still being flooded by surging production from Canada and the Bakken, and it was showing up in the non-Cushing storage in PADD 2 and PADD 4.

Figure 25: Cushing stocks vs. working capital level



Source: EIA, Genscape, Reuters, Company data, various news sources, Deutsche Bank

Figure 26: Non-Cushing Mid-Con storage is structural



Source: EIA, Deutsche Bank

Fundamental tightness at Cushing will cause prices to rally. For example, in the past year the rally and tightening Brent differential eventually did come in early Fall 2012, in our view for two reasons –

- First, Cushing storage finally fell below a sensitive threshold, around 30Mbbl, or less than 10Mbbl above the "working capital" inventory level of roughly 20Mbbl (ie, the storage needed by Cushing-linked refiners to maintain adequate inventory coverage).
- Second, crude-by-rail out of the Bakken reached a scale adequate to bring non-Cushing storage down to a more reasonable level and appeared to be ramping at a pace that would continue to drain the Mid-Con (ramping from ~70kbd at the beginning of summer to ~140kbd by mid-fall).

Our point here is emphasize that close Cushing-observation, historically the one and only linchpin for understanding WTI pricing, is only half of the picture – and simply inventory builds may not be bearish, nor draws bullish. An eye needs to be kept on the overall Inland Corridor balance and non-Cushing storage; and the shape of the crude price curve is crucial.

In our view the Inland Corridor balance will pivot on the timing of pipeline construction – meaningful delays in major projects will likely mean another layer of distortion on the WTI discount to Brent and LLS. The fundamental imbalance will play out in Cushing storage, made noisy by speculative activity.

North Central takeaway – Western Canada & Williston Basin

Most of the analysis we have seen of Western Canadian and Bakken supply-takeaway has focused on each basin in isolation. In our view the entire North Central region (what we often call "the Northern Tier") – the oil sands region, Southern Alberta/Saskatchewan, the Bakken/Three Forks, Minnesota and Wyoming – must be viewed collectively, since all of the crude produced in those regions must makes its way through the same chokepoints (or be sent to the same North Central refineries) to get to market.

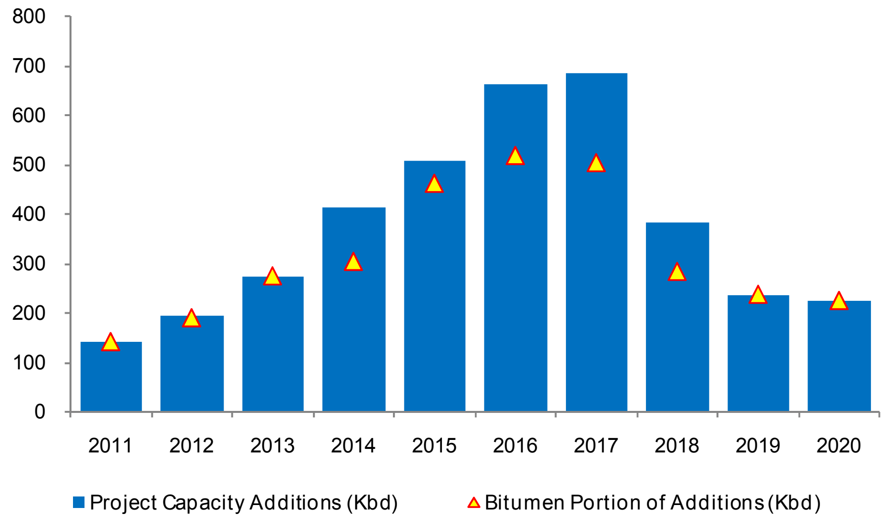
This point was dramatically illustrated in late January/early February when the most important of those chokepoints, Superior, Wisconsin, reached capacity and caused both Canadian and Bakken crude to back-up and caused Clearbrook, Syncrude and WCS differentials to WTI to blow-out to record or near-record levels.

In our summary analysis at the end of this section we look at the total takeaway capacity from the Northern Tier versus our projected production growth in the region. There are really five paths of takeaway for this crude – 1) local refineries in either the WCSB or the northern plains states (Wyoming, Montana, North Dakota or Minnesota); 2) East/Southeast on the Enbridge Mainline through the Superior, WI chokepoint, 3) Southeast on the Keystone pipeline to Cushing/Wood River, 4) West to the BC coast, or 5) South to the Guernsey, WY chokepoint, where the crude can either head south to Denver and Salt Lake City refineries or east to Cushing via the Platte Pipeline. By far the majority of the capacity, and of the shipper interest, is to the East on the Enbridge Mainline through Superior, which is why that chokepoint "maxed out" two weeks ago.

Before we get to the Northern Tier summary table, let us first take a high altitude view of the Western Canadian situation:

- **Production out of the Western Canadian basin**, driven both by handful of new mining mega-projects and a relentless progression of phased in situ projects, should add between 100kbd and 400kbd per year over the next decade or more. Growth should average between **150kbd and 200kbd**, though we see **upside** to that, given the large amount of capacity planned in the regional project queue.

Figure 27: Oil sands project queue – announced capacity addition plans, 2011-2020



Source: Company data, Oil Sands Review, Oil Sands Development Group, Alberta Oil Magazine, Reuters, CAPP, Deutsche Bank

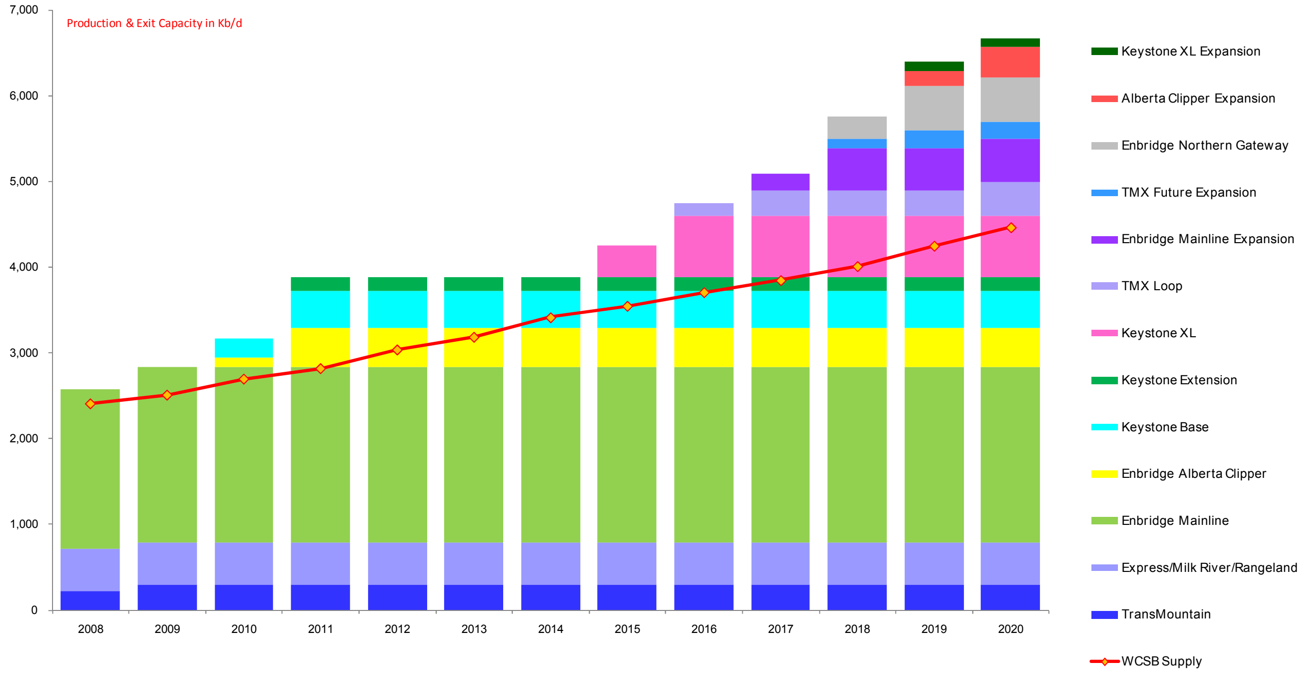
- While many of these projects are economic on a full cycle basis only when WTI is $85+/bbl (or higher – numerous oil sands projects are truly the global marginal barrel), there are **sufficient projects already well into development to sustain a high regional production growth rate as long as oil is above cash cost of production, or $40/bbl** for the next half decade or more. Obviously extreme cost inflation, a very low oil price, or another economic crisis could slow development, but we believe that robust growth in production out of Canada is a near certainty out to 2016.

- Much of the growth over the next five years will be bitumen rather than light synthetic crude. Dozens of in situ project phases will come onstream, as well as the Kearl mining project, which due to IMO's proprietary Paraffinic Frothing Treatment (PFT) process will, like an in situ project, produce diluent-blended bitumen deliverable to refineries via pipeline. Thus in the near-to-medium term there will be a **surge in Canadian heavy oil**.

- Simultaneously, the demand **for Canadian heavy crude is and will be increasing** meaningfully. In the Inland Corridor, approximately 490kbd of incremental heavy processing capacity will be added between 1Q12 and 1Q14, starting with 100kbd of capacity now coming onstream at COP/CVE's Wood River.

- Pipeline projects connecting the US Mid-Con to the Houston/Port Arthur area will open up the massive Gulf Coast refining complex to WCSB heavy barrels. – assuming the Canadians can get the crude either to Cushing or all the way to the coast via Keystone XL, should it be built. Seaway reversal will likely bring at least 200kbd of Canadian heavy to the GC and probably more. We expect Enbridge's Flanagan South and a Seaway expansion to add another 300-500kbd of Canadian heavy demand to the equation over the next few years.

Figure 28: Western Canadian trunkline takeaway capacity vs. WCSB supply growth



Source: CAPP, Company data, Deutsche Bank estimates

And an overview of the Williston Basin:

- **Bakken production** estimates for 2015 range from 700kbd to over 1Mbd, we are **expecting a bit over 800Kbd**. We assume the rig count, currently just below 200, tops out at around 240. Current growth is over 15kbd per month, so we do see upside to our estimate, though we think the pace of volume growth will slow by next year.
- We are perhaps less aggressive in our Bakken outlook than some others. Variability of well productivity is high in the Bakken – the difference between top quartile and lower quartile well results is quite wide. Most of the big operators are drilling their best acreage first, as you would expect, and as the basin matures, the average quality will be falling (EOG, for example, has experienced a drop in its well productivity over time). Technology and process improvements will partially offset that trend, as will increasing activity and the addition of other horizons, but the wide well productivity variability makes us wary of the high-end of the current published ranges. We also worry about the low local population and infrastructure, in the 50th smallest US state by GDP. Current investment plans are pushing North Dakota's economic capacity to the absolute maximum. Oil industry boosters who highlight North Dakota's best-in-US level of unemployment are inadvertently highlighting a major problem.
- Additionally the Bakken region is **short pipeline capacity.** While there are a handful of projects under development to increase the takeaway, but even those additions will not be enough to keep pace with the production growth.

Figure 29: Williston Basin exit pipeline capacity additions – the current queue

Pipeline	Operator	From	To	Mid-Con Exit?	Length (mi)	Init. Cap. (kbd)	Ult. Cap. (kbd)	Diam. (in)	Target Date
Butte Loop	True	Baker, ND	Casper, WY		323	50	50	16	2Q12
Plains Bakken North	PAA	Trenton, ND	Regina, SK		103	50	70	12	4Q12
Enbridge Bakken Expansion	Enbridge	Beaver Lodge, ND	Cromer, Manitoba		124	120	325	NA	1Q13
Saddle Butte Pipeline	High Prairie	Alexander, ND	Clearbrook, MN		450	150	150	16	4Q13
KXL Bakken Interconnect	TransCanada	Hardisty, AB	Port Arthur, TX	√	2,226	100	100	36	2015

Source: Company data, North Dakota DMR, North Dakota Pipeline Authority, various news sources, Pipeline, Deutsche Bank estimates

- As a result, **crude-by-rail will be the swing mode of transportation** for the foreseeable future, and there is a very good chance that rail will be a meaningful permanent component of regional takeaway capacity in the Bakken, unlike most other emerging plays where it will serve as a near- or medium-term solution until pipelines are built.

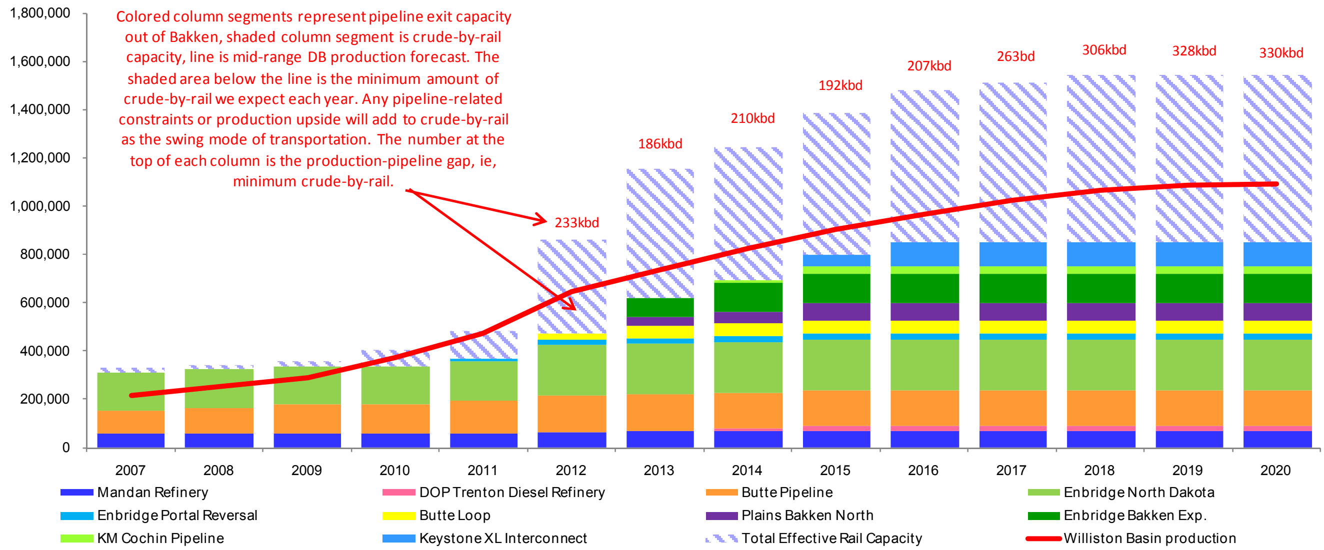
Figure 30: Williston Basin crude-by-rail loading terminals in the works

Terminal	Operator	Active/Planned	Capacity	Expansion Cap.
EOG Stanley	EOG	Active	70	70
DTS New Town	Dakota Transport Systems	Active	30	60
Small Rail Facilities	Multiple	Active	70	70
Bakken Oil Express	Lario Logistics	Active (as of 4Q11)	100	250
Dore	Watco/Kinder Morgan	4Q11/1Q12	60	60
Hess Tioga	Hess	1Q12	54	150
Rangeland COLT	Rangeland Energy	1Q12	80	100
Trenton Railport	Savage Cos.	1H12	60	60
Musket	Musket	1H12	70	70
Ross Rail Terminal	Plains All American	TBD	65	65
Fryburg	Great Northern	TBD	60	60
Berthold Rail	Enbridge	TBD	60	60
Zap Terminal	NA	TBD	NA	60
Total			**779**	**1,135**

Source: Company data, North Dakota DMR, North Dakota Pipeline Authority, various news sources, Deutsche Bank estimates

- We expect crude-by rail will ultimately claim 200+kbd of the takeaway pie in the Bakken, or 20-25% of total peak production. It will also capture any upside to production in the Bakken – if volumes surge over 1Mbd, rail is the swing mode of transport and will mop up the excess. However, it appears that an excess of crude loading terminal capacity is in the works. As we highlighted at the beginning of this section, the Bakken pipeline takeaway feeds into systems that also move Canadian crude, thus rising production in WCSB could also push more Bakken on rail. Finally, any pipeline constraints, planned (maintenance) or unplanned (leaks), will push more Bakken crude onto rail. So in all likelihood we will see 200kbd to 400kbd of crude-by-rail, with possible temporary surges above that.
- With crude-by-rail as the swing mode, **Bakken differentials could be especially volatile**. Rail reliability is inherently lower than pipelines, even in good weather environments, and the **North Dakota/Montana climate** has already had a major impact on Bakken differentials (both positive and negative) in the basin's short history. Winters can be harsh and snowy, springs can bring major flooding.

Figure 31: Williston Basin production vs. pipeline takeaway capacity – crude-by-rail has a future



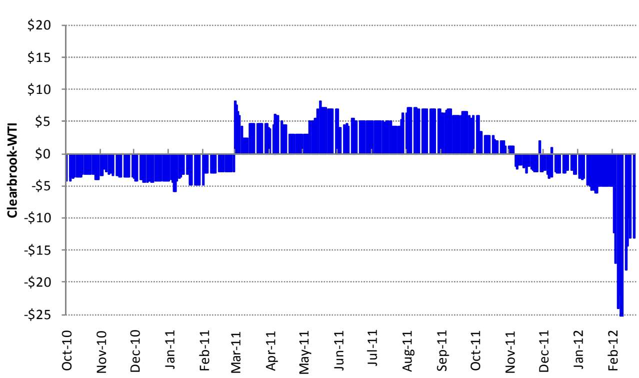
Source: North Dakota DMR ,North Dakota Pipeline Authority, EIA, company data, Wood Mackenzie, various news sources, Deutsche Bank estimates

To understand potential supply-takeaway imbalances for these basins though, we need to view the whole North Central together. The next table summarizes the supply and takeaway situation for the North Central US and the Western Canadian basin.

Some key takeaways for the North Central region:

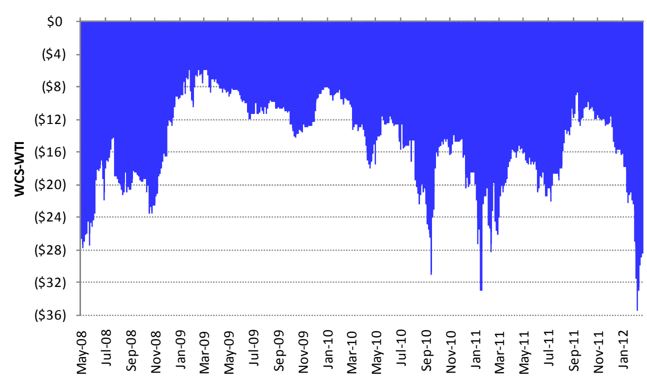
- Though the absolute supply-takeaway math implies a cushion at the moment, the balance has tightened enough that we have experienced recent blow-outs in the WTI-Clearbrook, WTI-WCS and WTI-Syncrude differentials. Shipper preference to move crude eastward towards Chicagoland, Sarnia and eastern PADD 2, has put pressure on the Enbridge mainline route through the Superior. WI chokepoint. As a result storage at Superior maxed out, and the Enbridge mainline throughput hit an all-time at nearly 1.8Mbd.

Figure 32: Clearbrook-WTI differential



Source: Bloomberg Finance LP, Deutsche Bank

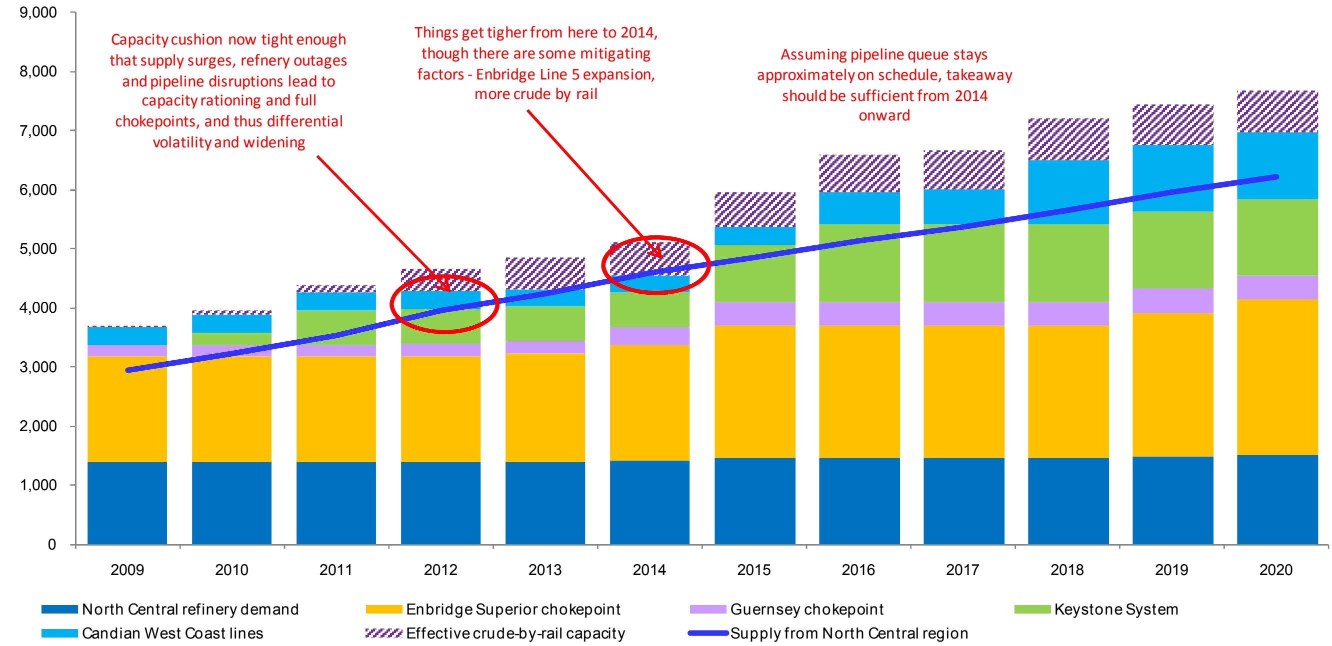
Figure 33: WCS-WTI differential



Source: Bloomberg Finance LP, Deutsche Bank

- While takeaway capacity from Western Canada looks sufficient until the 2016-17 time frame when viewed in isolation, when analyzed in tandem with the Williston Basin/Wyoming it becomes apparent that takeaway will likely be an issue from now until 2014 (see chart and table below). **We expect high volatility in the Canadian differentials until Enbridge expands the Mainline/Flanagan South route to an expanded Seaway by in 2H14**. Crude by rail will be the primary marginal release value until then.

Figure 34: North Central takeaway cushion narrows to 2014, implying volatile and wide differentials



Source: Company data, EIA, CAPP, North Dakota Pipeline Authority, Wyoming Pipeline Authority, Wood Mackenzie, Deutsche Bank estimates

- The recent differential blow-out highlights the importance of TransCanada's **Keystone XL**, and of the need for Enbridge to increase the amount of crude that can pass through the Superior, WI chokepoint (they are expanding Line 5 to Sarnia in 4Q12 by 50kbd, and will expand the Southern Access line to Flanagan, IL, in conjunction with the Gulf Access program in 2014).
- If Keystone XL is built, the North Central takeaway issues are essentially solved until the last couple of years of the decade, when some additional capacity will be needed (i.e., pipelines to the West Coast). Conversely, if Keystone XL isn't built, the West Coast pipelines will need to be accelerated towards the middle of the decade or crude will be backed up in large quantities (or production will be shut-in due to a painful differential). Regardless, Keystone XL, or another as of yet unconceived project, will need to be built in order to keep up with the growth.

Figure 35: Northern tier crude supply vs takeaway capacity – very tight in 2014 and beyond without expansions

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CRUDE SUPPLY												
Western Canadian Sedimentary Basin												
Blended Bitumen	996	1,162	1,244	1,334	1,445	1,628	1,728	1,886	2,031	2,209	2,460	2,681
Upgraded SCO	646	660	723	843	869	885	922	936	942	954	973	998
Conventional Heavy	308	309	300	289	286	281	274	265	257	246	233	219
Conv/Unconv Lt/Med	563	569	635	682	743	803	859	911	956	994	1,024	1,045
North Central US												
North Dakota	218	310	404	572	661	747	821	883	938	979	1,001	1,002
Montana	76	69	72	76	79	82	85	87	89	90	91	92
Wyoming	141	146	149	152	155	158	161	164	168	171	174	178
South Dakota	5	4	4	4	4	4	5	5	5	5	5	5
TOTAL NORTHERN TIER SUPPLY	**2,953**	**3,229**	**3,532**	**3,952**	**4,242**	**4,588**	**4,854**	**5,137**	**5,384**	**5,649**	**5,961**	**6,218**
Incremental YoY		276	303	420	291	345	267	283	247	265	311	258
TAKEAWAY CAPACITY												
WCSB Refineries												
Edmonton Imperial	177	177	177	177	177	177	177	177	177	177	177	177
Edmonton Suncor	128	128	128	128	128	128	128	128	128	128	128	128
Scotford Shell	133	133	133	133	133	133	133	133	133	133	133	133
Lloydminster Husky	24	24	24	24	24	24	24	24	24	24	24	24
Regina Co-op	95	95	95	95	95	95	95	95	95	95	95	95
Prince George Husky	11	11	11	11	11	11	11	11	11	11	11	11
Moose Jaw Asphalt	15	15	15	15	15	15	15	15	15	15	15	15
Redwater Bitumen Refinery	0	0	0	0	0	25	50	50	50	50	75	100
Montana/North Dakota Refiners												
Mandan Tesoro	58	58	58	63	68	68	68	68	68	68	68	68
Great Falls	10	10	10	10	10	10	10	10	10	10	10	10
Billings ExxonMobil	60	60	60	60	60	60	60	60	60	60	60	60
Billings Phillips 66	58	58	58	58	58	58	58	58	58	58	58	58
Laurel CHS	60	60	60	60	60	60	60	60	60	60	60	60
DOP Trenton Diesel Refinery Project	0	0	0	0	0	10	20	20	20	20	20	20
Wyoming Refiners												
Sinclair	74	74	74	74	74	74	74	74	74	74	74	74
Caspar Sinclair Little America	25	25	25	25	25	25	25	25	25	25	25	25
Newcastle Wyoming	14	14	14	14	14	14	14	14	14	14	14	14
Cheyenne HollyFrontier	52	52	52	52	52	52	52	52	52	52	52	52
Minnesota/Wisconsin Refiners												
St. Paul Flint Hills	320	320	320	320	320	320	320	320	320	320	320	320
St. Paul Northern Tier	74	74	74	74	74	74	74	74	74	74	74	74
Superior Calumet	45	45	45	45	45	45	45	45	45	45	45	45
Pipeline Spurs to Colorado/Utah Refiners												
Frontier Pipeline to Salt Lake City	65	65	65	65	65	65	65	65	65	65	65	65
RMPL to Chevron to Salt Lake City	15	15	15	15	15	15	15	15	15	15	15	15
Total to Refineries	**1,513**	**1,513**	**1,513**	**1,518**	**1,523**	**1,558**	**1,593**	**1,593**	**1,593**	**1,593**	**1,618**	**1,643**
Assuming 92% Utilization	**1,392**	**1,392**	**1,392**	**1,397**	**1,401**	**1,433**	**1,466**	**1,466**	**1,466**	**1,466**	**1,489**	**1,512**
Pipeline Exit Routes & Chokepoints												
West: Canadian Pacific Coast												
TransMountain	300	300	300	300	300	300	300	300	300	300	300	300
TMX Expansion	0	0	0	0	0	0	0	250	300	300	300	300
Northern Gateway	0	0	0	0	0	0	0	0	0	500	525	525
Total West to Coast	**300**	**300**	**300**	**300**	**300**	**300**	**300**	**550**	**600**	**1,100**	**1,125**	**1,125**
South: Guernsey, WY Chokepoint												
Platte Pipeline to Wood River, IL	143	143	143	143	143	143	143	143	143	143	143	143
Cheyenne/Legacy Pipeline from Guernsey to Denver	56	56	56	56	56	56	56	56	56	56	56	56
Kinder Morgan Pony Express to Cushing	0	0	0	0	0	105	210	210	210	210	210	210
Total South through Guernsey	**199**	**199**	**199**	**199**	**199**	**304**	**409**	**409**	**409**	**409**	**409**	**409**
Southeast: Keystone to Cushing/Wood River/Gulf Coast												
Keystone Mainline	0	218	591	591	591	591	591	591	591	591	591	591
Keystone XL	0	0	0	0	0	0	375	710	710	710	710	710
Total Southeast via Keystone System	**0**	**218**	**591**	**591**	**591**	**591**	**966**	**1,301**	**1,301**	**1,301**	**1,301**	**1,301**
East/Southeast: Superior, WI Chokepoint												
ENB Line 5 to Sarnia	491	491	491	491	491	491	491	491	491	491	491	491
ENB Line 6a to Chicagoland	577	577	577	577	577	577	577	577	577	577	577	577
ENB Line 14/64 to Chicagoland	318	318	318	318	318	318	318	318	318	318	318	318
Southern Access (Line 61) to Flanagan	400	400	400	400	400	400	400	400	400	400	400	400
Line 5 Expansion (adds to Superior throughput)	0	0	0	12	50	50	50	50	50	50	50	50
ENB Southern Access Expansion	0	0	0	0	0	100	400	400	400	400	600	800
Total E/SE through Superior	**1,786**	**1,786**	**1,786**	**1,798**	**1,836**	**1,936**	**2,236**	**2,236**	**2,236**	**2,236**	**2,436**	**2,636**
TOTAL TAKEAWAY	**3,677**	**3,895**	**4,268**	**4,285**	**4,327**	**4,564**	**5,377**	**5,962**	**6,012**	**6,512**	**6,760**	**6,983**
Takeaway cushion if….												
No capacity adds	724	666	736	321	35	(278)	(513)	(795)	(1,042)	(1,308)	(1,596)	(1,831)
Enbridge capacity expansions only	724	666	736	333	85	(128)	(63)	(345)	(592)	(858)	(946)	(981)
Enbridge expansion + Canadian West Coast	724	666	736	333	85	(128)	(63)	(95)	(292)	(58)	(121)	(156)
Enbridge + Keystone XL	724	666	736	333	85	(128)	312	365	118	(148)	(236)	(271)
Excess Capacity if Everything Built (incl KXL)	724	666	736	333	85	(23)	522	825	628	862	799	764

Note: We assume crude-by-rail will handle the shortfall

Source: Company data, EIA, CAPP, North Dakota Pipeline Authority, Wyoming Pipeline Authority, Wood Mackenzie, Deutsche Bank estimates

- As we have mentioned, there is **upside to our current Canadian production forecast**, given the large number of announced oil sands projects currently in the queue. There will be delays and disappointments within the project queue, but there is a chance that volumes will exceed expectations.
- Also mentioned earlier, crude-by-rail, mostly out of the Bakken, will be the swing mode of transportation in the Northern Tier, absorbing the excess production, but setting a wider inherent differential for all Northern Tier crudes when the use of rail surges.
- To reiterate the medium and long-term conclusion – the timing of pipeline construction and the potential for supply upside surprise will determine whether we see future structural discounts for North Central crudes. From here to 2014 we will be in a period of narrowing cushion, thus we would **expect high volatility with upside to differentials.**

Eagle Ford – a better place to be for long-term realizations

In this note we focus primarily on the broader geographic themes in the future of North American oil, and thus save detail on most of the specific growth basins in the US for later reports. Given the scale and importance of the Eagle Ford, and the contrast with the more challenging Bakken, we want to make a few points on the basin here. Key points:

- While Western Canada and the Bakken will have persistent takeaway issues and will need crude-by-rail on a permanent basis (thus pressuring the differential to WTI upward due to a higher marginal cost of transportation), **Eagle Ford pipeline takeaway will be surplus to requirements** once the current pipeline project queue is built.
- **Pipeline takeaway constraints will disappear by 4Q12**. Local crude, NGL and associate gas gathering/processing constraints will continue for some companies, but liquids production and takeaway should ramp quickly over the next two years.

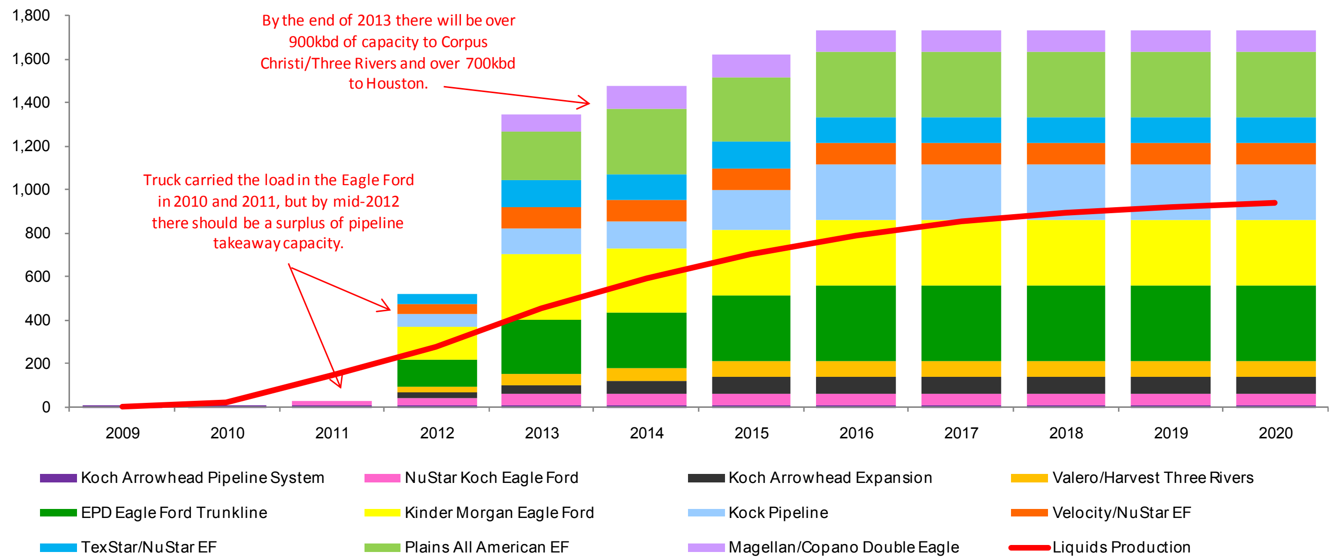
Figure 36: Eagle Ford exit pipeline capacity additions – the current queue

Pipeline	Operator	From	To	Length (mi)	Init. Cap. (kbd)	Ult. Cap. (kbd)	Diam. (in)	Target Date
Nustar Koch Eagle Ford	Koch	Pettus, TX	Corpus Christi, TX	66	30	50	10	3Q11
Koch Arrowhead Expansion	Koch	Eagle Ford, TX	Corpus Christi, TX	95	50	90	20	1Q12
Valero/Harvest Eagle Ford	Harvest	Atascosa, TX	Three Rivers Refinery	190	50	70	12	2Q12
EPD Eagle Ford Trunkline	Enterprise	Lyssy, TX	Sealy, TX (Houston)	220	250	350	24	2Q12
KM EF to Houston Ship Channel	KMP	Cuero, TX	Houston, TX	273	300	300	NA	2Q12
Koch Pipeline	Koch	Karnes County, TX	Corpus Christi, TX	95	120	250	20	2Q12
Velocity/NuStar EF	NuStar	Gardendale, TX	Oakville, TX	113	100	100	12	2Q12
TexStar/NuStar Eagle Ford	NuStar	Frio County, TX	Corpus Christi, TX	167	120	120	16	3Q12
Plains All American Eagle Ford	PAA	Eagle Ford, TX	Corpus Christi, TX	162	300	300	24	1Q13
Magellan/Copano Double Eagle	Magellan	Eagle Ford, TX	Corpus Christi, TX	190	100	100	24	1Q13
EPD EF Phase II Extension	Enterprise	Wilson, TX	Gardendale, TX	220	200	200	24	2Q13

Source: Company data, EIA, Texas Railroad Commission, Wood Mackenzie various news reports, Deutsche Bank estimates

- While high activity always raises cost inflation concerns, it appears that availability of pressure pumping equipment and crews has increased (partly shifting from the Haynesville) which is subduing completion costs in the near-term. All-in-all field economics and the takeaway situation in the Eagle Ford are much better than in the Bakken, and we thus have a strong preference for companies in our coverage with Eagle Ford vs Bakken exposure.

Figure 37: Eagle Ford production vs. pipeline takeaway capacity (Kbd)– no rail needed



Source: Company data, EIA, Wood Mackenzie, RigData, Baker Hughes, various news sources, Deutsche Bank estimates

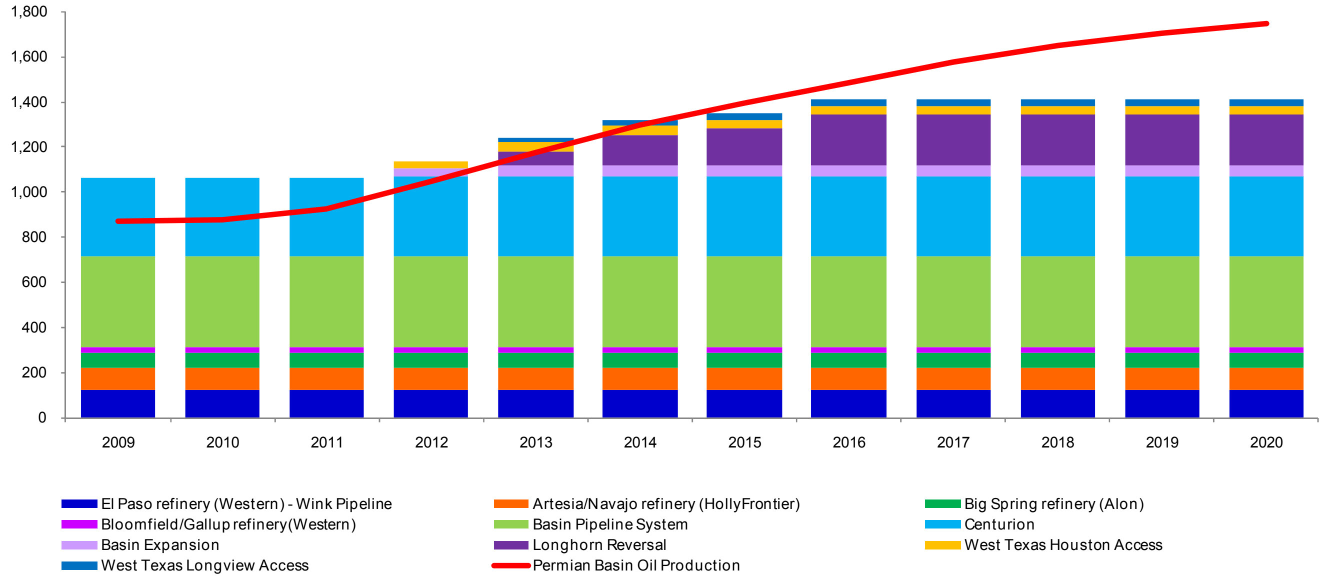
- The Eagle Ford surge is currently the main force that is **rapidly displacing imported light crude** along the Gulf Coast, which will eventually drive the widening Brent-LLS/WTI dynamic we describe elsewhere in the note. The addition of major trunklines to the Houston area, and to barge access in Corpus Christi, should accelerate the import displacement.
- The **physical proximity and low cost** and time of transport (once the trunklines are onstream) of Eagle Ford to the Gulf Coast refining complex means it will be more geographically challenged crudes, such as those produced in the Bakken, Niobrara, Permian and Canada that will struggle to find a market once all of the light crude imports are backed out of the Gulf. Eagle Ford oil, like LLS, will suffer a discount to Brent, but it will be **in a better competitive situation** than the inland crudes in the domestic light crude struggle to find a market that will likely ensue by mid-decade.

Permian – strong growth could overwhelm takeaway

After losing some momentum earlier in 2011 due to a lack of gas-gathering and transport infrastructure in the Delaware Basin, we have increased our Permian Basin expectation incrementally recently, as new high profile plays have emerged and the rig count has surged (up 22% YoY). The Wolfcamp and the Bone Springs are the highest profile plays near-term, with a handful of well results from the Wolfcamp in the Midland Basin generating substantial newsflow. And while new plays are garnering activity, producers are also leveraging new technologies to increase recoveries from established plays. Carbonate reservoirs with existing production history are highly economic in the current environment.

Infrastructure remains the key risk, though the Permian is structurally advantaged in that total oil production is down, ~1Mbd from a peak of ~2Mbd in 1973. In other words, unlike in the Eagle Ford, the pipeline takeaway does not start from scratch. Incremental capital is entering an already inflationary services environment, and as such we expect to hear about inflationary pressure for rigs, fracs and labor by mid-2012. Despite the rising costs and the need to additional infrastructure, we now see Permian production climbing back towards previous peaks, though in our model we've leveled off 2020 production at about 1.75Mbd under the assumption that a light crude oversupply will depress WTI pricing and cut-off growth at some point.

Figure 38: Permian Basin supply vs. refinery pull and pipeline takeaway capacity – the balance is rail and truck



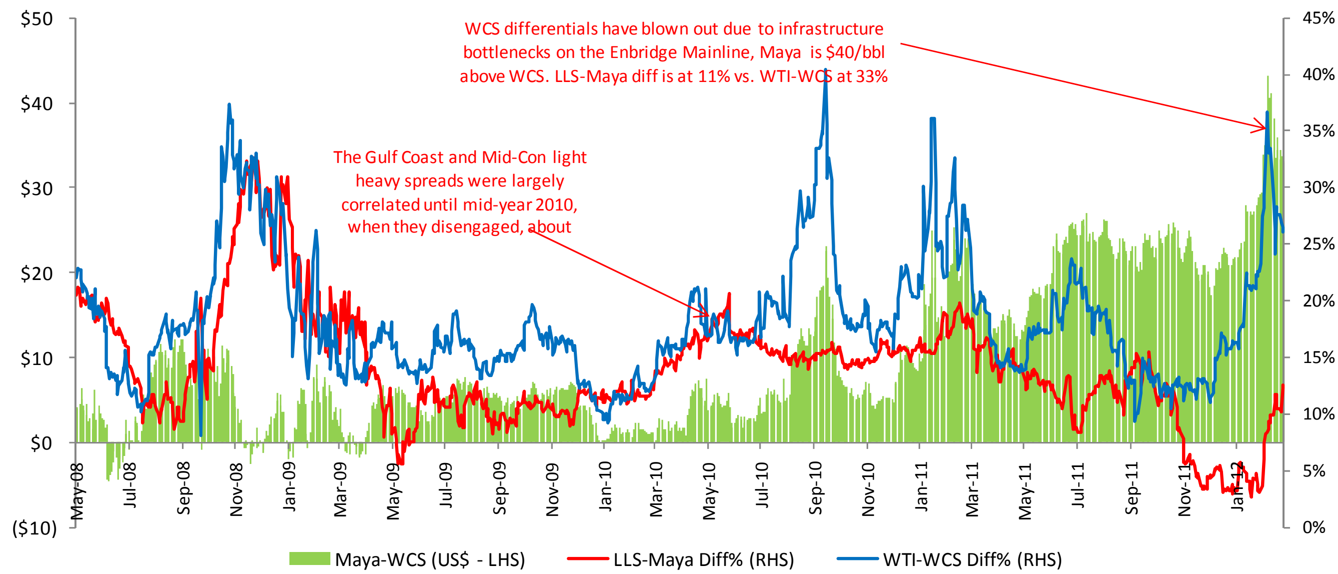
Source: Company data, various news sources, Wood Mackenzie, Rig Data, EIA ,Deutsche Bank estimates

The key takeaway is that the current pipeline expansion projects in the queue (Basin expansion, Longhorn reversal, the small Sunoco West Texas Gulf projects) will not be enough to handle expected Permian growth beyond 2014, thus new projects will be needed. The Permian does have rail terminal capacity and railcars (in fact, there was an expectation that some railcars would move out of the Permian to go the Bakken, but recalibration of Permian growth has apparently kept most of the railcars in place), as well as trucks, so total takeaway is likely sufficient, but the more truck and rail in use, the higher the marginal transportation cost, the more likely local refineries can access discounted crude. HollyFrontier and Western Refining are the key beneficiaries.

North American light-heavy differentials

As much as distortions have widened the Brent/LLS-WTI differential over the last 15 months, an even wider divergence has emerged between the Gulf Coast light-heavy differentials and the interior North American light-heavy spread. On the coast, LLS-Maya has traded narrowly, a symptom of both Maya production issues and strong demand for heavy from the complex PADD 3 refineries, who would like to run more heavy sour. Meanwhile WCS has weakened relative to already weak WTI, recently creating a $40+/bbl gulf relative to Maya.

Figure 39: Light-heavy spreads – a tale of two diffs (LLS-Maya vs. WTI-WCS since 2008)



Source: Bloomberg Finance LP, Deutsche Bank

Key points regarding the North American light-heavy balance and differential:

- The **recent blow-out in differentials** was largely the result, as we discussed in the Northern Tier section, of the pipeline **bottleneck at Superior,** WI, which temporarily filled up as a result of surging Bakken and Canadian production, exacerbated by a slower than expected ramp up of crude by rail out of the Bakken. Superior storage literally filled to the top of the tanks, which can hold about 5.5Mbbl.

Figure 40: Mid-Con/Canadian refinery expansions/conversions over next 2 years

Refinery	Owner	Expected Date	Incremental Capacity	Change in Heavy	Change in Light
Wood River (IL)	COP/Cenovus	4Q11	50	130	(80)
Mandan (ND)	Tesoro	2Q12	10	0	10
Detroit (MI)	Marathon	4Q12	10	80	(70)
Trenton Diesel Refinery (ND)	DOP	4Q12	20	0	20
Whiting (IN)	BP	2Q13	0	230	(230)
Redwater/NWU (AB)	NWU/CNQ	3Q14	50	50	0
Total			**165**	**490**	**(335)**

Source: Company data, Reuters, Deutsche Bank estimates

- While infrastructure limitations and strong growth in production likely mean a **volatile WTI-WCS differential, particularly for the next two years**, in our view the **increasing demand pull** from Mid-Con refinery conversions (see table above), pipeline access to the heavy-hungry complex Gulf Coast, and eventually major pipelines to the Canadian West Coast (and thus access to Asia and the US West Coast) **suggests a structurally narrower light-heavy** over the medium- and long-term.

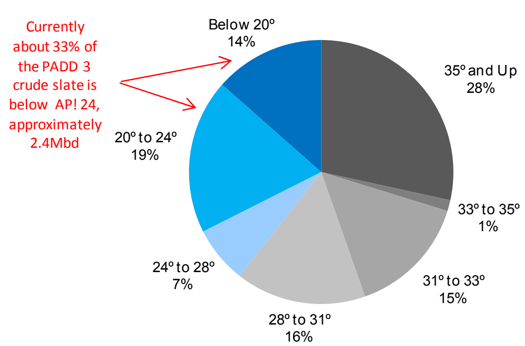
Figure 41: Major pipeline projects that will impact access to demand for Canadian heavy crude

Pipeline	Operator	From	To	Length (mi)	Init. Cap. (kbd)	Ult. Cap. (kbd)	Diam. (in)	Target Date	Est. Cost ($m)
Seaway Reversal	Enbridge/EPD	Cushing, OK	Freeport, TX	500	150	400	30	2Q12	1,300
Keystone XL Gulf Coast Proj.	TransCanada	Cushing, OK	Port Arthur, TX	500	500	830	36	2H13	2,300
GC Access/Flanagan South	Enbridge	Flanagan, IL	Cushing, OK	580	400	500	30	2Q14	1,900
Seaway Loop/expansion	Enterprise	Cushing, OK	Freeport, TX	500	400	400	36	2014-15	NA
Keystone XL Northern Leg	TransCanada	Hardisty, AB	Cushing, OK	1,667	700	830	36	2015	5,300
Keystone XL Texas Lateral	TransCanada	Port Arthur, TX	Houston/Tex City, TX	48	500	500	NA	2015	800
TransMountain expansion	Kinder Morgan	Edmonton, AB	Vancouver, BC	715	300	500	30	2016+	4,300
Northern Gateway Pipeline	Enbridge	Bruderheim, AB	Kitimat, BC	731	500	500	36	2017+	5,500

Note: Not all capacity listed here is incremental – for example Enbridge's Gulf Coast Access project will increase availability of Western Canadian heavy to the Seaway pipeline to the Gulf Coast, but Seaway capacity will set the maximum amount that can actually get to the GC on the Enbridge system. Similarly, the Keystone XL Houston lateral will add refineries that have access to heavy crude on the Keystone system, but won't add actual capacity to the Gulf Coast.
Source: Company data, EIA, CAPP, Wood Mackenzie various news reports, Deutsche Bank estimates

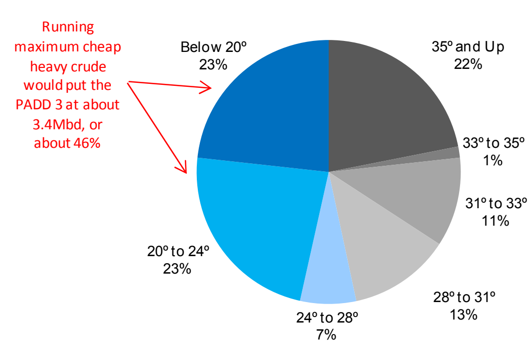
- We believe there will easily be **enough demand for Canadian heavy from the US Gulf Coast refiners to essentially fill planned pipeline projects to the Gulf Coast once built** (both Enbridge and Keystone systems). Gulf Coast refiners consistently tell us that they want to run more heavy. This unsatisfied demand for heavy is one reason the waterborne light-differential is so narrow. The arrival of much cheaper Canadian heavy will initially fill unused heavy capacity on the Gulf, then will displace more expensive waterborne heavy until heavy prices reach some kind of transportation cost-adjusted equilibrium.

Figure 42: GC refiners – the crude slate they have now



Source: Company data, EIA, Wood Mackenzie, Deutsche Bank estimates

Figure 43: GC refiners – the crude slate they want



Source: Company data, EIA, Wood Mackenzie, Deutsche Bank estimates

- How much **unutilized heavy capacity exists on the Gulf Coast** is a slippery question. We believe that PADD 3 refineries are currently running about 2.4Mbd of heavy crude, or roughly 33% of the crude slate. By our calculation (with an assist from Wood Mackenzie) there is about 1.5Mbd of coking capacity in PADD 3 (though EIA data shows that as of Fall 2011, PADD 3 coker throughput was a bit over 1.2Mbd). Motiva will add another 95kbd coker to the mix in 1H12. As a rough rule of thumb, a refinery's heavy capacity is roughly 1.7x to 2.5x its coking capacity, depending on the plant's full configuration. Assuming a range of 2.0x to 2.25x as the ratio for the highly complex Gulf

Coast, our back of the envelope calculation suggests that there is about 3.0Mbd to 3.4Mbd of heavy capacity in PADD 3, which means the Gulf Coast refiners, all things being equal, **would like to run another 600Kbd to 1Mbd of heavy**, were they able to get it at a "normal" discount to light on the Gulf Coast.

- Having said that, given the high, potentially very high, rate of bitumen production growth over the next decade, **the timing of pipeline startups will be critical**. If projects stay on schedule, the cumulative incremental demand pull on WCS and other Canadian heavy crudes should be sufficient to narrow the differential beyond 2014, as we highlight in the section on North Central takeaway (see Figure 34 on page 34), and keep it structurally narrower than it has been. However, if pipeline projects such as Keystone XL, Seaway Expansion/Gulf Coast Access or the Canadian West Coast projects are delayed or shelved, production growth could be strong enough to drive the differential to the extremes we've seen this year. At this time, the dynamic is clearly towards delays.

Figure 44: Western Canadian Heavy – Demand is on the way, expect long-term WTI-WCS to narrow

	Operator	1Q12	2Q12	3Q12	4Q12	1Q13	2Q13	3Q13	4Q13	1Q14	2Q14	3Q14	4Q14	1Q15	2Q15	3Q15	4Q15	1Q16	2Q16	3Q16	4Q16	1Q17	2Q17	3Q17	4Q17
POTENTIAL WCSB HEAVY SUPPLY																									
Total Increase in WCSB Bitumen Supply Capacity vs. YE 11		84	99	115	173	239	312	394	441	501	564	626	693	768	864	964	1,060	1,170	1,290	1,413	1,533	1,645	1,762	1,888	2,015
Assuming Capacity Utilizaiton of....	**85%**	**71**	**84**	**98**	**147**	**203**	**265**	**335**	**375**	**426**	**480**	**532**	**589**	**653**	**735**	**819**	**901**	**994**	**1,097**	**1,201**	**1,303**	**1,398**	**1,498**	**1,604**	**1,712**
Q to Q Incremental		71	13	14	49	56	62	70	40	50	54	52	57	64	82	85	82	93	102	104	102	95	100	107	108
DEMAND FOR WCSB HEAVY																									
Mid-Con/Canadian heavy refining capacity increases																									
Wood River CORE	Phillips 66	65	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Detroit HOUP	Marathon	0	0	0	40	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Whiting	BP	0	0	0	0	0	100	150	200	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
Redwater/NWU Bitumen Refinery	NWU/CNQ	0	0	0	0	0	0	0	0	0	25	50	50	50	50	50	50	75	100	100	100	100	125	150	150
Total		**65**	**130**	**130**	**170**	**210**	**310**	**360**	**410**	**440**	**465**	**490**	**490**	**490**	**490**	**490**	**490**	**515**	**540**	**540**	**540**	**540**	**565**	**590**	**590**
Assuming Capacity Utilization of....	**92%**	**60**	**120**	**120**	**156**	**193**	**285**	**331**	**377**	**405**	**428**	**451**	**451**	**451**	**451**	**451**	**451**	**474**	**497**	**497**	**497**	**497**	**520**	**543**	**543**
Pipeline access to Gulf Coast																									
Seaway Reversal/Flanagan South	ENB/EDP	0	0	100	150	200	300	300	300	300	350	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Seaway Expansion	ENB/EDP	0	0	0	0	0	0	0	0	0	0	0	200	400	400	400	400	400	400	400	400	400	400	400	400
Keystone XL	TransCanada	0	0	0	0	0	0	0	0	0	0	0	0	0	250	375	400	625	625	625	625	625	625	625	625
Total		**0**	**0**	**100**	**150**	**200**	**300**	**300**	**300**	**300**	**350**	**400**	**600**	**800**	**1,050**	**1,175**	**1,200**	**1,425**	**1,425**	**1,425**	**1,425**	**1,425**	**1,425**	**1,425**	**1,425**
Pipeline access to West Coast																									
TransMountain Expansion	Kinder Morgan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	300	300	300	300	300	300	300	300
Enbridge Northern Gateway	Enbridge	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	400
TransMountain Further Expansion	Kinder Morgan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**150**	**300**	**300**	**300**	**300**	**300**	**300**	**500**	**700**
Total Increase in Demand for WCSB Heavy vs. YE 11		**60**	**120**	**220**	**306**	**393**	**585**	**631**	**677**	**705**	**778**	**851**	**1,051**	**1,251**	**1,501**	**1,626**	**1,801**	**2,199**	**2,222**	**2,222**	**2,222**	**2,222**	**2,245**	**2,468**	**2,668**
Q to Q Incremental		60	60	100	87	87	192	46	46	28	73	73	200	200	250	125	175	398	23	0	0	0	23	223	200
Cumulative net WCSB Heavy Supply - Demand vs YE11		**12**	**(36)**	**(121)**	**(159)**	**(190)**	**(320)**	**(296)**	**(302)**	**(279)**	**(298)**	**(319)**	**(462)**	**(598)**	**(766)**	**(806)**	**(899)**	**(1,204)**	**(1,125)**	**(1,021)**	**(918)**	**(824)**	**(747)**	**(863)**	**(955)**
Q to Q incremental heavy supply - demand (kbd)		12	(47)	(86)	(38)	(31)	(130)	24	(6)	23	(19)	(21)	(143)	(136)	(168)	(40)	(93)	(305)	79	104	102	95	77	(116)	(92)

Source: Company data and presentations, Oil Sands Developer Group, Oil Sands Review, Alberta Oil Magazine, Upstream, CAPP, various news sources, Deutsche Bank

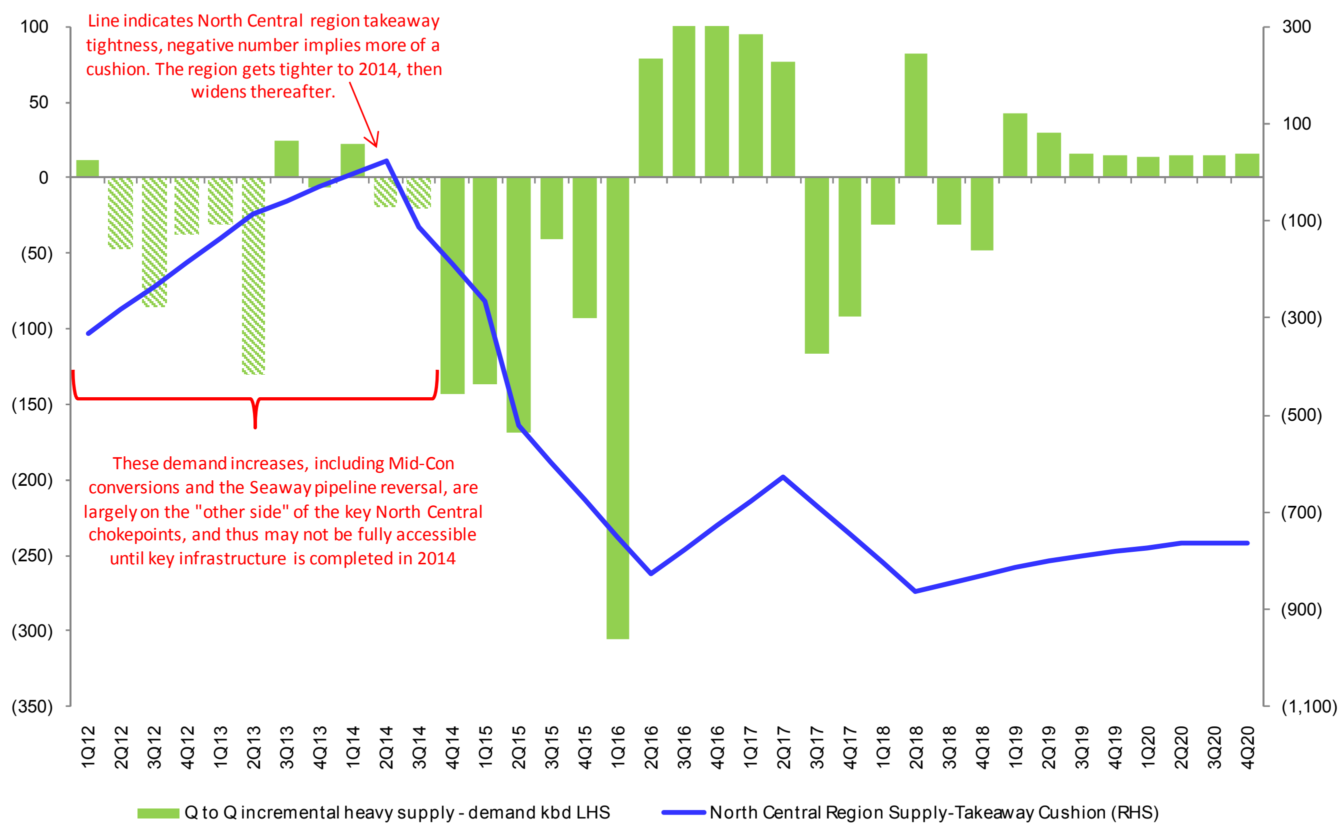
- While the Canadian forecast we use in our North American production model assumes about 1.4Mbd of bitumen supply growth from 2011 to 2020, the **announced oil sands project queue**, unrisked and at full capacity, suggests the **potential for as much as 2.5Mbd of growth**, or about 280kbd per year for the next nine years. But even if we assume 85% utilization and some delays driven by cost inflation or labor shortage, the current project queue would require multiple major pipelines to find a market for all production.

- The table above compares the bitumen production forecast if the entire announced project queue for the oil sands is built on schedule. We've assumed a 12-18 month ramp up from steam-in to peak production for each project, and an 85% utilization rate. To that we compare the various pipeline startups and refinery conversions that represent increases in demand for Canadian heavy, based on their announced schedules. As with our Inland Corridor balances, to which this is obviously closely related (though demand and takeaway are different), this exercise shows that if everything gets built on time, there **should**

be enough incremental demand over the medium- and long-term even if production surges above plan.

- As the chart below illustrates, however, individual quarters could have higher incremental supply growth than incremental demand pull, which suggests **volatility in the differential**. Furthermore, in the near-term we know that the Enbridge system has been strained due to the combination of Bakken and Western Canadian supply trying to move into Eastern PADD 2 or to Cushing. **The Superior chokepoint has reached capacity for periods**, with relief coming only when major oil sands upgrading projects were curtailed and/or shutdown. While crude-by-rail ramp up will relieve some pressure, and Enbridge will shortly widen the chokepoint by 50kbd by expanding Line 5, the chokepoint **won't be widened meaningfully until Enbridge twins Spearhead, expands the Southern Access portion of the mainline, and likely doubles the size of Seaway in 2H14.** We therefore see a volatile and wider-than-normal WTI-WCS differential until the Gulf Access route expansion.

Figure 45: Net Q to Q incremental Canadian heavy supply – demand vs. YE11 – volatile WTI-WCS until 2H14



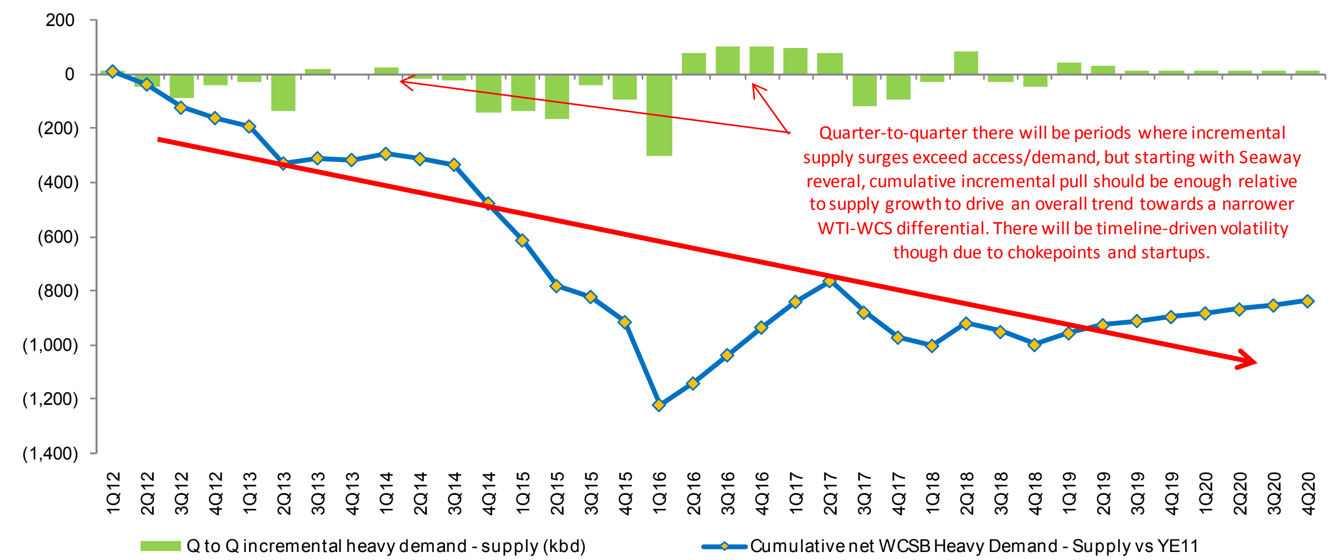
Source: Company data, Various news sources, CAPP, Deutsche Bank estimates

- From 2H14 forward the scale of the demand increases will be greater and cumulatively much larger than the production growth for the next decade, even the unrisked supply growth. We conclude that we should have a **structurally narrower WTI-WCS over the next decade beyond 2H14**.

- The wide current differential for WCS obviously penalizes bitumen producer realizations, and conversely benefits refiners (PADD 4, PADD 2 and Canadians) with access to the Canadian heavy. Over the long-run the WTI-WCS differential should be narrower, which will help bitumen-long Canadian upstream companies. Mid-Con refiners will get less of a discount for their Canadian crude, but relative to waterborne heavy crudes, we would expect WCS to still be cheaper due to abundance, less access to other (non-US) markets, and transportation cost differential.

- As more Canadian heavy reaches the Gulf Coast, we would expect Maya and other waterborne heavy crudes to either come down in price to remain competitive, or move to other markets. **This again supports a view that the Maya-WTI/LLS differential will be narrow and even negative, in total contrast to refiners expectations over the past five years.**

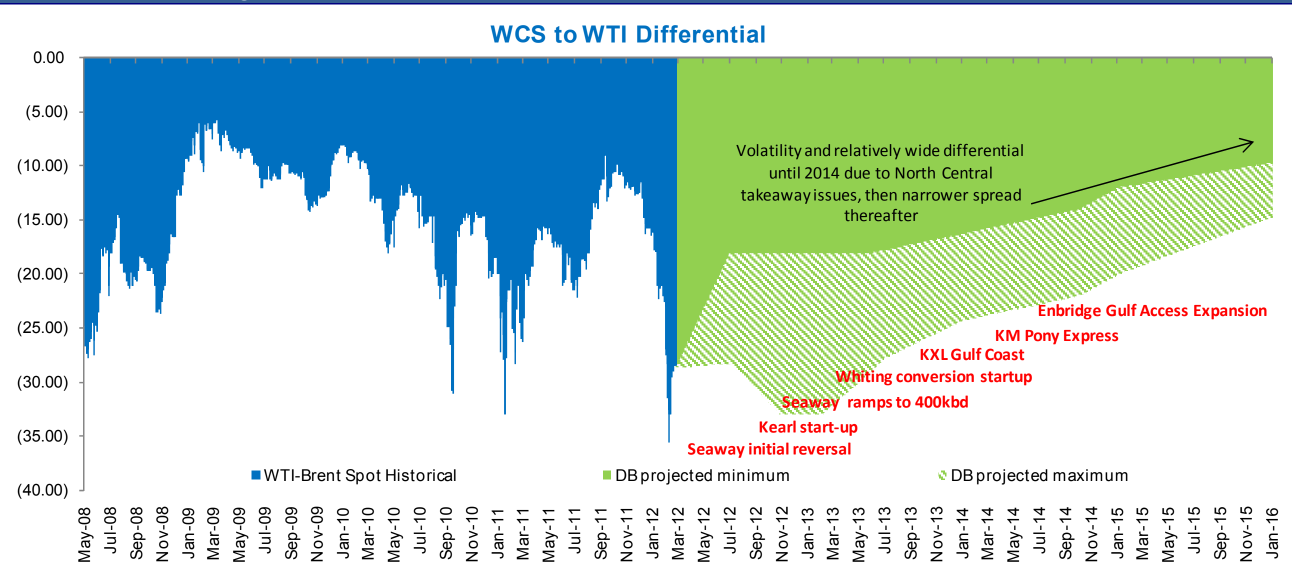
Figure 46: Incremental demand for Western Canadian heavy vs. increasing bitumen production, by quarter, assuming all pipeline and refinery expansions get built on schedule



Source: Company data and presentations, Oil Sands Developer Group, Oil Sands Review, Alberta Oil Magazine, Upstream, CAPP, various news sources, Deutsche Bank

Below we summarize the timing of important events in our forecast for the WCS-WTI differential over the next five years.

Figure 47: Inland heavy-light differential forecast – volatile and wide to 2014, then structurally narrower



Source: Bloomberg Finance LP, company data, various news sources, Deutsche Bank estimates

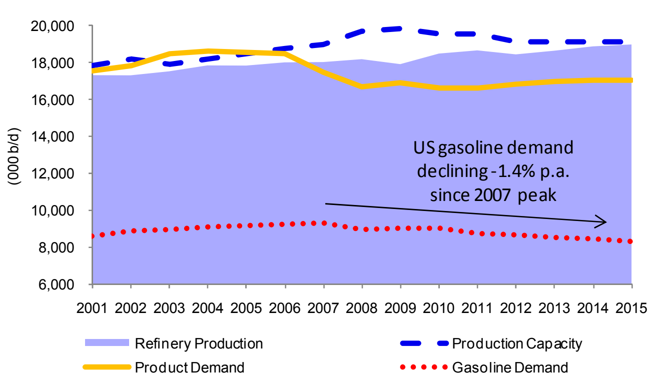
Supply-Demand Balances in the US

In order for US refiners to earn super-normal returns on the back of long-term advantaged crude pricing, they will need to simultaneously achieve global product pricing for their gasoline and diesel. They are currently able to do so across the US because the marginal cost of crude supply is Brent-priced waterborne light crudes. The Mid-Con is short refinery capacity and product, and the Gulf Coast refiners fill the gap. Once Gulf Coast refiners are no longer paying Brent prices for their light, and are in fact enjoying deeply discounted domestic light crude pricing, we would expect to see US product prices fall, as Gulf Coast and Mid-Con refiners battle in a market share "bankruptcy battle" in the Mid-Con. The linchpin will be product exports – if Gulf Coast refiners are able to continue to increase product exports, stealing share across the Atlantic Basin from less efficient foreign refiners, then the "bankruptcy battle" will be overseas rather than in the US Mid-Con, and US domestic product pricing will be close to global levels.

We intend to address this issue in depth in a subsequent thematic note in this series, but publish a few summary charts here to illustrate the playing field. The key point in the domestic supply-demand balance for refined products is that US capacity is forecast to remain relatively stable with flat or declining demand for products, mainly due to the weakness in gasoline markets (currently ~46% of US product consumption). Against this backdrop, the potential for exports in the Atlantic Basin is crucial for the profitability of the US refining system.

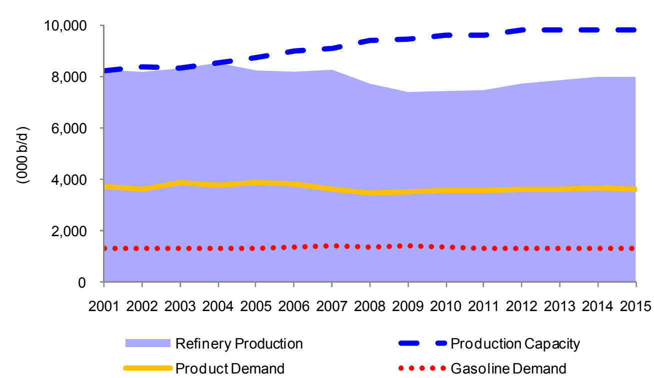
We see US refining capacity constant at 17.5m b/d. There are small expansions planned for the MidCon and the Rockies and the Motiva expansion this year (+300k b/d) is offset by Sunoco's potential shutdown of Marcus Hook (already idled) and Philadelphia. PADD 3 harbors ~55% of the US refining capacity and is the main platform for product exports in the Atlantic Basin.

Figure 48: US Refining Output vs. Demand



Source: Deutsche Bank, EIA

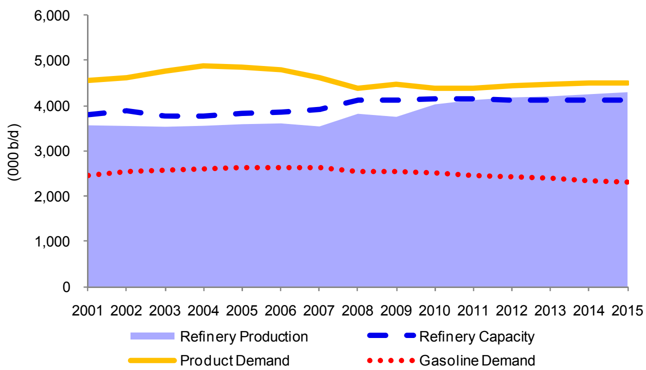
Figure 49: PADD 3 Refining Output vs. Demand



Source: Deutsche Bank, EIA

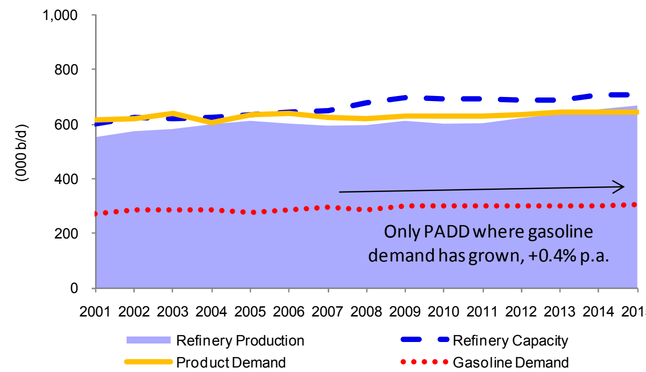
PADDs 2 and 4 are short products and are the clear winners if the current export trend is sustainable and have been our preferred locations for US refineries vs. the coastal PADDs 1 and 5.

Figure 50: PADD 2 Refining Output vs. Demand



Source: Deutsche Bank, EIA

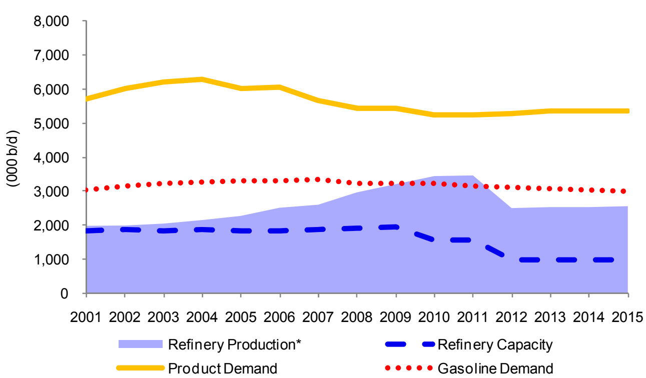
Figure 51: PADD 4 Refining Output vs. Demand



Source: Deutsche Bank, EIA

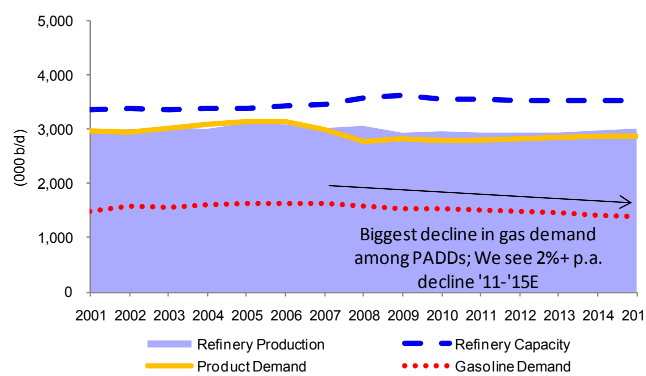
PADD 1 shows a tighter balance with the idling of ConocoPhillips's Trainer and Sunoco's Marcus Hook. Other idle refineries in EIA's reported PADD 1 operable capacity of 1.6m b/d are Yorktown (converted to a terminal) and Chevron's Perth Amboy (~150k b/d).

Figure 52: PADD 1 Refining Output vs. Demand



**Includes blenders' net production; Source: Deutsche Bank, EIA*

Figure 53: PADD 5 Refining Output vs. Demand



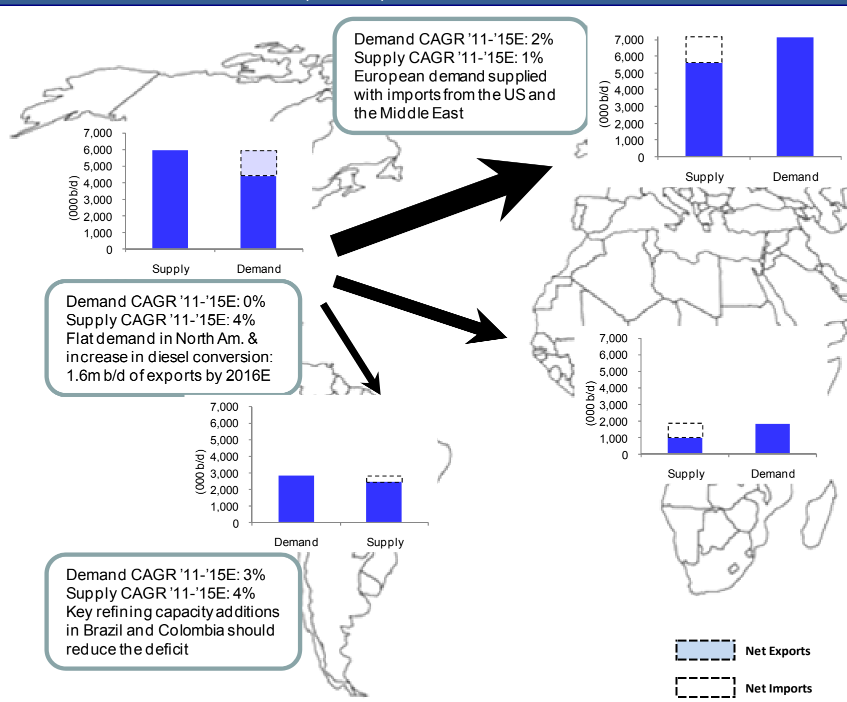
Source: Deutsche Bank, EIA

US Distillate Exports and Demand in the Atlantic Basin

Refining capacity rationalization in Europe, despite falling demand for products, and robust growth from emerging economies in Latin America and Africa should support US exports. We see the more competitive US refineries gaining market share in the Atlantic Basin and forecast distillate net exports of 1.6m b/d in 5 years (vs. current 0.9m b/d).

Figure 54: Distillate Balance in the Atlantic Basin (2011E)

Figure 55: Distillate Balance in the Atlantic Basin (2015E)



Source: Deutsche Bank, EIA, Wood Mackenzie

Gasoline Demand

Strong growth in LatAm (particularly Mexico and Brazil, where capacity should lag demand growth) should continue to support US exports and provide some relief to the US refiners given a declining domestic market (-1% p.a. decline in 2011-2015E).

Figure 56: Gasoline Balance in the Atlantic Basin (2011E)

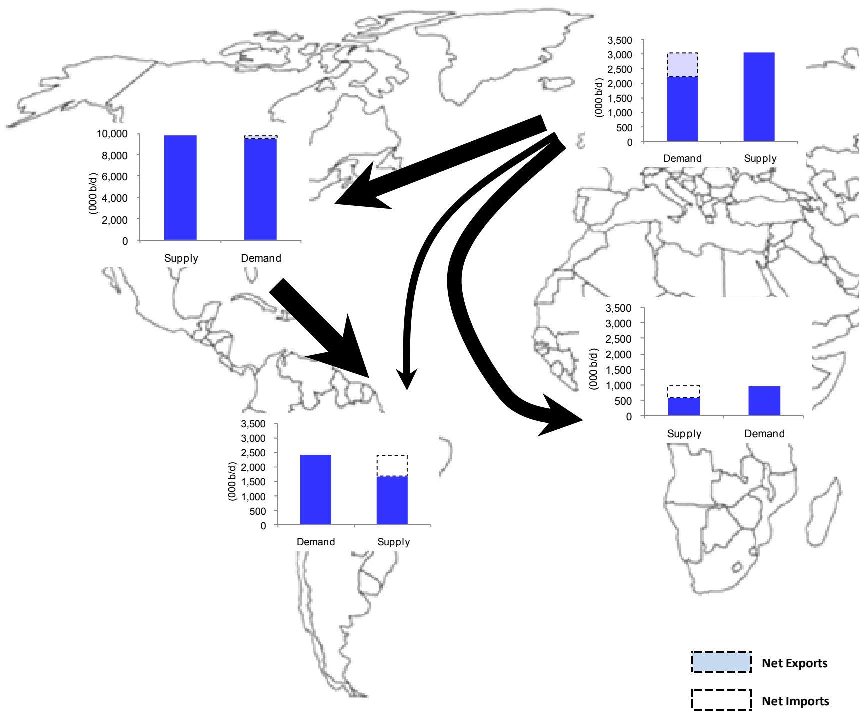
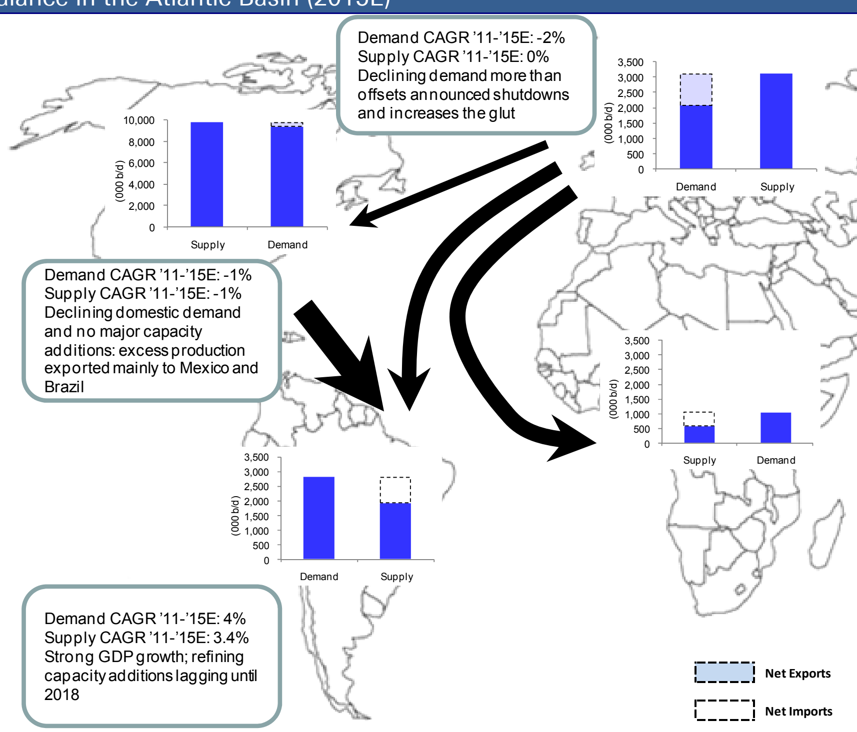


Figure 57: Gasoline Balance in the Atlantic Basin (2015E)



Source: Deutsche Bank

Appendix – crude export restrictions & the Jones Act

Brief history of American crude export restrictions

While US government-imposed restrictions on exports go back more than a century, largely driven by war-time necessity, the current export rules have their roots in the post World War II period. The end of the war and the emergence of the Cold War brought a more focused and comprehensive approach to export controls, culminating in the Export Control Act of 1949, which addressed the Soviet bloc security threat. From that point forward export controls of various commodities and goods have been justified under three codified objectives: 1) **short supply controls** to prevent the export of scarce goods important to the domestic economy and industry, 2) **foreign policy controls** to promote the foreign policy goals of the US, 3) **national security controls** to promote broad policy issues such as regional stability, human rights, anti-terrorism, missile technology and bio/chem warfare. Restrictions on the export of crude oil has been justified only under the first of these, short supply controls.

The embargo-like restrictions of the Export Control Act were renewed without changes in '51, '53, '56, '58, '60, '62 and '65. As US-Soviet relations in the late 1960's improved into a period of "détente," trade liberalization between the Eastern and Western blocs gained a degree of consensus and replaced the very strict ECA of 1949 with the less restrictive Export Administration Act of 1969, which was renewed in 1974 and 1977. The EAA was comprehensively rewritten in 1979, and amended in 1985, extending authorization to 1989, at which point the fall of the Berlin Wall and of the Soviet Union prompted another wave of liberalization.

The basic export control system outlined in the EAA of 1979 has remained intact. From 1989 to 1994 the EAA processes were continued via temporary statutory extensions, and by invocation of Presidential powers under the International Emergency Economic Powers Act (IEEPA). From 1994 to 2000, an Executive Order continued the IEEPA authorized export controls, at which point Congress passed legislation extending the EAA of 1979 until late 2001, when it again expired. Once that date was reached, export control authority again fell under IEEPA, as per an Executive Order, which is the source of authority today. Though Congress has periodically revisited the EAA and export control issues, there have been no successful legislative actions on the issue.

The EAA of 1979 set up restriction authorization for the export of certain goods, including crude, to protect domestic industries from shortage of scarce materials. Today, few of those short-supply controls are still in force, though a handful of restrictions remain in place. In addition to crude, one cannot export without an exemption permit, for example, unprocessed western red cedar or horses by sea.

Various pieces of legislation, such as the Outer Continental Shelf Lands Act, the Naval Petroleum Reserves Production Act, the Energy Policy and Conservation Act, the Trans Alaska Pipeline Authorization Act and PL 104-58 "Exports of Alaskan North Slope Oil," have carved out specific exceptions to the crude export restrictions. According to the EIA, US crude oil export restriction exceptions include: "1) crude oil derived from fields under the State waters of Alaska's Cook Inlet, 2) Alaska North Slope crude oil, 3) certain domestically produced crude oil destined for Canada, 4) shipments to US territories, and 5) California crude oil to Pacific Rim countries." The last exception is limited to 25kbd.

Though discretionary authority to restrict exists, refined products have not been subject to short supply export controls since 1981, when Secretary of Commerce Malcolm Baldridge lifted existing restrictions even though global oil markets were in turmoil.

The crude export licensing process under the EAA (and currently under the IEEPA authority) is administered within the Department of Commerce, by the Bureau of Industry and Security. The Export Administration Regulations (EAR), Section 154, consolidates the EAA and various other relevant pieces of legislation into the BIS's governing rules regarding crude export.

(Sources: Congressional Research Service reports; *Oil Regulation in 28 Jurisdictions Worldwide 2009: Getting the Deal Through*, United States section by Vinson & Elkins LLP, EAR Section 154, Bureau of Industry and Security).

… and a quick comment about the Jones Act

The Jones Act, Section 27 of the federal Merchant Marine Act of 1920, governs maritime commerce in United States waters between US ports. The Act mandates that all goods transported between two points in the United States be built in the US, be owned and operated by US citizens (at least 75%), carry a US flag and employ a crew manned by US citizens. The Act was named after the Chairman of the Senate Commerce Committee in 1920, Senator Wesley Jones from Washington state.

The purpose of the Act is to ensure that the country maintains a merchant marine and shipbuilding capability that might otherwise disappear in open competition with lower cost foreign shipyards, and that is necessary for national security and domestic commerce. In general the Jones Act is supported by a majority on both sides of the political aisle, including unions, most military leaders, and every US President since Ford.

The Jones Act, which itself was a restatement of numerous protectionist maritime restrictions dating back to the very first Congress, has gone through numerous revisions (including temporary liftings), most recently in 2006. In addition to cabotage (the transport of goods), the Jones Act addresses seaman's rights, granting legal recourse not allowed under international maritime law, such as the right to bring negligence claims against ship owners, captains or fellow crew members.

The "cabotage" rules ("cabotage" likely derives from the French "caboter" which refers to coastal sailing) requiring ships to be built in the US also limit the amount of foreign materials (steel) that can be used in repairs (no more than 10% by weight), which prevents most refurbishment in foreign shipyards.

It is possible to obtain waivers from provisions of the Jones Act from the US Maritime Administration, but waivers have generally only been granted in emergency situations, such as in the wake of Hurricane Katrina.

The Jones Act raises the cost of waterborne transportation in the US by 1) limiting the number of available vessels, 2) limiting the size of the vessels, as it is uneconomic for US shipbuilders to build anything but smaller coastal commercial vessels, and 3) raising the labor costs of coastal shipping. Furthermore, Jones Act ship-owners are highly incentivized to use older vessels because the cost of building new ones is so high. Marathon Petroleum has estimated Jones Act transportation costs of about $11+/bbl from Houston to Philadelphia, and in all likelihood rates would be even higher should demand for the route increase, given the severely limited size of the Jones Act fleet.

Figure 58: Senator Wesley Jones, of Jones Act fame

Source: Wikimedia Commons

Numerous attempts over the years have been made to scale back or eliminate the Jones Act. Most recently, in 2010 a piece of legislation, the Open America's Waters Act, was introduced that would have fully repealed the Jones Act. The bill's sponsors (Senators John McCain and Jim Risch) argued that based on a US International Trade Commission economic study, repeal of the Jones Act would have an "annual positive welfare impact" on the US economy of close to $1B. The effort to repeal was not successful.

An interesting piece of history regarding the protection of domestic shipping from a 2003 Congressional Research Service report on the Jones Act: "The defense justification for protection of domestic shipping dates at least as far back as the first treatise on national economic policy written in 1776. In *Wealth of Nations*, Adam Smith argued against the mercantile trade policies of his era in favor of free trade or laissez faire. However, when it came to domestic shipping, Smith believed this industry was a logical exception to free trade. He supported England's navigation laws: "The defense of Great Britain depends very much upon the number of its sailors and shipping. The act of navigation, therefore, very properly endeavors to give the sailors and shipping of Great Britain the monopoly of the trade of their own country."

While repeal of the Jones Act seems highly unlikely for political reasons, we do believe there is potential for emergency waivers of the Jones Act, for example in a situation where high product prices on the East Coast could be alleviated by bringing a greater volume of gasoline and diesel from Gulf Coast refineries to the East Coast by Aframax or Suezmax. In that scenario the Jones Act would be waived for the Houston to Philadelphia/New York route, possibly with the restriction that the vessels used be US flagged and manned, though not US built. The cost per barrel under such a waiver would likely be in the $2-3/bbl range, close to the cost of product transit on the Colonial pipeline.

Appendix – Basin assumptions

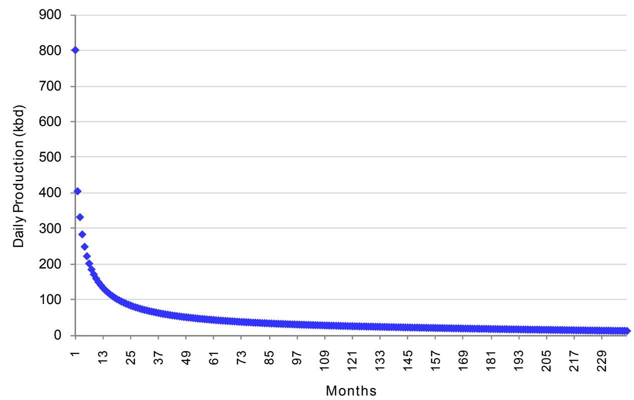
US Williston Basin (Bakken/Three Forks)

Figure 59: Williston Basin assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	3,218
Typical EUR (Kbbls)	600
30 day IP (bbl/d)	800
Initial Decline Rate	55%
Terminal Decline Rate	7%
Avg Drilling Time (days)	40
Typical Well Spacing (acres)	960
Current Rig Count	200
Peak Rig Count	224
Avg. Stream Composition:	
Oil	87%
NGL	3%
Gas	10%

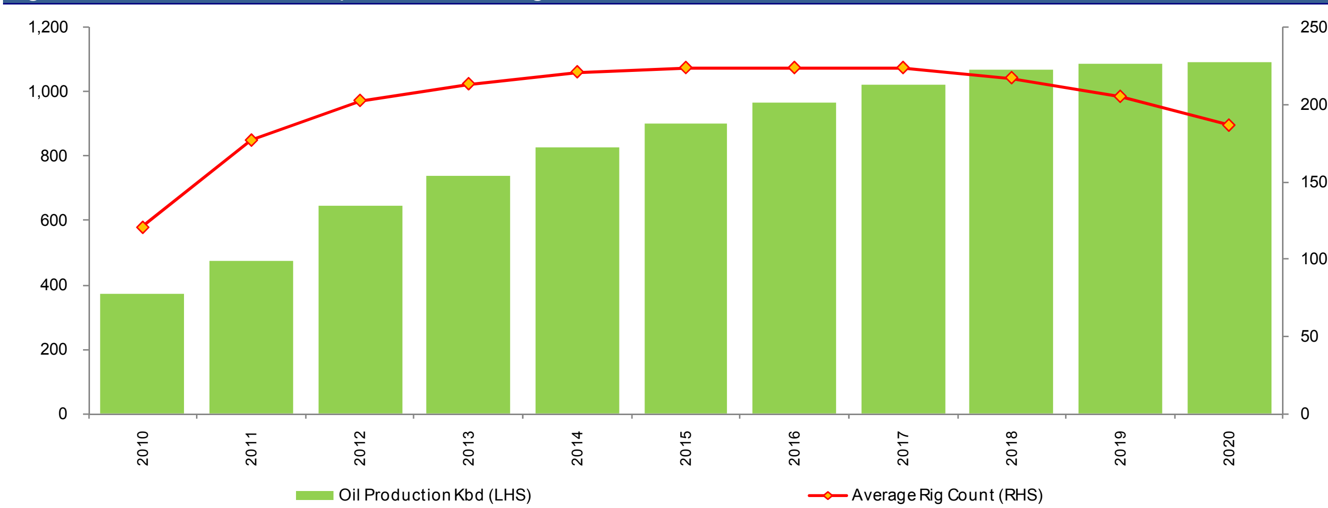
Source: USGS, North Dakota DNR Baker Hughes, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 60: Assumed Williston Basin type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 61: US Williston Basin production and rig count estimate



Source: USGS, North Dakota DNR Baker Hughes, Company data, Wood Mackenzie, Deutsche Bank estimates

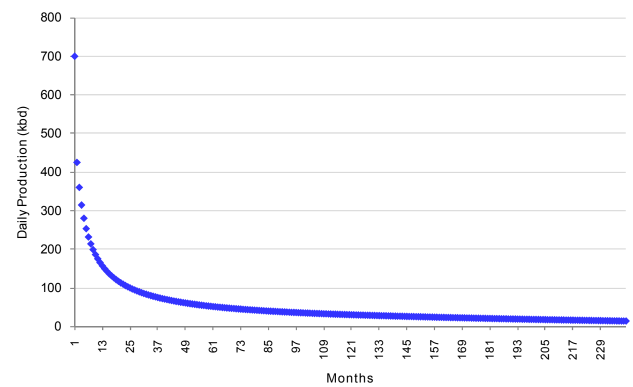
Eagle Ford – Oil & Gas Condensate Windows

Figure 62: Eagle Ford liquids windows assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	2,400
Typical EUR (Kbbls)	500
30 day IP (bbl/d)	700
Initial Decline Rate	35%
Terminal Decline Rate	7%
Avg Drilling Time (days)	40
Typical Well Spacing (acres)	160
Current Rig Count	202
Peak Rig Count	282
Avg. Stream Composition:	
Oil	65%
NGL	15%
Gas	20%

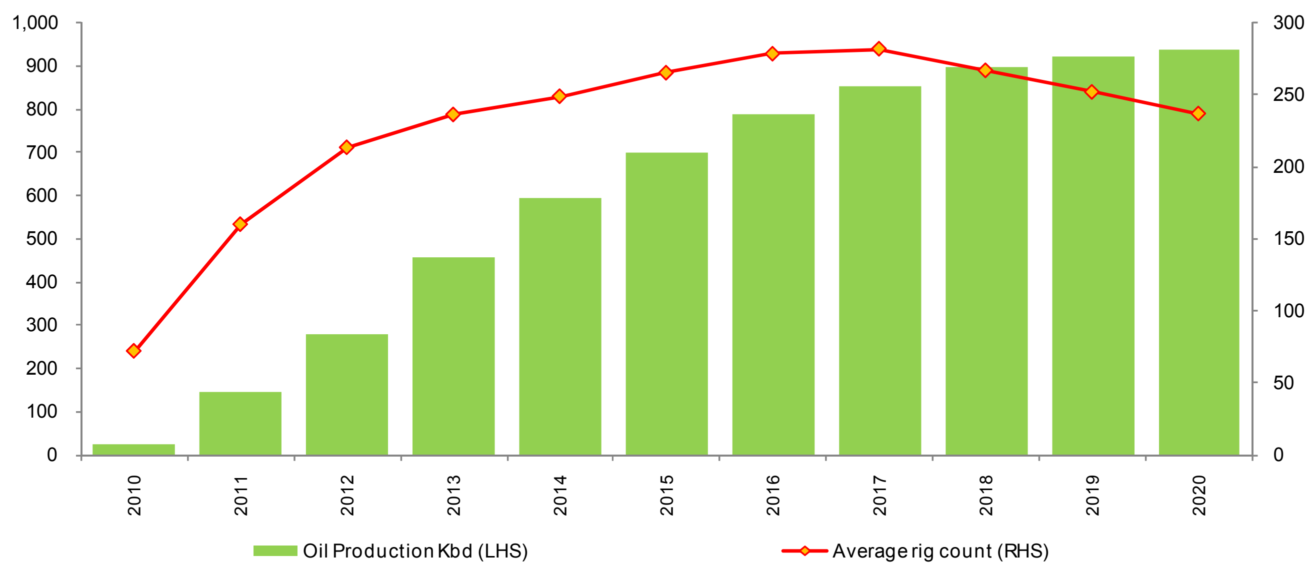
Source: USGS, Baker Hughes, Texas Railroad Commission, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 63: Assumed EF liquids windows type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 64: Eagle Ford oil production and rig count estimate



Source: USGS, Baker Hughes, Texas Railroad Commission, Company data, Wood Mackenzie, Deutsche Bank estimates

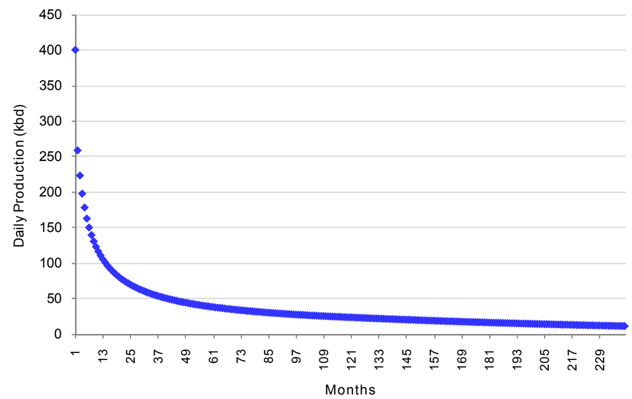
Permian Basin

Figure 65: Permian Basin assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	5,115
Typical EUR (Kbbls)	360
30 day IP (bbl/d)	400
Initial Decline Rate	30%
Terminal Decline Rate	7%
Avg Drilling Time (days)	25
Typical Well Spacing (acres)	160
Current Rig Count	490
Peak Rig Count	620
Avg. Stream Composition:	
Oil	69%
NGL	13%
Gas	18%

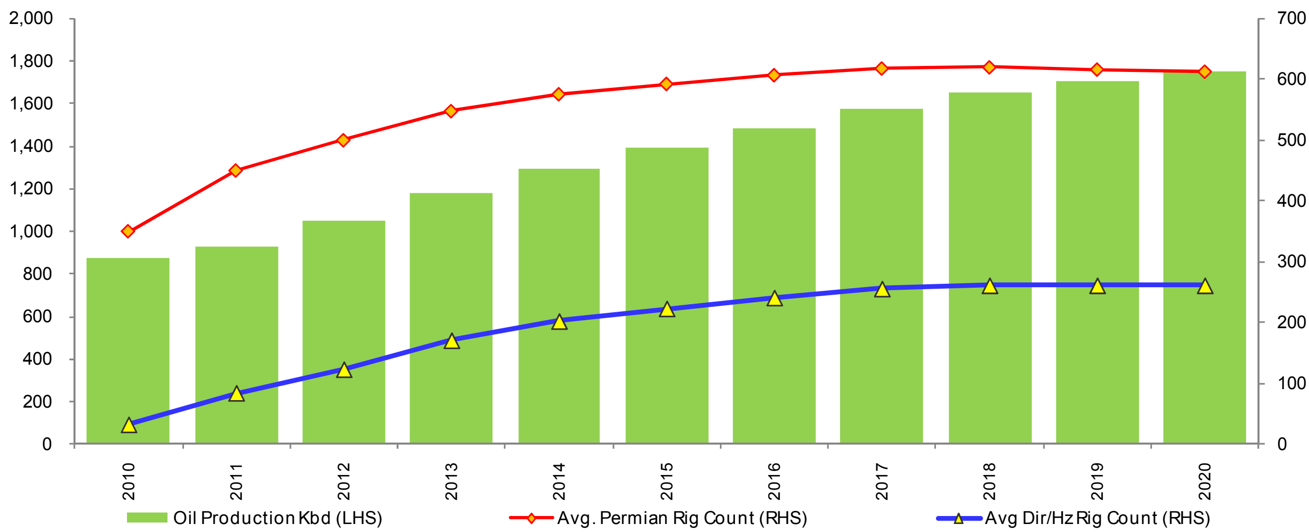
Source: USGS, Baker Hughes, Texas Railroad Commission, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 66: Assumed Permian Basin type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 67: Permian Basin production and rig count estimate



Source: USGS, Baker Hughes, Texas Railroad Commission, Company data, Wood Mackenzie, Deutsche Bank estimates

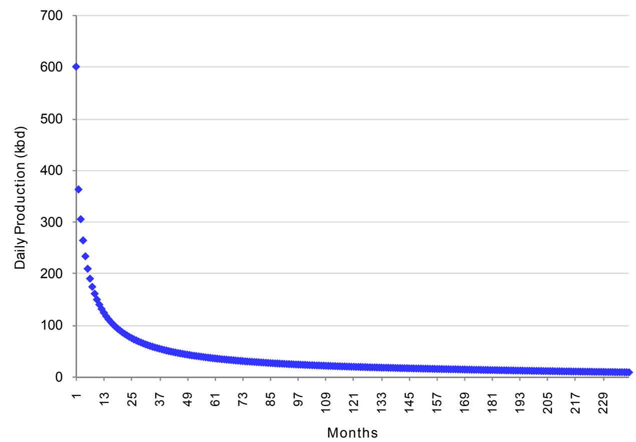
DJ Basin/Niobrara

Figure 68: DJ Basin/Niobrara assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	971
Typical EUR (Kbbls)	380
30 day IP (bbl/d)	600
Initial Decline Rate	34%
Terminal Decline Rate	7%
Avg Drilling Time (days)	25
Typical Well Spacing (acres)	320
Current Rig Count	38
Peak Rig Count	90
Avg. Stream Composition:	
Oil	55%
NGL	10%
Gas	35%

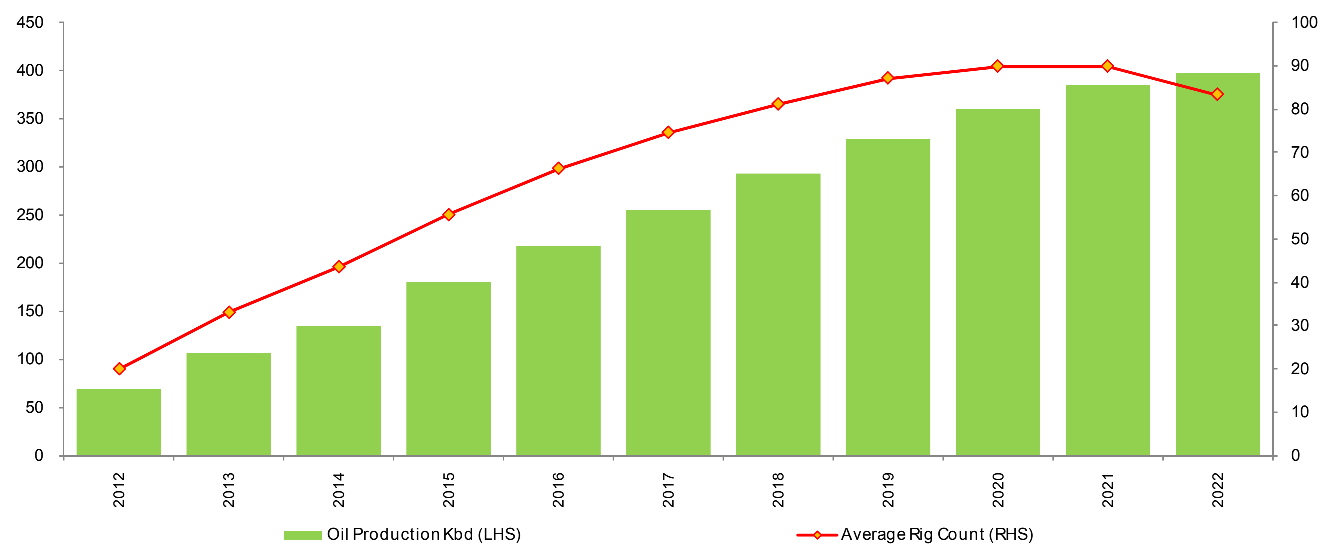
Source: USGS, Baker Hughes, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 69: Assumed DJ Basin/Niobrara type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 70: DJ Basin/Niobrara production and rig count estimate



Source: USGS, Baker Hughes, EIA, Company data, Wood Mackenzie, Deutsche Bank estimates

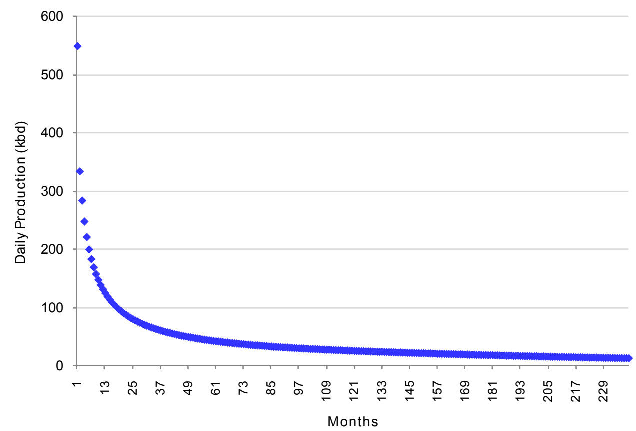
Utica Shale

Figure 71: Utica Shale assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	501
Typical EUR (Kbbls)	400
30 day IP (bbl/d)	550
Initial Decline Rate	35%
Terminal Decline Rate	7%
Avg Drilling Time (days)	40
Typical Well Spacing (acres)	160
Current Rig Count	11
Peak Rig Count	100
Avg. Stream Composition:	
Oil	75%
NGL	11%
Gas	14%

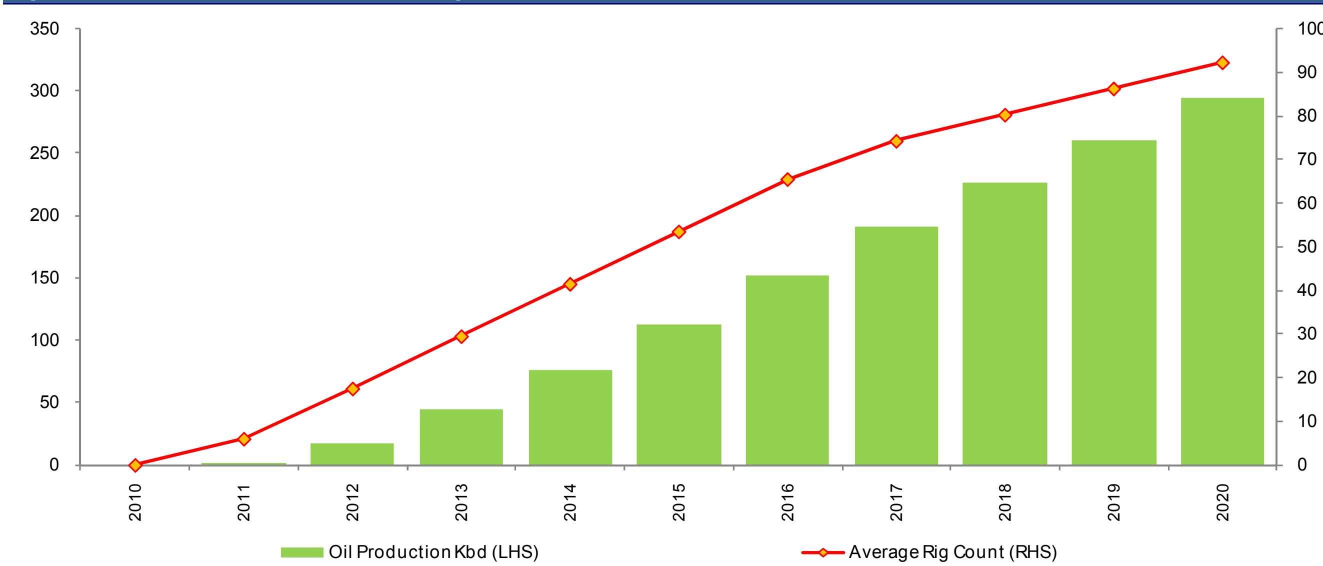
Source: USGS, Ohio DNR, Baker Hughes, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 72: Assumed Utica Shale type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 73: Utica Shale production and rig count estimate



Source: USGS, Baker Hughes, Ohio DNR, EIA, Company data, Wood Mackenzie, Deutsche Bank estimates

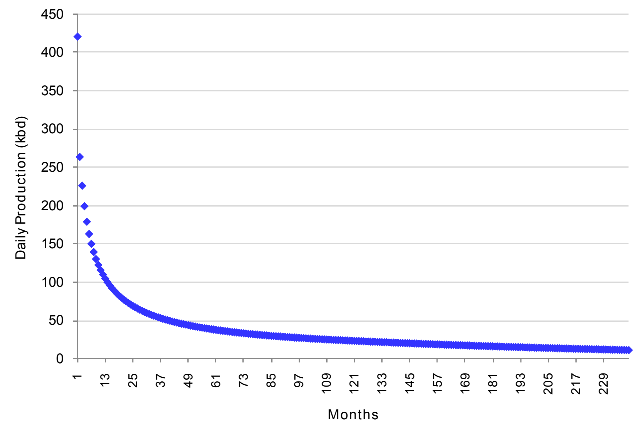
Uinta Basin

Figure 74: Uinta Basin assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	620
Typical EUR (Kbbls)	280
30 day IP (bbl/d)	420
Initial Decline Rate	33%
Terminal Decline Rate	7%
Avg Drilling Time (days)	30
Typical Well Spacing (acres)	320
Current Rig Count	24
Peak Rig Count	52
Avg. Stream Composition:	
Oil	85%
NGL	0%
Gas	15%

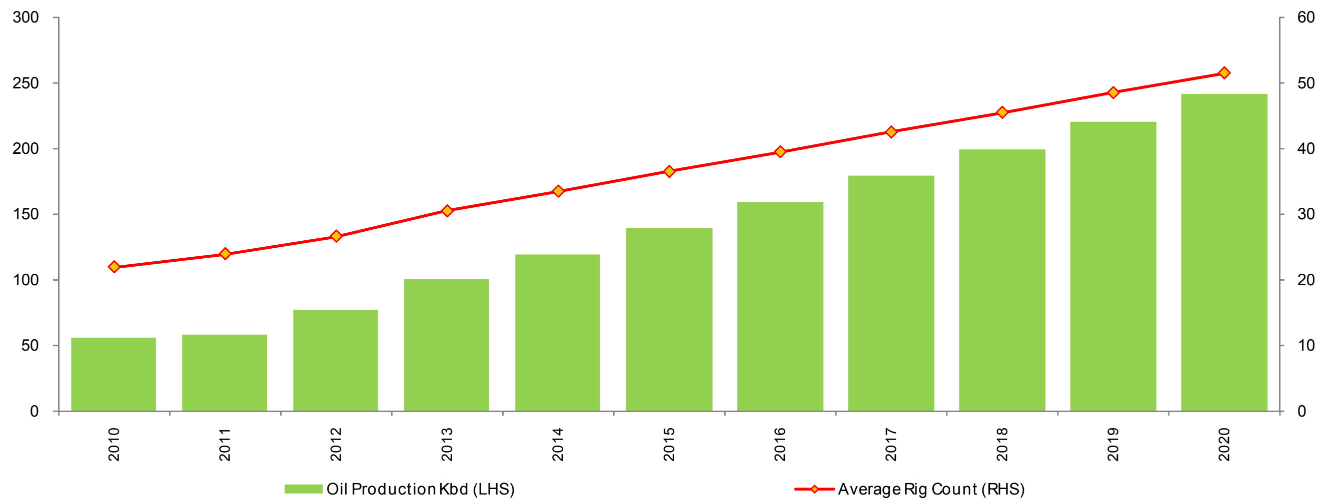
Source: USGS, Baker Hughes, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 75: Assumed Uinta Basin type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 76: Uinta Basin production and rig count estimate



Source: USGS, Baker Hughes, EIA, Company data, Wood Mackenzie, Deutsche Bank estimates

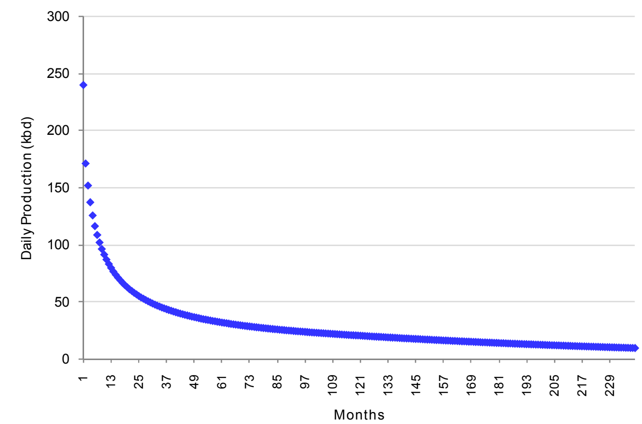
Mississippi Lime

Figure 77: Mississippian assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	446
Typical EUR (Kbbls)	340
30 day IP (bbl/d)	240
Initial Decline Rate	22%
Terminal Decline Rate	7%
Avg Drilling Time (days)	30
Typical Well Spacing (acres)	160
Current Rig Count	24
Peak Rig Count	110
Avg. Stream Composition:	
Oil	55%
NGL	0%
Gas	45%

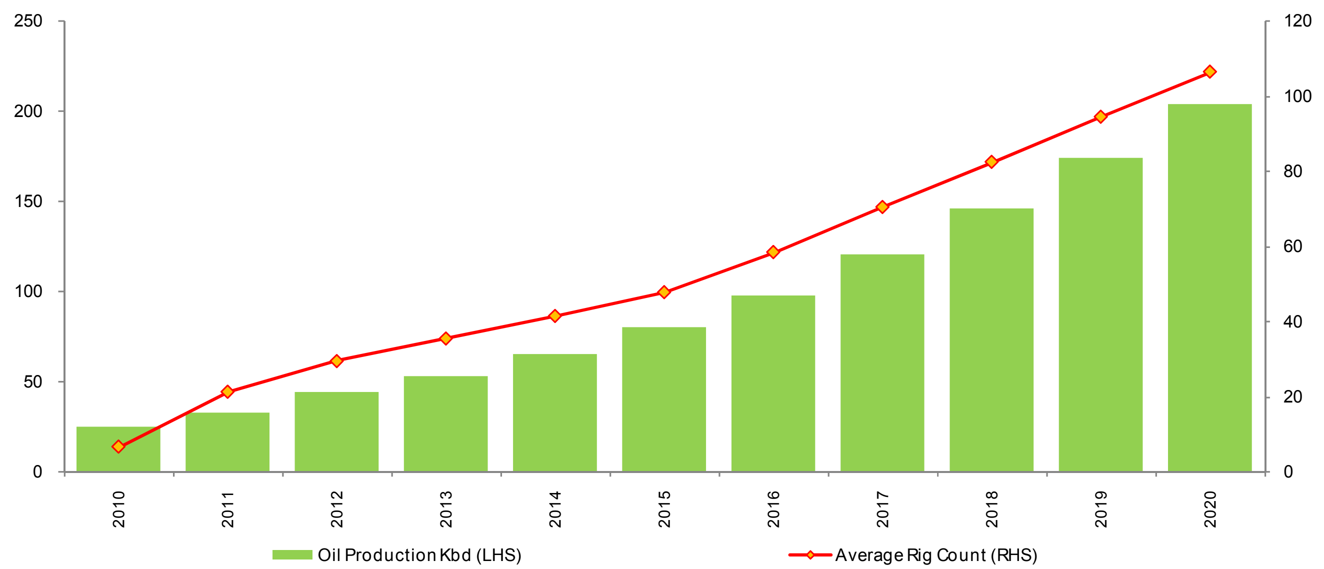
Source: USGS, Baker Hughes, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 78: Assumed Mississippian type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 79: Mississippian production and rig count estimate



Source: USGS, Baker Hughes, EIA, Company data, Wood Mackenzie, Deutsche Bank estimates

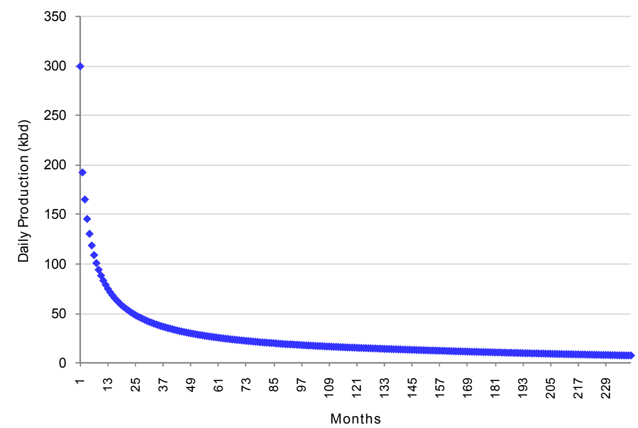
Monterey/California Shale

Figure 80: Monterey Shale assumptions

Assumptions	
Implied 10 year cumulative recovery (Mbbl)	450
Typical EUR (Kbbls)	150
30 day IP (bbl/d)	300
Initial Decline Rate	30%
Terminal Decline Rate	7%
Avg Drilling Time (days)	40
Typical Well Spacing (acres)	10
Current Rig Count	20
Peak Rig Count	76
Avg. Stream Composition:	
Oil	85%
NGL	0%
Gas	15%

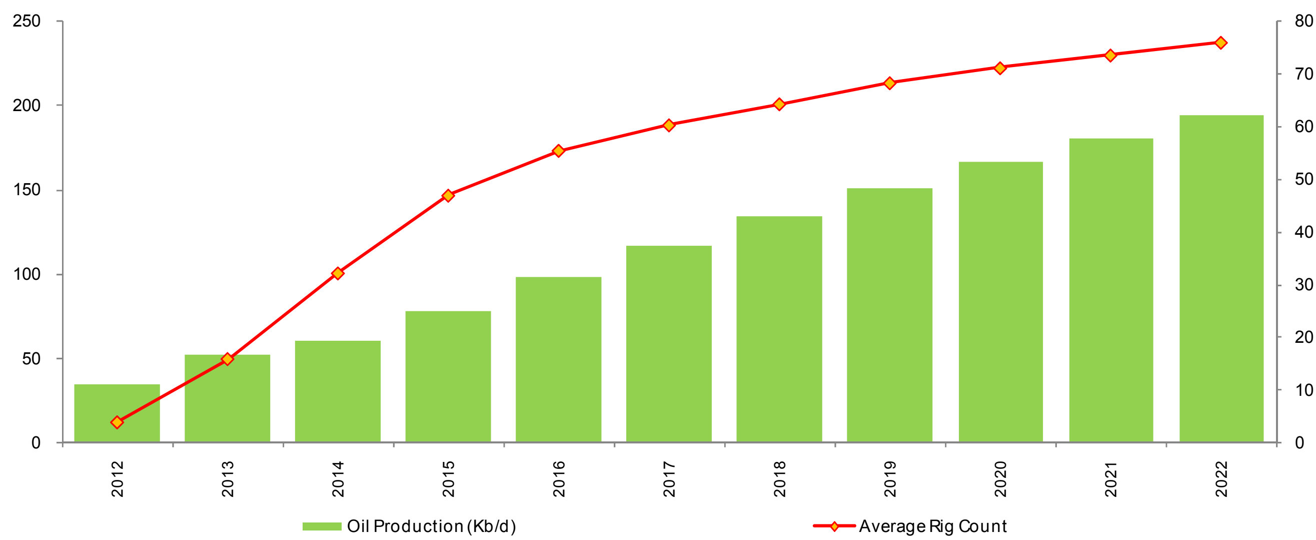
Source: USGS, Baker Hughes, Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 81: Assumed Monterey Shale type curve



Source: Company data, Wood Mackenzie, Deutsche Bank estimates

Figure 82: Monterey Shale production and rig count estimate



Source: USGS, Baker Hughes, EIA, Company data, Wood Mackenzie, Deutsche Bank estimates

Appendix – Oil sands project queue

Figure 83: Canadian oil sands announced project queue, by year, 2011 to 2015

Operator	Project/Phase	Method	Gross Capacity (kbd)	Start Up Q	Start Up Y	Total Capacity Add
Black Pearl Resources	Blackrod Pilot	SAGD	0.5	2Q	2011	
Laricina	Saleski Pilot	SAGD	1.8	2Q	2011	
Cenovus	Christina Lake Phase C	SAGD	40	3Q	2011	
Cenovus	Grand Rapids Pilot	SAGD	0.6	3Q	2011	
Devon	Jackfish 2	SAGD	35	3Q	2011	
Suncor	Firebag 3	SAGD	62.5	3Q	2011	**141**
Husky Energy	McMullen Air Injection Pilot	AIP	0.8	1Q	2012	
N-SOLV	Dover Demonstration	N-Solv	0.5	2Q	2012	
Pengrowth Energy	Lindbergh Pilot	SAGD	1.2	2Q	2012	
Southern Pacific	STP-McKay Thermal Phase 1	SAGD	12	3Q	2012	
Alberta Oil Sands	Clearwater West Phase I	SLP-SAGD	4.35	4Q	2012	
Cenovus	Christina Lake Phase D	SAGD	40	4Q	2012	
Imperial	Kearl Phase 1	Mining	110	4Q	2012	
Laricina	Germain Phase 1	SC-SAGD	5	4Q	2012	
Canadian Natural Resources	Horizon Phase 1 Tranche 2	Mining	5		2012	
KNOC	Black Gold Phase I	SAGD	10		2012	
Suncor	North Steepbank Extension	Mining			2012	
Value Creation	Terre de Grace TriStar Pilot Project	SAGD	1		2012	**195**
Canadian Natural Resources	Kirby South Phase 1	SAGD	45	2Q	2013	
Grizzly Oil Sands	Algar Lake Phase 1	SAGD	5.7	3Q	2013	
Cenovus	Christina Lake Phase E	SAGD	40		2013	
Connacher	Hangingstone Halfway Creek	SAGD	10		2013	
Ivanhoe Energy	Tamarack Phase 1	SAGD-HTL	20		2013	
MEG Energy	Christina Lake Phase 2B	SAGD	35		2013	
Oak Point Energy	Lewis Pilot	SAGD	1.7		2013	
Petrobank Energy	May River Phase 1	THAI	10		2013	
Statoil	Kai Kos Dehseh - Leismer Expansion Hub	SAGD	40		2013	
Suncor	Firebag 4	SAGD	62.5		2013	**275**
Laricina	Saleski Phase 1	SAGD	10.7	1Q	2014	
Harvest Energy	Blackgold Phase 1	SAGD	10	2Q	2014	
Athabasca Oil Sands	Hangingstone Project 1	SAGD	12		2014	
Athabasca Oil Sands	Dover West Leduc Carbonates Pilot	SAGD	12		2014	
Athabasca Oil Sands	Hangingstone East Halfway Creek Explo	SAGD	10		2014	
Black Pearl Resources	Onion Lake Thermal	SAGD	10		2014	
Canadian Natural Resources	Horizon Phase 2A	Mining	10		2014	
Cenovus	Foster Creek Phase F	SAGD	45		2014	
Connacher	Algar Expansion	SAGD	24		2014	
E-T Energy	Poplar Creek Project Phase 1	ET-DSP	10		2014	
Grizzly Oil Sands	Algar Lake Phase 2	SAGD	5.7		2014	
Husky Energy	Sunrise Phase 1	SAGD	60		2014	
Koch Exploration Canada	Gemini	SAGD	10		2014	
Osum Oil Sands	Taiga Phase 1	SAGD	17.5		2014	
Pengrowth Energy	Lindbergh Phase I	SAGD	12.5		2014	
PetroChina	MacKay Phase 1	SAGD	35		2014	
Shell	AOSP Jackpine Mine Phase 1B	Mining	100		2014	
Statoil	Kai Kos Dehseh - Leismer Commercial Hub	SAGD	20		2014	**414**
Devon	Jackfish 3	SAGD	35	1Q	2015	
Imperial	Cold Lake Phases 14-16, Nabiye	CSS	40	1Q	2015	
Laricina	Germain Phase 2	SC-SAGD	30	1Q	2015	
Southern Pacific	STP-McKay Thermal Phase 2A	SAGD	12	4Q	2015	
Athabasca Oil Sands	Dover Phase 1	SAGD	50		2015	
Athabasca Oil Sands	Dover West Clastics Project 1	SAGD	12		2015	
Canadian Natural Resources	Horizon Phase 2B	Mining	45		2015	
Cenovus	Foster Creek Phase G	SAGD	40		2015	
ConocoPhillips	Surmont Phase 2	SAGD	109		2015	
Grizzly Oil Sands	Thickwood Hills Phase 1 and 2	SAGD	10		2015	
Harvest Energy	Blackgold Phase 2	SAGD	20		2015	
Japan Canada Oil Sands	Hangingstone Phase 1	SAGD	35		2015	
KNOC	Black Gold Phase II	SAGD	20		2015	
Shell	Peace River Carmen Creek Phase 1	SAGD	40		2015	**508**

Source: Company data and presentations, Oil Sands Developer Group, Oil Sands Review, Alberta Oil Magazine, Upstream, CAPP, various news sources, Deutsche Bank

Figure 84: Canadian oil sands announced project queue, by year, 2016 to 2020

Operator	Project/Phase	Method	Capacity (kbd)	Q	Y	Capacity Add
Alberta Oil Sands	Clearwater West Phase II	SLP-SAGD	25		2016	
Alberta Oil Sands	Hangingstone	SAGD	25		2016	
Black Pearl Resources	Blackrod Phase 1	SAGD	20		2016	
Canadian Natural Resources	Kirby North Phase 1	SAGD	50		2016	
Cenovus	Narrows Lake Phase 1	SAGD	50		2016	
Cenovus	Christina Lake Phase F	SAGD	40		2016	
Cenovus	Foster Creek Phase H	SAGD	40		2016	
Devon	Pike Phase 1A	SAGD	35		2016	
Husky Energy	Sunrise Phase 2	SAGD	50		2016	
Marathon	Birchwood	SAGD	15		2016	
MEG Energy	Christina Lake Phase 3A	SAGD	50		2016	
Osum Oil Sands	Taiga Phase 2	SAGD	17.5		2016	
Southern Pacific	STP-McKay Thermal Phase 2B	SAGD	12		2016	
Statoil	Kai Kos Dehseh - Corner	SAGD	40		2016	
Suncor	Fort Hills Phase 1	Mining	145		2016	
Suncor	MacKay River 2	SAGD	40		2016	**665**
Alberta Oil Sands	Grand Rapids	SAGD	10		2017	
Athabasca Oil Sands	Hangingstone Project 2	SAGD	25		2017	
Black Pearl Resources	Blackrod Phase 2	SAGD	30		2017	
Canadian Natural Resources	Horizon Phase 3	Mining	80		2017	
Canadian Natural Resources	Grouse	SAGD	40		2017	
Cenovus	Grand Rapids Phase A	SAGD	60		2017	
Cenovus	Foster Creek Phase I	SAGD	45		2017	
Cenovus	Christina Lake Phase G	SAGD	40		2017	
Devon	Pike Phase 1B	SAGD	35		2017	
Devon	Pike Phase 1C	SAGD	35		2017	
Grizzly Oil Sands	Silvertip Phase 1 & 2	SAGD	10		2017	
Grizzly Oil Sands	Algar Lake Phase 3	SAGD	5		2017	
Laricina	Germain Phase 3	SC-SAGD	60		2017	
Laricina	Saleski Phase 2	SAGD	50		2017	
PetroChina	MacKay Phase 2	SAGD	40		2017	
Total	Joslyn Mine North Phases 1/2	Mining	100		2017	**685**
Alberta Oil Sands	Algar Lake	SAGD	25		2018	
Athabasca Oil Sands	Dover West Clastics Project 2	SAGD	42.5		2018	
Grizzly Oil Sands	Ells North Phase 1 & 2	SAGD	4		2018	
Husky Energy	Caribou Demonstration	SAGD	10		2018	
MEG Energy	Christina Lake Phase 3B	SAGD	50		2018	
MEG Energy	Surmont Phase 1	SAGD	50		2018	
Shell	AOSP Pierre River Mine Phase 1	Mining	100		2018	
Suncor	Firebag 5	SAGD	62.5		2018	**384**
Athabasca Oil Sands	Hangingstone Project 3	SAGD	25		2019	
Black Pearl Resources	Blackrod Phase 3	SAGD	30		2019	
Canadian Natural Resources	Kirby North Phase 2	SAGD	30		2019	
Cenovus	Christina Lake Phase H	SAGD	40		2019	
Grizzly Oil Sands	Kodiak Phae 1 & 2	SAGD	10		2019	
PetroChina	MacKay Phase 3	SAGD	40		2019	
Suncor	Firebag 6	SAGD	62.5		2019	**238**
Canadian Natural Resources	Leismer Phase 1	SAGD	30		2020	
Canadian Natural Resources	Kirby South Phase 2	SAGD	15		2020	
Grizzly Oil Sands	Silvertip Phase 3 & 4	SAGD	10		2020	
Husky Energy	Sunrise Phase 3	SAGD	50		2020	
Laricina	Saleski Phase 3	SAGD	50		2020	
MEG Energy	Christina Lake Phase 3C	SAGD	50		2020	**225**

Source: Company data and presentations, Oil Sands Developer Group, Oil Sands Review, Alberta Oil Magazine, Upstream, CAPP, various news sources, Deutsche Bank

Appendix 1

Important Disclosures

Additional information available upon request

Disclosure checklist

Company	Ticker	Recent price*	Disclosure
ExxonMobil	XOM.N	87.23 (USD) 27 Feb 12	14,15,17
Chevron	CVX.N	109.63 (USD) 27 Feb 12	7,14,15,17

*Prices are sourced from local exchanges via Reuters, Bloomberg and other vendors. Data is sourced from Deutsche Bank and subject companies

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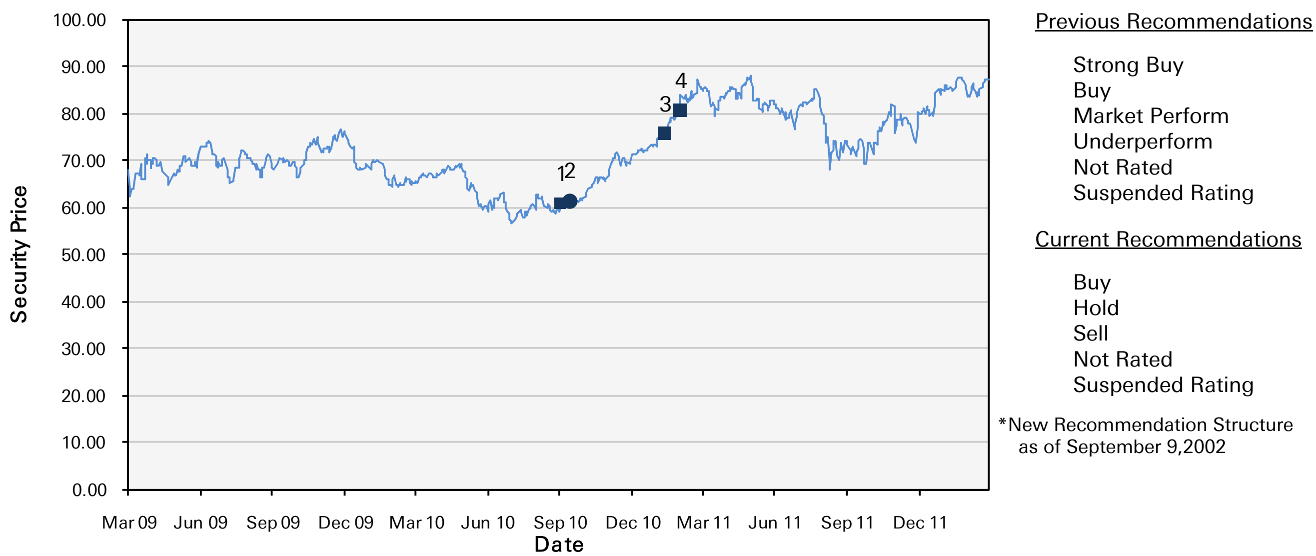
Historical recommendations and target price: ExxonMobil (XOM.N)

(as of 2/27/2012)



1.	09/02/2010:	Buy, Target Price Change USD70.00	3.	01/12/2011:	Hold, Target Price Change USD85.00
2.	09/13/2010:	Downgrade to Hold, Target Price Change USD65.00	4.	02/01/2011:	Hold, Target Price Change USD90.00

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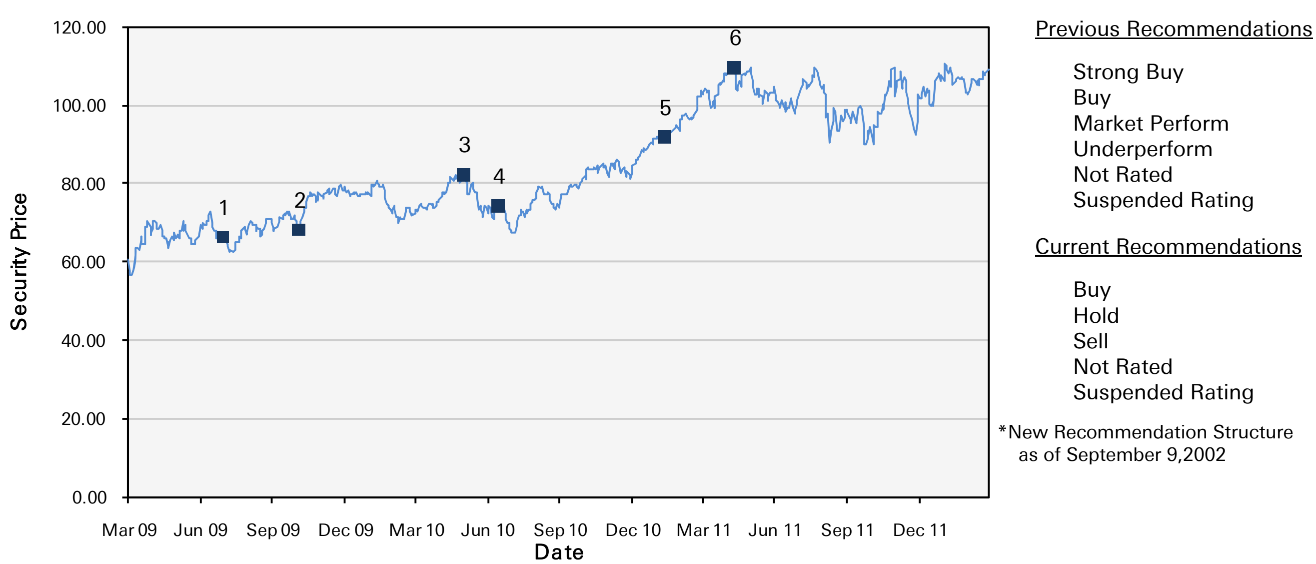
(as of 2/27/2012)



1.	06/30/2009:	Hold, Target Price Change USD72.00	4.	06/15/2010:	Hold, Target Price Change USD80.00
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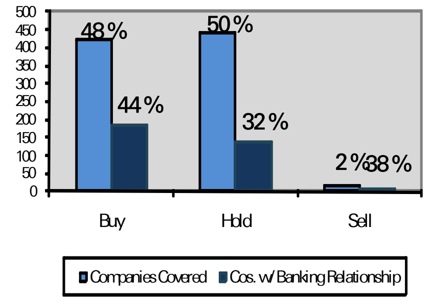

North American Universe

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Deutsche Bank Securities Inc.

North American locations

Deutsche Bank Securities Inc.
60 Wall Street
New York, NY 10005
Tel: (212) 250 2500

Deutsche Bank Securities Inc.
One International Place
12th Floor
Boston, MA 02110
United States of America
Tel: (1) 617 217 6100

Deutsche Bank Securities Inc.
222 South Riverside Plaza
30th Floor
Chicago, IL 60606
Tel: (312) 537-3758

Deutsche Bank Securities Inc.
1735 Market Street
24th Floor
Philadelphia, PA 19103
Tel: (215) 854 1546

Deutsche Bank Securities Inc.
101 California Street
46th Floor
San Francisco, CA 94111
Tel: (415) 617 2800

Deutsche Bank Securities Inc.
700 Louisiana Street
Houston, TX 77002
Tel: (832) 239-4600

International locations

Deutsche Bank Securities Inc.
60 Wall Street
New York, NY 10005
United States of America
Tel: (1) 212 250 2500

Deutsche Bank AG London
1 Great Winchester Street
London EC2N 2EQ
United Kingdom
Tel: (44) 20 7545 8000

Deutsche Bank AG
Große Gallusstraße 10-14
60272 Frankfurt am Main
Germany
Tel: (49) 69 910 00

Deutsche Bank AG
Deutsche Bank Place
Level 16
Corner of Hunter & Phillip Streets
Sydney, NSW 2000
Australia
Tel: (61) 2 8258 1234

Deutsche Bank AG
Filiale Hongkong
International Commerce Centre,
1 Austin Road West,Kowloon,
Hong Kong
Tel: (852) 2203 8888

Deutsche Securities Inc.
2-11-1 Nagatacho
Sanno Park Tower
Chiyoda-ku, Tokyo 100-6171
Japan
Tel: (81) 3 5156 6770

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